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Steptoe
STEPTOE & JOHNSON LLP

May 15, 2015

The Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.
Formula Rate Annual Update
Docket No. ER12-91-000

Dear Secretary Bose:

In accordance with Section 1(b)(ii) of Duke Energy Ohio, Inc.'s ("DEO") and Duke Energy Kentucky, Inc.'s ("DEK") Formula Rate Implementation Protocols, which appear as Attachment H-22A of PJM Interconnection, L.L.C.'s ("PJM") Open Access Transmission Tariff ("OATT"), DEO and DEK (together, "the Companies") submit the enclosed Formula Rate Annual Update.[1] In accordance with the Companies' Formula Rate Implementation Protocols, the Annual Update is submitted for informational purposes only, and is not a filing under Section 205 of the Federal Power Act. The Companies request that the Commission not act on or issue public notice of this

[1] DEO and DEK have submitted, or will soon submit, a filing revising the FERC Form 1 source for the rate divisor for Schedule 1A (Attachment H-22A, Appendix A, line 4), to be effective June 1, 2015. The attached calculations incorporate this revision, which reduces rates to customers.

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informational filing because the Formula Rate Implementation Protocols provide specific procedures for notice, review, and challenges to the Annual Updates.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Gary A. Morgans

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Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.							Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$	91,179,810
	REVENUE CREDITS (Note T)		Total	Allocator			
2	Account No. 454	(page 4, line 34)	$ 191,098	TP	0.97606	$	186,522
3	Account No. 456.1	(page 4, line 35)	994,051	TP	0.97606		970,250
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.97606		0
4b	Revenues from service provided by ISO at a discount		0	TP	0.97606		0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,625,589		1.00000		2,625,589
5b	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		(11,710)		1.00000		(11,710)
	Corrections Related to Prior Years (Note AA)		427,482		1.00000		427,482
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$	4,198,134
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$	86,981,677
	DIVISOR						
8	1 CP (Note A)						5,105,000
9	12 CP (Note B)						4,428,083
10	Reserved						
11	Reserved						
12	Reserved						
13	Reserved						
14	Reserved						
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$17.039				
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$19.643				
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$1.420				
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.637				
			Peak Rate				Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.378				
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.076	Capped at weekly rate			$0.054
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.005	Capped at weekly and daily rate			$2.242

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 826,664,425	NA		
2	Transmission	207.58.g	723,185,344	TP	0.97606	$ 705,869,805
3	Distribution	207.75.g	2,552,844,008	NA		
4	General & Intangible	205.5.g & 207.99.g	239,184,981	W/S	0.07608	18,196,707
5	Common	356.1	288,301,796	CE	0.05276	15,210,733
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 4,630,180,554	GP=	15.966%	$ 739,277,245
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 466,172,104	NA		
8	Transmission	219.25.c	253,017,104	TP	0.97606	$ 246,959,006
9	Distribution	219.26.c	842,102,247	NA		
10	General & Intangible	219.28.c	85,847,997	W/S	0.07608	6,531,141
11	Common	356.1	133,520,725	CE	0.05276	7,044,521
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 1,780,660,177			$ 260,534,669
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 360,492,321			
14	Transmission	(line 2 - line 8)	470,168,240			$ 458,910,799
15	Distribution	(line 3 - line 9)	1,710,741,761			
16	General & Intangible	(line 4 - line 10)	153,336,984			11,665,566
17	Common	(line 5 - line 11)	154,781,071			8,166,212
18	TOTAL NET PLANT (sum lines 13-17)		$ 2,849,520,377	NP=	16.801%	$ 478,742,577
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (234,803)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(731,323,907)	NP	0.16801	(122,868,359)
21	Account No. 283 (enter negative)	277.9.k	(54,593,410)	NP	0.16801	(9,172,136)
22	Account No. 190	234.8.c	26,088,854	NP	0.16801	4,383,139
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.16801	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (760,063,266)			$ (127,657,356)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 121,217		1.00000	$ 121,217
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 13,222,225			2,317,622
27	Materials & Supplies (Note G)	227.8.c & 227.16.c	8,989,674	TE	0.89049	8,005,226
28	Prepayments (Account 165)	111.57.c	2,581,432	GP	0.15966	412,164
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 24,793,331			$ 10,735,012
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 2,114,371,659			$ 361,941,450

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ 47,154,710	TE	0.89049	$ 41,990,854
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	19,656,001		1.00000	19,656,001
1b	Less Midcontinent ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.89049	0
2	Less Account 565	321.96.b	11,970,817	TE	0.89049	10,659,907
3	A&G	323.197.b	90,262,538	W/S	0.07608	6,866,990
3a	Less Actual PBOP Expense	(Note E)	30,714	W/S	0.07608	2,337
3b	Plus Fixed PBOP Expense	(Note E)	2,918,402	W/S	0.07608	222,026
3c	Less PJM Integration Costs included in A&G and Internal Integration Costs included in A&G	(Note Y)	0	W/S	0.07608	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.07608	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		2,900,317	W/S	0.07608	220,650
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.89049	0
6	Common	356.1	0	CE	0.05276	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 3b, 5a, 6, 7 less lines 1a, 1b, 2, 3a, 3c, 4, 5)		$ 105,777,801			$ 18,540,975
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 13,194,029	TP	0.97606	$ 12,878,119
10	General	336.10.b	15,383,329	W/S	0.07608	1,170,332
11	Common	336.11.b	12,449,212	CE	0.05276	656,817
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 41,026,570			$ 14,705,268
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	$ 8,349,724	W/S	0.07608	$ 635,230
14	Highway and vehicle	263.i	11,980	W/S	0.07608	911
15	PLANT RELATED					
16	Property	263.i	109,268,320	GP	0.15966	17,446,314
17	Gross Receipts	263.i	4,345,824	NA	zero	0
18	Other	263.i	0	GP	0.15966	0
19	Payments in lieu of taxes		0	GP	0.15966	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 121,975,848			$ 18,082,455
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.188500%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote K.		35.795046%			
23	1 / (1 - T) = (from line 21)		1.54293605			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	(415,547)			
25	Income Tax Calculation (line 22 * line 28)		$ 61,531,117	NA		$ 10,532,993
26	ITC adjustment (line 23 * line 24)		(641,162)	NP	0.16801	(107,721)
27	Total Income Taxes	(line 25 plus line 26)	$ 60,889,955			$ 10,425,272
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 171,898,416	NA		$ 29,425,840
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 501,568,590			$ 91,179,810

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

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

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)						$ 723,185,344	
2	Less transmission plant excluded from ISO rates (Note M)						0	
3	Less transmission plant included in OATT Ancillary Services (Note N)						17,315,539	
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)						$ 705,869,805	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.97606	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						$ 47,154,710	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						4,133,787	
8	Included transmission expenses (line 6 less line 7)						$ 43,020,923	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.91234	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.97606	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.89049	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	31,643,305	0.00	0			
13	Transmission	354.21.b	6,853,262	0.98	6,689,171			
14	Distribution	354.23.b	32,521,080	0.00	0		W&S Allocator	
15	Other	354.24,25,26.b	16,907,565	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		87,925,212		6,689,171	=	0.07608	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)				% Electric		W&S Allocator	
			$		(line 17 / line 20)		(line 16)	CE
17	Electric	200.3.c	3,724,258,898		0.69350	*	0.07608	= 0.05276
18	Gas	201.3.d	1,646,009,119					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		5,370,268,017					
	RETURN (R)						$	
21		Long Term Interest (117, sum of 62.c through 67.c)					93,044,618	
22		Preferred Dividends (118.29c) (positive number)					0	
	Development of Common Stock:							
23		Proprietary Capital (112.16.c)					2,198,695,145	
24		Less Preferred Stock (line 28)					0	
25		Less Account 216.1 (112.12.c) (enter negative)					(616,384,737)	
26		Common Stock (sum lines 23-25)					1,582,310,408	
		(Note P)	$	%	Cost		Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		1,774,842,381	53%	0.0524		0.0277	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000		0.0000	
29	Common Stock (line 26)		1,582,310,408	47%	**0.1138**		0.0536	
30	Total (sum lines 27-29)		3,357,152,789				0.0813	=R
	REVENUE CREDITS						Load	
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)		(310-311)					
31	a. Bundled Non-RQ Sales for Resale (311.x.h)						0	
32	b. Bundled Sales for Resale included in Divisor on page 1						0	
33	Total of (a)-(b)						0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)						$ 191,098	
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)		(330.x.n)				$ 994,051	

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

Note References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Letter

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

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

C Reserved

D Reserved

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

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

G Identified in Form 1 as being only transmission related.

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

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

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

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

Inputs Required:	FIT =	35.00%	
	SIT=	0.29%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

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

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

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

O Enter dollar amounts.

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

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

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

S Reserved

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

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

Note References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Letter

Letter	Note
U	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Reserved
X	Midcontinent ISO Exit Fees include (1) the charge that DEOK paid to the Midcontinent ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midcontinent ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM. Internal Integration Costs are the internal administrative costs incurred by Duke Energy Ohio and Duke Energy Kentucky to accomplish their move from the Midcontinent ISO into PJM.
AA	This amount reflects corrections to the prior year rate calculation, plus accumulated interest, and is included here in accordance with the formula rate protocols. It is shown on a combined basis, and not separately entered on the DEO and DEK tabs.

For the 12 months ended: 12/31/2014

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data

Schedule 1A Rate Calculation

Line No.		Source		Revenue Requirement	
A.	Schedule 1A Annual Revenue Requirements				
1	Total Load Dispatch & Scheduling (Account 561)	Attachment H-22A, Page 4, Line 7	$	4,133,787	
2	Revenue Credits for Schedule 1A - Note A		$	153,750	
3	Net Schedule 1A Revenue Requirement for Zone		$	3,980,037	
B.	Schedule 1A Rate Calculations				
4	Annual MWh - Note B	(301.10.d & 11.d)		32,189,584	MWh
5	Schedule 1A rate $/MWh (Line 3 / Line 4)	(Line 3 / Line 4)		$0.1236	$/MWh

Note:

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

B The annual MWh represent the load used by all transmission customers.

Rate Formula Template
Utilizing Attachment H-22A Data

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

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	705,869,805	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	458,910,799	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	18,540,975	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.63%	2.63%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,827,149	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.26%	0.26%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	18,082,455	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	2.56%	2.56%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**5.45%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	10,425,272	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	2.27%	2.27%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	29,425,840	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.41%	6.41%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**8.68%**

Rate Formula Template
Utilizing Attachment H-22A Data

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

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	5.45%	$0.00	$ -	8.68%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	5.45%	$0.00	$ -	8.68%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	5.45%	$0.00	$ -	8.68%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A											$0

Note Letter

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

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	705,869,805	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	458,910,799	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	18,540,975	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.63%	2.63%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,827,149	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.26%	0.26%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	18,082,455	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	2.56%	2.56%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**5.45%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	10,425,272	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	2.27%	2.27%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	29,425,840	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.41%	6.41%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**8.68%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

Line No.	(1) Project Name	(2) MTEP Project Number	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation Expense	(10) Annual Revenue Requirement	(11) True-Up Adjustment	(12) Network Upgrade Charge
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,629,793	5.45%	$960,341.05	$ 15,644,459	8.68%	$1,358,540.91	$306,707	$2,625,588.96	$ -	$2,625,588.96
1b	Project 2	P3	$ -	5.45%	$0.00	$ -	8.68%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	5.45%	$0.00	$ -	8.68%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,625,589	$0	$2,625,589
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$2,625,589

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

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

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

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
		Transmission Plant	
350	3501	Rights of Way	1.48
352	3520	Structures & Improvements	0.41
353	3530	Station Equipment	2.25
353	3532	Station Equipment - Major	2.77
353	3535	Station Equipment - Electronic	9.55
355	3550	Poles & Fixtures	2.28
356	3560	Overhead Conductors & Devices	2.31
		General and Intagible Plant	
303	3030	Miscellaneous Intangible Plant	20.00
390	3900	Land and Land Rights	1.77
391	3910	Structures and Improvements	18.56
392	3921	Electronic Data Processing Equipment	6.53
394	3940	Transportation Equipment	4.14
397	3970	Stores Equipment	6.93

Rate Formula Template
Utilizing Attachment H-22A Data

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

To be completed in conjunction with Attachment H-22A.

No.	(1)	(2) Reference	(3) Company Total
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenue Received In PJM vs. Midcontinent ISO	(Note A)	$0
	ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP		
2	Accumulated Balance of Deferral	(Note B)	($413,245)
3	Income Tax Rate for Deferral Calculation	(Note C)	35.80%
4	Deferred Income Taxes on Accumulated Deferral (Line 2 * Line 3)		($147,921)
5	Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4)		($265,324)
	INCOME TAXES		
6	CIT = (T/(1-T)) * (1 - (WCLTD/R))	Attachment H-22, page 3, line 22	35.80%
7	Income Taxes (Line 6 * Line 9)		($3,087)
	CARRYING COST ON DEFERRAL		
8	FERC Refund Rate	(Note D)	3.25%
9	Carrying Cost (Line 5 * Line 8)		($8,623)
10	Revenue Credit Adjustment (Line 1 + Line 7 + Line 9)		($11,710)

Note

A From Appendix E, Workpaper, Column (4).

B Accumulated balance of deferral as of December 31st of the year prior to effective date of new rates.

C Effective deferred tax rate during applicable test year.

D FERC Refund Rate is the approved rate as of December 31 of calendar year prior to the rate year (see 18 CFR Section 35.19a).

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = Prior month's Balance + (6)
Period	**Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A)**	**Actual Firm PTP Service Revenue Received from PJM (Note B)**	**Difference Between Revenue Received and Amount in Rates Excluding True Up**	**Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C)**	**Amount Deferred for Future Future Recovery**	**Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment**
Jan-12	$ 791,184	$ 1,562,590	$ (771,406)		$ (771,406)	$ (771,406)
Feb-12	648,305	(458,017)	1,106,322		1,106,322	334,916
Mar-12	743,316	534,345	208,971		208,971	543,887
Apr-12	606,138	550,254	55,884		55,884	599,772
May-12	741,629	508,520	233,109		233,109	832,880
Jun-12	775,567	711,074	64,493		64,493	897,374
Jul-12	772,561	699,566	72,995		72,995	970,369
Aug-12	848,270	763,862	84,408		84,408	1,054,777
Sep-12	399,762	1,373,308	(973,546)		(973,546)	81,231
Oct-12	413,655	783,232	(369,576)		(369,576)	(288,345)
Nov-12	663,143	866,738	(203,595)		(203,595)	(491,940)
Dec-12	652,756	888,677	(235,920)		(235,920)	(727,861)
Total	$ 8,056,287	$ 8,784,148	$ (727,861)		$ (727,861)	
Jan-13	627,310	$ 875,003	(247,693)		$ (247,693)	(975,554)
Feb-13	573,007	772,468	(199,461)		(199,461)	(1,175,015)
Mar-13	724,329	830,765	(106,436)		(106,436)	(1,281,452)
Apr-13	591,717	793,294	(201,577)		(201,577)	(1,483,028)
May-13	571,819	808,438	(236,620)		(236,620)	(1,719,648)
Jun-13			-	(60,655)	60,655	(1,658,993)
Jul-13			-	(60,655)	60,655	(1,598,338)
Aug-13			-	(60,655)	60,655	(1,537,683)
Sep-13			-	(60,655)	60,655	(1,477,028)
Oct-13			-	(60,655)	60,655	(1,416,373)
Nov-13			-	(60,655)	60,655	(1,355,718)
Dec-13			-	(60,655)	60,655	$ (1,295,063)
Total	$ 3,088,181	$ 4,079,968	$ (991,787)	$ (424,585)	$ (567,202)	
Jan-14			-	(60,655)	$ 60,655	$ (1,234,408)
Feb-14			-	(60,655)	60,655	(1,173,753)
Mar-14			-	(60,655)	60,655	(1,113,098)
Apr-14			-	(60,655)	60,655	(1,052,443)
May-14			-	(60,655)	60,655	(991,788)
Jun-14				(82,649)	82,649	(909,139)
Jul-14				(82,649)	82,649	(826,490)
Aug-14				(82,649)	82,649	(743,841)
Sep-14				(82,649)	82,649	(661,192)
Oct-14				(82,649)	82,649	(578,543)
Nov-14				(82,649)	82,649	(495,894)
Dec-14				(82,649)	82,649	$ (413,245)
Total	$ -	$ -	$ -	$ (881,818)	$ 881,818	
Jan-15				(82,649)	$ 82,649	$ (330,596)
Feb-15				(82,649)	82,649	(247,947)
Mar-15				(82,649)	82,649	(165,298)
Apr-15				(82,649)	82,649	(82,649)
May-15				(82,649)	82,649	$ 0
Total				$ (413,245)	$ 413,245	

Notes:

(A) Monthly Firm PTP service revenue from Midcontinent ISO during test year applicable to currently effectives NITS and PTP service rates.
(B) Actual monthly Firm PTP service revenue received from PJM during current period.
(C) Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.
The recovery of the amounts deferred between January 1, 2012, and December 31, 2012, will begin on June 1, 2013, and will end on May 31, 2014.
The recovery of the amounts deferred between January 1, 2013 and May 31, 2013, will begin on June 1, 2014, and will end on May 31, 2015.

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 90,596,962
	REVENUE CREDITS (Note T)					
2	Account No. 454	(page 4, line 34)	$ 172,456	TP	1.00000	$ 172,456
3	Account No. 456.1	(page 4, line 35)	945,275	TP	1.00000	945,275
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
4b	Revenues from service provided by ISO at a discount		0	TP	1.00000	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,718,684		1.00000	2,718,684
5b	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		(11,710)		1.00000	(11,710)
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 3,824,706
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 86,772,256
	DIVISOR					
8	1 CP (Note A)					4,245,000
9	12 CP (Note B)					3,694,166
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$20.441			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$23.489			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$1.703			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.957			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.452			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.090	Capped at weekly rate		$0.064
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.006	Capped at weekly and daily rate		$2.681

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ -	NA		
2	Transmission	207.58.g	672,169,972	TP	1.00000	$ 672,169,972
3	Distribution	207.75.g	2,160,621,705	NA		
4	General & Intangible	205.5.g & 207.99.g	224,477,882	W/S	0.08771	19,689,486
5	Common	356.1	257,078,903	CE	0.05798	14,906,666
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 3,314,348,462	GP=	21.324%	$ 706,766,124
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ (14,039)	NA		
8	Transmission	219.25.c	234,826,697	TP	1.00000	$ 234,826,697
9	Distribution	219.26.c	695,437,497	NA		
10	General & Intangible	219.28.c	78,223,452	W/S	0.08771	6,861,164
11	Common	356.1	108,838,504	CE	0.05798	6,310,978
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 1,117,312,111			$ 247,998,839
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 14,039			
14	Transmission	(line 2 - line 8)	437,343,275			$ 437,343,275
15	Distribution	(line 3 - line 9)	1,465,184,208			
16	General & Intangible	(line 4 - line 10)	146,254,430			12,828,322
17	Common	(line 5 - line 11)	148,240,399			8,595,688
18	TOTAL NET PLANT (sum lines 13-17)		$ 2,197,036,351	NP=	20.881%	$ 458,767,285
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(545,338,977)	NP	0.20881	(113,873,256)
21	Account No. 283 (enter negative)	277.9.k	(58,450,636)	NP	0.20881	(12,205,187)
22	Account No. 190	234.8.c	33,089,463	NP	0.20881	6,909,473
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.20881	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (570,700,150)			$ (119,168,970)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 121,217		1.00000	$ 121,217
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 10,880,841			2,059,144
27	Materials & Supplies (Note G)	227.8.c & 227.16.c	8,969,793	TE	0.89162	7,997,663
28	Prepayments (Account 165)	111.57.c	957,851	GP	0.21324	204,256
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 20,808,485			$ 10,261,063
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 1,647,265,903			$ 349,980,595

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	
	O&M							
1	Transmission	321.112.b	$	33,312,297	TE	0.89162	$	29,701,969
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b		19,656,001		1.00000		19,656,001
1b	Less Midcontinent ISO Exit Fees included in Transmission O&M	(Note X)		0	TE	0.89162		0
2	Less Account 565	321.96.b		12,520	TE	0.89162		11,163
3	A&G	323.197.b		73,121,895	W/S	0.08771		6,413,694
3a	Less Actual PBOP Expense	(Note E)		(8,900)	W/S	0.08771		(781)
3b	Plus Fixed PBOP Expense	(Note E)		2,342,494	W/S	0.08771		205,466
3c	Less PJM Integration Costs included in A&G and Internal Integration Costs included in A&G	(Note Y)		0	W/S	0.08771		0
4	Less FERC Annual Fees	350.14.b		0	W/S	0.08771		0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)			2,070,335	W/S	0.08771		181,594
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			0	TE	0.89162		0
6	Common	356.1		0	CE	0.05798		0
7	Transmission Lease Payments			0		1.00000		0
8	TOTAL O&M (sum lines 1, 3, 3b, 5a, 6, 7 less lines 1a, 1b, 2, 3a, 3c, 4, 5)		$	87,046,730			$	16,473,152
	DEPRECIATION EXPENSE							
9	Transmission	336.7.b	$	12,318,073	TP	1.00000	$	12,318,073
10	General	336.10.b		13,781,072	W/S	0.08771		1,208,770
11	Common	336.11.b		10,762,246	CE	0.05798		624,047
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$	36,861,391			$	14,150,890
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i. 4, 5, 12	$	6,353,089	W/S	0.08771	$	557,244
14	Highway and vehicle	263.i. 6		10,172	W/S	0.08771		892
15	PLANT RELATED							
16	Property	263.i. 14, 20		102,283,386	GP	0.21324		21,811,355
17	Gross Receipts	263.i. 22		4,345,824	NA	zero		0
18	Other	263.i		0	GP	0.21324		0
19	Payments in lieu of taxes			0	GP	0.21324		0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$	112,992,471			$	22,369,491
	INCOME TAXES (Note K)							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			35.000000%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =			33.913043%				
	where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from line 21)			1.53846154				
24	Amortized Investment Tax Credit	266.8.f (enter negative)		(387,486)				
25	Income Tax Calculation (line 22 * line 28)		$	44,970,359	NA		$	9,554,470
26	ITC adjustment (line 23 * line 24)			(596,132)	NP	0.20881		(124,480)
27	Total Income Taxes	(line 25 plus line 26)	$	44,374,227			$	9,429,991
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$	132,604,905	NA		$	28,173,438
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$	413,879,724			$	90,596,962

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO
SUPPORTING CALCULATIONS AND NOTES

Line No.							
	TRANSMISSION PLANT INCLUDED IN ISO RATES						
1	Total transmission plant (page 2, line 2, column 3)						$ 672,169,972
2	Less transmission plant excluded from ISO rates (Note M)						0
3	Less transmission plant included in OATT Ancillary Services (Note N)						0
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)						$ 672,169,972
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)						$ 33,312,297
7	Less transmission expenses included in OATT Ancillary Services (Note L)						3,610,328
8	Included transmission expenses (line 6 less line 7)						$ 29,701,969
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.89162
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.89162

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	19,570,396	0.00	0			
13	Transmission	354.21.b	5,848,497	1.00	5,848,497			
14	Distribution	354.23.b	27,513,062	0.00	0			
15	Other	354.24,25,26.b	13,746,180	0.00	0			
16	Total (sum lines 12-15)		66,678,135		5,848,497	=	0.08771	= WS

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

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	2,544,725,550	0.66108	*	0.08771	=	0.05798
18	Gas	201.3.d	1,304,627,168					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		3,849,352,718					

RETURN (R)

Line			$
21		Long Term Interest (117, sum of 62.c through 67.c)	78,258,893
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	1,785,439,216
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	(616,384,737)
26		Common Stock (sum lines 23-25)	1,169,054,479

Line		(Note P)	$	%	Cost	Weighted
27	Long Term Debt (112, sum of 18.c through 21.c)		1,457,270,887	55%	0.0537	0.0298 =WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000
29	Common Stock (line 26)		1,169,054,479	45%	**0.1138**	0.0507
30	Total (sum lines 27-29)		2,626,325,366			0.0805 =R

REVENUE CREDITS

Line				Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$	172,456
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$	945,275

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

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

Note Letter	
A	DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (1) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
B	DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (2) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
C	Reserved
D	Reserved
E	This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts.
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Reserved
T	The revenues credited on page 1 lines 2-5b shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

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

Note Letter	
U	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Reserved
X	Midcontinent ISO Exit Fees include (1) the charge that DEOK paid to the Midcontinent ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midcontinent ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM. Internal Integration Costs are the internal administrative costs incurred by Duke Energy Ohio and Duke Energy Kentucky to accomplish their move from the Midcontinent ISO into PJM.

(1) For the purpose of calculating the DEO annual peak, the DEK annual peak as reported on page 401, column d of Form 1, was subtracted from the DEO annual peak as reported on page 400.

(2) For the purpose of calculating the DEO monthly peak, the DEK monthly peak as reported on page 401, column d of Form 1, was subtracted from the DEO monthly peak as reported on page 400.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
RTEP - Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A.

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	672,169,972	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	437,343,275	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	16,473,152	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.45%	2.45%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,832,817	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.27%	0.27%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	22,369,491	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	3.33%	3.33%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**6.05%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	9,429,991	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	2.16%	2.16%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	28,173,438	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.44%	6.44%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**8.60%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	6.05%	$0.00	$ -	8.60%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	6.05%	$0.00	$ -	8.60%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	6.05%	$0.00	$ -	8.60%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A											$0

Note Letter

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

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	672,169,972	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	437,343,275	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	16,473,152	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.45%	2.45%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,832,817	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.27%	0.27%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	22,369,491	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	3.33%	3.33%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**6.05%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	9,429,991	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	2.16%	2.16%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	28,173,438	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.44%	6.44%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**8.60%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,629,793	6.05%	$1,066,843.16	$ 15,644,459	8.60%	$1,345,133.98	$306,707	$2,718,684.14	$ -	$2,718,684.14
1b	Project 2	P2	$ -	6.05%	$0.00	$ -	8.60%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	6.05%	$0.00	$ -	8.60%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,718,684	$0	$2,718,684
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$2,718,684

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

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.			Total		Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)						$ 4,638,983
	REVENUE CREDITS (Note T)						
2	Account No. 454	(page 4, line 34)	$ 18,642	TP	0.66058		$ 12,315
3	Account No. 456.1	(page 4, line 35)	48,776	TP	0.66058		32,221
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.66058		0
4b	Revenues from service provided by ISO at a discount		0	TP	0.66058		0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		0		1.00000		0
5b	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000		0
6	TOTAL REVENUE CREDITS (sum lines 2-5b)						$ 44,535
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)					$ 4,594,448
	DIVISOR						
8	1 CP (Note A)						860,000
9	12 CP (Note B)						733,917
10	Reserved						
11	Reserved						
12	Reserved						
13	Reserved						
14	Reserved						
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$5.342				
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$6.260				
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.445				
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.522				
			Peak Rate				Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.120				
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.024	Capped at weekly rate			$0.017
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.002	Capped at weekly and daily rate			$0.715

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 826,664,425	NA		
2	Transmission	207.58.g	51,015,372	TP	0.66058	$ 33,699,833
3	Distribution	207.75.g	392,222,303	NA		
4	General & Intangible	205.5.g & 207.99.g	14,707,099	W/S	0.03124	459,430
5	Common	356.1	31,222,893	CE	0.02423	756,433
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 1,315,832,092	GP=	2.654%	$ 34,915,696
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 466,186,143	NA		
8	Transmission	219.25.c	18,190,407	TP	0.66058	$ 12,016,254
9	Distribution	219.26.c	146,664,750	NA		
10	General & Intangible	219.28.c	7,624,545	W/S	0.03124	238,180
11	Common	356.1	24,682,221	CE	0.02423	597,973
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 663,348,066			$ 12,852,407
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 360,478,282			
14	Transmission	(line 2 - line 8)	32,824,965			$ 21,683,579
15	Distribution	(line 3 - line 9)	245,557,553			
16	General & Intangible	(line 4 - line 10)	7,082,554			221,250
17	Common	(line 5 - line 11)	6,540,672			158,460
18	TOTAL NET PLANT (sum lines 13-17)		$ 652,484,026	NP=	3.381%	$ 22,063,289
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (234,803)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(185,984,930)	NP	0.03381	(6,288,950)
21	Account No. 283 (enter negative)	277.9.k	3,857,226	NP	0.03381	130,429
22	Account No. 190	234.8.c	(7,000,609)	NP	0.03381	(236,721)
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.03381	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (189,363,116)			$ (6,395,242)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ -		1.00000	$ -
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 2,341,384			215,478
27	Materials & Supplies (Note G)	227.8.c & 227.16.c	19,881	TE	0.63560	12,636
28	Prepayments (Account 165)	111.57.c	1,623,581	GP	0.02654	43,082
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 3,984,846			$ 271,196
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 467,105,756			$ 15,939,243

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ 13,842,413	TE	0.63560	$ 8,798,260
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	0		1.00000	0
1b	Less Midcontinent ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.63560	0
2	Less Account 565	321.96.b	11,958,297	TE	0.63560	7,600,713
3	A&G	323.197.b	17,140,643	W/S	0.03124	535,450
3a	Less Actual PBOP Expense	(Note E)	39,614	W/S	0.03124	1,237
3b	Plus Fixed PBOP Expense	(Note E)	575,908	W/S	0.03124	17,991
3c	Less PJM Integration Costs included in A&G and Internal Integration Costs included in A&G	(Note Y)	0	W/S	0.03124	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.03124	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		829,982	W/S	0.03124	25,928
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.63560	0
6	Common	356.1	0	CE	0.02423	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 3b, 5a, 6, 7 less lines 1a, 1b, 2, 3a, 3c, 4, 5)		$ 18,731,071			$ 1,723,823
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 875,956	TP	0.66058	$ 578,641
10	General	336.10.b	1,602,257	W/S	0.03124	50,052
11	Common	336.11.b	1,686,966	CE	0.02423	40,870
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 4,165,179			$ 669,563
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i. 6, 7, 13	$ 1,996,635	W/S	0.03124	$ 62,372
14	Highway and vehicle	263.i. 5	1,808	W/S	0.03124	56
15	PLANT RELATED					
16	Property	263.i. 14, 22	6,984,934	GP	0.02654	185,346
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.02654	0
19	Payments in lieu of taxes		0	GP	0.02654	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 8,983,377			$ 247,774
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.900000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote K.		48.446528%			
23	1 / (1 - T) = (from line 21)		1.63666121			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	(28,061)			
25	Income Tax Calculation (line 22 * line 28)		$ 19,122,056	NA		$ 652,510
26	ITC adjustment (line 23 * line 24)		(45,926)	NP	0.03381	(1,553)
27	Total Income Taxes	(line 25 plus line 26)	$ 19,076,129			$ 650,957
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 39,470,436	NA		$ 1,346,866
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 90,426,192			$ 4,638,983

Formula Rate - Non-Levelized | For the 12 months ended: 12/31/2014

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		$ 51,015,372
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		17,315,539
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)		$ 33,699,833
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.66058
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		$ 13,842,413
7	Less transmission expenses included in OATT Ancillary Services (Note L)		523,459
8	Included transmission expenses (line 6 less line 7)		$ 13,318,954
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.96218
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.66058
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.63560

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	12,072,909	0.00	0			
13	Transmission	354.21.b	1,004,765	0.66	663,730			
14	Distribution	354.23.b	5,008,018	0.00	0			
15	Other	354.21,22,23.b	3,161,385	0.00	0			
16	Total (sum lines 12-15)		21,247,077		663,730	=	0.03124	= WS

COMMON PLANT ALLOCATOR (CE)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	1,179,533,348	0.77554	*	0.03124	=	0.02423
18	Gas	201.3.d	341,381,951					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,520,915,299					

RETURN (R)

Line			$
21		Long Term Interest (117, sum of 62.c through 67.c)	14,785,725
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	413,255,929
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	0
26		Common Stock (sum lines 23-25)	413,255,929

Line		(Note P)	$	%	Cost	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		317,571,494	43%	0.0466	0.0202	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000	
29	Common Stock (line 26)		413,255,929	57%	**0.1138**	0.0643	
30	Total (sum lines 27-29)		730,827,423			0.0845	=R

REVENUE CREDITS

Line			Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)		0
32	b. Bundled Sales for Resale included in Divisor on page 1		0
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$ 18,642
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$ 48,776

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template

Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. [1] Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
B	DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. [2] Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
C	Reserved
D	Reserved
E	This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	6.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts.
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Reserved
T	The revenues credited on page 1 lines 2-5b shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2014

Rate Formula Template

Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

Note References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Letter

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

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

W Reserved

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

Y PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM. Internal Integration Costs are the internal administrative costs incurred by Duke Energy Ohio and Duke Energy Kentucky to accomplish their move from the Midcontinent ISO into PJM.

(1) For the purpose of calculating the DEK annual peak, the DEK annual peak is as reported on page 401, column d of Form 1, at the time of the DEK annual peak.

(2) For the purpose of calculating the DEK monthly peak, the DEK monthly peak is as reported on page 401, column d of Form 1, at the time of the DEK monthly peak.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	33,699,833	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	21,683,579	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	1,723,823	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	5.12%	5.12%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	90,922	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.27%	0.27%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	247,774	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.74%	0.74%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**6.12%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	650,957	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	3.00%	3.00%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	1,346,866	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.21%	6.21%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**9.21%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A											$0

Note Letter

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

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Att. H-22A, p 2, line 2 col 5 (Note A)	33,699,833	
2	Net Transmission Plant - Total	Att. H-22A, p 2, line 14 col 5 (Note B)	21,683,579	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Att. H-22A, p 3, line 8 col 5	1,723,823	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	5.12%	5.12%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Att. H-22A, p 3, lines 10 & 11, col 5 (Note H)	90,922	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.27%	0.27%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Att. H-22A, p 3, line 20 col 5	247,774	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.74%	0.74%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**6.12%**
	INCOME TAXES			
10	Total Income Taxes	Att. H-22A, p 3, line 27 col 5	650,957	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	3.00%	3.00%
	RETURN			
12	Return on Rate Base	Att. H-22A, p 3, line 28 col 5	1,346,866	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.21%	6.21%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**9.21%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Project 1	P1	$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
1b	Project 2	P2	$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	6.12%	$0.00	$ -	9.21%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$0

Note Letter

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

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Accumulated Deferred Income Taxes
Accounts 190, Account 282, and Account 283

Account 190	DEO	DEK	DEOK
Per Books Total, Page 234, lines 8 & 17, column c	$ 24,670,806	$ (6,382,295)	$ 18,288,511
Less:			
FAS 106	2,616,029	1,748,832	$ 4,364,861
FAS 109	761,636	45,371	$ 807,007
Gas Non-Utility	(11,796,322)	(1,175,889)	(12,972,211)
Adjusted Balances - To Page 2, Line 22	$ 33,089,463	$ (7,000,609)	$ 26,088,854

Account 282	DEO	DEK	DEOK
Per Books Total, Page 275, lines 2 & 6, column k	$ 604,171,587	$ 184,348,722	$ 788,520,309
Less:			
FAS 109	58,496,082	2,070,538	60,566,620
Gas Non-Utility	336,528	(3,706,746)	(3,370,218)
Adjusted Balances - To Page 2, Line 20	$ 545,338,977	$ 185,984,930	$ 731,323,907

Account 283	DEO	DEK	DEOK
Per Books Total, Page 277, lines 3 & 18, column k	$ 50,157,976	$ (5,277,443)	$ 44,880,533
Less:			
FAS 106	4,519,908		4,519,908
Gas Non-Utility	(12,812,568)	(1,420,217)	(14,232,785)
Adjusted Balances - To Page 2, Line 20	$ 58,450,636	$ (3,857,226)	$ 54,593,410

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Materials and Supplies
Allocation of Account 163

Duke Energy Ohio

	M&S [2]	Percentage	163 [3]	Total M&S [1]
Production	-	0.00%	-	
Transmission	9,021,050	21.84%	(51,257)	8,969,793
Distribution	32,276,930	78.16%	(183,394)	
Total M&S	41,297,980	100.00%	(234,651)	

Duke Energy Kentucky

	M&S [2]	Percentage	163 [3]	
Production	20,275,478	98.24%	1,619,245	
Transmission	18,411	0.09%	1,470	19,881
Distribution	343,925	1.67%	27,467	
Total M&S	20,637,814	100.00%	1,648,182	

Duke Energy Ohio and Kentucky

	M&S		163	
Production	20,275,478		1,619,245	
Transmission	9,039,461		(49,787)	8,989,674
Distribution	32,620,855		(155,927)	
Total M&S	61,935,794		1,413,531	

[1] To Page 2, Line 27.
[2] Source FERC Form 1, page 227, line 12, column (c)
[3] Source FERC Form 1, page 227, line 16, column (c)

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Detail of Land Held for Future Use

	Transmission Related	Non-Transmission Related Portion	Reported on FERC Form 1
Duke Energy Ohio			
East Bend Station		$ -	$ -
J.M. Stuart Station		-	-
Woodsdale Station		2,012,790	2,012,790
Other Projects	$ 121,217	-	121,217
J.M. Stuart Station - Production		-	-
East Bend Station - Production	-	251,236	251,236
Total	$ 121,217	$ 2,264,026	$ 2,385,243
Duke Energy Kentucky			
	-	-	-
Duke Energy Ohio and Kentucky			
Balances - To Page 2, Line 25	$ 121,217	$ 2,264,026	$ 2,385,243

Source: FERC Form 1 Page 214

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Non-Safety Adv., Reg. Comm. Exp. & EPRI

Description	Source	DEO	DEK	DEOK
General Advertising - 930.1	Form 1, P. 323.191, col. b,	$ 268,224	$ 50,164	$ 318,388
Regulatory Commission Expense	Form 1, P.350, col. d,	1,210,542	634,639	1,845,181
Ohio Consumers' Counsel	Form 1, P.350, col. d,	201,413		201,413
PUCO - Division of Forecasting	Form 1, P.350, col. d,	112,641		112,641
Request for Rate Increase	Form 1, P.350, col. d,	129,050		129,050
Electric Power Research Institute	Form 1, P.353, col.d,	1,651,489	336,068	1,987,557
Less amounts recorded in a non-formula related account	FERC Account 506	1,382,566	133,577	1,516,143
Less amounts recorded in a non-formula related account	FERC Account 588	44,793	41,628	86,421
Less amounts recorded in a non-formula related account	FERC Account 910	75,665	15,684	91,349
Total Electric Power Research Institute		148,465	145,179	293,644
Subtotal		$ 2,070,335	$ 829,982	$ 2,900,317
Amount of Safety Related Advertising		-	-	-
Non-Safety Adv., Reg. Comm. Exp. & EPRI - To Page 3, Line 5		$ 2,070,335	$ 829,982	$ 2,900,317

Duke Energy Ohio and Duke Energy Kentucky

Balancing Authority Costs

	DEO	DEK	DEOK
A&G Expense			
A&G Expense, Page 323, line 197, column b	$ 80,542,376	$ 18,598,709	$ 99,141,085
Less: Duke / Progress merger costs to achieve. (Includes payroll taxes and depreciation expense)	7,139,520	1,351,490	8,491,010
Less: Lobbying Expense	49,082	18,374	67,456
Less: DEP acq of NC Muni's	110,844	15,186	126,030
Less: Midwest Generation Assets to Dynegy	84,580	11,588	96,168
Less: DEK acq East Bend	36,455	61,428	97,883
Less: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted A&G Expense - To Page 3, Line 3	$ 73,121,895	$ 17,140,643	$ 90,262,538
Transmission Expense			
Transmission Expense, Page 321, line 112, column b	$ 33,312,297	$ 13,842,413	$ 47,154,710
Add: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted Transmission Expense - To Page 3, Line 1	$ 33,312,297	$ 13,842,413	$ 47,154,710
Balancing Authority Costs in 561 through 561.3			
B.A. Costs in Transmission Expense on Page 321 of FF1	$ 3,610,328	$ 523,459	$ 4,133,787
Add: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted B.A. Costs - To Page 4, Line 7	$ 3,610,328	$ 523,459	$ 4,133,787

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

State Tax Composite Rate

State	Ohio	Kentucky	
	Duke Energy Ohio	Duke Energy Kentucky	TOTAL
Revenue Requirement	$ 90,596,961.77	$ 4,638,982.84	$ 95,235,944.61
Tax Rate	0.00%	6.00%	
State Taxes	$ -	$ 278,338.97	$ 278,338.97
Composite Tax Rate	0.00%	6.00%	0.29%

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Determination of Transmission Plant Included in OATT Ancillary Services

	DEO	DEK	DEOK
Total Generation Step-up Transformers	$ -	$ 17,315,539	$ 17,315,539
Assets removed through 2011 by FERC Agreement	-	-	-
Sole use Property	-	-	-
Distribution Use	-	-	-
Transmission plant included in OATT Ancillary Services - To Page 4, Line 3	$ -	$ 17,315,539	$ 17,315,539

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

Revenue Credits, Accounts 454 and 456

	Account 454		
	DEO	DEK	DEOK
Per Books Total, Page 300	$ 13,006,302	$ 765,901	$ 13,772,203
Tower Lease Revenues in per Books Total above	75,952	10,078	86,030
Rent from Electric Property in per Books Total above	1,930,071	171,283	2,101,354
Portion Attributable to Transmission	5.0%	5.0%	5.0%
Revenue Credit Applicable to Attachment H-22A	$ 172,456	$ 18,642	$ 191,098
Step-ups leased to Duke Energy Kentucky	-	-	-
Total Account 454 - To Page 4, Line 34	$ 172,456	$ 18,642	$ 191,098

	Account 456		
	DEO	DEK	DEOK
Total Account 456 Per Books Total, Page 300	$ 13,590,853	$ 4,935,649	$ 18,526,502
Less: Other Electric Revenues	1,201,733	1,631,155	2,832,888
Revenues from Transmission of Electricity for Others	$ 12,389,120	$ 3,304,494	$ 15,693,614
Less: Transmission Revenues - Load in Divisor			
Sch 1 - Scheduling, System Control & Dispatch	$ 257,665	$ -	257,665
Sch 2 - Reactive Supply & Voltage Control	(5,059,069)	-	(5,059,069)
Sch 4 - Day-Ahead Load Response Charge Allocation	(174,925)	-	(174,925)
Sch 4 - Real-Time Load Response Charge Allocation	(268,950)	-	(268,950)
Sch 8 - Non-Firm PTP	95,591	17,294	112,885
Sch 9 - NITS	16,662,425	-	16,662,425
Sch 24 - Load Balancing	-		-
Sch 26 - MTEP Project Cost Recovery	1,650,160	-	1,650,160
PJM Customer Payment Default	(1,539)	-	(1,539)
Facilities Charges	176,865	52,176	229,041
Other Transmission Revenues - FTR's	-	3,181,954	3,181,954
MISO - Sch 37	41,798	4,294	46,092
Miscellaneous Bilateral	(1,936,176)	-	(1,936,176)
Total Transmission Revenues - Load in Divisor	$ 11,443,845	$ 3,255,718	$ 14,699,563
Total Account 456.1 - To Page 4, Line 35	$ 945,275	$ 48,776	$ 994,051

Duke Energy Ohio and Duke Energy Kentucky

Duke Energy Ohio Consolidated
Capital Structure
December 31, 2014
(In Dollars)

	Actual 12/31/14		Purchase Accounting		Goodwill Impairments Sep09 and Jun10	Other Asset Impairment Charges		Adjusted 12/31/14	Midwest DENA Equity BU 75032	BU 75012 (3)	Remove Commercial Power (inlcludes reversal of CP CP impairements and purchase accounting)	Capital Structure without Purchase accounting and Midwest DENA	
Liabilities and Shareholders' Equity													
Current Maturities of Long-Term Debt	$ 156,524,070		$ -					$ 156,524,070				$ 156,524,070	
Non-Current Liabilities													
Long-Term Debt (3)	$ 1,583,623,545		$ 5,659,687					$ 1,589,283,232			$ (5,659,687)	$ 1,583,623,545	
Deferred Debt Expense	(7,878,850)		(2,838,763)					(10,717,613)			2,838,763	(7,878,850)	
Less: Current portion of deferred debt expense	(6,031,426)							(6,031,426)				(6,031,426)	
0257010 Unamortized Gain-Debt	362,985							362,985				362,985	
Total Long-Term Debt Excl. Current Maturities	**$ 1,570,076,254**		**$ 2,820,924**		**$ -**	**$ -**		**$ 1,572,897,178**	**$ -**	**$ -**	**$ (2,820,924)**	**$ 1,570,076,254**	
Total Long Term Debt	**$ 1,726,600,324**	**27%**	**$ 2,820,924**		**$ -**	**$ -**		**$ 1,729,421,248**	**$ -**	**$ -**	**$ (2,820,924)**	**$ 1,726,600,324**	**49%**
Common Stock Equity													
0201000 Common Stock Issued	$ 762,136,231		$ -					$ 762,136,231	$ -	$ -	$ (370,509,197)	$ 391,627,034	
207000 Premium on capital stock	-		362,457,437					362,457,437			(362,457,437)	-	
0208000 Donations From Stockholder	28,950,000		197,206,819					226,156,819			(203,924,057)	22,232,762	
0208001 Donations From Stockholder-DENA	1,462,336,840		-					1,462,336,840	(1,462,336,840)		-	-	
0208010 Donat Recvd From Stkhld Tax	15,641,578		68,538,328					84,179,906			(75,017,726)	9,162,180	
210020 Gain on Redemption of Capital	-		147,685					147,685			(147,685)	-	
0211003 Misc Paid In Capital	(44,006,414)		-					(44,006,414)		-	899,032,355	855,025,941	
0211004 Misc Paid In Capital Purch Acctg	943,842,010		(2,879,949,148)					(1,936,107,138)		-	2,490,915,795	554,808,657	
0211008 Misc PIC Pushdown Adj RE	1,817,546,493		-					1,817,546,493			(1,817,546,493)	-	
0211005 Misc Paid in Capital Premerger Equity	557,581,098		(603,514,486)					(45,933,388)			670,740,300	624,806,912	
0211007 Misc PIC Premerg RE for Div	-		(625,474,493)					(625,474,493)			625,474,493	-	
211110 PIC - Sharesaver (BDMS account)	-		(3,350,836)					(3,350,836)			3,350,836	-	
214010 Common stock equity inter-company	-		(21,750,868)					(21,750,868)			21,750,868	-	
												-	
0216000/0216100 Unappropriated RE/Undistr Subsid Earnings	(364,873,259)		961,227,241	(1)	1,403,452,846	117,257,663	(1)	2,117,064,491	(160,991,458)	-	(1,862,736,177)	93,336,856	
0216100 Unappropriated RE/Undistr Subsid Earnings - Equitization	-							-	1,631,002,899		(2,584,760,613)	(953,757,714)	
0438000 Dividends Declared on Common Stock	-							-				-	
Current Year Net Income	(493,115,998)		5,769,832	(2)	-	-	(2)	(487,346,166)	155,653	-	675,387,100	188,196,587	
Accum other comprehensive income (loss)	4		(45,455,363)					(45,455,359)	-	-	45,455,360	1	
Total Common Stock Equity	**$ 4,686,038,583**	**73%**	**$ (2,584,147,852)**		**$ 1,403,452,846**	**$ 117,257,663**		**$ 3,622,601,240**	**$ 7,830,254**	**$ -**	**$ (1,844,992,278)**	**$ 1,785,439,216**	**51%**
TOTAL CAPITALIZATION	**$ 6,412,638,907**		**$ (2,581,326,928)**		**$ 1,403,452,846**	**$ 117,257,663**		**$ 5,352,022,488**	**$ 7,830,254**	**$ -**	**$ (1,847,813,202)**	**$ 3,512,039,540**	

Adjustment to Proprietary Capital for Duke Ohio Attachment H-22A, page 4, line 23 $ (2,900,599,367)

Notes:
(1) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in prior year retained earnings balances net of tax at an assumed tax rate of 38% - 2006, 33.5% - 2007, 37.4% - 2008, 35.4% - 2009, 35.4% - 2010 and 35.4% - 2009 through 2013.
(2) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in current year retained earnings balances net of tax at an assumed tax rate of 35.4%.
(3) Midwest DENA Assets were reclassed from B.U. 75032 to B.U. 75012 in June 2011. No longer part of parent Duke Energy Ohio Consolidated as of 9/30/14.

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2014

2014 MONTHLY PEAKS IN KILOWATTS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
DEO - Monthly Transmission System Peak Load (1)	5,105,000	4,597,000	4,107,000	3,451,000	4,390,000	4,939,000	4,938,000	5,039,000	4,937,000	3,673,000	4,096,000	3,865,000	53,137,000	4,428,083
Less:														
DEK Monthly Peak Demand (2)	860,000	746,000	684,000	554,000	726,000	816,000	819,000	837,000	815,000	632,000	680,000	638,000	8,807,000	733,917
DEO - Monthly Transmission System Peak Load	4,245,000	3,851,000	3,423,000	2,897,000	3,664,000	4,123,000	4,119,000	4,202,000	4,122,000	3,041,000	3,416,000	3,227,000	44,330,000	3,694,166

Notes:

(1) DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak,
(2) Source: DEK peak as reported on FERC Form 1 Page 401b.

Prior Period Corrections to May 2015 Annual Update Filing

Line No.	Description		Revenue Impact of Correction	Calendar Year 2013 Revenue Requirement
1	May 15, 2014 Filing			$ 81,729,172
2				
3				
4	Reduction in ROE to 11.38%			
5		Return	$ (2,212,171)	
6		Income Tax	(1,196,883)	
7		Firm PTP Rev. Cr.	243	
8		MTEP Credit	123,605	
9			$ (3,285,206)	$ (3,285,206)
10				
11				
12	Corrected Revenue Requirement			$ 78,443,966
13				
14				
15	Corrections to May 15, 2014 Attachment H Filing			$ 3,285,206
16				
17	FERC Refund Rate			3.25%
18				
19	Total Annual Refunds Due to Customers			$ 3,391,975
20				
21	April 16, 2015 through May 31, 2015 (Line 19 / 365 * 46)			$ 427,482
22				
23	Total Refunds Due to Customers - To Attachment H, page 1 of 6			$ 427,482

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 15th day of May, 2015.

/s/ Gary A. Morgans

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