Twleve Months Ended 2017

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual/Projected FERC Form 1 Data

KENTUCKY POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 143)					$65,996,192
2	REVENUE CREDITS	(Worksheet E Ln 8) (Note A)	102,434	DA	1.00000	$	102,434
3	Facility Credits under PJM OATT Section 30.9	(Worksheet E Ln 9) (Note X)				$	-
4	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2 plus ln 3)				$	65,893,758

MEMO: The Carrying Charge Calculations on lines 7 to 12 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 5 is included in the total on line 4.

Line No.			Total	Allocator			Transmission Amount
5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		-	DA	1.00000	$	-
6	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
7	Annual Rate	((ln 1 - ln 107)/((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100))					17.42%
8	Monthly Rate	(ln 7 / 12)					1.45%
9	NET PLANT CARRYING CHARGE ON LINE 7 , w/o depreciation or ROE incentives (Note B)						
10	Annual Rate	((ln 1 - ln 107 - ln 112) /((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100))					13.36%
11	NET PLANT CARRYING CHARGE ON LINE 10, w/o Return, income taxes or ROE incentives (Note B)						
12	Annual Rate	((ln 1 - ln 107 - ln 112 - ln 138 - ln 139) /((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100))					3.69%
13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)						

Line No.	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES		
14			
15	Total Load Dispatch & Scheduling (Account 561)	Line 86 Below	2,786,464
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,356,634
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		344,825
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)	1,085,005

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Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 1.E)	1,188,773,639	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(10,271,623)	NA	0.00000	-
21	Transmission	(Worksheet A ln 3.E & Ln 147)	578,645,754	DA		568,447,497
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E)	-	TP	0.98238	-
23	Line Deliberately Left Blank		**N/A**	NA	0.00000	**N/A**
24	Line Deliberately Left Blank		**N/A**	NA	0.00000	**N/A**
25	Distribution	(Worksheet A ln 5.E)	804,748,310	NA	0.00000	-
26	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
27	General Plant	(Worksheet A ln 7.E)	39,431,099	W/S	0.06816	2,687,600
28	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	-	W/S	0.06816	-
29	Intangible Plant	(Worksheet A ln 9.E)	25,813,985	W/S	0.06816	1,759,466
30	TOTAL GROSS PLANT	(sum lns 19 to 29)	2,627,141,163	**GP(h)=**	**0.218068**	572,894,562
				GTD=	**0.41091**	
31	ACCUMULATED DEPRECIATION AND AMORTIZATION					
32	Production	(Worksheet A ln 12.E)	417,916,372	NA	0.00000	-
33	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(2,492,000)	NA	0.00000	-
34	Transmission	(Worksheet A ln 14.E & 28.E)	194,893,197	**TP1=**	0.97245	189,524,450
35	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.97245	-
36	Line Deliberately Left Blank		**N/A**	DA	0.00000	**N/A**
37	Line Deliberately Left Blank		**N/A**	DA	0.00000	**N/A**
38	Line Deliberately Left Blank		**N/A**	TP	0.00000	**N/A**
39	Line Deliberately Left Blank		**N/A**	W/S	0.00000	**N/A**
40	Line Deliberately Left Blank		**N/A**	DA	0.00000	**N/A**
41	Distribution	(Worksheet A ln 16.E)	235,781,378	NA	0.00000	-
42	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
43	General Plant	(Worksheet A ln 18.E)	12,048,236	W/S	0.06816	821,200
44	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	-	W/S	0.06816	-
45	Intangible Plant	(Worksheet A ln 20.E)	12,854,179	W/S	0.06816	876,133
46	TOTAL ACCUMULATED DEPRECIATION	(sum lns 32 to 45)	871,001,361			191,221,783
47	NET PLANT IN SERVICE					
48	Production	(ln 19 + ln 20 - ln 32 - ln 33)	763,077,645			-
49	Transmission	(ln 21 + ln 22 - ln 34 - ln 35)	383,752,557			378,923,047
50	Line Deliberately Left Blank		**N/A**			**N/A**
51	Line Deliberately Left Blank		**N/A**			**N/A**
52	Line Deliberately Left Blank		**N/A**			**N/A**
53	Line Deliberately Left Blank		**N/A**			**N/A**
54	Line Deliberately Left Blank		**N/A**			**N/A**
55	Distribution	(ln 25 + ln 26 - ln 41 - ln 42)	568,966,932			-
56	General Plant	(ln 27 + ln 28 - ln 43 - ln 44)	27,382,864			1,866,399
57	Intangible Plant	(ln 29 - ln 45)	12,959,806			883,333
58	TOTAL NET PLANT IN SERVICE	(sum lns 48 to 57)	1,756,139,803	**NP(h)=**	**0.217336**	381,672,778
59	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
60	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(59,084,467)	NA		-
61	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(399,746,052)	DA		(83,643,015)
62	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(274,326,803)	DA		(1,233,925)
63	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	57,873,322	DA		3,695,789
64	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
65	TOTAL ADJUSTMENTS	(sum lns 60 to 64)	(675,284,000)			(81,181,152)
66	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	972,246	DA		972,246
67	REGULATORY ASSETS	(Worksheet A ln 36.E)	-	DA		-
68	WORKING CAPITAL	(Note E)				
69	Cash Working Capital	(1/8 * ln 89)	763,491			750,035
70	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	53,175	TP	0.98238	52,237
71	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	43,510	W/S	0.06816	2,966
72	Stores Expense	(Worksheet C, ln 4.(F))	-	GP(h)	0.21807	-
73	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	56,506,330	W/S	0.06816	3,851,437
74	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	791,568	GP(h)	0.21807	172,615
75	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
76	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(55,251,482)	NA	0.00000	-
77	TOTAL WORKING CAPITAL	(sum lns 69 to 76)	2,906,592			4,829,291
78	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	(286,822)	DA	1.00000	(286,822)
79	RATE BASE (sum lns 58, 65, 66, 67, 77, 78)		1,084,447,818			306,006,341

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
80	Production	321.80.b	308,472,666			
81	Distribution	322.156.b	47,582,516			
82	Customer Related Expense	322 & 323.164,171,178.b	14,225,375			
83	Regional Marketing Expenses	322.131.b	1,145,306			
84	Transmission	321.112.b	37,054,807			
85	TOTAL O&M EXPENSES	(sum lns 80 to 84)	408,480,670			
86	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,786,464			
87	Less: Account 565	(Note H) 321.96.b	28,160,412			
88	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
89	Total O&M Allocable to Transmission	(lns 84 - 86 - 87 - 88)	6,107,931	TP	0.98238	6,000,283
90	Administrative and General	323.197.b (Note J)	23,232,806			
91	Less: Acct. 924, Property Insurance	323.185.b	665,351			
92	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(3,196,538)			
93	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
94	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(284,735)			
95	Acct. 928, Reg. Com. Exp.	323.189.b	-			
96	Acct. 930.1, Gen. Advert. Exp.	323.191.b	46,676			
97	Acct. 930.2, Misc. Gen. Exp.	323.192.b	318,019			
98	Balance of A & G	(ln 90 - sum ln 91 to ln 97)	25,684,033	W/S	0.06816	1,750,608
99	Plus: Acct. 924, Property Insurance	(ln 91)	665,351	GP(h)	0.21807	145,092
100	Acct. 928 - Transmission Specific	Worksheet F ln 19.(E) (Note L)	-	TP	0.98238	-
101	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 30.(E) (Note L)	-	TP	0.98238	-
102	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 37.(E) (Note L)	24,742	DA	1.00000	24,742
103	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	-	W/S	0.06816	-
104	A & G Subtotal	(sum lns 98 to 103)	26,374,126			1,920,442
105	O & M EXPENSE SUBTOTAL	(ln 89 + ln 104)	32,482,057			7,920,724
106	Line Deliberately Left Blank					
107	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
108	TOTAL O & M EXPENSE	(ln 105 + ln 107)	32,482,057			7,920,724
109	DEPRECIATION AND AMORTIZATION EXPENSE					
110	Production	336.2-6.f	37,739,752	NA	0.00000	-
111	Distribution	336.8.f	28,239,560	NA	0.00000	-
112	Transmission	336.7.f	15,810,827	TP1	0.97245	15,375,284
113	Line Deliberately Left Blank		N/A			N/A
114	General	336.10.f	1,701,846	W/S	0.06816	115,997
115	Intangible	336.1.f	4,396,601	W/S	0.06816	299,670
116	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 110+111+ 112+113+114+115)	87,888,586			15,790,951
117	TAXES OTHER THAN INCOME	(Note N)				
118	Labor Related					
119	Payroll	Worksheet H ln 22.(D)	2,664,689	W/S	0.06816	181,624
120	Plant Related					
121	Property	Worksheet H ln 22.(C) & ln 46.(C)	15,496,887	DA		5,216,311
122	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	5,819,400	NA	0.00000	-
123	Other	Worksheet H ln 22.(E)	1,137,600	GP(h)	0.21807	248,074
124	TOTAL OTHER TAXES	(sum lns 119 to 123)	25,118,576			5,646,009
125	INCOME TAXES	(Note O)				
126	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.82%			
127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.40%			
128	where WCLTD=(ln 167) and WACC = (ln 170)					
129	and FIT, SIT & p are as given in Note O.					
130	GRCF=1 / (1 - T) = (from ln 126)		1.6346			
131	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(25,656)			
132	Excess Deferred Income Tax	(Note U)	(26,400)	DA		(30,000)
133	Tax Affect of Permanent Differences	(Note U)	4,097,215	DA		1,350,007
134	Income Tax Calculation	(ln 127 * ln 139)	34,536,059			9,745,285
135	ITC adjustment	(ln 130 * ln 131)	(41,937)	NP(h)	0.21734	(9,114)
136	Excess Deferred Income Tax	(ln 130 * ln 132)	(43,153)			(49,037)
137	Tax Affect of Permanent Differences	(ln 130 * ln 133)	6,697,203			2,206,687
138	TOTAL INCOME TAXES	(sum lns 134 to 137)	41,148,173			11,893,821
139	RETURN ON RATE BASE (Rate Base*WACC)	(ln 79 * ln 170)	87,659,674			24,735,553
140	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		9,135	DA	1.00000	9,135
141	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
142	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 141 * ln127)		-			-
143	TOTAL REVENUE REQUIREMENT (sum lns 108, 116, 124, 138, 139, 140, 141, 142)		274,306,201			65,996,192

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
144	Total transmission plant	(ln 21)						578,645,754
145	Less transmission plant excluded from PJM Tariff (Note P)							
146	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (E)) (Note Q)							10,198,257
147	Transmission plant included in PJM Tariff	(ln 144 - ln 145 - ln 146)						568,447,497
148	Percent of transmission plant in PJM Tariff	(ln 147 / ln 144)					TP=	**0.98238**
			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
149	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
150	Production	354.20.b	18,098,536	8,152,988	26,251,524	NA	0.00000	-
151	Transmission	354.21.b	75,790	2,860,595	2,936,385	TP	0.98238	2,884,633
152	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
153	Distribution	354.23.b	8,228,443	994,011	9,222,454	NA	0.00000	-
154	Other (Excludes A&G)	354.24,25,26.b	1,892,888	2,018,620	3,911,508	NA	0.00000	-
155	Total	(sum lns 150 to 154)	28,295,657	14,026,214	42,321,871			2,884,633
156	Transmission related amount						W/S=	**0.06816**

ln No.						
157	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
158	Long Term Interest	(Worksheet M, ln. 21, col. (E))				47,340,901
159	Preferred Dividends	(Worksheet M, ln. 55, col. (E))				-
160	<u>Development of Common Stock:</u>					
161	Proprietary Capital	(Worksheet M, ln. 1, col. (E))				673,377,946
162	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))				-
163	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))				-
164	Less: Account 219	(Worksheet M, ln. 4, col. (E))				(1,307,982)
165	Common Stock	(ln 161 - ln 162 - ln 163 - ln 164)				674,685,928
166			$	%	Cost (Note S)	Weighted
167	Long Term Debt (Note T) Worksheet M, ln 11, ln 22, col.)		870,000,000	56.32%	0.0544	0.0306
168	Preferred Stock (ln 162)		-	0.00%	-	0.0000
169	Common Stock (ln 165)		674,685,928	43.68%	11.49%	0.0502
170	Total (Sum lns 167 to 169)		1,544,685,928		WACC=	**0.0808**

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Letter	**Notes**
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. 7) If AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's. Interest will be calculated based on Worksheet Q and any over under recovery will be filed and posted as part of the informational filing.
C	Transmission Plant Balances in this study are projected or actual average beginning of year end of year balances.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flowthrough and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation Section1.167(l)-l(h)(6)(ii). RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B. The company will not include the ADIT portion of deferred hedge gains and losses in rate base. Detailed balances for the projected or actual period, distinguished between utility and non-utility balances, will be filed and posted as part of the information filing.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 89. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 86. 2) Costs of Transmission of Electricity by Others, as described in Note H. 3) The impact of state regulatory deferrals and amortizations, as shown on line 88 4) All A&G Expenses, as shown on line 104.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 78 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 140.
G	Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 16 & 17 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
H	Removes cost of transmission service provided by others to determine the basis of cash working capital on line 89. To the extent such service is incurred to provide the PJM service at issue, e.g. lease payments to affiliates, such cost is added back on line 107 to determine the total O&M collected in the formula. The amounts on line 107 is also excluded in the calculation of the FCR percentage calculated on lines 6 through 12. The addbacks on line 107 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. The company records referenced on line 107 is the KENTUCKY POWER COMPANY general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from Transmission O&M expense.
J	General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
K	These deductions on lines 92 through 94 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
L	Expenses recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneouse General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
M	See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
O	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. See Worksheet G for the development of the Company's composite SIT. 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) (ln 131) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 35.00% SIT= 5.88% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes) The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable. If the statutory tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and post-change rate each is in effect.
P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 158) / average long term debt (ln 167). Preferred Stock cost rate = preferred dividends (ln 159) / preferred outstanding (ln 168). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO Membership. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of captial are shown on Worksheet M. Eligible Hedging Gains and Losses are computed on Worksheet M.The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.
T	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 167 above. The cost rates for long-term debt shall include interest expense and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance) and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429 and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock (if applicable) shall include the dividends.
U	Tax effect of permanent differences captures the differences in the income taxes due under the Federal and State calculatins that are not the result of timing differences.Transmission balances for the projected or actual period, will be filed and posted as part of the informational filing.
V	Cash investment in prepaid pension and benefits recorded in FERC Account 165 is permitted to be included in the formula. A labor expense allocation factor will be used to allocate total company costs. All other prepayments recorded in FERC Account 165 are directly assigned to the transmission function, allocated or excludable balances detailed on Worksheet C.
W	The formula rate shall allocate property tax expense based on the as filed net plant cost allocation method detailed on Worksheet H.
X	Under Section 30.9 of the PJM OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet A Supporting Plant Balances
KENTUCKY POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2017	(D) Balance @ December 31, 2016	(E) Average Balance for 2017
NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.					
Plant Investment Balances					
1	**Production Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	1,191,003,109	1,186,544,169	1,188,773,639
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	10,271,623	10,271,623	10,271,623
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	586,428,048	570,863,459	578,645,754
4	**Transmission Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	-	-	-
5	**Distribution Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	819,426,940	790,069,680	804,748,310
6	**Distribution Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	-	-	-
7	**General Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	39,688,921	39,173,277	39,431,099
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	-	-	-
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	29,760,788	21,867,181	25,813,985
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	2,666,307,806	2,608,517,766	2,637,412,786
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	10,271,623	10,271,623	10,271,623
Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	424,626,670	411,206,073	417,916,372
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	2,605,518	2,378,482	2,492,000
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	200,981,717	188,804,677	194,893,197
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	243,690,666	227,872,090	235,781,378
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	12,701,789	11,394,682	12,048,236
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	14,283,979	11,424,378	12,854,179
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	896,284,821	850,701,900	873,493,361
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	2,605,518	2,378,482	2,492,000
Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records - Note 1	10,198,257	10,198,257	10,198,257
24	**GSU Accumulated Depreciation**	Company Records - Note 1	5,478,329	5,259,165	5,368,747
25	**GSU Net Balance**	(Line 23 - Line 24)	4,719,928	4,939,092	4,829,510
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	200,981,717	188,804,677	194,893,197
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	5,478,329	5,259,165	5,368,747
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	195,503,388	183,545,512	189,524,450
Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	972,246	972,246	972,246
30	**Transmission Plant Held For Future**	Company Records - Note 1	972,246	972,246	972,246
Regulatory Assets and Liabilities Approved for Recovery In Ratebase					
	Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.				
31					-
32					-
33					-
34					-
35					-
36	Total Regulatory Deferrals Included in Ratebase		-	-	-

NOTE 1 On this worksheet, "Company Records" refers to AEP's property accounting ledger.

NOTE: The ratebase should not include the unamoritzed balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	**Description**	**Source**	**Balance @ December 31, 2017**	**Balance @ December 31, 2016**	**Average Balance for 2017**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	59,886,663	58,282,271	59,084,467
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	59,886,663	58,282,271	59,084,467
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	**Account 282**				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	404,432,488	395,059,616	399,746,052
8	Less: ARO Related Deferrals	Company Records - Note 1	24,695,530	24,695,530	24,695,530
9	Less: Other Excluded Deferrals	Company Records - Note 1	295,564,009	287,251,004	291,407,507
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	84,172,949	83,113,082	83,643,015
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	275,925,658	272,727,949	274,326,803
13	Less: ARO Related Deferrals	Company Records - Note 1	22,984,712	22,984,712	22,984,712
14	Less: Other Excluded Deferrals	Company Records - Note 1	251,690,088	248,526,244	250,108,166
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	1,250,858	1,216,993	1,233,925
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	57,873,322	57,873,322	57,873,322
18	Less: ARO Related Deferrals	Company Records - Note 1	25,204,320	25,204,320	25,204,320
19	Less: Other Excluded Deferrals	Company Records - Note 1	28,973,214	28,973,214	28,973,214
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	3,695,789	3,695,789	3,695,789
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	410	1,420	915
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	410	1,420	915
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1	-	-	-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax accounting ledger. Projected ending balances reflect proration required by IRS Letter Rule Section I.I67(I)-I(h)(6)(ii).

NOTE 2 ADIT balances should exclude balances related to hedging activity.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
KENTUCKY POWER COMPANY

Materials & Supplies

Line Number	(A)	(B)	(C) Source	(D) Balance @ December 31, 2017	(E) Balance @ December 31, 2016	(F) Average Balance for 2017
1						
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	53,175	53,175	53,175
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	43,510	43,510	43,510
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

Line		(C) Average of YE Balance	(D) Excludable Balances	(E) 100% Transmission Related	(F) Transmission Plant Related	(G) Transmission Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
5							
6	Totals as of December 31, 2017	2,046,416	(55,251,482)	0	791,568	56,506,330	57,297,898
7	Totals as of December 31, 2016	2,046,415	(55,251,482)		791,568	56,506,330	57,297,898
8	**Average Balance**	2,046,416	(55,251,482)	-	791,568	56,506,330	57,297,898

Prepayments Account 165 - Balance @ 12/31/2017

9	Acc. No.	Description	2017 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10	1650001	Prepaid Insurance	529,111	-		529,111		529,111	Plant Related Insurance Policies
11	1650005	Prepaid Employee Benefits	70,175				70,175	70,175	Health Savings Program
12	1650006	Other Prepayments	1,051	1,051				-	Distribution Prepayments
13	165000215	Prepaid Taxes	553,674	553,674			-	-	Prepaid Fees-Distribution
14	1650009	Prepaid Carry Cost-Factored AR	26,353	26,353			-	-	AR Factoring - Retail Only
15	1650010	Prepaid Pension Benefits	49,346,271	-			49,346,271	49,346,271	Prefunded Pension Expense
16	1650014	FAS 158 Qual Contra Asset	(49,346,271)	(49,346,271)			-	-	SFAS 158 Offset
17	1650016	FAS 112 ASSETS	0	-			-	-	
18	165001215	Prepaid Use Taxes	42,473	42,473			-	-	Use Taxes-Distribution
19	165001115	Prepaid Sales Taxes	290,618	290,618			-	-	Sales Taxes-Distribution
20	1650021	Prepaid Insurance - EIS	262,457	-		262,457		262,457	Prepaid Ins. - EIS
21	1650023	Prepaid Lease	7,011	7,011		-	-	-	Distribution Lease
22	1650031	Prepaid OCIP Work Comp	146,435	-			146,435	146,435	Work Comp
23	1650033	Prepaid OCIP Work Comp-Aff	117,058	-			117,058	117,058	Work Comp
24	1650035	PRW Without Med-D Benefits	6,826,392	-			6,826,392	6,826,392	Med-D Benefits
25	1650036	PRW for Med-D Benefits	0	-			-	-	
26	1650037	FAS 158 Contra-PRW Exc Med-D	(6,826,392)	(6,826,392)			-	-	SFAS 158 Offset
		Subtotal - Form 1, p 111.57.c	2,046,416	(55,251,482)	0	791,568	56,506,330	57,297,898	

Prepayments Account 165 - Balance @ 12/31/ 2016

27	Acc. No.	Description	2016 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
28	1650001	Prepaid Insurance	529,111	-		529,111		529,111	Plant Related Insurance Policies
29	1650005	Prepaid Employee Benefits	70,175	-			70,175	70,175	Health Savings Program
30	1650006	Other Prepayments	1,051	1,051				-	Distribution Prepayments
31	165000215	Prepaid Taxes	553,674	553,674			-	-	Prepaid Fees-Distribution
32	1650009	Prepaid Carry Cost-Factored AR	26,353	26,353			-	-	AR Factoring - Retail Only
33	1650010	Prepaid Pension Benefits	49,346,271	-			49,346,271	49,346,271	Prefunded Pension Expense
34	1650014	FAS 158 Qual Contra Asset	(49,346,271)	(49,346,271)			-	-	SFAS 158 Offset
35	1650016	FAS 112 ASSETS	0	-			-	-	
36	165001215	Prepaid Use Taxes	42,473	42,473			-	-	Use Taxes-Distribution
37	165001115	Prepaid Sales Taxes	290,618	290,618			-	-	Sales Taxes-Distribution
38	1650021	Prepaid Insurance - EIS	262,457	-		262,457		262,457	Prepaid Ins. - EIS
39	1650023	Prepaid Lease	7,011	7,011		-	-	-	Distribution Lease
40	1650031	Prepaid OCIP Work Comp	146,435	-			146,435	146,435	Work Comp
41	1650033	Prepaid OCIP Work Comp-Aff	117,058	-			117,058	117,058	Work Comp
42	1650035	PRW Without Med-D Benefits	6,826,392	-			6,826,392	6,826,392	Med-D Benefits
43	1650036	PRW for Med-D Benefits	0	-			-	-	
44	1650037	FAS 158 Contra-PRW Exc Med-D	(6,826,392)	(6,826,392)			-	-	SFAS 158 Offset
		Subtotal - Form 1, p 111.57.d	2,046,415	(55,251,482)		791,568	56,506,330	57,297,898	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
KENTUCKY POWER COMPANY

Line Number	**(A) Description**	**(B) 2017**
1	Net Funds from IPP Customers 12/31/2016 (2017 FORM 1, P269, line 6.b)	(277,687)
2	Interest Accrual (Company Records - Note 1)	(9,135)
3	Revenue Credits to Generators (Company Records - Note 1)	0
4	Other Adjustments	
5	Accounting Adjustment (Company Records - Note 1)	0
6		-
7	Net Funds from IPP Customers 12/31/2017 (2017 FORM 1, P269, line 6.f)	(286,822)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(282,255)

Note 1 On this worksheet Company Records refers to KENTUCKY POWER COMPANY's general ledger.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet E Supporting Revenue Credits
KENTUCKY POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	3,478,276	3,478,276	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	450,585	438,606	11,979
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	5,593,496	5,576,387	17,109
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	391,000	328,204	62,796
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	23,779,851	23,769,301	10,550
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	33,693,208	33,590,774	102,434
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	33,693,208	33,590,774	102,434

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or KENTUCKY POWER COMPANY's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.

9	**Facility Credits under PJM OATT Section 30.9**			-

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number	**Item No.**	**Description**	**2017 Expense**	**100% Non-Transmission**	**100% Transmission Specific**	**Explanation**
		Regulatory O&M Deferrals & Amortizations				
1		No Applicable Charges for KP	-			
2			-			
3						
4		**Total**	0			
		Detail of Account 561 Per FERC Form 1				
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	1,085,005			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	0			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	0			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	1,356,634			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	0			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Serv	344,825			
14		**Total of Account 561**	2,786,464			
		Account 928				
15	9280000	Regulatory Commission Exp	-	-	-	
16	9280001	Regulatory Commission Exp-Adm	-	-	-	
17	9280002	Regulatory Commission Exp-Case	-	-	-	
18	9280003	Rate Case Amortization	-	-		
19		**Total**	-	-	-	
		Account 930.1				
20	9301000	General Advertising Expenses	46,676	46,676	-	
21	9301001	Newspaper Advertising Space	-	-	-	
22	9301002	Radio Station Advertising Time	-	-	-	
23	9301003	TV Station Advertising Time	-	-	-	
24	9301006	Spec Corporate Comm Info Proj	-	-	-	
25	9301010	Publicity	-	-		
26	9301011	Dedications, Tours, & Openings	-	-	-	
27	9301012	Public Opinion Surveys	-	-	-	
28	9301014	Video Communications	-	-	-	
29	9301015	Other Corporate Comm Exp	-	-	-	
30		**Total**	46,676	46,676	-	
		Account 930.2				
31	9302000	Misc General Expenses	194,098	194,098		
32	9302003	Corporate & Fiscal Expenses	-	0		
33	9302004	Research, Develop&Demonstr Exp	-	0		
34	9302006	Assoc Business Development Materials Sold	-	0	0	
35	9302007	Assoc Business Development Exp	123,921	99,179	24,742	
36	9302458	AEPSC nonaffiliated expense	-	0		
37		**Total**	318,019	293,277	24,742	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
KENTUCKY POWER COMPANY

Kentucky Corporate Income Tax Rate	6.00%	
Apportionment Factor - Note 2	72.06%	
Effective State Tax Rate		4.32%
West Virginia Net Income Tax Rate	6.50%	
Apportionment Factor - Note 2	21.62%	
Effective State Tax Rate		1.41%
Michigan Business Income Tax Rate	6.00%	
Apportionment Factor - Note 2	0.08%	
Effective State Tax Rate		0.01%
State Income Tax Rate - Ohio	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	7.75%	
Apportionment Factor - Note 2	1.81%	
Effective State Tax Rate		0.14%
Total Effective State Income Tax Rate		5.88%

Note 1 The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% in 2009. The phase-out factors can be found in the Ohio Revised Code at 5733.01(G)2(a)(v). This tax has been replaced with a Commercial Activites Tax that is included in Schedule H and H-1.

Note 2 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H Supporting Taxes Other than Income
KENTUCKY POWER COMPANY

Line No.	(A) Account	(B) Total Company NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
2	Gross Receipts Tax	24,000				24,000
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Kentucky	12,849,463	12,849,463			
5	Real and Personal Property - W Va	2,647,424	2,647,424			
6	Real and Personal Property - Other Jurisdictions	-	-			
7	**Payroll Taxes**					
8	Federal Insurance Contribution (FICA)	2,597,038		2,597,038		
9	Federal Unemployment Tax	14,509		14,509		
10	State Unemployment Insurance	53,142		53,142		
11	**Production Taxes**					
12	State Severance Taxes	-				-
13	**Miscellaneous Taxes**					
14	State Business & Occupation Tax	5,783,000				5,783,000
15	State Public Service Commission Fees	1,137,600			1,137,600	
16	State Franchise Taxes	-			-	
17	State Lic/Registration Fee	-			-	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	12,400				12,400
20	Federal Excise Tax	-				-
21	Michigan Single Business Tax	-				-
22	Total Taxes by Allocable Basis	25,118,576	15,496,887	2,664,689	1,137,600	5,819,400
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					

NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
23	Functionalized Net Plant (TCOS, Lns 48 thru 58)	763,077,645	383,752,557	568,966,932	27,382,864	1,743,179,997
	KENTUCKY JURISDICTION					
24	Percentage of Plant in KENTUCKY JURISDICTION	3.37%	98.31%	100.00%	99.95%	
25	Net Plant in KENTUCKY JURISDICTION (Ln 23 * Ln 24)	25,715,717	377,267,138	568,966,932	27,369,172	999,318,959
26	Less: Net Value of Exempted Generation Plant	43,340,713				
27	Taxable Property Basis (Ln 25 - Ln 26)	(17,624,996)	377,267,138	568,966,932	27,369,172	955,978,246
28	Relative Valuation Factor	33.00%	100.00%	100.00%	100.00%	
29	Weighted Net Plant (Ln 27 * Ln 28)	(5,816,249)	377,267,138	568,966,932	27,369,172	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	-0.62%	40.12%	60.50%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	(169,271)	10,979,683	16,558,761	(27,369,172)	-
32	Weighted KENTUCKY JURISDICTION Plant (Ln 29 + 31)	(5,985,520)	388,246,821	585,525,693	0	967,786,994
33	Functional Percentage (Ln 32/Total Ln 32)	-0.62%	40.12%	60.50%		
34	Functionalized Expense in KENTUCKY JURISDICTION	(79,471)	5,154,815	7,774,118		12,849,463
	WEST VA JURISDICTION					
35	Net Plant in WEST VA JURISDICTION (Ln 23 - Ln 25)	737,361,928	6,485,418	-	13,691	743,861,038
36	Less: Net Value Exempted Generation Plant	464,647,356				
37	Taxable Property Basis	272,714,572	6,485,418	-	13,691	279,213,682
38	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
39	Weighted Net Plant (Ln 37 * Ln 38)	272,714,572	6,485,418	-	13,691	
40	General Plant Allocator (Ln 39 / (Total - General Plant)	97.68%	2.32%	0.00%	-100.00%	
41	Functionalized General Plant (Ln 41 * General Plant)	13,373	318	-	(13,691)	
42	Weighted WEST VA JURISDICTION Plant (Ln 39 + 41)	272,727,945	6,485,736	-	0	279,213,682
43	Functional Percentage (Ln 42/Total Ln 42)	97.68%	2.32%	0.00%		
44	Functionalized Expense in WEST VA JURISDICTION	2,585,928	61,496	-		2,647,424
45	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		-			-
46	Total Func. Property Taxes (Sum Lns 34, 44, 45)	2,506,457	5,216,311	7,774,118		15,496,887

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference
1	Revenue Taxes			
2	Gross Receipts Tax	24,000		
			24,000	P.263.2 ln 11 (i)
			-	P.263.2 ln 12 (i)
			-	P.263.1 ln 31 (i)
			-	P.263.1 ln 39 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Kentucky	12,849,463		
			12,849,463	P.263.1 ln 1 (i)
			-	P.263.1 ln 2 (i)
			-	P.263.1 ln 3 (i)
			-	P.263.1 ln 4 (i)
			-	P.263.1 ln 5 (i)
			-	P.263.1 ln 6 (i)
			-	P.263.1 ln 7 (i)
			-	P.263.1 ln 8 (i)
5	Real and Personal Property - W VA	2,647,424		
			2,647,424	P.263.1 ln 32 (i)
			-	P.263.1 ln 33 (i)
			-	P.263.1 ln 35 (i)
			-	P.263.1 ln 36 (i)
6	Real and Personal Property - Other	-		
			-	P.263.2 ln 22 (i)
			-	
			-	
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	2,597,038		
			2,597,038	P.263 ln 4 (i)
9	Federal Unemployment Tax	14,509		
			14,509	P.263 ln 5 (i)
10	State Unemployment Insurance	53,142		
			53,142	P.263 ln 29 (i)
			-	P.263.1 ln 40 (i)
			-	P.263.2 ln 1 (i)
11	Production Taxes	-		
12	State Severance Taxes		-	
13	Miscellaneous Taxes			
14	State Business & Occupation Tax	5,783,000		
			5,783,000	P.263.1 ln 29 (i)
			-	P.263.1 ln 30 (i)
15	State Public Service Commission Fees	1,137,600		
			1,137,600	P.263 ln 31 (i)
			-	P.263 ln 32 (i)
16	State Franchise Taxes	-		
			-	P.263.1 ln 19 (i)
			-	P.263.1 ln 24 (i)
17	State Lic/Registration Fee	-		
			-	P.263 ln 27 (i)
			-	P.263.1 ln 38 (i)
			-	
			-	
			-	
			-	
18	Misc. State and Local Tax	-		
			-	
19	Sales & Use	12,400		
			12,400	P.263 ln 34 (i)
			-	P.263 ln 35 (i)
20	Federal Excise Tax	-		
			-	P.263 ln 7 (i)
			-	P.263 ln 8 (i)
21	Michigan Single Business Tax	-		
			-	
22	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	25,118,576	25,118,576	

Note 1: The taxes assessed on each operating company can differ from year to year and between operating companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other operating companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14 of the Ferc Form 1.

AEP East Companies
Cost of Service Formula Rate Using 2017 FF1 Balances
Worksheet I RESERVED FOR FUTURE USE
KENTUCKY POWER COMPANY

AEP East Companies
Cost of Service Formula Rate Using 2017 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
KENTUCKY POWER COMPANY

I. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified for Regional Billing.

A. Determine 'R' with hypothetical basis point increase in ROE for Identified Projects

ROE w/o incentives (TCOS, ln 169)				11.49%
Project ROE Incentive Adder				
ROE with additional basis point incentive				11.49%
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 167 through169)				
	%	Cost		Weighted cost
Long Term Debt	56.32%	5.44%		3.065%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	43.68%	11.49%		5.019%
			R =	8.083%

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 79)	306,006,341
R (from A. above)	8.083%
Return (Rate Base x R)	24,735,553

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

Return (from B. above)	24,735,553
Effective Tax Rate (TCOS, ln 127)	39.40%
Income Tax Calculation (Return x CIT)	9,745,285
ITC Adjustment	(9,114)
Excess Deferred Income Tax	(49,037)
Tax Affect of Permanent Differences	2,206,687
Income Taxes	11,893,821

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1)	65,996,192
Lease Payments (TCOS, Ln 107)	-
Return (TCOS, ln 139)	24,735,553
Income Taxes (TCOS, ln 138)	11,893,821
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	29,366,819

B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.

Annual Revenue Requirement, Less Lease Payments, Return and Taxes	29,366,819
Return (from I.B. above)	24,735,553
Income Taxes (from I.C. above)	11,893,821
Annual Revenue Requirement, with Basis Point ROE increase	65,996,192
Depreciation (TCOS, ln 112)	15,375,284
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	50,620,907

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 49)	378,923,047
Annual Revenue Requirement, with Basis Point ROE increase	65,996,192
FCR with Basis Point increase in ROE	17.42%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	50,620,907
FCR with Basis Point ROE increase, less Depreciation	13.36%
FCR less Depreciation (TCOS, ln 10)	13.36%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Rate Year (2017) (P. 206, Ln 58(b)):	570,863,459
Transmission Plant @ End of Rate Year (2017) (P 207, Ln 58(g)):	586,428,048
Subtotal	1,157,291,507
Average Transmission Plant Balance for 2017	578,645,754
Annual Depreciation and Amortization Expense (TCOS, ln 112)	15,375,284
Composite Depreciation Rate	2.66%
Depreciable Life for Composite Depreciation Rate	37.63
Round to nearest whole year	38

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2017	-	-	$ -

KPCo Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

IV. **Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.**

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000)

Project Description:

Current Projected Year ARR	-
Current Projected Year ARR w/ Incentive	-
Current Projected Year Incentive ARR	-

Details			
Investment		Current Year	2016
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	13.36%
Useful life	38	FCR w/incentives approved for these facilities, less dep.	13.36%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:
INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2016	-	-	-	-	-	$ -					
2017	-	-	-	-	-	$ -					
2018	-	-	-	-	-	$ -					
2019	-	-	-	-	-	$ -					
2020	-	-	-	-	-	$ -					
2021	-	-	-	-	-	$ -					
2022	-	-	-	-	-	$ -					
2023	-	-	-	-	-	$ -					
2024	-	-	-	-	-	$ -					
2025	-	-	-	-	-	$ -					
2026	-	-	-	-	-	$ -					
2027	-	-	-	-	-	$ -					
2028	-	-	-	-	-	$ -					
2029	-	-	-	-	-	$ -					
2030	-	-	-	-	-	$ -					
2031	-	-	-	-	-	$ -					
2032	-	-	-	-	-	$ -					
2033	-	-	-	-	-	$ -					
2034	-	-	-	-	-	$ -					
2035	-	-	-	-	-	$ -					
2036	-	-	-	-	-	$ -					
2037	-	-	-	-	-	$ -					
2038	-	-	-	-	-	$ -					
2039	-	-	-	-	-	$ -					
2040	-	-	-	-	-	$ -					
2041	-	-	-	-	-	$ -					
2042	-	-	-	-	-	$ -					
2043	-	-	-	-	-	$ -					
2044	-	-	-	-	-	$ -					
2045	-	-	-	-	-	$ -					
2046	-	-	-	-	-	$ -					
2047	-	-	-	-	-	$ -					
2048	-	-	-	-	-	$ -					
2049	-	-	-	-	-	$ -					
2050	-	-	-	-	-	$ -					
2051	-	-	-	-	-	$ -					
2052	-	-	-	-	-	$ -					
2053	-	-	-	-	-	$ -					
2054	-	-	-	-	-	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
Project Totals		-		-	-	-					

** This is the total amount that needs to be reported to PJM for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

In order to calculate the proper monthly RTEP billing amount, PJM requires a 12 month revenue requirement for each RTEP project. As a result, notwithstanding the fact that the project was in service for a partial year, the project revenue requirement in the year that the project goes into service has been annualized (shown at the full-year level) so that PJM will collect the correct monthly billings.

AEP East Companies
Cost of Service Formula Rate Using 2017 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
KENTUCKY POWER COMPANY

I.

Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Regional Billing.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (TCOS, ln 169)			11.49%
Project ROE Incentive Adder			0
ROE with additional 0 basis point incentive			11.49%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 167 through169)

	%	Cost		Weighted cost
Long Term Debt	56.32%	5.44%		3.065%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	43.68%	11.49%		5.019%
			R =	8.083%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS		Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR	2017			
	As Projected in Prior Year WS J			$ -
	Actual after True-up			$ -
	True-up of ARR For 2017	-	-	-

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 79)	306,006,341
R (from A. above)	8.083%
Return (Rate Base x R)	24,735,553

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	24,735,553
Effective Tax Rate (TCOS, ln 127)	39.40%
Income Tax Calculation (Return x CIT)	9,745,285
ITC Adjustment	(9,114)
Excess Deferred Income Tax	(49,037)
Tax Affect of Permanent Differences	2,206,687
Income Taxes	11,893,821

II.

Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1)	65,996,192
Lease Payments (TCOS, Ln 107)	-
Return (TCOS, ln 139)	24,735,553
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Annual Revenue Requirement, Less Lease Payments, Return and Taxes	29,366,819
Return (from I.B. above)	24,735,553
Income Taxes (from I.C. above)	11,893,821
Annual Revenue Requirement, with 0 Basis Point ROE increase	65,996,192
Depreciation (TCOS, ln 112)	15,375,284
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	50,620,907

C. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (TCOS, ln 49)	378,923,047
Annual Revenue Requirement, with 0 Basis Point ROE increase	65,996,192
FCR with 0 Basis Point increase in ROE	17.42%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	50,620,907
FCR with 0 Basis Point ROE increase, less Depreciation	13.36%
FCR less Depreciation (TCOS, ln 10)	13.36%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III.

Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Rate Year (2017) (P. 206, Ln 58(b)):	570,863,459
Transmission Plant @ End of Rate Year (2017) (P. 207, Ln 58(g)):	586,428,048
Subtotal	1,157,291,507
Average Transmission Plant Balance for 2017	578,645,754
Annual Depreciation and Amortization Expense (TCOS, ln 112)	15,375,284
Composite Depreciation Rate	2.66%
Depreciable Life for Composite Depreciation Rate	37.63
Round to nearest whole year	38

KPCo Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

IV. **Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.**

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000)

Project Description:

0	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**#N/A**	**#N/A**	#N/A
Prior Yr True-Up	**#N/A**	**#N/A**	#N/A
True-Up Adjustment	**#N/A**	**#N/A**	**#N/A**

Details			
Investment		Current Year	0
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	13.36%
Useful life	38	FCR w/incentives approved for these facilities, less dep.	13.36%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:
INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR
TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE
LIFE OF THE PROJECT.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2015	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2016	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2017	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2018	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2019	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2020	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2021	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2022	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2023	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2024	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2025	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2026	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2027	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2028	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2029	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2030	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2031	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2032	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2033	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2034	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2035	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2036	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2037	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2038	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2039	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2040	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2041	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2042	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2043	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2044	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2045	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2046	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2047	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2048	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2049	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2050	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2051	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2052	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2053	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2054	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2055	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2056	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2057	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2058	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2059	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2060	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2061	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2062	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2063	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2073	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2074	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals		-			-	-	-					

** This is the total amount that needs to be reported to PJM for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

AEP East Companies
Cost of Service Formula Rate Using 2017 FF1 Balances
Worksheet L Reserved for Future Use
KENTUCKY POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital
Based on Average of Balances At 12/31/2016 & 12/31/2017

(A) Line	(B)	(C) Balances @ 12/31/2017	(D) Balances @ 12/31/2016	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	678,354,463	668,401,429	673,377,946
2	Less Preferred Stock (Ln 54 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	-	-	-
4	Less Account 219.1 (112.15.c&d)	(1,261,504)	(1,354,460)	(1,307,982)
5	**Average Balance of Common Equity**	679,615,967	669,755,889	**674,685,928**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	-	-	-
7	Less: Reacquired Bonds (112.19.c&d)	-	-	-
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	870,000,000	870,000,000	870,000,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	870,000,000	870,000,000	**870,000,000**

12 **NOTE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Column H of the FF1)**

Line	Description	Amount
13	**Annual Interest Expense for 2017**	
14	Interest on Long Term Debt (256-257.33.i)	46,818,148
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 33 below.	92,956
16	Plus: Allowed Hedge Recovery From Ln 38 below.	92,956
17	Amort of Debt Discount & Expense (117.63.c)	489,273
18	Amort of Loss on Reacquired Debt (117.64.c)	33,480
19	Less: Amort of Premium on Debt (117.65.c)	-
20	Less: Amort of Gain on Reacquired Debt (117.66.c)	-
21	**Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)**	**47,340,901**
22	**Average Cost of Debt for 2017 (Ln 21/Ln 11)**	**5.44%**

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

23 NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.

Line	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2017	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
24	Senior Unsecured Notes - Series E	92,956	-	92,956	154,928	September 2007	September 2017
25	Unsecured Notes						
26	Unsecured Notes						
27	Unsecured Notes						
28	Unsecured Notes						
29	Unsecured Notes						
30	Unsecured Notes						
31	Unsecured Notes						
32	Unsecured Notes			-			
					154,928		
33	Total Hedge Amortization	92,956	-				

Line	Description	Amount
34	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 32)	92,956
35	Total Average Capital Structure Balance for 2017 (TCOS, Ln 170)	1,544,685,928
36	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
37	Limit of Recoverable Amount	772,343
38	**Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)**	**92,956**

Development of Cost of Preferred Stock

Line	Preferred Stock	(C)	(D)	Average
39	4.125% Series - 100 - Dividend Rate (p. 250-251. 9.a)	4.125%	4.125%	
40	4.125% Series - 100 - Par Value (p. 250-251. 9.c)	$ 100.00	$ 100.00	
41	4.125% Series - 100 - Shares O/S (p.250-251. 9.e)	-	-	
42	4.125% Series - 100 - Monetary Value (Ln 40 * Ln 41)	-	-	-
43	4.125% Series - 100 - Dividend Amount (Ln 39 * Ln 42)	-	-	-
44	4.12% Series - 100 - Dividend Rate (p. 250-251 11.a)	4.120%	4.120%	
45	4.12% Series - 100 - Par Value (p. 250-251 11.c)	$ 100.00	$ 100.00	
46	4.12% Series - 100 - Shares O/S (p.250-251 11.e)	-	-	
47	4.12% Series - 100 - Monetary Value (Ln 45 * Ln 46)	-	-	-
48	4.12% Series - 100 - Dividend Amount (Ln 44 * Ln 47)	-	-	-
49	4.56% Series - 100 - Dividend Rate (p. 250-251. 10a)	4.560%	4.560%	
50	4.56% Series - 100 - Par Value (p. 250-251. 10c)	$ 100.00	$ 100.00	
51	4.56% Series - 100 - Shares O/S (p.250-251 10.e)	-	-	
52	4.56% Series - 100 - Monetary Value (Ln 50 * Ln 51)	-	-	-
53	4.56% Series - 100 - Dividend Amount (Ln 49 * Ln 52)	-	-	-
54	**Balance of Preferred Stock (Lns 42, 47, 52)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
55	**Dividends on Preferred Stock (Lns 43, 48, 53)**	-	-	-
56	**Average Cost of Preferred Stock (Ln 55/54)**	0.00%	0.00%	**0.00%**

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
KENTUCKY POWER COMPANY

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectiviely. Sales will be funtionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

Line	(A) Date	(B) Property Description	(C) Function (T) or (G) T = Transmission G = General	(D) Basis	(E) Proceeds	(F) (Gain) / Loss	(G) Functional Allocator	(H) Functionalized Proceeds (Gain) / Loss	(I) FERC Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 2017		-		-	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
KENTUCKY POWER COMPANY

1 Total AEP East Operating Company PBOP Settlement Amount -

Allocation of PBOP Settlement Amount for 2017

Line#	**Company**	**Actual Expense (Including AEPSC Billed OPEB)**	**Total Company Amount** **Ratio of Company Actual to Total**	**Allocation of PBOB Recovery Allowance**	**Labor Allocator for 2017**	**Actual Expense**	**Allowable Expense**	**One Year Functional Expense (Over)/Under**
		(A) **(Line 14)**	**(B)=(A)/Total (A)**	**(C)=(B) * 0**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
2	APCo	(16,200,897)	36.57%	-	8.052%	(1,304,430)	-	(1,304,430)
3	I&M	(11,509,436)	25.98%	-	5.095%	(586,456)	-	(586,456)
4	KPCo	(3,481,273)	7.86%	-	6.818%	(237,367)	-	(237,367)
5	KNGP	(378,229)	0.85%	-	9.691%	(36,653)	-	(36,653)
6	OPCo	(11,964,459)	27.01%	-	15.466%	(1,850,380)	-	(1,850,380)
7	WPCo	(769,194)	1.74%	-	2.347%	(18,050)	-	(18,050)
8	**Sum of Lines 2 to 7**	(44,303,488)		-		(4,033,336)	-	(4,033,336)

Detail of Actual PBOP Expenses to be Removed in Cost of Service

	APCo	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	(15,553,365)	(11,620,295)	(3,566,295)	(334,834)	(11,037,888)	(417,243)	(42,529,920)
10 Additional PBOP Ledger Entries (from Company Records)	465,717	918,897	369,757	4,572	135,109	(290,243)	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(15,087,648)	(10,701,398)	(3,196,538)	(330,262)	(10,902,779)	(707,486)	(40,926,111)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(1,113,249)	(808,038)	(284,735)	(47,967)	(1,061,680)	(61,708)	(3,377,377)
14 Company PBOP Expense (Ln 12 + Ln 13)	(16,200,897)	(11,509,436)	(3,481,273)	(378,229)	(11,964,459)	(769,194)	(44,303,488)

For the rate year 2017 and adjusted every four years thereafter, using the annual actuarial report produced for that year, filed as part of the informational filing, Worksheet O will be used to adjust PBOP costs for the next four years (i.e. 2017, 2018, 2019, 2020). If the annual actuarial report projects PBOP costs during the next four years, taken together with the then current cumulative PBOP cost/allowance position, will, absent a change in the PBOP allowance, cause the AEP Companies to over or under collect their cumulative PBOP costs by more than 20% of the projected next four year's total cost, the PBOP allowance shall be adjusted. Worksheet O will be used in the process of updating the PBOP allowance determining (a) the level of cumulative over or under collections during the period since the PBOP allowance was last set, including carrying costs based on the weighted average cost of capital ("WACC") each year from the actual formula rate; (b) the cumulative net present value of projected PBOP costs during the next four years, as estimated by the then current actuarial report, assuming a discount rate equal to the actual formula rate weighted average cost of capital for the prior calendar year; and (c) the cumulative net present value of continued collections over the next four years based on the then effective PBOP allowance, assuming a discount rate equal to the prior year WACC. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance used in the formula rate calculation shall be changed to the value that will cause the projected result (a)+(b)-(c) to equal zero. If the projected over or under collection during the next four years will be less than 20% of (b), then the PBOP allowacance will continue in effect for the next four years at the then effective rate. If it is determined through this procedure AEP Companies will over-recover or under-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP expense stated in the formula rate shown on Worksheet O. No other changes to the formula rate may be included in that filing.

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 07/1/2015
FOR SINGLE JURISDICTION COMPANIES
KENTUCKY POWER COMPANY

	PLANT ACCT.	**RATES** Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.44%
Structures & Improvements	352.0	2.08%
Station Equipment	353.0	2.15%
Towers & Fixtures	354.0	2.61%
Poles & Fixtures	355.0	3.95%
Overhead Conductors	356.0	2.91%
Underground Conduit	357.0	2.99%
Underground Conductors	358.0	2.62%

Reference:

Note 1: Rates Approved in KPSC Case No. 2014-00396.

General Note

Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet Q - True-up With Interest

Reconciliation Revenue Requirement For Year 2018 Available May 25, 2019		2018 Revenue Requirement Forecast by October 31, 2017		True-up Adjustment - Over (Under) Recovery
$16,511,590	-	$15,216,438	=	($1,295,152)

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.2780%				

An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020

Calculation of Interest					Monthly		
January	Year 2018	(107,929)	0.2780%	12	3,601		111,530
February	Year 2018	(107,929)	0.2780%	11	3,300		111,230
March	Year 2018	(107,929)	0.2780%	10	3,000		110,930
April	Year 2018	(107,929)	0.2780%	9	2,700		110,630
May	Year 2018	(107,929)	0.2780%	8	2,400		110,330
June	Year 2018	(107,929)	0.2780%	7	2,100		110,030
July	Year 2018	(107,929)	0.2780%	6	1,800		109,730
August	Year 2018	(107,929)	0.2780%	5	1,500		109,430
September	Year 2018	(107,929)	0.2780%	4	1,200		109,130
October	Year 2018	(107,929)	0.2780%	3	900		108,829
November	Year 2018	(107,929)	0.2780%	2	600		108,529
December	Year 2018	(107,929)	0.2780%	1	300		108,229
					23,403		1,318,555
					Annual		
January through December	Year 2019	1,318,555	0.2780%	12	43,987		1,362,542
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2020	(1,362,542)	0.2780%		3,788	(115,607)	1,250,723
February	Year 2020	(1,250,723)	0.2780%		3,477	(115,607)	1,138,592
March	Year 2020	(1,138,592)	0.2780%		3,165	(115,607)	1,026,150
April	Year 2020	(1,026,150)	0.2780%		2,853	(115,607)	913,396
May	Year 2020	(913,396)	0.2780%		2,539	(115,607)	800,327
June	Year 2020	(800,327)	0.2780%		2,225	(115,607)	686,945
July	Year 2020	(686,945)	0.2780%		1,910	(115,607)	573,247
August	Year 2020	(573,247)	0.2780%		1,594	(115,607)	459,234
September	Year 2020	(459,234)	0.2780%		1,277	(115,607)	344,903
October	Year 2020	(344,903)	0.2780%		959	(115,607)	230,254
November	Year 2020	(230,254)	0.2780%		640	(115,607)	115,287
December	Year 2020	(115,287)	0.2780%		320	(115,607)	0
					24,746		

True-Up Adjustment with Interest	1,387,289
Less Over (Under) Recovery	(1,295,152)
Total Interest	92,137

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.