AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2014 and Projected Net Plant at Year-End 2015

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$146,336,441
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,935,437	DA	1.00000	$	1,935,437
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	144,401,003

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)		5,557,149	DA	1.00000	$	5,557,149
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
6	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					18.15%
7	Monthly Rate	(ln 6 / 12)					1.51%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)						
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) /((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					15.37%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)						
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112 - ln 133 - ln 134) /((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))					5.02%
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	7,315,015
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		4,394,733
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		993,147
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	1,927,134

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Line No.	(1) **RATE BASE CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total** NOTE C	(4) **Allocator**		(5) **Total Transmission**
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	4,412,029,807	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(338,956,228)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	1,374,861,654	DA		1,299,785,571
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.94539	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		72,388,705	DA	1.00000	72,388,705
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		-	DA	1.00000	-
24	Distribution	(Worksheet A ln 5.C)	1,697,749,623	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	124,803,332	W/S	0.04555	5,685,139
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,921)	W/S	0.04555	(7,877)
28	Intangible Plant	(Worksheet A ln 9.C)	150,882,300	W/S	0.04555	6,873,109
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	7,493,586,272			1,384,724,647
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	2,397,644,253	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(114,651,301)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	563,292,787	**TP1=**	0.96510	543,635,615
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96510	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		618,791	DA	1.00000	618,791
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2015 (ln 111)		22,629,420	TP1	0.96510	21,839,723
38	Plus: Additional General & Intangible Depreciation for 2015 (ln 113 + ln 114)		21,447,493	W/S	0.04555	976,993
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	527,903,061	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	30,691,516	W/S	0.04555	1,398,084
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(150,819)	W/S	0.04555	(6,870)
44	Intangible Plant	(Worksheet A ln 20.C)	148,390,924	W/S	0.04555	6,759,620
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,597,816,125			575,221,956
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,790,080,627			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	811,568,867			756,149,955
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		71,769,914			71,769,914
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2015 (-ln 37)		(22,629,420)			(21,839,723)
52	Plus: Additional General & Intangible Depreciation for 2015 (-ln 38)		(21,447,493)			(976,993)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,169,846,562			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	94,089,714			4,286,048
56	Intangible Plant	(ln 28 - ln 44)	2,491,376			113,489
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,895,770,147			809,502,691
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(188,450)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,086,402,759)	DA		(173,277,941)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(777,187,050)	DA		(6,406,759)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	830,280,323	DA		10,542,483
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(1,033,497,936)			(169,142,217)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	6,107,653	DA		208,360
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	3,040,405			2,874,380
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,076,197	TP	0.94539	1,017,430
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	97,508	W/S	0.04555	4,442
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17684	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	124,122,012	W/S	0.04555	5,654,103
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,637,185	GP(h)	0.17684	820,022
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	32,501	DA	1.00000	32,501
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(122,703,309)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	10,302,499			10,402,877
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,998,301)	DA	1.00000	(2,998,301)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,875,684,062			647,973,410

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Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE** **REQUIREMENTS CALCULATION**	(2) **Data Sources** **(See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total** **Transmission**
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,286,751,004			
80	Distribution	322.156.b	64,522,349			
81	Customer Related Expense	322.164,171,178.b	30,582,594			
82	Regional Marketing Expenses	322.131.b	4,280,922			
83	Transmission	321.112.b	83,059,132			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,469,196,001			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	7,315,015			
86	Less: Account 565	(Note H) 321.96.b	51,257,771			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	24,323,238	TP	0.94539	22,995,037
89	Administrative and General	323.197.b (Note J)	126,248,321			
90	Less: Acct. 924, Property Insurance	323.185.b	4,600,367			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(9,242,967)			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(667,563)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,800,453			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	157,934			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	4,068,662			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	113,531,434	W/S	0.04555	5,171,673
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,600,367	GP(h)	0.17684	813,511
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94539	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94539	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	348,985	DA	1.00000	348,985
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	7,840,305	W/S	0.04555	357,148
103	A & G Subtotal	(sum lns 97 to 102)	126,321,091			6,691,317
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	150,644,329			29,686,354
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	150,644,329			29,686,354
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	107,319,605	NA	0.00000	-
110	Distribution	336.8.f	47,851,538	NA	0.00000	-
111	Transmission	336.7.f	22,629,420	TP1	0.96510	21,839,723
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		618,791	DA	1.00000	618,791
113	General	336.10.f	4,593,640	W/S	0.04555	209,253
114	Intangible	336.1.f	16,853,853	W/S	0.04555	767,740
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	199,866,847			23,435,507
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	13,404,670	W/S	0.04555	610,620
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,098,833	DA		8,788,633
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	17,229,219	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,937,839	GP(h)	0.17684	342,680
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	81,670,561			9,741,933
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.78%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.34%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6334			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,877,004)			
131	Income Tax Calculation	(ln 126 * ln 134)	115,797,164			26,092,395
132	ITC adjustment	(ln 129 * ln 130)	(7,965,902)	NP(h)	0.19662	(1,566,272)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	107,831,263			24,526,122
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	261,178,868			58,851,027
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		95,497	DA	1.00000	95,497
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT		801,287,365			146,336,441
	(sum lns 107, 115, 123, 133, 134, 135, 136, 137)					

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		1,374,861,654
140	Less transmission plant excluded from PJM Tariff (Note P)			-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			75,076,083
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		1,299,785,571
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP**	**0.94539**

144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	149,766,422	11,457,133	161,223,555	NA	0.00000	-
146	Transmission	354.21.b	4,523,503	5,338,844	9,862,347	TP	0.94539	9,323,801
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	20,535,701	1,830,486	22,366,187	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,741,490	5,487,673	11,229,163	NA	0.00000	-
150	Total	(sum lns 145 to 149)	180,567,116	24,114,136	204,681,252			9,323,801
151	Transmission related amount						**W/S=**	**0.04555**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
153	Long Term Interest	(Worksheet L, ln. 26, col. (D))				96,918,351
154	Preferred Dividends	(Worksheet L, ln. 31, col. (D))				-
155	<u>Development of Common Stock:</u>					
156	Proprietary Capital	(FF1 p 112, Ln 16.c)				1,953,950,018
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)				-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)				(33,162)
159	Less: Account 219	(FF1 p 112, Ln 15.c)				(14,359,735)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)				1,968,342,915
161			$	%	Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))		1,588,907,909	44.67%	0.0610	0.0272
163	Preferred Stock (ln 157)		-	0.00%	-	0.0000
164	Common Stock (ln 160)		1,968,342,915	55.33%	11.49%	0.0636
165	Total (Sum lns 162 to 164)		3,557,250,824		**WACC=**	**0.0908**

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Letter **Notes**

General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

A Revenue credits include:
1) Forfeited Discounts.
2) Miscellaneous Service Revenues.
3) Rental revenues earned on assets included in the rate base.
4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.
5) Other electric revenues.
6) Revenues for grandfathered PTP contracts included in the load divisor.
See Worksheet E for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.

C Transmission Plant balances in this study are projected as of December 31, 2015. Other ratebase amounts are as of December 31, 2014.

D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
2) AEP transmission equalization transfers, as shown on line 86
3) The impact of state regulatory deferrals and amortizations, as shown on line 87
4) All A&G Expenses, as shown on line 103.

F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.

G Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.

H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.
The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
The company records referenced on lines 105 and 106 is the INDIANA MICHIGAN POWER COMPANY general ledger.

I Removes the impact of state regulatory deferrals or their amortization from O&M expense.

J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.

K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.

N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base,
must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
(ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	5.81%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.

R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

S Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163).
Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership.
In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 162 above.

U This note only applies to the true-up template.

AEP East Companies
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Utilizing Historic Cost Data for 2014 with Year-End Rate Base Balances

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator		Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)				$139,300,330
167	REVENUE CREDITS	(Note A) (Worksheet E)	1,935,437	DA	1.00000	$ 1,935,437
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$ 137,364,893

MEMO: The Carrying Charge Calculations on lines 171 to 176 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 169 is included in the total on line 168.

169	Not applicable on this template		
170	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)		
171	Annual Rate	((ln 166 - ln 270 - ln 271)/ ln 213 x 100)	18.42%
172	Monthly Rate	(ln 171 / 12)	1.54%
173	NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)		
174	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276) / ln 213 x 100)	15.53%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)		
176	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276 - ln 298 - ln 299) / ln 213 x 100)	5.36%
177	Not applicable on this template		

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

179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	7,315,015
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		4,394,733
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		993,147
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	1,927,134

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Line No.	(1) **RATE BASE CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total** NOTE C	(4) **Allocator**		(5) **Total Transmission**
	GROSS PLANT IN SERVICE					
183	Production	(Worksheet A ln 1.C)	4,412,029,807	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(338,956,228)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	1,374,861,654	DA		1,299,785,571
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.94539	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	NA	0.00000	**N/A**
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		**N/A**	NA	0.00000	**N/A**
189	Distribution	(Worksheet A ln 5.C)	1,697,749,623	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A ln 7.C)	124,803,332	W/S	0.04555	5,685,139
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,921)	W/S	0.04555	(7,877)
193	Intangible Plant	(Worksheet A ln 9.C)	150,882,300	W/S	0.04555	6,873,109
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	7,421,197,567	**GP(h)=**	**0.176836**	1,312,335,942
				GTD=	**0.42302**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	2,397,644,253	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(114,651,301)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	563,292,787	**TP1=**	0.96510	543,635,615
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96510	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	DA	1.00000	**N/A**
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
202	Plus: Additional Transmission Depreciation for 2015 (ln 276)		**N/A**	TP1	0.96510	**N/A**
203	Plus: Additional General & Intangible Depreciation for 2015 (ln 275 + ln 276)		**N/A**	W/S	0.04555	**N/A**
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
205	Distribution	(Worksheet A ln 16.C)	527,903,061	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A ln 18.C)	30,691,516	W/S	0.04555	1,398,084
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(150,819)	W/S	0.04555	(6,870)
209	Intangible Plant	(Worksheet A ln 20.C)	148,390,924	W/S	0.04555	6,759,620
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	3,553,120,421			551,786,449
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	1,790,080,627			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	811,568,867			756,149,955
214	Plus: Transmission Plant-in-Service Additions (ln 187 - ln 200)		**N/A**			**N/A**
215	Plus: Additional Trans Plant on Transferred Assets (ln 188 - ln 201)		**N/A**			**N/A**
216	Plus: Additional Transmission Depreciation for 2015 (-ln 202)		**N/A**			**N/A**
217	Plus: Additional General & Intangible Depreciation for 2015 (-ln 203)		**N/A**			**N/A**
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 204)		**N/A**			**N/A**
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	1,169,846,562			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	94,089,714			4,286,048
221	Intangible Plant	(ln 193 - ln 209)	2,491,376			113,489
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	3,868,077,146	**NP(h)=**	**0.196622**	760,549,493
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(188,450)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(1,086,402,759)	DA		(173,277,941)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(777,187,050)	DA		(6,406,759)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	830,280,323	DA		10,542,483
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(1,033,497,936)			(169,142,217)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	6,107,653	DA		208,360
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	3,040,405			2,874,380
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,076,197	TP	0.94539	1,017,430
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	97,508	W/S	0.04555	4,442
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17684	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	124,122,012	W/S	0.04555	5,654,103
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,637,185	GP(h)	0.17684	820,022
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	32,501	DA	1.00000	32,501
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(122,703,309)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	10,302,499			10,402,877
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,998,301)	DA	1.00000	(2,998,301)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		2,847,991,061			599,020,212

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Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	1,286,751,004			
245	Distribution	322.156.b	64,522,349			
246	Customer Related Expense	322 & 323.164,171,178.b	30,582,594			
247	Regional Marketing Expenses	322.131.b	4,280,922			
248	Transmission	321.112.b	83,059,132			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	1,469,196,001			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	7,315,015			
251	Less: Account 565	(Note H) 321.96.b	51,257,771			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	24,323,238	TP	0.94539	22,995,037
254	Administrative and General	323.197.b (Note J)	126,248,321			
255	Less: Acct. 924, Property Insurance	323.185.b	4,600,367			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(9,242,967)			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(667,563)			
259	Acct. 928, Reg. Com. Exp.	323.189.b	13,800,453			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	157,934			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	4,068,662			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	113,531,434	W/S	0.04555	5,171,673
263	Plus: Acct. 924, Property Insurance	(ln 255)	4,600,367	GP(h)	0.17684	813,511
264	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94539	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94539	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	348,985	DA	1.00000	348,985
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	7,840,305	W/S	0.04555	357,148
268	A & G Subtotal	(sum lns 262 to 267)	126,321,091			6,691,317
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	150,644,329			29,686,354
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in Acct 565	(Company Records) (Note H)	-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	150,644,329			29,686,354
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	107,319,605	NA	0.00000	-
275	Distribution	336.8.f	47,851,538	NA	0.00000	-
276	Transmission	336.7.f	22,629,420	TP1	0.96510	21,839,723
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
278	General	336.10.f	4,593,640	W/S	0.04555	209,253
279	Intangible	336.1.f	16,853,853	W/S	0.04555	767,740
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	199,248,056			22,816,716
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 22.(D)	13,404,670	W/S	0.04555	610,620
284	Plant Related					
285	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,098,833	DA		8,788,633
286	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	17,229,219	NA	0.00000	-
287	Other	Worksheet H ln 22.(E)	1,937,839	GP(h)	0.17684	342,680
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	81,670,561			9,741,933
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.78%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.34%			
292	where WCLTD=(ln 327) and WACC = (ln 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from ln 290)		1.6334			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,877,004)			
296	Income Tax Calculation	(ln 291 * ln 299)	114,682,031			24,121,162
297	ITC adjustment	(ln 294 * ln 295)	(7,965,902)	NP(h)	0.19662	(1,566,272)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	106,716,129			22,554,890
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	258,663,701			54,404,941
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	95,497	DA	1.00000	95,497
301	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 301 * ln291)		-			-
303	TOTAL REVENUE REQUIREMENT (sum lns 272, 280, 288, 298, 299, 300, 301, 302)		797,038,273			139,300,330

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
304	Total transmission plant	(ln 185)		1,374,861,654
305	Less transmission plant excluded from PJM Tariff (Note P)			
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			75,076,083
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)		1,299,785,571
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)	**TP=**	**0.94539**

309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
310	Production	354.20.b	149,766,422	11,457,133	161,223,555	NA	0.00000	-
311	Transmission	354.21.b	4,523,503	5,338,844	9,862,347	TP	0.94539	9,323,801
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	20,535,701	1,830,486	22,366,187	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	5,741,490	5,487,673	11,229,163	NA	0.00000	-
315	Total	(sum lns 310 to 314)	180,567,116	24,114,136	204,681,252			9,323,801
316	Transmission related amount						**W/S=**	**0.04555**

317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
318	Long Term Interest	(Worksheet L, ln. 26, col. (D))	96,918,351
319	Preferred Dividends	(Worksheet L, ln. 31, col. (D))	-
320	Development of Common Stock:		
321	Proprietary Capital	(FF1 p 112, Ln 16.c)	1,953,950,018
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)	-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)	(33,162)
324	Less: Account 219	(FF1 p 112, Ln 15.c)	(14,359,735)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)	1,968,342,915

326		$	%	Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))	1,588,907,909	44.67%	0.0610	0.0272
328	Preferred Stock (ln 322)	-	0.00%	-	0.0000
329	Common Stock (ln 325)	1,968,342,915	55.33%	11.49%	0.0636
330	Total (Sum lns 327 to 329)	3,557,250,824		**WACC=**	**0.0908**

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Letter **Notes**

General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

A Revenue credits include:
1) Forfeited Discounts.
2) Miscellaneous Service Revenues.
3) Rental revenues earned on assets included in the rate base.
4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.
5) Other electric revenues.
6) Revenues for grandfathered PTP contracts included in the load divisor.
See Worksheet E for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.

C Transmission Plant balances in this study are historic as of December 31, 2014.

D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
2) AEP transmission equalization transfers, as shown on line 251
3) The impact of state regulatory deferrals and amortizations, as shown on line 252
4) All A&G Expenses, as shown on line 268.

F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.

G Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.

H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.
The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
The company records referenced on lines 270 and 271 is the INDIANA MICHIGAN POWER COMPANY general ledger.

I Removes the impact of state regulatory deferrals or their amortization from O&M expense.

J

General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.

K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.

N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 295) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	5.81%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.

R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328).
Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.
In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983.
This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 327 above.

U This note only applies to the true-up template.

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Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$136,055,527
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,935,437	DA	1.00000	$	1,935,437
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	134,120,090

MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.

Line No.			Total	Allocator			Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives)	(Worksheet K)	5,233,462	DA	1.00000	$	5,233,462
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					18.53%
7	Monthly Rate	(ln 6 / 12)					1.54%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)						
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					15.55%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)						
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134) / ln 48 x 100)					5.51%
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					7,315,015
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)						4,394,733
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)						993,147
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					1,927,134

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Line No.	(1) **RATE BASE CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total** NOTE C	(4) **Allocator**		(5) **Total Transmission**
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.E)	4,315,473,855	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(324,586,619)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	1,347,764,703	DA		1,272,641,955
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	0.94426	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	NA	0.00000	**N/A**
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		**N/A**	NA	0.00000	**N/A**
24	Distribution	(Worksheet A ln 5.E)	1,661,302,241	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.E)	123,011,738	W/S	0.04550	5,596,815
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(172,921)	W/S	0.04550	(7,868)
28	Intangible Plant	(Worksheet A ln 9.E)	148,169,802	W/S	0.04550	6,741,462
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	7,270,962,798	**GP(h)=**	**0.17673**	1,284,972,364
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	2,372,061,079	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(104,870,769)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	557,304,514	**TP1=**	0.96606	538,389,507
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.96606	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	DA	1.00000	**N/A**
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
37	Plus: Additional Transmission Depreciation for 2015 (ln 111)		**N/A**	TP1	0.96606	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2015 (ln 110 + ln 111)		**N/A**	W/S	0.04550	**N/A**
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
40	Distribution	(Worksheet A ln 16.E)	513,511,538	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.E)	29,767,973	W/S	0.04550	1,354,390
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(147,688)	W/S	0.04550	(6,720)
44	Intangible Plant	(Worksheet A ln 20.E)	144,957,905	W/S	0.04550	6,595,326
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,512,584,551			546,332,503
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,723,696,926			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	790,460,189			734,252,448
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		**N/A**			**N/A**
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		**N/A**			**N/A**
51	Plus: Additional Transmission Depreciation for 2015 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2015 (-ln 38)		**N/A**			**N/A**
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		**N/A**			**N/A**
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,147,790,704			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	93,218,531			4,241,277
56	Intangible Plant	(ln 28 - ln 44)	3,211,897			146,136
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,758,378,247	**NP(h)=**	**0.19653**	738,639,860
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(201,923)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(1,043,153,845)	DA		(167,486,831)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(750,830,616)	DA		(9,070,122)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	794,863,836	DA		11,605,297
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(999,322,547)			(164,951,657)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	5,879,361	DA		208,360
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	3,040,405			2,870,936
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,240,857	TP	0.94426	1,171,693
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	79,128	W/S	0.04550	3,600
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17673	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	123,490,882	W/S	0.04550	5,618,615
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	4,500,542	GP(h)	0.17673	795,365
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(121,296,158)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	11,055,655			10,460,209
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(2,950,553)	DA	1.00000	(2,950,553)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,773,040,163			581,406,221

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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) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,286,751,004			
80	Distribution	322.156.b	64,522,349			
81	Customer Related Expense	322.164,171,178.b	30,582,594			
82	Regional Marketing Expenses	322.131.b	4,280,922			
83	Transmission	321.112.b	83,059,132			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,469,196,001			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	7,315,015			
86	Less: Account 565	(Note H) 321.96.b	51,257,771			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	24,323,238	TP	0.94426	22,967,491
89	Administrative and General	323.197.b (Note J)	126,248,321			
90	Less: Acct. 924, Property Insurance	323.185.b	4,600,367			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(9,242,967)			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(667,563)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,800,453			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	157,934			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	4,068,662			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	113,531,434	W/S	0.04550	5,165,478
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,600,367	GP(h)	0.17673	813,007
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94539	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94539	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	348,985	DA	1.00000	348,985
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	7,840,305	W/S	0.04550	356,720
103	A & G Subtotal	(sum lns 97 to 102)	126,321,091			6,684,190
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	150,644,329			29,651,681
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	150,644,329			29,651,681
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	107,319,605	NA	0.00000	-
110	Distribution	336.8.f	47,851,538	NA	0.00000	-
111	Transmission	336.7.f	22,629,420	TP1	0.96606	21,861,374
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
113	General	336.10.f	4,593,640	W/S	0.04550	209,002
114	Intangible	336.1.f	16,853,853	W/S	0.04550	766,820
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	199,248,056			22,837,196
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	13,404,670	W/S	0.04550	609,889
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,098,833	DA		8,788,633
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	17,229,219	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,937,839	GP(h)	0.17673	342,468
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	81,670,561			9,740,989
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.78%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.79%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6334			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,877,004)			
131	Income Tax Calculation	(ln 126 * ln 134)	111,096,400			23,292,897
132	ITC adjustment	(ln 129 * ln 130)	(7,965,902)	NP(h)	0.19653	(1,565,551)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	103,130,498			21,727,346
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	248,029,514			52,002,818
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		95,497	DA	1.00000	95,497
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135)		782,818,455			136,055,527

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
139	Total transmission plant	(ln 20)		1,347,764,703
140	Less transmission plant excluded from PJM Tariff (Note P)			-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)			75,122,748
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)		1,272,641,955
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)	**TP**	**0.94426**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
145	Production	354.20.b	149,766,422	11,457,133	161,223,555	NA	0.00000	-
146	Transmission	354.21.b	4,523,503	5,338,844	9,862,347	TP	0.94426	9,312,632
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	20,535,701	1,830,486	22,366,187	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,741,490	5,487,673	11,229,163	NA	0.00000	-
150	Total	(sum lns 145 to 149)	180,567,116	24,114,136	204,681,252			9,312,632
151	Transmission related amount						**W/S=**	**0.04550**

ln No.						
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))				92,907,121
154	Preferred Dividends	(Worksheet M, ln. 55, col. (E))				-
155	Development of Common Stock:					Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))				1,938,051,970
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))				-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))				(64,599)
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))				(14,934,237)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)				1,953,050,805
			Capital Structure Weighting		Cost	
161		Average $	Actual	Cap Limit	(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, ln 11, ln 22, col. (E))	1,594,594,526	44.95%	0.00%	0.0583	0.0262
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-	0.0000
164	Common Stock (ln 160)	1,953,050,805	55.05%	0.00%	11.49%	0.0633
165	Total (Sum lns 162 to 164)	3,547,645,331			**WACC=**	**0.0894**
166	Capital Structure Equity Limit (Note U)	100.0%				

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2014 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, 2013 and December 31, 2014.

D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
2) AEP transmission equalization transfers, as shown on line 86
3) The impact of state regulatory deferrals and amortizations, as shown on line 87
4) All A&G Expenses, as shown on line 103.

F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.

G Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.

H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.
The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
The company records referenced on lines 105 and 106 is the INDIANA MICHIGAN POWER COMPANY general ledger.

I Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.

J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.

K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.

N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
(ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	5.81%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.

R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

S Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff. and on Worksheet M.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 162 above.

U Per Settlement, equity for INDIANA MICHIGAN POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.
During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet A Supporting Plant Balances
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	**Rate Base Item & Supporting Balance**	**Source of Data**	**Balance @ December 31, 2014**	**Balance @ December 31, 2013**	**Average Balance for 2014**
NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.					
Plant Investment Balances					
1	**Production Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	4,412,029,807	4,218,917,902	4,315,473,855
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	338,956,228	310,217,009	324,586,619
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	1,374,861,654	1,320,667,751	1,347,764,703
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	1,697,749,623	1,624,854,859	1,661,302,241
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	124,803,332	121,220,143	123,011,738
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	172,921	172,921	172,921
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	150,882,300	145,457,304	148,169,802
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	7,760,326,716	7,431,117,959	7,595,722,338
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	339,129,149	310,389,930	324,759,540
Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	2,397,644,253	2,346,477,905	2,372,061,079
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	114,651,301	95,090,237	104,870,769
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	563,292,787	551,316,240	557,304,514
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	527,903,061	499,120,014	513,511,538
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	30,691,516	28,844,430	29,767,973
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	150,819	144,557	147,688
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	148,390,924	141,524,886	144,957,905
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	3,667,922,541	3,567,283,475	3,617,603,008
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	114,802,120	95,234,793	105,018,457
Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records - Note 1	75,076,083	75,169,412	75,122,748
24	**GSU Accumulated Depreciation**	Company Records - Note 1	19,657,172	18,172,841	18,915,006
25	**GSU Net Balance**	(Line 23 - Line 24)	55,418,912	56,996,571	56,207,741
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	563,292,787	551,316,240	557,304,514
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	19,657,172	18,172,841	18,915,006
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	543,635,615	533,143,399	538,389,507
Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	6,107,653	5,651,068	5,879,361
30	**Transmission Plant Held For Future**	Company Records - Note 1	208,360	208,360	208,360
Regulatory Assets and Liabilities Approved for Recovery In Ratebase					
	Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.				
31					-
32					-
33					-
34					-
35					-
36	Total Regulatory Deferrals Included in Ratebase		-	-	-

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

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

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	**Description**	**Source**	**Balance @ December 31, 2014**	**Balance @ December 31, 2013**	**Average Balance for 2014**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	188,450	215,395	201,923
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	188,450	215,395	201,923
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	**Account 282**				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	1,086,402,759	999,904,930	1,043,153,845
8	Less: ARO Related Deferrals	Company Records - Note 1	84,131,261	77,712,096	80,921,679
9	Less: Other Excluded Deferrals	Company Records - Note 1	828,993,557	760,497,113	794,745,335
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	173,277,941	161,695,721	167,486,831
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	777,187,050	724,474,181	750,830,616
13	Less: ARO Related Deferrals	Company Records - Note 1	625,867,381	568,535,317	597,201,349
14	Less: Other Excluded Deferrals	Company Records - Note 1	144,912,910	144,205,379	144,559,145
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	6,406,759	11,733,485	9,070,122
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	830,280,323	759,447,349	794,863,836
18	Less: ARO Related Deferrals	Company Records - Note 1	713,091,768	648,303,915	680,697,842
19	Less: Other Excluded Deferrals	Company Records - Note 1	106,646,072	98,475,324	102,560,698
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	10,542,483	12,668,110	11,605,297
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	38,322,586	43,199,590	40,761,088
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	38,322,586	43,199,590	40,761,088
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1	0	0	-

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

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

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
INDIANA MICHIGAN POWER COMPANY

Materials & Supplies

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number			**Source**	**Balance @ December 31, 2014**	**Balance @ December 31, 2013**	**Average Balance for 2014**
1						
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,076,197	1,405,516	1,240,857
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	97,508	60,747	79,128
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

5		**Average of YE Balance**	**Excludable Balances**	**100% Transmission Related**	**Transmission Plant Related**	**Transmission Labor Related**	**Total Included in Ratebase (E)+(F)+(G)**
6	Totals as of December 31, 2014	6,088,389	(122,703,309)	32,501	4,637,185	124,122,012	128,791,698
7	Totals as of December 31, 2013	7,334,643	(119,889,006)		4,363,899	122,859,751	127,223,650
8	**Average Balance**	6,711,516	(121,296,158)	-	4,500,542	123,490,882	128,007,674

Prepayments Account 165 - Balance @ 12/31/2014

9	**Acc. No.**	**Description**	**2014 YE Balance**	**Excludable Balances**	**100% Transmission Related**	**Transmission Plant Related**	**Transmission Labor Related**	**Total Included in Ratebase (E)+(F)+(G)**	**Explanation**
10	1650001	Prepaid Insurance	3,657,188	-		3,657,188		3,657,188	Plant Related Insurance Policies
11	165000214	Prepaid Taxes	465,363	465,363				-	Prepaid Taxes-Distribution
12	1650003	Prepaid Rents	0	-				-	River Transport
13	1650005	Prepaid Employee Benefits	0	-				-	Benefits Generation
14	1650006	Other Prepayments	76,557	76,557				-	Relates to EPRI dues
15	1650009	Prepaid Carry Cost-Factored AR	89,544	89,544				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	111,640,109				111,640,109	111,640,109	Prefunded Pension Expense
17	1650014	FAS 158 Qual Contra Asset	(111,640,109)	(111,640,109)				-	SFAS 158 Offset
18	165001114	Prepaid Sales Taxes	429,718	429,718			-	-	Prepaid Sales Tax - Distribution
19	165001214	Prepaid Use Taxes	68,740	68,740			-	-	Prepaid Use Tax - Distribution
20	1650021	Prepaid Insurance - EIS	979,997	-		979,997		979,997	Energy INS Services
21	1650022	Prepaid SNF Container Costs	0	-			-	-	
22	1650023	Prepaid Lease	116,093	116,093			-	-	Prepaid Leases-Gen/Dist
23	1650026	Prepaid SNF Costs	0	-					
24	1650031	Prepaid OCIP Work Comp	104,824	-			104,824	104,824	Workers Compensation
25	1650033	Prepaid OCIP Work Comp-Aff	67,864	-			67,864	67,864	Workers Compensation
26	1650035	PRW without MED-D Benefits	(9,037,731)				(9,037,731)	(9,037,731)	Med-D Benefits
27	1650036	PRW for Med-D Benefits	21,346,946				21,346,946	21,346,946	Med-D Benefits
28	1650037	FAS 158 Contra-PRW Exc Med-D	(12,309,215)	(12,309,215)					SFAS 158 Offset
29	1650032	Prepaid OCIP WC LT	15,797		15,797			15,797	Workers Compensation-Transmission
30	1650034	Prepaid OCIP WC LT-Aff	16,704		16,704			16,704	Workers Compensation-Transmission
		Subtotal - Form 1, p 111.57.c	6,088,389	(122,703,309)	32,501	4,637,185	124,122,012	128,791,698	

Prepayments Account 165 - Balance @ 12/31/ 2013

31	**Acc. No.**	**Description**	**2013 YE Balance**	**Excludable Balances**	**100% Transmission Related**	**Transmission Plant Related**	**Transmission Labor Related**	**Total Included in Ratebase (E)+(F)+(G)**	**Explanation**
32	1650001	Prepaid Insurance	2,700,766	-		2,700,766		2,700,766	Plant Related Insurance Policies
33	165000213	Prepaid Taxes	432,563	432,563				-	Prepaid Taxes-Distribution
34	1650003	Prepaid Rents	(2,676)	(2,676)			-	-	River Transport
35	1650005	Prepaid Employee Benefits	0	-			-	-	Benefits Generation
36	1650006	Other Prepayments	1,093,543	1,093,543				-	Relates to EPRI dues
37	1650009	Prepaid Carry Cost-Factored AR	73,021	73,021				-	AR Factoring - Retail Only
38	1650010	Prepaid Pension Benefits	122,859,751				122,859,751	122,859,751	Prefunded Pension Expense
39	1650014	FAS 158 Qual Contra Asset	(122,859,751)	(122,859,751)				-	SFAS 158 Offset
40	165001113	Prepaid Sales Taxes	684,965	684,965			-	-	Prepaid Sales Tax - Distribution
41	165001213	Prepaid Use Taxes	513,909	513,909			-	-	Prepaid Use Tax - Distribution
42	1650021	Prepaid Insurance - EIS	1,663,133	-		1,663,133		1,663,133	Energy INS Services
43	1650022	Prepaid SNF Container Costs	0	-			-	-	
44	1650023	Prepaid Lease	175,420	175,420			-	-	Prepaid Leases
45	1650026	Prepaid SNF Costs	0	-					
		Subtotal - Form 1, p 111.57.d	7,334,643	(119,889,006)		4,363,899	122,859,751	127,223,650	

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet D Supporting IPP Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	**(A) Description**	**(B) 2014**
1	Net Funds from IPP Customers 12/31/2013 (2014 FORM 1, P269, line 6.b)	(2,902,804)
2	Interest Accrual (Company Records - Note 1)	(95,497)
3	Revenue Credits to Generators (Company Records - Note 1)	0
4	Other Adjustments	
5	Accounting Adjustment (Company Records - Note 1)	0
6		-
7	Net Funds from IPP Customers 12/31/2014 (2014 FORM 1, P269, line 6.f)	(2,998,301)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(2,950,553)

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 2014 FF1 Balances
Worksheet E Supporting Revenue Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	**Description**	**Total Company**	**Non-Transmission**	**Transmission**
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	4,970,731	4,970,731	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	4,432,814	4,376,027	56,787
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	6,630,380	6,303,160	327,220
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	1,825,520	1,119,238	706,282
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	46,164,272	45,319,124	845,148
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	64,023,717	62,088,280	1,935,437
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	64,023,717	62,088,280	1,935,437

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 2014 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number	**Item No.**	**Description**	**2014 Expense**	**100% Non-Transmission**	**100% Transmission Specific**	**Explanation**
		Regulatory O&M Deferrals & Amortizations				
1	5660000	Misc Transmission Expense	163,108			
2		**Total**	163,108			
		Detail of Account 561 Per FERC Form 1				
3	FF1 p 321.84.b	561 - Load Dispatching	0			
4	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	23,949			
5	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,666,974			
6	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	0			
7	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	4,394,733			
8	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	236,211			
9	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
10	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
11	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Serv	993,147			
12		**Total of Account 561**	7,315,015			
		Account 928				
13	9280000	Regulatory Commission Exp	10,905	10,905	-	
14	9280001	Regulatory Commission Exp-Adm	13,055,512	13,055,512	-	
15	9280002	Regulatory Commission Exp-Case	734,035	734,035	-	
16	9280003	Rate Case Amortization	-	-		
17		**Total**	13,800,452	13,800,452	-	
		Account 930.1				
18	9301000	General Advertising Expenses	27,929	27,929	-	
19	9301001	Newspaper Advertising Space	10,267	10,267	-	
20	9301002	Radio Station Advertising Time	2,245	2,245	-	
21	9301003	TV Station Advertising Time	-	-	-	
22	9301006	Spec Corporate Comm Info Proj	1,086	1,086	-	
23	9301007	Special Adv Space & Prod Exp	-	-	-	
24	9301008	Direct Mail and Handouts	-	-	-	
25	9301009	Fairs, Shows, and Exhibits	-	-	-	
26	9301010	Publicity	7,164	7,164	-	
27	9301011	Dedications, Tours, & Openings	2,500	2,500	-	
28	9301012	Public Opinion Surveys	26,006	26,006	-	
29	9301013	Movies Slide Films & Speeches	-	-	-	
30	9301014	Video Communications	-	-	-	
31	9301015	Other Corporate Comm Exp	80,737	80,737	-	
32		**Total**	157,934	157,934	-	
		Account 930.2				
33	9302000	Misc General Expenses	3,983,865	3,983,865		
34	9302003	Corporate & Fiscal Expenses	167,497	167,497		
35	9302004	Research, Develop&Demonstr Exp	9,089	9,089		
36	9302005	Nucl Fac Ins - Replce Engy Cst	-1,109,307	-1,109,307		
37	9302006	Assoc Business Development Materials Sold	35,835	35,835	0	
38	9302007	Assoc Business Development Exp	981,684	632,699	348,985	
39	9302458	AEPSC nonaffiliated expense	0	0		
40		**Total**	4,068,663	3,719,678	348,985	

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
INDIANA MICHIGAN POWER COMPANY

Indiana Corporate Income Tax Rate	7.25%	
Apportionment Factor - Note 2	61.52%	
Effective State Tax Rate		4.46%
Michigan Single Business Tax Rate	6.00%	
Apportionment Factor - Note 2	14.82%	
Effective State Tax Rate		0.89%
West Virginia Corporation Income Tax Rate	6.50%	
Apportionment Factor - Note 2	2.90%	
Effective State Tax Rate		0.19%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - Note 2	1.97%	
Effective State Tax Rate		0.12%
Missouri Corporation Income Tax Rate	6.25%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.54%	
Effective State Tax Rate		0.15%
Total Effective State Income Tax Rate		5.81%

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 2014 FF1 Balances
Worksheet H Supporting Taxes Other than Income
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Account**	**Total Company**	**Property**	**Labor**	**Other**	**Non-Allocable**
		NOTE 1				
1	**Revenue Taxes**					
2	Gross Receipts Tax	17,090,581				17,090,581
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Michigan	32,163,642	32,163,642			
5	Real and Personal Property - Indiana	16,928,314	16,928,314			
6	Real and Personal Property - Other Jurisdictions	6,877	6,877			
7	**Payroll Taxes**					
8	Federal Insurance Contribution (FICA)	12,553,020		12,553,020		
9	Federal Unemployment Tax	187,254		187,254		
10	State Unemployment Insurance	664,396		664,396		
11	**Production Taxes**					
12	State Severance Taxes	4,942				4,942
13	**Miscellaneous Taxes**					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	1,979,422			1,979,422	
16	State Franchise Taxes	(43,407)			(43,407)	
17	State Lic/Registration Fee	1,824			1,824	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	122,206				122,206
20	Federal Excise Tax	11,490				11,490
21	Michigan Single Business Tax	-				-
22	Total Taxes by Allocable Basis	81,670,561	49,098,833	13,404,670	1,937,839	17,229,219

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

Functional Property Tax Allocation

		Production	Transmsission	Distribution	General	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,790,080,627	811,568,867	1,169,846,562	94,089,714	3,865,585,770
	MICHIGAN JURISDICTION					
24	Percentage of Plant in MICHIGAN JURISDICTION	66.63%	15.89%	19.72%	18.34%	
25	Net Plant in MICHIGAN JURISDICTION (Ln 23 * Ln 24)	1,192,730,722	128,958,293	230,693,742	17,256,054	1,569,638,811
26	Less: Net Value of Exempted Generation Plant	296,212,474				
27	Taxable Property Basis (Ln 25 - Ln 26)	896,518,248	128,958,293	230,693,742	17,256,054	1,273,426,337
28	Relative Valuation Factor	100%	100%	100%	100%	
29	Weighted Net Plant (Ln 27 * Ln 28)	896,518,248	128,958,293	230,693,742	17,256,054	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	71.37%	10.27%	18.36%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	12,315,501	1,771,504	3,169,048	(17,256,054)	-
32	Weighted MICHIGAN JURISDICTION Plant (Ln 29 + 31)	908,833,749	130,729,797	233,862,790	(0)	1,273,426,337
33	Functional Percentage (Ln 32/Total Ln 32)	71.37%	10.27%	18.36%		
34	Functionalized Expense in MICHIGAN JURISDICTION	22,954,923	3,301,916	5,906,803		32,163,642
	INDIANA JURISDICTION					
35	Percentage of Plant in INDIANA JURISDICTION	33.37%	84.11%	80.28%	81.62%	
36	Net Plant in INDIANA JURISDICTION (Ln 23 * Ln 35)	597,349,905	682,610,574	939,152,820	76,796,025	2,295,909,324
37	Less: Net Value of Exempted Generation Plant	112,517,624				
38	Taxable Property Basis (Ln 36 - Ln 37)	484,832,281	682,610,574	939,152,820	76,796,025	2,183,391,700
39	Relative Valuation Factor	100%	100%	100%	100%	
40	Weighted Net Plant (Ln 38 * Ln 39)	484,832,281	682,610,574	939,152,820	76,796,025	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	23.01%	32.40%	44.58%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	17,674,579	24,884,594	34,236,851	(76,796,025)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	502,506,860	707,495,168	973,389,671	(0)	2,183,391,700
44	Functional Percentage (Ln 43/Total Ln 43)	23.01%	32.40%	44.58%		
45	Functionalized Expense in INDIANA JURISDICTION	3,896,046	5,485,365	7,546,903		16,928,314
46	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		1,352			6,877
47	Total Func. Property Taxes (Sum Lns 34, 45 46)	26,850,969	8,788,633	13,453,707		49,098,833

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)
Line No.	**Annual Tax Expenses by Type (Note 1)**	**Total Company**	**FERC FORM 1 Tie-Back**	**FERC FORM 1 Reference**
1	**Revenue Taxes**			
2	Gross Receipts Tax	17,090,581		
			91,151	P.263 ln 14 (i)
			16,868,000	P.263 ln 15 (i)
			(18,958)	P.263.2 ln 22 (i)
			150,388	P.263.2 ln 23 (i)
			-	P.263.2 ln 26 (i)
			-	P.263.2 ln 38 (i)
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - Michigan	32,163,642		
			(568,721)	P.263.1 ln 17 (i)
			32,483,403	P.263.1 ln 18 (i)
			(21,369)	P.263.1 ln 21 (i)
			54,842	P.263.1 ln 22 (i)
			3,487	P.263.1 ln 25 (i)
			212,000	P.263.1 ln 26 (i)
5	Real and Personal Property - Indiana	16,928,314		
			123,565	P.263 ln 24 (i)
			1,978,503	P.263 ln 25 (i)
			14,545,529	P.263 ln 26 (i)
			39,128	P.263 ln 28 (i)
			241,589	P.263 ln 29 (i)
			-	P.263 ln 30 (i)
			-	P.263 ln 31 (i)
6	Real and Personal Property - Other Jurisdictions	6,877		
			3,337	P.263.2 ln 7 (i)
			3,540	P.263.2 ln 8 (i)
			-	P.263.3 ln 3 (i)
			-	P.263.3 ln 4 (i)
7	**Payroll Taxes**			
8	Federal Insurance Contribution (FICA)	12,553,020		
			12,553,020	P.263 ln 3 (i)
9	Federal Unemployment Tax	187,254		
			187,254	P.263 ln 4 (i)
10	State Unemployment Insurance	664,396		
			530,523	P.263.1 ln 9 (i)
			(12,149)	P.263.2 ln 16 (i)
			213	P.263.2 ln 24 (i)
			145,809	P.263 ln 13 (i)
11	**Production Taxes**			
12	State Severance Taxes	4,942		
13	Misc States - 2013		4,942	P.263.3 ln 2 (i)
14	Misc States 2012		-	P.263.2 ln 33 (i)
15	**Miscellaneous Taxes**			
16	State Business & Occupation Tax	-		
			-	
17	State Public Service Commission Fees	1,979,422		
			392,716	P.263.1 ln 10 (i)
			176,679	P.263.1 ln 11 (i)
			703,152	P.263 ln 21 (i)
			706,875	P.263 ln 22 (i)
18	State Franchise Taxes	(43,407)		
			(49,460)	P.263.2 ln 4(i)
			6,053	P.263.2 ln 5(i)
19	State Lic/Registration Fee	1,824		
			1,500	P.263.1 ln 29 (i)
			25	P.263.1 ln 40 (i)
			225	P.263.3 ln 21(i)
			52	P.263.3 ln 22 (i)
			22	P.263 ln 17 (i)
			-	
20	Misc. State and Local Tax	-		
			-	
21	Sales & Use	122,206		
			11,806	P.263.1 ln 12 (i)
			110,400	P.263.1 ln 13 (i)
22	Federal Excise Tax	11,490		
			11,490	P.263 ln 6 (i)
			-	P.263 ln 6 (i)
23	Michigan Single Business Tax	-		
			-	
24	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	81,670,561	81,670,561	

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

AEP East Companies
Cost of Service Formula Rate Using 2014 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 (2014) (P.206, ln 58,(b)):	1,320,667,751
2	Transmission Plant @ End of Historic Period (2014) (P.207, ln 58,(g)):	1,374,861,654
3		2,695,529,405
4	Average Balance of Transmission Investment	1,347,764,703
5	Annual Depreciation Expense, Historic TCOS, ln 276	22,629,420
6	Composite Depreciation Rate	1.68%
7	Round to 1.68% to Reflect a Composite Life of 60 Years	1.68%

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	$ 11,085,240	1.68%	$ 186,232	$ 15,519	11	$ 170,709
10	February	$ 10,235,976	1.68%	$ 171,964	$ 14,330	10	$ 143,300
11	March	$ (183,572)	1.68%	$ (3,084)	$ (257)	9	$ (2,313)
12	April	$ 863,659	1.68%	$ 14,509	$ 1,209	8	$ 9,672
13	May	$ 12,069,115	1.68%	$ 202,761	$ 16,897	7	$ 118,279
14	June	$ 12,726,846	1.68%	$ 213,811	$ 17,818	6	$ 106,908
15	July	$ 4,590,061	1.68%	$ 77,113	$ 6,426	5	$ 32,130
16	August	$ 3,376,662	1.68%	$ 56,728	$ 4,727	4	$ 18,908
17	September	$ 2,516,387	1.68%	$ 42,275	$ 3,523	3	$ 10,569
18	October	$ 2,530,324	1.68%	$ 42,509	$ 3,542	2	$ 7,084
19	November	$ 2,532,125	1.68%	$ 42,540	$ 3,545	1	$ 3,545
20	December	$ 10,045,882	1.68%	$ 168,771	$ 14,064	0	$ -
21	Investment	$ 72,388,705				Depreciation Expense	$ 618,791

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 2015

			Estimated Cost (000's)	**Month in Service**
25	**Major Zonal Projects**			
26	TBSIIM- INDIANA SYS REHAB		$5,212	Dec-15
27	T/IN/Purchase/Rebuild Maj Eqp		$5,153	Dec-15
28	T/Auburn: 138 kV Station		$4,864	Jun-15
29			$0	
30		Subtotal	$15,229	
31	**PJM Socialized/Beneficiary Allocated Regional Projects**			
32			$0	
33		Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN POWER COMPANY

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

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

ROE w/o incentives (Projected TCOS, ln 164)	11.49%	
Project ROE Incentive Adder	🟩	<==ROE Adder Cannot Exceed 125 Basis Points
ROE with additional basis point incentive	11.49%	**<== ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012**

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

	%	Cost		Weighted cost
Long Term Debt	44.67%	6.10%		2.725%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	55.33%	11.49%		6.358%
			R =	9.082%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2015	5,557,149	5,557,149	$ -

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

Rate Base (Projected TCOS, ln 78)	647,973,410
R (from A. above)	9.082%
Return (Rate Base x R)	58,851,027

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

Return (from B. above)	58,851,027
Effective Tax Rate (Projected TCOS, ln 126)	44.34%
Income Tax Calculation (Return x CIT)	26,092,395
ITC Adjustment	(1,566,272)
Income Taxes	24,526,122

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

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

Annual Revenue Requirement (Projected TCOS, ln 1)	146,336,441
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	58,851,027
Income Taxes (Projected TCOS, ln 133)	24,526,122
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	62,959,291

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	62,959,291
Return (from I.B. above)	58,851,027
Income Taxes (from I.C. above)	24,526,122
Annual Revenue Requirement, with Basis Point ROE increase	146,336,441
Depreciation (Projected TCOS, ln 111)	21,839,723
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	124,496,717

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	756,149,955
Annual Revenue Requirement, with Basis Point ROE increase	146,336,441
FCR with Basis Point increase in ROE	19.35%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	124,496,717
FCR with Basis Point ROE increase, less Depreciation	16.46%
FCR less Depreciation (Projected TCOS, ln 9)	15.37%
Incremental FCR with Basis Point ROE increase, less Depreciation	1.10%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2014) (P.206, ln 58,(b)):	1,320,667,751
Transmission Plant @ End of Historic Period (2014) (P.207, ln 58,(g)):	1,374,861,654
Subtotal	2,695,529,405
Average Transmission Plant Balance for 2014	1,347,764,703
Annual Depreciation Rate (Projected TCOS, ln 111)	22,629,420
Composite Depreciation Rate	1.68%
Depreciable Life for Composite Depreciation Rate	59.56
Round to nearest whole year	60

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Current Projected Year ARR	**1,278,273**
Current Projected Year ARR w/ Incentive	**1,278,273**
Current Projected Year Incentive ARR	**-**

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

Details			
Investment	8,316,810	Current Year	**2015**
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	138,614

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**	**RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives**		**RTEP Projected Rev. Req't.From Prior Year Template with Incentives ****		
2009	8,316,810	69,307	8,247,503	1,336,778	1,336,778	$ -					
2010	8,247,503	138,614	8,108,890	1,384,783	1,384,783	$ -	$ 1,408,114		$ 1,408,114		
2011	8,108,890	138,614	7,970,276	1,363,481	1,363,481	$ -	$ 1,487,355		$ 1,487,355		
2012	7,970,276	138,614	7,831,663	1,342,179	1,342,179	$ -	$ 1,319,695		$ 1,319,695		
2013	7,831,663	138,614	7,693,049	1,320,877	1,320,877	$ -	$ 1,272,484		$ 1,272,484		
2014	7,693,049	138,614	7,554,436	1,299,575	1,299,575	$ -	$ 1,249,385		$ 1,249,385		
2015	7,554,436	138,614	7,415,822	1,278,273	1,278,273	$ -					
2016	7,415,822	138,614	7,277,209	1,256,971	1,256,971	$ -					
2017	7,277,209	138,614	7,138,595	1,235,669	1,235,669	$ -					
2018	7,138,595	138,614	6,999,982	1,214,367	1,214,367	$ -					
2019	6,999,982	138,614	6,861,368	1,193,065	1,193,065	$ -					
2020	6,861,368	138,614	6,722,755	1,171,763	1,171,763	$ -					
2021	6,722,755	138,614	6,584,141	1,150,460	1,150,460	$ -					
2022	6,584,141	138,614	6,445,528	1,129,158	1,129,158	$ -					
2023	6,445,528	138,614	6,306,914	1,107,856	1,107,856	$ -					
2024	6,306,914	138,614	6,168,301	1,086,554	1,086,554	$ -					
2025	6,168,301	138,614	6,029,687	1,065,252	1,065,252	$ -					
2026	6,029,687	138,614	5,891,074	1,043,950	1,043,950	$ -					
2027	5,891,074	138,614	5,752,460	1,022,648	1,022,648	$ -					
2028	5,752,460	138,614	5,613,847	1,001,346	1,001,346	$ -					
2029	5,613,847	138,614	5,475,233	980,044	980,044	$ -					
2030	5,475,233	138,614	5,336,620	958,742	958,742	$ -					
2031	5,336,620	138,614	5,198,006	937,440	937,440	$ -					
2032	5,198,006	138,614	5,059,393	916,138	916,138	$ -					
2033	5,059,393	138,614	4,920,779	894,836	894,836	$ -					
2034	4,920,779	138,614	4,782,166	873,534	873,534	$ -					
2035	4,782,166	138,614	4,643,552	852,232	852,232	$ -					
2036	4,643,552	138,614	4,504,939	830,930	830,930	$ -					
2037	4,504,939	138,614	4,366,325	809,628	809,628	$ -					
2038	4,366,325	138,614	4,227,712	788,326	788,326	$ -					
2039	4,227,712	138,614	4,089,098	767,024	767,024	$ -					
2040	4,089,098	138,614	3,950,485	745,722	745,722	$ -					
2041	3,950,485	138,614	3,811,871	724,420	724,420	$ -					
2042	3,811,871	138,614	3,673,258	703,118	703,118	$ -					
2043	3,673,258	138,614	3,534,644	681,816	681,816	$ -					
2044	3,534,644	138,614	3,396,031	660,514	660,514	$ -					
2045	3,396,031	138,614	3,257,417	639,211	639,211	$ -					
2046	3,257,417	138,614	3,118,804	617,909	617,909	$ -					
2047	3,118,804	138,614	2,980,190	596,607	596,607	$ -					
2048	2,980,190	138,614	2,841,577	575,305	575,305	$ -					
2049	2,841,577	138,614	2,702,963	554,003	554,003	$ -					
2050	2,702,963	138,614	2,564,350	532,701	532,701	$ -					
2051	2,564,350	138,614	2,425,736	511,399	511,399	$ -					
2052	2,425,736	138,614	2,287,123	490,097	490,097	$ -					
2053	2,287,123	138,614	2,148,509	468,795	468,795	$ -					
2054	2,148,509	138,614	2,009,896	447,493	447,493	$ -					
2055	2,009,896	138,614	1,871,282	426,191	426,191	$ -					
2056	1,871,282	138,614	1,732,669	404,889	404,889	$ -					
2057	1,732,669	138,614	1,594,055	383,587	383,587	$ -					
2058	1,594,055	138,614	1,455,442	362,285	362,285	$ -					
2059	1,455,442	138,614	1,316,828	340,983	340,983	$ -					
2060	1,316,828	138,614	1,178,215	319,681	319,681	$ -					
2061	1,178,215	138,614	1,039,601	298,379	298,379	$ -					
2062	1,039,601	138,614	900,988	277,077	277,077	$ -					
2063	900,988	138,614	762,374	255,775	255,775	$ -					
2064	762,374	138,614	623,761	234,473	234,473	$ -					
2065	623,761	138,614	485,147	213,171	213,171	$ -					
2066	485,147	138,614	346,534	191,869	191,869	$ -					
2067	346,534	138,614	207,920	170,567	170,567	$ -					
2068	207,920	138,614	69,307	149,265	149,265	$ -					
Project Totals		8,247,503		46,591,178	46,591,178	-					

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

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Current Projected Year ARR	**87,463**
Current Projected Year ARR w/ Incentive	**87,463**
Current Projected Year Incentive ARR	**-**

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

Details			
Investment	533,495	Current Year	**2015**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	8,892

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	533,495	4,446	529,049	85,750	85,750	$ -	$ 92,625		$ 92,625		
2014	529,049	8,892	520,158	88,829	88,829	$ -	$ 87,393		$ 87,393		
2015	520,158	8,892	511,266	87,463	87,463	$ -					
2016	511,266	8,892	502,374	86,096	86,096	$ -					
2017	502,374	8,892	493,483	84,730	84,730	$ -					
2018	493,483	8,892	484,591	83,363	83,363	$ -					
2019	484,591	8,892	475,700	81,997	81,997	$ -					
2020	475,700	8,892	466,808	80,630	80,630	$ -					
2021	466,808	8,892	457,917	79,264	79,264	$ -					
2022	457,917	8,892	449,025	77,897	77,897	$ -					
2023	449,025	8,892	440,133	76,531	76,531	$ -					
2024	440,133	8,892	431,242	75,165	75,165	$ -					
2025	431,242	8,892	422,350	73,798	73,798	$ -					
2026	422,350	8,892	413,459	72,432	72,432	$ -					
2027	413,459	8,892	404,567	71,065	71,065	$ -					
2028	404,567	8,892	395,675	69,699	69,699	$ -					
2029	395,675	8,892	386,784	68,332	68,332	$ -					
2030	386,784	8,892	377,892	66,966	66,966	$ -					
2031	377,892	8,892	369,001	65,599	65,599	$ -					
2032	369,001	8,892	360,109	64,233	64,233	$ -					
2033	360,109	8,892	351,218	62,866	62,866	$ -					
2034	351,218	8,892	342,326	61,500	61,500	$ -					
2035	342,326	8,892	333,434	60,134	60,134	$ -					
2036	333,434	8,892	324,543	58,767	58,767	$ -					
2037	324,543	8,892	315,651	57,401	57,401	$ -					
2038	315,651	8,892	306,760	56,034	56,034	$ -					
2039	306,760	8,892	297,868	54,668	54,668	$ -					
2040	297,868	8,892	288,976	53,301	53,301	$ -					
2041	288,976	8,892	280,085	51,935	51,935	$ -					
2042	280,085	8,892	271,193	50,568	50,568	$ -					
2043	271,193	8,892	262,302	49,202	49,202	$ -					
2044	262,302	8,892	253,410	47,836	47,836	$ -					
2045	253,410	8,892	244,519	46,469	46,469	$ -					
2046	244,519	8,892	235,627	45,103	45,103	$ -					
2047	235,627	8,892	226,735	43,736	43,736	$ -					
2048	226,735	8,892	217,844	42,370	42,370	$ -					
2049	217,844	8,892	208,952	41,003	41,003	$ -					
2050	208,952	8,892	200,061	39,637	39,637	$ -					
2051	200,061	8,892	191,169	38,270	38,270	$ -					
2052	191,169	8,892	182,277	36,904	36,904	$ -					
2053	182,277	8,892	173,386	35,537	35,537	$ -					
2054	173,386	8,892	164,494	34,171	34,171	$ -					
2055	164,494	8,892	155,603	32,805	32,805	$ -					
2056	155,603	8,892	146,711	31,438	31,438	$ -					
2057	146,711	8,892	137,820	30,072	30,072	$ -					
2058	137,820	8,892	128,928	28,705	28,705	$ -					
2059	128,928	8,892	120,036	27,339	27,339	$ -					
2060	120,036	8,892	111,145	25,972	25,972	$ -					
2061	111,145	8,892	102,253	24,606	24,606	$ -					
2062	102,253	8,892	93,362	23,239	23,239	$ -					
2063	93,362	8,892	84,470	21,873	21,873	$ -					
2064	84,470	8,892	75,578	20,506	20,506	$ -					
2065	75,578	8,892	66,687	19,140	19,140	$ -					
2066	66,687	8,892	57,795	17,774	17,774	$ -					
2067	57,795	8,892	48,904	16,407	16,407	$ -					
2068	48,904	8,892	40,012	15,041	15,041	$ -					
2069	40,012	8,892	31,121	13,674	13,674	$ -					
2070	31,121	8,892	22,229	12,308	12,308	$ -					
2071	22,229	8,892	13,337	10,941	10,941	$ -					
2072	13,337	8,892	4,446	9,575	9,575	$ -					
Project Totals		529,049		2,988,665	2,988,665	-					

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

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

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

Current Projected Year ARR	**3,604,460**
Current Projected Year ARR w/ Incentive	**3,604,460**
Current Projected Year Incentive ARR	**-**

Details			
Investment	22,043,484	Current Year	**2015**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	367,391

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**
2013	22,043,484	244,928	21,798,556	3,594,917	3,594,917	$ -
2014	21,798,556	367,391	21,431,165	3,660,920	3,660,920	$ -
2015	21,431,165	367,391	21,063,774	3,604,460	3,604,460	$ -
2016	21,063,774	367,391	20,696,382	3,547,999	3,547,999	$ -
2017	20,696,382	367,391	20,328,991	3,491,539	3,491,539	$ -
2018	20,328,991	367,391	19,961,599	3,435,078	3,435,078	$ -
2019	19,961,599	367,391	19,594,208	3,378,618	3,378,618	$ -
2020	19,594,208	367,391	19,226,817	3,322,157	3,322,157	$ -
2021	19,226,817	367,391	18,859,425	3,265,697	3,265,697	$ -
2022	18,859,425	367,391	18,492,034	3,209,236	3,209,236	$ -
2023	18,492,034	367,391	18,124,642	3,152,776	3,152,776	$ -
2024	18,124,642	367,391	17,757,251	3,096,315	3,096,315	$ -
2025	17,757,251	367,391	17,389,860	3,039,855	3,039,855	$ -
2026	17,389,860	367,391	17,022,468	2,983,394	2,983,394	$ -
2027	17,022,468	367,391	16,655,077	2,926,934	2,926,934	$ -
2028	16,655,077	367,391	16,287,685	2,870,473	2,870,473	$ -
2029	16,287,685	367,391	15,920,294	2,814,013	2,814,013	$ -
2030	15,920,294	367,391	15,552,903	2,757,552	2,757,552	$ -
2031	15,552,903	367,391	15,185,511	2,701,092	2,701,092	$ -
2032	15,185,511	367,391	14,818,120	2,644,631	2,644,631	$ -
2033	14,818,120	367,391	14,450,728	2,588,171	2,588,171	$ -
2034	14,450,728	367,391	14,083,337	2,531,710	2,531,710	$ -
2035	14,083,337	367,391	13,715,946	2,475,250	2,475,250	$ -
2036	13,715,946	367,391	13,348,554	2,418,789	2,418,789	$ -
2037	13,348,554	367,391	12,981,163	2,362,329	2,362,329	$ -
2038	12,981,163	367,391	12,613,771	2,305,868	2,305,868	$ -
2039	12,613,771	367,391	12,246,380	2,249,408	2,249,408	$ -
2040	12,246,380	367,391	11,878,989	2,192,947	2,192,947	$ -
2041	11,878,989	367,391	11,511,597	2,136,487	2,136,487	$ -
2042	11,511,597	367,391	11,144,206	2,080,026	2,080,026	$ -
2043	11,144,206	367,391	10,776,814	2,023,566	2,023,566	$ -
2044	10,776,814	367,391	10,409,423	1,967,105	1,967,105	$ -
2045	10,409,423	367,391	10,042,032	1,910,645	1,910,645	$ -
2046	10,042,032	367,391	9,674,640	1,854,184	1,854,184	$ -
2047	9,674,640	367,391	9,307,249	1,797,724	1,797,724	$ -
2048	9,307,249	367,391	8,939,857	1,741,263	1,741,263	$ -
2049	8,939,857	367,391	8,572,466	1,684,803	1,684,803	$ -
2050	8,572,466	367,391	8,205,075	1,628,342	1,628,342	$ -
2051	8,205,075	367,391	7,837,683	1,571,882	1,571,882	$ -
2052	7,837,683	367,391	7,470,292	1,515,421	1,515,421	$ -
2053	7,470,292	367,391	7,102,900	1,458,961	1,458,961	$ -
2054	7,102,900	367,391	6,735,509	1,402,500	1,402,500	$ -
2055	6,735,509	367,391	6,368,118	1,346,040	1,346,040	$ -
2056	6,368,118	367,391	6,000,726	1,289,579	1,289,579	$ -
2057	6,000,726	367,391	5,633,335	1,233,119	1,233,119	$ -
2058	5,633,335	367,391	5,265,943	1,176,659	1,176,659	$ -
2059	5,265,943	367,391	4,898,552	1,120,198	1,120,198	$ -
2060	4,898,552	367,391	4,531,161	1,063,738	1,063,738	$ -
2061	4,531,161	367,391	4,163,769	1,007,277	1,007,277	$ -
2062	4,163,769	367,391	3,796,378	950,817	950,817	$ -
2063	3,796,378	367,391	3,428,986	894,356	894,356	$ -
2064	3,428,986	367,391	3,061,595	837,896	837,896	$ -
2065	3,061,595	367,391	2,694,204	781,435	781,435	$ -
2066	2,694,204	367,391	2,326,812	724,975	724,975	$ -
2067	2,326,812	367,391	1,959,421	668,514	668,514	$ -
2068	1,959,421	367,391	1,592,029	612,054	612,054	$ -
2069	1,592,029	367,391	1,224,638	555,593	555,593	$ -
2070	1,224,638	367,391	857,247	499,133	499,133	$ -
2071	857,247	367,391	489,855	442,672	442,672	$ -
2072	489,855	367,391	122,464	386,212	386,212	$ -
Project Totals		21,921,020		122,985,308	122,985,308	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		**RTEP Projected Rev. Req't.From Prior Year Template with Incentives ****		
$ 1,301,059		$ 1,301,059		
$ 3,243,481		$ 3,243,481		

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b1659.14 (Fort Wayne - Marion: Relocate 138 kV line due to new 765 kV build into Sorenson)**

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

Details			
Investment	-	Current Year	2015
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

Page 6 of 9

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

A. Base Plan Facilities

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

Current Projected Year ARR	**133,078**
Current Projected Year ARR w/ Incentive	**133,078**
Current Projected Year Incentive ARR	**-**

Project Description: **RTEP ID: b2048 (Tanners Creek - Support for Transformer A/B Replacement)**

Details			
Investment	805,441	Current Year	**2015**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	13,424

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	805,441	-	805,441	123,780	123,780	$ -	$ -		$ -		
2014	805,441	13,424	792,017	135,141	135,141	$ -	$ 139,756		$ 139,756		
2015	792,017	13,424	778,593	133,078	133,078	$ -					
2016	778,593	13,424	765,169	131,015	131,015	$ -					
2017	765,169	13,424	751,745	128,952	128,952	$ -					
2018	751,745	13,424	738,321	126,889	126,889	$ -					
2019	738,321	13,424	724,897	124,826	124,826	$ -					
2020	724,897	13,424	711,473	122,763	122,763	$ -					
2021	711,473	13,424	698,049	120,700	120,700	$ -					
2022	698,049	13,424	684,625	118,637	118,637	$ -					
2023	684,625	13,424	671,201	116,574	116,574	$ -					
2024	671,201	13,424	657,777	114,511	114,511	$ -					
2025	657,777	13,424	644,353	112,448	112,448	$ -					
2026	644,353	13,424	630,929	110,385	110,385	$ -					
2027	630,929	13,424	617,505	108,322	108,322	$ -					
2028	617,505	13,424	604,081	106,259	106,259	$ -					
2029	604,081	13,424	590,657	104,196	104,196	$ -					
2030	590,657	13,424	577,233	102,133	102,133	$ -					
2031	577,233	13,424	563,809	100,070	100,070	$ -					
2032	563,809	13,424	550,385	98,007	98,007	$ -					
2033	550,385	13,424	536,961	95,944	95,944	$ -					
2034	536,961	13,424	523,537	93,881	93,881	$ -					
2035	523,537	13,424	510,113	91,818	91,818	$ -					
2036	510,113	13,424	496,689	89,755	89,755	$ -					
2037	496,689	13,424	483,265	87,692	87,692	$ -					
2038	483,265	13,424	469,841	85,629	85,629	$ -					
2039	469,841	13,424	456,417	83,566	83,566	$ -					
2040	456,417	13,424	442,993	81,503	81,503	$ -					
2041	442,993	13,424	429,569	79,440	79,440	$ -					
2042	429,569	13,424	416,145	77,377	77,377	$ -					
2043	416,145	13,424	402,720	75,314	75,314	$ -					
2044	402,720	13,424	389,296	73,251	73,251	$ -					
2045	389,296	13,424	375,872	71,188	71,188	$ -					
2046	375,872	13,424	362,448	69,125	69,125	$ -					
2047	362,448	13,424	349,024	67,062	67,062	$ -					
2048	349,024	13,424	335,600	64,999	64,999	$ -					
2049	335,600	13,424	322,176	62,936	62,936	$ -					
2050	322,176	13,424	308,752	60,873	60,873	$ -					
2051	308,752	13,424	295,328	58,810	58,810	$ -					
2052	295,328	13,424	281,904	56,747	56,747	$ -					
2053	281,904	13,424	268,480	54,684	54,684	$ -					
2054	268,480	13,424	255,056	52,621	52,621	$ -					
2055	255,056	13,424	241,632	50,558	50,558	$ -					
2056	241,632	13,424	228,208	48,495	48,495	$ -					
2057	228,208	13,424	214,784	46,432	46,432	$ -					
2058	214,784	13,424	201,360	44,369	44,369	$ -					
2059	201,360	13,424	187,936	42,306	42,306	$ -					
2060	187,936	13,424	174,512	40,243	40,243	$ -					
2061	174,512	13,424	161,088	38,180	38,180	$ -					
2062	161,088	13,424	147,664	36,117	36,117	$ -					
2063	147,664	13,424	134,240	34,054	34,054	$ -					
2064	134,240	13,424	120,816	31,991	31,991	$ -					
2065	120,816	13,424	107,392	29,928	29,928	$ -					
2066	107,392	13,424	93,968	27,865	27,865	$ -					
2067	93,968	13,424	80,544	25,802	25,802	$ -					
2068	80,544	13,424	67,120	23,739	23,739	$ -					
2069	67,120	13,424	53,696	21,676	21,676	$ -					
2070	53,696	13,424	40,272	19,613	19,613	$ -					
2071	40,272	13,424	26,848	17,550	17,550	$ -					
2072	26,848	13,424	13,424	15,487	15,487	$ -					
Project Totals		792,017		4,567,298	4,567,298	-					

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Current Projected Year ARR	**248,467**
Current Projected Year ARR w/ Incentive	**248,467**
Current Projected Year Incentive ARR	**-**

Project Description: **RTEP ID: b1818 (Expand the Allen station by installing a second 345/138 kV transformer and adding four exits by cutting in the Lincoln-Sterling and Timber Switch -Milan 138 kV double circuit tower line)**

Details			
Investment	1,616,790	Current Year	2015
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	26,947

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2015	1,616,790	-	1,616,790	248,467	248,467	$ -
2016	1,616,790	26,947	1,589,844	271,273	271,273	$ -
2017	1,589,844	26,947	1,562,897	267,132	267,132	$ -
2018	1,562,897	26,947	1,535,951	262,990	262,990	$ -
2019	1,535,951	26,947	1,509,004	258,849	258,849	$ -
2020	1,509,004	26,947	1,482,058	254,708	254,708	$ -
2021	1,482,058	26,947	1,455,111	250,567	250,567	$ -
2022	1,455,111	26,947	1,428,165	246,426	246,426	$ -
2023	1,428,165	26,947	1,401,218	242,285	242,285	$ -
2024	1,401,218	26,947	1,374,272	238,144	238,144	$ -
2025	1,374,272	26,947	1,347,325	234,003	234,003	$ -
2026	1,347,325	26,947	1,320,379	229,861	229,861	$ -
2027	1,320,379	26,947	1,293,432	225,720	225,720	$ -
2028	1,293,432	26,947	1,266,486	221,579	221,579	$ -
2029	1,266,486	26,947	1,239,539	217,438	217,438	$ -
2030	1,239,539	26,947	1,212,593	213,297	213,297	$ -
2031	1,212,593	26,947	1,185,646	209,156	209,156	$ -
2032	1,185,646	26,947	1,158,700	205,015	205,015	$ -
2033	1,158,700	26,947	1,131,753	200,874	200,874	$ -
2034	1,131,753	26,947	1,104,807	196,733	196,733	$ -
2035	1,104,807	26,947	1,077,860	192,591	192,591	$ -
2036	1,077,860	26,947	1,050,914	188,450	188,450	$ -
2037	1,050,914	26,947	1,023,967	184,309	184,309	$ -
2038	1,023,967	26,947	997,021	180,168	180,168	$ -
2039	997,021	26,947	970,074	176,027	176,027	$ -
2040	970,074	26,947	943,128	171,886	171,886	$ -
2041	943,128	26,947	916,181	167,745	167,745	$ -
2042	916,181	26,947	889,235	163,604	163,604	$ -
2043	889,235	26,947	862,288	159,462	159,462	$ -
2044	862,288	26,947	835,342	155,321	155,321	$ -
2045	835,342	26,947	808,395	151,180	151,180	$ -
2046	808,395	26,947	781,449	147,039	147,039	$ -
2047	781,449	26,947	754,502	142,898	142,898	$ -
2048	754,502	26,947	727,556	138,757	138,757	$ -
2049	727,556	26,947	700,609	134,616	134,616	$ -
2050	700,609	26,947	673,663	130,475	130,475	$ -
2051	673,663	26,947	646,716	126,333	126,333	$ -
2052	646,716	26,947	619,770	122,192	122,192	$ -
2053	619,770	26,947	592,823	118,051	118,051	$ -
2054	592,823	26,947	565,877	113,910	113,910	$ -
2055	565,877	26,947	538,930	109,769	109,769	$ -
2056	538,930	26,947	511,984	105,628	105,628	$ -
2057	511,984	26,947	485,037	101,487	101,487	$ -
2058	485,037	26,947	458,091	97,346	97,346	$ -
2059	458,091	26,947	431,144	93,204	93,204	$ -
2060	431,144	26,947	404,198	89,063	89,063	$ -
2061	404,198	26,947	377,251	84,922	84,922	$ -
2062	377,251	26,947	350,305	80,781	80,781	$ -
2063	350,305	26,947	323,358	76,640	76,640	$ -
2064	323,358	26,947	296,412	72,499	72,499	$ -
2065	296,412	26,947	269,465	68,358	68,358	$ -
2066	269,465	26,947	242,519	64,217	64,217	$ -
2067	242,519	26,947	215,572	60,075	60,075	$ -
2068	215,572	26,947	188,626	55,934	55,934	$ -
2069	188,626	26,947	161,679	51,793	51,793	$ -
2070	161,679	26,947	134,733	47,652	47,652	$ -
2071	134,733	26,947	107,786	43,511	43,511	$ -
2072	107,786	26,947	80,840	39,370	39,370	$ -
2073	80,840	26,947	53,893	35,229	35,229	$ -
2074	53,893	26,947	26,947	31,088	31,088	$ -
Project Totals		1,589,844		9,168,097	9,168,097	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Current Projected Year ARR	**35,564**
Current Projected Year ARR w/ Incentive	**35,564**
Current Projected Year Incentive ARR	**-**

Project Description: **RTEP ID: b1819 (Rebuild the Robinson Park-Sorneson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV)**

Details			
Investment	231,416	Current Year	2015
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	3,857

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2015	231,416	-	231,416	35,564	35,564	$ -
2016	231,416	3,857	227,559	38,828	38,828	$ -
2017	227,559	3,857	223,702	38,235	38,235	$ -
2018	223,702	3,857	219,845	37,643	37,643	$ -
2019	219,845	3,857	215,988	37,050	37,050	$ -
2020	215,988	3,857	212,131	36,457	36,457	$ -
2021	212,131	3,857	208,274	35,864	35,864	$ -
2022	208,274	3,857	204,417	35,272	35,272	$ -
2023	204,417	3,857	200,561	34,679	34,679	$ -
2024	200,561	3,857	196,704	34,086	34,086	$ -
2025	196,704	3,857	192,847	33,493	33,493	$ -
2026	192,847	3,857	188,990	32,901	32,901	$ -
2027	188,990	3,857	185,133	32,308	32,308	$ -
2028	185,133	3,857	181,276	31,715	31,715	$ -
2029	181,276	3,857	177,419	31,123	31,123	$ -
2030	177,419	3,857	173,562	30,530	30,530	$ -
2031	173,562	3,857	169,705	29,937	29,937	$ -
2032	169,705	3,857	165,848	29,344	29,344	$ -
2033	165,848	3,857	161,991	28,752	28,752	$ -
2034	161,991	3,857	158,134	28,159	28,159	$ -
2035	158,134	3,857	154,277	27,566	27,566	$ -
2036	154,277	3,857	150,420	26,973	26,973	$ -
2037	150,420	3,857	146,563	26,381	26,381	$ -
2038	146,563	3,857	142,707	25,788	25,788	$ -
2039	142,707	3,857	138,850	25,195	25,195	$ -
2040	138,850	3,857	134,993	24,603	24,603	$ -
2041	134,993	3,857	131,136	24,010	24,010	$ -
2042	131,136	3,857	127,279	23,417	23,417	$ -
2043	127,279	3,857	123,422	22,824	22,824	$ -
2044	123,422	3,857	119,565	22,232	22,232	$ -
2045	119,565	3,857	115,708	21,639	21,639	$ -
2046	115,708	3,857	111,851	21,046	21,046	$ -
2047	111,851	3,857	107,994	20,453	20,453	$ -
2048	107,994	3,857	104,137	19,861	19,861	$ -
2049	104,137	3,857	100,280	19,268	19,268	$ -
2050	100,280	3,857	96,423	18,675	18,675	$ -
2051	96,423	3,857	92,566	18,082	18,082	$ -
2052	92,566	3,857	88,709	17,490	17,490	$ -
2053	88,709	3,857	84,853	16,897	16,897	$ -
2054	84,853	3,857	80,996	16,304	16,304	$ -
2055	80,996	3,857	77,139	15,712	15,712	$ -
2056	77,139	3,857	73,282	15,119	15,119	$ -
2057	73,282	3,857	69,425	14,526	14,526	$ -
2058	69,425	3,857	65,568	13,933	13,933	$ -
2059	65,568	3,857	61,711	13,341	13,341	$ -
2060	61,711	3,857	57,854	12,748	12,748	$ -
2061	57,854	3,857	53,997	12,155	12,155	$ -
2062	53,997	3,857	50,140	11,562	11,562	$ -
2063	50,140	3,857	46,283	10,970	10,970	$ -
2064	46,283	3,857	42,426	10,377	10,377	$ -
2065	42,426	3,857	38,569	9,784	9,784	$ -
2066	38,569	3,857	34,712	9,192	9,192	$ -
2067	34,712	3,857	30,855	8,599	8,599	$ -
2068	30,855	3,857	26,999	8,006	8,006	$ -
2069	26,999	3,857	23,142	7,413	7,413	$ -
2070	23,142	3,857	19,285	6,821	6,821	$ -
2071	19,285	3,857	15,428	6,228	6,228	$ -
2072	15,428	3,857	11,571	5,635	5,635	$ -
2073	11,571	3,857	7,714	5,042	5,042	$ -
2074	7,714	3,857	3,857	4,450	4,450	$ -
Project Totals		227,559		1,312,257	1,312,257	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

I & M Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b1465.4 (Make switching improvements at Sullivan and Jefferson 765 kV stations)**

Current Projected Year ARR	**169,845**
Current Projected Year ARR w/ Incentive	**169,845**
Current Projected Year Incentive ARR	**-**

Details			
Investment	1,049,025	Current Year	**2015**
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	5	FCR w/o incentives, less depreciation	15.37%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.37%
CIAC (Yes or No)	No	Annual Depreciation Expense	17,484

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2015	1,049,025	10,199	1,038,826	169,845	169,845	$ -
2016	1,038,826	17,484	1,021,342	174,443	174,443	$ -
2017	1,021,342	17,484	1,003,859	171,756	171,756	$ -
2018	1,003,859	17,484	986,375	169,069	169,069	$ -
2019	986,375	17,484	968,891	166,382	166,382	$ -
2020	968,891	17,484	951,407	163,695	163,695	$ -
2021	951,407	17,484	933,924	161,009	161,009	$ -
2022	933,924	17,484	916,440	158,322	158,322	$ -
2023	916,440	17,484	898,956	155,635	155,635	$ -
2024	898,956	17,484	881,472	152,948	152,948	$ -
2025	881,472	17,484	863,989	150,261	150,261	$ -
2026	863,989	17,484	846,505	147,574	147,574	$ -
2027	846,505	17,484	829,021	144,887	144,887	$ -
2028	829,021	17,484	811,537	142,200	142,200	$ -
2029	811,537	17,484	794,054	139,513	139,513	$ -
2030	794,054	17,484	776,570	136,827	136,827	$ -
2031	776,570	17,484	759,086	134,140	134,140	$ -
2032	759,086	17,484	741,602	131,453	131,453	$ -
2033	741,602	17,484	724,119	128,766	128,766	$ -
2034	724,119	17,484	706,635	126,079	126,079	$ -
2035	706,635	17,484	689,151	123,392	123,392	$ -
2036	689,151	17,484	671,667	120,705	120,705	$ -
2037	671,667	17,484	654,184	118,018	118,018	$ -
2038	654,184	17,484	636,700	115,331	115,331	$ -
2039	636,700	17,484	619,216	112,645	112,645	$ -
2040	619,216	17,484	601,732	109,958	109,958	$ -
2041	601,732	17,484	584,249	107,271	107,271	$ -
2042	584,249	17,484	566,765	104,584	104,584	$ -
2043	566,765	17,484	549,281	101,897	101,897	$ -
2044	549,281	17,484	531,797	99,210	99,210	$ -
2045	531,797	17,484	514,314	96,523	96,523	$ -
2046	514,314	17,484	496,830	93,836	93,836	$ -
2047	496,830	17,484	479,346	91,149	91,149	$ -
2048	479,346	17,484	461,862	88,462	88,462	$ -
2049	461,862	17,484	444,379	85,776	85,776	$ -
2050	444,379	17,484	426,895	83,089	83,089	$ -
2051	426,895	17,484	409,411	80,402	80,402	$ -
2052	409,411	17,484	391,927	77,715	77,715	$ -
2053	391,927	17,484	374,444	75,028	75,028	$ -
2054	374,444	17,484	356,960	72,341	72,341	$ -
2055	356,960	17,484	339,476	69,654	69,654	$ -
2056	339,476	17,484	321,992	66,967	66,967	$ -
2057	321,992	17,484	304,509	64,280	64,280	$ -
2058	304,509	17,484	287,025	61,594	61,594	$ -
2059	287,025	17,484	269,541	58,907	58,907	$ -
2060	269,541	17,484	252,057	56,220	56,220	$ -
2061	252,057	17,484	234,574	53,533	53,533	$ -
2062	234,574	17,484	217,090	50,846	50,846	$ -
2063	217,090	17,484	199,606	48,159	48,159	$ -
2064	199,606	17,484	182,122	45,472	45,472	$ -
2065	182,122	17,484	164,639	42,785	42,785	$ -
2066	164,639	17,484	147,155	40,098	40,098	$ -
2067	147,155	17,484	129,671	37,412	37,412	$ -
2068	129,671	17,484	112,187	34,725	34,725	$ -
2069	112,187	17,484	94,704	32,038	32,038	$ -
2070	94,704	17,484	77,220	29,351	29,351	$ -
2071	77,220	17,484	59,736	26,664	26,664	$ -
2072	59,736	17,484	42,252	23,977	23,977	$ -
2073	42,252	17,484	24,769	21,290	21,290	$ -
2074	24,769	17,484	7,285	18,603	18,603	$ -
Project Totals		1,041,740		5,864,712	5,864,712	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

AEP East Companies
Cost of Service Formula Rate Using 2014 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, ln 164)	11.49%	
Project ROE Incentive Adder	0	<==ROE Adder Cannot Exceed 100 Basis Points
ROE with additional 0 basis point incentive	11.49%	**<== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012**

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

	%	Cost	Weighted cost
Long Term Debt	44.95%	5.83%	2.619%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	55.05%	11.49%	6.325%
		R =	8.944%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS

	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2014			
As Projected in Prior Year WS J	$ 4,959,187	$ 4,959,187	$ -
Actual after True-up	$ 5,233,462	$ 5,233,462	$ -
True-up of ARR For 2014	274,275	274,275	-

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

Rate Base (True-Up TCOS, ln 78)	581,406,221
R (from A. above)	8.944%
Return (Rate Base x R)	52,002,818

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

Return (from B. above)	52,002,818
Effective Tax Rate (True-Up TCOS, ln 126)	44.79%
Income Tax Calculation (Return x CIT)	23,292,897
ITC Adjustment	(1,565,551)
Income Taxes	21,727,346

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

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

Annual Revenue Requirement (True-Up TCOS, ln 1)	136,055,527
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	52,002,818
Income Taxes (True-Up TCOS, ln 133)	21,727,346
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	62,325,363

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	62,325,363
Return (from I.B. above)	52,002,818
Income Taxes (from I.C. above)	21,727,346
Annual Revenue Requirement, with 0 Basis Point ROE increase	136,055,527
Depreciation (True-Up TCOS, ln 111)	21,861,374
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	114,194,153

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

Net Transmission Plant (True-Up TCOS, ln 48)	734,252,448
Annual Revenue Requirement, with 0 Basis Point ROE increase	136,055,527
FCR with 0 Basis Point increase in ROE	18.53%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	114,194,153
FCR with 0 Basis Point ROE increase, less Depreciation	15.55%
FCR less Depreciation (True-Up TCOS, ln 9)	15.55%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, ln 58,(b)):	1,320,667,751
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	1,374,861,654
Subtotal	2,695,529,405
Average Transmission Plant Balance for	1,347,764,703
Annual Depreciation Rate (True-Up TCOS, ln 111)	22,629,420
Composite Depreciation Rate	1.68%
Depreciable Life for Composite Depreciation Rate	59.56
Round to nearest whole year	60

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

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

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**1,249,385**	**1,249,385**	-
Prior Yr True-Up	**1,324,291**	**1,324,291**	-
True-Up Adjustment	**74,906**	**74,906**	**-**

Details			
Investment	8,316,810	Current Year	**2014**
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	138,614

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2009	8,316,810	69,307	8,247,503	8,282,157	1,357,384	1,357,384	$ -	$ -	$ -	$ -	$ -	$ -
2010	8,247,503	138,614	8,108,890	8,178,197	1,410,522	1,410,522	$ -	$ 1,408,114	$ 2,408	$ 1,408,114	$ 2,408	$ -
2011	8,108,890	138,614	7,970,276	8,039,583	1,388,965	1,388,965	$ -	$ 1,487,355	$ (98,390)	$ 1,487,355	$ (98,390)	$ -
2012	7,970,276	138,614	7,831,663	7,900,970	1,367,407	1,367,407	$ -	$ 1,319,695	$ 47,712	$ 1,319,695	$ 47,712	$ -
2013	7,831,663	138,614	7,693,049	7,762,356	1,345,849	1,345,849	$ -	$ 1,272,484	$ 73,365	$ 1,272,484	$ 73,365	$ -
2014	7,693,049	138,614	7,554,436	7,623,743	1,324,291	1,324,291	$ -	$ 1,249,385	$ 74,906	$ 1,249,385	$ 74,906	$ -
2015	7,554,436	138,614	7,415,822	7,485,129	1,302,734	1,302,734	$ -		$ -		$ -	$ -
2016	7,415,822	138,614	7,277,209	7,346,516	1,281,176	1,281,176	$ -		$ -		$ -	$ -
2017	7,277,209	138,614	7,138,595	7,207,902	1,259,618	1,259,618	$ -		$ -		$ -	$ -
2018	7,138,595	138,614	6,999,982	7,069,289	1,238,060	1,238,060	$ -		$ -		$ -	$ -
2019	6,999,982	138,614	6,861,368	6,930,675	1,216,502	1,216,502	$ -		$ -		$ -	$ -
2020	6,861,368	138,614	6,722,755	6,792,062	1,194,945	1,194,945	$ -		$ -		$ -	$ -
2021	6,722,755	138,614	6,584,141	6,653,448	1,173,387	1,173,387	$ -		$ -		$ -	$ -
2022	6,584,141	138,614	6,445,528	6,514,835	1,151,829	1,151,829	$ -		$ -		$ -	$ -
2023	6,445,528	138,614	6,306,914	6,376,221	1,130,271	1,130,271	$ -		$ -		$ -	$ -
2024	6,306,914	138,614	6,168,301	6,237,608	1,108,714	1,108,714	$ -		$ -		$ -	$ -
2025	6,168,301	138,614	6,029,687	6,098,994	1,087,156	1,087,156	$ -		$ -		$ -	$ -
2026	6,029,687	138,614	5,891,074	5,960,381	1,065,598	1,065,598	$ -		$ -		$ -	$ -
2027	5,891,074	138,614	5,752,460	5,821,767	1,044,040	1,044,040	$ -		$ -		$ -	$ -
2028	5,752,460	138,614	5,613,847	5,683,154	1,022,482	1,022,482	$ -		$ -		$ -	$ -
2029	5,613,847	138,614	5,475,233	5,544,540	1,000,925	1,000,925	$ -		$ -		$ -	$ -
2030	5,475,233	138,614	5,336,620	5,405,927	979,367	979,367	$ -		$ -		$ -	$ -
2031	5,336,620	138,614	5,198,006	5,267,313	957,809	957,809	$ -		$ -		$ -	$ -
2032	5,198,006	138,614	5,059,393	5,128,700	936,251	936,251	$ -		$ -		$ -	$ -
2033	5,059,393	138,614	4,920,779	4,990,086	914,694	914,694	$ -		$ -		$ -	$ -
2034	4,920,779	138,614	4,782,166	4,851,473	893,136	893,136	$ -		$ -		$ -	$ -
2035	4,782,166	138,614	4,643,552	4,712,859	871,578	871,578	$ -		$ -		$ -	$ -
2036	4,643,552	138,614	4,504,939	4,574,246	850,020	850,020	$ -		$ -		$ -	$ -
2037	4,504,939	138,614	4,366,325	4,435,632	828,462	828,462	$ -		$ -		$ -	$ -
2038	4,366,325	138,614	4,227,712	4,297,019	806,905	806,905	$ -		$ -		$ -	$ -
2039	4,227,712	138,614	4,089,098	4,158,405	785,347	785,347	$ -		$ -		$ -	$ -
2040	4,089,098	138,614	3,950,485	4,019,792	763,789	763,789	$ -		$ -		$ -	$ -
2041	3,950,485	138,614	3,811,871	3,881,178	742,231	742,231	$ -		$ -		$ -	$ -
2042	3,811,871	138,614	3,673,258	3,742,565	720,674	720,674	$ -		$ -		$ -	$ -
2043	3,673,258	138,614	3,534,644	3,603,951	699,116	699,116	$ -		$ -		$ -	$ -
2044	3,534,644	138,614	3,396,031	3,465,338	677,558	677,558	$ -		$ -		$ -	$ -
2045	3,396,031	138,614	3,257,417	3,326,724	656,000	656,000	$ -		$ -		$ -	$ -
2046	3,257,417	138,614	3,118,804	3,188,111	634,442	634,442	$ -		$ -		$ -	$ -
2047	3,118,804	138,614	2,980,190	3,049,497	612,885	612,885	$ -		$ -		$ -	$ -
2048	2,980,190	138,614	2,841,577	2,910,884	591,327	591,327	$ -		$ -		$ -	$ -
2049	2,841,577	138,614	2,702,963	2,772,270	569,769	569,769	$ -		$ -		$ -	$ -
2050	2,702,963	138,614	2,564,350	2,633,657	548,211	548,211	$ -		$ -		$ -	$ -
2051	2,564,350	138,614	2,425,736	2,495,043	526,654	526,654	$ -		$ -		$ -	$ -
2052	2,425,736	138,614	2,287,123	2,356,430	505,096	505,096	$ -		$ -		$ -	$ -
2053	2,287,123	138,614	2,148,509	2,217,816	483,538	483,538	$ -		$ -		$ -	$ -
2054	2,148,509	138,614	2,009,896	2,079,203	461,980	461,980	$ -		$ -		$ -	$ -
2055	2,009,896	138,614	1,871,282	1,940,589	440,422	440,422	$ -		$ -		$ -	$ -
2056	1,871,282	138,614	1,732,669	1,801,976	418,865	418,865	$ -		$ -		$ -	$ -
2057	1,732,669	138,614	1,594,055	1,663,362	397,307	397,307	$ -		$ -		$ -	$ -
2058	1,594,055	138,614	1,455,442	1,524,749	375,749	375,749	$ -		$ -		$ -	$ -
2059	1,455,442	138,614	1,316,828	1,386,135	354,191	354,191	$ -		$ -		$ -	$ -
2060	1,316,828	138,614	1,178,215	1,247,522	332,634	332,634	$ -		$ -		$ -	$ -
2061	1,178,215	138,614	1,039,601	1,108,908	311,076	311,076	$ -		$ -		$ -	$ -
2062	1,039,601	138,614	900,988	970,295	289,518	289,518	$ -		$ -		$ -	$ -
2063	900,988	138,614	762,374	831,681	267,960	267,960	$ -		$ -		$ -	$ -
2064	762,374	138,614	623,761	693,068	246,402	246,402	$ -		$ -		$ -	$ -
2065	623,761	138,614	485,147	554,454	224,845	224,845	$ -		$ -		$ -	$ -
2066	485,147	138,614	346,534	415,841	203,287	203,287	$ -		$ -		$ -	$ -
2067	346,534	138,614	207,920	277,227	181,729	181,729	$ -		$ -		$ -	$ -
2068	207,920	138,614	69,307	138,614	160,171	160,171	$ -		$ -		$ -	$ -
Project Totals		8,247,503			47,692,847	47,692,847	-					

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

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

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

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

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**87,393**	**87,393**	-
Prior Yr True-Up	**90,480**	**90,480**	-
True-Up Adjustment	**3,087**	**3,087**	**-**

Details			
Investment	533,495	Current Year	**2014**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	8,892

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2013	533,495	4,446	529,049	531,272	87,072	87,072	$ -	$ 92,625	$ (5,553)	$ 92,625	$ (5,553)	$ -
2014	529,049	8,892	520,158	524,603	90,480	90,480	$ -	$ 87,393	$ 3,087	$ 87,393	$ 3,087	$ -
2015	520,158	8,892	511,266	515,712	89,097	89,097	$ -		$ -		$ -	$ -
2016	511,266	8,892	502,374	506,820	87,714	87,714	$ -		$ -		$ -	$ -
2017	502,374	8,892	493,483	497,929	86,332	86,332	$ -		$ -		$ -	$ -
2018	493,483	8,892	484,591	489,037	84,949	84,949	$ -		$ -		$ -	$ -
2019	484,591	8,892	475,700	480,146	83,566	83,566	$ -		$ -		$ -	$ -
2020	475,700	8,892	466,808	471,254	82,183	82,183	$ -		$ -		$ -	$ -
2021	466,808	8,892	457,917	462,362	80,800	80,800	$ -		$ -		$ -	$ -
2022	457,917	8,892	449,025	453,471	79,417	79,417	$ -		$ -		$ -	$ -
2023	449,025	8,892	440,133	444,579	78,034	78,034	$ -		$ -		$ -	$ -
2024	440,133	8,892	431,242	435,688	76,652	76,652	$ -		$ -		$ -	$ -
2025	431,242	8,892	422,350	426,796	75,269	75,269	$ -		$ -		$ -	$ -
2026	422,350	8,892	413,459	417,904	73,886	73,886	$ -		$ -		$ -	$ -
2027	413,459	8,892	404,567	409,013	72,503	72,503	$ -		$ -		$ -	$ -
2028	404,567	8,892	395,675	400,121	71,120	71,120	$ -		$ -		$ -	$ -
2029	395,675	8,892	386,784	391,230	69,737	69,737	$ -		$ -		$ -	$ -
2030	386,784	8,892	377,892	382,338	68,354	68,354	$ -		$ -		$ -	$ -
2031	377,892	8,892	369,001	373,447	66,972	66,972	$ -		$ -		$ -	$ -
2032	369,001	8,892	360,109	364,555	65,589	65,589	$ -		$ -		$ -	$ -
2033	360,109	8,892	351,218	355,663	64,206	64,206	$ -		$ -		$ -	$ -
2034	351,218	8,892	342,326	346,772	62,823	62,823	$ -		$ -		$ -	$ -
2035	342,326	8,892	333,434	337,880	61,440	61,440	$ -		$ -		$ -	$ -
2036	333,434	8,892	324,543	328,989	60,057	60,057	$ -		$ -		$ -	$ -
2037	324,543	8,892	315,651	320,097	58,674	58,674	$ -		$ -		$ -	$ -
2038	315,651	8,892	306,760	311,205	57,292	57,292	$ -		$ -		$ -	$ -
2039	306,760	8,892	297,868	302,314	55,909	55,909	$ -		$ -		$ -	$ -
2040	297,868	8,892	288,976	293,422	54,526	54,526	$ -		$ -		$ -	$ -
2041	288,976	8,892	280,085	284,531	53,143	53,143	$ -		$ -		$ -	$ -
2042	280,085	8,892	271,193	275,639	51,760	51,760	$ -		$ -		$ -	$ -
2043	271,193	8,892	262,302	266,748	50,377	50,377	$ -		$ -		$ -	$ -
2044	262,302	8,892	253,410	257,856	48,994	48,994	$ -		$ -		$ -	$ -
2045	253,410	8,892	244,519	248,964	47,612	47,612	$ -		$ -		$ -	$ -
2046	244,519	8,892	235,627	240,073	46,229	46,229	$ -		$ -		$ -	$ -
2047	235,627	8,892	226,735	231,181	44,846	44,846	$ -		$ -		$ -	$ -
2048	226,735	8,892	217,844	222,290	43,463	43,463	$ -		$ -		$ -	$ -
2049	217,844	8,892	208,952	213,398	42,080	42,080	$ -		$ -		$ -	$ -
2050	208,952	8,892	200,061	204,506	40,697	40,697	$ -		$ -		$ -	$ -
2051	200,061	8,892	191,169	195,615	39,314	39,314	$ -		$ -		$ -	$ -
2052	191,169	8,892	182,277	186,723	37,932	37,932	$ -		$ -		$ -	$ -
2053	182,277	8,892	173,386	177,832	36,549	36,549	$ -		$ -		$ -	$ -
2054	173,386	8,892	164,494	168,940	35,166	35,166	$ -		$ -		$ -	$ -
2055	164,494	8,892	155,603	160,049	33,783	33,783	$ -		$ -		$ -	$ -
2056	155,603	8,892	146,711	151,157	32,400	32,400	$ -		$ -		$ -	$ -
2057	146,711	8,892	137,820	142,265	31,017	31,017	$ -		$ -		$ -	$ -
2058	137,820	8,892	128,928	133,374	29,634	29,634	$ -		$ -		$ -	$ -
2059	128,928	8,892	120,036	124,482	28,252	28,252	$ -		$ -		$ -	$ -
2060	120,036	8,892	111,145	115,591	26,869	26,869	$ -		$ -		$ -	$ -
2061	111,145	8,892	102,253	106,699	25,486	25,486	$ -		$ -		$ -	$ -
2062	102,253	8,892	93,362	97,807	24,103	24,103	$ -		$ -		$ -	$ -
2063	93,362	8,892	84,470	88,916	22,720	22,720	$ -		$ -		$ -	$ -
2064	84,470	8,892	75,578	80,024	21,337	21,337	$ -		$ -		$ -	$ -
2065	75,578	8,892	66,687	71,133	19,954	19,954	$ -		$ -		$ -	$ -
2066	66,687	8,892	57,795	62,241	18,572	18,572	$ -		$ -		$ -	$ -
2067	57,795	8,892	48,904	53,350	17,189	17,189	$ -		$ -		$ -	$ -
2068	48,904	8,892	40,012	44,458	15,806	15,806	$ -		$ -		$ -	$ -
2069	40,012	8,892	31,121	35,566	14,423	14,423	$ -		$ -		$ -	$ -
2070	31,121	8,892	22,229	26,675	13,040	13,040	$ -		$ -		$ -	$ -
2071	22,229	8,892	13,337	17,783	11,657	11,657	$ -		$ -		$ -	$ -
2072	13,337	8,892	4,446	8,892	10,274	10,274	$ -		$ -		$ -	$ -
Project Totals		529,049			3,059,334	3,059,334	-					

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

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

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

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

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**3,243,481**	**3,243,481**	-
Prior Yr True-Up	**3,681,045**	**3,681,045**	-
True-Up Adjustment	**437,564**	**437,564**	**-**

Details			
Investment	21,759,833	Current Year	**2014**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	362,664

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	21,759,833	241,776	21,518,057	21,638,945	3,607,159	3,607,159	$ -
2014	21,518,057	362,664	21,155,393	21,336,725	3,681,045	3,681,045	$ -
2015	21,155,393	362,664	20,792,729	20,974,061	3,624,642	3,624,642	$ -
2016	20,792,729	362,664	20,430,065	20,611,397	3,568,239	3,568,239	$ -
2017	20,430,065	362,664	20,067,402	20,248,733	3,511,836	3,511,836	$ -
2018	20,067,402	362,664	19,704,738	19,886,070	3,455,432	3,455,432	$ -
2019	19,704,738	362,664	19,342,074	19,523,406	3,399,029	3,399,029	$ -
2020	19,342,074	362,664	18,979,410	19,160,742	3,342,626	3,342,626	$ -
2021	18,979,410	362,664	18,616,746	18,798,078	3,286,223	3,286,223	$ -
2022	18,616,746	362,664	18,254,082	18,435,414	3,229,820	3,229,820	$ -
2023	18,254,082	362,664	17,891,418	18,072,750	3,173,417	3,173,417	$ -
2024	17,891,418	362,664	17,528,754	17,710,086	3,117,014	3,117,014	$ -
2025	17,528,754	362,664	17,166,090	17,347,422	3,060,611	3,060,611	$ -
2026	17,166,090	362,664	16,803,427	16,984,759	3,004,208	3,004,208	$ -
2027	16,803,427	362,664	16,440,763	16,622,095	2,947,805	2,947,805	$ -
2028	16,440,763	362,664	16,078,099	16,259,431	2,891,402	2,891,402	$ -
2029	16,078,099	362,664	15,715,435	15,896,767	2,834,999	2,834,999	$ -
2030	15,715,435	362,664	15,352,771	15,534,103	2,778,596	2,778,596	$ -
2031	15,352,771	362,664	14,990,107	15,171,439	2,722,192	2,722,192	$ -
2032	14,990,107	362,664	14,627,443	14,808,775	2,665,789	2,665,789	$ -
2033	14,627,443	362,664	14,264,779	14,446,111	2,609,386	2,609,386	$ -
2034	14,264,779	362,664	13,902,116	14,083,447	2,552,983	2,552,983	$ -
2035	13,902,116	362,664	13,539,452	13,720,784	2,496,580	2,496,580	$ -
2036	13,539,452	362,664	13,176,788	13,358,120	2,440,177	2,440,177	$ -
2037	13,176,788	362,664	12,814,124	12,995,456	2,383,774	2,383,774	$ -
2038	12,814,124	362,664	12,451,460	12,632,792	2,327,371	2,327,371	$ -
2039	12,451,460	362,664	12,088,796	12,270,128	2,270,968	2,270,968	$ -
2040	12,088,796	362,664	11,726,132	11,907,464	2,214,565	2,214,565	$ -
2041	11,726,132	362,664	11,363,468	11,544,800	2,158,162	2,158,162	$ -
2042	11,363,468	362,664	11,000,804	11,182,136	2,101,759	2,101,759	$ -
2043	11,000,804	362,664	10,638,141	10,819,473	2,045,356	2,045,356	$ -
2044	10,638,141	362,664	10,275,477	10,456,809	1,988,953	1,988,953	$ -
2045	10,275,477	362,664	9,912,813	10,094,145	1,932,549	1,932,549	$ -
2046	9,912,813	362,664	9,550,149	9,731,481	1,876,146	1,876,146	$ -
2047	9,550,149	362,664	9,187,485	9,368,817	1,819,743	1,819,743	$ -
2048	9,187,485	362,664	8,824,821	9,006,153	1,763,340	1,763,340	$ -
2049	8,824,821	362,664	8,462,157	8,643,489	1,706,937	1,706,937	$ -
2050	8,462,157	362,664	8,099,493	8,280,825	1,650,534	1,650,534	$ -
2051	8,099,493	362,664	7,736,830	7,918,161	1,594,131	1,594,131	$ -
2052	7,736,830	362,664	7,374,166	7,555,498	1,537,728	1,537,728	$ -
2053	7,374,166	362,664	7,011,502	7,192,834	1,481,325	1,481,325	$ -
2054	7,011,502	362,664	6,648,838	6,830,170	1,424,922	1,424,922	$ -
2055	6,648,838	362,664	6,286,174	6,467,506	1,368,519	1,368,519	$ -
2056	6,286,174	362,664	5,923,510	6,104,842	1,312,116	1,312,116	$ -
2057	5,923,510	362,664	5,560,846	5,742,178	1,255,713	1,255,713	$ -
2058	5,560,846	362,664	5,198,182	5,379,514	1,199,309	1,199,309	$ -
2059	5,198,182	362,664	4,835,518	5,016,850	1,142,906	1,142,906	$ -
2060	4,835,518	362,664	4,472,855	4,654,187	1,086,503	1,086,503	$ -
2061	4,472,855	362,664	4,110,191	4,291,523	1,030,100	1,030,100	$ -
2062	4,110,191	362,664	3,747,527	3,928,859	973,697	973,697	$ -
2063	3,747,527	362,664	3,384,863	3,566,195	917,294	917,294	$ -
2064	3,384,863	362,664	3,022,199	3,203,531	860,891	860,891	$ -
2065	3,022,199	362,664	2,659,535	2,840,867	804,488	804,488	$ -
2066	2,659,535	362,664	2,296,871	2,478,203	748,085	748,085	$ -
2067	2,296,871	362,664	1,934,207	2,115,539	691,682	691,682	$ -
2068	1,934,207	362,664	1,571,543	1,752,875	635,279	635,279	$ -
2069	1,571,543	362,664	1,208,880	1,390,212	578,876	578,876	$ -
2070	1,208,880	362,664	846,216	1,027,548	522,473	522,473	$ -
2071	846,216	362,664	483,552	664,884	466,070	466,070	$ -
2072	483,552	362,664	120,888	302,220	409,666	409,666	$ -
Project Totals		21,638,945			124,283,139	124,283,139	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
$ 1,301,059	$ 2,306,100	$ 1,301,059	$ 2,306,100	$ -
$ 3,243,481	$ 437,564	$ 3,243,481	$ 437,564	$ -
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** This is the total amount that needs to be reported to PJM for billing to all regions.

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

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b1659.14 (Fort Wayne - Marion: Relocate 138 kV line due to new 765 kV build into Sorenson)**

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**239,172**	**239,172**	-
Prior Yr True-Up	**-**	**-**	-
True-Up Adjustment	**(239,172)**	**(239,172)**	**-**

Details			
Investment	-	Current Year	**2014**
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2014	-	-	-	-	-	-	$ -	$ 239,172	$ (239,172)	$ 239,172	$ (239,172)	$ -
2015	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2016	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2017	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2018	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2019	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2020	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2021	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2022	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2023	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2024	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2025	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2026	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2027	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2028	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2029	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2030	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2031	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2032	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2033	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2034	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2035	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2036	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2037	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2038	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2039	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2040	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2041	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2042	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2043	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2044	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2045	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2046	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2047	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2048	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2049	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2050	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2051	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2052	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2053	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2054	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2055	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2056	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2057	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2058	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2059	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2060	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2061	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2062	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2063	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2069	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2070	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2071	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2072	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2073	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals		-			-	-	-					

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

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

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b2048 (Tanners Creek - Support for Transformer A/B Replacemen)**

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	**139,756**	**139,756**	-
Prior Yr True-Up	**137,646**	**137,646**	-
True-Up Adjustment	**(2,110)**	**(2,110)**	**-**

Details			
Investment	805,441	Current Year	**2014**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	13,424

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Average Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**	**RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives**	**RTEP Rev Req't True-up w/o Incentives**	**RTEP Projected Rev. Req't.From Prior Year WS J with Incentives ****	**RTEP Rev Req't True-up with Incentives ****	**True-up of Incentive with Incentives ****
2013	805,441	-	805,441	805,441	125,266	125,266	$ -	$ 0	$ 125,266	$ 0	$ 125,266	$ -
2014	805,441	13,424	792,017	798,729	137,646	137,646	$ -	$ 139,756	$ (2,110)	$ 139,756	$ (2,110)	$ -
2015	792,017	13,424	778,593	785,305	135,558	135,558	$ -		$ -		$ -	$ -
2016	778,593	13,424	765,169	771,881	133,470	133,470	$ -		$ -		$ -	$ -
2017	765,169	13,424	751,745	758,457	131,383	131,383	$ -		$ -		$ -	$ -
2018	751,745	13,424	738,321	745,033	129,295	129,295	$ -		$ -		$ -	$ -
2019	738,321	13,424	724,897	731,609	127,207	127,207	$ -		$ -		$ -	$ -
2020	724,897	13,424	711,473	718,185	125,119	125,119	$ -		$ -		$ -	$ -
2021	711,473	13,424	698,049	704,761	123,032	123,032	$ -		$ -		$ -	$ -
2022	698,049	13,424	684,625	691,337	120,944	120,944	$ -		$ -		$ -	$ -
2023	684,625	13,424	671,201	677,913	118,856	118,856	$ -		$ -		$ -	$ -
2024	671,201	13,424	657,777	664,489	116,768	116,768	$ -		$ -		$ -	$ -
2025	657,777	13,424	644,353	651,065	114,680	114,680	$ -		$ -		$ -	$ -
2026	644,353	13,424	630,929	637,641	112,593	112,593	$ -		$ -		$ -	$ -
2027	630,929	13,424	617,505	624,217	110,505	110,505	$ -		$ -		$ -	$ -
2028	617,505	13,424	604,081	610,793	108,417	108,417	$ -		$ -		$ -	$ -
2029	604,081	13,424	590,657	597,369	106,329	106,329	$ -		$ -		$ -	$ -
2030	590,657	13,424	577,233	583,945	104,242	104,242	$ -		$ -		$ -	$ -
2031	577,233	13,424	563,809	570,521	102,154	102,154	$ -		$ -		$ -	$ -
2032	563,809	13,424	550,385	557,097	100,066	100,066	$ -		$ -		$ -	$ -
2033	550,385	13,424	536,961	543,673	97,978	97,978	$ -		$ -		$ -	$ -
2034	536,961	13,424	523,537	530,249	95,891	95,891	$ -		$ -		$ -	$ -
2035	523,537	13,424	510,113	516,825	93,803	93,803	$ -		$ -		$ -	$ -
2036	510,113	13,424	496,689	503,401	91,715	91,715	$ -		$ -		$ -	$ -
2037	496,689	13,424	483,265	489,977	89,627	89,627	$ -		$ -		$ -	$ -
2038	483,265	13,424	469,841	476,553	87,540	87,540	$ -		$ -		$ -	$ -
2039	469,841	13,424	456,417	463,129	85,452	85,452	$ -		$ -		$ -	$ -
2040	456,417	13,424	442,993	449,705	83,364	83,364	$ -		$ -		$ -	$ -
2041	442,993	13,424	429,569	436,281	81,276	81,276	$ -		$ -		$ -	$ -
2042	429,569	13,424	416,145	422,857	79,189	79,189	$ -		$ -		$ -	$ -
2043	416,145	13,424	402,720	409,433	77,101	77,101	$ -		$ -		$ -	$ -
2044	402,720	13,424	389,296	396,008	75,013	75,013	$ -		$ -		$ -	$ -
2045	389,296	13,424	375,872	382,584	72,925	72,925	$ -		$ -		$ -	$ -
2046	375,872	13,424	362,448	369,160	70,837	70,837	$ -		$ -		$ -	$ -
2047	362,448	13,424	349,024	355,736	68,750	68,750	$ -		$ -		$ -	$ -
2048	349,024	13,424	335,600	342,312	66,662	66,662	$ -		$ -		$ -	$ -
2049	335,600	13,424	322,176	328,888	64,574	64,574	$ -		$ -		$ -	$ -
2050	322,176	13,424	308,752	315,464	62,486	62,486	$ -		$ -		$ -	$ -
2051	308,752	13,424	295,328	302,040	60,399	60,399	$ -		$ -		$ -	$ -
2052	295,328	13,424	281,904	288,616	58,311	58,311	$ -		$ -		$ -	$ -
2053	281,904	13,424	268,480	275,192	56,223	56,223	$ -		$ -		$ -	$ -
2054	268,480	13,424	255,056	261,768	54,135	54,135	$ -		$ -		$ -	$ -
2055	255,056	13,424	241,632	248,344	52,048	52,048	$ -		$ -		$ -	$ -
2056	241,632	13,424	228,208	234,920	49,960	49,960	$ -		$ -		$ -	$ -
2057	228,208	13,424	214,784	221,496	47,872	47,872	$ -		$ -		$ -	$ -
2058	214,784	13,424	201,360	208,072	45,784	45,784	$ -		$ -		$ -	$ -
2059	201,360	13,424	187,936	194,648	43,697	43,697	$ -		$ -		$ -	$ -
2060	187,936	13,424	174,512	181,224	41,609	41,609	$ -		$ -		$ -	$ -
2061	174,512	13,424	161,088	167,800	39,521	39,521	$ -		$ -		$ -	$ -
2062	161,088	13,424	147,664	154,376	37,433	37,433	$ -		$ -		$ -	$ -
2063	147,664	13,424	134,240	140,952	35,346	35,346	$ -		$ -		$ -	$ -
2064	134,240	13,424	120,816	127,528	33,258	33,258	$ -		$ -		$ -	$ -
2065	120,816	13,424	107,392	114,104	31,170	31,170	$ -		$ -		$ -	$ -
2066	107,392	13,424	93,968	100,680	29,082	29,082	$ -		$ -		$ -	$ -
2067	93,968	13,424	80,544	87,256	26,994	26,994	$ -		$ -		$ -	$ -
2068	80,544	13,424	67,120	73,832	24,907	24,907	$ -		$ -		$ -	$ -
2069	67,120	13,424	53,696	60,408	22,819	22,819	$ -		$ -		$ -	$ -
2070	53,696	13,424	40,272	46,984	20,731	20,731	$ -		$ -		$ -	$ -
2071	40,272	13,424	26,848	33,560	18,643	18,643	$ -		$ -		$ -	$ -
2072	26,848	13,424	13,424	20,136	16,556	16,556	$ -		$ -		$ -	$ -
Project Totals		792,017			4,674,210	4,674,210	-					

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

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

I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b1818 (Expand the Allen station by installing a second 345/138 kV transformer and adding four exits by cutting in the Lincoln-Sterling and Timber Switch -Milan 138 kV double circuit tower line)**

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	#N/A	#N/A	#N/A
Prior Yr True-Up	#N/A	#N/A	#N/A
True-Up Adjustment	#N/A	#N/A	#N/A

Details			
Investment		Current Year	2014
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
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RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
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I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: **RTEP ID: b1819 (Rebuild the Robinson Park-Sorneson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV)**

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	#N/A	#N/A	#N/A
Prior Yr True-Up	#N/A	#N/A	#N/A
True-Up Adjustment	#N/A	#N/A	#N/A

Details			
Investment		Current Year	2014
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
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Project Totals		-			-	-	-

RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
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I & M Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

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

A. Base Plan Facilities

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

Project Description: RTEP ID: b1465.4 (Make switching improvements at Sullivan and Jefferson 765 kV stations)

2014	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	#N/A	#N/A	#N/A
Prior Yr True-Up	#N/A	#N/A	#N/A
True-Up Adjustment	#N/A	#N/A	#N/A

Details

Investment		Current Year	2014
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	15.55%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	15.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:
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Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
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Project Totals		-			-	-	-					

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AEP East Companies
Cost of Service Formula Rate Using 2014 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

	(A)	**(B)**	**(C)**	**(D)**	**(E)**
Line Number	**Issuance**	**Principle Outstanding**	**Interest Rate**	**Annual Expense** (See Note S on Projected Template)	**Notes**
1	**Long Term Debt (FF1.p. 256-257.h)**				
2	Advances From Associated Co.	-	5.375%	-	
3	Reacquired Bonds Rockport Series D	(40,000,000)	0.17%	(68,000)	
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**				
5	PCRB Lawrenceburg In. - Series I	25,000,000	0.050%	12,500	
6	PCRB Lawrenceburg In. - Series H	52,000,000	0.040%	20,800	
7	PCRB - Rockport In. - Series D	40,000,000	5.250%	2,100,000	
8	PCRB - Rockport In. - 2002 Series A	50,000,000	4.625%	2,312,500	
9	PCRB - Rockport In. - 2009 Series A	50,000,000	6.250%	3,125,000	
10	PCRB - Rockport In. - 2009 Series B	50,000,000	6.250%	3,125,000	
11	Senior Unsecured Notes - Series F	-	0.000%	-	
12	Senior Unsecured Notes - Series G	125,000,000	5.650%	7,062,500	
13	Senior Unsecured Notes - Series H	400,000,000	6.050%	24,200,000	
14	Senior Unsecured Notes - Series I	475,000,000	7.000%	33,250,000	
15	Senior Unsecured Notes - Series J	250,000,000	3.200%	8,000,000	
15	Fort Wayne Settlement	18,407,909	6.000%	1,104,475	
16	Multiple Draw Term Loan	93,500,000	1.545%	1,444,575	
17					
18	Issuance Discount, Premium, & Expenses:				
19	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees		-	
20	Allowable Hedge Amortization (See Ln 36 Below)			806,280	
21	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		2,188,650	
22	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
23	Reacquired Debt:				
24	Amortization of Loss	FF1.p. 117.64.c		8,235,783	
25	Amortization of Gain	FF1.p. 117.66.c		(1,712)	
26	**Total Interest on Long Term Debt**	1,588,907,909	6.10%	96,918,351	
27	**Preferred Stock (FF1.p. 250-251)**	**Preferred Shares Outstanding**			
28		-	0.00%	-	
29		-	0.00%	-	
30		-	0.00%	-	
31	**Dividends on Preferred Stock**	-	0.00%	-	
32	Net Total Hedge Gains and Losses (WS M, Ln 34, (E))			806,280	
33	Total Projected Capital Structure Balance for 2015 (Projected TCOS, Ln 165)			3,557,250,824	
34	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005	
35	Limit of Recoverable Amount			1,778,625	
36	**Recoverable Hedge Amortization (Lesser of Ln 32 or Ln 35)**			**806,280**	

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2013 & 12/31/2014

(A)	(B)	(C)	(D)	(E)
Line		**Balances @ 12/31/2014**	**Balances @ 12/31/2013**	**Average**
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	1,953,950,018	1,922,153,922	1,938,051,970
2	Less Preferred Stock (Ln 54 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	(33,162)	(96,036)	(64,599)
4	Less Account 219.1 (112.15.c&d)	(14,359,735)	(15,508,738)	(14,934,237)
5	**Average Balance of Common Equity**	1,968,342,915	1,937,758,696	**1,953,050,805**
	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)	40,000,000	40,000,000	40,000,000
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	1,628,907,910	1,640,281,142	1,634,594,526
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	1,588,907,910	1,600,281,142	**1,594,594,526**

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 2014**	
14	Interest on Long Term Debt (256-257.33.i)	82,484,400
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.	806,280
16	Plus: Allowed Hedge Recovery From Ln 38 below.	806,280
17	Amort of Debt Discount & Expense (117.63.c)	2,188,650
18	Amort of Loss on Reacquired Debt (117.64.c)	8,235,783
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)**	**92,907,121**
22	**Average Cost of Debt for 2014 (Ln 21/Ln 11)**	**5.83%**

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.

						Amortization Period	
	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	**Total Hedge (Gain)/Loss for 2014**	**Less Excludable Amounts (See NOTE on Line 23)**	**Net Includable Hedge Amount**	**Remaining Unamortized Balance**	**Beginning**	**Ending**
24	Senior Unsecured Notes - Series F	768,110		768,110	-	November 2004	November 2014
25	Senior Unsecured Notes - Series G	(383,570)		(383,570)	(351,606)	December-05	November-15
26	Senior Unsecured Notes - Series H	421,740		421,740	9,331,005	November-06	February-37
27				-			
28				-			
29				-			
30				-			
31				-			
32				-			
					8,979,399		
33	Total Hedge Amortization	806,280	-				
34	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 32)			806,280			
35	Total Average Capital Structure Balance for 2014 (True-UP TCOS, Ln 165)			3,547,645,331			
36	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005			
37	Limit of Recoverable Amount			1,773,823			
38	**Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)**			**806,280**			

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

AEP East Companies
Cost of Service Formula Rate Using 2014 FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
INDIANA MICHIGAN POWER COMPANY

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

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	**Date**	**Property Description**	**Function (T) or (G)** T = Transmission G = General	**Basis**	**Proceeds**	**(Gain) / Loss**	**Functional Allocator**	**Functionalized Proceeds (Gain) / Loss**	**FERC Account**
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 2014		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2014 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 30,000,000

Allocation of PBOP Settlement Amount for 2014

		Total Company Amount						
Line#	**Company**	**Actual Expense (Including AEPSC Billed OPEB)**	**Ratio of Company Actual to Total**	**Allocation of PBOB Recovery Allowance**	**Labor Allocator for 2014**	**Actual Expense**	**Allowable Expense**	**One Year Functional Expense (Over)/Under**
		(A) **(Line 14)**	**(B)=(A)/Total (A)**	**(C)=(B) * 30000000**	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	APCo	(13,980,707)	36.87%	11,060,258	7.080%	(989,797)	783,037	(1,772,834)
2								
3	I&M	(9,910,530)	26.13%	7,840,305	4.555%	(451,452)	357,148	(808,600)
4	KPCo	(3,026,000)	7.98%	2,393,895	7.063%	(213,739)	169,090	(382,829)
5	KNGP	(304,086)	0.80%	240,565	11.505%	(34,986)	27,677	(62,663)
6	OPCo	(10,311,857)	27.19%	8,157,799	18.192%	(1,875,953)	1,484,083	(3,360,036)
7	WPCo	(388,288)	1.02%	307,178	12.660%	(49,156)	38,888	(88,044)
8	**Sum of Lines 1 to 7**	(37,921,469)		30,000,000		(3,615,083)	2,859,923	(6,475,006)

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

	APCo	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	(13,415,837)	(10,057,152)	(3,040,335)	(285,159)	(9,435,001)	(361,523)	(36,595,007)
10 Additional PBOP Ledger Entries (from Company Records)	395,759	814,185	252,888	3,649	114,856	3,709	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(13,020,078)	(9,242,967)	(2,787,447)	(281,510)	(9,320,145)	(357,814)	(35,009,962)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(960,629)	(667,563)	(238,553)	(22,576)	(991,712)	(30,474)	(2,911,507)
14 Company PBOP Expense (Ln 12 + Ln 13)	(13,980,707)	(9,910,530)	(3,026,000)	(304,086)	(10,311,857)	(388,288)	(37,921,469)

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF July 1, 2014
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			**MICHIGAN**			**FERC WHOLESALE**			**COMPANY**
	PLANT ACCT.	*(1) 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	1.2700%	0.646552	0.8211%	1.1700%	0.139381	0.1631%	1.1700%	0.214067	0.2505%	1.23%
Structures & Improvements	352.0	1.3200%	0.646552	0.8534%	1.2700%	0.139381	0.1770%	1.2700%	0.214067	0.2719%	1.30%
Station Equipment	353.0	1.6900%	0.646552	1.0927%	1.6500%	0.139381	0.2300%	1.6500%	0.214067	0.3532%	1.68%
Towers & Fixtures	354.0	1.6000%	0.646552	1.0345%	1.4400%	0.139381	0.2007%	1.4400%	0.214067	0.3083%	1.54%
Poles & Fixtures	355.0	2.4300%	0.646552	1.5711%	2.3900%	0.139381	0.3331%	2.3900%	0.214067	0.5116%	2.42%
Overhead Conductors	356.0	1.5300%	0.646552	0.9892%	1.4500%	0.139381	0.2021%	1.4500%	0.214067	0.3104%	1.50%
Underground Conduit	357.0	1.5600%	0.646552	1.0086%	1.3900%	0.139381	0.1937%	1.3900%	0.214067	0.2976%	1.50%
Underground Conductors	358.0	1.5500%	0.646552	1.0022%	1.4600%	0.139381	0.2035%	1.4600%	0.214067	0.3125%	1.52%
Trails & Roads	359.0	1.4900%	0.646552	0.9634%	1.4700%	0.139381	0.2049%	1.4700%	0.214067	0.3147%	1.48%

(1) As approved in Indiana Case No. 44075.

(2) As approved in MICHIGAN Case No. U16801.

(3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.

(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

<u>GENERAL NOTES:</u>

The rates for each AEP company have been approved by their respective regulatory commissions.

I&M falls under the authority of Indiana, Michigan and the FERC. Therefore, I&M's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.

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