AEP EAST Companies Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For rates effective July 1, 2013

AEP Zone Transmission Service Revenue Requirement

Line No.			AEP Annual Revenue Requirement	APCo Annual Revenue Requirement	I&M Annual Revenue Requirement	KPCo Annual Revenue Requirement	KNG Annual Revenue Requirement	OPCo Annual Revenue Requirement	WPCo Annual Revenue Requirement
A.	**Network Service**								
1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Ln 1)	$715,074,806	$232,463,494	$125,959,874	$55,400,649	$3,760,479	$281,223,353	$16,266,957
2	LESS: REVENUE CREDITS	(TCOS Ln 2)	$15,741,753	$3,618,736	$947,294	$79,378	$306,055	$9,374,004	$1,416,286
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Ln 3)	$699,333,053	$228,844,758	$125,012,580	$55,321,271	$3,454,424	$271,849,349	$14,850,671
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:								
5	RTEP UPGRADES (W/O INCENTIVES)	(TCOS Ln 4)	$8,785,417	$1,956,928	$2,666,168	$0	$0	$3,768,661	$393,660
6	OTHER ZONAL UPGRADES (W/O INCENTIVES)	(Worksheet J)	$0	$0	$0	$0	$0	$0	$0
7	SUBTOTAL		$8,785,417	$1,956,928	$2,666,168	$0	$0	$3,768,661	$393,660
8	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Ln 3- Ln 7)	$690,547,636	$226,887,831	$122,346,412	$55,321,271	$3,454,424	$268,080,687	$14,457,011
9	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(Worksheet J)	$0	$0	$0	$0	$0	$0	$0
10	EXISTING ZONAL ATRR (W/ INCENTIVES)	(Ln 8 + Ln 9)	$690,547,636	$226,887,831	$122,346,412	$55,321,271	$3,454,424	$268,080,687	$14,457,011
11	BILLED HISTORICAL YEAR (2012) ACTUAL ATRR	Input from 2012 True-up	$645,853,979	$212,282,376	$118,409,508	$52,066,346	$2,579,861	$251,504,412	$9,011,475
12	BILLED PROJECTED (2012) ATRR FROM PRIOR YEAR	Input from Prior Year	$658,697,053	$213,852,440	$125,523,647	$51,786,703	$2,709,361	$257,889,879	$6,935,024
13	PRIOR YEAR TRUE-UP	(Ln 11 - Ln 12)	-$12,843,074	-$1,570,063	-$7,114,138	$279,643	-$129,500	-$6,385,468	$2,076,452
14	INTEREST ON PRIOR YEAR TRUE UP		-$754,543	-$92,243	-$417,962	$16,429	-$7,608	-$375,152	$121,994
15	**EXISTING ZONAL ATRR FOR PJM OATT**	(Ln 10 + Ln 13 + Ln 14)	**$676,950,019**	$225,225,524	$114,814,311	$55,617,343	$3,317,316	$261,320,067	$16,655,457
B.	**Point-to-Point Service**								
16	2012 AEP East Zone Network Service Peak Load		23,308.6 MW						
17	Annual Point-to-Point Rate in $/MW - Year	(Ln 15 / Ln 16)	$29,042.93						
18	Monthly Point-to-Point Rate in $/MW - Month	(Ln 17 / 12)	$2,420.24						
19	Weekly Point-to-Point Rate in $/MW - Weekly	(Ln 17 / 52)	$558.52						
20	Daily On-Peak Point-to-Point Rate in $/MW - Day	(Ln 17 / 260)	$111.70						
21	Daily Off-Peak Point-to-Point Rate in $/MW - Day	(Ln 17 / 365)	$79.57						
22	Hourly On-Peak Point-to-Point Rate in $/MW - Hour	(Ln 17 / 4160)	$6.98						
23	Hourly Off-Peak Point-to-Point Rate in $/MW - Hour	(Ln 17 / 8760)	$3.32						
C.	**PJM Regional Service**								
24	RTEP UPGRADE ATRR W/O INCENTIVES	(Ln 7)	8,785,417	1,956,928	2,666,168	-	-	3,768,661	393,660
25	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEP	(Worksheet J)	-	-	-	-	-	-	-
26	TRUE-UP ADJUSTMENT INCLUDING INTEREST		(344,539)	297,512	(132,763)	-	-	(509,288)	-
26a	DOCKET NO. AC10-47 ADJUSTMENT (JMG Acquisition)		-	-	-	-	-	-	-
27	**RTEP ATRR FOR PJM COLLECTION UNDER SCHEDULE 12**		**$ 8,440,878**	2,254,439	2,533,405	-	-	3,259,373	393,660

AEP EAST Companies Transmission Formula Rate Revenue Requirement
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AEP Transmission Schedule 1A Revenue Requirements

Line No.			AEP Annual Revenue Requirement	APCo Annual Revenue Requirement	I&M Annual Revenue Requirement	KPCo Annual Revenue Requirement	KNG Annual Revenue Requirement	OPCo Annual Revenue Requirement	WPCo Annual Revenue Requirement
A.	**Schedule 1A ARR**								
1	Total Load Dispatch & Scheduling (Account 561) (TCOS Line 14)		$37,112,586	$10,758,518	$8,132,792	$2,313,221	$50,457	$15,750,749	$106,849
2	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)		$20,583,439	$5,714,454	$5,531,795	$1,160,718	$1,263	$8,170,124	$5,085
3	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.6)		$4,274,634	$1,211,704	$1,083,397	$245,515	$0	$1,734,018	$0
4	Total 561 Internally Developed Costs	(Ln 1 - Ln 2 - Ln 3)	$12,254,513	$3,832,360	$1,517,600	$906,988	$49,194	$5,846,607	$101,764
5	Less: PTP Service Credit		$1,283,673	$394,538	$170,004	$92,534	$4,975	$612,966	$8,655
6	EXISTING ZONAL ARR	(Ln 4 - Ln 5)	$10,970,840	$3,437,822	$1,347,596	$814,454	$44,219	$5,233,641	$93,109
7	BILLED HISTORICAL YEAR (2012) ACTUAL ARR	Input from 2012 True-up	$10,970,840	$3,374,706	$1,460,086	$804,719	$43,377	$5,211,279	$76,674
8	BILLED PROJECTED (2012) ARR FROM PRIOR YEAR	Input from Prior Year	$10,761,555	$3,309,699	$1,430,625	$786,251	$42,357	$5,118,020	$74,603
9	PRIOR YEAR TRUE-UP	(Ln 7 - Ln 8)	$209,285	$65,007	$29,460	$18,468	$1,021	$93,259	$2,071
10	INTEREST ON PRIOR YEAR TRUE UP		$4,747	$1,460	$632	$348	$19	$2,255	$33
11	Net Schedule 1A Revenue Requirement for Zone		$11,184,872	$3,504,289	$1,377,688	$833,269	$45,258	$5,329,154	$95,213
B.	**Schedule 1A Rate Calculations**								
12	2012 AEP East Zone Annual MWh		134,854,616 MWh						
13	AEP Zone Rate for Schedule 1A Service.	(Line 11 / Line 12)	$0.0829						

AEP East Companies
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APPALACHIAN POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)				$232,463,494
2	REVENUE CREDITS	(Note A) (Worksheet E)	3,618,736	DA	1.00000	$ 3,618,736
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$ 228,844,758

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		Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		1,956,928	DA	1.00000	$ 1,956,928
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))				15.73%
7	Monthly Rate	(ln 6 / 12)				1.31%
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))				13.45%
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))				3.92%
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	10,758,518
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,714,454
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,211,704
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	3,832,360

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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)	5,620,438,618	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(71,986,517)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	2,040,266,144	DA		1,989,664,925
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.97520	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		140,824,365	DA	1.00000	140,824,365
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		-	DA	1.00000	-
24	Distribution	(Worksheet A ln 5.C)	2,988,920,393	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	(3,069)	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	195,239,795	W/S	0.07081	13,825,109
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(811,747)	W/S	0.07081	(57,481)
28	Intangible Plant	(Worksheet A ln 9.C)	123,626,312	W/S	0.07081	8,754,093
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	11,036,514,294			2,153,011,011
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	2,022,105,333	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(30,813,283)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	629,801,174	**TP1=**	0.98245	618,746,248
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.98245	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		1,562,690	DA	1.00000	1,562,690
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		32,626,776	TP1	0.98245	32,054,077
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		19,855,273	W/S	0.07081	1,405,970
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	918,499,290	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	(1,517)	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	63,986,336	W/S	0.07081	4,530,931
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(594,444)	W/S	0.07081	(42,093)
44	Intangible Plant	(Worksheet A ln 20.C)	91,986,512	W/S	0.07081	6,513,649
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,749,014,141			664,771,472
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	3,557,160,051			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,410,464,970			1,370,918,678
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		139,261,675			139,261,675
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(32,626,776)			(32,054,077)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(19,855,273)			(1,405,970)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	2,070,419,551			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	131,036,156			9,278,790
56	Intangible Plant	(ln 28 - ln 44)	31,639,800			2,240,443
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	7,287,500,153			1,488,239,539
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(197,320,252)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,229,418,143)	DA		(289,461,122)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(431,851,994)	DA		(30,244,723)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	399,990,470	DA		50,244,301
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(2,822,664)	DA		(641,429)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(1,461,422,583)			(270,102,973)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	5,319,071	DA		1,877,675
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	3,978,581			3,879,907
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,508,480	TP	0.97520	1,471,068
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	825,807	W/S	0.07081	58,476
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.18468	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	203,768,047	W/S	0.07081	14,429,002
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	3,057,772	GP(h)	0.18468	564,701
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	12,816	DA	1.00000	12,816
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(201,506,924)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	11,644,579			20,415,970
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,445,715)	DA	1.00000	(2,445,715)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		5,840,595,504			1,237,984,496

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APPALACHIAN 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	1,892,122,758			
80	Distribution	322.156.b	115,706,381			
81	Customer Related Expense	322.164,171,178.b	53,414,582			
82	Regional Marketing Expenses	322.131.b	5,904,349			
83	Transmission	321.112.b	64,421,229			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,131,569,299			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 15.C)	10,758,518			
86	Less: Account 565	(Note H) 321.96.b	35,116,817			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(13,282,753)			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	31,828,647	TP	0.97520	31,039,256
89	Administrative and General	323.197.b (Note J)	115,443,349			
90	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
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)	1,038,300			
94	Acct. 928, Reg. Com. Exp.	323.189.b	2,048,123			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,334,522			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	91,594,341	W/S	0.07081	6,485,879
98	Plus: Acct. 924, Property Insurance	(ln 90)	2,893,399	GP(h)	0.18468	534,345
99	Acct. 928 - Transmission Specific	Worksheet F ln 19.(E) (Note L)	-	TP	0.97520	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 36.(E) (Note L)	-	TP	0.97520	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 44.(E) (Note L)	785,229	DA	1.00000	785,229
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07081	946,207
103	A & G Subtotal	(sum lns 97 to 102)	108,635,409			8,751,660
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	140,464,056			39,790,916
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)	140,464,056			39,790,916
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	167,860,265	NA	0.00000	-
110	Distribution	336.8.f	101,779,757	NA	0.00000	-
111	Transmission	336.7.f	32,626,776	TP1	0.98245	32,054,077
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		1,562,690	DA	1.00000	1,562,690
113	General	336.10.f	3,140,253	W/S	0.07081	222,364
114	Intangible	336.1.f	16,715,020	W/S	0.07081	1,183,606
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	323,684,761			35,022,737
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 23.(D)	8,830,131	W/S	0.07081	625,270
119	Plant Related					
120	Property	Worksheet H ln 23.(C) & ln 58.(C)	50,923,379	DA		14,495,326
121	Gross Receipts/Sales & Use	Worksheet H ln 23.(F)	33,724,260	NA	0.00000	-
122	Other	Worksheet H ln 23.(E)	8,137,707	GP(h)	0.18468	1,502,850
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	101,615,477			16,623,445
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		42.12%			
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)		1.6479			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(397,195)			
131	Income Tax Calculation	(ln 126 * ln 134)	197,252,636			41,810,070
132	ITC adjustment	(ln 129 * ln 130)	(654,530)	NP(h)	0.19199	(125,661)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	196,598,106			41,684,409
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	468,310,711			99,264,090
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		77,897	DA	1.00000	77,897
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)		1,230,751,008			232,463,494

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SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							2,040,266,144
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)								50,601,219
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)							1,989,664,925
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)						TP	**0.97520**
				Payroll Billed from					
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total				
145	Production	354.20.b	57,348,833	20,738,274	78,087,107	NA	0.00000		-
146	Transmission	354.21.b	4,649,255	5,848,397	10,497,652	TP	0.97520		10,237,297
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000		-
150	Total	(sum lns 145 to 149)	105,276,294	39,296,000	144,572,294				10,237,297
151	Transmission related amount							**W/S=**	**0.07081**
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)								$
153	Long Term Interest	(Worksheet L, ln. 35, col. (D))							190,506,524
154	Preferred Dividends	(Worksheet L, ln. 40, col. (D))							-
155	Development of Common Stock:								
156	Proprietary Capital	(FF1 p 112, Ln 16.c)							3,052,563,357
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)							-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)							1,654,344
159	Less: Account 219	(FF1 p 112, Ln 15.c)							(29,897,592)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)							3,080,806,605
161				$	%		Cost (Note S)		Weighted
162	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))			3,709,883,415	54.63%		0.0514		0.0281
163	Preferred Stock (ln 157)			-	0.00%		-		0.0000
164	Common Stock (ln 160)			3,080,806,605	45.37%		11.49%		0.0521
165	Total (Sum lns 162 to 164)			6,790,690,020				**WACC=**	**0.0802**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

APPALACHIAN 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. Other ratebase amounts are as of December 31, 2012.
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 6 through 15, 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 APPALACHIAN 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=	6.64%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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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APPALACHIAN POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)				$218,844,211
167	REVENUE CREDITS	(Note A) (Worksheet E)	3,618,736	DA	1.00000	$ 3,618,736
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$ 215,225,475

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)	15.96%
172	Monthly Rate	(ln 171 / 12)	1.33%
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)	13.63%
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)	4.22%
177	Not applicable on this template		

178	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	10,758,518
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,714,454
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,211,704
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	3,832,360

AEP East Companies
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Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

APPALACHIAN 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)	5,620,438,618	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(71,986,517)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	2,040,266,144	DA		1,989,664,925
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.97520	-
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)	2,988,920,393	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	(3,069)	NA	0.00000	-
191	General Plant	(Worksheet A ln 7.C)	195,239,795	W/S	0.07081	13,825,109
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(811,747)	W/S	0.07081	(57,481)
193	Intangible Plant	(Worksheet A ln 9.C)	123,626,312	W/S	0.07081	8,754,093
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	10,895,689,929	**GP(h)=**	**0.184677**	2,012,186,646
				GTD=	**0.39562**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	2,022,105,333	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(30,813,283)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	629,801,174	**TP1=**	0.98245	618,746,248
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.98245	-
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 2013 (ln 276)		**N/A**	TP1	0.98245	**N/A**
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		**N/A**	W/S	0.07081	**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)	918,499,290	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	(1,517)	NA	0.00000	-
207	General Plant	(Worksheet A ln 18.C)	63,986,336	W/S	0.07081	4,530,931
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(594,444)	W/S	0.07081	(42,093)
209	Intangible Plant	(Worksheet A ln 20.C)	91,986,512	W/S	0.07081	6,513,649
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	3,694,969,402			629,748,735
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	3,557,160,051			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	1,410,464,970			1,370,918,678
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 2013 (-ln 202)		**N/A**			**N/A**
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	2,070,419,551			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	131,036,156			9,278,790
221	Intangible Plant	(ln 193 - ln 209)	31,639,800			2,240,443
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	7,200,720,527	**NP(h)=**	**0.191986**	1,382,437,911
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(197,320,252)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,229,418,143)	DA		(289,461,122)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(431,851,994)	DA		(30,244,723)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	399,990,470	DA		50,244,301
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(2,822,664)	DA		(641,429)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(1,461,422,583)			(270,102,973)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	5,319,071	DA		1,877,675
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	3,978,581			3,879,907
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,508,480	TP	0.97520	1,471,068
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	825,807	W/S	0.07081	58,476
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.18468	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	203,768,047	W/S	0.07081	14,429,002
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	3,057,772	GP(h)	0.18468	564,701
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	12,816	DA	1.00000	12,816
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(201,506,924)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	11,644,579			20,415,970
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,445,715)	DA	1.00000	(2,445,715)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		5,753,815,878			1,132,182,868

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Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

APPALACHIAN 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	1,892,122,758			
245	Distribution	322.156.b	115,706,381			
246	Customer Related Expense	322 & 323.164,171,178.b	53,414,582			
247	Regional Marketing Expenses	322.131.b	5,904,349			
248	Transmission	321.112.b	64,421,229			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	2,131,569,299			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 15.C)	10,758,518			
251	Less: Account 565	(Note H) 321.96.b	35,116,817			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(13,282,753)			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	31,828,647	TP	0.97520	31,039,256
254	Administrative and General	323.197.b (Note J)	115,443,349			
255	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
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)	1,038,300			
259	Acct. 928, Reg. Com. Exp.	323.189.b	2,048,123			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,334,522			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	91,594,341	W/S	0.07081	6,485,879
263	Plus: Acct. 924, Property Insurance	(ln 255)	2,893,399	GP(h)	0.18468	534,345
264	Acct. 928 - Transmission Specific	Worksheet F ln 19.(E) (Note L)	-	TP	0.97520	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 36.(E) (Note L)	-	TP	0.97520	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 44.(E) (Note L)	785,229	DA	1.00000	785,229
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07081	946,207
268	A & G Subtotal	(sum lns 262 to 267)	108,635,409			8,751,660
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	140,464,056			39,790,916
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)	140,464,056			39,790,916
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	167,860,265	NA	0.00000	-
275	Distribution	336.8.f	101,779,757	NA	0.00000	-
276	Transmission	336.7.f	32,626,776	TP1	0.98245	32,054,077
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	3,140,253	W/S	0.07081	222,364
279	Intangible	336.1.f	16,715,020	W/S	0.07081	1,183,606
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	322,122,071			33,460,047
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 23.(D)	8,830,131	W/S	0.07081	625,270
284	Plant Related					
285	Property	Worksheet H ln 23.(C) & ln 58.(C)	50,923,379	DA		14,495,326
286	Gross Receipts/Sales & Use	Worksheet H ln 23.(F)	33,724,260	NA	0.00000	-
287	Other	Worksheet H ln 23.(E)	8,137,707	GP(h)	0.18468	1,502,850
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	101,615,477			16,623,445
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		42.12%			
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)		1.6479			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(397,195)			
296	Income Tax Calculation	(ln 291 * ln 299)	194,321,854			38,236,864
297	ITC adjustment	(ln 294 * ln 295)	(654,530)	NP(h)	0.19199	(125,661)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	193,667,324			38,111,203
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	461,352,545			90,780,703
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		77,897	DA	1.00000	77,897
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)		1,219,299,371			218,844,211

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APPALACHIAN POWER COMPANY

SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						2,040,266,144
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)							50,601,219
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)						1,989,664,925
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)					**TP=**	**0.97520**
			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
310	Production	354.20.b	57,348,833	20,738,274	78,087,107	NA	0.00000	-
311	Transmission	354.21.b	4,649,255	5,848,397	10,497,652	TP	0.97520	10,237,297
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000	-
315	Total	(sum lns 310 to 314)	105,276,294	39,296,000	144,572,294			10,237,297
			✓	✓				
316	Transmission related amount						**W/S=**	**0.07081**

ln No.							
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
318	Long Term Interest	(Worksheet L, ln. 35, col. (D))					190,506,524
319	Preferred Dividends	(Worksheet L, ln. 40, col. (D))					-
320	Development of Common Stock:						
321	Proprietary Capital	(FF1 p 112, Ln 16.c)					3,052,563,357
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)					-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)					1,654,344
324	Less: Account 219	(FF1 p 112, Ln 15.c)					(29,897,592)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)					3,080,806,605
326			$	%	Cost (Note S)		Weighted
327	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))		3,709,883,415	54.63%	0.0514		0.0281
328	Preferred Stock (ln 322)		-	0.00%	-		0.0000
329	Common Stock (ln 325)		3,080,806,605	45.37%	11.49%		0.0521
330	Total (Sum lns 327 to 329)		6,790,690,020			**WACC=**	**0.0802**

AEP East Companies
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APPALACHIAN 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 historic as of December 31, 2012.
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 6 through 15, 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 APPALACHIAN 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=	6.64%	(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)					$218,162,992
2	REVENUE CREDITS	(Note A) (Worksheet E)	3,618,736	DA	1.00000	$	3,618,736
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	214,544,256

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)		2,261,880	DA	1.00000	$	2,261,880
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)					16.26%
7	Monthly Rate	(ln 6 / 12)					1.35%
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)					13.87%
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)					4.33%
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	10,758,518
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,714,454
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,211,704
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	3,832,360

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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.E)	5,401,632,776	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(69,957,445)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	1,991,143,960	DA		1,950,233,379
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	0.97945	-
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)	2,915,443,722	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	(3,069)	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.E)	192,101,022	W/S	0.07112	13,662,202
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(811,747)	W/S	0.07112	(57,731)
28	Intangible Plant	(Worksheet A ln 9.E)	116,437,753	W/S	0.07112	8,281,039
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	10,545,986,971	**GP(h)=**	**0.18700**	1,972,118,889
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	1,950,527,566	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(28,423,680)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	618,690,832	**TP1=**	0.98317	608,276,893
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.98317	-
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 2013 (ln 111)		N/A	TP1	0.98317	N/A
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		N/A	W/S	0.07112	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)	892,488,682	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	(1,482)	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.E)	63,406,955	W/S	0.07112	4,509,495
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(430,773)	W/S	0.07112	(30,637)
44	Intangible Plant	(Worksheet A ln 20.E)	87,125,001	W/S	0.07112	6,196,320
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,583,383,100			618,952,071
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	3,409,571,445			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,372,453,128			1,341,956,486
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 2013 (-ln 37)		N/A			N/A
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	2,022,953,454			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	128,313,093			9,125,612
56	Intangible Plant	(ln 28 - ln 44)	29,312,752			2,084,719
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	6,962,603,871	**NP(h)=**	**0.19435**	1,353,166,818
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(177,921,978)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(1,191,929,058)	DA		(273,611,596)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(432,760,567)	DA		(28,421,459)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	425,004,947	DA		49,949,881
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	(3,244,139)	DA		(778,649)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(1,380,850,795)			(252,861,822)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	5,583,920	DA		1,912,346
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	3,978,581			3,896,836
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,134,751	TP	0.97945	1,111,436
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	763,694	W/S	0.07112	54,314
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.18700	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	199,491,970	W/S	0.07112	14,187,845
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	3,168,302	GP(h)	0.18700	592,478
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	18,110	DA	1.00000	18,110
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(197,401,389)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	11,154,019			19,861,019
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(2,406,767)	DA	1.00000	(2,406,767)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		5,596,084,248			1,119,671,594

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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	1,892,122,758			
80	Distribution	322.156.b	115,706,381			
81	Customer Related Expense	322.164,171,178.b	53,414,582			
82	Regional Marketing Expenses	322.131.b	5,904,349			
83	Transmission	321.112.b	64,421,229			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,131,569,299			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 15.C)	10,758,518			
86	Less: Account 565	(Note H) 321.96.b	35,116,817			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(13,282,753)			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	31,828,647	TP	0.97945	31,174,687
89	Administrative and General	323.197.b (Note J)	115,443,349			
90	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
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)	1,038,300			
94	Acct. 928, Reg. Com. Exp.	323.189.b	2,048,123			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,334,522			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	91,594,341	W/S	0.07112	6,514,179
98	Plus: Acct. 924, Property Insurance	(ln 90)	2,893,399	GP(h)	0.18700	541,071
99	Acct. 928 - Transmission Specific	Worksheet F ln 19.(E) (Note L)	-	TP	0.97520	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 36.(E) (Note L)	-	TP	0.97520	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 44.(E) (Note L)	785,229	DA	1.00000	785,229
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07112	950,335
103	A & G Subtotal	(sum lns 97 to 102)	108,635,409			8,790,814
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	140,464,056			39,965,501
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)	140,464,056			39,965,501
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	167,860,265	NA	0.00000	-
110	Distribution	336.8.f	101,779,757	NA	0.00000	-
111	Transmission	336.7.f	32,626,776	TP1	0.98317	32,077,595
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
113	General	336.10.f	3,140,253	W/S	0.07112	223,334
114	Intangible	336.1.f	16,715,020	W/S	0.07112	1,188,770
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	322,122,071			33,489,700
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 23.(D)	8,830,131	W/S	0.07112	627,998
119	Plant Related					
120	Property	Worksheet H ln 23.(C) & ln 58.(C)	50,923,379	DA		14,495,326
121	Gross Receipts/Sales & Use	Worksheet H ln 23.(F)	33,724,260	NA	0.00000	-
122	Other	Worksheet H ln 23.(E)	8,137,707	GP(h)	0.18700	1,521,766
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	101,615,477			16,645,090
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		41.31%			
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)		1.6479			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(397,195)			
131	Income Tax Calculation	(ln 126 * ln 134)	187,179,555			37,451,121
132	ITC adjustment	(ln 129 * ln 130)	(654,530)	NP(h)	0.19435	(127,206)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	186,525,025			37,323,915
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	453,120,343			90,660,890
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		77,897	DA	1.00000	77,897
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)		1,203,924,869			218,162,992

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		1,991,143,960
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)			40,910,581
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		1,950,233,379
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	TP	**0.97945**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
145	Production	354.20.b	57,348,833	20,738,274	78,087,107	NA	0.00000	-
146	Transmission	354.21.b	4,649,255	5,848,397	10,497,652	TP	0.97945	10,281,964
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000	-
150	Total	(sum lns 145 to 149)	105,276,294	39,296,000	144,572,294			10,281,964
151	Transmission related amount						**W/S=**	**0.07112**

ln No.				
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)			$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))		198,340,666
154	Preferred Dividends	(Worksheet M, ln. 55, col. (E))		-
155	Development of Common Stock:			Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))		2,994,488,906
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))		-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))		1,632,577
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))		(44,220,373)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)		3,037,076,702

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))	3,722,145,904	55.07%	0.00%	0.0533	0.0293
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Commone Stock (ln 160)	3,037,076,702	44.93%	0.00%	11.49%	0.0516
165	Total (Sum lns 162 to 164)	6,759,222,605			**WACC=**	**0.0810**
166	Capital Structure Equity Limit (Note U)	100.0%				

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APPALACHIAN 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, 2011 and December 31, 2012.

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 6 through 15, 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 APPALACHIAN 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=	6.64%	(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) /average 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 APPALACHIAN 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 2012 FF1 Balances
Worksheet A Supporting Plant Balances
APPALACHIAN POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
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	5,620,438,618	5,182,826,934	5,401,632,776
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	71,986,517	67,928,373	69,957,445
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	2,040,266,144	1,942,021,775	1,991,143,960
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	2,988,920,393	2,841,967,051	2,915,443,722
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	3,069	3,069	3,069
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	195,239,795	188,962,248	192,101,022
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	811,747	811,747	811,747
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	123,626,312	109,249,193	116,437,753
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	10,968,491,262	10,265,027,201	10,616,759,232
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	72,801,333	68,743,189	70,772,261
Accumulated Depreciation & Amortization Balances					
12	Production Accumulated Depreciation	FF1, page 219, lns 20-24, Col. (b)	2,022,105,333	1,878,949,799	1,950,527,566
13	Production ARO Accumulated Depreciation	Company Records - Note 1	30,813,283	26,034,077	28,423,680
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	629,801,174	607,580,490	618,690,832
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	918,499,290	866,478,073	892,488,682
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	1,517	1,448	1,482
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	63,986,336	62,827,573	63,406,955
19	General ARO Accumulated Depreciation	Company Records - Note 1	594,444	267,102	430,773
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	91,986,512	82,263,489	87,125,001
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	3,726,378,645	3,498,099,424	3,612,239,035
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	31,409,243	26,302,627	28,855,935
Generation Step-Up Units					
23	GSU Investment Amount	Company Records - Note 1	50,601,219	31,219,942	40,910,581
24	GSU Accumulated Depreciation	Company Records - Note 1	11,054,926	9,772,952	10,413,939
25	GSU Net Balance	(Line 23 - Line 24)	39,546,292	21,446,990	30,496,641
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	Transmission Accumulated Depreciation	(Line 14 Above)	629,801,174	607,580,490	618,690,832
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	11,054,926	9,772,952	10,413,939
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	618,746,248	597,807,538	608,276,893
Plant Held For Future Use					
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	5,319,071	5,848,769	5,583,920
30	Transmission Plant Held For Future	Company Records - Note 1	1,877,675	1,947,017	1,912,346
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 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
APPALACHIAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	**Description**	**Source**	**Balance @ December 31, 2012**	**Balance @ December 31, 2011**	**Average Balance for 2012**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	197,320,252	158,523,703	177,921,978
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	197,320,252	158,523,703	177,921,978
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)	1,229,418,143	1,154,439,973	1,191,929,058
8	Less: ARO Related Deferrals	Company Records - Note 1	5,314,689	15,371,558	10,343,124
9	Less: Other Excluded Deferrals	Company Records - Note 1	934,642,332	881,306,346	907,974,339
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	289,461,122	257,762,069	273,611,596
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	431,851,994	433,669,140	432,760,567
13	Less: ARO Related Deferrals	Company Records - Note 1	2,971,021	3,683,424	3,327,223
14	Less: Other Excluded Deferrals	Company Records - Note 1	398,636,251	403,387,521	401,011,886
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	30,244,723	26,598,196	28,421,459
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	399,990,470	450,019,423	425,004,947
18	Less: ARO Related Deferrals	Company Records - Note 1	40,515,848	40,164,641	40,340,245
19	Less: Other Excluded Deferrals	Company Records - Note 1	309,230,321	360,199,321	334,714,821
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	50,244,301	49,655,461	49,949,881
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	3,205,027	4,445,172	3,825,100
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	382,363	779,558	580,961
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	2,822,664	3,665,614	3,244,139
25	Transmission Related Deferrals	Company Records - Note 1	641,429	915,869	778,649

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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
APPALACHIAN POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2012	(E) Balance @ December 31, 2011	(F) Average Balance for 2012
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,508,480	761,022	1,134,751
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	825,807	701,580	763,694
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

5		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
6	Totals as of December 31, 2012	5,331,711	(201,506,924)	12,816	3,057,772	203,768,047	206,838,635
7	Totals as of December 31, 2011	5,222,276	(193,295,853)	23,404	3,278,832	195,215,893	198,518,129
8	**Average Balance**	5,276,994	(197,401,389)	18,110	3,168,302	199,491,970	202,678,382

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	1,844,047	-		1,844,047		1,844,047	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	1,809,578	1,809,578		-		-	Prepaid Taxes
12	1650003	Prepaid Rents	0	-			-	-	Prepaid Distribution Rent Expense
13	1650004	Prepaid Interest	26,938	26,938				-	
14	1650005	Prepaid Employee Benefits	0	-			-	-	
15	1650006	Other Prepayments	12,816	-	12,816	-		12,816	PPD Sales
16	1650009	Prepaid Carry Cost-Factored AR	62,549	62,549				-	AR Factoring - Retail Only
17	1650010	Prepaid Pension Benefits	203,768,047				203,768,047	203,768,047	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(203,768,047)	(203,768,047)				-	SFAS 158 Offset
19	1650016	FAS 112 ASSETS	0	-			-	-	SFAS 112 Overfunding Asset
20	1650021	Prepaid Insurance - EIS	1,213,725	-		1,213,725		1,213,725	
21	1650023	Prepaid Lease	361,859	361,859				-	
22	165001112	Prepaid Sales Taxes	199	199				-	
		Subtotal - Form 1, p 111.57.c	5,331,711	(201,506,924)	12,816	3,057,772	203,768,047	206,838,635	

Prepayments Account 165 - Balance @ 12/31/ 2011

22	Acc. No.	Description	2011 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
23	1650001	Prepaid Insurance	1,935,794			1,935,794		1,935,794	Plant Related Insurance Policies
24	165000211	Prepaid Taxes	1,637,001	1,637,001		0		-	Prepaid Taxes
25	1650003	Prepaid Rents	0	0				-	Prepaid Distribution Rent Expense
26	1650004	Prepaid Interest	27,220	27,220				-	
27	1650005	Prepaid Employee Benefits	0						
28	1650006	Other Prepayments	23,404		23,404	0		23,404	PPD Sales
29	1650009	Prepaid Carry Cost-Factored AR	49,321	49,321				-	AR Factoring - Retail Only
30	1650010	Prepaid Pension Benefits	195,215,893				195,215,893	195,215,893	Prefunded Pension Expense
31	1650014	FAS 158 Qual Contra Asset	(195,215,893)	(195,215,893)				-	SFAS 158 Offset
32	1650016	FAS 112 ASSETS	0	0				-	SFAS 112 Overfunding Asset
33	1650021	Prepaid Insurance - EIS	1,343,038			1,343,038		1,343,038	
34	1650023	Prepaid Lease	206,498	206,498					
		Subtotal - Form 1, p 111.57.d	5,222,276	(193,295,853)	23,404	3,278,832	195,215,893	198,518,129	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
APPALACHIAN POWER COMPANY

Line Number	(A) Description	(B) 2012
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 20.b)	(2,367,818.00)
2	Interest Accrual (Company Records - Note 1)	(77,897.00)
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 12/31/2012 (2012 FORM 1, P269, line 23.f)	(2,445,715.00)
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(2,406,766.50)

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet E Supporting Revenue Credits
APPALACHIAN POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	5,024,400	5,024,400	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	1,833,084	1,470,159	362,925
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	21,091,928	19,091,646	2,000,282
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	7,744,030	6,488,501	1,255,529
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	59,627,918	59,627,918	-
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	95,321,360	91,702,624	3,618,736
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	95,321,360	91,702,624	3,618,736

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or APPALACHIAN 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 2012 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
APPALACHIAN POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C) 2012 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1	5700005	Maint Station-Reliability-Df	15,744			
2	5660007	Virginia T-RAC UnderRecovery	(13,438,947)			
3	5660000	Amortization Severance	140,450			
4						
5		**Total**	$ (13,282,753)			
		Detail of Account 561 Per FERC Form 1				
6	FF1 p 321.84.b	561 - Load Dispatching	0			
7	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	23,193			
8	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	3,210,973			
9	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(314)			
10	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,714,454			
11	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	598,508			
12	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
13	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
14	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services	1,211,704			
15		**Total of Account 561**	10,758,518			
		Account 928				
16	9280000	Regulatory Commission Exp	2,443	2,443	-	
17	9280001	Regulatory Commission Exp-Adm	1,473,176	1,473,176	-	
18	9280002	Regulatory Commission Exp-Case	572,503	572,503	-	
19		**Total**	2,048,123	2,048,123	-	
		Account 930.1				
20	9301000	General Advertising Expenses	67,832	67,832	-	
21	9301001	Newspaper Advertising Space	244,076	244,076	-	
22	9301002	Radio Station Advertising Time	4,902	4,902	-	
23	9301003	TV Station Advertising Time	565,322	565,322	-	
24	9301004	Newspaper Advertising Prod Exp	1,752	1,752		
25	9301005	Radio &TV Advertising Prod Exp	36,525	36,525	-	
26	9301006	Spec Corporate Comm Info Proj	2	2	-	
27	9301007	Special Adv Space & Prod Exp	345	345	-	
28	9301008	Direct Mail and Handouts	-	-	-	
29	9301009	Fairs, Shows, and Exhibits	269	269	-	
30	9301010	Publicity	21,223	21,223	-	
31	9301011	Dedications, Tours, & Openings	5	5	-	
32	9301012	Public Opinion Surveys	13,839	13,839	-	
33	9301013	Movies Slide Films & Speeches		-	-	
34	9301014	Video Communications	77	77	-	
35	9301015	Other Corporate Comm Exp	257,000	257,000	-	
36		**Total**	1,213,171	1,213,171	-	
		Account 930.2				
37	9302000	Misc General Expenses	822,994	822,994		
38	9302003	Corporate & Fiscal Expenses	132,749	132,749		
39	9302004	Research, Develop&Demonstr Exp	13,524	13,524		
40	9302006	Assoc Bus Dev - Materials Sold	1,970,687	1,970,687		
41	9302007	Assoc Business Development Exp	3,393,929	2,608,700	785,229	
43	9302458	Non Affiliated Expense	638	638		
44		**Total**	6,334,522	5,549,293	785,229	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
APPALACHIAN POWER COMPANY

Tennessee Income Tax Rate	6.50%	
Apportionment Factor - Note 2	1.98%	
Effective State Tax Rate		0.13%
West Virginia Net Income Tax Rate	7.75%	
Apportionment Factor - Note 2	52.71%	
Effective State Tax Rate		4.08%
Virginia Income Tax Rate	6.00%	
Apportionment Factor - Note 2	37.41%	
Effective State Tax Rate		2.24%
Michigan Business Income Tax Rate	6.00%	
Apportionment Factor - Note 2	0.11%	
Effective State Tax Rate		0.01%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinios Corporate Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.94%	
Effective State Tax Rate		0.18%
Total Effective State Income Tax Rate		6.64%

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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
APPALACHIAN POWER COMPANY

Line No.	(A) Account	(B) Total Company	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
		NOTE 1				
1	Revenue Taxes					
2	Gross Receipts Tax	13,315,273				13,315,273
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - West Virginia	34,549,317	34,549,317			
5	Real and Personal Property - Virginia	15,173,148	15,173,148			
6	Real and Personal Property - Tennessee	734,598	734,598			
7	Real and Personal Property - Other Jurisdictions	466,316	466,316			
8	Payroll Taxes					
9	Federal Insurance Contribution (FICA)	8,566,234		8,566,234		
10	Federal Unemployment Tax	27,378		27,378		
11	State Unemployment Insurance	236,519		236,519		
12	Production Taxes					
13	State Severance Taxes	-				-
14	Miscellaneous Taxes					
15	State Business & Occupation Tax	20,401,461				20,401,461
16	State Public Service Commission Fees	4,616,176			4,616,176	
17	State Franchise Taxes	3,519,086			3,519,086	
18	State Lic/Registration Fee	1,899			1,899	
19	Misc. State and Local Tax	546			546	
20	Sales & Use	540				540
21	Federal Excise Tax	6,986				6,986
22	Michigan Single Business Tax	-				-
23	Total Taxes by Allocable Basis	101,615,477	50,923,379	8,830,131	8,137,707	33,724,260
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					

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

Functional Property Tax Allocation

Line No.	Account	Production	Transmission	Distribution	General	Total
24	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	3,557,160,051	1,410,464,970	2,070,419,551	131,036,156	7,169,080,727
	VIRGINIA JURISDICTION					
25	Percentage of Plant in VIRGINIA JURISDICTION	14.60%	44.97%	55.78%	51.49%	
26	Net Plant in VIRGINIA JURISDICTION (Ln 24 * Ln 25)	519,520,961	634,267,997	1,154,977,049	67,468,340	2,376,234,348
27	Less: Net Value of Exempted Generation Plant	126,497,409				
28	Taxable Property Basis (Ln 26 - Ln 27)	393,023,552	634,267,997	1,154,977,049	67,468,340	2,249,736,939
29	Relative Valuation Factor	100%	100%	100%	100%	
30	Weighted Net Plant (Ln 28 * Ln 29)	393,023,552	634,267,997	1,154,977,049	67,468,340	
31	General Plant Allocator (Ln 30 / (Total - General Plant))	18.01%	29.06%	52.93%	-100.00%	
32	Functionalized General Plant (Ln 31 * General Plant)	12,150,955	19,609,414	35,707,971	(67,468,340)	-
33	Weighted VIRGINIA JURISDICTION Plant (Ln 30 + 32)	405,174,507	653,877,412	1,190,685,020	0	2,249,736,939
34	Functional Percentage (Ln 33/Total Ln 33)	18.01%	29.06%	52.93%		
35	Functionalized Expense in VIRGINIA JURISDICTION	2,732,663	4,410,017	8,030,468		15,173,148
	WEST VA JURISDICTION					
36	Percentage of Plant in WEST VA JURISDICTION	85.40%	51.89%	44.21%	48.34%	
37	Net Plant in WEST VA JURISDICTION (Ln 24 * Ln 36)	3,037,639,090	731,940,783	915,410,634	63,338,743	4,748,329,251
38	Less: Net Value of Exempted Generation Plant	1,954,604,153				
39	Taxable Property Basis (Ln 37 - Ln 38)	1,083,034,937	731,940,783	915,410,634	63,338,743	2,793,725,098
40	Relative Valuation Factor	100%	100%	100%	100%	
41	Weighted Net Plant (Ln 39 * Ln 40)	1,083,034,937	731,940,783	915,410,634	63,338,743	
42	General Plant Allocator (Ln 41 / (Total - General Plant))	39.67%	26.81%	33.53%	-100.00%	
43	Functionalized General Plant (Ln 42 * General Plant)	25,123,943	16,979,359	21,235,441	(63,338,743)	-
44	Weighted WEST VA JURISDICTION Plant (Ln 41 + 43)	1,108,158,880	748,920,142	936,646,075	0	2,793,725,098
45	Functional Percentage (Ln 44/Total Ln 44)	39.67%	26.81%	33.53%		
46	Functionalized Expense in WEST VA JURISDICTION	13,704,331	9,261,713	11,583,274		34,549,317
	TENNESSEE JURISDICTION					
47	Net Plant in TENNESSEE JURISDICTION (Ln 24 - Ln 26 - Ln 37	-	44,256,189	31,867	229,072	44,517,128
48	Less: Net Value Exempted Generation Plant					
49	Taxable Property Basis	-	44,256,189	31,867	229,072	44,517,128
50	Relative Valuation Factor	100%	100%	100%	100%	
51	Weighted Net Plant (Ln 49 * Ln 50)	-	44,256,189	31,867	229,072	
52	General Plant Allocator (Ln 51 / (Total - General Plant)	0.00%	99.93%	0.07%	-100.00%	
53	Functionalized General Plant (Ln 53 * General Plant)	-	228,907	165	(229,072)	
54	Weighted TENNESSEE JURISDICTION Plant (Ln 51 + 53)	-	44,485,096	32,032	0	44,517,128
55	Functional Percentage (Ln 54/Total Ln 54)	0.00%	99.93%	0.07%		
56	Functionalized Expense in TENNESSEE JURISDICTION	-	734,069	529		734,598
57	Total Other Jurisdictions: (Line 7 * Net Plant Allocator)		89,526			466,316
58	Total Func. Property Taxes (Sum Lns 35, 46 56, 57)	16,436,994	14,495,326	19,614,270		50,923,379

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
APPALACHIAN POWER COMPANY

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	Revenue Taxes			
2	Gross Receipts Tax	13,315,273		
			12,477,550	P.263.1 ln 4 (i)
			145,133	P.263.1 ln 33 (i)
			692,590	P.263.1 ln 34 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - West Virginia	34,549,317		
			16,414,766	P.263 ln 34 (i)
			18,184,510	P.263 ln 35 (i)
			(82,556)	P.263 ln 38 (i)
			(28,406)	P.263 ln 39 (i)
			61,003	P.263 ln 40 (i)
5	Real and Personal Property - Virginia	15,173,148		
			23	P.263.2 ln 22 (i)
			191	P.263.2 ln 23 (i)
			(29,546)	P.263.2 ln 24 (i)
			14,980,441	P.263.2 ln 25 (i)
			(2,240)	P.263.2 ln 29 (i)
			(100,722)	P.263.2 ln 30 (i)
			325,001	P.263.2 ln 31 (i)
6	Real and Personal Property - Tennessee	734,598		
			(64,602)	P.263.3 ln 10 (i)
			799,200	P.263.3 ln 11 (i)
7	Real and Personal Property - Other Jurisdictions	466,316		
			704	P.263.1 ln 36 (i)
			465,612	P.263.1 ln 37 (i)
8	Payroll Taxes			
9	Federal Insurance Contribution (FICA)	8,566,234		
			8,566,234	P.263 ln 6 (i)
10	Federal Unemployment Tax	27,378		
			27,378	P.263 ln 9 (i)
11	State Unemployment Insurance	236,519		
			111,767	P.263.1 ln 17 (i)
			14,244	P.263.1 ln 40 (i)
			110,391	P.263.2 ln 38 (i)
			117	P.263.3 ln 22 (i)
12	Production Taxes			
13	State Severance Taxes	-		
			-	
14	Miscellaneous Taxes			
15	State Business & Occupation Tax	20,401,461		
			390,088	P.263 ln 21 (i)
			19,769,873	P.263 ln 22 (i)
			241,500	P.263 ln 23 (i)
16	State Public Service Commission Fees	4,616,176		
			1,599,615	P.263 ln 26 (i)
			3,016,561	P.263 ln 27 (i)
17	State Franchise Taxes	3,519,086		
			(266,239)	P.263.1 ln 20 (i)
			282,774	P.263.1 ln 21 (i)
			(322,867)	P.263.1 ln 23 (i)
			(25,537)	P.263.1 ln 25 (i)
			89,833	P.263.1 ln 26 (i)
			6,672,000	P.263.2 ln 11 (i)
			(2,897,155)	P.263.2 ln 10 (i)
			(41,712)	P.263.3 ln 5 (i)
			14,876	P.263.3 ln 6 (i)
			13,113	P.263.3 ln 7 (i)
18	State Lic/Registration Fee	1,899		
			25	P.263.1 ln 10 (i)
			1,700	P.263.2 ln 13 (i)
			22	P.263.3 ln 14 (i)
			52	P.263.4 ln 25 (i)
			100	P.263.3 ln 26 (i)
19	Misc. State and Local Tax	546		
			546	P.263.1 ln 8 (i)
20	Sales & Use	540		
			688	P.263 ln 30 (i)
			1,172	P.263 ln 31(i)
			(583)	P.263.1 ln 32(i)
			24	P.263.2 ln 16 (i)
			(761)	P.263.2 ln 17 (i)
21	Federal Excise Tax	6,986		
			6,986	P.263 ln 14 (i)
22	Michigan Single Business Tax	-		
			-	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	101,615,477	101,615,477	

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 2012 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
APPALACHIAN POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,942,021,775
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	2,040,266,144
3		3,982,287,919
4	Average Balance of Transmission Investment	1,991,143,960
5	Annual Depreciation Expense, Historic TCOS, ln 276	32,626,776
6	Composite Depreciation Rate	1.64%
7	Round to 1.64% to Reflect a Composite Life of 61 Years	1.64%

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	$ 71,997,178	1.64%	$ 1,180,754	$ 98,396	11	$ 1,082,356
10	February	$ 5,649,481	1.64%	$ 92,651	$ 7,721	10	$ 77,210
11	March	$ 4,359,926	1.64%	$ 71,503	$ 5,959	9	$ 53,631
12	April	$ 3,540,020	1.64%	$ 58,056	$ 4,838	8	$ 38,704
13	May	$ 2,897,989	1.64%	$ 47,527	$ 3,961	7	$ 27,727
14	June	$ 5,135,780	1.64%	$ 84,227	$ 7,019	6	$ 42,114
15	July	$ 29,357,907	1.64%	$ 481,470	$ 40,122	5	$ 200,610
16	August	$ 4,600,335	1.64%	$ 75,445	$ 6,287	4	$ 25,148
17	September	$ 2,149,084	1.64%	$ 35,245	$ 2,937	3	$ 8,811
18	October	$ 1,559,798	1.64%	$ 25,581	$ 2,132	2	$ 4,264
19	November	$ 1,547,549	1.64%	$ 25,380	$ 2,115	1	$ 2,115
20	December	$ 8,029,318	1.64%	$ 131,681	$ 10,973	0	$ -
21	Investment	$ 140,824,365				Depreciation Expense	$ 1,562,690

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 2013

		Estimated Cost (000's)	Month in Service
25 **Major Zonal Projects**			
26 VIRGINIA SYS REHAB		$5,558	Aug-13
27 Line Rehab/Replace		$5,621	Dec-13
	Subtotal	$11,179	
28 **PJM Socialized/Beneficiary Allocated Regional Projects**			
29		$0	
30	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
APPALACHIAN 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	54.63%	5.14%		2.805%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	45.37%	11.49%		5.213%
			R =	8.018%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	1,956,928	1,956,928	$ -

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

Rate Base (Projected TCOS, ln 78)	1,237,984,496
R (from A. above)	8.018%
Return (Rate Base x R)	99,264,090

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

Return (from B. above)	99,264,090
Effective Tax Rate (Projected TCOS, ln 126)	42.12%
Income Tax Calculation (Return x CIT)	41,810,070
ITC Adjustment	(125,661)
Income Taxes	41,684,409

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)	232,463,494
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	99,264,090
Income Taxes (Projected TCOS, ln 133)	41,684,409
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	91,514,995

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	91,514,995
Return (from I.B. above)	99,264,090
Income Taxes (from I.C. above)	41,684,409
Annual Revenue Requirement, with Basis Point ROE increase	232,463,494
Depreciation (Projected TCOS, ln 111)	32,054,077
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	200,409,417

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	1,370,918,678
Annual Revenue Requirement, with Basis Point ROE increase	232,463,494
FCR with Basis Point increase in ROE	16.96%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	200,409,417
FCR with Basis Point ROE increase, less Depreciation	14.62%
FCR less Depreciation (Projected TCOS, ln 9)	13.45%
Incremental FCR with Basis Point ROE increase, less Depreciation	1.17%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,942,021,775
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	2,040,266,144
Subtotal	3,982,287,919
Average Transmission Plant Balance for 2012	1,991,143,960
Annual Depreciation Rate (Projected TCOS, ln 111)	32,626,776
Composite Depreciation Rate	1.64%
Depreciable Life for Composite Depreciation Rate	61.03
Round to nearest whole year	61

APCo 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: **RTEP ID: b0318 (Amos 765/138 kV Transformer)**

Current Projected Year ARR	**1,915,150**
Current Projected Year ARR w/ Incentive	**1,915,150**
Current Projected Year Incentive ARR	**-**

Details			
Investment	13,798,879	Current Year	**2013**
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	13.45%
Useful life	61	FCR w/incentives approved for these facilities, less dep.	13.45%
CIAC (Yes or No)	No	Annual Depreciation Expense	226,211

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2008	13,798,879	113,106	13,685,773	1,954,201	1,954,201	$ -					
2009	13,685,773	226,211	13,459,562	2,036,875	2,036,875	$ -	$ 1,124,469		$ 1,124,469		
2010	13,459,562	226,211	13,233,351	2,006,444	2,006,444	$ -	$ 2,027,403		$ 2,027,403		
2011	13,233,351	226,211	13,007,140	1,976,012	1,976,012	$ -	$ 2,050,107		$ 2,050,107		
2012	13,007,140	226,211	12,780,929	1,945,581	1,945,581	$ -	$ 1,906,118		$ 1,906,118		
2013	12,780,929	226,211	12,554,718	1,915,150	1,915,150	$ -					
2014	12,554,718	226,211	12,328,507	1,884,718	1,884,718	$ -					
2015	12,328,507	226,211	12,102,296	1,854,287	1,854,287	$ -					
2016	12,102,296	226,211	11,876,084	1,823,856	1,823,856	$ -					
2017	11,876,084	226,211	11,649,873	1,793,424	1,793,424	$ -					
2018	11,649,873	226,211	11,423,662	1,762,993	1,762,993	$ -					
2019	11,423,662	226,211	11,197,451	1,732,562	1,732,562	$ -					
2020	11,197,451	226,211	10,971,240	1,702,130	1,702,130	$ -					
2021	10,971,240	226,211	10,745,029	1,671,699	1,671,699	$ -					
2022	10,745,029	226,211	10,518,818	1,641,268	1,641,268	$ -					
2023	10,518,818	226,211	10,292,606	1,610,836	1,610,836	$ -					
2024	10,292,606	226,211	10,066,395	1,580,405	1,580,405	$ -					
2025	10,066,395	226,211	9,840,184	1,549,974	1,549,974	$ -					
2026	9,840,184	226,211	9,613,973	1,519,543	1,519,543	$ -					
2027	9,613,973	226,211	9,387,762	1,489,111	1,489,111	$ -					
2028	9,387,762	226,211	9,161,551	1,458,680	1,458,680	$ -					
2029	9,161,551	226,211	8,935,340	1,428,249	1,428,249	$ -					
2030	8,935,340	226,211	8,709,129	1,397,817	1,397,817	$ -					
2031	8,709,129	226,211	8,482,917	1,367,386	1,367,386	$ -					
2032	8,482,917	226,211	8,256,706	1,336,955	1,336,955	$ -					
2033	8,256,706	226,211	8,030,495	1,306,523	1,306,523	$ -					
2034	8,030,495	226,211	7,804,284	1,276,092	1,276,092	$ -					
2035	7,804,284	226,211	7,578,073	1,245,661	1,245,661	$ -					
2036	7,578,073	226,211	7,351,862	1,215,229	1,215,229	$ -					
2037	7,351,862	226,211	7,125,651	1,184,798	1,184,798	$ -					
2038	7,125,651	226,211	6,899,440	1,154,367	1,154,367	$ -					
2039	6,899,440	226,211	6,673,228	1,123,935	1,123,935	$ -					
2040	6,673,228	226,211	6,447,017	1,093,504	1,093,504	$ -					
2041	6,447,017	226,211	6,220,806	1,063,073	1,063,073	$ -					
2042	6,220,806	226,211	5,994,595	1,032,641	1,032,641	$ -					
2043	5,994,595	226,211	5,768,384	1,002,210	1,002,210	$ -					
2044	5,768,384	226,211	5,542,173	971,779	971,779	$ -					
2045	5,542,173	226,211	5,315,962	941,347	941,347	$ -					
2046	5,315,962	226,211	5,089,750	910,916	910,916	$ -					
2047	5,089,750	226,211	4,863,539	880,485	880,485	$ -					
2048	4,863,539	226,211	4,637,328	850,053	850,053	$ -					
2049	4,637,328	226,211	4,411,117	819,622	819,622	$ -					
2050	4,411,117	226,211	4,184,906	789,191	789,191	$ -					
2051	4,184,906	226,211	3,958,695	758,759	758,759	$ -					
2052	3,958,695	226,211	3,732,484	728,328	728,328	$ -					
2053	3,732,484	226,211	3,506,273	697,897	697,897	$ -					
2054	3,506,273	226,211	3,280,061	667,465	667,465	$ -					
2055	3,280,061	226,211	3,053,850	637,034	637,034	$ -					
2056	3,053,850	226,211	2,827,639	606,603	606,603	$ -					
2057	2,827,639	226,211	2,601,428	576,171	576,171	$ -					
2058	2,601,428	226,211	2,375,217	545,740	545,740	$ -					
2059	2,375,217	226,211	2,149,006	515,309	515,309	$ -					
2060	2,149,006	226,211	1,922,795	484,877	484,877	$ -					
2061	1,922,795	226,211	1,696,583	454,446	454,446	$ -					
2062	1,696,583	226,211	1,470,372	424,015	424,015	$ -					
2063	1,470,372	226,211	1,244,161	393,583	393,583	$ -					
2064	1,244,161	226,211	1,017,950	363,152	363,152	$ -					
2065	1,017,950	226,211	791,739	332,721	332,721	$ -					
2066	791,739	226,211	565,528	302,289	302,289	$ -					
2067	565,528	226,211	339,317	271,858	271,858	$ -					
Project Totals		13,459,562		70,061,829	70,061,829	-					

** 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.

APCo 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: **RTEP ID: b1712.2 (Altavista-Leesville 138kV line)**

Current Projected Year ARR	**41,778**
Current Projected Year ARR w/ Incentive	**41,778**
Current Projected Year Incentive ARR	**-**

Details			
Investment	267,989	Current Year	**2013**
Service Year (yyyy)	2011	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	13.45%
Useful life	61	FCR w/incentives approved for these facilities, less dep.	13.45%
CIAC (Yes or No)	No	Annual Depreciation Expense	4,393

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2011	267,989	-	267,989	36,052	36,052	$ -	$ -				
2012	267,989	226,211	41,778	231,831	231,831	$ -	$ -				
2013	41,778	41,778	-	41,778	41,778	$ -	$ -				
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	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
Project Totals		267,989		309,661	309,661	-					

** 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.

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	55.07%	5.33%	2.934%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	44.93%	11.49%	5.163%
		R =	8.097%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2012			
As Projected in Prior Year WS J	$ 1,906,118	$ 1,906,118	$ -
Actual after True-up	$ 2,261,880	$ 2,261,880	$ -
True-up of ARR For 2012	355,762	355,762	-

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

Rate Base (True-Up TCOS, ln 78)	1,119,671,594
R (fom A. above)	8.097%
Return (Rate Base x R)	90,660,890

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

Return (from B. above)	90,660,890
Effective Tax Rate (True-Up TCOS, ln 126)	41.31%
Income Tax Calculation (Return x CIT)	37,451,121
ITC Adjustment	(127,206)
Income Taxes	37,323,915

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)	218,162,992
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	90,660,890
Income Taxes (True-Up TCOS, ln 133)	37,323,915
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	90,178,187

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	90,178,187
Return (from I.B. above)	90,660,890
Income Taxes (from I.C. above)	37,323,915
Annual Revenue Requirement, with 0 Basis Point ROE increase	218,162,992
Depreciation (True-Up TCOS, ln 111)	32,077,595
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	186,085,397

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

Net Transmission Plant (True-Up TCOS, ln 48)	1,341,956,486
Annual Revenue Requirement, with 0 Basis Point ROE increase	218,162,992
FCR with 0 Basis Point increase in ROE	16.26%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	186,085,397
FCR with 0 Basis Point ROE increase, less Depreciation	13.87%
FCR less Depreciation (True-Up TCOS, ln 9)	13.87%
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)):	1,942,021,775
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	2,040,266,144
Subtotal	3,982,287,919
Average Transmission Plant Balance for	1,991,143,960
Annual Depreciation Rate (True-Up TCOS, ln 111)	32,626,776
Composite Depreciation Rate	1.64%
Depreciable Life for Composite Depreciation Rate	61.03
Round to nearest whole year	61

APCo 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: **RTEP ID: b0318 (Amos 765/138 kV Transformer)**

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	1,906,118	1,906,118	-
Prior Yr True-Up	2,014,191	2,014,191	-
True-Up Adjustment	108,073	108,073	-

Details

Investment	13,798,879	Current Year	2012
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	13.87%
Useful life	61	FCR w/incentives approved for these facilities, less dep.	13.87%
CIAC (Yes or No)	No	Annual Depreciation Expense	226,211

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	13,798,879	113,106	13,685,773	13,742,326	2,018,716	2,018,716	$ -	$ -	$ -	$ -	$ -	$ -
2009	13,685,773	226,211	13,459,562	13,572,668	2,108,295	2,108,295	$ -	$ 1,124,469	$ 983,826	$ 1,124,469	$ 983,826	$ -
2010	13,459,562	226,211	13,233,351	13,346,457	2,076,927	2,076,927	$ -	$ 2,027,403	$ 49,524	$ 2,027,403	$ 49,524	$ -
2011	13,233,351	226,211	13,007,140	13,120,246	2,045,559	2,045,559	$ -	$ 2,050,107	$ (4,548)	$ 2,050,107	$ (4,548)	$ -
2012	13,007,140	226,211	12,780,929	12,894,034	2,014,191	2,014,191	$ -	$ 1,906,118	$ 108,073	$ 1,906,118	$ 108,073	$ -
2013	12,780,929	226,211	12,554,718	12,667,823	1,982,823	1,982,823	$ -		$ -		$ -	$ -
2014	12,554,718	226,211	12,328,507	12,441,612	1,951,455	1,951,455	$ -		$ -		$ -	$ -
2015	12,328,507	226,211	12,102,296	12,215,401	1,920,087	1,920,087	$ -		$ -		$ -	$ -
2016	12,102,296	226,211	11,876,084	11,989,190	1,888,719	1,888,719	$ -		$ -		$ -	$ -
2017	11,876,084	226,211	11,649,873	11,762,979	1,857,351	1,857,351	$ -		$ -		$ -	$ -
2018	11,649,873	226,211	11,423,662	11,536,768	1,825,983	1,825,983	$ -		$ -		$ -	$ -
2019	11,423,662	226,211	11,197,451	11,310,557	1,794,615	1,794,615	$ -		$ -		$ -	$ -
2020	11,197,451	226,211	10,971,240	11,084,345	1,763,247	1,763,247	$ -		$ -		$ -	$ -
2021	10,971,240	226,211	10,745,029	10,858,134	1,731,879	1,731,879	$ -		$ -		$ -	$ -
2022	10,745,029	226,211	10,518,818	10,631,923	1,700,511	1,700,511	$ -		$ -		$ -	$ -
2023	10,518,818	226,211	10,292,606	10,405,712	1,669,142	1,669,142	$ -		$ -		$ -	$ -
2024	10,292,606	226,211	10,066,395	10,179,501	1,637,774	1,637,774	$ -		$ -		$ -	$ -
2025	10,066,395	226,211	9,840,184	9,953,290	1,606,406	1,606,406	$ -		$ -		$ -	$ -
2026	9,840,184	226,211	9,613,973	9,727,079	1,575,038	1,575,038	$ -		$ -		$ -	$ -
2027	9,613,973	226,211	9,387,762	9,500,868	1,543,670	1,543,670	$ -		$ -		$ -	$ -
2028	9,387,762	226,211	9,161,551	9,274,656	1,512,302	1,512,302	$ -		$ -		$ -	$ -
2029	9,161,551	226,211	8,935,340	9,048,445	1,480,934	1,480,934	$ -		$ -		$ -	$ -
2030	8,935,340	226,211	8,709,129	8,822,234	1,449,566	1,449,566	$ -		$ -		$ -	$ -
2031	8,709,129	226,211	8,482,917	8,596,023	1,418,198	1,418,198	$ -		$ -		$ -	$ -
2032	8,482,917	226,211	8,256,706	8,369,812	1,386,830	1,386,830	$ -		$ -		$ -	$ -
2033	8,256,706	226,211	8,030,495	8,143,601	1,355,462	1,355,462	$ -		$ -		$ -	$ -
2034	8,030,495	226,211	7,804,284	7,917,390	1,324,094	1,324,094	$ -		$ -		$ -	$ -
2035	7,804,284	226,211	7,578,073	7,691,178	1,292,726	1,292,726	$ -		$ -		$ -	$ -
2036	7,578,073	226,211	7,351,862	7,464,967	1,261,358	1,261,358	$ -		$ -		$ -	$ -
2037	7,351,862	226,211	7,125,651	7,238,756	1,229,989	1,229,989	$ -		$ -		$ -	$ -
2038	7,125,651	226,211	6,899,440	7,012,545	1,198,621	1,198,621	$ -		$ -		$ -	$ -
2039	6,899,440	226,211	6,673,228	6,786,334	1,167,253	1,167,253	$ -		$ -		$ -	$ -
2040	6,673,228	226,211	6,447,017	6,560,123	1,135,885	1,135,885	$ -		$ -		$ -	$ -
2041	6,447,017	226,211	6,220,806	6,333,912	1,104,517	1,104,517	$ -		$ -		$ -	$ -
2042	6,220,806	226,211	5,994,595	6,107,701	1,073,149	1,073,149	$ -		$ -		$ -	$ -
2043	5,994,595	226,211	5,768,384	5,881,489	1,041,781	1,041,781	$ -		$ -		$ -	$ -
2044	5,768,384	226,211	5,542,173	5,655,278	1,010,413	1,010,413	$ -		$ -		$ -	$ -
2045	5,542,173	226,211	5,315,962	5,429,067	979,045	979,045	$ -		$ -		$ -	$ -
2046	5,315,962	226,211	5,089,750	5,202,856	947,677	947,677	$ -		$ -		$ -	$ -
2047	5,089,750	226,211	4,863,539	4,976,645	916,309	916,309	$ -		$ -		$ -	$ -
2048	4,863,539	226,211	4,637,328	4,750,434	884,941	884,941	$ -		$ -		$ -	$ -
2049	4,637,328	226,211	4,411,117	4,524,223	853,573	853,573	$ -		$ -		$ -	$ -
2050	4,411,117	226,211	4,184,906	4,298,011	822,205	822,205	$ -		$ -		$ -	$ -
2051	4,184,906	226,211	3,958,695	4,071,800	790,836	790,836	$ -		$ -		$ -	$ -
2052	3,958,695	226,211	3,732,484	3,845,589	759,468	759,468	$ -		$ -		$ -	$ -
2053	3,732,484	226,211	3,506,273	3,619,378	728,100	728,100	$ -		$ -		$ -	$ -
2054	3,506,273	226,211	3,280,061	3,393,167	696,732	696,732	$ -		$ -		$ -	$ -
2055	3,280,061	226,211	3,053,850	3,166,956	665,364	665,364	$ -		$ -		$ -	$ -
2056	3,053,850	226,211	2,827,639	2,940,745	633,996	633,996	$ -		$ -		$ -	$ -
2057	2,827,639	226,211	2,601,428	2,714,534	602,628	602,628	$ -		$ -		$ -	$ -
2058	2,601,428	226,211	2,375,217	2,488,322	571,260	571,260	$ -		$ -		$ -	$ -
2059	2,375,217	226,211	2,149,006	2,262,111	539,892	539,892	$ -		$ -		$ -	$ -
2060	2,149,006	226,211	1,922,795	2,035,900	508,524	508,524	$ -		$ -		$ -	$ -
2061	1,922,795	226,211	1,696,583	1,809,689	477,156	477,156	$ -		$ -		$ -	$ -
2062	1,696,583	226,211	1,470,372	1,583,478	445,788	445,788	$ -		$ -		$ -	$ -
2063	1,470,372	226,211	1,244,161	1,357,267	414,420	414,420	$ -		$ -		$ -	$ -
2064	1,244,161	226,211	1,017,950	1,131,056	383,051	383,051	$ -		$ -		$ -	$ -
2065	1,017,950	226,211	791,739	904,845	351,683	351,683	$ -		$ -		$ -	$ -
2066	791,739	226,211	565,528	678,633	320,315	320,315	$ -		$ -		$ -	$ -
2067	565,528	226,211	339,317	452,422	288,947	288,947	$ -		$ -		$ -	$ -
Project Totals		13,459,562			72,737,377	72,737,377	-					

** 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.

APCo 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: **RTEP ID: b1712.2 (Altavista-Leesville 138kV line)**

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	247,688	247,688	-
True-Up Adjustment	247,688	247,688	-

Details			
Investment	267,989	Current Year	2012
Service Year (yyyy)	2011	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	13.87%
Useful life	61	FCR w/incentives approved for these facilities, less dep.	13.87%
CIAC (Yes or No)	No	Annual Depreciation Expense	4,393

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 **
2011	267,989	-	267,989	267,989	37,161	37,161	$ -	$ -	$ -	$ -	$ -	$ -
2012	267,989	226,211	41,778	154,883	247,688	247,688	$ -	$ -	$ -	$ -	$ -	$ -
2013	41,778	41,778	-	20,889	44,674	44,674	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals		267,989			329,524	329,524	-					

** 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 2012 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
APPALACHIAN POWER COMPANY

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

	(A)		(B)	(C)	(D)	(E)
Line Number	**Issuance**		**Principle Outstanding**	**Interest Rate**	**Annual Expense** (See Note S on Projected Template)	**Notes**
1	**Long Term Debt (FF1.p. 256-257.h)**					
2	Advances From Associated Co.		-	4.708%	-	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	WV EDA Amos Project, Series 2009A		54,375,000	0.150%	81,563	
6	WV EDA Amos Project, Series 2009B		50,000,000	0.500%	250,000	
7	IPC Mason Series L		100,000,000	2.000%	2,000,000	
8	WV EDA IPC Mountaineer Project, Series 2008A		75,000,000	0.120%	90,000	
9	WV EDA IPC Mountaineer Project, Series 2008B		50,275,000	0.160%	80,440	
10	IPC Putnam County, WV, Series 2008C		30,000,000	4.850%	1,455,000	
11	IPC Putnam County, WV, Series 2008D		40,000,000	4.850%	1,940,000	
12	Russell County, Va Series K		17,500,000	4.625%	809,375	
13	Amos Project, Series 2010A		50,000,000	5.375%	2,687,500	
14	Amos Project, Series 2011A		65,350,000	2.250%	1,470,375	
15	Senior Unsecured Notes - Series S		300,000,000	3.400%	10,200,000	
16	Senior Unsecured Notes - Series T		350,000,000	4.600%	16,100,000	
17	Senior Unsecured Notes - Series I		200,000,000	4.950%	9,900,000	
18	Senior Unsecured Notes - Series K		250,000,000	5.000%	12,500,000	
19	Senior Unsecured Notes - Series L		250,000,000	5.800%	14,500,000	
20	Senior Unsecured Notes - Series H		200,000,000	5.950%	11,900,000	
21	Senior Unsecured Notes - Series N		250,000,000	6.375%	15,937,500	
22	Senior Unsecured Notes - Series P		250,000,000	6.700%	16,750,000	
23	Senior Unsecured Notes - Series Q		500,000,000	7.000%	35,000,000	
24	Senior Unsecured Notes - Series R		350,000,000	7.950%	27,825,000	
25	Floating Rate Senior Unsecured Notes - Series D		275,000,000	0.685%	1,883,750	
26	Sale/Leaseback		2,383,415	13.641%	325,126	
27	Issuance Discount, Premium, & Expenses:					
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
29	Allowable Hedge Amortization (See Ln 45 Below)				1,619,222	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			3,859,577	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
32	Reacquired Debt:					
33	Amortization of Loss	FF1.p. 117.64.c			1,342,096	
34	Amortization of Gain	FF1.p. 117.66.c			-	
35	**Total Interest on Long Term Debt**		3,709,883,415	5.14%	190,506,524	
36	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
37	4.5% Series - $100 - 177,465 Shares O/S			4.50%	-	
38					-	
39					-	
40	**Dividends on Preferred Stock**		-	0.00%	-	
41	Eligible Hedging Gains and Losses (WS M, Ln 34, (E))				1,619,222	
42	Total Projected Capital Structure Balance for 2013 (Projected TCOS, Ln 165)				6,790,690,020	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
44	Limit of Recoverable Amount				3,395,345	
45	**Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)**				**1,619,222**	

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

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	3,052,563,357	2,936,414,454	2,994,488,906
2	Less Preferred Stock (Ln 54 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	1,654,344	1,610,810	1,632,577
4	Less Account 219.1 (112.15.c&d)	(29,897,592)	(58,543,154)	(44,220,373)
5	**Average Balance of Common Equity**	3,080,806,605	2,993,346,798	**3,037,076,702**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	-	-	-
7	Less: Reacquired Bonds (112.19.c&d)	-	-	-
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	3,709,883,415	3,734,408,392	3,722,145,904
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	3,709,883,415	3,734,408,392	**3,722,145,904**

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 2012**	
14	Interest on Long Term Debt (256-257.33.i)	193,138,993
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 33 below.	1,619,222
16	Plus: Allowed Hedge Recovery From Ln 38 below.	1,619,222
17	Amort of Debt Discount & Expense (117.63.c)	3,859,577
18	Amort of Loss on Reacquired Debt (117.64.c)	1,342,096
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)**	**198,340,666**
22	**Average Cost of Debt for 2012 (Ln 21/Ln 11)**	**5.33%**

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.

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2012	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 I	764,169		764,169	1,209,935	Jan-05	Feb-15
25	Senior Unsecured Notes - Series K	1,336,324		1,336,324	3,229,451	Jun-05	Jun-17
26	Senior Unsecured Notes - Series O	60,287		60,287	(0)	Aug-07	Aug-12
27	Senior Unsecured Notes - Series L	(238,880)		(238,880)	(656,918)	Sep-05	Oct-35
28	Senior Unsecured Notes - Series H	37,068		37,068	753,816	May-03	May-33
29	Senior Unsecured Notes - Series N	(194,198)		(194,198)	(4,515,114)	Apr-06	Apr-36
30	Senior Unsecured Notes - Series Q	159,672		159,672	4,025,043	Mar-08	Apr-38
31	Senior Unsecured Notes - Series S	826,212	-	826,212	1,981,131	May-10	May-15
32	Senior Unsecured Notes - Series T	(1,131,432)	-	(1,131,432)	(9,302,888)	Mar-11	Mar-21
				-			
33	Total Hedge Amortization	1,619,222	-				

34	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to)	1,619,222
35	Total Average Capital Structure Balance for 2012 (True-UP TCOS, Ln 165)	6,759,222,605
36	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
37	Limit of Recoverable Amount	3,379,611
38	**Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)**	**1,619,222**

Development of Cost of Preferred Stock

	Preferred Stock			**Average**
39	4.5% Series - 100 - Dividend Rate (p. 250-251. 7 & 10.a)	4.50%	4.50%	
40	4.5% Series - 100 - Par Value (p. 250-251. 8.c)	$ 100.00	$ 100.00	
41	4.5% Series - 100 - Shares O/S (p.250-251. 8 & 11.e)	-	-	
42	4.5% Series - 100 - Monetary Value (Ln 40 * Ln 41)	-	-	-
43	4.5% Series - 100 - Dividend Amount (Ln 39 * Ln 42)	-	-	-
44	0% Series - - Dividend Rate (p. 250-251.a)			
45	0% Series - - Par Value (p. 250-251.c)			
46	0% Series - - Shares O/S (p.250-251. e)			
47	4.5% Series - 100 - Monetary Value (Ln 45 * Ln 46)	-	-	-
48	0% Series - - Dividend Amount (Ln 44 * Ln 47)	-	-	-
49	0% Series - - Dividend Rate (p. 250-251.a)			
50	0% Series - - Par Value (p. 250-251.c)			
51	0% Series - - Shares O/S (p.250-251.e)			
52	4.5% Series - 100 - Monetary Value (Ln * Ln 49)	-	-	-
53	0% Series - - Dividend Amount (Ln 49 * Ln 52)	-	-	-
54	**Balance of Preferred Stock (Lns 42, 47, 52)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
55	**Dividends on Preferred Stock (Lns 43, 48, 53)**	-	-	-
56	**Average Cost of Preferred Stock (Ln 55/54)**	0.00%	0.00%	**0.00%**

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
APPALACHIAN POWER COMPANY

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectivielу. 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 2012		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
APPALACHIAN POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

Allocation of PBOP Settlement Amount for 2012:

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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 *	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy *	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927 -	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

* Sourced from Actuarial Report

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 2/1/2012
FOR MULTIPLE JURISDICTION COMPANIES
APPALACHIAN POWER COMPANY

		VIRGINIA			WEST VIRGINIA			FERC WHOLESALE			FERC KINGSPORT			COMPANY
		(1)			*(2)*			*(3)*			*(4)*			
	PLANT ACCT.	*VA SCC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*PSC OF WV APPROVED RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT														
Land Rights - Va.	350.1	0.66%	1.000000	0.66%										0.66%
Structures & Improvements	352.0	1.55%	0.455791	0.71%	1.55%	0.444609	0.69%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.62%
Station Equipment	353.0	1.95%	0.455791	0.89%	1.95%	0.444609	0.87%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.98%
Towers & Fixtures	354.0	1.14%	0.455791	0.52%	1.14%	0.444609	0.51%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.25%
Poles & Fixtures	355.0	2.77%	0.455791	1.26%	2.77%	0.444609	1.23%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	2.71%
Overhead Conductor	356.0	1.01%	0.455791	0.46%	1.01%	0.444609	0.45%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.13%
Underground Conduit	357.0	1.23%	0.455791	0.56%	1.24%	0.444609	0.55%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.33%
Underground Conductors	358.0	3.18%	0.455791	1.45%	3.18%	0.444609	1.41%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	3.08%

(1) As approved in VA Case No. PUE 2006-00065 on May 15, 2007.
Depreciation rates were made effective on January 1, 2006.

(2) Approved by PSC of WV Order dated July 26, 2006 in
Case No. 05-1278-E-PC-PW-42T effective July 1, 2006.

(3) Approved by FERC March 2, 1990 in Docket ER90-132

(4) Approved by FERC March 2, 1990 in Docket ER90-133

(5) 2009 Allocation factors based on APCo's 12 monthly Coincident Peaks for twelve months ended September 30, 2008 as provided by AEPSC Regulated Pricing. The demand allocation factors are updated annually as of January 1, based on the 12 monthly CP's as of the previous September 30th.

GENERAL NOTES:

The rates for each AEP company have been approved by their respective regulatory commissions.
APCo falls under the authority of Virginia, West Virginia and the FERC. Therefore, APCo's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.
Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)				$125,959,874
2	REVENUE CREDITS	(Note A) (Worksheet E)	947,294	DA	1.00000	$ 947,294
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$ 125,012,580

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		Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		2,666,168	DA	1.00000	$ 2,666,168
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))				17.38%
7	Monthly Rate	(ln 6 / 12)				1.45%
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))				14.80%
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))				4.58%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)					-
13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**					
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below				8,132,792
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)					5,531,795
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)					1,083,397
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)				1,517,600

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

INDIANA MICHIGAN 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.C)	4,037,746,725	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(303,665,963)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	1,278,027,455	DA		1,207,351,314
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.94470	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		56,854,607	DA	1.00000	56,854,607
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		-	DA	1.00000	-
24	Distribution	(Worksheet A ln 5.C)	1,553,155,453	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	107,811,687	W/S	0.04206	4,534,307
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,922)	W/S	0.04206	(7,273)
28	Intangible Plant	(Worksheet A ln 9.C)	139,775,289	W/S	0.04206	5,878,622
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	6,869,532,331			1,274,611,577
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	2,318,062,105	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(84,627,053)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	537,188,312	**TP1=**	0.96948	520,792,956
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96948	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		544,141	DA	1.00000	544,141
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		18,714,918	TP1	0.96948	18,143,726
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		18,589,864	W/S	0.04206	781,846
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	479,335,470	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	27,301,514	W/S	0.04206	1,148,238
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(138,294)	W/S	0.04206	(5,816)
44	Intangible Plant	(Worksheet A ln 20.C)	132,615,751	W/S	0.04206	5,577,508
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,447,586,728			546,982,599
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,500,645,710			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	740,839,143			686,558,358
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		56,310,466			56,310,466
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(18,714,918)			(18,143,726)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(18,589,864)			(781,846)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,073,819,983			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	80,475,545			3,384,613
56	Intangible Plant	(ln 28 - ln 44)	7,159,538			301,113
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,421,945,603			727,628,978
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(246,285)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(920,003,284)	DA		(151,405,593)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(664,464,895)	DA		(9,424,522)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	755,767,692	DA		15,048,413
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(828,946,772)			(145,781,702)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	6,294,968	DA		208,360
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	2,257,790			2,132,932
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,954,137	TP	0.94470	1,846,071
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	52,111	W/S	0.04206	2,192
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17875	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	144,686,210	W/S	0.04206	6,085,164
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	5,571,844	GP(h)	0.17875	995,960
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(139,407,819)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	15,114,273			11,062,318
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,810,348)	DA	1.00000	(2,810,348)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,611,597,724			590,307,606

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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	1,354,855,751			
80	Distribution	322.156.b	54,052,769			
81	Customer Related Expense	322.164,171,178.b	39,354,797			
82	Regional Marketing Expenses	322.131.b	5,602,674			
83	Transmission	321.112.b	40,026,099			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,493,892,090			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	8,132,792			
86	Less: Account 565	(Note H) 321.96.b	13,667,883			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	18,062,316	TP	0.94470	17,063,453
89	Administrative and General	323.197.b (Note J)	127,509,877			
90	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
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)	795,128			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	276,915			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	93,835,099	W/S	0.04206	3,946,485
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,407,050	GP(h)	0.17875	787,754
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94470	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94470	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	184,289	DA	1.00000	184,289
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04206	523,744
103	A & G Subtotal	(sum lns 97 to 102)	110,879,444			5,442,272
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	128,941,760			22,505,725
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)	128,941,760			22,505,725
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	67,479,165	NA	0.00000	-
110	Distribution	336.8.f	38,889,909	NA	0.00000	-
111	Transmission	336.7.f	18,714,918	TP1	0.96948	18,143,726
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		544,141	DA	1.00000	544,141
113	General	336.10.f	3,466,837	W/S	0.04206	145,807
114	Intangible	336.1.f	15,123,027	W/S	0.04206	636,039
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	144,217,997			19,469,713
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	12,399,142	W/S	0.04206	521,479
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	46,385,973	DA		8,974,114
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	12,850,498	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,628,831	GP(h)	0.17875	291,151
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	73,264,444			9,786,744
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.80%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.13%			
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)		1.6341			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,502,458)			
131	Income Tax Calculation	(ln 126 * ln 134)	102,404,032			23,146,704
132	ITC adjustment	(ln 129 * ln 130)	(7,357,258)	NP(h)	0.20284	(1,492,328)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	95,046,774			21,654,375
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	232,062,470			52,453,806
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		89,510	DA	1.00000	89,510
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)		673,622,955			125,959,874

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						1,278,027,455
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)							70,676,141
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						1,207,351,314
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					**TP**	**0.94470**
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA	0.00000	-
146	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP	0.94470	7,555,076
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA	0.00000	-
150	Total	(sum lns 145 to 149)	158,945,485	20,690,650	179,636,135			7,555,076
151	Transmission related amount						**W/S=**	**0.04206**
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							$
153	Long Term Interest	(Worksheet L, ln. 26, col. (D))						91,995,574
154	Preferred Dividends	(Worksheet L, ln. 31, col. (D))						-
155	Development of Common Stock:							
156	Proprietary Capital	(FF1 p 112, Ln 16.c)						1,803,774,755
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)						(104,879)
159	Less: Account 219	(FF1 p 112, Ln 15.c)						(28,884,204)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)						1,832,763,838
161				$	%		Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))			1,572,429,608	46.18%		0.0585	0.0270
163	Preferred Stock (ln 157)			-	0.00%		-	0.0000
164	Common Stock (ln 160)			1,832,763,838	53.82%		11.49%	0.0618
165	Total (Sum lns 162 to 164)			3,405,193,446			**WACC=**	**0.0889**

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INDIANA MICHIGAN 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. Other ratebase amounts are as of December 31, 2012.
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 3 through 12, 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 INDIANA MICHIGAN 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=	5.85%	(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	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 162 above.
U	This note only applies to the true-up template.

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Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$120,627,861
167	REVENUE CREDITS	(Note A) (Worksheet E)	947,294	DA	1.00000	$	947,294
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	119,680,567

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.

Line No.			
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)	17.57%
172	Monthly Rate	(ln 171 / 12)	1.46%
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)	14.93%
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)	4.83%
177	Not applicable on this template		

Line No.	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
178			
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	8,132,792
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,531,795
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,083,397
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	1,517,600

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INDIANA MICHIGAN 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)	4,037,746,725	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(303,665,963)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	1,278,027,455	DA		1,207,351,314
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.94470	-
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)	1,553,155,453	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)	107,811,687	W/S	0.04206	4,534,307
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,922)	W/S	0.04206	(7,273)
193	Intangible Plant	(Worksheet A ln 9.C)	139,775,289	W/S	0.04206	5,878,622
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	6,812,677,724	**GP(h)=**	**0.178749**	1,217,756,970
				GTD=	**0.42645**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	2,318,062,105	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(84,627,053)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	537,188,312	**TP1=**	0.96948	520,792,956
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96948	-
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 2013 (ln 276)		N/A	TP1	0.96948	N/A
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		N/A	W/S	0.04206	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)	479,335,470	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)	27,301,514	W/S	0.04206	1,148,238
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(138,294)	W/S	0.04206	(5,816)
209	Intangible Plant	(Worksheet A ln 20.C)	132,615,751	W/S	0.04206	5,577,508
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	3,409,737,805			527,512,886
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	1,500,645,710			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	740,839,143			686,558,358
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 2013 (-ln 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	1,073,819,983			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	80,475,545			3,384,613
221	Intangible Plant	(ln 193 - ln 209)	7,159,538			301,113
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	3,402,939,919	**NP(h)=**	**0.202838**	690,244,084
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(246,285)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(920,003,284)	DA		(151,405,593)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(664,464,895)	DA		(9,424,522)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	755,767,692	DA		15,048,413
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(828,946,772)			(145,781,702)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	6,294,968	DA		208,360
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	2,257,790			2,132,932
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,954,137	TP	0.94470	1,846,071
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	52,111	W/S	0.04206	2,192
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17875	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	144,686,210	W/S	0.04206	6,085,164
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	5,571,844	GP(h)	0.17875	995,960
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(139,407,819)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	15,114,273			11,062,318
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,810,348)	DA	1.00000	(2,810,348)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		2,592,592,040			552,922,712

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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					
244	Production	321.80.b	1,354,855,751			
245	Distribution	322.156.b	54,052,769			
246	Customer Related Expense	322 & 323.164,171,178.b	39,354,797			
247	Regional Marketing Expenses	322.131.b	5,602,674			
248	Transmission	321.112.b	40,026,099			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	1,493,892,090			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	8,132,792			
251	Less: Account 565	(Note H) 321.96.b	13,667,883			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	18,062,316	TP	0.94470	17,063,453
254	Administrative and General	323.197.b (Note J)	127,509,877			
255	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
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)	795,128			
259	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	276,915			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	93,835,099	W/S	0.04206	3,946,485
263	Plus: Acct. 924, Property Insurance	(ln 255)	4,407,050	GP(h)	0.17875	787,754
264	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94470	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94470	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	184,289	DA	1.00000	184,289
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04206	523,744
268	A & G Subtotal	(sum lns 262 to 267)	110,879,444			5,442,272
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	128,941,760			22,505,725
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)	128,941,760			22,505,725
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	67,479,165	NA	0.00000	-
275	Distribution	336.8.f	38,889,909	NA	0.00000	-
276	Transmission	336.7.f	18,714,918	TP1	0.96948	18,143,726
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	3,466,837	W/S	0.04206	145,807
279	Intangible	336.1.f	15,123,027	W/S	0.04206	636,039
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	143,673,856			18,925,572
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 22.(D)	12,399,142	W/S	0.04206	521,479
284	Plant Related					
285	Property	Worksheet H ln 22.(C) & ln 47.(C)	46,385,973	DA		8,974,114
286	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	12,850,498	NA	0.00000	-
287	Other	Worksheet H ln 22.(E)	1,628,831	GP(h)	0.17875	291,151
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	73,264,444			9,786,744
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.80%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.13%			
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)		1.6341			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,502,458)			
296	Income Tax Calculation	(ln 291 * ln 299)	101,658,795			21,680,795
297	ITC adjustment	(ln 294 * ln 295)	(7,357,258)	NP(h)	0.20284	(1,492,328)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	94,301,537			20,188,467
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	230,373,655			49,131,843
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	89,510	DA	1.00000	89,510
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)		670,644,762			120,627,861

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						1,278,027,455
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)							70,676,141
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)						1,207,351,314
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)					**TP=**	**0.94470**
			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
310	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA	0.00000	-
311	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP	0.94470	7,555,076
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA	0.00000	-
315	Total	(sum lns 310 to 314)	158,945,485	20,690,650	179,636,135			7,555,076
316	Transmission related amount						**W/S=**	**0.04206**

			$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		
318	Long Term Interest	(Worksheet L, ln. 26, col. (D))	91,995,574
319	Preferred Dividends	(Worksheet L, ln. 31, col. (D))	-
320	Development of Common Stock:		
321	Proprietary Capital	(FF1 p 112, Ln 16.c)	1,803,774,755
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)	-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)	(104,879)
324	Less: Account 219	(FF1 p 112, Ln 15.c)	(28,884,204)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)	1,832,763,838

		$	%	Cost (Note S)	Weighted
326					
327	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))	1,572,429,608	46.18%	0.0585	0.0270
328	Preferred Stock (ln 322)	-	0.00%	-	0.0000
329	Common Stock (ln 325)	1,832,763,838	53.82%	11.49%	0.0618
330	Total (Sum lns 327 to 329)	3,405,193,446		**WACC=**	**0.0889**

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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 historic as of December 31, 2012.
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 3 through 12, 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 INDIANA MICHIGAN 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=	5.85%	(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	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 327 above.
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)					$120,680,556
2	REVENUE CREDITS	(Note A) (Worksheet E)	947,294	DA	1.00000	$	947,294
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	119,733,262

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			Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		1,323,753	DA	1.00000	$	1,323,753
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)					17.76%
7	Monthly Rate	(ln 6 / 12)					1.48%
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)					15.10%
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)					4.92%
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	8,132,792
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,531,795
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,083,397
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	1,517,600

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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.E)	3,971,093,664	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(240,586,737)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	1,251,307,628	DA		1,196,024,411
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	0.95582	-
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)	1,517,305,278	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)	105,667,205	W/S	0.04255	4,496,430
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(179,651)	W/S	0.04255	(7,645)
28	Intangible Plant	(Worksheet A ln 9.E)	138,975,304	W/S	0.04255	5,913,781
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	6,743,582,690	**GP(h)=**	**0.17890**	1,206,426,977
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	2,289,818,877	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(81,929,364)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	534,462,451	**TP1=**	0.96663	516,627,997
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.96663	-
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 2013 (ln 111)		**N/A**	TP1	0.96663	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		**N/A**	W/S	0.04255	**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)	478,125,362	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)	26,878,601	W/S	0.04255	1,143,758
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(141,892)	W/S	0.04255	(6,038)
44	Intangible Plant	(Worksheet A ln 20.E)	130,178,936	W/S	0.04255	5,539,471
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,377,392,970			523,305,188
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,522,617,414			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	716,845,178			679,396,414
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 2013 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	1,039,179,916			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	78,750,845			3,351,065
56	Intangible Plant	(ln 28 - ln 44)	8,796,368			374,310
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,366,189,720	**NP(h)=**	**0.20294**	683,121,789
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(254,527)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(863,955,914)	DA		(146,826,257)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(660,516,314)	DA		(10,107,028)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	727,492,523	DA		15,457,493
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(797,234,232)			(141,475,792)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	7,013,691	DA		203,338
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	2,257,790			2,158,040
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,241,870	TP	0.95582	1,187,003
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	88,427	W/S	0.04255	3,763
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17890	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	141,807,875	W/S	0.04255	6,034,314
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	4,484,132	GP(h)	0.17890	802,211
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(137,425,350)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	12,454,742			10,185,331
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(2,765,593)	DA	1.00000	(2,765,593)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,585,658,328			549,269,073

AEP East Companies
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Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

INDIANA MICHIGAN 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	1,354,855,751			
80	Distribution	322.156.b	54,052,769			
81	Customer Related Expense	322.164,171,178.b	39,354,797			
82	Regional Marketing Expenses	322.131.b	5,602,674			
83	Transmission	321.112.b	40,026,099			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,493,892,090			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	8,132,792			
86	Less: Account 565	(Note H) 321.96.b	13,667,883			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	18,062,316	TP	0.95582	17,264,316
89	Administrative and General	323.197.b (Note J)	127,509,877			
90	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
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)	795,128			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	276,915			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	93,835,099	W/S	0.04255	3,992,941
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,407,050	GP(h)	0.17890	788,421
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94470	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94470	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	184,289	DA	1.00000	184,289
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04255	529,910
103	A & G Subtotal	(sum lns 97 to 102)	110,879,444			5,495,561
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	128,941,760			22,759,877
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)	128,941,760			22,759,877
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	67,479,165	NA	0.00000	-
110	Distribution	336.8.f	38,889,909	NA	0.00000	-
111	Transmission	336.7.f	18,714,918	TP1	0.96663	18,090,421
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
113	General	336.10.f	3,466,837	W/S	0.04255	147,523
114	Intangible	336.1.f	15,123,027	W/S	0.04255	643,526
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	143,673,856			18,881,470
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	12,399,142	W/S	0.04255	527,618
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	46,385,973	DA		8,974,114
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	12,850,498	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,628,831	GP(h)	0.17890	291,398
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	73,264,444			9,793,130
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.80%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		43.60%			
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)		1.6341			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,502,458)			
131	Income Tax Calculation	(ln 126 * ln 134)	100,971,702			21,449,328
132	ITC adjustment	(ln 129 * ln 130)	(7,357,258)	NP(h)	0.20294	(1,493,054)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	93,614,444			19,956,274
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	231,608,072			49,200,294
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		89,510	DA	1.00000	89,510
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)		671,192,086			120,680,556

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							1,251,307,628
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)								55,283,217
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)							1,196,024,411
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)						TP	**0.95582**
				Payroll Billed from					
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total				
145	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA	0.00000		-
146	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP	0.95582		7,644,011
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA	0.00000		-
150	Total	(sum lns 145 to 149)	158,945,485	20,690,650	179,636,135				7,644,011
151	Transmission related amount							W/S=	**0.04255**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))	94,555,778
154	Preferred Dividends	(Worksheet M, ln. 55, col. (E))	-
155	Development of Common Stock:		Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	1,782,377,444
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))	-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))	(167,822)
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))	(28,552,807)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	1,811,098,073

			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))	1,567,678,557	46.40%	0.00%	0.0603	0.0280
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Common Stock (ln 160)	1,811,098,073	53.60%	0.00%	11.49%	0.0616
165	Total (Sum lns 162 to 164)	3,378,776,629			WACC=	**0.0896**
166	Capital Structure Equity Limit (Note U)	100.0%				

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

INDIANA MICHIGAN 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, 2011 and December 31, 2012.
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 3 through 12, 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 INDIANA MICHIGAN 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 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= 5.85% (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	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 162 above.
U	Per Settlement, equity for INDIANA MICHIGAN 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 2012 FF1 Balances
Worksheet A Supporting Plant Balances
INDIANA MICHIGAN POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
	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	4,037,746,725	3,904,440,602	3,971,093,664
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	303,665,963	177,507,511	240,586,737
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	1,278,027,455	1,224,587,801	1,251,307,628
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	1,553,155,453	1,481,455,103	1,517,305,278
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	107,811,687	103,522,722	105,667,205
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	172,922	186,379	179,651
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	139,775,289	138,175,318	138,975,304
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	7,116,516,609	6,852,181,546	6,984,349,078
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	303,838,885	177,693,890	240,766,388
	Accumulated Depreciation & Amortization Balances				
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	2,318,062,105	2,261,575,648	2,289,818,877
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	84,627,053	79,231,676	81,929,364
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	537,188,312	531,736,589	534,462,451
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	479,335,470	476,915,254	478,125,362
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	27,301,514	26,455,688	26,878,601
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	138,294	145,489	141,892
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	132,615,751	127,742,121	130,178,936
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	3,494,503,152	3,424,425,300	3,459,464,226
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	84,765,347	79,377,165	82,071,256
	Generation Step-Up Units				
23	**GSU Investment Amount**	Company Records - Note 1	70,676,141	39,890,293	55,283,217
24	**GSU Accumulated Depreciation**	Company Records - Note 1	16,395,356	19,273,552	17,834,454
25	**GSU Net Balance**	(Line 23 - Line 24)	54,280,785	20,616,741	37,448,763
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation				
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	537,188,312	531,736,589	534,462,451
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	16,395,356	19,273,552	17,834,454
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	520,792,956	512,463,037	516,627,997
	Plant Held For Future Use				
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	6,294,968	7,732,413	7,013,691
30	**Transmission Plant Held For Future**	Company Records - Note 1	208,360	198,316	203,338
	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 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	Description	Source	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	246,285	262,768	254,527
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	246,285	262,768	254,527
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)	920,003,284	807,908,544	863,955,914
8	Less: ARO Related Deferrals	Company Records - Note 1	79,547,117	34,707,660	57,127,389
9	Less: Other Excluded Deferrals	Company Records - Note 1	689,050,574	630,953,963	660,002,269
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	151,405,593	142,246,921	146,826,257
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	664,464,895	656,567,733	660,516,314
13	Less: ARO Related Deferrals	Company Records - Note 1	489,889,606	451,069,253	470,479,430
14	Less: Other Excluded Deferrals	Company Records - Note 1	165,150,767	194,708,947	179,929,857
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	9,424,522	10,789,533	10,107,028
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	755,767,692	699,217,353	727,492,523
18	Less: ARO Related Deferrals	Company Records - Note 1	569,810,510	486,599,089	528,204,800
19	Less: Other Excluded Deferrals	Company Records - Note 1	170,908,769	196,751,691	183,830,230
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	15,048,413	15,866,573	15,457,493
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	48,130,448	52,632,906	50,381,677
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	48,130,448	52,632,906	50,381,677
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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
INDIANA MICHIGAN POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2012	(E) Balance @ December 31, 2011	(F) Average Balance for 2012
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,954,137	529,602	1,241,870
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	52,111	124,743	88,427
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, 2012	10,850,235	(139,407,819)	0	5,571,844	144,686,210	150,258,054
7	Totals as of December 31, 2011	6,883,076	(135,442,881)		3,396,419	138,929,539	142,325,958
8	**Average Balance**	8,866,656	(137,425,350)	-	4,484,132	141,807,875	146,292,006

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	3,887,518	-		3,887,518		3,887,518	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	436,231	436,231				-	Prepaid Taxes
12	1650003	Prepaid Rents	3,369	3,369				-	River Transport
13	1650005	Prepaid Employee Benefits	1,569	1,569				-	Benefits Generation
14	1650006	Other Prepayments	3,909,935	3,909,935				-	Relates to EPRI dues
15	1650009	Prepaid Carry Cost-Factored AR	47,917	47,917				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	144,686,210				144,686,210	144,686,210	Prefunded Pension Expense
17	1650014	FAS 158 Qual Contra Asset	(144,686,210)	(144,686,210)				-	SFAS 158 Offset
18	165001112	Prepaid Sales Taxes	600,600	600,600			-	-	Prepaid Sales Tax - Distribution
19	165001212	Prepaid Use Taxes	139,157	139,157			-	-	Prepaid Use Tax - Distribution
20	1650021	Prepaid Insurance - EIS	1,684,326	-		1,684,326		1,684,326	Energy INS Services
21	1650022	Prepaid SNF Container Costs	0	-			-	-	
22	1650023	Prepaid Lease	139,613	139,613			-	-	Prepaid Leases
23	1650026	Prepaid SNF Costs	0	-					
		Subtotal - Form 1, p 111.57.c	10,850,235	(139,407,819)	0	5,571,844	144,686,210	150,258,054	

Prepayments Account 165 - Balance @ 12/31/ 2011

24	Acc. No.	Description	2011 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
25	1650001	Prepaid Insurance	2,257,087	-		2,257,087		2,257,087	Plant Related Insurance Policies
26	165000211	Prepaid Taxes	312,823	312,823				-	Prepaid Taxes
27	1650003	Prepaid Rents	3,369	3,369			-	-	River Transport
28	1650005	Prepaid Employee Benefits	4,578	4,578			-	-	
29	1650006	Other Prepayments	34,988	34,988				-	Relates to EPRI dues
30	1650009	Prepaid Carry Cost-Factored AR	62,687	62,687				-	AR Factoring - Retail Only
31	1650010	Prepaid Pension Benefits	138,929,539				138,929,539	138,929,539	Prefunded Pension Expense
32	1650014	FAS 158 Qual Contra Asset	(138,929,539)	(138,929,539)				-	SFAS 158 Offset
33	165001111	Prepaid Sales Taxes	562,130	562,130			-	-	
34	165001211	Prepaid Use Taxes	111,303	111,303			-	-	
35	1650021	Prepaid Insurance - EIS	1,139,332	-		1,139,332		1,139,332	
36	1650022	Prepaid SNF Container Costs	0	-			-	-	
37	1650023	Prepaid Lease	175,980	175,980			-	-	
38	1650026	Prepaid SNF Costs	2,218,800	2,218,800					
		Subtotal - Form 1, p 111.57.d	6,883,076	(135,442,881)		3,396,419	138,929,539	142,325,958	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	(A) Description	(B) 2012
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 6.b)	(2,720,838)
2	Interest Accrual (Company Records - Note 1)	(89,510)
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 12/31/2012 (2012 FORM 1, P269, line 6.f)	(2,810,348)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(2,765,593)

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet E Supporting Revenue Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	4,504,166	4,504,166	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	3,366,681	3,309,894	56,787
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	7,495,108	7,069,523	425,585
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	1,609,822	1,176,732	433,090
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	37,512,337	37,480,505	31,832
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	54,488,114	53,540,820	947,294
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	54,488,114	53,540,820	947,294

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or INDIANA MICHIGAN 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 2012 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
INDIANA MICHIGAN POWER COMPANY

Line Number (A)	Item No.	(B) Description	(C) 2012 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1	5660000	Misc Transmission Expense	163,108			
2		**Total**	163,108			
		Detail of Account 561 Per FERC Form 1				
3	FF1 p 321.84.b	561 - Load Dispatching	0			
4	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	17,920			
5	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,172,559			
6	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(246)			
7	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,531,795			
8	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	327,367			
9	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
10	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
11	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Serv	1,083,397			
12		**Total of Account 561**	8,132,792			
		Account 928				
13	9280000	Regulatory Commission Exp	562	562	-	Miscellaneous Filing Support
14	9280001	Regulatory Commission Exp-Adm	11,887,446	11,887,446	-	Nuclear Regulatory Commission/FERC Hydro
15	9280002	Regulatory Commission Exp-Case	1,161,490	1,161,490	-	Indiana/Michigan Rate Cases
16	9280003	Rate Case Amortization	35,878	35,878		Indiana Rate Case
17		**Total**	13,085,376	13,085,376	-	
		Account 930.1				
18	9301000	General Advertising Expenses	35,272	35,272	-	
19	9301001	Newspaper Advertising Space	35,854	35,854	-	
20	9301002	Radio Station Advertising Time	32,901	32,901	-	
21	9301003	TV Station Advertising Time	1,100	1,100	-	
22	9301006	Spec Corporate Comm Info Proj	19,998	19,998	-	
23	9301007	Special Adv Space & Prod Exp	332	332	-	
24	9301008	Direct Mail and Handouts	10,800	10,800	-	
25	9301009	Fairs, Shows, and Exhibits	-	-	-	
26	9301010	Publicity	54,325	54,325	-	
27	9301011	Dedications, Tours, & Openings	6,410	6,410	-	
28	9301012	Public Opinion Surveys	8,226	8,226	-	
29	9301013	Movies Slide Films & Speeches	-	-	-	
30	9301014	Video Communications	58	58	-	
31	9301015	Other Corporate Comm Exp	71,640	71,640	-	
32		**Total**	276,916	276,916	-	
		Account 930.2				
33	9302000	Misc General Expenses	3,456,214	3,456,214		
34	9302003	Corporate & Fiscal Expenses	202,905	202,905		
35	9302004	Research, Develop&Demonstr Exp	6,800	6,800		
36	9302005	Nucl Fac Ins - Replce Engy Cst	930,795	930,795		
37	9302006	Assoc Business Development Materials Sold	26,708	26,708	0	
38	9302007	Assoc Business Development Exp	695,129	510,840	184,289	
39	9302458	AEPSC nonaffiliated expense	228	228		
40		**Total**	5,318,779	5,134,490	184,289	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
INDIANA MICHIGAN POWER COMPANY

Indiana Corporate Income Tax Rate	8.25%	
Apportionment Factor - Note 2	54.70%	
Effective State Tax Rate		4.51%
Michigan Single Business Tax Rate	6.00%	
Apportionment Factor - Note 2	13.30%	
Effective State Tax Rate		0.80%
West Virginia Corporation Income Tax Rate	7.75%	
Apportionment Factor - Note 2	3.27%	
Effective State Tax Rate		0.25%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - Note 2	1.83%	
Effective State Tax Rate		0.11%
Missouri Corporation Income Tax Rate	6.25%	
Apportionment Factor - Note 2	0.02%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.90%	
Effective State Tax Rate		0.18%
Total Effective State Income Tax Rate		5.85%

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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company NOTE 1	Property	Labor	Other	Non-Allocable
1	Revenue Taxes					
2	Gross Receipts Tax	12,786,739				12,786,739
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Michigan	29,333,515	29,333,515			
5	Real and Personal Property - Indiana	17,019,510	17,019,510			
6	Real and Personal Property - Other Jurisdictions	32,948	32,948			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	11,774,150		11,774,150		
9	Federal Unemployment Tax	52,982		52,982		
10	State Unemployment Insurance	572,010		572,010		
11	Production Taxes					
12	State Severance Taxes	14,448				14,448
13	Miscellaneous Taxes					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	1,610,995			1,610,995	
16	State Franchise Taxes	16,696			16,696	
17	State Lic/Registration Fee	1,140			1,140	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	130,278				130,278
20	Federal Excise Tax	4,990				4,990
21	Michigan Single Business Tax	(85,957)				(85,957)
22	Total Taxes by Allocable Basis	73,264,444	46,385,973	12,399,142	1,628,831	12,850,498
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
	NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.					

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,500,645,710	740,839,143	1,073,819,983	80,475,545	3,395,780,381
	MICHIGAN JURISDICTION					
24	Percentage of Plant in MICHIGAN JURISDICTION	64.23%	15.87%	19.63%	15.85%	
25	Net Plant in MICHIGAN JURISDICTION (Ln 23 * Ln 24)	963,906,886	117,557,033	210,764,884	12,758,460	1,304,987,263
26	Less: Net Value of Exempted Generation Plant	272,029,809				
27	Taxable Property Basis (Ln 25 - Ln 26)	691,877,077	117,557,033	210,764,884	12,758,460	1,032,957,454
28	Relative Valuation Factor	100%	100%	100%	100%	
29	Weighted Net Plant (Ln 27 * Ln 28)	691,877,077	117,557,033	210,764,884	12,758,460	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	67.82%	11.52%	20.66%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	8,652,514	1,470,151	2,635,795	(12,758,460)	-
32	Weighted MICHIGAN JURISDICTION Plant (Ln 29 + 31)	700,529,591	119,027,185	213,400,679	(0)	1,032,957,454
33	Functional Percentage (Ln 32/Total Ln 32)	67.82%	11.52%	20.66%		
34	Functionalized Expense in MICHIGAN JURISDICTION	19,893,361	3,380,087	6,060,068		29,333,515
	INDIANA JURISDICTION					
35	Percentage of Plant in INDIANA JURISDICTION	35.77%	84.13%	80.37%	84.15%	
36	Net Plant in INDIANA JURISDICTION (Ln 23 * Ln 35)	536,738,824	623,282,110	863,055,099	67,717,085	2,090,793,118
37	Less: Net Value of Exempted Generation Plant	124,507,515				
38	Taxable Property Basis (Ln 36 - Ln 37)	412,231,309	623,282,110	863,055,099	67,717,085	1,966,285,603
39	Relative Valuation Factor	100%	100%	100%	100%	
40	Weighted Net Plant (Ln 38 * Ln 39)	412,231,309	623,282,110	863,055,099	67,717,085	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	21.71%	32.83%	45.46%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	14,703,237	22,230,879	30,782,969	(67,717,085)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	426,934,546	645,512,989	893,838,068	0	1,966,285,603
44	Functional Percentage (Ln 43/Total Ln 43)	21.71%	32.83%	45.46%		
45	Functionalized Expense in INDIANA JURISDICTION	3,695,403	5,587,344	7,736,763		17,019,510
46	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		6,683			32,948
47	Total Func. Property Taxes (Sum Lns 34, 45 46)	23,588,763	8,974,114	13,796,831		46,385,973

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
INDIANA MICHIGAN 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	12,786,739		
			(2,320)	P.263 ln 13 (i)
			15,007,000	P.263 ln 14 (i)
			(2,800,000)	P.263 ln 15 (i)
			102,464	P.263.2 ln 15 (i)
			479,595	P.263.2 ln 16 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Michigan	29,333,515		
			(62,706)	P.263.1 ln 14 (i)
			29,185,900	P.263.1 ln 15 (i)
			(8,777)	P.263.1 ln 17 (i)
			15,078	P.263.1 ln 18 (i)
			(3,980)	P.263.1 ln 20 (i)
			208,000	P.263.1 ln 21 (i)
5	Real and Personal Property - Indiana	17,019,510		
			1,366	P.263 ln 22 (i)
			4,220	P.263 ln 23 (i)
			(221,902)	P.263 ln 24 (i)
			1,582,284	P.263 ln 25 (i)
			15,412,673	P.263 ln 26 (i)
			(4,129)	P.263 ln 27 (i)
			244,998	P.263 ln 28 (i)
6	Real and Personal Property - Other Jurisdictions	32,948		
			26,140	P.263 ln 38 (i)
			3,415	P.263.2 ln 1 (i)
			3,393	P.263.2 ln 2 (i)
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	11,774,150		
			11,774,150	P.263 ln 3 (i)
9	Federal Unemployment Tax	52,982		
			52,982	P.263 ln 4 (i)
10	State Unemployment Insurance	572,010		
			197,606	P.263 ln 12 (i)
			383,230	P.263.1 ln 7 (i)
			(8,826)	P.263.2 ln 9 (i)
11	Production Taxes			
12	State Severance Taxes	14,448		
13	Misc States - 2010		1,638	P.263.2 ln 32 (i)
14	Misc States 2012		12,810	P.263.2 ln 33 (i)
15	Miscellaneous Taxes			
16	State Business & Occupation Tax	-		
			-	
17	State Public Service Commission Fees	1,610,995		
			625,647	P.263 ln 20 (i)
			635,491	P.263 ln 21 (i)
			205,324	P.263.1 ln 8 (i)
			144,533	P.263.1 ln 9 (i)
18	State Franchise Taxes	16,696		
			(80,106)	P.263.1 ln 39(i)
			96,802	P.263.1 ln 40 (i)
			-	
19	State Lic/Registration Fee	1,140		
			1,000	P.263.1 ln 24 (i)
			25	P.263.1 ln 35 (i)
			100	P.263.3 ln 13 (i)
			15	P.263.3 ln 14 (i)
			-	
20	Misc. State and Local Tax	-		
			-	
21	Sales & Use	130,278		
			15,783	P.263.1 ln 10 (i)
			114,495	P.263.1 ln 11 (i)
22	Federal Excise Tax	4,990		
			4,990	P.263 ln 6 (i)
23	Michigan Single Business Tax	(85,957)		
			(85,957)	P.263.1 ln 5 (i)
24	Total Taxes by Allocable Basis	73,264,444	73,264,444	
	(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 2012 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
INDIANA MICHIGAN POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,224,587,801
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	1,278,027,455
3		2,502,615,256
4	Average Balance of Transmission Investment	1,251,307,628
5	Annual Depreciation Expense, Historic TCOS, ln 276	18,714,918
6	Composite Depreciation Rate	1.50%
7	Round to 1.5% to Reflect a Composite Life of 67 Years	1.50%

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	$ 25,112,081	1.50%	$ 376,681	$ 31,390	11	$ 345,290
10	February	$ 2,916,885	1.50%	$ 43,753	$ 3,646	10	$ 36,460
11	March	$ 2,032,083	1.50%	$ 30,481	$ 2,540	9	$ 22,860
12	April	$ 2,239,773	1.50%	$ 33,597	$ 2,800	8	$ 22,400
13	May	$ 2,535,031	1.50%	$ 38,025	$ 3,169	7	$ 22,183
14	June	$ 2,237,822	1.50%	$ 33,567	$ 2,797	6	$ 16,782
15	July	$ 6,984,144	1.50%	$ 104,762	$ 8,730	5	$ 43,650
16	August	$ 2,964,338	1.50%	$ 44,465	$ 3,705	4	$ 14,820
17	September	$ 1,945,996	1.50%	$ 29,190	$ 2,432	3	$ 7,296
18	October	$ 4,187,006	1.50%	$ 62,805	$ 5,234	2	$ 10,468
19	November	$ 1,545,395	1.50%	$ 23,181	$ 1,932	1	$ 1,932
20	December	$ 2,154,053	1.50%	$ 32,311	$ 2,693	0	$ -
21	Investment	$ 56,854,607				Depreciation Expense	$ 544,141

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 2013

			Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**			
26	TIMBall State University		$4,376	Jul-13
27		Subtotal	4,376	
28	**PJM Socialized/Beneficiary Allocated Regional Projects**			
29			$0	
30		Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN 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	46.18%	5.85%	2.702%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	53.82%	11.49%	6.184%
		R =	8.886%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	2,666,168	2,666,168	$ -

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

Rate Base (Projected TCOS, ln 78)	590,307,606
R (from A. above)	8.886%
Return (Rate Base x R)	52,453,806

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

Return (from B. above)	52,453,806
Effective Tax Rate (Projected TCOS, ln 126)	44.13%
Income Tax Calculation (Return x CIT)	23,146,704
ITC Adjustment	(1,492,328)
Income Taxes	21,654,375

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)	125,959,874
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	52,453,806
Income Taxes (Projected TCOS, ln 133)	21,654,375
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,851,692

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,851,692
Return (from I.B. above)	52,453,806
Income Taxes (from I.C. above)	21,654,375
Annual Revenue Requirement, with Basis Point ROE increase	125,959,874
Depreciation (Projected TCOS, ln 111)	18,143,726
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	107,816,148

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	686,558,358
Annual Revenue Requirement, with Basis Point ROE increase	125,959,874
FCR with Basis Point increase in ROE	18.35%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	107,816,148
FCR with Basis Point ROE increase, less Depreciation	15.70%
FCR less Depreciation (Projected TCOS, ln 9)	14.80%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.90%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,224,587,801
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	1,278,027,455
Subtotal	2,502,615,256
Average Transmission Plant Balance for 2012	1,251,307,628
Annual Depreciation Rate (Projected TCOS, ln 111)	18,714,918
Composite Depreciation Rate	1.50%
Depreciable Life for Composite Depreciation Rate	66.86
Round to nearest whole year	67

I & M 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:

RTEP ID: b0839 (Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer)

Current Projected Year ARR	**1,272,484**
Current Projected Year ARR w/ Incentive	**1,272,484**
Current Projected Year Incentive ARR	**-**

Details			
Investment	8,316,811	Current Year	2013
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	14.80%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	14.80%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,132

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2009	8,316,811	62,066	8,254,745	1,283,913	1,283,913	$ -					
2010	8,254,745	124,132	8,130,614	1,327,605	1,327,605	$ -	$ 1,408,114		$ 1,408,114		
2011	8,130,614	124,132	8,006,482	1,309,231	1,309,231	$ -	$ 1,487,355		$ 1,487,355		
2012	8,006,482	124,132	7,882,351	1,290,857	1,290,857	$ -	$ 1,319,695		$ 1,319,695		
2013	7,882,351	124,132	7,758,219	1,272,484	1,272,484	$ -					
2014	7,758,219	124,132	7,634,088	1,254,110	1,254,110	$ -					
2015	7,634,088	124,132	7,509,956	1,235,737	1,235,737	$ -					
2016	7,509,956	124,132	7,385,825	1,217,363	1,217,363	$ -					
2017	7,385,825	124,132	7,261,693	1,198,989	1,198,989	$ -					
2018	7,261,693	124,132	7,137,562	1,180,616	1,180,616	$ -					
2019	7,137,562	124,132	7,013,430	1,162,242	1,162,242	$ -					
2020	7,013,430	124,132	6,889,299	1,143,868	1,143,868	$ -					
2021	6,889,299	124,132	6,765,167	1,125,495	1,125,495	$ -					
2022	6,765,167	124,132	6,641,036	1,107,121	1,107,121	$ -					
2023	6,641,036	124,132	6,516,904	1,088,747	1,088,747	$ -					
2024	6,516,904	124,132	6,392,773	1,070,374	1,070,374	$ -					
2025	6,392,773	124,132	6,268,641	1,052,000	1,052,000	$ -					
2026	6,268,641	124,132	6,144,510	1,033,627	1,033,627	$ -					
2027	6,144,510	124,132	6,020,378	1,015,253	1,015,253	$ -					
2028	6,020,378	124,132	5,896,247	996,879	996,879	$ -					
2029	5,896,247	124,132	5,772,115	978,506	978,506	$ -					
2030	5,772,115	124,132	5,647,984	960,132	960,132	$ -					
2031	5,647,984	124,132	5,523,852	941,758	941,758	$ -					
2032	5,523,852	124,132	5,399,721	923,385	923,385	$ -					
2033	5,399,721	124,132	5,275,589	905,011	905,011	$ -					
2034	5,275,589	124,132	5,151,458	886,637	886,637	$ -					
2035	5,151,458	124,132	5,027,326	868,264	868,264	$ -					
2036	5,027,326	124,132	4,903,195	849,890	849,890	$ -					
2037	4,903,195	124,132	4,779,063	831,517	831,517	$ -					
2038	4,779,063	124,132	4,654,932	813,143	813,143	$ -					
2039	4,654,932	124,132	4,530,800	794,769	794,769	$ -					
2040	4,530,800	124,132	4,406,669	776,396	776,396	$ -					
2041	4,406,669	124,132	4,282,537	758,022	758,022	$ -					
2042	4,282,537	124,132	4,158,405	739,648	739,648	$ -					
2043	4,158,405	124,132	4,034,274	721,275	721,275	$ -					
2044	4,034,274	124,132	3,910,142	702,901	702,901	$ -					
2045	3,910,142	124,132	3,786,011	684,527	684,527	$ -					
2046	3,786,011	124,132	3,661,879	666,154	666,154	$ -					
2047	3,661,879	124,132	3,537,748	647,780	647,780	$ -					
2048	3,537,748	124,132	3,413,616	629,407	629,407	$ -					
2049	3,413,616	124,132	3,289,485	611,033	611,033	$ -					
2050	3,289,485	124,132	3,165,353	592,659	592,659	$ -					
2051	3,165,353	124,132	3,041,222	574,286	574,286	$ -					
2052	3,041,222	124,132	2,917,090	555,912	555,912	$ -					
2053	2,917,090	124,132	2,792,959	537,538	537,538	$ -					
2054	2,792,959	124,132	2,668,827	519,165	519,165	$ -					
2055	2,668,827	124,132	2,544,696	500,791	500,791	$ -					
2056	2,544,696	124,132	2,420,564	482,417	482,417	$ -					
2057	2,420,564	124,132	2,296,433	464,044	464,044	$ -					
2058	2,296,433	124,132	2,172,301	445,670	445,670	$ -					
2059	2,172,301	124,132	2,048,170	427,297	427,297	$ -					
2060	2,048,170	124,132	1,924,038	408,923	408,923	$ -					
2061	1,924,038	124,132	1,799,907	390,549	390,549	$ -					
2062	1,799,907	124,132	1,675,775	372,176	372,176	$ -					
2063	1,675,775	124,132	1,551,644	353,802	353,802	$ -					
2064	1,551,644	124,132	1,427,512	335,428	335,428	$ -					
2065	1,427,512	124,132	1,303,381	317,055	317,055	$ -					
2066	1,303,381	124,132	1,179,249	298,681	298,681	$ -					
2067	1,179,249	124,132	1,055,118	280,307	280,307	$ -					
2068	1,055,118	124,132	930,986	261,934	261,934	$ -					
Project Totals		7,385,825		48,175,299	48,175,299	-					

** 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.

I & M 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: **RTEP ID: b1465.2 (Replace the 100 MVAR 765 kV shunt reactor bank on Rockport - Jefferson 765 kV line with a 300 MVAR bank at Rockport Station)**

Current Projected Year ARR	**92,625**
Current Projected Year ARR w/ Incentive	**92,625**
Current Projected Year Incentive ARR	**-**

Details			
Investment	600,000	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	14.80%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	14.80%
CIAC (Yes or No)	No	Annual Depreciation Expense	8,955

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	600,000	4,478	595,522	92,625	92,625	$ -
2014	595,522	8,955	586,567	95,777	95,777	$ -
2015	586,567	8,955	577,612	94,452	94,452	$ -
2016	577,612	8,955	568,657	93,126	93,126	$ -
2017	568,657	8,955	559,701	91,801	91,801	$ -
2018	559,701	8,955	550,746	90,475	90,475	$ -
2019	550,746	8,955	541,791	89,150	89,150	$ -
2020	541,791	8,955	532,836	87,824	87,824	$ -
2021	532,836	8,955	523,881	86,499	86,499	$ -
2022	523,881	8,955	514,925	85,173	85,173	$ -
2023	514,925	8,955	505,970	83,848	83,848	$ -
2024	505,970	8,955	497,015	82,522	82,522	$ -
2025	497,015	8,955	488,060	81,197	81,197	$ -
2026	488,060	8,955	479,104	79,871	79,871	$ -
2027	479,104	8,955	470,149	78,546	78,546	$ -
2028	470,149	8,955	461,194	77,220	77,220	$ -
2029	461,194	8,955	452,239	75,894	75,894	$ -
2030	452,239	8,955	443,284	74,569	74,569	$ -
2031	443,284	8,955	434,328	73,243	73,243	$ -
2032	434,328	8,955	425,373	71,918	71,918	$ -
2033	425,373	8,955	416,418	70,592	70,592	$ -
2034	416,418	8,955	407,463	69,267	69,267	$ -
2035	407,463	8,955	398,507	67,941	67,941	$ -
2036	398,507	8,955	389,552	66,616	66,616	$ -
2037	389,552	8,955	380,597	65,290	65,290	$ -
2038	380,597	8,955	371,642	63,965	63,965	$ -
2039	371,642	8,955	362,687	62,639	62,639	$ -
2040	362,687	8,955	353,731	61,314	61,314	$ -
2041	353,731	8,955	344,776	59,988	59,988	$ -
2042	344,776	8,955	335,821	58,663	58,663	$ -
2043	335,821	8,955	326,866	57,337	57,337	$ -
2044	326,866	8,955	317,910	56,012	56,012	$ -
2045	317,910	8,955	308,955	54,686	54,686	$ -
2046	308,955	8,955	300,000	53,360	53,360	$ -
2047	300,000	8,955	291,045	52,035	52,035	$ -
2048	291,045	8,955	282,090	50,709	50,709	$ -
2049	282,090	8,955	273,134	49,384	49,384	$ -
2050	273,134	8,955	264,179	48,058	48,058	$ -
2051	264,179	8,955	255,224	46,733	46,733	$ -
2052	255,224	8,955	246,269	45,407	45,407	$ -
2053	246,269	8,955	237,313	44,082	44,082	$ -
2054	237,313	8,955	228,358	42,756	42,756	$ -
2055	228,358	8,955	219,403	41,431	41,431	$ -
2056	219,403	8,955	210,448	40,105	40,105	$ -
2057	210,448	8,955	201,493	38,780	38,780	$ -
2058	201,493	8,955	192,537	37,454	37,454	$ -
2059	192,537	8,955	183,582	36,129	36,129	$ -
2060	183,582	8,955	174,627	34,803	34,803	$ -
2061	174,627	8,955	165,672	33,478	33,478	$ -
2062	165,672	8,955	156,716	32,152	32,152	$ -
2063	156,716	8,955	147,761	30,826	30,826	$ -
2064	147,761	8,955	138,806	29,501	29,501	$ -
2065	138,806	8,955	129,851	28,175	28,175	$ -
2066	129,851	8,955	120,896	26,850	26,850	$ -
2067	120,896	8,955	111,940	25,524	25,524	$ -
2068	111,940	8,955	102,985	24,199	24,199	$ -
2069	102,985	8,955	94,030	22,873	22,873	$ -
2070	94,030	8,955	85,075	21,548	21,548	$ -
2071	85,075	8,955	76,119	20,222	20,222	$ -
2072	76,119	8,955	67,164	18,897	18,897	$ -
Project Totals		532,836		3,475,512	3,475,512	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	$ 92,584		$ 92,584		

** 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.

I & M 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:

RTEP ID: b1465.3 (Transpose the Rockport - Sullivan 765 kV line and the Rockport - Jefferson 765 kV line)

Current Projected Year ARR	**1,301,059**
Current Projected Year ARR w/ Incentive	**1,301,059**
Current Projected Year Incentive ARR	**-**

Details			
Investment	8,370,424	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	5	FCR w/o incentives, less depreciation	14.80%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	14.80%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,932

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	8,370,424	72,877	8,297,547	1,301,059	1,301,059	$ -
2014	8,297,547	8,955	8,288,592	1,235,812	1,235,812	$ -
2015	8,288,592	8,955	8,279,637	1,234,486	1,234,486	$ -
2016	8,279,637	8,955	8,270,682	1,233,161	1,233,161	$ -
2017	8,270,682	8,955	8,261,726	1,231,835	1,231,835	$ -
2018	8,261,726	8,955	8,252,771	1,230,510	1,230,510	$ -
2019	8,252,771	8,955	8,243,816	1,229,184	1,229,184	$ -
2020	8,243,816	8,955	8,234,861	1,227,859	1,227,859	$ -
2021	8,234,861	8,955	8,225,905	1,226,533	1,226,533	$ -
2022	8,225,905	8,955	8,216,950	1,225,208	1,225,208	$ -
2023	8,216,950	8,955	8,207,995	1,223,882	1,223,882	$ -
2024	8,207,995	8,955	8,199,040	1,222,557	1,222,557	$ -
2025	8,199,040	8,955	8,190,084	1,221,231	1,221,231	$ -
2026	8,190,084	8,955	8,181,129	1,219,906	1,219,906	$ -
2027	8,181,129	8,955	8,172,174	1,218,580	1,218,580	$ -
2028	8,172,174	8,955	8,163,219	1,217,255	1,217,255	$ -
2029	8,163,219	8,955	8,154,264	1,215,929	1,215,929	$ -
2030	8,154,264	8,955	8,145,308	1,214,604	1,214,604	$ -
2031	8,145,308	8,955	8,136,353	1,213,278	1,213,278	$ -
2032	8,136,353	8,955	8,127,398	1,211,952	1,211,952	$ -
2033	8,127,398	8,955	8,118,443	1,210,627	1,210,627	$ -
2034	8,118,443	8,955	8,109,487	1,209,301	1,209,301	$ -
2035	8,109,487	8,955	8,100,532	1,207,976	1,207,976	$ -
2036	8,100,532	8,955	8,091,577	1,206,650	1,206,650	$ -
2037	8,091,577	8,955	8,082,622	1,205,325	1,205,325	$ -
2038	8,082,622	8,955	8,073,667	1,203,999	1,203,999	$ -
2039	8,073,667	8,955	8,064,711	1,202,674	1,202,674	$ -
2040	8,064,711	8,955	8,055,756	1,201,348	1,201,348	$ -
2041	8,055,756	8,955	8,046,801	1,200,023	1,200,023	$ -
2042	8,046,801	8,955	8,037,846	1,198,697	1,198,697	$ -
2043	8,037,846	8,955	8,028,890	1,197,372	1,197,372	$ -
2044	8,028,890	8,955	8,019,935	1,196,046	1,196,046	$ -
2045	8,019,935	8,955	8,010,980	1,194,721	1,194,721	$ -
2046	8,010,980	8,955	8,002,025	1,193,395	1,193,395	$ -
2047	8,002,025	8,955	7,993,070	1,192,070	1,192,070	$ -
2048	7,993,070	8,955	7,984,114	1,190,744	1,190,744	$ -
2049	7,984,114	8,955	7,975,159	1,189,418	1,189,418	$ -
2050	7,975,159	8,955	7,966,204	1,188,093	1,188,093	$ -
2051	7,966,204	8,955	7,957,249	1,186,767	1,186,767	$ -
2052	7,957,249	8,955	7,948,293	1,185,442	1,185,442	$ -
2053	7,948,293	8,955	7,939,338	1,184,116	1,184,116	$ -
2054	7,939,338	8,955	7,930,383	1,182,791	1,182,791	$ -
2055	7,930,383	8,955	7,921,428	1,181,465	1,181,465	$ -
2056	7,921,428	8,955	7,912,473	1,180,140	1,180,140	$ -
2057	7,912,473	8,955	7,903,517	1,178,814	1,178,814	$ -
2058	7,903,517	8,955	7,894,562	1,177,489	1,177,489	$ -
2059	7,894,562	8,955	7,885,607	1,176,163	1,176,163	$ -
2060	7,885,607	8,955	7,876,652	1,174,838	1,174,838	$ -
2061	7,876,652	8,955	7,867,696	1,173,512	1,173,512	$ -
2062	7,867,696	8,955	7,858,741	1,172,187	1,172,187	$ -
2063	7,858,741	8,955	7,849,786	1,170,861	1,170,861	$ -
2064	7,849,786	8,955	7,840,831	1,169,535	1,169,535	$ -
2065	7,840,831	8,955	7,831,876	1,168,210	1,168,210	$ -
2066	7,831,876	8,955	7,822,920	1,166,884	1,166,884	$ -
2067	7,822,920	8,955	7,813,965	1,165,559	1,165,559	$ -
2068	7,813,965	8,955	7,805,010	1,164,233	1,164,233	$ -
2069	7,805,010	8,955	7,796,055	1,162,908	1,162,908	$ -
2070	7,796,055	8,955	7,787,099	1,161,582	1,161,582	$ -
2071	7,787,099	8,955	7,778,144	1,160,257	1,160,257	$ -
2072	7,778,144	8,955	7,769,189	1,158,931	1,158,931	$ -
Project Totals		601,235		71,945,985	71,945,985	-

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 2012 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN POWER COMPANY

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2012			
As Projected in Prior Year WS J	$ 1,412,279	$ 1,412,279	$ -
Actual after True-up	$ 1,323,753	$ 1,323,753	$ -
True-up of ARR For 2012	(88,526)	(88,526)	-

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	46.40%	6.03%		2.799%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	53.60%	11.49%		6.159%
			R =	8.957%

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

Rate Base (True-Up TCOS, ln 78)	549,269,073
R (from A. above)	8.957%
Return (Rate Base x R)	49,200,294

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

Return (from B. above)	49,200,294
Effective Tax Rate (True-Up TCOS, ln 126)	43.60%
Income Tax Calculation (Return x CIT)	21,449,328
ITC Adjustment	(1,493,054)
Income Taxes	19,956,274

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)	120,680,556
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	49,200,294
Income Taxes (True-Up TCOS, ln 133)	19,956,274
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,523,987

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,523,987
Return (from I.B. above)	49,200,294
Income Taxes (from I.C. above)	19,956,274
Annual Revenue Requirement, with 0 Basis Point ROE increase	120,680,556
Depreciation (True-Up TCOS, ln 111)	18,090,421
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	102,590,135

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

Net Transmission Plant (True-Up TCOS, ln 48)	679,396,414
Annual Revenue Requirement, with 0 Basis Point ROE increase	120,680,556
FCR with 0 Basis Point increase in ROE	17.76%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	102,590,135
FCR with 0 Basis Point ROE increase, less Depreciation	15.10%
FCR less Depreciation (True-Up TCOS, ln 9)	15.10%
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)):	1,224,587,801
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	1,278,027,455
Subtotal	2,502,615,256
Average Transmission Plant Balance for	1,251,307,628
Annual Depreciation Rate (True-Up TCOS, ln 111)	18,714,918
Composite Depreciation Rate	1.50%
Depreciable Life for Composite Depreciation Rate	66.86
Round to nearest whole year	67

I & M 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)

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	1,319,695	1,319,695	-
Prior Yr True-Up	1,323,753	1,323,753	-
True-Up Adjustment	4,058	4,058	-

Project Description:

RTEP ID: b0839 (Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer)

Details			
Investment	8,316,811	Current Year	2012
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.10%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	15.10%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,132

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 **
2009	8,316,811	62,066	8,254,745	8,285,778	1,313,234	1,313,234	$ -	$ -	$ -	$ -	$ -	$ -
2010	8,254,745	124,132	8,130,614	8,192,679	1,361,242	1,361,242	$ -	$ 1,408,114	$ (46,873)	$ 1,408,114	$ (46,873)	$ -
2011	8,130,614	124,132	8,006,482	8,068,548	1,342,497	1,342,497	$ -	$ 1,487,355	$ (144,858)	$ 1,487,355	$ (144,858)	$ -
2012	8,006,482	124,132	7,882,351	7,944,416	1,323,753	1,323,753	$ -	$ 1,319,695	$ 4,058	$ 1,319,695	$ 4,058	$ -
2013	7,882,351	124,132	7,758,219	7,820,285	1,305,009	1,305,009	$ -		$ -		$ -	$ -
2014	7,758,219	124,132	7,634,088	7,696,153	1,286,265	1,286,265	$ -		$ -		$ -	$ -
2015	7,634,088	124,132	7,509,956	7,572,022	1,267,521	1,267,521	$ -		$ -		$ -	$ -
2016	7,509,956	124,132	7,385,825	7,447,890	1,248,777	1,248,777	$ -		$ -		$ -	$ -
2017	7,385,825	124,132	7,261,693	7,323,759	1,230,033	1,230,033	$ -		$ -		$ -	$ -
2018	7,261,693	124,132	7,137,562	7,199,627	1,211,289	1,211,289	$ -		$ -		$ -	$ -
2019	7,137,562	124,132	7,013,430	7,075,496	1,192,545	1,192,545	$ -		$ -		$ -	$ -
2020	7,013,430	124,132	6,889,299	6,951,364	1,173,801	1,173,801	$ -		$ -		$ -	$ -
2021	6,889,299	124,132	6,765,167	6,827,233	1,155,057	1,155,057	$ -		$ -		$ -	$ -
2022	6,765,167	124,132	6,641,036	6,703,101	1,136,312	1,136,312	$ -		$ -		$ -	$ -
2023	6,641,036	124,132	6,516,904	6,578,970	1,117,568	1,117,568	$ -		$ -		$ -	$ -
2024	6,516,904	124,132	6,392,773	6,454,838	1,098,824	1,098,824	$ -		$ -		$ -	$ -
2025	6,392,773	124,132	6,268,641	6,330,707	1,080,080	1,080,080	$ -		$ -		$ -	$ -
2026	6,268,641	124,132	6,144,510	6,206,575	1,061,336	1,061,336	$ -		$ -		$ -	$ -
2027	6,144,510	124,132	6,020,378	6,082,444	1,042,592	1,042,592	$ -		$ -		$ -	$ -
2028	6,020,378	124,132	5,896,247	5,958,312	1,023,848	1,023,848	$ -		$ -		$ -	$ -
2029	5,896,247	124,132	5,772,115	5,834,181	1,005,104	1,005,104	$ -		$ -		$ -	$ -
2030	5,772,115	124,132	5,647,984	5,710,049	986,360	986,360	$ -		$ -		$ -	$ -
2031	5,647,984	124,132	5,523,852	5,585,918	967,616	967,616	$ -		$ -		$ -	$ -
2032	5,523,852	124,132	5,399,721	5,461,786	948,872	948,872	$ -		$ -		$ -	$ -
2033	5,399,721	124,132	5,275,589	5,337,655	930,127	930,127	$ -		$ -		$ -	$ -
2034	5,275,589	124,132	5,151,458	5,213,523	911,383	911,383	$ -		$ -		$ -	$ -
2035	5,151,458	124,132	5,027,326	5,089,392	892,639	892,639	$ -		$ -		$ -	$ -
2036	5,027,326	124,132	4,903,195	4,965,260	873,895	873,895	$ -		$ -		$ -	$ -
2037	4,903,195	124,132	4,779,063	4,841,129	855,151	855,151	$ -		$ -		$ -	$ -
2038	4,779,063	124,132	4,654,932	4,716,997	836,407	836,407	$ -		$ -		$ -	$ -
2039	4,654,932	124,132	4,530,800	4,592,866	817,663	817,663	$ -		$ -		$ -	$ -
2040	4,530,800	124,132	4,406,669	4,468,734	798,919	798,919	$ -		$ -		$ -	$ -
2041	4,406,669	124,132	4,282,537	4,344,603	780,175	780,175	$ -		$ -		$ -	$ -
2042	4,282,537	124,132	4,158,405	4,220,471	761,431	761,431	$ -		$ -		$ -	$ -
2043	4,158,405	124,132	4,034,274	4,096,340	742,687	742,687	$ -		$ -		$ -	$ -
2044	4,034,274	124,132	3,910,142	3,972,208	723,942	723,942	$ -		$ -		$ -	$ -
2045	3,910,142	124,132	3,786,011	3,848,077	705,198	705,198	$ -		$ -		$ -	$ -
2046	3,786,011	124,132	3,661,879	3,723,945	686,454	686,454	$ -		$ -		$ -	$ -
2047	3,661,879	124,132	3,537,748	3,599,814	667,710	667,710	$ -		$ -		$ -	$ -
2048	3,537,748	124,132	3,413,616	3,475,682	648,966	648,966	$ -		$ -		$ -	$ -
2049	3,413,616	124,132	3,289,485	3,351,551	630,222	630,222	$ -		$ -		$ -	$ -
2050	3,289,485	124,132	3,165,353	3,227,419	611,478	611,478	$ -		$ -		$ -	$ -
2051	3,165,353	124,132	3,041,222	3,103,288	592,734	592,734	$ -		$ -		$ -	$ -
2052	3,041,222	124,132	2,917,090	2,979,156	573,990	573,990	$ -		$ -		$ -	$ -
2053	2,917,090	124,132	2,792,959	2,855,025	555,246	555,246	$ -		$ -		$ -	$ -
2054	2,792,959	124,132	2,668,827	2,730,893	536,502	536,502	$ -		$ -		$ -	$ -
2055	2,668,827	124,132	2,544,696	2,606,762	517,757	517,757	$ -		$ -		$ -	$ -
2056	2,544,696	124,132	2,420,564	2,482,630	499,013	499,013	$ -		$ -		$ -	$ -
2057	2,420,564	124,132	2,296,433	2,358,499	480,269	480,269	$ -		$ -		$ -	$ -
2058	2,296,433	124,132	2,172,301	2,234,367	461,525	461,525	$ -		$ -		$ -	$ -
2059	2,172,301	124,132	2,048,170	2,110,236	442,781	442,781	$ -		$ -		$ -	$ -
2060	2,048,170	124,132	1,924,038	1,986,104	424,037	424,037	$ -		$ -		$ -	$ -
2061	1,924,038	124,132	1,799,907	1,861,973	405,293	405,293	$ -		$ -		$ -	$ -
2062	1,799,907	124,132	1,675,775	1,737,841	386,549	386,549	$ -		$ -		$ -	$ -
2063	1,675,775	124,132	1,551,644	1,613,710	367,805	367,805	$ -		$ -		$ -	$ -
2064	1,551,644	124,132	1,427,512	1,489,578	349,061	349,061	$ -		$ -		$ -	$ -
2065	1,427,512	124,132	1,303,381	1,365,447	330,317	330,317	$ -		$ -		$ -	$ -
2066	1,303,381	124,132	1,179,249	1,241,315	311,572	311,572	$ -		$ -		$ -	$ -
2067	1,179,249	124,132	1,055,118	1,117,184	292,828	292,828	$ -		$ -		$ -	$ -
2068	1,055,118	124,132	930,986	993,052	274,084	274,084	$ -		$ -		$ -	$ -
Project Totals		7,385,825			49,555,343	49,555,343	-					

** 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.

I & M 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: **RTEP ID: b1465.2 (Replace the 100 MVAR 765 kV shunt reactor bank on Rockport - Jefferson 765 kV line with a 300 MVAR bank at Rockport Station)**

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	92,584	92,584	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	(92,584)	(92,584)	-

Details			
Investment	-	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.10%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	15.10%
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 **
2013	-	-	-	-	-	-	$ -	$ 92,584	$ (92,584)	$ 92,584	$ (92,584)	$ -
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

I & M 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:

RTEP ID: b1465.3 (Transpose the Rockport - Sullivan 765 kV line and the Rockport - Jefferson 765 kV line)

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	5	FCR w/o incentives, less depreciation	15.10%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	15.10%
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 **
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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 2012 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
INDIANA MICHIGAN 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 Co.		-	5.375%	-	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	PCRB Lawrenceburg In. - Series I		25,000,000	0.110%	27,500	
6	PCRB Lawrenceburg In. - Series H		52,000,000	0.130%	67,600	
7	PCRB - Rockport In. - Series D		40,000,000	5.250%	2,100,000	
8	PCRB - Rockport In. - 2002 Series A		50,000,000	4.625%	2,312,500	
9	PCRB - Rockport In. - 2009 Series A		50,000,000	6.250%	3,125,000	
10	PCRB - Rockport In. - 2009 Series B		50,000,000	6.250%	3,125,000	
11	Senior Unsecured Notes - Series F		175,000,000	5.050%	8,837,500	
12	Senior Unsecured Notes - Series G		125,000,000	5.650%	7,062,500	
13	Senior Unsecured Notes - Series H		400,000,000	6.050%	24,200,000	
14	Senior Unsecured Notes - Series I		475,000,000	7.000%	33,250,000	
15	Fort Wayne Settlement		20,429,608	6.000%	1,225,776	
16	Multiple Draw Term Loan		110,000,000	1.720%	1,892,000	
17						
18	Issuance Discount, Premium, & Expenses:					
19	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
20	Allowable Hedge Amortization (See Ln 36 Below)				916,010	
21	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			2,372,191	
22	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
23	Reacquired Debt:					
24	Amortization of Loss	FF1.p. 117.64.c			1,483,709	
25	Amortization of Gain	FF1.p. 117.66.c			(1,712)	
26	**Total Interest on Long Term Debt**		1,572,429,608	5.85%	91,995,574	
27	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
28	4.125% Series - $100 - 55,257 Shares O/S		-	4.13%	-	
29	4.56% Series - $100 - 14,412 Shares O/S		-	4.56%	-	
30	4.12% Series - $100 - 11,055 Shares O/S		-	4.12%	-	
31	**Dividends on Preferred Stock**		-	0.00%	-	
32	Net Total Hedge Gains and Losses (WS M, Ln 34, (E))				916,010	
33	Total Projected Capital Structure Balance for 2013 (Projected TCOS, Ln 165)				3,405,193,446	
34	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
35	Limit of Recoverable Amount				1,702,597	
36	**Recoverable Hedge Amortization (Lesser of Ln 32 or Ln 35)**				**916,010**	

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	1,803,774,755	1,760,980,133	1,782,377,444
2	Less Preferred Stock (Ln 54 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	(104,879)	(230,765)	(167,822)
4	Less Account 219.1 (112.15.c&d)	(28,884,204)	(28,221,410)	(28,552,807)
5	**Average Balance of Common Equity**	1,832,763,838	1,789,432,308	**1,811,098,073**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	-	-	-
7	Less: Reacquired Bonds (112.19.c&d)	-	-	-
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	1,572,429,608	1,562,927,505	1,567,678,557
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	1,572,429,608	1,562,927,505	**1,567,678,557**

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 2012**	
14	Interest on Long Term Debt (256-257.33.i)	90,701,590
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 33 below.	916,010
16	Plus: Allowed Hedge Recovery From Ln 38 below.	916,010
17	Amort of Debt Discount & Expense (117.63.c)	2,372,191
18	Amort of Loss on Reacquired Debt (117.64.c)	1,483,709
19	Less: Amort of Premium on Debt (117.65.c)	-
20	Less: Amort of Gain on Reacquired Debt (117.66.c)	1,712
21	**Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)**	**94,555,778**
22	**Average Cost of Debt for 2012 (Ln 21/Ln 11)**	**6.03%**

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 2012	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 F	877,840		877,840	1,645,950	November 2004	November 2014
25	Senior Unsecured Notes - Series G	(383,570)		(383,570)	(1,118,746)	December-05	November-15
26	Senior Unsecured Notes - Series H	421,740		421,740	10,174,485	November-06	February-37
27				-			
28				-			
29				-			
30				-			
31				-			
32				-			
					10,701,690		
33	Total Hedge Amortization	916,010	-				

34	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 32)	916,010
35	Total Average Capital Structure Balance for 2012 (True-UP TCOS, Ln 165)	3,378,776,629
36	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
37	Limit of Recoverable Amount	1,689,388
38	**Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)**	**916,010**

Development of Cost of Preferred Stock

Line	Preferred Stock	12/31/2012	12/31/2011	Average
39	4.125% Series - 100 - Dividend Rate (p. 250-251. 9.a)	4.125%	4.125%	
40	4.125% Series - 100 - Par Value (p. 250-251. 9.c)	$ 100.00	$ 100.00	
41	4.125% Series - 100 - Shares O/S (p.250-251. 9.e)	-	-	
42	4.125% Series - 100 - Monetary Value (Ln 40 * Ln 41)	-	-	-
43	4.125% Series - 100 - Dividend Amount (Ln 39 * Ln 42)	-	-	-
44	4.12% Series - 100 - Dividend Rate (p. 250-251 11.a)	4.12%	4.12%	
45	4.12% Series - 100 - Par Value (p. 250-251 11.c)	$ 100.00	$ 100.00	
46	4.12% Series - 100 - Shares O/S (p.250-251 11.e)	-	-	
47	4.12% Series - 100 - Monetary Value (Ln 45 * Ln 46)	-	-	-
48	4.12% Series - 100 - Dividend Amount (Ln 44 * Ln 47)	-	-	-
49	4.56% Series - 100 - Dividend Rate (p. 250-251. 10a)	4.56%	4.56%	
50	4.56% Series - 100 - Par Value (p. 250-251. 10c)	$ 100.00	$ 100.00	
51	4.56% Series - 100 - Shares O/S (p.250-251 10.e)	-	-	
52	4.56% Series - 100 - Monetary Value (Ln 50 * Ln 51)	-	-	-
53	4.56% Series - 100 - Dividend Amount (Ln 49 * Ln 52)	-	-	-
54	**Balance of Preferred Stock (Lns 42, 47, 52)**	-	-	-
55	**Dividends on Preferred Stock (Lns 43, 48, 53)**	-	-	-
56	**Average Cost of Preferred Stock (Ln 55/54)**	0.00%	0.00%	**0.00%**

Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
INDIANA MICHIGAN 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 2012		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2010 FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
INDIANA MICHIGAN POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

Allocation of PBOP Settlement Amount for 2012

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 4/1/2012
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			MICHIGAN			FERC WHOLESALE			COMPANY
		(1)			*(2)*			*(3)*			
	PLANT ACCT.	*IURC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*MPSC APPROVED RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT											
Land Improvements	350.1	1.1600%	0.654549	0.7593%	1.1700%	0.152798	0.1788%	1.1700%	0.192653	0.2254%	1.16%
Structures & Improvements	352.0	1.1500%	0.654549	0.7527%	1.2700%	0.152798	0.1941%	1.2700%	0.192653	0.2447%	1.19%
Station Equipment	353.0	1.4600%	0.654549	0.9556%	1.6500%	0.152798	0.2521%	1.6500%	0.192653	0.3179%	1.53%
Towers & Fixtures	354.0	1.4600%	0.654549	0.9556%	1.4400%	0.152798	0.2200%	1.4400%	0.192653	0.2774%	1.45%
Poles & Fixtures	355.0	2.1900%	0.654549	1.4335%	2.3900%	0.152798	0.3652%	2.3900%	0.192653	0.4604%	2.26%
Overhead Conductors	356.0	1.2300%	0.654549	0.8051%	1.4500%	0.152798	0.2216%	1.4500%	0.192653	0.2793%	1.31%
Underground Conduit	357.0	1.4500%	0.654549	0.9491%	1.3900%	0.152798	0.2124%	1.3900%	0.192653	0.2678%	1.43%
Underground Conductors	358.0	1.3500%	0.654549	0.8836%	1.4600%	0.152798	0.2231%	1.4600%	0.192653	0.2813%	1.39%
Trails & Roads	359.0	1.5000%	0.654549	0.9818%	1.4700%	0.152798	0.2246%	1.4700%	0.192653	0.2832%	1.49%

(1) As approved in Indiana Case No. 43231.
(2) As approved in MICHIGAN Case No. U16801.
(3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.
(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:
The rates for each AEP company have been approved by their respective regulatory commissions.
I&M falls under the authority of Indiana, Michigan and the FERC. Therefore, I&M's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.
Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

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

Line No.			Total	Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)				$55,400,649
2	REVENUE CREDITS	(Note A) (Worksheet E)	79,378	DA	1.00000	$ 79,378
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$ 55,321,271

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 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))				16.13%
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))				13.78%
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))				3.47%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)					-

13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	2,313,221
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,160,718
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		245,515
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	906,988

AEP East Companies
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Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KENTUCKY POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	**RATE BASE CALCULATION**	**Data Sources (See "General Notes")**	**TO Total** NOTE C	**Allocator**		**Total Transmission**
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	551,473,235	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-3,614,563	NA	0.00000	0
20	Transmission	(Worksheet A ln 3.C & Ln 142)	490,121,490	DA		488,475,204
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	0	TP	0.99664	0
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		17,254,112	DA	1.00000	17,254,112
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)	651,987,726	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)	35,217,344	W/S	0.09694	3,414,092
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-81,055	W/S	0.09694	(7,858)
28	Intangible Plant	(Worksheet A ln 9.C)	17,734,036	W/S	0.09694	1,719,199
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	1,760,092,325			510,854,749
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	267,211,806	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-936,402	NA	0.00000	0
33	Transmission	(Worksheet A ln 14.C & 28.C)	154,839,705	**TP1=**	0.99581	154,190,968
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	0	**TP1=**	0.99581	0
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		193,867	DA	1.00000	193,867
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		7,897,690	TP1	0.99581	7,864,601
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		3,660,586	W/S	0.09694	354,870
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)	171,225,681	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)	7,962,549	W/S	0.09694	771,917
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-11,119	W/S	0.09694	(1,078)
44	Intangible Plant	(Worksheet A ln 20.C)	20,894,341	W/S	0.09694	2,025,570
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	632,938,704			165,400,715
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	281,583,267			0
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	335,281,785			334,284,237
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		17,060,245			17,060,245
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		0			0
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(7,897,690)			(7,864,601)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(3,660,586)			(354,870)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	480,762,045			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	27,184,859			2,635,395
56	Intangible Plant	(ln 28 - ln 44)	(3,160,305)			(306,371)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	1,127,153,621			345,454,035
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(26,644,638)	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(198,723,117)	DA		(58,756,969)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(18,533,602)	DA		(851,337)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	13,719,413	DA		3,137,219
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	0	DA		0
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(230,181,944)			(56,471,087)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	7,436,551	DA		30,592
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	0	DA		0
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	691,015			688,694
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	29,645	TP	0.99664	29,545
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	6,628	W/S	0.09694	643
71	Stores Expense	(Worksheet C, ln 4.(D))	0	GP(h)	0.28322	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	27,322,535	W/S	0.09694	2,648,741
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	634,845	GP(h)	0.28322	179,799
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)	(26,387,585)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,297,083			3,547,422
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(260,279)	DA	1.00000	(260,279)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		906,445,031			292,300,682

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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	371,701,916			
80	Distribution	322.156.b	40,373,125			
81	Customer Related Expense	322.164,171,178.b	9,222,773			
82	Regional Marketing Expenses	322.131.b	1,194,322			
83	Transmission	321.112.b	12,202,913			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	434,695,049			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,313,221			
86	Less: Account 565	(Note H) 321.96.b	4,361,575			
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)	5,528,117	TP	0.99664	5,509,548
89	Administrative and General	323.197.b (Note J)	19,906,103			
90	Less: Acct. 924, Property Insurance	323.185.b	605,545			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	1,994,927			
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)	193,112			
94	Acct. 928, Reg. Com. Exp.	323.189.b	155,946			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	68,468			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	290,504			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	16,597,601	W/S	0.09694	1,609,029
98	Plus: Acct. 924, Property Insurance	(ln 90)	605,545	GP(h)	0.28322	171,500
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.99664	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.99664	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	21,276	DA	1.00000	21,276
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,573,774	W/S	0.09694	249,511
103	A & G Subtotal	(sum lns 97 to 102)	19,798,196			2,051,316
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	25,326,313			7,560,864
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)	25,326,313			7,560,864
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	20,867,782	NA	0.00000	-
110	Distribution	336.8.f	22,040,399	NA	0.00000	-
111	Transmission	336.7.f	7,897,690	TP1	0.99581	7,864,601
112	Plus: Transmission Plant-in-Service Additions	(Worksheet I ln 21.I)	193,867	DA	1.00000	193,867
113	General	336.10.f	851,375	W/S	0.09694	82,535
114	Intangible	336.1.f	2,809,211	W/S	0.09694	272,335
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	54,660,324			8,413,338
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	1,700,019	W/S	0.09694	164,806
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	9,357,117	DA		3,583,173
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	186,263	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	916,572	GP(h)	0.28322	259,588
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	12,159,971			4,007,567
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.52%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		38.09%			
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)		1.6265			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(278,005)			
131	Income Tax Calculation	(ln 126 * ln 134)	30,406,252			9,805,082
132	ITC adjustment	(ln 129 * ln 130)	(452,162)	NP(h)	0.30010	(135,696)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	29,954,090			9,669,386
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	79,825,288			25,741,204
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	8,290	DA	1.00000	8,290
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)		201,934,276			55,400,649

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						490,121,490
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)							1,646,286
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						488,475,204
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					**TP**	**0.99664**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
145	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
146	Transmission	354.21.b	1,152,669	1,418,185	2,570,854	TP	0.99664	2,562,219
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	-
150	Total	(sum lns 145 to 149)	19,901,032	6,528,996	26,430,028			2,562,219
151	Transmission related amount						**W/S=**	**0.09694**

ln No.			$
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet L, ln. 35, col. (D))	35,553,541
154	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
155	Development of Common Stock:		
156	Proprietary Capital	(FF1 p 112, Ln 16.c)	479,610,035
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)	(408,880)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	480,018,915

ln No.		$	%	Cost (Note S)	Weighted
161					
162	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	550,000,000	53.40%	0.0646	0.0345
163	Preferred Stock (ln 157)	-	0.00%	-	0.0000
164	Common Stock (ln 160)	480,018,915	46.60%	11.49%	0.0535
165	Total (Sum lns 162 to 164)	1,030,018,915		**WACC=**	**0.0881**

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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, 2013. Other ratebase amounts are as of December 31, 2012.
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=	5.41%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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.

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

KENTUCKY POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$54,131,667
167	REVENUE CREDITS	(Note A) (Worksheet E)	79,378	DA	1.00000	$	79,378
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	54,052,289

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)	16.19%
172	Monthly Rate	(ln 171 / 12)	1.35%
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)	13.84%
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)	3.57%
177	Not applicable on this template		
178	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	2,313,221
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,160,718
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		245,515
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	906,988

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 with Year-End Rate Base 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					
183	Production	(Worksheet A ln 1.C)	551,473,235	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(3,614,563)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	490,121,490	DA		488,475,204
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.99664	-
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)	651,987,726	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)	35,217,344	W/S	0.09694	3,414,092
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(81,055)	W/S	0.09694	(7,858)
193	Intangible Plant	(Worksheet A ln 9.C)	17,734,036	W/S	0.09694	1,719,199
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	1,742,838,213	**GP(h)=**	**0.283217**	493,600,637
				GTD=	**0.42770**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	267,211,806	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(936,402)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	154,839,705	**TP1=**	0.99581	154,190,968
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.99581	-
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 2013 (ln 276)		**N/A**	TP1	0.99581	**N/A**
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		**N/A**	W/S	0.09694	**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)	171,225,681	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)	7,962,549	W/S	0.09694	771,917
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(11,119)	W/S	0.09694	(1,078)
209	Intangible Plant	(Worksheet A ln 20.C)	20,894,341	W/S	0.09694	2,025,570
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	621,186,561			156,987,377
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	281,583,267			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	335,281,785			334,284,237
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 2013 (-ln 202)		**N/A**			**N/A**
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	480,762,045			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	27,184,859			2,635,395
221	Intangible Plant	(ln 193 - ln 209)	(3,160,305)			(306,371)
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	1,121,651,652	**NP(h)=**	**0.300105**	336,613,260
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(26,644,638)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(198,723,117)	DA		(58,756,969)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(18,533,602)	DA		(851,337)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	13,719,413	DA		3,137,219
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(230,181,944)			(56,471,087)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	7,436,551	DA		30,592
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	691,015			688,694
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	29,645	TP	0.99664	29,545
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	6,628	W/S	0.09694	643
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.28322	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	27,322,535	W/S	0.09694	2,648,741
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	634,845	GP(h)	0.28322	179,799
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(26,387,585)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	2,297,083			3,547,422
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(260,279)	DA	1.00000	(260,279)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		900,943,062			283,459,908

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

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	371,701,916			
245	Distribution	322.156.b	40,373,125			
246	Customer Related Expense	322 & 323.164,171,178.b	9,222,773			
247	Regional Marketing Expenses	322.131.b	1,194,322			
248	Transmission	321.112.b	12,202,913			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	434,695,049			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,313,221			
251	Less: Account 565	(Note H) 321.96.b	4,361,575			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	5,528,117	TP	0.99664	5,509,548
254	Administrative and General	323.197.b (Note J)	19,906,103			
255	Less: Acct. 924, Property Insurance	323.185.b	605,545			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	1,994,927			
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)	193,112			
259	Acct. 928, Reg. Com. Exp.	323.189.b	155,946			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	68,468			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	290,504			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	16,597,601	W/S	0.09694	1,609,029
263	Plus: Acct. 924, Property Insurance	(ln 255)	605,545	GP(h)	0.28322	171,500
264	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.99664	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.99664	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	21,276	DA	1.00000	21,276
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,573,774	W/S	0.09694	249,511
268	A & G Subtotal	(sum lns 262 to 267)	19,798,196			2,051,316
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	25,326,313			7,560,864
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)	25,326,313			7,560,864
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	20,867,782	NA	0.00000	-
275	Distribution	336.8.f	22,040,399	NA	0.00000	-
276	Transmission	336.7.f	7,897,690	TP1	0.99581	7,864,601
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	851,375	W/S	0.09694	82,535
279	Intangible	336.1.f	2,809,211	W/S	0.09694	272,335
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	54,466,457			8,219,471
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 21.(D)	1,700,019	W/S	0.09694	164,806
284	Plant Related					
285	Property	Worksheet H ln 21.(C) & ln 35.(C)	9,357,117	DA		3,583,173
286	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	186,263	NA	0.00000	-
287	Other	Worksheet H ln 21.(E)	916,572	GP(h)	0.28322	259,588
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	12,159,971			4,007,567
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.52%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		38.09%			
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)		1.6265			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(278,005)			
296	Income Tax Calculation	(ln 291 * ln 299)	30,221,691			9,508,523
297	ITC adjustment	(ln 294 * ln 295)	(452,162)	NP(h)	0.30010	(135,696)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	29,769,529			9,372,827
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	79,340,762			24,962,649
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		8,290	DA	1.00000	8,290
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)		201,071,322			54,131,667

AEP East Companies
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KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF		
304	Total transmission plant	(ln 185)	490,121,490
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)		1,646,286
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)	488,475,204
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304) TP=	**0.99664**

ln No.		(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
309	WAGES & SALARY ALLOCATOR (W/S)							
310	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
311	Transmission	354.21.b	1,152,669	1,418,185	2,570,854	TP	0.99664	2,562,219
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	-
315	Total	(sum lns 310 to 314)	19,901,032	6,528,996	26,430,028			2,562,219
316	Transmission related amount						**W/S=**	**0.09694**

ln No.			$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		
318	Long Term Interest	(Worksheet L, ln. 35, col. (D))	35,553,541
319	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
320	Development of Common Stock:		
321	Proprietary Capital	(FF1 p 112, Ln 16.c)	479,610,035
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)	(408,880)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)	480,018,915

ln No.		$	%	Cost (Note S)	Weighted
326					
327	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	550,000,000	53.40%	0.0646	0.0345
328	Preferred Stock (ln 322)	-	0.00%	-	0.0000
329	Common Stock (ln 325)	480,018,915	46.60%	11.49%	0.0535
330	Total (Sum lns 327 to 329)	1,030,018,915		**WACC=**	**0.0881**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 with Year-End Rate Base 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 are projected as of December 31, 2012.

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=	5.41%	(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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KENTUCKY POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$52,145,724
2	REVENUE CREDITS	(Note A) (Worksheet E)	79,378	DA	1.00000	$	79,378
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	52,066,346

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			Transmission Amount
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)					16.37%
7	Monthly Rate	(ln 6 / 12)					1.36%
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)					13.90%
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)					3.74%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)						-

Line No.	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES		
13			
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	2,313,221
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,160,718
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		245,515
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	906,988

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	(1)	(2)	(3)	(4)		(5)
	RATE BASE CALCULATION	**Data Sources (See "General Notes")**	**TO Total**	**Allocator**		**Total Transmission**
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A ln 1.E)	549,114,863	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(3,614,563)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	473,321,457	DA		471,675,171
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.99652	-
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)	632,096,061	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)	34,681,918	W/S	0.09693	3,361,783
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(81,055)	W/S	0.09693	(7,857)
28	Intangible Plant	(Worksheet A ln 9.E)	16,615,414	W/S	0.09693	1,610,563
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	1,702,134,094	**GP(h)=**	**0.28002**	476,639,661
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	261,998,071	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(841,591)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	153,749,700	**TP1=**	0.99587	153,115,039
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.99587	-
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 2013 (ln 111)		N/A	TP1	0.99587	N/A
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		N/A	W/S	0.09693	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)	166,964,522	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)	7,994,972	W/S	0.09693	774,968
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(8,303)	W/S	0.09693	(805)
44	Intangible Plant	(Worksheet A ln 20.E)	19,811,837	W/S	0.09693	1,920,398
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	609,669,208			155,809,600
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	284,343,820			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	319,571,757			318,560,133
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 2013 (-ln 37)		N/A			N/A
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	465,131,539			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	26,614,194			2,579,764
56	Intangible Plant	(ln 28 - ln 44)	(3,196,423)			(309,835)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	1,092,464,887	**NP(h)=**	**0.29368**	320,830,061
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(27,437,154)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(195,354,334)	DA		(58,003,846)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(18,681,066)	DA		(1,091,464)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	16,839,991	DA		3,432,266
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(224,632,563)			(55,663,044)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	7,436,551	DA		30,592
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	691,015			688,611
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	113,716	TP	0.99652	113,320
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	16,793	W/S	0.09693	1,628
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.28002	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	26,494,005	W/S	0.09693	2,568,114
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	628,070	GP(h)	0.28002	175,875
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(25,607,264)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,336,335			3,547,548
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(256,134)	DA	1.00000	(256,134)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		877,349,076			268,489,024

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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	371,701,916			
80	Distribution	322.156.b	40,373,125			
81	Customer Related Expense	322.164,171,178.b	9,222,773			
82	Regional Marketing Expenses	322.131.b	1,194,322			
83	Transmission	321.112.b	12,202,913			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	434,695,049			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	2,313,221			
86	Less: Account 565	(Note H) 321.96.b	4,361,575			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	5,528,117	TP	0.99652	5,508,889
89	Administrative and General	323.197.b (Note J)	19,906,103			
90	Less: Acct. 924, Property Insurance	323.185.b	605,545			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	1,994,927			
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)	193,112			
94	Acct. 928, Reg. Com. Exp.	323.189.b	155,946			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	68,468			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	290,504			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	16,597,601	W/S	0.09693	1,608,837
98	Plus: Acct. 924, Property Insurance	(ln 90)	605,545	GP(h)	0.28002	169,568
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.99664	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 27.(E) (Note L)	-	TP	0.99664	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 34.(E) (Note L)	21,276	DA	1.00000	21,276
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,573,774	W/S	0.09693	249,481
103	A & G Subtotal	(sum lns 97 to 102)	19,798,196			2,049,161
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	25,326,313			7,558,050
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)	25,326,313			7,558,050
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	20,867,782	NA	0.00000	-
110	Distribution	336.8.f	22,040,399	NA	0.00000	-
111	Transmission	336.7.f	7,897,690	TP1	0.99587	7,865,089
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	851,375	W/S	0.09693	82,525
114	Intangible	336.1.f	2,809,211	W/S	0.09693	272,302
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	54,466,457			8,219,917
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	1,700,019	W/S	0.09693	164,786
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	9,357,117	DA		3,583,173
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	186,263	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	916,572	GP(h)	0.28002	256,663
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	12,159,971			4,004,622
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.52%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		37.79%			
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)		1.6265			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(278,005)			
131	Income Tax Calculation	(ln 126 * ln 134)	29,116,695			8,910,379
132	ITC adjustment	(ln 129 * ln 130)	(452,162)	NP(h)	0.29368	(132,789)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	28,664,533			8,777,590
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	77,044,055			23,577,255
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		8,290	DA	1.00000	8,290
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)		197,669,618			52,145,724

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		473,321,457
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)			1,646,286
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		471,675,171
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP=**	**0.99652**

ln No.				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
146	Transmission	354.21.b	1,152,669	1,418,185	2,570,854	TP	0.99652	2,561,912
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	-
150	Total	(sum lns 145 to 149)	19,901,032	6,528,996	26,430,028			2,561,912
151	Transmission related amount						**W/S=**	**0.09693**

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))				470,012,627
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))				(517,062)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)				470,529,689

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))	550,000,000	53.89%	0.00%	0.0646	0.0348
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Commone Stock (ln 160)	470,529,689	46.11%	0.00%	11.49%	0.0530
165	Total (Sum lns 162 to 164)	1,020,529,689			**WACC=**	**0.0878**
166	Capital Structure Equity Limit (Note U)	100.0%				

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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 reflect the average of the balances at December 31, 2011 and December 31, 2012.
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= 5.41% (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 2012 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, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
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	551,473,235	546,756,491	549,114,863
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	3,614,563	3,614,563	3,614,563
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	490,121,490	456,521,424	473,321,457
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	651,987,726	612,204,396	632,096,061
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	35,217,344	34,146,492	34,681,918
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	17,734,036	15,496,791	16,615,414
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	1,746,533,831	1,665,125,594	1,705,829,713
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	3,695,618	3,695,618	3,695,618
Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	267,211,806	256,784,336	261,998,071
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	936,402	746,780	841,591
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	154,839,705	152,659,695	153,749,700
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	171,225,681	162,703,363	166,964,522
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	7,962,549	8,027,395	7,994,972
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	11,119	5,487	8,303
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	20,894,341	18,729,332	19,811,837
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	622,134,082	598,904,121	610,519,102
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	947,521	752,267	849,894
Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records - Note 1	1,646,286	1,646,286	1,646,286
24	**GSU Accumulated Depreciation**	Company Records - Note 1	648,737	620,586	634,661
25	**GSU Net Balance**	(Line 23 - Line 24)	997,548	1,025,700	1,011,624
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	154,839,705	152,659,695	153,749,700
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	648,737	620,586	634,661
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	154,190,968	152,039,109	153,115,039
Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	7,436,551	7,436,551	7,436,551
30	**Transmission Plant Held For Future**	Company Records - Note 1	30,592	30,592	30,592
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 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	Description	Source	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	26,644,638	28,229,670	27,437,154
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	26,644,638	28,229,670	27,437,154
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)	198,723,117	191,985,551	195,354,334
8	Less: ARO Related Deferrals	Company Records - Note 1	1,282,377	1,105,092	1,193,735
9	Less: Other Excluded Deferrals	Company Records - Note 1	138,683,771	133,629,737	136,156,754
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	58,756,969	57,250,722	58,003,846
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	18,533,602	18,828,529	18,681,066
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	17,682,265	17,496,938	17,589,602
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	851,337	1,331,591	1,091,464
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	13,719,413	19,960,569	16,839,991
18	Less: ARO Related Deferrals	Company Records - Note 1	1,365,791	1,300,433	1,333,112
19	Less: Other Excluded Deferrals	Company Records - Note 1	9,216,403	14,932,824	12,074,614
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	3,137,219	3,727,312	3,432,266
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	355,759	633,764	494,762
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	355,759	633,764	494,762
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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
KENTUCKY POWER COMPANY

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

Materials & Supplies

Line Number		Source	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	29,645	197,787	113,716
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	6,628	26,958	16,793
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

5		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
6	Totals as of December 31, 2012	1,569,796	(26,387,585)	0	634,845	27,322,535	27,957,380
7	Totals as of December 31, 2011	1,459,828	(24,826,944)		621,296	25,665,476	26,286,772
8	**Average Balance**	1,514,812	(25,607,264)	-	628,070	26,494,005	27,122,076

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	366,671	-		366,671		366,671	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	515,095	515,095		-		-	Prepaid Fees
12	1650009	Prepaid Carry Cost-Factored AR	13,101	13,101				-	AR Factoring - Retail Only
13	1650010	Prepaid Pension Benefits	27,322,535				27,322,535	27,322,535	Prefunded Pension Expense
14	1650014	FAS 158 Qual Contra Asset	(27,322,535)	(27,322,535)				-	SFAS 158 Offset
15	1650016	FAS 112 ASSETS	0	-			-	-	
16	165001212	Prepaid Use Taxes	42,719	42,719			-	-	Use Taxes-Distribution
17	165001112	Prepaid Sales Taxes	294,773	294,773			-	-	Sales Taxes-Distribution
18	1650021	Prepaid Insurance - EIS	268,174	-		268,174		268,174	Prepaid Ins. - EIS
19	1650023	Prepaid Lease	69,262	69,262				-	Distribution Lease
		Subtotal - Form 1, p 111.57.c	1,569,796	(26,387,585)	0	634,845	27,322,535	27,957,380	

Prepayments Account 165 - Balance @ 12/31/ 2011

20	Acc. No.	Description	2011 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	352,266	-		352,266		352,266	Plant Related Insurance Policies
22	165000211	Prepaid Taxes	412,861	412,861		-		-	Prepaid Fees
23	1650009	Prepaid Carry Cost-Factored AR	20,357	20,357				-	AR Factoring - Retail Only
24	1650010	Prepaid Pension Benefits	25,665,476				25,665,476	25,665,476	Prefunded Pension Expense
25	1650014	FAS 158 Qual Contra Asset	(25,665,476)	(25,665,476)				-	SFAS 158 Offset
26	1650016	FAS 112 ASSETS	0	-			-	-	SFAS 112 Overfunding Asset
27	165001211	Prepaid Use Taxes	51,118	51,118			-	-	Use Taxes-Distribution
28	165001111	Prepaid Sales Taxes	348,741	348,741			-	-	Sales Taxes-Distribution
29	1650021	Prepaid Insurance - EIS	269,030	-		269,030		269,030	Prepaid Ins. - EIS
30	1650023	Prepaid Lease	5,454	5,454				-	Distribution Lease
								-	
		Subtotal - Form 1, p 111.57.d	1,459,828	(24,826,944)		621,296	25,665,476	26,286,772	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
KENTUCKY POWER COMPANY

Line Number	**(A) Description**	**(B) 2012**
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 13.b)	(251,989.00)
2	Interest Accrual (Company Records - Note 1)	(8,290.00)
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 12/31/2012 (2012 FORM 1, P269, line 13.f)	(260,279.00)
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(256,134.00)

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

AEP East Companies
Cost of Service Formula Rate Using 2012 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)**	3,268,233	3,268,233	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	353,912	340,356	13,556
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	7,006,537	6,980,262	26,275
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	242,814	203,267	39,547
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	20,241,015	20,241,015	
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	31,112,511	31,033,133	79,378
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	31,112,511	31,033,133	79,378

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 2012 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	2012 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	5,642			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	764,533			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(77)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	1,160,718			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	136,890			
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	245,515			
14		**Total of Account 561**	2,313,221			
		Account 928				
15	9280000	Regulatory Commission Exp	(3)	(3)	-	
16	9280001	Regulatory Commission Exp-Adm	(4)	(4)	-	
17	9280002	Regulatory Commission Exp-Case	155,954	155,954	-	
18		**Total**	155,947	155,947	-	
		Account 930.1				
19	9301000	General Advertising Expenses	8,325	8,325	-	
20	9301001	Newspaper Advertising Space	13,201	13,201	-	
21	9301002	Radio Station Advertising Time	2,750	2,750	-	
22	9301006	Spec Corp Comm Info Proj	-	-	-	
23	9301010	Publicity	1,278	1,278	-	
24	9301011	Dedications, Tours, & Openings	1	1	-	
25	9301012	Public Opinion Surveys	2,607	2,607	-	
26	9301014	Video Communications	13	13	-	
	9301015	Other Corporate Comm Exp	40,294	40,294		
27		**Total**	68,469	68,469	-	
		Account 930.2				
28	9302000	Misc General Expenses	166,816	166,816		
29	9302003	Corporate & Fiscal Expenses	20,488	20,488		
30	9302004	Research, Develop&Demonstr Exp	2,998	2,998		
31	9302006	Assoc Bus Dev Materials Sold	39,799	39,799		
32	9302007	Assoc Business Development Exp	60,370	39,094	21,276	
33	9302458	AEPSC Non Affiliated Expense	34	34		
34		**Total**	290,505	269,229	21,276	

AEP East Companies
Cost of Service Formula Rate Using 2012 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	86.11%	
Effective State Tax Rate		5.17%
West Virginia Corporate Income Tax	7.75%	
Apportionment Factor - Note 2	0.73%	
Effective State Tax Rate		0.06%
Michigan Business Income Tax	6.00%	
Apportionment Factor - Note 2	0.10%	
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	1.80%	
Effective State Tax Rate		0.17%
Total Effective State Income Tax Rate		5.41%

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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company NOTE 1	Property	Labor	Other	Non-Allocable
1	Revenue Taxes					
2	Gross Receipts Tax	174,213				174,213
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Kentucky	9,354,076	9,354,076			
5	Real and Personal Property - Other	3,041	3,041			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	1,660,027		1,660,027		
8	Federal Unemployment Tax	22,342		22,342		
9	State Unemployment Insurance	17,650		17,650		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	927,956			927,956	
15	State Franchise Taxes	(11,849)			(11,849)	
16	State Lic/Registration Fee	465			465	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	11,052				11,052
19	Federal Excise Tax	998				998
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	12,159,971	9,357,117	1,700,019	916,572	186,263

(Total Company Amount Ties to FFI p.114, Ln 14,(c))
NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsmission	Distribution	General	Total
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	281,583,267	335,281,785	480,762,045	27,184,859	1,124,811,957
	KENTUCKY JURISDICTION					
23	Percentage of Plant in KENTUCKY JURISDICTION	100.00%	100.00%	100.00%	100.00%	
24	Net Plant in KENTUCKY JURISDICTION (Ln 22 * Ln 23)	281,583,267	335,281,785	480,762,045	27,184,859	1,124,811,957
25	Less: Net Value of Exempted Generation Plant	103,264,979				
26	Taxable Property Basis (Ln 24 - Ln 25)	178,318,288	335,281,785	480,762,045	27,184,859	1,021,546,978
27	Relative Valuation Factor	33%	100%	100%	100%	
28	Weighted Net Plant (Ln 26 * Ln 27)	59,451,317	335,281,785	480,762,045	27,184,859	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	6.79%	38.30%	54.91%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	1,846,013	10,410,782	14,928,065	(27,184,859)	-
31	Weighted KENTUCKY JURISDICTION Plant (Ln 28 + 30)	61,297,330	345,692,567	495,690,110	0	902,680,006
32	Functional Percentage (Ln 31/Total Ln 31)	6.79%	38.30%	54.91%		
33	Functionalized Expense in KENTUCKY JURISDICTION	635,197	3,582,260	5,136,619		9,354,076
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		913			3,041
35	Total Func. Property Taxes (Sum Lns 33, 34)	635,197	3,583,173	5,136,619		9,357,117

AEP East Companies
Cost of Service Formula Rate Using 2012 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	174,213		
			30,112	P.263.1 ln 30 (i)
			144,101	P.263.1 ln 31 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Kentucky	9,354,076		
			(447)	P.263 ln 31 (i)
			(30,160)	P.263 ln 32 (i)
			(98,374)	P.263 ln 33 (i)
			9,603,943	P.263 ln 34 (i)
			18	P.263 ln 36 (i)
			(104,116)	P.263 ln 37 (i)
			(62,800)	P.263 ln 38 (i)
			16,699	P.263 ln 39 (i)
			311	P.263 ln 40 (i)
			2,257	P.263.1 ln 2 (i)
			26,745	P.263.1 ln 3 (i)
5	Real and Personal Property - Other	3,041		
			2,063	P.263.1 ln 15 (i)
			978	P.263.1 ln 16 (i)
			-	
			-	
6	Payroll Taxes			
7	Federal Insurance Contribution (FICA)	1,660,027		
			1,660,027	P.263 ln 4 (i)
8	Federal Unemployment Tax	22,342		
			22,342	P.263 ln 5 (i)
9	State Unemployment Insurance	17,650		
			17,086	P.263 ln 23 (i)
			564	P.263.1 ln 20 (i)
10	Production Taxes			
11	State Severance Taxes	-		
			-	
12	Miscellaneous Taxes			
13	State Business & Occupation Tax	-		
			-	
14	State Public Service Commission Fees	927,956		
			412,861	P.263 ln 25 (i)
			515,095	P.263 ln 26 (i)
15	State Franchise Taxes	(11,849)		
			(22,194)	P.263.1 ln 9 (i)
			10,345	P.263.1 ln 10 (i)
16	State Lic/Registration Fee	465		
			300	P.263 ln 19 (i)
			15	P.263.1 ln 20 (i)
			50	P.263.1 ln 18 (i)
			100	P.263.1 ln 21 (i)
17	Misc. State and Local Tax	-		
			-	
18	Sales & Use	11,052		
			1,247	P.263 ln 27 (i)
			9,805	P.263 ln 28 (i)
19	Federal Excise Tax	998		
			998	P.263 ln 7 (i)
20	Michigan Single Business Tax	-		
			-	
21	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	12,159,971	12,159,971	

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 2012 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 (2012) (P.206, ln 58,(b)):	456,521,424
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	490,121,490
3		946,642,914
4	Average Balance of Transmission Investment	473,321,457
5	Annual Depreciation Expense, Historic TCOS, ln 276	7,897,690
6	Composite Depreciation Rate	1.67%
7	Round to 1.67% to Reflect a Composite Life of 60 Years	1.67%

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	$ 10,342,016	1.67%	$ 172,712	$ 14,393	11	$ 158,323
10	February	$ 387,925	1.67%	$ 6,478	$ 540	10	$ 5,400
11	March	$ 539,244	1.67%	$ 9,005	$ 750	9	$ 6,750
12	April	$ 458,665	1.67%	$ 7,660	$ 638	8	$ 5,104
13	May	$ 478,248	1.67%	$ 7,987	$ 666	7	$ 4,662
14	June	$ 507,009	1.67%	$ 8,467	$ 706	6	$ 4,236
15	July	$ 295,250	1.67%	$ 4,931	$ 411	5	$ 2,055
16	August	$ 281,260	1.67%	$ 4,697	$ 391	4	$ 1,564
17	September	$ 898,044	1.67%	$ 14,997	$ 1,250	3	$ 3,750
18	October	$ 569,934	1.67%	$ 9,518	$ 793	2	$ 1,586
19	November	$ 314,271	1.67%	$ 5,248	$ 437	1	$ 437
20	December	$ 2,182,246	1.67%	$ 36,444	$ 3,037	0	$ -
21	Investment	$ 17,254,112				Depreciation Expense	$ 193,867

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 2013

		Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**		
26	N/A	$0	Multiple
27	Subtotal	$0	
28	**PJM Socialized/Beneficiary Allocated Regional Projects**		
29	N/A	$0	
30	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 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	53.40%	6.46%	3.452%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	46.60%	11.49%	5.355%
		R =	8.806%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	-	-	$ -

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

Rate Base (Projected TCOS, ln 78)	292,300,682
R (from A. above)	8.806%
Return (Rate Base x R)	25,741,204

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

Return (from B. above)	25,741,204
Effective Tax Rate (Projected TCOS, ln 126)	38.09%
Income Tax Calculation (Return x CIT)	9,805,082
ITC Adjustment	(135,696)
Income Taxes	9,669,386

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)	55,400,649
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	25,741,204
Income Taxes (Projected TCOS, ln 133)	9,669,386
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,990,059

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,990,059
Return (from I.B. above)	25,741,204
Income Taxes (from I.C. above)	9,669,386
Annual Revenue Requirement, with Basis Point ROE increase	55,400,649
Depreciation (Projected TCOS, ln 111)	7,864,601
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	47,536,048

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	334,284,237
Annual Revenue Requirement, with Basis Point ROE increase	55,400,649
FCR with Basis Point increase in ROE	16.57%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	47,536,048
FCR with Basis Point ROE increase, less Depreciation	14.22%
FCR less Depreciation (Projected TCOS, ln 9)	13.78%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.44%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	456,521,424
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	490,121,490
Subtotal	946,642,914
Average Transmission Plant Balance for 2012	473,321,457
Annual Depreciation Rate (Projected TCOS, ln 111)	7,897,690
Composite Depreciation Rate	1.67%
Depreciable Life for Composite Depreciation Rate	59.93
Round to nearest whole year	60

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	13.78%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	13.78%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
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.

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 2012 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	53.89%	6.46%		3.484%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	46.11%	11.49%		5.298%
			R =	8.781%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS		Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR	2012			
As Projected in Prior Year WS J				$ -
Actual after True-up		$ -	$ -	$ -
True-up of ARR For 2012		-	-	-

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

Rate Base (True-Up TCOS, ln 78)	268,489,024
R (from A. above)	8.781%
Return (Rate Base x R)	23,577,255

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

Return (from B. above)	23,577,255
Effective Tax Rate (True-Up TCOS, ln 126)	37.79%
Income Tax Calculation (Return x CIT)	8,910,379
ITC Adjustment	(132,789)
Income Taxes	8,777,590

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)	52,145,724
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	23,577,255
Income Taxes (True-Up TCOS, ln 133)	8,777,590
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,790,879

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,790,879
Return (from I.B. above)	23,577,255
Income Taxes (from I.C. above)	8,777,590
Annual Revenue Requirement, with 0 Basis Point ROE increase	52,145,724
Depreciation (True-Up TCOS, ln 111)	7,865,089
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	44,280,635

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

Net Transmission Plant (True-Up TCOS, ln 48)	318,560,133
Annual Revenue Requirement, with 0 Basis Point ROE increase	52,145,724
FCR with 0 Basis Point increase in ROE	16.37%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	44,280,635
FCR with 0 Basis Point ROE increase, less Depreciation	13.90%
FCR less Depreciation (True-Up TCOS, ln 9)	13.90%
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)):	456,521,424
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	490,121,490
Subtotal	946,642,914
Average Transmission Plant Balance for	473,321,457
Annual Depreciation Rate (True-Up TCOS, ln 111)	7,897,690
Composite Depreciation Rate	1.67%
Depreciable Life for Composite Depreciation Rate	59.93
Round to nearest whole year	60

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:

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details			
Investment		Current Year	2012
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	13.90%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	13.90%
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 2012 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	Notes Payable to Parent		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					-	
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**		550,000,000	6.46%	35,553,541	
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 2013 (Projected TCOS, Ln 165)				1,030,018,915	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
44	Limit of Recoverable Amount				515,009	
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 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	479,610,035	460,415,218	470,012,627
2	Less Preferred Stock (Ln 55 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	0	0	0
4	Less Account 219.1 (112.15.c&d)	-408,880	-625,244	-517,062
5	**Average Balance of Common Equity**	480,018,915	461,040,462	**470,529,689**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	0	0	0
7	Less: Reacquired Bonds (112.19.c&d)	0	0	0
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)	530,000,000	530,000,000	530,000,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	0	0	0
11	**Total Average Debt**	550,000,000	550,000,000	**550,000,000**

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 2012**	
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 2012 (Ln 21/Ln 11)**	**6.46%**

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. <u>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.</u>

Line	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2012	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	433,796	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 2012 (True-UP TCOS, Ln 165)	1,020,529,689
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
38	Limit of Recoverable Amount	510,265
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**	**92,956**

Development of Cost of Preferred Stock

Line	<u>**Preferred Stock**</u>	(C)	(D)	<u>**Average**</u>
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)**	-	-	-
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%	

Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

AEP East Companies
Cost of Service Formula Rate Using 2012 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 respectivielу. 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 2012		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2012 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 48,100,000

Allocation of PBOP Settlement Amount for 2012

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) **(Line 14)**	**(B)=(A)/Total (A)**	**(C)=(B) * 48100000**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927 -	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

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.

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$3,760,479
2	REVENUE CREDITS	(Note A) (Worksheet E)	306,055	DA	1.00000	$	306,055
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	3,454,424

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 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))					21.78%
7	Monthly Rate	(ln 6 / 12)					1.82%
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))					18.28%
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))					6.90%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)						-
13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**						
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					50,457
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)						1,263
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)						0
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					49,194

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT 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.C)	0	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	0	NA	0.00000	0
20	Transmission	(Worksheet A ln 3.C & Ln 142)	22,330,531	DA		22,330,531
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	0	TP	1.00000	0
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		6,128,348	DA	1.00000	6,128,348
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)	114,411,136	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)	2,558,752	W/S	0.13137	336,154
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	0	W/S	0.13137	0
28	Intangible Plant	(Worksheet A ln 9.C)	1,334,980	W/S	0.13137	175,382
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	146,763,747			28,970,415
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	0	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	0	NA	0.00000	0
33	Transmission	(Worksheet A ln 14.C & 28.C)	10,591,842	**TP1=**	1.00000	10,591,842
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	0	**TP1=**	1.00000	0
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		71,346	DA	1.00000	71,346
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		533,521	TP1	1.00000	533,521
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		124,292	W/S	0.13137	16,329
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)	44,733,167	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)	732,776	W/S	0.13137	96,268
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	0	W/S	0.13137	0
44	Intangible Plant	(Worksheet A ln 20.C)	1,516,239	W/S	0.13137	199,195
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	58,303,183			11,508,500
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	0			0
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	11,738,689			11,738,689
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		6,057,002			6,057,002
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		0			0
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(533,521)			(533,521)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(124,292)			(16,329)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	69,677,969			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	1,825,976			239,886
56	Intangible Plant	(ln 28 - ln 44)	(181,259)			(23,813)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	88,460,564			17,461,915
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	0	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(16,710,005)	DA		(3,243,399)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(902,525)	DA		(119,483)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	477,622	DA		20,136
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(55,004)	DA		(11,643)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(17,189,912)			(3,354,389)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	425,220	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)	57,983			57,983
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	232	TP	1.00000	232
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	3,123	W/S	0.13137	410
71	Stores Expense	(Worksheet C, ln 4.(D))	0	GP(h)	0.16242	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	5,767,913	W/S	0.13137	757,755
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	147,105	GP(h)	0.16242	23,893
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)	(3,499,352)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,477,004			840,273
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	-	DA	1.00000	-
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		74,172,876			14,947,799

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT 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	124,517,930			
80	Distribution	322.156.b	5,354,724			
81	Customer Related Expense	322.164,171,178.b	1,611,378			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	514,322			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	131,998,354			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	50,457			
86	Less: Account 565	(Note H) 321.96.b	-			
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)	463,865	TP	1.00000	463,865
89	Administrative and General	323.197.b (Note J)	2,534,881			
90	Less: Acct. 924, Property Insurance	323.185.b	195,760			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
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)	30,141			
94	Acct. 928, Reg. Com. Exp.	323.189.b	37			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	1,873,082	W/S	0.13137	246,075
98	Plus: Acct. 924, Property Insurance	(ln 90)	195,760	GP(h)	0.16242	31,795
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 26.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 33.(E) (Note L)	172,732	DA	1.00000	172,732
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
103	A & G Subtotal	(sum lns 97 to 102)	2,568,436			493,543
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,032,301			957,408
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)	3,032,301			957,408
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	3,905,071	NA	0.00000	-
111	Transmission	336.7.f	533,521	TP1	1.00000	533,521
112	Plus: Transmission Plant-in-Service Additions	(Worksheet I ln 21.I)	71,346	DA	1.00000	71,346
113	General	336.10.f	100,853	W/S	0.13137	13,249
114	Intangible	336.1.f	23,439	W/S	0.13137	3,079
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	4,634,230			621,196
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	151,897	W/S	0.13137	19,955
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	914,068	DA		131,791
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	3,847,999	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	404,905	GP(h)	0.16242	65,765
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	5,318,869			217,511
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.20%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		51.06%			
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)		1.6447			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 126 * ln 134)	3,294,746			663,979
132	ITC adjustment	(ln 129 * ln 130)	-	NP(h)	0.14393	-
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	3,294,746			663,979
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	6,452,677			1,300,385
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	-	DA	1.00000	-
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)		22,732,823			3,760,479

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		22,330,531
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)			-
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		22,330,531
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP**	**1.00000**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000	334,889
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000	-
150	Total	(sum lns 145 to 149)	1,779,547	769,576	2,549,123			334,889
151	Transmission related amount						**W/S=**	**0.13137**

ln No.			$
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		
153	Long Term Interest	(Worksheet L, ln. 35, col. (D))	904,000
154	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
155	Development of Common Stock:		
156	Proprietary Capital	(FF1 p 112, Ln 16.c)	29,956,296
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)	916
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	29,955,380

ln No.		$	%	Cost (Note S)	Weighted
161					
162	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	20,000,000	40.04%	0.0452	0.0181
163	Preferred Stock (ln 157)	-	0.00%	-	0.0000
164	Common Stock (ln 160)	29,955,380	59.96%	11.49%	0.0689
165	Total (Sum lns 162 to 164)	49,955,380		**WACC=**	**0.0870**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT 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. Other ratebase amounts are as of December 31, 2012.
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 KINGSPORT 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=	6.46%	(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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Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$2,965,411
167	REVENUE CREDITS	(Note A) (Worksheet E)	306,055	DA	1.00000	$	306,055
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	2,659,356

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)	25.26%
172	Monthly Rate	(ln 171 / 12)	2.11%
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)	20.72%
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)	10.15%
177	Not applicable on this template		

178	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	50,457
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,263
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		0
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	49,194

AEP East Companies
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Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

KINGSPORT 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)	-	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	22,330,531	DA		22,330,531
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	1.00000	-
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)	114,411,136	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)	2,558,752	W/S	0.13137	336,154
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-	W/S	0.13137	-
193	Intangible Plant	(Worksheet A ln 9.C)	1,334,980	W/S	0.13137	175,382
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	140,635,399	**GP(h)=**	**0.162420**	22,842,067
				GTD=	**0.16330**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	-	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	10,591,842	**TP1=**	1.00000	10,591,842
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	1.00000	-
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 2013 (ln 276)		N/A	TP1	1.00000	N/A
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		N/A	W/S	0.13137	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)	44,733,167	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)	732,776	W/S	0.13137	96,268
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-	W/S	0.13137	-
209	Intangible Plant	(Worksheet A ln 20.C)	1,516,239	W/S	0.13137	199,195
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	57,574,024			10,887,305
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	-			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	11,738,689			11,738,689
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 2013 (-ln 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	69,677,969			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	1,825,976			239,886
221	Intangible Plant	(ln 193 - ln 209)	(181,259)			(23,813)
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	83,061,375	**NP(h)=**	**0.143927**	11,954,762
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	-	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(16,710,005)	DA		(3,243,399)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(902,525)	DA		(119,483)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	477,622	DA		20,136
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(55,004)	DA		(11,643)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(17,189,912)			(3,354,389)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	425,220	DA		-
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	57,983			57,983
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	232	TP	1.00000	232
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	3,123	W/S	0.13137	410
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.16242	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	5,767,913	W/S	0.13137	757,755
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	147,105	GP(h)	0.16242	23,893
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(3,499,352)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	2,477,004			840,273
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	-	DA	1.00000	-
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		68,773,687			9,440,647

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KINGSPORT 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	124,517,930			
245	Distribution	322.156.b	5,354,724			
246	Customer Related Expense	322 & 323.164,171,178.b	1,611,378			
247	Regional Marketing Expenses	322.131.b	-			
248	Transmission	321.112.b	514,322			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	131,998,354			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	50,457			
251	Less: Account 565	(Note H) 321.96.b	-			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	463,865	TP	1.00000	463,865
254	Administrative and General	323.197.b (Note J)	2,534,881			
255	Less: Acct. 924, Property Insurance	323.185.b	195,760			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
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)	30,141			
259	Acct. 928, Reg. Com. Exp.	323.189.b	37			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	1,873,082	W/S	0.13137	246,075
263	Plus: Acct. 924, Property Insurance	(ln 255)	195,760	GP(h)	0.16242	31,795
264	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 26.(E) (Note L)	-	TP	1.00000	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 33.(E) (Note L)	172,732	DA	1.00000	172,732
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
268	A & G Subtotal	(sum lns 262 to 267)	2,568,436			493,543
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	3,032,301			957,408
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)	3,032,301			957,408
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	-	NA	0.00000	-
275	Distribution	336.8.f	3,905,071	NA	0.00000	-
276	Transmission	336.7.f	533,521	TP1	1.00000	533,521
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	100,853	W/S	0.13137	13,249
279	Intangible	336.1.f	23,439	W/S	0.13137	3,079
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	4,562,884			549,850
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 21.(D)	151,897	W/S	0.13137	19,955
284	Plant Related					
285	Property	Worksheet H ln 21.(C) & ln 35.(C)	914,068	DA		131,791
286	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	3,847,999	NA	0.00000	-
287	Other	Worksheet H ln 21.(E)	404,905	GP(h)	0.16242	65,765
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	5,318,869			217,511
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.20%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		51.06%			
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)		1.6447			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
296	Income Tax Calculation	(ln 291 * ln 299)	3,054,915			419,352
297	ITC adjustment	(ln 294 * ln 295)	-	NP(h)	0.14393	-
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	3,054,915			419,352
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	5,982,974			821,290
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	-	DA	1.00000	-
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)		21,951,943			2,965,411

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SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
304	Total transmission plant	(ln 185)							22,330,531
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)								-
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)							22,330,531
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)						TP=	**1.00000**
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
310	Production	354.20.b	0	0	-	NA	0.00000		-
311	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000		334,889
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
313	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000		-
314	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000		-
315	Total	(sum lns 310 to 314)	1,779,547	769,576	2,549,123				334,889
316	Transmission related amount							W/S=	**0.13137**

317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
318	Long Term Interest	(Worksheet L, ln. 35, col. (D))				904,000
319	Preferred Dividends	(Worksheet L, ln. 40, col. (D))				-
320	Development of Common Stock:					
321	Proprietary Capital	(FF1 p 112, Ln 16.c)				29,956,296
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)				916
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)				29,955,380
326			$	%	Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))		20,000,000	40.04%	0.0452	0.0181
328	Preferred Stock (ln 322)		-	0.00%	-	0.0000
329	Common Stock (ln 325)		29,955,380	59.96%	11.49%	0.0689
330	Total (Sum lns 327 to 329)		49,955,380		**WACC=**	**0.0870**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

KINGSPORT 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 historic as of December 31, 2012.
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 KINGSPORT 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=	6.46%	(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)					$2,885,916
2	REVENUE CREDITS	(Note A) (Worksheet E)	306,055	DA	1.00000	$	306,055
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	2,579,861

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)					26.48%
7	Monthly Rate	(ln 6 / 12)					2.21%
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)					21.58%
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)					10.91%
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	50,457
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		1,263
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		-
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	49,194

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KINGSPORT 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)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	-	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	21,297,488	DA		21,297,488
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	1.00000	-
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)	112,183,057	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)	2,505,217	W/S	0.13137	329,121
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	-	W/S	0.13137	-
28	Intangible Plant	(Worksheet A ln 9.E)	1,231,204	W/S	0.13137	161,748
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	137,216,965	**GP(h)=**	**0.15879**	21,788,357
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	-	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	10,398,159	**TP1=**	1.00000	10,398,159
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	1.00000	-
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 2013 (ln 111)		**N/A**	TP1	1.00000	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		**N/A**	W/S	0.13137	**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)	43,579,293	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)	697,030	W/S	0.13137	91,572
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	-	W/S	0.13137	-
44	Intangible Plant	(Worksheet A ln 20.E)	1,494,729	W/S	0.13137	196,369
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	56,169,210			10,686,099
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	10,899,330			10,899,330
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 2013 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	68,603,764			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	1,808,188			237,549
56	Intangible Plant	(ln 28 - ln 44)	(263,526)			(34,620)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	81,047,756	**NP(h)=**	**0.13698**	11,102,258
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(15,951,204)	DA		(2,914,009)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(1,353,108)	DA		(183,484)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	718,901	DA		68,464
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	(81,281)	DA		(17,244)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(16,666,692)			(3,046,272)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	336,096	DA		-
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	57,983			57,983
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	646	TP	1.00000	646
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	1,617	W/S	0.13137	212
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.15879	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	5,594,327	W/S	0.13137	734,950
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	139,831	GP(h)	0.15879	22,203
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(3,474,365)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,320,038			815,995
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	-	DA	1.00000	-
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		67,037,197			8,871,981

AEP East Companies
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KINGSPORT 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	124,517,930			
80	Distribution	322.156.b	5,354,724			
81	Customer Related Expense	322.164,171,178.b	1,611,378			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	514,322			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	131,998,354			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	50,457			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	463,865	TP	1.00000	463,865
89	Administrative and General	323.197.b (Note J)	2,534,881			
90	Less: Acct. 924, Property Insurance	323.185.b	195,760			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
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)	30,141			
94	Acct. 928, Reg. Com. Exp.	323.189.b	37			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	1,873,082	W/S	0.13137	246,075
98	Plus: Acct. 924, Property Insurance	(ln 90)	195,760	GP(h)	0.15879	31,084
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 26.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 33.(E) (Note L)	172,732	DA	1.00000	172,732
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
103	A & G Subtotal	(sum lns 97 to 102)	2,568,436			492,832
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,032,301			956,697
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)	3,032,301			956,697
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	3,905,071	NA	0.00000	-
111	Transmission	336.7.f	533,521	TP1	1.00000	533,521
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	100,853	W/S	0.13137	13,249
114	Intangible	336.1.f	23,439	W/S	0.13137	3,079
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	4,562,884			549,850
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	151,897	W/S	0.13137	19,955
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	914,068	DA		131,791
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	3,847,999	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	404,905	GP(h)	0.15879	64,294
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	5,318,869			216,040
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.20%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		50.97%			
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)		1.6447			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 126 * ln 134)	2,967,732			392,762
132	ITC adjustment	(ln 129 * ln 130)	-	NP(h)	0.13698	-
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	2,967,732			392,762
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	5,822,453			770,568
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		21,704,239			2,885,916

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						21,297,488
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)							-
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						21,297,488
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					**TP=**	**1.00000**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000	334,889
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000	-
150	Total	(sum lns 145 to 149)	1,779,547	769,576	2,549,123			334,889
151	Transmission related amount						**W/S=**	**0.13137**

ln No.			
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))	904,000
154	Preferred Dividends	(Worksheet M, ln. 56, col. (E))	-
155	Development of Common Stock:		Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	29,703,242
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))	(918)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	29,704,160

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))	20,000,000	40.24%	0.00%	0.0452	0.0182
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Common Stock (ln 160)	29,704,160	59.76%	0.00%	11.49%	0.0687
165	Total (Sum lns 162 to 164)	49,704,160			**WACC=**	**0.0869**
166	Capital Structure Equity Limit (Note U)	100.0%				

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Letter	**Notes**
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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, 2011 and December 31, 2012.
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 KINGSPORT 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 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=	6.46%	(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 KINGSPORT 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 2012 FF1 Balances
Worksheet A Supporting Plant Balances
KINGSPORT POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
	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	-	-	-
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	-	-	-
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	22,330,531	20,264,445	21,297,488
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	114,411,136	109,954,977	112,183,057
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	2,558,752	2,451,682	2,505,217
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	-	-	-
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	1,334,980	1,127,427	1,231,204
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	140,635,399	133,798,531	137,216,965
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	-	-	-
	Accumulated Depreciation & Amortization Balances				
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	-	-	-
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	10,591,842	10,204,475	10,398,159
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	44,733,167	42,425,418	43,579,293
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	732,776	661,283	697,030
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	1,516,239	1,473,219	1,494,729
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	57,574,024	54,764,395	56,169,210
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	-	-	-
	Generation Step-Up Units				
23	**GSU Investment Amount**	Company Records - Note 1	-	-	-
24	**GSU Accumulated Depreciation**	Company Records - Note 1	-	-	-
25	**GSU Net Balance**	(Line 23 - Line 24)	-	-	-
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation				
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	10,591,842	10,204,475	10,398,159
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	-	-	-
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	10,591,842	10,204,475	10,398,159
	Plant Held For Future Use				
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	425,220	246,973	336,096
30	**Transmission Plant Held For Future**	Company Records - Note 1	-	-	-
	Regulatory Assets and Liabilities Approved for Recovery In Ratebase				
	Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.				
31					-
32					-
33					-
34					-
35					-
36	Total Regulatory Deferrals Included in Ratebase		-	-	-

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

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
KINGSPORT POWER COMPANY

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	-	-	-
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	-	-	-
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)	16,710,005	15,192,403	15,951,204
8	Less: ARO Related Deferrals	Company Records - Note 1	0	0	-
9	Less: Other Excluded Deferrals	Company Records - Note 1	13,466,606	12,607,785	13,037,196
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	3,243,399	2,584,618	2,914,009
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	902,525	1,803,691	1,353,108
13	Less: ARO Related Deferrals	Company Records - Note 1	0	0	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	783,042	1,556,207	1,169,625
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	119,483	247,484	183,484
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	477,622	960,179	718,901
18	Less: ARO Related Deferrals	Company Records - Note 1	0	0	-
19	Less: Other Excluded Deferrals	Company Records - Note 1	457,486	843,387	650,437
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	20,136	116,792	68,464
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	55,004	107,557	81,281
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	0	0	-
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	55,004	107,557	81,281
25	Transmission Related Deferrals	Company Records - Note 1	11,643	22,844	17,244

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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
KINGSPORT POWER COMPANY

Materials & Supplies

Line Number	(A)	(B)	(C) Source	(D) Balance @ December 31, 2012	(E) Balance @ December 31, 2011	(F) Average Balance for 2012
1						
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	232	1,059	646
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	3,123	110	1,617
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, 2012	2,415,665	(3,499,352)	0	147,105	5,767,913	5,915,018
7	Totals as of December 31, 2011	2,103,919	(3,449,377)	0	132,556	5,420,740	5,553,296
8	**Average Balance**	2,259,792	(3,474,365)	-	139,831	5,594,327	5,734,157

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	27,614	-		27,614		27,614	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	1,783,096	1,783,096		-		-	Prepaid Taxes - Distribution
12	165000213	Prepaid Taxes	434,490	434,490				-	Prepaid Taxes - Distribution
13	1650003	Prepaid Rents	0	-			-	-	
14	1650004	Prepaid Interest	0	-				-	
15	1650005	Prepaid Employee Benefits	0	-			-	-	
16	1650006	Other Prepayments	0	-				-	
17	1650009	Prepaid Carry Cost-Factored AR	5,809	5,809				-	AR Factoring - Retail Only
18	1650010	Prepaid Pension Benefits	5,767,913				5,767,913	5,767,913	Prefunded Pension Expense
19	1650014	FAS 158 Qual Contra Asset	(5,767,913)	(5,767,913)				-	SFAS 158 Offset
20	1650016	FAS 112 ASSETS	0	-			-	-	
21	1650021	Prepaid Insurance - EIS	119,491	-		119,491		119,491	
22	1650023	Prepaid Lease	45,166	45,166			-	-	
								-	
		Subtotal - Form 1, p 111.57.c	2,415,665	(3,499,352)	0	147,105	5,767,913	5,915,018	

Prepayments Account 165 - Balance @ 12/31/ 2011

23	Acc. No.	Description	2011 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
24	1650001	Prepaid Insurance	31,453	-		31,453		31,453	Plant Related Insurance Policies
25	165000211	Prepaid Taxes	1,918,196	1,918,196		-		-	Prepaid Taxes
26	1650003	Prepaid Rents	0	-			-	-	
27	1650004	Prepaid Interest	0	-				-	
28	1650005	Prepaid Employee Benefits	0	-			-	-	
29	1650006	Other Prepayments	0	-				-	
30	1650009	Prepaid Carry Cost-Factored AR	6,646	6,646				-	AR Factoring - Retail Only
31	1650010	Prepaid Pension Benefits	5,420,740				5,420,740	5,420,740	Prefunded Pension Expense
32	1650014	FAS 158 Qual Contra Asset	(5,420,740)	(5,420,740)				-	SFAS 158 Offset
33	1650016	FAS 112 ASSETS	0	-			-	-	
34	1650021	Prepaid Insurance - EIS	101,103	-		101,103		101,103	
35	1650023	Prepaid Lease	46,521	46,521			-	-	
								-	
		Subtotal - Form 1, p 111.57.d	2,103,919	(3,449,377)	0	132,556	5,420,740	5,553,296	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
KINGSPORT POWER COMPANY

Line Number	(A) Description	(B) 2012
1	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 24.b)	-
2	Interest Accrual (Company Records - Note 1)	-
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 12/31/2012 (2012 FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	-

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet E Supporting Revenue Credits
KINGSPORT POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	243,738	243,738	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	18,683	18,683	-
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	1,320,393	1,281,248	39,145
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	308,757	41,847	266,910
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	2,662,417	2,662,417	-
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	4,553,988	4,247,933	306,055
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	4,553,988	4,247,933	306,055

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or KINGSPORT 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 2012 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
KINGSPORT POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C) 2012 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1		No Applicable Charges for KGPCO	-			
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	238			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	42,378			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(3)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	1,263			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	6,581			
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	0			
14		**Total of Account 561**	50,457			
		Account 928				
15	9280000	Regulatory Commission Exp	-	-	-	
16	9280001	Regulatory Commission Exp-Adm	(1)	(1)	-	
17	9280002	Regulatory Commission Exp-Case	38	38	-	
18		**Total**	37	37	-	
		Account 930.1				
19	9301000	General Advertising Expenses	145	145	-	
20	9301010	Publicity	73	73	-	
21	9301011	Dedications, Tours, & Openings	0	0	-	
22	9301012	Public Opinion Surveys	636	636	-	
23	9301013	Movies Slide Films & Speeches	-	-	-	
24	9301014	Video Communications	1	1	-	
25	9301015	Other Corporate Comm Exp	2,169	2,169	-	
26		**Total**	3,024	3,024	-	
		Account 930.2				
27	9302000	Misc General Expenses	(6,008)	(6,008)		
28	9302003	Corporate & Fiscal Expenses	866	866		
29	9302004	Research, Develop&Demonstr Exp	469	469		
30	9302005	Nucl Fac Ins - Replce Engy Cst	0	0		
31	9302006	Assoc Bus Dev - Materials Sold	0	0		
32	9302007	Assoc Business Development Exp	189,776	17,044	172,732	
33		**Total**	185,103	12,371	172,732	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
KINGSPORT POWER COMPANY

Tennessee Excise Tax Rate	6.50%	
Apportionment Factor - Note 2	99.32%	
Effective State Tax Rate		6.46%
Total Effective State Income Tax Rate		6.46%

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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
KINGSPORT 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	3,846,121				3,846,121
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Tennessee	914,068	914,068			
5	Real and Personal Property - Other	0	-			
6	**Payroll Taxes**					
7	Federal Insurance Contribution (FICA)	146,784		146,784		
8	Federal Unemployment Tax	388		388		
9	State Unemployment Insurance	4,725		4,725		
10	**Production Taxes**					
11	State Severance Taxes	-				-
12	**Miscellaneous Taxes**					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	484,651			484,651	
15	State Franchise Taxes	(81,618)			(81,618)	
16	State Lic/Registration Fee	1,872			1,872	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	1,878				1,878
19	Federal Excise Tax	-				-
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	5,318,869	914,068	151,897	404,905	3,847,999

(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)	-	11,738,689	69,677,969	1,825,976	83,242,634
	TENNESSEE JURISDICTION					
23	Percentage of Plant in TENNESSEE JURISDICTION		100.00%	100.00%	100.00%	
24	Net Plant in TENNESSEE JURISDICTION (Ln 22 * Ln 23)	-	11,738,689	69,677,969	1,825,976	83,242,634
25	Less: Net Value of Exempted Generation Plant	-				
26	Taxable Property Basis (Ln 24 - Ln 25)	-	11,738,689	69,677,969	1,825,976	83,242,634
27	Relative Valuation Factor		100%	100%	100%	3
28	Weighted Net Plant (Ln 26 * Ln 27)	-	11,738,689	69,677,969	1,825,976	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	0.00%	14.42%	85.58%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	-	263,270	1,562,706	(1,825,976)	-
31	Weighted TENNESSEE JURISDICTION Plant (Ln 28 + 30)	-	12,001,959	71,240,675	-	83,242,634
32	Functional Percentage (Ln 31/Total Ln 31)	0.00%	14.42%	85.58%		
33	Functionalized Expense in TENNESSEE JURISDICTION	-	131,791	782,277		914,068
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		-			-
35	Total Func. Property Taxes (Sum Lns 33, 34)	-	131,791	782,277		914,068

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
KINGSPORT 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	3,846,121		
			1,918,196	P.263 ln 34 (i)
			1,927,925	P.263 ln 35 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Tennessee	914,068		
			(75,032)	P.263 ln 19 (i)
			989,100	P.263 ln 20 (i)
5	Real and Personal Property - Other	-		
			-	
6	Payroll Taxes			
7	Federal Insurance Contribution (FICA)	146,784		
			146,784	P.263 ln 5 (i)
8	Federal Unemployment Tax	388		
			388	P.263 ln 6 (i)
9	State Unemployment Insurance	4,725		
			4,725	P.263 ln 31 (i)
10	Production Taxes			
11	State Severance Taxes	-		
			-	
12	Miscellaneous Taxes			
13	State Business & Occupation Tax	-		
			-	
14	State Public Service Commission Fees	484,651		
			484,651	P.263.1 ln 3 (i)
15	State Franchise Taxes	(81,618)		
			(81,618)	P.263 ln 27 (i)
			-	P.263 ln 29 (i)
16	State Lic/Registration Fee	1,872		
			1,802	P.263.1 ln 13 (i)
			45	P.263.1 ln 19 (i)
			25	P.263.1 ln 20 (i)
17	Misc. State and Local Tax	-		
			-	
18	Sales & Use	1,878		
			240	P.263 ln 14 (i)
			1,638	P.263 ln 15 (i)
19	Federal Excise Tax	-		
			-	
20	Michigan Single Business Tax	-		
			-	
21	Total Taxes by Allocable Basis	5,318,869	5,318,869	
	(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 2012 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
KINGSPORT POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	20,264,445
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	22,330,531
3		42,594,976
4	Average Balance of Transmission Investment	21,297,488
5	Annual Depreciation Expense, Historic TCOS, ln 276	533,521
6	Composite Depreciation Rate	2.51%
7	Round to 2.51% to Reflect a Composite Life of 40 Years	2.51%

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	$ 2,640,060	2.51%	$ 66,266	$ 5,522	11	$ 60,742
10	February	$ 49,040	2.51%	$ 1,231	$ 103	10	$ 1,030
11	March	$ 118,797	2.51%	$ 2,982	$ 248	9	$ 2,232
12	April	$ 93,618	2.51%	$ 2,350	$ 196	8	$ 1,568
13	May	$ 69,256	2.51%	$ 1,738	$ 145	7	$ 1,015
14	June	$ 145,532	2.51%	$ 3,653	$ 304	6	$ 1,824
15	July	$ 65,096	2.51%	$ 1,634	$ 136	5	$ 680
16	August	$ 70,442	2.51%	$ 1,768	$ 147	4	$ 588
17	September	$ 209,337	2.51%	$ 5,254	$ 438	3	$ 1,314
18	October	$ 55,626	2.51%	$ 1,396	$ 116	2	$ 232
19	November	$ 57,710	2.51%	$ 1,449	$ 121	1	$ 121
20	December	$ 2,553,834	2.51%	$ 64,101	$ 5,342	0	$ -
21	Investment	$ 6,128,348				Depreciation Expense	$ 71,346

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 2012

		Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**		
26	N/A	$0	Multiple
27	Subtotal	$0	
28	**PJM Socialized/Beneficiary Allocated Regional Projects**		
29	N/A	$0	
30	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
KINGSPORT 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	40.04%	4.52%	1.810%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	59.96%	11.49%	6.890%
		R =	8.700%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	-	-	$ -

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

Rate Base (Projected TCOS, ln 78)	14,947,799
R (from A. above)	8.700%
Return (Rate Base x R)	1,300,385

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

Return (from B. above)	1,300,385
Effective Tax Rate (Projected TCOS, ln 126)	51.06%
Income Tax Calculation (Return x CIT)	663,979
ITC Adjustment	-
Income Taxes	663,979

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)	3,760,479
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	1,300,385
Income Taxes (Projected TCOS, ln 133)	663,979
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,796,115

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,796,115
Return (from I.B. above)	1,300,385
Income Taxes (from I.C. above)	663,979
Annual Revenue Requirement, with Basis Point ROE increase	3,760,479
Depreciation (Projected TCOS, ln 111)	533,521
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	3,226,958

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	11,738,689
Annual Revenue Requirement, with Basis Point ROE increase	3,760,479
FCR with Basis Point increase in ROE	32.03%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	3,226,958
FCR with Basis Point ROE increase, less Depreciation	27.49%
FCR less Depreciation (Projected TCOS, ln 9)	18.28%
Incremental FCR with Basis Point ROE increase, less Depreciation	9.21%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	20,264,445
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	22,330,531
Subtotal	42,594,976
Average Transmission Plant Balance for 2012	21,297,488
Annual Depreciation Rate (Projected TCOS, ln 111)	533,521
Composite Depreciation Rate	2.51%
Depreciable Life for Composite Depreciation Rate	39.92
Round to nearest whole year	40

KgPCo 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	18.28%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	18.28%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
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.

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 2012 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
KINGSPORT 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	40.24%	4.52%		1.819%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	59.76%	11.49%		6.867%
			R =	8.685%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS		Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR	2012			
	As Projected in Prior Year WS J			$ -
	Actual after True-up	$ -	$ -	$ -
	True-up of ARR For 2012	-	-	-

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

Rate Base (True-Up TCOS, ln 78)	8,871,981
R (from A. above)	8.685%
Return (Rate Base x R)	770,568

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

Return (from B. above)	770,568
Effective Tax Rate (True-Up TCOS, ln 126)	50.97%
Income Tax Calculation (Return x CIT)	392,762
ITC Adjustment	-
Income Taxes	392,762

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)	2,885,916
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	770,568
Income Taxes (True-Up TCOS, ln 133)	392,762
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,722,587

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,722,587
Return (from I.B. above)	770,568
Income Taxes (from I.C. above)	392,762
Annual Revenue Requirement, with 0 Basis Point ROE increase	2,885,916
Depreciation (True-Up TCOS, ln 111)	533,521
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	2,352,395

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

Net Transmission Plant (True-Up TCOS, ln 48)	10,899,330
Annual Revenue Requirement, with 0 Basis Point ROE increase	2,885,916
FCR with 0 Basis Point increase in ROE	26.48%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	2,352,395
FCR with 0 Basis Point ROE increase, less Depreciation	21.58%
FCR less Depreciation (True-Up TCOS, ln 9)	21.58%
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)):	20,264,445
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	22,330,531
Subtotal	42,594,976
Average Transmission Plant Balance for	21,297,488
Annual Depreciation Rate (True-Up TCOS, ln 111)	533,521
Composite Depreciation Rate	2.51%
Depreciable Life for Composite Depreciation Rate	39.92
Round to nearest whole year	40

KgPCo 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:

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details			
Investment		Current Year	2012
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	21.58%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	21.58%
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 2012 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
KINGSPORT 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 Co.		20,000,000	4.520%	904,000	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	N/A for Kingsport Power Company				-	
6					-	
7					-	
8					-	
9					-	
10					-	
11					-	
12					-	
13					-	
14					-	
15					-	
16					-	
17					-	
18					-	
19					-	
20					-	
21					-	
22					-	
23					-	
24					-	
25					-	
26				0.000%		
27	Issuance Discount, Premium, & Expenses:					
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
29	Allowable Hedge Amortization (See Ln 45 Below)				-	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			-	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
32	Reacquired Debt:					
33	Amortization of Loss	FF1.p. 117.64.c			-	
34	Amortization of Gain	FF1.p. 117.66.c			-	
35	**Total Interest on Long Term Debt**		20,000,000	4.52%	904,000	
36	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
37	4.125% Series - $100 - Shares O/S		-	0.00%	-	
38					-	
39					-	
40	**Dividends on Preferred Stock**		-	0.00%	-	
41	Net Total Hedge Gains and Losses (WS M, Ln 35, (E))				-	
42	Total Projected Capital Structure Balance for 2013 (Projected TCOS, Ln 165)				49,955,380	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
44	Limit of Recoverable Amount				24,978	
45	**Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)**				**-**	

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

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	29,956,296	29,450,188	29,703,242
2	Less Preferred Stock (Ln 55 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	0	0	0
4	Less Account 219.1 (112.15.c&d)	916	-2,751	-918
5	**Average Balance of Common Equity**	29,955,380	29,452,939	**29,704,160**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	0	0	0
7	Less: Reacquired Bonds (112.19.c&d)	0	0	0
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)	0	0	0
10	Less: Fair Value Hedges (See Note on Ln 12 below)	0	0	0
11	**Total Average Debt**	20,000,000	20,000,000	**20,000,000**

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 2012**	
14	Interest on Long Term Debt (256-257.33.i)	904,000
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.	-
16	Plus: Allowed Hedge Recovery From Ln 39 below.	-
17	Amort of Debt Discount & Expense (117.63.c)	-
18	Amort of Loss on Reacquired Debt (117.64.c)	-
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)**	**904,000**
22	**Average Cost of Debt for 2012 (Ln 21/Ln 11)**	**4.52%**

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 2012	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	0	-	-			
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	-	-				

35	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)	-
36	Total Average Capital Structure Balance for 2012 (True-UP TCOS, Ln 165)	49,704,160
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
38	Limit of Recoverable Amount	24,852
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**	-

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)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
56	**Dividends on Preferred Stock (Lns 44, 49, 54)**	-	-	-
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
KINGSPORT 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 2012		-		-	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances

Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
KINGSPORT POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount	48,100,000

Allocation of PBOP Settlement Amount for 2012

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 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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

Line		APCo		I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9	Direct Charged PBOP Expense per Actuarial Report	10,991,074		9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10	Additional PBOP Ledger Entries (from Company Records)	(669,581)		(45,394)	-	-	1,105,077	-	
11	Medicare Subsidy	-		-	-	-	-	-	-
12	Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493		9,791,529	1,994,927 -	247,734	14,733,305	282,183	37,371,171
13	PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300		795,128	193,112	30,141	1,430,998	32,337	3,520,016
14	Company PBOP Expense (Ln 12 + Ln 13)	11,359,793		10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

KINGSPORT POWER COMPANY

	PLANT ACCT.	**RATES** Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.10%
Station Equipment	353.0	2.57%
Towers & Fixtures	354.0	1.91%
Poles & Fixtures	355.0	4.20%
Overhead Conductors	356.0	2.50%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		**2.59%**

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Case No. U-84-7308.

Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved for these plant accounts.

General Note

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

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

OHIO POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$281,223,353
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,374,004	DA	1.00000	$	9,374,004
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	271,849,349

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			Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		3,768,661	DA	1.00000	$	3,768,661
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))					22.52%
7	Monthly Rate	(ln 6 / 12)					1.88%
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))					18.89%
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))					8.26%
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	15,750,749
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		8,170,124
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,734,018
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	5,846,607

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

OHIO POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total NOTE C	Allocator		Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	9,635,707,327	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(156,781,322)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	2,007,735,450	DA		1,948,729,583
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	(3,120)	TP	0.97061	(3,028)
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		130,602,038	DA	1.00000	130,602,038
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		-	DA	1.00000	-
24	Distribution	(Worksheet A ln 5.C)	3,718,113,471	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	243,597,754	W/S	0.06771	16,493,878
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(306,041)	W/S	0.06771	(20,722)
28	Intangible Plant	(Worksheet A ln 9.C)	138,963,972	W/S	0.06771	9,409,178
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	15,717,629,529			2,105,210,927
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	4,248,263,554	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(83,178,723)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	817,203,711	**TP1=**	0.96845	791,423,913
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	(2,793)	**TP1=**	0.96845	(2,705)
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		1,744,661	DA	1.00000	1,744,661
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		44,851,117	TP1	0.96845	43,436,228
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		26,801,690	W/S	0.06771	1,814,729
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	1,391,679,118	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	91,783,557	W/S	0.06771	6,214,617
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(184,484)	W/S	0.06771	(12,491)
44	Intangible Plant	(Worksheet A ln 20.C)	120,774,423	W/S	0.06771	8,177,574
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	6,659,735,831			852,796,525
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	5,313,841,174			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,190,531,412			1,157,305,347
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		128,857,377			128,857,377
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(44,851,117)			(43,436,228)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(26,801,690)			(1,814,729)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	2,326,434,353			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	151,692,640			10,271,030
56	Intangible Plant	(ln 28 - ln 44)	18,189,549			1,231,605
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	9,057,893,698			1,252,414,402
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(376,657,740)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,764,794,823)	DA		(217,344,579)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(604,077,136)	DA		(20,707,549)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	359,572,801	DA		20,846,170
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(322,356)	DA		(191,502)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(2,386,279,254)			(217,397,460)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	16,588,944	DA		6,002,010
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	4,227,249			4,103,013
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,602,775	TP	0.97061	1,555,671
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	223,854	W/S	0.06771	15,157
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.12668	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	447,235,548	W/S	0.06771	30,282,087
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,444,103	GP(h)	0.12668	562,992
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	4,940	DA	1.00000	4,940
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(433,956,947)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	23,781,522			36,523,860
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,464,505)	DA	1.00000	(2,464,505)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		6,709,520,405			1,075,078,307

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

OHIO POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	**EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	**Data Sources (See "General Notes")**	**TO Total**	**Allocator**		**Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	2,425,125,006			
80	Distribution	322.156.b	155,564,708			
81	Customer Related Expense	322.164,171,178.b	239,467,579			
82	Regional Marketing Expenses	322.131.b	8,466,532			
83	Transmission	321.112.b	52,839,386			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,881,463,211			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	15,750,749			
86	Less: Account 565	(Note H) 321.96.b	22,667,784			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(19,397,139)			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	33,817,992	TP	0.97061	32,824,106
89	Administrative and General	323.197.b (Note J)	159,175,788			
90	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
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)	1,430,998			
94	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	119,347,556	W/S	0.06771	8,080,961
98	Plus: Acct. 924, Property Insurance	(ln 90)	6,727,215	GP(h)	0.12668	852,223
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97061	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.97061	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 39.(E) (Note L)	188,031	DA	1.00000	188,031
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06771	1,287,425
103	A & G Subtotal	(sum lns 97 to 102)	145,276,752			10,408,640
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	179,094,744			43,232,746
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)	1,351,836	DA	1.00000	1,351,836
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	180,446,580			44,584,582
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	329,291,837	NA	0.00000	-
110	Distribution	336.8.f	94,896,667	NA	0.00000	-
111	Transmission	336.7.f	44,851,117	TP1	0.96845	43,436,228
112	Plus: Transmission Plant-in-Service Additions	(Worksheet I ln 21.I)	1,744,661	DA	1.00000	1,744,661
113	General	336.10.f	2,874,916	W/S	0.06771	194,659
114	Intangible	336.1.f	23,926,774	W/S	0.06771	1,620,069
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	497,585,972			46,995,617
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	14,141,746	W/S	0.06771	957,530
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 46.(C)	214,463,890	DA		55,838,317
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	169,923,630	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	6,440,495	GP(h)	0.12668	815,900
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	404,969,761			57,611,748
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.64%			
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)		1.5572			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
131	Income Tax Calculation	(ln 126 * ln 134)	234,549,556			37,582,290
132	ITC adjustment	(ln 129 * ln 130)	(2,753,829)	NP(h)	0.12986	(357,606)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	231,795,728			37,224,684
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	591,684,933			94,806,722
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		1,906,482,974			281,223,353

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SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							2,007,735,450
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)								59,005,867
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)							1,948,729,583
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)						**TP**	**0.97061**
				Payroll Billed from					
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total				
145	Production	354.20.b	92,815,544	26,811,434	119,626,978	NA	0.00000		-
146	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.97061		14,555,650
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000		-
150	Total	(sum lns 145 to 149)	159,765,501	55,206,613	214,972,114				14,555,650
151	Transmission related amount							**W/S=**	**0.06771**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
153	Long Term Interest	(Worksheet L, ln. 51, col. (D))				216,794,185
154	Preferred Dividends	(Worksheet L, ln. 57, col. (D))				-
155	Development of Common Stock:					
156	Proprietary Capital	(FF1 p 112, Ln 16.c)				4,489,200,654
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)				-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)				2,204,800
159	Less: Account 219	(FF1 p 112, Ln 15.c)				(165,724,552)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)				4,652,720,406
161			$	%	Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 51, col. (B))		3,867,825,000	45.39%	0.0561	0.0254
163	Preferred Stock (ln 157)		-	0.00%	-	0.0000
164	Common Stock (ln 160)		4,652,720,406	54.61%	11.49%	0.0627
165	Total (Sum lns 162 to 164)		8,520,545,406		**WACC=**	**0.0882**

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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, 2013. Other ratebase amounts are as of December 31, 2012.
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 OHIO 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= 1.20% (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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OHIO POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$269,183,096
167	REVENUE CREDITS	(Note A) (Worksheet E)	9,374,004	DA	1.00000	$	9,374,004
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	259,809,092

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)	23.14%
172	Monthly Rate	(ln 171 / 12)	1.93%
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)	19.39%
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)	8.87%
177	Not applicable on this template		

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

179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	15,750,749
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		8,170,124
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,734,018
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	5,846,607

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OHIO 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)	9,635,707,327	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(156,781,322)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	2,007,735,450	DA		1,948,729,583
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	(3,120)	TP	0.97061	(3,028)
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)	3,718,113,471	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)	243,597,754	W/S	0.06771	16,493,878
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(306,041)	W/S	0.06771	(20,722)
193	Intangible Plant	(Worksheet A ln 9.C)	138,963,972	W/S	0.06771	9,409,178
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	15,587,027,491	**GP(h)=**	**0.126683**	1,974,608,889
				GTD=	**0.34034**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	4,248,263,554	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(83,178,723)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	817,203,711	**TP1=**	0.96845	791,423,913
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	(2,793)	**TP1=**	0.96845	(2,705)
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 2013 (ln 276)		N/A	TP1	0.96845	N/A
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		N/A	W/S	0.06771	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)	1,391,679,118	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)	91,783,557	W/S	0.06771	6,214,617
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(184,484)	W/S	0.06771	(12,491)
209	Intangible Plant	(Worksheet A ln 20.C)	120,774,423	W/S	0.06771	8,177,574
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	6,586,338,363			805,800,907
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	5,313,841,174			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	1,190,531,412			1,157,305,347
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 2013 (-ln 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	2,326,434,353			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	151,692,640			10,271,030
221	Intangible Plant	(ln 193 - ln 209)	18,189,549			1,231,605
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	9,000,689,128	**NP(h)=**	**0.129858**	1,168,807,982
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(376,657,740)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,764,794,823)	DA		(217,344,579)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(604,077,136)	DA		(20,707,549)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	359,572,801	DA		20,846,170
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(322,356)	DA		(191,502)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(2,386,279,254)			(217,397,460)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	16,588,944	DA		6,002,010
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	4,227,249			4,103,013
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,602,775	TP	0.97061	1,555,671
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	223,854	W/S	0.06771	15,157
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.12668	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	447,235,548	W/S	0.06771	30,282,087
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,444,103	GP(h)	0.12668	562,992
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	4,940	DA	1.00000	4,940
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(433,956,947)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	23,781,522			36,523,860
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,464,505)	DA	1.00000	(2,464,505)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		6,652,315,835			991,471,886

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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					
244	Production	321.80.b	2,425,125,006			
245	Distribution	322.156.b	155,564,708			
246	Customer Related Expense	322 & 323.164,171,178.b	239,467,579			
247	Regional Marketing Expenses	322.131.b	8,466,532			
248	Transmission	321.112.b	52,839,386			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	2,881,463,211			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	15,750,749			
251	Less: Account 565	(Note H) 321.96.b	22,667,784			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(19,397,139)			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	33,817,992	TP	0.97061	32,824,106
254	Administrative and General	323.197.b (Note J)	159,175,788			
255	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
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)	1,430,998			
259	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	119,347,556	W/S	0.06771	8,080,961
263	Plus: Acct. 924, Property Insurance	(ln 255)	6,727,215	GP(h)	0.12668	852,223
264	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97061	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.97061	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 39.(E) (Note L)	188,031	DA	1.00000	188,031
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06771	1,287,425
268	A & G Subtotal	(sum lns 262 to 267)	145,276,752			10,408,640
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	179,094,744			43,232,746
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)		1,351,836	DA	1.00000	1,351,836
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	180,446,580			44,584,582
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	329,291,837	NA	0.00000	-
275	Distribution	336.8.f	94,896,667	NA	0.00000	-
276	Transmission	336.7.f	44,851,117	TP1	0.96845	43,436,228
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	2,874,916	W/S	0.06771	194,659
279	Intangible	336.1.f	23,926,774	W/S	0.06771	1,620,069
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	495,841,311			45,250,956
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 22.(D)	14,141,746	W/S	0.06771	957,530
284	Plant Related					
285	Property	Worksheet H ln 22.(C) & ln 46.(C)	214,463,890	DA		55,838,317
286	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	169,923,630	NA	0.00000	-
287	Other	Worksheet H ln 22.(E)	6,440,495	GP(h)	0.12668	815,900
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	404,969,761			57,611,748
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.64%			
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)		1.5572			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
296	Income Tax Calculation	(ln 291 * ln 299)	232,549,815			34,659,600
297	ITC adjustment	(ln 294 * ln 295)	(2,753,829)	NP(h)	0.12986	(357,606)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	229,795,986			34,301,994
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	586,640,298			87,433,817
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		1,897,693,936			269,183,096

AEP East Companies
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OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						2,007,735,450
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)							59,005,867
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)						1,948,729,583
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)					TP=	**0.97061**
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
310	Production	354.20.b	92,815,544	26,811,434	119,626,978	NA	0.00000	-
311	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.97061	14,555,650
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000	-
315	Total	(sum lns 310 to 314)	159,765,501	55,206,613	214,972,114			14,555,650
316	Transmission related amount						W/S=	**0.06771**

ln No.							
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
318	Long Term Interest	(Worksheet L, ln. 51, col. (D))					216,794,185
319	Preferred Dividends	(Worksheet L, ln. 57, col. (D))					-
320	Development of Common Stock:						
321	Proprietary Capital	(FF1 p 112, Ln 16.c)					4,489,200,654
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)					-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)					2,204,800
324	Less: Account 219	(FF1 p 112, Ln 15.c)					(165,724,552)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)					4,652,720,406
326			$	%		Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, ln 51, col. (B))		3,867,825,000	45.39%		0.0561	0.0254
328	Preferred Stock (ln 322)		-	0.00%		-	0.0000
329	Common Stock (ln 325)		4,652,720,406	54.61%		11.49%	0.0627
330	Total (Sum lns 327 to 329)		8,520,545,406			WACC=	**0.0882**

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OHIO 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 historic as of December 31, 2012.
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 OHIO 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=	1.20%	(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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OHIO POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$262,126,968
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,374,004	DA	1.00000	$	9,374,004
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	252,752,964

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			Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		1,248,552	DA	1.00000	$	1,248,552
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)					22.95%
7	Monthly Rate	(ln 6 / 12)					1.91%
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)					19.12%
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)					9.02%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)						-

Line No.	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
13			
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	15,750,749
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		8,170,124
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,734,018
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	5,846,607

AEP East Companies
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OHIO POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total NOTE C	Allocator		Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.E)	9,594,903,388	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(147,663,530)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	1,975,031,336	DA		1,912,556,564
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	(3,120)	TP	0.96837	(3,021)
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)	3,629,498,388	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)	237,211,272	W/S	0.06755	16,024,335
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(302,345)	W/S	0.06755	(20,424)
28	Intangible Plant	(Worksheet A ln 9.E)	134,867,469	W/S	0.06755	9,110,703
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	15,423,542,858	**GP(h)=**	**0.12563**	1,937,668,157
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	3,995,173,718	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(62,740,187)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	800,387,107	**TP1=**	0.96959	776,047,164
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	(2,730)	**TP1=**	0.96959	(2,647)
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 2013 (ln 111)		**N/A**	TP1	0.96959	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		**N/A**	W/S	0.06755	**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)	1,377,680,530	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)	90,270,181	W/S	0.06755	6,098,022
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(180,547)	W/S	0.06755	(12,197)
44	Intangible Plant	(Worksheet A ln 20.E)	120,254,303	W/S	0.06755	8,123,540
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	6,320,842,375			790,253,883
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	5,514,806,327			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,174,643,838			1,136,509,025
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 2013 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	2,251,817,858			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	146,819,294			9,918,085
56	Intangible Plant	(ln 28 - ln 44)	14,613,166			987,163
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	9,102,700,483	**NP(h)=**	**0.12605**	1,147,414,274
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(365,058,899)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(1,721,775,224)	DA		(207,630,107)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(599,674,423)	DA		(25,438,664)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	386,507,941	DA		20,998,024
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	(435,825)	DA		(264,599)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(2,300,436,429)			(212,335,346)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	16,588,944	DA		6,002,010
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	4,227,249			4,093,531
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,296,983	TP	0.96837	1,255,956
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	249,065	W/S	0.06755	16,825
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.12563	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	435,409,304	W/S	0.06755	29,413,208
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	4,728,100	GP(h)	0.12563	593,994
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	6,260	DA	1.00000	6,260
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(419,893,914)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	26,023,046			35,379,775
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(2,464,505)	DA	1.00000	(2,464,505)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		6,842,411,539			973,996,207

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OHIO 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	2,425,125,006			
80	Distribution	322.156.b	155,564,708			
81	Customer Related Expense	322.164,171,178.b	239,467,579			
82	Regional Marketing Expenses	322.131.b	8,466,532			
83	Transmission	321.112.b	52,839,386			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,881,463,211			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	15,750,749			
86	Less: Account 565	(Note H) 321.96.b	22,667,784			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	(19,397,139)			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	33,817,992	TP	0.96837	32,748,251
89	Administrative and General	323.197.b (Note J)	159,175,788			
90	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
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)	1,430,998			
94	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	119,347,556	W/S	0.06755	8,062,286
98	Plus: Acct. 924, Property Insurance	(ln 90)	6,727,215	GP(h)	0.12563	845,144
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	0.97061	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.97061	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 39.(E) (Note L)	188,031	DA	1.00000	188,031
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06755	1,284,450
103	A & G Subtotal	(sum lns 97 to 102)	145,276,752			10,379,911
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	179,094,744			43,128,162
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)		1,351,836	DA	1.00000	1,351,836
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	180,446,580			44,479,998
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	329,291,837	NA	0.00000	-
110	Distribution	336.8.f	94,896,667	NA	0.00000	-
111	Transmission	336.7.f	44,851,117	TP1	0.96959	43,487,185
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	2,874,916	W/S	0.06755	194,209
114	Intangible	336.1.f	23,926,774	W/S	0.06755	1,616,326
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	495,841,311			45,297,720
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	14,141,746	W/S	0.06755	955,317
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 46.(C)	214,463,890	DA		55,838,317
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	169,923,630	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	6,440,495	GP(h)	0.12563	809,123
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	404,969,761			57,602,758
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		38.18%			
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)		1.5572			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
131	Income Tax Calculation	(ln 126 * ln 134)	223,399,885			31,800,286
132	ITC adjustment	(ln 129 * ln 130)	(2,753,829)	NP(h)	0.12605	(347,126)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	220,646,056			31,453,160
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	585,143,202			83,293,333
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		1,887,046,911			262,126,968

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							1,975,031,336
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)								62,474,772
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)							1,912,556,564
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)						**TP**	**0.96837**
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
145	Production	354.20.b	92,815,544	26,811,434	119,626,978	NA	0.00000		-
146	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.96837		14,522,013
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000		-
150	Total	(sum lns 145 to 149)	159,765,501	55,206,613	214,972,114				14,522,013
151	Transmission related amount							**W/S=**	**0.06755**

ln No.				
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)			$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))		217,821,003
154	Preferred Dividends	(Worksheet M, ln. 56, col. (E))		-
155	Development of Common Stock:			Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))		4,451,435,059
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))		-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))		2,204,800
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))		(181,723,094)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)		4,630,953,353

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))	3,965,075,000	46.13%	49.00%	0.0549	0.0269
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Commone Stock (ln 160)	4,630,953,353	53.87%	51.00%	11.49%	0.0586
165	Total (Sum lns 162 to 164)	8,596,028,353			**WACC=**	**0.0855**
166	Capital Structure Equity Limit (Note U)	51.0%				

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

OHIO 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, 2011 and December 31, 2012.
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 OHIO 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 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= 1.20% (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 OHIO POWER COMPANY is limited to 51% 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 2012 FF1 Balances
Worksheet A Supporting Plant Balances
OHIO POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
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	9,635,707,327	9,554,099,448	9,594,903,388
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	156,781,322	138,545,737	147,663,530
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	2,007,735,450	1,942,327,221	1,975,031,336
4	**Transmission Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	3,120	3,120	3,120
5	**Distribution Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	3,718,113,471	3,540,883,305	3,629,498,388
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	243,597,754	230,824,790	237,211,272
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	306,041	298,648	302,345
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	138,963,972	130,770,966	134,867,469
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	15,744,117,974	15,398,905,730	15,571,511,852
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	157,090,483	138,847,505	147,968,994
Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	4,248,263,554	3,742,083,882	3,995,173,718
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	83,178,723	42,301,650	62,740,187
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	817,203,711	783,570,503	800,387,107
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	2,793	2,667	2,730
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	1,391,679,118	1,363,681,942	1,377,680,530
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	91,783,557	88,756,804	90,270,181
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	184,484	176,610	180,547
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	120,774,423	119,734,183	120,254,303
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	6,669,704,363	6,097,827,314	6,383,765,839
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	83,366,000	42,480,927	62,923,464
Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records - Note 1	59,005,867	65,943,676	62,474,772
24	**GSU Accumulated Depreciation**	Company Records - Note 1	25,779,798	22,900,088	24,339,943
25	**GSU Net Balance**	(Line 23 - Line 24)	33,226,069	43,043,588	38,134,829
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	817,203,711	783,570,503	800,387,107
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	25,779,798	22,900,088	24,339,943
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	791,423,913	760,670,415	776,047,164
Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	16,588,944	16,588,944	16,588,944
30	**Transmission Plant Held For Future**	Company Records - Note 1	6,002,010	6,002,010	6,002,010
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 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
OHIO POWER COMPANY

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	376,657,740	353,460,058	365,058,899
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	376,657,740	353,460,058	365,058,899
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)	1,764,794,823	1,678,755,624	1,721,775,224
8	Less: ARO Related Deferrals	Company Records - Note 1	143,372,308	143,612,717	143,492,513
9	Less: Other Excluded Deferrals	Company Records - Note 1	1,404,077,936	1,337,227,272	1,370,652,604
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	217,344,579	197,915,635	207,630,107
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	604,077,136	595,271,709	599,674,423
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	583,369,588	565,101,929	574,235,759
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	20,707,549	30,169,780	25,438,664
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	359,572,801	413,443,081	386,507,941
18	Less: ARO Related Deferrals	Company Records - Note 1	92,573,078	82,805,850	87,689,464
19	Less: Other Excluded Deferrals	Company Records - Note 1	246,153,553	309,487,354	277,820,454
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	20,846,170	21,149,877	20,998,024
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	11,643,327	13,492,560	12,567,944
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	11,320,971	12,943,267	12,132,119
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	322,356	549,293	435,825
25	Transmission Related Deferrals	Company Records - Note 1	191,502	337,695	264,599

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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
OHIO POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2012	(E) Balance @ December 31, 2011	(F) Average Balance for 2012
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,602,775	991,190	1,296,983
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (t	223,854	274,275	249,065
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (t	0	0	-

Prepayment Balance Summary

5		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
6	Totals as of December 31, 2012	17,727,644	(433,956,947)	4,940	4,444,103	447,235,548	451,684,591
7	Totals as of December 31, 2011	22,771,855	(405,830,881)	7,580	5,012,096	423,583,060	428,602,736
8	**Average Balance**	20,249,750	(419,893,914)	6,260	4,728,100	435,409,304	440,143,664

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	2,862,276	-		2,862,276		2,862,276	Plant Related Insurance Policies
11	1650003	Prepaid Rents	46,896	46,896				-	Prepaid Rents Generation
12	1650004	Prepaid Interest	0	-			-	-	
13	1650005	Prepaid Employee Benefits	0	-			-	-	
14	1650006	Other Prepayments	4,940	-	4,940		-	4,940	Relates to Towers
15	1650009	Prepaid Carry Cost-Factored AR	125,583	125,583				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	447,235,548				447,235,548	447,235,548	Prepaid Pension Expense
17	165001212	Prepaid Taxes	140,000	140,000				-	Prepaid Taxes
18	1650013	Gavin JMG ST Prepaid Exp - Aff	0	-				-	
19	1650014	FAS 158 Qual Contra Asset	(447,235,548)	(447,235,548)				-	FAS 158 Liability
20	1650016	FAS 112 ASSETS	0	-					
21	1650017	Prepayments - Coal	0	-					
22	1650019	Prepaid Pension Expense - CG&E	4,770,193	4,770,193					
23	1650020	Prepaid Pension Expense - DP&L	8,195,929	8,195,929					
24	1650021	Prepaid Insurance - EIS	1,581,827	-		1,581,827		1,581,827	Energy INS Services
25	1650023	Prepaid Lease	0	-				-	
		Subtotal - Form 1, p 111.57.c	17,727,644	(433,956,947)	4,940	4,444,103	447,235,548	451,684,591	

Prepayments Account 165 - Balance @ 12/31/ 2011

26	Acc. No.	Description	2011 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
27	1650001	Prepaid Insurance	3,325,221	-		3,325,221		3,325,221	Plant Related Insurance Policies
28	1650003	Prepaid Rents	46,896	46,896				-	Prepaid Rents Generation
29	1650004	Prepaid Interest	0	-			-	-	
30	1650005	Prepaid Employee Benefits	0	-			-	-	
31	1650006	Other Prepayments	7,580	-	7,580			7,580	Relates to Towers
32	1650009	Prepaid Carry Cost-Factored AR	251,608	251,608				-	AR Factoring - Retail Only
33	1650010	Prepaid Pension Benefits	423,583,060				423,583,060	423,583,060	Prepaid Pension Expense
34	165001211	Prepaid Taxes	131,549	131,549		-		-	Prepaid Taxes
35	1650013	Gavin JMG ST Prepaid Exp - Aff	0	-				-	
36	1650014	FAS 158 Qual Contra Asset	(419,542,403)	(419,542,403)				-	FAS 158 Liability
37	1650016	FAS 112 ASSETS	0	-					
38	1650017	Prepayments - Coal	2,328,742	2,328,742					
39	1650019	Prepaid Pension Expense - CG&E	6,760,255	6,760,255					
40	1650020	Prepaid Pension Expense - DP&L	4,183,940	4,183,940					
41	1650021	Prepaid Insurance - EIS	1,686,875			1,686,875		1,686,875	Energy INS Services
42	1650023	Prepaid Lease	8,532	8,532					
		Subtotal - Form 1, p 111.57.d	22,771,855	(405,830,881)	7,580	5,012,096	423,583,060	428,602,736	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
OHIO POWER COMPANY

Line Number	**(A) Description**	**(B) 2012**
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 9.b)	(2,464,505.00)
2	Interest Accrual (Company Records - Note 1)	-
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 12/31/2012 (2012 FORM 1, P269, line 12.f)	(2,464,505.00)
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(2,464,505.00)

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet E Supporting Revenue Credits
OHIO POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	3,208,602	3,208,602	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	7,681,846	7,561,989	119,857
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	29,427,587	20,607,501	8,820,086
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	2,460,269	2,293,334	166,935
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	98,705,326	98,438,200	267,126
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	141,483,630	132,109,626	9,374,004
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	141,483,630	132,109,626	9,374,004

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or OHIO 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 2012 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
OHIO POWER COMPANY

(A) Line Number	Item No.	(B) Description	(C) 2012 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1	5660005	Ohio E-TCR Rider UnderRecovery	(19,397,139)			
2			-			
3						
4		**Total**	(19,397,139)			
		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	34,962			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	5,013,509			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(480)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	8,170,124			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	798,616			
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	1,734,018			
14		**Total of Account 561**	15,750,749			
		Account 928				
15	9280000	Regulatory Commission Exp	2,272	2,272	-	
16	9280001	Regulatory Commission Exp-Adm	361,418	361,418	-	
17	9280002	Regulatory Commission Exp-Case	1,363,182	1,363,182	-	
18		**Total**	1,726,872	1,726,872	-	
		Account 930.1				
19	9301000	General Advertising Expenses	124,848	124,848	-	
20	9301001	Newspaper Advertising Space	370,294	370,294	-	
21	9301003	TV Station Advertising Time	6,033,025	6,033,025		
22	9301006	Spec Corporate Comm Info Project	3	3		
23	9301007	Special Adv Space & Prod Exp	1,006,615	1,006,615	-	
24	9301008	Direct Mail and Handouts	-	-	-	
25	9301009	Fairs, Shows, and Exhibits	342,375	342,375	-	
26	9301010	Publicity	88,061	88,061	-	
27	9301011	Dedications, Tours, & Openings	9	9	-	
28	9301012	Public Opinion Surveys	93,007	93,007	-	
29	9301013	Movies Slide Films & Speeches	-	-	-	
30	9301014	Video Communications	112	112		
31	9301015	Other Corporate Comm Exp	6,037,198	6,037,198	-	
32		**Total**	14,095,547	14,095,547	-	
		Account 930.2				
33	9302000	Misc General Expenses	1,139,883	1,139,883		
34	9302003	Corporate & Fiscal Expenses	165,336	165,336		
35	9302004	Research, Develop&Demonstr Exp	16,094	16,094		
36	9302007	Assoc Business Development Exp	1,091,815	903,784	188,031	
37	9302019	gSMART-Ov/Und Misc Gen Exp	(1,301,988)	-1,301,988		
38	9302458	AEPSC Non-affiliated Exp	3,156	3,156		
39		**Total**	1,114,296	926,265	188,031	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
OHIO POWER COMPANY

West Virginia Corporate Income Tax	7.75%	
Apportionment Factor - Note 2	8.66%	
Effective State Tax Rate		0.67%
Illinois Corporation Income Tax	9.50%	
Apportionment Factor - Note 2	1.94%	
Effective State Tax Rate		0.18%
Michigan Business Income Tax	6.00%	
Apportionment Factor - Note 2	0.09%	
Effective State Tax Rate		0.01%
Kentucky Business Income Tax	6.00%	
Apportionment Factor - Note 2	0.93%	
Effective State Tax Rate		0.06%
Ohio Municipal Net Income Tax	0.36%	
Apportionment Factor - Note 2	79.18%	
Effective State Tax Rate		0.29%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Total Effective State Income Tax Rate		1.20%

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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
OHIO 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	153,709,013				153,709,013
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Ohio	200,874,277	200,874,277			
5	Real and Personal Property - West VA.	13,552,910	13,552,910			
6	Real and Personal Property - Other	36,703	36,703			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	12,667,108		12,667,108		
9	Federal Unemployment Tax	163,225		163,225		
10	State Unemployment Insurance	109,155		109,155		
11	Payroll Taxes	1,202,258		1,202,258		
12	Production Taxes					
13	State Severance Taxes	-				-
14	Miscellaneous Taxes					
15	State Public Service Commission Fees	5,879,061			5,879,061	
16	State Franchise Taxes	556,047			556,047	
17	State Lic/Registration Fee	5,387			5,387	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	(1,089)				(1,089)
20	Federal Excise Tax	8,233				8,233
21	State B & O Taxes	16,207,473				16,207,473
22	Total Taxes by Allocable Basis	404,969,761	214,463,890	14,141,746	6,440,495	169,923,630
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
	NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.					

Functional Property Tax Allocation

Line No.	Account	Production	Transmsission	Distribution	General	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	5,313,841,174	1,190,531,412	2,326,434,353	151,692,640	8,982,499,579
	OHIO JURISDICTION					
24	Percentage of Plant in OHIO JURISDICTION	62.26%	92.89%	99.96%	98.41%	
25	Net Plant in OHIO JURISDICTION (Ln 23 * Ln 24)	3,308,362,372	1,105,844,706	2,325,505,315	149,273,715	6,888,986,107
26	Less: Net Value Exempted Generation Plant	1,380,205,938				
27	Taxable Property Basis (Ln 25 - Ln 26)	1,928,156,434	1,105,844,706	2,325,505,315	149,273,715	5,508,780,169
28	Relative Valuation Factor	24%	85%	85%	24%	
29	Weighted Net Plant (Ln 27 * Ln 28)	462,757,544	939,968,000	1,976,679,517	35,825,692	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	13.69%	27.81%	58.49%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	4,905,777	9,964,773	20,955,141	(35,825,692)	-
30a	Ohio Company Merger Mitigation adjustment (Note 2)	31,000,000	(31,000,000)			-
32	Weighted OHIO JURISDICTION Plant (Ln 29 + 31 + 30a)	498,663,321	918,932,773	1,997,634,658	(0)	3,415,230,753
33	Functional Percentage (Ln 32/Total Ln 32)	14.60%	26.91%	58.49%		
34	Functionalized Payment in OHIO JURISDICTION	29,329,975	54,049,044	117,495,258		200,874,277
	WEST VA JURISDICTION					
35	Net Plant in WEST VA JURISDICTION (Ln - Ln 24)	2,005,478,802	84,686,706	929,038	2,418,925	2,093,513,472
36	Less: Net Value Exempted Generation Plant	1,447,919,082				
37	Taxable Property Basis	557,559,720	84,686,706	929,038	2,418,925	645,594,390
38	Relative Valuation Factor	100%	100%	100%	100%	
39	Weighted Net Plant (Ln 37 * Ln 38)	557,559,720	84,686,706	929,038	2,418,925	
40	General Plant Allocator (Ln 39 / (Total - General Plant)	86.69%	13.17%	0.14%	-100.00%	
41	Functionalized General Plant (Ln 41 * General Plant)	2,096,932	318,499	3,494	(2,418,925)	
42	Weighted WEST VA JURISDICTION Plant (Ln 39 + 41)	559,656,652	85,005,205	932,532	0	645,594,390
43	Functional Percentage (Ln 42/Total Ln 42)	86.69%	13.17%	0.14%		
44	Functionalized Payment in WEST VA JURISDICTION	11,748,826	1,784,507	19,577		13,552,910
45	Total Other Jurisdictions: (Line 7 * Net Plant Allocator)		4,766			36,703
						-
46	Total Functionalized Property Taxes (Sum Lns 33, 44, 45)	41,078,802	55,838,317	117,514,834		214,463,890

Note 2: This adjustment will apply to AEP Ohio only. This adjustment will be in effect for the Annual Updates prepared in 2012, 2013, 2014, 2015 and 2016.

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
OHIO 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	153,709,013		
			202,880	P.263 ln 9 (i)
			10,396,850	P.263 ln 10 (i)
			143,109,283	P.263 ln 13 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Ohio	200,874,277		
			(7,090)	P.263.1 ln 4 (i)
			381,603	P.263.1 ln 5 (i)
			200,347,858	P.263.1 ln 6 (i)
			(4,086)	P.263.1 ln 9 (i)
			210,434	P.263.1 ln 10 (i)
			(24,933)	P.263.1 ln 12 (i)
			(217,152)	P.263.1 ln 13 (i)
			(83,057)	P.263.1 ln 14 (i)
			270,700	P.263.1 ln 15 (i)
5	Real and Personal Property - West VA.	13,552,910		
			7,239,356	P.263.1 ln 17 (i)
			6,305,005	P.263.1 ln 18 (i)
			4,552	P.263.1 ln 22 (i)
			3,997	P.263.1 ln 23 (i)
6	Real and Personal Property - Other	36,703		
			2,385	P.263.1 ln 30 (i)
			(1,682)	P.263.1 ln 37 (i)
			36,000	P.263.1 ln 38 (i)
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	12,667,108		
			12,667,108	P.263 ln 3 (i)
9	Federal Unemployment Tax	163,225		
			163,225	P.263 ln 4 (i)
10	State Unemployment Insurance	109,155		
			57,984	P.263 ln 16 (i)
			51,171	P.263 ln 35 (i)
11	Payroll Taxes	1,202,258		
			1,202,258	P.263.2 ln 14 (i)
12	Production Taxes			
13	State Severance Taxes	-		
			-	
14	Miscellaneous Taxes			
15	State Public Service Commission Fees	5,879,061		
			5,879,061	P.263 ln 11 (i)
16	State Franchise Taxes	556,047		
			610,117	P.263 ln 32 (i)
			(61,721)	P.263 ln 33 (i)
			7,676	P.263 ln 34 (i)
			(25)	P.263.2 ln 21 (i)
17	State Lic/Registration Fee	5,387		
			625	P.263.2 ln 5 (i)
			4,762	P.263.2 ln 6 (i)
18	Misc. State and Local Tax	-		
			-	
19	Sales & Use	(1,089)		
			(1,790)	P.263 ln 14 (i)
			(69)	P.263 ln 15 (i)
			770	P.263 ln 37 (i)
20	Federal Excise Tax	8,233		
			8,233	P.263 ln 6 (i)
21	State B & O Taxes	16,207,473		
			144,162	P.263 ln 38 (i)
			15,735,811	P.263 ln 39 (i)
			327,500	P.263 ln 40(i)
22	Total Taxes by Allocable Basis	404,969,761	404,969,761	
	(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 2012 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
OHIO POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,942,327,221
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	2,007,735,450
3		3,950,062,671
4	Average Balance of Transmission Investment	1,975,031,336
5	Annual Depreciation Expense, Historic TCOS, ln 276	44,851,117
6	Composite Depreciation Rate	2.27%
7	Round to 2.27% to Reflect a Composite Life of 44 Years	2.27%

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	$ 54,876,199	2.27%	$ 1,245,690	$ 103,807	11	$ 1,141,877
10	February	$ 3,599,447	2.27%	$ 81,707	$ 6,809	10	$ 68,090
11	March	$ 4,309,900	2.27%	$ 97,835	$ 8,153	9	$ 73,377
12	April	$ 4,843,762	2.27%	$ 109,953	$ 9,163	8	$ 73,304
13	May	$ 6,588,560	2.27%	$ 149,560	$ 12,463	7	$ 87,241
14	June	$ 14,784,270	2.27%	$ 335,603	$ 27,967	6	$ 167,802
15	July	$ 5,112,238	2.27%	$ 116,048	$ 9,671	5	$ 48,355
16	August	$ 4,611,814	2.27%	$ 104,688	$ 8,724	4	$ 34,896
17	September	$ 3,724,990	2.27%	$ 84,557	$ 7,046	3	$ 21,138
18	October	$ 5,819,524	2.27%	$ 132,103	$ 11,009	2	$ 22,018
19	November	$ 3,469,582	2.27%	$ 78,760	$ 6,563	1	$ 6,563
20	December	$ 18,861,752	2.27%	$ 428,162	$ 35,680	0	$ -
21	Investment	$ 130,602,038				Depreciation Expense	$ 1,744,661

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 2013

		Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**		
26	Transmission Station Repl	$5,672	Dec-13
27	Coneville - Bixby 345kV	$8,248	Dec-13
28			
29			
30			
31	Subtotal	$13,920	
32	**PJM Socialized/Beneficiary Allocated Regional Projects**		
33		$0	
34	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
OHIO 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	45.39%	5.61%	2.544%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	54.61%	11.49%	6.274%
		R =	8.819%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	3,768,661	3,768,661	$ -

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

Rate Base (Projected TCOS, ln 78)	1,075,078,307
R (from A. above)	8.819%
Return (Rate Base x R)	94,806,722

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

Return (from B. above)	94,806,722
Effective Tax Rate (Projected TCOS, ln 126)	39.64%
Income Tax Calculation (Return x CIT)	37,582,290
ITC Adjustment	(357,606)
Income Taxes	37,224,684

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)	281,223,353
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	1,351,836
Return (Projected TCOS, ln 134)	94,806,722
Income Taxes (Projected TCOS, ln 133)	37,224,684
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	147,840,111

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	147,840,111
Return (from I.B. above)	94,806,722
Income Taxes (from I.C. above)	37,224,684
Annual Revenue Requirement, with Basis Point ROE increase	279,871,517
Depreciation (Projected TCOS, ln 111)	43,436,228
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	236,435,289

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	1,157,305,347
Annual Revenue Requirement, with Basis Point ROE increase	279,871,517
FCR with Basis Point increase in ROE	24.18%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	236,435,289
FCR with Basis Point ROE increase, less Depreciation	20.43%
FCR less Depreciation (Projected TCOS, ln 9)	18.89%
Incremental FCR with Basis Point ROE increase, less Depreciation	1.54%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	1,942,327,221
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	2,007,735,450
Subtotal	3,950,062,671
Average Transmission Plant Balance for 2012	1,975,031,336
Annual Depreciation Rate (Projected TCOS, ln 111)	44,851,117
Composite Depreciation Rate	2.27%
Depreciable Life for Composite Depreciation Rate	44.04
Round to nearest whole year	44

OPCo 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: **RTEP ID: b504 (765 kV circuit breaker installations at Hanging Rock)**

Current Projected Year ARR	**1,051,933**
Current Projected Year ARR w/ Incentive	**1,051,933**
Current Projected Year Incentive ARR	**-**

Details			
Investment	5,491,719	Current Year	2013
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,812

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2009	5,491,719	83,208	5,408,511	1,104,613	1,104,613	$ -	$ 894,796		$ 894,796		
2010	5,408,511	124,812	5,283,699	1,122,646	1,122,646	$ -	$ 1,094,271		$ 1,094,271		
2011	5,283,699	124,812	5,158,888	1,099,075	1,099,075	$ -	$ 1,210,680		$ 1,210,680		
2012	5,158,888	124,812	5,034,076	1,075,504	1,075,504	$ -	$ 1,057,666		$ 1,057,666		
2013	5,034,076	124,812	4,909,264	1,051,933	1,051,933	$ -					
2014	4,909,264	124,812	4,784,452	1,028,362	1,028,362	$ -					
2015	4,784,452	124,812	4,659,640	1,004,791	1,004,791	$ -					
2016	4,659,640	124,812	4,534,829	981,220	981,220	$ -					
2017	4,534,829	124,812	4,410,017	957,650	957,650	$ -					
2018	4,410,017	124,812	4,285,205	934,079	934,079	$ -					
2019	4,285,205	124,812	4,160,393	910,508	910,508	$ -					
2020	4,160,393	124,812	4,035,581	886,937	886,937	$ -					
2021	4,035,581	124,812	3,910,770	863,366	863,366	$ -					
2022	3,910,770	124,812	3,785,958	839,795	839,795	$ -					
2023	3,785,958	124,812	3,661,146	816,224	816,224	$ -					
2024	3,661,146	124,812	3,536,334	792,653	792,653	$ -					
2025	3,536,334	124,812	3,411,522	769,083	769,083	$ -					
2026	3,411,522	124,812	3,286,711	745,512	745,512	$ -					
2027	3,286,711	124,812	3,161,899	721,941	721,941	$ -					
2028	3,161,899	124,812	3,037,087	698,370	698,370	$ -					
2029	3,037,087	124,812	2,912,275	674,799	674,799	$ -					
2030	2,912,275	124,812	2,787,463	651,228	651,228	$ -					
2031	2,787,463	124,812	2,662,652	627,657	627,657	$ -					
2032	2,662,652	124,812	2,537,840	604,086	604,086	$ -					
2033	2,537,840	124,812	2,413,028	580,515	580,515	$ -					
2034	2,413,028	124,812	2,288,216	556,945	556,945	$ -					
2035	2,288,216	124,812	2,163,404	533,374	533,374	$ -					
2036	2,163,404	124,812	2,038,593	509,803	509,803	$ -					
2037	2,038,593	124,812	1,913,781	486,232	486,232	$ -					
2038	1,913,781	124,812	1,788,969	462,661	462,661	$ -					
2039	1,788,969	124,812	1,664,157	439,090	439,090	$ -					
2040	1,664,157	124,812	1,539,345	415,519	415,519	$ -					
2041	1,539,345	124,812	1,414,534	391,948	391,948	$ -					
2042	1,414,534	124,812	1,289,722	368,378	368,378	$ -					
2043	1,289,722	124,812	1,164,910	344,807	344,807	$ -					
2044	1,164,910	124,812	1,040,098	321,236	321,236	$ -					
2045	1,040,098	124,812	915,286	297,665	297,665	$ -					
2046	915,286	124,812	790,475	274,094	274,094	$ -					
2047	790,475	124,812	665,663	250,523	250,523	$ -					
2048	665,663	124,812	540,851	226,952	226,952	$ -					
2049	540,851	124,812	416,039	203,381	203,381	$ -					
2050	416,039	124,812	291,228	179,811	179,811	$ -					
2051	291,228	124,812	166,416	156,240	156,240	$ -					
2052	166,416	124,812	41,604	132,669	132,669	$ -					
2053	41,604	41,604	-	41,604	41,604	$ -					
2054	-	-	-	-	-	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
Project Totals				28,135,479	28,135,479	-					

** 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.

OPCo 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)

Current Projected Year ARR	**1,210,587**
Current Projected Year ARR w/ Incentive	**1,210,587**
Current Projected Year Incentive ARR	**-**

Project Description: **RTEP ID: B1231 (Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer)**

Details			
Investment	6,018,585	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	136,786

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	6,018,585	91,191	5,927,394	1,210,587	1,210,587	$ -	$ 832,082		$ 832,082		
2014	5,927,394	136,786	5,790,608	1,230,350	1,230,350	$ -					
2015	5,790,608	136,786	5,653,822	1,204,518	1,204,518	$ -					
2016	5,653,822	136,786	5,517,036	1,178,686	1,178,686	$ -					
2017	5,517,036	136,786	5,380,250	1,152,854	1,152,854	$ -					
2018	5,380,250	136,786	5,243,464	1,127,022	1,127,022	$ -					
2019	5,243,464	136,786	5,106,678	1,101,189	1,101,189	$ -					
2020	5,106,678	136,786	4,969,892	1,075,357	1,075,357	$ -					
2021	4,969,892	136,786	4,833,106	1,049,525	1,049,525	$ -					
2022	4,833,106	136,786	4,696,320	1,023,693	1,023,693	$ -					
2023	4,696,320	136,786	4,559,534	997,860	997,860	$ -					
2024	4,559,534	136,786	4,422,748	972,028	972,028	$ -					
2025	4,422,748	136,786	4,285,962	946,196	946,196	$ -					
2026	4,285,962	136,786	4,149,176	920,364	920,364	$ -					
2027	4,149,176	136,786	4,012,390	894,531	894,531	$ -					
2028	4,012,390	136,786	3,875,604	868,699	868,699	$ -					
2029	3,875,604	136,786	3,738,818	842,867	842,867	$ -					
2030	3,738,818	136,786	3,602,032	817,035	817,035	$ -					
2031	3,602,032	136,786	3,465,246	791,203	791,203	$ -					
2032	3,465,246	136,786	3,328,460	765,370	765,370	$ -					
2033	3,328,460	136,786	3,191,674	739,538	739,538	$ -					
2034	3,191,674	136,786	3,054,888	713,706	713,706	$ -					
2035	3,054,888	136,786	2,918,102	687,874	687,874	$ -					
2036	2,918,102	136,786	2,781,316	662,041	662,041	$ -					
2037	2,781,316	136,786	2,644,530	636,209	636,209	$ -					
2038	2,644,530	136,786	2,507,744	610,377	610,377	$ -					
2039	2,507,744	136,786	2,370,958	584,545	584,545	$ -					
2040	2,370,958	136,786	2,234,172	558,712	558,712	$ -					
2041	2,234,172	136,786	2,097,386	532,880	532,880	$ -					
2042	2,097,386	136,786	1,960,600	507,048	507,048	$ -					
2043	1,960,600	136,786	1,823,814	481,216	481,216	$ -					
2044	1,823,814	136,786	1,687,028	455,384	455,384	$ -					
2045	1,687,028	136,786	1,550,242	429,551	429,551	$ -					
2046	1,550,242	136,786	1,413,456	403,719	403,719	$ -					
2047	1,413,456	136,786	1,276,670	377,887	377,887	$ -					
2048	1,276,670	136,786	1,139,884	352,055	352,055	$ -					
2049	1,139,884	136,786	1,003,098	326,222	326,222	$ -					
2050	1,003,098	136,786	866,311	300,390	300,390	$ -					
2051	866,311	136,786	729,525	274,558	274,558	$ -					
2052	729,525	136,786	592,739	248,726	248,726	$ -					
2053	592,739	136,786	455,953	222,893	222,893	$ -					
2054	455,953	136,786	319,167	197,061	197,061	$ -					
2055	319,167	136,786	182,381	171,229	171,229	$ -					
2056	182,381	136,786	45,595	145,397	145,397	$ -					
2057	45,595	45,595	-	45,595	45,595	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals				30,834,748	30,834,748	-					

** 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.

OPCo 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: **RTEP ID: b0570 (Reconductor EAST LIMA-STERLING 138 KV LINE)**

Current Projected Year ARR	**219,263**
Current Projected Year ARR w/ Incentive	**219,263**
Current Projected Year Incentive ARR	-

Details			
Investment	1,107,003	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	25,159

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	1,107,003	12,580	1,094,423	219,263	219,263	$ -	$ 374,752		$ 374,752		
2014	1,094,423	25,159	1,069,264	227,091	227,091	$ -					
2015	1,069,264	25,159	1,044,105	222,340	222,340	$ -					
2016	1,044,105	25,159	1,018,946	217,589	217,589	$ -					
2017	1,018,946	25,159	993,787	212,837	212,837	$ -					
2018	993,787	25,159	968,628	208,086	208,086	$ -					
2019	968,628	25,159	943,468	203,334	203,334	$ -					
2020	943,468	25,159	918,309	198,583	198,583	$ -					
2021	918,309	25,159	893,150	193,832	193,832	$ -					
2022	893,150	25,159	867,991	189,080	189,080	$ -					
2023	867,991	25,159	842,832	184,329	184,329	$ -					
2024	842,832	25,159	817,673	179,578	179,578	$ -					
2025	817,673	25,159	792,514	174,826	174,826	$ -					
2026	792,514	25,159	767,354	170,075	170,075	$ -					
2027	767,354	25,159	742,195	165,324	165,324	$ -					
2028	742,195	25,159	717,036	160,572	160,572	$ -					
2029	717,036	25,159	691,877	155,821	155,821	$ -					
2030	691,877	25,159	666,718	151,070	151,070	$ -					
2031	666,718	25,159	641,559	146,318	146,318	$ -					
2032	641,559	25,159	616,399	141,567	141,567	$ -					
2033	616,399	25,159	591,240	136,816	136,816	$ -					
2034	591,240	25,159	566,081	132,064	132,064	$ -					
2035	566,081	25,159	540,922	127,313	127,313	$ -					
2036	540,922	25,159	515,763	122,562	122,562	$ -					
2037	515,763	25,159	490,604	117,810	117,810	$ -					
2038	490,604	25,159	465,444	113,059	113,059	$ -					
2039	465,444	25,159	440,285	108,308	108,308	$ -					
2040	440,285	25,159	415,126	103,556	103,556	$ -					
2041	415,126	25,159	389,967	98,805	98,805	$ -					
2042	389,967	25,159	364,808	94,054	94,054	$ -					
2043	364,808	25,159	339,649	89,302	89,302	$ -					
2044	339,649	25,159	314,489	84,551	84,551	$ -					
2045	314,489	25,159	289,330	79,800	79,800	$ -					
2046	289,330	25,159	264,171	75,048	75,048	$ -					
2047	264,171	25,159	239,012	70,297	70,297	$ -					
2048	239,012	25,159	213,853	65,546	65,546	$ -					
2049	213,853	25,159	188,694	60,794	60,794	$ -					
2050	188,694	25,159	163,535	56,043	56,043	$ -					
2051	163,535	25,159	138,375	51,292	51,292	$ -					
2052	138,375	25,159	113,216	46,540	46,540	$ -					
2053	113,216	25,159	88,057	41,789	41,789	$ -					
2054	88,057	25,159	62,898	37,038	37,038	$ -					
2055	62,898	25,159	37,739	32,286	32,286	$ -					
2056	37,739	25,159	12,580	27,535	27,535	$ -					
2057	12,580	12,580	-	12,580	12,580	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals				5,706,302	5,706,302	-					

** 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.

OPCo 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)

Current Projected Year ARR	**528,784**
Current Projected Year ARR w/ Incentive	**528,784**
Current Projected Year Incentive ARR	**-**

Project Description: **RTEP ID: b1034.1 (South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV)**

Details			
Investment	2,800,000	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	63,636

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	2,800,000	-	2,800,000	528,784	528,784	$ -					
2014	2,800,000	25,159	2,774,841	549,192	549,192	$ -					
2015	2,774,841	25,159	2,749,682	544,440	544,440	$ -					
2016	2,749,682	25,159	2,724,523	539,689	539,689	$ -					
2017	2,724,523	25,159	2,699,363	534,938	534,938	$ -					
2018	2,699,363	25,159	2,674,204	530,186	530,186	$ -					
2019	2,674,204	25,159	2,649,045	525,435	525,435	$ -					
2020	2,649,045	25,159	2,623,886	520,684	520,684	$ -					
2021	2,623,886	25,159	2,598,727	515,932	515,932	$ -					
2022	2,598,727	25,159	2,573,568	511,181	511,181	$ -					
2023	2,573,568	25,159	2,548,408	506,430	506,430	$ -					
2024	2,548,408	25,159	2,523,249	501,678	501,678	$ -					
2025	2,523,249	25,159	2,498,090	496,927	496,927	$ -					
2026	2,498,090	25,159	2,472,931	492,176	492,176	$ -					
2027	2,472,931	25,159	2,447,772	487,424	487,424	$ -					
2028	2,447,772	25,159	2,422,613	482,673	482,673	$ -					
2029	2,422,613	25,159	2,397,453	477,922	477,922	$ -					
2030	2,397,453	25,159	2,372,294	473,170	473,170	$ -					
2031	2,372,294	25,159	2,347,135	468,419	468,419	$ -					
2032	2,347,135	25,159	2,321,976	463,668	463,668	$ -					
2033	2,321,976	25,159	2,296,817	458,916	458,916	$ -					
2034	2,296,817	25,159	2,271,658	454,165	454,165	$ -					
2035	2,271,658	25,159	2,246,499	449,414	449,414	$ -					
2036	2,246,499	25,159	2,221,339	444,662	444,662	$ -					
2037	2,221,339	25,159	2,196,180	439,911	439,911	$ -					
2038	2,196,180	25,159	2,171,021	435,160	435,160	$ -					
2039	2,171,021	25,159	2,145,862	430,408	430,408	$ -					
2040	2,145,862	25,159	2,120,703	425,657	425,657	$ -					
2041	2,120,703	25,159	2,095,544	420,905	420,905	$ -					
2042	2,095,544	25,159	2,070,384	416,154	416,154	$ -					
2043	2,070,384	25,159	2,045,225	411,403	411,403	$ -					
2044	2,045,225	25,159	2,020,066	406,651	406,651	$ -					
2045	2,020,066	25,159	1,994,907	401,900	401,900	$ -					
2046	1,994,907	25,159	1,969,748	397,149	397,149	$ -					
2047	1,969,748	25,159	1,944,589	392,397	392,397	$ -					
2048	1,944,589	25,159	1,919,429	387,646	387,646	$ -					
2049	1,919,429	25,159	1,894,270	382,895	382,895	$ -					
2050	1,894,270	25,159	1,869,111	378,143	378,143	$ -					
2051	1,869,111	25,159	1,843,952	373,392	373,392	$ -					
2052	1,843,952	25,159	1,818,793	368,641	368,641	$ -					
2053	1,818,793	25,159	1,793,634	363,889	363,889	$ -					
2054	1,793,634	25,159	1,768,474	359,138	359,138	$ -					
2055	1,768,474	25,159	1,743,315	354,387	354,387	$ -					
2056	1,743,315	25,159	1,718,156	349,635	349,635	$ -					
2057	1,718,156	25,159	1,692,997	344,884	344,884	$ -					
2058	1,692,997	25,159	1,667,838	340,133	340,133	$ -					
2059	1,667,838	25,159	1,642,679	335,381	335,381	$ -					
2060	1,642,679	25,159	1,617,520	330,630	330,630	$ -					
2061	1,617,520	25,159	1,592,360	325,879	325,879	$ -					
2062	1,592,360	25,159	1,567,201	321,127	321,127	$ -					
2063	1,567,201	25,159	1,542,042	316,376	316,376	$ -					
2064	1,542,042	25,159	1,516,883	311,625	311,625	$ -					
2065	1,516,883	25,159	1,491,724	306,873	306,873	$ -					
2066	1,491,724	25,159	1,466,565	302,122	302,122	$ -					
2067	1,466,565	25,159	1,441,405	297,371	297,371	$ -					
2068	1,441,405	25,159	1,416,246	292,619	292,619	$ -					
2069	1,416,246	25,159	1,391,087	287,868	287,868	$ -					
2070	1,391,087	25,159	1,365,928	283,117	283,117	$ -					
2071	1,365,928	25,159	1,340,769	278,365	278,365	$ -					
2072	1,340,769	25,159	1,315,610	273,614	273,614	$ -					
Project Totals				24,801,548	24,801,548	-					

** 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.

OPCo 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: **RTEP ID: b1034.6 (138kV circuit breakers at South Canton Station)**

Current Projected Year ARR	**424,916**
Current Projected Year ARR w/ Incentive	**424,916**
Current Projected Year Incentive ARR	**-**

Details			
Investment	2,250,000	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	51,136

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	2,250,000	-	2,250,000	424,916	424,916	$ -
2014	2,250,000	25,159	2,224,841	445,323	445,323	$ -
2015	2,224,841	25,159	2,199,682	440,572	440,572	$ -
2016	2,199,682	25,159	2,174,523	435,821	435,821	$ -
2017	2,174,523	25,159	2,149,363	431,069	431,069	$ -
2018	2,149,363	25,159	2,124,204	426,318	426,318	$ -
2019	2,124,204	25,159	2,099,045	421,567	421,567	$ -
2020	2,099,045	25,159	2,073,886	416,815	416,815	$ -
2021	2,073,886	25,159	2,048,727	412,064	412,064	$ -
2022	2,048,727	25,159	2,023,568	407,313	407,313	$ -
2023	2,023,568	25,159	1,998,408	402,561	402,561	$ -
2024	1,998,408	25,159	1,973,249	397,810	397,810	$ -
2025	1,973,249	25,159	1,948,090	393,059	393,059	$ -
2026	1,948,090	25,159	1,922,931	388,307	388,307	$ -
2027	1,922,931	25,159	1,897,772	383,556	383,556	$ -
2028	1,897,772	25,159	1,872,613	378,805	378,805	$ -
2029	1,872,613	25,159	1,847,453	374,053	374,053	$ -
2030	1,847,453	25,159	1,822,294	369,302	369,302	$ -
2031	1,822,294	25,159	1,797,135	364,551	364,551	$ -
2032	1,797,135	25,159	1,771,976	359,799	359,799	$ -
2033	1,771,976	25,159	1,746,817	355,048	355,048	$ -
2034	1,746,817	25,159	1,721,658	350,297	350,297	$ -
2035	1,721,658	25,159	1,696,499	345,545	345,545	$ -
2036	1,696,499	25,159	1,671,339	340,794	340,794	$ -
2037	1,671,339	25,159	1,646,180	336,043	336,043	$ -
2038	1,646,180	25,159	1,621,021	331,291	331,291	$ -
2039	1,621,021	25,159	1,595,862	326,540	326,540	$ -
2040	1,595,862	25,159	1,570,703	321,789	321,789	$ -
2041	1,570,703	25,159	1,545,544	317,037	317,037	$ -
2042	1,545,544	25,159	1,520,384	312,286	312,286	$ -
2043	1,520,384	25,159	1,495,225	307,535	307,535	$ -
2044	1,495,225	25,159	1,470,066	302,783	302,783	$ -
2045	1,470,066	25,159	1,444,907	298,032	298,032	$ -
2046	1,444,907	25,159	1,419,748	293,280	293,280	$ -
2047	1,419,748	25,159	1,394,589	288,529	288,529	$ -
2048	1,394,589	25,159	1,369,429	283,778	283,778	$ -
2049	1,369,429	25,159	1,344,270	279,026	279,026	$ -
2050	1,344,270	25,159	1,319,111	274,275	274,275	$ -
2051	1,319,111	25,159	1,293,952	269,524	269,524	$ -
2052	1,293,952	25,159	1,268,793	264,772	264,772	$ -
2053	1,268,793	25,159	1,243,634	260,021	260,021	$ -
2054	1,243,634	25,159	1,218,474	255,270	255,270	$ -
2055	1,218,474	25,159	1,193,315	250,518	250,518	$ -
2056	1,193,315	25,159	1,168,156	245,767	245,767	$ -
2057	1,168,156	25,159	1,142,997	241,016	241,016	$ -
2058	1,142,997	25,159	1,117,838	236,264	236,264	$ -
2059	1,117,838	25,159	1,092,679	231,513	231,513	$ -
2060	1,092,679	25,159	1,067,520	226,762	226,762	$ -
2061	1,067,520	25,159	1,042,360	222,010	222,010	$ -
2062	1,042,360	25,159	1,017,201	217,259	217,259	$ -
2063	1,017,201	25,159	992,042	212,508	212,508	$ -
2064	992,042	25,159	966,883	207,756	207,756	$ -
2065	966,883	25,159	941,724	203,005	203,005	$ -
2066	941,724	25,159	916,565	198,254	198,254	$ -
2067	916,565	25,159	891,405	193,502	193,502	$ -
2068	891,405	25,159	866,246	188,751	188,751	$ -
2069	866,246	25,159	841,087	184,000	184,000	$ -
2070	841,087	25,159	815,928	179,248	179,248	$ -
2071	815,928	25,159	790,769	174,497	174,497	$ -
2072	790,769	25,159	765,610	169,746	169,746	$ -
Project Totals				18,569,453	18,569,453	-

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.

OPCo 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: **RTEP ID: b1864.1 (Add two additional 345/138 kV transformers at Kammer)**

Current Projected Year ARR	**333,178**
Current Projected Year ARR w/ Incentive	**333,178**
Current Projected Year Incentive ARR	**-**

Details			
Investment	1,750,000	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	39,773

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	1,750,000	3,314	1,746,686	333,178	333,178	$ -
2014	1,746,686	25,159	1,721,526	350,272	350,272	$ -
2015	1,721,526	25,159	1,696,367	345,520	345,520	$ -
2016	1,696,367	25,159	1,671,208	340,769	340,769	$ -
2017	1,671,208	25,159	1,646,049	336,018	336,018	$ -
2018	1,646,049	25,159	1,620,890	331,266	331,266	$ -
2019	1,620,890	25,159	1,595,731	326,515	326,515	$ -
2020	1,595,731	25,159	1,570,571	321,764	321,764	$ -
2021	1,570,571	25,159	1,545,412	317,012	317,012	$ -
2022	1,545,412	25,159	1,520,253	312,261	312,261	$ -
2023	1,520,253	25,159	1,495,094	307,510	307,510	$ -
2024	1,495,094	25,159	1,469,935	302,758	302,758	$ -
2025	1,469,935	25,159	1,444,776	298,007	298,007	$ -
2026	1,444,776	25,159	1,419,617	293,256	293,256	$ -
2027	1,419,617	25,159	1,394,457	288,504	288,504	$ -
2028	1,394,457	25,159	1,369,298	283,753	283,753	$ -
2029	1,369,298	25,159	1,344,139	279,002	279,002	$ -
2030	1,344,139	25,159	1,318,980	274,250	274,250	$ -
2031	1,318,980	25,159	1,293,821	269,499	269,499	$ -
2032	1,293,821	25,159	1,268,662	264,748	264,748	$ -
2033	1,268,662	25,159	1,243,502	259,996	259,996	$ -
2034	1,243,502	25,159	1,218,343	255,245	255,245	$ -
2035	1,218,343	25,159	1,193,184	250,494	250,494	$ -
2036	1,193,184	25,159	1,168,025	245,742	245,742	$ -
2037	1,168,025	25,159	1,142,866	240,991	240,991	$ -
2038	1,142,866	25,159	1,117,707	236,240	236,240	$ -
2039	1,117,707	25,159	1,092,547	231,488	231,488	$ -
2040	1,092,547	25,159	1,067,388	226,737	226,737	$ -
2041	1,067,388	25,159	1,042,229	221,986	221,986	$ -
2042	1,042,229	25,159	1,017,070	217,234	217,234	$ -
2043	1,017,070	25,159	991,911	212,483	212,483	$ -
2044	991,911	25,159	966,752	207,732	207,732	$ -
2045	966,752	25,159	941,593	202,980	202,980	$ -
2046	941,593	25,159	916,433	198,229	198,229	$ -
2047	916,433	25,159	891,274	193,478	193,478	$ -
2048	891,274	25,159	866,115	188,726	188,726	$ -
2049	866,115	25,159	840,956	183,975	183,975	$ -
2050	840,956	25,159	815,797	179,224	179,224	$ -
2051	815,797	25,159	790,638	174,472	174,472	$ -
2052	790,638	25,159	765,478	169,721	169,721	$ -
2053	765,478	25,159	740,319	164,969	164,969	$ -
2054	740,319	25,159	715,160	160,218	160,218	$ -
2055	715,160	25,159	690,001	155,467	155,467	$ -
2056	690,001	25,159	664,842	150,715	150,715	$ -
2057	664,842	25,159	639,683	145,964	145,964	$ -
2058	639,683	25,159	614,523	141,213	141,213	$ -
2059	614,523	25,159	589,364	136,461	136,461	$ -
2060	589,364	25,159	564,205	131,710	131,710	$ -
2061	564,205	25,159	539,046	126,959	126,959	$ -
2062	539,046	25,159	513,887	122,207	122,207	$ -
2063	513,887	25,159	488,728	117,456	117,456	$ -
2064	488,728	25,159	463,568	112,705	112,705	$ -
2065	463,568	25,159	438,409	107,953	107,953	$ -
2066	438,409	25,159	413,250	103,202	103,202	$ -
2067	413,250	25,159	388,091	98,451	98,451	$ -
2068	388,091	25,159	362,932	93,699	93,699	$ -
2069	362,932	25,159	337,773	88,948	88,948	$ -
2070	337,773	25,159	312,614	84,197	84,197	$ -
2071	312,614	25,159	287,454	79,445	79,445	$ -
2072	287,454	25,159	262,295	74,694	74,694	$ -
Project Totals				12,869,670	12,869,670	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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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.

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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.

OPCo 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	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
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	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals				-	-	-					

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

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AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
OHIO 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	49.00%	5.49%	2.692%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.00%	11.49%	5.860%
		R =	8.552%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2012			
As Projected in Prior Year WS J	$ 2,264,500	$ 2,264,500	$ -
Actual after True-up	$ 1,248,552	$ 1,248,552	$ -
True-up of ARR For 2012	(1,015,948)	(1,015,948)	-

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

Rate Base (True-Up TCOS, ln 78)	973,996,207
R (from A. above)	8.552%
Return (Rate Base x R)	83,293,333

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

Return (from B. above)	83,293,333
Effective Tax Rate (True-Up TCOS, ln 126)	38.18%
Income Tax Calculation (Return x CIT)	31,800,286
ITC Adjustment	(347,126)
Income Taxes	31,453,160

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)	262,126,968
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	1,351,836
Return (True-Up TCOS, ln 134)	83,293,333
Income Taxes (True-Up TCOS, ln 133)	31,453,160
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	146,028,639

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	146,028,639
Return (from I.B. above)	83,293,333
Income Taxes (from I.C. above)	31,453,160
Annual Revenue Requirement, with 0 Basis Point ROE increase	260,775,132
Depreciation (True-Up TCOS, ln 111)	43,487,185
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	217,287,947

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

Net Transmission Plant (True-Up TCOS, ln 48)	1,136,509,025
Annual Revenue Requirement, with 0 Basis Point ROE increase	260,775,132
FCR with 0 Basis Point increase in ROE	22.95%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	217,287,947
FCR with 0 Basis Point ROE increase, less Depreciation	19.12%
FCR less Depreciation (True-Up TCOS, ln 9)	19.12%
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)):	1,942,327,221
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	2,007,735,450
Subtotal	3,950,062,671
Average Transmission Plant Balance for	1,975,031,336
Annual Depreciation Rate (True-Up TCOS, ln 111)	44,851,117
Composite Depreciation Rate	2.27%
Depreciable Life for Composite Depreciation Rate	44.04
Round to nearest whole year	44

OPCo 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: **RTEP ID: b504 (765 kV circuit breaker installations at Hanging Rock)**

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	1,057,666	1,057,666	-
Prior Yr True-Up	1,099,203	1,099,203	-
True-Up Adjustment	41,537	41,537	-

Details			
Investment	5,491,719	Current Year	2012
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,812

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 **
2009	5,491,719	83,208	5,408,511	5,450,115	1,125,210	1,125,210	$ -	$ 894,796	$ 230,414	$ 894,796	$ 230,414	$ -
2010	5,408,511	124,812	5,283,699	5,346,105	1,146,928	1,146,928	$ -	$ 1,094,271	$ 52,657	$ 1,094,271	$ 52,657	$ -
2011	5,283,699	124,812	5,158,888	5,221,293	1,123,065	1,123,065	$ -	$ 1,210,680	$ (87,615)	$ 1,210,680	$ (87,615)	$ -
2012	5,158,888	124,812	5,034,076	5,096,482	1,099,203	1,099,203	$ -	$ 1,057,666	$ 41,537	$ 1,057,666	$ 41,537	$ -
2013	5,034,076	124,812	4,909,264	4,971,670	1,075,340	1,075,340	$ -		$ -		$ -	$ -
2014	4,909,264	124,812	4,784,452	4,846,858	1,051,477	1,051,477	$ -		$ -		$ -	$ -
2015	4,784,452	124,812	4,659,640	4,722,046	1,027,615	1,027,615	$ -		$ -		$ -	$ -
2016	4,659,640	124,812	4,534,829	4,597,234	1,003,752	1,003,752	$ -		$ -		$ -	$ -
2017	4,534,829	124,812	4,410,017	4,472,423	979,890	979,890	$ -		$ -		$ -	$ -
2018	4,410,017	124,812	4,285,205	4,347,611	956,027	956,027	$ -		$ -		$ -	$ -
2019	4,285,205	124,812	4,160,393	4,222,799	932,164	932,164	$ -		$ -		$ -	$ -
2020	4,160,393	124,812	4,035,581	4,097,987	908,302	908,302	$ -		$ -		$ -	$ -
2021	4,035,581	124,812	3,910,770	3,973,175	884,439	884,439	$ -		$ -		$ -	$ -
2022	3,910,770	124,812	3,785,958	3,848,364	860,576	860,576	$ -		$ -		$ -	$ -
2023	3,785,958	124,812	3,661,146	3,723,552	836,714	836,714	$ -		$ -		$ -	$ -
2024	3,661,146	124,812	3,536,334	3,598,740	812,851	812,851	$ -		$ -		$ -	$ -
2025	3,536,334	124,812	3,411,522	3,473,928	788,988	788,988	$ -		$ -		$ -	$ -
2026	3,411,522	124,812	3,286,711	3,349,117	765,126	765,126	$ -		$ -		$ -	$ -
2027	3,286,711	124,812	3,161,899	3,224,305	741,263	741,263	$ -		$ -		$ -	$ -
2028	3,161,899	124,812	3,037,087	3,099,493	717,401	717,401	$ -		$ -		$ -	$ -
2029	3,037,087	124,812	2,912,275	2,974,681	693,538	693,538	$ -		$ -		$ -	$ -
2030	2,912,275	124,812	2,787,463	2,849,869	669,675	669,675	$ -		$ -		$ -	$ -
2031	2,787,463	124,812	2,662,652	2,725,058	645,813	645,813	$ -		$ -		$ -	$ -
2032	2,662,652	124,812	2,537,840	2,600,246	621,950	621,950	$ -		$ -		$ -	$ -
2033	2,537,840	124,812	2,413,028	2,475,434	598,087	598,087	$ -		$ -		$ -	$ -
2034	2,413,028	124,812	2,288,216	2,350,622	574,225	574,225	$ -		$ -		$ -	$ -
2035	2,288,216	124,812	2,163,404	2,225,810	550,362	550,362	$ -		$ -		$ -	$ -
2036	2,163,404	124,812	2,038,593	2,100,999	526,499	526,499	$ -		$ -		$ -	$ -
2037	2,038,593	124,812	1,913,781	1,976,187	502,637	502,637	$ -		$ -		$ -	$ -
2038	1,913,781	124,812	1,788,969	1,851,375	478,774	478,774	$ -		$ -		$ -	$ -
2039	1,788,969	124,812	1,664,157	1,726,563	454,912	454,912	$ -		$ -		$ -	$ -
2040	1,664,157	124,812	1,539,345	1,601,751	431,049	431,049	$ -		$ -		$ -	$ -
2041	1,539,345	124,812	1,414,534	1,476,940	407,186	407,186	$ -		$ -		$ -	$ -
2042	1,414,534	124,812	1,289,722	1,352,128	383,324	383,324	$ -		$ -		$ -	$ -
2043	1,289,722	124,812	1,164,910	1,227,316	359,461	359,461	$ -		$ -		$ -	$ -
2044	1,164,910	124,812	1,040,098	1,102,504	335,598	335,598	$ -		$ -		$ -	$ -
2045	1,040,098	124,812	915,286	977,692	311,736	311,736	$ -		$ -		$ -	$ -
2046	915,286	124,812	790,475	852,881	287,873	287,873	$ -		$ -		$ -	$ -
2047	790,475	124,812	665,663	728,069	264,010	264,010	$ -		$ -		$ -	$ -
2048	665,663	124,812	540,851	603,257	240,148	240,148	$ -		$ -		$ -	$ -
2049	540,851	124,812	416,039	478,445	216,285	216,285	$ -		$ -		$ -	$ -
2050	416,039	124,812	291,228	353,633	192,423	192,423	$ -		$ -		$ -	$ -
2051	291,228	124,812	166,416	228,822	168,560	168,560	$ -		$ -		$ -	$ -
2052	166,416	124,812	41,604	104,010	144,697	144,697	$ -		$ -		$ -	$ -
2053	41,604	41,604	-	20,802	45,581	45,581	$ -		$ -		$ -	$ -
2054	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2055	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2056	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2057	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2058	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2059	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2060	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2061	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2062	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2063	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals					28,940,734	28,940,734	-					

** 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.

OPCo 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:

RTEP ID: B1231 (Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer)

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	832,082	832,082	-
Prior Yr True-Up	149,349	149,349	-
True-Up Adjustment	(682,733)	(682,733)	-

Details			
Investment	774,225	Current Year	2012
Service Year (yyyy)	2012	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No	Annual Depreciation Expense	17,596

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 **
2012	774,225	1,466	772,759	773,492	149,349	149,349	$ -	$ 832,082	$ (682,733)	$ 832,082	$ (682,733)	$ -
2013	772,759	17,596	755,163	763,961	163,657	163,657	$ -		$ -		$ -	$ -
2014	755,163	17,596	737,567	746,365	160,293	160,293	$ -		$ -		$ -	$ -
2015	737,567	17,596	719,971	728,769	156,929	156,929	$ -		$ -		$ -	$ -
2016	719,971	17,596	702,375	711,173	153,564	153,564	$ -		$ -		$ -	$ -
2017	702,375	17,596	684,779	693,577	150,200	150,200	$ -		$ -		$ -	$ -
2018	684,779	17,596	667,183	675,981	146,836	146,836	$ -		$ -		$ -	$ -
2019	667,183	17,596	649,587	658,385	143,472	143,472	$ -		$ -		$ -	$ -
2020	649,587	17,596	631,990	640,788	140,108	140,108	$ -		$ -		$ -	$ -
2021	631,990	17,596	614,394	623,192	136,744	136,744	$ -		$ -		$ -	$ -
2022	614,394	17,596	596,798	605,596	133,379	133,379	$ -		$ -		$ -	$ -
2023	596,798	17,596	579,202	588,000	130,015	130,015	$ -		$ -		$ -	$ -
2024	579,202	17,596	561,606	570,404	126,651	126,651	$ -		$ -		$ -	$ -
2025	561,606	17,596	544,010	552,808	123,287	123,287	$ -		$ -		$ -	$ -
2026	544,010	17,596	526,414	535,212	119,923	119,923	$ -		$ -		$ -	$ -
2027	526,414	17,596	508,818	517,616	116,559	116,559	$ -		$ -		$ -	$ -
2028	508,818	17,596	491,222	500,020	113,194	113,194	$ -		$ -		$ -	$ -
2029	491,222	17,596	473,626	482,424	109,830	109,830	$ -		$ -		$ -	$ -
2030	473,626	17,596	456,030	464,828	106,466	106,466	$ -		$ -		$ -	$ -
2031	456,030	17,596	438,434	447,232	103,102	103,102	$ -		$ -		$ -	$ -
2032	438,434	17,596	420,838	429,636	99,738	99,738	$ -		$ -		$ -	$ -
2033	420,838	17,596	403,242	412,040	96,374	96,374	$ -		$ -		$ -	$ -
2034	403,242	17,596	385,646	394,444	93,009	93,009	$ -		$ -		$ -	$ -
2035	385,646	17,596	368,050	376,848	89,645	89,645	$ -		$ -		$ -	$ -
2036	368,050	17,596	350,454	359,252	86,281	86,281	$ -		$ -		$ -	$ -
2037	350,454	17,596	332,858	341,656	82,917	82,917	$ -		$ -		$ -	$ -
2038	332,858	17,596	315,262	324,060	79,553	79,553	$ -		$ -		$ -	$ -
2039	315,262	17,596	297,666	306,464	76,189	76,189	$ -		$ -		$ -	$ -
2040	297,666	17,596	280,070	288,868	72,824	72,824	$ -		$ -		$ -	$ -
2041	280,070	17,596	262,474	271,272	69,460	69,460	$ -		$ -		$ -	$ -
2042	262,474	17,596	244,878	253,676	66,096	66,096	$ -		$ -		$ -	$ -
2043	244,878	17,596	227,282	236,080	62,732	62,732	$ -		$ -		$ -	$ -
2044	227,282	17,596	209,686	218,484	59,368	59,368	$ -		$ -		$ -	$ -
2045	209,686	17,596	192,090	200,888	56,004	56,004	$ -		$ -		$ -	$ -
2046	192,090	17,596	174,494	183,292	52,639	52,639	$ -		$ -		$ -	$ -
2047	174,494	17,596	156,898	165,696	49,275	49,275	$ -		$ -		$ -	$ -
2048	156,898	17,596	139,302	148,100	45,911	45,911	$ -		$ -		$ -	$ -
2049	139,302	17,596	121,706	130,504	42,547	42,547	$ -		$ -		$ -	$ -
2050	121,706	17,596	104,110	112,908	39,183	39,183	$ -		$ -		$ -	$ -
2051	104,110	17,596	86,514	95,312	35,819	35,819	$ -		$ -		$ -	$ -
2052	86,514	17,596	68,918	77,716	32,454	32,454	$ -		$ -		$ -	$ -
2053	68,918	17,596	51,322	60,120	29,090	29,090	$ -		$ -		$ -	$ -
2054	51,322	17,596	33,726	42,524	25,726	25,726	$ -		$ -		$ -	$ -
2055	33,726	17,596	16,130	24,928	22,362	22,362	$ -		$ -		$ -	$ -
2056	16,130	16,130	-	8,065	17,672	17,672	$ -		$ -		$ -	$ -
2057	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2058	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2059	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2060	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2061	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2062	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2063	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals					4,166,424	4,166,424	-					

** 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.

OPCo 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: **RTEP ID: b0570 (Reconductor EAST LIMA-STERLING 138 KV LINE)**

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	374,752	374,752	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	(374,752)	(374,752)	-

Details			
Investment	-	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
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 **
2013	-	-	-	-	-	-	$ -	$ 374,752	$ (374,752)	$ 374,752	$ (374,752)	$ -
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

OPCo 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:

RTEP ID: b1034.1 (South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV)

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
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 **
2013	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2014	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2015	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2016	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2017	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2018	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2019	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2020	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2021	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2022	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

OPCo 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: **RTEP ID: b1034.6 (138kV circuit breakers at South Canton Station)**

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
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 **
2013	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2014	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2015	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2016	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2017	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2018	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2019	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2020	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2021	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2022	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2023	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2024	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2025	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2031	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals					-	-	-					

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OPCo 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: **RTEP ID: b1864.1 (Add two additional 345/138 kV transformers at Kammer)**

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
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 **
2013	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2014	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2015	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2016	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2017	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2018	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2019	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2020	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2021	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

OPCo 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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
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 **
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	-	-	-	-	-	-	$ -		$ -		$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -
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 2012 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
OHIO 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	Fixed Rate Prom. Notes Payable to Parent		200,000,000	5.250%	10,500,000	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	Reacquired Bonds Marshall County Series F		(35,000,000)	0.300%	(105,000)	
6	Reacquired Bonds:Marshall County Series E		(50,000,000)	0.950%	(475,000)	
7	Reacquired Bonds:Ohio Air Quality Series 2005A		(54,500,000)	0.350%	(190,750)	
8	Reacquired Bonds:Ohio Air Quality Series 2005B		(54,500,000)	0.350%	(190,750)	
9	Reacquired Bonds: Air Quality Series 2005C		(54,500,000)	0.350%	(190,750)	
10	Reacquired Bonds: Air Quality Series 2005D		(54,500,000)	0.350%	(190,750)	
11	WV Economic Development Mitchell Series 2008A		(65,000,000)	0.170%	(110,500)	
12	WV Economic Development Sporn Series 2008C		(50,000,000)	0.100%	(50,000)	
13	Ohio Air Quality Revenue Bonds Series 2007A		(44,500,000)	0.280%	(124,600)	
14	Ohio Air Quality Revenue Bonds Series 2007B		56,000,000	5.100%	2,856,000	
15	Ohio Air Quality Revenue Bonds Series 2009A		60,000,000	3.875%	2,325,000	
16	Ohio Air Quality Revenue Bonds Series 2009B		32,245,000	5.800%	1,870,210	
17	Ohio Air Quality Series C		50,000,000	5.150%	2,575,000	
18	Marshall County Series F		35,000,000	0.300%	105,000	
19	Marshall County Series E		50,000,000	0.950%	475,000	
20	Mitchell Series 2007A		65,000,000	4.900%	3,185,000	
21	Reacquired Bonds:Ohio Air Quality Series 2005A		54,500,000	0.350%	190,750	
22	Reacquired Bonds:Ohio Air Quality Series 2005B		54,500,000	0.350%	190,750	
23	Reacquired Bonds: Air Quality Series 2005C		54,500,000	0.350%	190,750	
24	Reacquired Bonds: Air Quality Series 2005D		54,500,000	0.350%	190,750	
25	WV Economic Development Amos Series 2010A		86,000,000	3.125%	2,687,500	
26	Ohio Air Quality Cardinal Series 2010A		79,450,000	3.250%	2,582,125	
27	Ohio Air Quality Gavin Series 2010A		39,130,000	2.875%	1,124,988	
28	WV Economic Development Mitchell Series 2008A		65,000,000	0.170%	110,500	
29	WV Economic Development Kammer Series 2008B		50,000,000	0.130%	65,000	
30	WV Economic Development Sporn Series 2008C		50,000,000	0.100%	50,000	
31	Ohio Air Quality Revenue Bonds Series 2007A		44,500,000	0.280%	124,600	
32	Unsecured Medium Series A - Due 2013		250,000,000	5.500%	13,750,000	
33	Unsecured Medium Series B - Due 2033		250,000,000	6.600%	16,500,000	
34	Unsecured Medium Series F - Due 2035		250,000,000	5.850%	14,625,000	
35	Unsecured Medium Series G - Due 2018		350,000,000	6.050%	21,175,000	
36	Unsecured Medium Term Notes Series F due 02/2013		250,000,000	5.500%	13,750,000	
37	Unsecured Medium Term Notes Series G due 02/2033		250,000,000	6.600%	16,500,000	
38	Unsecured Medium Term Notes Series H due 01/2014		225,000,000	4.850%	10,912,500	
39	Unsecured Medium Term Notes Series I due 07/2033		225,000,000	6.375%	14,343,750	
40	Unsecured Medium Term Notes Series K due 06/2016		350,000,000	6.000%	21,000,000	
41	Unsecured Medium Term Notes Series L due 09/2013		250,000,000	5.750%	14,375,000	
42	Senior Unsecured Note Series M		500,000,000	5.375%	26,875,000	
43	Issuance Discount, Premium, & Expenses:					
44	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
45	Allowable Hedge Amortization (See Ln 62 Below)				(2,097,663)	
46	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			3,978,647	
47	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
48	Reacquired Debt:					
49	Amortization of Loss	FF1.p. 117.64.c			1,336,128	
50	Amortization of Gain	FF1.p. 117.66.c			-	
51	**Total Interest on Long Term Debt**		3,867,825,000	5.61%	216,794,185	
52	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
53			-	0.00%	-	
54			-	0.00%	-	
55			-	0.00%	-	
56			-	0.00%	-	
57	**Dividends on Preferred Stock**		-	0.00%	-	
58	Net Total Hedge Gains and Losses (WS M, Ln 30, (E))				(2,097,663)	
59	Total Projected Capital Structure Balance for 2013 (Projected TCOS, Ln 165)				8,520,545,406	
60	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
61	Limit of Recoverable Amount				4,260,273	
62	**Recoverable Hedge Amortization (Lesser of Ln 58 or Ln 61)**				**(2,097,663)**	

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

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	4,489,200,654	4,413,669,464	4,451,435,059
2	Less Preferred Stock (Ln 55 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	2,204,800	2,204,800	2,204,800
4	Less Account 219.1 (112.15.c&d)	(165,724,552)	(197,721,635)	(181,723,094)
5	**Average Balance of Common Equity**	4,652,720,406	4,609,186,299	**4,630,953,353**
	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)	462,500,000	418,000,000	440,250,000
8	LT Advances from Assoc. Companies (112.20.c&d)	200,000,000	200,000,000	200,000,000
9	Senior Unsecured Notes (112.21.c&d)	4,130,325,000	4,280,325,000	4,205,325,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	3,867,825,000	4,062,325,000	**3,965,075,000**

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 2012**	
14	Interest on Long Term Debt (256-257.33.i)	212,506,228
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 29 below.	(2,097,663)
16	Plus: Allowed Hedge Recovery From Ln 34 below.	(2,097,663)
17	Amort of Debt Discount & Expense (117.63.c)	3,978,647
18	Amort of Loss on Reacquired Debt (117.64.c)	1,336,128
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)**	**217,821,003**
22	**Average Cost of Debt for 2012 (Ln 21/Ln 11)**	**5.49%**

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 2012	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
24	SUN Cash Flow Hedge - 6.000%	(418,450)	-	(418,450)	(1,429,705)	Jun-06	Jun-16
25	SUN Cash Flow Hedge - 5.375%	(1,679,213)	-	(1,679,213)	(11,264,719)	Sep-09	Sep-19
26							
27							
28							
29	Total Hedge Amortization	(2,097,663)	-				

30	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 25)	(2,097,663)
31	Total Average Capital Structure Balance for 2012 (True-UP TCOS, Ln 165)	8,596,028,353
32	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
33	Limit of Recoverable Amount	4,298,014
34	**Recoverable Hedge Amortization (Lesser of Ln 30 or Ln 33)**	**(2,097,663)**

Development of Cost of Preferred Stock

Line	**Preferred Stock**	(C)	(D)	**Average**
35	0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	4.08%	
36	0% Series - 0 - Par Value (p. 250-251. 8.c)	$ -	$ -	
37	0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	-	-	
38	0% Series - 0 - Monetary Value (Ln 36 * Ln 37)	-	-	-
39	0% Series - 0 - Dividend Amount (Ln 35 * Ln 38)	-	-	-
40	0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.20%	
41	0% Series - 0 - Par Value (p. 250-251.c)	$ -	$ -	
42	0% Series - 0 - Shares O/S (p.250-251. e)	-	-	
43	0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	-
44	0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	-	-	-
45	0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.40%	
46	0% Series - 0 - Par Value (p. 250-251.c)	$ -	$ -	
47	0% Series - 0 - Shares O/S (p.250-251.e)	-	-	
48	0% Series - 0 - Monetary Value (Ln 46 * Ln 47)	-	-	-
49	0% Series - 0 - Dividend Amount (Ln 45 * Ln 48)	-	-	-
50	0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.50%	
51	0% Series - 0 - Par Value (p. 250-251.c)	$ -	$ -	
52	0% Series - 0 - Shares O/S (p.250-251.e)	-	-	
53	0% Series - 0 - Monetary Value (Ln 51 * Ln 52)	-	-	-
54	0% Series - 0 - Dividend Amount (Ln 50 * Ln 53)	-	-	-
55	**Balance of Preferred Stock (Lns 38, 43, 48, 54)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
56	**Dividends on Preferred Stock (Lns 39, 44, 49)**	-	-	-
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
OHIO POWER COMPANY

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectivielly. 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 2012		-		-	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances

Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service

OHIO POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

Allocation of PBOP Settlement Amount for 2012

			Total Company Amount					
Line#	**Company**	**Actual Expense (Including AEPSC Billed OPEB)**	**Ratio of Company Actual to Total**	**Allocation of PBOB Recovery Allowance**	**Labor Allocator for 2012**	**Actual Expense**	**Allowable Expense**	**One Year Functional Expense (Over)/Under**
		(A) (Line 14)	**(B)=(A)/Total (A)**	**(C)=(B) * 48100000**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10	Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11	Medicare Subsidy	-	-	-	-	-	-	-
12	Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
				-				
13	PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14	Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2012

FOR SINGLE JURISDICTION COMPANIES

OHIO POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.02%
Station Equipment	353.0	2.29%
Twrs and Fixtures Above 69 KV	354.0	1.88%
Twrs and Fixtures Below 69 KV	354.0	1.88%
Poles and Fixtures Above 69 KV	355.0	3.52%
Poles and Fixtures Below 69 KV	355.0	3.52%
Overhead Conductor & Devices Above 69KV	356.0	1.91%
Overhead Conductor & Devices MSP	356.0	1.91%
Overhead Conductor & Devices 138KV/Above	356.0	1.91%
Overhead Conductor & Devices 69KV/Below	356.0	1.91%
Overhead Conductor & Devices CLR 69KV/Below	356.0	1.91%
Underground Conduit	357.0	2.26%
Underground Conductors	358.0	3.27%

Reference:

Note 1: These are the weighted average of the depreciation rates in effect for Columbus Southern Power and Ohio Power prior to the merger of Columbus Southern into Ohio Power.

General Note:

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

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)				$16,266,957
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,416,286	DA	1.00000	$ 1,416,286
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$ 14,850,671

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		Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		393,660	DA	1.00000	$ 393,660
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))				19.30%
7	Monthly Rate	(ln 6 / 12)				1.61%
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))				16.46%
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))				2.98%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)					-

13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below	106,849
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,085
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		0
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	101,764

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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)	0	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	0	NA	0.00000	0
20	Transmission	(Worksheet A ln 3.E & Ln 142)	88,587,641	DA		88,587,641
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	0	TP	1.00000	0
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		18,317,776	DA	1.00000	18,317,776
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)	132,072,558	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)	5,034,700	W/S	0.07846	395,000
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-34,819	W/S	0.07846	(2,732)
28	Intangible Plant	(Worksheet A ln 9.C)	982,428	W/S	0.07846	77,077
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	244,960,284			107,374,762
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	0	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	0	NA	0.00000	0
33	Transmission	(Worksheet A ln 14.C & 28.C)	20,227,192	**TP1=**	1.00000	20,227,192
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	0	**TP1=**	1.00000	0
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		421,551	DA	1.00000	421,551
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2013 (ln 111)		1,970,536	TP1	1.00000	1,970,536
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 113 + ln 114)		204,920	W/S	0.07846	16,077
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)	41,591,445	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)	2,531,284	W/S	0.07846	198,593
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-18,391	W/S	0.07846	(1,443)
44	Intangible Plant	(Worksheet A ln 20.C)	742,028	W/S	0.07846	58,216
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	67,670,565			22,890,723
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	0			0
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	68,360,449			68,360,449
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		17,896,225			17,896,225
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		0			0
51	Plus: Additional Transmission Depreciation for 2013 (-ln 37)		(1,970,536)			(1,970,536)
52	Plus: Additional General & Intangible Depreciation for 2013 (-ln 38)		(204,920)			(16,077)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	90,481,113			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	2,486,988			195,118
56	Intangible Plant	(ln 28 - ln 44)	240,400			18,861
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	177,289,719			84,484,039
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	0	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(29,722,622)	DA		(14,921,144)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(3,862,468)	DA		(321,239)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	2,710,890	DA		255,759
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(27,057)	DA		(8,892)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(30,901,257)			(14,995,516)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	-	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)	156,943			156,943
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,614	TP	1.00000	1,614
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	1,519	W/S	0.07846	119
71	Stores Expense	(Worksheet C, ln 4.(D))	0	GP(h)	0.39294	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	8,047,475	W/S	0.07846	631,369
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	152,876	GP(h)	0.39294	60,071
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)	(7,804,737)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	555,690			850,116
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	-	DA	1.00000	-
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		146,944,152			70,338,640

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	(1)	(2)	(3)	(4)		(5)
Line No.	**EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	**Data Sources (See "General Notes")**	**TO Total**	**Allocator**		**Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	101,565,867			
80	Distribution	322.156.b	5,330,356			
81	Customer Related Expense	322.164,171,178.b	3,018,334			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	1,362,394			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	111,276,951			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	106,849			
86	Less: Account 565	(Note H) 321.96.b	-			
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)	1,255,545	TP	1.00000	1,255,545
89	Administrative and General	323.197.b (Note J)	2,731,308			
90	Less: Acct. 924, Property Insurance	323.185.b	208,083			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
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)	32,337			
94	Acct. 928, Reg. Com. Exp.	323.189.b	-			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	2,128,141	W/S	0.07846	166,964
98	Plus: Acct. 924, Property Insurance	(ln 90)	208,083	GP(h)	0.39294	81,764
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 29.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 35.(E) (Note L)	632	DA	1.00000	632
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
103	A & G Subtotal	(sum lns 97 to 102)	2,706,824			278,387
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,962,369			1,533,932
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)	3,962,369			1,533,932
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	4,242,661	NA	0.00000	-
111	Transmission	336.7.f	1,970,536	TP1	1.00000	1,970,536
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		421,551	DA	1.00000	421,551
113	General	336.10.f	157,755	W/S	0.07846	12,377
114	Intangible	336.1.f	47,165	W/S	0.07846	3,700
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	6,839,668			2,408,164
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	177,131	W/S	0.07846	13,897
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	1,726,413	DA		742,994
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	5,520,256	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	527,793	GP(h)	0.39294	207,391
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	7,951,593			964,282
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.03%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		59.28%			
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)		1.6675			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 127 * ln 135)	8,832,728			4,228,015
132	ITC adjustment	(ln 129 * ln 130)	-	NP(h)	0.42443	-
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	8,832,728			4,228,015
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	14,900,610			7,132,565
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		42,486,968			16,266,957

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SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							88,587,641
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)								-
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)							88,587,641
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)						TP	**1.00000**
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
145	Production	354.20.b	0	0	-	NA	0.00000		-
146	Transmission	354.21.b	1,068	204,657	205,725	TP	1.00000		205,725
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA	0.00000		-
150	Total	(sum lns 145 to 149)	1,790,613	831,574	2,622,187				205,725
151	Transmission related amount							W/S=	**0.07846**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet L, ln. 35, col. (D))	1,312,500
154	Preferred Dividends	(Worksheet L, ln. 40, col. (D))	-
155	Development of Common Stock:		
156	Proprietary Capital	(FF1 p 112, Ln 16.c)	90,109,311
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)	(473,816)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	90,583,127

161		$	%	Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))	25,000,000	21.63%	0.0525	0.0114
163	Preferred Stock (ln 157)	-	0.00%	-	0.0000
164	Common Stock (ln 160)	90,583,127	78.37%	11.49%	0.0900
165	Total (Sum lns 162 to 164)	115,583,127		**WACC=**	**0.1014**

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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, 2013. Other ratebase amounts are as of December 31, 2012.
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 WHEELING 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= 7.74% (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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WHEELING POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)				$13,275,803
167	REVENUE CREDITS	(Note A) (Worksheet E)	1,416,286	DA	1.00000	$ 1,416,286
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$ 11,859,517

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)	19.42%
172	Monthly Rate	(ln 171 / 12)	1.62%
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)	16.54%
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)	3.68%
177	Not applicable on this template		

178	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	106,849
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,085
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		-
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	101,764

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Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

WHEELING 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)	-	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.E & Ln 307)	88,587,641	DA		88,587,641
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 308)	-	TP	1.00000	-
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)	132,072,558	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)	5,034,700	W/S	0.07846	395,000
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(34,819)	W/S	0.07846	(2,732)
193	Intangible Plant	(Worksheet A ln 9.C)	982,428	W/S	0.07846	77,077
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	226,642,508	**GP(h)=**	**0.392940**	89,056,986
				GTD=	**0.40147**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	-	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	20,227,192	**TP1=**	1.00000	20,227,192
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	1.00000	-
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 2013 (ln 276)		**N/A**	TP1	1.00000	**N/A**
203	Plus: Additional General & Intangible Depreciation for 2013 (ln 275 + ln 276)		**N/A**	W/S	0.07846	**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)	41,591,445	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)	2,531,284	W/S	0.07846	198,593
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(18,391)	W/S	0.07846	(1,443)
209	Intangible Plant	(Worksheet A ln 20.C)	742,028	W/S	0.07846	58,216
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	65,073,558			20,482,558
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	-			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	68,360,449			68,360,449
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 2013 (-ln 202)		**N/A**			**N/A**
217	Plus: Additional General & Intangible Depreciation for 2013 (-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)	90,481,113			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	2,486,988			195,118
221	Intangible Plant	(ln 193 - ln 209)	240,400			18,861
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	161,568,950	**NP(h)=**	**0.424428**	68,574,428
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	-	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(29,722,622)	DA		(14,921,144)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(3,862,468)	DA		(321,239)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	2,710,890	DA		255,759
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(27,057)	DA		(8,892)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(30,901,257)			(14,995,516)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	-	DA		-
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	156,943			156,943
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,614	TP	1.00000	1,614
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	1,519	W/S	0.07846	119
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.39294	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet D, ln 6.G)	8,047,475	W/S	0.07846	631,369
238	Prepayments (Account 165) - Gross Plant	(Worksheet D, ln 6.F)	152,876	GP(h)	0.39294	60,071
239	Prepayments (Account 165) - Transmission Only	(Worksheet D, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet D, ln 6.D)	(7,804,737)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	555,690			850,116
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	-	DA	1.00000	-
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		131,223,383			54,429,028

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WHEELING 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	101,565,867			
245	Distribution	322.156.b	5,330,356			
246	Customer Related Expense	322 & 323.164,171,178.b	3,018,334			
247	Regional Marketing Expenses	322.131.b	-			
248	Transmission	321.112.b	1,362,394			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	111,276,951			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	106,849			
251	Less: Account 565	(Note H) 321.96.b	-			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	1,255,545	TP	1.00000	1,255,545
254	Administrative and General	323.197.b (Note J)	2,731,308			
255	Less: Acct. 924, Property Insurance	323.185.b	208,083			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
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)	32,337			
259	Acct. 928, Reg. Com. Exp.	323.189.b	-			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	2,128,141	W/S	0.07846	166,964
263	Plus: Acct. 924, Property Insurance	(ln 255)	208,083	GP(h)	0.39294	81,764
264	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 29.(E) (Note L)	-	TP	1.00000	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 35.(E) (Note L)	632	DA	1.00000	632
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
268	A & G Subtotal	(sum lns 262 to 267)	2,706,824			278,387
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	3,962,369			1,533,932
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)	3,962,369			1,533,932
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	-	NA	0.00000	-
275	Distribution	336.8.f	4,242,661	NA	0.00000	-
276	Transmission	336.7.f	1,970,536	TP1	1.00000	1,970,536
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
278	General	336.10.f	157,755	W/S	0.07846	12,377
279	Intangible	336.1.f	47,165	W/S	0.07846	3,700
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	6,418,117			1,986,613
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 21.(D)	177,131	W/S	0.07846	13,897
284	Plant Related					
285	Property	Worksheet H ln 21.(C) & ln 35.(C)	1,726,413	DA		742,994
286	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	5,520,256	NA	0.00000	-
287	Other	Worksheet H ln 21.(E)	527,793	GP(h)	0.39294	207,391
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	7,951,593			964,282
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.03%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		59.28%			
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)		1.6675			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
296	Income Tax Calculation	(ln 291 * ln 299)	7,887,761			3,271,697
297	ITC adjustment	(ln 294 * ln 295)	-	NP(h)	0.42443	-
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	7,887,761			3,271,697
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	13,306,474			5,519,279
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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)		39,526,314			13,275,803

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WHEELING POWER COMPANY

SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
304	Total transmission plant	(ln 185)							88,587,641
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)								-
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)							88,587,641
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)						**TP=**	**1.00000**
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
310	Production	354.20.b	0	0	-	NA		0.00000	-
311	Transmission	354.21.b	1,068	204,657	205,725	TP		1.00000	205,725
312	Regional Market Expenses	354.22.b	0	0	-	NA		0.00000	-
313	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA		0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA		0.00000	-
315	Total	(sum lns 310 to 314)	1,790,613	831,574	2,622,187				205,725
316	Transmission related amount							**W/S=**	**0.07846**

ln No.							
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
318	Long Term Interest	(Worksheet L, ln. 35, col. (D))					1,312,500
319	Preferred Dividends	(Worksheet L, ln. 40, col. (D))					-
320	Development of Common Stock:						
321	Proprietary Capital	(FF1 p 112, Ln 16.c)					90,109,311
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)					(473,816)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)					90,583,127
326			$	%		Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, ln 35, col. (B))		25,000,000	21.63%		0.0525	0.0114
328	Preferred Stock (ln 322)		-	0.00%		-	0.0000
329	Common Stock (ln 325)		90,583,127	78.37%		11.49%	0.0900
330	Total (Sum lns 327 to 329)		115,583,127			**WACC=**	**0.1014**

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WHEELING 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 historic as of December 31, 2012.

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 WHEELING 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=	7.74%	(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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WHEELING POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$10,427,761
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,416,286	DA	1.00000	$	1,416,286
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	9,011,475

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)					21.62%
7	Monthly Rate	(ln 6 / 12)					1.80%
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)					17.53%
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)					5.13%
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					106,849
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)						5,085
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)						-
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					101,764

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WHEELING 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)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	-	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	67,926,877	DA		67,926,877
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	1.00000	-
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)	127,637,585	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)	4,980,970	W/S	0.07846	390,785
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(34,819)	W/S	0.07846	(2,732)
28	Intangible Plant	(Worksheet A ln 9.E)	949,242	W/S	0.07846	74,473
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	201,459,855	**GP(h)=**	**0.33947**	68,389,403
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	-	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	19,688,526	**TP1=**	1.00000	19,688,526
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	1.00000	-
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 2013 (ln 111)		N/A	TP1	1.00000	N/A
38	Plus: Additional General & Intangible Depreciation for 2013 (ln 110 + ln 111)		N/A	W/S	0.07846	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)	40,456,536	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)	2,527,268	W/S	0.07846	198,278
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(17,973)	W/S	0.07846	(1,410)
44	Intangible Plant	(Worksheet A ln 20.E)	804,285	W/S	0.07846	63,101
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	63,458,641			19,948,494
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	48,238,351			48,238,351
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 2013 (-ln 37)		N/A			N/A
52	Plus: Additional General & Intangible Depreciation for 2013 (-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)	87,181,049			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	2,436,857			191,185
56	Intangible Plant	(ln 28 - ln 44)	144,957			11,373
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	138,001,214	**NP(h)=**	**0.35102**	48,440,908
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(25,583,410)	DA		(11,254,011)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(3,347,411)	DA		(313,740)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	2,924,783	DA		652,121
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	(42,106)	DA		(13,816)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(26,048,144)			(10,929,446)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	-	DA		-
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	156,943			156,943
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,019	TP	1.00000	1,019
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	760	W/S	0.07846	60
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.33947	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	7,946,927	W/S	0.07846	623,480
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	149,255	GP(h)	0.33947	50,667
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(7,710,537)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	544,366			832,169
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	-	DA	1.00000	-
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		112,497,437			38,343,632

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

WHEELING 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	101,565,867			
80	Distribution	322.156.b	5,330,356			
81	Customer Related Expense	322.164,171,178.b	3,018,334			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	1,362,394			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	111,276,951			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	106,849			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	1,255,545	TP	1.00000	1,255,545
89	Administrative and General	323.197.b (Note J)	2,731,308			
90	Less: Acct. 924, Property Insurance	323.185.b	208,083			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
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)	32,337			
94	Acct. 928, Reg. Com. Exp.	323.189.b	-			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	2,128,141	W/S	0.07846	166,964
98	Plus: Acct. 924, Property Insurance	(ln 90)	208,083	GP(h)	0.33947	70,638
99	Acct. 928 - Transmission Specific	Worksheet F ln 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 29.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 35.(E) (Note L)	632	DA	1.00000	632
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
103	A & G Subtotal	(sum lns 97 to 102)	2,706,824			267,260
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,962,369			1,522,805
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)	3,962,369			1,522,805
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	4,242,661	NA	0.00000	-
111	Transmission	336.7.f	1,970,536	TP1	1.00000	1,970,536
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	157,755	W/S	0.07846	12,377
114	Intangible	336.1.f	47,165	W/S	0.07846	3,700
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	6,418,117			1,986,613
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 21.(D)	177,131	W/S	0.07846	13,897
119	Plant Related					
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	1,726,413	DA		742,994
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	5,520,256	NA	0.00000	-
122	Other	Worksheet H ln 21.(E)	527,793	GP(h)	0.33947	179,169
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	7,951,593			936,061
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.03%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		57.69%			
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)		1.6675			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 126 * ln 134)	6,421,295			2,188,635
132	ITC adjustment	(ln 129 * ln 130)	-	NP(h)	0.35102	-
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	6,421,295			2,188,635
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	11,130,289			3,793,648
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
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		35,883,663			10,427,761
	(sum lns 107, 115, 123, 133, 134, 135)					

AEP East Companies
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WHEELING POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF		
139	Total transmission plant	(ln 20)	67,926,877
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)		-
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)	67,926,877
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139) TP	1.00000

ln No.	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	1,068	204,657	205,725	TP	1.00000	205,725
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA	0.00000	-
150	Total	(sum lns 145 to 149)	1,790,613	831,574	2,622,187			205,725
151	Transmission related amount						W/S=	0.07846

ln No.	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))	1,312,500
154	Preferred Dividends	(Worksheet M, ln. 56, col. (E))	-
155	Development of Common Stock:		Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	71,460,709
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))	(1,272,340)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	72,733,049

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))	25,000,000	25.58%	0.00%	0.0525	0.0134
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Commone Stock (ln 160)	72,733,049	74.42%	0.00%	11.49%	0.0855
165	Total (Sum lns 162 to 164)	97,733,049			WACC=	0.0989
166	Capital Structure Equity Limit (Note U)	100.0%				

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2012 with Average Ratebase Balances

WHEELING 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, 2011 and December 31, 2012.
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 WHEELING 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 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=	7.74%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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 WHEELING 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 2012 FF1 Balances
Worksheet A Supporting Plant Balances
WHEELING POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2012	(D) Balance @ December 31, 2011	(E) Average Balance for 2012
	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	-	-	-
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	-	-	-
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	88,587,641	47,266,113	67,926,877
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	132,072,558	123,202,612	127,637,585
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	5,034,700	4,927,240	4,980,970
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	34,819	34,819	34,819
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	982,428	916,055	949,242
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	226,677,327	176,312,020	201,494,674
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	34,819	34,819	34,819
	Accumulated Depreciation & Amortization Balances				
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	-	-	-
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	20,227,192	19,149,860	19,688,526
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	41,591,445	39,321,627	40,456,536
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	2,531,284	2,523,251	2,527,268
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	18,391	17,556	17,973
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	742,028	866,541	804,285
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	65,091,949	61,861,279	63,476,614
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	18,391	17,556	17,973
	Generation Step-Up Units				
23	**GSU Investment Amount**	Company Records - Note 1	-	-	-
24	**GSU Accumulated Depreciation**	Company Records - Note 1	-	-	-
25	**GSU Net Balance**	(Line 23 - Line 24)	-	-	-
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation				
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	20,227,192	19,149,860	19,688,526
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	-	-	-
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	20,227,192	19,149,860	19,688,526
	Plant Held For Future Use				
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	-	-	-
30	**Transmission Plant Held For Future**	Company Records - Note 1	-	-	-
	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 2012 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
WHEELING POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	Description	Source	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	-	-	-
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	-	-	-
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)	29,722,622	21,444,197	25,583,410
8	Less: ARO Related Deferrals	Company Records - Note 1	(994)	(702)	(848)
9	Less: Other Excluded Deferrals	Company Records - Note 1	14,802,472	13,858,022	14,330,247
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	14,921,144	7,586,877	11,254,011
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	3,862,468	2,832,354	3,347,411
13	Less: ARO Related Deferrals	Company Records - Note 1	0	0	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	3,541,229	2,526,113	3,033,671
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	321,239	306,241	313,740
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	2,710,890	3,138,676	2,924,783
18	Less: ARO Related Deferrals	Company Records - Note 1	40,281	44,886	42,584
19	Less: Other Excluded Deferrals	Company Records - Note 1	2,414,850	2,045,308	2,230,079
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	255,759	1,048,482	652,121
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	27,057	57,155	42,106
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	0	0	-
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	27,057	57,155	42,106
25	Transmission Related Deferrals	Company Records - Note 1	8,892	18,739	13,816

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 2012 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
WHEELING POWER COMPANY

Materials & Supplies

Line Number (A)	(B)	Source (C)	Balance @ December 31, 2012 (D)	Balance @ December 31, 2011 (E)	Average Balance for 2012 (F)
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,614	423	1,019
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	1,519	0	760
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

Line (A)	(B)	Average of YE Balance (C)	Excludable Balances (D)	100% Transmission Related (E)	Transmission Plant Related (F)	Transmission Labor Related (G)	Total Included in Ratebase (E)+(F)+(G) (H)
5							
6	Totals as of December 31, 2012	395,614	(7,804,737)	0	152,876	8,047,475	8,200,351
7	Totals as of December 31, 2011	375,676	(7,616,336)		145,633	7,846,379	7,992,012
8	**Average Balance**	385,645	(7,710,537)	-	149,255	7,946,927	8,096,182

Prepayments Account 165 - Balance @ 12/31/2012

9	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
10	1650001	Prepaid Insurance	43,469	-		43,469		43,469	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	242,738	242,738				-	Prepaid Taxes
12	1650010	Prepaid Pension Benefits	8,047,475				8,047,475	8,047,475	Prefunded Pension Expense
13	1650014	FAS 158 Qual Contra Asset	(8,047,475)	(8,047,475)				-	SFAS 158 Offset
14	1650016	FAS 112 ASSETS	0	-			-	-	
15	1650021	Prepaid Insurance - EIS	109,407	-		109,407		109,407	Energy INS Services
		Subtotal - Form 1, p 111.57.c	395,614	(7,804,737)	0	152,876	8,047,475	8,200,351	

Prepayments Account 165 - Balance @ 12/31/ 2011

16	Acc. No.	Description	2011 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
17	1650001	Prepaid Insurance	38,943			38,943		38,943	Plant Related Insurance Policies
18	165000211	Prepaid Taxes	230,043	230,043		0		-	Prepaid Taxes
19	1650010	Prepaid Pension Benefits	7,846,379				7,846,379	7,846,379	Prefunded Pension Expense
20	1650014	FAS 158 Qual Contra Asset	(7,846,379)	(7,846,379)				-	SFAS 158 Offset
21	1650016	FAS 112 ASSETS	0	0				-	
	1650021	Prepaid Insurance - EIS	106,690			106,690		106,690	
		Subtotal - Form 1, p 111.57.d	375,676	(7,616,336)		145,633	7,846,379	7,992,012	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet D Supporting IPP Credits
WHEELING POWER COMPANY

Line Number	(A) Description	(B) 2012
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 24.b)	-
2	Interest Accrual (Company Records - Note 1)	-
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 12/31/2012 (2012 FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	-

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

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet E Supporting Revenue Credits
WHEELING POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	142,741	142,741	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Record**	(5,425)	(5,425)	-
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	1,482,876	1,418,426	64,450
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	72,850	72,850	-
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	9,092,239	7,740,403	1,351,836
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	10,785,281	9,368,995	1,416,286
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	10,785,281	9,368,995	1,416,286

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or WHEELING 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 2012 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
WHEELING POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C) 2012 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1	5700005	Maint Station-Reliability-Df	-			
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	865			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	85,294			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(11)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,085			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	15,616			
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	0			
14		**Total of Account 561**	106,849			
		Account 928				
15	9280000	Regulatory Commission Exp	-	-	-	
16	9280001	Regulatory Commission Exp-Adm	-	-	-	
17	9280002	Regulatory Commission Exp-Case	-	-	-	
18		**Total**	-	-	-	
		Account 930.1				
19	9301000	General Advertising Expenses	263	263	-	
20	9301001	Newspaper Advertising Space	-	-	-	
21	9301007	Special Adv Space & Prod Exp	-	-	-	
22	9301008	Direct Mail and Handouts	-	-	-	
23	9301009	Fairs, Shows, and Exhibits	-	-	-	
24	9301010	Publicity	115	115	-	
25	9301011	Dedications, Tours, & Openings	-	-	-	
26	9301012	Public Opinion Surveys	586	586	-	
27	9301014	Video Communications	2	2	-	
28	9301015	Other Corporate Comm Exp	1,971	1,971	-	
29		**Total**	2,937	2,937	-	
		Account 930.2				
30	9302000	Misc General Expenses	14,907	14,907		
31	9302003	Corporate & Fiscal Expenses	1,447	1,447		
32	9302004	Research, Develop&Demonstr Exp	632	632		
33	9302006	Assoc Bus Dev-Materials Sold	3,899	3,899		
34	9302007	Assoc Business Development Exp	56,741	56,109	632	
35		**Total**	77,626	76,994	632	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
WHEELING POWER COMPANY

West Virginia Corporate Income Tax	7.75%	
Apportionment Factor - Note 2	99.85%	
Effective State Tax Rate		7.74%
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%
Total Effective State Income Tax Rate		7.74%

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 20% 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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
WHEELING POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company NOTE 1	Property	Labor	Other	Non-Allocable
1	Revenue Taxes					
2	Gross Receipts Tax	3,435,001				3,435,001
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - West Virginia	1,726,413	1,726,413			
5	Real and Personal Property - Other	0	-			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	173,332		173,332		
8	Federal Unemployment Tax	403		403		
9	State Unemployment Insurance	3,396		3,396		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	2,085,216				2,085,216
14	State Public Service Commission Fees	514,811			514,811	
15	State Franchise Taxes	12,952			12,952	
16	State Lic/Registration Fee	30			30	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	39				39
19	Federal Excise Tax	-				-
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	7,951,593	1,726,413	177,131	527,793	5,520,256

(Total Company Amount Ties to FFI p.114, Ln 14,(c))
NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

Functional Property Tax Allocation

Line		Production	Transmission	Distribution	General	Total
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	-	68,360,449	90,481,113	2,486,988	161,328,550
	WEST VIRGINA JURISDICTION					
23	Percentage of Plant in WEST VIRGINA JURISDICTION		100.00%	100.00%	100.00%	
24	Net Plant in WEST VIRGINA JURISDICTION (Ln 22 * Ln 23)	-	68,360,449	90,481,113	2,486,988	161,328,550
25	Less: Net Value of Exempted Generation Plant	-				
26	Taxable Property Basis (Ln 24 - Ln 25)	-	68,360,449	90,481,113	2,486,988	161,328,550
27	Relative Valuation Factor		100%	100%	100%	
28	Weighted Net Plant (Ln 26 * Ln 27)	-	68,360,449	90,481,113	2,486,988	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	0.00%	43.04%	56.96%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	-	1,070,322	1,416,666	(2,486,988)	-
31	Weighted WEST VIRGINA JURISDICTION Plant (Ln 28 + 30)	-	69,430,771	91,897,779	(0)	161,328,550
32	Functional Percentage (Ln 31/Total Ln 31)	0.00%	43.04%	56.96%		
33	Functionalized Expense in WEST VIRGINA JURISDICTION	-	742,994	983,419		1,726,413
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		-			-
35	Total Func. Property Taxes (Sum Lns 33, 34)	-	742,994	983,419		1,726,413

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
WHEELING POWER COMPANY

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	Revenue Taxes			
2	Gross Receipts Tax	3,435,001		
			3,435,001	P.263 ln 37 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - West Virginia	1,726,413		
			859,318	P.263 ln 26 (i)
			868,776	P.263 ln 27 (i)
			(6,679)	P.263 ln 31 (i)
			4,998	P.263 ln 32 (i)
5	Real and Personal Property - Ohio	-		
6	Payroll Taxes			
7	Federal Insurance Contribution (FICA)	173,332		
			173,332	P.263 ln 4 (i)
8	Federal Unemployment Tax	403		
			403	P.263 ln 5 (i)
9	State Unemployment Insurance	3,396		
			3,396	P.263 ln 38 (i)
10	Production Taxes			
11	State Severance Taxes	-		
12	Miscellaneous Taxes			
13	Muni Business & Occupation Tax	2,085,216		
			2,085,216	P.263.1 ln 8 (i)
14	State Public Service Commission Fees	514,811		
			222,595	P.263 ln 39 (i)
			292,216	P.263 ln 40 (i)
15	State Franchise Taxes	12,952		
			(84)	P.263 ln 23 (i)
			1,036	P.263 ln 24 (i)
			6,000	P.263.1 ln 9 (i)
			6,000	P.263.1 ln 10 (i)
16	State Lic/Registration Fee	30		
			25	P.263.1 ln 2 (i)
			15	P.263.1 ln 11 (i)
			(25)	P.263.1 ln 15 (i)
			15	P.263.1 ln 17 (i)
17	Misc. State and Local Tax	-		
18	Sales & Use	39		
			39	P.263 ln 35 (i)
19	Federal Excise Tax	-		
20	Michigan Single Business Tax	-		
21	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	7,951,593	7,951,593	

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 2012 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
WHEELING POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	47,266,113
2	Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	88,587,641
3		135,853,754
4	Average Balance of Transmission Investment	67,926,877
5	Annual Depreciation Expense, Historic TCOS, ln 276	1,970,536
6	Composite Depreciation Rate	2.90%
7	Round to 2.9% to Reflect a Composite Life of 34 Years	2.90%

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	$ 5,311,421	2.90%	$ 154,031	$ 12,836	11	$ 141,196
10	February	$ 8,837,046	2.90%	$ 256,274	$ 21,356	10	$ 213,560
11	March	$ 1,453,035	2.90%	$ 42,138	$ 3,512	9	$ 31,608
12	April	$ 1,069,078	2.90%	$ 31,003	$ 2,584	8	$ 20,672
13	May	$ 330,023	2.90%	$ 9,571	$ 798	7	$ 5,586
14	June	$ 244,673	2.90%	$ 7,096	$ 591	6	$ 3,546
15	July	$ 184,935	2.90%	$ 5,363	$ 447	5	$ 2,235
16	August	$ 70,282	2.90%	$ 2,038	$ 170	4	$ 680
17	September	$ 156,649	2.90%	$ 4,543	$ 379	3	$ 1,137
18	October	$ 185,596	2.90%	$ 5,382	$ 449	2	$ 898
19	November	$ 179,260	2.90%	$ 5,199	$ 433	1	$ 433
20	December	$ 295,778	2.90%	$ 8,578	$ 715	0	$ -
21	Investment	$ 18,317,776				Depreciation Expense	$ 421,551

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 2013

		Estimated Cost (000's)	Month in Service
25 **Major Zonal Projects**			
26 N/A		$0	Multiple
27	Subtotal	$0	
28 **PJM Socialized/Beneficiary Allocated Regional Projects**			
29 N/A		$0	
30	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
WHEELING POWER COMPANY

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2013	393,660	393,660	$ -

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	21.63%	5.25%	1.136%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	78.37%	11.49%	9.005%
		R =	10.140%

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

Rate Base (Projected TCOS, ln 78)	70,338,640
R (from A. above)	10.140%
Return (Rate Base x R)	7,132,565

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

Return (from B. above)	7,132,565
Effective Tax Rate (Projected TCOS, ln 126)	59.28%
Income Tax Calculation (Return x CIT)	4,228,015
ITC Adjustment	-
Income Taxes	4,228,015

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)	16,266,957
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	7,132,565
Income Taxes (Projected TCOS, ln 133)	4,228,015
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,906,378

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,906,378
Return (from I.B. above)	7,132,565
Income Taxes (from I.C. above)	4,228,015
Annual Revenue Requirement, with Basis Point ROE increase	16,266,957
Depreciation (Projected TCOS, ln 111)	1,970,536
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	14,296,421

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	68,360,449
Annual Revenue Requirement, with Basis Point ROE increase	16,266,957
FCR with Basis Point increase in ROE	23.80%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	14,296,421
FCR with Basis Point ROE increase, less Depreciation	20.91%
FCR less Depreciation (Projected TCOS, ln 9)	16.46%
Incremental FCR with Basis Point ROE increase, less Depreciation	4.45%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, ln 58,(b)):	47,266,113
Transmission Plant @ End of Historic Period (2012) (P.207, ln 58,(g)):	88,587,641
Subtotal	135,853,754
Average Transmission Plant Balance for 2012	67,926,877
Annual Depreciation Rate (Projected TCOS, ln 111)	1,970,536
Composite Depreciation Rate	2.90%
Depreciable Life for Composite Depreciation Rate	34.47
Round to nearest whole year	34

WPCo 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: **RTEP ID: b1864.1 (Two additional 345/138 kV transformers at Kammer)**

Current Projected Year ARR	**349,494**
Current Projected Year ARR w/ Incentive	**349,494**
Current Projected Year Incentive ARR	**-**

Details			
Investment	2,097,000	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	16.46%
Useful life	34	FCR w/incentives approved for these facilities, less dep.	16.46%
CIAC (Yes or No)	No	Annual Depreciation Expense	61,676

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	2,097,000	5,140	2,091,860	349,494	349,494	$ -
2014	2,091,860	61,676	2,030,184	395,878	395,878	$ -
2015	2,030,184	61,676	1,968,507	385,725	385,725	$ -
2016	1,968,507	61,676	1,906,831	375,572	375,572	$ -
2017	1,906,831	61,676	1,845,154	365,419	365,419	$ -
2018	1,845,154	61,676	1,783,478	355,266	355,266	$ -
2019	1,783,478	61,676	1,721,801	345,113	345,113	$ -
2020	1,721,801	61,676	1,660,125	334,960	334,960	$ -
2021	1,660,125	61,676	1,598,449	324,807	324,807	$ -
2022	1,598,449	61,676	1,536,772	314,654	314,654	$ -
2023	1,536,772	61,676	1,475,096	304,501	304,501	$ -
2024	1,475,096	61,676	1,413,419	294,348	294,348	$ -
2025	1,413,419	61,676	1,351,743	284,195	284,195	$ -
2026	1,351,743	61,676	1,290,066	274,042	274,042	$ -
2027	1,290,066	61,676	1,228,390	263,889	263,889	$ -
2028	1,228,390	61,676	1,166,713	253,736	253,736	$ -
2029	1,166,713	61,676	1,105,037	243,584	243,584	$ -
2030	1,105,037	61,676	1,043,360	233,431	233,431	$ -
2031	1,043,360	61,676	981,684	223,278	223,278	$ -
2032	981,684	61,676	920,007	213,125	213,125	$ -
2033	920,007	61,676	858,331	202,972	202,972	$ -
2034	858,331	61,676	796,654	192,819	192,819	$ -
2035	796,654	61,676	734,978	182,666	182,666	$ -
2036	734,978	61,676	673,301	172,513	172,513	$ -
2037	673,301	61,676	611,625	162,360	162,360	$ -
2038	611,625	61,676	549,949	152,207	152,207	$ -
2039	549,949	61,676	488,272	142,054	142,054	$ -
2040	488,272	61,676	426,596	131,901	131,901	$ -
2041	426,596	61,676	364,919	121,748	121,748	$ -
2042	364,919	61,676	303,243	111,595	111,595	$ -
2043	303,243	61,676	241,566	101,442	101,442	$ -
2044	241,566	61,676	179,890	91,289	91,289	$ -
2045	179,890	61,676	118,213	81,136	81,136	$ -
2046	118,213	61,676	56,537	70,983	70,983	$ -
2047	56,537	56,537	-	56,537	56,537	$ -
2048	-	-	-	-	-	$ -
2049	-	-	-	-	-	$ -
2050	-	-	-	-	-	$ -
2051	-	-	-	-	-	$ -
2052	-	-	-	-	-	$ -
2053	-	-	-	-	-	$ -
2054	-	-	-	-	-	$ -
2055	-	-	-	-	-	$ -
2056	-	-	-	-	-	$ -
2057	-	-	-	-	-	$ -
2058	-	-	-	-	-	$ -
2059	-	-	-	-	-	$ -
2060	-	-	-	-	-	$ -
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2062	-	-	-	-	-	$ -
2063	-	-	-	-	-	$ -
2064	-	-	-	-	-	$ -
2065	-	-	-	-	-	$ -
2066	-	-	-	-	-	$ -
2067	-	-	-	-	-	$ -
2068	-	-	-	-	-	$ -
2069	-	-	-	-	-	$ -
2070	-	-	-	-	-	$ -
2071	-	-	-	-	-	$ -
2072	-	-	-	-	-	$ -
Project Totals		2,097,000		8,109,239	8,109,239	-

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.

WPCo 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: **RTEP ID: b1864.2 (West Bellaire-Brues 138 kV Circuit)**

Current Projected Year ARR	**44,166**
Current Projected Year ARR w/ Incentive	**44,166**
Current Projected Year Incentive ARR	**-**

Details			
Investment	265,000	Current Year	**2013**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	16.46%
Useful life	34	FCR w/incentives approved for these facilities, less dep.	16.46%
CIAC (Yes or No)	No	Annual Depreciation Expense	7,794

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**
2013	265,000	650	264,350	44,166	44,166	$ -
2014	264,350	61,676	202,674	95,040	95,040	$ -
2015	202,674	61,676	140,998	84,887	84,887	$ -
2016	140,998	61,676	79,321	74,734	74,734	$ -
2017	79,321	61,676	17,645	64,581	64,581	$ -
2018	17,645	17,645	-	17,645	17,645	$ -
2019	-	-	-	-	-	$ -
2020	-	-	-	-	-	$ -
2021	-	-	-	-	-	$ -
2022	-	-	-	-	-	$ -
2023	-	-	-	-	-	$ -
2024	-	-	-	-	-	$ -
2025	-	-	-	-	-	$ -
2026	-	-	-	-	-	$ -
2027	-	-	-	-	-	$ -
2028	-	-	-	-	-	$ -
2029	-	-	-	-	-	$ -
2030	-	-	-	-	-	$ -
2031	-	-	-	-	-	$ -
2032	-	-	-	-	-	$ -
2033	-	-	-	-	-	$ -
2034	-	-	-	-	-	$ -
2035	-	-	-	-	-	$ -
2036	-	-	-	-	-	$ -
2037	-	-	-	-	-	$ -
2038	-	-	-	-	-	$ -
2039	-	-	-	-	-	$ -
2040	-	-	-	-	-	$ -
2041	-	-	-	-	-	$ -
2042	-	-	-	-	-	$ -
2043	-	-	-	-	-	$ -
2044	-	-	-	-	-	$ -
2045	-	-	-	-	-	$ -
2046	-	-	-	-	-	$ -
2047	-	-	-	-	-	$ -
2048	-	-	-	-	-	$ -
2049	-	-	-	-	-	$ -
2050	-	-	-	-	-	$ -
2051	-	-	-	-	-	$ -
2052	-	-	-	-	-	$ -
2053	-	-	-	-	-	$ -
2054	-	-	-	-	-	$ -
2055	-	-	-	-	-	$ -
2056	-	-	-	-	-	$ -
2057	-	-	-	-	-	$ -
2058	-	-	-	-	-	$ -
2059	-	-	-	-	-	$ -
2060	-	-	-	-	-	$ -
2061	-	-	-	-	-	$ -
2062	-	-	-	-	-	$ -
2063	-	-	-	-	-	$ -
2064	-	-	-	-	-	$ -
2065	-	-	-	-	-	$ -
2066	-	-	-	-	-	$ -
2067	-	-	-	-	-	$ -
2068	-	-	-	-	-	$ -
2069	-	-	-	-	-	$ -
2070	-	-	-	-	-	$ -
2071	-	-	-	-	-	$ -
2072	-	-	-	-	-	$ -
Project Totals		265,000		381,052	381,052	-

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 2012 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
WHEELING 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	25.58%	5.25%	1.343%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	74.42%	11.49%	8.551%
		R =	9.894%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2012			
As Projected in Prior Year WS J			$ -
Actual after True-up	$ -	$ -	$ -
True-up of ARR For 2012	-	-	-

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

Rate Base (True-Up TCOS, ln 78)	38,343,632
R (from A. above)	9.894%
Return (Rate Base x R)	3,793,648

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

Return (from B. above)	3,793,648
Effective Tax Rate (True-Up TCOS, ln 126)	57.69%
Income Tax Calculation (Return x CIT)	2,188,635
ITC Adjustment	-
Income Taxes	2,188,635

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)	10,427,761
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	3,793,648
Income Taxes (True-Up TCOS, ln 133)	2,188,635
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,445,479

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,445,479
Return (from I.B. above)	3,793,648
Income Taxes (from I.C. above)	2,188,635
Annual Revenue Requirement, with 0 Basis Point ROE increase	10,427,761
Depreciation (True-Up TCOS, ln 111)	1,970,536
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	8,457,225

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

Net Transmission Plant (True-Up TCOS, ln 48)	48,238,351
Annual Revenue Requirement, with 0 Basis Point ROE increase	10,427,761
FCR with 0 Basis Point increase in ROE	21.62%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	8,457,225
FCR with 0 Basis Point ROE increase, less Depreciation	17.53%
FCR less Depreciation (True-Up TCOS, ln 9)	17.53%
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)):	47,266,113
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	88,587,641
Subtotal	135,853,754
Average Transmission Plant Balance for	67,926,877
Annual Depreciation Rate (True-Up TCOS, ln 111)	1,970,536
Composite Depreciation Rate	2.90%
Depreciable Life for Composite Depreciation Rate	34.47
Round to nearest whole year	34

WPCo 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: **RTEP ID: b1864.1 (Two additional 345/138 kV transformers at Kammer)**

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	17.53%
Useful life	34	FCR w/incentives approved for these facilities, less dep.	17.53%
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 **
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2041	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2042	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2043	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2044	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2045	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2046	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2047	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2048	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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2063	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

WPCo 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: **RTEP ID: b1864.2 (West Bellaire-Brues 138 kV Circuit)**

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)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	17.53%
Useful life	34	FCR w/incentives approved for these facilities, less dep.	17.53%
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 **
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	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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 2012 FF1 Balances
Worksheet L Supporting Projected Cost of Debt
WHEELING 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 Co.		25,000,000	5.250%	1,312,500	
3						
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	N/A for Wheeling Power Company				-	
6					-	
7					-	
8					-	
9					-	
10					-	
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)				-	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			-	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
32	Reacquired Debt:					
33	Amortization of Loss	FF1.p. 117.64.c			-	
34	Amortization of Gain	FF1.p. 117.66.c			-	
35	**Total Interest on Long Term Debt**		25,000,000	5.25%	1,312,500	
36	**Preferred Stock (FF1.p. 250-251)**		**Preferred Shares Outstanding**			
37	None		-	0.00%	-	
38					-	
39					-	
40	**Dividends on Preferred Stock**		-		-	
41	Net Total Hedge Gains and Losses (WS M, Ln 35, (E))				-	
42	Total Projected Capital Structure Balance for 2013 (Projected TCOS, Ln 165)				115,583,127	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
44	Limit of Recoverable Amount				57,792	
45	**Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)**				-	

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

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A) Line	(B)	(C) Balances @ 12/31/2012	(D) Balances @ 12/31/2011	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	90,109,311	52,812,106	71,460,709
2	Less Preferred Stock (Ln 55 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	0	0	0
4	Less Account 219.1 (112.15.c&d)	-473,816	-2,070,864	-1,272,340
5	**Average Balance of Common Equity**	90,583,127	54,882,970	**72,733,049**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	0	0	0
7	Less: Reacquired Bonds (112.19.c&d)	0	0	0
8	LT Advances from Assoc. Companies (112.20.c&d)	25,000,000	25,000,000	25,000,000
9	Senior Unsecured Notes (112.21.c&d)	0	0	0
10	Less: Fair Value Hedges (See Note on Ln 12 below)	0	0	0
11	**Total Average Debt**	25,000,000	25,000,000	**25,000,000**

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 2012**	
14	Interest on Long Term Debt (256-257.33.i)	1,312,500
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.	-
16	Plus: Allowed Hedge Recovery From Ln 39 below.	-
17	Amort of Debt Discount & Expense (117.63.c)	-
18	Amort of Loss on Reacquired Debt (117.64.c)	-
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)**	**1,312,500**
22	**Average Cost of Debt for 2012 (Ln 21/Ln 11)**	**5.25%**

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 2012	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	0	-	-			
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	-	-				

35	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)	-
36	Total Average Capital Structure Balance for 2012 (True-UP TCOS, Ln 165)	97,733,049
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
38	Limit of Recoverable Amount	48,867
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**	-

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)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
56	**Dividends on Preferred Stock (Lns 44, 49, 54)**	-	-	-
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
WHEELING 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 2012		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
WHEELING POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

Allocation of PBOP Settlement Amount for 2012

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) **(Line 14)**	**(B)=(A)/Total (A)**	**(C)=(B) * 48100000**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	**Sum of Lines 1 to 7**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)

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

Line		APCo	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9	Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10	Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11	Medicare Subsidy	-	-	-	-	-	-	-
12	Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
				-				
13	PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14	Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.70%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	2.70%
Poles & Fixtures	355.0	2.70%
Overhead Conductors	356.0	2.70%
Underground Conduit	357.0	2.70%
Underground Conductors	358.0	2.70%
Trails & Roads	359.0	2.70%

Note 1: Rates Approved in WV Public Service Commission Case No. PSC 90-243-E-42T.

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.