BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company to Update its Transmission Cost Recovery Rider – Non-Bypassable	)))))	 Case No. 14-0358-EL-RDR
In the Matter of the Application of The Dayton Power and Light Company for the Waiver of Certain Commission Rules	))))	 Case No. 14-0423-EL-WVR

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

The Dayton Power and Light Company ("DP&L" or "the Company") hereby submits this amended 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).

1. DP&L filed its original application in this proceeding on March 15, 2014, seeking to update its TCRR-N, which is designed to recover transmission-related costs imposed on or charged to the Company by FERC or PJM, such as Network Integration Transmission Service. DP&L incorporates, as if fully rewritten herein, its initial Application, except to the extent modified by this Amended Application.

2. The preparation of the quarterly adjusted Transmission Cost Recovery Rider – Bypassable ("TCRR-B") revealed the need to amend the original TCRR-N true-up application. This amended application will promote stable, predictable, and fair rates. Without this amendment, customers will experience a significant spike in TCRR-B rates and the Company may not be able to fully recover its expenses. The TCRR-B has a large under-collection that would result in a prohibitively large rate increase in order to recover

these unforeseeable costs incurred by the Company. Such a rate increase would be detrimental to both the Company and its customers. While DP&L seeks to avoid sudden, sharp increases in customer rates, any extension of the overall recovery period places the Company's ability to ever recover these costs at risk. Even if the deferral balance is eventually recovered, it will likely be from very few remaining customers and would likely include years of carrying charges. DP&L therefore encourages the Commission to adopt a flexible regulatory approach as described below, which would be consistent with the policy goal set forth in section 4928.02 (G) of the Ohio Revised Code. This approach is in the public interest, and represents a reasonable balancing of important interests of both customers and the Company on an issue that would otherwise result in an adverse outcome for ratepayers. The Commission has the option of providing flexible regulatory treatment within a competitive market, and it should do so in this instance, as the approach being proposed is just and reasonable.

3. In its latest Electric Security Plan (ESP), Case No. 12-426-EL-SSO, the Company requested and received a stop-gap measure for its other quarterly riders 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"). The Company's TCRR-B is no different than the other quarterly true-up riders that were approved for this treatment. As the Commission did not provide guidance as to how an excessive TCRR-B deferral should be treated, the Company is proposing to include the deferral amount that exceeds the 10% threshold of the TCRR-B base costs in the TCRR-N. This methodology is a reasonable, balanced solution, as it is consistent with the rate treatment of DP&L's other quarterly true-up riders, it mitigates rate impacts for

customers, and ensures DP&L recovers its costs in a reasonable and timely manner. This amended TCRR-N application reflects this updated methodology.

4. Additionally, DP&L is proposing a new rate design for its Secondary class in this filing. The historically-based rate design previously used needed to be updated to accurately reflect the cost components in the TCRR-N. While this has caused some cost shifting within the Secondary class, this new rate design more appropriately aligns costs with the customers that cause those costs, and the overall bill impacts due to the rate re-design are immaterial.

5. Pursuant to O.A.C. §4901:1-36-03(B), the information listed below is being provided in support of this Amended 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-5	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

6. 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.

WHEREFORE, DP&L respectfully requests that the Commission approve its Amended Application with new tariff rates for its TCRR-N to be made effective on a bills-rendered basis beginning on June 1, 2014.

Respectfully submitted,

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Attorney for The Dayton Power and Light Company

The Dayton Power and Light Company
Case No. 14-0358-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

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	$0.0058230 per kWh

Residential Heating:

Energy Charge	$0.0058230 per kWh

Secondary:

Demand Charge	$1.9286593 per kW for all kW over 5 kW of Billing Demand
Energy Charge	$0.0097253 per kWh for the first 1,500 kWh $0.0005918 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 $0.0152147 per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge	$1.7967581 per kW for all kW of Billing Demand
Energy Charge	$0.0005918 per kWh
Reactive Demand Charge	$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 $0.0142855 per kWh in lieu of the above demand and energy charges.

Primary-Substation:

Demand Charge	$1.6519697 per kW for all kW of Billing Demand

Energy Charge	$0.0005918 per kWh
Reactive Demand Charge	$0.3923485 per kVar for all kVar of Billing Demand

High Voltage:

Demand Charge	$2.0555784 per kW for all kW of Billing Demand
Energy Charge	$0.0005918 per kWh
Reactive Demand Charge	$0.5077477 per kVar for all kVar of Billing Demand

Private Outdoor Lighting:

9,500 Lumens High Pressure Sodium	$0.0585429	/lamp/month
28,000 Lumens High Pressure Sodium	$0.1441056	/lamp/month
7,000 Lumens Mercury	$0.1125825	/lamp/month
21,000 Lumens Mercury	$0.2311694	/lamp/month
2,500 Lumens Incandescent	$0.0960704	/lamp/month
7,000 Lumens Fluorescent	$0.0990726	/lamp/month
4,000 Lumens PT Mercury	$0.0645473	/lamp/month

School:

Energy Charge	$0.0102269 per kWh

Street Lighting:

Energy Charge	$0.0006634 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. 14-0358-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

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

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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.

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ELECTRIC TRANSMISSION SERVICE
TRANSMISSION COST RECOVERY RIDER – NON-BYPASSABLE (TCRR-N)

CHARGES:

Residential:

Energy Charge $0.0058230~~0.0060153~~ per kWh

Residential Heating:

Energy Charge $0.0058230~~0.0060153~~ per kWh

Secondary:

Demand Charge $1.9286593~~1.6141635~~ per kW for all kW over 5 kW of Billing Demand

Energy Charge $0.0097253~~0.0041156~~ per kWh for the first 1,500 kWh
$0.0005918 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 $0.0152147 per kWh for all kWh in lieu of the above demand and energy charges.

Primary:

Demand Charge $1.7967581~~1.2362301~~ per kW for all kW of Billing Demand

Energy Charge $0.0005918~~0.0005466~~ per kWh

Reactive Demand Charge $0.3481988~~0.3379277~~ 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 $0.0142855 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~~14-358-EL-RDR dated ~~September 6, 2013~~__________, 2014 of the Public Utilities Commission of Ohio.

Issued ~~December 30, 2013~~__________, 2014 Effective ~~January~~June 1, 2014

Issued by
DEREK A. PORTER, President

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

Primary-Substation:

Demand Charge $1.6519697~~1.4074489~~ per kW for all kW of Billing Demand

Energy Charge $0.0005918~~0.0005466~~ per kWh

Reactive Demand Charge $0.3923485~~0.4141226~~ per kVar for all kVar of Billing Demand

High Voltage:

Demand Charge $2.0555784~~1.4858240~~ per kW for all kW of Billing Demand

Energy Charge $0.0005918~~0.0005466~~ per kWh

Reactive Demand Charge $0.5077477~~0.5150524~~ per kVar for all kVar of Billing Demand

Private Outdoor Lighting:

9,500 Lumens High Pressure Sodium	$0.0585429~~0.0372060~~	/lamp/month
28,000 Lumens High Pressure Sodium	$0.1441056~~0.0915840~~	/lamp/month
7,000 Lumens Mercury	$0.1125825~~0.0715500~~	/lamp/month
21,000 Lumens Mercury	$0.2311694~~0.1469160~~	/lamp/month
2,500 Lumens Incandescent	$0.0960704~~0.0610560~~	/lamp/month
7,000 Lumens Fluorescent	$0.0990726~~0.0629640~~	/lamp/month
4,000 Lumens PT Mercury	$0.0645473~~0.0410220~~	/lamp/month

School:

Energy Charge $0.0102269~~0.0040503~~ per kWh

Street Lighting:

Energy Charge $0.0006634~~0.0009590~~ per kWh

Filed pursuant to the Opinion and Order in Case No. ~~12-426-EL-SSO~~14-358-EL-RDR dated ~~September 6, 2013~~__________, 2014 of the Public Utilities Commission of Ohio.

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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. 14-0358-EL-RDR
Summary of Projected Jurisdictional Net Costs
June 2014 - May 2015
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Revised
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 2014 - May 2015 (D)
				Schedule C-1, Col (U)
	TCRR-N Costs			
1	Transmission Enhancement Charges (RTEP)	Demand - 1 CP	$	9,595,968
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$	(278,797)
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand	$	7,138,467
4	Black Start Service	Demand - 12 CP	$	209,114
5	TO Scheduling System Control and Dispatch Service	Energy	$	1,141,919
6	NERC/RFC Charges	Energy	$	355,207
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$	(4,669)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$	(47,205)
9	Network Integration Transmission Service	Demand - 1 CP	$	40,580,806
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$	184,205
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$	4,879,163
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$	37,688
13	Load Response Charge Allocation	Energy	$	22,100
14	Generation Deactivation	Demand - 1 CP	$	-
15	TCRR-N SubTotal		$	63,813,967
16	Projected TCRR-N Reconciliation		$	17,328,861
17	Projected TCRR-N Deferral Carrying Costs		$	375,312
18	TCRR-N SubTotal with Deferral		$	81,518,140
19	Gross Revenue Conversion Factor (WPB-1)			1.003
20				
21	**Total TCRR-N Recovery (Line 18 * Line 19)**		**$**	**81,762,695**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Summary of Current versus Proposed Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

Schedule B-2

Line (A)	Tariff Class (B)	Forecasted Distribution Billing Determinants (C) WPC-3, Col (O)		Current Rate (D) TCRR-N		Current Revenue (E) = (C) * (D)		Proposed Rate (F) Schedule C-3 TCRR-N		Proposed Revenue (G) = (C) * (F)		$ Difference (H) = (G) - (E)	% Difference (I) = (H) / (E)
	TCRR-N Rates												
1	Residential	5,367,475,927	kWh	$	0.0060153	$	32,286,978	$	0.0058230	$	31,254,812	$ (1,032,166)	-3%
2	Secondary[1]	527,831,048	0-1500 kWh	$	0.0041156	$	2,172,341	$	0.0097253	$	5,133,294		
3		3,460,764,006	>1500 kWh	$	-	$	-	$	0.0005918	$	2,048,080		
4		11,051,941	kW	$	1.6141635	$	17,839,640	$	1.9286593	$	21,315,429		
5						$	20,011,982			$	28,496,804	$ 8,484,822	42%
6	Primary	2,825,242,419	kWh	$	0.0005466	$	1,544,278	$	0.0005918	$	1,671,978		
7		6,158,220	kW	$	1.2362301	$	7,612,977	$	1.7967581	$	11,064,832		
8		3,670,699	kVar	$	0.3379277	$	1,240,431	$	0.3481988	$	1,278,133		
9						$	10,397,686			$	14,014,943	$ 3,617,258	35%
10	Substation	631,068,379	kWh	$	0.0005466	$	344,942	$	0.0005918	$	373,466		
11		1,110,235	kW	$	1.4074489	$	1,562,599	$	1.6519697	$	1,834,074		
12		626,173	kVar	$	0.4141226	$	259,312	$	0.3923485	$	245,678		
13						$	2,166,853			$	2,453,218	$ 286,365	13%
14	High Voltage	984,745,740	kWh	$	0.0005466	$	538,262	$	0.0005918	$	582,773		
15		1,910,390	kW	$	1.4858240	$	2,838,503	$	2.0555784	$	3,926,956		
16		865,983	kVar	$	0.5150524	$	446,027	$	0.5077477	$	439,701		
17						$	3,822,791			$	4,949,429	$ 1,126,638	29%
18	Private Outdoor Lighting[2]	29,250,923	kWh	$	0.0009540	$	27,905	$	0.0015011	$	43,909	$ 16,003	57%
19	School	49,949,992	kWh	$	0.0040503	$	202,312	$	0.0102269	$	510,834	$ 308,521	152%
20	Streetlighting	55,828,440	kWh	$	0.0009590	$	53,539	$	0.0006634	$	37,037	$ (16,503)	-31%
21	Total TCRR-N Rates					$	68,970,047			$	81,760,986	$ 12,790,939	

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

[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Rates are charged per fixture.

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Summary of Current and Proposed Rates
June 2014 - May 2015

Data: Actual and Forecasted
Type of Filing: Revised
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	$	0.0060153	kWh	$	0.0058230	kWh	$	(0.0001923)	-3%
2	Secondary[1]	$	0.0041156	0-1500 kWh	$	0.0097253	0-1500 kWh	$	0.0056097	136%
3		$	-	>1500 kWh	$	0.0005918	>1500 kWh	$	0.0005918	N/A
4		$	1.6141635	kW	$	1.9286593	kW	$	0.3144958	19%
5	Primary	$	0.0005466	kWh	$	0.0005918	kWh	$	0.0000452	8%
6		$	1.2362301	kW	$	1.7967581	kW	$	0.5605280	45%
7		$	0.3379277	kVar	$	0.3481988	kVar	$	0.0102711	3%
8	Substation	$	0.0005466	kWh	$	0.0005918	kWh	$	0.0000452	8%
9		$	1.4074489	kW	$	1.6519697	kW	$	0.2445208	17%
10		$	0.4141226	kVar	$	0.3923485	kVar	$	(0.0217741)	-5%
11	High Voltage	$	0.0005466	kWh	$	0.0005918	kWh	$	0.0000452	8%
12		$	1.4858240	kW	$	2.0555784	kW	$	0.5697544	38%
13		$	0.5150524	kVar	$	0.5077477	kVar	$	(0.0073047)	-1%
14	Private Outdoor Lighting[2]	$	0.0009540	kWh	$	0.0015011	kWh	$	0.0005471	57%
15	School	$	0.0040503	kWh	$	0.0102269	kWh	$	0.0061766	152%
16	Streetlighting	$	0.0009590	kWh	$	0.0006634	kWh	$	(0.0002956)	-31%

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

[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Rates are charged per fixture.

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Residential

Data: Actual and Forecasted
Type of Filing: Revised
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	$11.14	$11.13	($0.01)	-0.09%
2	0.0	100	$18.00	$17.98	($0.02)	-0.11%
3	0.0	200	$31.75	$31.71	($0.04)	-0.13%
4	0.0	400	$59.24	$59.16	($0.08)	-0.14%
5	0.0	500	$72.99	$72.89	($0.10)	-0.14%
6	0.0	750	$107.36	$107.22	($0.14)	-0.13%
7	0.0	1,000	$137.99	$137.80	($0.19)	-0.14%
8	0.0	1,200	$162.47	$162.24	($0.23)	-0.14%
9	0.0	1,400	$186.98	$186.71	($0.27)	-0.14%
10	0.0	1,500	$199.24	$198.95	($0.29)	-0.15%
11	0.0	2,000	$260.52	$260.14	($0.38)	-0.15%
12	0.0	2,500	$321.54	$321.06	($0.48)	-0.15%
13	0.0	3,000	$382.55	$381.97	($0.58)	-0.15%
14	0.0	4,000	$504.58	$503.81	($0.77)	-0.15%
15	0.0	5,000	$626.64	$625.68	($0.96)	-0.15%
16	0.0	7,500	$931.77	$930.33	($1.44)	-0.15%

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Secondary Unmetered

Data: Actual and Forecasted
Type of Filing: Revised
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	$13.44	$13.72	$0.28	2.08%
2	0.0	100	$20.20	$20.76	$0.56	2.77%
3	0.0	150	$26.98	$27.82	$0.84	3.11%
4	0.0	200	$33.73	$34.85	$1.12	3.32%
5	0.0	300	$47.23	$48.91	$1.68	3.56%
6	0.0	400	$60.78	$63.02	$2.24	3.69%
7	0.0	500	$74.29	$77.09	$2.80	3.77%
8	0.0	600	$87.82	$91.19	$3.37	3.84%
9	0.0	800	$114.85	$119.34	$4.49	3.91%
10	0.0	1,000	$141.93	$147.54	$5.61	3.95%
11	0.0	1,200	$168.98	$175.71	$6.73	3.98%
12	0.0	1,400	$196.02	$203.87	$7.85	4.00%
13	0.0	1,600	$215.34	$223.81	$8.47	3.93%
14	0.0	2,000	$238.48	$247.19	$8.71	3.65%
15	0.0	2,200	$249.96	$258.78	$8.82	3.53%
16	0.0	2,400	$261.43	$270.37	$8.94	3.42%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Secondary Single Phase

Data: Actual and Forecasted
Type of Filing: Revised
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	$110.10	$114.31	$4.21	3.82%
2	5	1,500	$211.54	$219.95	$8.41	3.98%
3	10	1,500	$291.64	$301.62	$9.98	3.42%
4	25	5,000	$733.01	$749.78	$16.77	2.29%
5	25	7,500	$876.48	$894.73	$18.25	2.08%
6	25	10,000	$1,019.93	$1,039.66	$19.73	1.93%
7	50	15,000	$1,707.38	$1,737.93	$30.55	1.79%
8	50	25,000	$2,275.63	$2,312.10	$36.47	1.60%
9	200	50,000	$6,099.30	$6,197.74	$98.44	1.61%
10	200	100,000	$8,940.50	$9,068.53	$128.03	1.43%
11	300	125,000	$11,963.15	$12,137.43	$174.28	1.46%
12	500	200,000	$19,012.78	$19,294.34	$281.56	1.48%
13	1,000	300,000	$32,150.35	$32,648.33	$497.98	1.55%
14	1,000	500,000	$42,405.11	$43,021.45	$616.34	1.45%
15	2,500	750,000	$79,254.18	$80,490.22	$1,236.04	1.56%
16	2,500	1,000,000	$91,503.34	$92,887.33	$1,383.99	1.51%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Secondary Three Phase

Data: Actual and Forecasted
Type of Filing: Revised — Schedule B-5
Work Paper Reference: None — Page 4 of 10

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	$83.62	$86.42	$2.80	3.35%
2	5	1,500	$218.88	$227.29	$8.41	3.84%
3	10	1,500	$298.98	$308.96	$9.98	3.34%
4	25	5,000	$740.35	$757.12	$16.77	2.27%
5	25	7,500	$883.82	$902.07	$18.25	2.06%
6	25	10,000	$1,027.27	$1,047.00	$19.73	1.92%
7	50	25,000	$2,282.97	$2,319.44	$36.47	1.60%
8	200	50,000	$6,106.64	$6,205.08	$98.44	1.61%
9	200	125,000	$10,368.45	$10,511.28	$142.83	1.38%
10	500	200,000	$19,020.12	$19,301.68	$281.56	1.48%
11	1,000	300,000	$32,157.69	$32,655.67	$497.98	1.55%
12	1,000	500,000	$42,412.45	$43,028.79	$616.34	1.45%
13	2,500	750,000	$79,261.52	$80,497.56	$1,236.04	1.56%
14	2,500	1,000,000	$91,510.68	$92,894.67	$1,383.99	1.51%
15	5,000	1,500,000	$155,494.17	$157,960.30	$2,466.13	1.59%
16	5,000	2,000,000	$179,426.67	$182,188.70	$2,762.03	1.54%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Primary Service

Data: Actual and Forecasted
Type of Filing: Revised
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	$226.71	$229.58	$2.87	1.27%
2	5	2,500	$305.65	$308.58	$2.93	0.96%
3	10	5,000	$515.36	$521.25	$5.89	1.14%
4	25	7,500	$883.09	$897.56	$14.47	1.64%
5	25	10,000	$1,013.84	$1,028.42	$14.58	1.44%
6	50	20,000	$1,928.94	$1,958.12	$29.18	1.51%
7	50	30,000	$2,446.35	$2,475.99	$29.64	1.21%
8	200	50,000	$5,850.68	$5,966.05	$115.37	1.97%
9	200	75,000	$7,144.18	$7,260.68	$116.50	1.63%
10	200	100,000	$8,437.70	$8,555.33	$117.63	1.39%
11	500	250,000	$20,937.77	$21,231.82	$294.05	1.40%
12	1,000	300,000	$31,422.90	$32,001.96	$579.06	1.84%
13	2,500	1,000,000	$90,766.78	$92,225.74	$1,458.96	1.61%
14	5,000	2,500,000	$202,755.76	$205,696.27	$2,940.51	1.45%
15	10,000	5,000,000	$402,567.66	$408,448.68	$5,881.02	1.46%
16	25,000	7,500,000	$760,342.43	$774,818.99	$14,476.56	1.90%
17	25,000	10,000,000	$881,172.93	$895,762.49	$14,589.56	1.66%
18	50,000	15,000,000	$1,517,740.97	$1,546,694.10	$28,953.13	1.91%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Primary Substation

Data: Actual and Forecasted
Type of Filing: Revised
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	$95,509.86	$96,256.98	$747.12	0.78%
2	5,000	2,000,000	$172,616.80	$173,877.07	$1,260.27	0.73%
3	5,000	3,000,000	$218,955.70	$220,261.17	$1,305.47	0.60%
4	10,000	4,000,000	$342,214.76	$344,735.31	$2,520.55	0.74%
5	10,000	5,000,000	$388,553.66	$391,119.41	$2,565.75	0.66%
6	15,000	6,000,000	$511,812.72	$515,593.55	$3,780.83	0.74%
7	15,000	7,000,000	$558,151.62	$561,977.65	$3,826.03	0.69%
8	15,000	8,000,000	$604,490.52	$608,361.75	$3,871.23	0.64%
9	25,000	9,000,000	$804,669.77	$810,925.95	$6,256.18	0.78%
10	25,000	10,000,000	$851,008.67	$857,310.05	$6,301.38	0.74%
11	30,000	12,500,000	$1,043,776.06	$1,051,360.31	$7,584.25	0.73%
12	30,000	15,000,000	$1,159,623.31	$1,167,320.56	$7,697.25	0.66%
13	50,000	17,500,000	$1,583,151.17	$1,595,640.93	$12,489.76	0.79%
14	50,000	20,000,000	$1,698,998.42	$1,711,601.18	$12,602.76	0.74%
15	50,000	25,000,000	$1,930,692.92	$1,943,521.68	$12,828.76	0.66%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
High Voltage Service

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

Line No.	Level of (kW)	Level of (kWh)	Total Current Bill	Total Proposed Bill	TCRR-N Dollar Variance	Total Percent Change
(A)	(B)	(C)	(D)	(E)	(F = E - D)	(G = F / D)
1	1,000	500,000	$39,850.62	$40,439.43	$588.81	1.48%
2	2,000	1,000,000	$78,852.65	$80,030.28	$1,177.63	1.49%
3	3,000	1,500,000	$116,719.61	$118,486.06	$1,766.45	1.51%
4	3,500	2,000,000	$147,206.74	$149,278.90	$2,072.16	1.41%
5	5,000	2,500,000	$192,453.41	$195,397.49	$2,944.08	1.53%
6	7,500	3,000,000	$252,459.61	$256,841.84	$4,382.23	1.74%
7	7,500	4,000,000	$298,674.41	$303,101.84	$4,427.43	1.48%
8	10,000	5,000,000	$381,787.99	$387,676.15	$5,888.16	1.54%
9	20,000	6,000,000	$575,597.92	$587,193.45	$11,595.53	2.01%
10	12,500	7,000,000	$511,116.37	$518,510.48	$7,394.11	1.45%
11	12,500	8,000,000	$557,331.17	$564,770.48	$7,439.31	1.33%
12	15,000	9,000,000	$640,444.76	$649,344.81	$8,900.05	1.39%
13	20,000	10,000,000	$760,457.12	$772,233.45	$11,776.33	1.55%
14	40,000	20,000,000	$1,517,795.46	$1,541,348.13	$23,552.67	1.55%
15	60,000	30,000,000	$2,275,133.73	$2,310,462.72	$35,328.99	1.55%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Private Outdoor Lighting

Data: Actual and Forecasted
Type of Filing: Revised
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	$12.71	$12.75	$0.04	0.31%
3	21000 -					
4	Mercury	154	$23.03	$23.11	$0.08	0.35%
5	2500 -					
6	Incandescent	64	$12.14	$12.18	$0.04	0.33%
7	7000 -					
8	Fluorescent	66	$13.60	$13.64	$0.04	0.29%
9	4000 -					
10	Mercury	43	$13.81	$13.83	$0.02	0.14%
11	9500 - High					
12	Pressure Sodium	39	$10.59	$10.61	$0.02	0.19%
13	28000 - High					
14	Pressure Sodium	96	$14.36	$14.41	$0.05	0.35%

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

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
School Rate

Data: Actual and Forecasted
Type of Filing: Revised
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	$158.49	$164.67	$6.18	3.90%
2	0.0	2,500	$337.78	$353.22	$15.44	4.57%
3	0.0	5,000	$635.74	$666.62	$30.88	4.86%
4	0.0	10,000	$1,231.71	$1,293.48	$61.77	5.01%
5	0.0	15,000	$1,827.68	$1,920.33	$92.65	5.07%
6	0.0	25,000	$3,014.02	$3,168.44	$154.42	5.12%
7	0.0	50,000	$5,979.88	$6,288.71	$308.83	5.16%
8	0.0	75,000	$8,945.68	$9,408.93	$463.25	5.18%
9	0.0	100,000	$11,911.51	$12,529.17	$617.66	5.19%
10	0.0	150,000	$17,843.22	$18,769.71	$926.49	5.19%
11	0.0	200,000	$23,774.85	$25,010.17	$1,235.32	5.20%
12	0.0	250,000	$29,706.56	$31,250.71	$1,544.15	5.20%
13	0.0	300,000	$35,638.19	$37,491.17	$1,852.98	5.20%
14	0.0	350,000	$41,569.90	$43,731.71	$2,161.81	5.20%
15	0.0	400,000	$47,501.53	$49,972.17	$2,470.64	5.20%
16	0.0	450,000	$53,433.24	$56,212.71	$2,779.47	5.20%
17	0.0	500,000	$59,364.87	$62,453.17	$3,088.30	5.20%

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Typical Bill Comparison
Street Lighting

Data: Actual and Forecasted
Type of Filing: Revised
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	$5.55	$5.54	($0.01)	-0.18%
2	0.0	100	$9.06	$9.03	($0.03)	-0.33%
3	0.0	200	$16.06	$16.00	($0.06)	-0.37%
4	0.0	400	$30.16	$30.04	($0.12)	-0.40%
5	0.0	500	$37.22	$37.07	($0.15)	-0.40%
6	0.0	750	$54.82	$54.60	($0.22)	-0.40%
7	0.0	1,000	$72.41	$72.11	($0.30)	-0.41%
8	0.0	1,200	$86.49	$86.14	($0.35)	-0.40%
9	0.0	1,400	$100.56	$100.15	($0.41)	-0.41%
10	0.0	1,600	$114.65	$114.18	($0.47)	-0.41%
11	0.0	2,000	$142.82	$142.23	($0.59)	-0.41%
12	0.0	2,500	$177.81	$177.07	($0.74)	-0.42%
13	0.0	3,000	$212.77	$211.88	($0.89)	-0.42%
14	0.0	4,000	$282.71	$281.53	($1.18)	-0.42%
15	0.0	5,000	$352.66	$351.18	($1.48)	-0.42%

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2014 - May 2015
(Revenue)/Expense in $

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

			2014 Forecast							Total Forecast
Line	Description	Type of Charge	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jun - Dec 2014
(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	$ 788,710	$ 815,000	$ 815,000	$ 788,710	$ 815,000	$ 788,710	$ 815,000	$ 5,626,129
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$ (22,915)	$ (23,679)	$ (23,679)	$ (22,915)	$ (23,679)	$ (22,915)	$ (23,679)	$ (163,459)
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand - 12 CP	$ 586,723	$ 606,281	$ 606,281	$ 586,723	$ 606,281	$ 586,723	$ 606,281	$ 4,185,293
4	Black Start Service	Demand - 12 CP	$ 17,187	$ 17,760	$ 17,760	$ 17,187	$ 17,760	$ 17,187	$ 17,760	$ 122,604
5	TO Scheduling System Control and Dispatch Service	Energy	$ 102,265	$ 108,149	$ 93,301	$ 93,973	$ 82,251	$ 85,868	$ 96,481	$ 662,289
6	NERC/RFC Charges	Energy	$ 31,811	$ 33,641	$ 29,022	$ 29,231	$ 25,585	$ 26,710	$ 30,012	$ 206,013
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$ (108)	$ (104)	$ (123)	$ (121)	$ (110)	$ (1,214)	$ (1,122)	$ (2,902)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$ (3,374)	$ (3,372)	$ (4,276)	$ (3,262)	$ (2,551)	$ (3,031)	$ (4,649)	$ (24,515)
9	Network Integration Transmission Service	Demand - 1 CP	$ 3,302,230	$ 3,412,304	$ 3,412,304	$ 3,302,230	$ 3,412,304	$ 3,302,230	$ 3,412,304	$ 23,555,905
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ 15,140	$ 15,645	$ 15,645	$ 15,140	$ 15,645	$ 15,140	$ 15,645	$ 108,000
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 436,955	$ 462,096	$ 398,655	$ 401,527	$ 351,441	$ 366,893	$ 412,242	$ 2,829,810
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 21,985
13	Load Response Charge Allocation	Energy	$ 1,816	$ 1,877	$ 1,877	$ 1,816	$ 1,877	$ 1,816	$ 1,877	$ 12,957
14	Generation Deactivation	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 5,259,582	$ 5,448,739	$ 5,364,909	$ 5,213,381	$ 5,304,946	$ 5,167,259	$ 5,381,293	$ 37,140,108
16	TCRR-N Deferral carrying costs		$ 68,009	$ 59,972	$ 50,523	$ 43,577	$ 39,700	$ 35,928	$ 29,846	$ 327,556
17										
18	Total TCRR-N Demand - 1 CP costs		$ 4,079,683	$ 4,215,794	$ 4,214,871	$ 4,079,782	$ 4,216,609	$ 4,078,920	$ 4,213,499	$ 29,099,158
19	Total TCRR-N Demand - 12 CP costs		$ 603,911	$ 624,041	$ 624,041	$ 603,911	$ 624,041	$ 603,911	$ 624,041	$ 4,307,897
20	Total TCRR-N Energy costs		$ 575,988	$ 608,904	$ 525,996	$ 529,689	$ 464,295	$ 484,428	$ 543,753	$ 3,733,053
21										
22	**Total TCRR-N including carrying costs**		**$ 5,327,591**	**$ 5,508,711**	**$ 5,415,431**	**$ 5,256,958**	**$ 5,344,646**	**$ 5,203,187**	**$ 5,411,139**	**$ 37,467,664**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Monthly Jurisdictional Net Costs
June 2014 - May 2015
(Revenue)/Expense in $

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

Line	Description	Type of Charge	2015 Forecast Jan	Feb	Mar	Apr	May	Total Forecast Jan - May 2015	Total Forecast Jun 2014 - May 2015
(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	$ 815,000	$ 736,129	$ 815,000	$ 788,710	$ 815,000	$ 3,969,839	$ 9,595,968
2	Incremental Capacity Transfer Rights Credit	Demand - 1 CP	$ (23,679)	$ (21,387)	$ (23,679)	$ (22,915)	$ (23,679)	$ (115,338)	$ (278,797)
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand - 12 CP	$ 606,281	$ 547,608	$ 606,281	$ 586,723	$ 606,281	$ 2,953,174	$ 7,138,467
4	Black Start Service	Demand - 12 CP	$ 17,760	$ 16,042	$ 17,760	$ 17,187	$ 17,760	$ 86,510	$ 209,114
5	TO Scheduling System Control and Dispatch Service	Energy	$ 109,815	$ 107,318	$ 89,270	$ 85,435	$ 87,792	$ 479,631	$ 1,141,919
6	NERC/RFC Charges	Energy	$ 34,159	$ 33,383	$ 27,769	$ 26,576	$ 27,309	$ 149,195	$ 355,207
7	Firm PTP Transmission Service Credits	Demand - 1 CP	$ (1,320)	$ (129)	$ (111)	$ (103)	$ (104)	$ (1,767)	$ (4,669)
8	Non-Firm PTP Transmission Service Credits	Demand - 1 CP	$ (4,538)	$ (4,538)	$ (4,538)	$ (4,538)	$ (4,538)	$ (22,690)	$ (47,205)
9	Network Integration Transmission Service	Demand - 1 CP	$ 3,439,514	$ 3,131,431	$ 3,494,587	$ 3,408,826	$ 3,550,542	$ 17,024,901	$ 40,580,806
10	Expansion Cost Recovery Charges (ECRC)	Demand - 1 CP	$ 15,645	$ 14,131	$ 15,645	$ 15,140	$ 15,645	$ 76,205	$ 184,205
11	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ 469,216	$ 458,546	$ 381,432	$ 365,044	$ 375,115	$ 2,049,353	$ 4,879,163
12	Michigan-Ontario Interface Phase Angle Regulators Charge	Energy	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 3,141	$ 15,703	$ 37,688
13	Load Response Charge Allocation	Energy	$ 1,877	$ 1,695	$ 1,877	$ 1,816	$ 1,877	$ 9,143	$ 22,100
14	Generation Deactivation	Demand - 1 CP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TCRR-N SubTotal		$ 5,482,872	$ 5,023,369	$ 5,424,434	$ 5,271,043	$ 5,472,140	$ 26,673,859	$ 63,813,967
16	TCRR-N Deferral carrying costs		$ 21,416	$ 13,550	$ 7,632	$ 3,836	$ 1,322	$ 47,756	$ 375,312
17									
18	Total TCRR-N Demand - 1 CP costs		$ 4,240,622	$ 3,855,637	$ 4,296,904	$ 4,185,120	$ 4,352,866	$ 20,931,150	$ 50,030,308
19	Total TCRR-N Demand - 12 CP costs		$ 624,041	$ 563,650	$ 624,041	$ 603,911	$ 624,041	$ 3,039,684	$ 7,347,581
20	Total TCRR-N Energy costs		$ 618,209	$ 604,082	$ 503,489	$ 482,012	$ 495,233	$ 2,703,025	$ 6,436,078
21									
22	**Total TCRR-N including carrying costs**		**$ 5,504,288**	**$ 5,036,919**	**$ 5,432,066**	**$ 5,274,879**	**$ 5,473,463**	**$ 26,721,615**	**$ 64,189,279**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Monthly Costs by Tariff Class
June 2014 - May 2015

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

Line	Description	Tariff Allocator	2014 Forecast							Source
			Jun	Jul	Aug	Sep	Oct	Nov	Dec	
(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**		$ 4,079,683	$ 4,215,794	$ 4,214,871	$ 4,079,782	$ 4,216,609	$ 4,078,920	$ 4,213,499	Schedule C-1, Page 1, Line 18
2	Tariff Class									
3	Residential	37.51%	$ 1,530,264	$ 1,581,319	$ 1,580,972	$ 1,530,301	$ 1,581,624	$ 1,529,978	$ 1,580,458	Col (C) * Line 1
4	Secondary	37.07%	$ 1,512,276	$ 1,562,730	$ 1,562,388	$ 1,512,312	$ 1,563,032	$ 1,511,993	$ 1,561,879	Col (C) * Line 1
5	Primary	16.30%	$ 664,808	$ 686,988	$ 686,838	$ 664,824	$ 687,121	$ 664,684	$ 686,614	Col (C) * Line 1
6	Primary Substation	2.55%	$ 103,985	$ 107,454	$ 107,431	$ 103,987	$ 107,475	$ 103,965	$ 107,396	Col (C) * Line 1
7	High Voltage	5.85%	$ 238,499	$ 246,456	$ 246,402	$ 238,505	$ 246,504	$ 238,454	$ 246,322	Col (C) * Line 1
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
9	School	0.73%	$ 29,851	$ 30,847	$ 30,840	$ 29,852	$ 30,853	$ 29,846	$ 30,830	Col (C) * Line 1
10	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
11	**Total TCRR-N Demand Costs**	100.00%	$ 4,079,683	$ 4,215,794	$ 4,214,871	$ 4,079,782	$ 4,216,609	$ 4,078,920	$ 4,213,499	Sum (Line 3 thru 10)
12										
13	**TCRR-N Demand-Based Costs - 12 CP**		$ 603,911	$ 624,041	$ 624,041	$ 603,911	$ 624,041	$ 603,911	$ 624,041	Schedule C-1, Page 1, Line 19
14	Tariff Class									
15	Residential	39.67%	$ 239,546	$ 247,531	$ 247,531	$ 239,546	$ 247,531	$ 239,546	$ 247,531	Col (C) * Line 13
16	Secondary	32.29%	$ 195,005	$ 201,505	$ 201,505	$ 195,005	$ 201,505	$ 195,005	$ 201,505	Col (C) * Line 13
17	Primary	17.85%	$ 107,806	$ 111,400	$ 111,400	$ 107,806	$ 111,400	$ 107,806	$ 111,400	Col (C) * Line 13
18	Primary Substation	3.43%	$ 20,722	$ 21,413	$ 21,413	$ 20,722	$ 21,413	$ 20,722	$ 21,413	Col (C) * Line 13
19	High Voltage	6.14%	$ 37,087	$ 38,323	$ 38,323	$ 37,087	$ 38,323	$ 37,087	$ 38,323	Col (C) * Line 13
20	Private Outdoor Lighting	0.11%	$ 688	$ 711	$ 711	$ 688	$ 711	$ 688	$ 711	Col (C) * Line 13
21	School	0.49%	$ 2,953	$ 3,051	$ 3,051	$ 2,953	$ 3,051	$ 2,953	$ 3,051	Col (C) * Line 13
22	Street Lighting	0.02%	$ 103	$ 107	$ 107	$ 103	$ 107	$ 103	$ 107	Col (C) * Line 13
23	**Total TCRR-N Demand Costs**	100.00%	$ 603,911	$ 624,041	$ 624,041	$ 603,911	$ 624,041	$ 603,911	$ 624,041	Sum (Line 15 thru 22)
24										
25	**TCRR-N Energy-Based Costs**		$ 575,988	$ 608,904	$ 525,996	$ 529,689	$ 464,295	$ 484,428	$ 543,753	Schedule C-1, Page 1, Line 20
26	Tariff Class									
27	Residential	38.53%	$ 221,904	$ 234,585	$ 202,644	$ 204,067	$ 178,874	$ 186,630	$ 209,485	Col (C) * Line 25
28	Secondary	28.63%	$ 164,898	$ 174,321	$ 150,586	$ 151,643	$ 132,922	$ 138,686	$ 155,669	Col (C) * Line 25
29	Primary	20.28%	$ 116,802	$ 123,477	$ 106,665	$ 107,413	$ 94,152	$ 98,235	$ 110,265	Col (C) * Line 25
30	Primary Substation	4.53%	$ 26,090	$ 27,581	$ 23,825	$ 23,993	$ 21,031	$ 21,943	$ 24,630	Col (C) * Line 25
31	High Voltage	7.07%	$ 40,712	$ 43,038	$ 37,178	$ 37,439	$ 32,817	$ 34,240	$ 38,433	Col (C) * Line 25
32	Private Outdoor Lighting	0.21%	$ 1,209	$ 1,278	$ 1,104	$ 1,112	$ 975	$ 1,017	$ 1,142	Col (C) * Line 25
33	School	0.36%	$ 2,065	$ 2,183	$ 1,886	$ 1,899	$ 1,665	$ 1,737	$ 1,949	Col (C) * Line 25
34	Street Lighting	0.40%	$ 2,308	$ 2,440	$ 2,108	$ 2,123	$ 1,861	$ 1,941	$ 2,179	Col (C) * Line 25
35	**Total TCRR-N Energy Costs**	100.00%	$ 575,988	$ 608,904	$ 525,996	$ 529,689	$ 464,295	$ 484,428	$ 543,753	Sum (Line 27 thru 34)

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Monthly Costs by Tariff Class
June 2014 - May 2015

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

			2015 Forecast						Total Forecast Costs
Line	Description	Tariff Allocator	Jan	Feb	Mar	Apr	May	Source	May 2014 - June 2015
(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**		$ 4,240,622	$ 3,855,637	$ 4,296,904	$ 4,185,120	$ 4,352,866	Schedule C-1, Page 2, Line 18	
2	Tariff Class								
3	Residential	37.51%	$ 1,590,632	$ 1,446,226	$ 1,611,743	$ 1,569,813	$ 1,632,734	Col (C) * Line 1	$ 18,766,063
4	Secondary	37.07%	$ 1,571,934	$ 1,429,225	$ 1,592,796	$ 1,551,360	$ 1,613,541	Col (C) * Line 1	$ 18,545,466
5	Primary	16.30%	$ 691,034	$ 628,298	$ 700,206	$ 681,990	$ 709,325	Col (C) * Line 1	$ 8,152,730
6	Primary Substation	2.55%	$ 108,087	$ 98,274	$ 109,522	$ 106,672	$ 110,948	Col (C) * Line 1	$ 1,275,196
7	High Voltage	5.85%	$ 247,907	$ 225,401	$ 251,198	$ 244,663	$ 254,469	Col (C) * Line 1	$ 2,924,779
8	Private Outdoor Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1	$ -
9	School	0.73%	$ 31,029	$ 28,212	$ 31,441	$ 30,623	$ 31,850	Col (C) * Line 1	$ 366,074
10	Street Lighting	0.00%	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1	$ -
11	**Total TCRR-N Demand Costs**	100.00%	$ 4,240,622	$ 3,855,637	$ 4,296,904	$ 4,185,120	$ 4,352,866	Sum (Line 3 thru 10)	$ 50,030,308
12									
13	**TCRR-N Demand-Based Costs - 12 CP**		$ 624,041	$ 563,650	$ 624,041	$ 603,911	$ 624,041	Schedule C-1, Page 2, Line 19	
14	Tariff Class								
15	Residential	39.67%	$ 247,531	$ 223,577	$ 247,531	$ 239,546	$ 247,531	Col (C) * Line 13	$ 2,914,480
16	Secondary	32.29%	$ 201,505	$ 182,004	$ 201,505	$ 195,005	$ 201,505	Col (C) * Line 13	$ 2,372,555
17	Primary	17.85%	$ 111,400	$ 100,619	$ 111,400	$ 107,806	$ 111,400	Col (C) * Line 13	$ 1,311,640
18	Primary Substation	3.43%	$ 21,413	$ 19,341	$ 21,413	$ 20,722	$ 21,413	Col (C) * Line 13	$ 252,119
19	High Voltage	6.14%	$ 38,323	$ 34,615	$ 38,323	$ 37,087	$ 38,323	Col (C) * Line 13	$ 451,228
20	Private Outdoor Lighting	0.11%	$ 711	$ 642	$ 711	$ 688	$ 711	Col (C) * Line 13	$ 8,374
21	School	0.49%	$ 3,051	$ 2,756	$ 3,051	$ 2,953	$ 3,051	Col (C) * Line 13	$ 35,926
22	Street Lighting	0.02%	$ 107	$ 97	$ 107	$ 103	$ 107	Col (C) * Line 13	$ 1,259
23	**Total TCRR-N Demand Costs**	100.00%	$ 624,041	$ 563,650	$ 624,041	$ 603,911	$ 624,041	Sum (Line 15 thru 22)	$ 7,347,581
24									
25	**TCRR-N Energy-Based Costs**		$ 618,209	$ 604,082	$ 503,489	$ 482,012	$ 495,233	Schedule C-1, Page 2, Line 20	
26	Tariff Class								
27	Residential	38.53%	$ 238,170	$ 232,728	$ 193,973	$ 185,699	$ 190,793	Col (C) * Line 25	$ 2,479,551
28	Secondary	28.63%	$ 176,985	$ 172,941	$ 144,142	$ 137,994	$ 141,779	Col (C) * Line 25	$ 1,842,565
29	Primary	20.28%	$ 125,364	$ 122,499	$ 102,100	$ 97,745	$ 100,426	Col (C) * Line 25	$ 1,305,145
30	Primary Substation	4.53%	$ 28,002	$ 27,362	$ 22,806	$ 21,833	$ 22,432	Col (C) * Line 25	$ 291,527
31	High Voltage	7.07%	$ 43,696	$ 42,697	$ 35,587	$ 34,069	$ 35,004	Col (C) * Line 25	$ 454,912
32	Private Outdoor Lighting	0.21%	$ 1,298	$ 1,268	$ 1,057	$ 1,012	$ 1,040	Col (C) * Line 25	$ 13,513
33	School	0.36%	$ 2,216	$ 2,166	$ 1,805	$ 1,728	$ 1,776	Col (C) * Line 25	$ 23,075
34	Street Lighting	0.40%	$ 2,477	$ 2,421	$ 2,018	$ 1,932	$ 1,984	Col (C) * Line 25	$ 25,790
35	**Total TCRR-N Energy Costs**	100.00%	$ 618,209	$ 604,082	$ 503,489	$ 482,012	$ 495,233	Sum (Line 27 thru 34)	$ 6,436,078

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Summary of Proposed Rates
June 2014 - May 2015

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

TCRR-N Rates

Line (A)	Description (B)		Residential (C)		Secondary[1] (D)		Primary (E)		Primary Substation (F)		High Voltage (G)		Private Outdoor Lighting[2] (H)		School (I)		Street Lighting (J)	Source (K)
1	TCRR-N Base Rates																	
2	Demand (kWh, kW)	$	0.0035222	$	1.3473784	$	1.3339293	$	1.1585108	$	1.5423210	$	0.0000082	$	0.0073713	$	0.0000006	Schedule C-3a, Line 21
3	Energy (0-1500 kWh)	$	0.0004633	$	0.0076203	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	Schedule C-3a, Line 25 + Line 40
4	Energy (>1500 kWh)	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	$	0.0004633	Schedule C-3a, Line 40
5	Reactive (kWh, kW, kVar)	$	0.0005291	$	0.2091892	$	0.3481988	$	0.3923485	$	0.5077477	$	0.0002790	$	0.0007009	$	0.0000220	Schedule C-3a, Line 48
6																		
7	TCRR-N Reconciliation Rates																	
8	Demand (kWh, kW)	$	0.0011799	$	0.3720917	$	0.4628288	$	0.4934589	$	0.5132574	$	0.0006221	$	0.0015629	$	0.0000490	Schedule C-3b, Line 26
9	Energy (0-1500 kWh)	$	0.0001285	$	0.0021050	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	Schedule C-3b, Line 27 + Line 31
10	Energy (>1500 kWh)	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	$	0.0001285	Schedule C-3b, Line 27
11																		
12																		
13	**Total TCRR-N Rates $/kW**			**$**	**1.9286593**	**$**	**1.7967581**	**$**	**1.6519697**	**$**	**2.0555784**							
14	**$/kWh for 0-1500 kWh**	**$**	**0.0058230**	**$**	**0.0097253**	**$**	**0.0005918**	**$**	**0.0005918**	**$**	**0.0005918**	**$**	**0.0015011**	**$**	**0.0102269**	**$**	**0.0006634**	
15	**$/kWh for >1500 kWh**	**$**	**0.0058230**	**$**	**0.0005918**	**$**	**0.0005918**	**$**	**0.0005918**	**$**	**0.0005918**	**$**	**0.0015011**	**$**	**0.0102269**	**$**	**0.0006634**	
16	**$/kVar**					**$**	**0.3481988**	**$**	**0.3923485**	**$**	**0.5077477**							

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

[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Rates are charged per fixture.

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Development of Proposed Base Rates
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Revised
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		37.51%	37.07%	16.30%	2.55%	5.85%	0.00%	0.73%	0.00%	WPC-2, Col (F)
2	Demand-Based Allocators - 12 CP		39.67%	32.29%	17.85%	3.43%	6.14%	0.11%	0.49%	0.02%	WPC-2, Col (H)
3											
4	Demand-Based Components										
5	Transmission Enhancement Charges (RTEP)	$ 9,595,968	$ 3,599,389	$ 3,557,078	$ 1,563,719	$ 244,587	$ 560,982	$ -	$ 70,214	$ -	Col (C) * Line 1
6	Incremental Capacity Transfer Rights Credit	$ (278,797)	$ (104,575)	$ (103,346)	$ (45,432)	$ (7,106)	$ (16,299)	$ -	$ (2,040)	$ -	Col (C) * Line 1
7	Black Start Service	$ 209,114	$ 82,947	$ 67,523	$ 37,330	$ 7,175	$ 12,842	$ 238	$ 1,022	$ 36	Col (C) * Line 2
8	Firm PTP Transmission Service Credits	$ (4,669)	$ (1,751)	$ (1,731)	$ (761)	$ (119)	$ (273)	$ -	$ (34)	$ -	Col (C) * Line 1
9	Non-Firm PTP Transmission Service Credits	$ (47,205)	$ (17,706)	$ (17,498)	$ (7,692)	$ (1,203)	$ (2,760)	$ -	$ (345)	$ -	Col (C) * Line 1
10	Network Integration Transmission Service	$ 40,580,806	$ 15,221,612	$ 15,042,681	$ 6,612,879	$ 1,034,343	$ 2,372,360	$ -	$ 296,932	$ -	Col (C) * Line 1
11	Expansion Cost Recovery Charges (ECRC)	$ 184,205	$ 69,094	$ 68,282	$ 30,017	$ 4,695	$ 10,769	$ -	$ 1,348	$ -	Col (C) * Line 1
12	Generation Deactivation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Col (C) * Line 1
13	Subtotal	$ 50,239,422	$ 18,849,010	$ 18,612,989	$ 8,190,060	$ 1,282,372	$ 2,937,621	$ 238	$ 367,096	$ 36	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	$ 50,390,140	$ 18,905,557	$ 18,668,828	$ 8,214,630	$ 1,286,219	$ 2,946,434	$ 239	$ 368,198	$ 36	Line 13 * Line 14
16											
17	Portion of Secondary Demand Greater Than 5 kW		NA	79.76%	NA	NA	NA	NA	NA	NA	WPC-3, Column (P), Line 4 / (Line 4 + Line 5)
18	Demand-Based Component Cost		$ 18,905,557	$ 14,891,147	$ 8,214,630	$ 1,286,219	$ 2,946,434	$ 239	$ 368,198	$ 36	Line 15 * Line 17
19											
20	Projected Billing Determinants (kWh, kW)		5,367,475,927	11,051,941	6,158,220	1,110,235	1,910,390	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
21	Demand Portion of TCRR-N Rate		$ 0.0035222	$ 1.3473784	$ 1.3339293	$ 1.1585108	$ 1.5423210	$ 0.0000082	$ 0.0073713	$ 0.0000006	Line 18 / Line 20
22											
23	Secondary Energy Portion of Demand-Based Component Cost		NA	$ 3,777,681	NA	NA	NA	NA	NA	NA	Line 15 - Line 18
24	Secondary 0-1500 kWh Billing Determinants		5,367,475,927	527,831,048	6,158,220	1,110,235	1,910,390	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
25	Secondary 0-1500 kWh TCRR-N Rate		$ -	$ 0.0071570	$ -	$ -	$ -	$ -	$ -	$ -	Line 23 / Line 24
26											
27	Energy-Based Allocators		38.53%	28.63%	20.28%	4.53%	7.07%	0.21%	0.36%	0.40%	WPC-2, Col (D)
28											
29	Energy-Based Components										
30	TO Scheduling System Control and Dispatch Service	$ 1,141,919	$ 439,934	$ 326,917	$ 231,565	$ 51,724	$ 80,713	$ 2,397	$ 4,094	$ 4,576	Col (C) * Line 27
31	NERC/RFC Charges	$ 355,207	$ 136,847	$ 101,691	$ 72,031	$ 16,089	$ 25,107	$ 746	$ 1,274	$ 1,423	Col (C) * Line 27
32	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 4,879,163	$ 1,879,737	$ 1,396,841	$ 989,425	$ 221,006	$ 344,867	$ 10,244	$ 17,493	$ 19,552	Col (C) * Line 27
33	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 37,688	$ 14,520	$ 10,790	$ 7,643	$ 1,707	$ 2,664	$ 79	$ 135	$ 151	Col (C) * Line 27
34	Load Response Charge Allocation	$ 22,100	$ 8,514	$ 6,327	$ 4,482	$ 1,001	$ 1,562	$ 46	$ 79	$ 89	Col (C) * Line 27
35	Subtotal	$ 6,436,078	$ 2,479,551	$ 1,842,565	$ 1,305,145	$ 291,527	$ 454,912	$ 13,513	$ 23,075	$ 25,790	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	$ 6,455,386	$ 2,486,990	$ 1,848,093	$ 1,309,060	$ 292,402	$ 456,276	$ 13,553	$ 23,144	$ 25,868	Line 35 * Line 36
38											
39	Projected Billing Determinants (kWh)		5,367,475,927	3,988,595,054	2,825,242,419	631,068,379	984,745,740	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
40	Energy Portion of TCRR-N Rate		$ 0.0004633	$ 0.0004633	$ 0.0004633	$ 0.0004633	$ 0.0004633	$ 0.0004633	$ 0.0004633	$ 0.0004633	Line 37 / Line 39
41											
42	Reactive-Based Components										
43	Reactive Supply and Voltage Control from Gen Sources	$ 7,138,467	$ 2,831,534	$ 2,305,032	$ 1,274,310	$ 244,943	$ 438,386	$ 8,136	$ 34,903	$ 1,223	Col (C) * Line 2
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	$ 7,159,883	$ 2,840,028	$ 2,311,947	$ 1,278,133	$ 245,678	$ 439,701	$ 8,160	$ 35,008	$ 1,227	Line 43 * Line 44
46											
47	Projected Billing Determinants (kWh, kW, kVar)		5,367,475,927	11,051,941	3,670,699	626,173	865,983	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
48	Reactive Portion of TCRR-N Rate		$ 0.0005291	$ 0.2091892	$ 0.3481988	$ 0.3923485	$ 0.5077477	$ 0.0002790	$ 0.0007009	$ 0.0000220	Line 45 / Line 47
49											
50	**Total Base TCRR-N Component Cost**	**$ 64,005,409**									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. 14-0358-EL-RDR
Development of Proposed Reconciliation Rate - TCRR-N
June 2014 - May 2015

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

Reconciliation TCRR-N Rate

Line	Description	Under Recovery	Demand/ Energy Ratios	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)	(M)
1	Demand-Based Allocators - 12 CP			39.67%	32.29%	17.85%	3.43%	6.14%	0.11%	0.49%	0.02%	WPC-2, Col (H)
2	Energy-Based Allocators			38.53%	28.63%	20.28%	4.53%	7.07%	0.21%	0.36%	0.40%	WPC-2, Col (D)
3												
4	TCRR-N Under Recovery[2]	$ 17,328,861										WPC-1b, Col (C) Line 6
5	TCRR-N Under Recovery of Carrying Costs Total	$ 375,312										WPC-1b, Col (H) Line 19
6	TCRR-N Under Recovery	$ 17,704,173										Line 4 + Line 5
7	Gross Revenue Conversion Factor	1.003										WPB-1, Line 4
8	Total TCRR-N Under Recovery	$ 17,757,286										Line 6 * Line 7
9												
10	Base TCRR-N Component Costs											
11	Total Demand-Based Component Cost	$ 57,550,023	89.91%									Schedule C-3a, Col (C) Line 15 + Line 45
12	Total Energy-Based Components Cost	$ 6,455,386	10.09%									Schedule C-3a, Col (C) Line 37
13	Total Base TCRR-N Component Cost	$ 64,005,409	100.00%									Line 11 + Line 12
14												
15	TCRR-N Under Recovery - Demand (Line 8 * Col (D), Line 11)	$ 15,966,341		$ 6,333,185	$ 5,155,578	$ 2,850,202	$ 547,855	$ 980,522	$ 18,197	$ 78,067	$ 2,736	Col (C) * Line 1
16	TCRR-N Under Recovery - Energy (Line 8 * Col (D), Line 12)	$ 1,790,944		$ 689,976	$ 512,724	$ 363,178	$ 81,122	$ 126,587	$ 3,760	$ 6,421	$ 7,177	Col (C) * Line 2
17	TCRR-N Under Recovery Total	$ 17,757,286		$ 7,023,161	$ 5,668,302	$ 3,213,380	$ 628,978	$ 1,107,108	$ 21,957	$ 84,488	$ 9,912	Line 15 + Line 16
18												
19	Portion of Secondary Demand Greater Than 5 kW			NA	79.76%	NA	NA	NA	NA	NA	NA	Schedule C-3a, Col (E) Line 17
20	Demand-Based Under Recovery			$ 6,333,185	$ 4,112,335	$ 2,850,202	$ 547,855	$ 980,522	$ 18,197	$ 78,067	$ 2,736	Line 15 * Line 19
21												
22	Projected Billing Determinants (kWh, kW)			5,367,475,927	11,051,941	6,158,220	1,110,235	1,910,390	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
23	Projected Billing Determinants (kWh)			5,367,475,927	3,988,595,054	2,825,242,419	631,068,379	984,745,740	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
24												
25	TCRR-N Reconciliation Rates											
26	Demand Portion of TCRR-N Rate (kWh, kW)			$ 0.0011799	$ 0.3720917	$ 0.4628288	$ 0.4934589	$ 0.5132574	$ 0.0006221	$ 0.0015629	$ 0.0000490	Line 20 / Line 22
27	Energy Portion of TCRR-N Rate (kWh)			$ 0.0001285	$ 0.0001285	$ 0.0001285	$ 0.0001285	$ 0.0001285	$ 0.0001285	$ 0.0001285	$ 0.0001285	Line 16 / Line 23
28												
29	Secondary Energy Portion of Under Recovery			NA	$ 1,043,243	NA	NA	NA	NA	NA	NA	Line 15 - Line 20
30	Secondary 0-1500 kWh Billing Determinants			5,367,475,927	527,831,048	2,825,242,419	631,068,379	984,745,740	29,250,923	49,949,992	55,828,440	WPC-3, Column (P)
31	Secondary 0-1500 kWh TCRR-N Rate			$ -	$ 0.0019765	$ -	$ -	$ -	$ -	$ -	$ -	Line 29 / Line 30

[1] Secondary customers are charged for all kW over 5kW of Billing Demand
[2] The TCRR-N Under Recovery includes the amount of the TCRR-B deferral that exceeds 10% of the TCRR-B base costs (see Case No. 14-0661-EL-RDR).

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Actual Charges and Revenues
January 2014
(Revenue)/Expense in $

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

January 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	$ (3,235,434)	**$ (3,235,434)**
2	Transmission Enhancement Charges (RTEP)	$ 804,202	NA		**$ 804,202**
3	Incremental Capacity Transfer Rights Credit	NA	$ (30,688)		**$ (30,688)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 595,491	NA		**$ 595,491**
5	Black Start Service	$ 18,111	NA		**$ 18,111**
6	TO Scheduling System Control and Dispatch Service	$ 121,485	NA		**$ 121,485**
7	NERC/RFC Charges	$ 39,469	NA		**$ 39,469**
8	Firm PTP Transmission Service	NA	$ (186)		**$ (186)**
9	Non-Firm PTP Transmission Service	NA	$ (14,013)		**$ (14,013)**
10	Network Integration Transmission Service	$ 3,310,380	NA		**$ 3,310,380**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,506	NA		**$ 15,506**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 494,572	NA		**$ 494,572**
13	Michigan-Ontario Interface PARs Charge	$ 2,852	NA		**$ 2,852**
14	Load Response Charge Allocation	$ 8,430	NA		**$ 8,430**
15	SubTotal	$ 5,410,498	$ (44,888)	$ (3,235,434)	**$ 2,130,176**
16	TCRR-N Deferral carrying costs (WPC-1b)				**$ 20,340**
17					
18	**Total TCRR-N including carrying costs**	$ 5,410,498	$ (44,888)	$ (3,235,434)	**$ 2,150,517**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Monthly Revenues Collected by Tariff Class

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

		2014	
Line	Description	January	Total
(A)	(B)	(C)	(D)
	TCRR-N		
1	Residential	$ (1,967,267)	**$ (1,967,267)**
2	Secondary	$ (765,578)	**$ (765,578)**
3	Primary	$ (369,027)	**$ (369,027)**
4	Primary Substation	$ (24,511)	**$ (24,511)**
5	High Voltage	$ (95,125)	**$ (95,125)**
6	Private Outdoor Lighting	$ (1,104)	**$ (1,104)**
7	Schools	$ (8,495)	**$ (8,495)**
8	Street Lighting	$ (4,327)	**$ (4,327)**
9	**Total TCRR-N**	**$ (3,235,434)**	**$ (3,235,434)**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Monthly (Over) / Under Recovery

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

			2014		
Line	Description	Prior Period True-up Balance	January	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)
	TCRR-N				
1	Net Costs		$5,365,610	$5,365,610	Schedule D-1, Col (C) + Col (D)
2	Revenues		($3,235,434)	($3,235,434)	Schedule D-1, Col (E)
3	(Over)/ Under Recovery		$2,130,176	$2,130,176	Line 1 + Line 2
4	Carrying Costs		$20,340	$20,340	Schedule D-1, Col (F)
5	(Over)/ Under Recovery with Carrying Costs		$2,150,517	$2,150,517	Line 3 + Line 4
6	YTD Under Recovery (without Carrying Costs)		$6,003,023	$6,003,023	Line 3 + Line 7
7	**YTD Under Recovery**	**3,872,847**	**$6,023,363**	**$6,023,363**	Line 5 + Line 7

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Transmission Cost Recovery Rider - Non-Bypassable

Workpapers

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Computation of Gross Revenue Conversion Factor

Data: Actual
Type of Filing: Revised
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. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

June 2014 - 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)	$ 788,710	NA	**$ 788,710**
3	Incremental Capacity Transfer Rights Credit	NA	$ (22,915)	**$ (22,915)**
4	Reactive Supply and Voltage Control from Gen Sources	$ 586,723	NA	**$ 586,723**
5	Black Start Service	$ 17,187	NA	**$ 17,187**
6	TO Scheduling System Control and Dispatch Service	$ 102,265	NA	**$ 102,265**
7	NERC/RFC Charges	$ 31,811	NA	**$ 31,811**
8	Firm PTP Transmission Service Credits	NA	$ (108)	**$ (108)**
9	Non-Firm PTP Transmission Service Credits	NA	$ (3,374)	**$ (3,374)**
10	Network Integration Transmission Service	$ 3,302,230	NA	**$ 3,302,230**
11	Expansion Cost Recovery Charges (ECRC)	$ 15,140	NA	**$ 15,140**
12	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 436,955	NA	**$ 436,955**
13	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
14	Load Response Charge Allocation	$ 1,816	NA	**$ 1,816**
15	Generation Deactivation	$ -	NA	**$ -**
16	TCRR-N SubTotal	$ 5,285,978	$ (26,396)	**$ 5,259,582**
17	TCRR-N Deferral carrying costs (WPC-1b)			**$ 68,009**
18				
19	**Total TCRR-N including carrying costs**	$ 5,285,978	$ (26,396)	**$ 5,327,591**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

July 2014 - 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)	$ 815,000	NA	**$ 815,000**
22	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
23	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
24	Black Start Service	$ 17,760	NA	**$ 17,760**
25	TO Scheduling System Control and Dispatch Service	$ 108,149	NA	**$ 108,149**
26	NERC/RFC Charges	$ 33,641	NA	**$ 33,641**
27	Firm PTP Transmission Service Credits	NA	$ (104)	**$ (104)**
28	Non-Firm PTP Transmission Service Credits	NA	$ (3,372)	**$ (3,372)**
29	Network Integration Transmission Service	$ 3,412,304	NA	**$ 3,412,304**
30	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
31	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 462,096	NA	**$ 462,096**
32	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
33	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
34	Generation Deactivation	$ -	NA	**$ -**
35	TCRR-N SubTotal	$ 5,475,894	$ (27,155)	**$ 5,448,739**
36	TCRR-N Deferral carrying costs (WPC-1b)			**$ 59,972**
37				
38	**Total TCRR-N including carrying costs**	$ 5,475,894	$ (27,155)	**$ 5,508,711**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

August 2014 - 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)	$ 815,000	NA	**$ 815,000**
41	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
42	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
43	Black Start Service	$ 17,760	NA	**$ 17,760**
44	TO Scheduling System Control and Dispatch Service	$ 93,301	NA	**$ 93,301**
45	NERC/RFC Charges	$ 29,022	NA	**$ 29,022**
46	Firm PTP Transmission Service Credits	NA	$ (123)	**$ (123)**
47	Non-Firm PTP Transmission Service Credits	NA	$ (4,276)	**$ (4,276)**
48	Network Integration Transmission Service	$ 3,412,304	NA	**$ 3,412,304**
49	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
50	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 398,655	NA	**$ 398,655**
51	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
52	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
53	Generation Deactivation	$ -	NA	**$ -**
54	TCRR-N SubTotal	$ 5,392,986	$ (28,078)	**$ 5,364,909**
55	TCRR-N Deferral carrying costs (WPC-1b)			**$ 50,523**
56				
57	**Total TCRR-N including carrying costs**	$ 5,392,986	$ (28,078)	**$ 5,415,431**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

September 2014 - 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)	$ 788,710	NA	**$ 788,710**
60	Incremental Capacity Transfer Rights Credit	NA	$ (22,915)	**$ (22,915)**
61	Reactive Supply and Voltage Control from Gen Sources	$ 586,723	NA	**$ 586,723**
62	Black Start Service	$ 17,187	NA	**$ 17,187**
63	TO Scheduling System Control and Dispatch Service	$ 93,973	NA	**$ 93,973**
64	NERC/RFC Charges	$ 29,231	NA	**$ 29,231**
65	Firm PTP Transmission Service Credits	NA	$ (121)	**$ (121)**
66	Non-Firm PTP Transmission Service Credits	NA	$ (3,262)	**$ (3,262)**
67	Network Integration Transmission Service	$ 3,302,230	NA	**$ 3,302,230**
68	Expansion Cost Recovery Charges (ECRC)	$ 15,140	NA	**$ 15,140**
69	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 401,527	NA	**$ 401,527**
70	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
71	Load Response Charge Allocation	$ 1,816	NA	**$ 1,816**
72	Generation Deactivation	$ -	NA	**$ -**
73	TCRR-N SubTotal	$ 5,239,679	$ (26,298)	**$ 5,213,381**
74	TCRR-N Deferral carrying costs (WPC-1b)			**$ 43,577**
75				
76	**Total TCRR-N including carrying costs**	$ 5,239,679	$ (26,298)	**$ 5,256,958**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

October 2014 - 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)	$ 815,000	NA	**$ 815,000**
79	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
80	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
81	Black Start Service	$ 17,760	NA	**$ 17,760**
82	TO Scheduling System Control and Dispatch Service	$ 82,251	NA	**$ 82,251**
83	NERC/RFC Charges	$ 25,585	NA	**$ 25,585**
84	Firm PTP Transmission Service Credits	NA	$ (110)	**$ (110)**
85	Non-Firm PTP Transmission Service Credits	NA	$ (2,551)	**$ (2,551)**
86	Network Integration Transmission Service	$ 3,412,304	NA	**$ 3,412,304**
87	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
88	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 351,441	NA	**$ 351,441**
89	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
90	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
91	Generation Deactivation	$ -	NA	**$ -**
92	TCRR-N SubTotal	$ 5,331,285	$ (26,340)	**$ 5,304,946**
93	TCRR-N Deferral carrying costs (WPC-1b)			**$ 39,700**
94				
95	**Total TCRR-N including carrying costs**	$ 5,331,285	$ (26,340)	**$ 5,344,646**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

November 2014 - 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)	$ 788,710	NA	**$ 788,710**
98	Incremental Capacity Transfer Rights Credit	NA	$ (22,915)	**$ (22,915)**
99	Reactive Supply and Voltage Control from Gen Sources	$ 586,723	NA	**$ 586,723**
100	Black Start Service	$ 17,187	NA	**$ 17,187**
101	TO Scheduling System Control and Dispatch Service	$ 85,868	NA	**$ 85,868**
102	NERC/RFC Charges	$ 26,710	NA	**$ 26,710**
103	Firm PTP Transmission Service Credits	NA	$ (1,214)	**$ (1,214)**
104	Non-Firm PTP Transmission Service Credits	NA	$ (3,031)	**$ (3,031)**
105	Network Integration Transmission Service	$ 3,302,230	NA	**$ 3,302,230**
106	Expansion Cost Recovery Charges (ECRC)	$ 15,140	NA	**$ 15,140**
107	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 366,893	NA	**$ 366,893**
108	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
109	Load Response Charge Allocation	$ 1,816	NA	**$ 1,816**
110	Generation Deactivation	$ -	NA	**$ -**
111	TCRR-N SubTotal	$ 5,194,419	$ (27,160)	**$ 5,167,259**
112	TCRR-N Deferral carrying costs (WPC-1b)			**$ 35,928**
113				
114	**Total TCRR-N including carrying costs**	$ 5,194,419	$ (27,160)	**$ 5,203,187**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

December 2014 - Forecast

Line	Description	Total PJM Bill Charges	Total PJM Bill Revenues	Total Net Costs
(A)	(B)	(C)	(D)	(E) = (C)+(D)
115	**TCRR-N Costs & Revenues**			
116	Transmission Enhancement Charges (RTEP)	$ 815,000	NA	**$ 815,000**
117	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
118	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
119	Black Start Service	$ 17,760	NA	**$ 17,760**
120	TO Scheduling System Control and Dispatch Service	$ 96,481	NA	**$ 96,481**
121	NERC/RFC Charges	$ 30,012	NA	**$ 30,012**
122	Firm PTP Transmission Service Credits	NA	$ (1,122)	**$ (1,122)**
123	Non-Firm PTP Transmission Service Credits	NA	$ (4,649)	**$ (4,649)**
124	Network Integration Transmission Service	$ 3,412,304	NA	**$ 3,412,304**
125	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
126	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 412,242	NA	**$ 412,242**
127	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
128	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
129	Generation Deactivation	$ -	NA	**$ -**
130	TCRR-N SubTotal	$ 5,410,743	$ (29,450)	**$ 5,381,293**
131	TCRR-N Deferral carrying costs (WPC-1b)			**$ 29,846**
132				
133	**Total TCRR-N including carrying costs**	$ 5,410,743	$ (29,450)	**$ 5,411,139**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

January 2015 - 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)	$ 815,000	NA	**$ 815,000**
136	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
137	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
138	Black Start Service	$ 17,760	NA	**$ 17,760**
139	TO Scheduling System Control and Dispatch Service	$ 109,815	NA	**$ 109,815**
140	NERC/RFC Charges	$ 34,159	NA	**$ 34,159**
141	Firm PTP Transmission Service Credits	NA	$ (1,320)	**$ (1,320)**
142	Non-Firm PTP Transmission Service Credits	NA	$ (4,538)	**$ (4,538)**
143	Network Integration Transmission Service	$ 3,439,514	NA	**$ 3,439,514**
144	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
145	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 469,216	NA	**$ 469,216**
146	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
147	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
148	Generation Deactivation	$ -	NA	**$ -**
149	TCRR-N SubTotal	$ 5,512,409	$ (29,537)	**$ 5,482,872**
150	TCRR-N Deferral carrying costs (WPC-1b)			**$ 21,416**
151				
152	**Total TCRR-N including carrying costs**	$ 5,512,409	$ (29,537)	**$ 5,504,288**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

February 2015 - 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)	$ 736,129	NA	**$ 736,129**
155	Incremental Capacity Transfer Rights Credit	NA	$ (21,387)	**$ (21,387)**
156	Reactive Supply and Voltage Control from Gen Sources	$ 547,608	NA	**$ 547,608**
157	Black Start Service	$ 16,042	NA	**$ 16,042**
158	TO Scheduling System Control and Dispatch Service	$ 107,318	NA	**$ 107,318**
159	NERC/RFC Charges	$ 33,383	NA	**$ 33,383**
160	Firm PTP Transmission Service Credits	NA	$ (129)	**$ (129)**
161	Non-Firm PTP Transmission Service Credits	NA	$ (4,538)	**$ (4,538)**
162	Network Integration Transmission Service	$ 3,131,431	NA	**$ 3,131,431**
163	Expansion Cost Recovery Charges (ECRC)	$ 14,131	NA	**$ 14,131**
164	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 458,546	NA	**$ 458,546**
165	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
166	Load Response Charge Allocation	$ 1,695	NA	**$ 1,695**
167	Generation Deactivation	$ -	NA	**$ -**
168	TCRR-N SubTotal	$ 5,049,423	$ (26,054)	**$ 5,023,369**
169	TCRR-N Deferral carrying costs (WPC-1b)			**$ 13,550**
170				
171	**Total TCRR-N including carrying costs**	$ 5,049,423	$ (26,054)	**$ 5,036,919**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

March 2015 - 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)	$ 815,000	NA	**$ 815,000**
174	Incremental Capacity Transfer Rights Credit	NA	$ (23,679)	**$ (23,679)**
175	Reactive Supply and Voltage Control from Gen Sources	$ 606,281	NA	**$ 606,281**
176	Black Start Service	$ 17,760	NA	**$ 17,760**
177	TO Scheduling System Control and Dispatch Service	$ 89,270	NA	**$ 89,270**
178	NERC/RFC Charges	$ 27,769	NA	**$ 27,769**
179	Firm PTP Transmission Service Credits	NA	$ (111)	**$ (111)**
180	Non-Firm PTP Transmission Service Credits	NA	$ (4,538)	**$ (4,538)**
181	Network Integration Transmission Service	$ 3,494,587	NA	**$ 3,494,587**
182	Expansion Cost Recovery Charges (ECRC)	$ 15,645	NA	**$ 15,645**
183	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 381,432	NA	**$ 381,432**
184	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
185	Load Response Charge Allocation	$ 1,877	NA	**$ 1,877**
186	Generation Deactivation	$ -	NA	**$ -**
187	TCRR-N SubTotal	$ 5,452,762	$ (28,328)	**$ 5,424,434**
188	TCRR-N Deferral carrying costs (WPC-1b)			**$ 7,632**
189				
190	**Total TCRR-N including carrying costs**	$ 5,452,762	$ (28,328)	**$ 5,432,066**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

April 2015 - 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)	$ 788,710	NA	**$ 788,710**
193	Incremental Capacity Transfer Rights Credit	NA	$ (22,915)	**$ (22,915)**
194	Reactive Supply and Voltage Control from Gen Sources	$ 586,723	NA	**$ 586,723**
195	Black Start Service	$ 17,187	NA	**$ 17,187**
196	TO Scheduling System Control and Dispatch Service	$ 85,435	NA	**$ 85,435**
197	NERC/RFC Charges	$ 26,576	NA	**$ 26,576**
198	Firm PTP Transmission Service Credits	NA	$ (103)	**$ (103)**
199	Non-Firm PTP Transmission Service Credits	NA	$ (4,538)	**$ (4,538)**
200	Network Integration Transmission Service	$ 3,408,826	NA	**$ 3,408,826**
201	Expansion Cost Recovery Charges (ECRC)	$ 15,140	NA	**$ 15,140**
202	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 365,044	NA	**$ 365,044**
203	Michigan-Ontario Interface Phase Angle Regulators Charge	$ 3,141	NA	**$ 3,141**
204	Load Response Charge Allocation	$ 1,816	NA	**$ 1,816**
205	Generation Deactivation	$ -	NA	**$ -**
206	TCRR-N SubTotal	$ 5,298,599	$ (27,556)	**$ 5,271,043**
207	TCRR-N Deferral carrying costs (WPC-1b)			**$ 3,836**
208				
209	**Total TCRR-N including carrying costs**	$ 5,298,599	$ (27,556)	**$ 5,274,879**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Charges and Revenues
June 2014 - May 2015
(Revenue)/Expense in $

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

May 2015 - Forecast

Line (A)	Description (B)		Total PJM Bill Charges (C)		PJM Bill Revenues (D)		Total Net Costs (E) = (C)+(D)
210	**TCRR-N Costs & Revenues**						
211	Transmission Enhancement Charges (RTEP)	$	815,000		NA	**$**	**815,000**
212	Incremental Capacity Transfer Rights Credit		NA	$	(23,679)	**$**	**(23,679)**
213	Reactive Supply and Voltage Control from Gen Sources	$	606,281		NA	**$**	**606,281**
214	Black Start Service	$	17,760		NA	**$**	**17,760**
215	TO Scheduling System Control and Dispatch Service	$	87,792		NA	**$**	**87,792**
216	NERC/RFC Charges	$	27,309		NA	**$**	**27,309**
217	Firm PTP Transmission Service Credits		NA	$	(104)	**$**	**(104)**
218	Non-Firm PTP Transmission Service Credits		NA	$	(4,538)	**$**	**(4,538)**
219	Network Integration Transmission Service	$	3,550,542		NA	**$**	**3,550,542**
220	Expansion Cost Recovery Charges (ECRC)	$	15,645		NA	**$**	**15,645**
221	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$	375,115		NA	**$**	**375,115**
222	Michigan-Ontario Interface Phase Angle Regulators Charge	$	3,141		NA	**$**	**3,141**
223	Load Response Charge Allocation	$	1,877		NA	**$**	**1,877**
224	Generation Deactivation	$	-		NA	**$**	**-**
225	TCRR-N SubTotal	$	5,500,461	$	(28,321)	**$**	**5,472,140**
226	TCRR-N Deferral carrying costs (WPC-1b)					**$**	**1,322**
227							
228	**Total TCRR-N including carrying costs**	$	5,500,461	$	(28,321)	**$**	**5,473,463**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Calculation of Carrying Costs - TCRR-N
January 2014 - May 2015 (Over) / Under Recovery

Data: Actual and Forecasted
Type of Filing: Revised
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	Jan-14	3,872,846.58	5,365,610.46	(3,235,434.12)	2,130,176.34	6,003,022.92	20,340.18	6,023,363.09	6,003,022.92	(1,065,088.17)	4,937,934.75
2	Feb-14	6,023,363.09	5,001,863.92	(5,957,649.63)	(955,785.71)	5,067,577.38	22,842.72	5,090,420.10	5,067,577.38	477,892.86	5,545,470.24
3	Mar-14	5,090,420.10	5,350,296.11	(5,588,903.88)	(238,607.76)	4,851,812.33	20,476.86	4,872,289.19	4,851,812.33	119,303.88	4,971,116.21
4	Apr-14	4,872,289.19	5,196,655.46	(4,904,441.71)	292,213.74	5,164,502.93	20,671.61	5,185,174.54	5,164,502.93	(146,106.87)	5,018,396.06
5	May-14	5,185,174.54	5,374,137.15	(5,139,274.14)	234,863.01	5,420,037.54	21,842.32	5,441,879.86	5,420,037.54	(117,431.50)	5,302,606.04
6	Jun-14	17,328,860.94	5,259,581.78	(6,896,343.26)	(1,636,761.48)	15,692,099.46	68,009.42	15,760,108.88	15,692,099.46	818,380.74	16,510,480.20
7	Jul-14	15,760,108.88	5,448,739.15	(7,850,311.06)	(2,401,571.91)	13,358,536.97	59,972.28	13,418,509.25	13,358,536.97	1,200,785.95	14,559,322.93
8	Aug-14	13,418,509.25	5,364,908.61	(7,671,321.00)	(2,306,412.39)	11,112,096.86	50,522.83	11,162,619.69	11,112,096.86	1,153,206.19	12,265,303.06
9	Sep-14	11,162,619.69	5,213,381.01	(6,380,542.30)	(1,167,161.30)	9,995,458.40	43,576.82	10,039,035.22	9,995,458.40	583,580.65	10,579,039.04
10	Oct-14	10,039,035.22	5,304,945.67	(6,107,127.13)	(802,181.46)	9,236,853.76	39,700.30	9,276,554.06	9,236,853.76	401,090.73	9,637,944.49
11	Nov-14	9,276,554.06	5,167,258.73	(6,275,880.70)	(1,108,621.97)	8,167,932.09	35,928.37	8,203,860.46	8,167,932.09	554,310.99	8,722,243.07
12	Dec-14	8,203,860.46	5,381,293.21	(7,297,728.20)	(1,916,434.99)	6,287,425.47	29,846.01	6,317,271.48	6,287,425.47	958,217.50	7,245,642.96
13	Jan-15	6,317,271.48	5,482,872.09	(7,719,281.88)	(2,236,409.79)	4,080,861.69	21,415.82	4,102,277.51	4,080,861.69	1,118,204.89	5,199,066.58
14	Feb-15	4,102,277.51	5,023,368.92	(6,649,044.60)	(1,625,675.68)	2,476,601.84	13,549.75	2,490,151.59	2,476,601.84	812,837.84	3,289,439.67
15	Mar-15	2,490,151.59	5,424,434.37	(6,699,124.43)	(1,274,690.07)	1,215,461.52	7,632.02	1,223,093.54	1,215,461.52	637,345.03	1,852,806.55
16	Apr-15	1,223,093.54	5,271,042.95	(5,854,582.20)	(583,539.25)	639,554.28	3,836.28	643,390.56	639,554.28	291,769.63	931,323.91
17	May-15	643,390.56	5,472,140.49	(6,116,853.44)	(644,712.95)	(1,322.39)	1,322.39	0.00	(1,322.39)	322,356.48	321,034.08
18											
19					"Current cycle" carrying costs		375,312.30				

* The January 2014 First of Month Balance is 68.1% of the December 2013 TCRR End of Month Balance.

** The June 2014 First of Month Balance includes the amount of the TCRR-B deferral that exceeds 10% of the TCRR-B base costs (see Case No. 14-0661-EL-RDR).

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Summary of Energy and Demand Usage by Tariff Class
Allocation Factors

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

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	447,289,661	38.53%	1,110,235	37.51%	929,463	39.67%
3	Secondary	332,382,921	28.63%	1,097,184	37.07%	756,637	32.29%
4	Primary	235,436,868	20.28%	482,331	16.30%	418,298	17.85%
5	Primary Substation	52,589,032	4.53%	75,443	2.55%	80,404	3.43%
6	High Voltage	82,062,145	7.07%	173,035	5.85%	143,902	6.14%
7	Private Outdoor Lighting	2,437,577	0.21%	0	0.00%	2,671	0.11%
8	School	4,162,499	0.36%	21,658	0.73%	11,457	0.49%
9	Street Lighting	4,652,370	0.40%	0	0.00%	401	0.02%
10	**Total**	**1,161,013,073**	**100.00%**	**2,959,886**	**100.00%**	**2,343,233**	**100.00%**

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
Projected Monthly Billing Determinants
June 2014 - May 2015
kWh / kW / kVar

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

			2014 Forecast							2015 Forecast					Total Forecast	
Line (A)	Tariff Class (B)	Units (C)	Jun (D)	Jul (E)	Aug (F)	Sep (G)	Oct (H)	Nov (I)	Dec (J)	Jan (K)	Feb (L)	Mar (M)	Apr (N)	May (O)	June '14 - May '15 (P)	
1	Residential	kWh	388,758,402	515,440,559	479,555,084	395,045,555	332,608,838	372,935,849	535,595,519	631,638,119	497,528,540	487,764,826	385,465,284	345,139,352	5,367,475,927	kWh
2	Secondary[1]	0-1500 kWh	45,620,637	47,629,995	46,784,870	40,017,162	42,146,651	44,709,385	47,060,296	42,571,312	41,838,871	45,781,861	40,050,758	43,619,250	527,831,048	kWh
3		>1500 kWh	317,617,742	345,281,203	344,532,961	284,819,819	279,405,105	268,070,428	285,437,231	290,169,450	264,978,527	263,965,038	242,993,157	273,493,345	3,460,764,006	kWh
4		0-5 kW	252,034	250,777	247,015	213,567	230,782	243,714	249,203	214,055	211,491	238,760	211,591	240,739	2,803,726	kW
5		>5 kW	1,015,780	1,035,923	1,012,786	890,513	927,757	920,293	944,577	841,193	817,141	909,655	803,365	932,957	11,051,941	kW
6	Primary	kWh	262,487,561	267,007,632	269,764,198	229,096,003	241,576,179	234,238,624	232,604,063	220,327,711	205,781,805	219,923,828	206,652,719	235,782,096	2,825,242,419	kWh
7		kW	572,130	579,033	554,916	496,652	514,686	519,769	527,617	458,431	438,365	509,966	456,653	530,002	6,158,220	kW
8		kVar	336,366	340,405	321,967	290,482	300,920	302,538	320,937	275,485	269,387	320,838	275,890	315,485	3,670,699	kVar
9	Primary Substation	kWh	59,593,592	59,312,996	59,740,199	48,787,863	52,500,759	57,665,990	54,317,640	51,592,104	44,716,523	44,674,019	42,344,530	55,822,164	631,068,379	kWh
10		kW	102,141	102,330	99,136	83,872	89,948	95,397	103,747	89,163	79,665	89,119	81,442	94,274	1,110,235	kW
11		kVar	56,378	56,605	56,095	46,808	51,004	53,775	58,645	50,412	46,397	51,512	45,202	53,341	626,173	kVar
12	High Voltage	kWh	93,288,698	95,663,837	99,527,359	82,422,824	84,159,804	83,424,425	80,760,853	71,539,008	69,766,186	71,278,157	72,933,628	79,980,961	984,745,740	kWh
13		kW	178,062	185,477	185,867	161,487	164,235	167,064	159,347	131,499	136,999	149,319	136,261	154,774	1,910,390	kW
14		kVar	76,828	79,558	81,739	68,590	72,051	72,084	71,921	72,134	61,722	81,618	51,631	76,107	865,983	kVar
15	Private Outdoor Lighting[2]	kWh	2,609,873	2,603,945	2,564,371	2,189,268	2,358,691	2,484,684	2,690,682	2,351,374	2,225,713	2,512,911	2,185,208	2,474,203	29,250,923	kWh
16	School	kWh	3,771,075	3,862,446	3,812,666	3,997,409	4,567,185	4,384,798	3,706,438	4,671,878	4,529,154	4,277,377	3,887,626	4,481,940	49,949,992	kWh
17	Streetlighting	kWh	4,897,270	4,883,604	4,813,556	4,114,092	4,437,759	4,688,237	5,072,295	4,431,239	5,014,046	4,760,426	4,085,944	4,629,972	55,828,440	kWh
	Total kWh		1,178,644,850	1,341,686,217	1,311,095,264	1,090,489,995	1,043,760,971	1,072,602,420	1,247,245,017	1,319,292,195	1,136,379,365	1,144,938,443	1,000,598,854	1,045,423,283	13,932,156,874	kWh
	Total kW		1,868,112	1,902,764	1,852,704	1,632,524	1,696,627	1,702,523	1,735,289	1,520,286	1,472,169	1,658,060	1,477,720	1,712,007	20,230,786	kW
	Total kVar		469,572	476,567	459,801	405,880	423,976	428,397	451,503	398,030	377,505	453,968	372,723	444,932	5,162,855	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. Rates are charged per fixture.

The Dayton Power and Light Company
Case No. 14-0358-EL-RDR
TCRR-N Rate - Calculation of Private Outdoor Lighting Charges

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

Line	Description	kWh / Fixture	Jun '14 - May '15	Source
(A)	(B)	(C)	(D)	(E)
1	**Private Outdoor Lighting Rate ($/kWh)**		$0.0015011	Schedule C-3
2				
3	**Private Outdoor Lighting Charge ($/Fixture/Month)**			
4	9500 Lumens High Pressure Sodium	39	$0.0585429	Line 1 * Col (C) Line 4
5	28000 Lumens High Pressure Sodium	96	$0.1441056	Line 1 * Col (C) Line 5
6	7000 Lumens Mercury	75	$0.1125825	Line 1 * Col (C) Line 6
7	21000 Lumens Mercury	154	$0.2311694	Line 1 * Col (C) Line 7
8	2500 Lumens Incandescent	64	$0.0960704	Line 1 * Col (C) Line 8
9	7000 Lumens Fluorescent	66	$0.0990726	Line 1 * Col (C) Line 9
10	4000 Lumens PT Mercury	43	$0.0645473	Line 1 * Col (C) Line 10