STEPTOE & JOHNSON LLP

ATTORNEYS AT LAW

Gary A. Morgans
202.429.6234
gmorgans@steptoe.com

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
Tel 202.429.3000
Fax 202.429.3902
steptoe.com

May 24, 2012

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER12-91-000, *et al.*

Dear Ms. Bose:

Pursuant to the Commission's April 24, 2012 "Order on Proposed Tariff Revisions and Establishing Hearing and Settlement Judge Procedures" in Docket Nos. ER12-91-000 *et al.*,[1] Duke Energy Ohio, Inc. ("Duke Energy Ohio"), Duke Energy Kentucky, Inc., ("Duke Energy Kentucky") (together, "the Companies") and PJM Interconnection, L.L.C. ("PJM") hereby submit the enclosed compliance filing.[2] Additionally, the Companies and PJM file herewith a refund report in accordance with Ordering Paragraph C of the Order.

[1] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,068 (2012) ("Order").

[2] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of the Companies as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, the Companies have requested PJM to submit this filing in the eTariff system as part of PJM's electronic Intra PJM Tariff.

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## I. DESCRIPTION OF THE COMPLIANCE FILING

The Commission required the Companies to modify PJM's Open Access Transmission Tariff ("PJM OATT") in this proceeding in the following respects:

1. Include in the PJM OATT the provisions from the Settlement Agreement ("Settlement Agreement") between the Companies and Indiana Municipal Power Agency ("IMPA") that provide for the PJM Regional Transmission Expansion Plan ("RTEP") credit and cap mechanism of the Settlement Agreement. Order at P 49.
2. Revise Schedule 1A, Part B of the PJM OATT to provide that any change to this rate must be made as a tariff filing under Section 205 of the Federal Power Act ("FPA"). Order at P 60.
3. Revise Attachment H-22B to make the changes identified in Appendix B to the Companies' November 21, 2011 answer to the parties' protests. Order at P 63.
4. Revise Attachment H-22A to make the changes discussed in the Companies' November 21, 2011 answer to the parties' protests. Order at P 61.
5. Revise the PJM OATT to exclude Legacy Midwest ISO Transmission Expansion Plan ("MTEP") and Transition Costs from the Companies' formula rates. Order at P 76.

The Companies have complied with these requirements by making the following changes to their filing:

1. The Companies have added a new Attachment H-22C to the PJM OATT, which contains the provisions of the Settlement Agreement that provide for the PJM RTEP credit and cap mechanism, including the provisions outlining the parties' obligations as a result of the credit and cap mechanism. The Companies made minor modifications to the incorporated provisions (e.g., adding necessary defined terms) in order to make the provisions operate properly as tariff provisions. In order to assist the Commission in its review of Attachment H-22C, the Companies are including a redlined version of Attachment H-22C, comparing the

Attachment to the Settlement Agreement (attached as Appendix C). The Companies have also revised Attachment H-22 to state that the Companies and IMPA are subject to the provisions of Attachment H-22C.

2. The Companies have footnoted the Companies' percentage share in PJM OATT Schedule 1A, Part B indicating that a Section 205 filing is necessary to change this share. While the Commission's order refers to a "rate," the Companies believe that the Commission intended to refer to the Companies' percentage share, as that was the change that the Companies made in submitting the filing as well as the focus of the Commission's order on this matter.
3. The Companies have included in PJM OATT Attachment H-22A the changes discussed in their November 21, 2011 answer in this proceeding.
4. The Companies have included in PJM OATT Attachment H-22B the changes included in Appendix B to their November 21, 2011 answer in this proceeding.
5. The Companies have modified PJM OATT Attachment JJ by deleting the provisions providing for the recovery of MTEP Legacy Costs from Network Customers in the DEOK Zone and for PJM's remittance of such payments to the Midwest ISO. The Companies have also deleted the following provisions from PJM OATT Attachment H-22A:

   - Page 3, line 1c (Midwest ISO Fees).
   - Page 3, line 3d (PJM Integration Costs).

Appendix A to this compliance filing contains a marked version of the Tariff revisions described above, and Appendix B contains a clean version of the Tariff revisions described above. PJM also has included a marked and clean version, in Appendices A and B respectively, of modifications to Tariff Section 1, Definitions O-P-Q, as well as Tariff Attachment DD. These modifications are necessary to remove language that had been shown in italics in the October 14, 2011 filing in this proceeding to reflect then-pending language in another proceeding (Docket No. ER11-4628-000).

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While that language was accepted by the Commission in Docket No. ER11-4628-000, the Commission set a later effective date than what was established in this proceeding. Thus, PJM is removing that italicized language herein. PJM requests that the Commission accept these revisions effective January 1, 2012.

## II. REFUND REPORT

In accordance with the Ordering Paragraph C of the Order, PJM and the Companies are submitting a refund report contained in Appendix D, covering January-April, 2012. The refund report reflects removal of the Legacy MTEP and Transition Costs from the Companies' formula rate.[3] As shown in Appendix D, PJM will refund a total of $33,732.62, inclusive of interest, for Network Integration Transmission Service. PJM will refund a total of $50,922.07, inclusive of interest, for the MTEP Legacy project cost.

## III. SERVICE

The Companies' submission of this compliance filing is without prejudice to the Companies' right to seek rehearing and/or a court appeal of the Order, and to surcharge their customers for any amounts due to the Companies as a result of any modifications to the Order as a result of such rehearing and/or court appeal.

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. PJM also

[3] Order at P 76.

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has served the parties listed on the Commission's official service list for Docket Nos. ER10-1562, ER12-91 and ER12-92.

In accordance with the Commission's regulations,[4] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM and is available by following such link.[5] If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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[4] 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

[5] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected commissions.

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Respectfully submitted,

/s/ Gary A. Morgans

Gary A. Morgans
Steptoe & Johnson LLP
1330 Connecticut Avenue, NW
Washington, DC 20036

Paul R. Kinny
Associate General Counsel
Duke Energy Corporation
550 South Tryon Street
Mail Code DEC45A
Charlotte, NC 28202

*Attorneys for Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.*

*On behalf of PJM Interconnection, L.L.C., Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.*

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that I have this day caused the foregoing document to be served via electronic mail upon each party designated on the official service list in these proceedings.

Dated at Washington, D.C. this 24th day of May, 2012.

______/s/________________

Jennifer Tribulski

# Appendix A

## Sections of the PJM Open Access Transmission Tariff

## (Redlined Version)

**Definitions – O – P - Q**

**1.27C Office of the Interconnection:**

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.

**1.28 Open Access Same-Time Information System (OASIS):**

The information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

**1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:**

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

**1.28A.01 Option to Build:**

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

**1.28B Optional Interconnection Study:**

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

**1.28C Optional Interconnection Study Agreement:**

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

**1.29 Part I:**

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

**1.30 Part II:**

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31 Part III:**

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31A Part IV:**

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31B Part V:**

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31C Part VI:**

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.32 Parties:**

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

**1.32.01 PJM:**

PJM Interconnection, L.L.C.

**1.32A PJM Administrative Service:**

The services provided by PJM pursuant to Schedule 9 of this Tariff.

**1.32B PJM Control Area:**

The Control Area that is recognized by NERC as the PJM Control Area.

**1.32C PJM Interchange Energy Market:**

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

**1.32D PJM Manuals:**

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

**1.32E PJM Region:**

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

**1.32F PJM South Region:**

The VACAR Control Zone.

**1.32.F.01 PJMSettlement:**

PJM Settlement, Inc. (or its successor).

**1.32G PJM West Region:**

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; the Duquesne Light Company, American Transmission Systems, Incorporated, and Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

**1.33 Point(s) of Delivery:**

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**1.33A Point of Interconnection:**

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

**1.34 Point(s) of Receipt:**

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**1.35 Point-To-Point Transmission Service:**

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

**1.36 Power Purchaser:**

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

~~***1.36.01 PRD Curve***~~

~~*PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.*~~

~~***1.36.02 PRD Provider***~~

~~*PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.*~~

~~***1.36.03 PRD Reservation Price***~~

~~*PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.*~~

~~***1.36.04 PRD Substation:***~~

~~*PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.*~~

**1.36.~~*05*~~01 Pre-Confirmed Application:**

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

**1.36A Pre-Expansion PJM Zones:**

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

~~***1.36A.01 Price Responsive Demand***~~

~~*Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.*~~

**1.36A.~~02~~01 Project Financing:**

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

**1.36A.~~03~~02 Project Finance Entity:**

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

**1.36B Queue Position:**

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

## SCHEDULE 1A
## Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

| Zone | Rate ($/MWh) |
|---|---|
| Atlantic City Electric Company | 0.0781 |
| Baltimore Gas and Electric Company | 0.0430 |
| Delmarva Power & Light Company | 0.0743 |
| PECO Energy Company | 0.1189 |
| PP&L, Inc. Group | 0.0618 |
| Potomac Electric Power Company | 0.0186 |
| Public Service Electric and Gas Company | 0.1030 |
| Jersey Central Power & Light Company | 0.0796 |
| Metropolitan Edison Company | 0.0796 |
| Pennsylvania Electric Company | 0.0796 |
| Rockland Electric Company | 0.2475 |
| Commonwealth Edison Company | 0.2223 |
| AEP East Operating Companies | Rate updated annually Per Attachment H-14 |
| The Dayton Power and Light Company | 0.0797 |
| Duquesne Light Company[1] | 0.0520 |
| American Transmission Systems, Incorporated ("ATSI") | Rate updated annually Per Attachment H-21 |
| Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK") | Rate updated annually Per Attachment H-22 |

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$0.1019/MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

| **Transmission Owner** | **Share (%)** |
|---|---|
| Atlantic City Electric Company | 0.50 |
| Baltimore Gas and Electric Company | 0.80 |
| Delmarva Power & Light Company | 0.77 |
| PECO Energy Company | 2.68 |
| PP&L, Inc. Group | 1.36 |
| Potomac Electric Power Company | 0.33 |
| Public Service Electric and Gas Company | 2.64 |
| Jersey Central Power & Light Company | 1.30 |
| Metropolitan Edison Company | 0.43 |
| Pennsylvania Electric Company | 0.66 |
| Rockland Electric Company | 0.20 |
| Commonwealth Edison Company | 37.62 |
| AEP East Operating Companies | 47.90 |
| The Dayton Power and Light Company | 2.36 |
| Duquesne Light Company | 0.45 |
| American Transmission Systems, Incorporated ("ATSI") | 0.00 |
| Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK") | ~~0.00~~0.00[2] |

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

**ATTACHMENT H-22**
**Annual Transmission Rates – DEOK**
**for Network Integration Transmission Service**
**and Point-to-Point Transmission Service**

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are equal to the results of the formula shown in Attachment H-22A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (jointly, "DEOK"). Service utilizing other DEOK facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate in this attachment shall be effective until amended by DEOK or modified by the Commission.

3. In addition to the rate set forth in paragraph 1, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse DEOK for any amounts payable by it as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

4. DEOK and Indiana Municipal Power Agency shall be subject to the additional provisions of Attachment H-22C.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

**Rate Formula Template**
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | | | Total | | Allocator | Allocated Amount |
|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 29) | | | | | $ - |
| | REVENUE CREDITS (Note T) | | Total | | Allocator | |
| 2 | Account No. 454 | (page 4, line 34) | $ - | TP | 0.00000 | $ - |
| 3 | Account No. 456.1 | (page 4, line 35) | 0 | TP | 0.00000 | 0 |
| 4a | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.00000 | 0 |
| 4b | Revenues from service provided by ISO at a discount | | 0 | TP | 0.00000 | 0 |
| 5a | Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12) | | 0 | | 1.00000 | 0 |
| ~~5b~~ | ~~RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)~~ | | ~~0~~ | | ~~1.00000~~ | ~~0~~ |
| 5b~~c~~ | Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3) | | 0 | | 1.00000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5c) | | | | | $ - |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | | $ - |
| | DIVISOR | | | | | |
| 8 | 1 CP (Note A) | | | | | 0 |
| 9 | 12 CP (Note B) | | | | | 0 |
| 10 | Reserved | | | | | |
| 11 | Reserved | | | | | |
| 12 | Reserved | | | | | |
| 13 | Reserved | | | | | |
| 14 | Reserved | | | | | |
| 15 | Annual Cost ($/kW/Yr) - 1 CP | (line 7 / line 8) | $0.000 | | | |
| 16 | Annual Cost ($/kW/Yr) - 12 CP | (line 7 / line 9) | $0.000 | | | |
| 17 | Network Rate ($/kW/Mo) | (line 15 / 12) | $0.000 | | | |
| 17a | Point-To-Point Rate ($/kW/Mo) | (line 16 / 12) | $0.000 | | | |
| | | | Peak Rate | | | Off-Peak Rate |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16 / 52) | $0.000 | | | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16 / 260; line 16 / 365) | $0.000 | Capped at weekly rate | | $0.000 |
| 20 | Point-To-Point Rate ($/MWh) | (line 16 / 4,160; line 16 / 8,760 * 1000) | $0.000 | Capped at weekly and daily rate | | $0.000 |

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | (1) RATE BASE: | (2) Form No. 1 Page, Line, Col. | (3) Company Total | | (4) Allocator | (5) Transmission (Col. 3 times Col. 4) |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | |
| 1 | Production | 205.46.g | $ - | NA | | |
| 2 | Transmission | 207.58.g | 0 | TP | 0.00000 | $ - |
| 3 | Distribution | 207.75.g | 0 | NA | | |
| 4 | General & Intangible | 205.5.g & 207.99.g | 0 | W/S | 0.00000 | 0 |
| 5 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | $ - | GP= | 0.000% | $ - |
| | ACCUMULATED DEPRECIATION | | | | | |
| 7 | Production | 219.20-24.c | $ - | NA | | |
| 8 | Transmission | 219.25.c | 0 | TP | 0.00000 | $ - |
| 9 | Distribution | 219.26.c | 0 | NA | | |
| 10 | General & Intangible | 219.28.c | 0 | W/S | 0.00000 | 0 |
| 11 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | $ - | | | $ - |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | $ - | | | |
| 14 | Transmission | (line 2 - line 8) | 0 | | | $ - |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | $ - | NP= | 0.000% | $ - |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | 273.8.k | $ - | NA | zero | $ - |
| 20 | Account No. 282 (enter negative) | 275.2.k | 0 | NP | 0.00000 | 0 |
| 21 | Account No. 283 (enter negative) | 277.9.k | 0 | NP | 0.00000 | 0 |
| 22 | Account No. 190 | 234.8.c | 0 | NP | 0.00000 | 0 |
| 23 | Account No. 255 (enter negative) | 267.8.h | 0 | NP | 0.00000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19- 23) | | $ - | | | $ - |
| 25 | LAND HELD FOR FUTURE USE (Note G) | 214.x.d | $ - | TP | 0.00000 | $ - |
| | WORKING CAPITAL (Note H) | | | | | |
| 26 | CWC | calculated | $ - | | | 0 |
| 27 | Materials & Supplies (Note G) | 227.8.c & .16.c | 0 | TE | 0.00000 | 0 |
| 28 | Prepayments (Account 165) | 111.57.c | 0 | GP | 0.00000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | $ - | | | $ - |
| 30 | RATE BASE (sum lines 18, 24, 25, & 29) | | $ - | | | $ - |

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | (1) RATE BASE | (2) Form No. 1 Page, Line, Col. | (3) Company Total | | (4) Allocator | (5) Transmission (Col. 3 times Col. 4) |
|---|---|---|---|---|---|---|
| | O&M | | | | | |
| 1 | Transmission | 321.112.b | $ - | TE | 0.00000 | $ - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 321.88.b, 92.b; 322.121.b | 0 | | 1.00000 | 0 |
| 1b | Less Midwest ISO Fees included in Transmission O&M | (Note X) | 0 | TE | 0.00000 | 0 |
| ~~1c~~ | ~~Plus Midwest ISO Fees~~ | ~~(Note X)~~ | ~~0~~ | | ~~1.00000~~ | ~~0~~ |
| 2 | Less Account 565 | 321.96.b | 0 | TE | 0.00000 | 0 |
| 3 | A&G | 323.197.b | 0 | W/S | 0.00000 | 0 |
| 3a | Less Actual PBOP Expense | (Note E) | 0 | W/S | 0.00000 | 0 |
| 3b | Plus Fixed PBOP Expense | (Note E) | 0 | W/S | 0.00000 | 0 |
| 3c | Less PJM integration Costs included in A&G | (Note Y) | 0 | W/S | 0.00000 | 0 |
| ~~3d~~ | ~~Plus PJM Integration Costs~~ | ~~(Note Y)~~ | ~~0~~ | | ~~1.00000~~ | ~~0~~ |
| 4 | Less FERC Annual Fees | 350.14.b | 0 | W/S | 0.00000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I) | | 0 | W/S | 0.00000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | | 0 | TE | 0.00000 | 0 |
| 6 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 7 | Transmission Lease Payments | | 0 | | 1.00000 | 0 |
| 8 | TOTAL O&M (Sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | | $ - | | | $ - |
| | DEPRECIATION EXPENSE | | | | | |
| 9 | Transmission | 336.7.b | $ - | TP | 0.00000 | $ - |
| 10 | General | 336.10.b | 0 | W/S | 0.00000 | 0 |
| 11 | Common | 336.11.b | 0 | CE | 0.00000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | | $ - | | | $ - |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | 263.i | $ - | W/S | 0.00000 | $ - |
| 14 | Highway and vehicle | 263.i | 0 | W/S | 0.00000 | 0 |
| 15 | PLANT RELATED | | | | | |
| 16 | Property | 263.i | 0 | GP | 0.00000 | 0 |
| 17 | Gross Receipts | 263.i | 0 | NA | zero | 0 |
| 18 | Other | 263.i | 0 | GP | 0.00000 | 0 |
| 19 | Payments in lieu of taxes | | 0 | GP | 0.00000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | | $ - | | | $ - |
| | INCOME TAXES (Note K) | | | | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.000000% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.000000% | | | |
| | where WCLTD=(page 4, line 27) and R= (page 4, line 30) | | | | | |
| | and FIT, SIT & p are as given in footnote K. | | | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit | 266.8.f (enter negative) | 0 | | | |
| 25 | Income Tax Calculation (line 22 * line 28) | | $ - | NA | | $ - |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.00000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | $ - | | | $ - |

| | | | | |
|---|---|---|---|---|
| 28 | RETURN<br>[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)] | $ - | NA | $ - |
| 29 | REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28) | $ - | | $ - |

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)
SUPPORTING CALCULATIONS AND NOTES

| Line No. | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | | | | | $ - | | |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | | | | 0 | | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N) | | | | | | 0 | | |
| 4 | Transmission plant included in ISO Rates (line 1 less lines 2 & 3) | | | | | | $ - | | |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | | | | | TP= | 0.00000 | | |
| | **TRANSMISSION EXPENSES** | | | | | | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | | | | $ - | | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | | | | 0 | | |
| 8 | Included transmission expenses (line 6 less line 7) | | | | | | $ - | | |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | | | | 0.00000 | | |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | | | TP | 0.00000 | | |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | | | | | TE= | 0.00000 | | |
| | **WAGES & SALARY ALLOCATOR (W&S)** | | | | | | | | |
| | | Form 1 Reference | $ | TP | Allocation | | | | |
| 12 | Production | 354.20.b | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 354.21.b | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 354.23.b | 0 | 0.00 | 0 | | W&S Allocator | | |
| 15 | Other | 354.24,25,26.b | 0 | 0.00 | 0 | | ($ / Allocation) | | |
| 16 | Total (sum lines 12-15) | | 0 | | 0 | = | 0.00000 | = | WS |
| | **COMMON PLANT ALLOCATOR (CE) (Note O)** | | | | | | | | |
| | | | $ | | % Electric | | W&S Allocator | | |
| 17 | Electric | 200.3.c | 0 | | (line 17 / line 20) | | (line 16) | | CE |
| 18 | Gas | 201.3.d | 0 | | 0.00000 | * | 0.00000 | = | 0.00000 |
| 19 | Water | 201.3.e | 0 | | | | | | |
| 20 | Total (sum lines 17 - 19) | | 0 | | | | | | |
| | **RETURN (R)** | | | | | | $ | | |
| 21 | | Long Term Interest (117, sum of 62.c through 67.c) | | | | | 0 | | |
| 22 | | Preferred Dividends (118.29c) (positive number) | | | | | 0 | | |
| | Development of Common Stock: | | | | | | | | |
| 23 | | Proprietary Capital (112.16.c) | | | | | 0 | | |
| 24 | | Less Preferred Stock (line 28) | | | | | 0 | | |
| 25 | | Less Account 216.1 (112.12.c) (enter negative) | | | | | 0 | | |
| 26 | | Common Stock (sum lines 23-25) | | | | | 0 | | |
| | | (Note P) | $ | % | Cost | | Weighted | | |
| 27 | Long Term Debt (112, sum of 18.c through 21.c) | | 0 | 0% | 0.0000 | | 0.0000 | = | WCLTD |
| 28 | Preferred Stock (112.3.c) | | 0 | 0% | 0.0000 | | 0.0000 | | |
| 29 | Common Stock (line 26) | | 0 | 0% | 0.1238 | | 0.0000 | | |
| 30 | Total (sum lines 27-29) | | 0 | | | | 0.0000 | = | R |

**REVENUE CREDITS**

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) (Note Q) | (310-311) | |
| 31 | a. Bundled Non-RQ Sales for Resale (311.x.h) | | 0 |
| 32 | b. Bundled Sales for Resale included in Divisor on page 1 | | - |
| 33 | Total of (a)-(b) | | 0 |
| 34 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $ - |
| 35 | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U) | (330.x.n) | $ - |

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

A DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C Reserved

D Reserved

E This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | |
| | SIT= | 0.00% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Reserved

T The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

U On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.

V Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Reserved

X Midwest ISO Fees include (1) the charges that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.

Y PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

For the 12 months ended 12/31/_____

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

| Line No. | | Source | Revenue Requirement | |
|---|---|---|---|---|
| A. | Schedule 1A Annual Revenue Requirements | | | |
| 1 | Total Load Dispatch & Scheduling (Account 561) | Attachment H-22A, Page 4, Line 7 | $ - | |
| 2 | Revenue Credits for Schedule 1A - Note A | | $ - | |
| 3 | Net Schedule 1A Revenue Requirement for Zone | | $ - | |
| B. | Schedule 1A Rate Calculations | | | |
| 4 | 2010 Annual MWh - Note B | (401a.22b & 24b) | - | MWh |
| 5 | Schedule 1A rate $/MWh (Line 3 / Line 4) | (Line 3 / Line 4) | $0.0000 | $/MWh |

Notes:

A Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of DEOK's zone during the year used to calculate rates under Attachment H-22A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A

| Line No. | (1) | (2)<br>Attachment H-22A Page, Line, Col. | (3)<br>Transmission | (4)<br>Allocator |
|---|---|---|---|---|
| | TRANSMISSION PLANT | | | |
| 1 | Gross Transmission Plant - Total | Sch. H-22A, p 2, line 2 col 5 (Note A) | - | |
| 2 | Net Transmission Plant - Total | Sch. H-22A, p 2, line 14 col 5 (Note B) | - | |
| | O&M EXPENSE | | | |
| 3 | Total O&M Allocated to Transmission | Sch. H-22A, p 3, line 8 col 5 | - | |
| 4 | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | 0.00% | 0.00% |
| | GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| 5 | Total G&C Depreciation Expense | Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H) | - | |
| 6 | Annual Allocation Factor for G&C Depreciation Expense | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| | TAXES OTHER THAN INCOME TAXES | | | |
| 7 | Total Other Taxes | Sch. H-22A, p 3, line 20 col 5 | - | |
| 8 | Annual Allocation Factor for Other Taxes | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| **9** | **Annual Allocation Factor for Expense** | **Sum of lines 4, 6 and 8** | | **0.00%** |
| | INCOME TAXES | | | |
| 10 | Total Income Taxes | Sch. H-22A, p 3, line 27 col 5 | - | |
| 11 | Annual Allocation Factor for Income Taxes | (line 8 divided by line 2 col 3) | 0.00% | 0.00% |
| | RETURN | | | |
| 12 | Return on Rate Base | Sch. H-22A, p 3, line 28 col 5 | - | |
| 13 | Annual Allocation Factor for Return on Rate Base | (line 10 divided by line 2 col 3) | 0.00% | 0.00% |
| **14** | **Annual Allocation Factor for Return** | **Sum of lines 11 and 13** | | **0.00%** |

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

**Network Upgrade Charge Calculation By Project**

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name | RTEP Project Number | Project Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation Expense | Annual Revenue Requirement | True-Up Adjustment | Network Upgrade Charge |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 12) | (Col. 6 * Col. 7) | (Note E) | (Sum Col. 5, 8 & 9) | (Note F) | Sum Col. 10 & 11 (Note G) |
| 1b | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 1c | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 2 | Annual Totals | | | | | | | | | $0 | $0 | $0 |
| 3 | RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c | | | | | | | | | | | $0 |

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A

| Line No. | (1) | (2) Attachment H-22A Page, Line, Col. | (3) Transmission | (4) Allocator |
|---|---|---|---|---|
| | TRANSMISSION PLANT | | | |
| 1 | Gross Transmission Plant - Total | Sch. H-22A, p 2, line 2 col 5 (Note A) | - | |
| 2 | Net Transmission Plant - Total | Sch. H-22A, p 2, line 14 col 5 (Note B) | - | |
| | O&M EXPENSE | | | |
| 3 | Total O&M Allocated to Transmission | Sch. H-22A, p 3, line 8 col 5 | - | |
| 4 | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | 0.00% | 0.00% |
| | GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| 5 | Total G&C Depreciation Expense | Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H) | - | |
| 6 | Annual Allocation Factor for G&C Depreciation Expense | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| | TAXES OTHER THAN INCOME TAXES | | | |
| 7 | Total Other Taxes | Sch. H-22A, p 3, line 20 col 5 | - | |
| 8 | Annual Allocation Factor for Other Taxes | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| **9** | **Annual Allocation Factor for Expense** | **Sum of lines 4, 6 and 8** | | **0.00%** |
| | INCOME TAXES | | | |
| 10 | Total Income Taxes | Sch. H-22A, p 3, line 27 col 5 | - | |
| 11 | Annual Allocation Factor for Income Taxes | (line 8 divided by line 2 col 3) | 0.00% | 0.00% |
| | RETURN | | | |
| 12 | Return on Rate Base | Sch. H-22A, p 3, line 28 col 5 | - | |
| 13 | Annual Allocation Factor for Return on Rate Base | (line 10 divided by line 2 col 3) | 0.00% | 0.00% |
| **14** | **Annual Allocation Factor for Return** | **Sum of lines 11 and 13** | | **0.00%** |

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

**Network Upgrade Charge Calculation By Project**

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name | MTEP Project Number | Project Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation Expense | Annual Revenue Requirement | True-Up Adjustment | Network Upgrade Charge |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 12) | (Col. 6 * Col. 7) | (Note E) | (Sum Col. 5, 8 & 9) | (Note F) | Sum Col. 10 & 11 (Note G) |
| 1b | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 1c | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 2 | Annual Totals | | | | | | | | | $0 | $0 | $0 |
| 3 | Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a | | | | | | | | | | | $0 |

Notes:
- A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
- B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
- C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
- D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
- E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
- F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
- G. The Network Upgrade Charge is the value to be used in Schedule 26.
- H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

| FERC Account Number (A) | Company Account Number (B) | Description (C) | Actual Accrual Rates (D) % |
|---|---|---|---|
| | | **Wholly Owned Transmission Plant** | |
| 350 | 3403 | Rights of Way | 1.54 |
| 352 | 3420 | Structures &  Improvements | 1.90 |
| 352 | 3424 | Structures &  Improvements - Duke Ohio - Loc. in Ky. | 1.90 |
| 353 | 3430 | Station Equipment | 1.44 |
| 353 | 3434 | Station Equipment - Duke Ohio - Loc. in Ky. | 1.44 |
| 354 | 3440 | Towers & Fixtures | 1.85 |
| 354 | 3444 | Towers & Fixtures - Duke Ohio - Loc. in Ky. | 1.85 |
| 355 | 3450 | Poles & Fixtures | 2.31 |
| 355 | 3454 | Poles & Fixtures - Duke Ohio - Loc. in Ky. | 2.31 |
| 356 | 3460 | Overhead Conductors & Devices | 1.91 |
| 356 | 3464 | Overhead Conductors & Devices - Duke Ohio - Loc. in Ky. | 1.91 |
| 357 | 3470 | Underground Conduit | 1.43 |
| 358 | 3480 | Underground Conductors & Devices | 2.37 |
| | | **Commonly Owned Transmission Plant - CCD Projects** | |
| 352 | 3421 | Structures &  Improvements - CCD Projects | 2.50 |
| 352 | 3425 | Structures &  Improvements - CCD Projects | 2.50 |
| 353 | 3431 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3432 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3435 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3437 | Station Equipment - CCD Projects | 1.44 |
| 354 | 3441 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3442 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3445 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3446 | Towers & Fixtures - CCD Projects - Loc. In Ky. | 3.00 |
| 354 | 3448 | Towers & Fixtures - CCD Projects | 3.00 |
| 355 | 3451 | Poles & Fixtures - CCD Projects | 3.00 |
| 355 | 3455 | Poles & Fixtures - CCD Projects | 3.00 |
| 356 | 3461 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3462 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3465 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3466 | Overhead Conductors & Devices - CCD Projects - Loc. In Ky. | 2.50 |
| | | **Commonly Owned Transmission Plant - CD Projects** | |
| 352 | 3423 | Structures &  Improvements - CD Projects | 2.50 |
| 353 | 3433 | Station Equipment - CD Projects | 1.44 |
| 353 | 3438 | Station Equipment - CD Projects | 1.44 |
| 354 | 3447 | Towers & Fixtures - CD Projects | 3.00 |
| 356 | 3467 | Overhead Conductors & Devices - CD Projects | 2.50 |
| | | **General and Intagible Plant** | |
| 303 | 3030 | Miscellaneous Intangible Plant | 20.00 |
| 389 | 3890 | Land and Land Rights | N/A |
| 390 | 3900 | Structures and Improvements | 2.50 |
| 391 | 3910 | Office Furniture and Equipment | 2.00 |
| 391 | 3911 | Electronic Data Processing Equipment | 20.00 |
| 391 | 3920 | Transportation Equipment | 8.33 |
| 391 | 3921 | Trailers | 4.25 |
| 392 | 3940 | Tools, Shop & Garage Equipment | 4.00 |
| 392 | 3950 | Laboratory Equipment | 6.67 |
| 393 | 3960 | Power Operated Equipment | 5.88 |
| 393 | 3970 | Communication Equipment | 6.67 |
| 394 | 3980 | Miscellaneous Equipment | 5.00 |

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

| FERC Account Number (A) | Company Account Number (B) | Description (C) | Actual Accrual Rates (D) |
|---|---|---|---|
| | | | % |
| | | **Transmission Plant** | |
| 350 | 3501 | Rights of Way | 1.48 |
| 352 | 3520 | Structures & Improvements | 0.41 |
| 353 | 3530 | Station Equipment | 2.25 |
| 353 | 3532 | Station Equipment - Major | 2.77 |
| 353 | 3535 | Station Equipment – Electronic | 9.55 |
| 355 | 3550 | Poles & Fixtures | 2.28 |
| 356 | 3560 | Overhead Conductors & Devices | 2.31 |
| | | **General and Intangible Plant** | 20.00 |
| 303 | 3030 | Miscellaneous Intangible Plant | 1.77 |
| 390 | 3900 | Land and Land Rights | 18.56 |
| 391 | 39110 | Structures and Improvements | 6.53 |
| 392 | 3921 | Electronic Data Processing Equipment | 4.14 |
| 394 | 3940 | Transportation Equipment | 6.93 |
| 397 | 3970 | Stores Equipment | |

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Firm PTP Service Revenue Credit Adjustment Calculation

To be completed in conjunction with Attachment H-22A

| | (1) | (2) | (3) |
|---|---|---|---|
| No. | | **Reference** | **Company Total** |
| | **REVENUE CREDIT TRUE-UP** | | |
| 1 | Difference Between Revenue Received In PJM vs. Midwest ISO | (Note A) | $0 |
| | **ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP** | | |
| 2 | Accumulated Balance of Deferral | (Note B) | $0 |
| 3 | Income Tax Rate for Deferral Calculation | (Note C) | 0.00% |
| 4 | Deferred Income Taxes on Accumulated Deferral (line 2 * line 3) | | $0 |
| 5 | Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4) | | $0 |
| | **INCOME TAXES** | | |
| 6 | CIT = (T/(1-T)) * (1 - (WCLTD/R)) | Attachment H-22, page 3, line 22 | 0.00% |
| 7 | Income Taxes (Line 6 * Line 9) | | $0 |
| | **CARRYING COST ON DEFERRAL** | | |
| 8 | FERC Refund Rate | (Note D) | 0.00% |
| 9 | Carrying Cost (Line 5 * Line 8) | ~~(Note C)~~ | $0 |
| 10 | Revenue Credit Adjustment (Line 1 + Line 7 + Line 9) | | $0 |

Notes
A. From Appendix E, Workpaper, Column (4).
B. Accumulated balance of deferral as of December 31st of the year prior to effective date of new rate.
C. Effective deferred tax rate during applicable test year.
D. FERC Refund Rate is the approved rate as of December 31 of calendar prior to the rate year (see 18 C.F.R. Section 35.19a).

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

| (1) Period | (2) Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A) | (3) Actual Firm PTP Service Revenue Received from PJM (Note B) | (4) = (2) - (3) Difference Between Revenue Received and Amount in Rates Excluding True Up | (5) Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C) | (6) = (4) - (5) Amount Deferred for Future Recovery | (7) = Prior month's Balance + (6) Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment |
|---|---|---|---|---|---|---|
| Jan-12 | $ - | $ - | $ - | | $ - | $ - |
| Feb-12 | - | - | - | | - | - |
| Mar-12 | - | - | - | | - | - |
| Apr-12 | - | - | - | | - | - |
| May-12 | - | - | - | | - | - |
| Jun-12 | - | - | - | | - | - |
| Jul-12 | - | - | - | | - | - |
| Aug-12 | - | - | - | | - | - |
| Sep-12 | - | - | - | | - | - |
| Oct-12 | - | - | - | | - | - |
| Nov-12 | - | - | - | | - | - |
| Dec-12 | - | - | - | | - | - |
| **Total** | | | | $ | $ - | - |
| | | | | | | - |
| Jan-13 | - | - | - | | $ - | - |
| Feb-13 | - | - | - | | - | - |
| Mar-13 | - | - | - | | - | - |
| Apr-13 | - | - | - | | - | - |
| May-13 | - | - | - | | - | - |
| Jun-13 | | | - | - | - | - |
| Jul-13 | | | | - | - | - |
| Aug-13 | | | | - | - | - |
| Sep-13 | | | | - | - | - |
| Oct-13 | | | | - | - | - |
| Nov-13 | | | | - | - | - |
| Dec-13 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |
| Jan-14 | | | | $ - | $ - | $ - |
| Feb-14 | | | | - | - | - |
| Mar-14 | | | | - | - | - |
| Apr-14 | | | | - | - | - |
| May-14 | | | | - | - | - |
| Jun-14 | | | | - | - | - |
| Jul-14 | | | | - | - | - |
| Aug-14 | | | | - | - | - |
| Sep-14 | | | | - | - | - |
| Oct-14 | | | | - | - | - |
| Nov-14 | | | | - | - | - |
| Dec-14 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |
| Jan-15 | | | | $ - | $ - | $ - |
| Feb-15 | | | | - | - | - |
| Mar-15 | | | | - | - | - |
| Apr-15 | | | | - | - | - |
| May-15 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |

Notes:

A. Monthly Firm PTP service revenue from Midwest ISO during test year applicable to currently effectives NITS and PTP service rates.
B. Actual monthly Firm PTP service revenue received from PJM during current period.
C. Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.

The recovery of the 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.

**ATTACHMENT H-22B**
**DEOK FORMULA RATE IMPLEMENTATION PROTOCOLS**

## Definitions

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by DEOK on or before May 15 of each year that sets forth the DEOK Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on DEOK as provided in Section 2.b below.

"DEOK" means Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc.

"First Rate Year" means the period that begins on January 1, 2012, and ends on May 31, 2012.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("FERC") as provided in Section 3.a below.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Attachment H-22A of the PJM Tariff.

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in DEOK's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate different from the result under the Formula Rate as calculated without such change.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to DEOK as provided in Section 2.a below.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1.b below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year except for the First Rate Year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2.a below.

**Section 1 Annual Updates**

a. Beginning with the Rate Year that commences on June 1, 2012, and during each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-22A and the Network Integration Transmission Service and Point-to-Point rates derived therefrom shall be applicable to transmission services provided by PJM for the DEOK zone during the Rate Year.

b. On or before May 15, 2012, and on or before May 15 of each succeeding Rate Year, DEOK shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year, and:
   (i) post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;
   (ii) submit such Annual Update as an informational filing with the FERC;
   (iii) provide contact information for inquiries concerning the Annual Update;
   (iv) send an email or other similar electronic communication to all Interested Parties that have previously requested such notification through procedures to be established by DEOK that informs the recipient that the Annual Update is available and that provides the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

d. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's "Publication Date."

e. Within two business days of the Publication Date, DEOK shall also provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit DEOK to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from DEOK about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on DEOK's books, which reflect:
   (i) the FERC's Uniform System of Accounts, and

(ii) applicable FERC Form No. 1[1] as each exists as of the later of the date of DEOK's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

g. The Annual Update for the Rate Year:

(i) shall, to the extent specified in the Formula Rate, be based upon DEOK's FERC Form No. 1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of DEOK consistent with Section 1.f above;

(ii) shall, as and to the extent specified in the Formula Rate, provide the formula rate calculations and all inputs thereto, as well as supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[2]

(iii) shall provide sufficient information[3] to enable customers to replicate the calculation of the formula results from FERC Form No. 1 and other applicable accounting inputs and to compare that calculation to that of prior years, including all workpapers necessary to explain any changes made since the last update, and to include as applicable:

(1) a copy of the FERC Form No. 1 used for the update if it is not otherwise publicly available;

(2) identification of any changes in the formula references to the FERC Form No. 1;

(3) identification of all adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in a FERC Form No. 1 footnote;

1. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

2. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 for the most recent calendar year or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information provided by DEOK with the Annual Update. Where the reconciliation is provided through a worksheet included in the filed Formula Rate Template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

3. As appropriate, competitively sensitive information may be provided only to those persons bound by the terms of a suitable confidentiality agreement or protective order.

(4) a reconciliation of annual and monthly peak demands shown on the FERC Form 1 and annual and monthly peak demands used in the formula in sufficient detail to enable transparent reconciliation of these two measures;

(5) a description of those factors influencing any change in the annual revenue requirement, including an identification of any respects in which charges under the formula rate materially differ from the preceding Annual Update (e.g., due to changes in accounting procedures, the purchase or sale of major assets, or other such significant changes) and identification of the major reason(s) for the differences, if any, between the Annual Update and the prior year's Annual Update; and

(6) any changes to the data inputs made as a result of a reconciliation made under Section 4 below.

(iv) shall describe material changes, if any, in DEOK's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or did affect the charges under the Formula Rate ("Material Accounting Changes");[4]

(v) shall be subject to challenge and review only in accordance with the procedures set forth in this Attachment H-22B, as to the appropriateness of the input data, the prudence of the costs and expenditures included for recovery in the Annual Update, and the application of the Formula Rate according to its terms and the procedures in this Attachment H-22B (including terms and procedures related to challenges concerning Material Accounting Changes);

(vi) except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act ("FPA") Section 205 or Section 206 filing).

h. Formula Rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other Than Pensions ("PBOP") shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or Section 206 to modify stated values for depreciation rates or PBOP expense under the Formula Rate or Protocols shall not open review of other components of the Formula Rate or Protocols.

i. Extraordinary property losses recorded in FERC Account 182.1 shall be amortized for Formula Rate purposes pursuant to a Section 205 or 206 filing made effective by the Commission.

[4] Such notice may incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

j. Any change to the underlying Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f above shall be grounds for a presumption that the application of the Formula Rate shall be modified to restore the balance of the Formula Rate as accepted by the FERC (the intent being to prevent such changes in these underlying Uniform System of Accounts or FERC Form No. 1 from causing an automatic shift in the charges calculated under the Formula Rate without input from other interested parties). Any interested party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, shall first raise the matter with DEOK. ~~in accordance with Section 2.a below before pursuing a Formal Challenge.~~

**Section 2 <u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested parties shall have up to one hundred eighty (180) days after the Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify DEOK in writing, which may be made electronically, of any specific challenges, including challenges related to the rate treatment of Material Accounting Changes, to the application of the Formula Rate and to changes to the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, above, ("Preliminary Challenge"). <u>Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not bar a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.</u>~~Failure to raise an issue with DEOK in accordance with Section 1.j above or to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge, regarding any issue as to a given Annual Update, shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.~~

b. Interested Parties shall have up to one hundred fifty (150) days after each annual Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to serve reasonable information requests on DEOK.~~; provided, however, that the parties making such requests shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable.~~ Such information requests shall be limited to what is necessary to determine if DEOK has properly applied the Formula Rate, the requirements and procedures of this Attachment H-22B, and the prudence of the costs and expenditures included for recovery in the Annual Update, and shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

c. DEOK shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by DEOK within the Discovery Period and for which DEOK is unable to provide a response within fifteen (15) business days after the end of the Discovery Period, the Review Period shall be extended day-for-day until DEOK's response is provided.

d. To the extent DEOK and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, DEOK or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

e. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

f. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

g. In any proceeding initiated to address a Preliminary or Formal Challenge or *sua sponte* by the FERC, a party or parties seeking to modify the Formula Rate in any respect shall bear the applicable burden under the FPA.

**Section 3 Resolution of Challenges**

a. If DEOK and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of DEOK to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the FERC, which shall be served on DEOK by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update. ~~A party's Formal Challenge may not raise any issue that was not the subject of that party's Preliminary Challenge during the applicable Review Period.~~ Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge.

Failure to notify DEOK of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issues in a Preliminary Challenge or Formal Challenge.

b. Any response by DEOK to a Formal Challenge must be submitted to the FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

c. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, DEOK shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate, consistent with Section 1.g(v), and that it followed the applicable requirements and procedures in this Attachment H-22B, in that year's Annual Update. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

d. Subject to judicial review of FERC orders, each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols or by any other means by the FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

e. ~~Except as specifically provided herein, ~~N~~n~~othing herein shall be deemed to limit in any way the right of DEOK to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of DEOK or any Interested Party to initiate a proceeding at the FERC at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and the FERC's regulations.

f. Subject to Section 2.e above, it is recognized that resolution of Formal Challenges concerning Material Accounting Changes or related to the Uniform System of Accounts or FERC Form No. 1 as described above may necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the Formula Rate to achieve a just and reasonable end result consistent with the intent of the Formula Rate.

g. In making or resolving any Preliminary or Formal Challenge under this Section, a party may rely on all information provided by DEOK, including information provided under the terms of a confidentiality agreement or protective order; provided, however, that parties receiving such information pursuant to a confidentiality agreement or protective order shall be bound by the restrictions placed by such agreement or order on disclosure or use of confidential information.

**Section 4 Changes to Annual Informational Filings**

~~Any changes to the data inputs, including but not limited to revisions to DEOK's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments and any refunds or surcharges. However, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. § 35.19a) for the then current rate year shall be made in the event that the Formula Rate is replaced by a stated rate for DEOK.~~

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of Duke Energy Kentucky, Inc., or Duke Energy Ohio, Inc., or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any FERC proceeding to consider a prior year's Annual Update, DEOK shall promptly notify the Interested Parties, file a correction to the Annual Update with the FERC as an amended informational filing describing the change(s) and the cost impact, and provide a copy of the amended informational filing to PJM for prompt posting by PJM.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by DEOK and the Interested Parties, a correction made under Section 4.a prior to the time determined for filing of a Formal Complaint shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Party Annual Review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the Annual Review shall then be limited to the aspects of the Formula Rate affected by the corrections.

## ATTACHMENT H-22C

## ADDITIONAL PROVISIONS REGARDING DEOK AND INDIANA MUNICIPAL POWER AGENCY

Duke Energy Ohio, Inc. ("DEO"), a corporation organized and existing under the laws of the State of Ohio, and Duke Energy Kentucky, Inc. ("DEK"), a corporation existing under the laws of the State of Kentucky, and the Indiana Municipal Power Agency ("IMPA") (each a "Settling Party" and all collectively, the "Settling Parties"), shall be subject to the provisions of this Attachment, which implements the Settlement Agreement ("Agreement") entered into between the Duke Companies and IMPA in Docket Nos. ER12-91-000 and ER12-92-000 on April 5, 2012.

## ARTICLE I
## [Reserved]

## ARTICLE II
## DEFINITIONS; RULES OF INTERPRETATION AND CONSTRUCTION

2.1 All defined terms have the meanings set forth in this Attachment. All rules of construction and interpretation of this Attachment shall be as set forth in the PJM Tariff or PJM Agreements.

The "Duke Companies" means Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

"DEO" means Duke Energy Ohio, Inc.

"IMPA" means the Indiana Municipal Power Agency.

"IMPA PJM RTEP Credit Cap" initially shall be $575,000, and shall be adjusted as described in Section 4.1.

"Internal Integration Costs" means internal integration costs identified in the Duke Companies' filing submitted in Docket Nos. ER12-91-000 and ER12-92-000 as costs incurred by the Duke Companies in connection with their move into PJM that are recovered from IMPA under the Duke Companies' PJM Formula Rate or otherwise.

"Legacy MTEP Costs" means all costs associated with, or relating to, any obligation of the Duke Companies or IMPA to pay any portion of the costs of MISO Transmission Expansion Planning ("MTEP") projects identified and approved by the MISO Board of Directors prior to the Duke Companies' integration into PJM, including any such costs related to Multi-Value Projects ("MVP").

"MISO" or "Midwest ISO" means the Midwest Independent Transmission System Operator, Inc.

"PJM" means PJM Interconnection, L.L.C.

"PJM Agreements" means the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, and the Consolidated Transmission Owners Agreement.

"PJM Formula Rate" means the formula rate and rate protocols identified and submitted by the Duke Companies in the filing in Docket Nos. ER12-91-000 and ER12-92-000.

"PJM RTEP Costs" means costs charged by PJM to IMPA under Schedule 12 of the PJM Tariff associated with a PJM Regional Transmission Expansion Plan ("RTEP"). Costs associated with facilities owned by PJM transmission owners other than the Duke Companies and charged to IMPA under a successor rate schedule will also be considered PJM RTEP Costs for purposes of this Attachment.

"PJM Tariff" means PJM Interconnection, L.C.C. Open Access Transmission Tariff.

"PJM Transition Costs" means costs identified as "Transition Costs" in the Duke Companies' filings submitted in Docket Nos. ER12-91-000 and ER12-92-000 and included in the proposed PJM Formula Rate, specifically, costs associated with: (1) the Duke Companies' requirement under Article Five, Section II.B of the MISO Transmission Owners' Agreement ("MISO TOA") to pay certain amounts to MISO as an exit fee ("MISO Exit Fee"); (2) the Duke Companies' agreement, approved by the Commission in Docket No. ER11-2059-000, to pay MISO $1.8 million to resolve a dispute over MISO tariff revisions proposed to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the withdrawal of the Duke Companies from MISO ("MISO LTTR Exit Charge"); and (3) the Duke Companies' agreement to pay PJM approximately $1 million as compensation for PJM's costs incurred in connection with the Duke Companies' transition to PJM ("PJM Integration Costs").

## ARTICLE III
## SCOPE OF ATTACHMENT

3.1. The Settling Parties hereby settle and resolve all issues between them involving the matters raised in Docket Nos. ER12-91-000 and ER12-92-000, on the terms set forth in the following Article IV.

## ARTICLE IV
## TERMS

4.1. The Duke Companies commit as follows:

(a) Reimbursement of PJM Transition Costs & Internal Integration Costs.

For each billing month, DEO agrees to reimburse IMPA for any amounts owed to the Duke Companies by IMPA for that month for the portion of PJM Transition Costs and Internal Integration Costs associated with the load IMPA serves for the Village of Blanchester, Ohio.

(b) Crediting Payment of PJM RTEP Costs.

i. DEO agrees to utilize the PJM billing line-item transfer process to credit IMPA amounts equal to the monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, until total DEO line-item transfers to IMPA under this provision equal the initial IMPA PJM RTEP Credit Cap, as follows:

a. Initially, the IMPA PJM RTEP Credit Cap shall be $575,000, subject to adjustment as set forth in subparagraph 4.1(b).i.b and 4.1(b).i.d.

b. For each billing month for which IMPA has or will have paid RTEP costs, regardless of whether prior to the Effective Date of this Attachment, until the month in which the IMPA PJM RTEP Credit Cap is reached, DEO agrees to execute and perform a billing line-item transfer, in accordance with PJM financial settlement rules and procedures, equal to any amounts charged to IMPA that month by PJM for PJM RTEP Costs associated with the load that IMPA serves for the Village of Blanchester, Ohio. The IMPA PJM RTEP Credit Cap will be decremented by the same amount.

c. In the event that any month's PJM RTEP Cost charged by PJM with respect to the load that IMPA serves for the Village of Blanchester, Ohio exceeds the remaining balance of the IMPA PJM RTEP Credit Cap, DEO shall not have an obligation to execute and perform a billing line-item transfer for an amount equal to the remaining balance of the IMPA PJM RTEP Credit Cap, but instead shall directly reimburse IMPA for the remaining balance amount. In the event it is determined that IMPA has been compensated for an amount that exceeds the IMPA RTEP Credit Cap, IMPA shall, upon receipt of suitable documentation from the Duke Companies, and within 120 days, refund said over payment. Thereafter DEO shall have no further obligation under this Attachment to execute and perform any line item transfer or otherwise reimburse IMPA in connection with PJM RTEP Costs charged to IMPA. Upon being notified the IMPA RTEP Credit Cap has been reached, by virtue of billing line-item transfer, or direct payment by the Duke Companies, IMPA will work with the Duke Companies, and PJM to cancel the Declaration of Authority that allows for such billing line-item transfer.

d. In the event that the PJM Formula Rate as filed by the Duke Companies is modified for any reason, the IMPA PJM Credit Cap shall be adjusted as follows:

1. Within 30 days of issuance of an order modifying the PJM Formula Rate, the Duke Companies shall in good faith estimate the annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Estimated Annual Adjustment") and the amount of IMPA's RTEP payments ("Estimated Annual RTEP Amount") for each year through 2022. IMPA will review the estimate and give good faith commentary, and the Settling Parties will work in good faith to arrive at mutually acceptable estimates.

2. Prior to each year, the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the coming year will be compared.

3. If the Estimated Annual Adjustment is equal to or greater than the Estimated Annual RTEP Amount, DEO shall not credit IMPA any amount during the coming year. If a Declaration of Authority has been provided to PJM allowing for a billing line-item transfer of RTEP costs to the Duke Companies, IMPA will work with PJM and the Duke Companies to cancel such transfer, effective January 1, for the year in which the Estimated Annual Adjustment is greater than the Estimated Annual RTEP Amount.

4. If the Estimated Annual Adjustment is less than the Estimated Annual RTEP Amount, DEO shall compensate IMPA for the difference. DEO shall have the option of compensating IMPA through PJM billing line-item transfers and/or through direct compensation, and shall have the option of tendering such compensation in up to 12 equal monthly installments during the course of the year in question. DEO shall notify IMPA of the method and intervals of payment before the year begins. In the event DEO elects to utilize a billing line-item transfer to effectuate compensation to IMPA, IMPA will work with the Duke Companies to provide a suitable Declaration of Authority to PJM, that allows for such billing line-item transfer.

5. Within 30 days following the end of the year, DEO will true up the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the prior year using actual data. The true-up will result in determination of the actual annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Actual Annual Adjustment") and the actual amount of IMPA's RTEP payments ("Actual Annual RTEP Amount"). DEO will provide the true up calculation and supporting data to IMPA for review. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment exceeds the amount paid to IMPA by DEO for the year in question, DEO will reimburse IMPA for the difference. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment is less than the amount paid to IMPA by DEO, IMPA will reimburse DEO for the difference. However, in no event shall IMPA be obligated to reimburse DEO an amount under this provision that exceeds the total amount paid by DEO to IMPA during the year in question, and in no event shall DEO be required to pay to IMPA an amount that would cause the remaining balance of the IMPA PJM RTEP Credit Cap to be less than zero, after the adjustment to the IMPA PJM RTEP Credit Cap described in the next paragraph. All reimbursements due under this provision shall be paid within 60 days following the end of the year.

6. Once the trued-up amounts are known, the IMPA PJM RTEP Credit Cap will be decremented by the higher of the Actual Annual RTEP Amount or the Actual Annual Adjustment, thereby reflecting the actual value received by IMPA in the year in question.

7. The parties shall discuss in good faith, at least once per year, whether adjustments should be made to the following year's estimated amounts.

8. If the PJM Formula Rate is accepted subject to refund and set for hearing, DEO will perform PJM billing line-item transfers to credit IMPA's RTEP amount until FERC issues a final order on the PJM Formula Rate, to the extent otherwise consistent with this

Attachment. If (a) FERC's order results in an adjustment to the proposed PJM Formula Rate, and therefore requires an adjustment to the IMPA PJM RTEP Credit Cap per the methodology described above, and (b) as a result of such adjustment DEO has overpaid on the credit, then credit overpayments shall be netted against refund obligations to IMPA, and the refund obligation would be reduced correspondingly.

e. Hypothetical example calculation: IMPA PJM RTEP Credit Cap is 995 dollars; monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, are 20 dollars. Each month for the first 49 months, PJM would bill IMPA $20, and DEO would perform a billing line item transfer to credit IMPA $20, such that IMPA's net obligation to PJM for PJM RTEP Costs in each such month would be $0. During each of these months, the remaining balance of the IMPA PJM RTEP Credit Cap would be reduced by $20. Thus, after 49 months, the IMPA PJM RTEP Credit Cap would be reduced by $980 (49 months x $20/month), such that the remaining balance would be $15 ($995-$980=$15). Because the remaining balance of $15 would be less than the next month's PJM RTEP Cost of $20, in that next ($50^{th}$) month: PJM would bill IMPA $20, IMPA would pay PJM $20, and DEO would reimburse IMPA for the $15 remaining balance of the IMPA PJM RTEP Credit Cap. Thereafter, DEO would no longer be obligated under this Attachment to perform billing line item transfers associated with IMPA's PJM RTEP Costs, or to otherwise reimburse IMPA for such costs.

ii. DEO agrees to act in good faith and use commercially reasonable efforts in cooperation with IMPA to establish and implement a billing line-item transfer as contemplated in Paragraph 4.1 above. If at any time for any reason the billing line-item transfer mechanism for reimbursing IMPA cannot be effectuated, DEO shall implement an alternate mechanism, such as direct reimbursement to IMPA, to achieve the same result as contemplated in Paragraph 4.1.b.i above.

4.2 IMPA agrees and commits as follows:

(a) Lawfulness and Effectiveness of Rate as Filed

The Settling Parties acknowledge and agree that the PJM Formula Rate and related protocols submitted by the Duke Companies in the above-referenced proceeding will not be amended or revised in any respect or for any reason as a result of, or associated with, this Attachment. The Settling Parties further agree that (a) the considerations provided by the Duke Companies under this Attachment to IMPA are in resolution of "hold harmless" claims made by IMPA pursuant to Article V, Section 2 of the Midwest ISO Transmission Owners Agreement and resolve all claims raised by IMPA in these proceedings; and that (b) the obligation of the Duke Companies to provide such considerations is contingent upon the Commission not modifying the Agreement. IMPA agrees to fully pay its share of the rates as approved by the Commission in Docket Nos. ER12-91-000 and ER12-92-000, including but not limited to its share of Legacy MTEP Costs, subject to the reimbursements and credit established above.

(b) Crediting Payments of PJM RTEP Costs.

IMPA agrees to act in good faith and use commercially reasonable efforts in cooperation with DEO and PJM to negotiate, execute, implement and perform billing line-item transfers as contemplated in Paragraph 4.1 above, and to terminate the line-item transfer process at the time contemplated in Paragraph 4.1 above.

(c) Resolution of All Hold Harmless Obligations.

Payment by DEO of the amounts and credits established in this Attachment according to the terms of this Attachment shall fully satisfy and discharge any and all obligations of the Duke Companies to render payment to IMPA according to the terms of Article V, Section 2 of the Midwest ISO Transmission Owners Agreement in connection with the Duke Companies' withdrawal from MISO, and such satisfaction and discharge shall not be affected by any amendment, substitute or successor to that provision, or any amendment, substitute or successor to the PJM Formula Rate filed in this proceeding. IMPA agrees not to make any protest or raise any claim against the Duke Companies or their parents or affiliates, before any government agency or court, asserting that the Duke Companies or their parents or affiliates owe IMPA or its members, respectively, any further "hold harmless" or other compensation under Article V, Section 2 of the Midwest ISO Transmission Owners Agreement, or any other monies or damages of any nature in connection with the Duke Companies' withdrawal from the Midwest ISO.

(d) Rate of Return

IMPA's protest in the above-referenced proceeding had raised the issue of the Duke Companies' rate of return on equity. Under this Attachment, IMPA is agreeing to move to withdraw its protest as set forth in the following subparagraph and thereby retract any claim that an outcome of this proceeding should be a reduction of the Duke Companies' rate of return on equity. This agreement is without prejudice to IMPA's right to raise the issue of the Duke Companies' rate of return on equity in subsequent proceedings, through a filing under Federal Power Act Section 206 or otherwise, provided that IMPA agrees that it will not (a) initiate a proceeding prior to January 1, 2016 seeking a reduction of the Duke 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 Duke Companies in which the reduction would become effective prior to January 1, 2016.

(e) Withdrawal of Pleadings.

IMPA will move to withdraw its protest filed in the above-referenced proceeding within fifteen (15) days of the earlier of (a) issuance of a Commission order accepting the Agreement without modification or condition, or (b) issuance of a Commission order accepting the PJM Formula Rate, and not modifying or conditioning the Agreement. In the event that the Commission establishes a hearing in these dockets, IMPA agrees not to participate in such hearing.

4.3 The Settling Parties agree that the payments and credits identified in Sections 4.1(a) through 4.1(b) shall not be adjusted, upwards or downwards, for any reason including but not limited to any order eliminating, reducing or otherwise modifying any Settling Party's obligation(s) to pay for any PJM Transition Costs, PJM RTEP Costs or Legacy MTEP Costs.

## ARTICLE V
## MISCELLANEOUS PROVISIONS

5.1. Scope of the Attachment. This Attachment constitutes the entire agreement among the Settling Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no other oral understandings, terms or conditions, and none of the Settling Parties has relied upon any representation, express or implied, not contained in this Attachment. Nothing in this Attachment should be construed as negating or fulfilling the obligations or responsibilities of the Duke Companies or IMPA under the PJM Tariff or PJM Agreements.

5.2. Non-Severability. The Settling Parties agree and understand that the various provisions of this Attachment are not severable and shall not become operative unless and until it becomes effective as described in Section 5.3.

5.3. Effectiveness of Attachment. This Attachment and the provisions hereof shall become effective upon the earlier of (a) issuance of an order by the Commission accepting or approving this Attachment without condition or modification, or (b) issuance of an order by the Commission accepting or approving the PJM Formula Rate filed by the Duke Companies in these dockets, and not modifying or conditioning this Attachment.

5.4 Reservations. Except as provided under Section 5.6 (confidentiality of settlement discussions) and Section 5.7 (assurances of cooperation), no Settling Party shall be bound by any part of this Attachment unless and until it becomes effective in the manner provided by Section 5.3 hereof. If this Attachment is not accepted or approved in its entirety without modification or condition, it shall be deemed withdrawn, shall not be considered to be part of the record in this proceeding, and shall be null and void and of no force and effect, unless all of the Settling Parties otherwise agree in writing to such modification or condition.

5.5. No Precedent. This Attachment is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding unless it is approved or permitted to take effect as to all of its terms and conditions without modification. It is further understood and agreed that this Attachment constitutes a negotiated agreement and, except as explicitly set forth herein, no Settling Party shall be deemed to have approved, accepted, agreed or consented to any principle or position in this proceeding.

5.6. Settlement Discussions. The discussions between and among the Settling Parties that have produced this Attachment have been conducted with the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

5.7. Further Assurances. Each Settling Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this Attachment with the Commission, and (ii) efforts to obtain Commission acceptance or approval of the Attachment.

No Settling Party shall take any actions that are inconsistent with the provisions of this Attachment.

5.8. Waiver. No provision of this Attachment may be waived except through a writing signed by an authorized representative of the waiving Settling Party. Waiver of any provision of this Attachment shall not be deemed to waive any other provisions.

5.9. Modifications/Standard of Review. Unless the Settling Parties otherwise agree in writing, any modifications to this Attachment proposed by one of the Settling Parties after the Attachment 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 Serv. 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. Utils. 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.

5.10. Successors and Assigns. This Attachment is binding upon and for the benefit of the Settling Parties and their successors and assigns.

5.11. Captions. The captions in this Attachment are for convenience only and are not a part of this Attachment and do not in any way limit or amplify the terms and provisions of this Attachment and shall have no effect on its interpretation.

5.12. Ambiguities Neutrally Construed. This Attachment is the result of negotiations among, and has been reviewed by, each Settling Party and its respective counsel. Accordingly, this Attachment shall be deemed to be the product of each Settling Party, and no ambiguity shall be construed in favor of or against any Settling Party.

5.13. Authorization. Each person executing this Attachment on behalf of a Settling Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this Attachment to be executed on behalf of, the Settling Party that he or she represents.

5.14. Notices. All notices, demands, and other communications hereunder shall be in writing and shall be delivered to each Settling Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Settling Party on the official service list in Docket No. ER12-91-000 and ER12-92-000.

5.15. Counterparts. This Attachment may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

## 5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used~~, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals~~.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

  - For point (1), price equals: [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100%

plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the

March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

| **Geographic Location Within the PJM Region Encompassing These Zones** | **Cost of New Entry in $/MW-Year** |
|---|---|
| PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”) | 122,040 |
| BGE, PEPCO (“CONE Area 2”) | 112,868 |
| AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK (“CONE Area 3”) | 115,479 |
| PPL, MetEd, Penelec (“CONE Area 4”) | 112,868 |
| Dominion (“CONE Area 5”) | 112,868 |

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined, as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

**ATTACHMENT JJ**
**MTEP PROJECT COST RECOVERY FOR DEOK ZONE**

## I. Definitions

A. DEOK – Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff – The Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

D. ~~Midwest ISO Transmission Owner – Any transmission owner in the Midwest ISO, including any independent transmission company, responsible for the construction of MTEP Projects under Attachment FF of the Midwest ISO Tariff.~~ [Reserved]

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by DEOK ~~or by Midwest ISO Transmission Owners~~ pursuant to Attachment FF of the Midwest ISO Tariff ~~for which all or a portion of the revenue requirement is allocated to DEOK pursuant to the Midwest ISO Tariff~~.

~~G. Network Service Peak Load – A Network Service Transmission Customer's share of the previous year's DEOK zonal peak load (1 CP).~~

## II. Introduction and Purpose

~~Transmission Customers taking transmission service for deliveries in the DEOK Zone shall pay a portion of the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment JJ sets forth the method by which Transmission Customers taking transmission service for deliveries into the DEOK Zone are charged for the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment also sets forth the method by which the PJM Office of the Interconnection will transmit to the Midwest ISO the revenues received from Transmission Customers taking transmission service for deliveries into the DEOK Zone for the cost of MTEP Projects to be constructed by Midwest ISO Transmission Owners. Finally, it~~This Attachment JJ addresses the manner in which the PJM Office of the Interconnection will distribute to Duke Energy Ohio, Inc. on behalf of DEOK the revenues received from the Midwest ISO for the cost of MTEP Projects constructed by DEOK.

## III. ~~MTEP Project Revenue Requirements Allocated to DEOK Zone~~ [Reserved]

~~**A. Recovery of Annual Revenue Requirements for Midwest ISO Transmission Owners' MTEP Projects**~~

~~Each month, and pursuant to agreed-upon settlement procedures, PJM shall bill each Network Customer in the DEOK Zone its monthly share of the revenue requirements~~

~~allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, determined in accordance with the Midwest ISO Tariff and as billed by the Midwest ISO to PJM ("Network Customer's MTEP Project Charge"). A Network Customer's share of such revenue requirements shall be based on its Network Service Peak Load in the DEOK Zone.~~

### ~~B. Revenue Distribution from Payments Made by Transmission Customers in DEOK Zone; Shortfall in Payment~~

~~Each month, and pursuant to agreed-upon settlement procedures, the PJM Office of the Interconnection shall remit to the Midwest ISO the revenue requirements allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, as set forth in Section III.A. In addition, in the event that the revenues received by PJM from a Network Customer pursuant to Section III.A. are less than the Network Customer's MTEP Project Share ("Shortfall"), and PJM makes up such Shortfall in its remittance to the Midwest ISO, (a) PJM shall apply such Shortfall to the financial settlement of Duke Energy Ohio, Inc.'s account (on behalf of DEOK), and (b) such Network Customer shall thereafter be obligated to remit such Shortfall directly to DEOK instead of to PJM, together with any Late Payment Charges that would otherwise be due to PJMSettlement under Section 7.1A of this Tariff. DEOK shall have all rights to seek recovery of such Shortfall directly from the Network Customer, and such rights shall be enforceable by DEOK at FERC and in any court of competent jurisdiction. DEOK shall be a third party beneficiary under the Network Customer's service agreement with PJM for the limited purpose of seeking recovery of such Shortfall.~~

## IV. DEOK MTEP Project Revenue Requirements Allocated to Midwest ISO Zones

### A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–22 to this Tariff, DEOK will periodically update the Annual Revenue Requirements for MTEP Projects constructed by DEOK. No later than May 1 each year, DEOK shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year.

### B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the Annual Revenue Requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO in accordance with the Midwest ISO Tariff.

### C. Monthly Revenue Requirements Owed from the Midwest ISO Zones

Each month, and pursuant to agreed-upon settlement procedures, the Midwest ISO shall remit an amount to the PJM Office of the Interconnection from revenues collected by the Midwest ISO in proportion to DEOK's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 38.

**D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO**

Pursuant to agreed-upon settlement procedures, PJM shall credit to Duke Energy Ohio's account (on behalf of DEOK) in the subsequent month the amount of revenue requirements that the Midwest ISO remits to PJM pursuant to Section IV.C for the prior month.

# Appendix B

## Sections of the PJM Open Access Transmission Tariff

## (Clean Version)

**Definitions – O – P - Q**

**1.27C Office of the Interconnection:**

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.

**1.28 Open Access Same-Time Information System (OASIS):**

The information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

**1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:**

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

**1.28A.01 Option to Build:**

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

**1.28B Optional Interconnection Study:**

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

**1.28C Optional Interconnection Study Agreement:**

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

**1.29 Part I:**

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

**1.30 Part II:**

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31 Part III:**

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31A Part IV:**

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31B Part V:**

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.31C Part VI:**

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**1.32 Parties:**

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

**1.32.01 PJM:**

PJM Interconnection, L.L.C.

**1.32A PJM Administrative Service:**

The services provided by PJM pursuant to Schedule 9 of this Tariff.

**1.32B PJM Control Area:**

The Control Area that is recognized by NERC as the PJM Control Area.

**1.32C PJM Interchange Energy Market:**

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

**1.32D PJM Manuals:**

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

**1.32E PJM Region:**

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

**1.32F PJM South Region:**

The VACAR Control Zone.

**1.32.F.01 PJMSettlement:**

PJM Settlement, Inc. (or its successor).

**1.32G PJM West Region:**

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; the Duquesne Light Company, American Transmission Systems, Incorporated, and Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

**1.33 Point(s) of Delivery:**

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**1.33A Point of Interconnection:**

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

**1.34 Point(s) of Receipt:**

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**1.35 Point-To-Point Transmission Service:**

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

**1.36 Power Purchaser:**

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

**1.36.01 Pre-Confirmed Application:**

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

**1.36A Pre-Expansion PJM Zones:**

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

**1.36A.01 Project Financing:**

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

**1.36A.02 Project Finance Entity:**

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

**1.36B Queue Position:**

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

**SCHEDULE 1A**
**Transmission Owner Scheduling, System Control and Dispatch Service**

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

| **Zone** | **Rate ($/MWh)** |
|---|---|
| Atlantic City Electric Company | 0.0781 |
| Baltimore Gas and Electric Company | 0.0430 |
| Delmarva Power & Light Company | 0.0743 |
| PECO Energy Company | 0.1189 |
| PP&L, Inc. Group | 0.0618 |
| Potomac Electric Power Company | 0.0186 |
| Public Service Electric and Gas Company | 0.1030 |
| Jersey Central Power & Light Company | 0.0796 |
| Metropolitan Edison Company | 0.0796 |
| Pennsylvania Electric Company | 0.0796 |
| Rockland Electric Company | 0.2475 |
| Commonwealth Edison Company | 0.2223 |
| AEP East Operating Companies | Rate updated annually Per Attachment H-14 |
| The Dayton Power and Light Company | 0.0797 |
| Duquesne Light Company[1] | 0.0520 |
| American Transmission Systems, Incorporated ("ATSI") | Rate updated annually Per Attachment H-21 |
| Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK") | Rate updated annually Per Attachment H-22 |

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$0.1019/MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

| **Transmission Owner** | **Share (%)** |
|---|---|
| Atlantic City Electric Company | 0.50 |
| Baltimore Gas and Electric Company | 0.80 |
| Delmarva Power & Light Company | 0.77 |
| PECO Energy Company | 2.68 |
| PP&L, Inc. Group | 1.36 |
| Potomac Electric Power Company | 0.33 |
| Public Service Electric and Gas Company | 2.64 |
| Jersey Central Power & Light Company | 1.30 |
| Metropolitan Edison Company | 0.43 |
| Pennsylvania Electric Company | 0.66 |
| Rockland Electric Company | 0.20 |
| Commonwealth Edison Company | 37.62 |
| AEP East Operating Companies | 47.90 |
| The Dayton Power and Light Company | 2.36 |
| Duquesne Light Company | 0.45 |
| American Transmission Systems, Incorporated ("ATSI") | 0.00 |
| Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK") | 0.00[2] |

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

**ATTACHMENT H-22**
**Annual Transmission Rates – DEOK**
**for Network Integration Transmission Service**
**and Point-to-Point Transmission Service**

1. The Annual Transmission Revenue Requirements (“ATRR”) and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are equal to the results of the formula shown in Attachment H-22A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (jointly, “DEOK”). Service utilizing other DEOK facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate in this attachment shall be effective until amended by DEOK or modified by the Commission.

3. In addition to the rate set forth in paragraph 1, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse DEOK for any amounts payable by it as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

4. DEOK and Indiana Municipal Power Agency shall be subject to the additional provisions of Attachment H-22C.

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

**Rate Formula Template**
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | | | Total | | Allocator | Allocated Amount |
|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 29) | | | | | $ - |
| | REVENUE CREDITS (Note T) | | | | | |
| 2 | Account No. 454 | (page 4, line 34) | $ - | TP | 0.00000 | $ - |
| 3 | Account No. 456.1 | (page 4, line 35) | 0 | TP | 0.00000 | 0 |
| 4a | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.00000 | 0 |
| 4b | Revenues from service provided by ISO at a discount | | 0 | TP | 0.00000 | 0 |
| 5a | Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12) | | 0 | | 1.00000 | 0 |
| 5b | Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3) | | 0 | | 1.00000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5c) | | | | | $ - |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | | $ - |
| | DIVISOR | | | | | |
| 8 | 1 CP (Note A) | | | | | 0 |
| 9 | 12 CP (Note B) | | | | | 0 |
| 10 | Reserved | | | | | |
| 11 | Reserved | | | | | |
| 12 | Reserved | | | | | |
| 13 | Reserved | | | | | |
| 14 | Reserved | | | | | |
| 15 | Annual Cost ($/kW/Yr) - 1 CP | (line 7 / line 8) | $0.000 | | | |
| 16 | Annual Cost ($/kW/Yr) - 12 CP | (line 7 / line 9) | $0.000 | | | |
| 17 | Network Rate ($/kW/Mo) | (line 15 / 12) | $0.000 | | | |
| 17a | Point-To-Point Rate ($/kW/Mo) | (line 16 / 12) | $0.000 | | | |
| | | | Peak Rate | | | Off-Peak Rate |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16 / 52) | $0.000 | | | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16 / 260; line 16 / 365) | $0.000 | Capped at weekly rate | | $0.000 |
| 20 | Point-To-Point Rate ($/MWh) | (line 16 / 4,160; line 16 / 8,760 * 1000) | $0.000 | Capped at weekly and daily rate | | $0.000 |

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | (1) RATE BASE: | (2) Form No. 1 Page, Line, Col. | (3) Company Total | | (4) Allocator | (5) Transmission (Col. 3 times Col. 4) |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | |
| 1 | Production | 205.46.g | $ - | NA | | |
| 2 | Transmission | 207.58.g | 0 | TP | 0.00000 | $ - |
| 3 | Distribution | 207.75.g | 0 | NA | | |
| 4 | General & Intangible | 205.5.g & 207.99.g | 0 | W/S | 0.00000 | 0 |
| 5 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | $ - | GP= | 0.000% | $ - |
| | ACCUMULATED DEPRECIATION | | | | | |
| 7 | Production | 219.20-24.c | $ - | NA | | |
| 8 | Transmission | 219.25.c | 0 | TP | 0.00000 | $ - |
| 9 | Distribution | 219.26.c | 0 | NA | | |
| 10 | General & Intangible | 219.28.c | 0 | W/S | 0.00000 | 0 |
| 11 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | $ - | | | $ - |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | $ - | | | |
| 14 | Transmission | (line 2 - line 8) | 0 | | | $ - |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | $ - | NP= | 0.000% | $ - |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | 273.8.k | $ - | NA | zero | $ - |
| 20 | Account No. 282 (enter negative) | 275.2.k | 0 | NP | 0.00000 | 0 |
| 21 | Account No. 283 (enter negative) | 277.9.k | 0 | NP | 0.00000 | 0 |
| 22 | Account No. 190 | 234.8.c | 0 | NP | 0.00000 | 0 |
| 23 | Account No. 255 (enter negative) | 267.8.h | 0 | NP | 0.00000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19- 23) | | $ - | | | $ - |
| 25 | LAND HELD FOR FUTURE USE (Note G) | 214.x.d | $ - | TP | 0.00000 | $ - |
| | WORKING CAPITAL (Note H) | | | | | |
| 26 | CWC | calculated | $ - | | | 0 |
| 27 | Materials & Supplies (Note G) | 227.8.c & .16.c | 0 | TE | 0.00000 | 0 |
| 28 | Prepayments (Account 165) | 111.57.c | 0 | GP | 0.00000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | $ - | | | $ - |
| 30 | RATE BASE (sum lines 18, 24, 25, & 29) | | $ - | | | $ - |

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

| Line No. | (1) RATE BASE | (2) Form No. 1 Page, Line, Col. | (3) Company Total | | (4) Allocator | (5) Transmission (Col. 3 times Col. 4) |
|---|---|---|---|---|---|---|
| | O&M | | | | | |
| 1 | Transmission | 321.112.b | $ - | TE | 0.00000 | $ - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 321.88.b, 92.b; 322.121.b | 0 | | 1.00000 | 0 |
| 1b | Less Midwest ISO Fees included in Transmission O&M | (Note X) | 0 | TE | 0.00000 | 0 |
| 2 | Less Account 565 | 321.96.b | 0 | TE | 0.00000 | 0 |
| 3 | A&G | 323.197.b | 0 | W/S | 0.00000 | 0 |
| 3a | Less Actual PBOP Expense | (Note E) | 0 | W/S | 0.00000 | 0 |
| 3b | Plus Fixed PBOP Expense | (Note E) | 0 | W/S | 0.00000 | 0 |
| 3c | Less PJM integration Costs included in A&G | (Note Y) | 0 | W/S | 0.00000 | 0 |
| 4 | Less FERC Annual Fees | 350.14.b | 0 | W/S | 0.00000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I) | | 0 | W/S | 0.00000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | | 0 | TE | 0.00000 | 0 |
| 6 | Common | 356.1 | 0 | CE | 0.00000 | 0 |
| 7 | Transmission Lease Payments | | 0 | | 1.00000 | 0 |
| 8 | TOTAL O&M (Sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | | $ - | | | $ - |
| | DEPRECIATION EXPENSE | | | | | |
| 9 | Transmission | 336.7.b | $ - | TP | 0.00000 | $ - |
| 10 | General | 336.10.b | 0 | W/S | 0.00000 | 0 |
| 11 | Common | 336.11.b | 0 | CE | 0.00000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | | $ - | | | $ - |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | 263.i | $ - | W/S | 0.00000 | $ - |
| 14 | Highway and vehicle | 263.i | 0 | W/S | 0.00000 | 0 |
| 15 | PLANT RELATED | | | | | |
| 16 | Property | 263.i | 0 | GP | 0.00000 | 0 |
| 17 | Gross Receipts | 263.i | 0 | NA | zero | 0 |
| 18 | Other | 263.i | 0 | GP | 0.00000 | 0 |
| 19 | Payments in lieu of taxes | | 0 | GP | 0.00000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | | $ - | | | $ - |
| | INCOME TAXES (Note K) | | | | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.000000% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.000000% | | | |
| | where WCLTD=(page 4, line 27) and R= (page 4, line 30) | | | | | |
| | and FIT, SIT & p are as given in footnote K. | | | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit | 266.8.f (enter negative) | 0 | | | |
| 25 | Income Tax Calculation (line 22 * line 28) | | $ - | NA | | $ - |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.00000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | $ - | | | $ - |

| | | | | |
|---|---|---|---|---|
| 28 | RETURN<br>[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)] | $ - | NA | $ - |
| 29 | REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28) | $ - | | $ - |

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)
SUPPORTING CALCULATIONS AND NOTES

| Line No. | **TRANSMISSION PLANT INCLUDED IN ISO RATES** | | | |
|---|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | $ | - |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N) | | | 0 |
| 4 | Transmission plant included in ISO Rates (line 1 less lines 2 & 3) | | $ | - |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP= | | 0.00000 |
| | **TRANSMISSION EXPENSES** | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | $ | - |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | $ | - |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE= | | 0.00000 |

**WAGES & SALARY ALLOCATOR (W&S)**

| Line No. | | Form 1 Reference | $ | TP | Allocation | | W&S Allocator ($ / Allocation) | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | Production | 354.20.b | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 354.21.b | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 354.23.b | 0 | 0.00 | 0 | | | | |
| 15 | Other | 354.24,25,26.b | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | | 0 | | 0 | = | 0.00000 | = | WS |

**COMMON PLANT ALLOCATOR (CE) (Note O)**

| Line No. | | | $ | % Electric (line 17 / line 20) | | W&S Allocator (line 16) | | CE |
|---|---|---|---|---|---|---|---|---|
| 17 | Electric | 200.3.c | 0 | | | | | |
| 18 | Gas | 201.3.d | 0 | 0.00000 | * | 0.00000 | = | 0.00000 |
| 19 | Water | 201.3.e | 0 | | | | | |
| 20 | Total (sum lines 17 - 19) | | 0 | | | | | |

**RETURN (R)**

| Line No. | | | | $ |
|---|---|---|---|---|
| 21 | | Long Term Interest (117, sum of 62.c through 67.c) | | 0 |
| 22 | | Preferred Dividends (118.29c) (positive number) | | 0 |
| | Development of Common Stock: | | | |
| 23 | | Proprietary Capital (112.16.c) | | 0 |
| 24 | | Less Preferred Stock (line 28) | | 0 |
| 25 | | Less Account 216.1 (112.12.c) (enter negative) | | 0 |
| 26 | | Common Stock | (sum lines 23-25) | 0 |

| Line No. | | (Note P) | $ | % | Cost | Weighted | | |
|---|---|---|---|---|---|---|---|---|
| 27 | Long Term Debt (112, sum of 18.c through 21.c) | | 0 | 0% | 0.0000 | 0.0000 | = | WCLTD |
| 28 | Preferred Stock (112.3.c) | | 0 | 0% | 0.0000 | 0.0000 | | |
| 29 | Common Stock (line 26) | | 0 | 0% | 0.1238 | 0.0000 | | |
| 30 | Total (sum lines 27-29) | | 0 | | | 0.0000 | = | R |

**REVENUE CREDITS**

| Line | Description | Reference | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) (Note Q) | (310-311) | |
| 31 | a. Bundled Non-RQ Sales for Resale (311.x.h) | | 0 |
| 32 | b. Bundled Sales for Resale included in Divisor on page 1 | | - |
| 33 | Total of (a)-(b) | | 0 |
| 34 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $ - |
| 35 | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U) | (330.x.n) | $ - |

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

A DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C Reserved

D Reserved

E This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | |
| | SIT= | 0.00% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Reserved

T The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

U On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.

V Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Reserved

X Midwest ISO Fees include (1) the charges that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.

Y PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

For the 12 months ended 12/31/_____

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

| | Line No. | | Source | Revenue Requirement | |
|---|---|---|---|---|---|
| A. | Schedule 1A Annual Revenue Requirements | | | | |
| | 1 | Total Load Dispatch & Scheduling (Account 561) | Attachment H-22A, Page 4, Line 7 | $ - | |
| | 2 | Revenue Credits for Schedule 1A - Note A | | $ - | |
| | 3 | Net Schedule 1A Revenue Requirement for Zone | | $ - | |
| B. | Schedule 1A Rate Calculations | | | | |
| | 4 | 2010 Annual MWh - Note B | (401a.22b & 24b) | - | MWh |
| | 5 | Schedule 1A rate $/MWh (Line 3 / Line 4) | (Line 3 / Line 4) | $0.0000 | $/MWh |

Notes:

A Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of DEOK's zone during the year used to calculate rates under Attachment H-22A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Line No. | | Attachment H-22A Page, Line, Col. | Transmission | Allocator |
| | TRANSMISSION PLANT | | | |
| 1 | Gross Transmission Plant - Total | Sch. H-22A, p 2, line 2 col 5 (Note A) | - | |
| 2 | Net Transmission Plant - Total | Sch. H-22A, p 2, line 14 col 5 (Note B) | - | |
| | O&M EXPENSE | | | |
| 3 | Total O&M Allocated to Transmission | Sch. H-22A, p 3, line 8 col 5 | - | |
| 4 | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | 0.00% | 0.00% |
| | GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| 5 | Total G&C Depreciation Expense | Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H) | - | |
| 6 | Annual Allocation Factor for G&C Depreciation Expense | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| | TAXES OTHER THAN INCOME TAXES | | | |
| 7 | Total Other Taxes | Sch. H-22A, p 3, line 20 col 5 | - | |
| 8 | Annual Allocation Factor for Other Taxes | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| **9** | **Annual Allocation Factor for Expense** | **Sum of lines 4, 6 and 8** | | **0.00%** |
| | INCOME TAXES | | | |
| 10 | Total Income Taxes | Sch. H-22A, p 3, line 27 col 5 | - | |
| 11 | Annual Allocation Factor for Income Taxes | (line 8 divided by line 2 col 3) | 0.00% | 0.00% |
| | RETURN | | | |
| 12 | Return on Rate Base | Sch. H-22A, p 3, line 28 col 5 | - | |
| 13 | Annual Allocation Factor for Return on Rate Base | (line 10 divided by line 2 col 3) | 0.00% | 0.00% |
| **14** | **Annual Allocation Factor for Return** | **Sum of lines 11 and 13** | | **0.00%** |

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

**Network Upgrade Charge Calculation By Project**

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name | RTEP Project Number | Project Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation Expense | Annual Revenue Requirement | True-Up Adjustment | Network Upgrade Charge |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 12) | (Col. 6 * Col. 7) | (Note E) | (Sum Col. 5, 8 & 9) | (Note F) | Sum Col. 10 & 11 (Note G) |
| 1b | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 1c | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 2 | Annual Totals | | | | | | | | | $0 | $0 | $0 |
| 3 | RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c | | | | | | | | | | | $0 |

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A

| Line No. | (1) | (2) Attachment H-22A Page, Line, Col. | (3) Transmission | (4) Allocator |
|---|---|---|---|---|
| | TRANSMISSION PLANT | | | |
| 1 | Gross Transmission Plant - Total | Sch. H-22A, p 2, line 2 col 5 (Note A) | - | |
| 2 | Net Transmission Plant - Total | Sch. H-22A, p 2, line 14 col 5 (Note B) | - | |
| | O&M EXPENSE | | | |
| 3 | Total O&M Allocated to Transmission | Sch. H-22A, p 3, line 8 col 5 | - | |
| 4 | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | 0.00% | 0.00% |
| | GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| 5 | Total G&C Depreciation Expense | Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H) | - | |
| 6 | Annual Allocation Factor for G&C Depreciation Expense | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| | TAXES OTHER THAN INCOME TAXES | | | |
| 7 | Total Other Taxes | Sch. H-22A, p 3, line 20 col 5 | - | |
| 8 | Annual Allocation Factor for Other Taxes | (line 5 divided by line 1 col 3) | 0.00% | 0.00% |
| **9** | **Annual Allocation Factor for Expense** | **Sum of lines 4, 6 and 8** | | **0.00%** |
| | INCOME TAXES | | | |
| 10 | Total Income Taxes | Sch. H-22A, p 3, line 27 col 5 | - | |
| 11 | Annual Allocation Factor for Income Taxes | (line 8 divided by line 2 col 3) | 0.00% | 0.00% |
| | RETURN | | | |
| 12 | Return on Rate Base | Sch. H-22A, p 3, line 28 col 5 | - | |
| 13 | Annual Allocation Factor for Return on Rate Base | (line 10 divided by line 2 col 3) | 0.00% | 0.00% |
| **14** | **Annual Allocation Factor for Return** | **Sum of lines 11 and 13** | | **0.00%** |

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

**Network Upgrade Charge Calculation By Project**

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name | MTEP Project Number | Project Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation Expense | Annual Revenue Requirement | True-Up Adjustment | Network Upgrade Charge |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 12) | (Col. 6 * Col. 7) | (Note E) | (Sum Col. 5, 8 & 9) | (Note F) | Sum Col. 10 & 11 (Note G) |
| 1b | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 1c | | | $ - | 0.00% | $0.00 | $ - | 0.00% | $0.00 | $0 | $0.00 | $ - | $0.00 |
| 2 | Annual Totals | | | | | | | | | $0 | $0 | $0 |
| 3 | Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a | | | | | | | | | | | $0 |

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

| FERC Account Number (A) | Company Account Number (B) | Description (C) | Actual Accrual Rates (D) % |
|---|---|---|---|
| | | **Wholly Owned Transmission Plant** | |
| 350 | 3403 | Rights of Way | 1.54 |
| 352 | 3420 | Structures & Improvements | 1.90 |
| 352 | 3424 | Structures & Improvements - Duke Ohio - Loc. in Ky. | 1.90 |
| 353 | 3430 | Station Equipment | 1.44 |
| 353 | 3434 | Station Equipment - Duke Ohio - Loc. in Ky. | 1.44 |
| 354 | 3440 | Towers & Fixtures | 1.85 |
| 354 | 3444 | Towers & Fixtures - Duke Ohio - Loc. in Ky. | 1.85 |
| 355 | 3450 | Poles & Fixtures | 2.31 |
| 355 | 3454 | Poles & Fixtures - Duke Ohio - Loc. in Ky. | 2.31 |
| 356 | 3460 | Overhead Conductors & Devices | 1.91 |
| 356 | 3464 | Overhead Conductors & Devices - Duke Ohio - Loc. in Ky. | 1.91 |
| 357 | 3470 | Underground Conduit | 1.43 |
| 358 | 3480 | Underground Conductors & Devices | 2.37 |
| | | **Commonly Owned Transmission Plant - CCD Projects** | |
| 352 | 3421 | Structures & Improvements - CCD Projects | 2.50 |
| 352 | 3425 | Structures & Improvements - CCD Projects | 2.50 |
| 353 | 3431 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3432 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3435 | Station Equipment - CCD Projects | 1.44 |
| 353 | 3437 | Station Equipment - CCD Projects | 1.44 |
| 354 | 3441 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3442 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3445 | Towers & Fixtures - CCD Projects | 3.00 |
| 354 | 3446 | Towers & Fixtures - CCD Projects - Loc. In Ky. | 3.00 |
| 354 | 3448 | Towers & Fixtures - CCD Projects | 3.00 |
| 355 | 3451 | Poles & Fixtures - CCD Projects | 3.00 |
| 355 | 3455 | Poles & Fixtures - CCD Projects | 3.00 |
| 356 | 3461 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3462 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3465 | Overhead Conductors & Devices - CCD Projects | 2.50 |
| 356 | 3466 | Overhead Conductors & Devices - CCD Projects - Loc. In Ky. | 2.50 |
| | | **Commonly Owned Transmission Plant - CD Projects** | |
| 352 | 3423 | Structures & Improvements - CD Projects | 2.50 |
| 353 | 3433 | Station Equipment - CD Projects | 1.44 |
| 353 | 3438 | Station Equipment - CD Projects | 1.44 |
| 354 | 3447 | Towers & Fixtures - CD Projects | 3.00 |
| 356 | 3467 | Overhead Conductors & Devices - CD Projects | 2.50 |
| | | **General and Intagible Plant** | |
| 303 | 3030 | Miscellaneous Intangible Plant | 20.00 |
| 389 | 3890 | Land and Land Rights | N/A |
| 390 | 3900 | Structures and Improvements | 2.50 |
| 391 | 3910 | Office Furniture and Equipment | 2.00 |
| 391 | 3911 | Electronic Data Processing Equipment | 20.00 |
| 391 | 3920 | Transportation Equipment | 8.33 |
| 391 | 3921 | Trailers | 4.25 |
| 392 | 3940 | Tools, Shop & Garage Equipment | 4.00 |
| 392 | 3950 | Laboratory Equipment | 6.67 |
| 393 | 3960 | Power Operated Equipment | 5.88 |
| 393 | 3970 | Communication Equipment | 6.67 |
| 394 | 3980 | Miscellaneous Equipment | 5.00 |

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

| FERC Account Number (A) | Company Account Number (B) | Description (C) | Actual Accrual Rates (D) |
|---|---|---|---|
| | | | % |
| | | **Transmission Plant** | |
| 350 | 3501 | Rights of Way | 1.48 |
| 352 | 3520 | Structures & Improvements | 0.41 |
| 353 | 3530 | Station Equipment | 2.25 |
| 353 | 3532 | Station Equipment - Major | 2.77 |
| 353 | 3535 | Station Equipment – Electronic | 9.55 |
| 355 | 3550 | Poles & Fixtures | 2.28 |
| 356 | 3560 | Overhead Conductors & Devices | 2.31 |
| | | **General and Intangible Plant** | 20.00 |
| 303 | 3030 | Miscellaneous Intangible Plant | 1.77 |
| 390 | 3900 | Land and Land Rights | 18.56 |
| 391 | 39110 | Structures and Improvements | 6.53 |
| 392 | 3921 | Electronic Data Processing Equipment | 4.14 |
| 394 | 3940 | Transportation Equipment | 6.93 |
| 397 | 3970 | Stores Equipment | |

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Firm PTP Service Revenue Credit Adjustment Calculation

To be completed in conjunction with Attachment H-22A

| | (1) | (2) | (3) |
|---|---|---|---|
| No. | | Reference | Company Total |
| | **REVENUE CREDIT TRUE-UP** | | |
| 1 | Difference Between Revenue Received In PJM vs. Midwest ISO | (Note A) | $0 |
| | **ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP** | | |
| 2 | Accumulated Balance of Deferral | (Note B) | $0 |
| 3 | Income Tax Rate for Deferral Calculation | (Note C) | 0.00% |
| 4 | Deferred Income Taxes on Accumulated Deferral (line 2 * line 3) | | $0 |
| 5 | Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4) | | $0 |
| | **INCOME TAXES** | | |
| 6 | CIT = (T/(1-T)) * (1 - (WCLTD/R)) | Attachment H-22, page 3, line 22 | 0.00% |
| 7 | Income Taxes (Line 6 * Line 9) | | $0 |
| | **CARRYING COST ON DEFERRAL** | | |
| 8 | FERC Refund Rate | (Note D) | 0.00% |
| 9 | Carrying Cost (Line 5 * Line 8) | | $0 |
| 10 | Revenue Credit Adjustment (Line 1 + Line 7 + Line 9) | | $0 |

Notes
A. From Appendix E, Workpaper, Column (4).
B. Accumulated balance of deferral as of December 31st of the year prior to effective date of new rate.
C. Effective deferred tax rate during applicable test year.
D. FERC Refund Rate is the approved rate as of December 31 of calendar prior to the rate year (see 18 C.F.R. Section 35.19a).

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

| (1) Period | (2) Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A) | (3) Actual Firm PTP Service Revenue Received from PJM (Note B) | (4) = (2) - (3) Difference Between Revenue Received and Amount in Rates Excluding True Up | (5) Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C) | (6) = (4) - (5) Amount Deferred for Future Recovery | (7) = Prior month's Balance + (6) Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment |
|---|---|---|---|---|---|---|
| Jan-12 | $ - | $ - | $ - | | $ - | $ - |
| Feb-12 | - | - | - | | - | - |
| Mar-12 | - | - | - | | - | - |
| Apr-12 | - | - | - | | - | - |
| May-12 | - | - | - | | - | - |
| Jun-12 | - | - | - | | - | - |
| Jul-12 | - | - | - | | - | - |
| Aug-12 | - | - | - | | - | - |
| Sep-12 | - | - | - | | - | - |
| Oct-12 | - | - | - | | - | - |
| Nov-12 | - | - | - | | - | - |
| Dec-12 | - | - | - | | - | - |
| **Total** | | | | $ | $ - | - |
| | | | | | | - |
| Jan-13 | - | - | - | | $ - | - |
| Feb-13 | - | - | - | | - | - |
| Mar-13 | - | - | - | | - | - |
| Apr-13 | - | - | - | | - | - |
| May-13 | - | - | - | | - | - |
| Jun-13 | | | - | - | - | - |
| Jul-13 | | | | - | - | - |
| Aug-13 | | | | - | - | - |
| Sep-13 | | | | - | - | - |
| Oct-13 | | | | - | - | - |
| Nov-13 | | | | - | - | - |
| Dec-13 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |
| Jan-14 | | | | $ - | $ - | $ - |
| Feb-14 | | | | - | - | - |
| Mar-14 | | | | - | - | - |
| Apr-14 | | | | - | - | - |
| May-14 | | | | - | - | - |
| Jun-14 | | | | - | - | - |
| Jul-14 | | | | - | - | - |
| Aug-14 | | | | - | - | - |
| Sep-14 | | | | - | - | - |
| Oct-14 | | | | - | - | - |
| Nov-14 | | | | - | - | - |
| Dec-14 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |
| Jan-15 | | | | $ - | $ - | $ - |
| Feb-15 | | | | - | - | - |
| Mar-15 | | | | - | - | - |
| Apr-15 | | | | - | - | - |
| May-15 | | | | - | - | $ - |
| **Total** | | | | $ - | $ - | |

Notes:

A. Monthly Firm PTP service revenue from Midwest ISO during test year applicable to currently effectives NITS and PTP service rates.

B. Actual monthly Firm PTP service revenue received from PJM during current period.

C. Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.
The recovery of the 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.

## ATTACHMENT H-22B
## DEOK FORMULA RATE IMPLEMENTATION PROTOCOLS

**Definitions**

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by DEOK on or before May 15 of each year that sets forth the DEOK Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on DEOK as provided in Section 2.b below.

"DEOK" means Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc.

"First Rate Year" means the period that begins on January 1, 2012, and ends on May 31, 2012.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("FERC") as provided in Section 3.a below.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Attachment H-22A of the PJM Tariff.

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in DEOK's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate different from the result under the Formula Rate as calculated without such change.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to DEOK as provided in Section 2.a below.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1.b below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year except for the First Rate Year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2.a below.

**Section 1 <u>Annual Updates</u>**

a. Beginning with the Rate Year that commences on June 1, 2012, and during each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-22A and the Network Integration Transmission Service and Point-to-Point rates derived therefrom shall be applicable to transmission services provided by PJM for the DEOK zone during the Rate Year.

b. On or before May 15, 2012, and on or before May 15 of each succeeding Rate Year, DEOK shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year, and:
   (i) post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;
   (ii) submit such Annual Update as an informational filing with the FERC;
   (iii) provide contact information for inquiries concerning the Annual Update;
   (iv) send an email or other similar electronic communication to all Interested Parties that have previously requested such notification through procedures to be established by DEOK that informs the recipient that the Annual Update is available and that provides the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

d. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's "Publication Date."

e. Within two business days of the Publication Date, DEOK shall also provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit DEOK to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from DEOK about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on DEOK's books, which reflect:
   (i) the FERC's Uniform System of Accounts, and

(ii) applicable FERC Form No. 1[1] as each exists as of the later of the date of DEOK's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

g. The Annual Update for the Rate Year:

(i) shall, to the extent specified in the Formula Rate, be based upon DEOK's FERC Form No. 1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of DEOK consistent with Section 1.f above;

(ii) shall, as and to the extent specified in the Formula Rate, provide the formula rate calculations and all inputs thereto, as well as supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[2]

(iii) shall provide sufficient information[3] to enable customers to replicate the calculation of the formula results from FERC Form No. 1 and other applicable accounting inputs and to compare that calculation to that of prior years, including all workpapers necessary to explain any changes made since the last update, and to include as applicable:

(1) a copy of the FERC Form No. 1 used for the update if it is not otherwise publicly available;

(2) identification of any changes in the formula references to the FERC Form No. 1;

(3) identification of all adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in a FERC Form No. 1 footnote;

1. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

2. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 for the most recent calendar year or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information provided by DEOK with the Annual Update. Where the reconciliation is provided through a worksheet included in the filed Formula Rate Template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

3. As appropriate, competitively sensitive information may be provided only to those persons bound by the terms of a suitable confidentiality agreement or protective order.

(4) a reconciliation of annual and monthly peak demands shown on the FERC Form 1 and annual and monthly peak demands used in the formula in sufficient detail to enable transparent reconciliation of these two measures;

(5) a description of those factors influencing any change in the annual revenue requirement, including an identification of any respects in which charges under the formula rate materially differ from the preceding Annual Update (e.g., due to changes in accounting procedures, the purchase or sale of major assets, or other such significant changes) and identification of the major reason(s) for the differences, if any, between the Annual Update and the prior year's Annual Update; and

(6) any changes to the data inputs made as a result of a reconciliation made under Section 4 below.

(iv) shall describe material changes, if any, in DEOK's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or did affect the charges under the Formula Rate ("Material Accounting Changes");[4]

(v) shall be subject to challenge and review only in accordance with the procedures set forth in this Attachment H-22B, as to the appropriateness of the input data, the prudence of the costs and expenditures included for recovery in the Annual Update, and the application of the Formula Rate according to its terms and the procedures in this Attachment H-22B (including terms and procedures related to challenges concerning Material Accounting Changes);

(vi) except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act ("FPA") Section 205 or Section 206 filing).

h. Formula Rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other Than Pensions ("PBOP") shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or Section 206 to modify stated values for depreciation rates or PBOP expense under the Formula Rate or Protocols shall not open review of other components of the Formula Rate or Protocols.

i. Extraordinary property losses recorded in FERC Account 182.1 shall be amortized for Formula Rate purposes pursuant to a Section 205 or 206 filing made effective by the Commission.

[4] Such notice may incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

j. Any change to the underlying Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f above shall be grounds for a presumption that the application of the Formula Rate shall be modified to restore the balance of the Formula Rate as accepted by the FERC (the intent being to prevent such changes in these underlying Uniform System of Accounts or FERC Form No. 1 from causing an automatic shift in the charges calculated under the Formula Rate without input from other interested parties). Any interested party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, shall first raise the matter with DEOK.

**Section 2 <u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested parties shall have up to one hundred eighty (180) days after the Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify DEOK in writing, which may be made electronically, of any specific challenges, including challenges related to the rate treatment of Material Accounting Changes, to the application of the Formula Rate and to changes to the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, above, ("Preliminary Challenge"). Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not bar a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

b. Interested Parties shall have up to one hundred fifty (150) days after each annual Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to serve reasonable information requests on DEOK. Such information requests shall be limited to what is necessary to determine if DEOK has properly applied the Formula Rate, the requirements and procedures of this Attachment H-22B, and the prudence of the costs and expenditures included for recovery in the Annual Update, and shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

c. DEOK shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by DEOK within the Discovery Period and for which DEOK is unable to provide a response within fifteen (15) business days after the end of the Discovery Period, the Review Period shall be extended day-for-day until DEOK's response is provided.

d. To the extent DEOK and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, DEOK or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

e. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

f. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

g. In any proceeding initiated to address a Preliminary or Formal Challenge or *sua sponte* by the FERC, a party or parties seeking to modify the Formula Rate in any respect shall bear the applicable burden under the FPA.

**Section 3** **<u>Resolution of Challenges</u>**

a. If DEOK and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of DEOK to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the FERC, which shall be served on DEOK by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify DEOK of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issues in a Preliminary Challenge or Formal Challenge.

b. Any response by DEOK to a Formal Challenge must be submitted to the FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

c. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, DEOK shall bear the burden, consistent with Section 205 of the

Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate, consistent with Section 1.g(v), and that it followed the applicable requirements and procedures in this Attachment H-22B, in that year's Annual Update. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

d. Subject to judicial review of FERC orders, each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols or by any other means by the FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

e. Nothing herein shall be deemed to limit in any way the right of DEOK to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of DEOK or any Interested Party to initiate a proceeding at the FERC at any time with respect to the Formula Rate or any Annual Update consistent with the party’s full rights under the FPA, including Sections 205, 206 and 306, and the FERC’s regulations.

f. Subject to Section 2.e above, it is recognized that resolution of Formal Challenges concerning Material Accounting Changes or related to the Uniform System of Accounts or FERC Form No. 1 as described above may necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the Formula Rate to achieve a just and reasonable end result consistent with the intent of the Formula Rate.

g. In making or resolving any Preliminary or Formal Challenge under this Section, a party may rely on all information provided by DEOK, including information provided under the terms of a confidentiality agreement or protective order; provided, however, that parties receiving such information pursuant to a confidentiality agreement or protective order shall be bound by the restrictions placed by such agreement or order on disclosure or use of confidential information.

## Section 4 <u>Changes to Annual Informational Filings</u>

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year’s FERC Form No. 1 report of Duke Energy Kentucky, Inc., or Duke Energy Ohio, Inc., or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any FERC proceeding to consider a prior year's Annual Update, DEOK shall promptly notify the Interested Parties, file a correction to the Annual Update with the FERC as an amended informational filing describing the change(s) and the cost impact, and provide a copy of the amended informational filing to PJM for prompt posting by PJM.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by DEOK and the Interested Parties, a correction made under Section 4.a prior to the time determined for filing of a Formal Complaint shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Party Annual Review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the Annual Review shall then be limited to the aspects of the Formula Rate affected by the corrections.

## ATTACHMENT H-22C

## ADDITIONAL PROVISIONS REGARDING DEOK AND INDIANA MUNICIPAL POWER AGENCY

Duke Energy Ohio, Inc. ("DEO"), a corporation organized and existing under the laws of the State of Ohio, and Duke Energy Kentucky, Inc. ("DEK"), a corporation existing under the laws of the State of Kentucky, and the Indiana Municipal Power Agency ("IMPA") (each a "Settling Party" and all collectively, the "Settling Parties"), shall be subject to the provisions of this Attachment, which implements the Settlement Agreement ("Agreement") entered into between the Duke Companies and IMPA in Docket Nos. ER12-91-000 and ER12-92-000 on April 5, 2012.

### ARTICLE I
### [Reserved]

### ARTICLE II
### DEFINITIONS; RULES OF INTERPRETATION AND CONSTRUCTION

2.1 All defined terms have the meanings set forth in this Attachment. All rules of construction and interpretation of this Attachment shall be as set forth in the PJM Tariff or PJM Agreements.

The "Duke Companies" means Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

"DEO" means Duke Energy Ohio, Inc.

"IMPA" means the Indiana Municipal Power Agency.

"IMPA PJM RTEP Credit Cap" initially shall be $575,000, and shall be adjusted as described in Section 4.1.

"Internal Integration Costs" means internal integration costs identified in the Duke Companies' filing submitted in Docket Nos. ER12-91-000 and ER12-92-000 as costs incurred by the Duke Companies in connection with their move into PJM that are recovered from IMPA under the Duke Companies' PJM Formula Rate or otherwise.

"Legacy MTEP Costs" means all costs associated with, or relating to, any obligation of the Duke Companies or IMPA to pay any portion of the costs of MISO Transmission Expansion Planning ("MTEP") projects identified and approved by the MISO Board of Directors prior to the Duke Companies' integration into PJM, including any such costs related to Multi-Value Projects ("MVP").

"MISO" or "Midwest ISO" means the Midwest Independent Transmission System Operator, Inc.

"PJM" means PJM Interconnection, L.L.C.

"PJM Agreements" means the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, and the Consolidated Transmission Owners Agreement.

"PJM Formula Rate" means the formula rate and rate protocols identified and submitted by the Duke Companies in the filing in Docket Nos. ER12-91-000 and ER12-92-000.

"PJM RTEP Costs" means costs charged by PJM to IMPA under Schedule 12 of the PJM Tariff associated with a PJM Regional Transmission Expansion Plan ("RTEP"). Costs associated with facilities owned by PJM transmission owners other than the Duke Companies and charged to IMPA under a successor rate schedule will also be considered PJM RTEP Costs for purposes of this Attachment.

"PJM Tariff" means PJM Interconnection, L.C.C. Open Access Transmission Tariff.

"PJM Transition Costs" means costs identified as "Transition Costs" in the Duke Companies' filings submitted in Docket Nos. ER12-91-000 and ER12-92-000 and included in the proposed PJM Formula Rate, specifically, costs associated with: (1) the Duke Companies' requirement under Article Five, Section II.B of the MISO Transmission Owners' Agreement ("MISO TOA") to pay certain amounts to MISO as an exit fee ("MISO Exit Fee"); (2) the Duke Companies' agreement, approved by the Commission in Docket No. ER11-2059-000, to pay MISO $1.8 million to resolve a dispute over MISO tariff revisions proposed to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the withdrawal of the Duke Companies from MISO ("MISO LTTR Exit Charge"); and (3) the Duke Companies' agreement to pay PJM approximately $1 million as compensation for PJM's costs incurred in connection with the Duke Companies' transition to PJM ("PJM Integration Costs").

## ARTICLE III
## SCOPE OF ATTACHMENT

3.1. The Settling Parties hereby settle and resolve all issues between them involving the matters raised in Docket Nos. ER12-91-000 and ER12-92-000, on the terms set forth in the following Article IV.

## ARTICLE IV
## TERMS

4.1. The Duke Companies commit as follows:

(a) Reimbursement of PJM Transition Costs & Internal Integration Costs.

For each billing month, DEO agrees to reimburse IMPA for any amounts owed to the Duke Companies by IMPA for that month for the portion of PJM Transition Costs and Internal Integration Costs associated with the load IMPA serves for the Village of Blanchester, Ohio.

(b) Crediting Payment of PJM RTEP Costs.

i. DEO agrees to utilize the PJM billing line-item transfer process to credit IMPA amounts equal to the monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, until total DEO line-item transfers to IMPA under this provision equal the initial IMPA PJM RTEP Credit Cap, as follows:

a. Initially, the IMPA PJM RTEP Credit Cap shall be $575,000, subject to adjustment as set forth in subparagraph 4.1(b).i.b and 4.1(b).i.d.

b. For each billing month for which IMPA has or will have paid RTEP costs, regardless of whether prior to the Effective Date of this Attachment, until the month in which the IMPA PJM RTEP Credit Cap is reached, DEO agrees to execute and perform a billing line-item transfer, in accordance with PJM financial settlement rules and procedures, equal to any amounts charged to IMPA that month by PJM for PJM RTEP Costs associated with the load that IMPA serves for the Village of Blanchester, Ohio. The IMPA PJM RTEP Credit Cap will be decremented by the same amount.

c. In the event that any month's PJM RTEP Cost charged by PJM with respect to the load that IMPA serves for the Village of Blanchester, Ohio exceeds the remaining balance of the IMPA PJM RTEP Credit Cap, DEO shall not have an obligation to execute and perform a billing line-item transfer for an amount equal to the remaining balance of the IMPA PJM RTEP Credit Cap, but instead shall directly reimburse IMPA for the remaining balance amount. In the event it is determined that IMPA has been compensated for an amount that exceeds the IMPA RTEP Credit Cap, IMPA shall, upon receipt of suitable documentation from the Duke Companies, and within 120 days, refund said over payment. Thereafter DEO shall have no further obligation under this Attachment to execute and perform any line item transfer or otherwise reimburse IMPA in connection with PJM RTEP Costs charged to IMPA. Upon being notified the IMPA RTEP Credit Cap has been reached, by virtue of billing line-item transfer, or direct payment by the Duke Companies, IMPA will work with the Duke Companies, and PJM to cancel the Declaration of Authority that allows for such billing line-item transfer.

d. In the event that the PJM Formula Rate as filed by the Duke Companies is modified for any reason, the IMPA PJM Credit Cap shall be adjusted as follows:

1. Within 30 days of issuance of an order modifying the PJM Formula Rate, the Duke Companies shall in good faith estimate the annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Estimated Annual Adjustment") and the amount of IMPA's RTEP payments ("Estimated Annual RTEP Amount") for each year through 2022. IMPA will review the estimate and give good faith commentary, and the Settling Parties will work in good faith to arrive at mutually acceptable estimates.

2. Prior to each year, the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the coming year will be compared.

3. If the Estimated Annual Adjustment is equal to or greater than the Estimated Annual RTEP Amount, DEO shall not credit IMPA any amount during the coming year. If a Declaration of Authority has been provided to PJM allowing for a billing line-item transfer of RTEP costs to the Duke Companies, IMPA will work with PJM and the Duke Companies to cancel such transfer, effective January 1, for the year in which the Estimated Annual Adjustment is greater than the Estimated Annual RTEP Amount.

4. If the Estimated Annual Adjustment is less than the Estimated Annual RTEP Amount, DEO shall compensate IMPA for the difference. DEO shall have the option of compensating IMPA through PJM billing line-item transfers and/or through direct compensation, and shall have the option of tendering such compensation in up to 12 equal monthly installments during the course of the year in question. DEO shall notify IMPA of the method and intervals of payment before the year begins. In the event DEO elects to utilize a billing line-item transfer to effectuate compensation to IMPA, IMPA will work with the Duke Companies to provide a suitable Declaration of Authority to PJM, that allows for such billing line-item transfer.

5. Within 30 days following the end of the year, DEO will true up the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the prior year using actual data. The true-up will result in determination of the actual annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Actual Annual Adjustment") and the actual amount of IMPA's RTEP payments ("Actual Annual RTEP Amount"). DEO will provide the true up calculation and supporting data to IMPA for review. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment exceeds the amount paid to IMPA by DEO for the year in question, DEO will reimburse IMPA for the difference. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment is less than the amount paid to IMPA by DEO, IMPA will reimburse DEO for the difference. However, in no event shall IMPA be obligated to reimburse DEO an amount under this provision that exceeds the total amount paid by DEO to IMPA during the year in question, and in no event shall DEO be required to pay to IMPA an amount that would cause the remaining balance of the IMPA PJM RTEP Credit Cap to be less than zero, after the adjustment to the IMPA PJM RTEP Credit Cap described in the next paragraph. All reimbursements due under this provision shall be paid within 60 days following the end of the year.

6. Once the trued-up amounts are known, the IMPA PJM RTEP Credit Cap will be decremented by the higher of the Actual Annual RTEP Amount or the Actual Annual Adjustment, thereby reflecting the actual value received by IMPA in the year in question.

7. The parties shall discuss in good faith, at least once per year, whether adjustments should be made to the following year's estimated amounts.

8. If the PJM Formula Rate is accepted subject to refund and set for hearing, DEO will perform PJM billing line-item transfers to credit IMPA's RTEP amount until FERC issues a final order on the PJM Formula Rate, to the extent otherwise consistent with this

Attachment. If (a) FERC's order results in an adjustment to the proposed PJM Formula Rate, and therefore requires an adjustment to the IMPA PJM RTEP Credit Cap per the methodology described above, and (b) as a result of such adjustment DEO has overpaid on the credit, then credit overpayments shall be netted against refund obligations to IMPA, and the refund obligation would be reduced correspondingly.

e. Hypothetical example calculation: IMPA PJM RTEP Credit Cap is 995 dollars; monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, are 20 dollars. Each month for the first 49 months, PJM would bill IMPA $20, and DEO would perform a billing line item transfer to credit IMPA $20, such that IMPA's net obligation to PJM for PJM RTEP Costs in each such month would be $0. During each of these months, the remaining balance of the IMPA PJM RTEP Credit Cap would be reduced by $20. Thus, after 49 months, the IMPA PJM RTEP Credit Cap would be reduced by $980 (49 months x $20/month), such that the remaining balance would be $15 ($995-$980=$15). Because the remaining balance of $15 would be less than the next month's PJM RTEP Cost of $20, in that next (50th) month: PJM would bill IMPA $20, IMPA would pay PJM $20, and DEO would reimburse IMPA for the $15 remaining balance of the IMPA PJM RTEP Credit Cap. Thereafter, DEO would no longer be obligated under this Attachment to perform billing line item transfers associated with IMPA's PJM RTEP Costs, or to otherwise reimburse IMPA for such costs.

ii. DEO agrees to act in good faith and use commercially reasonable efforts in cooperation with IMPA to establish and implement a billing line-item transfer as contemplated in Paragraph 4.1 above. If at any time for any reason the billing line-item transfer mechanism for reimbursing IMPA cannot be effectuated, DEO shall implement an alternate mechanism, such as direct reimbursement to IMPA, to achieve the same result as contemplated in Paragraph 4.1.b.i above.

4.2 IMPA agrees and commits as follows:

(a) Lawfulness and Effectiveness of Rate as Filed

The Settling Parties acknowledge and agree that the PJM Formula Rate and related protocols submitted by the Duke Companies in the above-referenced proceeding will not be amended or revised in any respect or for any reason as a result of, or associated with, this Attachment. The Settling Parties further agree that (a) the considerations provided by the Duke Companies under this Attachment to IMPA are in resolution of "hold harmless" claims made by IMPA pursuant to Article V, Section 2 of the Midwest ISO Transmission Owners Agreement and resolve all claims raised by IMPA in these proceedings; and that (b) the obligation of the Duke Companies to provide such considerations is contingent upon the Commission not modifying the Agreement. IMPA agrees to fully pay its share of the rates as approved by the Commission in Docket Nos. ER12-91-000 and ER12-92-000, including but not limited to its share of Legacy MTEP Costs, subject to the reimbursements and credit established above.

(b) Crediting Payments of PJM RTEP Costs.

IMPA agrees to act in good faith and use commercially reasonable efforts in cooperation with DEO and PJM to negotiate, execute, implement and perform billing line-item transfers as contemplated in Paragraph 4.1 above, and to terminate the line-item transfer process at the time contemplated in Paragraph 4.1 above.

(c) Resolution of All Hold Harmless Obligations.

Payment by DEO of the amounts and credits established in this Attachment according to the terms of this Attachment shall fully satisfy and discharge any and all obligations of the Duke Companies to render payment to IMPA according to the terms of Article V, Section 2 of the Midwest ISO Transmission Owners Agreement in connection with the Duke Companies' withdrawal from MISO, and such satisfaction and discharge shall not be affected by any amendment, substitute or successor to that provision, or any amendment, substitute or successor to the PJM Formula Rate filed in this proceeding. IMPA agrees not to make any protest or raise any claim against the Duke Companies or their parents or affiliates, before any government agency or court, asserting that the Duke Companies or their parents or affiliates owe IMPA or its members, respectively, any further "hold harmless" or other compensation under Article V, Section 2 of the Midwest ISO Transmission Owners Agreement, or any other monies or damages of any nature in connection with the Duke Companies' withdrawal from the Midwest ISO.

(d) Rate of Return

IMPA's protest in the above-referenced proceeding had raised the issue of the Duke Companies' rate of return on equity. Under this Attachment, IMPA is agreeing to move to withdraw its protest as set forth in the following subparagraph and thereby retract any claim that an outcome of this proceeding should be a reduction of the Duke Companies' rate of return on equity. This agreement is without prejudice to IMPA's right to raise the issue of the Duke Companies' rate of return on equity in subsequent proceedings, through a filing under Federal Power Act Section 206 or otherwise, provided that IMPA agrees that it will not (a) initiate a proceeding prior to January 1, 2016 seeking a reduction of the Duke 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 Duke Companies in which the reduction would become effective prior to January 1, 2016.

(e) Withdrawal of Pleadings.

IMPA will move to withdraw its protest filed in the above-referenced proceeding within fifteen (15) days of the earlier of (a) issuance of a Commission order accepting the Agreement without modification or condition, or (b) issuance of a Commission order accepting the PJM Formula Rate, and not modifying or conditioning the Agreement. In the event that the Commission establishes a hearing in these dockets, IMPA agrees not to participate in such hearing.

4.3 The Settling Parties agree that the payments and credits identified in Sections 4.1(a) through 4.1(b) shall not be adjusted, upwards or downwards, for any reason including but not limited to any order eliminating, reducing or otherwise modifying any Settling Party's obligation(s) to pay for any PJM Transition Costs, PJM RTEP Costs or Legacy MTEP Costs.

## ARTICLE V
## MISCELLANEOUS PROVISIONS

5.1. Scope of the Attachment. This Attachment constitutes the entire agreement among the Settling Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no other oral understandings, terms or conditions, and none of the Settling Parties has relied upon any representation, express or implied, not contained in this Attachment. Nothing in this Attachment should be construed as negating or fulfilling the obligations or responsibilities of the Duke Companies or IMPA under the PJM Tariff or PJM Agreements.

5.2. Non-Severability. The Settling Parties agree and understand that the various provisions of this Attachment are not severable and shall not become operative unless and until it becomes effective as described in Section 5.3.

5.3. Effectiveness of Attachment. This Attachment and the provisions hereof shall become effective upon the earlier of (a) issuance of an order by the Commission accepting or approving this Attachment without condition or modification, or (b) issuance of an order by the Commission accepting or approving the PJM Formula Rate filed by the Duke Companies in these dockets, and not modifying or conditioning this Attachment.

5.4 Reservations. Except as provided under Section 5.6 (confidentiality of settlement discussions) and Section 5.7 (assurances of cooperation), no Settling Party shall be bound by any part of this Attachment unless and until it becomes effective in the manner provided by Section 5.3 hereof. If this Attachment is not accepted or approved in its entirety without modification or condition, it shall be deemed withdrawn, shall not be considered to be part of the record in this proceeding, and shall be null and void and of no force and effect, unless all of the Settling Parties otherwise agree in writing to such modification or condition.

5.5. No Precedent. This Attachment is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding unless it is approved or permitted to take effect as to all of its terms and conditions without modification. It is further understood and agreed that this Attachment constitutes a negotiated agreement and, except as explicitly set forth herein, no Settling Party shall be deemed to have approved, accepted, agreed or consented to any principle or position in this proceeding.

5.6. Settlement Discussions. The discussions between and among the Settling Parties that have produced this Attachment have been conducted with the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

5.7. Further Assurances. Each Settling Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this Attachment with the Commission, and (ii) efforts to obtain Commission acceptance or approval of the Attachment.

No Settling Party shall take any actions that are inconsistent with the provisions of this Attachment.

5.8. Waiver. No provision of this Attachment may be waived except through a writing signed by an authorized representative of the waiving Settling Party. Waiver of any provision of this Attachment shall not be deemed to waive any other provisions.

5.9. Modifications/Standard of Review. Unless the Settling Parties otherwise agree in writing, any modifications to this Attachment proposed by one of the Settling Parties after the Attachment 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 Serv. 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. Utils. 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.

5.10. Successors and Assigns. This Attachment is binding upon and for the benefit of the Settling Parties and their successors and assigns.

5.11. Captions. The captions in this Attachment are for convenience only and are not a part of this Attachment and do not in any way limit or amplify the terms and provisions of this Attachment and shall have no effect on its interpretation.

5.12. Ambiguities Neutrally Construed. This Attachment is the result of negotiations among, and has been reviewed by, each Settling Party and its respective counsel. Accordingly, this Attachment shall be deemed to be the product of each Settling Party, and no ambiguity shall be construed in favor of or against any Settling Party.

5.13. Authorization. Each person executing this Attachment on behalf of a Settling Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this Attachment to be executed on behalf of, the Settling Party that he or she represents.

5.14. Notices. All notices, demands, and other communications hereunder shall be in writing and shall be delivered to each Settling Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Settling Party on the official service list in Docket No. ER12-91-000 and ER12-92-000.

5.15. Counterparts. This Attachment may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

## 5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual

Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

| **Geographic Location Within the PJM Region Encompassing These Zones** | **Cost of New Entry in $/MW-Year** |
|---|---|
| PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”) | 122,040 |
| BGE, PEPCO (“CONE Area 2”) | 112,868 |
| AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK (“CONE Area 3”) | 115,479 |
| PPL, MetEd, Penelec (“CONE Area 4”) | 112,868 |
| Dominion (“CONE Area 5”) | 112,868 |

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined, as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity

Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the

first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

## ATTACHMENT JJ
## MTEP PROJECT COST RECOVERY FOR DEOK ZONE

### I. Definitions

A. DEOK – Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff – The Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

D. [Reserved]

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by DEOK pursuant to Attachment FF of the Midwest ISO Tariff.

### II. Introduction and Purpose

This Attachment JJ addresses the manner in which the PJM Office of the Interconnection will distribute to Duke Energy Ohio, Inc. on behalf of DEOK the revenues received from the Midwest ISO for the cost of MTEP Projects constructed by DEOK.

**III.** [Reserved]

### IV. DEOK MTEP Project Revenue Requirements Allocated to Midwest ISO Zones

#### A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–22 to this Tariff, DEOK will periodically update the Annual Revenue Requirements for MTEP Projects constructed by DEOK. No later than May 1 each year, DEOK shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year.

#### B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the Annual Revenue Requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO in accordance with the Midwest ISO Tariff.

**C. Monthly Revenue Requirements Owed from the Midwest ISO Zones**

Each month, and pursuant to agreed-upon settlement procedures, the Midwest ISO shall remit an amount to the PJM Office of the Interconnection from revenues collected by the Midwest ISO in proportion to DEOK's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 38.

**D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO**

Pursuant to agreed-upon settlement procedures, PJM shall credit to Duke Energy Ohio's account (on behalf of DEOK) in the subsequent month the amount of revenue requirements that the Midwest ISO remits to PJM pursuant to Section IV.C for the prior month.

# Appendix C

## Redlined Version of Attachment H-22C
## Comparing the Attachment to the Settlement Agreement

**ATTACHMENT H-22C**~~UNITED STATES OF AMERICA~~
~~BEFORE THE~~
~~FEDERAL ENERGY REGULATORY COMMISSION~~
**ADDITIONAL PROVISIONS REGARDING DEOK AND INDIANA MUNICIPAL POWER AGENCY**

~~)~~
~~**PJM Interconnection, L.L.C.,** ) **Docket No. ER12-91-000**~~
Duke Energy Ohio, ~~**Inc.** )~~

~~**ER12-92-000**~~

~~**Duke Energy Kentucky, Inc** )~~
~~)~~

~~**SETTLEMENT AGREEMENT**This Settlement Agreement ("Agreement") is made pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 385.602 (2011), by and among Duke Energy Ohio,~~ Inc. ("DEO"), a corporation organized and existing under the laws of the State of Ohio, and Duke Energy Kentucky, Inc. ("DEK"), a corporation existing under the laws of the State of Kentucky, and the Indiana Municipal Power Agency ("IMPA")~~,~~ (each a "Settling Party" and all collectively, the "Settling Parties")~~. The Settling Parties enter into this Agreement to resolve all issues between and among the Settling Parties~~**, shall be subject to the provisions of this Attachment, which implements the Settlement Agreement ("Agreement") entered into between the Duke Companies and IMPA** in Docket Nos. ER12-91-000 and ER12-92-~~000.~~**000 on April 5, 2012.**

**ARTICLE I**

~~**Background**~~

~~**1.1**. On October 14, 2011 in Docket Nos. ER12-91-000 and ER12-92-000, under section 205 of the Federal Power Act ("FPA") DEO and DEK (jointly, the "Duke Companies") jointly filed modifications to the PJM Open Access Transmission Tariff ("PJM OATT" or "Tariff") in order to accomplish the Duke Companies' move from the Midwest Independent Transmission System Operator, Inc. ("MISO") Regional Transmission Organization ("RTO") to the PJM RTO. The Companies proposed~~

~~modifications to the PJM OATT pertaining to establishing and recovering the Duke Companies' transmission revenue requirement, including formula rate protocols. In addition, under section 205 of the FPA, PJM submitted proposed modifications to the PJM OATT, the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM OA"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("PJM RAA") and the Consolidated Transmission Owners Agreement ("PJM TOA") (collectively the "PJM Agreements"). The Duke Companies and PJM jointly requested an effective date of January 1, 2012, for the proposed Tariff changes.~~

~~**1.2**. On November 4, 2011, a timely motion to intervene and protest was filed in this proceeding by IMPA. Also on November 4, 2011, a timely motion to intervene, protest, and request for suspension and hearings was filed in this proceeding by American Municipal Power ("AMP"). No other party protested the filings.~~

~~**1.3** On November 21, 2011, the Duke Companies filed an Answer and Motion for Leave to Answer to the comments and protests. On December 6, 2011, IMPA and AMP jointly submitted a Response. On December 16, 2011, the Duke Companies submitted an Answer and Motion for Leave to Answer, which responded to the joint IMPA/AMP Answer.~~

~~**1.4** On December 27, 2011, the Duke Companies filed a Request for Deferral of Action requesting that the Commission enable the Duke Companies, AMP and IMPA to continue settlement discussions that, if successful, would resolve all issues in this proceeding. The request was submitted on the condition that it~~

~~would have no effect on the requested effective date of January 1, 2012. On December 29, 2011, the Duke Companies and PJM submitted a ministerial filing that contained no changes to the existing tariff records filed in these dockets on October 14, 2011, for the sole purpose of deferring the Commission's actions in this proceeding. The Commission issued public notice of the filing and established a comment date of January 19, 2012. No comments were filed.~~

~~**1.5** On February 24, 2012, the Duke Companies filed a similar Request for Deferral of Action. The Commission issued public notice of the filing and established a comment date of March 16, 2012.~~

~~**1.6** The Settling Parties reached an agreement-in-principle to settle all issues between them in this proceeding on March 1, 2012. The agreement-in-principle resulted in this Settlement Agreement.~~

~~NOW, THEREFORE, in consideration of the promises and the mutual covenants and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Settling Parties, intending to be legally bound, agree as follows:~~

**[reserved]**

## ARTICLE II
## DEFINITIONS; RULES OF INTERPRETATION AND CONSTRUCTION

**2.1** ~~Unless otherwise stated here, all~~**All** defined terms have the meanings set forth in ~~the filings submitted in the above-referenced proceeding by the Duke Companies and PJM, and all~~**this Attachment. All** rules of construction and interpretation of this ~~Agreement~~**Attachment** shall be as set forth in the PJM Tariff or PJM Agreements.

**The "Duke Companies" means Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.**

"Agreement~~" has the meaning given to such term in the introduction to this Agreement.~~ **DEO" means Duke Energy Ohio, Inc.**

**"IMPA" means the Indiana Municipal Power Agency.**

"IMPA PJM RTEP Credit Cap" initially shall be $575,000, and shall be adjusted as described in Section 4.1.

"Internal Integration Costs" means internal integration costs identified in the Duke Companies' filing submitted in ~~the above-referenced dockets~~**Docket Nos. ER12-91-000 and ER12-92-000** as costs incurred by the Duke Companies in connection with their move into PJM that are recovered from IMPA under the Duke Companies' PJM Formula Rate or otherwise.

"Legacy MTEP Costs" means all costs associated with, or relating to, any obligation of the Duke Companies or IMPA to pay any portion of the costs of MISO Transmission Expansion Planning ("MTEP") projects identified and approved by the MISO Board of Directors prior to the Duke Companies' integration into PJM, including any such costs related to Multi-Value Projects ("MVP").

**"MISO" or "Midwest ISO" means the Midwest Independent Transmission System Operator, Inc.**

**"PJM" means PJM Interconnection, L.L.C.**

**"PJM Agreements" means the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the Reliability Assurance**

**Agreement Among Load Serving Entities in the PJM Region, and the Consolidated Transmission Owners Agreement.**

"PJM Formula Rate" means the formula rate and rate protocols identified and submitted by the Duke Companies in the filing in~~ the above-referenced~~ Docket Nos. ER12-91-000 and ER12-92-000.

"PJM RTEP Costs" means costs charged by PJM to IMPA under Schedule 12 of the PJM Tariff associated with a PJM Regional Transmission Expansion Plan ("RTEP"). Costs associated with facilities owned by PJM transmission owners other than the Duke Companies and charged to IMPA under a successor rate schedule will also be considered PJM RTEP Costs for purposes of this ~~Agreement~~**Attachment**.

**"PJM Tariff" means PJM Interconnection, L.C.C. Open Access Transmission Tariff.**

"PJM Transition Costs" means costs identified as "Transition Costs" in the Duke Companies' filings submitted in ~~the above-referenced proceeding~~**Docket Nos. ER12-91-000 and ER12-92-000** and included in the proposed PJM Formula Rate, specifically, costs associated with: (1) the Duke Companies' requirement under Article Five, Section II.B of the MISO Transmission Owners' Agreement ("MISO TOA") to pay certain amounts to MISO as an exit fee ("MISO Exit Fee"); (2) the Duke Companies' agreement, approved by the Commission in Docket No. ER11-2059-000, to pay MISO $1.8 million to resolve a dispute over MISO tariff revisions proposed to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the withdrawal of the Duke

Companies from MISO ("MISO LTTR Exit Charge"); and (3) the Duke Companies' agreement to pay PJM approximately $1 million as compensation for PJM's costs incurred in connection with the Duke Companies' transition to PJM ("PJM Integration Costs").

## ARTICLE III

## ~~Scope of the Settlement Agreement~~

## SCOPE OF ATTACHMENT

**3.1**. The Settling Parties hereby settle and resolve all issues between them involving the matters raised in Docket Nos. ER12-91-000 and ER12-92-000, on the terms set forth in the following Article IV.

## ARTICLE IV

## ~~Terms of Settlement Agreement~~

## TERMS

**4.1.** The Duke Companies commit as follows:

(a) *Reimbursement of PJM Transition Costs & Internal Integration Costs*.

For each billing month, DEO agrees to reimburse IMPA for any amounts owed to the Duke Companies by IMPA for that month for the portion of PJM Transition Costs and Internal Integration Costs associated with the load IMPA serves for the Village of Blanchester, Ohio.

(b) *Crediting Payment of PJM RTEP Costs*.

i. DEO agrees to utilize the PJM billing line-item transfer process to credit IMPA amounts equal to the monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, until total DEO line-item transfers to IMPA under this provision equal the initial IMPA PJM RTEP Credit Cap, as follows:

a. Initially, the IMPA PJM RTEP Credit Cap shall be $575,000, subject to adjustment as set forth in subparagraph 4.1(b).i.b and 4.1(b).i.d.

b. For each billing month for which IMPA has or will have paid RTEP costs, regardless of whether prior to the Effective Date of this ~~Agreement~~**Attachment**, until the month in which the IMPA PJM RTEP Credit Cap is reached, DEO agrees to execute and perform a billing line-item transfer, in accordance with PJM financial settlement rules and procedures, equal to any amounts charged to IMPA that month by PJM for PJM RTEP Costs associated with the load that IMPA serves for the Village of Blanchester, Ohio,. The IMPA PJM RTEP Credit Cap will be decremented by the same amount.

c. In the event that any month's PJM RTEP Cost charged by PJM with respect to the load that IMPA serves for the Village of Blanchester, Ohio exceeds the remaining balance of the IMPA PJM RTEP Credit Cap, DEO shall not have an obligation to execute and perform a billing line-item transfer for an amount equal to the remaining balance of the IMPA PJM RTEP Credit Cap, but instead shall directly reimburse IMPA for the remaining balance amount. In the event it is determined that IMPA has been compensated for an amount that exceeds the IMPA RTEP Credit Cap, IMPA shall, upon receipt of suitable documentation from the Duke Companies, and within 120 days, refund said over payment. Thereafter DEO shall have no further obligation under this ~~Agreement~~**Attachment** to execute and perform any line item transfer or otherwise reimburse IMPA in connection with PJM

RTEP Costs charged to IMPA. Upon being notified the IMPA RTEP Credit Cap has been reached, by virtue of billing line-item transfer, or direct payment by the Duke Companies, IMPA will work with the Duke Companies, and PJM to cancel the Declaration of Authority that allows for such billing line-item transfer.

d. In the event that the PJM Formula Rate as filed by the Duke Companies is modified for any reason, the IMPA PJM Credit Cap shall be adjusted as follows:

1. Within 30 days of issuance of an order modifying the PJM Formula Rate, the Duke Companies shall in good faith estimate the annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Estimated Annual Adjustment") and the amount of IMPA's RTEP payments ("Estimated Annual RTEP Amount") for each year through 2022. IMPA will review the estimate and give good faith commentary, and the Settling Parties will work in good faith to arrive at mutually acceptable estimates.

2. Prior to each year, the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the coming year will be compared.

3. If the Estimated Annual Adjustment is equal to or greater than the Estimated Annual RTEP ~~amount~~**Amount**, DEO shall not credit IMPA any amount during the coming year. If a Declaration of Authority has been provided to PJM allowing for a billing line-item transfer of RTEP costs to the Duke Companies, IMPA will work with PJM and the Duke Companies to cancel such transfer, effective

January 1, for the year in which the Estimated Annual Adjustment is greater than the Estimated Annual RTEP ~~amount~~**Amount**.

4. If the Estimated Annual Adjustment is less than the Estimated Annual RTEP Amount, DEO shall compensate IMPA for the difference. DEO shall have the option of compensating IMPA through PJM billing line-item transfers and/or through direct compensation, and shall have the option of tendering such compensation in up to 12 equal monthly installments during the course of the year in question. DEO shall notify IMPA of the method and intervals of payment before the year begins. In the event DEO elects to utilize a billing line-item transfer to effectuate compensation to IMPA, IMPA will work with the Duke Companies to provide a suitable Declaration of Authority to PJM, that allows for such billing line-item transfer.

5. Within 30 days following the end of the year, DEO will true up the Estimated Annual Adjustment and the Estimated Annual RTEP Amount for the prior year using actual data. The true-up will result in determination of the actual annual difference between the charges to IMPA under the PJM Formula Rate as filed by the Duke Companies and the PJM Formula Rate as modified ("Actual Annual Adjustment") and the actual amount of IMPA's RTEP payments ("Actual Annual RTEP Amount"). DEO will provide the true up calculation and supporting data to IMPA for review. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment exceeds the amount paid to IMPA by DEO for the year in question, DEO will reimburse IMPA for the difference. If the difference between the Actual Annual RTEP Amount and the Actual Annual Adjustment is less

than the amount paid to IMPA by DEO, IMPA will reimburse DEO for the difference. However, in no event shall IMPA be obligated to reimburse DEO an amount under this provision that exceeds the total amount paid by DEO to IMPA during the year in question, and in no event shall DEO be required to pay to IMPA an amount that would cause the remaining balance of the IMPA PJM RTEP Credit Cap to be less than zero, after the adjustment to the IMPA PJM RTEP Credit Cap described in the next paragraph. All reimbursements due under this provision shall be paid within 60 days following the end of the year.

6. Once the trued-up amounts are known, the IMPA PJM RTEP Credit Cap will be decremented by the higher of the Actual Annual RTEP Amount or the Actual Annual Adjustment, thereby reflecting the actual value received by IMPA in the year in question.

7. The parties shall discuss in good faith, at least once per year, whether adjustments should be made to the following year's estimated amounts.

8. If the PJM Formula Rate is accepted subject to refund and set for hearing, DEO will perform PJM billing line-item transfers to credit IMPA's RTEP amount until FERC issues a final order on the PJM Formula Rate, to the extent otherwise consistent with this ~~Agreement~~**Attachment**. If (a) FERC's order results in an adjustment to the proposed PJM Formula Rate, and therefore requires an adjustment to the IMPA PJM RTEP Credit Cap per the methodology described above, and (b) as a result of such adjustment DEO has overpaid on the credit, then

credit overpayments shall be netted against refund obligations to IMPA, and the refund obligation would be reduced correspondingly.

e. Hypothetical example calculation: IMPA PJM RTEP Credit Cap is 995 dollars; monthly PJM RTEP Costs for the load that IMPA serves for the Village of Blanchester, Ohio, are 20 dollars. Each month for the first 49 months, PJM would bill IMPA $20, and DEO would perform a billing line item transfer to credit IMPA $20, such that IMPA's net obligation to PJM for PJM RTEP Costs in each such month would be $0. During each of these months, the remaining balance of the IMPA PJM RTEP Credit Cap would be reduced by $20. Thus, after 49 months, the IMPA PJM RTEP Credit Cap would be reduced by $980 (49 months x $20/month), such that the remaining balance would be $15 ($995-$980=$15). Because the remaining balance of $15 would be less than the next month's PJM RTEP Cost of $20, in that next (50th) month: PJM would bill IMPA $20, IMPA would pay PJM $20, and DEO would reimburse IMPA for the $15 remaining balance of the IMPA PJM RTEP Credit Cap. Thereafter, DEO would no longer be obligated under this ~~Agreement~~**Attachment** to perform billing line item transfers associated with IMPA's PJM RTEP Costs, or to otherwise reimburse IMPA for such costs.

ii. DEO agrees to act in good faith and use commercially reasonable efforts in cooperation with IMPA to establish and implement a billing line-item transfer as contemplated in Paragraph 4.1 above. If at any time for any reason the billing line-item transfer mechanism for reimbursing IMPA cannot be effectuated, DEO shall implement an alternate mechanism, such as direct reimbursement to IMPA, to achieve the same result as contemplated in Paragraph 4.1.b.i above.

**4.2.** IMPA agrees and commits as follows:

(a) *Lawfulness and Effectiveness of Rate as Filed*

The Settling Parties acknowledge and agree that the PJM Formula Rate and related protocols submitted by the Duke Companies in the above-referenced proceeding will not be amended or revised in any respect or for any reason as a result of, or associated with, this ~~Agreement~~**Attachment**. The Settling Parties further agree that (a) the considerations provided by the Duke Companies under this ~~Agreement~~**Attachment** to IMPA are in resolution of "hold harmless" claims made by IMPA pursuant to Article V, Section ~~II~~**2** of the ~~MISO TO~~**Midwest ISO Transmission Owners** Agreement and resolve all claims raised by IMPA in these proceedings; and that (b) the obligation of the Duke Companies to provide such considerations is contingent upon the Commission not modifying ~~this~~**the** Agreement. IMPA agrees to fully pay its share of the rates as approved by the Commission in ~~these proceedings,~~**Docket Nos. ER12-91-000 and ER12-92-000,** including but not limited to its share of Legacy MTEP Costs, subject to the reimbursements and credit established above.

(b) *Crediting Payments of PJM RTEP Costs*.

IMPA agrees to act in good faith and use commercially reasonable efforts in cooperation with DEO and PJM to negotiate, execute, implement and perform billing line-item transfers as contemplated in Paragraph 4.1 above, and to terminate the line-item transfer process at the time contemplated in Paragraph 4.1 above.

(c) *Resolution of All Hold Harmless Obligations*.

Payment by DEO of the amounts and credits established in this ~~Agreement~~**Attachment** according to the terms of this ~~Agreement~~**Attachment** shall fully satisfy and discharge any and all obligations of the Duke Companies to render payment to IMPA according to the terms of Article V, Section 2 of the ~~MISO~~**Midwest ISO** Transmission Owners Agreement in connection with the Duke Companies' withdrawal from MISO, and such satisfaction and discharge shall not be affected by any amendment, substitute or successor to that provision, or any amendment, substitute or successor to the PJM Formula Rate filed in this proceeding. IMPA agrees not to make any protest or raise any claim against the Duke Companies or their parents or affiliates, before any government agency or court, asserting that the Duke Companies or their parents or affiliates owe IMPA or its members, respectively, any further "hold harmless" or other compensation under Article V, Section 2 of the Midwest ISO Transmission Owners Agreement, or any other monies or damages of any nature in connection with the Duke Companies' withdrawal from the Midwest ISO.

(d) *Rate of Return*

IMPA's protest in the above-referenced proceeding had raised the issue of the Duke Companies' rate of return on equity. Under this ~~Agreement~~**Attachment**, IMPA is agreeing to move to withdraw its protest as set forth in the following subparagraph and thereby retract any claim that an outcome of this proceeding should be a reduction of the Duke Companies' rate of return on equity. This ~~Agreement~~**agreement** is without prejudice to IMPA's right to raise the issue of the Duke Companies' rate of return on equity in subsequent proceedings, through a filing under Federal Power Act Section 206 or otherwise, provided that IMPA agrees that it will not (a) initiate a proceeding prior to January 1, 2016 seeking a reduction of the Duke 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 Duke Companies in which the reduction would become effective prior to January 1, 2016.

(e) *Withdrawal of Pleadings*.

IMPA will move to withdraw its protest filed in the above-referenced proceeding within fifteen (15) days of the earlier of (a) issuance of a Commission order accepting ~~this~~**the** Agreement without modification or condition, or (b) issuance of a Commission order accepting the PJM Formula Rate, and not modifying or conditioning ~~this~~**the** Agreement. In the event that the Commission establishes a hearing in these dockets, IMPA agrees not to participate in such hearing.

**4.3** The Settling Parties agree that the payments and credits identified in Sections 4.1(a) through 4.1(b) shall not be adjusted, upwards or downwards, for any reason including but not limited to any order eliminating, reducing or otherwise modifying any Settling Party's obligation(s) to pay for any PJM Transition Costs, PJM RTEP Costs or Legacy MTEP Costs.

## ARTICLE V
## Miscellaneous Provisions

**5.1***.* *Scope of the ~~Agreement~~**Attachment**.* This ~~Settlement Agreement~~**Attachment** constitutes the entire agreement among the Settling Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no other oral understandings, terms or conditions, and none of the Settling Parties has relied upon any representation, express or implied, not contained in this ~~Settlement Agreement~~**Attachment**. Nothing in this ~~Agreement~~**Attachment** should be construed as negating or fulfilling the obligations or responsibilities of the Duke Companies or IMPA under the PJM Tariff or PJM Agreements.

**5.2.** *Non-Severability*. The Settling Parties agree and understand that the various provisions of this ~~Agreement~~**Attachment** are not severable and shall not become operative unless and until it becomes effective as described in Section 5.3.

**5.3.** *Effectiveness of ~~Settlement Agreement~~**Attachment**.* This ~~Agreement~~**Attachment** and the provisions hereof shall become effective upon the earlier of (a) issuance of an order by the Commission accepting or approving this ~~Agreement~~**Attachment** without condition or modification, or (b) issuance of an order by the Commission accepting or approving the PJM Formula Rate filed by the Duke Companies in these dockets, and not modifying or conditioning this ~~Agreement~~**Attachment**.

**5.4** *Reservations.* Except as provided under Section 5.6 (confidentiality of settlement discussions) and Section 5.7 (assurances of cooperation), no Settling Party shall be bound by any part of this ~~Agreement~~**Attachment** unless and until it becomes effective in the manner provided by Section 5.3 hereof. If this ~~Agreement~~**Attachment** is not accepted or approved in its entirety without modification or condition, it shall be deemed withdrawn, shall not be considered to be part of the record in this proceeding, and shall be null and void and of no force and effect, unless all of the Settling Parties otherwise agree in writing to such modification or condition.

**5.5.** *No Precedent.* This ~~Agreement~~**Attachment** is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding unless it is approved or permitted to take effect as to all of its terms and conditions without modification. It is further understood and agreed that this ~~Settlement Agreement~~**Attachment** constitutes a negotiated agreement and, except as explicitly set forth herein, no Settling Party shall be deemed to have approved, accepted, agreed or consented to any principle or position in this proceeding.

**5.6.** *Settlement Discussions.* The discussions between and among the Settling Parties that have produced this ~~Settlement Agreement~~**Attachment** have been conducted with the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

**5.7***.* *Further Assurances*. Each Settling Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this ~~Agreement~~**Attachment** with the Commission, and (ii) efforts to obtain Commission acceptance or approval of the ~~Agreement~~**Attachment**. No Settling Party shall take any actions that are inconsistent with the provisions of this ~~Settlement Agreement~~**Attachment**.

**5.8.** *Waiver*. No provision of this ~~Settlement Agreement~~**Attachment** may be waived except through a writing signed by an authorized representative of the waiving Settling Party. Waiver of any provision of this ~~Settlement Agreement~~**Attachment** shall not be deemed to waive any other provisions.

**5.9***.* *Modifications/Standard of Review*. Unless the Settling Parties otherwise agree in writing, any modifications to this ~~Settlement Agreement~~**Attachment** proposed by one of the Settling Parties after the ~~Settlement Agreement~~**Attachment** 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 Serv. 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. Utils. 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.

**5.10***.* *Successors and Assigns.* This ~~Settlement Agreement~~**Attachment** is binding upon and for the benefit of the Settling Parties and their successors and assigns.

**5.11.** *Captions.* The captions in this ~~Settlement Agreement~~**Attachment** are for convenience only and are not a part of this ~~Settlement Agreement~~**Attachment** and do not in any way limit or amplify the terms and provisions of this ~~Settlement Agreement~~**Attachment** and shall have no effect on its interpretation.

**5.12**. *Ambiguities Neutrally Construed*. This ~~Settlement Agreement~~**Attachment** is the result of negotiations among, and has been reviewed by, each Settling Party and its respective counsel. Accordingly, this ~~Agreement~~**Attachment** shall be deemed to be the product of each Settling Party, and no ambiguity shall be construed in favor of or against any Settling Party.

**5.13.** *Authorization*. Each person executing this ~~Agreement~~**Attachment** on behalf of a Settling Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this ~~Settlement Agreement~~**Attachment** to be executed on behalf of, the Settling Party that he or she represents.

**5.14.** *Notices*. All notices, demands, and other communications hereunder shall be in writing and shall be delivered to each Settling Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Settling Party on the official service list in Docket No. ER12-91-000 and ER12-92-000.

**5.15.** *Counterparts.* This ~~Settlement Agreement~~**Attachment** may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

~~IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.~~

~~DUKE ENERGY OHIO, INC.~~

~~By: ________________________________ Date: _______________~~

~~DUKE ENERGY KENTUCKY, INC.~~

~~By: ________________________________ Date: _______________~~

~~INDIANA MUNICIPAL POWER AGENCY~~

~~By: ________________________________ Date: _______________~~

# Appendix D

## Refund Report for the Period
## January - April, 2012

**Network Integration Transmission Service Refunds for Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.**

| Customer Name | Code | Jan-12 Charge Refund | Jan-12 Interest | Feb-12 Charge Refund | Feb-12 Interest | Mar-12 Charge Refund | Mar-12 Interest | Apr-12 Charge Refund | Apr-12 Interest | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy Ohio, Inc. (EDC) | DEOEDC | $6,875.03 | $79.58 | $6,431.46 | $54.32 | $6,875.37 | $40.90 | $6,653.72 | $23.04 | **$27,033.43** |
| Duke Energy Kentucky, Inc. | DEK | $1,360.90 | $15.75 | $1,273.10 | $10.75 | $1,360.90 | $8.10 | $1,317.00 | $4.56 | **$5,351.06** |
| American Municipal Power, Inc. (Lebanon-Duke) | AMPLEB | $97.96 | $1.13 | $91.64 | $0.77 | $97.96 | $0.58 | $94.80 | $0.33 | **$385.18** |
| Appalachian Power Company (Buckeye) | AEPBCK | $85.87 | $0.99 | $80.33 | $0.68 | $85.87 | $0.51 | $83.10 | $0.29 | **$337.64** |
| American Municipal Power, Inc. (Hamilton-Duke) | AMPHAM | $45.88 | $0.53 | $42.92 | $0.36 | $45.88 | $0.27 | $44.40 | $0.15 | **$180.40** |
| East Kentucky Power Cooperative, Inc. | EKPC | $42.47 | $0.49 | $39.73 | $0.34 | $42.47 | $0.25 | $41.10 | $0.14 | **$166.99** |
| Indiana Municipal Power Agency | IMPA | $21.70 | $0.25 | $20.30 | $0.17 | $21.70 | $0.13 | $21.00 | $0.07 | **$85.32** |
| Dayton Power & Light Company (Georgetown DEO) | DAYGTN | $16.74 | $0.19 | $15.66 | $0.13 | $16.74 | $0.10 | $16.20 | $0.06 | **$65.82** |
| American Municipal Power, Inc. (Williamstown-Duke) | AMPWTN | $15.19 | $0.18 | $14.21 | $0.12 | $15.19 | $0.09 | $14.70 | $0.05 | **$59.73** |
| Appalachian Power Company (Gen - V of Bethel Ohio) | AEPVOB | $8.99 | $0.10 | $8.41 | $0.07 | $8.99 | $0.05 | $8.70 | $0.03 | **$35.35** |
| Appalachian Power Company (Gen - V of Ripley Ohio) | AEPVOR | $6.51 | $0.08 | $6.09 | $0.05 | $6.51 | $0.04 | $6.30 | $0.02 | **$25.60** |
| Appalachian Power Company (Gen - V of Hamersville Ohio) | AEPVOH | $1.55 | $0.02 | $1.45 | $0.01 | $1.55 | $0.01 | $1.50 | $0.01 | **$6.09** |
| **TOTAL** | | $8,578.79 | $99.30 | $8,025.30 | $67.78 | $8,579.13 | $51.04 | $8,302.52 | $28.75 | **$33,732.62** |

**Interest Calculation**

| Month | Revenues Refunded | Date Collected | Date Adjusted | 1Q 2012 Days | 1Q 2012 Amount | 2Q 2012 Days | 2Q 2012 Amount | Interest Amount |
|---|---|---|---|---|---|---|---|---|
| Jan-12 | $8,578.79 | 2/10/2012 | 6/18/2012 | 51 | $38.85 | 79 | $60.45 | $99.30 |
| Feb-12 | $8,025.30 | 3/16/2012 | 6/18/2012 | 16 | $11.40 | 79 | $56.38 | $67.78 |
| Mar-12 | $8,579.13 | 4/13/2012 | 6/18/2012 | | | 67 | $51.04 | $51.04 |
| Apr-12 | $8,302.52 | 5/11/2012 | 6/18/2012 | | | 39 | $28.75 | $28.75 |
| | $33,485.74 | | | | | | | $246.88 |

Use FERC-specified annual interest rates (1Q & 2Q 2012 = 3.25%) compounded quarterly

Monthly Interest Amount = Quarterly Interest Rate * (# of Days / 366) * (Revenues Refunded + past quarter interest)

## MTEP Project Cost Recovery Refunds for Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

| | | Jan-12 | | Feb-12 | | Mar-12 | | Apr-12 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Name** | **Code** | **Charge Refund** | **Interest** | **Charge Refund** | **Interest** | **Charge Refund** | **Interest** | **Charge Refund** | **Interest** | **TOTAL** |
| American Municipal Power, Inc. (Lebanon-Duke) | AMPLEB | $3,608.10 | $41.77 | $3,608.10 | $30.47 | $3,608.10 | $21.47 | $3,608.10 | $12.50 | **$14,538.60** |
| Appalachian Power Company (Buckeye) | AEPBCK | $3,159.19 | $36.57 | $3,159.19 | $26.68 | $3,159.19 | $18.80 | $3,159.19 | $10.94 | **$12,729.75** |
| American Municipal Power, Inc. (Hamilton-Duke) | AMPHAM | $1,683.40 | $19.49 | $1,683.40 | $14.22 | $1,683.40 | $10.02 | $1,683.40 | $5.83 | **$6,783.15** |
| East Kentucky Power Cooperative, Inc. | EKPC | $1,559.95 | $18.06 | $1,559.95 | $13.17 | $1,559.95 | $9.28 | $1,559.95 | $5.40 | **$6,285.72** |
| Indiana Municipal Power Agency | IMPA | $802.42 | $9.29 | $802.42 | $6.78 | $802.42 | $4.77 | $802.42 | $2.78 | **$3,233.30** |
| Dayton Power & Light Company (Georgetown DEO) | DAYGTN | $617.25 | $7.14 | $617.25 | $5.21 | $617.25 | $3.67 | $617.25 | $2.14 | **$2,487.17** |
| American Municipal Power, Inc. (Williamstown-Duke) | AMPWTN | $566.75 | $6.56 | $566.75 | $4.79 | $566.75 | $3.37 | $566.75 | $1.96 | **$2,283.68** |
| Appalachian Power Company (Gen - V of Bethel Ohio) | AEPVOB | $336.68 | $3.90 | $336.68 | $2.84 | $336.68 | $2.00 | $336.68 | $1.17 | **$1,356.63** |
| Appalachian Power Company (Gen - V of Ripley Ohio) | AEPVOR | $241.29 | $2.79 | $241.29 | $2.04 | $241.29 | $1.44 | $241.29 | $0.84 | **$972.26** |
| Appalachian Power Company (Gen - V of Hamersville Ohio) | AEPVOH | $61.72 | $0.71 | $61.72 | $0.52 | $61.72 | $0.37 | $61.72 | $0.21 | **$248.70** |
| Energy Plus Holdings LLC (Duke Energy OH) | EPHDEO | | | $3.10 | $0.03 | | | | | **$3.13** |
| **TOTAL** | | $12,636.75 | $146.28 | $12,639.85 | $106.75 | $12,636.75 | $75.18 | $12,636.75 | $43.76 | **$50,922.07** |

**Interest Calculation**

| | Revenues | Date | Date | 1Q 2012 | | 2Q 2012 | | Interest |
|---|---|---|---|---|---|---|---|---|
| **Month** | **Refunded** | **Collected** | **Adjusted** | **Days** | **Amount** | **Days** | **Amount** | **Amount** |
| Jan-12 | $12,636.75 | 2/10/2012 | 6/18/2012 | 51 | $57.23 | 79 | $89.05 | $146.28 |
| Feb-12 | $12,639.85 | 3/16/2012 | 6/18/2012 | 16 | $17.96 | 79 | $88.79 | $106.75 |
| Mar-12 | $12,636.75 | 4/13/2012 | 6/18/2012 | | | 67 | $75.18 | $75.18 |
| Apr-12 | $12,636.75 | 5/11/2012 | 6/18/2012 | | | 39 | $43.76 | $43.76 |
| | $50,550.10 | | | | | | | $371.97 |

Use FERC-specified annual interest rates (1Q & 2Q 2012 = 3.25%) compounded quarterly

Monthly Interest Amount = Quarterly Interest Rate * (# of Days / 366) * (Revenues Refunded + past quarter interest)