Tvelve Months Ended 2021

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

Indiana Michigan Power Company

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 130)					$162,340,701
2	REVENUE CREDITS	(worksheet E Ln 8) (Note A)	3,146,000	DA	1.00000	$	3,146,000
3	Facility Credits under PJM OATT Section 30.9	(worksheet E Ln 9) (Note X)				$	-
4	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2 plus ln 3)				$	159,194,701

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

5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		5,251,215	DA	1.00000	$	5,251,215
6	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
7	Annual Rate	((ln 1 - ln 95)/((ln 42) x 100))					13.33%
8	Monthly Rate	(ln 7 / 12)					1.11%
9	NET PLANT CARRYING CHARGE ON LINE 7 , w/o depreciation or ROE incentives (Note B)						
10	Annual Rate	((ln 1 - ln 95 - ln 100) /((ln 42) x 100))					9.91%
11	NET PLANT CARRYING CHARGE ON LINE 10, w/o Return, income taxes or ROE incentives (Note B)						
12	Annual Rate	((ln 1 - ln 95 - ln 100 - ln 125 - ln 126) /((ln 42) x 100))					3.41%
13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)						

14	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
15	Total Load Dispatch & Scheduling (Account 561)	Line 75 Below	7,335,000
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,371,000
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,365,000
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)	599,000

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

Indiana Michigan Power Company

	(1)	(2)	(3)	(4)		(5)
Line No.	**RATE BASE CALCULATION**	**Data Sources (See "General Notes")**	**TO Total** NOTE C	**Allocator**		**Total Transmission**
	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 14.(b))	5,346,552,000	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 14.(c))	(454,806,000)	NA	0.00000	-
21	Transmission	(Worksheet A ln 14.(d) & TCOS Ln 134)	1,748,260,000	DA		1,689,211,000
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 14.(e))	-	TP	0.96622	-
23	Distribution	(Worksheet A ln 14.(f))	2,826,911,000	NA	0.00000	-
24	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 14.(g))	-	NA	0.00000	-
25	General Plant	(Worksheet A ln 14.(h))	176,092,000	W/S	0.04487	7,902,056
26	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 14.(i))	-	W/S	0.04487	-
27	Intangible Plant	(Worksheet A ln 14.(j))	328,736,000	W/S	0.04487	14,751,893
28	TOTAL GROSS PLANT	(sum lns 19 to 27)	9,971,745,000	**GP**	**0.171672**	1,711,864,950
				GTD=	**0.36921**	
29	ACCUMULATED DEPRECIATION AND AMORTIZATION					
30	Production	(Worksheet A ln 28.(b))	2,415,925,000	NA	0.00000	-
31	Less: Production ARO (Enter Negative)	(Worksheet A ln 28.(c))	(172,170,000)	NA	0.00000	-
32	Transmission	(Worksheet A ln 28.(d) & ln 43.(c))	483,386,000	**TP1=**	0.97496	471,284,000
33	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 28.(e))	-	**TP1=**	0.97496	-
34	Distribution	(Worksheet A ln 28.(f))	754,480,000	NA	0.00000	-
35	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 28.(g))	-	NA	0.00000	-
36	General Plant	(Worksheet A ln 28.(h))	33,669,000	W/S	0.04487	1,510,883
37	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 28.(i))	-	W/S	0.04487	-
38	Intangible Plant	(Worksheet A ln 28.(j))	123,072,000	W/S	0.04487	5,522,806
39	TOTAL ACCUMULATED DEPRECIATION	(sum lns 30 to 38)	3,638,362,000			478,317,688
40	NET PLANT IN SERVICE					
41	Production	(ln 19 + ln 20 - ln 30 - ln 31)	2,647,991,000			-
42	Transmission	(ln 21 + ln 22 - ln 32 - ln 33)	1,264,874,000			1,217,927,000
43	Distribution	(ln 23 + ln 24 - ln 34 - ln 35)	2,072,431,000			-
44	General Plant	(ln 25 + ln 26 - ln 36 - ln 37)	142,423,000			6,391,174
45	Intangible Plant	(ln 27 - ln 38)	205,664,000			9,229,088
46	TOTAL NET PLANT IN SERVICE	(sum lns 41 to 45)	6,333,383,000	**NP**	**0.194769**	1,233,547,261
47	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
48	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(27,236,500)	NA		-
49	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(1,425,828,000)	DA		(251,977,000)
50	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(569,457,000)	DA		(2,160,000)
51	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	718,488,500	DA		10,192,500
52	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
53	TOTAL ADJUSTMENTS	(sum lns 48 to 52)	(1,304,033,000)			(243,944,500)
54	PLANT HELD FOR FUTURE USE	(Worksheet A ln 44.(e) & ln 45.(e))	1,445,000	DA		208,000
55	REGULATORY ASSETS	(Worksheet A ln 51.(e))	-	DA		-
56	UNFUNDED RESERVES (ENTER NEGATIVE) (NOTE Y)	(Worksheet A ln 54.(e))	(156,000)	W/S	0.04487	(7,000)
57	WORKING CAPITAL	(Note E)				
58	Cash Working Capital	(1/8 * ln 78)	2,621,000			2,532,473
59	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	1,489,000	TP	0.96622	1,438,708
60	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	534,000	W/S	0.04487	23,963
61	Stores Expense	(Worksheet C, ln 4.(F))	-	GP	0.17167	-
62	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	179,248,500	W/S	0.04487	8,043,703
63	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	8,784,000	GP	0.17167	1,507,963
64	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
65	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(175,932,500)	NA	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 58 to 65)	16,744,000			13,546,810
67	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	(3,581,000)	DA	1.00000	(3,581,000)
68	RATE BASE (sum lns 46, 53, 54, 55, 56, 66, 67)		5,043,802,000			999,769,571

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

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					
69	Production	321.80.b	964,376,000			
70	Distribution	322.156.b	74,149,000			
71	Customer Related Expense	322 & 323.164,171,178.b	39,013,000			
72	Regional Marketing Expenses	322.131.b	4,690,000			
73	Transmission	321.112.b	219,349,000			
74	TOTAL O&M EXPENSES	(sum lns 69 to 73)	1,301,577,000			
75	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	7,335,000			
76	Less: Account 565	(Note H) 321.96.b	191,046,000			
77	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
78	Total O&M Allocable to Transmission	(lns 73 - 75 - 76 - 77)	20,968,000	TP	0.96622	20,259,788
79	Administrative and General	323.197.b (Notes J and M)	122,809,000			
80	Less: Acct. 924, Property Insurance	323.185.b	4,334,000			
81	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(9,580,000)			
82	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
83	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(2,429,000)			
84	Acct. 928, Reg. Com. Exp.	323.189.b	11,576,000			
85	Acct. 930.1, Gen. Advert. Exp.	323.191.b	79,000			
86	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,376,000			
87	Balance of A & G	(ln 79 - sum ln 80 to ln 86)	112,453,000	W/S	0.04487	5,046,282
88	Plus: Acct. 924, Property Insurance	(ln 80)	4,334,000	GP	0.17167	744,025
89	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	29,000	TP	0.96622	28,020
90	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.96622	-
91	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	1,168,000	DA	1.00000	1,168,000
92	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C (Note M)	(33,621,601)	W/S	0.04487	(1,508,756)
93	A & G Subtotal	(sum lns 87 to 92)	84,362,399			5,477,572
94	O & M EXPENSE SUBTOTAL	(ln 78 + ln 93)	105,330,399			25,737,359
95	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
96	TOTAL O & M EXPENSE	(ln 94 + ln 95)	105,330,399			25,737,359
97	DEPRECIATION AND AMORTIZATION EXPENSE					
98	Production	336.2-6.f	341,885,000	NA	0.00000	-
99	Distribution	336.8.f	100,959,000	NA	0.00000	-
100	Transmission	336.7.f	42,690,000	TP1	0.97496	41,621,218
101	General	336.10.f	6,770,000	W/S	0.04487	303,801
102	Intangible	336.1.f	48,536,000	W/S	0.04487	2,178,033
103	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 98+99+ 100+101+102)	540,840,000			44,103,052
104	TAXES OTHER THAN INCOME	(Note N)				
105	Labor Related					
106	Payroll	Worksheet H ln 23.(D)	14,133,000	W/S	0.04487	634,213
107	Plant Related					
108	Property	Worksheet H ln 23.(C)	73,633,000	DA		12,011,913
109	Gross Receipts/Sales & Use	Worksheet H ln 23.(F)	22,419,000	NA	0.00000	-
110	Other	Worksheet H ln 23.(E)	2,732,000	GP	0.17167	469,007
111	TOTAL OTHER TAXES	(sum lns 106 to 110)	112,917,000			13,115,132
112	INCOME TAXES	(Note O)				
113	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		24.95%			
114	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		22.66%			
115	where WCLTD=(ln 154) and WACC = (ln 157)					
116	and FIT, SIT & p are as given in Note O.					
117	GRCF=1 / (1 - T) = (from ln 113)		1.3324			
118	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,257,000)			
119	Excess Deferred Income Tax	(Note U)	(46,279,000)	DA		(3,430,000)
120	Tax Effect of Permanent and Flow-Through Differences	(Note U)	3,513,000	DA		1,273,000
121	Income Tax Calculation	(ln 114 * ln 126)	77,393,318			15,340,706
122	ITC adjustment	(ln 117 * ln 118)	(5,672,219)	GP	0.17167	(973,759)
123	Excess Deferred Income Tax	(ln 117 * ln 119)	(61,664,224)			(4,570,286)
124	Tax Effect of Permanent and Flow-Through Differences	(ln 117 * ln 120)	4,680,879			1,696,203
125	TOTAL INCOME TAXES	(sum lns 121 to 124)	14,737,755			11,492,864
126	RETURN ON RATE BASE (Rate Base*WACC)	(ln 68 * ln 157)	341,545,583			67,700,295
127	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		192,000	DA	1.00000	192,000
128	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
129	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 128 * ln114)		-			-
130	TOTAL REVENUE REQUIREMENT (sum lns 96, 103, 111, 125, 126, 127, 128, 129)		1,115,562,736			162,340,701

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

Indiana Michigan Power Company

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
131	Total transmission plant	(ln 21)		1,748,260,000
132	Less transmission plant excluded from PJM Tariff (Worksheet A, ln 42, Col. (d)) (Note P)			-
133	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 42, Col. (b)) (Note Q)			59,049,000
134	Transmission plant included in PJM Tariff	(ln 131 - ln 132 - ln 133)		1,689,211,000
135	Percent of transmission plant in PJM Tariff	(ln 134 / ln 131)	**TP=**	**0.96622**

ln No.		(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
136	WAGES & SALARY ALLOCATOR (W/S)							
137	Production	354.20.b	145,739,000	13,180,000	158,919,000	NA	0.00000	-
138	Transmission	354.21.b	4,744,000	4,702,000	9,446,000	TP	0.96622	9,126,953
139	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
140	Distribution	354.23.b	19,534,000	2,237,000	21,771,000	NA	0.00000	-
141	Other (Excludes A&G)	354.24,25,26.b	7,882,000	5,370,000	13,252,000	NA	0.00000	-
142	Total	(sum lns 137 to 141)	177,899,000	25,489,000	203,388,000			9,126,953
143	Transmission related amount						**W/S=**	**0.04487**

ln No.							
144	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
145	Long Term Interest	(Worksheet M, ln. 37, col. (d))					131,555,000
146	Preferred Dividends	(Worksheet M, ln. 71)					-
147	Development of Common Stock:						
148	Proprietary Capital	(Worksheet M, ln. 14, col. (b))					2,706,873,000
149	Less: Preferred Stock	(Worksheet M, ln. 14, col. (c))					-
150	Less: Account 216.1	(Worksheet M, ln. 14, col. (d))					(5,778,000)
151	Less: Account 219	(Worksheet M, ln. 14, col. (e))					(8,423,000)
152	Common Stock	(ln 148 - ln 149 - ln 150 - ln 151)					2,721,074,000
				Capital Structure Percentages		Cost	
153			$	%	Cap Limit	(Note S)	Weighted
154	Long Term Debt (Note T) Worksheet M, ln 28, col. (g), ln 38, col. (d))		3,380,686,000	55.41%	55.41%	3.89%	0.0216
155	Preferred Stock (ln 149)		-	0.00%	0.00%	-	0.0000
156	Common Stock (ln 152)		2,721,074,000	44.59%	44.59%	10.35%	0.0462
157	Total (Sum lns 154 to 156)		6,101,760,000			**WACC=**	**0.0677**
158	Capital Structure Equity Limit (Note Z)	55%					

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

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.
7) If AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based.
See Worksheet E for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's. Interest will be calculated based on Worksheet Q and any over under recovery will be filed and posted as part of the informational filing.

C Transmission Plant Balances in this study are projected or actual average of 13-month balances.

D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flowthrough and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated.
In compliance with FERC Rulemaking the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation Section1.167(l)-l(h)(6)(ii).
RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
The company will not include the ADIT portion of deferred hedge gains and losses in rate base. Detailed balances for the projected or actual period, distinguished between utility and non-utility balances, will be filed and posted as part of the information filing.

E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 78. It excludes:
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 75.
2) Costs of Transmission of Electricity by Others, as described in Note H.
3) The impact of state regulatory deferrals and amortizations, as shown on line 77
4) All A&G Expenses, as shown on line 93.

F Consistent with Paragraph 657 of Order 2003-A, the amount on line 67 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 127.

G Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 16 & 17 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.

H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 78. To the extent such service is incurred to provide the PJM service at issue, e.g. lease payments to affiliates, such cost is added back on line 95 to determine the total O&M collected in the formula. The amounts on line 95 is also excluded in the calculation of the FCR percentage calculated on lines 6 through 12.
The addbacks on line 95 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
The company records referenced on line 95 is the Indiana Michigan Power Company general ledger.

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

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

K These deductions on lines 81 through 83 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L Expenses recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneous General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

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

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

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
(ln 118) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	21.00%	
	SIT=	5.00%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable.
If the statutory tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and post-change rate each is in effect.

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

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

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

S Long Term Debt cost rate = Long-Term Interest (ln 145) / Long-Term Debt (ln 154). Preferred Stock cost rate = preferred dividends (ln 146) / preferred outstanding (ln 155).
Common Stock cost rate (ROE) = 10.35%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO Membership.
The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of captial are shown on Worksheet M.
Eligible Hedging Gains and Losses are computed on Worksheet M.The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983.
This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 154 above.
The cost rates for long-term debt shall include interest expense and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance) and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429 and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock (if applicable) shall include the dividends.

U Excess / (Deficit) Deferred Income Taxes will be amortized over the average remaining life of the assets to which it relates, unless the Commission requires a different amortization period. The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State tax calculations that are not the result of a timing difference, including but not limited to depreciation related to capitalized AFUDC equity and meals and entertainment deductions. The Tax Effect of Flow-Through differences captures current tax expense related to timing differences on items for which tax deductions were used to reduce customer rates through the use of flow-through accounting in a prior period. Transmission balances for the projected or actual period, will be filed and posted as part of the informational filing.

V Cash investment in prepaid pension and benefits recorded in FERC Account 165 is permitted to be included in the formula. A labor expense allocation factor will be used to allocate total company costs. All other prepayments recorded in FERC Account 165 are directly assigned to the transmission function, allocated or excludable balances detailed on Worksheet C.

W The formula rate shall allocate property tax expense based on the as filed net plant cost allocation method detailed on Worksheet H.

X Under Section 30.9 of the PJM OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

Y The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilites recorded to Accounts 228.1-228.4 from rate base.

Z Per the settlement in EL17-13, equity is limited to 55% in of the Company's capital structure. If the percentage of actual equity exceeds the cap, the excess is included as long term debt in the capital structure.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet A Rate Base
Indiana Michigan Power Company

		Gross Plant In Service								
Line No	Month (a)	Production (b)	Production ARO (c)	Transmission (d)	Transmission ARO (e)	Distribution (f)	Distribution ARO (g)	General (h)	General ARO (i)	Intangible (j)
	(Note A)	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	Acct. 359.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	Acct. 399.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5
1	December Prior to Rate Year	5,286,045,000	454,818,000	1,720,329,000		2,684,145,000		174,882,000		295,686,000
2	January	5,285,005,000	454,812,000	1,721,292,000		2,720,325,000		175,516,000		294,532,000
3	February	5,311,992,000	454,808,000	1,723,537,000		2,739,044,000		175,878,000		302,352,000
4	March	5,309,113,000	454,806,000	1,724,831,000		2,757,704,000		175,961,000		308,059,000
5	April	5,345,479,000	454,805,000	1,727,987,000		2,776,286,000		176,045,000		315,605,000
6	May	5,366,332,000	454,804,000	1,735,188,000		2,803,182,000		176,112,000		323,043,000
7	June	5,365,659,000	454,804,000	1,750,367,000		2,827,240,000		176,175,000		327,986,000
8	July	5,363,921,000	454,804,000	1,751,907,000		2,854,196,000		176,232,000		335,428,000
9	August	5,374,741,000	454,804,000	1,758,199,000		2,872,132,000		176,297,000		342,935,000
10	September	5,377,496,000	454,804,000	1,762,561,000		2,898,051,000		176,381,000		347,095,000
11	October	5,374,296,000	454,804,000	1,769,560,000		2,915,271,000		176,473,000		354,548,000
12	November	5,373,457,000	454,804,000	1,785,951,000		2,942,462,000		176,556,000		361,929,000
13	December of Rate Year	5,371,634,000	454,804,000	1,795,677,000		2,959,810,000		176,694,000		364,366,000
14	Average of the 13 Monthly Balances	5,346,552,000	454,806,000	1,748,260,000	-	2,826,911,000	-	176,092,000	-	328,736,000

		Accumulated Depreciation								
Line No	Month (a)	Production (b)	Production ARO (c)	Transmission (d)	Transmission ARO (e)	Distribution (f)	Distribution ARO (g)	General (h)	General ARO (i)	Intangible (j)
	(Note A)	FF1, page 219, lns 20-24, Col. (b)	Company Records (Included in total in Column (b))	FF1, page 219, ln 25, Col. (b)	Company Records (Included in total in Column (d))	FF1, page 219, ln 26, Col. (b)	Company Records (Included in total in Column (f))	FF1, page 219, ln 28, Col. (b)	Company Records (Included in total in Column (h))	FF1, page 200, ln 21, Col. (b)
15	December Prior to Rate Year	2,237,073,000	161,600,000	480,945,000		723,173,000		36,327,000		112,200,000
16	January	2,260,770,000	163,358,000	481,619,000		727,761,000		35,882,000		106,733,000
17	February	2,283,681,000	165,118,000	481,948,000		732,815,000		35,439,000		110,413,000
18	March	2,307,089,000	166,879,000	482,282,000		737,942,000		34,999,000		112,353,000
19	April	2,386,715,000	168,642,000	482,618,000		743,148,000		34,554,000		116,194,000
20	May	2,408,546,000	170,405,000	482,960,000		748,430,000		34,109,000		120,126,000
21	June	2,432,155,000	172,168,000	483,317,000		753,819,000		33,666,000		121,662,000
22	July	2,455,992,000	173,932,000	483,704,000		759,295,000		33,224,000		125,739,000
23	August	2,479,781,000	175,695,000	484,094,000		764,876,000		32,783,000		129,905,000
24	September	2,503,254,000	177,459,000	484,497,000		770,529,000		32,343,000		130,865,000
25	October	2,526,988,000	179,222,000	484,908,000		776,287,000		31,902,000		135,165,000
26	November	2,550,542,000	180,986,000	485,334,000		782,118,000		31,458,000		139,555,000
27	December of Rate Year	2,574,434,000	182,750,000	485,792,000		788,052,000		31,014,000		139,024,000
28	Average of the 13 Monthly Balances	2,415,925,000	172,170,000	483,386,000	-	754,480,000	-	33,669,000	-	123,072,000

Line No	Month (a) (Note A)	OATT Ancillary Services (GSU) Plant In Service (b) Company Records (included in total in column (d) of gross plant above)	OATT Ancillary Services (GSU) Accumulated Depreciation (c) Company Records (included in total in column (b) of accumulated depreciation above)	Excluded Plant - Plant In Service (d) Company Records	Excluded Plant - Accumulated Depreciation (e) Company Records
29	December Prior to Rate Year	59,049,000	11,389,000		
30	January	59,049,000	11,508,000		
31	February	59,049,000	11,627,000		
32	March	59,049,000	11,746,000		
33	April	59,049,000	11,864,000		
34	May	59,049,000	11,983,000		
35	June	59,049,000	12,102,000		
36	July	59,049,000	12,221,000		
37	August	59,049,000	12,340,000		
38	September	59,049,000	12,459,000		
39	October	59,049,000	12,577,000		
40	November	59,049,000	12,696,000		
41	December of Rate Year	59,049,000	12,815,000		
42	Average of the 13 Monthly Balances	59,049,000	12,102,000	-	-
43	Transmission Accum Depreciation net of GSU		471,284,000		

	Plant Held For Future Use (a)	Source of Data (b)	Balance @ December 31, 2021 (c)	Balance @ December 31, 2020 (d)	Average Balance for 2021 (e)
44	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	1,445,000	1,445,000	1,445,000
45	**Transmission Plant Held For Future Use (Included in total on line 44)**	Company Records - Note 1	208,000	208,000	208,000

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.

46					-
47					-
48					-
49					-
50					-
51	Total Regulatory Deferrals Included in Ratebase		-	-	-

Unfunded Reserves Summary (Company Records)

52	Description	Account			
53a	Accum Prv I/D Worker's Com		156,000	156,000	156,000
53b					-
54		Total	156,000	156,000	156,000

NOTE 1: On this worksheet, "Company Records" refers to AEP's property accounting ledger.
NOTE 2: The ratebase should not include the unamoritzed balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
Indiana Michigan Power Company

	(A)	(B)	(C)	(D)	(E)
Line Number	**Description**	**Source**	**Balance @ December 31, 2021**	**Balance @ December 31, 2020**	**Average Balance for 2021**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	27,320,000	27,153,000	27,236,500
3	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 4 (Note 1)	-	-	-
4	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 3 (Note 1)	27,320,000	27,153,000	27,236,500
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)	1,430,202,000	1,421,454,000	1,425,828,000
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)	74,833,000	74,833,000	74,833,000
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)	1,103,035,000	1,095,001,000	1,099,018,000
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	252,334,000	251,620,000	251,977,000
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	571,204,000	567,710,000	569,457,000
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)	551,428,000	551,428,000	551,428,000
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)	17,609,000	14,129,000	15,869,000
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	2,167,000	2,153,000	2,160,000
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	716,189,000	720,788,000	718,488,500
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)	626,761,000	626,761,000	626,761,000
19	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)	79,268,000	83,802,000	81,535,000
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	10,161,000	10,226,000	10,192,500
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	25,893,000	29,866,000	27,879,500
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	25,893,000	29,866,000	27,879,500
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 20 (Note 1)	-	-	-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax forecast and accounting ledger. The PTRR will use projected ending balances and reflect proration required by IRS Letter Rule Section I.l67(l)-l(h)(6)(ii). Line item detail of actual deferred tax items will be included on Worksheets B-1 and B-2.

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

Indiana Michigan Power Company
SPECIFIED DEFERRED CREDITS - Actual Cycle Only
PERIOD ENDED DECEMBER 31, 2021

(DEBIT) CREDIT

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		AVERAGE ELECTRIC UTILITY	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2020			FUNCTIONALIZATION 12/31/2021		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2020	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2020	BALANCE AS OF 12-31-2021	(B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1.00	ACCOUNT 281:														
2.01															
2.02		0	0			0	0	0	0						
2.03															
2.04		0	0	0	0	0									
2.05		0	0	0	0	0									
2.06		0	0	0	0	0									
3	TOTAL ACCOUNT 281	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 281 - ARO-Related Deferrals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	ACCOUNT 282:														
5.01		0	0			0	0	0	0						
5.02		0	0			0	0	0	0						
5.03		0	0			0	0	0	0						
5.04		0	0			0	0	0	0						
5.05		0	0			0	0	0	0						
5.06		0	0			0	0	0	0						
5.07		0	0			0	0	0	0						
5.08		0	0			0	0	0	0						
5.09		0	0			0	0	0	0						
5.10		0	0			0	0	0	0						
5.38		0	0			0	0	0	0						
5.39				0	0	0									
5.40				0	0	0									
5.41				0	0	0									
6	TOTAL ACCOUNT 282	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	ACCOUNT 282 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	ACCOUNT 283:														
9.01		0	0			0	0	0	0						
9.02		0	0			0	0	0	0						
9.03		0	0			0	0	0	0						
9.04		0	0			0	0	0	0						
9.05		0	0			0	0	0	0						
9.06		0	0			0	0	0	0						
9.07		0	0			0	0	0	0						
9.08		0	0			0	0	0	0						
9.09		0	0			0	0	0	0						
9.10		0	0			0	0	0	0						
9.93		0	0			0	0	0	0						
9.94				0	0	0									
9.95				0	0	0									
9.96				0	0	0									
9.97				0	0	0									
9.98				0	0	0									
9.99				0	0	0									
10		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	DEFD STATE INCOME TAXES	0	0			0	0	0	0						
11.01				0	0	0									
12	TOTAL ACCOUNT 283	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	ACCOUNT 283 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	JURISDICTIONAL AMOUNTS FUNCTIONALIZED														
15	TOTAL COMPANY AMOUNTS FUNCTIONALIZED														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
17	NOTE: POST 1970 ACCUMULATED DEFERRED														
18	INV TAX CRED. (JDITC) IN A/C 255														
18.01		0	0			0	0	0	0						
18.02		0	0			0	0	0	0						
19															
20	TOTAL ACCOUNT 255	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Indiana Michigan Power Company
ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190 - Actual Cycle Only
PERIOD ENDED DECEMBER 31, 2021

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		AVERAGE ELECTRIC UTILITY	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2020			FUNCTIONALIZATION 12/31/2021		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2020	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2020	BALANCE AS OF 12-31-2021	(B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1	ACCOUNT 190:														
2.01		0	0			0	0	0	0						
2.02		0	0			0	0	0	0						
2.03		0	0			0	0	0	0						
2.04		0	0			0	0	0	0						
2.05		0	0			0	0	0	0						
2.06		0	0			0	0	0	0						
2.07		0	0			0	0	0	0						
2.08		0	0			0	0	0	0						
2.09		0	0			0	0	0	0						
2.10		0	0			0	0	0	0						
2.79		0	0			0	0	0	0						
2.80				0	0	0									
2.81				0	0	0									
2.82				0	0	0									
2.83				0	0	0									
2.84				0	0	0									
2.85				0	0	0									
2.86				0	0	0									
2.87				0	0	0									
2.88				0	0	0									
2.89				0	0	0									
2.90				0	0	0	0	0	0						
2.91		0	0			0	0	0	0						
3	TOTAL ACCOUNT 190	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 190 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0

INDIANA MICHIGAN POWER COMPANY, INC.
Worksheet B-3
Excess/ Deficient ADIT Worksheet for Total Company and Functional Balances
For Year Ended December 31, 2019
Debit/(Credit)

A	B	C	D	E
TOTAL COMPANY BALANCES				
Line No.	**Account (NOTE A)**	**Description of Account**	**Protected Unprotected**	**Tax Rate Change Act**
	Deferred Tax Account (NOTE B)			
1a	1904001	ADFIT - FAS 109 Excess	N/A	TCJA 2017
1b	2811001	ADFIT - Accel Amortization Property	Protected	TCJA 2017
1c	2814001	ADFIT - Accel Amort FAS 109 Excess	Protected	TCJA 2017
1d	2821001	ADFIT - Utility Property	Protected	TCJA 2017
1e	2821001	ADFIT - Utility Property	Unprotected	TCJA 2017
1f	2824001	ADFIT - Utility Property FAS 109 Excess	Protected	TCJA 2017
1g	2824001	ADFIT - Utility Property FAS 109 Excess	Unprotected	TCJA 2017
1h	2831001	ADFIT - Other Utility Deferrals	Unprotected	TCJA 2017
1i	2834001	ADFIT - Other FAS 109 Excess	Unprotected	TCJA 2017
1j	**NOTE E**			
	Regulatory Deferral Accounts			
2a	182.3	Regulatory Asset		TCJA 2017
2b	254	Regulatory Liability		TCJA 2017
2c	**NOTE E**			
3	Total For Accounting Entires (Sum of Lines 1a through 2b)			
TRANSMISSION FUNCTION BALANCES				
	Deferred Tax Account (NOTE B)			
4a	1904001	ADFIT - FAS 109 Excess	N/A	TCJA 2017
4b	2821001	ADFIT - Utility Property	Protected	TCJA 2017
4c	2821001	ADFIT - Utility Property	Unprotected	TCJA 2017
4d	2824001	ADFIT - Utility Property FAS 109 Excess	Protected	TCJA 2017
4e	2824001	ADFIT - Utility Property FAS 109 Excess	Unprotected	TCJA 2017
4f	2831001	ADFIT - Other Utility Deferrals	Unprotected	TCJA 2017
4g	2834001	ADFIT - Other FAS 109 Excess	Unprotected	TCJA 2017
4h	**NOTE E**			
	Regulatory Deferral Accounts			
5a	182.3	Regulatory Asset		TCJA 2017
5b	254	Regulatory Liability		TCJA 2017
5c	**NOTE E**			
6	Total For Accounting Entires (Sum of Lines 4a through 5b)			

GENERAL NOTE: ADIT Tax balances provided in the formula presented in Attachment H-14B are maintained on both a to
formula, the information for excess and deficient ADIT is also presented for both total company and the transmission functi
transmission functional summary.

NOTE A In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC Tax subaccount nur

the fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1
in the fourth position of the account number indicates accounts used to track regulatory accounting requireme
balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, b
The amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subac

NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line

NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will

NOTE D: The ten year amortization period for unprotected excess ADIT is consistent with the period agreed upon by the *Company, et al, 166 FERC ¶ 61,135 (2019).*

NOTE E: In the event of future tax rate changes, additional lines will be inserted in both the Total Company and Transı that may be necessary to track that tax rate change.

NOTE F: The amount of excess amortization entries shown in lines 1a through 1j and 4a through 4h are shown as a de and 6 is the offset recorded to the 410/411 account and will tie to the total company and transmission function service.

F	G	H	I	J
			1/1/2019 Beginning Balances	
Excess Balance at Remeasurement (NOTE C)	**Amortization Methodology (NOTE D)**	**Amotization Period**	**Excess ADIT Regulatory Offset**	**Excess ADIT in Utility Deferrals**
			141,975,892	
(11,772,442)	**ARAM**	**Life of Asset**		(11,692,443)
			11,692,443	
(410,365,997)	**ARAM**	**Life of Asset**		(383,352,324)
(148,924,633)	**10 Years**	**1/2018 - 12/2027**		(137,178,388)
			383,352,324	
			137,178,388	
(5,353,470)	**10 Years**	**1/2018 - 12/2027**		(1,876,626)
			46,082,952	
			(3,777,595)	
			(716,504,404)	
			0	(534,099,781)
			23,470,157	
(82,304,124)	**ARAM**	**Life of Asset**		(79,548,435)
(14,907,164)	**10 Years**	**1/2018 - 12/2027**		(13,431,855)
			79,548,435	
			13,431,855	
5,174,807	**10 Years**	**1/2018 - 12/2027**		4,687,796
			4,064,407	
			(2,105,953)	
			(118,408,901)	
			0	(88,292,494)

tal company and transmission functional basis. Because both sets of numbers are presented in the
on on this worksheet. Account 281 only applies to the generation function, so is not presented in the

nbers to identify balances associated with utility operations vs regulatory reporting requirements. A "1" in
" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4"

" designation will be included in the determination of ratebase to be recovered in the formula rate.   A "4"
nts. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1"
ut at the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate.
ccount established for this purpose.

of ADIT accounts provided for each specific change in tax rates.

remain static on this workpaper.

e Company and its customers and approved for the Company's PJM formula rates. *Appalachian Power*

mission Funcational sections above as required to reflect any new ADIT or regulatory deferral accounts

ebit or credit to the ADIT account from which it is being amortized. The total in line 3
al amounts of excess or deficient ADIT amortization shown on line 119 of the cost of

K	L	M	N	O	P
	Balance Sheet Entries		Tax Expense Entries		12/31/2019 Er
Balance Sheet Account Reclassifications	**182.3**	**254**	**410/411 Excess Amortization**	**410/411 Deferred Tax Expense/ (Benefit)**	**Excess ADIT Regulatory Offset**
					Sum of Cc
		27,657,906			169,633,798
			178,989	50,779	
		(229,768)			11,462,675
			12,050,328	33,866,541	
			17,506,744	(22,830,662)	
		(45,916,869)			337,435,455
		5,323,928			142,502,316
			12,742,930	(5,149,292)	
		(47,999,123)			(1,916,171)
					(3,777,595)
		61,163,926			(655,340,478)
-	-	-	(42,478,991)	(5,937,366)	-
			NOTE F		

K	L	M	N	O	P
					Sum of Cc
		6,035,548			29,505,705
			1,147,396	13,319,418	
			3,749,270	(20,310,000)	
		(14,466,814)			65,081,621
		16,560,730			29,992,585
			(1,308,950)	7,091,176	
		(12,428,476)			(8,364,069)
					(2,105,953)
		4,299,012			(114,109,889)
-	-	-	(3,587,716)	(100,594)	-
			NOTE F		

Q	R
ıding Balance	
Excess ADIT in Utility Deferrals	**Reference**
ıls (I) - (O)	**-**
	WS B - 2 Col B/C, ADIT item 3.16
(11,462,675)	
	WS B - 1, Col B/C, ADIT Item 2.06
(337,435,455)	WS B - 1 Cols O+P+Q+R+S , ADIT Item 5.5ǃ
(142,502,306)	
	WS B - 1 Col B/C, ADIT Item 5.59
5,717,012	WS B - 1 Col B/C, Items 10.25
	WS B - 1 Col B/C, Item 10.28
	Company Records
	FERC Form 1 p. 278 Ln. 3 Cols, (b) /(f)
(485,683,424)	

Q	R
ıls (I) - (O)	
	Company Records
(65,081,621)	WS B - 1 Col Q, ADIT 5.59
(29,992,585)	
	Company Records
10,470,022	WS B - 1 Col Q, item 10.25
	Company Records
	Company Records
	Company Records
(84,604,184)	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
Indiana Michigan Power Company

Materials & Supplies

Line Number	(A)	(B)	(C) Source	(D) Balance @ December 31, 2021	(E) Balance @ December 31, 2020	(F) Average Balance for 2021
1						
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,489,000	1,489,000	1,489,000
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	534,000	534,000	534,000
4		Stores Expense (Undistributed) - Account 163	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary (Note 1)

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, 2021	12,100,000	(181,403,000)	0	8,784,000	184,719,000	193,503,000
7		Totals as of December 31, 2020	12,100,000	(170,462,000)		8,784,000	173,778,000	182,562,000
8		**Average Balance**	12,100,000	(175,932,500)	-	8,784,000	179,248,500	188,032,500

Prepayments Account 165 - Balance @ 12/31/2021

9	Acc. No.	Description	2021 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	5,770,000	-		5,770,000		5,770,000	Plant Related Insurance Policies
11	165000218	Prepaid Taxes	-	-				-	
12	165000219	Prepaid Taxes	956,000	956,000				-	Prepaid Taxes-Distribution
13	1650003	Prepaid Rents	8,000	8,000				-	River Transport
14	1650005	Prepaid Employee Benefits	-	-				-	
15	1650006	Other Prepayments	1,288,000	1,288,000				-	Relates to EPRI dues
16	1650009	Prepaid Carry Cost-Factored AR	212,000	212,000				-	AR Factoring
17	1650010	Prepaid Pension Benefits	95,923,000	-			95,923,000	95,923,000	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(95,923,000)	(95,923,000)				-	SFAS 158 Offset
19	165001119	Prepaid Sales Taxes	752,000	752,000				-	Prepaid Sales Tax - Distribution
20	165001219	Prepaid Use Taxes	100,000	100,000				-	Prepaid Use Tax - Distribution
21	1650021	Prepaid Insurance - EIS	2,526,000	-		2,526,000		2,526,000	Energy INS Services
22	1650022	Prepaid SNF Container Costs	-	-				-	
23	1650023	Prepaid Lease	488,000	-		488,000		488,000	Prepaid Leases-All Functions
24	1650026	Prepaid SNF Costs	-	-				-	
25	1650030	Other Payments - Long Term	-	-				-	Other - Dist
26	1650035	PRW without MED-D Benefits	88,796,000	-			88,796,000	88,796,000	Med-D Benefits
27	1650037	FAS 158 Contra-PRW Exc Med-D	(88,796,000)	(88,796,000)				-	SFAS 158 Offset
28									
29									
30									
31									
		Subtotal - Form 1, p 111.57.c	12,100,000	(181,403,000)	0	8,784,000	184,719,000	193,503,000	

Prepayments Account 165 - Balance @ 12/31/ 2020

32	Acc. No.	Description	2020 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
33	1650001	Prepaid Insurance	5,770,000	-		5,770,000		5,770,000	Plant Related Insurance Policies
34	165000218	Prepaid Taxes	-	-				-	
35	165000219	Prepaid Taxes	956,000	956,000				-	Prepaid Taxes-Distribution
36	1650003	Prepaid Rents	8,000	8,000				-	River Transport
37	1650005	Prepaid Employee Benefits	-	-				-	
38	1650006	Other Prepayments	1,288,000	1,288,000				-	Relates to EPRI dues
39	1650009	Prepaid Carry Cost-Factored AR	212,000	212,000				-	AR Factoring
40	1650010	Prepaid Pension Benefits	95,923,000	-			95,923,000	95,923,000	Prefunded Pension Expense
41	1650014	FAS 158 Qual Contra Asset	(95,923,000)	(95,923,000)				-	SFAS 158 Offset
42	165001119	Prepaid Sales Taxes	752,000	752,000				-	Prepaid Sales Tax - Distribution
43	165001219	Prepaid Use Taxes	100,000	100,000				-	Prepaid Use Tax - Distribution
44	1650021	Prepaid Insurance - EIS	2,526,000	-		2,526,000		2,526,000	Energy INS Services
45	1650022	Prepaid SNF Container Costs	-	-				-	
46	1650023	Prepaid Lease	488,000	-		488,000		488,000	Prepaid Leases-All Functions
47	1650026	Prepaid SNF Costs	-	-				-	
48	1650030	Other Payments - Long Term	-	-				-	Other - Dist
49	1650035	PRW without MED-D Benefits	77,855,000	-			77,855,000	77,855,000	Med-D Benefits
50	1650037	FAS 158 Contra-PRW Exc Med-D	(77,855,000)	(77,855,000)				-	SFAS 158 Offset
51									
52									
53									
54									
		Subtotal - Form 1, p 111.57.d	12,100,000	(170,462,000)		8,784,000	173,778,000	182,562,000	

Note 1: Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to the company resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or state income taxes which are attributable to income earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
Indiana Michigan Power Company

Line Number	(A) Description	(B) 2021
1	Net Funds from IPP Customers 12/31/2020 (2021 FORM 1, P269)	(3,485,000)
2	Interest Accrual (Company Records - Note 1)	(192,000)
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 12/31/2021 (2021 FORM 1, P269)	(3,677,000)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(3,581,000)

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 Actual/Projected 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)**	5,398,000	5,398,000	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	3,808,000	3,750,000	58,000
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	9,838,000	7,664,000	2,174,000
4	**Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)**	2,855,000	1,941,000	914,000
5	**Account 456 - Other Electric Revenues - (Company Records - Notes 1,2)**	39,464,000	39,464,000	-
5a	**Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)**		-	
5b	**Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)**		-	
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	61,363,000	58,217,000	3,146,000
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**		-	
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	61,363,000	58,217,000	3,146,000

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.

Note 2 The total of line 4 and line 5 will equal total Account 456 as listed on FF1 p.300.21-22.(b)

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

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
Indiana Michigan Power Company

Line Number	(A) Item No.	(B) Description	(C) 2021 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1						
2						
3						
4		**Total**	0			
		Detail of Account 561 Per FERC Form 1				
5						
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	0			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	373,000			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	0			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,371,000			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	226,000			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services	1,365,000			
14		**Total of Account 561**	7,335,000			
		Account 928				
15	9280000	Regulatory Commission Exp	1,000	1,000	-	
16	9280001	Regulatory Commission Exp-Adm	8,050,000	8,050,000	-	
17	9280002	Regulatory Commission Exp-Case	3,497,000	3,497,000	-	
18	9280005	Reg Com Exp-FERC Trans Cases	29,000	-	29,000	
19						
20		**Total (FERC Form 1 p.323.189.b)**	11,577,000	11,548,000	29,000	
		Account 930.1				
21	9301000	General Advertising Expenses	1,000	1,000	-	
22	9301001	Newspaper Advertising Space	12,000	12,000	-	
23	9301002	Radio Station Advertising Time	1,000	1,000	-	
24	9301003	TV Station Advertising Time	-	-	-	
25	9301006	Spec Corporate Comm Info Proj	-	-	-	
26	9301007	Special Adv Space & Prod Exp	-	-	-	
27	9301008	Direct Mail and Handouts	-	-	-	
28	9301009	Fairs, Shows, and Exhibits	-	-	-	
29	9301010	Publicity	1,000	1,000	-	
30	9301011	Dedications, Tours, & Openings	-	-	-	
31	9301012	Public Opinion Surveys	46,000	46,000	-	
32	9301013	Movies Slide Films & Speeches	-	-	-	
33	9301014	Video Communications	-	-	-	
34	9301015	Other Corporate Comm Exp	17,000	17,000	-	
35				-	-	
36				-	-	
37		**Total (FERC Form 1 p.323.191.b)**	78,000	78,000	-	
		Account 930.2				
38	9302000	Misc General Expenses	3,969,000	3,969,000		
39	9302003	Corporate & Fiscal Expenses	129,000	129,000		
40	9302004	Research, Develop&Demonstr Exp	-	-		
	9302005	Nucl Fac Ins - Replce Engy Cst	-			
41	9302006	Assoc Business Development Materials Sold	88,000	88,000		
42	9302007	Assoc Business Development Exp	2,190,000	1,022,000	1,168,000	
43		**Total (FERC Form 1 p.323.192.b)**	6,376,000	5,208,000	1,168,000	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
Indiana Michigan Power Company

Indiana Corporate Income Tax Rate	5.38%	
Apportionment Factor - Note 2	69.74%	
Effective State Tax Rate		3.75%
Michigan Single Business Tax Rate	6.00%	
Apportionment Factor - Note 2	14.75%	
Effective State Tax Rate		0.89%
West Virginia Corporation Income Tax Rate	6.50%	
Apportionment Factor - Note 2	2.15%	
Effective State Tax Rate		0.14%
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	5.00%	
Apportionment Factor - Note 2	1.11%	
Effective State Tax Rate		0.06%
Missouri Corporation Income Tax Rate	4.00%	
Apportionment Factor - Note 2	0.01%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.65%	
Effective State Tax Rate		0.16%
Total Effective State Income Tax Rate		5.00%

Note 1 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H Supporting Taxes Other than Income
Indiana Michigan Power Company

Line No.	(A) Account	(B) Total Company NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
2	Gross Receipts Tax	22,525,000				22,525,000
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Michigan	52,219,000	52,219,000			
5	Real and Personal Property - Indiana	21,388,000	21,388,000			
6	Real and Personal Property - Other Jurisdictions	26,000	26,000			
7	**Payroll Taxes**					
8	Federal Insurance Contribution (FICA)	13,642,000		13,642,000		
9	Federal Unemployment Tax	77,000		77,000		
10	State Unemployment Insurance	414,000		414,000		
11	**Production Taxes**					
12	State Severance Taxes	-				-
13	**Miscellaneous Taxes**					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	2,718,000			2,718,000	
16	State Franchise Taxes	29,000			29,000	
17	State Lic/Registration Fee	-			-	
18	Misc. State and Local Tax	(15,000)			(15,000)	
19	Sales & Use	146,000				146,000
20	Federal Excise Tax	3,000				3,000
21	Gross Receipts Audit	(255,000)				(255,000)
22						
23	Total Taxes by Allocable Basis	112,917,000	73,633,000	14,133,000	2,732,000	22,419,000

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

Functional Property Tax Allocation

Line No.	Account	Production	Transmsission	Distribution	General	Total
24	Functionalized Net Plant (TCOS, Lns 41 thru 46)	2,647,991,000	1,264,874,000	2,072,431,000	142,423,000	6,127,719,000
	MICHIGAN JURISDICTION					
25	Percentage of Plant in MICHIGAN JURISDICTION	82.71%	16.36%	18.49%	14.99%	
26	Net Plant in MICHIGAN JURISDICTION (Ln 24 * Ln 25)	2,190,153,356	206,933,386	383,192,492	21,349,208	2,801,628,442
27	Less: Net Value of Exempted Generation Plant	448,826,670				
28	Taxable Property Basis (Ln 26 - Ln 27)	1,741,326,686	206,933,386	383,192,492	21,349,208	2,352,801,772
29	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
30	Weighted Net Plant (Ln 28 * Ln 29)	1,741,326,686	206,933,386	383,192,492	21,349,208	
31	General Plant Allocator (Ln 30 / (Total - General Plant))	74.69%	8.88%	16.44%	-100.00%	
32	Functionalized General Plant (Ln 31 * General Plant)	15,945,401	1,894,898	3,508,910	(21,349,208)	-
33	Weighted MICHIGAN JURISDICTION Plant (Ln 30 + 32)	1,757,272,087	208,828,284	386,701,402	(0)	2,352,801,772
34	Functional Percentage (Ln 33/Total Ln 33)	74.69%	8.88%	16.44%		
	INDIANA JURISDICTION					
35	Percentage of Plant in INDIANA JURISDICTION	17.29%	83.64%	81.51%	84.86%	
36	Net Plant in INDIANA JURISDICTION (Ln 24 * Ln 35)	457,837,644	1,057,940,614	1,689,238,508	120,860,158	3,325,876,923
37	Less: Net Value of Exempted Generation Plant	135,862,530				
38	Taxable Property Basis (Ln 36 - Ln 37)	321,975,114	1,057,940,614	1,689,238,508	120,860,158	3,190,014,393
39	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
40	Weighted Net Plant (Ln 38 * Ln 39)	321,975,114	1,057,940,614	1,689,238,508	120,860,158	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	10.49%	34.47%	55.04%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	12,679,051	41,660,620	66,520,486	(120,860,158)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	334,654,165	1,099,601,234	1,755,758,994	(0)	3,190,014,393
44	Functional Percentage (Ln 43/Total Ln 43)	10.49%	34.47%	55.04%		
45	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)	-	5,064	-	-	26,000

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
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	22,525,000	22,525,000	

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	Tax Year	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference	Tax Year Factor (Note 2)	Transmission Function (Note 2)
3	Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)		73,633,000				12,011,913
4	Real and Personal Property - Michigan		52,219,000				4,634,816
		2021		52,219,000		8.88%	4,634,816
							-
							-
							-
							-
5	Real and Personal Property - Indiana		21,388,000				7,372,466
		2021		21,388,000		34.47%	7,372,466
							-
							-
							-
							-
							-
							-
							-
							-
6	Real and Personal Property - Other		26,000				4,631
		2021		26,000		17.81%	4,631
							-
							-
							-
							-
			-				-
7	Real and Personal Property - Other Jurisdictions			-			-
							-
							-

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)	13,642,000	13,642,000	
10	Federal Unemployment Tax	77,000	77,000	
11	State Unemployment Insurance	414,000	414,000	
12	**Production Taxes**	-		
13	State Severance Taxes		-	
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax	-	-	
16	State Public Service Commission Fees	2,718,000	2,718,000	
17	State Franchise Taxes	29,000	29,000	
18	State Lic/Registration Fee	-	-	
19	Misc. State and Local Tax	(15,000)	(15,000)	
20	Sales & Use	146,000	146,000	
21	Federal Excise Tax	3,000	3,000	
22	Michigan Single Business Tax	(255,000)	(255,000)	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	112,917,000	112,917,000	

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.(c) of the Ferc Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assesed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year.

AEP East Companies
Cost of Service Formula Rate Using 2021 FF1 Balances
Worksheet I RESERVED FOR FUTURE USE
Indiana Michigan Power Company

AEP East Companies
Cost of Service Formula Rate Using 2021 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 (TCOS, ln 156)			10.35%
Project ROE Incentive Adder			
ROE with additional basis point incentive			10.35%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 154 through156)

	%	Cost	Weighted cost
Long Term Debt	55.41%	3.89%	2.156%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	44.59%	10.35%	4.616%
		R =	6.772%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2021	5,251,215	5,251,215	$ -

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

Rate Base (TCOS, ln 68)	999,769,571
R (from A. above)	6.772%
Return (Rate Base x R)	67,700,295

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

Return (from B. above)	67,700,295
Effective Tax Rate (TCOS, ln 114)	22.66%
Income Tax Calculation (Return x CIT)	15,340,706
ITC Adjustment	(973,759)
Excess Deferred Income Tax	(4,570,286)
Tax Affect of Permanent Differences	1,696,203
Income Taxes	11,492,864

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

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

Annual Revenue Requirement (TCOS, ln 1)	162,340,701
Lease Payments (TCOS, Ln 95)	-
Return (TCOS, ln 126)	67,700,295
Income Taxes (TCOS, ln 125)	11,492,864
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	83,147,543

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

Annual Revenue Requirement, Less Lease Payments, Return and Taxes	83,147,543
Return (from I.B. above)	67,700,295
Income Taxes (from I.C. above)	11,492,864
Annual Revenue Requirement, with Basis Point ROE increase	162,340,701
Depreciation (TCOS, ln 100)	41,621,218
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	120,719,483

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)	1,217,927,000
Annual Revenue Requirement, with Basis Point ROE increase	162,340,701
FCR with Basis Point increase in ROE	13.33%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	120,719,483
FCR with Basis Point ROE increase, less Depreciation	9.91%
FCR less Depreciation (TCOS, ln 10)	9.91%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for 2021 (TCOS, ln 21)	1,689,211,000
Annual Depreciation and Amortization Expense (TCOS, ln 100)	41,621,218
Composite Depreciation Rate	2.46%
Depreciable Life for Composite Depreciation Rate	40.59
Round to nearest whole year	41

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

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

A. Base Plan Facilities

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

Project Description:

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

Current Projected Year ARR	**786,905**
Current Projected Year ARR w/ Incentive	**786,905**
Current Projected Year Incentive ARR	-

Details

Investment	8,327,150	Current Year	**2021**
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	203,101

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	8,327,150	101,551	8,225,599	921,895	921,895	$ -		
2010	8,225,599	203,101	8,022,498	1,008,347	1,008,347	$ -	$ 1,408,114	$ 1,408,114
2011	8,022,498	203,101	7,819,397	988,216	988,216	$ -	$ 1,487,355	$ 1,487,355
2012	7,819,397	203,101	7,616,296	968,085	968,085	$ -	$ 1,319,695	$ 1,319,695
2013	7,616,296	203,101	7,413,195	947,954	947,954	$ -	$ 1,272,484	$ 1,272,484
2014	7,413,195	203,101	7,210,093	927,823	927,823	$ -	$ 1,249,385	$ 1,249,385
2015	7,210,093	203,101	7,006,992	907,692	907,692	$ -	$ 1,278,273	$ 1,278,273
2016	7,006,992	203,101	6,803,891	887,560	887,560	$ -	$ 1,254,654	$ 1,254,654
2017	6,803,891	203,101	6,600,790	867,429	867,429	$ -	$ 1,132,871	$ 1,132,871
2018	6,600,790	203,101	6,397,688	847,298	847,298	$ -	$ 933,326	$ 933,326
2019	6,397,688	203,101	6,194,587	827,167	827,167	$ -	$ 856,880	$ 856,880
2020	6,194,587	203,101	5,991,486	807,036	807,036	$ -	$ 804,584	$ 804,584
2021	5,991,486	203,101	5,788,385	786,905	786,905	$ -		
2022	5,788,385	203,101	5,585,284	766,773	766,773	$ -		
2023	5,585,284	203,101	5,382,182	746,642	746,642	$ -		
2024	5,382,182	203,101	5,179,081	726,511	726,511	$ -		
2025	5,179,081	203,101	4,975,980	706,380	706,380	$ -		
2026	4,975,980	203,101	4,772,879	686,249	686,249	$ -		
2027	4,772,879	203,101	4,569,777	666,118	666,118	$ -		
2028	4,569,777	203,101	4,366,676	645,987	645,987	$ -		
2029	4,366,676	203,101	4,163,575	625,855	625,855	$ -		
2030	4,163,575	203,101	3,960,474	605,724	605,724	$ -		
2031	3,960,474	203,101	3,757,373	585,593	585,593	$ -		
2032	3,757,373	203,101	3,554,271	565,462	565,462	$ -		
2033	3,554,271	203,101	3,351,170	545,331	545,331	$ -		
2034	3,351,170	203,101	3,148,069	525,200	525,200	$ -		
2035	3,148,069	203,101	2,944,968	505,069	505,069	$ -		
2036	2,944,968	203,101	2,741,866	484,937	484,937	$ -		
2037	2,741,866	203,101	2,538,765	464,806	464,806	$ -		
2038	2,538,765	203,101	2,335,664	444,675	444,675	$ -		
2039	2,335,664	203,101	2,132,563	424,544	424,544	$ -		
2040	2,132,563	203,101	1,929,462	404,413	404,413	$ -		
2041	1,929,462	203,101	1,726,360	384,282	384,282	$ -		
2042	1,726,360	203,101	1,523,259	364,150	364,150	$ -		
2043	1,523,259	203,101	1,320,158	344,019	344,019	$ -		
2044	1,320,158	203,101	1,117,057	323,888	323,888	$ -		
2045	1,117,057	203,101	913,955	303,757	303,757	$ -		
2046	913,955	203,101	710,854	283,626	283,626	$ -		
2047	710,854	203,101	507,753	263,495	263,495	$ -		
2048	507,753	203,101	304,652	243,364	243,364	$ -		
2049	304,652	203,101	101,551	223,232	223,232	$ -		
2050	101,551	101,551	-	106,583	106,583	$ -		
2051	-	-	-	-	-	$ -		
2052	-	-	-	-	-	$ -		
2053	-	-	-	-	-	$ -		
2054	-	-	-	-	-	$ -		
2055	-	-	-	-	-	$ -		
2056	-	-	-	-	-	$ -		
2057	-	-	-	-	-	$ -		
2058	-	-	-	-	-	$ -		
2059	-	-	-	-	-	$ -		
2060	-	-	-	-	-	$ -		
2061	-	-	-	-	-	$ -		
2062	-	-	-	-	-	$ -		
2063	-	-	-	-	-	$ -		
2064	-	-	-	-	-	$ -		
2065	-	-	-	-	-	$ -		
2066	-	-	-	-	-	$ -		
2067	-	-	-	-	-	$ -		
2068	-	-	-	-	-	$ -		
Project Totals		8,327,150		25,660,072	25,660,072	-		

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

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

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

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

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

A. Base Plan Facilities

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

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

Current Projected Year ARR	**61,041**
Current Projected Year ARR w/ Incentive	**61,041**
Current Projected Year Incentive ARR	**-**

Details			
Investment	585,981	Current Year	2021
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	14,292

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	585,981	7,146	578,835	64,874	64,874	$ -	$ 92,625		$ 92,625		
2014	578,835	14,292	564,543	70,957	70,957	$ -	$ 87,393		$ 87,393		
2015	564,543	14,292	550,250	69,541	69,541	$ -	$ 87,463		$ 87,463		
2016	550,250	14,292	535,958	68,124	68,124	$ -	$ 85,936		$ 85,936		
2017	535,958	14,292	521,666	66,707	66,707	$ -	$ 77,494		$ 77,494		
2018	521,666	14,292	507,374	65,291	65,291	$ -	$ 70,215		$ 70,215		
2019	507,374	14,292	493,082	63,874	63,874	$ -	$ 65,616		$ 65,616		
2020	493,082	14,292	478,789	62,458	62,458	$ -	$ 61,867		$ 61,867		
2021	478,789	14,292	464,497	61,041	61,041	$ -					
2022	464,497	14,292	450,205	59,624	59,624	$ -					
2023	450,205	14,292	435,913	58,208	58,208	$ -					
2024	435,913	14,292	421,620	56,791	56,791	$ -					
2025	421,620	14,292	407,328	55,374	55,374	$ -					
2026	407,328	14,292	393,036	53,958	53,958	$ -					
2027	393,036	14,292	378,744	52,541	52,541	$ -					
2028	378,744	14,292	364,452	51,125	51,125	$ -					
2029	364,452	14,292	350,159	49,708	49,708	$ -					
2030	350,159	14,292	335,867	48,291	48,291	$ -					
2031	335,867	14,292	321,575	46,875	46,875	$ -					
2032	321,575	14,292	307,283	45,458	45,458	$ -					
2033	307,283	14,292	292,991	44,041	44,041	$ -					
2034	292,991	14,292	278,698	42,625	42,625	$ -					
2035	278,698	14,292	264,406	41,208	41,208	$ -					
2036	264,406	14,292	250,114	39,792	39,792	$ -					
2037	250,114	14,292	235,822	38,375	38,375	$ -					
2038	235,822	14,292	221,529	36,958	36,958	$ -					
2039	221,529	14,292	207,237	35,542	35,542	$ -					
2040	207,237	14,292	192,945	34,125	34,125	$ -					
2041	192,945	14,292	178,653	32,708	32,708	$ -					
2042	178,653	14,292	164,361	31,292	31,292	$ -					
2043	164,361	14,292	150,068	29,875	29,875	$ -					
2044	150,068	14,292	135,776	28,458	28,458	$ -					
2045	135,776	14,292	121,484	27,042	27,042	$ -					
2046	121,484	14,292	107,192	25,625	25,625	$ -					
2047	107,192	14,292	92,899	24,209	24,209	$ -					
2048	92,899	14,292	78,607	22,792	22,792	$ -					
2049	78,607	14,292	64,315	21,375	21,375	$ -					
2050	64,315	14,292	50,023	19,959	19,959	$ -					
2051	50,023	14,292	35,731	18,542	18,542	$ -					
2052	35,731	14,292	21,438	17,125	17,125	$ -					
2053	21,438	14,292	7,146	15,709	15,709	$ -					
2054	7,146	7,146	-	7,500	7,500	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		585,981		1,805,698	1,805,698	-					

** 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	**2,278,398**
Current Projected Year ARR w/ Incentive	**2,278,398**
Current Projected Year Incentive ARR	**-**

Details			
Investment	21,957,101	Current Year	**2021**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	535,539

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	21,957,101	357,026	21,600,075	2,515,694	2,515,694	$ -	$ 1,301,059		$ 1,301,059		
2014	21,600,075	535,539	21,064,536	2,649,972	2,649,972	$ -	$ 3,243,481		$ 3,243,481		
2015	21,064,536	535,539	20,528,997	2,596,890	2,596,890	$ -	$ 3,604,460		$ 3,604,460		
2016	20,528,997	535,539	19,993,458	2,543,808	2,543,808	$ -	$ 3,506,792		$ 3,506,792		
2017	19,993,458	535,539	19,457,919	2,490,726	2,490,726	$ -	$ 3,162,406		$ 3,162,406		
2018	19,457,919	535,539	18,922,380	2,437,644	2,437,644	$ -	$ 2,623,914		$ 2,623,914		
2019	18,922,380	535,539	18,386,841	2,384,562	2,384,562	$ -	$ 2,433,873		$ 2,433,873		
2020	18,386,841	535,539	17,851,302	2,331,480	2,331,480	$ -	$ 2,310,007		$ 2,310,007		
2021	17,851,302	535,539	17,315,763	2,278,398	2,278,398	$ -					
2022	17,315,763	535,539	16,780,224	2,225,316	2,225,316	$ -					
2023	16,780,224	535,539	16,244,684	2,172,234	2,172,234	$ -					
2024	16,244,684	535,539	15,709,145	2,119,152	2,119,152	$ -					
2025	15,709,145	535,539	15,173,606	2,066,070	2,066,070	$ -					
2026	15,173,606	535,539	14,638,067	2,012,988	2,012,988	$ -					
2027	14,638,067	535,539	14,102,528	1,959,906	1,959,906	$ -					
2028	14,102,528	535,539	13,566,989	1,906,824	1,906,824	$ -					
2029	13,566,989	535,539	13,031,450	1,853,742	1,853,742	$ -					
2030	13,031,450	535,539	12,495,911	1,800,660	1,800,660	$ -					
2031	12,495,911	535,539	11,960,372	1,747,578	1,747,578	$ -					
2032	11,960,372	535,539	11,424,833	1,694,496	1,694,496	$ -					
2033	11,424,833	535,539	10,889,294	1,641,414	1,641,414	$ -					
2034	10,889,294	535,539	10,353,755	1,588,332	1,588,332	$ -					
2035	10,353,755	535,539	9,818,216	1,535,250	1,535,250	$ -					
2036	9,818,216	535,539	9,282,677	1,482,168	1,482,168	$ -					
2037	9,282,677	535,539	8,747,138	1,429,086	1,429,086	$ -					
2038	8,747,138	535,539	8,211,599	1,376,004	1,376,004	$ -					
2039	8,211,599	535,539	7,676,060	1,322,922	1,322,922	$ -					
2040	7,676,060	535,539	7,140,521	1,269,840	1,269,840	$ -					
2041	7,140,521	535,539	6,604,982	1,216,758	1,216,758	$ -					
2042	6,604,982	535,539	6,069,443	1,163,676	1,163,676	$ -					
2043	6,069,443	535,539	5,533,904	1,110,594	1,110,594	$ -					
2044	5,533,904	535,539	4,998,364	1,057,512	1,057,512	$ -					
2045	4,998,364	535,539	4,462,825	1,004,430	1,004,430	$ -					
2046	4,462,825	535,539	3,927,286	951,348	951,348	$ -					
2047	3,927,286	535,539	3,391,747	898,266	898,266	$ -					
2048	3,391,747	535,539	2,856,208	845,184	845,184	$ -					
2049	2,856,208	535,539	2,320,669	792,102	792,102	$ -					
2050	2,320,669	535,539	1,785,130	739,020	739,020	$ -					
2051	1,785,130	535,539	1,249,591	685,938	685,938	$ -					
2052	1,249,591	535,539	714,052	632,856	632,856	$ -					
2053	714,052	535,539	178,513	579,774	579,774	$ -					
2054	178,513	178,513	-	187,360	187,360	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		21,957,101		67,297,973	67,297,973	-					

** 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	**124,826**
Current Projected Year ARR w/ Incentive	**124,826**
Current Projected Year Incentive ARR	**-**

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

Details			
Investment	1,112,263	Current Year	2021
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	10	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	27,128

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **
2016	1,112,263	4,521	1,107,742	114,544	114,544	$ -	$ 226,163	$ 226,163
2017	1,107,742	27,128	1,080,613	135,582	135,582	$ -	$ 7,946	$ 7,946
2018	1,080,613	27,128	1,053,485	132,893	132,893	$ -	$ 18,182	$ 18,182
2019	1,053,485	27,128	1,026,357	130,204	130,204	$ -	$ 125,631	$ 125,631
2020	1,026,357	27,128	999,228	127,515	127,515	$ -	$ 125,733	$ 125,733
2021	999,228	27,128	972,100	124,826	124,826	$ -		
2022	972,100	27,128	944,971	122,137	122,137	$ -		
2023	944,971	27,128	917,843	119,448	119,448	$ -		
2024	917,843	27,128	890,715	116,759	116,759	$ -		
2025	890,715	27,128	863,586	114,070	114,070	$ -		
2026	863,586	27,128	836,458	111,382	111,382	$ -		
2027	836,458	27,128	809,330	108,693	108,693	$ -		
2028	809,330	27,128	782,201	106,004	106,004	$ -		
2029	782,201	27,128	755,073	103,315	103,315	$ -		
2030	755,073	27,128	727,944	100,626	100,626	$ -		
2031	727,944	27,128	700,816	97,937	97,937	$ -		
2032	700,816	27,128	673,688	95,248	95,248	$ -		
2033	673,688	27,128	646,559	92,559	92,559	$ -		
2034	646,559	27,128	619,431	89,870	89,870	$ -		
2035	619,431	27,128	592,303	87,181	87,181	$ -		
2036	592,303	27,128	565,174	84,492	84,492	$ -		
2037	565,174	27,128	538,046	81,803	81,803	$ -		
2038	538,046	27,128	510,918	79,114	79,114	$ -		
2039	510,918	27,128	483,789	76,425	76,425	$ -		
2040	483,789	27,128	456,661	73,737	73,737	$ -		
2041	456,661	27,128	429,532	71,048	71,048	$ -		
2042	429,532	27,128	402,404	68,359	68,359	$ -		
2043	402,404	27,128	375,276	65,670	65,670	$ -		
2044	375,276	27,128	348,147	62,981	62,981	$ -		
2045	348,147	27,128	321,019	60,292	60,292	$ -		
2046	321,019	27,128	293,891	57,603	57,603	$ -		
2047	293,891	27,128	266,762	54,914	54,914	$ -		
2048	266,762	27,128	239,634	52,225	52,225	$ -		
2049	239,634	27,128	212,506	49,536	49,536	$ -		
2050	212,506	27,128	185,377	46,847	46,847	$ -		
2051	185,377	27,128	158,249	44,158	44,158	$ -		
2052	158,249	27,128	131,120	41,469	41,469	$ -		
2053	131,120	27,128	103,992	38,780	38,780	$ -		
2054	103,992	27,128	76,864	36,091	36,091	$ -		
2055	76,864	27,128	49,735	33,403	33,403	$ -		
2056	49,735	27,128	22,607	30,714	30,714	$ -		
2057	22,607	22,607	-	23,727	23,727	$ -		
2058	-	-	-	-	-	$ -		
2059	-	-	-	-	-	$ -		
2060	-	-	-	-	-	$ -		
2061	-	-	-	-	-	$ -		
2062	-	-	-	-	-	$ -		
2063	-	-	-	-	-	$ -		
2064	-	-	-	-	-	$ -		
2065	-	-	-	-	-	$ -		
2066	-	-	-	-	-	$ -		
2067	-	-	-	-	-	$ -		
2068	-	-	-	-	-	$ -		
2069	-	-	-	-	-	$ -		
2070	-	-	-	-	-	$ -		
2071	-	-	-	-	-	$ -		
2072	-	-	-	-	-	$ -		
2073	-	-	-	-	-	$ -		
2074	-	-	-	-	-	$ -		
2075	-	-	-	-	-	$ -		
Project Totals		1,112,263		3,464,182	3,464,182	-		

** 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: b2048 (Tanners Creek - Support for Transformer A/B Replacement)**

Current Projected Year ARR	**86,203**
Current Projected Year ARR w/ Incentive	**86,203**
Current Projected Year Incentive ARR	-

Details			
Investment	818,037	Current Year	**2021**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	19,952

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	818,037	-	818,037	81,083	81,083	$ -	$ -		$ -		
2014	818,037	19,952	798,085	100,046	100,046	$ -	$ 139,756		$ 139,756		
2015	798,085	19,952	778,133	98,069	98,069	$ -	$ 133,078		$ 133,078		
2016	778,133	19,952	758,181	96,091	96,091	$ -	$ 132,118		$ 132,118		
2017	758,181	19,952	738,229	94,113	94,113	$ -	$ 119,121		$ 119,121		
2018	738,229	19,952	718,276	92,136	92,136	$ -	$ 98,812		$ 98,812		
2019	718,276	19,952	698,324	90,158	90,158	$ -	$ 90,112		$ 90,112		
2020	698,324	19,952	678,372	88,180	88,180	$ -	$ 87,283		$ 87,283		
2021	678,372	19,952	658,420	86,203	86,203	$ -					
2022	658,420	19,952	638,468	84,225	84,225	$ -					
2023	638,468	19,952	618,516	82,247	82,247	$ -					
2024	618,516	19,952	598,564	80,270	80,270	$ -					
2025	598,564	19,952	578,612	78,292	78,292	$ -					
2026	578,612	19,952	558,659	76,315	76,315	$ -					
2027	558,659	19,952	538,707	74,337	74,337	$ -					
2028	538,707	19,952	518,755	72,359	72,359	$ -					
2029	518,755	19,952	498,803	70,382	70,382	$ -					
2030	498,803	19,952	478,851	68,404	68,404	$ -					
2031	478,851	19,952	458,899	66,426	66,426	$ -					
2032	458,899	19,952	438,947	64,449	64,449	$ -					
2033	438,947	19,952	418,995	62,471	62,471	$ -					
2034	418,995	19,952	399,042	60,494	60,494	$ -					
2035	399,042	19,952	379,090	58,516	58,516	$ -					
2036	379,090	19,952	359,138	56,538	56,538	$ -					
2037	359,138	19,952	339,186	54,561	54,561	$ -					
2038	339,186	19,952	319,234	52,583	52,583	$ -					
2039	319,234	19,952	299,282	50,605	50,605	$ -					
2040	299,282	19,952	279,330	48,628	48,628	$ -					
2041	279,330	19,952	259,378	46,650	46,650	$ -					
2042	259,378	19,952	239,425	44,673	44,673	$ -					
2043	239,425	19,952	219,473	42,695	42,695	$ -					
2044	219,473	19,952	199,521	40,717	40,717	$ -					
2045	199,521	19,952	179,569	38,740	38,740	$ -					
2046	179,569	19,952	159,617	36,762	36,762	$ -					
2047	159,617	19,952	139,665	34,784	34,784	$ -					
2048	139,665	19,952	119,713	32,807	32,807	$ -					
2049	119,713	19,952	99,761	30,829	30,829	$ -					
2050	99,761	19,952	79,808	28,851	28,851	$ -					
2051	79,808	19,952	59,856	26,874	26,874	$ -					
2052	59,856	19,952	39,904	24,896	24,896	$ -					
2053	39,904	19,952	19,952	22,919	22,919	$ -					
2054	19,952	19,952	0	20,941	20,941	$ -					
2055	0	0	-	0	0	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		818,037		2,561,318	2,561,318	-					

** 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: 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)**

Current Projected Year ARR	**1,397,056**
Current Projected Year ARR w/ Incentive	**1,397,056**
Current Projected Year Incentive ARR	**-**

Details			
Investment	13,008,915	Current Year	2021
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	10	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	317,291

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 **		
2014	13,008,915	52,882	12,956,034	1,339,689	1,339,689	$ -	$ -		$ -		
2015	12,956,034	317,291	12,638,743	1,585,753	1,585,753	$ -	$ 248,467		$ 248,467		
2016	12,638,743	317,291	12,321,452	1,554,303	1,554,303	$ -	$ 562,247		$ 562,247		
2017	12,321,452	317,291	12,004,162	1,522,854	1,522,854	$ -	$ 1,427,903		$ 1,427,903		
2018	12,004,162	317,291	11,686,871	1,491,404	1,491,404	$ -	$ 1,271,398		$ 1,271,398		
2019	11,686,871	317,291	11,369,581	1,459,955	1,459,955	$ -	$ 1,164,196		$ 1,164,196		
2020	11,369,581	317,291	11,052,290	1,428,505	1,428,505	$ -	$ 1,113,451		$ 1,113,451		
2021	11,052,290	317,291	10,734,999	1,397,056	1,397,056	$ -					
2022	10,734,999	317,291	10,417,709	1,365,606	1,365,606	$ -					
2023	10,417,709	317,291	10,100,418	1,334,157	1,334,157	$ -					
2024	10,100,418	317,291	9,783,127	1,302,707	1,302,707	$ -					
2025	9,783,127	317,291	9,465,837	1,271,258	1,271,258	$ -					
2026	9,465,837	317,291	9,148,546	1,239,808	1,239,808	$ -					
2027	9,148,546	317,291	8,831,256	1,208,359	1,208,359	$ -					
2028	8,831,256	317,291	8,513,965	1,176,909	1,176,909	$ -					
2029	8,513,965	317,291	8,196,674	1,145,460	1,145,460	$ -					
2030	8,196,674	317,291	7,879,384	1,114,011	1,114,011	$ -					
2031	7,879,384	317,291	7,562,093	1,082,561	1,082,561	$ -					
2032	7,562,093	317,291	7,244,803	1,051,112	1,051,112	$ -					
2033	7,244,803	317,291	6,927,512	1,019,662	1,019,662	$ -					
2034	6,927,512	317,291	6,610,221	988,213	988,213	$ -					
2035	6,610,221	317,291	6,292,931	956,763	956,763	$ -					
2036	6,292,931	317,291	5,975,640	925,314	925,314	$ -					
2037	5,975,640	317,291	5,658,349	893,864	893,864	$ -					
2038	5,658,349	317,291	5,341,059	862,415	862,415	$ -					
2039	5,341,059	317,291	5,023,768	830,965	830,965	$ -					
2040	5,023,768	317,291	4,706,478	799,516	799,516	$ -					
2041	4,706,478	317,291	4,389,187	768,066	768,066	$ -					
2042	4,389,187	317,291	4,071,896	736,617	736,617	$ -					
2043	4,071,896	317,291	3,754,606	705,167	705,167	$ -					
2044	3,754,606	317,291	3,437,315	673,718	673,718	$ -					
2045	3,437,315	317,291	3,120,024	642,268	642,268	$ -					
2046	3,120,024	317,291	2,802,734	610,819	610,819	$ -					
2047	2,802,734	317,291	2,485,443	579,370	579,370	$ -					
2048	2,485,443	317,291	2,168,153	547,920	547,920	$ -					
2049	2,168,153	317,291	1,850,862	516,471	516,471	$ -					
2050	1,850,862	317,291	1,533,571	485,021	485,021	$ -					
2051	1,533,571	317,291	1,216,281	453,572	453,572	$ -					
2052	1,216,281	317,291	898,990	422,122	422,122	$ -					
2053	898,990	317,291	581,699	390,673	390,673	$ -					
2054	581,699	317,291	264,409	359,223	359,223	$ -					
2055	264,409	264,409	-	277,513	277,513	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
Project Totals		13,008,915		40,516,719	40,516,719	-					

** 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: 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)**

Current Projected Year ARR	**373,465**
Current Projected Year ARR w/ Incentive	**373,465**
Current Projected Year Incentive ARR	**-**

Details			
Investment	3,315,854	Current Year	2021
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	80,874

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2016	3,315,854	-	3,315,854	328,664	328,664	$ -	$ 486,138		$ 486,138		
2017	3,315,854	80,874	3,234,980	405,530	405,530	$ -	$ 574,408		$ 574,408		
2018	3,234,980	80,874	3,154,105	397,514	397,514	$ -	$ 355,679		$ 355,679		
2019	3,154,105	80,874	3,073,231	389,498	389,498	$ -	$ 367,592		$ 367,592		
2020	3,073,231	80,874	2,992,356	381,481	381,481	$ -	$ 376,071		$ 376,071		
2021	2,992,356	80,874	2,911,482	373,465	373,465	$ -					
2022	2,911,482	80,874	2,830,607	365,449	365,449	$ -					
2023	2,830,607	80,874	2,749,733	357,433	357,433	$ -					
2024	2,749,733	80,874	2,668,858	349,417	349,417	$ -					
2025	2,668,858	80,874	2,587,984	341,400	341,400	$ -					
2026	2,587,984	80,874	2,507,109	333,384	333,384	$ -					
2027	2,507,109	80,874	2,426,235	325,368	325,368	$ -					
2028	2,426,235	80,874	2,345,360	317,352	317,352	$ -					
2029	2,345,360	80,874	2,264,486	309,336	309,336	$ -					
2030	2,264,486	80,874	2,183,611	301,320	301,320	$ -					
2031	2,183,611	80,874	2,102,737	293,303	293,303	$ -					
2032	2,102,737	80,874	2,021,862	285,287	285,287	$ -					
2033	2,021,862	80,874	1,940,988	277,271	277,271	$ -					
2034	1,940,988	80,874	1,860,113	269,255	269,255	$ -					
2035	1,860,113	80,874	1,779,239	261,239	261,239	$ -					
2036	1,779,239	80,874	1,698,364	253,222	253,222	$ -					
2037	1,698,364	80,874	1,617,490	245,206	245,206	$ -					
2038	1,617,490	80,874	1,536,615	237,190	237,190	$ -					
2039	1,536,615	80,874	1,455,741	229,174	229,174	$ -					
2040	1,455,741	80,874	1,374,866	221,158	221,158	$ -					
2041	1,374,866	80,874	1,293,992	213,142	213,142	$ -					
2042	1,293,992	80,874	1,213,117	205,125	205,125	$ -					
2043	1,213,117	80,874	1,132,243	197,109	197,109	$ -					
2044	1,132,243	80,874	1,051,368	189,093	189,093	$ -					
2045	1,051,368	80,874	970,494	181,077	181,077	$ -					
2046	970,494	80,874	889,619	173,061	173,061	$ -					
2047	889,619	80,874	808,745	165,044	165,044	$ -					
2048	808,745	80,874	727,870	157,028	157,028	$ -					
2049	727,870	80,874	646,996	149,012	149,012	$ -					
2050	646,996	80,874	566,121	140,996	140,996	$ -					
2051	566,121	80,874	485,247	132,980	132,980	$ -					
2052	485,247	80,874	404,372	124,963	124,963	$ -					
2053	404,372	80,874	323,498	116,947	116,947	$ -					
2054	323,498	80,874	242,623	108,931	108,931	$ -					
2055	242,623	80,874	161,749	100,915	100,915	$ -					
2056	161,749	80,874	80,874	92,899	92,899	$ -					
2057	80,874	80,874	0	84,883	84,883	$ -					
2058	0	0	-	0	0	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
Project Totals		3,315,854		10,382,120	10,382,120	-					

** 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: b2831.1 (Upgrade Tanner Creek-Miami Fort 345kV circuit)**

Current Projected Year ARR	**77,582**
Current Projected Year ARR w/ Incentive	**77,582**
Current Projected Year Incentive ARR	**-**

Details			
Investment	653,739	Current Year	2021
Service Year (yyyy)	2019	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	15,945

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 **		
2019	653,739	7,972	645,767	72,375	72,375	$ -	$ 67,813		$ 67,813		
2020	645,767	15,945	629,822	79,162	79,162	$ -	$ 66,522		$ 66,522		
2021	629,822	15,945	613,877	77,582	77,582	$ -					
2022	613,877	15,945	597,932	76,001	76,001	$ -					
2023	597,932	15,945	581,987	74,421	74,421	$ -					
2024	581,987	15,945	566,043	72,841	72,841	$ -					
2025	566,043	15,945	550,098	71,260	71,260	$ -					
2026	550,098	15,945	534,153	69,680	69,680	$ -					
2027	534,153	15,945	518,208	68,099	68,099	$ -					
2028	518,208	15,945	502,263	66,519	66,519	$ -					
2029	502,263	15,945	486,318	64,938	64,938	$ -					
2030	486,318	15,945	470,373	63,358	63,358	$ -					
2031	470,373	15,945	454,429	61,777	61,777	$ -					
2032	454,429	15,945	438,484	60,197	60,197	$ -					
2033	438,484	15,945	422,539	58,617	58,617	$ -					
2034	422,539	15,945	406,594	57,036	57,036	$ -					
2035	406,594	15,945	390,649	55,456	55,456	$ -					
2036	390,649	15,945	374,704	53,875	53,875	$ -					
2037	374,704	15,945	358,759	52,295	52,295	$ -					
2038	358,759	15,945	342,814	50,714	50,714	$ -					
2039	342,814	15,945	326,870	49,134	49,134	$ -					
2040	326,870	15,945	310,925	47,554	47,554	$ -					
2041	310,925	15,945	294,980	45,973	45,973	$ -					
2042	294,980	15,945	279,035	44,393	44,393	$ -					
2043	279,035	15,945	263,090	42,812	42,812	$ -					
2044	263,090	15,945	247,145	41,232	41,232	$ -					
2045	247,145	15,945	231,200	39,651	39,651	$ -					
2046	231,200	15,945	215,256	38,071	38,071	$ -					
2047	215,256	15,945	199,311	36,491	36,491	$ -					
2048	199,311	15,945	183,366	34,910	34,910	$ -					
2049	183,366	15,945	167,421	33,330	33,330	$ -					
2050	167,421	15,945	151,476	31,749	31,749	$ -					
2051	151,476	15,945	135,531	30,169	30,169	$ -					
2052	135,531	15,945	119,586	28,588	28,588	$ -					
2053	119,586	15,945	103,642	27,008	27,008	$ -					
2054	103,642	15,945	87,697	25,427	25,427	$ -					
2055	87,697	15,945	71,752	23,847	23,847	$ -					
2056	71,752	15,945	55,807	22,267	22,267	$ -					
2057	55,807	15,945	39,862	20,686	20,686	$ -					
2058	39,862	15,945	23,917	19,106	19,106	$ -					
2059	23,917	15,945	7,972	17,525	17,525	$ -					
2060	7,972	7,972	-	8,368	8,368	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
2076	-	-	-	-	-	$ -					
2077	-	-	-	-	-	$ -					
2078	-	-	-	-	-	$ -					
Project Totals		653,739		2,014,494	2,014,494	-					

** 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: b1465.5 (Make switching improvements at Sullivan and Jefferson 765 kV stations)**

Current Projected Year ARR	**65,740**
Current Projected Year ARR w/ Incentive	**65,740**
Current Projected Year Incentive ARR	**-**

Details			
Investment	633,540	Current Year	2021
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	9.91%
Useful life	41	FCR w/incentives approved for these facilities, less dep.	9.91%
CIAC (Yes or No)	No	Annual Depreciation Expense	15,452

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	633,540	10,301	623,239	72,587	72,587	$ -	$ -		$ -		
2014	623,239	15,452	607,786	76,461	76,461	$ -	$ -		$ -		
2015	607,786	15,452	592,334	74,929	74,929	$ -					
2016	592,334	15,452	576,882	73,398	73,398	$ -					
2017	576,882	15,452	561,430	71,866	71,866	$ -					
2018	561,430	15,452	545,978	70,335	70,335	$ -					
2019	545,978	15,452	530,525	68,803	68,803	$ -					
2020	530,525	15,452	515,073	67,271	67,271	$ -	$ 66,652		$ 66,652		
2021	515,073	15,452	499,621	65,740	65,740	$ -					
2022	499,621	15,452	484,169	64,208	64,208	$ -					
2023	484,169	15,452	468,717	62,677	62,677	$ -					
2024	468,717	15,452	453,264	61,145	61,145	$ -					
2025	453,264	15,452	437,812	59,613	59,613	$ -					
2026	437,812	15,452	422,360	58,082	58,082	$ -					
2027	422,360	15,452	406,908	56,550	56,550	$ -					
2028	406,908	15,452	391,456	55,019	55,019	$ -					
2029	391,456	15,452	376,003	53,487	53,487	$ -					
2030	376,003	15,452	360,551	51,955	51,955	$ -					
2031	360,551	15,452	345,099	50,424	50,424	$ -					
2032	345,099	15,452	329,647	48,892	48,892	$ -					
2033	329,647	15,452	314,195	47,361	47,361	$ -					
2034	314,195	15,452	298,742	45,829	45,829	$ -					
2035	298,742	15,452	283,290	44,297	44,297	$ -					
2036	283,290	15,452	267,838	42,766	42,766	$ -					
2037	267,838	15,452	252,386	41,234	41,234	$ -					
2038	252,386	15,452	236,934	39,703	39,703	$ -					
2039	236,934	15,452	221,481	38,171	38,171	$ -					
2040	221,481	15,452	206,029	36,639	36,639	$ -					
2041	206,029	15,452	190,577	35,108	35,108	$ -					
2042	190,577	15,452	175,125	33,576	33,576	$ -					
2043	175,125	15,452	159,673	32,045	32,045	$ -					
2044	159,673	15,452	144,220	30,513	30,513	$ -					
2045	144,220	15,452	128,768	28,981	28,981	$ -					
2046	128,768	15,452	113,316	27,450	27,450	$ -					
2047	113,316	15,452	97,864	25,918	25,918	$ -					
2048	97,864	15,452	82,412	24,387	24,387	$ -					
2049	82,412	15,452	66,960	22,855	22,855	$ -					
2050	66,960	15,452	51,507	21,323	21,323	$ -					
2051	51,507	15,452	36,055	19,792	19,792	$ -					
2052	36,055	15,452	20,603	18,260	18,260	$ -					
2053	20,603	15,452	5,151	16,729	16,729	$ -					
2054	5,151	5,151	-	5,406	5,406	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		633,540		1,941,784	1,941,784	-					

** 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 2021 FF1 Balances
Worksheet L Reserved for Future Use
Indiana Michigan Power Company

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital
Indiana Michigan Power Company

		Average Balance of Common Equity				
Line No	Month (a)	Proprietary Capital (b)	Less: Preferred Stock (c)	Less Undistributed Sub Earnings (Acct 216.1) (d)	Less AOCI (Acct 219.1) (e)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(e)
	(Note A)	(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)	
1	December Prior to Rate Year	2,661,167,000		(6,033,664)	(8,595,000)	2,675,795,664
2	January	2,695,684,000		(5,968,838)	(8,566,000)	2,710,218,838
3	February	2,673,017,000		(5,940,324)	(8,537,000)	2,687,494,324
4	March	2,701,694,000		(5,910,125)	(8,509,000)	2,716,113,125
5	April	2,701,999,000		(5,874,530)	(8,480,000)	2,716,353,530
6	May	2,674,514,000		(5,712,083)	(8,452,000)	2,688,678,083
7	June	2,698,942,000		(5,700,947)	(8,423,000)	2,713,065,947
8	July	2,733,990,000		(5,670,736)	(8,394,000)	2,748,054,736
9	August	2,721,313,000		(5,645,279)	(8,366,000)	2,735,324,279
10	September	2,734,073,000		(5,632,538)	(8,337,000)	2,748,042,538
11	October	2,744,896,000		(5,692,147)	(8,308,000)	2,758,896,147
12	November	2,715,190,000		(5,675,353)	(8,280,000)	2,729,145,353
13	December of Rate Year	2,732,874,000		(5,658,229)	(8,251,000)	2,746,783,229
14	Average of the 13 Monthly Balances	2,706,873,000	-	(5,778,000)	(8,423,000)	2,721,074,000

		Average Balance of Long Term Debt					
Line No	Month (a)	Acct 221 Bonds (b)	Less: Acct 222 Reacquired Bonds (c)	Acct 223 LT Advances from Assoc. Companies (d)	Acct 224 Senior Unsecured Notes (e)	Less: Fair Value Hedges (f)	Gross Proceeds Outstanding Long-Term Debt (g)=(b)-(c)+(d)+(e)-(f)
	(Note A)	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1	
15	December Prior to Rate Year		-		3,408,605,000		3,408,605,000
16	January		-		3,397,491,000		3,397,491,000
17	February		-		3,391,642,000		3,391,642,000
18	March		-		3,386,361,000		3,386,361,000
19	April		-		3,444,114,000		3,444,114,000
20	May		-		3,440,828,000		3,440,828,000
21	June		-		3,398,261,000		3,398,261,000
22	July		-		3,381,446,000		3,381,446,000
23	August		-		3,377,746,000		3,377,746,000
24	September		-		3,374,075,000		3,374,075,000
25	October		-		3,354,434,000		3,354,434,000
26	November		-		3,298,763,000		3,298,763,000
27	December of Rate Year		-		3,295,153,000		3,295,153,000
28	Average of the 13 Monthly Balances	-	-	-	3,380,686,000	-	3,380,686,000

NOTE 1: 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. (Page 257 Column H of the FF1)

Development of Cost of Long Term Debt Based on Average Outstanding Balance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	**Annual Interest Expense for 2021**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			127,770,000			
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below.			2,028,000			
32	Plus: Allowed Hedge Recovery From Ln 55 below.			2,028,000			
33	Amort of Debt Discount & Expense - Acct 428 (117.63.c)			2,145,000			
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			1,640,000			
35	Less: Amort of Premium on Debt - Acct 429 (117.65.c)						
36	Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c)						
37	**Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)**			131,555,000			
38	**Average Cost of Debt for 2021 (Ln 37/ ln 28 (g))**			**3.89%**			

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

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

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2021	Less Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
40	Senior Unsecured Notes - Series F	-	-	-	-	November 2004	November 2014
41	Senior Unsecured Notes - Series G	-	-	-	-	12/07/05	11/30/15
42	Senior Unsecured Notes - Series H	422,000	-	422,000	7,222,000	11/14/06	02/28/37
43	Senior Unsecured Notes - Series J	1,606,000	-	1,606,000	5,154,000	03/15/13	03/15/23
44				-			
45				-			
46				-			
47				-			
48				-			
49					12,376,000		
50	Total Hedge Amortization	2,028,000	-				

51	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48)	2,028,000
52	Total Average Capital Structure Balance for 2021 (TCOS, Ln 157)	6,101,760,000
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
54	Limit of Recoverable Amount	3,050,880
55	**Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)**	**2,028,000**

Development of Cost of Preferred Stock

	<u>Preferred Stock</u>			<u>Average</u>
56	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%	
57	0% Series - 0 - Par Value (p. 250-251)	$ -	$ -	
58	0% Series - 0 - Shares O/S (p.250-251)	-	-	
59	0% Series - 0 - Monetary Value (Ln 57 * Ln 58)	-	-	-
60	0% Series - 0 - Dividend Amount (Ln 56 * Ln 59)	-	-	-

61	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%	
62	0% Series - 0 - Par Value (p. 250-251)	$ -	$ -	
63	0% Series - 0 - Shares O/S (p.250-251)	-	-	
64	0% Series - 0 - Monetary Value (Ln 62 * Ln 63)	-	-	-
65	0% Series - 0 - Dividend Amount (Ln 61 * Ln 64)	-	-	-
66	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%	
67	0% Series - 0 - Par Value (p. 250-251)	$ -	$ -	
68	0% Series - 0 - Shares O/S (p.250-251)	-	-	
69	0% Series - 0 - Monetary Value (Ln 67 * Ln 68)	-	-	-
70	0% Series - 0 - Dividend Amount (Ln 66 * Ln 69)	-	-	-
71	**Balance of Preferred Stock (Lns 59, 64, 69)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
72	**Dividends on Preferred Stock (Lns 60, 65, 70)**	-	-	**-**
73	**Average Cost of Preferred Stock (Ln 72/71)**	0.00%	0.00%	**0.00%**

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
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 2021		-		-	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
Indiana Michigan Power Company

1 Total AEP East Operating Company PBOP Settlement Amount (127,042,000)

Allocation of PBOP Settlement Amount for 2021

Line#	Company	Total Company Amount Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2021	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * -127042000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
2	APCo	(16,579,000)	36.54%	(46,416,231)	9.207%	(1,526,430)	(4,273,546)	2,747,116
3	I&M	(12,009,000)	26.46%	(33,621,601)	4.475%	(537,358)	(1,504,441)	967,083
4	KPCo	(3,821,000)	8.42%	(10,697,655)	7.824%	(298,953)	(836,980)	538,026
5	KNGP	(376,000)	0.83%	(1,052,687)	11.212%	(42,157)	(118,027)	75,870
6	OPCo	(11,910,000)	26.25%	(33,344,430)	11.570%	(1,377,956)	(3,857,865)	2,479,909
7	WPCo	(682,000)	1.50%	(1,909,396)	3.184%	(21,718)	(60,803)	39,085
8	**Sum of Lines 2 to 7**	(45,377,000)		(127,042,000)		(3,804,572)	(10,651,662)	6,847,090

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	(12,806,000)	(10,920,000)	(3,094,000)	(262,000)	(8,879,000)	(329,000)	(36,290,000)
10 Additional PBOP Ledger Entries (from Company Records)	351,000	1,340,000	306,000	-	-	(263,000)	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(12,455,000)	(9,580,000)	(2,788,000)	(262,000)	(8,879,000)	(592,000)	(34,556,000)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(4,124,000)	(2,429,000)	(1,033,000)	(114,000)	(3,031,000)	(89,000)	(10,820,000)
14 Company PBOP Expense (Ln 12 + Ln 13)	(16,579,000)	(12,009,000)	(3,821,000)	(376,000)	(11,910,000)	(681,000)	(45,376,000)

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

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 3/6/2019
FOR MULTIPLE JURISDICTION COMPANIES
Appalachian Power Company

		VIRGINIA			WEST VIRGINIA			FERC WHOLESALE			FERC KINGSPORT			COMPANY
	PLANT ACCT.	(1) VA SCC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(2) PSC OF WV APPROVED RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(3) FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(4) FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT														
Land Rights - Va.	350.1	0.66%	1.000000	0.66%										0.66%
Energy Storage Equip	351.0				14.22%	1.000000	14.22%							14.22%
Structures & Improvements	352.0	1.55%	0.492648	0.76%	1.62%	0.414603	0.67%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	1.63%
Station Equipment	353.0	1.95%	0.492648	0.96%	2.37%	0.414603	0.98%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	2.14%
Towers & Fixtures	354.0	1.14%	0.492648	0.56%	1.59%	0.414603	0.66%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	1.42%
Poles & Fixtures	355.0	2.77%	0.492648	1.36%	2.71%	0.414603	1.12%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	2.68%
Overhead Conductor	356.0	1.01%	0.492648	0.50%	1.53%	0.414603	0.63%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	1.33%
Underground Conduit	351.0	1.23%	0.492648	0.61%	3.71%	0.414603	1.54%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	2.35%
Underground Conductors	351.0	3.18%	0.492648	1.57%	5.24%	0.414603	2.17%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	3.94%
GENERAL PLANT														
Structures & Improvements	390.0	1.50%	0.519557	0.78%	1.91%	0.425935	0.81%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	1.78%
Office Furniture & Equipment	391.0	2.78%	0.519557	1.44%	3.17%	0.425935	1.35%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	2.98%
Transportation Equipment	392.0	0.00%	0.519557	0.00%	3.40%	0.425935	1.45%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	1.64%
Stores Equipment	393.0	1.60%	0.519557	0.83%	1.80%	0.425935	0.77%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	1.79%
Tools Shop & Garage Equipment	394.0	2.07%	0.519557	1.08%	2.57%	0.425935	1.09%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	2.36%
Laboratory Equipment	395.0	1.53%	0.519557	0.79%	4.01%	0.425935	1.71%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	2.69%
Power Operated Equipment	396.0	0.00%	0.519557	0.00%	3.90%	0.425935	1.66%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	1.85%
Communication Equipment	397.0	3.27%	0.519557	1.70%	4.98%	0.425935	2.12%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	4.01%
Miscellaneous Equipment	398.0	2.51%	0.519557	1.30%	2.70%	0.425935	1.15%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	2.64%

(1) As approved in VA Case No. PUE 2011-00037 on Nov. 30, 2011.
Depreciation rates were made effective on January 1, 2012.

(2) Approved by PSC of WV Order dated May 26, 2015 in
Case No. 14-1151-E-D effective June 1, 2015.

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

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

(5) Transmission allocation factors are changed annually in January based on
September factors as per the PJM tariff approved in FERC Docket ER08-1329
Attachment H-14B, Part II, pg. 15 of 21.

(6) Energy Storage Equipment is a new account established per FERC Order 784.

GENERAL NOTES:

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

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

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

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF October 31, 2018
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			MICHIGAN			FERC WHOLESALE			COMPANY
		(1)			(2)			(3)			
	PLANT ACCT.	IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT											
Land Improvements	350.1	1.4800%	0.652103	0.9651%	1.4400%	0.144206	0.2077%	1.4400%	0.203691	0.2933%	1.47%
Structures & Improvements	352.0	1.5500%	0.652103	1.0108%	1.5000%	0.144206	0.2163%	1.5000%	0.203691	0.3055%	1.53%
Station Equipment	353.0	1.8600%	0.652103	1.2129%	1.8400%	0.144206	0.2653%	1.8400%	0.203691	0.3748%	1.85%
Towers & Fixtures	354.0	1.6900%	0.652103	1.1021%	1.5700%	0.144206	0.2264%	1.5700%	0.203691	0.3198%	1.65%
Poles & Fixtures	355.0	2.8500%	0.652103	1.8585%	2.8300%	0.144206	0.4081%	2.8300%	0.203691	0.5764%	2.84%
Overhead Conductors	356.0	1.9700%	0.652103	1.2846%	1.8900%	0.144206	0.2725%	1.8900%	0.203691	0.3850%	1.94%
Underground Conduit	357.0	1.8600%	0.652103	1.2129%	1.7700%	0.144206	0.2552%	1.7700%	0.203691	0.3605%	1.83%
Underground Conductors	358.0	1.7000%	0.652103	1.1086%	1.6600%	0.144206	0.2394%	1.6600%	0.203691	0.3381%	1.69%
Trails & Roads	359.0	1.5000%	0.652103	0.9782%	1.4800%	0.144206	0.2134%	1.4800%	0.203691	0.3015%	1.49%

(1) As approved in Indiana Case No. 44967.
(2) As approved in MICHIGAN Case No. U18370.
(3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.
(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 09/1/2016
FOR SINGLE JURISDICTION COMPANIES
KINGSPORT POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.04%
Station Equipment	353.0	1.49%
Towers & Fixtures	354.0	0.12%
Poles & Fixtures	355.0	2.14%
Overhead Conductors	356.0	0.77%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		**1.46%**
GENERAL PLANT		
Structures & Improvements	390.0	1.71%
Office Furniture & Equipment	391.0	2.82%
Stores Equipment	393.0	2.22%
Tools Shop & Garage Equipmen	394.0	3.12%
Laboratory Equipment	395.0	3.17%
Communication Equipment	397.0	3.32%
Miscellaneous Equipment	398.0	4.92%
Total General Plant		3.25%

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Docket No. 16-00001.
K
Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved

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

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

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

Reference:

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

General Note

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 1/1/2012
FOR SINGLE JURISDICTION COMPANIES
OHIO POWER COMPANY

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

Reference:

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

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 3/6/2019
FOR SINGLE JURISDICTION COMPANIES
WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.15%
Station Equipment	353.0	2.22%
Towers & Fixtures	354.0	2.65%
Poles & Fixtures	355.0	2.41%
Overhead Conductors	356.0	1.32%
Underground Conduit	351.0	9.94%
Underground Conductors	351.0	13.98%
Trails & Roads	359.0	-
GENERAL PLANT		
Structures & Improvements	390.0	1.08%
Office Furniture & Equipment	391.0	2.13%
Stores Equipment	393.0	1.78%
Tools Shop & Garage Equipment	394.0	1.65%
Communication Equipment	397.0	5.09%
Miscellaneous Equipment	398.0	2.76%

Note 1: Rates Approved in WV Public Service Commission Case No. 14-1151-E-D.

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

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

Reconciliation Revenue Requirement For Year 2019 Available May 25, 2020		2019 Forecasted Revenue Requirement For Year 2019		True-up Adjustment - Over (Under) Recovery
$134,215,103	-	$128,079,761	=	($6,135,342)

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges from 35.19a			0.4195%				

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

Calculation of Interest					Monthly		
January	Year 2019	(511,279)	0.4195%	12	25,738		537,016
February	Year 2019	(511,279)	0.4195%	11	23,593		534,871
March	Year 2019	(511,279)	0.4195%	10	21,448		532,727
April	Year 2019	(511,279)	0.4195%	9	19,303		530,582
May	Year 2019	(511,279)	0.4195%	8	17,159		528,437
June	Year 2019	(511,279)	0.4195%	7	15,014		526,292
July	Year 2019	(511,279)	0.4195%	6	12,869		524,147
August	Year 2019	(511,279)	0.4195%	5	10,724		522,003
September	Year 2019	(511,279)	0.4195%	4	8,579		519,858
October	Year 2019	(511,279)	0.4195%	3	6,434		517,713
November	Year 2019	(511,279)	0.4195%	2	4,290		515,568
December	Year 2019	(511,279)	0.4195%	1	2,145		513,423
					167,295		6,302,638
					Annual		
January through December	Year 2019	6,302,638	0.4195%	12	317,275		6,619,913
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2021	(6,619,913)	0.4195%		27,771	(566,817)	6,080,866
February	Year 2021	(6,080,866)	0.4195%		25,509	(566,817)	5,539,558
March	Year 2021	(5,539,558)	0.4195%		23,238	(566,817)	4,995,979
April	Year 2021	(4,995,979)	0.4195%		20,958	(566,817)	4,450,120
May	Year 2021	(4,450,120)	0.4195%		18,668	(566,817)	3,901,971
June	Year 2021	(3,901,971)	0.4195%		16,369	(566,817)	3,351,523
July	Year 2021	(3,351,523)	0.4195%		14,060	(566,817)	2,798,765
August	Year 2021	(2,798,765)	0.4195%		11,741	(566,817)	2,243,689
September	Year 2021	(2,243,689)	0.4195%		9,412	(566,817)	1,686,284
October	Year 2021	(1,686,284)	0.4195%		7,074	(566,817)	1,126,541
November	Year 2021	(1,126,541)	0.4195%		4,726	(566,817)	564,449
December	Year 2021	(564,449)	0.4195%		2,368	(566,817)	0
					181,894		

True-Up Adjustment with Interest	6,801,806
Less Over (Under) Recovery	(6,135,342)
Total Interest	666,464

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

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

Reconciliation Revenue Requirement For Year 2019 Available May 25, 2020		2019 Forecasted Revenue Requirement For Year 2019		True-up Adjustment - Over (Under) Recovery
$5,686,029	-	$5,249,721	=	($436,308)

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharg from 35.19a			0.4195%				

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

Calculation of Interest					Monthly		
January	Year 2019	(36,359)	0.4195%	12	1,830		38,189
February	Year 2019	(36,359)	0.4195%	11	1,678		38,037
March	Year 2019	(36,359)	0.4195%	10	1,525		37,884
April	Year 2019	(36,359)	0.4195%	9	1,373		37,732
May	Year 2019	(36,359)	0.4195%	8	1,220		37,579
June	Year 2019	(36,359)	0.4195%	7	1,068		37,427
July	Year 2019	(36,359)	0.4195%	6	915		37,274
August	Year 2019	(36,359)	0.4195%	5	763		37,122
September	Year 2019	(36,359)	0.4195%	4	610		36,969
October	Year 2019	(36,359)	0.4195%	3	458		36,817
November	Year 2019	(36,359)	0.4195%	2	305		36,664
December	Year 2019	(36,359)	0.4195%	1	153		36,512
					11,897		448,205
					Annual		
January through December	Year 2019	448,205	0.4195%	12	22,563		470,768
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2021	(470,768)	0.4195%		1,975	(40,309)	432,434
February	Year 2021	(432,434)	0.4195%		1,814	(40,309)	393,940
March	Year 2021	(393,940)	0.4195%		1,653	(40,309)	355,284
April	Year 2021	(355,284)	0.4195%		1,490	(40,309)	316,465
May	Year 2021	(316,465)	0.4195%		1,328	(40,309)	277,484
June	Year 2021	(277,484)	0.4195%		1,164	(40,309)	238,340
July	Year 2021	(238,340)	0.4195%		1,000	(40,309)	199,031
August	Year 2021	(199,031)	0.4195%		835	(40,309)	159,557
September	Year 2021	(159,557)	0.4195%		669	(40,309)	119,918
October	Year 2021	(119,918)	0.4195%		503	(40,309)	80,113
November	Year 2021	(80,113)	0.4195%		336	(40,309)	40,140
December	Year 2021	(40,140)	0.4195%		168	(40,309)	0
					12,935		

True-Up Adjustment with Interest	483,703
Less Over (Under) Recovery	(436,308)
Total Interest	47,395

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

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

Reconciliation Revenue Requirement For Year 2019 Available May 25, 2020		2019 Forecasted Revenue Requirement For Year 2019		True-up Adjustment - Over (Under) Recovery
$476,749	-	$1,592,590	=	$1,115,841

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.4195%				

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

Calculation of Interest					Monthly		
January	Year 2019	92,987	0.4195%	12	(4,681)		(97,668)
February	Year 2019	92,987	0.4195%	11	(4,291)		(97,278)
March	Year 2019	92,987	0.4195%	10	(3,901)		(96,888)
April	Year 2019	92,987	0.4195%	9	(3,511)		(96,497)
May	Year 2019	92,987	0.4195%	8	(3,121)		(96,107)
June	Year 2019	92,987	0.4195%	7	(2,731)		(95,717)
July	Year 2019	92,987	0.4195%	6	(2,340)		(95,327)
August	Year 2019	92,987	0.4195%	5	(1,950)		(94,937)
September	Year 2019	92,987	0.4195%	4	(1,560)		(94,547)
October	Year 2019	92,987	0.4195%	3	(1,170)		(94,157)
November	Year 2019	92,987	0.4195%	2	(780)		(93,767)
December	Year 2019	92,987	0.4195%	1	(390)		(93,377)
					(30,426)		(1,146,267)
					Annual		
January through December	Year 2019	(1,146,267)	0.4195%	12	(57,703)		(1,203,970)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2021	1,203,970	0.4195%		(5,051)	103,088	(1,105,933)
February	Year 2021	1,105,933	0.4195%		(4,639)	103,088	(1,007,485)
March	Year 2021	1,007,485	0.4195%		(4,226)	103,088	(908,624)
April	Year 2021	908,624	0.4195%		(3,812)	103,088	(809,348)
May	Year 2021	809,348	0.4195%		(3,395)	103,088	(709,655)
June	Year 2021	709,655	0.4195%		(2,977)	103,088	(609,545)
July	Year 2021	609,545	0.4195%		(2,557)	103,088	(509,014)
August	Year 2021	509,014	0.4195%		(2,135)	103,088	(408,062)
September	Year 2021	408,062	0.4195%		(1,712)	103,088	(306,686)
October	Year 2021	306,686	0.4195%		(1,287)	103,088	(204,885)
November	Year 2021	204,885	0.4195%		(859)	103,088	(102,657)
December	Year 2021	102,657	0.4195%		(431)	103,088	0
					(33,081)		

True-Up Adjustment with Interest	(1,237,051)
Less Over (Under) Recovery	1,115,841
Total Interest	(121,210)

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