

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2009 and Projected Net Plant at Year-End 2010

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$79,599,351
2	REVENUE CREDITS	(Note A) (Worksheet E)	3,042,204	DA 1.00000	\$ 3,042,204
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			\$ 76,557,147

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)		1,408,114	DA 1.00000	\$ 1,408,114
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
6	Annual Rate	$(\text{In } 1 - \text{In } 105 - \text{In } 106) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100)$			17.88%
7	Monthly Rate	(In 6 / 12)			1.49%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	$(\text{In } 1 - \text{In } 105 - \text{In } 106 - \text{In } 111 - \text{In } 112) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100)$			15.48%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	$(\text{In } 1 - \text{In } 105 - \text{In } 106 - \text{In } 111 - \text{In } 112 - \text{In } 133 - \text{In } 134) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100)$			5.23%
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			4,342,170
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,348,093
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				442,226
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			1,551,851

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	(1)	(2)	(3)	(4)	(5)
Line No.	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total NOTE C	Allocator	Total Transmission
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.C)	3,610,392,143	NA 0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(155,199,856)	NA 0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	1,153,823,876	DA	1,121,624,749
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 143)	-	TP 0.97209	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.D)		40,715,364	DA 1.00000	40,715,364
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, In 22.D)		-	DA 1.00000	-
24	Distribution	(Worksheet A In 5.C)	1,360,318,756	NA 0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA 0.00000	-
26	General Plant	(Worksheet A In 7.C)	97,685,547	W/S 0.04127	4,031,547
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(191,891)	W/S 0.04127	(7,919)
28	Intangible Plant	(Worksheet A In 9.C)	130,559,946	W/S 0.04127	5,388,295
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	6,238,103,885		1,171,752,035
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.C)	2,210,457,182	NA 0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(69,632,189)	NA 0.00000	-
33	Transmission	(Worksheet A In 14.C & 28.C)	504,959,262	TP1= 0.96338	486,465,295
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1= 0.96338	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.I)		262,440	DA 1.00000	262,440
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I In 24.D)		-	DA 1.00000	-
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		16,178,988	TP1 0.96338	15,586,438
38	Plus: Additional General & Intangible Depreciation for 2010 (In 113 + In 114)		28,087,990	W/S 0.04127	1,159,210
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I In 23.D)		-	DA 1.00000	-
40	Distribution	(Worksheet A In 16.C)	443,905,896	NA 0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA 0.00000	-
42	General Plant	(Worksheet A In 18.C)	23,904,062	W/S 0.04127	986,536
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(135,119)	W/S 0.04127	(5,576)
44	Intangible Plant	(Worksheet A In 20.C)	100,238,014	W/S 0.04127	4,136,889
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	3,258,226,526		508,591,231
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	1,314,367,294		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	648,864,614		635,159,454
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		40,452,924		40,452,924
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		-		-
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		(16,178,988)		(15,586,438)
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		(28,087,990)		(1,159,210)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		-		-
54	Distribution	(In 24 + In 25 - In 40 - In 41)	916,412,860		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	73,724,713		3,042,667
56	Intangible Plant	(In 28 - In 44)	30,321,932		1,251,406
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	2,979,877,359		663,160,804
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(295,177)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(648,884,207)	DA	(117,964,260)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(563,868,587)	DA	(10,775,182)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	640,478,175	DA	17,196,270
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(572,569,796)		(111,543,172)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,896,232	DA	202,362
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA	-
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 * In 88)	2,426,486		2,358,772
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,199,375	TP 0.97209	1,165,905
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	602,830	W/S 0.04127	24,879
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h) 0.18250	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	49,899,129	W/S 0.04127	2,059,370
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	5,346,093	GP(h) 0.18250	975,673
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA 1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(45,794,268)	NA 0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	13,679,645		6,584,599
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(5,827,949)	DA 1.00000	(5,827,949)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,423,055,492		552,576,644

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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
79	OPERATION & MAINTENANCE EXPENSE				
80	Production	321.80.b	1,266,511,562		
81	Distribution	322.156.b	66,872,997		
82	Customer Related Expense	322.164,171,178.b	24,425,007		
83	Regional Marketing Expenses	322.131.b	2,515,197		
84	Transmission	321.112.b	(12,458,696)		
85	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,347,866,067		
86	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,342,170		
87	Less: Account 565	(Note H) 321.96.b	(36,212,757)		
88	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	19,411,891	TP 0.97209	18,870,174
89	Administrative and General	323.197.b (Note J)	131,275,366		
90	Less: Acct. 924, Property Insurance	323.185.b	1,944,130		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	15,357,327		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(4,008,620)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,125,097		
94	Acct. 928, Reg. Com. Exp.	323.189.b	11,098,908		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,280,072		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	3,996,701		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	100,481,751	W/S 0.04127	4,146,948
98	Plus: Acct. 924, Property Insurance	(In 90)	1,944,130	GP(h) 0.18250	354,808
99	Acct. 928 - Transmission Specific	Worksheet F In 19.(E) (Note L)	-	TP 0.97209	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 34.(E) (Note L)	-	TP 0.97209	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 40.(E) (Note L)	161,509	DA 1.00000	161,509
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	9,519,127	W/S 0.04127	392,861
103	A & G Subtotal	(sum Ins 97 to 102)	112,106,517		5,056,125
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	131,518,408		23,926,299
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	(38,399,880)	DA 1.00000	(38,399,880)
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	93,118,528		(14,473,581)
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	56,540,775	NA 0.00000	-
110	Distribution	336.8.f	32,840,053	NA 0.00000	-
111	Transmission	336.7.f	16,178,988	TP1 0.96338	15,586,438
112	Plus: Transmission Plant-in-Service Additions (Worksheet I In 21.I)		262,440	DA 1.00000	262,440
113	General	336.10.f	3,259,582	W/S 0.04127	134,525
114	Intangible	336.1.f	24,828,408	W/S 0.04127	1,024,685
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111 +112+113+114)	133,910,246		17,008,088
116	TAXES OTHER THAN INCOME	(Note N)			
117	Labor Related				
118	Payroll	Worksheet H In 22.(D)	10,754,313	W/S 0.04127	443,838
119	Plant Related				
120	Property	Worksheet H In 22.(C) & In 47.(C)	41,866,818	DA	8,479,544
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	14,443,752	NA 0.00000	-
122	Other	Worksheet H In 22.(E)	1,807,288	GP(h) 0.18250	329,834
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	68,872,171		9,253,216
124	INCOME TAXES	(Note O)			
125	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		38.18%		
126	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		39.77%		
127	where WCLTD=(In 162) and WACC = (In 165)				
128	and FIT, SIT & p are as given in Note O.				
129	$GRCF=1 / (1 - T) =$ (from In 125)		1.6176		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(2,315,777)		
131	Income Tax Calculation	(In 126 * In 134)	85,361,311		19,466,606
132	ITC adjustment	(In 129 * In 130)	(3,745,909)	NP(h) 0.21432	(802,809)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	81,615,402		18,663,797
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	214,615,952		48,943,065
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		204,766	DA 1.00000	204,766
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use (In 136 * In126)		-		-
138	TOTAL REVENUE REQUIREMENT (sum Ins 107, 115, 123, 133, 134, 135, 136, 137)		592,337,065		79,599,351

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SUPPORTING CALCULATIONS

In								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)					1,153,823,876	
140	Less transmission plant excluded from PJM Tariff (Note P)						-	
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)						32,199,127	
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					<u>1,121,624,749</u>	
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)				TP	0.97209	
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Payroll Billed from					
145	Production	354.20.b	Direct Payroll	AEP Service Corp.	Total			
146	Transmission	354.21.b	129,658,142	11,914,620	141,572,762	NA	0.00000	
147	Regional Market Expenses	354.22.b	4,844,828	2,902,179	7,747,007	TP	0.97209	
148	Distribution	354.23.b	0	0	-	NA	0.00000	
149	Other (Excludes A&G)	354.24,25,26.b	19,581,915	1,971,387	21,553,302	NA	0.00000	
150	Total	(sum Ins 145 to 149)	<u>160,350,122</u>	<u>22,123,727</u>	<u>182,473,849</u>			
151	Transmission related amount					W/S=	0.04127	
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						<u>\$</u>	
153	Long Term Interest	(Worksheet L, In. 32, col. (D))					107,827,975	
154	Preferred Dividends	(Worksheet L, In. 37, col. (D))					339,382	
155	<u>Development of Common Stock:</u>							
156	Proprietary Capital	(FF1 p 112, Ln 16.c)					1,680,859,984	
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)					8,076,800	
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)					(581,331)	
159	Less: Account 219	(FF1 p 112, Ln 15.c)					<u>(21,700,504)</u>	
160	Common Stock	(In 156 - In 157 - In 158 - In 159)					1,695,065,019	
161						Cost		
162	Long Term Debt (Note T) Worksheet L, In 32, col. (B))		\$	%		(Note S)	Weighted	
163	Preferred Stock (In 157)		1,717,000,000	50.20%		0.0628	0.0315	
164	Common Stock (In 160)		8,076,800	0.24%		0.0420	0.0001	
165	Total (Sum Ins 162 to 164)		<u>1,695,065,019</u>	49.56%		11.49%	<u>0.0569</u>	
			3,420,141,819			WACC=	0.0886	

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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, 2010. Other ratebase amounts are as of December 31, 2009.
- 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 Ancillary 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 included 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 seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. 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) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.
Inputs Required: FIT = 35.00%
SIT = 4.89% (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 (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 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 \$259,022,855 at 12/31/07 is not included in the balance in line 162 above.
- U **This note only applies to the true-up template.**

AEP East Companies
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Utilizing Historic Cost Data for 2009 with Year-End Rate Base Balances

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)			\$76,401,921
167	REVENUE CREDITS	(Note A) (Worksheet E)	3,042,204	DA 1.00000	\$ 3,042,204
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)			\$ 73,359,717

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	((In 166 - In 270 - In 271) / In 213 x 100)			18.07%
172	Monthly Rate	(In 171 / 12)			1.51%
173	NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)				
174	Annual Rate	((In 166 - In 270 - In 271 - In 276) / In 213 x 100)			15.62%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)				
176	Annual Rate	((In 166 - In 270 - In 271 - In 276 - In 298 - In 299) / In 213 x 100)			5.44%
177	Not applicable on this template				
178	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES				
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below			4,342,170
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,348,093
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				442,226
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)			1,551,851

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Line No.	(1)	(2)	(3)	(4)	(5)
	<u>RATE BASE CALCULATION</u>	<u>Data Sources</u> <u>(See "General Notes")</u>	<u>TO Total</u> <u>NOTE C</u>	<u>Allocator</u>	<u>Total</u> <u>Transmission</u>
183	GROSS PLANT IN SERVICE				
183	Production	(Worksheet A In 1.C)	3,610,392,143	NA	0.00000
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(155,199,856)	NA	0.00000
185	Transmission	(Worksheet A In 3.C & Ln 307)	1,153,823,876	DA	
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 308)	-	TP	0.97209
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000
189	Distribution	(Worksheet A In 5.C)	1,360,318,756	NA	0.00000
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000
191	General Plant	(Worksheet A In 7.C)	97,685,547	W/S	0.04127
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(191,891)	W/S	0.04127
193	Intangible Plant	(Worksheet A In 9.C)	130,559,946	W/S	0.04127
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	6,197,388,521	GP(h)=	0.182502
				GTD=	0.44613
195	ACCUMULATED DEPRECIATION AND AMORTIZATION				
196	Production	(Worksheet A In 12.C)	2,210,457,182	NA	0.00000
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(69,632,189)	NA	0.00000
198	Transmission	(Worksheet A In 14.C & 28.C)	504,959,262	TP1=	0.96338
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.96338
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
202	Plus: Additional Transmission Depreciation for 2010 (In 276)		N/A	TP1	0.96338
203	Plus: Additional General & Intangible Depreciation for 2010 (In 275 + In 276)		N/A	W/S	0.04127
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
205	Distribution	(Worksheet A In 16.C)	443,905,896	NA	0.00000
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	0.00000
207	General Plant	(Worksheet A In 18.C)	23,904,062	W/S	0.04127
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(135,119)	W/S	0.04127
209	Intangible Plant	(Worksheet A In 20.C)	100,238,014	W/S	0.04127
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	3,213,697,108		
211	NET PLANT IN SERVICE				
212	Production	(In 183 + In 184 - In 196 - In 197)	1,314,367,294		
213	Transmission	(In 185 + In 186 - In 198 - In 199)	648,864,614		
214	Plus: Transmission Plant-in-Service Additions (In 187 - In 200)		N/A		
215	Plus: Additional Trans Plant on Transferred Assets (In 188 - In 201)		N/A		
216	Plus: Additional Transmission Depreciation for 2010 (-In 202)		N/A		
217	Plus: Additional General & Intangible Depreciation for 2010 (-In 203)		N/A		
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 204)		N/A		
219	Distribution	(In 189 + In 190 - In 205 - In 206)	916,412,860		
220	General Plant	(In 191 + In 192 - In 207 - In 208)	73,724,713		
221	Intangible Plant	(In 193 - In 209)	30,321,932		
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	2,983,691,413	NP(h)=	0.214316
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(295,177)	NA	
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(648,884,207)	DA	
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(563,868,587)	DA	
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	640,478,175	DA	
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(572,569,796)		
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,896,232	DA	
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA	
232	WORKING CAPITAL	(Note E)			
233	Cash Working Capital	(1/8 * In 253)	2,426,486		
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,199,375	TP	0.97209
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	602,830	W/S	0.04127
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.18250
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	49,899,129	W/S	0.04127
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	5,346,093	GP(h)	0.18250
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(45,794,268)	NA	0.00000
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	13,679,645		
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(5,827,949)	DA	1.00000
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		2,426,869,545		528,869,367

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INDIANA MICHIGAN POWER COMPANY

	(1)	(2)	(3)	(4)	(5)
Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allocator	Total Transmission
244	OPERATION & MAINTENANCE EXPENSE				
245	Production	321.80.b	1,266,511,562		
246	Distribution	322.156.b	66,872,997		
247	Customer Related Expense	322 & 323.164,171,178.b	24,425,007		
248	Regional Marketing Expenses	322.131.b	2,515,197		
249	Transmission	321.112.b	(12,458,696)		
250	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	1,347,866,067		
251	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,342,170		
252	Less: Account 565	(Note H) 321.96.b	(36,212,757)		
253	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	19,411,891	TP	0.97209
254	Administrative and General	323.197.b (Note J)	131,275,366		
255	Less: Acct. 924, Property Insurance	323.185.b	1,944,130		
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	15,357,327		
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(4,008,620)		
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,125,097		
259	Acct. 928, Reg. Com. Exp.	323.189.b	11,098,908		
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,280,072		
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	3,996,701		
262	Balance of A & G	(In 254 - sum In 255 to In 261)	100,481,751	W/S	0.04127
263	Plus: Acct. 924, Property Insurance	(In 255)	1,944,130	GP(h)	0.18250
264	Acct. 928 - Transmission Specific	Worksheet F In 19.(E) (Note L)	-	TP	0.97209
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 34.(E) (Note L)	-	TP	0.97209
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 40.(E) (Note L)	161,509	DA	1.00000
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	9,519,127	W/S	0.04127
268	A & G Subtotal	(sum Ins 262 to 267)	112,106,517		5,056,125
269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)	131,518,408		23,926,299
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	(38,399,880)	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	(In 269 + In 270 + In 271)	93,118,528		(14,473,581)
273	DEPRECIATION AND AMORTIZATION EXPENSE				
274	Production	336.2-6.f	56,540,775	NA	0.00000
275	Distribution	336.8.f	32,840,053	NA	0.00000
276	Transmission	336.7.f	16,178,988	TP1	0.96338
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
278	General	336.10.f	3,259,582	W/S	0.04127
279	Intangible	336.1.f	24,828,408	W/S	0.04127
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+276+277+278+279) (Note N)	133,647,806		16,745,648
281	TAXES OTHER THAN INCOME				
282	Labor Related				
283	Payroll	Worksheet H In 22.(D)	10,754,313	W/S	0.04127
284	Plant Related				
285	Property	Worksheet H In 22.(C) & In 47.(C)	41,866,818	DA	8,479,544
286	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	14,443,752	NA	0.00000
287	Other	Worksheet H In 22.(E)	1,807,288	GP(h)	0.18250
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)	68,872,171		9,253,216
289	INCOME TAXES	(Note O)			
290	$T=1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p) =$		38.18%		
291	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		39.77%		
292	where WCLTD=(In 327) and WACC = (In 330)				
293	and FIT, SIT & p are as given in Note O.				
294	$GRCF=1 / (1 - T) =$ (from In 290)		1.6176		
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(2,315,777)		
296	Income Tax Calculation	(In 291 * In 299)	85,495,675		18,631,427
297	ITC adjustment	(In 294 * In 295)	(3,745,909)	NP(h)	0.21432
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	81,749,766		17,828,618
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	214,953,773		46,843,254
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		204,766	DA	1.00000
301	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291)		-		-
303	TOTAL REVENUE REQUIREMENT	(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)	592,546,810		76,401,921

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SUPPORTING CALCULATIONS

In									
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
304	Total transmission plant	(In 185)						1,153,823,876	
305	Less transmission plant excluded from PJM Tariff (Note P)								
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)							32,199,127	
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)						1,121,624,749	
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)						TP= 0.97209	
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)							
			Direct Payroll	Payroll Billed from	Total				
310	Production	354.20.b	129,658,142	11,914,620	141,572,762	NA	0.00000	-	
311	Transmission	354.21.b	4,844,828	2,902,179	7,747,007	TP	0.97209	7,530,816	
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-	
313	Distribution	354.23.b	19,581,915	1,971,387	21,553,302	NA	0.00000	-	
314	Other (Excludes A&G)	354.24,25,26.b	6,265,237	5,335,541	11,600,778	NA	0.00000	-	
315	Total	(sum Ins 310 to 314)	160,350,122	22,123,727	182,473,849			7,530,816	
316	Transmission related amount							W/S= 0.04127	
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$	
318	Long Term Interest	(Worksheet L, In. 32, col. (D))						107,827,975	
319	Preferred Dividends	(Worksheet L, In. 37, col. (D))						339,382	
320	Development of Common Stock:								
321	Proprietary Capital	(FF1 p 112, Ln 16.c)						1,680,859,984	
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						8,076,800	
323	Less: Account 216.1	(FF1 p 112, Ln 12.c)						(581,331)	
324	Less: Account 219	(FF1 p 112, Ln 15.c)						(21,700,504)	
325	Common Stock	(In 321 - In 322 - In 323 - In 324)						1,695,065,019	
326			\$	%			Cost	Weighted	
327	Long Term Debt (Note T) Worksheet L, In 32, col. (B))		1,717,000,000	50.20%			0.0628	0.0315	
328	Preferred Stock (In 322)		8,076,800	0.24%			0.0420	0.0001	
329	Common Stock (In 325)		1,695,065,019	49.56%			11.49%	0.0569	
330	Total (Sum Ins 327 to 329)		3,420,141,819					WACC= 0.0886	

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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 historic as of December 31, 2009.**
- 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 Ancillary 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 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 seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. 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) (In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.
Inputs Required: FIT = 35.00%
SIT= 4.89% (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 (In 318) / long term debt (In 327). Preferred Stock cost rate = preferred dividends (In 319) / preferred outstanding (In 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 \$259,022,855 at 12/31/07 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)	(In 138)			\$78,684,946
2	REVENUE CREDITS	(Note A) (Worksheet E)	3,042,204	DA 1.00000	\$ 3,042,204
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			\$ 75,642,742

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)		1,443,357	DA 1.00000	\$ 1,443,357
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
6	Annual Rate	((In 1 - In 105 - In 106) / In 48 x 100)			18.84%
7	Monthly Rate	(In 6 / 12)			1.57%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	((In 1 - In 105 - In 106 - In 111) / In 48 x 100)			16.33%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	((In 1 - In 105 - In 106 - In 111 - In 133 - In 134) / In 48 x 100)			5.56%
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			4,342,170
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,348,093
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				442,226
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			1,551,851

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Line No.	(1)	(2)	(3)	(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total NOTE C	Allocator	Total Transmission
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.E)	3,560,632,012	NA	0.00000
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(182,877,510)	NA	0.00000
20	Transmission	(Worksheet A In 3.E & Ln 142)	1,134,691,923	DA	1,102,648,409
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)	-	TP	0.97176
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000
24	Distribution	(Worksheet A In 5.E)	1,321,563,306	NA	0.00000
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	-	NA	0.00000
26	General Plant	(Worksheet A In 7.E)	94,317,836	W/S	0.04126
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(191,891)	W/S	0.04126
28	Intangible Plant	(Worksheet A In 9.E)	140,422,727	W/S	0.04126
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	6,068,558,402	GP(h)=	0.18329
				GTD=	0.00000
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.E)	2,180,805,256	NA	0.00000
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(66,565,083)	NA	0.00000
33	Transmission	(Worksheet A In 14.E & 28.E)	499,475,841	TP1=	0.96341
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.96341
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		N/A	TP1	0.96341
38	Plus: Additional General & Intangible Depreciation for 2010 (In 110 + In 111)		N/A	W/S	0.04126
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
40	Distribution	(Worksheet A In 16.E)	439,128,604	NA	0.00000
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000
42	General Plant	(Worksheet A In 18.E)	23,057,289	W/S	0.04126
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(131,579)	W/S	0.04126
44	Intangible Plant	(Worksheet A In 20.E)	102,506,889	W/S	0.04126
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	3,178,277,217		486,376,366
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	1,263,514,329		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	635,216,082		621,446,953
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		N/A		N/A
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		N/A		N/A
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		N/A		N/A
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		N/A		N/A
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		N/A		N/A
54	Distribution	(In 24 + In 25 - In 40 - In 41)	882,434,702		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	71,200,235		2,937,473
56	Intangible Plant	(In 28 - In 44)	37,915,838		1,564,275
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	2,890,281,185	NP(h)=	0.21657
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(300,957)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(576,522,070)	DA	(112,444,373)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(519,045,186)	DA	(10,848,930)
62	Account No. 190.1 (enter negative)	(Worksheet B, In 17 & In 20.E)	660,094,697	DA	17,667,300
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(435,773,515)		(105,626,003)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	7,821,831	DA	202,362
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA	-
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 * In 88)	2,426,486		2,357,963
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	930,824	TP	0.97176
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	732,413	W/S	0.04126
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.18329
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	56,812,366	W/S	0.04126
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	5,291,007	GP(h)	0.18329
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(54,247,703)	NA	0.00000
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	11,945,393		6,606,402
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(5,732,389)	DA	1.00000
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,468,542,505		521,399,073

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Locator	(5) Total Transmission
79	OPERATION & MAINTENANCE EXPENSE				
79	Production	321.80.b	1,266,511,562		
80	Distribution	322.156.b	66,872,997		
81	Customer Related Expense	322.164,171,178.b	24,425,007		
82	Regional Marketing Expenses	322.131.b	2,515,197		
83	Transmission	321.112.b	(12,458,696)		
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,347,866,067		
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,342,170		
86	Less: Account 565	(Note H) 321.96.b	(36,212,757)		
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	19,411,891	TP 0.97176	18,863,702
89	Administrative and General	323.197.b (Note J)	131,275,366		
90	Less: Acct. 924, Property Insurance	323.185.b	1,944,130		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	15,357,327		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(4,008,620)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,125,097		
94	Acct. 928, Reg. Com. Exp.	323.189.b	11,098,908		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,280,072		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	3,996,701		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	100,481,751	W/S	4,145,526
98	Plus: Acct. 924, Property Insurance	(In 90)	1,944,130	GP(h)	356,346
99	Acct. 928 - Transmission Specific	Worksheet F In 19.(E) (Note L)	-	TP	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 34.(E) (Note L)	-	TP	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 40.(E) (Note L)	161,509	DA	161,509
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	9,519,127	W/S	392,726
103	A & G Subtotal	(sum Ins 97 to 102)	112,106,517	0.04126	5,056,106
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	131,518,408		23,919,809
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	(38,399,880)	DA 1.00000	(38,399,880)
106	Plus: Transmission Lease Payments To Affiliates in	Acct 565 (Company Records) (Note H)	-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	93,118,528		(14,480,071)
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	56,540,775	NA	-
110	Distribution	336.8.f	32,840,053	NA	-
111	Transmission	336.7.f	16,178,988	TP1	15,587,045
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
113	General	336.10.f	3,259,582	W/S	134,479
114	Intangible	336.1.f	24,828,408	W/S	1,024,333
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+ 111+112+113+114)	133,647,806		16,745,858
116	TAXES OTHER THAN INCOME	(Note N)			
117	Labor Related				
118	Payroll	Worksheet H In 22.(D)	10,754,313	W/S	443,685
119	Plant Related				
120	Property	Worksheet H In 22.(C) & In 47.(C)	41,866,818	DA	8,479,544
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	14,443,752	NA	-
122	Other	Worksheet H In 22.(E)	1,807,288	GP(h)	331,263
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	68,872,171		9,254,493
124	INCOME TAXES	(Note O)			
125	$T=1 - \{[(1 - \text{SIT}) * (1 - \text{FIT})] / (1 - \text{SIT} * \text{FIT} * p)\} =$		38.18%		
126	$\text{EIT}=(T/(1-T)) * (1-(\text{WCLTD}/\text{WACC})) =$		37.65%		
127	where WCLTD=(In 162) and WACC = (In 165)				
128	and FIT, SIT & p are as given in Note O.				
129	$\text{GRCF}=1 / (1 - T) =$ (from In 125)		1.6176		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(2,315,777)		
131	Income Tax Calculation	(In 126 * In 134)	87,753,415		18,535,046
132	ITC adjustment	(In 129 * In 130)	(3,745,909)	NP(h) 0.21657	(811,252)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	84,007,507		17,723,794
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	233,106,327		49,236,107
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		204,766	DA 1.00000	204,766
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 136 * In126)		-		-
138	TOTAL REVENUE REQUIREMENT (sum Ins 107, 115, 123, 133, 134, 135)		612,957,105		78,684,946

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						1,134,691,923
140	Less transmission plant excluded from PJM Tariff (Note P)							-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)							32,043,514
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						1,102,648,409
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	0.97176
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)		Payroll Billed from				
			Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	129,658,142	11,914,620	141,572,762	NA	0.00000	-
146	Transmission	354.21.b	4,844,828	2,902,179	7,747,007	TP	0.97176	7,528,233
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	19,581,915	1,971,387	21,553,302	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	6,265,237	5,335,541	11,600,778	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	160,350,122	22,123,727	182,473,849			7,528,233
151	Transmission related amount						W/S=	0.04126
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E))						105,048,408
154	Preferred Dividends	(Worksheet M, In. 55, col. (E))						339,452
155	Development of Common Stock:							Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))						1,562,608,858
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E))						8,078,500
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E))						(1,046,000)
159	Less: Account 219	(Worksheet M, In. 4, col. (E))						(20,967,173)
160	Common Stock	(In 156 - In 157 - In 158 - In 159)						1,576,543,530
161		Average \$		Capital Structure Weighting			Cost	
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))		Actual	Cap Limit		(Note S)	Weighted	
163	Preferred Stock (In 157)	1,417,000,000	47.21%	49.73%		0.0741	0.0369	
164	Common Stock (In 160)	8,078,500	0.27%	0.27%		0.0420	0.0001	
165	Total (Sum Ins 162 to 164)	1,576,543,530	52.52%	50.00%		11.49%	0.0575	
165		3,001,622,030				WACC=	0.0944	
166	Capital Structure Equity Limit (Note U)	50.0%						

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 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, 2008 and December 31, 2009.**
- 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 Ancillary 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 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 "WS" 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. Act 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 seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. 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) (In 130) multiplied by $(1/1-T)$. If the applicable tax rates are zero enter 0.
Inputs Required: FIT = 35.00%
SIT= 4.89% (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 (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 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 \$259,022,855 at 12/31/07 is not included in the balance in line 162 above.
- U **Per Settlement, equity for INDIANA MICHIGAN POWER COMPANY is limited to 50% 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 2009 FF1 Balances
Worksheet A Supporting Plant Balances
INDIANA MICHIGAN POWER COMPANY

<u>Line</u>	<u>(A)</u>	<u>(B)</u>	<u>(C)</u>	<u>(D)</u>	<u>(E)</u>
<u>Number</u>	<u>Rate Base Item & Supporting Balance</u>	<u>Source of Data</u>	<u>Balance @ December 31, 2009</u>	<u>Balance @ December 31, 2008</u>	<u>Average Balance for 2009</u>
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	3,610,392,143	3,510,871,880	3,560,632,012
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	155,199,856	210,555,163	182,877,510
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	1,153,823,876	1,115,559,969	1,134,691,923
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	1,360,318,756	1,282,807,855	1,321,563,306
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	97,685,547	90,950,125	94,317,836
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	191,891	191,891	191,891
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	130,559,946	150,285,508	140,422,727
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	6,352,780,268	6,150,475,337	6,251,627,803
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	155,391,747	210,747,054	183,069,401
Accumulated Depreciation & Amortization Balances					
12	Production Accumulated Depreciation	FF1, page 219, lns 20-24, Col. (b)	2,210,457,182	2,151,153,329	2,180,805,256
13	Production ARO Accumulated Depreciation	Company Records - Note 1	69,632,189	63,497,976	66,565,083
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	504,959,262	493,992,419	499,475,841
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	443,905,896	434,351,312	439,128,604
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	23,904,062	22,210,516	23,057,289
19	General ARO Accumulated Depreciation	Company Records - Note 1	135,119	128,038	131,579
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	100,238,014	104,775,764	102,506,889
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	3,283,464,416	3,206,483,340	3,244,973,878
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	69,767,308	63,626,014	66,696,661
Generation Step-Up Units					
23	GSU Investment Amount	Company Records - Note 1	32,199,127	31,887,901	32,043,514
24	GSU Accumulated Depreciation	Company Records - Note 1	18,493,967	18,054,803	18,274,385
25	GSU Net Balance	(Line 23 - Line 24)	13,705,160	13,833,098	13,769,129
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	Transmission Accumulated Depreciation	(Line 14 Above)	504,959,262	493,992,419	499,475,841
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	18,493,967	18,054,803	18,274,385
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	486,465,295	475,937,616	481,201,456
Plant Held For Future Use					
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	7,896,232	7,747,429	7,821,831
30	Transmission Plant Held For Future	Company Records - Note 1	202,362	202,362	202,362
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 2009 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
INDIANA MICHIGAN POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) Source</u>	<u>(C) Balance @ December 31, 2009</u>	<u>(D) Balance @ December 31, 2008</u>	<u>(E) Average Balance for 2009</u>
1	<u>Account 281</u>				
2	Year End Utility Deferrals	FF1, p. 272 - 273, In 8, Col. (k)	295,177	306,737	300,957
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	295,177	306,737	300,957
5	Transmission Related Deferrals	Ln 2 - In 3 - In 4	-	-	-
6	<u>Account 282</u>				
7	Year End Utility Deferrals	FF1, p. 274 - 275, In 5, Col. (k)	648,884,207	504,159,932	576,522,070
8	Less: ARO Related Deferrals	Company Records - Note 1	31,225,679	54,159,014	42,692,347
9	Less: Other Excluded Deferrals	Company Records - Note 1	499,694,268	343,076,433	421,385,351
10	Transmission Related Deferrals	Ln 7 - In 8 - In 9	117,964,260	106,924,485	112,444,373
11	<u>Account 283</u>				
12	Year End Utility Deferrals	FF1, p. 276 - 277, In 9, Col. (k)	563,868,587	474,221,784	519,045,186
13	Less: ARO Related Deferrals	Company Records - Note 1	381,149,459	328,952,816	355,051,138
14	Less: Other Excluded Deferrals	Company Records - Note 1	171,943,946	134,346,291	153,145,119
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	10,775,182	10,922,677	10,848,930
16	<u>Account 190</u>				
17	Year End Utility Deferrals	FF1, p. 234, In 8, Col. (c)	640,478,175	679,711,219	660,094,697
18	Less: ARO Related Deferrals	Company Records - Note 1	411,407,834	380,836,004	396,121,919
19	Less: Other Excluded Deferrals	Company Records - Note 1	211,874,071	280,736,886	246,305,479
20	Transmission Related Deferrals	Ln 17 - In 18 - In 19	17,196,270	18,138,329	17,667,300
21	<u>Account 255</u>				
22	Year End ITC Balances	FF1, p. 266-267, In 8, Col. (h)	57,732,141	60,047,918	58,890,030
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	57,732,141	60,047,918	58,890,030
24	ITC Balances Includeable Ratebase	Ln 22 - In 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 2009 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
INDIANA MICHIGAN POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Materials & Supplies								
Line Number		Source	Balance @ December 31, 2009	Balance @ December 31, 2008	Average Balance for 2009			
1								
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,199,375	662,273	930,824			
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (602,830	861,996	732,413			
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (0	0	-			

Prepayment Balance Summary

	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, 2009	9,450,954	(45,794,268)	0	5,346,093	49,899,129	55,245,222
7	Totals as of December 31, 2008	6,260,385	(62,701,138)		5,235,921	63,725,603	68,961,524
8	Average Balance	7,855,670	(54,247,703)	-	5,291,007	56,812,366	62,103,373

Prepayments Account 165 - Balance @ 12/31/2009

9	Acc. No.	Description	2009 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	4,164,212	-	-	4,164,212	-	4,164,212	Plant Related Insurance Policies
11	165000208	Prepaid Taxes	295,297	-	-	295,297	-	295,297	Prepaid PSC Fees
12	1650003	Prepaid Rents	1,224	1,224	-	-	-	-	River Transport
13	1650005	Prepaid Employee Benefits	8,590	-	-	-	8,590	8,590	
14	1650006	Other Prepayments	118,889	118,889	-	-	-	-	Relates to EPRI dues
15	1650009	Prepaid Carry Cost-Factored AR	77,268	77,268	-	-	-	-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	49,890,539	-	-	-	49,890,539	49,890,539	Prefunded Pension Expense
17	1650014	FAS 158 Qual Contra Asset	(49,890,539)	(49,890,539)	-	-	-	-	SFAS 158 Offset
18	165001209	Prepaid Sales/Use Taxes	763,535	763,535	-	-	-	-	
19	1650021	Prepaid Insurance - EIS	886,584	-	-	886,584	-	886,584	
20	1650022	Prepaid SNF Container Costs	2,218,800	2,218,800	-	-	-	-	
21	1650023	Prepaid Lease	916,555	916,555	-	-	-	-	
Subtotal - Form 1, p 111.57.c			9,450,954	(45,794,268)	0	5,346,093	49,899,129	55,245,222	

Prepayments Account 165 - Balance @ 12/31/2008

22	Acc. No.	Description	2008 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	4,891,617	-	-	4,891,617	-	4,891,617	Plant Related Insurance Policies
24	165000208	Prepaid Taxes	344,304	-	-	344,304	-	344,304	Prepaid PSC Fees
25	1650003	Prepaid Rents	1,224	1,224	-	-	-	-	
26	1650004	Prepaid Interest	10,264	10,264	-	-	-	-	
27	1650005	Prepaid Employee Benefits	11,110	-	-	-	11,110	11,110	
28	1650006	Other Prepayments	14,690	14,690	-	-	-	-	
29	1650009	Prepaid Carry Cost-Factored AR	171,116	171,116	-	-	-	-	AR Factoring - Retail Only
30	1650010	Prepaid Pension Benefits	63,714,493	-	-	-	63,714,493	63,714,493	Prefunded Pension Expense
31	1650014	FAS 158 Qual Contra Asset	(63,714,493)	(63,714,493)	-	-	-	-	SFAS 158 Offset
32	1650016	FAS 112 ASSETS	816,061	816,061	-	-	-	-	SFAS 112 Overfunding Asset
Subtotal - Form 1, p 111.57.d			6,260,385	(62,701,138)		5,235,921	63,725,603	68,961,524	

AEP East Companies
Cost of Service Formula Rate Using 2009 FF1 Balances
Worksheet D Supporting IPP Credits
INDIANA MICHIGAN POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) 2009</u>
1	Net Funds from IPP Customers 12/31/2008 (2009 FORM 1, P269, line 8.b)	(5,636,829)
2	Interest Accrual (Company Records - Note 1)	(204,766)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4	<u>Other Adjustments</u>	
5	Accounting Adjustment (Company Records - Note 1)	13,646
6		-
7	Net Funds from IPP Customers 12/31/2009 (2009 FORM 1, P269, line 8.f)	(5,827,949)
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(5,732,389)

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 2009 FF1 Balances
 Worksheet E Supporting Revenue Credits
 INDIANA MICHIGAN POWER COMPANY

<u>Line Number</u>	<u>Description</u>	<u>Total Company</u>	<u>Non-Transmission</u>	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	4,415,641	4,415,641	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	1,728,983	1,672,196	56,787
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	7,978,297	7,568,585	409,712
4	Account 4560015, Associated Business Development- (Company Records - Note 1)	2,278,980	1,681,812	597,168
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	199,128,288	199,128,288	-
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	215,530,189	214,466,522	1,063,667
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	2,175,633	197,096	1,978,537
8	Total Other Operating Revenues To Reduce Revenue Requirement	217,705,822	214,663,618	3,042,204

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 2009 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
INDIANA MICHIGAN POWER COMPANY

<u>Line</u> <u>Number</u>	<u>(A)</u> <u>Item No.</u>	<u>(B)</u> <u>Description</u>	<u>(C)</u> <u>2009</u> <u>Expense</u>	<u>(D)</u> <u>100%</u> <u>Non-Transmission</u>	<u>(E)</u> <u>100%</u> <u>Transmission</u> <u>Specific</u>	<u>(F)</u> <u>Explanation</u>
Regulatory O&M Deferrals & Amortizations						
1		No Applicable Charges for I&M	-			
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	35,788			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,381,094			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	5,738			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	2,348,093			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	129,231			
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	442,226			
14		Total of Account 561	4,342,170			
Account 928						
15	9280000	Regulatory Commission Exp	67,594	67,594		- Indiana Rate Case Filing Support
16	9280001	Regulatory Commission Exp-Adm	10,798,915	10,798,915		- Nuclear Regulatory Commission/FERC Hydro
17	9280002	Regulatory Commission Exp-Case	192,678	192,678		- Indiana Rate Case Filing Support
18	9280003	Rate Case Amortization	39,722	39,722		
19		Total	11,098,909	11,098,909		-
Account 930.1						
20	9301000	General Advertising Expenses	679,019	679,019		-
21	9301001	Newspaper Advertising Space	31,137	31,137		-
22	9301002	Radio Station Advertising Time	34,398	34,398		-
23	9301003	TV Station Advertising Time	3,400	3,400		-
24	9301006	Spec Corporate Comm Info Proj	12,550	12,550		-
25	9301007	Special Adv Space & Prod Exp	4,699	4,699		-
26	9301008	Direct Mail and Handouts	2,366	2,366		-
27	9301009	Fairs, Shows, and Exhibits	10,222	10,222		-
28	9301010	Publicity	5,393	5,393		-
29	9301011	Dedications, Tours, & Openings	3,853	3,853		-
30	9301012	Public Opinion Surveys	173,365	173,365		-
31	9301013	Movies Slide Films & Speeches	70,251	70,251		-
32	9301014	Video Communications	959	959		-
33	9301015	Other Corporate Comm Exp	248,460	248,460		-
34		Total	1,280,072	1,280,072		-
Account 930.2						
35	9302000	Misc General Expenses	3,177,809	3,177,809		
36	9302003	Corporate & Fiscal Expenses	230,018	230,018		
37	9302004	Research, Develop&Demonstr Exp	21,232	21,232		
38	9302005	Nucl Fac Ins - Replce Engy Cst	-537,681	-537,681		
39	9302007	Assoc Business Development Exp	1,105,323	943,814	161,509	
40		Total	3,996,701	3,835,192	161,509	

AEP East Companies
Cost of Service Formula Rate Using 2009 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
INDIANA MICHIGAN POWER COMPANY

Indiana Corporate Income Tax Rate	8.50%	
Apportionment Factor - Note 2	51.26%	
Effective State Tax Rate		4.36%
Michigan Single Business Tax Rate	6.04%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
West Virginia Corporation Income Tax Rate	8.50%	
Apportionment Factor - Note 2	4.61%	
Effective State Tax Rate		0.39%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	6.65%	
Effective State Tax Rate		0.00%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - Note 2	1.69%	
Effective State Tax Rate		0.10%
Missouri Corporation Income Tax Rate	6.25%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	7.30%	
Apportionment Factor - Note 2	0.58%	
Effective State Tax Rate		0.04%
Total Effective State Income Tax Rate		<u>4.89%</u>

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 2009 FF1 Balances
Worksheet H Supporting Taxes Other than Income
INDIANA MICHIGAN 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	14,471,548				14,471,548
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Michigan	25,520,304	25,520,304			
5	Real and Personal Property - Indiana	16,327,344	16,327,344			
6	Real and Personal Property - Other Jurisdictions	19,170	19,170			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	10,565,124		10,565,124		
9	Federal Unemployment Tax	47,835		47,835		
10	State Unemployment Insurance	141,354		141,354		
11	Production Taxes					
12	State Severance Taxes	-				-
13	Miscellaneous Taxes					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	1,447,217			1,447,217	
16	State Franchise Taxes	359,726			359,726	
17	State Lic/Registration Fee	345			345	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	(49,106)				(49,106)
20	Federal Excise Tax	21,310				21,310
21	Michigan Single Business Tax	-				-
22	Total Taxes by Allocable Basis	68,872,171	41,866,818	10,754,313	1,807,288	14,443,752

(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	Transmission	Distribution	General	Total
23 Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,314,367,294	648,664,614	916,412,860	73,724,713	2,953,369,481
MICHIGAN JURISDICTION					
24 Percentage of Plant in MICHIGAN JURISDICTION	53.74%	14.43%	19.34%	14.53%	
25 Net Plant in MICHIGAN JURISDICTION (Ln 23 * Ln 24)	706,402,701	93,607,513	177,276,360	10,714,341	988,000,915
26 Less: Net Value of Exempted Generation Plant	262,490,906				
27 Taxable Property Basis (Ln 25 - Ln 26)	443,911,795	93,607,513	177,276,360	10,714,341	725,510,009
28 Relative Valuation Factor	100%	100%	100%	100%	4
29 Weighted Net Plant (Ln 27 * Ln 28)	443,911,795	93,607,513	177,276,360	10,714,341	
30 General Plant Allocator (Ln 29 / (Total - General Plant))	62.10%	13.10%	24.80%	-100.00%	
31 Functionalized General Plant (Ln 30 * General Plant)	6,653,961	1,403,118	2,657,262	(10,714,341)	-
32 Weighted MICHIGAN JURISDICTION Plant (Ln 29 + 31)	450,565,756	95,010,631	179,933,622	(0)	725,510,009
33 Functional Percentage (Ln 32/Total Ln 32)	62.10%	13.10%	24.80%		
34 Functionalized Expense in MICHIGAN JURISDICTION	15,848,954	3,342,063	6,329,287		25,520,304
INDIANA JURISDICTION					
35 Percentage of Plant in INDIANA JURISDICTION	46.26%	85.57%	80.66%	85.47%	
36 Net Plant in INDIANA JURISDICTION (Ln 23 * Ln 35)	607,964,593	555,257,101	739,136,500	63,010,372	1,965,368,566
37 Less: Net Value of Exempted Generation Plant	136,292,439				
38 Taxable Property Basis (Ln 36 - Ln 37)	471,672,154	555,257,101	739,136,500	63,010,372	1,829,076,127
39 Relative Valuation Factor	100%	100%	100%	100%	4
40 Weighted Net Plant (Ln 38 * Ln 39)	471,672,154	555,257,101	739,136,500	63,010,372	
41 General Plant Allocator (Ln 40 / (Total - General Plant))	26.71%	31.44%	41.85%	-100.00%	
42 Functionalized General Plant (Ln 41 * General Plant)	16,828,500	19,810,676	26,371,196	(63,010,372)	-
43 Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	488,500,654	575,067,777	765,507,696	0	1,829,076,127
44 Functional Percentage (Ln 43/Total Ln 43)	26.71%	31.44%	41.85%		
45 Functionalized Expense in INDIANA JURISDICTION	4,360,627	5,133,373	6,833,345		16,327,344
46 Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		4,108			19,170
47 Total Func. Property Taxes (Sum Lns 34, 45 46)	20,209,581	8,479,544	13,162,631		41,866,818

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
INDIANA MICHIGAN 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	14,471,548	126,203 13,803,000 (47,518) 589,863	P.263 In 16 (i) P.263 In 17 (i) P.263.2 In 11 (i) P.263.2 In 12 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Michigan	25,520,304	1,162,964 24,125,289 1,616 (38,565) 269,000	P.263.1 In 15 (i) P.263.1 In 16 (i) P.263.1 In 18 (i) P.263.1 In 19 (i) P.263.1 In 20 (i)
5	Real and Personal Property - Indiana	16,327,344	(1,956,036) (53,096) 17,797,179 54,053 92,164 393,080	P.263 In 24 (i) P.263 In 25 (i) P.263 In 26 (i) P.263 In 27 (i) P.263 In 28 (i) P.263 In 29 (i)
6	Real and Personal Property - Other Jurisdictions	19,170	5,638 4,238 3,561 1,754 429 3,550	P.263 In 35 (i) P.263.1 In 32 (i) P.263.1 In 33 (i) P.263.2 In 15 (i) P.263.2 In 22 (i) P.263.2 In 27 (i)
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	10,565,124	10,565,124	P.263 In 3 (i)
9	Federal Unemployment Tax	47,835	47,835	P.263 In 4 (i)
10	State Unemployment Insurance	141,354	28,899 125,726 (13,271)	P.263 In 15 (i) P.263.1 In 8 (i) P.263.1 In 39 (i)
11	Production Taxes			
12	State Severance Taxes	-	-	
13	Miscellaneous Taxes			
14	State Business & Occupation Tax	-	-	
15	State Public Service Commission Fees	1,447,217	557,311 524,078 258,075 107,753	P.263 In 22 (i) P.263 In 23 (i) P.263.1 In 9 (i) P.263.1 In 10 (i)
16	State Franchise Taxes	359,726	(2,247) 331,296 30,041 8 628	P.263.1 In 30 (i) P.263.1 In 31 (i) P.263.2 In 10 (i) P.263.3 In 6 (i) P.263.3 In 7 (i)
17	State Lic/Registration Fee	345	59 25 25 30 20 22 12 100 52	P.263 In 14 (i) P.263.1 In 5 (i) P.263.1 In 23 (i) P.263.1 In 26 (i) P.263.3 In 5 (i) P.263.3 In 19 (i) P.263.3 In 20 (i) P.263.3 In 21 (i) P.263.3 In 22 (i)
18	Misc. State and Local Tax	-	-	
19	Sales & Use	(49,106)	97 2,414 7,730 79,353 (138,700)	P.263 In 19 (i) P.263 In 20 (i) P.263.1 In 11 (i) P.263.1 In 12 (i) P.263.1 In 13 (i)
20	Federal Excise Tax	21,310	21,310	P.263 In 6 (i)
21	Michigan Single Business Tax	-	-	
22	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	68,872,171	68,872,171	

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 state 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 2009 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 (2009) (P.206, In 58,(b)):	1,115,559,969
2	Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	1,153,823,876
3		2,269,383,845
4	Average Balance of Transmission Investment	1,134,691,923
5	Annual Depreciation Expense, Historic TCOS, In 276	16,178,988
6	Composite Depreciation Rate	1.43%
7	Round to 1.43% to Reflect a Composite Life of 70 Years	1.43%

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	\$ 3,224,063	1.43%	\$ 46,104	\$ 3,842	11 \$	42,262
10	February	\$ 3,144,733	1.43%	\$ 44,970	\$ 3,747	10 \$	37,470
11	March	\$ 3,242,206	1.43%	\$ 46,364	\$ 3,864	9 \$	34,776
12	April	\$ 4,353,615	1.43%	\$ 62,257	\$ 5,188	8 \$	41,504
13	May	\$ 3,145,651	1.43%	\$ 44,983	\$ 3,749	7 \$	26,243
14	June	\$ 3,244,161	1.43%	\$ 46,391	\$ 3,866	6 \$	23,196
15	July	\$ 3,165,897	1.43%	\$ 45,272	\$ 3,773	5 \$	18,865
16	August	\$ 3,214,988	1.43%	\$ 45,974	\$ 3,831	4 \$	15,324
17	September	\$ 3,206,843	1.43%	\$ 45,858	\$ 3,821	3 \$	11,463
18	October	\$ 3,191,102	1.43%	\$ 45,633	\$ 3,803	2 \$	7,606
19	November	\$ 3,130,494	1.43%	\$ 44,766	\$ 3,731	1 \$	3,731
20	December	\$ 4,451,611	1.43%	\$ 63,658	\$ 5,305	0 \$	-
21	Investment	<u>\$ 40,715,364</u>				Depreciation Expense	<u>\$ 262,440</u>

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 2010

	<u>Estimated Cost</u> <u>(000's)</u>	<u>Month in</u> <u>Service</u>
25 <u>Major Zonal Projects</u>		
26	-	
27	Subtotal	-
28 <u>PJM Socialized/Beneficiary Allocated Regional Projects</u>		
29	\$0	
30	Subtotal	\$0

AEP East Companies
Cost of Service Formula Rate Using 2009 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, In 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, Ins 162 through 164)			
	%	Cost	Weighted cost
Long Term Debt	50.20%	6.28%	3.153%
Preferred Stock	0.24%	4.20%	0.010%
Common Stock	49.56%	11.49%	5.695%
		R =	8.857%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
	Rev Require	W Incentives	Incentive Amounts	
PROJECTED YEAR	2010	1,408,114	1,408,114	\$ -

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

Rate Base (Projected TCOS, In 78)	552,576,644
R (from A. above)	8.857%
Return (Rate Base x R)	48,943,065

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

Return (from B. above)	48,943,065
Effective Tax Rate (Projected TCOS, In 126)	39.77%
Income Tax Calculation (Return x CIT)	19,466,606
ITC Adjustment	(802,809)
Income Taxes	18,663,797

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, In 1)	79,599,351
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	(38,399,880)
Return (Projected TCOS, In 134)	48,943,065
Income Taxes (Projected TCOS, In 133)	18,663,797
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	50,392,369

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	50,392,369
Return (from I.B. above)	48,943,065
Income Taxes (from I.C. above)	18,663,797
Annual Revenue Requirement, with Basis Point ROE increase	117,999,231
Depreciation (Projected TCOS, In 111)	15,586,438
Annual Rev. Req. w/ Basis Point ROE increase, less Depreciation	102,412,793

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48)	635,159,454
Annual Revenue Requirement, with Basis Point ROE increase	117,999,231
FCR with Basis Point increase in ROE	18.58%
Annual Rev. Req. w/ Basis Point ROE increase, less Dep.	102,412,793
FCR with Basis Point ROE increase, less Depreciation	16.12%
FCR less Depreciation (Projected TCOS, In 9)	15.48%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.65%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2009) (P.206, In 58,(b)):	1,115,559,969
Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	1,153,823,876
Subtotal	2,269,383,845
Average Transmission Plant Balance for 2009	1,134,691,923
Annual Depreciation Rate (Projected TCOS, In 111)	16,178,988
Composite Depreciation Rate	1.43%
Depreciable Life for Composite Depreciation Rate	70.13
Round to nearest whole year	70

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. [REDACTED] (e.g. ER05-925-000)

Project Description: [REDACTED]

Current Projected Year ARR	1,408,114
Current Projected Year ARR w/ Incentive	1,408,114
Current Projected Year Incentive ARR	-

Details		Current Year	2010
Investment	8,496,106		
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.48%
Useful life	70	FCR w/incentives approved for these facilities, less dep.	15.48%
CIAC (Yes or No)	No	Annual Depreciation Expense	121,373

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	8,496,106	60,686	8,435,420	1,366,213	1,366,213	\$ -		
2010	8,435,420	121,373	8,314,047	1,408,114	1,408,114	\$ -		
2011	8,314,047	121,373	8,192,674	1,389,330	1,389,330	\$ -		
2012	8,192,674	121,373	8,071,301	1,370,545	1,370,545	\$ -		
2013	8,071,301	121,373	7,949,928	1,351,761	1,351,761	\$ -		
2014	7,949,928	121,373	7,828,555	1,332,976	1,332,976	\$ -		
2015	7,828,555	121,373	7,707,182	1,314,192	1,314,192	\$ -		
2016	7,707,182	121,373	7,585,809	1,295,407	1,295,407	\$ -		
2017	7,585,809	121,373	7,464,436	1,276,623	1,276,623	\$ -		
2018	7,464,436	121,373	7,343,063	1,257,838	1,257,838	\$ -		
2019	7,343,063	121,373	7,221,690	1,239,054	1,239,054	\$ -		
2020	7,221,690	121,373	7,100,317	1,220,269	1,220,269	\$ -		
2021	7,100,317	121,373	6,978,944	1,201,484	1,201,484	\$ -		
2022	6,978,944	121,373	6,857,571	1,182,700	1,182,700	\$ -		
2023	6,857,571	121,373	6,736,198	1,163,915	1,163,915	\$ -		
2024	6,736,198	121,373	6,614,825	1,145,131	1,145,131	\$ -		
2025	6,614,825	121,373	6,493,452	1,126,346	1,126,346	\$ -		
2026	6,493,452	121,373	6,372,080	1,107,562	1,107,562	\$ -		
2027	6,372,080	121,373	6,250,707	1,088,777	1,088,777	\$ -		
2028	6,250,707	121,373	6,129,334	1,069,993	1,069,993	\$ -		
2029	6,129,334	121,373	6,007,961	1,051,208	1,051,208	\$ -		
2030	6,007,961	121,373	5,886,588	1,032,424	1,032,424	\$ -		
2031	5,886,588	121,373	5,765,215	1,013,639	1,013,639	\$ -		
2032	5,765,215	121,373	5,643,842	994,854	994,854	\$ -		
2033	5,643,842	121,373	5,522,469	976,070	976,070	\$ -		
2034	5,522,469	121,373	5,401,096	957,285	957,285	\$ -		
2035	5,401,096	121,373	5,279,723	938,501	938,501	\$ -		
2036	5,279,723	121,373	5,158,350	919,716	919,716	\$ -		
2037	5,158,350	121,373	5,036,977	900,932	900,932	\$ -		
2038	5,036,977	121,373	4,915,604	882,147	882,147	\$ -		
2039	4,915,604	121,373	4,794,231	863,363	863,363	\$ -		
2040	4,794,231	121,373	4,672,858	844,578	844,578	\$ -		
2041	4,672,858	121,373	4,551,485	825,793	825,793	\$ -		
2042	4,551,485	121,373	4,430,112	807,009	807,009	\$ -		
2043	4,430,112	121,373	4,308,739	788,224	788,224	\$ -		
2044	4,308,739	121,373	4,187,367	769,440	769,440	\$ -		
2045	4,187,367	121,373	4,065,994	750,655	750,655	\$ -		
2046	4,065,994	121,373	3,944,621	731,871	731,871	\$ -		
2047	3,944,621	121,373	3,823,248	713,086	713,086	\$ -		
2048	3,823,248	121,373	3,701,875	694,302	694,302	\$ -		
2049	3,701,875	121,373	3,580,502	675,517	675,517	\$ -		
2050	3,580,502	121,373	3,459,129	656,733	656,733	\$ -		
2051	3,459,129	121,373	3,337,756	637,948	637,948	\$ -		
2052	3,337,756	121,373	3,216,383	619,163	619,163	\$ -		
2053	3,216,383	121,373	3,095,010	600,379	600,379	\$ -		
2054	3,095,010	121,373	2,973,637	581,594	581,594	\$ -		
2055	2,973,637	121,373	2,852,264	562,810	562,810	\$ -		
2056	2,852,264	121,373	2,730,891	544,025	544,025	\$ -		
2057	2,730,891	121,373	2,609,518	525,241	525,241	\$ -		
2058	2,609,518	121,373	2,488,145	506,456	506,456	\$ -		
2059	2,488,145	121,373	2,366,772	487,672	487,672	\$ -		
2060	2,366,772	121,373	2,245,399	468,887	468,887	\$ -		
2061	2,245,399	121,373	2,124,027	450,103	450,103	\$ -		
2062	2,124,027	121,373	2,002,654	431,318	431,318	\$ -		
2063	2,002,654	121,373	1,881,281	412,533	412,533	\$ -		
2064	1,881,281	121,373	1,759,908	393,749	393,749	\$ -		
2065	1,759,908	121,373	1,638,535	374,964	374,964	\$ -		
2066	1,638,535	121,373	1,517,162	356,180	356,180	\$ -		
2067	1,517,162	121,373	1,395,789	337,395	337,395	\$ -		
2068	1,395,789	121,373	1,274,416	318,611	318,611	\$ -		
Project Totals		7,221,690		52,304,605	52,304,605	-		

** 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. Th 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 2009 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN 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, In 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, Ins 162 through 164)			
	%	Cost	Weighted cost
Long Term Debt	49.73%	7.41%	3.687%
Preferred Stock	0.27%	4.20%	0.011%
Common Stock	50.00%	11.49%	<u>5.745%</u>
		R =	9.443%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS				
TRUE-UP YEAR	2009	Rev Require	W Incentives	Incentive Amounts
As Projected in Prior Year WS J				\$ -
Actual after True-up		\$ 1,443,357	\$ 1,443,357	\$ -
True-up of ARR For 2009		1,443,357	1,443,357	-

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

Rate Base (True-Up TCOS, In 78)	521,399,073
R (from A. above)	9.443%
Return (Rate Base x R)	49,236,107

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

Return (from B. above)	49,236,107
Effective Tax Rate (True-Up TCOS, In 126)	37.65%
Income Tax Calculation (Return x CIT)	18,535,046
ITC Adjustment	(811,252)
Income Taxes	17,723,794

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, In 1)	78,684,946
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	(38,399,880)
Return (True-Up TCOS, In 134)	49,236,107
Income Taxes (True-Up TCOS, In 133)	<u>17,723,794</u>
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	50,124,925

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

Annual Revenue Requirement, Less TEA Charges, Return and Tax	50,124,925
Return (from I.B. above)	49,236,107
Income Taxes (from I.C. above)	<u>17,723,794</u>
Annual Revenue Requirement, with 0 Basis Point ROE increase	117,084,826
Depreciation (True-Up TCOS, In 111)	<u>15,587,045</u>
Annual Rev. Req. w/ 0 Basis Point ROE increase, less Depreciation	101,497,781

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

Net Transmission Plant (True-Up TCOS, In 48)	621,446,953
Annual Revenue Requirement, with 0 Basis Point ROE increase	117,084,826
FCR with 0 Basis Point increase in ROE	18.84%

Annual Rev. Req. w/ 0 Basis Point ROE increase, less Dep.	101,497,781
FCR with 0 Basis Point ROE increase, less Depreciation	16.33%
FCR less Depreciation (True-Up TCOS, In 9)	<u>16.33%</u>
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, In 58,(b)):	1,115,559,969
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	1,153,823,876
Subtotal	<u>2,269,383,845</u>
Average Transmission Plant Balance for	1,134,691,923
Annual Depreciation Rate (True-Up TCOS, In 111)	16,178,988
Composite Depreciation Rate	1.43%
Depreciable Life for Composite Depreciation Rate	70.13
Round to nearest whole year	70

AEP East Companies
Cost of Service Formula Rate Using 2009 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

<u>Line Number</u>	<u>(A) Issuance</u>	<u>(B) Principle Outstanding</u>	<u>(C) Interest Rate</u>	<u>(D) Annual Expense (See Note S on Projected Template)</u>	<u>(E) Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)				
2	Advances From Associated Co.	25,000,000	5.375%	1,343,750	
3					
4	Installment Purchase Contracts (FF1.p. 256-257.h, a)				
5	PCRB Lawrenceburg In. - Series I	25,000,000	0.230%	57,500	
6	PCRB Lawrenceburg In. - Series H	52,000,000	0.320%	166,400	
7	Reacquired PCRB's			-	
8	PCRB - Rockport In. - 2006 Series A	(50,000,000)	0.107%	(53,699)	
9	PCRB - Rockport In. - 1995 Series B	(50,000,000)	0.144%	(71,767)	
10	PCRB - Rockport In. - 2006 Series A	50,000,000	0.107%	53,699	
11	PCRB - Rockport In. - 1995 Series B	50,000,000	0.144%	71,767	
12					
13	PCRB - Rockport In. - 2002 Series A	50,000,000	4.625%	2,312,500	
14	PCRB - Rockport In. - 2009 Series A	50,000,000	6.250%	3,125,000	
15	PCRB - Rockport In. - 2009 Series B	50,000,000	6.250%	3,125,000	
16	PCRB - Rockport In. - 2007 Series D	40,000,000	5.250%	2,100,000	
17	Senior Unsecured Notes - Series D	150,000,000	6.000%	9,000,000	
18	Senior Unsecured Notes - Series E	100,000,000	6.375%	6,375,000	
19	Senior Unsecured Notes - Series F	175,000,000	5.050%	8,837,500	
20	Senior Unsecured Notes - Series G	125,000,000	5.650%	7,062,500	
21	Senior Unsecured Notes - Series H	400,000,000	6.050%	24,200,000	
22	Senior Unsecured Notes - Series I	475,000,000	7.000%	33,250,000	
23					
24	Issuance Discount, Premium, & Expenses:				
25	Auction Fees			568,563	FF1.p. 256 & 257.Lines Described as Fees
26	Allowable Hedge Amortization (See Ln 42 Below)			1,551,518	
27	Amort of Debt Discount and Expenses			3,157,632	FF1.p. 117.63.c
28	Amort of Debt Premimums (Enter Negative)			-	FF1.p. 117.65.c
29	Reacquired Debt:				
30	Amortization of Loss			1,596,824	FF1.p. 117.64.c
31	Amortization of Gain			(1,712)	FF1.p. 117.66.c
32	Total Interest on Long Term Debt	1,717,000,000	6.28%	107,827,975	
33	Preferred Stock (FF1.p. 250-251)				
		Preferred Shares Outstanding			
34	4.125% Series - \$100 - 55,301 Shares O/S	5,530,100	4.13%	228,117	
35	4.56% Series - \$100 - 14,412 Shares O/S	1,441,200	4.56%	65,719	
36	4.12% Series - \$100 - 11,055 Shares O/S	1,105,500	4.12%	45,547	
37	Dividends on Preferred Stock	8,076,800	4.20%	339,382	
38	Net Total Hedge Gains and Losses (WS M, Ln 34, (E))			1,551,518	
39	Total Projected Capital Structure Balance for 2010 (Projected TCOS, Ln 165)			3,420,141,819	
40	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005	
41	Limit of Recoverable Amount			1,710,071	
42	Recoverable Hedge Amortization (Lesser of Ln 38 or Ln 41)			1,551,518	

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2008 & 12/31/2009

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2009	Balances @ 12/31/2008	Average
Development of Average Balance of Common Equity				
1	Proprietary Capital (112.16.c&d)	1,680,859,984	1,444,357,731	1,562,608,858
2	Less Preferred Stock (Ln 54 Below)	8,076,800	8,080,200	8,078,500
3	Less Account 216.1 (112.12.c&d)	(581,331)	(1,510,668)	(1,046,000)
4	Less Account 219.1 (112.15.c&d)	(21,700,504)	(20,233,842)	(20,967,173)
5	Average Balance of Common Equity	1,695,065,019	1,458,022,041	1,576,543,530
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)	-	100,000,000	50,000,000
8	LT Advances from Assoc. Companies (112.20.c&d)	25,000,000	-	12,500,000
9	Senior Unsecured Notes (112.21.c&d)	1,692,000,000	1,217,000,000	1,454,500,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	Total Average Debt	1,717,000,000	1,117,000,000	1,417,000,000
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 2009			
14	Interest on Long Term Debt (256-257.33.i)			100,346,371
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.			1,551,518
16	Plus: Allowed Hedge Recovery From Ln 38 below.			1,500,811
17	Amort of Debt Discount & Expense (117.63.c)			3,157,632
18	Amort of Loss on Reacquired Debt (117.64.c)			1,596,824
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)			105,048,408
22	Average Cost of Debt for 2009 (Ln 21/Ln 11)			7.41%

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 2009	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Amortization Period		
				Remaining Unamortized Balance	Beginning	Ending
24 Senior Unsecured Notes - Series F	877,839		877,839	4,279,469	November 2004	November 2014
25 Senior Unsecured Notes - Series G	(383,570)		(383,570)	(2,269,456)	December 2005	December 2015
26 Senior Unsecured Notes - Series H	1,057,249		1,057,249	12,626,807	November 2006	March 2037
27			-			
28			-			
29			-			
30			-			
31			-			
32			-			
33 Total Hedge Amortization	1,551,518	-		14,636,820		
34 Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 32)			1,551,518			
35 Total Average Capital Structure Balance for 2009 (True-UP TCOS, Ln 165)			3,001,622,030			
36 Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005			
37 Limit of Recoverable Amount			1,500,811			
38 Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)			1,500,811			

Development of Cost of Preferred Stock

Preferred Stock			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)	55,301	55,335	
42 4.125% Series - 100 - Monetary Value (Ln 40 * Ln 41)	5,530,100	5,533,500	5,531,800
43 4.125% Series - 100 - Dividend Amount (Ln 39 * Ln 42)	228,117	228,257	228,187
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)	11,055	11,055	
47 4.12% Series - 100 - Monetary Value (Ln 45 * Ln 46)	1,105,500	1,105,500	1,105,500
48 4.12% Series - 100 - Dividend Amount (Ln 44 * Ln 47)	45,547	45,547	45,547
49 4.56% Series - 100 - Dividend Rate (p. 250-251. 10.a)	4.56%	4.56%	
50 4.56% Series - 100 - Par Value (p. 250-251. 10.c)	\$ 100.00	\$ 100.00	
51 4.56% Series - 100 - Shares O/S (p.250-251 10.e)	14,412	14,412	
52 4.56% Series - 100 - Monetary Value (Ln 50 * Ln 51)	1,441,200	1,441,200	1,441,200
53 4.56% Series - 100 - Dividend Amount (Ln 49 * Ln 52)	65,719	65,719	65,719
54 Balance of Preferred Stock (Lns 42, 47, 52)	8,076,800	8,080,200	8,078,500
55 Dividends on Preferred Stock (Lns 43, 48, 53)	339,382	339,522	339,452
56 Average Cost of Preferred Stock (Ln 55/54)	4.20%	4.20%	4.20%

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

AEP East Companies
Cost of Service Formula Rate Using 2009 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 use are recorded in accounts 411.6 or 411.7 respectively. Sales will be functionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

Line	(A) Date	(B) Property Description	(C) Function (T) or (G) T = Transmission G = General	(D) Basis	(E) Proceeds	(F) (Gain) / Loss	(G) Functional Allocator	(H) Functionalized Proceeds (Gain) / Loss	(I) FERC Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4					Net (Gain) or Loss for 2009	- =====		- =====	

AEP East Companies
 Cost of Service Formula Rate Using 2008 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 2008:

Line#	Company	Total Company Amount						
		Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOP Recovery Allowance	Labor Allocator for 2008	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	18,441,517	29.26%	14,073,264	7.028%	1,296,063	989,064	306,999
2	CSP	10,281,860	16.31%	7,846,390	4.162%	427,913	326,553	101,360
3	I&M	12,473,804	19.79%	9,519,127	4.127%	514,802	392,861	121,941
4	KPCo	3,529,520	5.60%	2,693,481	8.595%	303,351	231,496	71,855
5	KNGP	544,295	0.86%	415,367	11.148%	60,678	46,305	14,373
6	OPCo	17,102,723	27.13%	13,051,591	7.326%	1,252,955	956,167	296,788
7	WPCo	656,219	1.04%	500,780	4.102%	26,916	20,540	6,376
8	Sum of Lines 1 to 7	63,029,939		48,100,000		3,882,678	2,962,986	919,692

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

	APCo	CSP	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	25,117,708	11,854,216	19,543,777	4,099,566	620,366	20,108,946	765,967	82,110,546
10 Additional PBOP Ledger Entries (from Company Records)	(3,087,412)	24,390	(4,186,450)	(1)	-	(210,679)	-	
11 Medicare Subsidy	(5,206,873)	(2,393,921)	(4,008,620)	(867,380)	(123,297)	(4,175,705)	(152,317)	(16,928,113)
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	16,823,423	9,484,685	11,348,707	3,232,185	497,069	15,722,562	613,650	57,722,281
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,618,094	797,175	1,125,097	297,335	47,226	1,380,161	42,569	5,307,658
14 Company PBOP Expense (Ln 12 + Ln 13)	18,441,517	10,281,860	12,473,804	3,529,520	544,295	17,102,723	656,219	63,029,939

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 1/1/2009
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

	INDIANA			MICHIGAN			FERC WHOLESALE			COMPANY	
	(1) PLANT ACCT.	IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(2) MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(3) 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%	1.0700%	0.152798	0.1635%	1.0700%	0.192653	0.2061%	1.13%
Structures & Improvements	352.0	1.1500%	0.654549	0.7527%	1.1100%	0.152798	0.1696%	1.1100%	0.192653	0.2138%	1.14%
Station Equipment	353.0	1.4600%	0.654549	0.9556%	1.4200%	0.152798	0.2170%	1.4200%	0.192653	0.2736%	1.45%
Towers & Fixtures	354.0	1.4600%	0.654549	0.9556%	1.3100%	0.152798	0.2002%	1.3100%	0.192653	0.2524%	1.41%
Poles & Fixtures	355.0	2.1900%	0.654549	1.4335%	2.1400%	0.152798	0.3270%	2.1400%	0.192653	0.4123%	2.17%
Overhead Conductors	356.0	1.2300%	0.654549	0.8051%	1.1400%	0.152798	0.1742%	1.1400%	0.192653	0.2196%	1.20%
Underground Conduit	357.0	1.4500%	0.654549	0.9491%	1.3100%	0.152798	0.2002%	1.3100%	0.192653	0.2524%	1.40%
Underground Conductors	358.0	1.3500%	0.654549	0.8836%	1.2500%	0.152798	0.1910%	1.2500%	0.192653	0.2408%	1.32%
Trails & Roads	359.0	1.5000%	0.654549	0.9818%	1.4900%	0.152798	0.2277%	1.4900%	0.192653	0.2871%	1.50%

(1) As approved in Indiana Case No. 43231.

(2) As approved in MICHIGAN Case No. U15162.

(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 jurisdiction's 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.