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Steptoe
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May 15, 2014

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 – Corrected
Docket No. ER12-91-000

Dear Secretary Bose:

On May 14, 2014, Duke Energy Ohio, Inc. ("DEO") and Duke Energy Kentucky, Inc. ("DEK") (together, "the Companies") submitted their Formula Rate Annual Update in the above-captioned docket. Enclosed for filing is a corrected version of the Companies' Annual Update. The correction in the filing appears on Attachment H-22A for DEOK, Page 1 of 6, Line 8, which is being corrected from 5,153,000 kW to 5,146,000 kW. This changes the Annual Cost on line 15 from $15.861/kW-year to $15.882/kW-year and the monthly network rate on line 17 from $1.322/kW-month to $1.324/kW-month.

In accordance with the Companies' Formula Rate Implementation Protocols, the corrected Annual Update is submitted for informational purposes only, and is not a filing

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under Section 205 of the Federal Power Act. The Companies request that the Commission not act on or issue public notice of this 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 12/31/2013

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 84,513,652
	REVENUE CREDITS (Note T)		Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 181,444	TP	0.96469	$ 175,038
3	Account No. 456.1	(page 4, line 35)	1,007,758	TP	0.96469	972,177
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.96469	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.96469	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,662,478		1.00000	2,662,478
5b	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		(1,025,212)		1.00000	(1,025,212)
	Corrections Related to Prior Years		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 2,784,480
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 81,729,172
	DIVISOR					
8	1 CP (Note A)					5,146,000
9	12 CP (Note B)					4,357,833
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$15.882			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$18.755			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$1.324			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.563			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.361			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.072	Capped at weekly rate		$0.051
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.005	Capped at weekly and daily rate		$2.141

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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	$ 4,272,260,362	NA		
2	Transmission	207.58.g	709,106,552	TP	0.96469	$ 684,069,750
3	Distribution	207.75.g	2,500,428,108	NA		
4	General & Intangible	205.5.g & 207.99.g	256,697,727	W/S	0.03374	8,661,545
5	Common	356.1	270,374,070	CE	0.02799	7,566,439
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 8,008,866,819	GP=	8.744%	$ 700,297,733
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 1,765,405,481	NA		
8	Transmission	219.25.c	252,686,076	TP	0.96469	$ 243,764,354
9	Distribution	219.26.c	828,269,105	NA		
10	General & Intangible	219.28.c	114,530,778	W/S	0.03374	3,864,520
11	Common	356.1	120,931,347	CE	0.02799	3,384,273
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 3,081,822,787			$ 251,013,147
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 2,506,854,881			
14	Transmission	(line 2 - line 8)	456,420,476			$ 440,305,395
15	Distribution	(line 3 - line 9)	1,672,159,003			
16	General & Intangible	(line 4 - line 10)	142,166,949			4,797,025
17	Common	(line 5 - line 11)	149,442,723			4,182,166
18	TOTAL NET PLANT (sum lines 13-17)		$ 4,927,044,032	NP=	9.119%	$ 449,284,586
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (87,010,074)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(1,215,631,035)	NP	0.09119	(110,850,295)
21	Account No. 283 (enter negative)	277.9.k	(88,083,206)	NP	0.09119	(8,032,083)
22	Account No. 190	234.8.c	132,939,268	NP	0.09119	12,122,393
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.09119	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (1,257,785,047)			$ (106,759,985)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 121,217		1.00000	$ 121,217
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 20,415,851			1,766,296
27	Materials & Supplies (Note G)	227.8.c & 277.16.c	9,997,460	TE	0.92626	9,260,233
28	Prepayments (Account 165)	111.57.c	35,789,576	GP	0.08744	3,129,451
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 66,202,887			$ 14,155,981
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 3,735,583,089			$ 356,801,798

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

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	$ 35,353,827	TE	0.92626	$ 32,746,787
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b, 322.121.b	15,434,390		1.00000	15,434,390
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.92626	0
2	Less Account 565	321.96.b	8,986,849	TE	0.92626	8,324,146
3	A&G	323.197.b	153,820,763	W/S	0.03374	5,190,250
3a	Less Actual PBOP Expense	(Note E)	1,773,609	W/S	0.03374	59,845
3b	Plus Fixed PBOP Expense	(Note E)	2,918,402	W/S	0.03374	98,473
3c	Less PJM Integration Costs included in A&G	(Note Y)	0	W/S	0.03374	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.03374	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		2,571,331	W/S	0.03374	86,762
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.92626	0
6	Common	356.1	0	CE	0.02799	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 163,326,813			$ 14,130,367
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 12,695,227	TP	0.96469	$ 12,246,990
10	General	336.10.b	21,259,734	W/S	0.03374	717,350
11	Common	336.11.b	13,664,730	CE	0.02799	382,409
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 47,619,691			$ 13,346,749
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	$ 10,977,180	W/S	0.03374	$ 370,394
14	Highway and vehicle	263.i	19,751	W/S	0.03374	666
15	PLANT RELATED					
16	Property	263.i	110,139,454	GP	0.08744	9,630,627
17	Gross Receipts	263.i	4,505,259	NA	zero	0
18	Other	263.i	0	GP	0.08744	0
19	Payments in lieu of taxes		0	GP	0.08744	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 125,641,644			$ 10,001,687
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.182000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		45.371258%			
	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)		1.54278133			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	(440,384)			
25	Income Tax Calculation (line 22 * line 28)		$ 153,895,200	NA		$ 14,699,200
26	ITC adjustment (line 23 * line 24)		(679,416)	NP	0.09119	(61,954)
27	Total Income Taxes	(line 25 plus line 26)	$ 153,215,784			$ 14,637,246
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 339,190,944	NA		$ 32,397,603
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 828,994,876			$ 84,513,652

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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)					$ 709,106,552
2	Less transmission plant excluded from ISO rates (Note M)					0
3	Less transmission plant included in OATT Ancillary Services (Note N)					25,036,802
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)					$ 684,069,750
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	0.96469
	TRANSMISSION EXPENSES					
6	Total transmission expenses (page 3, line 1, column 3)					$ 35,353,827
7	Less transmission expenses included in OATT Ancillary Services (Note L)					1,408,515
8	Included transmission expenses (line 6 less line 7)					$ 33,945,312
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					0.96016
10	Percentage of transmission plant included in ISO Rates (line 5)				TP	0.96469
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)				TE=	0.92626

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		
12	Production	354.20.b	63,902,666	0.00	0		
13	Transmission	354.21.b	4,131,237	0.96	3,985,373		
14	Distribution	354.23.b	31,295,891	0.00	0		W&S Allocator
15	Other	354.24,25,26.b	18,782,652	0.00	0		($ / Allocation)
16	Total (sum lines 12-15)		118,112,446		3,985,373	=	0.03374 = WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	6,894,483,114	0.82938	*	0.03374	=	0.02799
18	Gas	201.3.d	1,418,340,451					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		8,312,823,565					

RETURN (R)

Line No.			$
21		Long Term Interest (117, sum of 62.c through 67.c)	84,296,499
22		Preferred Dividends (118 29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	3,941,509,258
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	(472,780,021)
26		Common Stock (sum lines 23-25)	3,468,729,237

Line No.	(Note P)	$	%	Cost	Weighted
27	Long Term Debt (112, sum of 18.c through 21.c)	2,191,842,381	39%	0.0385	0.0149 =WCLTD
28	Preferred Stock (112.3.c)	0	0%	0.0000	0.0000
29	Common Stock (line 26)	3,468,729,237	61%	0.1238	0.0759
30	Total (sum lines 27-29)	5,660,571,618			0.0908 =R

REVENUE CREDITS

Line No.			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)		$ 181,444
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x n)	$ 1,007,758

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

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

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. 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=	0.28%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

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

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

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

O Enter dollar amounts.

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

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

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

S Reserved

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

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

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

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

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	Midwest ISO Exit Fees include (1) the charge that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.
Z	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: 12/31/2013

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective June 1, 2014

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	$	1,408,515	
2	Revenue Credits for Schedule 1A - Note A		$	123,311	
3	Net Schedule 1A Revenue Requirement for Zone		$	1,285,204	
B.	Schedule 1A Rate Calculations				
4	2013 Annual MWh - Note B	(401a.22b & 24b)		23,846,378	MWh
5	Schedule 1A rate $/MWh (Line 3 / Line 4)	(Line 3 / Line 4)		$0.0539	$/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 Load expressed in MWh consistent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year

Rate Formula Template
Utilizing Attachment H-22A Data

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

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

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	684,069,750	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	440,305,395	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	14,130,367	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.07%	2.07%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,099,759	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.16%	0.16%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	10,001,687	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.46%	1.46%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.69%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	14,637,246	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.32%	3.32%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	32,397,603	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.36%	7.36%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.68%**

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 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	3.69%	$0.00	$ -	10.68%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	3.69%	$0.00	$ -	10.68%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	3.69%	$0.00	$ -	10.68%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c											$0

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.

For the 12 months ended: 12/31/2013

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

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

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	684,069,750	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	440,305,395	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	14,130,367	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.07%	2.07%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,099,759	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.16%	0.16%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	10,001,687	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.46%	1.46%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.69%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	14,637,246	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.32%	3.32%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	32,397,603	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.36%	7.36%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.68%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,643,147	3.69%	$650,764.91	$ 15,964,520	10.68%	$1,705,381.75	$306,331	$2,662,477.66	$ -	$2,662,477.66
1b	Project 2	P3	$ -	3.69%	$0.00	$ -	10.68%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	3.69%	$0.00	$ -	10.68%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,662,478	$0	$2,662,478
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$2,662,478

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.

	(1)	(2)	(3)
No.		Reference	Company Total
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenue Received In PJM vs. Midwest ISO	(Note A)	($991,787)
	ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP		
2	Accumulated Balance of Deferral	(Note B)	($1,295,063)
3	Income Tax Rate for Deferral Calculation	(Note C)	45.37%
4	Deferred Income Taxes on Accumulated Deferral (Line 2 * Line 3)		($587,586)
5	Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4)		($707,477)
	INCOME TAXES		
6	CIT = (T/(1-T)) * (1 - (WCLTD/R))	Attachment H-22, page 3, line 22	45.37%
7	Income Taxes (Line 6 * Line 9)		($10,432)
	CARRYING COST ON DEFERRAL		
8	FERC Refund Rate	(Note D)	3.25%
9	Carrying Cost (Line 5 * Line 8)		($22,993)
10	Revenue Credit Adjustment (Line 1 + Line 7 + Line 9)		($1,025,212)

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					$ -	$ (1,295,063)
Feb-14					-	(1,295,063)
Mar-14					-	(1,295,063)
Apr-14					-	(1,295,063)
May-14					-	(1,295,063)
Jun-14					-	(1,295,063)
Jul-14					-	(1,295,063)
Aug-14					-	(1,295,063)
Sep-14					-	(1,295,063)
Oct-14					-	(1,295,063)
Nov-14					-	(1,295,063)
Dec-14					-	$ (1,295,063)
Total				$ -	$ -	
Jan-15					$ -	$ (1,295,063)
Feb-15					-	(1,295,063)
Mar-15					-	(1,295,063)
Apr-15					-	(1,295,063)
May-15					-	$ (1,295,063)
Total				$ -	$ -	

Notes:

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

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

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)					$ 81,752,520
	REVENUE CREDITS (Note T)					
2	Account No. 454	(page 4, line 34)	$ 163,190	TP	0.97961	$ 159,863
3	Account No. 456.1	(page 4, line 35)	939,109	TP	0.97961	919,962
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.97961	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.97961	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,702,346		1.00000	2,702,346
5b	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		(1,025,212)		1.00000	(1,025,212)
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 2,756,958
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 78,995,562
	DIVISOR					
8	1 CP (Note A)					4,295,000
9	12 CP (Note B)					3,638,833
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$18.392			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$21.709			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$1.533			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.809			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.417			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.083	Capped at weekly rate		$0.059
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.005	Capped at weekly and daily rate		$2.478

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

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	$ 3,465,019,849	NA		
2	Transmission	207.58 g	665,074,281	TP	0.97961	$ 651,514,416
3	Distribution	207.75 g	2,118,397,113	NA		
4	General & Intangible	205.5 g & 207.99.g	245,447,036	W/S	0.03478	8,537,822
5	Common	356.1	239,971,862	CE	0.02928	7,025,559
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 6,733,910,141	GP=	9.906%	$ 667,077,797
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 1,303,134,293	NA		
8	Transmission	219.25.c	234,993,182	TP	0.97961	$ 230,202,024
9	Distribution	219.26.c	681,054,969	NA		
10	General & Intangible	219.28.c	108,521,565	W/S	0.03478	3,774,899
11	Common	356.1	97,689,983	CE	0.02928	2,860,030
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 2,425,393,992			$ 236,836,953
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 2,161,885,556			
14	Transmission	(line 2 - line 8)	430,081,099			$ 421,312,392
15	Distribution	(line 3 - line 9)	1,437,342,144			
16	General & Intangible	(line 4 - line 10)	136,925,471			4,762,923
17	Common	(line 5 - line 11)	142,281,879			4,165,529
18	TOTAL NET PLANT (sum lines 13-17)		$ 4,308,516,149	NP=	9.986%	$ 430,240,844
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (86,615,578)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(1,035,945,559)	NP	0.09986	(103,447,701)
21	Account No. 283 (enter negative)	277.9.k	(92,278,087)	NP	0.09986	(9,214,727)
22	Account No. 190	234.8.c	139,113,973	NP	0.09986	13,891,677
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.09986	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (1,075,725,251)			$ (98,770,751)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 121,217		1.00000	$ 121,217
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 17,659,057			1,580,799
27	Materials & Supplies (Note G)	227.8.c & 277.16.c	9,966,887	TE	0.93249	9,293,982
28	Prepayments (Account 165)	111.57.c	34,113,864	GP	0.09906	3,379,404
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 61,739,808			$ 14,254,185
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 3,294,651,923			$ 345,845,495

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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	$ 25,124,061	TE	0.93249	$ 23,427,833
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	15,316,689		1.00000	15,316,689
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.93249	0
2	Less Account 565	321.96.b	42,038	TE	0.93249	39,200
3	A&G	323.197.b	132,266,115	W/S	0.03478	4,600,848
3a	Less Actual PBOP Expense	(Note E)	1,225,300	W/S	0.03478	42,622
3b	Plus Fixed PBOP Expense	(Note E)	2,342,494	W/S	0.03478	81,483
3c	Less PJM Integration Costs included in A&G	(Note Y)	0	W/S	0.03478	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.03478	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		1,876,185	W/S	0.03478	65,263
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.93249	0
6	Common	356.1	0	CE	0.02928	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 141,272,458			$ 12,646,390
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 11,845,312	TP	0.97961	$ 11,603,804
10	General	336.10.b	20,133,182	W/S	0.03478	700,328
11	Common	336.11.b	11,646,132	CE	0.02928	340,959
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 43,624,626			$ 12,645,091
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i 4, 5, 12	$ 9,022,646	W/S	0.03478	$ 313,851
14	Highway and vehicle	263.i. 6	16,796	W/S	0.03478	584
15	PLANT RELATED					
16	Property	263.i 14, 20	103,346,700	GP	0.09906	10,237,780
17	Gross Receipts	263.i 22	4,505,259	NA	zero	0
18	Other	263.i	0	GP	0.09906	0
19	Payments in lieu of taxes		0	GP	0.09906	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 116,891,401			$ 10,552,215
	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)) =		45.589350%			
	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)	(403,726)			
25	Income Tax Calculation (line 22 * line 28)		$ 137,133,551	NA		$ 14,395,154
26	ITC adjustment (line 23 * line 24)		(621,117)	NP	0.09986	(62,024)
27	Total Income Taxes	(line 25 plus line 26)	$ 136,512,434			$ 14,333,130
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 300,801,721	NA		$ 31,575,694
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 739,102,640			$ 81,752,520

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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)		$ 665,074,281
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		13,559,865
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)		$ 651,514,416
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.97961
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		$ 25,124,061
7	Less transmission expenses included in OATT Ancillary Services (Note L)		1,208,628
8	Included transmission expenses (line 6 less line 7)		$ 23,915,433
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.95189
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.97961
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.93249

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	52,203,923	0.00	0			
13	Transmission	354.21.b	3,468,725	0.98	3,398,003			
14	Distribution	354.23.b	26,712,409	0.00	0			
15	Other	354.24,25,26 b	15,301,417	0.00	0			
16	Total (sum lines 12-15)		97,686,474		3,398,003	=	0.03478	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	5,787,117,909	0.84165	*	0.03478	=	0.02928
18	Gas	201.3.d	1,088,806,042					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		6,875,923,951					

RETURN (R)

Line No.			$
21		Long Term Interest (117, sum of 62.c through 67.c)	69,358,977
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16 c)	3,563,555,144
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12 c) (enter negative)	(472,780,021)
26		Common Stock (sum lines 23-25)	3,090,775,123

Line No.		(Note P) $	%	Cost	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	1,859,270,887	38%	0.0373	0.0140	=WCLTD
28	Preferred Stock (112.3 c)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	3,090,775,123	62%	0.1238	0.0773	
30	Total (sum lines 27-29)	4,950,046,010			0.0913	=R

REVENUE CREDITS

Line No.			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)		$ 163,190
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$ 939,109

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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	Midwest ISO Exit Fees include (1) the charge that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

(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.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	651,514,416	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	421,312,392	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	12,646,390	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	1.94%	1.94%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,041,287	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.16%	0.16%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	10,552,215	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.62%	1.62%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.72%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	14,333,130	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.40%	3.40%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	31,575,694	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.49%	7.49%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.90%**

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 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	3.72%	$0.00	$ -	10.90%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	3.72%	$0.00	$ -	10.90%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	3.72%	$0.00	$ -	10.90%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c											$0

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.

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	Sch. H-22A, p 2, line 2 col 5 (Note A)	651,514,416	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	421,312,392	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	12,646,390	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	1.94%	1.94%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	1,041,287	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.16%	0.16%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	10,552,215	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.62%	1.62%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.72%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	14,333,130	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.40%	3.40%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	31,575,694	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.49%	7.49%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.90%**

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 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,643,147	3.72%	$656,421.36	$ 15,964,520	10.90%	$1,739,593.60	$306,331	$2,702,345.96	$ -	$2,702,345.96
1b	Project 2	P2	$ -	3.72%	$0.00	$ -	10.90%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	3.72%	$0.00	$ -	10.90%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,702,346	$0	$2,702,346
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$2,702,346

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: 12/31/2013

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 4,055,781
	REVENUE CREDITS (Note T)		Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 18,254	TP	0.73935	$ 13,496
3	Account No. 456.1	(page 4, line 35)	68,649	TP	0.73935	50,756
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.73935	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.73935	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)					$ 64,252
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 3,991,529
	DIVISOR					
8	1 CP (Note A)					858,000
9	12 CP (Note B)					719,000
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$4.652			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$5.552			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.388			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.463			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.107			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.021	Capped at weekly rate		$0.015
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.001	Capped at weekly and daily rate		$0.634

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

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	$ 807,240,513	NA		
2	Transmission	207.58 g	44,032,271	TP	0.73935	$ 32,555,334
3	Distribution	207.75.g	382,030,995	NA		
4	General & Intangible	205.5 g & 207.99 g	11,250,691	W/S	0.02398	269,800
5	Common	356.1	30,402,208	CE	0.01848	561,865
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 1,274,956,678	GP=	2.619%	$ 33,386,999
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24 c	$ 462,271,188	NA		
8	Transmission	219.25.c	17,692,894	TP	0.73935	$ 13,081,271
9	Distribution	219.26 c	147,214,136	NA		
10	General & Intangible	219.28 c	6,009,213	W/S	0.02398	144,105
11	Common	356.1	23,241,364	CE	0.01848	429,525
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 656,428,795			$ 13,654,901
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 344,969,325			
14	Transmission	(line 2 - line 8)	26,339,377			$ 19,474,063
15	Distribution	(line 3 - line 9)	234,816,859			
16	General & Intangible	(line 4 - line 10)	5,241,478			125,695
17	Common	(line 5 - line 11)	7,160,844			132,340
18	TOTAL NET PLANT (sum lines 13-17)		$ 618,527,883	NP=	3.190%	$ 19,732,098
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (394,496)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(179,685,476)	NP	0.03190	(5,732,274)
21	Account No. 283 (enter negative)	277.9.k	4,194,881	NP	0.03190	133,824
22	Account No. 190	234.8.c	(6,174,705)	NP	0.03190	(196,984)
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.03190	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		$ (182,059,796)			$ (5,795,434)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ -		1.00000	$ -
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 2,756,794			164,332
27	Materials & Supplies (Note G)	227.8.c & 277.16.c	30,573	TE	0.72490	22,163
28	Prepayments (Account 165)	111.57.c	1,675,712	GP	0.02619	43,881
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 4,463,079			$ 230,376
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 440,931,166			$ 14,167,040

Formula Rate - Non-Levelized

For the 12 months ended: 12/31/2013

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	$ 10,229,766	TE	0.72490	$ 7,415,608
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	117,701		1.00000	117,701
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.72490	0
2	Less Account 565	321.96.b	8,944,811	TE	0.72490	6,484,138
3	A&G	323.197.b	21,554,648	W/S	0.02398	516,896
3a	Less Actual PBOP Expense	(Note E)	548,309	W/S	0.02398	13,149
3b	Plus Fixed PBOP Expense	(Note E)	575,908	W/S	0.02398	13,811
3c	Less PJM Integration Costs included in A&G	(Note Y)	0	W/S	0.02398	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.02398	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		695,146	W/S	0.02398	16,670
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.72490	0
6	Common	356.1	0	CE	0.01848	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 22,054,355			$ 1,314,657
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 849,915	TP	0.73935	$ 628,386
10	General	336.10.b	1,126,552	W/S	0.02398	27,016
11	Common	336.11.b	2,018,598	CE	0.01848	37,306
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 3,995,065			$ 692,708
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i. 6, 7, 13	$ 1,954,534	W/S	0.02398	$ 46,871
14	Highway and vehicle	263.i. 5	2,955	W/S	0.02398	71
15	PLANT RELATED					
16	Property	263.i. 14, 22	6,792,754	GP	0.02619	177,880
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.02619	0
19	Payments in lieu of taxes		0	GP	0.02619	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 8,750,243			$ 224,822
	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)) =		48.280752%			
	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)		1.63666121			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	(36,658)			
25	Income Tax Calculation (line 22 * line 28)		$ 18,499,696	NA		$ 594,392
26	ITC adjustment (line 23 * line 24)		(59,997)	NP	0.03190	(1,914)
27	Total Income Taxes	(line 25 plus line 26)	$ 18,439,700			$ 592,478
28	RETURN		$ 38,316,918	NA		$ 1,231,116
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 91,556,281			$ 4,055,781

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2013

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)				$	44,032,271
2	Less transmission plant excluded from ISO rates (Note M)					0
3	Less transmission plant included in OATT Ancillary Services (Note N)					11,476,937
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)				$	32,555,334
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	0.73935
	TRANSMISSION EXPENSES					
6	Total transmission expenses (page 3, line 1, column 3)				$	10,229,766
7	Less transmission expenses included in OATT Ancillary Services (Note L)					199,887
8	Included transmission expenses (line 6 less line 7)				$	10,029,879
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					0.98046
10	Percentage of transmission plant included in ISO Rates (line 5)				TP	0.73935
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)				TE=	0.72490

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	11,698,743	0.00	0			
13	Transmission	354.21.b	662,512	0.74	489,829			
14	Distribution	354.23.b	4,583,482	0.00	0			
15	Other	354.21,22,23 b	3,481,235	0.00	0			
16	Total (sum lines 12-15)		20,425,972		489,829	=	0.02398	= WS

COMMON PLANT ALLOCATOR (CE)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	1,107,365,205	0.77066	*	0.02398	=	0.01848
18	Gas	201.3.d	329,534,409					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,436,899,614					

RETURN (R)

Line			$
21		Long Term Interest (117, sum of 62.c through 67.c)	14,937,522
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	377,954,114
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)	377,954,114

Line		(Note P)	$	%	Cost	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		332,571,494	47%	0.0449	0.0210	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000	
29	Common Stock (line 26)		377,954,114	53%	0.1238	0.0659	
30	Total (sum lines 27-29)		710,525,608			0.0869	=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)		$	18,254
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$	68,649

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/2013

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

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

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended: 12/31/2013

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

(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	Sch. H-22A, p 2, line 2 col 5 (Note A)	32,555,334	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	19,474,063	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	1,314,657	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	4.04%	4.04%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	64,322	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.20%	0.20%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	224,822	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.69%	0.69%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**4.93%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	592,478	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.04%	3.04%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	1,231,116	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.32%	6.32%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**9.36%**

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 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	4.93%	$0.00	$ -	9.36%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	4.93%	$0.00	$ -	9.36%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	4.93%	$0.00	$ -	9.36%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c											$0

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.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
Legacy MTEP Credit

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

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	32,555,334	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	19,474,063	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	1,314,657	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	4.04%	4.04%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	64,322	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.20%	0.20%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	224,822	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.69%	0.69%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**4.93%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	592,478	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.04%	3.04%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	1,231,116	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.32%	6.32%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**9.36%**

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 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Project 1	P1	$ -	4.93%	$0.00	$ -	9.36%	$0.00	$0	$0.00	$ -	$0.00
1b	Project 2	P2	$ -	4.93%	$0.00	$ -	9.36%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	4.93%	$0.00	$ -	9.36%	$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: 12/31/2013

Accumulated Deferred Income Taxes
Accounts 190 and Account 282

Account 190	DEO	DEK	DEOK
Per Books Total, Page 234, lines 8 & 17, column c	$ 137,096,360	$ (4,337,602)	$ 132,758,758
Less:			
FAS 106 and FAS 109 Related items	(2,017,613)	1,837,103	(180,510)
Adjusted Balances - To Page 2, Line 22	$ 139,113,973	$ (6,174,705)	$ 132,939,268

Account 282	DEO	DEK	DEOK
Per Books Total, Page 275, lines 2 & 6, column k	$ 1,101,028,877	$ 179,130,574	$ 1,280,159,451
Less:			
FAS 106 and FAS 109 Related items	65,083,318	(554,902)	64,528,416
Adjusted Balances - To Page 2, Line 20	$ 1,035,945,559	$ 179,685,476	$ 1,215,631,035

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

Materials and Supplies
Allocation of Account 163

Duke Energy Ohio

	M&S [2]	Percentage	163 [3]	Total M&S [1]
Production	40,286,103	47.23%	60,079	
Transmission	9,952,046	11.67%	14,841	9,966,887
Distribution	35,054,074	41.10%	52,276	
Total M&S	85,292,223	100.00%	127,196	

Duke Energy Kentucky

	M&S [2]	Percentage	163 [3]	
Production	17,582,198	97.99%	841,157	
Transmission	29,177	0.16%	1,396	30,573
Distribution	331,227	1.85%	15,846	
Total M&S	17,942,602	100.00%	858,399	

Duke Energy Ohio and Kentucky

	M&S		163	
Production	57,868,301		901,236	
Transmission	9,981,223		16,237	9,997,460
Distribution	35,385,301		68,122	
Total M&S	103,234,825		985,595	

(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: 12/31/2013

Detail of Land Held for Future Use

	Transmission Related	Non-Transmission Related Portion	Reported on FERC Form 1
Duke Energy Ohio			
East Bend Station		$ 1,959,275	$ 1,959,275
J.M. Stuart Station		272,173	272,173
Woodsdale Station		2,012,790	2,012,790
Other Projects	$ 121,217	146,413	267,630
J.M. Stuart Station - Production		91,232	91,232
East Bend Station - Production	-	251,236	251,236
Total	$ 121,217	$ 4,733,119	$ 4,854,336
Duke Energy Kentucky			
	-	-	-
Duke Energy Ohio and Kentucky			
Balances - To Page 2, Line 25	$ 121,217	$ 4,733,119	$ 4,854,336

Source: FERC Form 1 Page 214

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

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

Description	Source	DEO	DEK	DEOK
General Advertising - 930.1	Form 1, P. 323.191, col. b,	$ 45,370	$ 8,488	$ 53,858
Regulatory Commission Expense	Form 1, P.350, col. d,	1,296,245	602,198	1,898,443
Ohio Consumers' Counsel	Form 1, P.350, col. d,	227,177		227,177
PUCO - Division of Forecasting	Form 1, P.350, col. d,	112,949		112,949
Request for Rate Increase	Form 1, P.350, col. d,	102,946		102,946
Electric Power Research Institute	Form 1, P.353, col.d,	710,632	307,645	1,018,277
Less amounts recorded in a non-formula related account	FERC Account 506	515,536	181,431	696,967
Less amounts recorded in a non-formula related account	FERC Account 588	28,333	26,153	54,486
Less amounts recorded in a non-formula related account	FERC Account 910	75,265	15,601	90,866
Total Electric Power Research Institute		91,498	84,460	175,958
Subtotal		$ 1,876,185	$ 695,146	$ 2,571,331
Amount of Safety Related Advertising		-	-	-
Non-Safety Adv., Reg. Comm. Exp. & EPRI - To Page 3, Line 5		$ 1,876,185	$ 695,146	$ 2,571,331

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

Balancing Authority Costs

	DEO	DEK	DEOK
A&G Expense			
A&G Expense, Page 323, line 197, column b	$ 143,718,447	$ 23,631,896	$ 167,350,343
Less: Duke / Progress merger costs to achieve. Includes payroll taxes and A&G expense.	11,452,332	2,077,248	13,529,580
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	$ 132,266,115	$ 21,554,648	$ 153,820,763
Transmission Expense			
Transmission Expense, Page 321, line 112, column b	$ 25,124,061	$ 10,229,766	$ 35,353,827
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	$ 25,124,061	$ 10,229,766	$ 35,353,827
Balancing Authority Costs in 561 through 561.3			
B.A. Costs in Transmission Expense on Page 321 of FF1	$ 1,208,628	$ 199,887	$ 1,408,515
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	$ 1,208,628	$ 199,887	$ 1,408,515

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

State Tax Composite Rate

State	Ohio	Kentucky	
	Duke Energy Ohio	Duke Energy Kentucky	TOTAL
Revenue Requirement	$ 81,752,520.14	$ 4,055,781.07	$ 85,808,301.21
Tax Rate	0.00%	6.00%	
State Taxes	$ -	$ 243,346.86	$ 243,346.86
Composite Tax Rate	0.00%	6.00%	0.28%

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

Determination of Transmission Plant Included in OATT Ancillary Services

	DEO	DEK	DEOK
Total Generation Step-up Transformers	$ 13,559,865	$ 11,476,937	$ 25,036,802
Assets removed through 2011 by FERC Agreement	-	-	-
Sole use Property	-	-	-
Distribution Use	-	-	-
Transmission plant included in OATT Ancillary Services - To Page 4, Line 3	$ 13,559,865	$ 11,476,937	$ 25,036,802

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended: 12/31/2013

Revenue Credits, Accounts 454 and 456

	Account 454 DEO	Account 454 DEK	Account 454 DEOK
Per Books Total, Page 300	$ 14,319,978	$ 801,022	$ 15,121,000
Tower Lease Revenues in per Books Total above	84,914	9,690	94,604
Rent from Electric Property in per Books Total above	1,565,516	171,283	1,736,799
Portion Attributable to Transmission	5.0%	5.0%	5.0%
Revenue Credit Applicable to Attachment H-22A	$ 163,190	$ 18,254	$ 181,444
Step-ups leased to Duke Energy Kentucky	-	-	-
Total Account 454 - To Page 4, Line 34	$ 163,190	$ 18,254	$ 181,444

	Account 456 DEO	Account 456 DEK	Account 456 DEOK
Total Account 456 Per Books Total, Page 300	$ 4,947,272	$ 1,807,183	$ 6,754,455
Less: Other Electric Revenues	230,252	780,298	1,010,550
Revenues from Transmission of Electricity for Others	$ 4,717,020	$ 1,026,885	$ 5,743,905
Less: Transmission Revenues - Load in Divisor			
Sch 1 - Scheduling, System Control & Dispatch	$ 341,051	$ -	341,051
Sch 2 - Reactive Supply & Voltage Control	(4,765,084)	-	(4,765,084)
Sch 4 - Day-Ahead Load Response Charge Allocation	(113,863)	-	(113,863)
Sch 4 - Real-Time Load Response Charge Allocation	(101,669)	-	(101,669)
Sch 8 - Non-Firm PTP	73,213	17,956	91,169
Sch 9 - NITS	4,053,242	-	4,053,242
Sch 24 - Load Balancing	162,711		162,711
Sch 26 - MTEP Project Cost Recovery	3,540,630	-	3,540,630
PJM Customer Payment Default	680	-	680
Facilities Charges	184,388	16,513	200,901
Other Transmission Revenues - FTR's	-	923,767	923,767
Miscellaneous Bilateral	402,612	-	402,612
Total Transmission Revenues - Load in Divisor	$ 3,777,911	$ 958,236	$ 4,736,147
Total Account 456.1 - To Page 4, Line 35	$ 939,109	$ 68,649	$ 1,007,758

Duke Energy Ohio and Duke Energy Kentucky

Duke Energy Ohio Consolidated
Capital Structure
December 31, 2013
(In Dollars)

	Actual 12/31/13		Purchase Accounting		Goodwill Impairments Sep09 and Jun10	Other Asset Impairment Charges		Adjusted 12/31/13	Midwest DENA Equity BU 75032	Midwest DENA Equity BU 75012 (3)	Capital Structure without Purchase accounting and Midwest DENA	
Liabilities and Shareholders' Equity												
Current Maturities of Long-Term Debt	$ 47,195,535		$ -					$ 47,195,535			$ 47,195,535	
Non-Current Liabilities												
Long-Term Debt (3)	$ 2,140,513,304		$ 5,819,478					$ 2,146,332,782			$ 2,146,332,782	
Deferred Debt Expense	(14,587,591)		(3,037,311)					(17,624,902)			(17,624,902)	
Less: Current portion of deferred debt expense	(6,821,566)							(6,821,566)			(6,821,566)	
0257010 Unamortized Gain-Debt	404,469							404,469			404,469	
Total Long-Term Debt Excl. Current Maturities	**$ 2,119,508,616**		**$ 2,782,167**		**$ -**	**$ -**		**$ 2,122,290,783**	**$ -**	**$ -**	**$ 2,122,290,783**	
Total Long Term Debt	**$ 2,166,704,151**	**29%**	**$ 2,782,167**		**$ -**	**$ -**		**$ 2,169,486,318**	**$ -**	**$ -**	**$ 2,169,486,318**	**40%**
Common Stock Equity												
0201000 Common Stock Issued	$ 762,136,231		$ -					$ 762,136,231	$ -	$ -	$ 762,136,231	
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			226,156,819	
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			84,179,906	
210020 Gain on Redemption of Capital	-		147,685					147,685			147,685	
0211003 Misc Paid In Capital	(44,006,414)		-					(44,006,414)		(651,142,288)	(695,148,702)	
0211004 Misc Paid In Capital Purch Acctg	1,095,122,010		(2,879,949,148)					(1,784,827,138)		(15,964,862)	(1,800,792,000)	
0211008 Misc PIC Pushdown Adj RE	1,766,266,493		-					1,766,266,493			1,766,266,493	
0211005 Misc Paid in Capital Premerger Equity	557,581,098		(603,514,486)					(45,933,388)			(45,933,388)	
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	(477,451,772)		941,852,979	(1)	1,403,452,846	117,257,663	(1)	1,985,111,716	(161,046,648)	(251,296,964)	1,572,768,104	
0216100 Unappropriated RE/Undistr Subsid Earnings - Equitization	-							-	1,644,041,551		1,644,041,551	
0438000 Dividends Declared on Common Stock	-							-			-	
Current Year Net Income	112,578,514		19,374,262	(2)	-	-	(2)	131,952,776	55,190	(15,435,464)	116,572,502	
Accum other comprehensive income (loss)	1,638		(45,455,363)					(45,453,725)	-	-	(45,453,725)	
Total Common Stock Equity	**$ 5,279,156,216**	**71%**	**$ (2,589,917,684)**		**$ 1,403,452,846**	**$ 117,257,663**		**$ 4,209,949,041**	**$ 20,713,253**	**$ (933,839,578)**	**$ 3,296,822,716**	**60%**
TOTAL CAPITALIZATION	**$ 7,445,860,367**		**$ (2,587,135,517)**		**$ 1,403,452,846**	**$ 117,257,663**		**$ 6,379,435,359**	**$ 20,713,253**	**$ (933,839,578)**	**$ 5,466,309,034**	

Adjustment to Proprietary Capital for Duke Ohio Attachment H-22A, page 4, line 23 $ (1,715,601,072)

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 201:
(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.

Duke Energy Ohio and Duke Energy Kentucky

2013 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)	4,264,000	4,236,000	3,838,000	3,431,000	4,568,000	4,880,000	5,109,000	4,997,000	5,146,000	3,842,000	3,791,000	4,192,000	52,294,000	4,357,833
Less:														
DEK Monthly Peak Demand (2)	710,000	681,000	619,000	563,000	727,000	813,000	858,000	853,000	851,000	662,000	610,000	681,000	8,628,000	719,000
DEO - Monthly Transmission System Peak Load	3,554,000	3,555,000	3,219,000	2,868,000	3,841,000	4,067,000	4,251,000	4,144,000	4,295,000	3,180,000	3,181,000	3,511,000	43,666,000	3,638,833

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, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010, 12/31/2011 and 12/31/2012, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation.

(2) Source: DEK peak as reported on FERC Form 1 Page 401b.

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, 2014.

/s/ Gary A. Morgans

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