BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
The Dayton Power and Light Company to	)	Case No. 15-0361-EL-RDR
Update its Transmission Cost Recovery	)	
Rider – Non-Bypassable	)	

APPLICATION OF THE DAYTON POWER AND LIGHT COMPANY TO UPDATE ITS TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE

The Dayton Power and Light Company ("DP&L" or "the Company") hereby submits this application to update its Transmission Cost Recovery Rider – Non-Bypassable ("TCRR-N") pursuant to R.C. §4928.05(A)(2) and O.A.C. §4901:1-36-03(B).

In support of this Application DP&L states as follows:

1. DP&L 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. By the Opinion and Order issued on September 6, 2013 in Case No. 12-0426-EL-SSO, the Commission approved the implementation of DP&L's TCRR-N beginning January 1, 2014 and its request for waiver of paragraph (B) of O.A.C. § 4901:1-36-04. The TCRR-N is a non-bypassable rider that is designed to recover transmission-related costs imposed on or charged to the Company by FERC or PJM, such as Network Integration Transmission Service.

3. O.A.C. §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."

4. By the Opinion and Order issued in Case No. 12-0426-EL-SSO, the Commission approved DP&L's request to file the annual update to the TCRR-N on March 15, for rates to become effective on June 1.

5. DP&L's most recent application to update its TCRR-N, filed in Case No. 14-0358-EL-RDR, was approved by Finding and Order dated May 28, 2014.

6. By way of this application, DP&L seeks to update its TCRR-N, which reflects Retail Transmission Organization ("RTO") related costs not otherwise being recovered.

7. The TCRR-N revenue requirement remains substantially unchanged for the period June 2015 through May 2016. The rate impact varies by customer class, mainly due to the allocation of 2015-2016 costs using DP&L's 2014 zonal peak. This method is consistent with DP&L's previous rate designs and PJM's method of billing certain costs, such as Network Integration Transmission Service. Overall typical bill impacts are minimal.

8. DP&L is proposing to include in the TCRR-N one new line item, Operating Reserves, solely to the extent that DP&L incurs this charge as a transmission owner. In that case, the transmission owner Operating Reserves charge is a RTO-related transmission cost not otherwise being recovered, and it is applicable to all transmission customers, regardless of supplier. Therefore its inclusion in the TCRR-N is appropriate. This addition has been made in an effort to ensure that the TCRR-N properly assigns costs and credits to the customers that cause costs/credits to be incurred.

9. DP&L is also proposing to include in the TCRR-N the remaining Transmission Cost Recovery Rider – Bypassable ("TCRR-B") balance, as well as future adjustments to prior TCRR-B costs, as of January 1, 2016. On page 36 of the Commission's Opinion and Order in Case No. 12-0426-EL-SSO, the Commission stated that "DP&L should file with the Commission a proposal at the end of the ESP term for appropriate collection of any uncollected TCRR balance, including whether the uncollected TCRR balance should be collected through a bypassable or nonbypassable TCRR true-up rider." Additionally, in the Commission's Second Entry on Rehearing on March 19, 2014, the Commission accelerated DP&L's blending schedule so that 100% of DP&L's SSO load would be supplied using the Competitive Bid Process ("CBP") beginning January 1, 2016 (pp. 18-19). At that point, all of the legacy ESP generation rates (Base Generation, Fuel Rider, PJM RPM Rider, and TCRR-B) will be completely phased out. Therefore DP&L must propose a means to collect the remaining TCRR-B balance beginning January 1, 2016, as the TCRR-B will no longer apply to SSO customers at that time.

10. Collection of the December 31, 2015 TCRR-B balance through the TCRR-N is the most reasonable method. First, the TCRR-B balance and going-forward adjustments constitute RTO-related costs not otherwise being recovered, and the TCRR-N is the appropriate avenue for recovery of such costs. Second, such treatment is consistent with the Commission's treatment of DP&L's other quarterly bypassable riders. For those riders, the Commission approved a stop-gap measure where any deferral amount that exceeded the 10% threshold of a rider's base costs would be recovered through the Reconciliation Rider – Non-Bypassable ("RR-N"). Therefore any remaining

deferral as of December 31, 2015 for the Fuel Rider and PJM RPM Rider will be rolled into the RR-N. This is appropriate, as those legacy ESP generation rates will be completely phased out at that point. The Company's TCRR-B is no different than the other quarterly true-up riders that were approved for this treatment. Therefore it is appropriate that any remaining TCRR-B balance as of December 31, 2015 be treated in a similar manner and recovered through the TCRR-N.

11. The Company will strive to minimize the final TCRR-B balance through its quarterly updates to the rider, so the distribution rate impacts should be minimal. In addition to the final TCRR-B balance, DP&L also notes that PJM may continue to charge DP&L TCRR-B adjustments related to billing periods prior to January 2016. These costs will very likely be nominal, but they have the potential to go on for months or years. As these future costs relate to the TCRR-B balance as of December 31, 2015 and are RTO-related costs not otherwise being recovered, they are also appropriate for recovery from customers through the TCRR-N.

12. Consistent with its prior TCRR filings, DP&L 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.

13. Pursuant to O.A.C. §4901:1-36-03(B), the information listed below is being provided in support of this Application. The following supporting Schedules and 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

14. Pursuant to O.A.C. §4901:1-36-04(A), carrying charges based on the cost of debt approved in DP&L's most recent rate setting proceeding (Case No. 12-0426-EL-SSO) have been applied to under- and over-recovery of costs.

15. DP&L'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.

16. Pursuant to §4901:1-36-06(A), DP&L has included the biennial information detailing the electric utility's policies and procedures for minimizing costs in the TCRR-N where the electric utility has control over such costs.

WHEREFORE, DP&L respectfully requests that the Commission approve its Application with new tariff rates for its TCRR-N to be made effective, consistent with the

Opinion and Order dated September 6th, 2013 in Case No. 12-426-EL-SSO, on a bills-rendered basis beginning on June 1, 2015.

Respectfully submitted,

/s/ Judi L. Sobecki
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Attorney for The Dayton Power and Light Company

The Dayton Power and Light Company
Case No. 15-361-EL-RDR
Transmission Cost Recovery Rider – Non-Bypassable

Schedule A-1

Copy of Proposed Tariff Schedules

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

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
T1	Fourth Revised	Table of Contents	1	January 1, 2014
T2	Twenty-Third Revised	Tariff Index	1	
RULES AND REGULATIONS				
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				
T8	Ninth Revised	Transmission Cost Recovery Rider – Non-Bypassable	4	
RIDERS				
T9	Tenth Revised	Transmission Cost Recovery Rider – Bypassable	3	March 1, 2015

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 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	$0.0050582 per kWh

Residential Heating:

Energy Charge	$0.0050582 per kWh

Secondary:

Demand Charge	$1.4906355 per kW for all kW over 5 kW of Billing Demand
Energy Charge	$0.0072081 per kWh for the first 1,500 kWh $0.0004127 per kWh for all kWh over 1,500 kWh

If the Maximum Charge provision contained in Electric Generation Service Tariff Sheet No. G12 applies, the Customer will be charged an energy charge of $0.0155951 per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge	$1.3908253 per kW for all kW of Billing Demand
Energy Charge	$0.0004127 per kWh
Reactive Demand Charge	$0.3280736 per kVar for all kVar of Billing Demand

If the Maximum Charge provision contained in Electric Generation Service Tariff Sheet No. G13 applies, the Customer will be charged an energy charge of $0.0146426 per kWh in lieu of the above demand and energy charges.

Primary-Substation:

Demand Charge	$1.3323045 per kW for all kW of Billing Demand

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

Energy Charge	$0.0004127 per kWh
Reactive Demand Charge	$0.3235679 per kVar for all kVar of Billing Demand

High Voltage:

Demand Charge	$1.5724393 per kW for all kW of Billing Demand
Energy Charge	$0.0004127 per kWh
Reactive Demand Charge	$0.5011181 per kVar for all kVar of Billing Demand

Private Outdoor Lighting:

9,500 Lumens High Pressure Sodium	$0.0189384	/lamp/month
28,000 Lumens High Pressure Sodium	$0.0466176	/lamp/month
7,000 Lumens Mercury	$0.0364200	/lamp/month
21,000 Lumens Mercury	$0.0747824	/lamp/month
2,500 Lumens Incandescent	$0.0310784	/lamp/month
7,000 Lumens Fluorescent	$0.0320496	/lamp/month
4,000 Lumens PT Mercury	$0.0208808	/lamp/month

School:

Energy Charge	$0.0050199 per kWh

Street Lighting:

Energy Charge	$0.0004186 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)

DETERMINATION OF KILOVAR BILLING DEMAND:

If kilovars are not measured, a ninety percent (90%) power factor will be assumed for billing purposes. Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to measure kilovars shall be subject to an additional charge of thirty-four dollars ($34.00) per month.

Kilovar billing demand shall be determined at the time of maximum kilowatt billing demand.

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.

The Dayton Power and Light Company
Case No. 15-361-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 TRANSMISSION SERVICE
TARIFF INDEX

Sheet No.	Version	Description	Number of Pages	Tariff Sheet Effective Date
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TARIFFS				
T8	Ninth~~Eighth~~ Revised	Transmission Cost Recovery Rider – Non-Bypassable	4	~~January 1, 2015~~
RIDERS				
T9	Tenth Revised	Transmission Cost Recovery Rider – Bypassable	3	March 1, 2015

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)
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Schedule 1A (Transmission Owner Scheduling, System Control and Dispatch Services)
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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 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 $0.0050582~~0.0049232~~ per kWh

Residential Heating:

Energy Charge $0.0050582~~0.0049232~~ per kWh

Secondary:

Demand Charge $1.4906355~~1.6727848~~ per kW for all kW over 5 kW of Billing Demand

Energy Charge $0.0072081~~0.0082777~~ per kWh for the first 1,500 kWh
$0.0004127~~0.0005034~~ per kWh for all kWh over 1,500 kWh

If the Maximum Charge provision contained in Electric Generation Service Tariff Sheet No. G12 applies, the Customer will be charged an energy charge of $0.0155951 per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge $1.3908253~~1.4784868~~ per kW for all kW of Billing Demand

Energy Charge $0.0004127~~0.0005034~~ per kWh

Reactive Demand Charge $0.3280736~~0.3481988~~ per kVar for all kVar of Billing Demand

If the Maximum Charge provision contained in Electric Generation Service Tariff Sheet No. G13 applies, the Customer will be charged an energy charge of $0.0146426 per kWh in lieu of the above demand and energy charges.

Filed pursuant to the Opinion and Order in Case No. 12-426-EL-SSO dated September 6, 2013 of the Public Utilities Commission of Ohio.

Issued ~~December 30, 2014~~ Effective ~~January 1, 2015~~

Issued by
THOMAS A. RAGA~~DEREK A. PORTER~~, President and Chief Executive Officer

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

Primary-Substation:

Demand Charge	$1.3323045~~1.3126352~~ per kW for all kW of Billing Demand
Energy Charge	$0.0004127~~0.0005034~~ per kWh
Reactive Demand Charge	$0.3235679~~0.3923485~~ per kVar for all kVar of Billing Demand

High Voltage:

Demand Charge	$1.5724393~~1.7026292~~ per kW for all kW of Billing Demand
Energy Charge	$0.0004127~~0.0005034~~ per kWh
Reactive Demand Charge	$0.5011181~~0.5077477~~ per kVar for all kVar of Billing Demand

Private Outdoor Lighting:

9,500 Lumens High Pressure Sodium	$0.0189384~~0.0384111~~	/lamp/month
28,000 Lumens High Pressure Sodium	$0.0466176~~0.0945504~~	/lamp/month
7,000 Lumens Mercury	$0.0364200~~0.0738675~~	/lamp/month
21,000 Lumens Mercury	$0.0747824~~0.1516746~~	/lamp/month
2,500 Lumens Incandescent	$0.0310784~~0.0630336~~	/lamp/month
7,000 Lumens Fluorescent	$0.0320496~~0.0650034~~	/lamp/month
4,000 Lumens PT Mercury	$0.0208808~~0.0423507~~	/lamp/month

School:

Energy Charge	$0.0050199~~0.0090637~~ per kWh

Street Lighting:

Energy Charge	$0.0004186~~0.0005413~~ per kWh

Filed pursuant to the Opinion and Order in Case No. 12-426-EL-SSO dated September 6, 2013 of the Public Utilities Commission of Ohio.

Issued ~~December 30, 2014~~

Effective ~~January 1, 2015~~

Issued by
THOMAS A. RAGA~~DEREK A. PORTER~~, 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.

DETERMINATION OF KILOVAR BILLING DEMAND:

If kilovars are not measured, a ninety percent (90%) power factor will be assumed for billing purposes. Customers with billing demands less than one thousand kilowatts (1,000 kW) requesting metering devices to measure kilovars shall be subject to an additional charge of thirty-four dollars ($34.00) per month.

Kilovar billing demand shall be determined at the time of maximum kilowatt billing demand.

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.

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Summary of Projected Jurisdictional Net Costs
June 2015 - May 2016
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPB-1

Schedule B-1
Page 1 of 1

Line (A)	Description (B)	Demand/Energy (C)		Total Costs/Revenues Jun 2015 - May 2016 (D)
				Schedule C-1, Col (U)
	TCRR-N Costs			
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$	11,722,076
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$	-
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand	$	7,176,625
4	Black Start Service	Demand - 12 CP	$	216,835
5	TO Scheduling System Control and Dispatch Service	Energy	$	1,197,047
6	NERC/RFC Charges	Energy	$	429,991
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$	(448)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$	(78,513)
9	Network Integration Transmission Service	Demand - 1 CP	$	39,029,733
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$	-
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$	3,593,978
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$	41,609
13	Load Response Charge Allocation	Energy	$	317,371
14	Generation Deactivation	Demand - 1 CP	$	-
15	TCRR-N SubTotal		$	63,646,303
16	Projected TCRR-N Reconciliation		$	1,475,724
17	Projected TCRR-N Deferral Carrying Costs		$	8,807
18	TCRR-N SubTotal with Deferral		$	65,130,834
19	Gross Revenue Conversion Factor (WPB-1)			1.003
20				
21	**Total TCRR-N Recovery (Line 18 * Line 19)**		**$**	**65,326,226**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Summary of Current versus Proposed Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

Schedule B-2

Line (A)	Tariff Class (B)	Forecasted Distribution Billing Determinants (C) WPC-3, 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	5,328,185,036	kWh	$ 0.0049232	$ 26,231,721	$ 0.0050582	$ 26,951,026	$ 719,305	3%
2	Secondary[1]	520,904,516	0-1500 kWh	$ 0.0082777	$ 4,311,891	$ 0.0072081	$ 3,754,720		
3		3,412,520,105	>1500 kWh	$ -	$ -	$ 0.0004127	$ 1,408,347		
4		10,959,932	kW	$ 1.6727848	$ 18,333,608	$ 1.4906355	$ 16,337,264		
5					$ 22,645,499		$ 21,500,331	$ (1,145,168)	-5%
6	Primary	2,873,649,517	kWh	$ 0.0005034	$ 1,446,595	$ 0.0004127	$ 1,185,955		
7		6,155,464	kW	$ 1.4784868	$ 9,100,773	$ 1.3908253	$ 8,561,176		
8		3,577,402	kVar	$ 0.3481988	$ 1,245,647	$ 0.3280736	$ 1,173,651		
9					$ 11,793,015		$ 10,920,782	$ (872,233)	-7%
10	Substation	642,143,105	kWh	$ 0.0005034	$ 323,255	$ 0.0004127	$ 265,012		
11		1,128,371	kW	$ 1.3126352	$ 1,481,140	$ 1.3323045	$ 1,503,334		
12		633,793	kVar	$ 0.3923485	$ 248,668	$ 0.3235679	$ 205,075		
13					$ 2,053,062		$ 1,973,422	$ (79,641)	-4%
14	High Voltage	955,968,029	kWh	$ 0.0005034	$ 481,234	$ 0.0004127	$ 394,528		
15		1,815,344	kW	$ 1.7026292	$ 3,090,858	$ 1.5724393	$ 2,854,519		
16		781,405	kVar	$ 0.5077477	$ 396,756	$ 0.5011181	$ 391,576		
17					$ 3,968,849		$ 3,640,623	$ (328,226)	-8%
18	Private Outdoor Lighting[2]	28,447,513	kWh	$ 0.0009849	$ 28,018	$ 0.0004856	$ 13,814	$ (14,204)	-51%
19	School	60,387,834	kWh	$ 0.0090637	$ 547,337	$ 0.0050199	$ 303,141	$ (244,196)	-45%
20	Streetlighting	54,188,739	kWh	$ 0.0005413	$ 29,332	$ 0.0004186	$ 22,683	$ (6,649)	-23%
21	Total TCRR-N Rates				$ 67,296,833		$ 65,325,821	$ (1,971,012)	

[1] Secondary customers are charged for all kW over 5kW of Billing Demand
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage.

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Summary of Current and Proposed Rates
June 2015 - May 2016

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

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	$	0.0049232	kWh	$	0.0050582	kWh	$	0.0001350	3%
2	Secondary[1]	$	0.0082777	0-1500 kWh	$	0.0072081	0-1500 kWh	$	(0.0010696)	-13%
3		$	-	>1500 kWh	$	0.0004127	>1500 kWh	$	0.0004127	N/A
4		$	1.6727848	kW	$	1.4906355	kW	$	(0.1821493)	-11%
5	Primary	$	0.0005034	kWh	$	0.0004127	kWh	$	(0.0000907)	-18%
6		$	1.4784868	kW	$	1.3908253	kW	$	(0.0876615)	-6%
7		$	0.3481988	kVar	$	0.3280736	kVar	$	(0.0201252)	-6%
8	Substation	$	0.0005034	kWh	$	0.0004127	kWh	$	(0.0000907)	-18%
9		$	1.3126352	kW	$	1.3323045	kW	$	0.0196693	1%
10		$	0.3923485	kVar	$	0.3235679	kVar	$	(0.0687806)	-18%
11	High Voltage	$	0.0005034	kWh	$	0.0004127	kWh	$	(0.0000907)	-18%
12		$	1.7026292	kW	$	1.5724393	kW	$	(0.1301899)	-8%
13		$	0.5077477	kVar	$	0.5011181	kVar	$	(0.0066296)	-1%
14	Private Outdoor Lighting[2]	$	0.0009849	kWh	$	0.0004856	kWh	$	(0.0004993)	-51%
15	School	$	0.0090637	kWh	$	0.0050199	kWh	$	(0.0040438)	-45%
16	Streetlighting	$	0.0005413	kWh	$	0.0004186	kWh	$	(0.0001227)	-23%

[1] Secondary customers are charged for all kW over 5kW of Billing Demand
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage.

The Dayton Power and Light Company
Case No. 15-0361-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	$13.61	$13.62	$0.01	0.07%
2	0.0	100	$20.25	$20.26	$0.01	0.05%
3	0.0	200	$33.51	$33.54	$0.03	0.09%
4	0.0	400	$60.05	$60.10	$0.05	0.08%
5	0.0	500	$73.33	$73.40	$0.07	0.10%
6	0.0	750	$106.48	$106.58	$0.10	0.09%
7	0.0	1,000	$136.28	$136.41	$0.13	0.10%
8	0.0	1,200	$160.12	$160.28	$0.16	0.10%
9	0.0	1,400	$183.94	$184.13	$0.19	0.10%
10	0.0	1,500	$195.87	$196.07	$0.20	0.10%
11	0.0	2,000	$255.45	$255.72	$0.27	0.11%
12	0.0	2,500	$314.84	$315.18	$0.34	0.11%
13	0.0	3,000	$374.18	$374.58	$0.40	0.11%
14	0.0	4,000	$492.87	$493.41	$0.54	0.11%
15	0.0	5,000	$611.58	$612.25	$0.67	0.11%
16	0.0	7,500	$908.39	$909.40	$1.01	0.11%

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Secondary Unmetered

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	$23.55	$23.50	($0.05)	-0.21%
2	0.0	100	$30.04	$29.93	($0.11)	-0.37%
3	0.0	150	$36.51	$36.35	($0.16)	-0.44%
4	0.0	200	$42.97	$42.76	($0.21)	-0.49%
5	0.0	300	$55.90	$55.58	($0.32)	-0.57%
6	0.0	400	$68.86	$68.43	($0.43)	-0.62%
7	0.0	500	$81.79	$81.26	($0.53)	-0.65%
8	0.0	600	$94.74	$94.10	($0.64)	-0.68%
9	0.0	800	$120.61	$119.75	($0.86)	-0.71%
10	0.0	1,000	$146.49	$145.42	($1.07)	-0.73%
11	0.0	1,200	$172.40	$171.12	($1.28)	-0.74%
12	0.0	1,400	$198.25	$196.75	($1.50)	-0.76%
13	0.0	1,600	$217.72	$216.16	($1.56)	-0.72%
14	0.0	2,000	$243.65	$242.26	($1.39)	-0.57%
15	0.0	2,200	$256.53	$255.22	($1.31)	-0.51%
16	0.0	2,400	$269.39	$268.16	($1.23)	-0.46%

Secondary customers are charged for all kW over 5kW of Billing Demand

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Secondary Single Phase

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	5	750	$116.14	$115.34	($0.80)	-0.69%
2	5	1,500	$213.21	$211.61	($1.60)	-0.75%
3	10	1,500	$284.12	$281.61	($2.51)	-0.88%
4	25	5,000	$722.47	$718.67	($3.80)	-0.53%
5	25	7,500	$883.50	$880.74	($2.76)	-0.31%
6	25	10,000	$1,044.50	$1,042.77	($1.73)	-0.17%
7	50	15,000	$1,721.03	$1,716.80	($4.23)	-0.25%
8	50	25,000	$2,359.44	$2,359.34	($0.10)	0.00%
9	200	50,000	$6,082.79	$6,065.69	($17.10)	-0.28%
10	200	100,000	$9,274.73	$9,278.26	$3.53	0.04%
11	300	125,000	$12,288.99	$12,284.63	($4.36)	-0.04%
12	500	200,000	$19,527.62	$19,517.78	($9.84)	-0.05%
13	1,000	300,000	$32,488.43	$32,428.78	($59.65)	-0.18%
14	1,000	500,000	$44,227.43	$44,250.32	$22.89	0.05%
15	2,500	750,000	$80,175.15	$80,028.00	($147.15)	-0.18%
16	2,500	1,000,000	$94,561.17	$94,517.19	($43.98)	-0.05%

Secondary customers are charged for all kW over 5kW of Billing Demand

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Secondary Three Phase

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	5	500	$91.12	$90.59	($0.53)	-0.58%
2	5	1,500	$220.55	$218.95	($1.60)	-0.73%
3	10	1,500	$291.46	$288.95	($2.51)	-0.86%
4	25	5,000	$729.81	$726.01	($3.80)	-0.52%
5	25	7,500	$890.84	$888.08	($2.76)	-0.31%
6	25	10,000	$1,051.84	$1,050.11	($1.73)	-0.16%
7	50	25,000	$2,366.78	$2,366.68	($0.10)	0.00%
8	200	50,000	$6,090.13	$6,073.03	($17.10)	-0.28%
9	200	125,000	$10,878.07	$10,891.92	$13.85	0.13%
10	500	200,000	$19,534.96	$19,525.12	($9.84)	-0.05%
11	1,000	300,000	$32,495.77	$32,436.12	($59.65)	-0.18%
12	1,000	500,000	$44,234.77	$44,257.66	$22.89	0.05%
13	2,500	750,000	$80,182.49	$80,035.34	($147.15)	-0.18%
14	2,500	1,000,000	$94,568.51	$94,524.53	($43.98)	-0.05%
15	5,000	1,500,000	$158,511.19	$158,218.18	($293.01)	-0.18%
16	5,000	2,000,000	$186,997.29	$186,910.63	($86.66)	-0.05%

Secondary customers are charged for all kW over 5kW of Billing Demand

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Primary Service

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	5	1,000	$231.82	$231.24	($0.58)	-0.25%
2	5	2,500	$320.93	$320.21	($0.72)	-0.22%
3	10	5,000	$535.51	$534.08	($1.43)	-0.27%
4	25	7,500	$883.90	$880.79	($3.11)	-0.35%
5	25	10,000	$1,031.60	$1,028.26	($3.34)	-0.32%
6	50	20,000	$1,954.09	$1,947.41	($6.68)	-0.34%
7	50	30,000	$2,539.39	$2,531.80	($7.59)	-0.30%
8	200	50,000	$5,716.33	$5,692.31	($24.02)	-0.42%
9	200	75,000	$7,179.56	$7,153.28	($26.28)	-0.37%
10	200	100,000	$8,642.76	$8,614.21	($28.55)	-0.33%
11	500	250,000	$21,434.75	$21,363.37	($71.38)	-0.33%
12	1,000	300,000	$42,754.70	$42,630.08	($124.62)	-0.29%
13	2,500	1,000,000	$91,794.69	$91,460.47	($334.22)	-0.36%
14	5,000	2,500,000	$210,442.62	$209,728.82	($713.80)	-0.34%
15	10,000	5,000,000	$419,335.42	$417,907.83	($1,427.59)	-0.34%
16	25,000	7,500,000	$761,982.83	$758,867.36	($3,115.47)	-0.41%
17	25,000	10,000,000	$903,998.33	$900,656.11	($3,342.22)	-0.37%
18	50,000	15,000,000	$1,522,415.80	$1,516,184.87	($6,230.93)	-0.41%

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

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Primary Substation

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	3,000	1,000,000	$94,321.53	$94,189.90	($131.63)	-0.14%
2	5,000	2,000,000	$174,621.11	$174,371.50	($249.61)	-0.14%
3	5,000	3,000,000	$230,126.51	$229,786.20	($340.31)	-0.15%
4	10,000	4,000,000	$347,617.38	$347,118.15	($499.23)	-0.14%
5	10,000	5,000,000	$403,122.78	$402,532.85	($589.93)	-0.15%
6	15,000	6,000,000	$520,613.67	$519,864.83	($748.84)	-0.14%
7	15,000	7,000,000	$576,119.07	$575,279.53	($839.54)	-0.15%
8	15,000	8,000,000	$631,624.47	$630,694.23	($930.24)	-0.15%
9	25,000	9,000,000	$811,100.86	$809,943.49	($1,157.37)	-0.14%
10	25,000	10,000,000	$866,606.26	$865,358.19	($1,248.07)	-0.14%
11	30,000	12,500,000	$1,067,355.24	$1,065,812.21	($1,543.03)	-0.14%
12	30,000	15,000,000	$1,206,118.74	$1,204,348.96	($1,769.78)	-0.15%
13	50,000	17,500,000	$1,592,824.16	$1,590,554.78	($2,269.38)	-0.14%
14	50,000	20,000,000	$1,731,587.66	$1,729,091.53	($2,496.13)	-0.14%
15	50,000	25,000,000	$2,009,114.66	$2,006,165.03	($2,949.63)	-0.15%

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

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
High Voltage Service

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

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	1,000	500,000	$40,884.98	$40,706.23	($178.75)	-0.44%
2	2,000	1,000,000	$81,192.51	$80,835.01	($357.50)	-0.44%
3	3,000	1,500,000	$120,926.41	$120,390.16	($536.25)	-0.44%
4	3,500	2,000,000	$154,436.79	$153,788.49	($648.30)	-0.42%
5	5,000	2,500,000	$200,394.09	$199,500.34	($893.75)	-0.45%
6	7,500	3,000,000	$258,798.23	$257,525.63	($1,272.60)	-0.49%
7	7,500	4,000,000	$313,372.23	$312,008.93	($1,363.30)	-0.44%
8	10,000	5,000,000	$399,063.36	$397,275.85	($1,787.51)	-0.45%
9	20,000	6,000,000	$453,637.36	$450,425.14	($3,212.22)	-0.71%
10	12,500	7,000,000	$539,328.49	$537,026.08	($2,302.41)	-0.43%
11	12,500	8,000,000	$593,902.49	$591,509.38	($2,393.11)	-0.40%
12	15,000	9,000,000	$679,593.64	$676,776.33	($2,817.31)	-0.41%
13	20,000	10,000,000	$796,401.89	$792,826.87	($3,575.02)	-0.45%
14	40,000	20,000,000	$1,591,079.03	$1,583,929.00	($7,150.03)	-0.45%
15	60,000	30,000,000	$2,385,756.06	$2,375,031.02	($10,725.04)	-0.45%

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

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Private Outdoor Lighting

Data: Actual and Forecasted
Type of Filing: Original
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	$14.08	$14.04	($0.04)	-0.28%
3	21000 -					
4	Mercury	154	$25.26	$25.18	($0.08)	-0.32%
5	2500 -					
6	Incandescent	64	$13.12	$13.09	($0.03)	-0.23%
7	7000 -					
8	Fluorescent	66	$14.16	$14.13	($0.03)	-0.21%
9	4000 -					
10	Mercury	43	$12.97	$12.95	($0.02)	-0.15%
11	9500 - High					
12	Pressure Sodium	39	$11.64	$11.62	($0.02)	-0.17%
13	28000 - High					
14	Pressure Sodium	96	$16.05	$16.00	($0.05)	-0.31%

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

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
School Rate

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	1,000	$171.92	$167.88	($4.04)	-2.35%
2	0.0	2,500	$355.70	$345.59	($10.11)	-2.84%
3	0.0	5,000	$661.15	$640.93	($20.22)	-3.06%
4	0.0	10,000	$1,272.18	$1,231.74	($40.44)	-3.18%
5	0.0	15,000	$1,883.15	$1,822.49	($60.66)	-3.22%
6	0.0	25,000	$3,099.54	$2,998.44	($101.10)	-3.26%
7	0.0	50,000	$6,140.46	$5,938.27	($202.19)	-3.29%
8	0.0	75,000	$9,181.38	$8,878.09	($303.29)	-3.30%
9	0.0	100,000	$12,222.29	$11,817.91	($404.38)	-3.31%
10	0.0	150,000	$18,304.16	$17,697.59	($606.57)	-3.31%
11	0.0	200,000	$24,385.99	$23,577.23	($808.76)	-3.32%
12	0.0	250,000	$30,467.86	$29,456.91	($1,010.95)	-3.32%
13	0.0	300,000	$36,549.69	$35,336.55	($1,213.14)	-3.32%
14	0.0	350,000	$42,631.56	$41,216.23	($1,415.33)	-3.32%
15	0.0	400,000	$48,713.39	$47,095.87	($1,617.52)	-3.32%
16	0.0	450,000	$54,795.26	$52,975.55	($1,819.71)	-3.32%
17	0.0	500,000	$60,877.09	$58,855.19	($2,021.90)	-3.32%

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Typical Bill Comparison
Street Lighting

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	$16.19	$16.18	($0.01)	-0.06%
2	0.0	100	$19.97	$19.96	($0.01)	-0.05%
3	0.0	200	$27.50	$27.48	($0.02)	-0.07%
4	0.0	400	$42.62	$42.57	($0.05)	-0.12%
5	0.0	500	$50.16	$50.10	($0.06)	-0.12%
6	0.0	750	$69.02	$68.93	($0.09)	-0.13%
7	0.0	1,000	$87.88	$87.76	($0.12)	-0.14%
8	0.0	1,200	$102.99	$102.84	($0.15)	-0.15%
9	0.0	1,400	$118.06	$117.89	($0.17)	-0.14%
10	0.0	1,600	$133.15	$132.95	($0.20)	-0.15%
11	0.0	2,000	$163.32	$163.07	($0.25)	-0.15%
12	0.0	2,500	$200.85	$200.54	($0.31)	-0.15%
13	0.0	3,000	$238.33	$237.96	($0.37)	-0.16%
14	0.0	4,000	$313.34	$312.85	($0.49)	-0.16%
15	0.0	5,000	$388.32	$387.71	($0.61)	-0.16%

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2015 - May 2016
(Revenue)/Expense in $

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

			2015 Forecast							Total Forecast
Line	Description	Type of Charge	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jun - Dec 2015
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = Sum (D) thru (J)
			WPC-1a, Col (E), Lines 1 thru 19	WPC-1a, Col (E), Lines 20 thru 38	WPC-1a, Col (E), Lines 39 thru 57	WPC-1a, Col (E), Lines 58 thru 76	WPC-1a, Col (E), Lines 77 thru 95	WPC-1a, Col (E), Lines 96 thru 114	WPC-1a, Col (E), Lines 115 thru 133	
	TCRR-N Costs & Revenues									
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 6,837,878
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand - 12 CP	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 4,186,364
4	Black Start Service	Demand - 12 CP	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 126,487
5	TO Scheduling System Control and Dispatch Service	Energy	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 698,277
6	NERC/RFC Charges	Energy	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 250,828
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$ (37)	$ (37)	$ (37)	$ (37)	$ (37)	$ (37)	$ (37)	$ (261)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (45,799)
9	Network Integration Transmission Service	Demand - 1 CP	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 22,767,344
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 2,096,487
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 24,272
13	Load Response Charge Allocation	Energy	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 185,133
14	Generation Deactivation	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 37,127,010
16	TCRR-N Deferral carrying costs		$ 6,187	$ 5,105	$ 2,276	$ (265)	$ (313)	$ 1,494	$ 2,575	$ 17,060
17										
18	Total TCRR-N Demand - 1 CP costs		$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 29,559,161
19	Total TCRR-N Demand - 12 CP costs		$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 4,312,851
20	Total TCRR-N Energy costs		$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 3,254,997
21										
22	**Total TCRR-N including carrying costs**		**$ 5,310,046**	**$ 5,308,964**	**$ 5,306,134**	**$ 5,303,594**	**$ 5,303,546**	**$ 5,305,353**	**$ 5,306,433**	**$ 37,144,070**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2015 - May 2016
(Revenue)/Expense in $

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

Line	Description	Type of Charge	2016 Forecast Jan	Feb	Mar	Apr	May	Total Forecast Jan - May 2016	Total Forecast Jun 2015 - May 2016
(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T) = sum (O) thru (S)	(U) = (K) + (T)
			WPC-1a, Col (E), Lines 134 thru 152	WPC-1a, Col (E), Lines 153 thru 171	WPC-1a, Col (E), Lines 172 thru 190	WPC-1a, Col (E), Lines 191 thru 209	WPC-1a, Col (E), Lines 210 thru 228		
	TCRR-N Costs & Revenues								
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 976,840	$ 4,884,198	$ 11,722,076
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand - 12 CP	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 598,052	$ 2,990,260	$ 7,176,625
4	Black Start Service	Demand - 12 CP	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 18,070	$ 90,348	$ 216,835
5	TO Scheduling System Control and Dispatch Service	Energy	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 99,754	$ 498,770	$ 1,197,047
6	NERC/RFC Charges	Energy	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 35,833	$ 179,163	$ 429,991
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$ (37)	$ (37)	$ (37)	$ (37)	$ (37)	$ (187)	$ (448)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (6,543)	$ (32,714)	$ (78,513)
9	Network Integration Transmission Service	Demand - 1 CP	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 3,252,478	$ 16,262,389	$ 39,029,733
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 299,498	$ 1,497,491	$ 3,593,978
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 3,467	$ 17,337	$ 41,609
13	Load Response Charge Allocation	Energy	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 26,448	$ 132,238	$ 317,371
14	Generation Deactivation	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 5,303,859	$ 26,519,293	$ 63,646,303
16	TCRR-N Deferral carrying costs		$ 1,058	$ (1,823)	$ (3,283)	$ (2,982)	$ (1,223)	$ (8,253)	$ 8,807
17									
18	Total TCRR-N Demand - 1 CP costs		$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 21,113,687	$ 50,672,848
19	Total TCRR-N Demand - 12 CP costs		$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 3,080,608	$ 7,393,460
20	Total TCRR-N Energy costs		$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 2,324,998	$ 5,579,995
21									
22	**Total TCRR-N including carrying costs**		**$ 5,304,916**	**$ 5,302,036**	**$ 5,300,576**	**$ 5,300,876**	**$ 5,302,635**	**$ 26,511,040**	**$ 63,655,110**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Monthly Costs by Tariff Class
June 2015 - May 2016

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

			2015 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-2 Col (D), (F), (H)								
1	**TCRR-N Demand-Based Costs - 1 CP**		$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	Schedule C-1, Page 1, Line 18
2	Tariff Class									
3	Residential	41.53%	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	Col (C) * Line 1
4	Secondary	33.41%	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	Col (C) * Line 1
5	Primary	16.30%	$ 688,513	$ 688,513	$ 688,513	$ 688,513	$ 688,513	$ 688,513	$ 688,513	Col (C) * Line 1
6	Primary Substation	2.85%	$ 120,306	$ 120,306	$ 120,306	$ 120,306	$ 120,306	$ 120,306	$ 120,306	Col (C) * Line 1
7	High Voltage	5.44%	$ 229,715	$ 229,715	$ 229,715	$ 229,715	$ 229,715	$ 229,715	$ 229,715	Col (C) * Line 1
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
9	School	0.47%	$ 19,718	$ 19,718	$ 19,718	$ 19,718	$ 19,718	$ 19,718	$ 19,718	Col (C) * Line 1
10	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
11	**Total TCRR-N Demand Costs**	100.00%	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	Sum (Line 3 thru 10)
12										
13	**TCRR-N Demand-Based Costs - 12 CP**		$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	Schedule C-1, Page 1, Line 19
14	Tariff Class									
15	Residential	41.68%	$ 256,818	$ 256,818	$ 256,818	$ 256,818	$ 256,818	$ 256,818	$ 256,818	Col (C) * Line 13
16	Secondary	31.10%	$ 191,615	$ 191,615	$ 191,615	$ 191,615	$ 191,615	$ 191,615	$ 191,615	Col (C) * Line 13
17	Primary	17.40%	$ 107,215	$ 107,215	$ 107,215	$ 107,215	$ 107,215	$ 107,215	$ 107,215	Col (C) * Line 13
18	Primary Substation	3.51%	$ 21,634	$ 21,634	$ 21,634	$ 21,634	$ 21,634	$ 21,634	$ 21,634	Col (C) * Line 13
19	High Voltage	5.69%	$ 35,058	$ 35,058	$ 35,058	$ 35,058	$ 35,058	$ 35,058	$ 35,058	Col (C) * Line 13
20	Private Outdoor Lighting	0.13%	$ 810	$ 810	$ 810	$ 810	$ 810	$ 810	$ 810	Col (C) * Line 13
21	School	0.46%	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	Col (C) * Line 13
22	Street Lighting	0.02%	$ 126	$ 126	$ 126	$ 126	$ 126	$ 126	$ 126	Col (C) * Line 13
23	**Total TCRR-N Demand Costs**	100.00%	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	Sum (Line 15 thru 22)
24										
25	**TCRR-N Energy-Based Costs**		$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	Schedule C-1, Page 1, Line 20
26	Tariff Class									
27	Residential	38.40%	$ 178,548	$ 178,548	$ 178,548	$ 178,548	$ 178,548	$ 178,548	$ 178,548	Col (C) * Line 25
28	Secondary	28.35%	$ 131,810	$ 131,810	$ 131,810	$ 131,810	$ 131,810	$ 131,810	$ 131,810	Col (C) * Line 25
29	Primary	20.71%	$ 96,296	$ 96,296	$ 96,296	$ 96,296	$ 96,296	$ 96,296	$ 96,296	Col (C) * Line 25
30	Primary Substation	4.63%	$ 21,518	$ 21,518	$ 21,518	$ 21,518	$ 21,518	$ 21,518	$ 21,518	Col (C) * Line 25
31	High Voltage	6.89%	$ 32,035	$ 32,035	$ 32,035	$ 32,035	$ 32,035	$ 32,035	$ 32,035	Col (C) * Line 25
32	Private Outdoor Lighting	0.21%	$ 953	$ 953	$ 953	$ 953	$ 953	$ 953	$ 953	Col (C) * Line 25
33	School	0.44%	$ 2,024	$ 2,024	$ 2,024	$ 2,024	$ 2,024	$ 2,024	$ 2,024	Col (C) * Line 25
34	Street Lighting	0.39%	$ 1,816	$ 1,816	$ 1,816	$ 1,816	$ 1,816	$ 1,816	$ 1,816	Col (C) * Line 25
35	**Total TCRR-N Energy Costs**	100.00%	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	Sum (Line 27 thru 34)

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Monthly Costs by Tariff Class
June 2015 - May 2016

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

Line	Description	Tariff Allocator	Jan	Feb	Mar	Apr	May	Source	Total Forecast Costs May 2014 - June 2015
			2016 Forecast						
(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U) = Sum (D) thru (J) and Sum (O) thru (S)
		WPC-2 Col (D), (F), (H)							
1	**TCRR-N Demand-Based Costs - 1 CP**		$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	Schedule C-1, Page 2, Line 18	
2	Tariff Class								
3	Residential	41.53%	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	$ 1,753,568	Col (N) * Line 1	$ 21,042,814
4	Secondary	33.41%	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	$ 1,410,918	Col (N) * Line 1	$ 16,931,020
5	Primary	16.30%	$ 688,513	$ 688,513	$ 688,513	$ 688,513	$ 688,513	Col (N) * Line 1	$ 8,262,152
6	Primary Substation	2.85%	$ 120,306	$ 120,306	$ 120,306	$ 120,306	$ 120,306	Col (N) * Line 1	$ 1,443,666
7	High Voltage	5.44%	$ 229,715	$ 229,715	$ 229,715	$ 229,715	$ 229,715	Col (N) * Line 1	$ 2,756,577
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (N) * Line 1	$ -
9	School	0.47%	$ 19,718	$ 19,718	$ 19,718	$ 19,718	$ 19,718	Col (N) * Line 1	$ 236,619
10	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (N) * Line 1	$ -
11	**Total TCRR-N Demand Costs**	100.00%	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	$ 4,222,737	Sum (Line 3 thru 10)	$ 50,672,848
12									
13	**TCRR-N Demand-Based Costs - 12 CP**		$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	Schedule C-1, Page 2, Line 19	
14	Tariff Class								
15	Residential	41.68%	$ 256,818	$ 256,818	$ 256,818	$ 256,818	$ 256,818	Col (N) * Line 13	$ 3,081,816
16	Secondary	31.10%	$ 191,615	$ 191,615	$ 191,615	$ 191,615	$ 191,615	Col (N) * Line 13	$ 2,299,382
17	Primary	17.40%	$ 107,215	$ 107,215	$ 107,215	$ 107,215	$ 107,215	Col (N) * Line 13	$ 1,286,585
18	Primary Substation	3.51%	$ 21,634	$ 21,634	$ 21,634	$ 21,634	$ 21,634	Col (N) * Line 13	$ 259,613
19	High Voltage	5.69%	$ 35,058	$ 35,058	$ 35,058	$ 35,058	$ 35,058	Col (N) * Line 13	$ 420,695
20	Private Outdoor Lighting	0.13%	$ 810	$ 810	$ 810	$ 810	$ 810	Col (N) * Line 13	$ 9,722
21	School	0.46%	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	Col (N) * Line 13	$ 34,136
22	Street Lighting	0.02%	$ 126	$ 126	$ 126	$ 126	$ 126	Col (N) * Line 13	$ 1,511
23	**Total TCRR-N Demand Costs**	100.00%	$ 616,122	$ 616,122	$ 616,122	$ 616,122	$ 616,122	Sum (Line 15 thru 22)	$ 7,393,460
24									
25	**TCRR-N Energy-Based Costs**		$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	Schedule C-1, Page 2, Line 20	
26	Tariff Class								
27	Residential	38.40%	$ 178,548	$ 178,548	$ 178,548	$ 178,548	$ 178,548	Col (N) * Line 25	$ 2,142,577
28	Secondary	28.35%	$ 131,810	$ 131,810	$ 131,810	$ 131,810	$ 131,810	Col (N) * Line 25	$ 1,581,714
29	Primary	20.71%	$ 96,296	$ 96,296	$ 96,296	$ 96,296	$ 96,296	Col (N) * Line 25	$ 1,155,556
30	Primary Substation	4.63%	$ 21,518	$ 21,518	$ 21,518	$ 21,518	$ 21,518	Col (N) * Line 25	$ 258,219
31	High Voltage	6.89%	$ 32,035	$ 32,035	$ 32,035	$ 32,035	$ 32,035	Col (N) * Line 25	$ 384,415
32	Private Outdoor Lighting	0.21%	$ 953	$ 953	$ 953	$ 953	$ 953	Col (N) * Line 25	$ 11,439
33	School	0.44%	$ 2,024	$ 2,024	$ 2,024	$ 2,024	$ 2,024	Col (N) * Line 25	$ 24,283
34	Street Lighting	0.39%	$ 1,816	$ 1,816	$ 1,816	$ 1,816	$ 1,816	Col (N) * Line 25	$ 21,790
35	**Total TCRR-N Energy Costs**	100.00%	$ 465,000	$ 465,000	$ 465,000	$ 465,000	$ 465,000	Sum (Line 27 thru 34)	$ 5,579,995

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Summary of Proposed Rates
June 2015 - May 2016

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

Schedule C-3
Page 1 of 1

TCRR-N Rates

Line	Description	Residential	Secondary[1]	Primary	Primary Substation	High Voltage	Private Outdoor Lighting[2]	School	Street Lighting	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	TCRR-N Base Rates									
2	Demand (kWh, kW)	$ 0.0039782	$ 1.2404548	$ 1.3524218	$ 1.2900311	$ 1.5298597	$ 0.0000101	$ 0.0039467	$ 0.0000008	Schedule C-3a, Line 21
3	Energy (0-1500 kWh)	$ 0.0004033	$ 0.0070344	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	Schedule C-3a, Line 25 + Line 40
4	Energy (>1500 kWh)	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	Schedule C-3a, Line 40
5	Reactive (kWh, kW, kVar)	$ 0.0005610	$ 0.2194427	$ 0.3280736	$ 0.3235679	$ 0.5011181	$ -	$ 0.0005566	$ -	Schedule C-3a, Line 48
6										
7	TCRR-N Reconciliation Rates									
8	Demand (kWh, kW)	$ 0.0001063	$ 0.0307380	$ 0.0384035	$ 0.0422734	$ 0.0425796	$ 0.0000628	$ 0.0001039	$ 0.0000051	Schedule C-3b, Line 26
9	Energy (0-1500 kWh)	$ 0.0000094	$ 0.0001737	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	Schedule C-3b, Line 27 + Line 31
10	Energy (>1500 kWh)	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	Schedule C-3b, Line 27
11										
12										
13	**Total TCRR-N Rates $/kW**		**$ 1.4906355**	**$ 1.3908253**	**$ 1.3323045**	**$ 1.5724393**				
14	**$/kWh for 0-1500 kWh**	**$ 0.0050582**	**$ 0.0072081**	**$ 0.0004127**	**$ 0.0004127**	**$ 0.0004127**	**$ 0.0004856**	**$ 0.0050199**	**$ 0.0004186**	
15	**$/kWh for >1500 kWh**	**$ 0.0050582**	**$ 0.0004127**	**$ 0.0004127**	**$ 0.0004127**	**$ 0.0004127**	**$ 0.0004856**	**$ 0.0050199**	**$ 0.0004186**	
16	**$/kVar**			**$ 0.3280736**	**$ 0.3235679**	**$ 0.5011181**				

[1] Secondary customers are charged for all kW over 5kW of Billing Demand
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage.

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Development of Proposed Base Rates
(Revenue)/Expense in $

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

Line	Description	"Current" Cycle Base Costs	Residential	Secondary[1]	Primary	Primary Substation	High Voltage	Private Outdoor Lighting	School	Street Lighting	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		Schedule B-1, Col (D)									
	TCRR-N Base Costs										
1	Demand-Based Allocators - 1 CP		41.53%	33.41%	16.30%	2.85%	5.44%	0.00%	0.47%	0.00%	WPC-2, Col (F)
2	Demand-Based Allocators - 12 CP		41.68%	31.10%	17.40%	3.51%	5.69%	0.13%	0.46%	0.02%	WPC-2, Col (H)
3											
4	Demand-Based Components										
5	Transmission Enhancement Charges (RTEP)	$ 11,722,076	$ 4,867,804	$ 3,916,628	$ 1,911,272	$ 333,961	$ 637,675	$ -	$ 54,737	$ -	Col (C) * Line 1
6	Incremental Capacity Transfer Rights Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
7	Black Start Service	$ 216,835	$ 90,383	$ 67,436	$ 37,733	$ 7,614	$ 12,338	$ 285	$ 1,001	$ 44	Col (C) * Line 2
8	Firm PTP Transmission Service Credits	$ (448)	$ (186)	$ (150)	$ (73)	$ (13)	$ (24)	$ -	$ (2)	$ -	Col (C) * Line 1
9	Non-Firm PTP Transmission Service Credits	$ (78,513)	$ (32,604)	$ (26,233)	$ (12,801)	$ (2,237)	$ (4,271)	$ -	$ (367)	$ -	Col (C) * Line 1
10	Network Integration Transmission Service	$ 39,029,733	$ 16,207,801	$ 13,040,774	$ 6,363,755	$ 1,111,955	$ 2,123,198	$ -	$ 182,251	$ -	Col (C) * Line 1
11	Expansion Cost Recovery Charges (ECRC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
12	Generation Deactivation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
13	Subtotal	$ 50,889,683	$ 21,133,198	$ 16,998,456	$ 8,299,885	$ 1,451,280	$ 2,768,916	$ 285	$ 237,620	$ 44	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	1.003	WPB-1, Line 4
15	Total Demand-Based Component Cost	$ 51,042,352	$ 21,196,597	$ 17,049,451	$ 8,324,784	$ 1,455,634	$ 2,777,222	$ 286	$ 238,333	$ 44	Line 13 * Line 14
16											
17	Portion of Secondary Demand Greater Than 5 kW		NA	79.74%	NA	NA	NA	NA	NA	NA	WPC-3, Column (P), Line 4 / (Line 4 + Line 5)
18	Demand-Based Component Cost		$ 21,196,597	$ 13,595,301	$ 8,324,784	$ 1,455,634	$ 2,777,222	$ 286	$ 238,333	$ 44	Line 15 * Line 17
19											
20	Projected Billing Determinants (kWh, kW)		5,328,185,036	10,959,932	6,155,464	1,128,371	1,815,344	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
21	Demand Portion of TCRR-N Rate		$ 0.0039782	$ 1.2404548	$ 1.3524218	$ 1.2900311	$ 1.5298597	$ 0.0000101	$ 0.0039467	$ 0.0000008	Line 18 / Line 20
22											
23	Secondary Energy Portion of Demand-Based Component Cost		NA	$ 3,454,150	NA	NA	NA	NA	NA	NA	Line 15 - Line 18
24	Secondary 0-1500 kWh Billing Determinants		5,328,185,036	520,904,516	6,155,464	1,128,371	1,815,344	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
25	Secondary 0-1500 kWh TCRR-N Rate		$ -	$ 0.0066311	$ -	$ -	$ -	$ -	$ -	$ -	Line 23 / Line 24
26											
27	Energy-Based Allocators		38.40%	28.35%	20.71%	4.63%	6.89%	0.21%	0.44%	0.39%	WPC-2, Col (D)
28											
29	Energy-Based Components										
30	TO Scheduling System Control and Dispatch Service	$ 1,197,047	$ 459,636	$ 339,317	$ 247,895	$ 55,394	$ 82,467	$ 2,454	$ 5,209	$ 4,675	Col (C) * Line 27
31	NERC/RFC Charges	$ 429,991	$ 165,106	$ 121,886	$ 89,046	$ 19,898	$ 29,623	$ 882	$ 1,871	$ 1,679	Col (C) * Line 27
32	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 3,593,978	$ 1,379,997	$ 1,018,755	$ 744,273	$ 166,315	$ 247,595	$ 7,368	$ 15,640	$ 14,035	Col (C) * Line 27
33	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 41,609	$ 15,977	$ 11,794	$ 8,617	$ 1,925	$ 2,866	$ 85	$ 181	$ 162	Col (C) * Line 27
34	Load Response Charge Allocation	$ 317,371	$ 121,863	$ 89,963	$ 65,724	$ 14,687	$ 21,864	$ 651	$ 1,381	$ 1,239	Col (C) * Line 27
35	Subtotal	$ 5,579,995	$ 2,142,577	$ 1,581,714	$ 1,155,556	$ 258,219	$ 384,415	$ 11,439	$ 24,283	$ 21,790	Sum (Line 30 thru 34)
36	Gross Revenue Conversion Factor	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	WPB-1, Line 4
37	Total Energy-Based Component Cost	$ 5,596,735	$ 2,149,005	$ 1,586,459	$ 1,159,023	$ 258,994	$ 385,568	$ 11,474	$ 24,356	$ 21,856	Line 35 * Line 36
38											
39	Projected Billing Determinants (kWh)		5,328,185,036	3,933,424,621	2,873,649,517	642,143,105	955,968,029	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
40	Energy Portion of TCRR-N Rate		$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	$ 0.0004033	Line 37 / Line 39
41											
42	Reactive-Based Components										
43	Reactive Supply and Voltage Control from Gen Sources	$ 7,176,625	$ 2,980,223	$ 2,397,883	$ 1,170,141	$ 204,462	$ 390,405	$ -	$ 33,511	$ -	Col (C) * Line 1
44	Gross Revenue Conversion Factor	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	1.003	WPB-1, Line 4
45	Total Reactive-Based Component Cost	$ 7,198,155	$ 2,989,164	$ 2,405,077	$ 1,173,651	$ 205,075	$ 391,576	$ -	$ 33,612	$ -	Line 43 * Line 44
46											
47	Projected Billing Determinants (kWh, kW, kVar)		5,328,185,036	10,959,932	3,577,402	633,793	781,405	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
48	Reactive Portion of TCRR-N Rate		$ 0.0005610	$ 0.2194427	$ 0.3280736	$ 0.3235679	$ 0.5011181	$ -	$ 0.0005566	$ -	Line 45 / Line 47
49											
50	**Total Base TCRR-N Component Cost**	**$ 63,837,242**									Sum (Line 15, 37, 45)

[1] Secondary customers are charged for all kW over 5kW of Billing Demand

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Development of Proposed Reconciliation Rate - TCRR-N
June 2015 - May 2016

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

Schedule C-3b
Page 1 of 1

Reconciliation TCRR-N Rate

Line (A)	Description (B)	Under Recovery (C)	Demand/ Energy Ratios (D)	Residential (E)	Secondary[1] (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (J)	School (K)	Street Lighting (L)	Source (M)
1	Demand-Based Allocators - 12 CP			41.68%	31.10%	17.40%	3.51%	5.69%	0.13%	0.46%	0.02%	WPC-2, Col (H)
2	Energy-Based Allocators			38.40%	28.35%	20.71%	4.63%	6.89%	0.21%	0.44%	0.39%	WPC-2, Col (D)
3												
4	TCRR-N Under Recovery	$ 1,475,724										WPC-1b, Col (C) Line 6
5	TCRR-N Under Recovery of Carrying Costs Total	$ 8,807										WPC-1b, Col (H) Line 19
6	TCRR-N Under Recovery	$ 1,484,531										Line 4 + Line 5
7	Gross Revenue Conversion Factor	1.003										WPB-1, Line 4
8	Total TCRR-N Under Recovery	$ 1,488,984										Line 6 * Line 7
9												
10	Base TCRR-N Component Costs											
11	Total Demand-Based Component Cost	$ 58,240,507	91.23%									Schedule C-3a, Col (C) Line 15 + Line 45
12	Total Energy-Based Components Cost	$ 5,596,735	8.77%									Schedule C-3a, Col (C) Line 37
13	Total Base TCRR-N Component Cost	$ 63,837,242	100.00%									Line 11 + Line 12
14												
15	TCRR-N Under Recovery - Demand (Line 8 * Col (D), Line 11)	$ 1,358,442		$ 566,240	$ 422,478	$ 236,392	$ 47,700	$ 77,297	$ 1,786	$ 6,272	$ 278	Col (C) * Line 1
16	TCRR-N Under Recovery - Energy (Line 8 * Col (D), Line 12)	$ 130,542		$ 50,125	$ 37,004	$ 27,034	$ 6,041	$ 8,993	$ 268	$ 568	$ 510	Col (C) * Line 2
17	TCRR-N Under Recovery Total	$ 1,488,984		$ 616,364	$ 459,482	$ 263,425	$ 53,741	$ 86,290	$ 2,054	$ 6,840	$ 787	Line 15 + Line 16
18												
19	Portion of Secondary Demand Greater Than 5 kW			NA	79.74%	NA	NA	NA	NA	NA	NA	Schedule C-3a, Col (E) Line 17
20	Demand-Based Under Recovery			$ 566,240	$ 336,886	$ 236,392	$ 47,700	$ 77,297	$ 1,786	$ 6,272	$ 278	Line 15 * Line 19
21												
22	Projected Billing Determinants (kWh, kW)			5,328,185,036	10,959,932	6,155,464	1,128,371	1,815,344	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
23	Projected Billing Determinants (kWh)			5,328,185,036	3,933,424,621	2,873,649,517	642,143,105	955,968,029	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
24												
25	TCRR-N Reconciliation Rates											
26	Demand Portion of TCRR-N Rate (kWh, kW)			$ 0.0001063	$ 0.0307380	$ 0.0384035	$ 0.0422734	$ 0.0425796	$ 0.0000628	$ 0.0001039	$ 0.0000051	Line 20 / Line 22
27	Energy Portion of TCRR-N Rate (kWh)			$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	$ 0.0000094	Line 16 / Line 23
28												
29	Secondary Energy Portion of Under Recovery			NA	$ 85,592	NA	NA	NA	NA	NA	NA	Line 15 - Line 20
30	Secondary 0-1500 kWh Billing Determinants			5,328,185,036	520,904,516	2,873,649,517	642,143,105	955,968,029	28,447,513	60,387,834	54,188,739	WPC-3, Column (P)
31	Secondary 0-1500 kWh TCRR-N Rate			$ -	$ 0.0001643	$ -	$ -	$ -	$ -	$ -	$ -	Line 29 / Line 30

[1] Secondary customers are charged for all kW over 5kW of Billing Demand

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

February 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (6,783,041)	**$ (6,783,041)**
2	Transmission Enhancement Charges (RTEP)	$ 822,504	NA		**$ 822,504**
3	Incremental Capacity Transfer Rights Credit	NA	$ (27,890)		**$ (27,890)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 589,721	NA		**$ 589,721**
5	Black Start Service	$ 17,399	NA		**$ 17,399**
6	TO Scheduling System Control and Dispatch Service	$ 104,586	NA		**$ 104,586**
7	NERC/RFC Charges	$ 33,978	NA		**$ 33,978**
8	Firm PTP Transmission Service	NA	$ (167)		**$ (167)**
9	Non-Firm PTP Transmission Service	NA	$ (12,838)		**$ (12,838)**
10	Network Integration Transmission Service	$ 2,990,749	NA		**$ 2,990,749**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,510	NA		**$ 15,510**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 433,676	NA		**$ 433,676**
13	Michigan-Ontario Interface PARs Charge	$ 3,821	NA		**$ 3,821**
14	Load Response Charge Allocation	$ 69,799	NA		**$ 69,799**
15	PJM Default Charges	$ -	NA		**$ -**
16	Operating Reserve	$ 606,588	NA		**$ 606,588**
17	SubTotal	$ 5,688,331	$ (40,894)	$ (6,783,041)	**$ (1,135,604)**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 22,472**
19					
20	**Total TCRR-N including carrying costs**	$ 5,688,331	$ (40,894)	$ (6,783,041)	**$ (1,113,132)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1

March 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,998,467)	**$ (5,998,467)**
2	Transmission Enhancement Charges (RTEP)	$ 818,349	NA		**$ 818,349**
3	Incremental Capacity Transfer Rights Credit	NA	$ (30,827)		**$ (30,827)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 585,351	NA		**$ 585,351**
5	Black Start Service	$ 23,218	NA		**$ 23,218**
6	TO Scheduling System Control and Dispatch Service	$ 102,008	NA		**$ 102,008**
7	NERC/RFC Charges	$ 33,147	NA		**$ 33,147**
8	Firm PTP Transmission Service	NA	$ (189)		**$ (189)**
9	Non-Firm PTP Transmission Service	NA	$ (12,950)		**$ (12,950)**
10	Network Integration Transmission Service	$ 3,309,706	NA		**$ 3,309,706**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,504	NA		**$ 15,504**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 412,752	NA		**$ 412,752**
13	Michigan-Ontario Interface PARs Charge	$ 3,844	NA		**$ 3,844**
14	Load Response Charge Allocation	$ 58,580	NA		**$ 58,580**
15	PJM Default Charges	$ 233	NA		**$ 233**
16	SubTotal	$ 5,362,691	$ (43,966)	$ (5,998,467)	**$ (679,743)**
17	TCRR-N Deferral carrying costs (WPC-1b)				**$ 18,826**
18					
19	**Total TCRR-N including carrying costs**	$ 5,362,691	$ (43,966)	$ (5,998,467)	**$ (660,916)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1
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April 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,314,844)	**$ (5,314,844)**
2	Transmission Enhancement Charges (RTEP)	$ 818,035	NA		**$ 818,035**
3	Incremental Capacity Transfer Rights Credit	NA	$ (29,821)		**$ (29,821)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 595,864	NA		**$ 595,864**
5	Black Start Service	$ 17,926	NA		**$ 17,926**
6	TO Scheduling System Control and Dispatch Service	$ 84,634	NA		**$ 84,634**
7	NERC/RFC Charges	$ 27,502	NA		**$ 27,502**
8	Firm PTP Transmission Service	NA	$ (152)		**$ (152)**
9	Non-Firm PTP Transmission Service	NA	$ (4,300)		**$ (4,300)**
10	Network Integration Transmission Service	$ 3,201,791	NA		**$ 3,201,791**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,498	NA		**$ 15,498**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 374,365	NA		**$ 374,365**
13	Michigan-Ontario Interface PARs Charge	$ 3,709	NA		**$ 3,709**
14	Load Response Charge Allocation	$ 79,566	NA		**$ 79,566**
15	PJM Default Charges	$ -	NA		**$ -**
16	SubTotal	$ 5,218,889	$ (34,273)	$ (5,314,844)	**$ (130,228)**
17	TCRR-N Deferral carrying costs (WPC-1b)				**$ 17,235**
18					
19	**Total TCRR-N including carrying costs**	$ 5,218,889	$ (34,273)	$ (5,314,844)	**$ (112,992)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

Data: Actual
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Work Paper Reference No(s).: WPC-1b

Schedule D-1
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May 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (4,859,923)	**$ (4,859,923)**
2	Transmission Enhancement Charges (RTEP)	$ 817,851	NA		**$ 817,851**
3	Incremental Capacity Transfer Rights Credit	NA	$ (30,809)		**$ (30,809)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 601,470	NA		**$ 601,470**
5	Black Start Service	$ 17,916	NA		**$ 17,916**
6	TO Scheduling System Control and Dispatch Service	$ 91,279	NA		**$ 91,279**
7	NERC/RFC Charges	$ 29,662	NA		**$ 29,662**
8	Firm PTP Transmission Service	NA	$ (146)		**$ (146)**
9	Non-Firm PTP Transmission Service	NA	$ (3,319)		**$ (3,319)**
10	Network Integration Transmission Service	$ 3,307,695	NA		**$ 3,307,695**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,494	NA		**$ 15,494**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 365,376	NA		**$ 365,376**
13	Michigan-Ontario Interface PARs Charge	$ 3,752	NA		**$ 3,752**
14	Load Response Charge Allocation	$ 20,754	NA		**$ 20,754**
15	PJM Default Charges	$ -	NA		**$ -**
16	SubTotal	$ 5,271,250	$ (34,275)	$ (4,859,923)	**$ 377,052**
17	TCRR-N Deferral carrying costs (WPC-1b)				**$ 17,815**
18					
19	**Total TCRR-N including carrying costs**	$ 5,271,250	$ (34,275)	$ (4,859,923)	**$ 394,867**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1
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June 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,450,541)	**$ (5,450,541)**
2	Transmission Enhancement Charges (RTEP)	$ 903,890	NA		**$ 903,890**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 598,577	NA		**$ 598,577**
5	Black Start Service	$ 17,104	NA		**$ 17,104**
6	TO Scheduling System Control and Dispatch Service	$ 101,824	NA		**$ 101,824**
7	NERC/RFC Charges	$ 33,088	NA		**$ 33,088**
8	Firm PTP Transmission Service	NA	$ (144)		**$ (144)**
9	Non-Firm PTP Transmission Service	NA	$ (3,772)		**$ (3,772)**
10	Network Integration Transmission Service	$ 3,200,667	NA		**$ 3,200,667**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,492	NA		**$ 15,492**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 408,570	NA		**$ 408,570**
13	Michigan-Ontario Interface PARs Charge	$ 3,840	NA		**$ 3,840**
14	Load Response Charge Allocation	$ 6,697	NA		**$ 6,697**
15	PJM Default Charges	$ -	NA		**$ -**
16	SubTotal	$ 5,289,750	$ (3,916)	$ (5,450,541)	**$ (164,707)**
17	TCRR-N Deferral carrying costs (WPC-1b)				**$ 18,325**
18					
19	**Total TCRR-N including carrying costs**	$ 5,289,750	$ (3,916)	$ (5,450,541)	**$ (146,382)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1
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July 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,845,944)	**$ (5,845,944)**
2	Transmission Enhancement Charges (RTEP)	$ 962,921	NA		**$ 962,921**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 599,328	NA		**$ 599,328**
5	Black Start Service	$ 17,504	NA		**$ 17,504**
6	TO Scheduling System Control and Dispatch Service	$ 101,361	NA		**$ 101,361**
7	NERC/RFC Charges	$ 32,919	NA		**$ 32,919**
8	Firm PTP Transmission Service	NA	$ 1,321		**$ 1,321**
9	Non-Firm PTP Transmission Service	NA	$ (3,387)		**$ (3,387)**
10	Network Integration Transmission Service	$ 3,308,976	NA		**$ 3,308,976**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,491	NA		**$ 15,491**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 392,394	NA		**$ 392,394**
13	Michigan-Ontario Interface PARs Charge	$ 3,786	NA		**$ 3,786**
14	Load Response Charge Allocation	$ 13,776	NA		**$ 13,776**
	PJM Default Charges	$ -	NA		**$ -**
15	SubTotal	$ 5,448,456	$ (2,065)	$ (5,845,944)	**$ (399,553)**
16	TCRR-N Deferral carrying costs (WPC-1b)				**$ 17,239**
17					
18	**Total TCRR-N including carrying costs**	$ 5,448,456	$ (2,065)	$ (5,845,944)	**$ (382,314)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

August 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,741,559)	**$ (5,741,559)**
2	Transmission Enhancement Charges (RTEP)	$ 964,139	NA		**$ 964,139**
3	Incremental Capacity Transfer Rights Credit	NA	$ (112)		**$ (112)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 605,038	NA		**$ 605,038**
5	Black Start Service	$ 17,620	NA		**$ 17,620**
6	TO Scheduling System Control and Dispatch Service	$ 107,970	NA		**$ 107,970**
7	NERC/RFC Charges	$ 35,069	NA		**$ 35,069**
8	Firm PTP Transmission Service	NA	$ (50)		**$ (50)**
9	Non-Firm PTP Transmission Service	NA	$ (2,722)		**$ (2,722)**
10	Network Integration Transmission Service	$ 3,313,150	NA		**$ 3,313,150**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,511	NA		**$ 15,511**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 420,843	NA		**$ 420,843**
13	Michigan-Ontario Interface PARs Charge	$ 3,559	NA		**$ 3,559**
14	Load Response Charge Allocation	$ 16,544	NA		**$ 16,544**
15	PJM Default Charges	$ -	NA		**$ -**
16	Operating Reserve	$ 45,601	NA		**$ 45,601**
17	SubTotal	$ 5,545,044	$ (2,884)	$ (5,741,559)	**$ (199,399)**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 16,076**
19					
20	**Total TCRR-N including carrying costs**	$ 5,545,044	$ (2,884)	$ (5,741,559)	**$ (183,323)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

September 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,913,974)	**$ (5,913,974)**
2	Transmission Enhancement Charges (RTEP)	$ 1,071,861	NA		**$ 1,071,861**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 601,723	NA		**$ 601,723**
5	Black Start Service	$ 17,490	NA		**$ 17,490**
6	TO Scheduling System Control and Dispatch Service	$ 91,605	NA		**$ 91,605**
7	NERC/RFC Charges	$ 29,752	NA		**$ 29,752**
8	Firm PTP Transmission Service	NA	$ (150)		**$ (150)**
9	Non-Firm PTP Transmission Service	NA	$ (2,845)		**$ (2,845)**
10	Network Integration Transmission Service	$ 3,206,274	NA		**$ 3,206,274**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,510	NA		**$ 15,510**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 365,183	NA		**$ 365,183**
13	Michigan-Ontario Interface PARs Charge	$ 3,884	NA		**$ 3,884**
14	Load Response Charge Allocation	$ 7,431	NA		**$ 7,431**
15	PJM Default Charges	$ -	NA		**$ -**
16	Operating Reserve	$ -	NA		**$ -**
17	SubTotal	$ 5,410,716	$ (2,995)	$ (5,913,974)	**$ (506,253)**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 14,689**
19					
20	**Total TCRR-N including carrying costs**	$ 5,410,716	$ (2,995)	$ (5,913,974)	**$ (491,564)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

October 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,096,455)	**$ (5,096,455)**
2	Transmission Enhancement Charges (RTEP)	$ 976,840	NA		**$ 976,840**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 602,261	NA		**$ 602,261**
5	Black Start Service	$ 17,288	NA		**$ 17,288**
6	TO Scheduling System Control and Dispatch Service	$ 89,032	NA		**$ 89,032**
7	NERC/RFC Charges	$ 28,915	NA		**$ 28,915**
8	Firm PTP Transmission Service	NA	$ (153)		**$ (153)**
9	Non-Firm PTP Transmission Service	NA	$ (2,735)		**$ (2,735)**
10	Network Integration Transmission Service	$ 3,313,150	NA		**$ 3,313,150**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,510	NA		**$ 15,510**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 334,070	NA		**$ 334,070**
13	Michigan-Ontario Interface PARs Charge	$ 3,727	NA		**$ 3,727**
14	Load Response Charge Allocation	$ 19,497	NA		**$ 19,497**
15	PJM Default Charges	$ (813)	NA		**$ (813)**
16	Operating Reserve	$ 22,130	NA		**$ 22,130**
17	SubTotal	$ 5,421,607	$ (2,888)	$ (5,096,455)	**$ 322,265**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 14,371**
19					
20	**Total TCRR-N including carrying costs**	$ 5,421,607	$ (2,888)	$ (5,096,455)	**$ 336,635**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

November 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,213,614)	**$ (5,213,614)**
2	Transmission Enhancement Charges (RTEP)	$ 976,707	NA		**$ 976,707**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 600,451	NA		**$ 600,451**
5	Black Start Service	$ 17,040	NA		**$ 17,040**
6	TO Scheduling System Control and Dispatch Service	$ 97,243	NA		**$ 97,243**
7	NERC/RFC Charges	$ 31,572	NA		**$ 31,572**
8	Firm PTP Transmission Service	NA	$ (150)		**$ (150)**
9	Non-Firm PTP Transmission Service	NA	$ (5,768)		**$ (5,768)**
10	Network Integration Transmission Service	$ 3,206,275	NA		**$ 3,206,275**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,511	NA		**$ 15,511**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 358,968	NA		**$ 358,968**
13	Michigan-Ontario Interface PARs Charge	$ 3,839	NA		**$ 3,839**
14	Load Response Charge Allocation	$ 5,567	NA		**$ 5,567**
15	PJM Default Charges	$ -	NA		**$ -**
16	Operating Reserve	$ -	NA		
17	SubTotal	$ 5,313,174	$ (5,918)	$ (5,213,614)	**$ 93,641**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 15,286**
19					
20	**Total TCRR-N including carrying costs**	$ 5,313,174	$ (5,918)	$ (5,213,614)	**$ 108,928**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1
Page 1 of 1

December 2014 - 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	TCRR-N Retail Revenue	NA	NA	$ (5,712,535)	**$ (5,712,535)**
2	Transmission Enhancement Charges (RTEP)	$ 976,840	NA		**$ 976,840**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 597,971	NA		**$ 597,971**
5	Black Start Service	$ 17,266	NA		**$ 17,266**
6	TO Scheduling System Control and Dispatch Service	$ 103,322	NA		**$ 103,322**
7	NERC/RFC Charges	$ 74,751	NA		**$ 74,751**
8	Firm PTP Transmission Service	NA	$ (151)		**$ (151)**
9	Non-Firm PTP Transmission Service	NA	$ (10,063)		**$ (10,063)**
10	Network Integration Transmission Service	$ 3,313,150	NA		**$ 3,313,150**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,511	NA		**$ 15,511**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 375,569	NA		**$ 375,569**
13	Michigan-Ontario Interface PARs Charge	$ 3,848	NA		**$ 3,848**
14	Load Response Charge Allocation	$ 11,320	NA		**$ 11,320**
15	PJM Default Charges	$ -	NA		**$ -**
16	Operating Reserve	$ -	NA		**$ -**
17	SubTotal	$ 5,489,547	$ (10,214)	$ (5,712,535)	**$ (233,202)**
18	TCRR-N Deferral carrying costs (WPC-1b)				**$ 15,062**
19					
20	**Total TCRR-N including carrying costs**	$ 5,489,547	$ (10,214)	$ (5,712,535)	**$ (218,140)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

Schedule D-1
Page 1 of 1

January 2015 - 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	TCRR-N Retail Revenue	NA	NA	$ (6,458,428)	**$ (6,458,428)**
2	Transmission Enhancement Charges (RTEP)	$ 993,946	NA		**$ 993,946**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 599,636	NA		**$ 599,636**
5	Black Start Service	$ 17,270	NA		**$ 17,270**
6	TO Scheduling System Control and Dispatch Service	$ 113,194	NA		**$ 113,194**
7	NERC/RFC Charges	$ 43,990	NA		**$ 43,990**
8	Firm PTP Transmission Service	NA	$ (199)		**$ (199)**
9	Non-Firm PTP Transmission Service	NA	$ (11,116)		**$ (11,116)**
10	Network Integration Transmission Service	$ 3,120,064	NA		**$ 3,120,064**
11	Expansion Cost Recovery Charges (ECRC)	$ 14,924	NA		**$ 14,924**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 447,620	NA		**$ 447,620**
13	Michigan-Ontario Interface PARs Charge	$ 3,767	NA		**$ 3,767**
14	Load Response Charge Allocation	$ 8,551	NA		**$ 8,551**
15	SubTotal	$ 5,362,963	$ (11,315)	$ (6,458,428)	**$ (1,106,780)**
16	TCRR-N Deferral carrying costs (WPC-1b)				**$ 12,364**
17					
18	**Total TCRR-N including carrying costs**	$ 5,362,963	$ (11,315)	$ (6,458,428)	**$ (1,094,416)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Actual Charges and Revenues
February 2014 - February 2015
(Revenue)/Expense in $

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

February 2015 - Estimate

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	TCRR-N Retail Revenue	NA	NA	$ (6,206,097)	**$ (6,206,097)**
2	Transmission Enhancement Charges (RTEP)	$ 993,946	NA		**$ 993,946**
3	Incremental Capacity Transfer Rights Credit	NA	$ -		**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 601,175	NA		**$ 601,175**
5	Black Start Service	$ 17,168	NA		**$ 17,168**
6	TO Scheduling System Control and Dispatch Service	$ 107,560	NA		**$ 107,560**
7	NERC/RFC Charges	$ 41,889	NA		**$ 41,889**
8	Firm PTP Transmission Service	NA	$ (197)		**$ (197)**
9	Non-Firm PTP Transmission Service	NA	$ (9,954)		**$ (9,954)**
10	Network Integration Transmission Service	$ 2,818,122	NA		**$ 2,818,122**
11	Expansion Cost Recovery Charges (ECRC)	$ 14,925	NA		**$ 14,925**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 396,793	NA		**$ 396,793**
13	Michigan-Ontario Interface PARs Charge	$ 3,564	NA		**$ 3,564**
14	Load Response Charge Allocation	$ 12,975	NA		**$ 12,975**
15	SubTotal	$ 5,008,117	$ (10,152)	$ (6,206,097)	**$ (1,208,131)**
16	TCRR-N Deferral carrying costs (WPC-1b)				**$ 7,647**
17					
18	**Total TCRR-N including carrying costs**	$ 5,008,117	$ (10,152)	$ (6,206,097)	**$ (1,200,484)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Monthly Revenues Collected by Tariff Class

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

		2014											**2015**		
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	$ (3,838,820)	$ (3,121,305)	$ (2,454,269)	$ (1,949,038)	$ (1,847,348)	$ (2,217,059)	$ (2,025,894)	$ (2,153,862)	$ (1,565,941)	$ (1,750,708)	$ (2,386,377)	$ (2,995,903)	$ (2,804,329)	**$ (31,110,853)**
2	Secondary	$ (1,611,755)	$ (1,572,262)	$ (1,544,484)	$ (1,571,177)	$ (2,024,775)	$ (2,092,239)	$ (2,051,996)	$ (2,113,321)	$ (1,977,898)	$ (1,922,992)	$ (1,923,761)	$ (1,980,418)	$ (1,964,897)	**$ (24,351,976)**
3	Primary	$ (846,288)	$ (816,204)	$ (824,128)	$ (844,123)	$ (1,011,969)	$ (1,017,967)	$ (1,022,170)	$ (1,048,722)	$ (975,499)	$ (1,003,263)	$ (939,305)	$ (949,734)	$ (917,741)	**$ (12,217,112)**
4	Primary Substation	$ (175,778)	$ (173,223)	$ (174,659)	$ (178,442)	$ (174,879)	$ (180,123)	$ (177,836)	$ (178,324)	$ (175,070)	$ (173,223)	$ (167,322)	$ (169,467)	$ (166,756)	**$ (2,265,103)**
5	High Voltage	$ (283,076)	$ (289,000)	$ (292,506)	$ (293,170)	$ (348,943)	$ (299,507)	$ (424,030)	$ (368,342)	$ (358,069)	$ (321,634)	$ (255,209)	$ (314,685)	$ (305,953)	**$ (4,154,125)**
6	Private Outdoor Lighting	$ (2,240)	$ (2,232)	$ (2,232)	$ (2,226)	$ (2,257)	$ (2,264)	$ (2,261)	$ (2,258)	$ (2,258)	$ (2,246)	$ (2,251)	$ (2,259)	$ (2,247)	**$ (29,230)**
7	Schools	$ (20,755)	$ (19,914)	$ (18,232)	$ (17,426)	$ (37,929)	$ (34,346)	$ (34,932)	$ (46,709)	$ (39,282)	$ (37,114)	$ (35,876)	$ (43,533)	$ (41,741)	**$ (427,786)**
8	Street Lighting	$ (4,330)	$ (4,328)	$ (4,335)	$ (4,322)	$ (2,441)	$ (2,439)	$ (2,440)	$ (2,436)	$ (2,437)	$ (2,435)	$ (2,434)	$ (2,429)	$ (2,432)	**$ (39,237)**
9	**Total TCRR-N**	**$ (6,783,041)**	**$ (5,998,467)**	**$ (5,314,844)**	**$ (4,859,923)**	**$ (5,450,541)**	**$ (5,845,944)**	**$ (5,741,559)**	**$ (5,913,974)**	**$ (5,096,455)**	**$ (5,213,614)**	**$ (5,712,535)**	**$ (6,458,428)**	**$ (6,206,097)**	**$ (74,595,422)**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Monthly (Over) / Under Recovery

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

		Prior Period	2014											2015			
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		$5,647,437	$5,318,725	$5,184,616	$5,236,975	$5,285,834	$5,446,391	$5,542,160	$5,407,721	$5,418,719	$5,307,255	$5,479,333	$5,351,648	$4,997,965	$69,624,779	Schedule D-1, Col (C) + Col (D)
2	Revenues		($6,783,041)	($5,998,467)	($5,314,844)	($4,859,923)	($5,450,541)	($5,845,944)	($5,741,559)	($5,913,974)	($5,096,455)	($5,213,614)	($5,712,535)	($6,458,428)	($6,206,097)	($74,595,422)	Schedule D-1, Col (E)
3	(Over)/ Under Recovery		($1,135,604)	($679,743)	($130,228)	$377,052	($164,707)	($399,553)	($199,399)	($506,253)	$322,265	$93,641	($233,202)	($1,106,780)	($1,208,131)	($4,970,643)	Line 1 + Line 2
4	Carrying Costs		$22,472	$18,826	$17,235	$17,815	$18,325	$17,239	$16,076	$14,689	$14,371	$15,286	$15,062	$12,364	$7,647	$207,409	Schedule D-1, Col (F)
5	(Over)/ Under Recovery with Carrying Costs		($1,113,132)	($660,916)	($112,992)	$394,867	($146,382)	($382,314)	($183,323)	($491,564)	$336,635	$108,928	($218,140)	($1,094,416)	($1,200,484)	($4,763,234)	Line 3 + Line 4
6	YTD Under Recovery (without Carrying Costs)		$4,887,759	$4,230,489	$4,119,087	$4,513,374	$4,366,481	$3,985,254	$3,803,093	$3,312,917	$3,649,870	$3,757,882	$3,539,967	$2,448,249	$1,252,482	$1,052,720	Line 3 + Line 7
7	**YTD Under Recovery**	**6,023,363**	**$4,910,231**	**$4,249,315**	**$4,136,322**	**$4,531,189**	**$4,384,807**	**$4,002,492**	**$3,819,169**	**$3,327,606**	**$3,664,241**	**$3,773,169**	**$3,555,029**	**$2,460,613**	**$1,260,129**	**$1,260,129**	Line 5 + Line 7

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Transmission Cost Recovery Rider - Non-Bypassable

Workpapers

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Computation of Gross Revenue Conversion Factor

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

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	1.003	Line 1 / Line 3

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

June 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
1	**TCRR-N Costs & Revenues**			
2	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
3	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
4	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
5	Black Start Service	$ 18,070	NA	**$ 18,070**
6	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
7	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
8	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
9	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
10	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
11	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
13	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
14	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
15	Generation Deactivation	$ -	NA	**$ -**
16	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
17	TCRR-N Deferral carrying costs (WPC-1b)			**$ 6,187**
18				
19	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,310,046**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

July 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
20	**TCRR-N Costs & Revenues**			
21	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
22	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
23	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
24	Black Start Service	$ 18,070	NA	**$ 18,070**
25	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
26	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
27	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
28	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
29	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
30	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
31	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
32	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
33	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
34	Generation Deactivation	$ -	NA	**$ -**
35	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
36	TCRR-N Deferral carrying costs (WPC-1b)			**$ 5,105**
37				
38	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,308,964**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

August 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
39	**TCRR-N Costs & Revenues**			
40	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
41	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
42	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
43	Black Start Service	$ 18,070	NA	**$ 18,070**
44	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
45	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
46	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
47	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
48	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
49	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
50	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
51	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
52	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
53	Generation Deactivation	$ -	NA	**$ -**
54	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
55	TCRR-N Deferral carrying costs (WPC-1b)			**$ 2,276**
56				
57	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,306,134**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

September 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
58	**TCRR-N Costs & Revenues**			
59	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
60	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
61	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
62	Black Start Service	$ 18,070	NA	**$ 18,070**
63	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
64	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
65	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
66	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
67	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
68	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
69	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
70	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
71	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
72	Generation Deactivation	$ -	NA	**$ -**
73	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
74	TCRR-N Deferral carrying costs (WPC-1b)			**$ (265)**
75				
76	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,303,594**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

October 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
77	**TCRR-N Costs & Revenues**			
78	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
79	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
80	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
81	Black Start Service	$ 18,070	NA	**$ 18,070**
82	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
83	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
84	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
85	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
86	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
87	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
88	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
89	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
90	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
91	Generation Deactivation	$ -	NA	**$ -**
92	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
93	TCRR-N Deferral carrying costs (WPC-1b)			**$ (313)**
94				
95	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,303,546**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

November 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
96	**TCRR-N Costs & Revenues**			
97	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
98	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
99	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
100	Black Start Service	$ 18,070	NA	**$ 18,070**
101	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
102	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
103	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
104	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
105	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
106	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
107	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
108	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
109	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
110	Generation Deactivation	$ -	NA	**$ -**
111	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
112	TCRR-N Deferral carrying costs (WPC-1b)			**$ 1,494**
113				
114	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,305,353**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

December 2015 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	**Total Net Costs** (E) = (C)+(D)
115	**TCRR-N Costs & Revenues**			
116	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
117	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
118	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
119	Black Start Service	$ 18,070	NA	**$ 18,070**
120	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
121	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
122	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
123	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
124	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
125	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
126	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
127	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
128	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
129	Generation Deactivation	$ -	NA	**$ -**
130	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
131	TCRR-N Deferral carrying costs (WPC-1b)			**$ 2,575**
132				
133	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,306,433**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

January 2016 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
134	**TCRR-N Costs & Revenues**			
135	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
136	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
137	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
138	Black Start Service	$ 18,070	NA	**$ 18,070**
139	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
140	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
141	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
142	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
143	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
144	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
145	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
146	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
147	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
148	Generation Deactivation	$ -	NA	**$ -**
149	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
150	TCRR-N Deferral carrying costs (WPC-1b)			**$ 1,058**
151				
152	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,304,916**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original — Workpaper C-1a
Work Paper Reference No(s).: WPC-1b — Page 9 of 12

February 2016 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
153	**TCRR-N Costs & Revenues**			
154	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
155	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
156	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
157	Black Start Service	$ 18,070	NA	**$ 18,070**
158	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
159	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
160	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
161	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
162	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
163	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
164	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
165	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
166	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
167	Generation Deactivation	$ -	NA	**$ -**
168	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
169	TCRR-N Deferral carrying costs (WPC-1b)			**$ (1,823)**
170				
171	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,302,036**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

Workpaper C-1a

March 2016 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
172	**TCRR-N Costs & Revenues**			
173	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
174	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
175	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
176	Black Start Service	$ 18,070	NA	**$ 18,070**
177	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
178	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
179	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
180	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
181	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
182	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
183	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
184	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
185	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
186	Generation Deactivation	$ -	NA	**$ -**
187	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
188	TCRR-N Deferral carrying costs (WPC-1b)			**$ (3,283)**
189				
190	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,300,576**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original — Workpaper C-1a
Work Paper Reference No(s).: WPC-1b — Page 11 of 12

April 2016 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Total Net Costs (E) = (C)+(D)
191	**TCRR-N Costs & Revenues**			
192	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
193	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
194	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
195	Black Start Service	$ 18,070	NA	**$ 18,070**
196	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
197	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
198	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
199	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
200	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
201	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
202	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
203	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
204	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
205	Generation Deactivation	$ -	NA	**$ -**
206	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
207	TCRR-N Deferral carrying costs (WPC-1b)			**$ (2,982)**
208				
209	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,300,876**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Charges and Revenues
June 2015 - May 2016
(Revenue)/Expense in $

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

May 2016 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	**Total Net Costs** (E) = (C)+(D)
210	**TCRR-N Costs & Revenues**			
211	Transmission Enhancement Charges (RTEP)	$ 976,840	NA	**$ 976,840**
212	Incremental Capacity Transfer Rights Credit	NA	$ -	**$ -**
213	Reactive Supply and Voltage Control from Gen Sources	$ 598,052	NA	**$ 598,052**
214	Black Start Service	$ 18,070	NA	**$ 18,070**
215	TO Scheduling System Control and Dispatch Service	$ 99,754	NA	**$ 99,754**
216	NERC/RFC Charges	$ 35,833	NA	**$ 35,833**
217	Firm PTP Transmission Service Credits	NA	$ (37)	**$ (37)**
218	Non-Firm PTP Transmission Service Credits	NA	$ (6,543)	**$ (6,543)**
219	Network Integration Transmission Service	$ 3,252,478	NA	**$ 3,252,478**
220	Expansion Cost Recovery Charges (ECRC)	$ -	NA	**$ -**
221	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 299,498	NA	**$ 299,498**
222	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,467	NA	**$ 3,467**
223	Load Response Charge Allocation	$ 26,448	NA	**$ 26,448**
224	Generation Deactivation	$ -	NA	**$ -**
225	TCRR-N SubTotal	$ 5,310,439	$ (6,580)	**$ 5,303,859**
226	TCRR-N Deferral carrying costs (WPC-1b)			**$ (1,223)**
227				
228	**Total TCRR-N including carrying costs**	$ 5,310,439	$ (6,580)	**$ 5,302,635**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Calculation of Carrying Costs - TCRR-N
January 2015 - May 2016 (Over) / Under Recovery

Data: Actual and Forecasted
Type of Filing: Original
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 @ 4.94%	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) * (4.94% / 12)	(I) = (G) + (H)	(J) = (G)	(K) = - (F) * .5	(L) = (J) + (K)
1	Feb-14	6,023,363.09	$5,647,437	(6,783,041.17)	(1,135,604.38)	4,887,758.71	22,472.36	4,910,231.08	4,887,758.71	567,802.19	5,455,560.90
2	Mar-14	4,910,231.08	$5,318,725	(5,998,467.46)	(679,742.51)	4,230,488.57	18,826.07	4,249,314.64	4,230,488.57	339,871.25	4,570,359.82
3	Apr-14	4,249,314.64	$5,184,616	(5,314,843.52)	(130,227.83)	4,119,086.81	17,235.42	4,136,322.23	4,119,086.81	65,113.92	4,184,200.73
4	May-14	4,136,322.23	$5,236,975	(4,859,923.08)	377,051.78	4,513,374.01	17,814.77	4,531,188.78	4,513,374.01	(188,525.89)	4,324,848.12
5	Jun-14	4,531,188.78	$5,285,834	(5,450,541.44)	(164,707.43)	4,366,481.35	18,325.49	4,384,806.84	4,366,481.35	82,353.72	4,448,835.06
6	Jul-14	4,384,806.84	$5,446,391	(5,845,943.87)	(399,553.33)	3,985,253.51	17,238.84	4,002,492.34	3,985,253.51	199,776.67	4,185,030.17
7	Aug-14	4,002,492.34	$5,542,160	(5,741,558.98)	(199,399.17)	3,803,093.17	16,076.25	3,819,169.42	3,803,093.17	99,699.59	3,902,792.76
8	Sep-14	3,819,169.42	$5,407,721	(5,913,973.79)	(506,252.80)	3,312,916.63	14,689.13	3,327,605.75	3,312,916.63	253,126.40	3,566,043.03
9	Oct-14	3,327,605.75	$5,418,719	(5,096,454.73)	322,264.70	3,649,870.46	14,370.69	3,664,241.15	3,649,870.46	(161,132.35)	3,488,738.11
10	Nov-14	3,664,241.15	$5,307,255	(5,213,614.16)	93,641.32	3,757,882.47	15,286.48	3,773,168.96	3,757,882.47	(46,820.66)	3,711,061.81
11	Dec-14	3,773,168.96	$5,479,333	(5,712,534.79)	(233,201.83)	3,539,967.12	15,062.01	3,555,029.14	3,539,967.12	116,600.92	3,656,568.04
12	Jan-15	3,555,029.14	$5,351,648	(6,458,428.24)	(1,106,780.44)	2,448,248.69	12,364.25	2,460,612.94	2,448,248.69	553,390.22	3,001,638.92
13	Feb-15	2,460,612.94	$4,997,965	(6,206,096.62)	(1,208,131.41)	1,252,481.54	7,647.43	1,260,128.97	1,252,481.54	604,065.70	1,856,547.24
14	Mar-15	1,260,128.97	$5,424,434	(5,835,023.77)	(410,589.40)	849,539.57	4,345.04	853,884.60	849,539.57	205,294.70	1,054,834.27
15	Apr-15	853,884.60	$5,271,043	(5,017,912.26)	253,130.69	1,107,015.29	4,038.64	1,111,053.93	1,107,015.29	(126,565.35)	980,449.95
16	May-15	1,111,053.93	$5,472,140	(5,112,787.18)	359,353.31	1,470,407.24	5,316.73	1,475,723.97	1,470,407.24	(179,676.65)	1,290,730.58
17	Jun-15	1,475,723.97	$5,303,859	(5,251,119.19)	52,739.38	1,528,463.35	6,187.37	1,534,650.72	1,528,463.35	(26,369.69)	1,502,093.66
18	Jul-15	1,534,650.72	$5,303,859	(5,894,301.35)	(590,442.78)	944,207.94	5,105.42	949,313.36	944,207.94	295,221.39	1,239,429.33
19	Aug-15	949,313.36	$5,303,859	(6,097,523.10)	(793,664.53)	155,648.83	2,275.76	157,924.59	155,648.83	396,832.26	552,481.09
20	Sep-15	157,924.59	$5,303,859	(5,748,260.77)	(444,402.20)	(286,477.60)	(264.77)	(286,742.37)	(286,477.60)	222,201.10	(64,276.51)
21	Oct-15	(286,742.37)	$5,303,859	(4,882,241.78)	421,616.79	134,874.42	(312.78)	134,561.64	134,874.42	(210,808.40)	(75,933.97)
22	Nov-15	134,561.64	$5,303,859	(4,847,372.46)	456,486.11	591,047.75	1,494.45	592,542.20	591,047.75	(228,243.06)	362,804.69
23	Dec-15	592,542.20	$5,303,859	(5,238,875.09)	64,983.48	657,525.68	2,574.62	660,100.30	657,525.68	(32,491.74)	625,033.94
24	Jan-16	660,100.30	$5,303,859	(6,110,514.62)	(806,656.05)	(146,555.75)	1,057.69	(145,498.06)	(146,555.75)	403,328.02	256,772.28
25	Feb-16	(145,498.06)	$5,303,859	(5,897,762.27)	(593,903.70)	(739,401.76)	(1,822.52)	(741,224.28)	(739,401.76)	296,951.85	(442,449.91)
26	Mar-16	(741,224.28)	$5,303,859	(5,415,181.05)	(111,322.48)	(852,546.76)	(3,282.50)	(855,829.26)	(852,546.76)	55,661.24	(796,885.52)
27	Apr-16	(855,829.26)	$5,303,859	(5,040,280.81)	263,577.76	(592,251.50)	(2,982.44)	(595,233.95)	(592,251.50)	(131,788.88)	(724,040.38)
28	May-16	(595,233.95)	$5,303,859	(4,707,401.21)	596,457.36	1,223.41	(1,223.41)	(0.00)	1,223.41	(298,228.68)	(297,005.27)
29											
30						"Current cycle" carrying costs	8,806.87				

* The January 2016 First of Month Balance will include the remaining TCRR-B under/over recovery, which is currently forecasted to be zero.

The Dayton Power and Light Company
Case No. 15-0361-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).: None

Workpaper C-2

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)
		Internal Documents		Internal Documents		Internal Documents	
1	**Tariff Class**						
2	Residential	444,015,420	38.40%	1,155,367	41.53%	975,184	41.68%
3	Secondary	327,785,385	28.35%	929,607	33.41%	727,597	31.10%
4	Primary	239,470,793	20.71%	453,638	16.30%	407,116	17.40%
5	Primary Substation	53,511,925	4.63%	79,265	2.85%	82,150	3.51%
6	High Voltage	79,664,002	6.89%	151,351	5.44%	133,121	5.69%
7	Private Outdoor Lighting	2,370,626	0.21%	0	0.00%	3,076	0.13%
8	School	5,032,320	0.44%	12,992	0.47%	10,802	0.46%
9	Street Lighting	4,515,728	0.39%	0	0.00%	478	0.02%
10	**Total**	**1,156,366,199**	**100.00%**	**2,782,221**	**100.00%**	**2,339,524**	**100.00%**

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
Projected Monthly Billing Determinants
June 2015 - May 2016
kWh / kW / kVar

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

Workpaper C-3
Page 1 of 1

			2015 Forecast							2016 Forecast						
Line	Tariff Class	Units	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Total Forecast June '15 - May '16	
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
1	Residential	kWh	382,327,978	470,621,348	451,887,942	435,695,513	319,150,403	358,268,285	475,663,415	597,116,052	591,547,957	508,014,353	408,782,838	329,108,952	5,328,185,036	kWh
2	Secondary[1]	0-1500 kWh	41,806,751	42,993,124	46,572,429	43,777,308	42,195,502	42,927,291	43,602,730	45,243,254	41,799,400	44,126,123	43,467,193	42,393,411	520,904,516	kWh
3		>1500 kWh	291,894,436	325,725,144	342,674,097	315,078,409	274,592,855	256,860,033	259,764,222	291,803,987	273,601,525	262,225,922	257,150,765	261,148,710	3,412,520,105	kWh
4		0-5 kW	231,131	232,920	251,659	234,489	236,370	237,803	228,205	226,982	208,504	226,820	232,465	237,236	2,784,584	kW
5		>5 kW	948,300	973,413	1,033,638	979,779	934,114	900,400	848,834	851,941	823,844	871,800	874,749	919,121	10,959,932	kW
6	Primary	kWh	249,955,671	264,422,376	276,462,099	259,082,115	252,055,232	230,704,850	219,368,902	229,381,510	220,506,935	214,043,411	226,584,087	231,082,329	2,873,649,517	kWh
7		kW	536,666	554,339	583,907	546,355	530,271	512,906	483,029	476,107	461,799	472,627	488,582	508,875	6,155,464	kW
8		kVar	312,414	320,357	332,833	308,691	302,199	293,253	279,464	277,824	280,980	282,351	288,642	298,395	3,577,402	kVar
9	Primary Substation	kWh	56,988,052	61,730,117	62,274,420	57,061,774	56,801,842	58,099,770	45,776,796	52,219,588	46,541,594	44,338,178	49,706,061	50,604,913	642,143,105	kWh
10		kW	97,336	102,267	106,608	96,765	95,915	94,836	89,563	91,729	83,692	88,023	88,248	93,388	1,128,371	kW
11		kVar	52,545	57,540	59,327	54,071	53,672	53,058	49,133	51,203	48,026	49,540	53,771	51,907	633,793	kVar
12	High Voltage	kWh	85,125,860	79,801,659	107,862,648	90,612,914	84,287,817	75,412,422	61,448,968	75,245,120	71,722,084	69,672,054	77,485,770	77,290,713	955,968,029	kWh
13		kW	162,096	142,456	213,176	166,780	165,218	150,292	116,029	137,976	131,436	138,236	141,291	150,358	1,815,344	kW
14		kVar	67,894	58,496	91,886	70,779	69,564	59,561	44,202	55,675	54,743	73,529	74,778	60,298	781,405	kVar
15	Private Outdoor Lighting[2]	kWh	2,391,824	2,471,551	2,588,201	2,342,956	2,364,021	2,370,168	2,309,455	2,311,341	2,216,667	2,321,644	2,360,973	2,398,711	28,447,513	kWh
16	School	kWh	3,715,780	3,340,066	3,849,890	16,572,761	4,219,186	3,577,558	3,808,687	4,134,350	4,416,873	4,591,487	3,821,412	4,339,784	60,387,834	kWh
17	Streetlighting	kWh	4,566,383	4,699,977	4,930,873	4,467,060	4,515,013	4,532,441	4,420,903	4,415,294	4,189,690	4,393,622	4,493,644	4,563,839	54,188,739	kWh
	Total kWh		1,118,772,735	1,255,805,362	1,299,102,599	1,224,690,810	1,040,181,871	1,032,752,818	1,116,164,078	1,301,870,496	1,256,542,725	1,153,726,794	1,073,852,743	1,002,931,362	13,876,394,394	kWh
	Total kW		1,744,398	1,772,475	1,937,329	1,789,680	1,725,518	1,658,434	1,537,455	1,557,752	1,500,771	1,570,687	1,592,870	1,671,743	20,059,112	kW
	Total kVar		432,853	436,392	484,046	433,541	425,434	405,872	372,799	384,703	383,748	405,420	417,192	410,600	4,992,599	kVar

[1] Secondary customers are charged for all kW over 5kW of Billing Demand
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage.

The Dayton Power and Light Company
Case No. 15-0361-EL-RDR
TCRR-N Rate - Calculation of Private Outdoor Lighting Charges

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

Line	Description	kWh / Fixture	Jun '15 - May '16	Source
(A)	(B)	(C)	(D)	(E)
1	**Private Outdoor Lighting Rate ($/kWh)**		$0.0004856	Schedule C-3
2				
3	**Private Outdoor Lighting Charge ($/Fixture/Month)**			
4	9500 Lumens High Pressure Sodium	39	$0.0189384	Line 1 * Col (C) Line 4
5	28000 Lumens High Pressure Sodium	96	$0.0466176	Line 1 * Col (C) Line 5
6	7000 Lumens Mercury	75	$0.0364200	Line 1 * Col (C) Line 6
7	21000 Lumens Mercury	154	$0.0747824	Line 1 * Col (C) Line 7
8	2500 Lumens Incandescent	64	$0.0310784	Line 1 * Col (C) Line 8
9	7000 Lumens Fluorescent	66	$0.0320496	Line 1 * Col (C) Line 9
10	4000 Lumens PT Mercury	43	$0.0208808	Line 1 * Col (C) Line 10

The Dayton Power and Light Company
Case No. 15-361-EL-RDR
Transmission Cost Recovery Rider – Non-Bypassable

Biennial Attachment

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
The Dayton Power and Light Company to	)	Case No. 15-0361-EL-RDR
Update its Transmission Cost Recovery Rider	)	
and PJM RPM Rider.		

TRANSMISSION COST RECOVERY RIDER NONBYPASSABLE – BIENNIAL ATTACHMENT

Pursuant to Section 4901:1-36-06 of the Ohio Administrative Code, The Dayton Power and Light Company ("DP&L" or "the Company") submits the following information detailing the electric utility's policies and procedures for minimizing costs over which the Company has control in the Transmission Cost Recovery Rider Nonbypassable ("TCRR-N").

As part of the Opinion and Order in Case 12-426-EL-SSO, the Public Utilities Commission of Ohio ("PUCO") approved DP&L's proposal to bifurcate the Transmission Cost Recovery Rider into market-based and nonmarket-based elements. The TCRR-N includes the nonmarket elements that are cost based and contained in the Company's FERC approved tariff rates. Descriptions of the charges included within the TCRR-N are set forth below:

1. <u>Network Integration Transmission Service (NITS)</u>

Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. All network customers in the AP zone receive rebates to hold them harmless from the network rate conversion upon PJM integration. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC.

2. Transmission Enhancement Charges (RTEP)

All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates.

3. Transmission Owner Scheduling, System Control and Dispatch Service

All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM.

4. Reactive Supply and Voltage Control from Generation and Other Sources Service

All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM.

5. Black Start Service

All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM.

6. Michigan-Ontario Interface Phase Angle Regulators (Schedule 10)

Schedule 10 recovers the costs allocated to PJM from MISO for a portion of the revenue requirement associated with the ITC Transmission's Phase Angle Regulators (PARs) on the Michigan-Ontario Interface.

7. PJM Scheduling, System Control & Dispatch Service (Schedules 1, 9-1 through 9-6)

PJM's monthly operating expenses are allocated to PJM members on an unbundled basis. Charge refunds are provided in the year following any year in which there is an over collection of PJM's monthly operating expenses.

8. PJM Settlement, Inc. (Schedule 9)

Jan-Mar 2015 rate of $0.0044/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.

Since DP&L is assessed these costs based on the Company's load and its cost based FERC approved tariffs, the Company has no control over the costs levels.

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Commission of Ohio Docketing Information System on

3/16/2015 4:18:38 PM

in

Case No(s). 15-0361-EL-RDR

Summary: Application of The Dayton Power and Light Company to update its Transmission Cost Recovery Rider - Non-Bypassable electronically filed by Mr. Robert J Adams on behalf of The Dayton Power and Light Company