AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2013 and Projected Net Plant at Year-End 2014

KENTUCKY POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$59,918,302
2	REVENUE CREDITS	(Note A) (Worksheet E)	207,513	DA	1.00000	$	207,513
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	59,710,789

MEMO: The Carrying Charge Calculations on lines 6 to 11 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 4 is included in the total on line 3.

Line No.			Total	Allocator			Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		-	DA	1.00000	$	-
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
6	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					16.07%
7	Monthly Rate	(ln 6 / 12)					1.34%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)						
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) /((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					13.79%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)						
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112 - ln 133 - ln 134) /((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					3.39%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)						-

Line No.	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
13			
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	2,158,022
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		955,673
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		225,073
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	977,276

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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					
18	Production	(Worksheet A ln 1.C)	1,461,312,977	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-16,408,685	NA	0.00000	0
20	Transmission	(Worksheet A ln 3.C & Ln 142)	508,900,048	DA		497,668,663
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	0	TP	0.97793	0
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		40,832,862	DA	1.00000	40,832,862
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		0	DA	1.00000	0
24	Distribution	(Worksheet A ln 5.C)	692,853,256	NA	0.00000	0
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	0	NA	0.00000	0
26	General Plant	(Worksheet A ln 7.C)	36,769,944	W/S	0.10335	3,800,233
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-81,055	W/S	0.10335	(8,377)
28	Intangible Plant	(Worksheet A ln 9.C)	15,790,189	W/S	0.10335	1,631,942
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	2,739,969,536			543,925,322
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	586,600,561	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-1,486,408	NA	0.00000	0
33	Transmission	(Worksheet A ln 14.C & 28.C)	162,742,412	**TP1=**	0.96563	157,148,615
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	0	**TP1=**	0.96563	0
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		87,748	DA	1.00000	87,748
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2014 (ln 111)		8,716,316	TP1	0.96563	8,416,718
38	Plus: Additional General & Intangible Depreciation for 2014 (ln 113 + ln 114)		4,078,267	W/S	0.10335	421,495
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		0	DA	1.00000	0
40	Distribution	(Worksheet A ln 16.C)	184,127,054	NA	0.00000	0
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	0	NA	0.00000	0
42	General Plant	(Worksheet A ln 18.C)	8,349,589	W/S	0.10335	862,944
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-16,751	W/S	0.10335	(1,731)
44	Intangible Plant	(Worksheet A ln 20.C)	19,219,728	W/S	0.10335	1,986,390
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	972,418,515			168,922,178
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	859,790,139			0
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	346,157,636			340,520,048
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		40,745,114			40,745,114
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		0			0
51	Plus: Additional Transmission Depreciation for 2014 (-ln 37)		(8,716,316)			(8,416,718)
52	Plus: Additional General & Intangible Depreciation for 2014 (-ln 38)		(4,078,267)			(421,495)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	508,726,202			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	28,356,051			2,930,644
56	Intangible Plant	(ln 28 - ln 44)	(3,429,539)			(354,448)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	1,767,551,021			375,003,144
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(86,593,718)	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(308,760,451)	DA		(67,644,357)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(38,350,785)	DA		(751,482)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	27,866,034	DA		3,283,964
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	0	DA		0
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(405,838,920)			(65,111,875)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	7,405,959	DA		0
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	0	DA		0
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	690,370			675,133
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	73,844	TP	0.97793	72,214
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	19,298	W/S	0.10335	1,994
71	Stores Expense	(Worksheet C, ln 4.(D))	0	GP(h)	0.18639	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	52,071,422	W/S	0.10335	5,381,666
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	594,031	GP(h)	0.18639	110,722
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	0	DA	1.00000	0
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(51,258,645)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,190,320			6,241,729
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(268,842)	DA	1.00000	(268,842)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		1,371,039,537			315,864,156

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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					
79	Production	321.80.b	419,527,034			
80	Distribution	322.156.b	39,260,806			
81	Customer Related Expense	322.164,171,178.b	9,455,286			
82	Regional Marketing Expenses	322.131.b	985,648			
83	Transmission	321.112.b	14,383,875			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	483,612,649			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,158,022			
86	Less: Account 565	(Note H) 321.96.b	6,702,896			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	5,522,957	TP	0.97793	5,401,066
89	Administrative and General	323.197.b (Note J)	19,790,491			
90	Less: Acct. 924, Property Insurance	323.185.b	549,852			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(1,007,225)			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(81,950)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	266,578			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	62,281			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	431,209			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	19,569,746	W/S	0.10335	2,022,565
98	Plus: Acct. 924, Property Insurance	(ln 90)	549,852	GP(h)	0.18639	102,487
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97793	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.97793	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	130,948	DA	1.00000	130,948
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	3,749,390	W/S	0.10335	387,506
103	A & G Subtotal	(sum lns 97 to 102)	23,999,936			2,643,505
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	29,522,893			8,044,571
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565	(Company Records) (Note H)	-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	29,522,893			8,044,571
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	20,841,536	NA	0.00000	-
110	Distribution	336.8.f	23,769,486	NA	0.00000	-
111	Transmission	336.7.f	8,716,316	TP1	0.96563	8,416,718
112	Plus: Transmission Plant-in-Service Additions	(Worksheet I ln 21.I)	87,748	DA	1.00000	87,748
113	General	336.10.f	904,657	W/S	0.10335	93,498
114	Intangible	336.1.f	3,173,610	W/S	0.10335	327,998
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	57,493,353			8,925,961
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	1,491,727	W/S	0.10335	154,172
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	10,052,912	DA		3,811,273
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	412,430	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	983,264	GP(h)	0.18639	183,271
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	12,940,333			4,148,716
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.68%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		45.35%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6308			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(230,012)			
131	Income Tax Calculation	(ln 126 * ln 134)	52,635,782			12,126,388
132	ITC adjustment	(ln 129 * ln 130)	(375,095)	NP(h)	0.19723	(73,979)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	52,260,687			12,052,409
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	116,059,283			26,738,082
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	8,563	DA	1.00000	8,563
136	(Gains) / Losses on Sales of Plant Held for Future Use	(Worksheet N, ln 4, Cols. ((F) & (H))	-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use	(ln 136 * ln126)	-			-
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135, 136, 137)		268,285,112			59,918,302

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		508,900,048
140	Less transmission plant excluded from PJM Tariff (Note P)			-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			11,231,385
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		497,668,663
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP**	**0.97793**

ln No.	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	7,058,720	2,308,874	9,367,594	NA	0.00000	-
146	Transmission	354.21.b	1,003,540	1,449,798	2,453,338	TP	0.97793	2,399,193
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	7,156,760	638,084	7,794,844	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,865,818	1,732,295	3,598,113	NA	0.00000	-
150	Total	(sum lns 145 to 149)	17,084,838	6,129,051	23,213,889			2,399,193
151	Transmission related amount						**W/S=**	**0.10335**

ln No.	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet L, ln. 35, col. (D))	37,933,541
154	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
155	Development of Common Stock:		
156	Proprietary Capital	(FF1 p 112, Ln 16.c)	839,369,490
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)	-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)	-
159	Less: Account 219	(FF1 p 112, Ln 15.c)	(5,419,702)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	844,789,192

ln No.		$	%	Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	750,000,000	47.03%	0.0506	0.0238
163	Preferred Stock (ln 157)	-	0.00%	-	0.0000
164	Common Stock (ln 160)	844,789,192	52.97%	11.49%	0.0609
165	Total (Sum lns 162 to 164)	1,594,789,192		**WACC=**	**0.0847**

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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. 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.
C	Transmission Plant balances in this study are projected as of December 31, 2014. Other ratebase amounts are as of December 31, 2013.
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 flow throughs 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 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.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85. 2) AEP transmission equalization transfers, as shown on line 86 3) The impact of state regulatory deferrals and amortizations, as shown on line 87 4) All A&G Expenses, as shown on line 103.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 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 135.
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 15 & 16 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 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 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 lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from 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 91 through 93 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 reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. 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, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
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 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 35.00% SIT= 5.66% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes)
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 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). 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. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
T	This note only applies to Indiana Michigan Power Company.
U	This note only applies to the true-up template.

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KENTUCKY POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$55,904,674
167	REVENUE CREDITS	(Note A) (Worksheet E)	207,513	DA	1.00000	$	207,513
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	55,697,161

MEMO: The Carrying Charge Calculations on lines 171 to 176 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 169 is included in the total on line 168.

169	Not applicable on this template		
170	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)		
171	Annual Rate	((ln 166 - ln 270 - ln 271)/ ln 213 x 100)	16.42%
172	Monthly Rate	(ln 171 / 12)	1.37%
173	NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)		
174	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276) / ln 213 x 100)	13.95%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)		
176	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276 - ln 298 - ln 299) / ln 213 x 100)	3.71%
177	Not applicable on this template		

178 **REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**

179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	2,158,022
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		955,673
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		225,073
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	977,276

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KENTUCKY POWER COMPANY

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					
183	Production	(Worksheet A ln 1.C)	1,461,312,977	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(16,408,685)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	508,900,048	DA		497,668,663
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.97793	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A ln 5.C)	692,853,256	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A ln 7.C)	36,769,944	W/S	0.10335	3,800,233
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(81,055)	W/S	0.10335	(8,377)
193	Intangible Plant	(Worksheet A ln 9.C)	15,790,189	W/S	0.10335	1,631,942
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	2,699,136,674	**GP(h)=**	**0.186390**	503,092,460
				GTD=	**0.41412**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	586,600,561	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(1,486,408)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	162,742,412	**TP1=**	0.96563	157,148,615
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96563	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2014 (ln 276)		N/A	TP1	0.96563	N/A
203	Plus: Additional General & Intangible Depreciation for 2014 (ln 275 + ln 276)		N/A	W/S	0.10335	N/A
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A ln 16.C)	184,127,054	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A ln 18.C)	8,349,589	W/S	0.10335	862,944
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(16,751)	W/S	0.10335	(1,731)
209	Intangible Plant	(Worksheet A ln 20.C)	19,219,728	W/S	0.10335	1,986,390
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	959,536,184			159,996,217
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	859,790,139			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	346,157,636			340,520,048
214	Plus: Transmission Plant-in-Service Additions (ln 187 - ln 200)		N/A			N/A
215	Plus: Additional Trans Plant on Transferred Assets (ln 188 - ln 201)		N/A			N/A
216	Plus: Additional Transmission Depreciation for 2014 (-ln 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for 2014 (-ln 203)		N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 204)		N/A			N/A
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	508,726,202			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	28,356,051			2,930,644
221	Intangible Plant	(ln 193 - ln 209)	(3,429,539)			(354,448)
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	1,739,600,490	**NP(h)=**	**0.197227**	343,096,244
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(86,593,718)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(308,760,451)	DA		(67,644,357)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(38,350,785)	DA		(751,482)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	27,866,034	DA		3,283,964
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(405,838,920)			(65,111,875)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	7,405,959	DA		-
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	690,370			675,133
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	73,844	TP	0.97793	72,214
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	19,298	W/S	0.10335	1,994
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.18639	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	52,071,422	W/S	0.10335	5,381,666
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	594,031	GP(h)	0.18639	110,722
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(51,258,645)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	2,190,320			6,241,729
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(268,842)	DA	1.00000	(268,842)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		1,343,089,006			283,957,256

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KENTUCKY POWER COMPANY

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					
244	Production	321.80.b	419,527,034			
245	Distribution	322.156.b	39,260,806			
246	Customer Related Expense	322 & 323.164,171,178.b	9,455,286			
247	Regional Marketing Expenses	322.131.b	985,648			
248	Transmission	321.112.b	14,383,875			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	483,612,649			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,158,022			
251	Less: Account 565	(Note H) 321.96.b	6,702,896			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	5,522,957	TP	0.97793	5,401,066
254	Administrative and General	323.197.b (Note J)	19,790,491			
255	Less: Acct. 924, Property Insurance	323.185.b	549,852			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(1,007,225)			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(81,950)			
259	Acct. 928, Reg. Com. Exp.	323.189.b	266,578			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	62,281			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	431,209			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	19,569,746	W/S	0.10335	2,022,565
263	Plus: Acct. 924, Property Insurance	(ln 255)	549,852	GP(h)	0.18639	102,487
264	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97793	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.97793	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	130,948	DA	1.00000	130,948
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	3,749,390	W/S	0.10335	387,506
268	A & G Subtotal	(sum lns 262 to 267)	23,999,936			2,643,505
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	29,522,893			8,044,571
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in Acct 565	(Company Records) (Note H)	-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	29,522,893			8,044,571
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	20,841,536	NA	0.00000	-
275	Distribution	336.8.f	23,769,486	NA	0.00000	-
276	Transmission	336.7.f	8,716,316	TP1	0.96563	8,416,718
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	904,657	W/S	0.10335	93,498
279	Intangible	336.1.f	3,173,610	W/S	0.10335	327,998
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	57,405,605			8,838,213
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 21.(D)	1,491,727	W/S	0.10335	154,172
284	Plant Related					
285	Property	Worksheet H ln 21.(C) & ln 35.(C)	10,052,912	DA		3,811,273
286	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	412,430	NA	0.00000	-
287	Other	Worksheet H ln 21.(E)	983,264	GP(h)	0.18639	183,271
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	12,940,333			4,148,716
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.68%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		45.35%			
292	where WCLTD=(ln 327) and WACC = (ln 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from ln 290)		1.6308			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(230,012)			
296	Income Tax Calculation	(ln 291 * ln 299)	51,562,729			10,901,445
297	ITC adjustment	(ln 294 * ln 295)	(375,095)	NP(h)	0.19723	(73,979)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	51,187,634			10,827,466
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	113,693,254			24,037,144
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	8,563	DA	1.00000	8,563
301	(Gains) / Losses on Sales of Plant Held for Future Use	(Worksheet N, ln 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use	(ln 301 * ln291)	-			-
303	TOTAL REVENUE REQUIREMENT (sum lns 272, 280, 288, 298, 299, 300, 301, 302)		264,758,283			55,904,674

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
304	Total transmission plant	(ln 185)		508,900,048
305	Less transmission plant excluded from PJM Tariff (Note P)			
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			11,231,385
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)		497,668,663
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)	**TP=**	**0.97793**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
310	Production	354.20.b	7,058,720	2,308,874	9,367,594	NA	0.00000	-
311	Transmission	354.21.b	1,003,540	1,449,798	2,453,338	TP	0.97793	2,399,193
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	7,156,760	638,084	7,794,844	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	1,865,818	1,732,295	3,598,113	NA	0.00000	-
315	Total	(sum lns 310 to 314)	17,084,838	6,129,051	23,213,889			2,399,193
316	Transmission related amount						**W/S=**	**0.10335**

ln No.			$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		
318	Long Term Interest	(Worksheet L, ln. 35, col. (D))	37,933,541
319	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
320	<u>Development of Common Stock:</u>		
321	Proprietary Capital	(FF1 p 112, Ln 16.c)	839,369,490
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)	-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)	-
324	Less: Account 219	(FF1 p 112, Ln 15.c)	(5,419,702)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)	844,789,192

ln No.		$	%	Cost (Note S)	Weighted
326					
327	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	750,000,000	47.03%	0.0506	0.0238
328	Preferred Stock (ln 322)	-	0.00%	-	0.0000
329	Common Stock (ln 325)	844,789,192	52.97%	11.49%	0.0609
330	Total (Sum lns 327 to 329)	1,594,789,192		**WACC=**	**0.0847**

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KENTUCKY POWER COMPANY

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. 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.
C	Transmission Plant balances in this study are projected as of December 31, 2013.
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 flow throughs 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 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.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250. 2) AEP transmission equalization transfers, as shown on line 251 3) The impact of state regulatory deferrals and amortizations, as shown on line 252 4) All A&G Expenses, as shown on line 268.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 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 300.
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 180 & 181 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 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176. The addbacks on lines 270 and 271 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 lines 270 and 271 is the KENTUCKY POWER COMPANY general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from 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 256 through 258 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 reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. 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, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
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 295) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	5.66%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

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 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). 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 remaining a member of the PJM RTO. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
T	This note only applies to Indiana Michigan Power Company.
U	This note only applies to the true-up template.

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Line No.			Total		Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$55,759,881
2	REVENUE CREDITS	(Note A) (Worksheet E)	207,513	DA	1.00000	$	207,513
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	55,552,368

MEMO: The Carrying Charge Calculations on lines 6 to 11 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 4 is included in the total on line 3.

4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		-	DA	1.00000	$	-
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					16.53%
7	Monthly Rate	(ln 6 / 12)					1.38%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)						
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					13.99%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)						
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134) / ln 48 x 100)					3.78%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)						-

13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	2,158,022
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		955,673
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		225,073
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	977,276

AEP East Companies
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Utilizing Actual Cost Data for 2013 with Average Ratebase Balances

KENTUCKY POWER COMPANY

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					
18	Production	(Worksheet A ln 1.E)	1,006,393,106	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(10,011,624)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	499,510,769	DA		493,071,934
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.98711	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
24	Distribution	(Worksheet A ln 5.E)	672,420,491	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.E)	35,993,644	W/S	0.10432	3,754,920
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(81,055)	W/S	0.10432	(8,456)
28	Intangible Plant	(Worksheet A ln 9.E)	16,762,113	W/S	0.10432	1,748,653
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	2,220,987,443	**GP(h)=**	**0.22448**	498,567,051
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	426,906,184	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(1,211,405)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	158,791,059	**TP1=**	0.98034	155,669,791
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.98034	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for 2014 (ln 111)		N/A	TP1	0.98034	N/A
38	Plus: Additional General & Intangible Depreciation for 2014 (ln 110 + ln 111)		N/A	W/S	0.10432	N/A
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
40	Distribution	(Worksheet A ln 16.E)	177,676,368	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.E)	8,156,069	W/S	0.10432	850,855
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(13,935)	W/S	0.10432	(1,454)
44	Intangible Plant	(Worksheet A ln 20.E)	20,057,035	W/S	0.10432	2,092,385
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	790,361,373			158,611,578
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	570,686,703			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	340,719,711			337,402,142
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		N/A			N/A
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		N/A			N/A
51	Plus: Additional Transmission Depreciation for 2014 (-ln 37)		N/A			N/A
52	Plus: Additional General & Intangible Depreciation for 2014 (-ln 38)		N/A			N/A
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	494,744,124			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	27,770,455			2,897,063
56	Intangible Plant	(ln 28 - ln 44)	(3,294,922)			(343,732)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	1,430,626,071	**NP(h)=**	**0.23763**	339,955,473
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(56,619,178)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(253,741,784)	DA		(63,200,663)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(28,442,194)	DA		(801,410)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	20,792,724	DA		3,210,592
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(318,010,432)			(60,791,481)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	7,421,255	DA		15,296
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	690,370			681,471
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	51,745	TP	0.98711	51,077
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	12,963	W/S	0.10432	1,352
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.22448	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	39,696,979	W/S	0.10432	4,141,259
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	614,438	GP(h)	0.22448	137,929
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(38,823,115)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,243,379			5,013,088
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(264,561)	DA	1.00000	(264,561)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		1,122,015,712			283,927,816

AEP East Companies
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KENTUCKY POWER COMPANY

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					
79	Production	321.80.b	419,527,034			
80	Distribution	322.156.b	39,260,806			
81	Customer Related Expense	322.164,171,178.b	9,455,286			
82	Regional Marketing Expenses	322.131.b	985,648			
83	Transmission	321.112.b	14,383,875			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	483,612,649			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,158,022			
86	Less: Account 565	(Note H) 321.96.b	6,702,896			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	5,522,957	TP	0.98711	5,451,765
89	Administrative and General	323.197.b (Note J)	19,790,491			
90	Less: Acct. 924, Property Insurance	323.185.b	549,852			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(1,007,225)			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(81,950)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	266,578			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	62,281			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	431,209			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	19,569,746	W/S	0.10432	2,041,550
98	Plus: Acct. 924, Property Insurance	(ln 90)	549,852	GP(h)	0.22448	123,431
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97793	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.97793	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	130,948	DA	1.00000	130,948
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	3,749,390	W/S	0.10432	391,143
103	A & G Subtotal	(sum lns 97 to 102)	23,999,936			2,687,072
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	29,522,893			8,138,837
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	29,522,893			8,138,837
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	20,841,536	NA	0.00000	-
110	Distribution	336.8.f	23,769,486	NA	0.00000	-
111	Transmission	336.7.f	8,716,316	TP1	0.98034	8,544,984
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	904,657	W/S	0.10432	94,375
114	Intangible	336.1.f	3,173,610	W/S	0.10432	331,077
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	57,405,605			8,970,436
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	1,491,727	W/S	0.10432	155,620
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	10,052,912	DA		3,811,273
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	412,430	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	983,264	GP(h)	0.22448	220,723
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	12,940,333			4,187,615
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.68%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		42.99%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6308			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(230,012)			
131	Income Tax Calculation	(ln 126 * ln 134)	41,043,123			10,386,026
132	ITC adjustment	(ln 129 * ln 130)	(375,095)	NP(h)	0.23763	(89,133)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	40,668,028			10,296,893
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	95,464,884			24,157,537
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		8,563	DA	1.00000	8,563
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135)		236,010,306			55,759,881

AEP East Companies
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KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		499,510,769
140	Less transmission plant excluded from PJM Tariff (Note P)			-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			6,438,835
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		493,071,934
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP=**	**0.98711**

ln No.				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	7,058,720	2,308,874	9,367,594	NA	0.00000	-
146	Transmission	354.21.b	1,003,540	1,449,798	2,453,338	TP	0.98711	2,421,714
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	7,156,760	638,084	7,794,844	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,865,818	1,732,295	3,598,113	NA	0.00000	-
150	Total	(sum lns 145 to 149)	17,084,838	6,129,051	23,213,889			2,421,714
151	Transmission related amount						**W/S=**	**0.10432**

ln No.			
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))	35,553,541
154	Preferred Dividends	(Worksheet M, ln. 56, col. (E))	-
155	Development of Common Stock:		Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	659,489,763
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))	-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))	-
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))	(2,914,291)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	662,404,054

ln No.			**Capital Structure Weighting**		Cost	
161		Average $	Actual	Cap Limit	(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, ln 11, ln 22, col. (E))	650,000,000	49.53%	0.00%	0.0547	0.0271
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Commone Stock (ln 160)	662,404,054	50.47%	0.00%	11.49%	0.0580
165	Total (Sum lns 162 to 164)	1,312,404,054			**WACC=**	**0.0851**
166	Capital Structure Equity Limit (Note U)	100.0%				

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2013 with Average Ratebase Balances

KENTUCKY POWER COMPANY

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. 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.
C	Transmission Plant balances in this study reflect the average of the balances at December 31, 2012 and December 31, 2013.
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 flow throughs 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 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.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85. 2) AEP transmission equalization transfers, as shown on line 86 3) The impact of state regulatory deferrals and amortizations, as shown on line 87 4) All A&G Expenses, as shown on line 103.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 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 135.
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 15 & 16 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 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 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 lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
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 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemplyoment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
L	Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. 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, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
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 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 35.00% SIT= 5.66% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes)
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 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). 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. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
T	This note only applies to Indiana Michigan Power Company.
U	Per Settlement, equity for KENTUCKY POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure. During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies
Cost of Service Formula Rate Using 2013 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, 2013	(D) Balance @ December 31, 2012	(E) Average Balance for 2013
	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	1,461,312,977	551,473,235	1,006,393,106
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	16,408,685	3,614,563	10,011,624
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	508,900,048	490,121,490	499,510,769
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	692,853,256	651,987,726	672,420,491
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	36,769,944	35,217,344	35,993,644
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	81,055	81,055	81,055
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	15,790,189	17,734,036	16,762,113
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	2,715,626,414	1,746,533,831	2,231,080,123
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	16,489,740	3,695,618	10,092,679
	Accumulated Depreciation & Amortization Balances				
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	586,600,561	267,211,806	426,906,184
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	1,486,408	936,402	1,211,405
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	162,742,412	154,839,705	158,791,059
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	184,127,054	171,225,681	177,676,368
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	8,349,589	7,962,549	8,156,069
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	16,751	11,119	13,935
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	19,219,728	20,894,341	20,057,035
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	961,039,344	622,134,082	791,586,713
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	1,503,160	947,521	1,225,340
	Generation Step-Up Units				
23	**GSU Investment Amount**	Company Records - Note 1	11,231,385	1,646,286	6,438,835
24	**GSU Accumulated Depreciation**	Company Records - Note 1	5,593,797	648,737	3,121,267
25	**GSU Net Balance**	(Line 23 - Line 24)	5,637,588	997,548	3,317,568
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation				
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	162,742,412	154,839,705	158,791,059
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	5,593,797	648,737	3,121,267
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	157,148,615	154,190,968	155,669,791
	Plant Held For Future Use				
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	7,405,959	7,436,551	7,421,255
30	**Transmission Plant Held For Future**	Company Records - Note 1	-	30,592	15,296
	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 unamortized balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	**Description**	**Source**	**Balance @ December 31, 2013**	**Balance @ December 31, 2012**	**Average Balance for 2013**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	86,593,718	26,644,638	56,619,178
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	86,593,718	26,644,638	56,619,178
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)	308,760,451	198,723,117	253,741,784
8	Less: ARO Related Deferrals	Company Records - Note 1	9,586,589	1,282,377	5,434,483
9	Less: Other Excluded Deferrals	Company Records - Note 1	231,529,505	138,683,771	185,106,638
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	67,644,357	58,756,969	63,200,663
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	38,350,785	18,533,602	28,442,194
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	37,599,303	17,682,265	27,640,784
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	751,482	851,337	801,410
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	27,866,034	13,719,413	20,792,724
18	Less: ARO Related Deferrals	Company Records - Note 1	7,184,115	1,365,791	4,274,953
19	Less: Other Excluded Deferrals	Company Records - Note 1	17,397,955	9,216,403	13,307,179
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	3,283,964	3,137,219	3,210,592
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	125,747	355,759	240,753
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	125,747	355,759	240,753
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1	0	0	-

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

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

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
KENTUCKY POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2013	(E) Balance @ December 31, 2012	(F) Average Balance for 2013
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	73,844	29,645	51,745
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	19,298	6,628	12,963
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

Line		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
5							
6	Totals as of December 31, 2013	1,406,809	(51,258,645)	0	594,031	52,071,422	52,665,453
7	Totals as of December 31, 2012	1,569,795	(26,387,585)		634,845	27,322,535	27,957,380
8	**Average Balance**	1,488,302	(38,823,115)	-	614,438	39,696,979	40,311,417

Prepayments Account 165 - Balance @ 12/31/2013

9	Acc. No.	Description	2013 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	357,881	-		357,881		357,881	Plant Related Insurance Policies
11	165000213	Prepaid Taxes	473,122	473,122		-		-	Prepaid Fees-Distribution
12	1650009	Prepaid Carry Cost-Factored AR	14,962	14,962				-	AR Factoring - Retail Only
13	1650010	Prepaid Pension Benefits	52,071,422				52,071,422	52,071,422	Prefunded Pension Expense
14	1650014	FAS 158 Qual Contra Asset	(52,071,422)	(52,071,422)				-	SFAS 158 Offset
15	1650016	FAS 112 ASSETS	0	-			-	-	
16	165001213	Prepaid Use Taxes	47,060	47,060			-	-	Use Taxes-Distribution
17	165001113	Prepaid Sales Taxes	274,001	274,001			-	-	Sales Taxes-Distribution
18	1650021	Prepaid Insurance - EIS	236,150	-		236,150		236,150	Prepaid Ins. - EIS
19	1650023	Prepaid Lease	3,632	3,632				-	Distribution Lease
		Subtotal - Form 1, p 111.57.c	1,406,809	(51,258,645)	0	594,031	52,071,422	52,665,453	

Prepayments Account 165 - Balance @ 12/31/ 2012

20	Acc. No.	Description	2012 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
21	1650001	Prepaid Insurance	366,671	-		366,671		366,671	Plant Related Insurance Policies
22	165000212	Prepaid Taxes	515,095	515,095		-		-	Prepaid Fees
23	1650009	Prepaid Carry Cost-Factored AR	13,101	13,101				-	AR Factoring - Retail Only
24	1650010	Prepaid Pension Benefits	27,322,535				27,322,535	27,322,535	Prefunded Pension Expense
25	1650014	FAS 158 Qual Contra Asset	(27,322,535)	(27,322,535)				-	SFAS 158 Offset
26	1650016	FAS 112 ASSETS	0	-			-	-	
27	165001212	Prepaid Use Taxes	42,719	42,719			-	-	Use Taxes-Distribution
28	165001112	Prepaid Sales Taxes	294,773	294,773			-	-	Sales Taxes-Distribution
29	1650021	Prepaid Insurance - EIS	268,174	-		268,174		268,174	Prepaid Ins. - EIS
30	1650023	Prepaid Lease	69,262	69,262				-	Distribution Lease
								-	
		Subtotal - Form 1, p 111.57.d	1,569,795	(26,387,585)		634,845	27,322,535	27,957,380	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet D Supporting IPP Credits
KENTUCKY POWER COMPANY

Line Number	(A) Description	(B) 2013
1	Net Funds from IPP Customers 12/31/2012 (2013 FORM 1, P269, line 13.b)	(260,279)
2	Interest Accrual (Company Records - Note 1)	(8,563)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4	Other Adjustments	
5	Accounting Adjustment (Company Records - Note 1)	-
6		-
7	Net Funds from IPP Customers 12/31/2013 (2013 FORM 1, P269, line 13.f)	(268,842)
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(264,561)

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

AEP East Companies
Cost of Service Formula Rate Using 2013 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)**	3,340,356	3,340,356	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	380,114	366,558	13,556
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	6,403,606	6,389,806	13,800
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	479,654	299,497	180,157
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	20,889,297	20,889,297	
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	31,493,027	31,285,514	207,513
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	31,493,027	31,285,514	207,513

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.

AEP East Companies
Cost of Service Formula Rate Using 2013 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**	**2013 Expense**	**100% Non-Transmission**	**100% Transmission Specific**	**Explanation**
		Regulatory O&M Deferrals & Amortizations				
1		No Applicable Charges for KPCO	-			
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	9,421			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	821,922			
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	955,672			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	145,934			
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 Servi	225,073			
14		**Total of Account 561**	2,158,022			
		Account 928				
15	9280000	Regulatory Commission Exp	62,408	62,408	-	
16	9280001	Regulatory Commission Exp-Adm	-	-	-	
17	9280002	Regulatory Commission Exp-Case	204,170	204,170	-	
18		**Total**	266,578	266,578	-	
		Account 930.1				
19	9301000	General Advertising Expenses	5,094	5,094	-	
20	9301001	Newspaper Advertising Space	21,635	21,635	-	
21	9301002	Radio Station Advertising Time	50	50	-	
21	9301003	TV Station Advertising Time	2,600	2,600		
22	9301006	Spec Corp Comm Info Proj	-	-	-	
23	9301010	Publicity	2,913	2,913	-	
24	9301011	Dedications, Tours, & Openings	-	-	-	
25	9301012	Public Opinion Surveys	4,388	4,388	-	
26	9301014	Video Communications	7	7	-	
	9301015	Other Corporate Comm Exp	25,595	25,595		
27		**Total**	62,282	62,282	-	
		Account 930.2				
28	9302000	Misc General Expenses	126,164	126,164		
29	9302003	Corporate & Fiscal Expenses	20,435	20,435		
30	9302004	Research, Develop&Demonstr Exp	3,453	3,453		
31	9302006	Assoc Bus Dev Materials Sold	41,678	41,678		
32	9302007	Assoc Business Development Exp	239,471	108,523	130,948	
33	9302458	AEPSC Non Affiliated Expense	7	7		
34		**Total**	431,208	300,260	130,948	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
KENTUCKY POWER COMPANY

Kentucky Corporate Income Tax	6.00%	
Apportionment Factor - Note 2	90.99%	
Effective State Tax Rate		5.46%
West Virginia Corporate Income Tax	7.00%	
Apportionment Factor - Note 2	0.70%	
Effective State Tax Rate		0.05%
Michigan Business Income Tax	6.00%	
Apportionment Factor - Note 2	0.11%	
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%
Illinios Income Tax	9.50%	
Apportionment Factor - Note 2	1.45%	
Effective State Tax Rate		0.14%
Total Effective State Income Tax Rate		5.66%

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 2013 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	55,187				55,187
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Kentucky	10,052,049	10,052,049			
5	Real and Personal Property - Other	863	863			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	1,421,332		1,421,332		
8	Federal Unemployment Tax	39,040		39,040		
9	State Unemployment Insurance	31,355		31,355		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	988,217			988,217	
15	State Franchise Taxes	(5,338)			(5,338)	
16	State Lic/Registration Fee	385			385	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	354,754				354,754
19	Federal Excise Tax	2,489				2,489
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	12,940,333	10,052,912	1,491,727	983,264	412,430
	(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					
		Production	Transmsission	Distribution	General	Total
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	859,790,139	346,157,636	508,726,202	28,356,051	1,743,030,029
	KENTUCKY JURISDICTION					
23	Percentage of Plant in KENTUCKY JURISDICTION	27.81%	98.12%	100.00%	99.52%	
24	Net Plant in KENTUCKY JURISDICTION (Ln 22 * Ln 23)	239,107,638	339,649,872	508,726,202	28,219,942	1,115,703,655
25	Less: Net Value of Exempted Generation Plant	96,713,445				
26	Taxable Property Basis (Ln 24 - Ln 25)	142,394,193	339,649,872	508,726,202	28,219,942	1,018,990,210
27	Relative Valuation Factor	33%	100%	100%	100%	
28	Weighted Net Plant (Ln 26 * Ln 27)	47,474,224	339,649,872	508,726,202	28,219,942	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	5.30%	37.91%	56.79%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	1,495,473	10,699,221	16,025,249	(28,219,942)	-
31	Weighted KENTUCKY JURISDICTION Plant (Ln 28 + 30)	48,969,697	350,349,094	524,751,451	0	924,070,240
32	Functional Percentage (Ln 31/Total Ln 31)	5.30%	37.91%	56.79%		
33	Functionalized Expense in KENTUCKY JURISDICTION	532,693	3,811,102	5,708,254		10,052,049
	WEST VA JURISDICTION					
34	Net Plant in WEST VA JURISDICTION (Ln - Ln)	620,682,502	6,507,764	-	136,109	627,326,374
35	Less: Net Value Exempted Generation Plant	428,923,105				
36	Taxable Property Basis	191,759,397	6,507,764	-	136,109	198,403,269
37	Relative Valuation Factor	100.00%	100.00%	100%	100.00%	
38	Weighted Net Plant (Ln 36 * Ln 37)	191,759,397	6,507,764	-	136,109	
39	General Plant Allocator (Ln 38 / (Total - General Plant)	96.72%	3.28%	0.00%	-100.00%	
40	Functionalized General Plant (Ln 40 * General Plant)	131,642	4,468	-	(136,109)	
41	Weighted WEST VA JURISDICTION Plant (Ln 38 + 40)	191,891,039	6,512,232	-	0	198,403,269
42	Functional Percentage (Ln 41/Total Ln 41)	96.72%	3.28%	0.00%		
43	Functionalized Payment in WEST VA JURISDICTION	-	-	-		-
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		170			863
35	Total Func. Property Taxes (Sum Lns 33, 34)	532,693	3,811,273	5,708,254		10,052,912

AEP East Companies
Cost of Service Formula Rate Using 2013 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	55,187		
			(31,461)	P.263.1 ln 29 (i)
			54,373	P.263.1 ln 30 (i)
			(39,083)	P.263.1 ln 31 (i)
			71,358	P.263.1 ln 39 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Kentucky	10,052,049		
			811	P.263 ln 31 (i)
			66,347	P.263 ln 32 (i)
			15,173	P.263 ln 33 (i)
			9,939,409	P.263 ln 34 (i)
			(10,026)	P.263 ln 36 (i)
			(4,165)	P.263 ln 37 (i)
			17,300	P.263 ln 38 (i)
			27,000	P.263 ln 39 (i)
			200	P.263.1 ln 37 (i)
			-	
			-	
5	Real and Personal Property - Other	863		
			863	P.263.1 ln 15 (i)
			-	P.263.1 ln 16 (i)
			-	
			-	
6	Payroll Taxes			
7	Federal Insurance Contribution (FICA)	1,421,332		
			1,421,332	P.263 ln 4 (i)
8	Federal Unemployment Tax	39,040		
			39,040	P.263 ln 5 (i)
9	State Unemployment Insurance	31,355		
			30,355	P.263 ln 23 (i)
			1,000	P.263.1 ln 19 (i)
10	Production Taxes			
11	State Severance Taxes	-		
			-	
12	Miscellaneous Taxes			
13	State Business & Occupation Tax	-		
			-	
14	State Public Service Commission Fees	988,217		
			515,095	P.263 ln 25 (i)
			473,122	P.263 ln 26 (i)
15	State Franchise Taxes	(5,338)		
			(9,120)	P.263.1 ln 6 (i)
			3,782	P.263.1 ln 7 (i)
16	State Lic/Registration Fee	385		
			340	P.263 ln 19 (i)
			-	P.263 ln 20 (i)
			45	P.263.1 ln 17 (i)
			-	P.263.1 ln 20 (i)
17	Misc. State and Local Tax	-		
			-	
18	Sales & Use	354,754		
			1,109	P.263 ln 27 (i)
			11,175	P.263 ln 28 (i)
			342,470	P.263.1 ln 10 (i)
19	Federal Excise Tax	2,489		
			2,489	P.263 ln 7 (i)
20	Michigan Single Business Tax	-		
			-	
21	Total Taxes by Allocable Basis	12,940,333	12,940,333	
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))			

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 2013 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
KENTUCKY POWER COMPANY

(A) (B) (C) (D) (E) (F) (G) (H) (I)

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2013) (P.206, ln 58,(b)):	490,121,490
2	Transmission Plant @ End of Historic Period (2013) (P.207, ln 58,(g)):	508,900,048
3		999,021,538
4	Average Balance of Transmission Investment	499,510,769
5	Annual Depreciation Expense, Historic TCOS, ln 276	8,716,316
6	Composite Depreciation Rate	1.74%
7	Round to 1.74% to Reflect a Composite Life of 57 Years	1.74%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

8	Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	$ 1,101,989	1.74%	$ 19,175	$ 1,598	11	$ 17,578
10	February	$ 1,334,779	1.74%	$ 23,225	$ 1,935	10	$ 19,350
11	March	$ 702,057	1.74%	$ 12,216	$ 1,018	9	$ 9,162
12	April	$ 729,546	1.74%	$ 12,694	$ 1,058	8	$ 8,464
13	May	$ 725,118	1.74%	$ 12,617	$ 1,051	7	$ 7,357
14	June	$ 1,243,188	1.74%	$ 21,631	$ 1,803	6	$ 10,818
15	July	$ 701,341	1.74%	$ 12,203	$ 1,017	5	$ 5,085
16	August	$ 713,320	1.74%	$ 12,412	$ 1,034	4	$ 4,136
17	September	$ 683,522	1.74%	$ 11,893	$ 991	3	$ 2,973
18	October	$ 659,373	1.74%	$ 11,473	$ 956	2	$ 1,912
19	November	$ 629,688	1.74%	$ 10,957	$ 913	1	$ 913
20	December	$ 31,608,941	1.74%	$ 549,996	$ 45,833	0	$ -
21	Investment	$ 40,832,862				Depreciation Expense	$ 87,748

III. Plant Transferred

22		$ -	<== This input area is for original cost plant
23		$ -	<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.
24	(Ln 7 * Ln 22)	$ -	<== This input area is for additional Depreciation Expense

IV. List of Major Projects Expected to be In-Service in 2014

			Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**			
26	Hazard Area Improvements		$32,618	Dec-14
27		Subtotal	$32,618	
28	**PJM Socialized/Beneficiary Allocated Regional Projects**			
29	N/A		$0	
30		Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2013 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 (Projected TCOS, ln 164)			11.49%
Project ROE Incentive Adder			<==ROE Adder Cannot Exceed 125 Basis Points
ROE with additional basis point incentive			11.49% **<== ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012**

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the Projected TCOS, lns 162 through164)

	%	Cost	Weighted cost
Long Term Debt	47.03%	5.06%	2.379%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	52.97%	11.49%	6.086%
		R =	8.465%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2014	-	-	$ -

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

Rate Base (Projected TCOS, ln 78)	315,864,156
R (from A. above)	8.465%
Return (Rate Base x R)	26,738,082

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

Return (from B. above)	26,738,082
Effective Tax Rate (Projected TCOS, ln 126)	45.35%
Income Tax Calculation (Return x CIT)	12,126,388
ITC Adjustment	(73,979)
Income Taxes	12,052,409

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 (Projected TCOS, ln 1)	59,918,302
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	26,738,082
Income Taxes (Projected TCOS, ln 133)	12,052,409
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	21,127,811

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	21,127,811
Return (from I.B. above)	26,738,082
Income Taxes (from I.C. above)	12,052,409
Annual Revenue Requirement, with Basis Point ROE increase	59,918,302
Depreciation (Projected TCOS, ln 111)	8,416,718
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	51,501,584

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	340,520,048
Annual Revenue Requirement, with Basis Point ROE increase	59,918,302
FCR with Basis Point increase in ROE	17.60%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	51,501,584
FCR with Basis Point ROE increase, less Depreciation	15.12%
FCR less Depreciation (Projected TCOS, ln 9)	13.79%
Incremental FCR with Basis Point ROE increase, less Depreciation	1.33%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2013) (P.206, ln 58,(b)):	490,121,490
Transmission Plant @ End of Historic Period (2013) (P.207, ln 58,(g)):	508,900,048
Subtotal	999,021,538
Average Transmission Plant Balance for 2013	499,510,769
Annual Depreciation Rate (Projected TCOS, ln 111)	8,716,316
Composite Depreciation Rate	1.74%
Depreciable Life for Composite Depreciation Rate	57.31
Round to nearest whole year	57

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	2008
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	1	FCR w/o incentives, less depreciation	13.79%
Useful life	57	FCR w/incentives approved for these facilities, less dep.	13.79%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2008	-	-	-	-	-	$ -
2009	-	-	-	-	-	$ -
2010	-	-	-	-	-	$ -
2011	-	-	-	-	-	$ -
2012	-	-	-	-	-	$ -
2013	-	-	-	-	-	$ -
2014	-	-	-	-	-	$ -
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	-	-	-	-	-	$ -
Project Totals		-		-	-	-

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.

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		

** 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 2013 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 (True-Up TCOS, ln 164) 11.49%
Project ROE Incentive Adder 0 <==ROE Adder Cannot Exceed 100 Basis Points
ROE with additional 0 basis point incentive 11.49% **<== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012**
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, lns 162 through164)

	%	Cost		Weighted cost
Long Term Debt	49.53%	5.47%		2.709%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	50.47%	11.49%		5.799%
			R =	8.508%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2013			
As Projected in Prior Year WS J			$ -
Actual after True-up	$ -	$ -	$ -
True-up of ARR For 2013	-	-	-

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

Rate Base (True-Up TCOS, ln 78)	283,927,816
R (from A. above)	8.508%
Return (Rate Base x R)	24,157,537

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

Return (from B. above)	24,157,537
Effective Tax Rate (True-Up TCOS, ln 126)	42.99%
Income Tax Calculation (Return x CIT)	10,386,026
ITC Adjustment	(89,133)
Income Taxes	10,296,893

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 (True-Up TCOS, ln 1)	55,759,881
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	24,157,537
Income Taxes (True-Up TCOS, ln 133)	10,296,893
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	21,305,451

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	21,305,451
Return (from I.B. above)	24,157,537
Income Taxes (from I.C. above)	10,296,893
Annual Revenue Requirement, with 0 Basis Point ROE increase	55,759,881
Depreciation (True-Up TCOS, ln 111)	8,544,984
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	47,214,897

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

Net Transmission Plant (True-Up TCOS, ln 48)	337,402,142
Annual Revenue Requirement, with 0 Basis Point ROE increase	55,759,881
FCR with 0 Basis Point increase in ROE	16.53%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	47,214,897
FCR with 0 Basis Point ROE increase, less Depreciation	13.99%
FCR less Depreciation (True-Up TCOS, ln 9)	13.99%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, ln 58,(b)):	490,121,490
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	508,900,048
Subtotal	999,021,538
Average Transmission Plant Balance for	499,510,769
Annual Depreciation Rate (True-Up TCOS, ln 111)	8,716,316
Composite Depreciation Rate	1.74%
Depreciable Life for Composite Depreciation Rate	57.31
Round to nearest whole year	57

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:

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details			
Investment		Current Year	2013
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	13.99%
Useful life	57	FCR w/incentives approved for these facilities, less dep.	13.99%
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 **
2008	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2009	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2010	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2011	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2012	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2013	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2014	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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 2013 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
KENTUCKY POWER COMPANY

Calculation of Projected Interest Expense Based on Outstanding Debt at Year End

Line Number	(A) Issuance		(B) Principle Outstanding	(C) Interest Rate	(D) Annual Expense (See Note S on Projected Template)	(E) Notes
1	**Long Term Debt (FF1.p. 256-257.h)**					
2	Advances from Associated Companies		20,000,000	5.250%	1,050,000	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	Senior Unsecured Notes - Series D		75,000,000	5.625%	4,218,750	
6	Senior Unsecured Notes - Series E		325,000,000	6.000%	19,500,000	
7	Senior Unsecured Notes - 7.250%		40,000,000	7.250%	2,900,000	
8	Senior Unsecured Notes - 8.030%		30,000,000	8.030%	2,409,000	
9	Senior Unsecured Notes - 8.130%		60,000,000	8.130%	4,878,000	
10	Floating Rate Term Credit Agreement Due 2015		200,000,000	1.190%	2,380,000	
11					-	
12					-	
13					-	
14					-	
15					-	
16					-	
17					-	
18					-	
19					-	
20					-	
21					-	
22					-	
23					-	
24					-	
25					-	
26						
27	Issuance Discount, Premium, & Expenses:					
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
29	Allowable Hedge Amortization (See Ln 45 Below)				92,956	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			471,186	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
32	Reacquired Debt:					
33	Amortization of Loss	FF1.p. 117.64.c			33,649	
34	Amortization of Gain	FF1.p. 117.66.c			-	
35	**Total Interest on Long Term Debt**		750,000,000	5.06%	37,933,541	
36	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
37			-	0.00%	-	
38					-	
39					-	
40	**Dividends on Preferred Stock**		-		-	
41	Net Total Hedge Gains and Losses (WS M, Ln 35, (E))				92,956	
42	Total Projected Capital Structure Balance for 2014 (Projected TCOS, Ln 165)				1,594,789,192	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
44	Limit of Recoverable Amount				797,395	
45	**Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)**				**92,956**	

AEP East Companies
Transmission Cost of Service Formula Rate
KENTUCKY POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2012 & 12/31/2013

(A) Line	(B)	(C) Balances @ 12/31/2013	(D) Balances @ 12/31/2012	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	839,369,490	479,610,035	659,489,763
2	Less Preferred Stock (Ln 55 Below)	-	-	-
3	Less Account 216.1 (112.12.c&d)	-	-	-
4	Less Account 219.1 (112.15.c&d)	(5,419,702)	(408,880)	(2,914,291)
5	**Average Balance of Common Equity**	844,789,192	480,018,915	**662,404,054**
	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)	20,000,000	20,000,000	20,000,000
9	Senior Unsecured Notes (112.21.c&d)	730,000,000	530,000,000	630,000,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	750,000,000	550,000,000	**650,000,000**

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)**

13	**Annual Interest Expense for 2013**	
14	Interest on Long Term Debt (256-257.33.i)	35,048,706
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 34 below.	92,956
16	Plus: Allowed Hedge Recovery From Ln 39 below.	92,956
17	Amort of Debt Discount & Expense (117.63.c)	471,186
18	Amort of Loss on Reacquired Debt (117.64.c)	33,649
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)**	**35,553,541**
22	**Average Cost of Debt for 2013 (Ln 21/Ln 11)**	**5.47%**

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 2013	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	340,840	September 2007	September 2017
25	Senior Unsecured Notes	0		-			
26	Senior Unsecured Notes	0		-			
27	Senior Unsecured Notes	0		-			
28	Senior Unsecured Notes	0		-			
29	Senior Unsecured Notes	0		-			
30	Senior Unsecured Notes	0		-			
31	Senior Unsecured Notes	0		-			
32	Senior Unsecured Notes	0		-			
33	Senior Unsecured Notes	0	-	-			
34	Total Hedge Amortization	92,956	-				

35	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)	92,956
36	Total Average Capital Structure Balance for 2013 (True-UP TCOS, Ln 165)	1,312,404,054
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
38	Limit of Recoverable Amount	656,202
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**	**92,956**

Development of Cost of Preferred Stock

Line	Preferred Stock	(C)	(D)	Average	
40	0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	0.00%		
41	0% Series - 0 - Par Value (p. 250-251. 8.c)	$ -	$ -		
42	0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	-	-		
43	0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	-	
44	0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	-	-	-	
45	0% Series - - Dividend Rate (p. 250-251.a)				
46	0% Series - - Par Value (p. 250-251.c)				
47	0% Series - - Shares O/S (p.250-251. e)				
48	0% Series - - Monetary Value (Ln 46 * Ln 47)	-	-	-	
49	0% Series - - Dividend Amount (Ln 45 * Ln 48)	-	-	-	
50	0% Series - - Dividend Rate (p. 250-251.a)				
51	0% Series - - Par Value (p. 250-251.c)				
52	0% Series - - Shares O/S (p.250-251.e)				
53	0% Series - - Monetary Value (Ln 51 * Ln 52)	-	-	-	
54	0% Series - - Dividend Amount (Ln 50 * Ln 53)	-	-	-	
55	**Balance of Preferred Stock (Lns 43, 48, 53)**	-	-	-	
56	**Dividends on Preferred Stock (Lns 44, 49, 54)**	-	-	-	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%		

AEP East Companies
Cost of Service Formula Rate Using 2013 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.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	**Date**	**Property Description**	**Function (T) or (G)** T = Transmission G = General	**Basis**	**Proceeds**	**(Gain) / Loss**	**Functional Allocator**	**Functionalized Proceeds (Gain) / Loss**	**FERC Account**
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 2013		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
KENTUCKY POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 30,000,000

Allocation of PBOP Settlement Amount for 2013

Line#	Company	Total Company Amount Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2013	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) **(Line 14)**	**(B)=(A)/Total (A)**	**(C)=(B) * 30000000**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	APCo	(4,215,559)	48.37%	14,511,689	7.115%	(299,951)	1,032,553	(1,332,504)
2								
3	I&M	(3,395,590)	38.96%	11,689,019	3.672%	(124,685)	429,217	(553,902)
4	KPCo	(1,089,175)	12.50%	3,749,390	10.335%	(112,568)	387,506	(500,074)
5	KNGP	(91,189)	1.05%	313,910	12.878%	(11,743)	40,424	(52,167)
6	OPCo	191,908	-2.20%	(660,626)	6.682%	12,823	(44,141)	56,964
7	WPCo	(115,215)	1.32%	396,617	7.229%	(8,328)	28,670	(36,998)
8	**Sum of Lines 1 to 7**	(8,714,820)		30,000,000		(544,452)	1,874,228	(2,418,680)

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	(4,054,293)	(3,376,008)	(1,007,225)	(81,745)	(4,165,372)	(103,680)	(12,788,323)
10 Additional PBOP Ledger Entries (from Company Records)	223,423	257,059	(0)	0	4,866,605	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(3,830,870)	(3,118,949)	(1,007,225)	(81,745)	701,233	(103,680)	(7,441,236)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(384,689)	(276,641)	(81,950)	(9,444)	(509,325)	(11,535)	(1,273,584)
14 Company PBOP Expense (Ln 12 + Ln 13)	(4,215,559)	(3,395,590)	(1,089,175)	(91,189)	191,908	(115,215)	(8,714,820)

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

KENTUCKY POWER COMPANY

	PLANT ACCT.	**RATES** Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.71%
Station Equipment	353.0	1.71%
Towers & Fixtures	354.0	1.71%
Poles & Fixtures	355.0	1.71%
Overhead Conductors	356.0	1.71%
Underground Conduit	357.0	1.71%
Underground Conductors	358.0	1.71%
Trails & Roads	359.0	1.71%

Reference:

Note 1: Rates Approved in Kentucky Public Service Commission Case No. 91-066.

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.