BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
The Dayton Power and Light Company d/b/a	)	Case No. 22-0152-EL-RDR
"AES Ohio" to Update its Transmission	)	
Cost Recovery Rider – Non-Bypassable	)	

AMENDED APPLICATION OF THE DAYTON POWER AND LIGHT COMPANY D/B/A AES OHIO TO UPDATE ITS TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE

The Dayton Power and Light Company d/b/a AES Ohio ("AES Ohio" or "the Company") submits this Amended Application to update its Transmission Cost Recovery Rider – Non-Bypassable ("TCRR-N") pursuant to R.C. 4928.05(A)(2) and Ohio Adm.Code 4901:1-36-03(B).

In support of this Application, AES Ohio states as follows:

1. AES Ohio is a public utility and electric light company as defined by R.C. 4905.02 and 4905.03(C), respectively, and an electric distribution utility as defined by R.C. 4928.01(A)(6).

2. Ohio Adm.Code 4901:1-36-03(B) provides: "Each electric utility with an approved transmission cost recovery rider shall update the rider on an annual basis pursuant to a schedule set forth by Commission Order. Each application to update the transmission cost recovery rider shall include all information set forth in the appendix to this rule."

3. AES Ohio implemented a TCRR-N on January 1, 2014. The TCRR-N is a non-bypassable rider designed to recover transmission-related costs imposed on or charged to the Company by FERC or PJM, such as Network Integration Transmission Service ("NITS").

4. In the August 26, 2016 Finding and Order in Case No. 08-1094-EL-SSO, the Commission reaffirmed that AES Ohio's TCRR-N should continue.

5. Pursuant to the Commission's October 20, 2017 Opinion and Order in Case No. 16-395-EL-SSO, *et al*., AES Ohio continued the TCRR-N and implemented the TCRR-N Opt-Out Pilot Program ("the Pilot Program"). Since its inception, the Pilot Program has enrolled a number of qualifying customers who have taken all of the necessary steps to opt-out of the TCRR-N and, instead, pay all of their respective transmission expenses directly to their supplier. The TCRR-N was continued by the Commission's December 18, 2019 Second Finding and Order in Case No. 08-1094-EL-SSO, *et al.*, and enrollment in the Pilot Program was reopened pursuant to the June 16, 2021 Opinion and Order in Case No. 18-1875-EL-GRD, *et al*. AES Ohio has removed the Pilot Program participants from the rate calculations applicable to all non-participating customers. This included adjusting actual and forecasted usage for tariff classes to reflect only non-Pilot customers and adjusting forecasted charges to reflect only those anticipated for non-Pilot customers.

6. On March 3, 2020, AES Ohio filed an Application for a Formula rate and started recovery of that rate on May 3, 2020. A Settlement with interested parties was reached and filed on December 10, 2020 and FERC approved the Settlement on April 15, 2021.

7. Consistent with past practices and directives of the Commission, AES Ohio filed its most recent application to update its TCRR-N on March 16, 2021, in Case No. 21-0224-EL-RDR. AES Ohio's Application was approved by Finding and Order dated May 19, 2021, for rates effective on June 1, 2021. AES Ohio will continue to pass through Regional Transmission Expansion Plan (RTEP) credits to customers as the result of FERC approving a settlement in Case No. EL-05-121-009, which resulted in substantial credits being owed to customers in the Dayton zone.

8. The TCRR-N revenue requirement is lower for the period June 2022 through May 2023 than it was in the prior period. The primary cause for this lower revenue requirement is the under-collection balance that was prominent in the Company's 2021 TCRR-N filing has been remedied.

9. Consistent with its prior TCRR filings, AES Ohio has included an estimate for carrying costs on the under or over collection for TCRR-N throughout the forecast period to minimize over or under-collection and thereby precisely recover all costs.

10. Pursuant to Ohio Adm.Code 4901:1-36-03(B), the information listed below is being provided in support of this Application. The following Schedules, supported by additional Workpapers, are structured to show the TCRR-N detail:

Schedule A-1 Copy of proposed tariff schedules;

Schedule A-2 Copy of redlined current tariff schedules;

Schedule B-1 Summary of Projected Jurisdictional TCRR-N Net Costs;

Schedule B-2	Summary of Current versus Proposed Revenues;
Schedule B-3	Summary of Current and Proposed Rates;
Schedule B-4	Typical Bill Comparisons;
Schedule C-1	Projected Monthly Jurisdictional TCRR-N Costs;
Schedule C-2	Projected Monthly TCRR-N Costs by Tariff Class;
Schedule C-3	Summary of Proposed TCRR-N Rates;
Schedule C-3(a)	Development of Proposed Base Rates;
Schedule C-3(b)	Development of Proposed Reconciliation Rates;
Schedule D-1	Actual Charges and Revenues;
Schedule D-2	Monthly Revenues by Tariff Class
Schedule D-3	Monthly Over and Under Recovery; and
Schedule D-3(a)	Reconciliation to Company's Financial Records

11. Pursuant to Ohio Adm.Code 4901:1-36-04(A), carrying charges based on the cost of debt approved in AES Ohio's most recent rate setting proceeding have been applied to under- and over-recovery of costs.

12. AES Ohio's proposed updated TCRR-N rates as reflected in Schedule A-1 and supported by the remaining Schedules and Workpapers are just and reasonable and should be approved.

13. AES Ohio submits this Amended Application to correct minor errors on Workpaper C-1c, resulting in a $356,338 decrease in the revenue requirement. In addition, AES

Ohio has incorporated the refund associated with the 50-basis point return on equity adder that was ordered by the Federal Energy Regulatory Commission's July 15, 2021 Order on Paper Hearing and the February 17, 2022 Order Addressing Arguments Raised on Rehearing in Case No. ER20-1068-000 into the revenue requirement. The amount of that refund was not available at the time of the original Application in this proceeding. This impact reduces AES Ohio's revenue requirement by an additional $185,753, for a total adjusted decrease of the revenue requirement of $542,091.

14. As a result of this update, a typical residential customer using 1,000 kWh per month can expect a decrease of $1.67 or (1.72)%.

WHEREFORE, AES Ohio respectfully requests that the Commission approve its Amended Application with new tariff rates for its TCRR-N to be made effective, on a bills-rendered basis beginning on June 1, 2022.

Respectfully submitted,

*/s/ Christopher C. Hollon*___________

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(willing to accept service by email)

CERTIFICATE OF SERVICE

I certify that the foregoing document was e-filed with the Public Utilities Commission of Ohio on April 29, 2022. The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

The Staff of the Public Utilities Commission of Ohio
John Jones john.jones@ohioAGO.gov

The Office of the Ohio Consumers' Counsel
Angela O'Brien angela.obrien@occ.ohio.gov
John Finnigan john.finnigan@occ.ohio.gov

Interstate Gas Supply, Inc.
Stacie Cathcart stacie.cathcart@igs.com
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/s/ Christopher C. Hollon
Christopher C. Hollon (0086480)

Schedule A-1

Copy of Proposed Tariff Schedules

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
TARIFF INDEX

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
TARIFF INDEX

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
D21	Seventeenth Revised	Primary-Substation	3	January 1, 2020
D22	Sixteenth Revised	High Voltage	3	January 1, 2020
D23	Eighteenth Revised	Private Outdoor Lighting	3	January 1, 2020
D24	Thirteenth Revised	Reserved	1	October 1, 2018
D25	Seventeenth Revised	Street Lighting	4	January 1, 2020
D26	Third Revised	Miscellaneous Service Charges	1	October 1, 2018
D35	Third Revised	Interconnection Tariff	29	October 14, 2015

RIDERS

D27	Eighth Revised	Solar Generation Fund Rider	1	January 1, 2022
D28	Twenty-Second Revised	Universal Service Fund Rider	1	January 1, 2022
D29	Seventeenth Revised	Infrastructure Investment Rider	1	April 1, 2022
D30	Tenth Revised	Storm Cost Recovery Rider	1	November 1, 2020
D31	Eighth Revised	Reserved	1	December 19, 2019
D32	Fifth Revised	Reserved	1	December 19, 2019
D33	Fourth Revised	Excise Tax Surcharge Rider	1	October 1, 2018
D34	First Revised	Switching Fees	2	January 1, 2006
D36	Eighth Revised	Reserved	1	December 19, 2019
D37	Seventh Revised	Reserved	1	November 29, 2019
D38	Twelfth Revised	Energy Efficiency Rider	1	January 1, 2021
D39	Twenty-Sixth Revised	Economic Development Rider	1	December 1, 2021
D40	Ninth Revised	Legacy Generation Resource Rider	1	January 1, 2022
D41	Second Revised	Tax Savings Credit Rider	1	November 1, 2021

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with Distribution Service from the Company that will be metered and billed on a demand, energy, and monthly customer charge basis.

APPLICABLE:

Available to any Secondary Nonresidential Customer for lighting and for power, provided that all electric service is supplied at one location on the Customer's premises. This rate is applicable when any portion of the Customer's service is rendered at Secondary voltage.

REQUIRED SERVICES:

The Customer may take Generation Service from DP&L under Standard Service Tariff Sheet No. G10. Otherwise, the Customer may choose an Alternate Generation Supplier ("AGS") for its Generation Service. If an AGS is chosen: (1) The AGS must sign a service agreement with the Company and abide by the terms of the Alternate Generation Supplier Coordination Tariff Sheet No. G8, and (2) Customer must take service under the Competitive Retail Generation Service Tariff Sheet No. G9. All Customers are required to take service under Tariff Sheet No. T8 of the Transmission Schedule.

RATE PER MONTH:

Customer Charge:

Single-phase Service	$ 16.73 per Customer
Three-phase Service	$ 25.77 per Customer

THE FOLLOWING SERVICE IS NOT AVAILABLE FOR NEW INSTALLATIONS:

Unmetered Service	$ 14.16 per Customer

Demand Charge:

$3.6569905 per kW for all kW of Billing Demand

MINIMUM CHARGE:

The Minimum Charge shall be the Customer Charge.

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SECONDARY

MAXIMUM CHARGE:

The billing under the Demand and Energy charge provisions shall not exceed $0.0383541 per kWh for total billed charges under this tariff, the Transmission Cost Recovery Rider – Nonbypassable (if applicable), and the Rate Stabilization Charge. The Maximum Charge amount of this tariff is $0.0112602.

ADDITIONAL RIDERS:

Service under this Tariff Sheet shall also be subject to the following riders:

Universal Service Fund Rider on Sheet No. D28.
Infrastructure Investment Rider No. D29.
Storm Cost Recovery Rider on Sheet No. D30.
Excise Tax Rider on Sheet No. D33.
Switching Fee Rider on Sheet No. D34.
Energy Efficiency Rider on Sheet No. D38.
Economic Development Cost Recovery Rider on Sheet No. D39.
Legacy Generation Rider on Sheet No. D40.
Tax Savings Credit Rider on Sheet No. D41.

PRIMARY VOLTAGE METERING:

The above rates are based upon Secondary Voltage Level of Service and metering. When metering is at Primary Voltage Level of Service, both the kilowatt billing demand and the energy kilowatt-hours will be adjusted downward by one percent (1%) for billing purposes.

OFF-PEAK METERING SURCHARGE:

Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to determine billing demands during off-peak periods shall be subject to an additional charge of twenty dollars ($20.00) per month. No demand less than one thousand kilowatts (1,000 kW) shall be designated as off-peak unless the Customer has elected the metering surcharge option.

For Customers who elect to be supplied through off-peak metering, the Term of Contract shall be a minimum period of one (1) year and for such time thereafter until terminated by the Company or the Customer giving thirty (30) days written notice.

DETERMINATION OF KILOWATT BILLING DEMAND:

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ELECTRIC DISTRIBUTION SERVICE
SECONDARY

The billing demand shall be the greatest thirty (30) minute integrated demand ascertained in kilowatts by instruments suitable for the purpose. Such billing demand shall be the greatest of the following:

1. Off-peak: Seventy-five percent (75%) of the greatest such demand occurring during the billing month, either within the period between 8:00 p.m. of one day and 8:00 a.m. the following day, or on any Saturday or Sunday, or on the following observed legal holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day or Christmas Day; or

2. On-peak: One hundred percent (100%) of the greatest such demand occurring during the billing month at any time not within the period and not on the days specifically mentioned in paragraph 1 above; or

3. Seventy-five percent (75%) of the greatest of such off-peak or on-peak demand as used for billing in the months of June, July, August, December, January and February during the past eleven month period prior to the current billing month.

SECONDARY RATE PROVISION:

When the use of a Customer's load does not result in billing demands proportionate to the facilities installed, the billing demand may be determined by taking eighty-five percent (85%) of such total connected load. The Maximum Charge provisions of this Tariff Sheet shall not be applicable to these Customers.

UNMETERED SERVICE PROVISION:

A. THIS PROVISION IS IN THE PROCESS OF ELIMINATION AND IS WITHDRAWN EXCEPT FOR THE PRESENT INSTALLATIONS OF CUSTOMERS THAT HAVE ELECTED TO COMPLY WITH SECTION B OF DP&L'S UNMETERED SERVICE PROVISION. ALL NEW SERVICE REQUESTS SHALL TAKE SERVICE UNDER SINGLE OR THREE PHASE METERED SERVICE.

Unmetered single-phase service is available under this provision upon mutual agreement between the Company and the Customer for lighting and/or incidental power purposes for rated loads less than five (5) kilowatts having uniformity of consumption which can be predicted accurately.

This rate is available on application and only to those Customers whose rated load requirements of five (5) kilowatts or less can be served at one point of delivery.

For each monthly billing period the kW billing demand shall be the estimated or measured load in kilowatts, and the kilowatt-hours consumed shall be the product of the estimated or measured load in kilowatts multiplied by seven hundred and thirty (730) hours.

The Customer shall furnish electrical protection devices which meet local electric code requirements. In the absence of a local electrical code, the National Electrical Code will be followed.

The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the Customer's equipment at any time to verify or measure such load. In the event the Customer fails to notify the Company of an increase in load, the Company reserves the right to refuse to serve the location thereafter under this rate, and shall be entitled to bill the Customer retroactively on the basis of the increased load for the full period such load was connected. If the character of such load should change, so as to require metered service, the Customer shall provide the facilities to permit the metering.

The Term of Contract shall be a minimum period of one (1) year or such shorter period as may be agreed between the Company and the Customer.

B. UNMETERED SERVICE COMPLIANCE PROVISION FOR EXISTING INSTALLATIONS

Concurrent with the effective date of this tariff, existing customers who elect to maintain an Unmetered Service Provision must comply with the following:

I. Provide the Company with written validation of the type of usage, quantities and characteristics of service within 6 months of the effective date of this tariff
II. Provide written validation of the type and quantity of service to the Company annually

COUNTY FAIR AND AGRICULTURAL SOCIETES:

Energy Charge: $0.0121124/kWh

This charge replaces the demand change for County Fair and Agricultural Societies; all other rates and tariffs applicable to secondary customers apply. The County Fairs and Agricultural societies provision exists as required by Ohio Revised Code Section 4928.80.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

RULES AND REGULATIONS:

All Distribution Service of the Company is rendered under and subject to the Rules and Regulations contained within this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with Distribution Service from the Company that will be metered and billed on a demand and monthly customer charge basis.

APPLICABLE:

Available to any Customer for lighting and for power, provided that all electric service is supplied at one location on the Customer's premises.

REQUIRED SERVICES:

The Customer may take Generation Service from DP&L under Standard Service Tariff Sheet No. G10. Otherwise, the Customer may choose an Alternate Generation Supplier ("AGS") for its Generation Service. If an AGS is chosen: (1) The AGS must sign a service agreement with the Company and abide by the terms of the Alternate Generation Supplier Coordination Tariff Sheet No. G8, and (2) Customer must take service under the Competitive Retail Generation Service Tariff Sheet No. G9. All Customers are required to take service under Tariff Sheet No. T8 of the Transmission Schedule.

RATE PER MONTH:

Customer Charge:

$242.12 per Customer

Demand Charge:

$2.0325100 per kW for all kW of Billing Demand

Reactive Demand Charge:

$0.6984153 per kVar for all kVar of Billing Demand

MINIMUM CHARGE:

The Minimum Charge shall be the Customer Charge.

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ELECTRIC DISTRIBUTION SERVICE
PRIMARY

MAXIMUM CHARGE:

The billing under the Demand and Energy charge provisions shall not exceed $0.0358229 per kWh for total billed charges under this tariff, Transmission Cost Recovery Rider – Nonbypassable (if applicable), and the Rate Stabilization Rider. The Maximum Charge amount of this tariff is $0.0051169.

ADDITIONAL RIDERS:

Service under this Tariff Sheet shall also be subject to the following riders:

Universal Service Fund Rider on Sheet No. D28.
Infrastructure Investment Rider on Sheet No. D29.
Storm Cost Recovery Rider on Sheet No. D30.
Excise Tax Rider on Sheet No. D33.
Switching Fee Rider on Sheet No. D34.
Energy Efficiency Rider on Sheet No. D38.
Economic Development Cost Recovery Rider on Sheet No. D39.
Legacy Generation Rider on Sheet No. D40.
Tax Savings Credit Rider on Sheet No D41.

SECONDARY VOLTAGE METERING:

The above rates are based upon Primary Voltage Level of Service and metering. When metering is at Secondary Voltage Level of Service, both the kilowatt billing demand and the energy kilowatt-hours will be adjusted upward by one percent (1%) for billing purposes.

OFF-PEAK METERING SURCHARGE:

Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to determine billing demands during off-peak periods shall be subject to an additional charge of twenty dollars ($20.00) per month. No demands less than one thousand kilowatts (1,000 kW) shall be designated as off-peak unless the Customer has elected the metering surcharge option.

For Customers who elect to be supplied through off-peak metering, the Term of Contract shall be a minimum period of one (1) year and for such time thereafter until terminated by the Company or the Customer giving thirty (30) days written notice.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

DETERMINATION OF KILOWATT BILLING DEMAND:

The billing demand shall be the greatest thirty (30) minute integrated demand ascertained in kilowatts by instruments suitable for the purpose. Such billing demand shall be the greatest of the following:

1. Off-peak: Seventy-five percent (75%) of the greatest such demand occurring during the billing month, either within the period between 8:00 p.m. of one day and 8:00 a.m. the following day, or on any Saturday or Sunday, or on the following observed legal holiday: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day or Christmas Day; or

2. On-peak: One hundred percent (100%) of the greatest such demand occurring during the billing month at any time not within the period and not on the days specifically mentioned in paragraph 1 above; or

3. Seventy-five percent (75%) of the greatest of such off-peak or on-peak demand as used for billing in the months of June, July, August, December, January and February during the past eleven (11) month period prior to the current billing month. Where a Customer's establishment contains two or more buildings with separate services, each service having a monthly demand of five hundred (500) kW or higher, served under this Tariff Sheet, and such buildings are separated by street, alley, or railroad right-of-way, and there is no other intervening property under separate ownership, the demand of all such accounts at coincident times shall be added together for the determination of this Paragraph 3.

PRIMARY RATE PROVISION:

When the use of a Customer's load does not result in billing demands proportionate to the facilities installed the billing demand may be determined by taking eighty-five percent (85%) of such total connected load. The Maximum Charge provisions of this Tariff Sheet shall not be applicable to these Customers.

COUNTY FAIR AND AGRICULTURAL SOCIETES:

Energy Charge: $0.0052124/kWh

This charge replaces the demand change for County Fair and Agricultural Societies; all other rates and tariffs applicable to Primary customers apply. The County Fairs and Agricultural societies provision exists as required by Ohio Revised Code Section 4928.80.

RULES AND REGULATIONS:

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ELECTRIC DISTRIBUTION SERVICE
PRIMARY

All Distribution Service of the Company is rendered under and subject to the Rules and Regulations contained in this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

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ELECTRIC TRANSMISSION SERVICE
TARIFF INDEX

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with retail transmission service. This Transmission Cost Recovery Rider (TCRR-N) is designed to recover transmission-related costs imposed on or charged to the Company by FERC or PJM. These costs include but are not limited to:

Network Integration Transmission Service (NITS)

Schedule 1	(Scheduling, System Control and Dispatch Service)
Schedule 1A	(Transmission Owner Scheduling, System Control and Dispatch Services)
Schedule 2	(Reactive Supply and Voltage Control from Generation or Other Sources Services)
Schedule 6A	(Black Start Service)
Schedule 7	(Firm Point-To-Point Service Credits to AEP Point of Delivery)
Schedule 8	(Non-Firm Point-To-Point Service Credits)
Schedule 10-NERC	(North American Electric Reliability Corporation Charge)
Schedule 10-RFC	(Reliability First Corporation Charge)

Schedule 10-Michigan-Ontario Interface (Phase Angle Regulators Charge)

Schedule 12	(Transmission Enhancement Charge)
Schedule 12A(b)	(Incremental Capacity Transfer Rights Credit)
Schedule 13	(Expansion Cost Recovery Charge)

PJM Emergency Load Response Program – Load Response Charge Allocation

Part V – Generation Deactivation

APPLICABLE:

Required for any Customer that has not enrolled in the TCRR-N Opt-Out Pilot Program and is served under the Electric Distribution Service Tariff Sheet D17-D25 based on the following rates.

CHARGES:

Filed pursuant to the Finding and Order in Case No. 22-0152-EL-RDR dated _____ of the Public Utilities Commission of Ohio.

Issued ____ Effective June 1, 2022

Issued by
KRISTINA LUND, President and Chief Executive Officer

Residential:

Energy Charge	$0.0052516 per kWh

Residential Heating:

Energy Charge	$0.0052516 per kWh

Secondary:

Demand Charge	$1.9202477 per kW for all kW of Billing Demand
Energy Charge	$0.0004389 per kWh

County Fair and Agricultural Societies:

Energy Charge	$0.0056119 per kWh

If the Maximum Charge provision contained in Electric Distribution Service Tariff Sheet No. D19 applies, the Customer will be charged an energy charge of $0.0112239 per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge	$1.7446842 per kW for all kW of Billing Demand
Energy Charge	$0.0004389 per kWh

County Fair and Agricultural Societies:

Energy Charge	$0.0041582 per kWh

If the Maximum Charge provision contained in Electric Distribution Service Tariff Sheet No. D20 applies, the Customer will be charged an energy charge of $0.0139560 per kWh in lieu of the above demand and energy charges.

Primary-Substation:

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

Demand Charge	$1.7738512 per kW for all kW of Billing Demand
Energy Charge	$0.0004389 per kWh

High Voltage:

Demand Charge	$1.9963511 per kW for all kW of Billing Demand
Energy Charge	$0.0004389 per kWh

Private Outdoor Lighting:

3,600 Lumens Light Emitting Diode (LED)	$0.0059304/lamp/month
8,400 Lumens Light Emitting Diode (LED)	$0.0127080/lamp/month
9,500 Lumens High Pressure Sodium	$0.0165204/lamp/month
28,000 Lumens High Pressure Sodium	$0.0406656/lamp/month
7,000 Lumens Mercury	$0.0317700/lamp/month
21,000 Lumens Mercury	$0.0652344/lamp/month
2,500 Lumens Incandescent	$0.0271104/lamp/month
7,000 Lumens Fluorescent	$0.0279576/lamp/month
4,000 Lumens PT Mercury	$0.0182148/lamp/month

Street Lighting:

Energy Charge	$0.0004218 per kWh

DETERMINATION OF KILOWATT BILLING DEMAND:

Billing demand shall be determined as defined on the applicable Electric Distribution Service Tariff Sheet Nos. D17 through D25.

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

TRANSMISSION RULES AND REGULATIONS:

All retail electric transmission and ancillary services of the Company are rendered under and subject to the Rules and Regulations contained in this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

Except where noted herein, this service shall be provided under the terms, conditions, and rates of PJM's Tariff filed at the Federal Energy Regulatory Commission.

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on an annual basis. The TCRR-N shall be filed with the Public Utilities Commission of Ohio on or before March 15 of each year and be effective for bills rendered June 1 through May 31 of the subsequent year, unless otherwise ordered by the Commission.

This Rider is subject to reconciliation, including but not limited to, refunds to customers, based upon the results of audits as approved and ordered by the Commission.

OPT-OUT PILOT PROGRAM:

Pursuant to the June 16, 2021 Opinion and Order issued by the Public Utilities Commission of Ohio in Case Nos.18-1875-EL-GRD, et al., the Company is reopening enrollment for a pilot program That enables qualifying accounts to opt-out of the TCRR-N for the duration of the pilot program. The pilot program is described in paragraph 14b. of the October 23, 2020 Stipulation and Recommendation that was filed in Case Nos 18-1875-EL-GRD, et al. To receive additional information, qualified customers should contact transmissionoptout@aes.com.

AES Ohio
Case No. 22-0152-EL-RDR
Transmission Cost Recovery Rider – Non-Bypassable

Schedule A-2

Copy of Red-lined Current Tariff Schedules

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
TARIFF INDEX

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
D1	Third Revised	Table of Contents	1	November 29, 2019
D2	Ninety-Nineth~~Eighth~~ Revised	Tariff Index	2	June~~April~~ 1, 2022
RULES AND REGULATIONS				
D3	First Revised	Application and Contract for Service	3	October 1, 2018
D4	Third Revised	Credit Requirements of Customer	1	October 1, 2018
D5	Seventh Revised	Billing and Payment for Electric Service	8	October 1, 2018
D6	Second Revised	Disconnection/Reconnection of Service	5	October 1, 2018
D7	Third Revised	Meters and Metering Equipment- Location and Installation	3	January 21, 2022
D8	First Revised	Service Facilities – Location and Installation	3	October 1, 2018
D9	First Revised	Equipment on Customer's Premises	3	October 1, 2018
D10	First Revised	Use and Character of Service	5	October 1, 2018
D11	Second Revised	Emergency Electrical Procedures	12	October 1, 2018
D12	Second Revised	Extension of Electric Facilities	5	March 1, 2014
D13	Second Revised	Extension of Electric Facilities to House Trailer Parks	2	October 1, 2018
D14	Second Revised	Definitions and Amendments	4	October 1, 2018
D15	Original	Additional Charges	1	January 1, 2001
D16	Original	Open Access Terms and Conditions	3	January 1, 2001
TARIFFS				
D17	Eighteenth Revised	Residential	2	January 1, 2020
D18	Eighteenth Revised	Residential Heating	2	January 1, 2020
D19	Twenty-Fifth~~ourth~~ Revised	Secondary	5	June 1, 2022~~1~~

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
TARIFF INDEX

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
D20	Twenty-Third~~Second~~ Revised	Primary	4	June 1, 2022~~1~~
D21	Seventeenth Revised	Primary-Substation	3	January 1, 2020
D22	Sixteenth Revised	High Voltage	3	January 1, 2020
D23	Eighteenth Revised	Private Outdoor Lighting	3	January 1, 2020
D24	Thirteenth Revised	Reserved	1	October 1, 2018
D25	Seventeenth Revised	Street Lighting	4	January 1, 2020
D26	Third Revised	Miscellaneous Service Charges	1	October 1, 2018
D35	Third Revised	Interconnection Tariff	29	October 14, 2015

RIDERS

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
D27	Eighth Revised	Solar Generation Fund Rider	1	January 1, 2022
D28	Twenty-Second Revised	Universal Service Fund Rider	1	January 1, 2022
D29	Seventeenth Revised	Infrastructure Investment Rider	1	April 1, 2022
D30	Tenth Revised	Storm Cost Recovery Rider	1	November 1, 2020
D31	Eighth Revised	Reserved	1	December 19, 2019
D32	Fifth Revised	Reserved	1	December 19, 2019
D33	Fourth Revised	Excise Tax Surcharge Rider	1	October 1, 2018
D34	First Revised	Switching Fees	2	January 1, 2006
D36	Eighth Revised	Reserved	1	December 19, 2019
D37	Seventh Revised	Reserved	1	November 29, 2019
D38	Twelfth Revised	Energy Efficiency Rider	1	January 1, 2021
D39	Twenty-Sixth Revised	Economic Development Rider	1	December 1, 2021
D40	Ninth Revised	Legacy Generation Resource Rider	1	January 1, 2022

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
TARIFF INDEX

D41	Second Revised	Tax Savings Credit Rider	1	November 1, 2021

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with Distribution Service from the Company that will be metered and billed on a demand, energy, and monthly customer charge basis.

APPLICABLE:

Available to any Secondary Nonresidential Customer for lighting and for power, provided that all electric service is supplied at one location on the Customer's premises. This rate is applicable when any portion of the Customer's service is rendered at Secondary voltage.

REQUIRED SERVICES:

The Customer may take Generation Service from DP&L under Standard Service Tariff Sheet No. G10. Otherwise, the Customer may choose an Alternate Generation Supplier ("AGS") for its Generation Service. If an AGS is chosen: (1) The AGS must sign a service agreement with the Company and abide by the terms of the Alternate Generation Supplier Coordination Tariff Sheet No. G8, and (2) Customer must take service under the Competitive Retail Generation Service Tariff Sheet No. G9. All Customers are required to take service under Tariff Sheet No. T8 of the Transmission Schedule.

RATE PER MONTH:

Customer Charge:

Single-phase Service	$ 16.73 per Customer
Three-phase Service	$ 25.77 per Customer

THE FOLLOWING SERVICE IS NOT AVAILABLE FOR NEW INSTALLATIONS:

Unmetered Service	$ 14.16 per Customer

Demand Charge:

$3.6569905 per kW for all kW of Billing Demand

MINIMUM CHARGE:

The Minimum Charge shall be the Customer Charge.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

MAXIMUM CHARGE:

The billing under the Demand and Energy charge provisions shall not exceed $0.0383541~~0435273~~ per kWh for total billed charges under this tariff, the Transmission Cost Recovery Rider – Nonbypassable (if applicable), and the Rate Stabilization Charge. The Maximum Charge amount of this tariff is $0.0112602.

ADDITIONAL RIDERS:

Service under this Tariff Sheet shall also be subject to the following riders:

Universal Service Fund Rider on Sheet No. D28.
Infrastructure Investment Rider No. D29.
Storm Cost Recovery Rider on Sheet No. D30.
Excise Tax Rider on Sheet No. D33.
Switching Fee Rider on Sheet No. D34.
Energy Efficiency Rider on Sheet No. D38.
Economic Development Cost Recovery Rider on Sheet No. D39.
Legacy Generation Rider on Sheet No. D40.
Tax Savings Credit Rider on Sheet No. D41.

PRIMARY VOLTAGE METERING:

The above rates are based upon Secondary Voltage Level of Service and metering. When metering is at Primary Voltage Level of Service, both the kilowatt billing demand and the energy kilowatt-hours will be adjusted downward by one percent (1%) for billing purposes.

OFF-PEAK METERING SURCHARGE:

Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to determine billing demands during off-peak periods shall be subject to an additional charge of twenty dollars ($20.00) per month. No demand less than one thousand kilowatts (1,000 kW) shall be designated as off-peak unless the Customer has elected the metering surcharge option.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

For Customers who elect to be supplied through off-peak metering, the Term of Contract shall be a minimum period of one (1) year and for such time thereafter until terminated by the Company or the Customer giving thirty (30) days written notice.

DETERMINATION OF KILOWATT BILLING DEMAND:

The billing demand shall be the greatest thirty (30) minute integrated demand ascertained in kilowatts by instruments suitable for the purpose. Such billing demand shall be the greatest of the following:

1. Off-peak: Seventy-five percent (75%) of the greatest such demand occurring during the billing month, either within the period between 8:00 p.m. of one day and 8:00 a.m. the following day, or on any Saturday or Sunday, or on the following observed legal holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day or Christmas Day; or

2. On-peak: One hundred percent (100%) of the greatest such demand occurring during the billing month at any time not within the period and not on the days specifically mentioned in paragraph 1 above; or

3. Seventy-five percent (75%) of the greatest of such off-peak or on-peak demand as used for billing in the months of June, July, August, December, January and February during the past eleven month period prior to the current billing month.

SECONDARY RATE PROVISION:

When the use of a Customer's load does not result in billing demands proportionate to the facilities installed, the billing demand may be determined by taking eighty-five percent (85%) of such total connected load. The Maximum Charge provisions of this Tariff Sheet shall not be applicable to these Customers.

UNMETERED SERVICE PROVISION:

A. THIS PROVISION IS IN THE PROCESS OF ELIMINATION AND IS WITHDRAWN EXCEPT FOR THE PRESENT INSTALLATIONS OF CUSTOMERS THAT HAVE ELECTED TO COMPLY WITH SECTION B OF DP&L'S UNMETERED SERVICE PROVISION. ALL NEW SERVICE REQUESTS SHALL TAKE SERVICE UNDER SINGLE OR THREE PHASE METERED SERVICE.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

Unmetered single-phase service is available under this provision upon mutual agreement between the Company and the Customer for lighting and/or incidental power purposes for rated loads less than five (5) kilowatts having uniformity of consumption which can be predicted accurately.

This rate is available on application and only to those Customers whose rated load requirements of five (5) kilowatts or less can be served at one point of delivery.

For each monthly billing period the kW billing demand shall be the estimated or measured load in kilowatts, and the kilowatt-hours consumed shall be the product of the estimated or measured load in kilowatts multiplied by seven hundred and thirty (730) hours.

The Customer shall furnish electrical protection devices which meet local electric code requirements. In the absence of a local electrical code, the National Electrical Code will be followed.

The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the Customer's equipment at any time to verify or measure such load. In the event the Customer fails to notify the Company of an increase in load, the Company reserves the right to refuse to serve the location thereafter under this rate, and shall be entitled to bill the Customer retroactively on the basis of the increased load for the full period such load was connected. If the character of such load should change, so as to require metered service, the Customer shall provide the facilities to permit the metering.

The Term of Contract shall be a minimum period of one (1) year or such shorter period as may be agreed between the Company and the Customer.

B. UNMETERED SERVICE COMPLIANCE PROVISION FOR EXISTING INSTALLATIONS

Concurrent with the effective date of this tariff, existing customers who elect to maintain an Unmetered Service Provision must comply with the following:

I. Provide the Company with written validation of the type of usage, quantities and characteristics of service within 6 months of the effective date of this tariff
II. Provide written validation of the type and quantity of service to the Company annually

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
SECONDARY

COUNTY FAIR AND AGRICULTURAL SOCIETES:

Energy Charge: $0.0121124/kWh

This charge replaces the demand change for County Fair and Agricultural Societies; all other rates and tariffs applicable to secondary customers apply. The County Fairs and Agricultural societies provision exists as required by Ohio Revised Code Section 4928.80.

RULES AND REGULATIONS:

All Distribution Service of the Company is rendered under and subject to the Rules and Regulations contained within this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with Distribution Service from the Company that will be metered and billed on a demand and monthly customer charge basis.

APPLICABLE:

Available to any Customer for lighting and for power, provided that all electric service is supplied at one location on the Customer's premises.

REQUIRED SERVICES:

The Customer may take Generation Service from DP&L under Standard Service Tariff Sheet No. G10. Otherwise, the Customer may choose an Alternate Generation Supplier ("AGS") for its Generation Service. If an AGS is chosen: (1) The AGS must sign a service agreement with the Company and abide by the terms of the Alternate Generation Supplier Coordination Tariff Sheet No. G8, and (2) Customer must take service under the Competitive Retail Generation Service Tariff Sheet No. G9. All Customers are required to take service under Tariff Sheet No. T8 of the Transmission Schedule.

RATE PER MONTH:

Customer Charge:

$242.12 per Customer

Demand Charge:

$2.0325100 per kW for all kW of Billing Demand

Reactive Demand Charge:

$0.6984153 per kVar for all kVar of Billing Demand

MINIMUM CHARGE:

The Minimum Charge shall be the Customer Charge.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

MAXIMUM CHARGE:

The billing under the Demand and Energy charge provisions shall not exceed $0.0358229~~0353772~~ per kWh for total billed charges under this tariff, Transmission Cost Recovery Rider – Nonbypassable (if applicable), and the Rate Stabilization Rider. The Maximum Charge amount of this tariff is $0.0051169.

ADDITIONAL RIDERS:

Service under this Tariff Sheet shall also be subject to the following riders:

Universal Service Fund Rider on Sheet No. D28.
Infrastructure Investment Rider on Sheet No. D29.
Storm Cost Recovery Rider on Sheet No. D30.
Excise Tax Rider on Sheet No. D33.
Switching Fee Rider on Sheet No. D34.
Energy Efficiency Rider on Sheet No. D38.
Economic Development Cost Recovery Rider on Sheet No. D39.
Legacy Generation Rider on Sheet No. D40.
Tax Savings Credit Rider on Sheet No D41.

SECONDARY VOLTAGE METERING:

The above rates are based upon Primary Voltage Level of Service and metering. When metering is at Secondary Voltage Level of Service, both the kilowatt billing demand and the energy kilowatt-hours will be adjusted upward by one percent (1%) for billing purposes.

OFF-PEAK METERING SURCHARGE:

Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to determine billing demands during off-peak periods shall be subject to an additional charge of twenty dollars ($20.00) per month. No demands less than one thousand kilowatts (1,000 kW) shall be designated as off-peak unless the Customer has elected the metering surcharge option.

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

For Customers who elect to be supplied through off-peak metering, the Term of Contract shall be a minimum period of one (1) year and for such time thereafter until terminated by the Company or the Customer giving thirty (30) days written notice.

DETERMINATION OF KILOWATT BILLING DEMAND:

The billing demand shall be the greatest thirty (30) minute integrated demand ascertained in kilowatts by instruments suitable for the purpose. Such billing demand shall be the greatest of the following:

1. Off-peak: Seventy-five percent (75%) of the greatest such demand occurring during the billing month, either within the period between 8:00 p.m. of one day and 8:00 a.m. the following day, or on any Saturday or Sunday, or on the following observed legal holiday: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day or Christmas Day; or

2. On-peak: One hundred percent (100%) of the greatest such demand occurring during the billing month at any time not within the period and not on the days specifically mentioned in paragraph 1 above; or

3. Seventy-five percent (75%) of the greatest of such off-peak or on-peak demand as used for billing in the months of June, July, August, December, January and February during the past eleven (11) month period prior to the current billing month. Where a Customer's establishment contains two or more buildings with separate services, each service having a monthly demand of five hundred (500) kW or higher, served under this Tariff Sheet, and such buildings are separated by street, alley, or railroad right-of-way, and there is no other intervening property under separate ownership, the demand of all such accounts at coincident times shall be added together for the determination of this Paragraph 3.

PRIMARY RATE PROVISION:

When the use of a Customer's load does not result in billing demands proportionate to the facilities installed the billing demand may be determined by taking eighty-five percent (85%) of such total connected load. The Maximum Charge provisions of this Tariff Sheet shall not be applicable to these Customers.

COUNTY FAIR AND AGRICULTURAL SOCIETES:

Energy Charge: $0.0052124/kWh

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
PRIMARY

This charge replaces the demand change for County Fair and Agricultural Societies; all other rates and tariffs applicable to Primary customers apply. The County Fairs and Agricultural societies provision exists as required by Ohio Revised Code Section 4928.80.

RULES AND REGULATIONS:

All Distribution Service of the Company is rendered under and subject to the Rules and Regulations contained in this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TARIFF INDEX

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
T1	Fifth Revised	Table of Contents	1	November 1, 2017
T2	Thirty-Sixth~~Fifth~~ Revised	Tariff Index	1	June 1, 202~~2~~1

RULES AND REGULATIONS

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
T3	Third Revised	Application and Contract for Service	3	January 1, 2014
T4	First Revised	Credit Requirements of Customer	1	November 1, 2002
T5	Original	Billing and Payment for Electric Service	1	January 1, 2001
T6	Original	Use and Character of Service	1	January 1, 2001
T7	Second Revised	Definitions and Amendments	3	June 20, 2005

TARIFFS

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
T8	Twentieth~~Nineteenth~~ Revised	Transmission Cost Recovery Rider – Non-Bypassable	5	June 1, 2022~~1~~

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TARIFF INDEX

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

DESCRIPTION OF SERVICE:

This Tariff Sheet provides the Customer with retail transmission service. This Transmission Cost Recovery Rider (TCRR-N) is designed to recover transmission-related costs imposed on or charged to the Company by FERC or PJM. These costs include but are not limited to:

Network Integration Transmission Service (NITS)

Schedule 1	(Scheduling, System Control and Dispatch Service)
Schedule 1A	(Transmission Owner Scheduling, System Control and Dispatch Services)
Schedule 2	(Reactive Supply and Voltage Control from Generation or Other Sources Services)
Schedule 6A	(Black Start Service)
Schedule 7	(Firm Point-To-Point Service Credits to AEP Point of Delivery)
Schedule 8	(Non-Firm Point-To-Point Service Credits)
Schedule 10-NERC	(North American Electric Reliability Corporation Charge)
Schedule 10-RFC	(Reliability First Corporation Charge)

Schedule 10-Michigan-Ontario Interface (Phase Angle Regulators Charge)

Schedule 12	(Transmission Enhancement Charge)
Schedule 12A(b)	(Incremental Capacity Transfer Rights Credit)
Schedule 13	(Expansion Cost Recovery Charge)

PJM Emergency Load Response Program – Load Response Charge Allocation

Part V – Generation Deactivation

APPLICABLE:

Required for any Customer that has not enrolled in the TCRR-N Opt-Out Pilot Program and is served under the Electric Distribution Service Tariff Sheet D17-D25 based on the following rates.

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

CHARGES:

Residential:

Energy Charge $0.0052516~~0069195~~ per kWh

Residential Heating:

Energy Charge $0.0052516~~0069195~~ per kWh

Secondary:

Demand Charge $1.9202477~~2.8577596~~ per kW for all kW of Billing Demand

Energy Charge $0.0004389~~0006746~~ per kWh

County Fair and Agricultural Societies:
Energy Charge $0.0056119~~0081986~~ per kWh

If the Maximum Charge provision contained in Electric Distribution Service Tariff Sheet No. D19 applies, the Customer will be charged an energy charge of $0.0112239~~0163971~~ per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge $1.7446842~~2.2902323~~ per kW for all kW of Billing Demand

Energy Charge $0.0004389~~0006746~~ per kWh

County Fair and Agricultural Societies:
Energy Charge $0.0041582~~0054042~~ per kWh

THE DAYTON POWER AND LIGHT COMPANY
Sheet No. T8
MacGregor Park
1065 Woodman Drive
Sheet No. T8
Dayton, Ohio 45432

Twentieth~~Nineteenth~~ Revised

Cancels
Nineteenth~~Eighteenth~~ Revised

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

If the Maximum Charge provision contained in Electric Distribution Service Tariff Sheet No. D20 applies, the Customer will be charged an energy charge of $0.0139560~~0135103~~ per kWh in lieu of the above demand and energy charges.

Primary-Substation:

Demand Charge	$1.7738512~~2.2865784~~ per kW for all kW of Billing Demand
Energy Charge	$0.0004389~~0006746~~ per kWh

High Voltage:

Demand Charge	$1.9963511~~2.4310049~~ per kW for all kW of Billing Demand
Energy Charge	$0.0004389~~0006746~~ per kWh

Private Outdoor Lighting:

3,600 Lumens Light Emitting Diode (LED)	$0.0059304~~0107884~~	/lamp/month
8,400 Lumens Light Emitting Diode (LED)	$0.0127080~~0231180~~	/lamp/month
9,500 Lumens High Pressure Sodium	$0.0165204~~0300534~~	/lamp/month
28,000 Lumens High Pressure Sodium	$0.0406656~~0739776~~	/lamp/month
7,000 Lumens Mercury	$0.0317700~~0577950~~	/lamp/month
21,000 Lumens Mercury	$0.0652344~~1186724~~	/lamp/month
2,500 Lumens Incandescent	$0.0271104~~0493184~~	/lamp/month
7,000 Lumens Fluorescent	$0.0279576~~0508596~~	/lamp/month
4,000 Lumens PT Mercury	$0.0182148~~0331358~~	/lamp/month

Street Lighting:

Energy Charge	$0.0004218~~0007684~~ per kWh

Filed pursuant to the Finding and Order in Case No. 22~~1~~-0152~~0224~~-EL-RDR dated _____~~May 19, 2021~~ of the Public Utilities Commission of Ohio.

Issued ____~~May 25, 2021~~

Effective June 1, 2022~~1~~

Issued by
KRISTINA LUND, President and Chief Executive Officer

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

DETERMINATION OF KILOWATT BILLING DEMAND:

Billing demand shall be determined as defined on the applicable Electric Distribution Service Tariff Sheet Nos. D17 through D25.

TRANSMISSION RULES AND REGULATIONS:

All retail electric transmission and ancillary services of the Company are rendered under and subject to the Rules and Regulations contained in this Schedule and any terms and conditions set forth in any Service Agreement between the Company and the Customer.

Except where noted herein, this service shall be provided under the terms, conditions, and rates of PJM's Tariff filed at the Federal Energy Regulatory Commission.

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on an annual basis. The TCRR-N shall be filed with the Public Utilities Commission of Ohio on or before March 15 of each year and be effective for bills rendered June 1 through May 31 of the subsequent year, unless otherwise ordered by the Commission.

This Rider is subject to reconciliation, including but not limited to, refunds to customers, based upon the results of audits as approved and ordered by the Commission.

OPT-OUT PILOT PROGRAM:

P.U.C.O. No. 17
ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

Pursuant to the June 16, 2021~~October 20, 2017~~ Opinion and Order issued by the Public Utilities Commission of Ohio in Case Nos.18-1875-EL-GRD, et al.~~16-395-EL-SSO~~, the Company is reopening enrollment for ~~implementing~~ a pilot program That ~~which~~ enables ~~up to 50~~ qualifying accounts to opt-out of the TCRR-N for the duration of the pilot program. The pilot program is described in paragraph 14~~VI.~~b~~C~~. of the October 23, 2020~~March 13, 2017 Amended~~ Stipulation and Recommendation that was filed in Case Nos~~.~~ 18-1875-EL-GRD, et al ~~16-395-EL-SSO~~. To receive additional information, qualified customers should contact transmissionoptout@aes.com.

AES Ohio
Case No. 22-0152-EL-RDR
Summary of Projected Jurisdictional Net Costs
June 2022 - May 2023
(Revenue)/Expense in $

Line (A)	Description (B)	Demand/Energy (C)		Total Costs/Revenues[1] June 2022 - May 2023 (D)
				Schedule C-1, Col (U)
	TCRR-N Costs			
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$	10,249,188
2	Incremental Capacity Transfer Rights Credits	Demand - 1 CP	$	(167,570)
3	Reactive Supply and Voltage Control from Gen Sources	Demand - 12 CP	$	2,360,745
4	Black Start Service	Demand - 12 CP	$	228,332
5	TO Scheduling System Control and Dispatch Service	Energy	$	1,077,747
6	NERC/RFC Charges	Energy	$	552,366
7	Firm PTP Transmission Service	Demand - 1 CP	$	-
8	Non-Firm PTP Transmission Service	Demand - 1 CP	$	(64,892)
9	Network Integration Transmission Service	Demand - 1 CP	$	52,467,434
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$	-
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$	4,676,931
12	Load Response	Energy	$	15,746
13	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	Energy	$	7,912
14	Bilateral Charge	Energy	$	-
15	TCRR-N SubTotal		$	71,403,940
16	Projected TCRR-N Reconciliation		$	(4,677,584)
17	Projected TCRR-N Deferral Carrying Costs		$	(129,512)
18	TCRR-N SubTotal with Deferral		$	66,596,844
19	Gross Revenue Conversion Factor (WPB-1)			1.003
20				
21	**Total TCRR-N Recovery (Line 18 * Line 19)**		**$**	**66,770,448**

[1]Total Costs/Revenues for all customers not participating in TCRR-N Opt Out Pilot Program as of 3/15/2022

AES Ohio
Case No. 22-0152-EL-RDR
Summary of Current versus Proposed Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Actual and Forecasted — Amended
Type of Filing: Original — Schedule B-2
Work Paper Reference No(s).: WPC-3 —

Line (A)	Tariff Class (B)	Forecasted Distribution Billing Determinants[1] (C) WPC-3a, Col (P)		Current Rate (D)	Current Revenue (E) = (C) * (D)	Proposed Rate (F) Schedule C-3	Proposed Revenue (G) = (C) * (F)	$ Difference (H) = (G) - (E)	% Difference (I) = (H) / (E)
	TCRR-N Rates			TCRR-N		TCRR-N			
1	Residential	5,505,729,722	kWh	$ 0.0069195	$ 38,096,897	$ 0.0052516	$ 28,913,890	$ (9,183,007)	-24%
2									
3	Secondary	3,543,494,762	All kWh	$ 0.0006746	$ 2,390,442	$ 0.0004389	$ 1,555,240		
4			>1500 kWh	$ 0.0006746	$ -	$ 0.0004389	$ -		
4		9,545,874	All kW	$ 2.8577596	$ 27,279,813	$ 1.9202477	$ 18,330,442		
5					$ 29,670,254		$ 19,885,682	$ (9,784,572)	-33%
6									
7	Primary	2,577,720,486	kWh	$ 0.0006746	$ 1,738,930	$ 0.0004389	$ 1,131,362		
8		5,495,123	kW	$ 2.2902323	$ 12,585,109	$ 1.7446842	$ 9,587,255		
9		50,685,088	kVar	$ -	$ -	$ -	$ -		
10					$ 14,324,039		$ 10,718,616	$ (3,605,423)	-25%
11									
12	Substation	834,370,955	kWh	$ 0.0006746	$ 562,867	$ 0.0004389	$ 366,205		
13		1,516,609	kW	$ 2.2865784	$ 3,467,845	$ 1.7738512	$ 2,690,238		
14		661,915	kVar	$ -	$ -	$ -	$ -		
15					$ 4,030,712		$ 3,056,444	$ (974,268)	-24%
16									
17	High Voltage	963,296,112	kWh	$ 0.0006746	$ 649,840	$ 0.0004389	$ 422,791		
18		1,876,550	kW	$ 2.4310049	$ 4,561,903	$ 1.9963511	$ 3,746,253		
19		792,975	kVar	$ -	$ -	$ -	$ -		
20					$ 5,211,743		$ 4,169,044	$ (1,042,699)	-20%
21									
22	Private Outdoor Lighting	23,908,368	kWh	$ 0.0007706	$ 18,424	$ 0.0004236	$ 10,128	$ (8,296)	-45%
23									
24	Street Lighting	38,017,167	kWh	$ 0.0007684	$ 29,212	$ 0.0004218	$ 16,036	$ (13,177)	-45%
25									
26	Total TCRR-N Rates				$ 91,381,280		$ 66,769,840	$ (24,611,441)	-27%

[1] Forecasted Distribution Billing Determinants for all customers not participating in the TCRR-N Pilot Program as of 3/15/2022

AES Ohio
Case No. 22-0152-EL-RDR
Summary of Current and Proposed Rates
June 2022 - May 2023

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Amended
Schedule B-3

Line	Tariff Class		Current Rates	Billing Units		Proposed Rates	Billing Units		$ Difference	% Difference
(A)	(B)		(C)	(D)		(E) Schedule C-3	(F)		(G) = (E) - (C)	(H) = (G) / (C)
	TCRR-N Rates		TCRR-N			TCRR-N				
1	Residential	$	0.0069195	kWh	$	0.0052516	kWh	$	(0.0016679)	-24.1%
2	Secondary	$	0.0006746	0-1500 kWh	$	0.0004389	kWh	$	(0.0002357)	-34.9%
3		$	0.0006746	>1500 kWh	$	0.0004389	kWh	$	(0.0002357)	-34.9%
4		$	2.8577596	kW	$	1.9202477	kW	$	(0.9375119)	-32.8%
5	Primary	$	0.0006746	kWh	$	0.0004389	kWh	$	(0.0002357)	-34.9%
6		$	2.2902323	kW	$	1.7446842	kW	$	(0.5455481)	-23.8%
7		$	-	kVar	$	-	kVar	$	-	N/A
8	Substation	$	0.0006746	kWh	$	0.0004389	kWh	$	(0.0002357)	-34.9%
9		$	2.2865784	kW	$	1.7738512	kW	$	(0.5127272)	-22.4%
10		$	-	kVar	$	-	kVar	$	-	N/A
11	High Voltage	$	0.0006746	kWh	$	0.0004389	kWh	$	(0.0002357)	-34.9%
12		$	2.4310049	kW	$	1.9963511	kW	$	(0.4346538)	-17.9%
13		$	-	kVar	$	-	kVar	$	-	N/A
14	Private Outdoor Lighting	$	0.0007706	kWh	$	0.0004236	kWh	$	(0.0003470)	-45.0%
15	Streetlighting	$	0.0007684	kWh	$	0.0004218	kWh	$	(0.0003466)	-45.1%

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Residential

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference: None

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	0.0	50	$12.03	$11.95	($0.08)	-0.67%
2	0.0	100	$16.52	$16.35	($0.17)	-1.03%
3	0.0	200	$25.50	$25.17	($0.33)	-1.29%
4	0.0	400	$43.50	$42.83	($0.67)	-1.54%
5	0.0	500	$52.49	$51.66	($0.83)	-1.58%
6	0.0	750	$74.97	$73.72	($1.25)	-1.67%
7	0.0	1,000	$97.15	$95.48	($1.67)	-1.72%
8	0.0	1,200	$114.91	$112.91	($2.00)	-1.74%
9	0.0	1,400	$132.66	$130.32	($2.34)	-1.76%
10	0.0	1,500	$141.53	$139.03	($2.50)	-1.77%
11	0.0	2,000	$185.90	$182.56	($3.34)	-1.80%
12	0.0	2,500	$230.07	$225.90	($4.17)	-1.81%
13	0.0	3,000	$274.20	$269.20	($5.00)	-1.82%
14	0.0	4,000	$362.48	$355.81	($6.67)	-1.84%
15	0.0	5,000	$450.80	$442.46	($8.34)	-1.85%
16	0.0	7,500	$671.52	$659.01	($12.51)	-1.86%

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Secondary Unmetered

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference: None

Amended
Schedule B-4

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	0.0	50	$17.16	$17.15	($0.01)	-0.06%
2	0.0	100	$20.28	$20.26	($0.02)	-0.10%
3	0.0	150	$23.38	$23.34	($0.04)	-0.17%
4	0.0	200	$26.45	$26.40	($0.05)	-0.19%
5	0.0	300	$32.67	$32.60	($0.07)	-0.21%
6	0.0	400	$38.86	$38.77	($0.09)	-0.23%
7	0.0	500	$45.09	$44.97	($0.12)	-0.27%
8	0.0	600	$51.25	$51.11	($0.14)	-0.27%
9	0.0	800	$63.67	$63.48	($0.19)	-0.30%
10	0.0	1,000	$76.05	$75.81	($0.24)	-0.32%
11	0.0	1,200	$88.46	$88.18	($0.28)	-0.32%
12	0.0	1,400	$100.84	$100.51	($0.33)	-0.33%
13	0.0	1,600	$112.89	$112.51	($0.38)	-0.34%
14	0.0	2,000	$136.15	$135.68	($0.47)	-0.35%
15	0.0	2,200	$147.68	$147.16	($0.52)	-0.35%
16	0.0	2,400	$159.24	$158.67	($0.57)	-0.36%

Under the Proposed Rates, Secondary customers are charged for all kWh and all kW of billing demand.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Secondary Single Phase

Data: Actual and Forecasted	Amended
Type of Filing: Original	Schedule B-4
Work Paper Reference: None	Page 3 of 9

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	5	750	$90.10	$85.23	($4.87)	-5.40%
2	5	1,500	$142.05	$137.01	($5.04)	-3.55%
3	10	1,500	$163.56	$153.83	($9.73)	-5.95%
4	25	5,000	$490.33	$465.71	($24.62)	-5.02%
5	25	7,500	$634.62	$609.41	($25.21)	-3.97%
6	25	10,000	$778.88	$753.08	($25.80)	-3.31%
7	50	15,000	$1,250.00	$1,199.58	($50.42)	-4.03%
8	50	25,000	$1,821.52	$1,768.75	($52.77)	-2.90%
9	200	50,000	$4,345.67	$4,146.38	($199.29)	-4.59%
10	200	100,000	$7,203.28	$6,992.21	($211.07)	-2.93%
11	300	125,000	$9,362.31	$9,051.60	($310.71)	-3.32%
12	500	200,000	$15,075.43	$14,559.53	($515.90)	-3.42%
13	1,000	300,000	$24,396.77	$23,388.55	($1,008.22)	-4.13%
14	1,000	500,000	$35,737.25	$34,681.89	($1,055.36)	-2.95%
15	2,500	750,000	$60,866.14	$58,345.58	($2,520.56)	-4.14%
16	2,500	1,000,000	$74,841.28	$72,261.80	($2,579.48)	-3.45%

Under the Proposed Rates, Secondary customers are charged for all kWh and all kW of billing demand.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Secondary Three Phase

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	5	500	$74.60	$69.79	($4.81)	-6.44%
2	5	1,500	$151.03	$145.99	($5.04)	-3.34%
3	10	1,500	$172.54	$162.81	($9.73)	-5.64%
4	25	5,000	$499.31	$474.69	($24.62)	-4.93%
5	25	7,500	$643.60	$618.39	($25.21)	-3.92%
6	25	10,000	$787.86	$762.06	($25.80)	-3.27%
7	50	25,000	$1,830.51	$1,777.74	($52.77)	-2.88%
8	200	50,000	$4,354.65	$4,155.36	($199.29)	-4.58%
9	200	125,000	$8,641.07	$8,424.11	($216.96)	-2.51%
10	500	200,000	$15,084.41	$14,568.51	($515.90)	-3.42%
11	1,000	300,000	$24,405.76	$23,397.54	($1,008.22)	-4.13%
12	1,000	500,000	$35,746.24	$34,690.88	($1,055.36)	-2.95%
13	2,500	750,000	$60,875.12	$58,354.56	($2,520.56)	-4.14%
14	2,500	1,000,000	$74,850.26	$72,270.78	($2,579.48)	-3.45%
15	5,000	1,500,000	$120,856.79	$115,815.68	($5,041.11)	-4.17%
16	5,000	2,000,000	$148,607.84	$143,448.88	($5,158.96)	-3.47%

Under the Proposed Rates, Secondary customers are charged for all kWh and all kW of billing demand.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Primary Service

Data: Actual and Forecasted | Amended
Type of Filing: Original | Schedule B-4
Work Paper Reference: None |

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	5	1,000	$325.00	$322.03	($2.97)	-0.91%
2	5	2,500	$409.28	$405.96	($3.32)	-0.81%
3	10	5,000	$577.10	$570.46	($6.64)	-1.15%
4	25	7,500	$801.48	$786.07	($15.41)	-1.92%
5	25	10,000	$941.10	$925.10	($16.00)	-1.70%
6	50	20,000	$1,638.05	$1,606.06	($31.99)	-1.95%
7	50	30,000	$2,191.01	$2,156.66	($34.35)	-1.57%
8	200	50,000	$4,144.00	$4,023.10	($120.90)	-2.92%
9	200	75,000	$5,526.38	$5,399.59	($126.79)	-2.29%
10	200	100,000	$6,908.77	$6,776.09	($132.68)	-1.92%
11	500	250,000	$16,897.22	$16,565.52	($331.70)	-1.96%
12	1,000	500,000	$33,544.52	$32,881.12	($663.40)	-1.98%
13	2,500	1,000,000	$69,462.30	$67,862.73	($1,599.57)	-2.30%
14	5,000	2,500,000	$164,722.66	$161,405.67	($3,316.99)	-2.01%
15	10,000	5,000,000	$328,195.68	$321,561.70	($6,633.98)	-2.02%
16	25,000	7,500,000	$548,137.84	$532,731.39	($15,406.45)	-2.81%
17	25,000	10,000,000	$683,376.34	$667,380.64	($15,995.70)	-2.34%
18	50,000	15,000,000	$1,095,025.96	$1,064,213.05	($30,812.91)	-2.81%

For the purpose of typical bill comparison, a 90% Power Factor is assumed.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Primary Substation

Data: Actual and Forecasted — Amended
Type of Filing: Original — Schedule B-4
Work Paper Reference: None —

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	3,000	1,000,000	$67,121.90	$65,348.02	($1,773.88)	-2.64%
2	5,000	2,000,000	$128,718.96	$125,683.92	($3,035.04)	-2.36%
3	5,000	3,000,000	$182,205.36	$178,934.62	($3,270.74)	-1.80%
4	10,000	4,000,000	$255,968.44	$249,898.37	($6,070.07)	-2.37%
5	10,000	5,000,000	$309,454.84	$303,149.07	($6,305.77)	-2.04%
6	15,000	6,000,000	$383,217.95	$374,112.84	($9,105.11)	-2.38%
7	15,000	7,000,000	$436,704.35	$427,363.54	($9,340.81)	-2.14%
8	15,000	8,000,000	$490,190.75	$480,614.24	($9,576.51)	-1.95%
9	25,000	9,000,000	$584,230.56	$569,291.08	($14,939.48)	-2.56%
10	25,000	10,000,000	$637,716.96	$622,541.78	($15,175.18)	-2.38%
11	30,000	12,500,000	$791,709.65	$773,381.58	($18,328.07)	-2.31%
12	30,000	15,000,000	$925,425.65	$906,508.33	($18,917.32)	-2.04%
13	50,000	17,500,000	$1,140,248.41	$1,110,487.30	($29,761.11)	-2.61%
14	50,000	20,000,000	$1,273,964.41	$1,243,614.05	($30,350.36)	-2.38%
15	50,000	25,000,000	$1,541,396.41	$1,509,867.55	($31,528.86)	-2.05%

For the purpose of typical bill comparison, a 90% Power Factor is assumed.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
High Voltage Service

Data: Actual and Forecasted — Amended
Type of Filing: Original — Schedule B-4
Work Paper Reference: None —

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	1,000	500,000	$31,918.24	$31,365.74	($552.50)	-1.73%
2	2,000	1,000,000	$62,510.29	$61,405.28	($1,105.01)	-1.77%
3	3,000	1,500,000	$92,702.63	$91,045.12	($1,657.51)	-1.79%
4	3,500	2,000,000	$121,162.09	$119,169.40	($1,992.69)	-1.64%
5	5,000	2,500,000	$153,087.32	$150,324.80	($2,762.52)	-1.80%
6	7,500	3,000,000	$188,478.37	$184,511.37	($3,967.00)	-2.10%
7	7,500	4,000,000	$241,931.47	$237,728.77	($4,202.70)	-1.74%
8	10,000	5,000,000	$304,049.05	$298,524.01	($5,525.04)	-1.82%
9	10,000	6,000,000	$357,502.15	$351,741.41	($5,760.74)	-1.61%
10	12,500	7,000,000	$419,619.74	$412,536.67	($7,083.07)	-1.69%
11	12,500	8,000,000	$473,072.84	$465,754.07	($7,318.77)	-1.55%
12	15,000	9,000,000	$535,190.42	$526,549.31	($8,641.11)	-1.61%
13	20,000	10,000,000	$605,972.50	$594,922.42	($11,050.08)	-1.82%
14	40,000	20,000,000	$1,209,819.40	$1,187,719.25	($22,100.15)	-1.83%
15	60,000	30,000,000	$1,813,666.29	$1,780,516.06	($33,150.23)	-1.83%

For the purpose of typical bill comparison, a 90% Power Factor is assumed.

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Private Outdoor Lighting

Data: Actual and Forecasted | Amended
Type of Filing: Original | Schedule B-4
Work Paper Reference: None |

Line No.	Fixture	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	7000 -					
2	Mercury	75	$14.45	$14.42	($0.03)	-0.21%
3	21000 -					
4	Mercury	154	$19.02	$18.97	($0.05)	-0.26%
5	2500 -					
6	Incandescent	64	$13.91	$13.89	($0.02)	-0.14%
7	7000 -					
8	Fluorescent	66	$14.12	$14.10	($0.02)	-0.14%
9	4000 -					
10	Mercury	43	$13.06	$13.05	($0.01)	-0.08%
11	9500 - High					
12	Pressure Sodium	39	$12.36	$12.35	($0.01)	-0.08%
13	28000 - High					
14	Pressure Sodium	96	$15.66	$15.63	($0.03)	-0.19%
15	3600					
16	LED	14	$10.91	$10.91	$0.00	0.00%
17	8400					
18	LED	30	$11.83	$11.82	($0.01)	-0.08%

Note: Current and proposed bills included monthly charge for 1 fixture

AES Ohio
Case No. 22-0152-EL-RDR
Typical Bill Comparison
Street Lighting

Data: Actual and Forecasted — Amended
Type of Filing: Original — Schedule B-4
Work Paper Reference: None —

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	0.0	50	$12.20	$12.18	($0.02)	-0.16%
2	0.0	100	$15.86	$15.83	($0.03)	-0.19%
3	0.0	200	$23.15	$23.08	($0.07)	-0.30%
4	0.0	400	$37.79	$37.65	($0.14)	-0.37%
5	0.0	500	$45.11	$44.94	($0.17)	-0.38%
6	0.0	750	$63.39	$63.13	($0.26)	-0.41%
7	0.0	1,000	$81.65	$81.30	($0.35)	-0.43%
8	0.0	1,200	$96.28	$95.86	($0.42)	-0.44%
9	0.0	1,400	$110.88	$110.39	($0.49)	-0.44%
10	0.0	1,600	$125.53	$124.98	($0.55)	-0.44%
11	0.0	2,000	$154.77	$154.08	($0.69)	-0.45%
12	0.0	2,500	$191.12	$190.25	($0.87)	-0.46%
13	0.0	3,000	$227.42	$226.38	($1.04)	-0.46%
14	0.0	4,000	$300.06	$298.67	($1.39)	-0.46%
15	0.0	5,000	$372.71	$370.98	($1.73)	-0.46%

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted | Amended
Type of Filing: Revised | Schedule C-1
Work Paper Reference No(s).: WPC-1a |

			2022 Forecast							Total Forecast
Line	Description	Type of Charge	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jun - Dec 2022
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = Sum (D) thru (J)
			WPC-1a, Col (E), Lines 2 thru 15	WPC-1a, Col (E), Lines 21 thru 34	WPC-1a, Col (E), Lines 40 thru 53	WPC-1a, Col (E), Lines 59 thru 72	WPC-1a, Col (E), Lines 78thru 91	WPC-1a, Col (E), Lines 97 thru 110	WPC-1a, Col (E), Lines 116 thru 129	
	TCRR-N Costs & Revenues									
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$ 854,584	$ 856,050	$ 854,717	$ 845,149	$ 844,418	$ 843,919	$ 770,277	$ 5,869,113
2	Incremental Capacity Transfer Rights Credits	Demand - 1 CP	$ (10,299)	$ (10,671)	$ (10,654)	$ (10,185)	$ (10,491)	$ (10,136)	$ (9,816)	$ (72,252)
3	Reactive Supply and Voltage Control from Gen Sources	Demand - 12 CP	$ 200,639	$ 201,340	$ 198,497	$ 199,622	$ 199,838	$ 201,214	$ 191,272	$ 1,392,422
4	Black Start Service	Demand - 12 CP	$ 15,580	$ 19,354	$ 58,425	$ (23,840)	$ 17,426	$ 17,551	$ 16,693	$ 121,189
5	TO Scheduling System Control and Dispatch Service	Energy	$ 97,084	$ 104,869	$ 109,305	$ 87,419	$ 82,728	$ 86,087	$ 87,547	$ 655,040
6	NERC/RFC Charges	Energy	$ 51,912	$ 56,095	$ 17,348	$ 87,896	$ 44,248	$ 46,035	$ 46,795	$ 350,330
7	Firm PTP Transmission Service	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Non-Firm PTP Transmission Service	Demand - 1 CP	$ (5,099)	$ (4,663)	$ (5,906)	$ (5,735)	$ (5,020)	$ (4,114)	$ (6,985)	$ (37,522)
9	Network Integration Transmission Service	Demand - 1 CP	$ 4,286,555	$ 4,429,440	$ 4,429,440	$ 4,286,555	$ 4,429,440	$ 4,286,555	$ 4,429,440	$ 30,577,426
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 459,993	$ 521,077	$ 542,613	$ 436,291	$ 376,914	$ 391,302	$ 397,469	$ 3,125,657
12	Load Response	Energy	$ 152	$ 1,358	$ 1,283	$ 6,181	$ 3,079	$ 1,296	$ 2,397	$ 15,746
13	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	Energy	$ 761	$ 823	$ 858	$ 686	$ 649	$ 675	$ 656	$ 5,107
14	Bilateral Charges	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 5,951,861	$ 6,175,073	$ 6,195,924	$ 5,910,038	$ 5,983,231	$ 5,860,385	$ 5,925,745	$ 42,002,257
16	TCRR-N Deferral carrying costs		$ (17,690)	$ (16,479)	$ (16,431)	$ (16,681)	$ (14,788)	$ (10,519)	$ (6,870)	$ (99,458)
17										
18	Total TCRR-N Demand - 1 CP costs		$ 5,125,741	$ 5,270,156	$ 5,267,597	$ 5,115,784	$ 5,258,348	$ 5,116,225	$ 5,182,916	$ 36,336,766
19	Total TCRR-N Demand - 12 CP costs		$ 216,219	$ 220,694	$ 256,921	$ 175,781	$ 217,264	$ 218,765	$ 207,966	$ 1,513,611
20	Total TCRR-N Energy costs		$ 609,902	$ 684,222	$ 671,406	$ 618,472	$ 507,618	$ 525,395	$ 534,864	$ 4,151,880
21										
22	**Total TCRR-N including carrying costs**		**$ 5,934,171**	**$ 6,158,594**	**$ 6,179,493**	**$ 5,893,357**	**$ 5,968,443**	**$ 5,849,866**	**$ 5,918,876**	**$ 41,902,799**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted	Amended
Type of Filing: Original	Schedule C-1
Work Paper Reference No(s).: WPC-1a	

Line	Description	Type of Charge	2023 Forecast Jan	Feb	Mar	Apr	May	Total Forecast Jan - May 2023	Total Forecast Jun 2022 - May 2023
(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T) = sum (O) thru (S)	(U) = (K) + (T)
			WPC-1a, Col (E), Lines 135 thru 148	WPC-1a, Col (E), Lines 154 thru 167	WPC-1a, Col (E), Lines 173 thru 186	WPC-1a, Col (E), Lines 192 thru 205	WPC-1a, Col (E), Lines 210 thru 223		
	TCRR-N Costs & Revenues								
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$ 947,088	$ 998,801	$ 815,585	$ 758,145	$ 860,456	$ 4,380,074	$ 10,249,188
2	Incremental Capacity Transfer Rights Credits	Demand - 1 CP	$ (9,683)	$ (9,163)	$ (25,270)	$ (24,453)	$ (26,749)	$ (95,318)	$ (167,570)
3	Reactive Supply and Voltage Control from Gen Sources	Demand - 12 CP	$ 181,941	$ 183,179	$ 198,581	$ 198,863	$ 205,760	$ 968,324	$ 2,360,745
4	Black Start Service	Demand - 12 CP	$ 15,917	$ 32,885	$ 27,159	$ 15,382	$ 15,800	$ 107,143	$ 228,332
5	TO Scheduling System Control and Dispatch Service	Energy	$ 85,206	$ 77,357	$ 78,585	$ 98,593	$ 82,966	$ 422,707	$ 1,077,747
6	NERC/RFC Charges	Energy	$ 71,028	$ (36)	$ 45,521	$ 41,171	$ 44,353	$ 202,036	$ 552,366
7	Firm PTP Transmission Service	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Non-Firm PTP Transmission Service	Demand - 1 CP	$ (10,684)	$ (9,285)	$ (4,597)	$ 433	$ (3,237)	$ (27,370)	$ (64,892)
9	Network Integration Transmission Service	Demand - 1 CP	$ 4,372,286	$ 4,372,286	$ 4,429,440	$ 4,286,555	$ 4,429,440	$ 21,890,008	$ 52,467,434
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 395,440	$ (42,415)	$ 437,221	$ 366,502	$ 394,525	$ 1,551,273	$ 4,676,931
12	Load Response	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,746
13	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	Energy	$ 884	$ (1)	$ 668	$ 604	$ 650	$ 2,805	$ 7,912
14	Bilateral Charges	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 6,049,422	$ 5,603,609	$ 6,002,892	$ 5,741,796	$ 6,003,965	$ 29,401,683	$ 71,403,940
16	TCRR-N Deferral carrying costs		$ (6,087)	$ (7,507)	$ (7,832)	$ (6,138)	$ (2,490)	$ (30,054)	$ (129,512)
17									
18	Total TCRR-N Demand - 1 CP costs		$ 5,299,007	$ 5,352,639	$ 5,215,158	$ 5,020,680	$ 5,259,911	$ 26,147,394	$ 62,484,160
19	Total TCRR-N Demand - 12 CP costs		$ 197,857	$ 216,064	$ 225,740	$ 214,245	$ 221,560	$ 1,075,467	$ 2,589,078
20	Total TCRR-N Energy costs		$ 552,558	$ 34,906	$ 561,994	$ 506,871	$ 522,494	$ 2,178,822	$ 6,330,702
21									
22	**Total TCRR-N including carrying costs**		**$ 6,043,335**	**$ 5,596,101**	**$ 5,995,060**	**$ 5,735,658**	**$ 6,001,475**	**$ 29,371,629**	**$ 71,274,428**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Costs by Tariff Class
June 2022 - May 2023

Data: Forecasted | Amended
Type of Filing: Original | Schedule C-2
Work Paper Reference No(s).: WPC-2a |

			2022 Forecast							
Line	Description	Tariff Allocator	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		WPC-2a Col (D), (F), (H)								
1	**TCRR-N Demand-Based Costs - 1 CP**		$ 5,125,741	$ 5,270,156	$ 5,267,597	$ 5,115,784	$ 5,258,348	$ 5,116,225	$ 5,182,916	Schedule C-1, Page 1, Line 18
2	Tariff Class									
3	Residential	43.45%	$ 2,226,991	$ 2,289,736	$ 2,288,624	$ 2,222,666	$ 2,284,606	$ 2,222,857	$ 2,251,833	Col (C) * Line 1
4	Secondary	30.13%	$ 1,544,617	$ 1,588,135	$ 1,587,364	$ 1,541,616	$ 1,584,577	$ 1,541,749	$ 1,561,846	Col (C) * Line 1
5	Primary	15.81%	$ 810,576	$ 833,413	$ 833,009	$ 809,001	$ 831,546	$ 809,071	$ 819,617	Col (C) * Line 1
6	Primary Substation	4.44%	$ 227,649	$ 234,063	$ 233,949	$ 227,206	$ 233,538	$ 227,226	$ 230,188	Col (C) * Line 1
7	High Voltage	6.16%	$ 315,908	$ 324,809	$ 324,651	$ 315,295	$ 324,081	$ 315,322	$ 319,432	Col (C) * Line 1
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
9	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
10	**Total TCRR-N Demand Costs**	100.00%	$ 5,125,741	$ 5,270,156	$ 5,267,597	$ 5,115,784	$ 5,258,348	$ 5,116,225	$ 5,182,916	Sum (Line 3 thru 10)
11										
12	**TCRR-N Demand-Based Costs - 12 CP**		$ 216,219	$ 220,694	$ 256,921	$ 175,781	$ 217,264	$ 218,765	$ 207,966	Schedule C-1, Page 1, Line 19
13	Tariff Class									
14	Residential	40.13%	$ 86,778	$ 88,575	$ 103,114	$ 70,549	$ 87,198	$ 87,800	$ 83,466	Col (C) * Line 13
15	Secondary	30.50%	$ 65,947	$ 67,312	$ 78,362	$ 53,614	$ 66,266	$ 66,724	$ 63,430	Col (C) * Line 13
16	Primary	17.79%	$ 38,471	$ 39,267	$ 45,713	$ 31,276	$ 38,657	$ 38,924	$ 37,002	Col (C) * Line 13
17	Primary Substation	5.13%	$ 11,084	$ 11,314	$ 13,171	$ 9,011	$ 11,138	$ 11,215	$ 10,661	Col (C) * Line 13
18	High Voltage	6.39%	$ 13,816	$ 14,102	$ 16,417	$ 11,232	$ 13,883	$ 13,979	$ 13,289	Col (C) * Line 13
19	Private Outdoor Lighting	0.02%	$ 44	$ 45	$ 52	$ 36	$ 44	$ 45	$ 42	Col (C) * Line 13
20	Street Lighting	0.04%	$ 78	$ 80	$ 93	$ 64	$ 79	$ 79	$ 75	Col (C) * Line 13
21	**Total TCRR-N Demand Costs**	100.00%	$ 216,219	$ 220,694	$ 256,921	$ 175,781	$ 217,264	$ 218,765	$ 207,966	Sum (Line 15 thru 22)
22										
23	**TCRR-N Energy-Based Costs**		$ 609,902	$ 684,222	$ 671,406	$ 618,472	$ 507,618	$ 525,395	$ 534,864	Schedule C-1, Page 1, Line 20
24	Tariff Class									
25	Residential	40.82%	$ 248,986	$ 279,326	$ 274,094	$ 252,484	$ 207,230	$ 214,487	$ 218,352	Col (C) * Line 25
26	Secondary	26.27%	$ 160,247	$ 179,775	$ 176,407	$ 162,499	$ 133,373	$ 138,044	$ 140,532	Col (C) * Line 25
27	Primary	19.11%	$ 116,572	$ 130,777	$ 128,328	$ 118,210	$ 97,023	$ 100,420	$ 102,230	Col (C) * Line 25
28	Primary Substation	6.19%	$ 37,733	$ 42,331	$ 41,538	$ 38,263	$ 31,405	$ 32,505	$ 33,090	Col (C) * Line 25
29	High Voltage	7.14%	$ 43,563	$ 48,872	$ 47,956	$ 44,175	$ 36,257	$ 37,527	$ 38,203	Col (C) * Line 25
30	Private Outdoor Lighting	0.18%	$ 1,081	$ 1,213	$ 1,190	$ 1,096	$ 900	$ 931	$ 948	Col (C) * Line 25
31	Street Lighting	0.28%	$ 1,719	$ 1,929	$ 1,893	$ 1,743	$ 1,431	$ 1,481	$ 1,508	Col (C) * Line 25
32	**Total TCRR-N Energy Costs**	100.00%	$ 609,902	$ 684,222	$ 671,406	$ 618,472	$ 507,618	$ 525,395	$ 534,864	Sum (Line 27 thru 34)

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Costs by Tariff Class
June 2022 - May 2023

Data: Forecasted | Amended
Type of Filing: Original | Schedule C-2
Work Paper Reference No(s).: WPC-2 |

Line (L)	Description (M)	Tariff Allocator (N)	2023 Forecast Jan (O)	Feb (P)	Mar (Q)	Apr (R)	May (S)	Source (T)	Total Forecast (U) = Sum (D) thru (J) and Sum (O) thru (S)
		WPC-2 Col (D), (F), (H)							
1	**TCRR-N Demand-Based Costs - 1 CP**		$ 5,299,007	$ 5,352,639	$ 5,215,158	$ 5,020,680	$ 5,259,911	Schedule C-1, Page 2, Line 18	
2	Tariff Class								
3	Residential	43.45%	$ 2,302,271	$ 2,325,572	$ 2,265,841	$ 2,181,345	$ 2,285,285	Col (N) * Line 1	$ 27,147,627
4	Secondary	30.13%	$ 1,596,830	$ 1,612,991	$ 1,571,562	$ 1,512,957	$ 1,585,048	Col (N) * Line 1	$ 18,829,292
5	Primary	15.81%	$ 837,976	$ 846,457	$ 824,716	$ 793,962	$ 831,793	Col (N) * Line 1	$ 9,881,136
6	Primary Substation	4.44%	$ 235,344	$ 237,726	$ 231,620	$ 222,983	$ 233,608	Col (N) * Line 1	$ 2,775,099
7	High Voltage	6.16%	$ 326,587	$ 329,892	$ 321,419	$ 309,433	$ 324,177	Col (N) * Line 1	$ 3,851,006
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (N) * Line 1	$ -
9	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (N) * Line 1	$ -
10	**Total TCRR-N Demand Costs**	100.00%	$ 5,299,007	$ 5,352,639	$ 5,215,158	$ 5,020,680	$ 5,259,911	Sum (Line 3 thru 9)	$ 62,484,160
11									
12	**TCRR-N Demand-Based Costs - 12 CP**		$ 197,857	$ 216,064	$ 225,740	$ 214,245	$ 221,560	Schedule C-1, Page 2, Line 19	
13	Tariff Class								
14	Residential	40.13%	$ 79,409	$ 86,716	$ 90,600	$ 85,986	$ 88,922	Col (N) * Line 12	$ 1,039,114
15	Secondary	30.50%	$ 60,347	$ 65,900	$ 68,851	$ 65,345	$ 67,576	Col (N) * Line 12	$ 789,676
16	Primary	17.79%	$ 35,204	$ 38,443	$ 40,165	$ 38,119	$ 39,421	Col (N) * Line 12	$ 460,660
17	Primary Substation	5.13%	$ 10,143	$ 11,076	$ 11,572	$ 10,983	$ 11,358	Col (N) * Line 12	$ 132,725
18	High Voltage	6.39%	$ 12,643	$ 13,806	$ 14,424	$ 13,690	$ 14,157	Col (N) * Line 12	$ 165,437
19	Private Outdoor Lighting	0.02%	$ 40	$ 44	$ 46	$ 44	$ 45	Col (N) * Line 12	$ 527
20	Street Lighting	0.04%	$ 72	$ 78	$ 82	$ 78	$ 80	Col (N) * Line 12	$ 938
21	**Total TCRR-N Demand Costs**	100.00%	$ 197,857	$ 216,064	$ 225,740	$ 214,245	$ 221,560	Sum (Line 14 thru 20)	$ 2,589,078
22									
23	**TCRR-N Energy-Based Costs**		$ 552,558	$ 34,906	$ 561,994	$ 506,871	$ 522,494	Schedule C-1, Page 2, Line 20	
24	Tariff Class								
25	Residential	40.82%	$ 225,576	$ 14,250	$ 229,428	$ 206,924	$ 213,302	Col (N) * Line 23	$ 2,584,439
26	Secondary	26.27%	$ 145,181	$ 9,171	$ 147,660	$ 133,177	$ 137,282	Col (N) * Line 23	$ 1,663,348
27	Primary	19.11%	$ 105,612	$ 6,672	$ 107,416	$ 96,880	$ 99,866	Col (N) * Line 23	$ 1,210,005
28	Primary Substation	6.19%	$ 34,185	$ 2,159	$ 34,769	$ 31,359	$ 32,325	Col (N) * Line 23	$ 391,661
29	High Voltage	7.14%	$ 39,467	$ 2,493	$ 40,141	$ 36,204	$ 37,320	Col (N) * Line 23	$ 452,180
30	Private Outdoor Lighting	0.18%	$ 980	$ 62	$ 996	$ 899	$ 926	Col (N) * Line 23	$ 11,223
31	Street Lighting	0.28%	$ 1,558	$ 98	$ 1,584	$ 1,429	$ 1,473	Col (N) * Line 23	$ 17,846
32	**Total TCRR-N Energy Costs**	100.00%	$ 552,558	$ 34,906	$ 561,994	$ 506,871	$ 522,494	Sum (Line 25 thru 31)	$ 6,330,702

AES Ohio
Case No. 22-0152-EL-RDR
Summary of Proposed Rates
June 2022 - May 2023

Data: Forecasted | Amended
Type of Filing: Original | Schedule C-3
Work Paper Reference No(s).: None | Page 1 of 1

TCRR-N Rates

Line	Description		Residential	Secondary	Primary	Primary Substation	High Voltage	Private Outdoor Lighting	Street Lighting	Source
(A)	(B)		(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	TCRR-N Base Rates									
2	Demand (kWh, kW)		$ 0.0051329	$ 2.0605878	$ 1.8869013	$ 1.9223170	$ 2.1459131	$ 0.0000221	$ 0.0000248	Schedule C-3a, Line 18
3	Energy (kWh)		$ 0.0004706	$ 0.0004706	$ 0.0004706	$ 0.0004706	$ 0.0004706	$ 0.0004706	$ 0.0004706	Schedule C-3a, Line 34
4										
5	TCRR-N Reconciliation Rates									
6	Demand (kWh, kW)		$ (0.0003202)	$ (0.1403401)	$ (0.1422171)	$ (0.1484658)	$ (0.1495620)	$ (0.0000374)	$ (0.0000419)	Schedule C-3b, Line 23
7	Energy (kWh)		$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	Schedule C-3b, Line 24
8										
9	**Total TCRR-N Rates**	**$/kW**		**$ 1.9202477**	**$ 1.7446842**	**$ 1.7738512**	**$ 1.9963511**			Line 2 + Line 6
10		**$/kWh**	**$ 0.0052516**	**$ 0.0004389**	**$ 0.0004389**	**$ 0.0004389**	**$ 0.0004389**	**$ 0.0004236**	**$ 0.0004218**	Line 3 + Line 7
11										
12	TCRR-N Max Rates	$/kW	NA	$ 0.0112239	$ 0.0103956	NA	NA	NA	NA	Schedule C-3b, Line 8

AES Ohio
Case No. 22-0152-EL-RDR
Development of Proposed Base Rates
(Revenue)/Expense in $

Data: Forecasted | Amended
Type of Filing: Original | Schedule C-3a
Work Paper Reference No(s).: WPB-1, WPC-2a, WPC-3a |

Line	Description	"Current" Cycle Base Costs	Residential	Secondary	Primary	Primary Substation	High Voltage	Private Outdoor Lighting	Street Lighting	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Schedule B-1, Col (D)								
	TCRR-N Base Costs									
1	Demand-Based Allocators - 1 CP		43.45%	30.13%	15.81%	4.44%	6.16%	0.00%	0.00%	WPC-2a, Col (F)
2	Demand-Based Allocators - 12 CP		40.13%	30.50%	17.79%	5.13%	6.39%	0.02%	0.04%	WPC-2a, Col (H)
3										
4	Demand-Based Components									
5	Transmission Enhancement Charges (RTEP)	$ 10,249,188	$ 4,452,986	$ 3,088,542	$ 1,620,789	$ 455,195	$ 631,675	$ -	$ -	Col (C) * Line 1
6	Incremental Capacity Transfer Rights Credit	$ (167,570)	$ (72,804)	$ (50,496)	$ (26,499)	$ (7,442)	$ (10,328)	$ -	$ -	Col (C) * Line 1
7	Reactive Supply and Voltage Control from Gen Sources	$ 2,360,745	$ 947,474	$ 720,034	$ 420,034	$ 121,020	$ 150,847	$ 481	$ 856	Col (C) * Line 2
8	Black Start Service	$ 228,332	$ 91,640	$ 69,642	$ 40,626	$ 11,705	$ 14,590	$ 46	$ 83	Col (C) * Line 2
9	Firm PTP Transmission Service Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
10	Non-Firm PTP Transmission Service Credits	$ (64,892)	$ (28,194)	$ (19,555)	$ (10,262)	$ (2,882)	$ (3,999)	$ -	$ -	Col (C) * Line 1
11	Network Integration Transmission Service	$ 52,467,434	$ 22,795,638	$ 15,810,802	$ 8,297,109	$ 2,330,227	$ 3,233,658	$ -	$ -	Col (C) * Line 1
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
13	Subtotal	$ 65,073,238	$ 28,186,741	$ 19,618,969	$ 10,341,797	$ 2,907,823	$ 4,016,444	$ 527	$ 938	Sum (Line 5 thru 12)
14	Gross Revenue Conversion Factor	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	WPB-1, Line 4
15	Total Demand-Based Component Cost	$ 65,242,869	$ 28,260,217	$ 19,670,111	$ 10,368,755	$ 2,915,403	$ 4,026,914	$ 528	$ 941	Line 13 * Line 14
16										
17	Projected Billing Determinants (kWh, kW)		5,505,729,722	9,545,874	5,495,123	1,516,609	1,876,550	23,908,368	38,017,167	WPC-3a, Column (P)
18	**Demand Portion of TCRR-N Rate**		**$ 0.0051329**	**$ 2.0605878**	**$ 1.8869013**	**$ 1.9223170**	**$ 2.1459131**	**$ 0.0000221**	**$ 0.0000248**	Line 14 / Line 16
19										
20	Energy-Based Allocators		40.82%	26.27%	19.11%	6.19%	7.14%	0.18%	0.28%	WPC-2a, Col (D)
21										
22	Energy-Based Components									
23	TO Scheduling System Control and Dispatch Service	$ 1,077,747	$ 439,978	$ 283,171	$ 205,993	$ 66,677	$ 76,980	$ 1,911	$ 3,038	Col (C) * Line 20
24	NERC/RFC Charges	$ 552,366	$ 225,497	$ 145,130	$ 105,575	$ 34,173	$ 39,454	$ 979	$ 1,557	Col (C) * Line 20
25	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 4,676,931	$ 1,909,305	$ 1,228,831	$ 893,915	$ 289,347	$ 334,057	$ 8,291	$ 13,184	Col (C) * Line 20
26	Bilateral Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 20
27	Load Response Charge Allocation	$ 15,746	$ 6,428	$ 4,137	$ 3,010	$ 974	$ 1,125	$ 28	$ 44	Col (C) * Line 20
28	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 7,912	$ 3,230	$ 2,079	$ 1,512	$ 489	$ 565	$ 14	$ 22	Col (C) * Line 20
29	Subtotal	$ 6,330,702	$ 2,584,439	$ 1,663,348	$ 1,210,005	$ 391,661	$ 452,180	$ 11,223	$ 17,846	Sum (Line 23 thru 28)
30	Gross Revenue Conversion Factor	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	WPB-1, Line 4
31	Total Energy-Based Component Cost	$ 6,347,205	$ 2,591,176	$ 1,667,684	$ 1,213,159	$ 392,682	$ 453,359	$ 11,252	$ 17,892	Line 29 * Line 30
32										
33	Projected Billing Determinants (kWh)		5,505,729,722	3,543,494,762	2,577,720,486	834,370,955	963,296,112	23,908,368	38,017,167	WPC-3a, Column (P)
34	**Energy Portion of TCRR-N Rate**		**$ 0.0004706**	**$ 0.0004706**	**$ 0.0004706**	**$ 0.0004706**	**$ 0.0004706**	**$ 0.0004706**	**$ 0.0004706**	Line 31 / Line 33
35										
36										
37	**Total Base TCRR-N Component Cost**	**$ 71,590,074**								Line 15 + Line 31

AES Ohio
Case No. 22-0152-EL-RDR
Development of Proposed Reconciliation Rate - TCRR-N
June 2022 - May 2023

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPB-1, WPC-1b, WPC-2, WPC-3

Amended
Schedule C-3b

Reconciliation TCRR-N Rate

Line	Description	Under Recovery	Demand/ Energy Ratios	Residential	Secondary	Primary	Primary Substation	High Voltage	Private Outdoor Lighting	Street Lighting	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Demand-Based Allocators - 12 CP			40.13%	30.50%	17.79%	5.13%	6.39%	0.02%	0.04%	WPC-2a, Col (H)
2	Energy-Based Allocators			40.82%	26.27%	19.11%	6.19%	7.14%	0.18%	0.28%	WPC-2a, Col (D)
3											
4	TCRR-N Under Recovery	$ (4,677,584)									WPC-1b, Col (C) Line 18
5	TCRR-N Under Recovery of Carrying Costs Total	$ (129,512)									WPC-1b, Col (H) Line 31
6	TCRR-N Under Recovery	$ (4,807,096)									Line 4 + Line 5
7	Gross Revenue Conversion Factor	1.003									WPB-1, Line 4
8	Total TCRR-N Under Recovery	$ (4,819,627)									Line 6 * Line 7
9											
10	Base TCRR-N Component Costs										
11	Total Demand-Based Component Cost	$ 65,242,869	91.13%								Schedule C-3a, Col (C) Line 15
12	Total Energy-Based Components Cost	$ 6,347,205	8.87%								Schedule C-3a, Col (C) Line 31
13	Total Base TCRR-N Component Cost	$ 71,590,074	100.00%								Line 11 + Line 12
14											
15	TCRR-N Under Recovery - Demand (Line 8 * Col (D), Line 11)	$ (4,392,317)		$ (1,762,836)	$ (1,339,669)	$ (781,501)	$ (225,164)	$ (280,661)	$ (894)	$ (1,592)	Col (C) * Line 1
16	TCRR-N Under Recovery - Energy (Line 8 * Col (D), Line 12)	$ (427,310)		$ (174,445)	$ (112,273)	$ (81,673)	$ (26,436)	$ (30,521)	$ (758)	$ (1,205)	Col (C) * Line 2
17	TCRR-N Under Recovery Total	$ (4,819,627)		$ (1,937,280)	$ (1,451,942)	$ (863,174)	$ (251,601)	$ (311,182)	$ (1,652)	$ (2,796)	Line 15 + Line 16
18											
19	Projected Billing Determinants (kWh, kW)			5,505,729,722	9,545,874	5,495,123	1,516,609	1,876,550	23,908,368	38,017,167	WPC-3a, Column (P)
20	Projected Billing Determinants (kWh)			5,505,729,722	3,543,494,762	2,577,720,486	834,370,955	963,296,112	23,908,368	38,017,167	WPC-3a, Column (P)
21											
22	TCRR-N Reconciliation Rates										
23	Demand Portion of TCRR-N Rate (kWh, kW)			$ (0.0003202)	$ (0.1403401)	$ (0.1422171)	$ (0.1484658)	$ (0.1495620)	$ (0.0000374)	$ (0.0000419)	Line 15 / Line 19
24	Energy Portion of TCRR-N Rate (kWh)			$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	$ (0.0000317)	Line 16 / Line 20

AES Ohio
Case No. 22-0152-EL-RDR
Development of Proposed Maximum Charge Rate - TCRR-N
June 2022 - May 2023

Data: Forecasted	Amended
Type of Filing: Original	Schedule C-3c
Work Paper Reference No(s).: WPC-3a	

Line (A)	Description (B)		Secondary (C)		Primary (D)	Source (E)
1	Total Non-Max. Charge Revenue (Demand & Energy)	$	19,885,853	$	10,718,740	Schedule C-3a Line 15 + Line 31 + Schedule C-3b Line 17
2	Total Non-Max. Charge Billing Determinants (kWh)		3,543,494,762		2,577,720,486	WPC-3a Column P
3						
4	Average Non-Max. Charge $/kWh	$	0.0056119	$	0.0041582	Line 1 / Line 2
5						
6	Max. Charge Rate Factor[1]		2		2.5	
7						
8	**Max. Charge Rate:**	**$**	**0.0112239**	**$**	**0.0103956**	Line 4 x Line 6

[1]The Max. Charge Rate Factor was established during AES Ohio's most recent Electric Security Plan

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

February 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 1,011,311	$ -		**$ 1,011,311**
2	Incremental Capacity Transfer	$ -	$ (22,946)		**$ (22,946)**
3	Operating Reserve	$ 2,760,191	$ -		**$ 2,760,191**
4	TCRR Revenue Rider	$ -	$ -	$ (3,582,599)	**$ (3,582,599)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 196,030	$ -		**$ 196,030**
6	Black Start Service	$ 15,180	$ -		**$ 15,180**
7	TO Scheduling System Control and Dispatch Service	$ 88,342	$ -		**$ 88,342**
8	NERC/RFC Charges	$ 51,170	$ -		**$ 51,170**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (6,013)		**$ (6,013)**
11	Network Integration Transmission Service	$ 4,128,159	$ -		**$ 4,128,159**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 487,771	$ -		**$ 487,771**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 473	$ -		**$ 473**
16	CAPS Funding	$ 618	$ -		**$ 618**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ 171	$ -		**$ 171**
20	SubTotal	$ 8,739,415	$ (28,959)	$ (3,582,599)	**$ 5,127,857**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 62,668**
22					
23	**Total TCRR-N including carrying costs**	$ 8,739,415	$ (28,959)	$ (3,582,599)	**$ 5,190,524**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

March 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 819,917	$ -		**$ 819,917**
2	Incremental Capacity Transfer	$ -	$ (25,404)		**$ (25,404)**
3	Operating Reserve	$ (173,773)	$ -		**$ (173,773)**
4	TCRR Revenue Rider	$ -	$ -	$ (3,521,762)	**$ (3,521,762)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 199,933	$ -		**$ 199,933**
6	Black Start Service	$ 27,344	$ -		**$ 27,344**
7	TO Scheduling System Control and Dispatch Service	$ 79,204	$ -		**$ 79,204**
8	NERC/RFC Charges	$ 45,879	$ -		**$ 45,879**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (4,622)		**$ (4,622)**
11	Network Integration Transmission Service	$ 4,570,273	$ -		**$ 4,570,273**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 440,668	$ -		**$ 440,668**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 721	$ -		**$ 721**
16	CAPS Funding	$ 673	$ -		**$ 673**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ 1,001.29	$ -		**$ 1,001**
20	SubTotal	$ 6,011,841	$ (30,026)	$ (3,521,762)	**$ 2,460,053**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 78,094**
22					
23	**Total TCRR-N including carrying costs**	$ 6,011,841	$ (30,026)	$ (3,521,762)	**$ 2,538,147**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

April 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs (F) = (C)+(D)+(E)**
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 762,172	$ -		**$ 762,172**
2	Incremental Capacity Transfer	$ -	$ (24,583)		**$ (24,583)**
3	Operating Reserve	$ (3)	$ -		**$ (3)**
4	TCRR Revenue Rider	$ -	$ -	$ (3,050,784)	**$ (3,050,784)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 200,218	$ -		**$ 200,218**
6	Black Start Service	$ 15,487	$ -		**$ 15,487**
7	TO Scheduling System Control and Dispatch Service	$ 99,371	$ -		**$ 99,371**
8	NERC/RFC Charges	$ 41,496	$ -		**$ 41,496**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ 435		**$ 435**
11	Network Integration Transmission Service	$ 426,358	$ -		**$ 426,358**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 369,392	$ -		**$ 369,392**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 2,748	$ -		**$ 2,748**
16	CAPS Funding	$ 608	$ -		**$ 608**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ 107	$ -		**$ 107**
20	SubTotal	$ 1,917,954	$ (24,148)	$ (3,050,784)	**$ (1,156,978)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 81,013**
22					
23	**Total TCRR-N including carrying costs**	$ 1,917,954	$ (24,148)	$ (3,050,784)	**$ (1,075,966)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

May 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs** (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 865,027	$ -		**$ 865,027**
2	Incremental Capacity Transfer	$ -	$ (26,891)		**$ (26,891)**
3	Operating Reserve	$ (23)	$ -		**$ (23)**
4	TCRR Revenue Rider	$ -	$ -	$ (2,844,632)	**$ (2,844,632)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 207,161	$ -		**$ 207,161**
6	Black Start Service	$ 15,908	$ -		**$ 15,908**
7	TO Scheduling System Control and Dispatch Service	$ 83,620	$ -		**$ 83,620**
8	NERC/RFC Charges	$ 44,702	$ -		**$ 44,702**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (3,254)		**$ (3,254)**
11	Network Integration Transmission Service	$ 4,379,825	$ -		**$ 4,379,825**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 397,636	$ -		**$ 397,636**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 283	$ -		**$ 283**
16	CAPS Funding	$ 655	$ -		**$ 655**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ (1,407)	$ -		**$ (1,407)**
20	SubTotal	$ 5,993,386	$ (30,145)	$ (2,844,632)	**$ 3,118,609**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 85,260**
22					
23	**Total TCRR-N including carrying costs**	$ 5,993,386	$ (30,145)	$ (2,844,632)	**$ 3,203,869**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

June 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 859,123	$ -		**$ 859,123**
2	Incremental Capacity Transfer	$ -	$ (10,354)		**$ (10,354)**
3	Operating Reserve	$ 2	$ -		**$ 2**
4	TCRR Revenue Rider	$ -	$ -	$ (7,852,408)	**$ (7,852,408)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 202,006	$ -		**$ 202,006**
6	Black Start Service	$ 15,686	$ -		**$ 15,686**
7	TO Scheduling System Control and Dispatch Service	$ 97,849	$ -		**$ 97,849**
8	NERC/RFC Charges	$ 52,321	$ -		**$ 52,321**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (5,126)		**$ (5,126)**
11	Network Integration Transmission Service	$ 4,265,032	$ -		**$ 4,265,032**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 463,619	$ -		**$ 463,619**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 153	$ -		**$ 153**
16	CAPS Funding	$ 767	$ -		**$ 767**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ 341	$ -		**$ 341**
20	SubTotal	$ 5,956,899	$ (15,480)	$ (7,852,408)	**$ (1,910,988)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 88,016**
22					
23	**Total TCRR-N including carrying costs**	$ 5,956,899	$ (15,480)	$ (7,852,408)	**$ (1,822,972)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

July 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs** (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 860,597	$ -		**$ 860,597**
2	Incremental Capacity Transfer	$ -	$ (10,728)		**$ (10,728)**
3	Operating Reserve	$ 5,629	$ -		**$ 5,629**
4	TCRR Revenue Rider	$ -	$ -	$ (8,843,834)	**$ (8,843,834)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 202,711	$ -		**$ 202,711**
6	Black Start Service	$ 19,486	$ -		**$ 19,486**
7	TO Scheduling System Control and Dispatch Service	$ 105,696	$ -		**$ 105,696**
8	NERC/RFC Charges	$ 56,537	$ -		**$ 56,537**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (4,688)		**$ (4,688)**
11	Network Integration Transmission Service	$ 4,412,695	$ -		**$ 4,412,695**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 525,185	$ -		**$ 525,185**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 1,369	$ -		**$ 1,369**
16	CAPS Funding	$ 829	$ -		**$ 829**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 6,190,735	$ (15,416)	$ (8,843,834)	**$ (2,668,515)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 79,209**
22					
23	**Total TCRR-N including carrying costs**	$ 6,190,735	$ (15,416)	$ (8,843,834)	**$ (2,589,305)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

August 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 859,257	$ -		**$ 859,257**
2	Incremental Capacity Transfer	$ -	$ (10,711)		**$ (10,711)**
3	Operating Reserve	$ 5,306	$ -		**$ 5,306**
4	TCRR Revenue Rider	$ -	$ -	$ (9,014,164)	**$ (9,014,164)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 199,848	$ -		**$ 199,848**
6	Black Start Service	$ 58,823	$ -		**$ 58,823**
7	TO Scheduling System Control and Dispatch Service	$ 110,166	$ -		**$ 110,166**
8	NERC/RFC Charges	$ 17,485	$ -		**$ 17,485**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (5,937)		**$ (5,937)**
11	Network Integration Transmission Service	$ 4,405,967	$ -		**$ 4,405,967**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 546,890	$ -		**$ 546,890**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 1,293	$ -		**$ 1,293**
16	CAPS Funding	$ 865	$ -		**$ 865**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 6,205,900	$ (16,648)	$ (9,014,164)	**$ (2,824,913)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 68,539**
22					
23	**Total TCRR-N including carrying costs**	$ 6,205,900	$ (16,648)	$ (9,014,164)	**$ (2,756,374)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

September 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 849,638	$ -		**$ 849,638**
2	Incremental Capacity Transfer	$ -	$ (10,239)		**$ (10,239)**
3	Operating Reserve	$ 12,932	$ -		**$ 12,932**
4	TCRR Revenue Rider	$ -	$ -	$ (8,946,550)	**$ (8,946,550)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 200,981	$ -		**$ 200,981**
6	Black Start Service	$ (24,003)	$ -		**$ (24,003)**
7	TO Scheduling System Control and Dispatch Service	$ 88,108	$ -		**$ 88,108**
8	NERC/RFC Charges	$ 88,589	$ -		**$ 88,589**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (5,766)		**$ (5,766)**
11	Network Integration Transmission Service	$ 4,201,799	$ -		**$ 4,201,799**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 439,730	$ -		**$ 439,730**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 6,230	$ -		**$ 6,230**
16	CAPS Funding	$ 691	$ -		**$ 691**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 5,864,695	$ (16,005)	$ (8,946,550)	**$ (3,097,859)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 56,968**
22					
23	**Total TCRR-N including carrying costs**	$ 5,864,695	$ (16,005)	$ (8,946,550)	**$ (3,040,891)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b | Page 9 of 13

October 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs** (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 848,904	$ -		**$ 848,904**
2	Incremental Capacity Transfer	$ -	$ (10,547)		**$ (10,547)**
3	Operating Reserve	$ -	$ -		**$ -**
4	TCRR Revenue Rider	$ -	$ -	$ (7,556,775)	**$ (7,556,775)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 201,199	$ -		**$ 201,199**
6	Black Start Service	$ 17,544	$ -		**$ 17,544**
7	TO Scheduling System Control and Dispatch Service	$ 83,381	$ -		**$ 83,381**
8	NERC/RFC Charges	$ 44,597	$ -		**$ 44,597**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (5,046)		**$ (5,046)**
11	Network Integration Transmission Service	$ 4,337,524	$ -		**$ 4,337,524**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 379,885	$ -		**$ 379,885**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 3,103	$ -		**$ 3,103**
16	CAPS Funding	$ 654	$ -		**$ 654**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 5,916,791	$ (15,593)	$ (7,556,775)	**$ (1,655,576)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 47,689**
22					
23	**Total TCRR-N including carrying costs**	$ 5,916,791	$ (15,593)	$ (7,556,775)	**$ (1,607,888)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

November 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs (F) = (C)+(D)+(E)**
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 848,401	$ -		**$ 848,401**
2	Incremental Capacity Transfer	$ -	$ (10,189)		**$ (10,189)**
3	Operating Reserve	$ 20	$ -		**$ 20**
4	TCRR Revenue Rider	$ -	$ -	$ (7,214,265)	**$ (7,214,265)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 202,584	$ -		**$ 202,584**
6	Black Start Service	$ 17,671	$ -		**$ 17,671**
7	TO Scheduling System Control and Dispatch Service	$ 86,766	$ -		**$ 86,766**
8	NERC/RFC Charges	$ 46,398	$ -		**$ 46,398**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (4,135)		**$ (4,135)**
11	Network Integration Transmission Service	$ 4,195,893	$ -		**$ 4,195,893**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 394,387	$ -		**$ 394,387**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 1,306	$ -		**$ 1,306**
16	CAPS Funding	$ 680	$ -		**$ 680**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 5,794,107	$ (14,325)	$ (7,214,265)	**$ (1,434,482)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 41,699**
22					
23	**Total TCRR-N including carrying costs**	$ 5,794,107	$ (14,325)	$ (7,214,265)	**$ (1,392,783)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

December 2021 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 774,368	$ -		**$ 774,368**
2	Incremental Capacity Transfer	$ -	$ (9,868)		**$ (9,868)**
3	Operating Reserve	$ 0	$ -		**$ 0**
4	TCRR Revenue Rider	$ -	$ -	$ (8,006,203)	**$ (8,006,203)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 192,575	$ -		**$ 192,575**
6	Black Start Service	$ 16,807	$ -		**$ 16,807**
7	TO Scheduling System Control and Dispatch Service	$ 88,238	$ -		**$ 88,238**
8	NERC/RFC Charges	$ 47,164	$ -		**$ 47,164**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (7,022)		**$ (7,022)**
11	Network Integration Transmission Service	$ 4,145,848	$ -		**$ 4,145,848**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 400,602	$ -		**$ 400,602**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 2,416	$ -		**$ 2,416**
16	CAPS Funding	$ 661	$ -		**$ 661**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 5,668,678	$ (16,890)	$ (8,006,203)	**$ (2,354,414)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 34,288**
22					
23	**Total TCRR-N including carrying costs**	$ 5,668,678	$ (16,890)	$ (8,006,203)	**$ (2,320,126)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

January 2022 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	**Total Net Costs** (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 952,118	$ -		**$ 952,118**
2	Incremental Capacity Transfer	$ -	$ (9,734)		**$ (9,734)**
3	Operating Reserve	$ 0	$ -		**$ 0**
4	TCRR Revenue Rider	$ -	$ -	$ (8,838,144)	**$ (8,838,144)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 183,180	$ -		**$ 183,180**
6	Black Start Service	$ 16,025	$ -		**$ 16,025**
7	TO Scheduling System Control and Dispatch Service	$ 85,878	$ -		**$ 85,878**
8	NERC/RFC Charges	$ 71,588	$ -		**$ 71,588**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (10,741)		**$ (10,741)**
11	Network Integration Transmission Service	$ 4,305,009	$ -		**$ 4,305,009**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 398,557	$ -		**$ 398,557**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 273	$ -		**$ 273**
16	CAPS Funding	$ 891	$ -		**$ 891**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 6,013,518	$ (20,475)	$ (8,838,144)	**$ (2,845,100)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 24,027**
22					
23	**Total TCRR-N including carrying costs**	**$ 6,013,518.15**	**$ (20,474.67)**	$ (8,838,144)	**$ (2,821,074)**

AES Ohio
Case No. 22-0152-EL-RDR
Actual Charges and Revenues
February 2021 - February 2022
(Revenue)/Expense in $

Data: Actual | Amended
Type of Filing: Original | Schedule D-1
Work Paper Reference No(s).: WPC-1b |

February 2022 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Retail Revenues (E)	Total Net Costs (F) = (C)+(D)+(E)
	Transmission Cost Recovery Rider - Non-Bypassable (TCRR-N)				
1	Transmission Enhancement Charges (RTEP)	$ 1,004,106	$ -		**$ 1,004,106**
2	Incremental Capacity Transfer	$ -	$ (9,212)		**$ (9,212)**
3	Operating Reserve	$ -	$ -		**$ -**
4	TCRR Revenue Rider	$ -	$ -	$ (8,825,551)	**$ (8,825,551)**
5	Reactive Supply and Voltage Control from Gen Sources	$ 184,427	$ -		**$ 184,427**
6	Black Start Service	$ 33,109	$ -		**$ 33,109**
7	TO Scheduling System Control and Dispatch Service	$ 77,967	$ -		**$ 77,967**
8	NERC/RFC Charges	$ (36)	$ -		**$ (36)**
9	Firm PTP Transmission Service	$ -	$ -		**$ -**
10	Non-Firm PTP Transmission Service	$ -	$ (9,334)		**$ (9,334)**
11	Network Integration Transmission Service	$ 4,102,624	$ -		**$ 4,102,624**
12	Expansion Cost Recovery Charges (ECRC)	$ -	$ -		**$ -**
13	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ (42,749)	$ -		**$ (42,749)**
14	PJM Interface Phase Angle Regulators	$ -	$ -		**$ -**
15	Load Response	$ 527	$ -		**$ 527**
16	CAPS Funding	$ (1)	$ -		**$ (1)**
17	Bilateral Charge	$ -	$ -		**$ -**
18	Generation Deactivation	$ -	$ -		**$ -**
19	PJM Default Charges	$ -	$ -		**$ -**
20	SubTotal	$ 5,359,973	$ (18,546)	$ (8,825,551)	**$ (3,484,125)**
21	TCRR-N Deferral carrying costs (WPC-1b)				**$ 11,464**
22					
23	**Total TCRR-N including carrying costs**	$ 5,359,973	$ (18,546)	$ (8,825,551)	**$ (3,472,661)**

AES Ohio
Case No. 22-0152-EL-RDR
Monthly Revenues Collected by Tariff Class

Data: Actual | Amended
Type of Filing: Original | Schedule D-2
Work Paper Reference No(s).: None | Page 1 of 1

		2021											2022		
Line	Description	February	March	April	May	June	July	August	September	October	November	December	January	February	Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	TCRR-N														
1	Residential	-$1,770,690	-$1,670,651	-$1,216,650	-$1,021,805	-$2,862,497	-$3,501,453	-$3,610,052	-$3,498,048	-$2,515,954	-$2,380,064	-$3,223,958	-$3,858,636	-$4,045,948	**-$35,176,406**
2	Secondary	-$977,521	-$1,036,359	-$1,008,641	-$983,386	-$2,965,491	-$3,183,054	-$3,185,306	-$3,235,045	-$2,960,997	-$2,880,596	-$2,850,435	-$2,985,777	-$2,880,077	**-$31,132,685**
3	Primary	-$501,595	-$480,113	-$494,086	-$499,585	-$1,265,144	-$1,344,362	-$1,411,041	-$1,386,624	-$1,287,075	-$1,219,649	-$1,148,490	-$1,276,798	-$1,170,087	**-$13,484,649**
4	Primary Substation	-$151,724	-$149,750	-$153,189	-$156,811	-$321,288	-$332,133	-$341,219	-$345,850	-$343,343	-$339,397	-$332,250	-$319,584	-$329,716	**-$3,616,254**
5	High Voltage	-$179,280	-$183,128	-$176,461	-$181,271	-$434,241	-$479,120	-$462,508	-$476,960	-$445,357	-$390,529	-$447,037	-$393,321	-$395,610	**-$4,644,823**
6	Private Outdoor Lighting	-$709	-$702	-$703	-$701	-$1,479	-$1,475	-$1,462	-$1,459	-$1,463	-$1,449	-$1,452	-$1,442	-$1,432	**-$15,928**
7	Street Lighting	-$1,080	-$1,060	-$1,053	-$1,074	-$2,266	-$2,237	-$2,576	-$2,563	-$2,586	-$2,579	-$2,582	-$2,586	-$2,682	**-$26,924**
8	**Total TCRR-N**	**-$3,582,599**	**-$3,521,763**	**-$3,050,783**	**-$2,844,633**	**-$7,852,406**	**-$8,843,834**	**-$9,014,164**	**-$8,946,549**	**-$7,556,775**	**-$7,214,263**	**-$8,006,204**	**-$8,838,144**	**-$8,825,552**	**-$88,097,669**

AES Ohio
Case No. 22-0152-EL-RDR
Monthly (Over) / Under Recovery

Data: Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Amended
Schedule D-3

		Prior Period	2021											2022			
Line	Description	True-up Balance	February	March	April	May	June	July	August	September	October	November	December	January	February	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	TCRR-N																
1	Net Costs		$8,710,456	$5,981,815	$1,893,806	$5,963,241	$5,941,419	$6,175,319	$6,189,252	$5,848,691	$5,901,198	$5,779,783	$5,651,788	$5,993,043	$5,341,427	$75,371,237	Schedule D-1, Col (C) + Col (D)
2	Revenues		($3,582,599)	($3,521,762)	($3,050,784)	($2,844,632)	($7,852,408)	($8,843,834)	($9,014,164)	($8,946,550)	($7,556,775)	($7,214,265)	($8,006,203)	($8,838,144)	($8,825,551)	($88,097,669)	Schedule D-1, Col (E)
3	(Over)/ Under Recovery		$5,127,857	$2,460,053	($1,156,978)	$3,118,609	($1,910,988)	($2,668,515)	($2,824,913)	($3,097,859)	($1,655,576)	($1,434,482)	($2,354,414)	($2,845,100)	($3,484,125)	($12,726,432)	Line 1 + Line 2
4	Carrying Costs		$62,668	$78,094	$81,013	$85,260	$88,016	$79,209	$68,539	$56,968	$47,689	$41,699	$34,288	$24,027	$11,464	$758,934	Schedule D-1, Col (F)
5	(Over)/ Under Recovery with Carrying Costs		$5,190,524	$2,538,147	($1,075,966)	$3,203,869	($1,822,972)	($2,589,305)	($2,756,374)	($3,040,891)	($1,607,888)	($1,392,783)	($2,320,126)	($2,821,074)	($3,472,661)	($11,967,499)	Line 3 + Line 4
6	YTD Under Recovery (without Carrying Costs)		$18,230,808	$20,753,529	$19,674,644	$22,874,266	$21,048,537	$18,468,039	$15,722,335	$12,693,015	$11,094,407	$9,707,614	$7,394,899	$4,584,087	$1,123,989	$376,519	Line 3 + Line 7
7	**YTD Under Recovery**	**13,102,951**	**$18,293,475**	**$20,831,623**	**$19,755,657**	**$22,959,526**	**$21,136,554**	**$18,547,248**	**$15,790,875**	**$12,749,983**	**$11,142,096**	**$9,749,313**	**$7,429,187**	**$4,608,113**	**$1,135,453**	**$1,135,453**	Line 5 + Line 7

AES Ohio
Case No. 22-0152-EL-RDR
Transmission Cost Recovery Rider - Non-Bypassable

Workpapers

AES Ohio
Case No. 22-0152-EL-RDR
Computation of Gross Revenue Conversion Factor

Data: Actual	Amended
Type of Filing: Original	Workpaper B-1
Work Paper Reference No(s).: None	Page 1 of 1

Line (A)	Item Description (B)	Gross Revenues (C)	Source (D)
1	Operating Revenues	100.000%	
2	Less: Commercial Activities Tax (CAT)	0.260%	Current Statutory Rate
3	Percentage of Income After CAT	99.740%	Line 1 - Line 2
4	CAT Tax Gross Revenue Conversion Factor	1.00261	Line 1 / Line 3

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b; WPC-1c

Amended
Workpaper C-1a

June 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment Factor (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 859,123	NA	Demand - 1 CP	99.472%	**$ 854,584**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,354)	Demand - 1 CP	99.472%	**$ (10,299)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 202,006	NA	Reactive Demand - 12 CP	99.324%	**$ 200,639**
5	Black Start Service	$ 15,686	NA	Demand - 12 CP	99.324%	**$ 15,580**
6	TO Scheduling System Control and Dispatch Service	$ 97,849	NA	Energy	99.218%	**$ 97,084**
7	NERC/RFC Charges	$ 52,321	NA	Energy	99.218%	**$ 51,912**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (5,126)	Demand - 1 CP	99.472%	**$ (5,099)**
10	Network Integration Transmission Service	$ 4,309,324	NA	Demand - 1 CP	99.472%	**$ 4,286,555**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 463,619	NA	Energy	99.218%	**$ 459,993**
13	Load Response	$ 153		Energy	99.218%	**$ 152**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 767	NA	Energy	99.218%	**$ 761**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,000,849	$ (15,480)			**$ 5,951,861**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (17,690)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,000,849	$ (15,480)			**$ 5,934,171**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

July 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 860,597	NA	Demand - 1 CP	99.472%	**$ 856,050**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,728)	Demand - 1 CP	99.472%	**$ (10,671)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 202,711	NA	Reactive Demand - 12 CP	99.324%	**$ 201,340**
5	Black Start Service	$ 19,486	NA	Demand - 12 CP	99.324%	**$ 19,354**
6	TO Scheduling System Control and Dispatch Service	$ 105,696	NA	Energy	99.218%	**$ 104,869**
7	NERC/RFC Charges	$ 56,537	NA	Energy	99.218%	**$ 56,095**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (4,688)	Demand - 1 CP	99.472%	**$ (4,663)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 525,185	NA	Energy	99.218%	**$ 521,077**
13	Load Response	$ 1,369		Energy	99.218%	**$ 1,358**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 829	NA	Energy	99.218%	**$ 823**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,225,379	$ (15,416)			**$ 6,175,073**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (16,479)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,225,379	$ (15,416)			**$ 6,158,594**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

August 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 859,257	NA	Demand - 1 CP	99.472%	**$ 854,717**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,711)	Demand - 1 CP	99.472%	**$ (10,654)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 199,848	NA	Reactive Demand - 12 CP	99.324%	**$ 198,497**
5	Black Start Service	$ 58,823	NA	Demand - 12 CP	99.324%	**$ 58,425**
6	TO Scheduling System Control and Dispatch Service	$ 110,166	NA	Energy	99.218%	**$ 109,305**
7	NERC/RFC Charges	$ 17,485	NA	Energy	99.218%	**$ 17,348**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (5,937)	Demand - 1 CP	99.472%	**$ (5,906)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 546,890	NA	Energy	99.218%	**$ 542,613**
13	Load Response	$ 1,293		Energy	99.218%	**$ 1,283**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 865	NA	Energy	99.218%	**$ 858**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,247,595	$ (16,648)			**$ 6,195,924**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (16,431)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,247,595	$ (16,648)			**$ 6,179,493**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted | Amended
Type of Filing: Original | Workpaper C-1a
Work Paper Reference No(s).: WPC-1b |

September 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 849,638	NA	Demand - 1 CP	99.472%	**$ 845,149**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,239)	Demand - 1 CP	99.472%	**$ (10,185)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 200,981	NA	Reactive Demand - 12 CP	99.324%	**$ 199,622**
5	Black Start Service	$ (24,003)	NA	Demand - 12 CP	99.324%	**$ (23,840)**
6	TO Scheduling System Control and Dispatch Service	$ 88,108	NA	Energy	99.218%	**$ 87,419**
7	NERC/RFC Charges	$ 88,589	NA	Energy	99.218%	**$ 87,896**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (5,766)	Demand - 1 CP	99.472%	**$ (5,735)**
10	Network Integration Transmission Service	$ 4,309,324	NA	Demand - 1 CP	99.472%	**$ 4,286,555**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 439,730	NA	Energy	99.218%	**$ 436,291**
13	Load Response	$ 6,230		Energy	99.218%	**$ 6,181**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 691	NA	Energy	99.218%	**$ 686**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 5,959,289	$ (16,005)			**$ 5,910,038**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (16,681)**
18						
19	**Total TCRR-N including carrying costs**	$ 5,959,289	$ (16,005)			**$ 5,893,357**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted | Amended
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October 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 848,904	NA	Demand - 1 CP	99.472%	**$ 844,418**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,547)	Demand - 1 CP	99.472%	**$ (10,491)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 201,199	NA	Reactive Demand - 12 CP	99.324%	**$ 199,838**
5	Black Start Service	$ 17,544	NA	Demand - 12 CP	99.324%	**$ 17,426**
6	TO Scheduling System Control and Dispatch Service	$ 83,381	NA	Energy	99.218%	**$ 82,728**
7	NERC/RFC Charges	$ 44,597	NA	Energy	99.218%	**$ 44,248**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (5,046)	Demand - 1 CP	99.472%	**$ (5,020)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 379,885	NA	Energy	99.218%	**$ 376,914**
13	Load Response	$ 3,103		Energy	99.218%	**$ 3,079**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 654	NA	Energy	99.218%	**$ 649**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,032,236	$ (15,593)			**$ 5,983,231**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (14,788)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,032,236	$ (15,593)			**$ 5,968,443**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

November 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 848,401	NA	Demand - 1 CP	99.472%	**$ 843,919**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (10,189)	Demand - 1 CP	99.472%	**$ (10,136)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 202,584	NA	Reactive Demand - 12 CP	99.324%	**$ 201,214**
5	Black Start Service	$ 17,671	NA	Demand - 12 CP	99.324%	**$ 17,551**
6	TO Scheduling System Control and Dispatch Service	$ 86,766	NA	Energy	99.218%	**$ 86,087**
7	NERC/RFC Charges	$ 46,398	NA	Energy	99.218%	**$ 46,035**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (4,135)	Demand - 1 CP	99.472%	**$ (4,114)**
10	Network Integration Transmission Service	$ 4,309,324	NA	Demand - 1 CP	99.472%	**$ 4,286,555**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 394,387	NA	Energy	99.218%	**$ 391,302**
13	Load Response	$ 1,306		Energy	99.218%	**$ 1,296**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 680	NA	Energy	99.218%	**$ 675**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 5,907,518	$ (14,325)			**$ 5,860,385**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (10,519)**
18						
19	**Total TCRR-N including carrying costs**	$ 5,907,518	$ (14,325)			**$ 5,849,866**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

December 2022 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 774,368	NA	Demand - 1 CP	99.472%	**$ 770,277**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (9,868)	Demand - 1 CP	99.472%	**$ (9,816)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 192,575	NA	Reactive Demand - 12 CP	99.324%	**$ 191,272**
5	Black Start Service	$ 16,807	NA	Demand - 12 CP	99.324%	**$ 16,693**
6	TO Scheduling System Control and Dispatch Service	$ 88,238	NA	Energy	99.218%	**$ 87,547**
7	NERC/RFC Charges	$ 47,164	NA	Energy	99.218%	**$ 46,795**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (7,022)	Demand - 1 CP	99.472%	**$ (6,985)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 400,602	NA	Energy	99.218%	**$ 397,469**
13	Load Response	$ 2,416		Energy	99.218%	**$ 2,397**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 661	NA	Energy	99.218%	**$ 656**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 5,975,799	$ (16,890)			**$ 5,925,745**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (6,870)**
18						
19	**Total TCRR-N including carrying costs**	$ 5,975,799	$ (16,890)			**$ 5,918,876**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

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January 2023 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 952,118	NA	Demand - 1 CP	99.472%	**$ 947,088**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (9,734)	Demand - 1 CP	99.472%	**$ (9,683)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 183,180	NA	Reactive Demand - 12 CP	99.324%	**$ 181,941**
5	Black Start Service	$ 16,025	NA	Demand - 12 CP	99.324%	**$ 15,917**
6	TO Scheduling System Control and Dispatch Service	$ 85,878	NA	Energy	99.218%	**$ 85,206**
7	NERC/RFC Charges	$ 71,588	NA	Energy	99.218%	**$ 71,028**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (10,741)	Demand - 1 CP	99.472%	**$ (10,684)**
10	Network Integration Transmission Service	$ 4,395,511	NA	Demand - 1 CP	99.472%	**$ 4,372,286**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 398,557	NA	Energy	99.218%	**$ 395,440**
13	Load Response	$ 273		Energy	99.218%	**$ -**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 891	NA	Energy	99.218%	**$ 884**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,104,020	$ (20,475)			**$ 6,049,422**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (6,087)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,104,020	$ (20,475)			**$ 6,043,335**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted | Amended
Type of Filing: Original | Workpaper C-1a
Work Paper Reference No(s).: WPC-1b |

February 2023 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 1,004,106	NA	Demand - 1 CP	99.472%	**$ 998,801**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (9,212)	Demand - 1 CP	99.472%	**$ (9,163)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 184,427	NA	Reactive Demand - 12 CP	99.324%	**$ 183,179**
5	Black Start Service	$ 33,109	NA	Demand - 12 CP	99.324%	**$ 32,885**
6	TO Scheduling System Control and Dispatch Service	$ 77,967	NA	Energy	99.218%	**$ 77,357**
7	NERC/RFC Charges	$ (36)	NA	Energy	99.218%	**$ (36)**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (9,334)	Demand - 1 CP	99.472%	**$ (9,285)**
10	Network Integration Transmission Service	$ 4,395,511	NA	Demand - 1 CP	99.472%	**$ 4,372,286**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ (42,749)	NA	Energy	99.218%	**$ (42,415)**
13	Load Response	$ 527		Energy	99.218%	**$ -**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ (1)	NA	Energy	99.218%	**$ (1)**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 5,652,860	$ (18,546)			**$ 5,603,609**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (7,507)**
18						
19	**Total TCRR-N including carrying costs**	$ 5,652,860	$ (18,546)			**$ 5,596,101**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted — Amended
Type of Filing: Original — Workpaper C-1a
Work Paper Reference No(s).: WPC-1b —

March 2023 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 819,917	NA	Demand - 1 CP	99.472%	**$ 815,585**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (25,404)	Demand - 1 CP	99.472%	**$ (25,270)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 199,933	NA	Reactive Demand - 12 CP	99.324%	**$ 198,581**
5	Black Start Service	$ 27,344	NA	Demand - 12 CP	99.324%	**$ 27,159**
6	TO Scheduling System Control and Dispatch Service	$ 79,204	NA	Energy	99.218%	**$ 78,585**
7	NERC/RFC Charges	$ 45,879	NA	Energy	99.218%	**$ 45,521**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (4,622)	Demand - 1 CP	99.472%	**$ (4,597)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 440,668	NA	Energy	99.218%	**$ 437,221**
13	Load Response	$ 721		Energy	99.218%	**$ -**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 673	NA	Energy	99.218%	**$ 668**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,067,308	$ (30,026)			**$ 6,002,892**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (7,832)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,067,308	$ (30,026)			**$ 5,995,060**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted	Amended
Type of Filing: Original	Workpaper C-1a
Work Paper Reference No(s).: WPC-1b	

April 2023 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 762,172	NA	Demand - 1 CP	99.472%	**$ 758,145**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (24,583)	Demand - 1 CP	99.472%	**$ (24,453)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 200,218	NA	Reactive Demand - 12 CP	99.324%	**$ 198,863**
5	Black Start Service	$ 15,487	NA	Demand - 12 CP	99.324%	**$ 15,382**
6	TO Scheduling System Control and Dispatch Service	$ 99,371	NA	Energy	99.218%	**$ 98,593**
7	NERC/RFC Charges	$ 41,496	NA	Energy	99.218%	**$ 41,171**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ 435	Demand - 1 CP	99.472%	**$ 433**
10	Network Integration Transmission Service	$ 4,309,324	NA	Demand - 1 CP	99.472%	**$ 4,286,555**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 369,392	NA	Energy	99.218%	**$ 366,502**
13	Load Response	$ 2,748		Energy	99.218%	**$ -**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 608	NA	Energy	99.218%	**$ 604**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 5,800,815	$ (24,148)			**$ 5,741,796**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (6,138)**
18						
19	**Total TCRR-N including carrying costs**	$ 5,800,815	$ (24,148)			**$ 5,735,658**

AES Ohio
Case No. 22-0152-EL-RDR
Projected Charges and Revenues
June 2022 - May 2023
(Revenue)/Expense in $

Data: Forecasted | Amended
Type of Filing: Original | Workpaper C-1a
Work Paper Reference No(s).: WPC-1b |

May 2023 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Type of Charge (E)	Adjustment (F) WPC-1c	Total Net Costs (G) = ((C)+(D)) x (F)
1	**TCRR-N Costs & Revenues**					
2	Transmission Enhancement Charges (RTEP)	$ 865,027	NA	Demand - 1 CP	99.472%	**$ 860,456**
3	Incremental Capacity Transfer Rights Credits	$ -	$ (26,891)	Demand - 1 CP	99.472%	**$ (26,749)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 207,161	NA	Reactive Demand - 12 CP	99.324%	**$ 205,760**
5	Black Start Service	$ 15,908	NA	Demand - 12 CP	99.324%	**$ 15,800**
6	TO Scheduling System Control and Dispatch Service	$ 83,620	NA	Energy	99.218%	**$ 82,966**
7	NERC/RFC Charges	$ 44,702	NA	Energy	99.218%	**$ 44,353**
8	Firm PTP Transmission Service			Demand - 1 CP	99.472%	**$ -**
9	Non-Firm PTP Transmission Service	$ -	$ (3,254)	Demand - 1 CP	99.472%	**$ (3,237)**
10	Network Integration Transmission Service	$ 4,452,968	NA	Demand - 1 CP	99.472%	**$ 4,429,440**
11	Expansion Cost Recovery Charges (ECRC)	$ -		Demand - 1 CP	99.472%	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 397,636	NA	Energy	99.218%	**$ 394,525**
13	Load Response	$ 283		Energy	99.218%	**$ -**
14	Consumer Advocates of PJM States, Inc. (CAPS) Funding Charge	$ 655	NA	Energy	99.218%	**$ 650**
15	Bilateral Charge	$ -	NA	Energy	99.218%	**$ -**
16	TCRR-N SubTotal	$ 6,067,960	$ (30,145)			**$ 6,003,965**
17	TCRR-N Deferral carrying costs (WPC-1b)					**$ (2,490)**
18						
19	**Total TCRR-N including carrying costs**	$ 6,067,960	$ (30,145)			**$ 6,001,475**

AES Ohio
Case No. 22-0152-EL-RDR
Calculation of Carrying Costs - TCRR-N
January 2021 - May 2023 (Over) / Under Recovery

Data: Actual and Forecasted — Amended
Type of Filing: Original — Workpaper C-1b
Work Paper Reference No(s).: None —

		MONTHLY ACTIVITY							CARRYING COST CALCULATION		
Line No.	Period	First of Month Balance	New TCRR Charges	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost @ 4.80%	End of Month Balance	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (L) * (4.8% / 12)	(I) = (G) + (H)	(J) = (G)	(K) = - (F) * .5	(L) = (J) + (K)
1	Jan-21	$ 8,645,524.97	$ 8,217,120.82	$ (3,803,104.57)	$ 4,414,016.25	$ 13,059,541.22	$ 43,410.13	$ 13,102,951.35	$ 13,059,541.22	$ (2,207,008.12)	$ 10,852,533.09
2	Feb-21	$ 13,102,951.35	$ 8,710,455.85	$ (3,582,599.00)	$ 5,127,856.85	$ 18,230,808.20	$ 62,667.52	$ 18,293,475.72	$ 18,230,808.20	$ (2,563,928.43)	$ 15,666,879.77
3	Mar-21	$ 18,293,475.72	$ 5,981,814.68	$ (3,521,763.00)	$ 2,460,051.68	$ 20,753,527.40	$ 78,094.01	$ 20,831,621.40	$ 20,753,527.40	$ (1,230,025.84)	$ 19,523,501.56
4	Apr-21	$ 20,831,621.40	$ 1,893,805.72	$ (3,050,783.00)	$ (1,156,977.28)	$ 19,674,644.12	$ 81,012.53	$ 19,755,656.65	$ 19,674,644.12	$ 578,488.64	$ 20,253,132.76
5	May-21	$ 19,755,656.65	$ 5,963,241.13	$ (2,844,633.00)	$ 3,118,608.13	$ 22,874,264.78	$ 85,259.84	$ 22,959,524.63	$ 22,874,264.78	$ (1,559,304.07)	$ 21,314,960.72
6	Jun-21	$ 22,959,524.63	$ 5,941,419.19	$ (7,852,406.00)	$ (1,910,986.81)	$ 21,048,537.82	$ 88,016.12	$ 21,136,553.94	$ 21,048,537.82	$ 955,493.41	$ 22,004,031.22
7	Jul-21	$ 21,136,553.94	$ 6,175,319.33	$ (8,843,834.00)	$ (2,668,514.67)	$ 18,468,039.27	$ 79,209.19	$ 18,547,248.46	$ 18,468,039.27	$ 1,334,257.34	$ 19,802,296.61
8	Aug-21	$ 18,547,248.46	$ 6,189,251.50	$ (9,014,164.00)	$ (2,824,912.50)	$ 15,722,335.96	$ 68,539.17	$ 15,790,875.13	$ 15,722,335.96	$ 1,412,456.25	$ 17,134,792.21
9	Sep-21	$ 15,790,875.13	$ 5,848,690.72	$ (8,946,549.00)	$ (3,097,858.28)	$ 12,693,016.85	$ 56,967.78	$ 12,749,984.63	$ 12,693,016.85	$ 1,548,929.14	$ 14,241,945.99
10	Oct-21	$ 12,749,984.63	$ 5,901,198.22	$ (7,556,775.00)	$ (1,655,576.78)	$ 11,094,407.85	$ 47,688.78	$ 11,142,096.64	$ 11,094,407.85	$ 827,788.39	$ 11,922,196.24
11	Nov-21	$ 11,142,096.64	$ 5,779,782.56	$ (7,214,263.00)	$ (1,434,480.44)	$ 9,707,616.20	$ 41,699.43	$ 9,749,315.62	$ 9,707,616.20	$ 717,240.22	$ 10,424,856.42
12	Dec-21	$ 9,749,315.62	$ 5,651,788.32	$ (8,006,204.00)	$ (2,354,415.68)	$ 7,394,899.94	$ 34,288.43	$ 7,429,188.37	$ 7,394,899.94	$ 1,177,207.84	$ 8,572,107.78
13	Jan-22	$ 7,429,188.37	$ 5,993,043.48	$ (8,838,144.00)	$ (2,845,100.52)	$ 4,584,087.85	$ 24,026.55	$ 4,608,114.41	$ 4,584,087.85	$ 1,422,550.26	$ 6,006,638.11
14	Feb-22	$ 4,608,114.41	$ 5,341,426.72	$ (8,825,552.00)	$ (3,484,125.28)	$ 1,123,989.13	$ 11,464.21	$ 1,135,453.33	$ 1,123,989.13	$ 1,742,062.64	$ 2,866,051.77
15	Mar-22	$ 1,135,453.33	$ 5,869,102.23	$ (8,358,389.42)	$ (2,489,287.19)	$ (1,353,833.86)	$ (436.76)	$ (1,354,270.62)	$ (1,353,833.86)	$ 1,244,643.60	$ (109,190.26)
16	Apr-22	$ (1,354,270.62)	$ 5,683,349.63	$ (7,601,623.94)	$ (1,918,274.31)	$ (3,272,544.93)	$ (9,253.63)	$ (3,281,798.57)	$ (3,272,544.93)	$ 959,137.16	$ (2,313,407.78)
17	May-22	$ (3,281,798.57)	$ 5,869,102.23	$ (7,249,000.34)	$ (1,379,898.11)	$ (4,661,696.68)	$ (15,886.99)	$ (4,677,583.67)	$ (4,661,696.68)	$ 689,949.06	$ (3,971,747.62)
18	Jun-22	$ (4,677,583.67)	$ 5,951,861.23	$ (5,441,883.35)	$ 509,977.88	$ (4,167,605.79)	$ (17,690.38)	$ (4,185,296.17)	$ (4,167,605.79)	$ (254,988.94)	$ (4,422,594.73)
19	Jul-22	$ (4,185,296.17)	$ 6,175,072.91	$ (6,043,849.35)	$ 131,223.56	$ (4,054,072.62)	$ (16,478.74)	$ (4,070,551.35)	$ (4,054,072.62)	$ (65,611.78)	$ (4,119,684.39)
20	Aug-22	$ (4,070,551.35)	$ 6,195,924.13	$ (6,270,455.36)	$ (74,531.23)	$ (4,145,082.58)	$ (16,431.27)	$ (4,161,513.85)	$ (4,145,082.58)	$ 37,265.62	$ (4,107,816.97)
21	Sep-22	$ (4,161,513.85)	$ 5,910,037.58	$ (5,927,373.77)	$ (17,336.19)	$ (4,178,850.05)	$ (16,680.73)	$ (4,195,530.77)	$ (4,178,850.05)	$ 8,668.10	$ (4,170,181.95)
22	Oct-22	$ (4,195,530.77)	$ 5,983,230.53	$ (4,985,964.46)	$ 997,266.07	$ (3,198,264.71)	$ (14,787.59)	$ (3,213,052.30)	$ (3,198,264.71)	$ (498,633.03)	$ (3,696,897.74)
23	Nov-22	$ (3,213,052.30)	$ 5,860,385.13	$ (4,693,830.02)	$ 1,166,555.11	$ (2,046,497.19)	$ (10,519.10)	$ (2,057,016.29)	$ (2,046,497.19)	$ (583,277.55)	$ (2,629,774.74)
24	Dec-22	$ (2,057,016.29)	$ 5,925,745.40	$ (5,246,657.76)	$ 679,087.64	$ (1,377,928.65)	$ (6,869.89)	$ (1,384,798.54)	$ (1,377,928.65)	$ (339,543.82)	$ (1,717,472.47)
25	Jan-23	$ (1,384,798.54)	$ 6,049,422.42	$ (6,323,482.39)	$ (274,059.96)	$ (1,658,858.50)	$ (6,087.31)	$ (1,664,945.82)	$ (1,658,858.50)	$ 137,029.98	$ (1,521,828.52)
26	Feb-23	$ (1,664,945.82)	$ 5,603,608.65	$ (6,027,415.85)	$ (423,807.21)	$ (2,088,753.02)	$ (7,507.40)	$ (2,096,260.42)	$ (2,088,753.02)	$ 211,903.60	$ (1,876,849.42)
27	Mar-23	$ (2,096,260.42)	$ 6,002,891.92	$ (5,726,360.14)	$ 276,531.78	$ (1,819,728.64)	$ (7,831.98)	$ (1,827,560.62)	$ (1,819,728.64)	$ (138,265.89)	$ (1,957,994.53)
28	Apr-23	$ (1,827,560.62)	$ 5,741,795.53	$ (5,155,537.04)	$ 586,258.49	$ (1,241,302.13)	$ (6,137.73)	$ (1,247,439.85)	$ (1,241,302.13)	$ (293,129.25)	$ (1,534,431.37)
29	May-23	$ (1,247,439.85)	$ 6,003,964.62	$ (4,754,034.87)	$ 1,249,929.75	$ 2,489.90	$ (2,489.90)	$ 0.00	$ 2,489.90	$ (624,964.88)	$ (622,474.98)
30											
31						"Current cycle" carrying costs:	$ (129,512.01)				

AES Ohio
Case No. 22-0152-EL-RDR
Energy and Demand Charge Adjustments for TCRR-N Pilot Program
June 2022 - May 2023

Data: Actual	Amended
Type of Filing: Original	Workpaper C-1c
Work Paper Reference No(s).: WPC-3a; WPC-3b	Page 1 of 1

Line (A)	Description (B)	Values (C)
1	**Energy Charges Adjustment**	
2	Total kWh for All Customers	14,124,839,999
3	Total kWh for TCRR-N Pilot Program Customers	110,478,757
4	% Adjustment for Energy Charges	99.218%
5		
6	**Demand 1-CP Charges Adjustment**	
7	Zonal 1-CP for All Customers in 2022	2,526,410
8	Zonal 1-CP for TCRR-N Pilot Program Participants TCRR-N in 2022	13,349
9	Zonal 1-CP for All Customers (less Non-Pilot Participants) in 2022	2,513,061
10	% Adjustment for 1-CP Demand Charges	99.472%
11		
12	**Demand 12-CP Charges Adjustment**	
13	Zonal 12-CP for All Customers in 2022	2,036,023
14	Zonal 12-CP for TCRR-N Pilot Program Participants TCRR-N in 2022	13,772
15	Zonal 12-CP for All Customers (less Non-Pilot Participants) in 2022	2,022,251
16	% Adjustment for 1-CP Demand Charges	99.324%

AES Ohio
Case No. 22-0152-EL-RDR
Summary of Energy and Demand Usage by Tariff Class
Allocation Factors

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-3a; WPC-2b

Amended
Workpaper C-2a

Line	Tariff Class	Monthly Energy Average	% of Total	1 Coincident Peak	% of Total	12 Coincident Peak	% of Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		WPC-3a[1]					
1	**Tariff Class**						
2	Residential	458,810,810	40.82%	1,097,655	43.45%	817,148	40.13%
3	Secondary	295,291,230	26.27%	761,321	30.13%	620,993	30.50%
4	Primary[2]	214,810,041	19.11%	399,522	15.81%	362,258	17.79%
5	Primary Substation	69,530,913	6.19%	112,205	4.44%	104,373	5.13%
6	High Voltage	80,274,676	7.14%	155,707	6.16%	130,098	6.39%
7	Private Outdoor Lighting	1,992,364	0.18%	-	0.00%	414	0.02%
8	Street Lighting	3,168,097	0.28%	-	0.00%	738	0.04%
9	**Total**	**1,123,878,131**	**100.00%**	**2,526,410**	**100.00%**	**2,036,023**	**100.00%**

[1] kWh data from WPC-3a divided by 12 months to calculate Monthly Energy Average
[2] Primary 1 and 12 Coincident Peak values adjusted for TCRR-N Pilot Program participants (see WPC-2b)

AES Ohio
Case No. 22-0152-EL-RDR
Demand Usage Adjusted for TCRR-N Pilot Program
Allocation Factors

Data: Actual and Forecasted | Amended
Type of Filing: Original | Workpaper C-2b
Work Paper Reference No(s).: None |

Line (A)	Tariff Class (B)	1 Coincident Peak (kW) (C) Internal Documents	12 Coincident Peak (kW) (D) Internal Documents
1	All Primary Customers Coincident Peaks	412,871	376,030
2	- TCRR-N Pilot Participants from 2021	13,349	13,772
3	+ Pilot Participants returning to TCRR-N in 2022	0	0
4	Adjusted Primary Coincident Peaks	399,522	362,258
5			
6	All Primary Substation Customers Coincident Peaks	112,205	104,373
7	- Primary Substation TCRR-N Pilot Participants	0	0
8	+ Pilot Participants returning to TCRR-N in 2022	0	0
9	Adjusted Primary Substation Coincident Peaks	112,205	104,373
10			
11	All High Voltage Customers Coincident Peaks	155,707	130,098
12	- High Voltage TCRR-N Pilot Participants	0	0
13	+ Pilot Participants returning to TCRR-N in 2022	0	0
14	Adjusted High Voltage Coincident Peaks	155,707	130,098

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Billing Determinants
June 2022 - May 2023
kWh / kW / kVar

Data: Forecasted | Amended
Type of Filing: Original | Workpaper C-3a
Work Paper Reference No(s).: WPC-3b |

			2022 Forecast							2023 Forecast						
Line (A)	Tariff Class (B)	Units (C)	Jun (D)	Jul (E)	Aug (F)	Sep (G)	Oct (H)	Nov (I)	Dec (J)	Jan (K)	Feb (L)	Mar (M)	Apr (N)	May (O)	Total Forecast June '22 - May '23 (P)	
1	Residential	kWh	425,547,647	518,421,182	523,746,703	470,971,908	367,577,013	355,682,329	456,295,862	586,918,043	549,941,335	506,858,797	400,108,800	343,660,103	5,505,729,722	kWh
2	Secondary[1]	kWh	291,379,170	322,956,462	335,319,091	322,855,335	271,709,313	237,995,683	264,650,160	321,030,195	304,311,190	300,846,189	283,876,708	286,565,265	3,543,494,762	kWh
3		kW	774,705	822,565	850,755	825,889	742,609	691,295	705,830	834,342	867,009	857,197	801,749	771,928	9,545,874	kW
4		Max kWh	53,584,331	42,606,866	40,308,788	44,737,969	49,780,031	57,254,215	44,953,708	36,282,218	22,102,072	23,317,584	27,533,789	34,677,011	477,138,582	kWh
5	Primary[2]	kWh	229,138,407	225,159,033	242,364,083	236,859,980	211,485,871	198,214,844	194,073,673	218,522,831	213,648,637	208,450,922	206,322,581	193,479,625	2,577,720,486	kWh
6		kW	488,657	469,652	488,390	485,770	454,741	443,202	426,108	452,003	449,791	438,435	448,516	449,859	5,495,123	kW
7		Max kWh	4,655,431	3,719,482	3,421,518	3,666,865	4,065,890	5,063,688	7,227,722	6,750,865	2,663,272	2,101,871	3,411,169	3,937,314	50,685,088	kWh
8	Primary Substation[3]	kWh	68,723,950	67,461,127	73,149,751	74,786,950	71,801,250	75,653,439	66,991,111	68,967,742	69,308,042	63,744,865	70,969,882	62,812,846	834,370,955	kWh
9		kW	127,505	124,856	125,420	126,568	124,852	132,209	121,620	128,626	123,761	124,510	127,169	129,514	1,516,609	kW
10	High Voltage[3]	kWh	81,825,620	84,955,820	90,275,204	89,921,471	82,203,816	77,792,656	75,614,989	79,679,742	78,123,482	74,473,536	77,467,207	70,962,568	963,296,112	kWh
11		kW	165,701	165,170	176,816	167,386	159,358	156,469	147,083	145,504	147,599	146,909	147,090	151,465	1,876,550	kW
12	Private Outdoor Lighting[4]	kWh	2,086,460	1,932,031	1,934,040	1,934,964	1,913,782	2,031,199	1,894,535	2,081,638	2,011,628	2,021,446	2,042,475	2,024,169	23,908,368	kWh
13	Streetlighting	kWh	3,335,411	3,055,240	3,042,042	3,022,799	3,017,414	3,178,116	2,981,170	3,369,236	3,268,631	3,250,351	3,260,974	3,235,783	38,017,167	kWh
14																
15	Total kWh		1,102,036,665	1,223,940,896	1,269,830,915	1,200,353,408	1,009,708,458	950,548,266	1,062,501,500	1,280,569,426	1,220,612,945	1,159,646,106	1,044,048,627	962,740,360	13,486,537,573	kWh
16	Total kW		1,556,568	1,582,244	1,641,381	1,605,614	1,481,559	1,423,174	1,400,642	1,560,475	1,588,160	1,567,051	1,524,524	1,502,765	18,434,156	kW
17	Secondary Max kWh		53,584,331	42,606,866	40,308,788	44,737,969	49,780,031	57,254,215	44,953,708	36,282,218	22,102,072	23,317,584	27,533,789	34,677,011	477,138,582	kWh
18	Primary Max kWh		4,655,431	3,719,482	3,421,518	3,666,865	4,065,890	5,063,688	7,227,722	6,750,865	2,663,272	2,101,871	3,411,169	3,937,314	50,685,088	kWh

[1] Secondary customers are charged for all kW of Billing Demand. Includes County Fair Provision

[2] Primary projected monthly billing determinants adjusted for all Primary TCRR-N Pilot Program participants. Includes County Fair Provision

[3] Primary Substation and High Voltage classes have no TCRR-N Pilot Program participants

[4] Private Outdoor Lighting $/kWh rates are based on assumed usage

AES Ohio
Case No. 22-0152-EL-RDR
Projected Monthly Billing Determinants Adjusted for TCRR-N Pilot Program Participants
June 2022 - May 2023
kWh / kW

Data: Forecasted & Historical — Amended
Type of Filing: Original — Workpaper C-3b
Work Paper Reference No(s).: None —

		2022 Forecast							2023 Forecast				
Line (A)	Tariff Class (B)	Jun (D)	Jul (E)	Aug (F)	Sep (G)	Oct (H)	Nov (I)	Dec (J)	Jan (K)	Feb (L)	Mar (M)	Apr (N)	May (O)
1	Projected kWh for all Primary customers	237,745,979	235,484,789	251,946,862	247,024,738	220,980,492	207,283,675	202,876,743	227,424,321	222,637,348	216,613,361	215,788,996	202,391,940
2	- TCRR-N Pilot Participants[1]	8,607,572	10,325,756	9,582,779	10,164,758	9,494,621	9,068,831	8,803,070	8,901,490	8,988,711	8,162,439	9,466,415	8,912,315
3	**Adjusted Primary kWh Billing Determinants**	**229,138,407**	**225,159,033**	**242,364,083**	**236,859,980**	**211,485,871**	**198,214,844**	**194,073,673**	**218,522,831**	**213,648,637**	**208,450,922**	**206,322,581**	**193,479,625**
4													
5	Projected kW for all Primary Customers	504,588	485,589	505,040	502,153	470,837	460,138	442,070	467,480	465,716	454,559	463,166	465,222
6	-TCRR-N Pilot Participants[2]	15,931	15,937	16,651	16,383	16,096	16,937	15,962	15,478	15,924	16,124	14,651	15,363
7	**Adjusted Primary kW Billing Determinants**	**488,657**	**469,652**	**488,390**	**485,770**	**454,741**	**443,202**	**426,108**	**452,003**	**449,791**	**438,435**	**448,516**	**449,859**
8													
9	Projected kWh for all Primary Substation customers	68,723,950	67,461,127	73,149,751	74,786,950	71,801,250	75,653,439	66,991,111	68,967,742	69,308,042	63,744,865	70,969,882	62,812,846
10	- TCRR-N Pilot Participants[1]	-	-	-	-	-	-	-	-	-	-	-	-
11	**Adjusted Primary Substation kWh Billing Determinants**	**68,723,950**	**67,461,127**	**73,149,751**	**74,786,950**	**71,801,250**	**75,653,439**	**66,991,111**	**68,967,742**	**69,308,042**	**63,744,865**	**70,969,882**	**62,812,846**
12													
13	Projected kW for all Primary Substation Customers	127,505	124,856	125,420	126,568	124,852	132,209	121,620	128,626	123,761	124,510	127,169	129,514
14	-TCRR-N Pilot Participants[2]	-	-	-	-	-	-	-	-	-	-	-	-
15	**Adjusted Primary Substation kW Billing Determinants**	**127,505**	**124,856**	**125,420**	**126,568**	**124,852**	**132,209**	**121,620**	**128,626**	**123,761**	**124,510**	**127,169**	**129,514**
16													
17	Projected kWh for all High Voltage customers	81,825,620	84,955,820	90,275,204	89,921,471	82,203,816	77,792,656	75,614,989	79,679,742	78,123,482	74,473,536	77,467,207	70,962,568
18	- TCRR-N Pilot Participants[1]	-	-	-	-	-	-	-	-	-	-	-	-
19	**Adjusted High Voltage kWh Billing Determinants**	**81,825,620**	**84,955,820**	**90,275,204**	**89,921,471**	**82,203,816**	**77,792,656**	**75,614,989**	**79,679,742**	**78,123,482**	**74,473,536**	**77,467,207**	**70,962,568**
20													
21	Projected kW for all High Voltage customers	165,701	165,170	176,816	167,386	159,358	156,469	147,083	145,504	147,599	146,909	147,090	151,465
22	- TCRR-N Pilot Participants[2]	-	-	-	-	-	-	-	-	-	-	-	-
23	**Adjusted High Voltage kW Billing Determinants**	**165,701**	**165,170**	**176,816**	**167,386**	**159,358**	**156,469**	**147,083**	**145,504**	**147,599**	**146,909**	**147,090**	**151,465**

[1] Historical TCRR-N Pilot Participants' kWh (January 2021 through December 2021) for Primary, Primary Substation, and High Voltage tariff classes, respectively.
[2] Historical TCRR-N Pilot Participants' kW (January 2021 through December 2021) for Primary, Primary Substation, and High Voltage tariff classes, respectively.

AES Ohio
Case No. 22-0152-EL-RDR
TCRR-N Rate - Calculation of Private Outdoor Lighting Charges

Data: Forecasted	Amended
Type of Filing: Original	WPC-4
Work Paper Reference No(s).: None	Page 1 of 1

Line	**Description**	**kWh / Fixture**	**Jun 2022 - May 2023**	**Source**
(A)	(B)	(C)	(D)	(E)
1	**Private Outdoor Lighting Rate ($/kWh)**		$0.0004236	Schedule C-3
2				
3	**Private Outdoor Lighting Charge ($/Fixture/Month)**			
4	3,600 Lumens Light Emitting Diode	14	$0.0059304	Line 1 * Col (C) Line 4
5	8,400 Lumens Light Emitting Diode	30	$0.0127080	Line 1 * Col (C) Line 5
6	9,500 Lumens High Pressure Sodium	39	$0.0165204	Line 1 * Col (C) Line 6
7	28,000 Lumens High Pressure Sodium	96	$0.0406656	Line 1 * Col (C) Line 7
8	7,000 Lumens Mercury	75	$0.0317700	Line 1 * Col (C) Line 8
9	21,000 Lumens Mercury	154	$0.0652344	Line 1 * Col (C) Line 9
10	2,500 Lumens Incandescent	64	$0.0271104	Line 1 * Col (C) Line 10
11	7,000 Lumens Fluorescent	66	$0.0279576	Line 1 * Col (C) Line 11
12	4,000 Lumens PT Mercury	43	$0.0182148	Line 1 * Col (C) Line 12

AES Ohio
Case No. 22-0152-EL-RDR
TCRR-N Rate - Calculation of County Fair Charges

Data: Forecasted | Amended
Type of Filing: Original | WPC-5
Work Paper Reference No(s).: None |

Line	Description	Values	Source
(A)	(B)	(C)	(D)
1	**Secondary Total Class Charges**	$19,885,682.10	Schedule B-2
2	**Secondary Total Class kWh**	3,543,494,762	WPC-3a, Line 2
3	Secondary County Fair Rate	$0.0056119	Line 1 / Line 2
4			
5			
6	**Primary Total Class Charges**	$10,718,616.20	Schedule B-2
7	**Primary Total Class kWh**	2,577,720,486	WPC-3a, Line 5
8	Primary County Fair Rate	$0.0041582	Line 6 / Line 7