Tvelve Months Ended 2022

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)					$179,464,475
2	REVENUE CREDITS	(worksheet E Ln 8) (Note A)	4,410,000	DA	1.00000	$	4,410,000
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)				$	175,054,475

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)		5,322,411	DA	1.00000	$	5,322,411
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))					13.84%
8	Monthly Rate	(ln 7 / 12)					1.15%
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))					10.40%
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))					3.51%
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	7,152,000
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		5,159,000
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,466,000
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)	527,000

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Line No.	(1) **RATE BASE CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total** NOTE C	(4) **Allocator**		(5) **Total Transmission**
	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 14.(b))	5,392,745,000	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 14.(c))	(449,180,000)	NA	0.00000	-
21	Transmission	(Worksheet A ln 14.(d) & TCOS Ln 134)	1,821,484,000	DA		1,762,434,000
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 14.(e))	-	TP	0.96758	-
23	Distribution	(Worksheet A ln 14.(f))	2,921,891,000	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))	209,412,000	W/S	0.04650	9,738,389
26	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 14.(i))	-	W/S	0.04650	-
27	Intangible Plant	(Worksheet A ln 14.(j))	404,755,000	W/S	0.04650	18,822,520
28	TOTAL GROSS PLANT	(sum lns 19 to 27)	10,301,107,000	**GP**	**0.173864**	1,790,994,908
				GTD=	**0.37156**	
29	ACCUMULATED DEPRECIATION AND AMORTIZATION					
30	Production	(Worksheet A ln 28.(b))	2,645,116,000	NA	0.00000	-
31	Less: Production ARO (Enter Negative)	(Worksheet A ln 28.(c))	(195,751,000)	NA	0.00000	-
32	Transmission	(Worksheet A ln 28.(d) & ln 43.(c))	478,846,000	**TP1=**	0.97173	465,307,000
33	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 28.(e))	-	**TP1=**	0.97173	-
34	Distribution	(Worksheet A ln 28.(f))	789,345,000	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))	39,221,000	W/S	0.04650	1,823,913
37	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 28.(i))	-	W/S	0.04650	-
38	Intangible Plant	(Worksheet A ln 28.(j))	156,369,000	W/S	0.04650	7,271,704
39	TOTAL ACCUMULATED DEPRECIATION	(sum lns 30 to 38)	3,913,146,000			474,402,617
40	NET PLANT IN SERVICE					
41	Production	(ln 19 + ln 20 - ln 30 - ln 31)	2,494,200,000			-
42	Transmission	(ln 21 + ln 22 - ln 32 - ln 33)	1,342,638,000			1,297,127,000
43	Distribution	(ln 23 + ln 24 - ln 34 - ln 35)	2,132,546,000			-
44	General Plant	(ln 25 + ln 26 - ln 36 - ln 37)	170,191,000			7,914,475
45	Intangible Plant	(ln 27 - ln 38)	248,386,000			11,550,816
46	TOTAL NET PLANT IN SERVICE	(sum lns 41 to 45)	6,387,961,000	**NP**	**0.206105**	1,316,592,291
47	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
48	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(26,606,000)	NA		-
49	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(1,273,596,500)	DA		(232,037,000)
50	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(683,974,000)	DA		(2,789,000)
51	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	862,637,000	DA		34,862,000
52	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
53	TOTAL ADJUSTMENTS	(sum lns 48 to 52)	(1,121,539,500)			(199,964,000)
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))	(327,000)	W/S	0.04650	(15,207)
57	WORKING CAPITAL	(Note E)				
58	Cash Working Capital	(1/8 * ln 78)	2,962,375			2,866,339
59	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	469,000	TP	0.96758	453,796
60	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	492,000	W/S	0.04650	22,880
61	Stores Expense	(Worksheet C, ln 4.(F))	-	GP	0.17386	-
62	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	161,994,000	W/S	0.04650	7,533,286
63	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	1,644,500	GP	0.17386	285,920
64	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
65	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(160,897,000)	NA	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 58 to 65)	6,664,875			11,162,220
67	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	(3,753,500)	DA	1.00000	(3,753,500)
68	RATE BASE (sum lns 46, 53, 54, 55, 56, 66, 67)		5,270,450,875			1,124,229,805

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
69	Production	321.80.b	926,693,000			
70	Distribution	322.156.b	77,283,000			
71	Customer Related Expense	322 & 323.164,171,178.b	38,183,000			
72	Regional Marketing Expenses	322.131.b	4,451,000			
73	Transmission	321.112.b	244,038,000			
74	TOTAL O&M EXPENSES	(sum lns 69 to 73)	1,290,648,000			
75	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	7,152,000			
76	Less: Account 565	(Note H) 321.96.b	213,187,000			
77	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
78	Total O&M Allocable to Transmission	(lns 73 - 75 - 76 - 77)	23,699,000	TP	0.96758	22,930,711
79	Administrative and General	323.197.b (Notes J and M)	116,118,000			
80	Less: Acct. 924, Property Insurance	323.185.b	1,879,000			
81	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(13,880,000)			
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)	(3,720,000)			
84	Acct. 928, Reg. Com. Exp.	323.189.b	12,349,000			
85	Acct. 930.1, Gen. Advert. Exp.	323.191.b	78,000			
86	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,231,000			
87	Balance of A & G	(ln 79 - sum ln 80 to ln 86)	113,181,000	W/S	0.04650	5,263,311
88	Plus: Acct. 924, Property Insurance	(ln 80)	1,879,000	GP	0.17386	326,691
89	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	31,000	TP	0.96758	29,995
90	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.96758	-
91	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	558,000	DA	1.00000	558,000
92	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C (Note M)	(34,158,363)	W/S	0.04650	(1,588,483)
93	A & G Subtotal	(sum lns 87 to 92)	81,490,637			4,589,514
94	O & M EXPENSE SUBTOTAL	(ln 78 + ln 93)	105,189,637			27,520,226
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)	105,189,637			27,520,226
97	DEPRECIATION AND AMORTIZATION EXPENSE					
98	Production	336.2-6.f	367,841,000	NA	0.00000	-
99	Distribution	336.8.f	99,201,000	NA	0.00000	-
100	Transmission	336.7.f	45,892,000	TP1	0.97173	44,594,439
101	General	336.10.f	8,755,000	W/S	0.04650	407,138
102	Intangible	336.1.f	66,341,000	W/S	0.04650	3,085,088
103	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 98+99+ 100+101+102)	588,030,000			48,086,665
104	TAXES OTHER THAN INCOME	(Note N)				
105	Labor Related					
106	Payroll	Worksheet H ln 23.(D)	14,018,000	W/S	0.04650	651,886
107	Plant Related					
108	Property	Worksheet H ln 23.(C)	75,409,000	DA		13,115,532
109	Gross Receipts/Sales & Use	Worksheet H ln 23.(F)	25,557,000	NA	0.00000	-
110	Other	Worksheet H ln 23.(E)	3,203,000	GP	0.17386	556,887
111	TOTAL OTHER TAXES	(sum lns 106 to 110)	118,187,000			14,324,305
112	INCOME TAXES	(Note O)				
113	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		24.88%			
114	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		23.56%			
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)		1.3312			
118	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(3,893,000)			
119	Excess Deferred Income Tax	(Note U)	(39,084,000)	DA		(3,559,000)
120	Tax Effect of Permanent and Flow-Through Differences	(Note U)	1,952,000	DA		576,000
121	Income Tax Calculation	(ln 114 * ln 126)	84,257,683			17,972,845
122	ITC adjustment	(ln 117 * ln 118)	(5,182,299)	GP	0.17386	(901,017)
123	Excess Deferred Income Tax	(ln 117 * ln 119)	(52,027,992)			(4,737,684)
124	Tax Effect of Permanent and Flow-Through Differences	(ln 117 * ln 120)	2,598,471			766,762
125	TOTAL INCOME TAXES	(sum lns 121 to 124)	29,645,863			13,100,907
126	RETURN ON RATE BASE (Rate Base*WACC)	(ln 68 * ln 157)	357,601,874			76,279,372
127	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		153,000	DA	1.00000	153,000
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)		1,198,807,375			179,464,475

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SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
131	Total transmission plant	(ln 21)							1,821,484,000
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)								59,050,000
134	Transmission plant included in PJM Tariff	(ln 131 - ln 132 - ln 133)							1,762,434,000
135	Percent of transmission plant in PJM Tariff	(ln 134 / ln 131)						TP=	**0.96758**

ln No.			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
136	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
137	Production	354.20.b	148,039,000	12,464,000	160,503,000	NA	0.00000	-
138	Transmission	354.21.b	4,254,000	5,655,000	9,909,000	TP	0.96758	9,587,764
139	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
140	Distribution	354.23.b	21,216,000	2,308,000	23,524,000	NA	0.00000	-
141	Other (Excludes A&G)	354.24,25,26.b	7,050,000	5,187,000	12,237,000	NA	0.00000	-
142	Total	(sum lns 137 to 141)	180,559,000	25,614,000	206,173,000			9,587,764
143	Transmission related amount						W/S=	**0.04650**

ln No.							
144	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
145	Long Term Interest	(Worksheet M, ln. 37, col. (d))					120,288,000
146	Preferred Dividends	(Worksheet M, ln. 71)					-
147	Development of Common Stock:						
148	Proprietary Capital	(Worksheet M, ln. 14, col. (b))					2,854,118,000
149	Less: Preferred Stock	(Worksheet M, ln. 14, col. (c))					-
150	Less: Account 216.1	(Worksheet M, ln. 14, col. (d))					(5,571,000)
151	Less: Account 219	(Worksheet M, ln. 14, col. (e))					(5,754,000)
152	Common Stock	(ln 148 - ln 149 - ln 150 - ln 151)					2,865,443,000

ln No.			**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))	3,278,393,000	53.36%	53.36%	3.67%	0.0196
155	Preferred Stock (ln 149)	-	0.00%	0.00%	-	0.0000
156	Common Stock (ln 152)	2,865,443,000	46.64%	46.64%	10.35%	0.0483
157	Total (Sum lns 154 to 156)	6,143,836,000			WACC=	**0.0679**

158 Capital Structure Equity Limit (Note Z) 55%

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Letter **Notes**

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

A Revenue credits include:
1) Forfeited Discounts.
2) Miscellaneous Service Revenues.
3) Rental revenues earned on assets included in the rate base.
4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.
5) Other electric revenues.
6) Revenues for grandfathered PTP contracts included in the load divisor.
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 (Miscellaneouse 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=	4.91%	(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

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)
		Gross Plant In Service								
	(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	5,317,702,000	449,061,000	1,806,836,000		2,836,486,000		199,516,000		375,104,000
2	January	5,314,654,000	449,075,000	1,807,898,000		2,849,446,000		200,763,000		383,671,000
3	February	5,312,074,000	449,091,000	1,807,325,000		2,861,809,000		202,023,000		391,219,000
4	March	5,309,902,000	449,108,000	1,808,822,000		2,874,934,000		203,189,000		390,430,000
5	April	5,348,483,000	449,127,000	1,812,309,000		2,890,172,000		204,711,000		396,774,000
6	May	5,400,690,000	449,146,000	1,814,383,000		2,904,680,000		206,607,000		403,110,000
7	June	5,401,702,000	449,168,000	1,818,901,000		2,921,920,000		208,815,000		403,571,000
8	July	5,405,310,000	449,191,000	1,821,453,000		2,936,075,000		211,081,000		409,737,000
9	August	5,413,693,000	449,216,000	1,823,747,000		2,950,836,000		213,347,000		415,811,000
10	September	5,413,534,000	449,243,000	1,825,411,000		2,966,340,000		215,414,000		418,206,000
11	October	5,466,344,000	449,272,000	1,836,306,000		2,980,400,000		217,308,000		424,157,000
12	November	5,510,298,000	449,304,000	1,840,154,000		2,994,217,000		218,826,000		430,105,000
13	December of Rate Year	5,491,304,000	449,338,000	1,855,742,000		3,017,263,000		220,759,000		419,915,000
14	Average of the 13 Monthly Balances	5,392,745,000	449,180,000	1,821,484,000	-	2,921,891,000	-	209,412,000	-	404,755,000

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)
		Accumulated Depreciation								
	(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	2,442,312,000	185,750,000	472,308,000		759,461,000		39,872,000		135,160,000
16	January	2,468,138,000	187,412,000	473,292,000		764,347,000		39,727,000		140,228,000
17	February	2,493,223,000	189,075,000	474,277,000		769,526,000		39,565,000		145,415,000
18	March	2,519,063,000	190,740,000	475,260,000		774,727,000		39,424,000		143,386,000
19	April	2,602,919,000	192,405,000	476,247,000		779,988,000		39,280,000		148,691,000
20	May	2,627,954,000	194,072,000	477,443,000		784,665,000		39,195,000		154,100,000
21	June	2,655,002,000	195,740,000	478,644,000		789,415,000		39,128,000		153,832,000
22	July	2,682,211,000	197,410,000	479,855,000		794,226,000		39,061,000		159,367,000
23	August	2,709,439,000	199,082,000	481,072,000		799,093,000		39,008,000		165,005,000
24	September	2,736,451,000	200,755,000	482,294,000		803,998,000		38,962,000		167,147,000
25	October	2,820,652,000	202,430,000	483,519,000		808,964,000		38,924,000		172,934,000
26	November	2,846,278,000	204,108,000	484,767,000		813,991,000		38,888,000		178,820,000
27	December of Rate Year	2,782,869,000	205,787,000	486,024,000		819,087,000		38,840,000		168,717,000
28	Average of the 13 Monthly Balances	2,645,116,000	195,751,000	478,846,000	-	789,345,000	-	39,221,000	-	156,369,000

Line No	Month (a)	OATT Ancillary Services (GSU) Plant In Service (b)	OATT Ancillary Services (GSU) Accumulated Depreciation (c)	Excluded Plant - Plant In Service (d)	Excluded Plant - Accumulated Depreciation (e)
	(Note A)	Company Records (included in total in column (d) of gross plant above)	Company Records (included in total in column (b) of accumulated depreciation above)	Company Records	Company Records
29	December Prior to Rate Year	59,050,000	12,802,000		
30	January	59,050,000	12,921,000		
31	February	59,050,000	13,040,000		
32	March	59,050,000	13,159,000		
33	April	59,050,000	13,277,000		
34	May	59,050,000	13,405,000		
35	June	59,050,000	13,533,000		
36	July	59,050,000	13,660,000		
37	August	59,050,000	13,788,000		
38	September	59,050,000	13,915,000		
39	October	59,050,000	14,043,000		
40	November	59,050,000	14,170,000		
41	December of Rate Year	59,050,000	14,298,000		
42	Average of the 13 Monthly Balances	59,050,000	13,539,000	-	-
43	Transmission Accum Depreciation net of GSU		465,307,000		

	Plant Held For Future Use (a)	Source of Data (b)	Balance @ December 31, 2022 (c)	Balance @ December 31, 2021 (d)	Average Balance for 2022 (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	2282003	21,000	21,000	21,000
53b	Accm Prv I/D - Asbestos - Curr	2282011	28,000	28,000	28,000
53c	Accm Prv I/D - Asbestos	2282012	278,000	278,000	278,000
54		Total	327,000	327,000	327,000

NOTE 1: On this worksheet, "Company Records" refers to AEP's property accounting ledger.
NOTE 2: The ratebase should not include the unamortized 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, 2022**	**Balance @ December 31, 2021**	**Average Balance for 2022**
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	26,678,000	26,534,000	26,606,000
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)	26,678,000	26,534,000	26,606,000
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)	1,280,092,000	1,267,101,000	1,273,596,500
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)	74,346,000	74,346,000	74,346,000
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)	973,163,000	961,264,000	967,213,500
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	232,583,000	231,491,000	232,037,000
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	685,831,000	682,117,000	683,974,000
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)	620,696,000	620,696,000	620,696,000
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)	62,338,000	58,640,000	60,489,000
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	2,797,000	2,781,000	2,789,000
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	839,708,000	885,566,000	862,637,000
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)	690,996,000	690,996,000	690,996,000
19	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)	114,777,000	158,781,000	136,779,000
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	33,936,000	35,790,000	34,862,000
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	19,104,000	22,997,000	21,050,500
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	19,104,000	22,997,000	21,050,500
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.I67(I)-I(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, 2022

(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	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2021			FUNCTIONALIZATION 12/31/2022		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2022	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2022	ELECTRIC UTILITY (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 ACOUNT 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, 2022

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	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2021			FUNCTIONALIZATION 12/31/2022		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2022	BALANCE AS OF 12-31-2021	BALANCE AS OF 12-31-2022	ELECTRIC UTILITY (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, 2022
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 num 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 requiremer balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, bu 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 Transr 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
			1/1/2022 Beginning Balances	
Excess Balance at Remeasurement (NOTE C)	**Amortization Methodology (NOTE D)**	**Amotization Period**	**Excess ADIT Regulatory Offset**	**Excess ADIT in Utility Deferrals**
(11,772,442)	**ARAM**	**Life of Asset**		
(410,365,997)	**ARAM**	**Life of Asset**		
(148,924,633)	**10 Years**	**1/2018 - 12/2027**		
(5,353,470)	**10 Years**	**1/2018 - 12/2027**		
			0	-

F	G	H	I	J
(82,304,124)	**ARAM**	**Life of Asset**		
(14,907,164)	**10 Years**	**1/2018 - 12/2027**		
5,174,807	**10 Years**	**1/2018 - 12/2027**		
			0	-

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"
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.
:count 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*

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

:bit 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		12/31/2022 Er
Balance Sheet Account Reclassifications	182.3	254	410/411 Excess Amortization	410/411 Deferred Tax Expense/ (Benefit)	Excess ADIT Regulatory Offset
					Sum of Co
					-
					-
					-
					-
					-
					-
					-
-	-	-	-	-	-

NOTE F

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					Sum of Co
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					-
					-
					-
					-
					-
-	-	-	-	-	-

NOTE F

Q	R
ıding Balance	
Excess ADIT in Utility Deferrals	**Reference**
ɔls (I) - (O)	**-**
	WS B - 2 Col B/C, ADIT item 3.21
-	
	WS B - 1, Col B/C, ADIT Item 2.06
-	WS B - 1 Cols O+P+Q+R+S , ADIT Item 5.63
-	
	WS B - 1 Col B/C, ADIT Item 5.62
-	WS B - 1 Col B/C, Items 10.30
	WS B - 1 Col B/C, Item 10.33
	Company Records
	FERC Form 1 p. 278 Ln. 3 Cols, (b) /(f)
-	
ɔls (I) - (O)	
	Company Records
-	WS B - 1 Col Q, ADIT 5.63
-	
	Company Records
-	WS B - 1 Col Q, item 10.30
	Company Records
	Company Records
	Company Records
-	

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

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2022	(E) Balance @ December 31, 2021	(F) Average Balance for 2022
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	469,000	469,000	469,000
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	492,000	492,000	492,000
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, 2022	(4,835,000)	(161,861,000)	0	(2,901,000)	159,927,000	157,026,000
7	Totals as of December 31, 2021	10,318,000	(159,933,000)		6,190,000	164,061,000	170,251,000
8	**Average Balance**	2,741,500	(160,897,000)	-	1,644,500	161,994,000	163,638,500

Prepayments Account 165 - Balance @ 12/31/2022

9	Acc. No.	Description	2022 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10	1650001	Prepaid Insurance	(1,910,000)	-		(1,910,000)		(1,910,000)	Plant Related Insurance Policies
11	165000219	Prepaid Taxes	-	-				-	
12	165000220	Prepaid Taxes	(430,000)	(430,000)				-	Prepaid Taxes-Distribution
13	1650003	Prepaid Rents	(3,000)	(3,000)				-	River Transport
14	1650005	Prepaid Employee Benefits	-	-				-	
15	1650006	Other Prepayments	(759,000)	(759,000)				-	Relates to EPRI dues
16	1650009	Prepaid Carry Cost-Factored AR	(55,000)	(55,000)				-	AR Factoring
17	1650010	Prepaid Pension Benefits	54,678,000	-			54,678,000	54,678,000	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(54,678,000)	(54,678,000)				-	SFAS 158 Offset
19	165001120	Prepaid Sales Taxes	(372,000)	(372,000)				-	Prepaid Sales Tax - Distribution
20	165001220	Prepaid Use Taxes	(41,000)	(41,000)				-	Prepaid Use Tax - Distribution
21	1650021	Prepaid Insurance - EIS	(901,000)	-		(901,000)		(901,000)	Energy INS Services
22	1650022	Prepaid SNF Container Costs	-	-				-	
23	1650023	Prepaid Lease	(90,000)	-		(90,000)		(90,000)	Prepaid Leases-All Functions
24	1650026	Prepaid SNF Costs	-	-				-	
25	1650030	Other Payments - Long Term	(274,000)	(274,000)				-	Other - Dist
26	1650035	PRW without MED-D Benefits	105,249,000	-			105,249,000	105,249,000	Med-D Benefits
27	1650037	FAS 158 Contra-PRW Exc Med-D	(105,249,000)	(105,249,000)				-	SFAS 158 Offset
28									
29									
30									
31									
		Subtotal - Form 1, p 111.57.c	(4,835,000)	(161,861,000)	0	(2,901,000)	159,927,000	157,026,000	

Prepayments Account 165 - Balance @ 12/31/ 2021

32	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
33	1650001	Prepaid Insurance	4,075,000	-		4,075,000		4,075,000	Plant Related Insurance Policies
34	165000219	Prepaid Taxes	-	-				-	
35	165000220	Prepaid Taxes	917,000	917,000				-	Prepaid Taxes-Distribution
36	1650003	Prepaid Rents	7,000	7,000				-	River Transport
37	1650005	Prepaid Employee Benefits	-	-				-	
38	1650006	Other Prepayments	1,619,000	1,619,000				-	Relates to EPRI dues
39	1650009	Prepaid Carry Cost-Factored AR	118,000	118,000				-	AR Factoring
40	1650010	Prepaid Pension Benefits	70,671,000	-			70,671,000	70,671,000	Prefunded Pension Expense
41	1650014	FAS 158 Qual Contra Asset	(70,671,000)	(70,671,000)				-	SFAS 158 Offset
42	165001120	Prepaid Sales Taxes	794,000	794,000				-	Prepaid Sales Tax - Distribution
43	165001220	Prepaid Use Taxes	88,000	88,000				-	Prepaid Use Tax - Distribution
44	1650021	Prepaid Insurance - EIS	1,922,000	-		1,922,000		1,922,000	Energy INS Services
45	1650022	Prepaid SNF Container Costs	-	-				-	
46	1650023	Prepaid Lease	193,000	-		193,000		193,000	Prepaid Leases-All Functions
47	1650026	Prepaid SNF Costs	-	-				-	
48	1650030	Other Payments - Long Term	585,000	585,000				-	Other - Dist
49	1650035	PRW without MED-D Benefits	93,390,000	-			93,390,000	93,390,000	Med-D Benefits
50	1650037	FAS 158 Contra-PRW Exc Med-D	(93,390,000)	(93,390,000)				-	SFAS 158 Offset
51									
52									
53									
54									
		Subtotal - Form 1, p 111.57.d	10,318,000	(159,933,000)		6,190,000	164,061,000	170,251,000	

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) 2022
1	Net Funds from IPP Customers 12/31/2021 (2022 FORM 1, P269)	(3,677,000)
2	Interest Accrual (Company Records - Note 1)	(153,000)
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 12/31/2022 (2022 FORM 1, P269)	(3,830,000)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(3,753,500)

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)**	5,063,000	5,063,000	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	3,808,000	3,719,000	89,000
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	11,234,000	7,400,000	3,834,000
4	**Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)**	2,885,000	2,398,000	487,000
5	**Account 456 - Other Electric Revenues - (Company Records - Notes 1,2)**	58,554,000	58,554,000	-
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))**	81,544,000	77,134,000	4,410,000
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**		-	
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	81,544,000	77,134,000	4,410,000

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

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number	Item No.	Description	2022 Expense	100% Non-Transmission	100% Transmission Specific	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	279,000			
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	5,159,000			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	248,000			
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	1,466,000			
14		**Total of Account 561**	7,152,000			
		Account 928				
15	9280000	Regulatory Commission Exp	3,000	3,000	-	
16	9280001	Regulatory Commission Exp-Adm	10,286,000	10,286,000	-	
17	9280002	Regulatory Commission Exp-Case	2,029,000	2,029,000	-	
18	9280005	Reg Com Exp-FERC Trans Cases	31,000	-	31,000	
19						
20		**Total (FERC Form 1 p.323.189.b)**	12,349,000	12,318,000	31,000	
		Account 930.1				
21	9301000	General Advertising Expenses	13,000	13,000	-	
22	9301001	Newspaper Advertising Space	10,000	10,000	-	
23	9301002	Radio Station Advertising Time	-	-	-	
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	7,000	7,000	-	
30	9301011	Dedications, Tours, & Openings	-	-	-	
31	9301012	Public Opinion Surveys	19,000	19,000	-	
32	9301013	Movies Slide Films & Speeches	-	-	-	
33	9301014	Video Communications	-	-	-	
34	9301015	Other Corporate Comm Exp	29,000	29,000	-	
35				-	-	
36				-	-	
37		**Total (FERC Form 1 p.323.191.b)**	78,000	78,000	-	
		Account 930.2				
38	9302000	Misc General Expenses	4,091,000	4,091,000		
39	9302003	Corporate & Fiscal Expenses	200,000	200,000		
40	9302004	Research, Develop&Demonstr Exp	-	-		
	9302005	Nucl Fac Ins - Replce Engy Cst	-			
41	9302006	Assoc Business Development Materials Sold	46,000	46,000		
42	9302007	Assoc Business Development Exp	1,894,000	1,336,000	558,000	
43		**Total (FERC Form 1 p.323.192.b)**	6,231,000	5,673,000	558,000	

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	4.90%	
Apportionment Factor - Note 2	77.20%	
Effective State Tax Rate		3.78%
Michigan Single Business Tax Rate	6.00%	
Apportionment Factor - Note 2	15.30%	
Effective State Tax Rate		0.92%
West Virginia Corporation Income Tax Rate	6.50%	
Apportionment Factor - Note 2	1.44%	
Effective State Tax Rate		0.09%
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	1.10%	
Effective State Tax Rate		0.06%
Missouri Corporation Income Tax Rate	4.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	9.50%	
Apportionment Factor - Note 2	0.60%	
Effective State Tax Rate		0.06%
Total Effective State Income Tax Rate		4.91%

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	25,482,000				25,482,000
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Michigan	53,989,000	53,989,000			
5	Real and Personal Property - Indiana	21,410,000	21,410,000			
6	Real and Personal Property - Other Jurisdictions	10,000	10,000			
7	**Payroll Taxes**					
8	Federal Insurance Contribution (FICA)	13,922,000		13,922,000		
9	Federal Unemployment Tax	29,000		29,000		
10	State Unemployment Insurance	67,000		67,000		
11	**Production Taxes**					
12	State Severance Taxes	-				-
13	**Miscellaneous Taxes**					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	3,222,000			3,222,000	
16	State Franchise Taxes	(19,000)			(19,000)	
17	State Lic/Registration Fee	-			-	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	64,000				64,000
20	Federal Excise Tax	11,000				11,000
21	Gross Receipts Audit	-				-
22						
23	Total Taxes by Allocable Basis	118,187,000	75,409,000	14,018,000	3,203,000	25,557,000
	(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.		Production	Transmsission	Distribution	General	Total
24	Functionalized Net Plant (TCOS, Lns 41 thru 46)	2,494,200,000	1,342,638,000	2,132,546,000	170,191,000	6,139,575,000
	MICHIGAN JURISDICTION					
25	Percentage of Plant in MICHIGAN JURISDICTION	79.83%	16.27%	18.91%	14.63%	
26	Net Plant in MICHIGAN JURISDICTION (Ln 24 * Ln 25)	1,991,188,453	218,414,658	403,244,872	24,903,268	2,637,751,251
27	Less: Net Value of Exempted Generation Plant	490,065,509				
28	Taxable Property Basis (Ln 26 - Ln 27)	1,501,122,944	218,414,658	403,244,872	24,903,268	2,147,685,742
29	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
30	Weighted Net Plant (Ln 28 * Ln 29)	1,501,122,944	218,414,658	403,244,872	24,903,268	
31	General Plant Allocator (Ln 30 / (Total - General Plant))	70.71%	10.29%	19.00%	-100.00%	
32	Functionalized General Plant (Ln 31 * General Plant)	17,610,314	2,562,316	4,730,638	(24,903,268)	-
33	Weighted MICHIGAN JURISDICTION Plant (Ln 30 + 32)	1,518,733,258	220,976,974	407,975,510	(0)	2,147,685,742
34	Functional Percentage (Ln 33/Total Ln 33)	70.71%	10.29%	19.00%		
	INDIANA JURISDICTION					
35	Percentage of Plant in INDIANA JURISDICTION	20.17%	83.73%	81.09%	85.22%	
36	Net Plant in INDIANA JURISDICTION (Ln 24 * Ln 35)	503,011,547	1,124,223,342	1,729,301,128	145,044,096	3,501,580,113
37	Less: Net Value of Exempted Generation Plant	172,210,768				
38	Taxable Property Basis (Ln 36 - Ln 37)	330,800,779	1,124,223,342	1,729,301,128	145,044,096	3,329,369,345
39	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
40	Weighted Net Plant (Ln 38 * Ln 39)	330,800,779	1,124,223,342	1,729,301,128	145,044,096	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	10.39%	35.30%	54.31%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	15,067,776	51,207,696	78,768,624	(145,044,096)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	345,868,555	1,175,431,038	1,808,069,752	(0)	3,329,369,345
44	Functional Percentage (Ln 43/Total Ln 43)	10.39%	35.30%	54.31%		
45	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)	(0)	2,061	(0)	-	10,000

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	25,482,000		
			25,482,000	

	(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)**		**75,409,000**				**13,115,532**
4	Real and Personal Property - Michigan		53,989,000				5,554,968
		2021		53,989,000		10.29%	5,554,968
							-
							-
							-
							-
5	Real and Personal Property - Indiana		21,410,000				7,558,782
		2021		21,410,000		35.30%	7,558,782
							-
							-
							-
							-
							-
							-
							-
							-
6	Real and Personal Property - Other		10,000				1,781
		2021		10,000		17.81%	1,781
							-
							-
							-
							-
			-				-
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)	13,922,000		
			13,922,000	
10	Federal Unemployment Tax	29,000		
			29,000	
11	State Unemployment Insurance	67,000		
			67,000	
12	**Production Taxes**	-		
13	State Severance Taxes		-	
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax	-		
			-	
16	State Public Service Commission Fees	3,222,000		
			3,222,000	
17	State Franchise Taxes	(19,000)		
			(19,000)	
18	State Lic/Registration Fee	-		
			-	
19	Misc. State and Local Tax	-		
			-	
20	Sales & Use	64,000		
			64,000	
21	Federal Excise Tax	11,000		
			11,000	
22	Michigan Single Business Tax	-		
			-	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	118,187,000	118,187,000	

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 2022 FF1 Balances
Worksheet I RESERVED FOR FUTURE USE
Indiana Michigan Power Company

AEP East Companies
Cost of Service Formula Rate Using 2022 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
Indiana Michigan Power Company

Page 1 of 10

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	53.36%	3.67%	1.958%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	46.64%	10.35%	4.827%
		R =	6.785%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2022	5,322,411	5,322,411	$ -

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

Rate Base (TCOS, ln 68)	1,124,229,805
R (from A. above)	6.785%
Return (Rate Base x R)	76,279,372

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

Return (from B. above)	76,279,372
Effective Tax Rate (TCOS, ln 114)	23.56%
Income Tax Calculation (Return x CIT)	17,972,845
ITC Adjustment	(901,017)
Excess Deferred Income Tax	(4,737,684)
Tax Affect of Permanent Differences	766,762
Income Taxes	13,100,907

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)	179,464,475
Lease Payments (TCOS, Ln 95)	-
Return (TCOS, ln 126)	76,279,372
Income Taxes (TCOS, ln 125)	13,100,907
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	90,084,196

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

Annual Revenue Requirement, Less Lease Payments, Return and Taxes	90,084,196
Return (from I.B. above)	76,279,372
Income Taxes (from I.C. above)	13,100,907
Annual Revenue Requirement, with Basis Point ROE increase	179,464,475
Depreciation (TCOS, ln 100)	44,594,439
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	134,870,036

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)	1,297,127,000
Annual Revenue Requirement, with Basis Point ROE increase	179,464,475
FCR with Basis Point increase in ROE	13.84%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	134,870,036
FCR with Basis Point ROE increase, less Depreciation	10.40%
FCR less Depreciation (TCOS, ln 10)	10.40%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for 2022 (TCOS, ln 21)	1,762,434,000
Annual Depreciation and Amortization Expense (TCOS, ln 100)	44,594,439
Composite Depreciation Rate	2.53%
Depreciable Life for Composite Depreciation Rate	39.52
Round to nearest whole year	40

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	**792,610**
Current Projected Year ARR w/ Incentive	**792,610**
Current Projected Year Incentive ARR	**-**

Details			
Investment	8,327,150	Current Year	**2022**
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	208,179

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	104,089	8,223,061	964,501	964,501	$ -		
2010	8,223,061	208,179	8,014,882	1,052,357	1,052,357	$ -	$ 1,408,114	$ 1,408,114
2011	8,014,882	208,179	7,806,703	1,030,711	1,030,711	$ -	$ 1,487,355	$ 1,487,355
2012	7,806,703	208,179	7,598,524	1,009,065	1,009,065	$ -	$ 1,319,695	$ 1,319,695
2013	7,598,524	208,179	7,390,346	987,420	987,420	$ -	$ 1,272,484	$ 1,272,484
2014	7,390,346	208,179	7,182,167	965,774	965,774	$ -	$ 1,249,385	$ 1,249,385
2015	7,182,167	208,179	6,973,988	944,129	944,129	$ -	$ 1,278,273	$ 1,278,273
2016	6,973,988	208,179	6,765,809	922,483	922,483	$ -	$ 1,254,654	$ 1,254,654
2017	6,765,809	208,179	6,557,631	900,838	900,838	$ -	$ 1,132,871	$ 1,132,871
2018	6,557,631	208,179	6,349,452	879,192	879,192	$ -	$ 933,326	$ 933,326
2019	6,349,452	208,179	6,141,273	857,546	857,546	$ -	$ 856,880	$ 856,880
2020	6,141,273	208,179	5,933,094	835,901	835,901	$ -	$ 804,584	$ 804,584
2021	5,933,094	208,179	5,724,916	814,255	814,255	$ -	$ 786,905	$ 786,905
2022	5,724,916	208,179	5,516,737	792,610	792,610	$ -		
2023	5,516,737	208,179	5,308,558	770,964	770,964	$ -		
2024	5,308,558	208,179	5,100,379	749,318	749,318	$ -		
2025	5,100,379	208,179	4,892,201	727,673	727,673	$ -		
2026	4,892,201	208,179	4,684,022	706,027	706,027	$ -		
2027	4,684,022	208,179	4,475,843	684,382	684,382	$ -		
2028	4,475,843	208,179	4,267,664	662,736	662,736	$ -		
2029	4,267,664	208,179	4,059,486	641,090	641,090	$ -		
2030	4,059,486	208,179	3,851,307	619,445	619,445	$ -		
2031	3,851,307	208,179	3,643,128	597,799	597,799	$ -		
2032	3,643,128	208,179	3,434,949	576,154	576,154	$ -		
2033	3,434,949	208,179	3,226,771	554,508	554,508	$ -		
2034	3,226,771	208,179	3,018,592	532,863	532,863	$ -		
2035	3,018,592	208,179	2,810,413	511,217	511,217	$ -		
2036	2,810,413	208,179	2,602,234	489,571	489,571	$ -		
2037	2,602,234	208,179	2,394,056	467,926	467,926	$ -		
2038	2,394,056	208,179	2,185,877	446,280	446,280	$ -		
2039	2,185,877	208,179	1,977,698	424,635	424,635	$ -		
2040	1,977,698	208,179	1,769,519	402,989	402,989	$ -		
2041	1,769,519	208,179	1,561,341	381,343	381,343	$ -		
2042	1,561,341	208,179	1,353,162	359,698	359,698	$ -		
2043	1,353,162	208,179	1,144,983	338,052	338,052	$ -		
2044	1,144,983	208,179	936,804	316,407	316,407	$ -		
2045	936,804	208,179	728,626	294,761	294,761	$ -		
2046	728,626	208,179	520,447	273,116	273,116	$ -		
2047	520,447	208,179	312,268	251,470	251,470	$ -		
2048	312,268	208,179	104,089	229,824	229,824	$ -		
2049	104,089	104,089	-	109,501	109,501	$ -		
2050	-	-	-	-	-	$ -		
2051	-	-	-	-	-	$ -		
2052	-	-	-	-	-	$ -		
2053	-	-	-	-	-	$ -		
2054	-	-	-	-	-	$ -		
2055	-	-	-	-	-	$ -		
2056	-	-	-	-	-	$ -		
2057	-	-	-	-	-	$ -		
2058	-	-	-	-	-	$ -		
2059	-	-	-	-	-	$ -		
2060	-	-	-	-	-	$ -		
2061	-	-	-	-	-	$ -		
2062	-	-	-	-	-	$ -		
2063	-	-	-	-	-	$ -		
2064	-	-	-	-	-	$ -		
2065	-	-	-	-	-	$ -		
2066	-	-	-	-	-	$ -		
2067	-	-	-	-	-	$ -		
2068	-	-	-	-	-	$ -		
Project Totals		8,327,150		26,076,531	26,076,531	-		

** 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	**61,869**
Current Projected Year ARR w/ Incentive	**61,869**
Current Projected Year Incentive ARR	-

Details			
Investment	585,981	Current Year	**2022**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	14,650

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	7,325	578,656	67,872	67,872	$ -	$ 92,625		$ 92,625		
2014	578,656	14,650	564,007	74,054	74,054	$ -	$ 87,393		$ 87,393		
2015	564,007	14,650	549,357	72,531	72,531	$ -	$ 87,463		$ 87,463		
2016	549,357	14,650	534,708	71,008	71,008	$ -	$ 85,936		$ 85,936		
2017	534,708	14,650	520,058	69,485	69,485	$ -	$ 77,494		$ 77,494		
2018	520,058	14,650	505,409	67,961	67,961	$ -	$ 70,215		$ 70,215		
2019	505,409	14,650	490,759	66,438	66,438	$ -	$ 65,616		$ 65,616		
2020	490,759	14,650	476,110	64,915	64,915	$ -	$ 61,867		$ 61,867		
2021	476,110	14,650	461,460	63,392	63,392	$ -	$ 61,041		$ 61,041		
2022	461,460	14,650	446,811	61,869	61,869	$ -					
2023	446,811	14,650	432,161	60,345	60,345	$ -					
2024	432,161	14,650	417,511	58,822	58,822	$ -					
2025	417,511	14,650	402,862	57,299	57,299	$ -					
2026	402,862	14,650	388,212	55,776	55,776	$ -					
2027	388,212	14,650	373,563	54,253	54,253	$ -					
2028	373,563	14,650	358,913	52,729	52,729	$ -					
2029	358,913	14,650	344,264	51,206	51,206	$ -					
2030	344,264	14,650	329,614	49,683	49,683	$ -					
2031	329,614	14,650	314,965	48,160	48,160	$ -					
2032	314,965	14,650	300,315	46,637	46,637	$ -					
2033	300,315	14,650	285,666	45,113	45,113	$ -					
2034	285,666	14,650	271,016	43,590	43,590	$ -					
2035	271,016	14,650	256,367	42,067	42,067	$ -					
2036	256,367	14,650	241,717	40,544	40,544	$ -					
2037	241,717	14,650	227,068	39,021	39,021	$ -					
2038	227,068	14,650	212,418	37,498	37,498	$ -					
2039	212,418	14,650	197,769	35,974	35,974	$ -					
2040	197,769	14,650	183,119	34,451	34,451	$ -					
2041	183,119	14,650	168,470	32,928	32,928	$ -					
2042	168,470	14,650	153,820	31,405	31,405	$ -					
2043	153,820	14,650	139,170	29,882	29,882	$ -					
2044	139,170	14,650	124,521	28,358	28,358	$ -					
2045	124,521	14,650	109,871	26,835	26,835	$ -					
2046	109,871	14,650	95,222	25,312	25,312	$ -					
2047	95,222	14,650	80,572	23,789	23,789	$ -					
2048	80,572	14,650	65,923	22,266	22,266	$ -					
2049	65,923	14,650	51,273	20,742	20,742	$ -					
2050	51,273	14,650	36,624	19,219	19,219	$ -					
2051	36,624	14,650	21,974	17,696	17,696	$ -					
2052	21,974	14,650	7,325	16,173	16,173	$ -					
2053	7,325	7,325	-	7,706	7,706	$ -					
2054	-	-	-	-	-	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		585,981		1,835,004	1,835,004	-					

** 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	**2,308,748**
Current Projected Year ARR w/ Incentive	**2,308,748**
Current Projected Year Incentive ARR	-

Details			
Investment	21,957,101	Current Year	**2022**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	548,928

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	365,952	21,591,149	2,629,937	2,629,937	$ -	$ 1,301,059		$ 1,301,059		
2014	21,591,149	548,928	21,042,222	2,765,351	2,765,351	$ -	$ 3,243,481		$ 3,243,481		
2015	21,042,222	548,928	20,493,294	2,708,275	2,708,275	$ -	$ 3,604,460		$ 3,604,460		
2016	20,493,294	548,928	19,944,367	2,651,200	2,651,200	$ -	$ 3,506,792		$ 3,506,792		
2017	19,944,367	548,928	19,395,439	2,594,125	2,594,125	$ -	$ 3,162,406		$ 3,162,406		
2018	19,395,439	548,928	18,846,512	2,537,049	2,537,049	$ -	$ 2,623,914		$ 2,623,914		
2019	18,846,512	548,928	18,297,584	2,479,974	2,479,974	$ -	$ 2,433,873		$ 2,433,873		
2020	18,297,584	548,928	17,748,657	2,422,899	2,422,899	$ -	$ 2,310,007		$ 2,310,007		
2021	17,748,657	548,928	17,199,729	2,365,824	2,365,824	$ -	$ 2,278,398		$ 2,278,398		
2022	17,199,729	548,928	16,650,802	2,308,748	2,308,748	$ -					
2023	16,650,802	548,928	16,101,874	2,251,673	2,251,673	$ -					
2024	16,101,874	548,928	15,552,947	2,194,598	2,194,598	$ -					
2025	15,552,947	548,928	15,004,019	2,137,523	2,137,523	$ -					
2026	15,004,019	548,928	14,455,091	2,080,447	2,080,447	$ -					
2027	14,455,091	548,928	13,906,164	2,023,372	2,023,372	$ -					
2028	13,906,164	548,928	13,357,236	1,966,297	1,966,297	$ -					
2029	13,357,236	548,928	12,808,309	1,909,221	1,909,221	$ -					
2030	12,808,309	548,928	12,259,381	1,852,146	1,852,146	$ -					
2031	12,259,381	548,928	11,710,454	1,795,071	1,795,071	$ -					
2032	11,710,454	548,928	11,161,526	1,737,996	1,737,996	$ -					
2033	11,161,526	548,928	10,612,599	1,680,920	1,680,920	$ -					
2034	10,612,599	548,928	10,063,671	1,623,845	1,623,845	$ -					
2035	10,063,671	548,928	9,514,744	1,566,770	1,566,770	$ -					
2036	9,514,744	548,928	8,965,816	1,509,695	1,509,695	$ -					
2037	8,965,816	548,928	8,416,889	1,452,619	1,452,619	$ -					
2038	8,416,889	548,928	7,867,961	1,395,544	1,395,544	$ -					
2039	7,867,961	548,928	7,319,034	1,338,469	1,338,469	$ -					
2040	7,319,034	548,928	6,770,106	1,281,394	1,281,394	$ -					
2041	6,770,106	548,928	6,221,179	1,224,318	1,224,318	$ -					
2042	6,221,179	548,928	5,672,251	1,167,243	1,167,243	$ -					
2043	5,672,251	548,928	5,123,324	1,110,168	1,110,168	$ -					
2044	5,123,324	548,928	4,574,396	1,053,092	1,053,092	$ -					
2045	4,574,396	548,928	4,025,469	996,017	996,017	$ -					
2046	4,025,469	548,928	3,476,541	938,942	938,942	$ -					
2047	3,476,541	548,928	2,927,613	881,867	881,867	$ -					
2048	2,927,613	548,928	2,378,686	824,791	824,791	$ -					
2049	2,378,686	548,928	1,829,758	767,716	767,716	$ -					
2050	1,829,758	548,928	1,280,831	710,641	710,641	$ -					
2051	1,280,831	548,928	731,903	653,566	653,566	$ -					
2052	731,903	548,928	182,976	596,490	596,490	$ -					
2053	182,976	182,976	-	192,488	192,488	$ -					
2054	-	-	-	-	-	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		21,957,101		68,378,321	68,378,321	-					

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

Current Projected Year ARR	**127,072**
Current Projected Year ARR w/ Incentive	**127,072**
Current Projected Year Incentive ARR	-

Details			
Investment	1,112,263	Current Year	**2022**
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	10	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	27,807

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	4,634	1,107,629	120,042	120,042	$ -	$ 226,163		$ 226,163		
2017	1,107,629	27,807	1,079,822	141,528	141,528	$ -	$ 7,946		$ 7,946		
2018	1,079,822	27,807	1,052,015	138,637	138,637	$ -	$ 18,182		$ 18,182		
2019	1,052,015	27,807	1,024,209	135,745	135,745	$ -	$ 125,631		$ 125,631		
2020	1,024,209	27,807	996,402	132,854	132,854	$ -	$ 125,733		$ 125,733		
2021	996,402	27,807	968,596	129,963	129,963	$ -	$ 124,826		$ 124,826		
2022	968,596	27,807	940,789	127,072	127,072	$ -					
2023	940,789	27,807	912,983	124,180	124,180	$ -					
2024	912,983	27,807	885,176	121,289	121,289	$ -					
2025	885,176	27,807	857,369	118,398	118,398	$ -					
2026	857,369	27,807	829,563	115,507	115,507	$ -					
2027	829,563	27,807	801,756	112,616	112,616	$ -					
2028	801,756	27,807	773,950	109,724	109,724	$ -					
2029	773,950	27,807	746,143	106,833	106,833	$ -					
2030	746,143	27,807	718,337	103,942	103,942	$ -					
2031	718,337	27,807	690,530	101,051	101,051	$ -					
2032	690,530	27,807	662,723	98,159	98,159	$ -					
2033	662,723	27,807	634,917	95,268	95,268	$ -					
2034	634,917	27,807	607,110	92,377	92,377	$ -					
2035	607,110	27,807	579,304	89,486	89,486	$ -					
2036	579,304	27,807	551,497	86,595	86,595	$ -					
2037	551,497	27,807	523,690	83,703	83,703	$ -					
2038	523,690	27,807	495,884	80,812	80,812	$ -					
2039	495,884	27,807	468,077	77,921	77,921	$ -					
2040	468,077	27,807	440,271	75,030	75,030	$ -					
2041	440,271	27,807	412,464	72,139	72,139	$ -					
2042	412,464	27,807	384,658	69,247	69,247	$ -					
2043	384,658	27,807	356,851	66,356	66,356	$ -					
2044	356,851	27,807	329,044	63,465	63,465	$ -					
2045	329,044	27,807	301,238	60,574	60,574	$ -					
2046	301,238	27,807	273,431	57,682	57,682	$ -					
2047	273,431	27,807	245,625	54,791	54,791	$ -					
2048	245,625	27,807	217,818	51,900	51,900	$ -					
2049	217,818	27,807	190,012	49,009	49,009	$ -					
2050	190,012	27,807	162,205	46,118	46,118	$ -					
2051	162,205	27,807	134,398	43,226	43,226	$ -					
2052	134,398	27,807	106,592	40,335	40,335	$ -					
2053	106,592	27,807	78,785	37,444	37,444	$ -					
2054	78,785	27,807	50,979	34,553	34,553	$ -					
2055	50,979	27,807	23,172	31,662	31,662	$ -					
2056	23,172	23,172	-	24,377	24,377	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
Project Totals		1,112,263		3,521,609	3,521,609	-					

** 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	**87,433**
Current Projected Year ARR w/ Incentive	**87,433**
Current Projected Year Incentive ARR	-

Details			
Investment	818,037	Current Year	**2022**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	20,451

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	85,056	85,056	$ -	$ -		$ -		
2014	818,037	20,451	797,586	104,444	104,444	$ -	$ 139,756		$ 139,756		
2015	797,586	20,451	777,135	102,318	102,318	$ -	$ 133,078		$ 133,078		
2016	777,135	20,451	756,684	100,191	100,191	$ -	$ 132,118		$ 132,118		
2017	756,684	20,451	736,233	98,065	98,065	$ -	$ 119,121		$ 119,121		
2018	736,233	20,451	715,782	95,938	95,938	$ -	$ 98,812		$ 98,812		
2019	715,782	20,451	695,331	93,812	93,812	$ -	$ 90,112		$ 90,112		
2020	695,331	20,451	674,881	91,685	91,685	$ -	$ 87,283		$ 87,283		
2021	674,881	20,451	654,430	89,559	89,559	$ -	$ 86,203		$ 86,203		
2022	654,430	20,451	633,979	87,433	87,433	$ -					
2023	633,979	20,451	613,528	85,306	85,306	$ -					
2024	613,528	20,451	593,077	83,180	83,180	$ -					
2025	593,077	20,451	572,626	81,053	81,053	$ -					
2026	572,626	20,451	552,175	78,927	78,927	$ -					
2027	552,175	20,451	531,724	76,801	76,801	$ -					
2028	531,724	20,451	511,273	74,674	74,674	$ -					
2029	511,273	20,451	490,822	72,548	72,548	$ -					
2030	490,822	20,451	470,371	70,421	70,421	$ -					
2031	470,371	20,451	449,920	68,295	68,295	$ -					
2032	449,920	20,451	429,469	66,169	66,169	$ -					
2033	429,469	20,451	409,018	64,042	64,042	$ -					
2034	409,018	20,451	388,568	61,916	61,916	$ -					
2035	388,568	20,451	368,117	59,789	59,789	$ -					
2036	368,117	20,451	347,666	57,663	57,663	$ -					
2037	347,666	20,451	327,215	55,537	55,537	$ -					
2038	327,215	20,451	306,764	53,410	53,410	$ -					
2039	306,764	20,451	286,313	51,284	51,284	$ -					
2040	286,313	20,451	265,862	49,157	49,157	$ -					
2041	265,862	20,451	245,411	47,031	47,031	$ -					
2042	245,411	20,451	224,960	44,905	44,905	$ -					
2043	224,960	20,451	204,509	42,778	42,778	$ -					
2044	204,509	20,451	184,058	40,652	40,652	$ -					
2045	184,058	20,451	163,607	38,525	38,525	$ -					
2046	163,607	20,451	143,156	36,399	36,399	$ -					
2047	143,156	20,451	122,706	34,273	34,273	$ -					
2048	122,706	20,451	102,255	32,146	32,146	$ -					
2049	102,255	20,451	81,804	30,020	30,020	$ -					
2050	81,804	20,451	61,353	27,893	27,893	$ -					
2051	61,353	20,451	40,902	25,767	25,767	$ -					
2052	40,902	20,451	20,451	23,641	23,641	$ -					
2053	20,451	20,451	-	21,514	21,514	$ -					
2054	-	-	-	-	-	$ -					
2055	-	-	-	-	-	$ -					
2056	-	-	-	-	-	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
Project Totals		818,037		2,604,217	2,604,217	-					

** 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	**1,418,586**
Current Projected Year ARR w/ Incentive	**1,418,586**
Current Projected Year Incentive ARR	**-**

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

Details			
Investment	13,008,915	Current Year	2022
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	10	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	325,223

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	54,204	12,954,712	1,404,000	1,404,000	$ -	$ -	$ -
2015	12,954,712	325,223	12,629,489	1,655,294	1,655,294	$ -	$ 248,467	$ 248,467
2016	12,629,489	325,223	12,304,266	1,621,479	1,621,479	$ -	$ 562,247	$ 562,247
2017	12,304,266	325,223	11,979,043	1,587,663	1,587,663	$ -	$ 1,427,903	$ 1,427,903
2018	11,979,043	325,223	11,653,820	1,553,848	1,553,848	$ -	$ 1,271,398	$ 1,271,398
2019	11,653,820	325,223	11,328,597	1,520,032	1,520,032	$ -	$ 1,164,196	$ 1,164,196
2020	11,328,597	325,223	11,003,374	1,486,217	1,486,217	$ -	$ 1,113,451	$ 1,113,451
2021	11,003,374	325,223	10,678,151	1,452,402	1,452,402	$ -	$ 1,397,056	$ 1,397,056
2022	10,678,151	325,223	10,352,929	1,418,586	1,418,586	$ -		
2023	10,352,929	325,223	10,027,706	1,384,771	1,384,771	$ -		
2024	10,027,706	325,223	9,702,483	1,350,956	1,350,956	$ -		
2025	9,702,483	325,223	9,377,260	1,317,140	1,317,140	$ -		
2026	9,377,260	325,223	9,052,037	1,283,325	1,283,325	$ -		
2027	9,052,037	325,223	8,726,814	1,249,510	1,249,510	$ -		
2028	8,726,814	325,223	8,401,591	1,215,694	1,215,694	$ -		
2029	8,401,591	325,223	8,076,368	1,181,879	1,181,879	$ -		
2030	8,076,368	325,223	7,751,145	1,148,063	1,148,063	$ -		
2031	7,751,145	325,223	7,425,923	1,114,248	1,114,248	$ -		
2032	7,425,923	325,223	7,100,700	1,080,433	1,080,433	$ -		
2033	7,100,700	325,223	6,775,477	1,046,617	1,046,617	$ -		
2034	6,775,477	325,223	6,450,254	1,012,802	1,012,802	$ -		
2035	6,450,254	325,223	6,125,031	978,987	978,987	$ -		
2036	6,125,031	325,223	5,799,808	945,171	945,171	$ -		
2037	5,799,808	325,223	5,474,585	911,356	911,356	$ -		
2038	5,474,585	325,223	5,149,362	877,541	877,541	$ -		
2039	5,149,362	325,223	4,824,139	843,725	843,725	$ -		
2040	4,824,139	325,223	4,498,917	809,910	809,910	$ -		
2041	4,498,917	325,223	4,173,694	776,094	776,094	$ -		
2042	4,173,694	325,223	3,848,471	742,279	742,279	$ -		
2043	3,848,471	325,223	3,523,248	708,464	708,464	$ -		
2044	3,523,248	325,223	3,198,025	674,648	674,648	$ -		
2045	3,198,025	325,223	2,872,802	640,833	640,833	$ -		
2046	2,872,802	325,223	2,547,579	607,018	607,018	$ -		
2047	2,547,579	325,223	2,222,356	573,202	573,202	$ -		
2048	2,222,356	325,223	1,897,134	539,387	539,387	$ -		
2049	1,897,134	325,223	1,571,911	505,571	505,571	$ -		
2050	1,571,911	325,223	1,246,688	471,756	471,756	$ -		
2051	1,246,688	325,223	921,465	437,941	437,941	$ -		
2052	921,465	325,223	596,242	404,125	404,125	$ -		
2053	596,242	325,223	271,019	370,310	370,310	$ -		
2054	271,019	271,019	-	285,109	285,109	$ -		
2055	-	-	-	-	-	$ -		
2056	-	-	-	-	-	$ -		
2057	-	-	-	-	-	$ -		
2058	-	-	-	-	-	$ -		
2059	-	-	-	-	-	$ -		
2060	-	-	-	-	-	$ -		
2061	-	-	-	-	-	$ -		
2062	-	-	-	-	-	$ -		
2063	-	-	-	-	-	$ -		
2064	-	-	-	-	-	$ -		
2065	-	-	-	-	-	$ -		
2066	-	-	-	-	-	$ -		
2067	-	-	-	-	-	$ -		
2068	-	-	-	-	-	$ -		
2069	-	-	-	-	-	$ -		
2070	-	-	-	-	-	$ -		
2071	-	-	-	-	-	$ -		
2072	-	-	-	-	-	$ -		
2073	-	-	-	-	-	$ -		
Project Totals		13,008,915		41,188,386	41,188,386	-		

** 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	**380,260**
Current Projected Year ARR w/ Incentive	**380,260**
Current Projected Year Incentive ARR	**-**

Details			
Investment	3,315,854	Current Year	2022
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	82,896

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	344,769	344,769	$ -	$ 486,138		$ 486,138		
2017	3,315,854	82,896	3,232,958	423,356	423,356	$ -	$ 574,408		$ 574,408		
2018	3,232,958	82,896	3,150,061	414,737	414,737	$ -	$ 355,679		$ 355,679		
2019	3,150,061	82,896	3,067,165	406,117	406,117	$ -	$ 367,592		$ 367,592		
2020	3,067,165	82,896	2,984,269	397,498	397,498	$ -	$ 376,071		$ 376,071		
2021	2,984,269	82,896	2,901,372	388,879	388,879	$ -	$ 373,465		$ 373,465		
2022	2,901,372	82,896	2,818,476	380,260	380,260	$ -					
2023	2,818,476	82,896	2,735,580	371,640	371,640	$ -					
2024	2,735,580	82,896	2,652,683	363,021	363,021	$ -					
2025	2,652,683	82,896	2,569,787	354,402	354,402	$ -					
2026	2,569,787	82,896	2,486,891	345,783	345,783	$ -					
2027	2,486,891	82,896	2,403,994	337,164	337,164	$ -					
2028	2,403,994	82,896	2,321,098	328,544	328,544	$ -					
2029	2,321,098	82,896	2,238,201	319,925	319,925	$ -					
2030	2,238,201	82,896	2,155,305	311,306	311,306	$ -					
2031	2,155,305	82,896	2,072,409	302,687	302,687	$ -					
2032	2,072,409	82,896	1,989,512	294,067	294,067	$ -					
2033	1,989,512	82,896	1,906,616	285,448	285,448	$ -					
2034	1,906,616	82,896	1,823,720	276,829	276,829	$ -					
2035	1,823,720	82,896	1,740,823	268,210	268,210	$ -					
2036	1,740,823	82,896	1,657,927	259,591	259,591	$ -					
2037	1,657,927	82,896	1,575,031	250,971	250,971	$ -					
2038	1,575,031	82,896	1,492,134	242,352	242,352	$ -					
2039	1,492,134	82,896	1,409,238	233,733	233,733	$ -					
2040	1,409,238	82,896	1,326,342	225,114	225,114	$ -					
2041	1,326,342	82,896	1,243,445	216,494	216,494	$ -					
2042	1,243,445	82,896	1,160,549	207,875	207,875	$ -					
2043	1,160,549	82,896	1,077,653	199,256	199,256	$ -					
2044	1,077,653	82,896	994,756	190,637	190,637	$ -					
2045	994,756	82,896	911,860	182,017	182,017	$ -					
2046	911,860	82,896	828,963	173,398	173,398	$ -					
2047	828,963	82,896	746,067	164,779	164,779	$ -					
2048	746,067	82,896	663,171	156,160	156,160	$ -					
2049	663,171	82,896	580,274	147,541	147,541	$ -					
2050	580,274	82,896	497,378	138,921	138,921	$ -					
2051	497,378	82,896	414,482	130,302	130,302	$ -					
2052	414,482	82,896	331,585	121,683	121,683	$ -					
2053	331,585	82,896	248,689	113,064	113,064	$ -					
2054	248,689	82,896	165,793	104,444	104,444	$ -					
2055	165,793	82,896	82,896	95,825	95,825	$ -					
2056	82,896	82,896	-	87,206	87,206	$ -					
2057	-	-	-	-	-	$ -					
2058	-	-	-	-	-	$ -					
2059	-	-	-	-	-	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
Project Totals		3,315,854		10,556,006	10,556,006	-					

** 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	**79,219**
Current Projected Year ARR w/ Incentive	**79,219**
Current Projected Year Incentive ARR	-

Details			
Investment	653,739	Current Year	**2022**
Service Year (yyyy)	2019	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	16,343

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	8,172	645,568	75,720	75,720	$ -	$ 67,813		$ 67,813		
2020	645,568	16,343	629,224	82,617	82,617	$ -	$ 66,522		$ 66,522		
2021	629,224	16,343	612,881	80,918	80,918	$ -	$ 77,582		$ 77,582		
2022	612,881	16,343	596,537	79,219	79,219	$ -					
2023	596,537	16,343	580,194	77,519	77,519	$ -					
2024	580,194	16,343	563,850	75,820	75,820	$ -					
2025	563,850	16,343	547,507	74,121	74,121	$ -					
2026	547,507	16,343	531,163	72,421	72,421	$ -					
2027	531,163	16,343	514,820	70,722	70,722	$ -					
2028	514,820	16,343	498,476	69,023	69,023	$ -					
2029	498,476	16,343	482,133	67,323	67,323	$ -					
2030	482,133	16,343	465,789	65,624	65,624	$ -					
2031	465,789	16,343	449,446	63,925	63,925	$ -					
2032	449,446	16,343	433,102	62,225	62,225	$ -					
2033	433,102	16,343	416,759	60,526	60,526	$ -					
2034	416,759	16,343	400,415	58,827	58,827	$ -					
2035	400,415	16,343	384,072	57,127	57,127	$ -					
2036	384,072	16,343	367,728	55,428	55,428	$ -					
2037	367,728	16,343	351,385	53,729	53,729	$ -					
2038	351,385	16,343	335,041	52,029	52,029	$ -					
2039	335,041	16,343	318,698	50,330	50,330	$ -					
2040	318,698	16,343	302,354	48,631	48,631	$ -					
2041	302,354	16,343	286,011	46,931	46,931	$ -					
2042	286,011	16,343	269,667	45,232	45,232	$ -					
2043	269,667	16,343	253,324	43,533	43,533	$ -					
2044	253,324	16,343	236,980	41,833	41,833	$ -					
2045	236,980	16,343	220,637	40,134	40,134	$ -					
2046	220,637	16,343	204,294	38,435	38,435	$ -					
2047	204,294	16,343	187,950	36,735	36,735	$ -					
2048	187,950	16,343	171,607	35,036	35,036	$ -					
2049	171,607	16,343	155,263	33,337	33,337	$ -					
2050	155,263	16,343	138,920	31,637	31,637	$ -					
2051	138,920	16,343	122,576	29,938	29,938	$ -					
2052	122,576	16,343	106,233	28,239	28,239	$ -					
2053	106,233	16,343	89,889	26,539	26,539	$ -					
2054	89,889	16,343	73,546	24,840	24,840	$ -					
2055	73,546	16,343	57,202	23,141	23,141	$ -					
2056	57,202	16,343	40,859	21,441	21,441	$ -					
2057	40,859	16,343	24,515	19,742	19,742	$ -					
2058	24,515	16,343	8,172	18,043	18,043	$ -					
2059	8,172	8,172	-	8,597	8,597	$ -					
2060	-	-	-	-	-	$ -					
2061	-	-	-	-	-	$ -					
2062	-	-	-	-	-	$ -					
2063	-	-	-	-	-	$ -					
2064	-	-	-	-	-	$ -					
2065	-	-	-	-	-	$ -					
2066	-	-	-	-	-	$ -					
2067	-	-	-	-	-	$ -					
2068	-	-	-	-	-	$ -					
2069	-	-	-	-	-	$ -					
2070	-	-	-	-	-	$ -					
2071	-	-	-	-	-	$ -					
2072	-	-	-	-	-	$ -					
2073	-	-	-	-	-	$ -					
2074	-	-	-	-	-	$ -					
2075	-	-	-	-	-	$ -					
2076	-	-	-	-	-	$ -					
2077	-	-	-	-	-	$ -					
2078	-	-	-	-	-	$ -					
Project Totals		653,739		2,047,189	2,047,189	-					

** 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	**66,616**
Current Projected Year ARR w/ Incentive	**66,616**
Current Projected Year Incentive ARR	-

Details			
Investment	633,540	Current Year	**2022**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	10.40%
Useful life	40	FCR w/incentives approved for these facilities, less dep.	10.40%
CIAC (Yes or No)	No	Annual Depreciation Expense	15,839

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	10,559	622,981	75,883	75,883	$ -	$ -	$ -
2014	622,981	15,839	607,143	79,790	79,790	$ -	$ -	$ -
2015	607,143	15,839	591,304	78,143	78,143	$ -		
2016	591,304	15,839	575,466	76,496	76,496	$ -		
2017	575,466	15,839	559,627	74,850	74,850	$ -		
2018	559,627	15,839	543,789	73,203	73,203	$ -		
2019	543,789	15,839	527,950	71,556	71,556	$ -		
2020	527,950	15,839	512,112	69,909	69,909	$ -	$ 66,652	$ 66,652
2021	512,112	15,839	496,273	68,262	68,262	$ -	$ 65,740	$ 65,740
2022	496,273	15,839	480,435	66,616	66,616	$ -		
2023	480,435	15,839	464,596	64,969	64,969	$ -		
2024	464,596	15,839	448,758	63,322	63,322	$ -		
2025	448,758	15,839	432,919	61,675	61,675	$ -		
2026	432,919	15,839	417,081	60,028	60,028	$ -		
2027	417,081	15,839	401,242	58,381	58,381	$ -		
2028	401,242	15,839	385,404	56,735	56,735	$ -		
2029	385,404	15,839	369,565	55,088	55,088	$ -		
2030	369,565	15,839	353,727	53,441	53,441	$ -		
2031	353,727	15,839	337,888	51,794	51,794	$ -		
2032	337,888	15,839	322,050	50,147	50,147	$ -		
2033	322,050	15,839	306,211	48,500	48,500	$ -		
2034	306,211	15,839	290,373	46,854	46,854	$ -		
2035	290,373	15,839	274,534	45,207	45,207	$ -		
2036	274,534	15,839	258,696	43,560	43,560	$ -		
2037	258,696	15,839	242,857	41,913	41,913	$ -		
2038	242,857	15,839	227,019	40,266	40,266	$ -		
2039	227,019	15,839	211,180	38,620	38,620	$ -		
2040	211,180	15,839	195,342	36,973	36,973	$ -		
2041	195,342	15,839	179,503	35,326	35,326	$ -		
2042	179,503	15,839	163,665	33,679	33,679	$ -		
2043	163,665	15,839	147,826	32,032	32,032	$ -		
2044	147,826	15,839	131,988	30,385	30,385	$ -		
2045	131,988	15,839	116,149	28,739	28,739	$ -		
2046	116,149	15,839	100,311	27,092	27,092	$ -		
2047	100,311	15,839	84,472	25,445	25,445	$ -		
2048	84,472	15,839	68,634	23,798	23,798	$ -		
2049	68,634	15,839	52,795	22,151	22,151	$ -		
2050	52,795	15,839	36,957	20,504	20,504	$ -		
2051	36,957	15,839	21,118	18,858	18,858	$ -		
2052	21,118	15,839	5,280	17,211	17,211	$ -		
2053	5,280	5,280	-	5,554	5,554	$ -		
2054	-	-	-	-	-	$ -		
2055	-	-	-	-	-	$ -		
2056	-	-	-	-	-	$ -		
2057	-	-	-	-	-	$ -		
2058	-	-	-	-	-	$ -		
2059	-	-	-	-	-	$ -		
2060	-	-	-	-	-	$ -		
2061	-	-	-	-	-	$ -		
2062	-	-	-	-	-	$ -		
2063	-	-	-	-	-	$ -		
2064	-	-	-	-	-	$ -		
2065	-	-	-	-	-	$ -		
2066	-	-	-	-	-	$ -		
2067	-	-	-	-	-	$ -		
2068	-	-	-	-	-	$ -		
2069	-	-	-	-	-	$ -		
2070	-	-	-	-	-	$ -		
2071	-	-	-	-	-	$ -		
2072	-	-	-	-	-	$ -		
Project Totals		633,540		1,972,956	1,972,956	-		

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

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

AEP East Companies
Cost of Service Formula Rate Using 2022 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	2,764,649,000		(5,658,229)	(5,926,000)	2,776,233,229
2	January	2,795,778,000		(5,635,730)	(5,897,000)	2,807,310,730
3	February	2,796,864,000		(5,589,245)	(5,868,000)	2,808,321,245
4	March	2,824,706,000		(5,582,283)	(5,840,000)	2,836,128,283
5	April	2,825,214,000		(5,562,844)	(5,811,000)	2,836,587,844
6	May	2,813,324,000		(5,545,143)	(5,783,000)	2,824,652,143
7	June	2,849,848,000		(5,544,221)	(5,754,000)	2,861,146,221
8	July	2,886,255,000		(5,541,334)	(5,725,000)	2,897,521,334
9	August	2,889,083,000		(5,537,232)	(5,697,000)	2,900,317,232
10	September	2,903,998,000		(5,535,923)	(5,668,000)	2,915,201,923
11	October	2,919,497,000		(5,534,501)	(5,639,000)	2,930,670,501
12	November	2,904,275,000		(5,675,353)	(5,611,000)	2,915,561,353
13	December of Rate Year	2,930,040,000		(5,485,144)	(5,582,000)	2,941,107,144
14	Average of the 13 Monthly Balances	2,854,118,000	-	(5,571,000)	(5,754,000)	2,865,443,000

		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		-		3,269,009,000		3,269,009,000
16	January		-		3,254,763,000		3,254,763,000
17	February		-		3,249,136,000		3,249,136,000
18	March		-		3,243,624,000		3,243,624,000
19	April		-		3,231,907,000		3,231,907,000
20	May		-		3,299,274,000		3,299,274,000
21	June		-		3,295,949,000		3,295,949,000
22	July		-		3,284,198,000		3,284,198,000
23	August		-		3,280,810,000		3,280,810,000
24	September		-		3,277,484,000		3,277,484,000
25	October		-		3,266,948,000		3,266,948,000
26	November		-		3,334,068,000		3,334,068,000
27	December of Rate Year		-		3,331,941,000		3,331,941,000
28	Average of the 13 Monthly Balances	-	-	-	3,278,393,000	-	3,278,393,000

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 2022**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			116,905,000			
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)			2,079,000			
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			1,304,000			
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)**			120,288,000			
38	**Average Cost of Debt for 2022 (Ln 37/ ln 28 (g))**			**3.67%**			

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 2022	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	6,801,000	11/14/06	02/28/37
43	Senior Unsecured Notes - Series J	1,606,000	-	1,606,000	3,548,000	03/15/13	03/15/23
44				-			
45				-			
46				-			
47				-			
48				-			
49					10,349,000		
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 2022 (TCOS, Ln 157)	6,143,836,000
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
54	Limit of Recoverable Amount	3,071,918
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 2022		-		-	

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 2022

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2022	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	(21,654,000)	35.88%	(45,576,757)	10.559%	(2,286,344)	(4,812,235)	2,525,891
3	I&M	(16,229,000)	26.89%	(34,158,363)	4.637%	(752,490)	(1,583,820)	831,330
4	KPCo	(5,029,000)	8.33%	(10,584,904)	8.698%	(437,439)	(920,709)	483,270
5	KNGP	(537,000)	0.89%	(1,130,263)	12.563%	(67,464)	(141,997)	74,533
6	OPCo	(15,972,000)	26.46%	(33,617,436)	12.672%	(2,023,979)	(4,260,016)	2,236,037
7	WPCo	(938,000)	1.55%	(1,974,277)	3.775%	(35,411)	(74,533)	39,122
8	**Sum of Lines 2 to 7**	(60,359,000)		(127,042,000)		(5,603,126)	(11,793,309)	6,190,183

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	(18,399,000)	(15,727,000)	(4,563,000)	(409,000)	(12,905,000)	(478,000)	(52,481,000)
10 Additional PBOP Ledger Entries (from Company Records)	519,000	1,847,000	418,000	-	-	(376,000)	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(17,880,000)	(13,880,000)	(4,145,000)	(409,000)	(12,905,000)	(854,000)	(50,073,000)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(5,244,000)	(3,720,000)	(1,263,000)	(166,000)	(4,133,000)	(120,000)	(14,646,000)
14 Company PBOP Expense (Ln 12 + Ln 13)	(23,124,000)	(17,600,000)	(5,408,000)	(575,000)	(17,038,000)	(974,000)	(64,719,000)

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 1/1/2020
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	1.99%	0.494821	0.98%	1.62%	0.411083	0.67%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.86%
Station Equipment	353.0	2.70%	0.494821	1.34%	2.37%	0.411083	0.97%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	2.52%
Towers & Fixtures	354.0	1.64%	0.494821	0.81%	1.59%	0.411083	0.65%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.67%
Poles & Fixtures	355.0	3.46%	0.494821	1.71%	2.71%	0.411083	1.11%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	3.03%
Overhead Conductor	356.0	1.65%	0.494821	0.82%	1.53%	0.411083	0.63%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.66%
Underground Conduit	357.0	2.49%	0.494821	1.23%	3.71%	0.411083	1.53%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	2.97%
Underground Conductors	358.0	4.72%	0.494821	2.34%	5.24%	0.411083	2.15%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	4.70%
GENERAL PLANT														
Structures & Improvements	390.0	1.89%	0.523756	0.99%	1.91%	0.425941	0.81%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.98%
Office Furniture & Equipment	391.0	3.21%	0.523756	1.68%	3.17%	0.425941	1.35%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.21%
Transportation Equipment	392.0	3.46%	0.523756	1.81%	3.40%	0.425941	1.45%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.44%
Stores Equipment	393.0	1.78%	0.523756	0.93%	1.80%	0.425941	0.77%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.88%
Tools Shop & Garage Equipment	394.0	2.59%	0.523756	1.36%	2.57%	0.425941	1.09%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	2.63%
Laboratory Equipment	395.0	3.87%	0.523756	2.03%	4.01%	0.425941	1.71%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.92%
Power Operated Equipment	396.0	0.00%	0.523756	0.00%	3.90%	0.425941	1.66%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.84%
Communication Equipment	397.0	5.05%	0.523756	2.64%	4.98%	0.425941	2.12%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	4.94%
Miscellaneous Equipment	398.0	2.67%	0.523756	1.40%	2.70%	0.425941	1.15%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	2.73%

(1) As approved in VA Case No. PUE 2020-00015 on Nov. 24, 2020
Depreciation rates were made effective on January 1, 2020.

(2) Approved by PSC of WV Order dated 2/27/2019 in
Case No. 18-0645-E-D effective 03/06/2019.

(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) Distribution Plant (recorded by state) is assigned only to jurisdictions within each state.

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 MARCH 11, 2020
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			MICHIGAN AND FERC			COMPANY
	PLANT ACCT.	(1) IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(2) MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT								
Land Improvements	350.1	1.6600%	0.662335	1.0995%	1.6200%	0.337665	0.5470%	1.65%
Structures & Improvements	352.0	1.7700%	0.662335	1.1723%	1.7400%	0.337665	0.5875%	1.76%
Station Equipment	353.0	2.4300%	0.662335	1.6095%	2.4100%	0.337665	0.8138%	2.42%
Towers & Fixtures	354.0	2.5700%	0.662335	1.7022%	2.4500%	0.337665	0.8273%	2.53%
Poles & Fixtures	355.0	3.1900%	0.662335	2.1128%	3.1700%	0.337665	1.0704%	3.18%
Overhead Conductors	356.0	2.3500%	0.662335	1.5565%	2.2800%	0.337665	0.7699%	2.33%
Underground Conduit	357.0	2.3000%	0.662335	1.5234%	2.2100%	0.337665	0.7462%	2.27%
Underground Conductors	358.0	1.9300%	0.662335	1.2783%	1.9000%	0.337665	0.6416%	1.92%
Trails & Roads	359.0	1.6100%	0.662335	1.0664%	1.5900%	0.337665	0.5369%	1.60%
GENERAL PLANT								
	390.0	2.0800%	0.681868	1.4183%	2.0800%	0.318132	0.6617%	2.08%
	391.0	4.7900%	0.681868	3.2661%	4.8400%	0.318132	1.5398%	4.81%
$0 at Dec 2018 - use old rate	392.0	4.6400%	0.681868	3.1639%	4.6800%	0.318132	1.4889%	4.65%
	393.0	7.3500%	0.681868	5.0117%	7.3800%	0.318132	2.3478%	7.36%
	394.0	6.9900%	0.681868	4.7663%	7.0700%	0.318132	2.2492%	7.02%
	395.0	5.4100%	0.681868	3.6889%	5.4600%	0.318132	1.7370%	5.43%
	396.0	4.8100%	0.681868	3.2798%	4.9000%	0.318132	1.5588%	4.84%
	397.0	3.9100%	0.681868	2.6661%	3.9300%	0.318132	1.2503%	3.92%
	398.0	3.3200%	0.681868	2.2638%	3.3500%	0.318132	1.0657%	3.33%

(1) As approved in Indiana Cause No. 45235 effective March 11, 2020.
(2) As approved in Michigan Case No. U-20359 effective February 1, 2020.
(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
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 4/1/2012
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 3/1/2019
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 2020 Available May 25, 2021		2020 Forecasted Revenue Requirement For Year 2020		True-up Adjustment - Over (Under) Recovery
$143,872,945	-	$138,188,457	=	($5,684,488)

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
			0.3145%				

An over or under collection will be recovered prorata over 2019, held for 2020 and returned prorate over 2021

Calculation of Interest					**Monthly**		
January	Year 2020	(473,707)	0.3145%	12	17,878		491,585
February	Year 2020	(473,707)	0.3145%	11	16,388		490,095
March	Year 2020	(473,707)	0.3145%	10	14,898		488,605
April	Year 2020	(473,707)	0.3145%	9	13,408		487,116
May	Year 2020	(473,707)	0.3145%	8	11,918		485,626
June	Year 2020	(473,707)	0.3145%	7	10,429		484,136
July	Year 2020	(473,707)	0.3145%	6	8,939		482,646
August	Year 2020	(473,707)	0.3145%	5	7,449		481,156
September	Year 2020	(473,707)	0.3145%	4	5,959		479,667
October	Year 2020	(473,707)	0.3145%	3	4,469		478,177
November	Year 2020	(473,707)	0.3145%	2	2,980		476,687
December	Year 2020	(473,707)	0.3145%	1	1,490		475,197
					116,205		**5,800,693**
					Annual		
January through December	Year 2020	5,800,693	0.3145%	12	218,918		**6,019,612**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2022	(6,019,612)	0.3145%		18,932	(511,948)	5,526,595
February	Year 2022	(5,526,595)	0.3145%		17,381	(511,948)	5,032,028
March	Year 2022	(5,032,028)	0.3145%		15,826	(511,948)	4,535,906
April	Year 2022	(4,535,906)	0.3145%		14,265	(511,948)	4,038,224
May	Year 2022	(4,038,224)	0.3145%		12,700	(511,948)	3,538,976
June	Year 2022	(3,538,976)	0.3145%		11,130	(511,948)	3,038,158
July	Year 2022	(3,038,158)	0.3145%		9,555	(511,948)	2,535,765
August	Year 2022	(2,535,765)	0.3145%		7,975	(511,948)	2,031,792
September	Year 2022	(2,031,792)	0.3145%		6,390	(511,948)	1,526,234
October	Year 2022	(1,526,234)	0.3145%		4,800	(511,948)	1,019,086
November	Year 2022	(1,019,086)	0.3145%		3,205	(511,948)	510,343
December	Year 2022	(510,343)	0.3145%		1,605	(511,948)	0
					123,764		

True-Up Adjustment with Interest	6,143,376
Less Over (Under) Recovery	(5,684,488)
Total Interest	458,888

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 2020 Available May 25, 2021		2020 Forecasted Revenue Requirement For Year 2020		True-up Adjustment - Over (Under) Recovery
$5,447,219	-	$5,012,170	=	($435,049)

Interest Rate on Amount of Refunds or Surcharge from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.3145%				

An over or under collection will be recovered prorata over 2019, held for 2020 and returned prorate over 2021

Calculation of Interest					**Monthly**		
January	Year 2020	(36,254)	0.3145%	12	1,368		37,622
February	Year 2020	(36,254)	0.3145%	11	1,254		37,508
March	Year 2020	(36,254)	0.3145%	10	1,140		37,394
April	Year 2020	(36,254)	0.3145%	9	1,026		37,280
May	Year 2020	(36,254)	0.3145%	8	912		37,166
June	Year 2020	(36,254)	0.3145%	7	798		37,052
July	Year 2020	(36,254)	0.3145%	6	684		36,938
August	Year 2020	(36,254)	0.3145%	5	570		36,824
September	Year 2020	(36,254)	0.3145%	4	456		36,710
October	Year 2020	(36,254)	0.3145%	3	342		36,596
November	Year 2020	(36,254)	0.3145%	2	228		36,482
December	Year 2020	(36,254)	0.3145%	1	114		36,368
					8,893		**443,942**
					Annual		
January through December	Year 2020	443,942	0.3145%	12	16,754		**460,696**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2022	(460,696)	0.3145%		1,449	(39,181)	422,965
February	Year 2022	(422,965)	0.3145%		1,330	(39,181)	385,114
March	Year 2022	(385,114)	0.3145%		1,211	(39,181)	347,145
April	Year 2022	(347,145)	0.3145%		1,092	(39,181)	309,056
May	Year 2022	(309,056)	0.3145%		972	(39,181)	270,847
June	Year 2022	(270,847)	0.3145%		852	(39,181)	232,518
July	Year 2022	(232,518)	0.3145%		731	(39,181)	194,069
August	Year 2022	(194,069)	0.3145%		610	(39,181)	155,498
September	Year 2022	(155,498)	0.3145%		489	(39,181)	116,807
October	Year 2022	(116,807)	0.3145%		367	(39,181)	77,993
November	Year 2022	(77,993)	0.3145%		245	(39,181)	39,058
December	Year 2022	(39,058)	0.3145%		123	(39,181)	0
					9,472		

True-Up Adjustment with Interest	470,168
Less Over (Under) Recovery	(435,049)
Total Interest	35,120

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 2020 Available May 25, 2021		2020 Forecasted Revenue Requirement For Year 2020		True-up Adjustment - Over (Under) Recovery
$385,704	-	$1,646,007	=	$1,260,303

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
			0.3145%				

An over or under collection will be recovered prorata over 2019, held for 2020 and returned prorate over 2021

Calculation of Interest					**Monthly**		
January	Year 2020	105,025	0.3145%	12	(3,964)		(108,989)
February	Year 2020	105,025	0.3145%	11	(3,633)		(108,659)
March	Year 2020	105,025	0.3145%	10	(3,303)		(108,328)
April	Year 2020	105,025	0.3145%	9	(2,973)		(107,998)
May	Year 2020	105,025	0.3145%	8	(2,642)		(107,668)
June	Year 2020	105,025	0.3145%	7	(2,312)		(107,337)
July	Year 2020	105,025	0.3145%	6	(1,982)		(107,007)
August	Year 2020	105,025	0.3145%	5	(1,652)		(106,677)
September	Year 2020	105,025	0.3145%	4	(1,321)		(106,346)
October	Year 2020	105,025	0.3145%	3	(991)		(106,016)
November	Year 2020	105,025	0.3145%	2	(661)		(105,686)
December	Year 2020	105,025	0.3145%	1	(330)		(105,356)
					(25,764)		**(1,286,067)**
					Annual		
January through December	Year 2020	(1,286,067)	0.3145%	12	(48,536)		**(1,334,603)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2022	**1,334,603**	0.3145%		(4,197)	113,504	(1,225,297)
February	Year 2022	1,225,297	0.3145%		(3,854)	113,504	(1,115,647)
March	Year 2022	1,115,647	0.3145%		(3,509)	113,504	(1,005,652)
April	Year 2022	1,005,652	0.3145%		(3,163)	113,504	(895,311)
May	Year 2022	895,311	0.3145%		(2,816)	113,504	(784,623)
June	Year 2022	784,623	0.3145%		(2,468)	113,504	(673,587)
July	Year 2022	673,587	0.3145%		(2,118)	113,504	(562,202)
August	Year 2022	562,202	0.3145%		(1,768)	113,504	(450,467)
September	Year 2022	450,467	0.3145%		(1,417)	113,504	(338,380)
October	Year 2022	338,380	0.3145%		(1,064)	113,504	(225,941)
November	Year 2022	225,941	0.3145%		(711)	113,504	(113,148)
December	Year 2022	113,148	0.3145%		(356)	113,504	(0)
					(27,440)		
True-Up Adjustment with Interest						(1,362,043)	
Less Over (Under) Recovery						1,260,303	
Total Interest						(101,740)	

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.