

Attachment 5

TO13 Formula Rate Spreadsheet

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Overview of SCE Retail Base TRR

SCE's retail Base Transmission Revenue Requirement is the sum of the following components:

<u>TRR Component</u>	<u>Amount</u>
Prior Year TRR	\$1,026,569,313
Incremental Forecast Period TRR	\$100,670,219
True-Up Adjustment	\$59,638,034
Cost Adjustment	<u>\$0</u>
Base TRR (retail)	\$1,186,877,565

These components represent the following costs that SCE incurs:

- 1) The Prior Year TRR component is the TRR associated with the Prior Year (most recent calendar year).
The Prior Year TRR is calculated using End-of-Year Rate Base values, as set forth in the "1-BaseTRR" Worksheet.
- 2) The Incremental Forecast Period TRR is the component of Base TRR associated with forecast additions to in-service plant or CWIP, as set forth in the "2-IFPTRR" Worksheet.
- 3) The True Up Adjustment is a component of the Base TRR that reflects the difference between projected and actual costs, as set forth in the "3-TrueUpAdjust" Worksheet.
- 4) The Cost Adjustment component may be included as provided in the Tariff protocols.

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Cells shaded yellow are input cells

Formula Transmission Rate

Line	Notes	FERC Form 1 Reference or Instruction	2017 Value
RATE BASE			
1	ISO Transmission Plant	6-PlantInService, Line 19	\$8,573,445,553
2	General Plant + Electric Miscellaneous Intangible Plant	6-PlantInService, Line 27	\$249,198,610
3	Transmission Plant Held for Future Use	11-PHFU, Line 8	\$9,942,155
4	Abandoned Plant	12-AbandonedPlant, Line 3	\$0
<u>Working Capital amounts</u>			
5	Materials and Supplies	13-WorkCap, Line 16	\$13,397,450
6	Prepayments	13-WorkCap, Line 36	\$12,825,874
7	Cash Working Capital	(Line 65 + Line 66) / 16	<u>\$7,824,979</u>
8	Working Capital	Line 5 + Line 6 + Line 7	\$34,048,303
<u>Accumulated Depreciation Reserve Balances</u>			
9	Transmission Depreciation Reserve - ISO	Negative amount	
10	Distribution Depreciation Reserve - ISO	Negative amount	
11	General + Intangible Plant Depreciation Reserve	Negative amount	
12	Accumulated Depreciation Reserve	8-AccDep, Line 13, Col. 12 8-AccDep, Line 16, Col. 5 8-AccDep, Line 26 Line 9 + Line 10 + Line 11	-\$1,633,677,100 \$0 -\$97,766,503 -\$1,731,443,603
13	Accumulated Deferred Income Taxes	Negative amount	
14	CWIP Plant	9-ADIT, Line 5, Col. 2	-\$1,649,594,793
15	Other Regulatory Assets/Liabilities	14-IncentivePlant, L 13, Col 1	\$150,629,632
15a	Unfunded Reserves	23-RegAssets, Line 14	\$0
16	Network Upgrade Credits	34-UnfundedReserves, Line 6 22-NUCs, Line 5	-\$10,031,267 -\$93,345,105
17	Rate Base	L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L15a + L16	\$5,532,849,486
OTHER TAXES			
18	Sub-Total Local Taxes	FF1 263.1, Row 30, Column i	FF1 263.2 (see note to left)
19	Transmission Plant Allocation Factor		27-Allocators, Line 22
20	Property Taxes		Line 18 * Line 19
21	Payroll Taxes Expense		
22	FICA		Line 23 + Line 24+ Line 25
23	Fed Ins Cont Amt -- Current	FF1 263, Row 6, Column i	FF1 263 (see note to left)
24	FICA/OASDI Emp Incntv.	FF1 263, Row 7, Column i	FF1 263 (see note to left)
25	FICA/HIT Emp Incntv.	FF1 263, Row 8, Column i	FF1 263 (see note to left)
26	CA SUI Current	FF1 263, Row 21, Column i	FF1 263 (see note to left)
27	Fed Unemp Tax Act- Current	FF1 263, Row 9, Column i	FF1 263 (see note to left)
28	CADI Vol Plan Assess	FF1 263.1, Row 1, Column i	FF1 263.1 (see note to left)
29	SF Pysl Exp Tx - SCE	FF1 263, Row 39, Column i	FF1 263.1 (see note to left)
30	Total Electric Payroll Tax Expense		Line 22 + (Line 26 to Line 29)
31	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 51
32	Remaining Electric Payroll Tax Expense to Allocate		Line 30 - Line 31
33	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9
34	Payroll Taxes Expense		Line 32 * Line 33
35	Other Taxes		Line 20 + Line 34

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Cells shaded yellow are input cells

Formula Transmission Rate

Line	Notes	FERC Form 1 Reference or Instruction	2017 Value
RETURN AND CAPITALIZATION CALCULATIONS			
<u>Debt</u>			
36	Long Term Debt Amount	5-ROR-1, Line 8	\$11,068,242,563
37	Cost of Long Term Debt	5-ROR-1, Line 16	\$514,972,726
38	Long Term Debt Cost Percentage	5-ROR-1, Line 17	4.6527%
<u>Preferred Stock</u>			
39	Preferred Stock Amount	5-ROR-1, Line 21	\$2,224,620,929
40	Cost of Preferred Stock	5-ROR-1, Line 25	\$128,084,089
41	Preferred Stock Cost Percentage	5-ROR-1, Line 26	5.7576%
<u>Equity</u>			
42	Common Stock Equity Amount	5-ROR-1, Line 32	\$12,575,222,880
43	Total Capital	Line 36 + Line 39 + Line 42	\$25,868,086,372
<u>Capital Percentages</u>			
44	Long Term Debt Capital Percentage	Line 36 / Line 43	42.7872%
45	Preferred Stock Capital Percentage	Line 39 / Line 43	8.5999%
46	Common Stock Capital Percentage	Line 42 / Line 43	<u>48.6129%</u>
<u>Annual Cost of Capital Components</u>			
47	Long Term Debt Cost Percentage	Line 38	4.6527%
48	Preferred Stock Cost Percentage	Line 41	5.7576%
49	Return on Common Equity	Note 1 SCE Return on Equity	9.80%
<u>Calculation of Cost of Capital Rate</u>			
50	Weighted Cost of Long Term Debt	Line 38 * Line 44	1.9908%
51	Weighted Cost of Preferred Stock	Line 41 * Line 45	0.4951%
52	Weighted Cost of Common Stock	Line 46 * Line 49	<u>4.7641%</u>
53	Cost of Capital Rate	Line 50 + Line 51 + Line 52	7.2500%
54	Equity Rate of Return Including Common and Preferred Stock	Used for Tax calculation Line 51 + Line 52	5.2592%
55	Return on Capital: Rate Base times Cost of Capital Rate	Line 17 * Line 53	\$401,129,961
INCOME TAXES			
56	Federal Income Tax Rate	26-Tax Rates, Line 1	35.0000%
57	State Income Tax Rate	26-Tax Rates, Line 8	8.8400%
58	Composite Tax Rate	= F + [S * (1 - F)] (L56 + L57) - (L56 * L57)	40.7460%
<u>Calculation of Credits and Other:</u>			
59	Amortization of Excess Deferred Tax Liability	Note 2	\$200
60	Investment Tax Credit Flowed Through	Note 2	-\$520,000
61	South Georgia Income Tax Adjustment	Note 2	<u>\$2,606,000</u>
62	Credits and Other	Line 59 + Line 60+ Line 61	\$2,086,200
63	Income Taxes:	Formula on Line 64	\$206,047,016
64	Income Taxes = [((RB * ER) + D) * (CTR/(1 - CTR))] + CO/(1 - CTR)		
Where:			
	RB = Rate Base	Line 17	
	ER = Equity Rate of Return Including Common and Preferred Stock	Line 54	
	CTR = Composite Tax Rate	Line 58	
	CO = Credits and Other	Line 62	
	D = Book Depreciation of AFUDC Equity Book Basis	SCE Records	\$3,535,511

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Cells shaded yellow are input cells

Formula Transmission Rate

Line	Notes	FERC Form 1 Reference or Instruction	2017 Value
PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT			
<u>Component of Prior Year TRR:</u>			
65		19-OandM, Line 137, Col. 6	\$78,644,834
66		20-AandG, Line 23	\$46,554,833
67		22-NUCs, Line 10	\$6,116,851
68		17-Depreciation, Line 70	\$239,582,731
69		12-AbandonedPlant, Line 1	\$0
70		Line 35	\$60,990,527
71	Negative amount	21-Revenue Credits, Line 44	-\$58,832,606
72		Line 55	\$401,129,961
73		Line 63	\$206,047,016
74	Gain negative, loss positive	11-PHFU, Line 10	\$0
75		23-RegAssets, Line 16	\$0
76		15-IncentiveAdder, Line 14	<u>\$34,550,171</u>
77		Sum of Lines 65 to 76	\$1,014,784,318
78		L 77 * FF Factor (28-FFU, L 5)	\$9,341,800
79		L 77 * U Factor (28-FFU, L 5)	\$2,443,195
80		Line 77 + Line 78+ Line 79	\$1,026,569,313
TOTAL BASE TRANSMISSION REVENUE REQUIREMENT			
<u>Calculation of Base Transmission Revenue Requirement</u>			
81		Line 80	\$1,026,569,313
82		2-IFPTRR, Line 82	\$100,670,219
83		3-TrueUpAdjust, Line 62	\$59,638,034
84	Initial Prior Year?: No If Initial Prior Year, enter "Yes", else "No"		
85	Cost Adjustment Note 4		\$0
86	Base Transmission Revenue Requirement (Retail) For Retail Purposes	L 81 + L 82 + L 83 + L 85	\$1,186,877,565
<u>Wholesale Base Transmission Revenue Requirement</u>			
87	Base TRR (Retail)	Line 86	\$1,186,877,565
88	Wholesale Difference to the Base TRR	25-WholesaleDifference, Line 44	<u>-\$6,024,468</u>
89	Wholesale Base Transmission Revenue Requirement	Line 87 + Line 88	\$1,180,853,097

Notes:

1) No change in Return on Common Equity will be made absent a Section 205 filing at the Commission.

Does not include any project-specific ROE adders.

In the event that the Return on Common Equity is revised from the initial value, enter cite to Commission Order approving the revised ROE on following link
Order approving revised ROE: [redacted]

2) No change in "Credits and Other" terms will be made absent a filing at the Commission

3) The True Up Adjustment for the initial Base TRR is \$0.

4) Cost Adjustment may be included as provided in the Tariff protocols.

Calculation of Incremental Forecast Period TRR ("IFPTRR")

The IFP TRR is equal to the sum of:

- 1) Forecast Plant Additions * AFCR
- 2) Forecast Period Incremental CWIP * AFCR for CWIP

1) Calculation of Annual Fixed Charge Rates:

Line a) Annual Fixed Charge Rate for CWIP ("AFCRCWIP")

1
2 AFCRCWIP represents the return and income tax costs associated with \$1 of CWIP,
3 expressed as a percent.

4
5 $AFCRCWIP = CLTD + (COS * (1/(1 - CTR)))$

6
7 where:

8 CLTD = Weighted Cost of Long Term Debt

9 COS = Weighted Cost of Common and Preferred Stock

10 CTR = Composite Tax Rate

		<u>Reference</u>
11		
12	Wtd. Cost of Long Term Debt:	1.991% 1-BaseTRR, Line 50
13	Wtd. Cost of Common + Pref. Stock:	5.259% 1-BaseTRR, Line 54
14	Composite Tax Rate:	40.746% 1-BaseTRR, Line 58

15
16 $AFCRCWIP = 10.866\% \text{ Line 12} + (\text{Line 13} * (1/(1 - \text{Line 14})))$

17
18 **b) Annual Fixed Charge Rate ("AFCR")**

19
20 The AFCR is calculated by dividing the Prior Year TRR (without CWIP related costs)
21 by Net Plant:

22
23 $AFCR = (\text{Prior Year TRR} - \text{CWIP-related costs}) / \text{Net Plant}$

24
25 **Determination of Net Plant:**

		<u>Reference</u>
26		
27	Transmission Plant - ISO:	\$8,573,445,553 6-PlantInService, Line 13
28	Distribution Plant - ISO:	\$0 6-PlantInService, Line 16
29	Transmission Dep. Reserve - ISO:	\$1,633,677,100 8-AccDep, Line 13
30	Distribution Dep. Reserve - ISO:	\$0 8-AccDep, Line 16
31	Net Plant:	\$6,939,768,453 (L27 + L28) - (L29 + L30)

32
33 **Determination of Prior Year TRR without CWIP related costs:**

34
35 **a) Determination of CWIP-Related Costs**

36 **1) Direct (without ROE adder) CWIP costs**

37	CWIP Plant - Prior Year:	\$150,629,632	10-CWIP, L 13 C1
38	AFCRCWIP:	10.866%	Line 16
39	Direct CWIP Related Costs:	\$16,368,112	Line 37 * Line 38

40
41 **2) CWIP ROE Adder costs:**

42	IREF:	\$8,204	15-IncentiveAdder, Line 3
43			
44	Tehachapi CWIP Amount:	\$150,976	10-CWIP, Line 13
45	Tehachapi ROE Adder %:	1.25%	15-IncentiveAdder, Line 5
46	Tehachapi ROE Adder \$:	\$1,548	Formula on Line 52

47			
48	DCR CWIP Amount:	\$0	10-CWIP, Line 13
49	DCR ROE Adder %:	1.00%	15-IncentiveAdder, Line 6
50	DCR ROE Adder \$:	\$0	Formula on Line 52

51
52 $ROE \text{ Adder } \$ = (\text{CWIP}/\$1,000,000) * \text{IREF} * (\text{ROE Adder}/1\%)$

53			
54	CWIP Related Costs wo FF&U:	\$16,369,661	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	\$190,106	(28-FFU, L5 FF Factor + U Factor) * L54
56	CWIP Related Costs with FF&U:	\$16,559,766	Line 54 + Line 55

57

Schedule 2
Incremental Forecast Period TRR

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

58 **b) Determination of AFCR:**

59			
60	CWIP Related Costs wo FF&U:	\$16,369,661	Line 54
61	Prior Year TRR wo FF&U:	\$1,014,784,318	1-BaseTRR, Line 77
62	Prior Year TRR wo CWIP Related Costs:	\$998,414,657	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	\$93,899,750	(1-BaseTRR, Line 65 + Line 66) * .75
64	AFCR:	13.034%	(Line 62 - Line 63) / Line 31
65			

66 **2) Calculation of IFP TRR**

67			
68			<u>Reference</u>
69	Forecast Plant Additions:	\$512,181,617	16-PlantAdditions, L 25, C10
70	AFCR:	13.034%	Line 64
71	AFCR * Forecast Plant Additions:	\$66,756,681	Line 69 * Line 70
72			
73	Forecast Period Incremental CWIP:	\$301,458,237	10-CWIP, L 54, C8
74	AFCRCWIP:	10.866%	Line 16
75	AFCRCWIP * FP Incremental CWIP:	\$32,757,846	Line 73 * Line 74
76			
77	IFPTRR without FF&U:	\$99,514,527	Line 71 + Line 75
78			
79	Franchise Fees Expense:	\$916,101	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	\$239,591	Line 77 * U (from 28-FFU, L 5)
81			
82	Incremental Forecast Period TRR:	\$100,670,219	Line 77 + Line 79 + Line 80

Calculation of True Up Adjustment Component of TRR

1) Summary of True Up Adjustment calculation:

- a) Attribute True Up TRR to months in the Prior Year (see Note #1) to determine "Monthly True Up TRR" for each month (see Note #2). If formula was not in effect in Prior Year, do not populate Column 2 or 3, Lines 11 to 22.
- b) Determine monthly retail transmission revenues attributable to this formula transmission rate received during Prior Year.
- c) Compare costs in (a) to revenues in (b) on a monthly basis and determine "Cumulative Excess (-) or Shortfall (+) in Revenue with Interest".
- d) Continue interest calculation through the end of the previous Rate Effective Period (Line 31).
- e) Amortize this ending balance from (d) over the current Rate Effective Period so that the ending balance on Line 54 is equal to \$0.

2) Comparison of True Up TRR and Actual Retail Transmission Revenues received during the Prior Year, Including previous year True Up Adjustment.

Line		True Up TRR:	\$1,014,525,809	Source:	From 4-TUTRR,	Line 45					
		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	
	Calculations:		See Note 2	See Note 3	See Note 4	= C2 - C3 + C 4	See Note 5	See Note 6	See Note 7	=C7 + C8	
					One-Time and Previous Period True Up Adjustment	Monthly Excess (-) or Shortfall (+) in Revenue	Monthly Interest Rate	Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month	Interest for Current Month	Cumulative Excess (-) or Shortfall (+) in Revenue with Interest	
	Month	Year	Monthly True Up TRR	Actual Retail Base Transmission Revenues							
11	January	2017	\$84,543,817.42	\$88,876,406		-\$4,332,588	0.29%	-\$4,332,588	-\$6,282	-\$4,338,871	
12	February	2017	\$84,543,817.42	\$76,214,394		\$8,329,424	0.29%	\$3,990,553	-\$505	\$3,990,048	
13	March	2017	\$84,543,817.42	\$88,623,013		-\$4,079,196	0.29%	-\$89,148	\$5,656	-\$83,492	
14	April	2017	\$84,543,817.42	\$83,996,142		\$547,676	0.31%	\$464,184	\$590	\$464,774	
15	May	2017	\$84,543,817.42	\$92,695,249		-\$8,151,432	0.31%	-\$7,686,657	-\$11,194	-\$7,697,851	
16	June	2017	\$84,543,817.42	\$104,845,652		-\$20,301,835	0.31%	-\$27,999,686	-\$55,331	-\$28,055,017	
17	July	2017	\$84,543,817.42	\$123,594,050		-\$39,050,233	0.33%	-\$67,105,250	-\$157,014	-\$67,262,265	
18	August	2017	\$84,543,817.42	\$125,785,396		-\$41,241,578	0.33%	-\$108,503,843	-\$290,014	-\$108,793,857	
19	September	2017	\$84,543,817.42	\$106,851,758		-\$22,307,941	0.33%	-\$131,101,798	-\$395,828	-\$131,497,625	
20	October	2017	\$84,543,817.42	\$100,653,472		-\$16,109,655	0.35%	-\$147,607,280	-\$488,434	-\$148,095,714	
21	November	2017	\$84,543,817.42	\$88,159,107		-\$3,615,290	0.35%	-\$151,711,003	-\$524,662	-\$152,235,665	
22	December	2017	\$84,543,817.42	\$89,149,113		-\$4,605,296	0.35%	-\$156,840,961	-\$540,884	-\$157,381,845	
23	January	2018	---	---		\$0	0.35%	-\$157,381,845	-\$550,836	-\$157,932,681	
24	February	2018	---	---		\$0	0.35%	-\$157,932,681	-\$552,764	-\$158,485,446	
25	March	2018	---	---		\$0	0.35%	-\$158,485,446	-\$554,699	-\$159,040,145	
26	April	2018	---	---		\$0	0.37%	-\$159,040,145	-\$588,449	-\$159,628,593	
27	May	2018	---	---		\$0	0.37%	-\$159,628,593	-\$590,626	-\$160,219,219	
28	June	2018	---	---		\$0	0.37%	-\$160,219,219	-\$592,811	-\$160,812,030	
29	July	2018	---	---		\$0	0.37%	-\$160,812,030	-\$595,005	-\$161,407,035	
30	August	2018	---	---		\$0	0.37%	-\$161,407,035	-\$597,206	-\$162,004,241	
31	September	2018	---	---		\$0	0.37%	-\$162,004,241	-\$599,416	-\$162,603,656	
32	October	2018	---	---		\$0	0.37%	-\$162,603,656	-\$601,634	-\$163,205,290	
33	November	2018	---	---		\$0	0.37%	-\$163,205,290	-\$603,860	-\$163,809,150	
34	December	2018	---	---		\$0	0.37%	-\$163,809,150	-\$606,094	-\$164,415,243	
35											

Schedule 3
True Up Adjustment

36 3) Amortization of December balance over Rate Effective Period:

37		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>
38			See Note 8	See Note 9	See Note 10	=C3 + C4	See Note 11	=C5 + C6	= - C4
39						Month			True Up
40			Monthly	Month		Ending	Interest	Month	Adjustment
41			Interest	Beginning		Balance	for Current	Ending	Received (+)/
42		Year	Rate	Balance	Amortization	wo Interest	Month	Balance	Returned (-)
43	January	2019	0.37%	-\$164,415,243	-\$4,969,836	-\$169,385,080	-\$609,186	-\$169,994,265	\$4,969,836
44	February	2019	0.37%	-\$169,994,265	-\$4,969,836	-\$174,964,101	-\$629,549	-\$175,593,650	\$4,969,836
45	March	2019	0.37%	-\$175,593,650	-\$4,969,836	-\$180,563,486	-\$649,987	-\$181,213,473	\$4,969,836
46	April	2019	0.37%	-\$181,213,473	-\$4,969,836	-\$186,183,309	-\$670,499	-\$186,853,808	\$4,969,836
47	May	2019	0.37%	-\$186,853,808	-\$4,969,836	-\$191,823,645	-\$691,086	-\$192,514,731	\$4,969,836
48	June	2019	0.37%	-\$192,514,731	-\$4,969,836	-\$197,484,567	-\$711,749	-\$198,196,316	\$4,969,836
49	July	2019	0.37%	-\$198,196,316	-\$4,969,836	-\$203,166,152	-\$732,487	-\$203,898,638	\$4,969,836
50	August	2019	0.37%	-\$203,898,638	-\$4,969,836	-\$208,868,475	-\$753,300	-\$209,621,775	\$4,969,836
51	September	2019	0.37%	-\$209,621,775	-\$4,969,836	-\$214,591,611	-\$774,189	-\$215,365,800	\$4,969,836
52	October	2019	0.37%	-\$215,365,800	-\$4,969,836	-\$220,335,636	-\$795,155	-\$221,130,791	\$4,969,836
53	November	2019	0.37%	-\$221,130,791	-\$4,969,836	-\$226,100,628	-\$816,197	-\$226,916,825	\$4,969,836
54	December	2019	0.37%	-\$226,916,825	-\$4,969,836	-\$231,886,661	-\$837,316	-\$232,723,977	\$4,969,836
55					-\$59,638,034		Shortfall or Excess Revenue in Prior Year:		\$59,638,034
56									
57									
58									
59									
60									
61	Shortfall or Excess Revenue in Prior Year:								
62	True Up Adjustment:								
63									
64									
65									
66									
67									
68									

Total Amortization in Rate Effective Period (See Instruction #4): -\$59,638,034

59 4) True Up Adjustment

60			<u>Notes:</u>
61	Shortfall or Excess Revenue in Prior Year:	\$59,638,034	Column 8, Line 55
62	True Up Adjustment:	\$59,638,034	Line 61. Positive amount is to be collected by SCE (included in Base TRR as a positive amount). Negative amount is to be returned to customers by SCE (included in Base TRR as a negative amount).
63			

64 5) Final True Up Adjustment

65 The Final True Up Adjustment begins on the month after the last True Up Adjustment and extends through the termination date of
66 this formula transmission rate.
67 The Final True Up Adjustment shall be calculated as above, with interest to the termination date of the Formula Transmission Rate.
68

69 Partial Year TRR Attribution Allocation Factors:

70	Partial Year		
71	Month	TRR AAF	Note:
72	January	6.376%	See Note 2.
73	February	5.655%	
74	March	7.183%	
75	April	8.224%	
76	May	8.018%	
77	June	8.945%	
78	July	9.891%	
79	August	10.141%	
80	September	10.218%	
81	October	9.179%	
82	November	7.530%	
83	December	8.640%	
84	Total:	100.000%	

86 Transmission Revenues: (Note 12)

87	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	
88	See Note 13	See Note 14					Sum of left	
91	Actual						Monthly	
92	Prior	Retail Base					Total	
93	Year	Transmission	Other		Public		Retail	
94	Month	Revenues	Transmission	Distribution	Generation	Purpose	Other	Revenue
95	Jan	\$88,876,406	-\$7,087,025	\$363,695,814	\$311,346,758	\$49,601,040	\$51,035,736	\$857,468,728
96	Feb	\$76,214,394	-\$6,699,589	\$307,753,182	\$259,118,518	\$36,338,088	\$47,178,057	\$719,902,650
97	Mar	\$88,623,013	-\$7,723,146	\$356,417,097	\$297,947,007	\$38,088,669	\$54,002,238	\$827,354,879
98	Apr	\$83,996,142	-\$7,536,484	\$188,886,686	\$282,082,099	\$37,109,156	\$51,830,193	\$636,367,793
99	May	\$92,695,249	-\$8,104,572	\$355,261,646	\$311,024,347	\$43,230,142	\$56,581,146	\$850,687,959
100	Jun	\$104,845,652	-\$12,956,109	\$402,432,158	\$527,362,392	\$45,581,306	\$64,335,180	\$1,131,600,579
101	Jul	\$123,594,050	-\$19,621,540	\$460,524,056	\$644,206,334	\$73,983,882	\$77,772,627	\$1,360,459,409
102	Aug	\$125,785,396	-\$18,661,552	\$472,206,916	\$682,290,749	\$79,884,679	\$78,382,836	\$1,419,889,024
103	Sep	\$106,851,758	-\$15,843,048	\$396,942,806	\$580,474,930	\$62,680,552	\$65,928,576	\$1,197,035,573
104	Oct	\$100,653,472	-\$15,014,567	\$247,390,825	\$390,764,399	\$42,021,234	\$61,154,923	\$826,970,286
105	Nov	\$88,159,107	-\$13,029,919	\$343,372,179	\$293,271,394	\$40,310,842	\$53,305,059	\$805,388,662
106	Dec	\$89,149,113	-\$13,623,612	\$351,130,269	\$301,056,365	\$38,410,019	\$55,407,794	\$821,529,949
107	Totals:	\$1,169,443,752	-\$145,901,162	\$4,246,013,634	\$4,880,945,294	\$587,239,607	\$716,914,366	\$11,454,655,492

108
109 "Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b: **\$11,454,655,492**

Instructions:

- 1) Enter applicable years on Column 1, Lines 11-34 and 43-54.
- 2) Enter Previous Period True Up Adjustment (if any) on Column 4, Lines 23-34. See Note 4 for definition of Previous Period True Up Adjustment. Enter with the same sign as in previous Informational Update. If there is no Previous Period True Up Adjustment, then enter \$0 in these cells.
- 3) Enter monthly interest rates in accordance with interest rate specified in the regulations of FERC at 18 C.F.R. §35.19a on lines 11 to 34, Column 6. If interest rate for any months not known, use most recent known month.
- 4) Enter "Total Amortization" amount on Line 57, column 6 to set September Month Ending Balance Column 7, Line 54 equal to \$0. Iterate if necessary to solve. (i.e., so that the Month Beginning Balance in Column 3, Line 43 is completely amortized away by the Amortization amounts in Column 4). This instruction requires that the amount on Line 57 Column 6 be calculated so that any over or under collection at the beginning of the Rate Effective Period is completely amortized over the following 12 months, as reflected by the Line 54, Column 7 amount being equal to zero. It may be necessary to iterate for the formula to calculate the correct value in that cell, which can be accomplished in Excel using the Goal Seek function.
- 5) Enter any One Time Adjustments on Column 4, Line 11 (or other appropriate). If SCE is owed enter as positive, if SCE is to return to customers enter as negative. One Time Adjustments include:
 - a) Enter CWIP mechanism final balance in first True Up Adjustment calculation in accordance with tariff protocols.
 - b) In the event that a Commission Order revises SCE's True Up TRR for a previous Prior Year, SCE shall also include that difference in the True Up Adjustment, including interest, at the first opportunity, in accordance with tariff protocols. Entering on Line 11 (or other appropriate) ensures these One Time Adjustments are recovered from or returned to customers.
 - c) Any refunds attributable to SCE's previous CWIP TRR cases (Docket Nos. ER08-375, ER09-187, ER10-160, and ER11-1952), not previously returned to customers.
 - d) Amounts resulting from input errors impacting the True Up TRR in a previous Formula Rate filing pursuant to Protocol Section 3(d)(8).
- 6) Fill in matrix of all retail revenues from Prior Year in table on lines 95 to 106.
- 7) Enter Total Sales to Ultimate Consumers on line 109 and verify that it equals the total on line 107.
- 8) If true up period is less than entire calendar year, then adjust calculation accordingly by including \$0 Monthly True Up TRR and for Actual Retail Base Transmission Revenues for any months not included in True Up Period.

Notes:

- 1) The true up period is the portion (all or part) of the Prior Year for which the Formula Transmission Rate was in effect.
- 2) The Monthly True Up TRR is derived by multiplying the annual True Up TRR on Line 1 by 1/12, if formula was in effect. In the event of a Partial Year True Up, use the Partial Year TRR Attribution Allocation Factors on Lines 72 to 83 for each month of Partial Year True Up. Only enter in the Prior Year, Lines 11 to 22, or portion of year formula was in effect in case of Partial Year True Up. Partial Year True Up Allocation Factors calculated based on three years (2008-2010) of monthly SCE retail base transmission revenues.
- 3) "Actual Retail Base Transmission Revenues" are SCE retail transmission revenues attributable to this formula transmission rate. as shown on Lines 95 to 106, Column 1.
- 4) The "Previous Period True Up Adjustment" are the values of the "True Up Adjustment Received/Returned" in the previous Informational Filing (Same sign). These are the 12 monthly values of the "True Up Adjustment Received/Returned" in Column 8, Lines 43 -54 from the previous Informational Filing, They are input into Column 4, lines 23-34 of this current Informational Filing, corresponding to the Rate Effective Period of the previous Informational Filing. In the event that the Formula Rate timelines in effect during the previous Informational Filing differ from this Informational Filing, enter the Previous Period True Up Adjustment in this Informational Filing on the lines corresponding to the Rate Effective Period from the previous Informational Filing. One Time True Up Adjustment amounts (see Instruction #5) attributable to a previous Prior Year are entered on Column 4, Line 11 (or other appropriate).
- 5) Monthly Interest Rates in accordance with interest rate specified in the regulations of FERC (See Instruction #3).
- 6) "Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month" is: 1) in month 1, the amount in Column 5; and 2) in subsequent months is the amount in Column 9 for previous month plus the current month amount in Column 5.
- 7) Interest for Current Month is calculated on average of beginning and ending balances (Column 9 previous month and Column 7 current month). (First month average is 1/2 of ending balance).
- 8) The Interest Rate in Rate Effective Period is equal to average of interest rates in previous 12 months (lines 23-34).
- 9) The "Month Beginning Balance" is Month Ending Balance from previous month in Column 7 (January is from Column 9, Line 34).
- 10) Amortization equals amount in Line 57 divided by 12 each month. See Instruction #4 also for further detail.
- 11) Interest for Current Month is calculated on average of beginning and end balances (wo interest) in Columns 3 and 5.
- 12) Only provide if formula was in effect during Prior Year.
- 13) Only include Base Transmission Revenue attributable to this formula transmission rate. Any other Base Transmission Revenue or refunds is included in "Other". The Base Transmission Revenues shown in Column 1 shall be reduced to reflect any retail customer refunds provided by SCE associated with the formula transmission rate that are made through a CPUC-authorized mechanism.
- 14) Other Transmission Revenue includes the following:
 - a) Transmission Revenue Balancing Account Adjustment revenue.
 - b) Transmission Access Charge Balancing Account Adjustment.
 - c) Reliability Services Revenue.
 - d) Any Base Transmission Revenue not attributable to this formula.

Calculation of True Up TRR

A) Rate Base for True Up TRR

<u>Line</u>	<u>Rate Base Item</u>	<u>Calculation Method</u>	<u>Notes</u>	<u>FERC Form 1 Reference or Instruction</u>	<u>Amount</u>
1	ISO Transmission Plant	13-Month Avg.		6-PlantInService, Line 18	\$8,389,794,318
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		6-PlantInService, Line 24	\$252,097,756
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		11-PHFU, Line 9	\$9,942,155
4	Abandoned Plant	BOY/EOY Avg.		12-AbandonedPlant Line 4	\$0
<u>Working Capital Amounts</u>					
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	\$13,057,097
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	\$10,647,093
7	Cash Working Capital	1/16 (O&M + A&G)		1-Base TRR Line 7	<u>\$7,824,979</u>
8	Working Capital			Line 5 + Line 6 + Line 7	\$31,529,169
<u>Accumulated Depreciation Reserve Amounts</u>					
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	8-AccDep, Line 14, Col. 12	-\$1,549,914,567
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	8-AccDep, Line 17, Col. 5	\$0
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	8-AccDep, Line 23	<u>-\$102,849,091</u>
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	-\$1,652,763,658
13	Accumulated Deferred Income Taxes	BOY/EOY Avg.		9-ADIT, Line 15	-\$1,600,478,572
14	CWIP Plant	13-Month Avg.		14-IncentivePlant, L 13, C2	\$106,441,483
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	22-NUCs, Line 9	-\$106,562,330
15a	Unfunded Reserves			34-UnfundedReserves, Line 7	-\$10,165,091
16	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		23-RegAssets, Line 15	\$0
17	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L15a+L16	\$5,419,835,230

B) Return on Capital

<u>Line</u>					
18	Cost of Capital Rate		See Instruction 1	Instruction 1, Line j	7.2500%
19	Return on Capital: Rate Base times Cost of Capital Rate			Line 17 * Line 18	\$392,936,461

C) Income Taxes

20	Income Taxes = $(((RB * ER) + D) * (CTR / (1 - CTR))) + CO / (1 - CTR)$				\$201,959,865
----	-------------------------------------------------------------------------	--	--	--	---------------

Where:

21	RB = Rate Base			Line 17	\$5,419,835,230
22	ER = Equity ROR inc. Com. and Pref. Stock	Instruction 1		Instruction 1, Line k	5.2592%
23	CTR = Composite Tax Rate			1-Base TRR L 58	40.7460%
24	CO = Credits and Other			1-Base TRR L 62	\$2,086,200
25	D = Book Depreciation of AFUDC Equity Book Basis			1-Base TRR L 64	\$3,535,511

D) True Up TRR Calculation

26	O&M Expense		1-Base TRR L 65	\$78,644,834
27	A&G Expense		1-Base TRR L 66	\$46,554,833
27a	PBOPs True Up TRR Adjustment		35-PBOPs L 14	-\$6,505
28	Network Upgrade Interest Expense		1-Base TRR L 67	\$6,116,851
29	Depreciation Expense		1-Base TRR L 68	\$239,582,731
30	Abandoned Plant Amortization Expense		1-Base TRR L 69	\$0
31	Other Taxes		1-Base TRR L 70	\$60,990,527
32	Revenue Credits		1-Base TRR L 71	-\$58,832,606
33	Return on Capital		Line 19	\$392,936,461
34	Income Taxes		Line 20	\$201,959,865
35	Gains and Losses on Transmission Plant Held for Future Use -- Land		1-Base TRR L 74	\$0
36	Amortization and Regulatory Debits/Credits		1-Base TRR L 75	\$0
37	Total without True Up Incentive Adder		Sum Line 26 to Line 36	\$967,946,991
38	True Up Incentive Adder		15-IncentiveAdder L 20	\$34,932,083
39	True Up TRR without Franchise Fees and Uncollectibles Expense included:		Line 37 + Line 38	\$1,002,879,073

E) Calculation of final True Up TRR with Franchise Fees and Uncollectibles Expenses

<u>Line</u>			<u>Reference:</u>
40	True Up TRR wo FF:	\$1,002,879,073	Line 39
41	Franchise Fee Factor:	0.921%	28-FFU, L 5
42	Franchise Fee Expense:	\$9,232,204	Line 40 * Line 41
43	Uncollectibles Expense Factor:	0.241%	28-FFU, L 5
44	Uncollectibles Expense:	\$2,414,532	Line 42 * Line 43
45	True Up TRR:	\$1,014,525,809	L 40 + L 42 + L 44

Instructions:

1) Use weighted average (by time) of the Return on Equity in effect during the Prior Year in determining the "Cost of Capital Rate" on Line 18 and the "Equity Rate of Return Including Preferred Stock" on Line 22 in the event that the ROE is revised during the Prior Year. In this event, the ROE used in Schedule 1 will differ from the ROE used in this Schedule 4, because the Schedule 1 ROE will be the most recent ROE, whereas the Schedule 4 Cost of Capital Rate and Equity Rate of Return including Com. + Pref. Stock will be based on the weighted-average ROE.

Calculation of weighted average Cost of Capital Rate in Prior Year:

If ROE does not change during year, then attribute all days to Line a "ROE at end of Prior Year" and none to "ROE at start of PY"

	<u>Percentage</u>	<u>Reference:</u>	<u>From</u>	<u>To</u>	<u>Days ROE In Effect</u>
a ROE at end of Prior Year	9.80%	1-Base TRR L 49	Jan 1, 2017	Dec 31, 2017	365
b ROE start of Prior Year	9.80%	See Line e below			
c				Total days in year:	365
d Wtd. Avg. ROE in Prior Year	9.80%	((Line a ROE * Line a days) + (Line b ROE * Line b days)) / Total Days in Year			

Commission Decisions approving ROE:

	<u>Reference:</u>	
e End of Prior Year	Settlement in ER11-3697	
f Beginning of Prior Year	Settlement in ER11-3697	
	<u>Percentage</u>	<u>Reference:</u>
g Wtd. Cost of Long Term Debt	1.9908%	1-Base TRR L 50
h Wtd. Cost of Preferred Stock	0.4951%	1-Base TRR L 51
i Wtd. Cost of Common Stock	4.7641%	1-Base TRR L 46 * Line d
j Cost of Capital Rate	7.2500%	Sum of Lines f to h

Calculation of Equity Rate of Return Including Common and Preferred Stock:

	<u>Percentage</u>	<u>Reference:</u>
k	5.2592%	Sum of Lines g to h

2) Beginning with the True Up Adjustment calculation for 2012 utilizing the True Up TRR for 2012, exclude from CWIP recovery the capital cost of facilities that were purchased for the portion of Tehachapi Segment 8 near the Chino Airport, but due to the April 25, 2011 Notice of Presumed Hazard issued to SCE by the FAA are not used in the construction of Tehachapi or in any other CWIP incentive project. Additionally, SCE will permanently exclude from Plant In Service, Rate Base, and transmission rates these capital costs if the facilities are not used in the construction of any SCE transmission project.

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

	Notes	FERC Form 1 Reference or Instruction	2017 Value	
RETURN AND CAPITALIZATION CALCULATIONS				
<u>Calculation of Long Term Debt Amount</u>				
1	Bonds -- Account 221	13-month avg.	5-ROR-2, Line 1	\$10,684,345,055
2	Less Reacquired Bonds -- Account 222	13-month avg.	5-ROR-2, Line 2	-\$40,384,615
2a	Long Term Debt Advances from Associated Companies -- Account 223	13-month avg.	5-ROR-2, Line 2a	\$0
3	Other Long Term Debt -- Account 224	13-month avg.	5-ROR-2, Line 3	\$424,282,124
4	Not Used			
5	Not Used			
6	Not Used			
7	Not Used			
8	Long Term Debt Amount	L1 + L2 + L2a + L3		\$11,068,242,563
<u>Calculation of Cost of Long-Term Debt</u>				
9	Interest on Long-Term Debt -- Account 427		FF1 117.62c	\$488,235,571
10	Amortization of Debt Discount and Expense -- Account 428		FF1 117.63c	\$10,026,888
11	Amortization of Loss on Reacquired Debt -- Account 428.1		FF1 117.64c	\$16,710,267
12	Less Amortization of Premium on Debt -- Account 429	Enter negative	FF1 117.65c	\$0
13	Less Amort. of Gain on Reacquired Debt -- Account 429.1	Enter negative	FF1 117.66c	\$0
13a	Interest on Debt to Associated Companies -- Account 430		FF1 117.67c	\$0
14	Not Used			
15	Not Used			
16	Cost of Long Term Debt	Sum of Lines 9 to 13a		\$514,972,726
17	Long-Term Debt Cost Percentage	Line 16 / Line 8		4.6527%
<u>Calculation of Preferred Stock Amount</u>				
18	Preferred Stock Amount -- Account 204	13-month avg.	5-ROR-2, Line 18	\$2,281,594,181
19	Unamortized Issuance Costs	13-month avg.	5-ROR-2, Line 19	-\$44,042,736
20	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	5-ROR-2, Line 20	-\$12,930,516
21	Preferred Stock Amount		Sum of Lines 18 to 20	\$2,224,620,929
<u>Calculation of Cost of Preferred Stock</u>				
22	Cost of Preferred Stock -- Account 437	Enter positive	FF1 118.29c	\$124,097,672
23	Amortization of Net Gain (Loss) From Purchases and Tender Offers		See Note 3	\$779,760
24	Amortization Issuance Costs		See Note 4	\$3,206,657
25	Cost of Preferred Stock -- Account 437		Sum of Lines 22 to 24	\$128,084,089
26	Preferred Stock Cost Percentage	Line 25 / Line 21		5.7576%
<u>Calculation of Common Stock Equity Amount</u>				
27	Total Proprietary Capital	13-month avg.	5-ROR-2, Line 27	\$14,822,803,188
28	Less Preferred Stock Amount -- Account 204	Same as L 18, but negative	5-ROR-2, Line 18	-\$2,281,594,181
29	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 20, but reverse sign	See Note 5	\$12,930,516
30	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.	5-ROR-2, Line 30	\$2,603,770
31	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg.	5-ROR-2, Line 31	\$18,479,587
32	Common Stock Equity Amount		Sum of Lines 27 to 31	\$12,575,222,880

Notes:

- 1) Not Used
- 2) Not Used
- 3) Total annual amortization associated with events listed in note 10 on 5-ROR-2.
- 4) Total annual amortization associated with preferred equity issues listed in note 9 on 5-ROR-2.
- 5) Negative of Line 20, charge to common equity reversed for ratemaking.

Calculation of 13-Month Average Capitalization Balances

Line	Item	Col 1 13-Month Avg. = Sum (Cols. 2-14)/13	Col 2 December	Col 3 January	Col 4 February	Col 5 March	Col 6 April	Col 7 May	Col 8 June	Col 9 July	Col 10 August	Col 11 September	Col 12 October	Col 13 November	Col 14 December
Bonds -- Account 221 (Note 1):															
1		\$10,684,345,055	\$10,296,542,857	\$10,431,542,857	\$10,392,257,143	\$10,957,257,143	\$10,957,257,143	\$10,557,257,143	\$10,557,257,143	\$10,857,257,143	\$10,817,971,429	\$10,817,971,429	\$10,817,971,429	\$10,717,971,429	\$10,717,971,429
Reacquired Bonds -- Account 222 (Note 2): enter - of FF1															
2		-\$40,384,615	-\$165,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000	-\$30,000,000
Long Term Debt Advances from Associated Companies (Note 2a):															
2a		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Other Long Term Debt -- Account 224 (Note 3):															
3		\$424,282,124	\$306,621,506	\$471,616,306	\$471,611,083	\$606,605,839	\$606,600,572	\$606,595,284	\$606,589,973	\$306,584,639	\$306,579,284	\$306,573,905	\$306,568,504	\$306,563,080	\$306,557,633
4	NOT USED														
5	NOT USED														
6	NOT USED														
7	NOT USED														
Preferred Stock Amount -- Account 204 (Note 8):															
18		\$2,281,594,181	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,720,064,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950	\$2,245,054,950
Unamortized Issuance Costs (Note 9): enter negative															
19		-\$44,042,736	-\$43,904,550	-\$43,612,325	-\$43,320,100	-\$43,027,875	-\$42,735,649	-\$42,443,424	-\$54,784,211	-\$54,456,894	-\$41,423,177	-\$41,138,642	-\$40,854,108	-\$40,569,573	-\$40,285,039
Net Gain (Loss) From Purchase and Tender Offers Note 10):															
20		-\$12,930,516	-\$7,396,211	-\$7,345,987	-\$7,295,763	-\$7,195,315	-\$7,145,091	-\$7,145,091	-\$7,094,867	-\$19,793,826	-\$19,708,188	-\$19,622,550	-\$19,536,911	-\$19,451,273	-\$19,365,634
Total Proprietary Capital (Note 11):															
27		\$14,822,803,188	\$14,482,786,817	\$14,615,648,032	\$14,509,372,060	\$14,623,685,111	\$14,705,023,359	\$14,808,546,334	\$15,195,168,410	\$14,852,851,255	\$14,841,775,399	\$14,993,193,820	\$15,128,682,538	\$15,267,986,011	\$14,671,722,293
Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 12): enter - of FF1															
30		\$2,603,770	\$2,603,436	\$2,603,437	\$2,603,437	\$2,603,437	\$2,603,437	\$2,604,191	\$2,604,191	\$2,604,191	\$2,604,191	\$2,604,050	\$2,604,050	\$2,603,481	\$2,603,481
Accumulated Other Comprehensive Loss -- Account 219 (Note 13): enter - of FF1															
31		\$18,479,587	\$20,446,907	\$19,981,024	\$19,515,140	\$17,543,914	\$18,734,452	\$18,250,527	\$18,131,535	\$17,647,610	\$18,713,013	\$18,000,214	\$17,516,289	\$17,032,364	\$18,721,643

Instructions:

- 1) Enter 13 months of balances for capital structure for Prior Year and December previous to Prior Year in Columns 2-14. Beginning and End of year amounts in Columns 2 and 14 are from FERC Form 1, as referenced in below notes.
- 2) **NOT USED**
- 3) Update notes 9 and 10 as necessary.

Notes:

- 1) Amount in Column 2 from FF1 112.18d, amount in Column 14 from FF1 112.18c, amounts in columns 3-13 from SCE internal records.
- 2) Amount in Column 2 from FF1 112.19d, amount in Column 14 from FF1 112.19c, amounts in columns 3-13 from SCE internal records.
- 2a) Amount in Column 2 from FF1 112.20d, amount in Column 14 from FF1 112.20c, amounts in columns 3-13 from SCE internal records.
- 3) Amount in Column 2 from FF1 112.21d, amount in Column 14 from FF1 112.21c, amounts in columns 3-13 from SCE internal records.
- 4) **NOT USED**
- 5) **NOT USED**
- 6) **NOT USED**
- 7) **NOT USED**
- 8) Amount in Column 2 from FF1 112.3d, amount in Column 14 from FF1 112.3c, amounts in columns 3-13 from SCE internal records.
- 9) Amounts in columns 2-14 are from SCE internal records.

List associated securities, Face Amount, Issuance Date, Issuance Costs, Amortization Period, and Annual Amortization:

<u>Issue</u>	<u>Face Amount</u>	<u>Issuance Date</u>	<u>Issuance Costs</u>	<u>Amortization Period (Years)</u>	<u>Annual Amortization</u>	<u>Notes</u>
Series E Pref., 6.250%	\$350,000,000	1/17/12	\$5,957,289	10	\$595,729	
Series G Pref., 5.100%	\$400,000,000	1/29/13	\$12,972,286	30	\$432,410	
Series H, Pref., 5.75%	\$275,000,000	3/6/14	\$6,272,358	10	\$627,236	
Series J., Pref., 5.375%	\$325,000,000	8/24/15	\$6,419,578	10	\$641,958	
Series K Pref., 5.45%	\$300,000,000	3/8/16	\$6,959,810	10	\$695,981	
Series L Pref., 5.00%	\$475,000,000	6/26/17	\$12,800,620	30	\$213,344	Six months of amortization in 2017.
					\$3,206,657	Total Annual Amortization (sum of "Issues" listed above)

- 10) Amounts in columns 2-14 are from SCE internal records.

List associated securities and event, Event Date, Amortization Amount, Amortization Period, and Annual Amortization:

<u>Issue/Event</u>	<u>Event Date</u>	<u>Amortization Amount</u>	<u>Amortization Period (Years)</u>	<u>Annual Amortization</u>	<u>Notes</u>
8.540% Preferred, premium	November 1985	-\$286,600	34	-\$8,429	Net gain from open-market purchase of 67,400 shares in November 1985
12.000% Preferred, redemption	February 1986	\$6,247,500	34	\$183,750	Redemption premium paid to holders (so loss to company)
12.000% Preferred, redemption	February 1986	\$1,025,000	34	\$30,147	Initial issue discount
Series A	6/16/12	\$0	0	\$0	Fully amortized
Series B	2/28/13	\$2,586,351	30	\$86,212	Redeemed by Series G
Series C	2/28/13	\$2,886,866	30	\$96,229	Redeemed by Series G
Series D	3/31/16	\$2,147,803	10	\$214,780	Redeemed by Series K
Series F	7/19/17	\$12,749,183	30	\$177,072	Redeemed by Series L. Five months of amortization in 2017
				\$779,760	Total Annual Amortization (sum of "Issues/Events" listed above)

- 11) Amount in Column 2 from FF1 112.16d, amount in Column 14 from FF1 112.16c, amounts in columns 3-13 from SCE internal records.
- 12) Amount in Column 2 from FF1 112.12d (opposite sign), amount in Column 14 from FF1 112.12c (opposite sign), amounts in columns 3-13 from SCE internal records.
- 13) Amount in Column 2 from FF1 112.15d (opposite sign), amount in Column 14 from FF1 112.15c (opposite sign), amounts in columns 3-13 from SCE internal records.

Plant In Service

Inputs are shaded yellow

1) Transmission Plant - ISO

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year (See Note 1):

Prior Year: 2017

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
	Sum C2 - C11											
Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	Dec 2016	\$86,845,703	165,326,927	\$531,582,611	\$3,249,175,449	\$2,233,991,232	\$324,258,228	\$1,235,903,791	\$185,508,197	\$81,951,072	\$182,027,086	\$8,276,570,295
2	Jan 2017	\$81,997,511	\$165,330,397	\$528,854,083	\$3,250,037,231	\$2,231,001,014	\$335,699,493	\$1,232,564,516	\$185,656,754	\$81,997,920	\$160,125,968	\$8,253,264,889
3	Feb 2017	\$82,013,020	\$165,784,066	\$534,882,418	\$3,256,654,353	\$2,213,130,982	\$339,965,913	\$1,235,030,894	\$186,119,194	\$82,775,424	\$161,709,715	\$8,258,065,980
4	Mar 2017	\$82,413,677	\$165,733,853	\$532,806,954	\$3,260,114,606	\$2,225,922,423	\$342,740,514	\$1,241,178,225	\$186,361,377	\$83,455,651	\$161,453,728	\$8,282,181,008
5	Apr 2017	\$82,424,960	\$165,734,429	\$540,340,485	\$3,290,596,932	\$2,251,979,965	\$344,598,339	\$1,244,265,048	\$186,611,561	\$83,540,944	\$161,600,158	\$8,351,692,820
6	May 2017	\$82,438,880	\$165,704,351	\$548,767,497	\$3,303,060,549	\$2,258,078,709	\$345,368,677	\$1,242,476,528	\$187,117,539	\$83,717,689	\$168,349,232	\$8,385,079,651
7	Jun 2017	\$81,409,531	\$165,534,488	\$552,041,270	\$3,313,909,561	\$2,261,350,618	\$347,377,534	\$1,244,803,717	\$188,491,607	\$84,190,542	\$167,806,375	\$8,406,915,243
8	Jul 2017	\$81,421,876	\$165,199,675	\$554,107,049	\$3,321,544,471	\$2,263,663,368	\$350,109,485	\$1,244,039,916	\$188,624,718	\$84,257,050	\$167,839,950	\$8,420,807,556
9	Aug 2017	\$81,875,011	\$164,728,138	\$558,293,842	\$3,350,799,129	\$2,265,082,996	\$350,778,178	\$1,246,103,080	\$188,962,876	\$84,383,656	\$168,194,579	\$8,459,201,484
10	Sep 2017	\$81,886,831	\$164,709,520	\$560,085,940	\$3,354,129,789	\$2,263,017,844	\$354,174,067	\$1,247,812,337	\$189,290,136	\$84,485,994	\$168,808,262	\$8,468,400,719
11	Oct 2017	\$81,898,670	\$164,708,798	\$557,690,365	\$3,337,803,870	\$2,267,000,466	\$357,358,231	\$1,247,335,361	\$189,937,864	\$84,808,333	\$169,009,660	\$8,457,551,618
12	Nov 2017	\$87,866,111	\$164,907,957	\$559,289,849	\$3,340,005,249	\$2,268,750,108	\$362,445,561	\$1,244,772,136	\$190,107,796	\$84,849,890	\$171,154,663	\$8,474,149,319
13	Dec 2017	\$87,876,203	\$164,901,118	\$569,698,023	\$3,409,447,774	\$2,283,380,922	\$364,424,080	\$1,245,933,686	\$190,222,489	\$84,920,374	\$172,640,885	\$8,573,445,553
14	13-Mo. Avg:	\$83,259,076	\$165,254,132	\$548,341,568	\$3,310,559,920	\$2,252,796,204	\$347,638,331	\$1,242,478,403	\$187,924,008	\$83,794,965	\$167,747,712	\$8,389,794,318

2) Distribution Plant - ISO

Balances for Distribution Plant - ISO for December of Prior Year and year before Prior Year (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5
	Sum C2 - C4				
Line	Mo/YR	360	361	362	Total
15	Dec 2016	\$0	\$0	\$0	\$0
16	Dec 2017	\$0	\$0	\$0	\$0
17	Average:	\$0	\$0	\$0	\$0

3) ISO Transmission Plant

ISO Transmission Plant is the sum of "Transmission Plant - ISO" and "Distribution Plant - ISO"

	<u>Amount</u>	<u>Source</u>
18	Average value: \$8,389,794,318	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value: \$8,573,445,553	Sum of Line 13, Col 12 and Line 16, Col 5

4) General Plant + Electric Miscellaneous Intangible Plant ("G&I Plant")

General and Intangible Plant is an allocated portion of Total G&I Plant based on the Trans. W&S Allocation Factor

	Note 1 Prior Year Month	Data Source	Col 1 General Plant Balances	Col 2 Intangible Plant Balances	Col 3 Total G&I Plant Balances	Notes
20	December	FF1 206.99.b and 204.5b	\$2,941,903,413	\$1,588,136,353	\$4,530,039,766	BOY amount from previous PY
21	December	FF1 207.99.g and 205.5g	\$3,102,162,333	\$1,324,870,316	\$4,427,032,649	End of year ("EOY") amount

a) BOY/EOY Average G&I Plant

		<u>Amount</u>	<u>Source</u>
22	Average BOY/EOY Value:	\$4,478,536,208	Average of Line 20 and 21.
23	Transmission W&S Allocation Factor:	5.6290%	27-Allocators, Line 9
24	General + Intangible Plant:	\$252,097,756	Line 22 * Line 23.

b) EOY G&I Plant

		<u>Amount</u>	<u>Source</u>
25	EOY Value:	\$4,427,032,649	Line 21.
26	Transmission W&S Allocation Factor:	5.6290%	27-Allocators, Line 9
27	General + Intangible Plant:	\$249,198,610	Line 25 * Line 26.

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

1) Total Transmission Activity by Account (See Note 3)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
												Sum C2 - C11
<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>		<u>Total</u>
28 Jan 2017	\$1,861,680	\$3,470	-\$4,196,691	\$1,596,560	-\$2,209,532	\$40,169,441	-\$10,554,272	\$196,564	-\$1,096,818	-\$18,664,747		\$7,105,655
29 Feb 2017	\$15,315	\$453,669	\$9,058,082	\$14,060,416	-\$12,641,360	\$14,690,403	\$7,096,603	\$440,544	\$3,236,355	\$1,582,775		\$37,992,801
30 Mar 2017	-\$156,368	\$66,267	-\$3,400,337	\$8,769,751	\$9,454,939	\$8,292,498	\$10,378,573	-\$1,566	-\$271,785	-\$285,477		\$32,846,494
31 Apr 2017	\$11,283	\$557	\$11,418,768	\$27,822,315	\$19,248,445	\$7,317,227	\$7,679,623	-\$426,444	\$1,527,526	\$143,907		\$74,743,207
32 May 2017	\$13,565	\$68,720	\$8,911,158	\$18,492,078	\$4,954,766	\$3,185,788	-\$908,108	\$505,657	\$146,860	\$6,702,521		\$42,073,004
33 Jun 2017	\$394,350	\$391,396	\$4,923,779	\$25,328,529	\$2,382,156	\$6,909,030	\$4,359,728	\$1,179,037	-\$485,348	-\$509,250		\$44,873,407
34 Jul 2017	\$12,352	\$769,044	\$3,184,633	\$17,621,548	\$1,799,359	\$9,434,393	-\$2,765,816	\$2,497,941	-\$1,798,501	\$56,723		\$30,811,677
35 Aug 2017	\$453,134	-\$409,300	\$6,584,775	\$67,541,915	\$1,172,077	\$2,145,575	\$5,558,400	\$107,895	\$3,470,262	\$319,790		\$86,944,523
36 Sep 2017	\$11,821	\$38,745	\$2,739,452	\$7,712,274	-\$1,944,157	\$7,464,055	\$3,977,572	\$334,696	-\$1,279,010	\$546,197		\$19,601,645
37 Oct 2017	\$11,839	-\$303	-\$3,740,698	-\$38,877,996	\$3,098,234	\$10,429,139	-\$1,456,898	\$164,361	\$1,897,821	\$200,525		-\$28,273,977
38 Nov 2017	-\$4,172	\$216,863	\$2,431,279	\$5,104,081	\$1,380,363	\$17,752,143	-\$1,478,412	-\$1,998,396	\$6,260	\$1,849,534		\$25,259,541
39 Dec 2017	\$10,092	\$15,035	\$15,929,204	\$161,530,877	\$10,951,835	\$6,747,806	\$2,832,915	\$127,444	\$2,622,053	\$1,295,679		\$202,062,940
40 Total:	\$2,634,891	\$1,614,163	\$53,843,402	\$316,702,349	\$37,647,126	\$134,537,498	\$24,719,907	\$3,127,731	\$7,975,675	-\$6,761,823		\$576,040,918

2) ISO Incentive Plant Activity (See Note 4)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u> Sum C2 - C11
<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>	
41 Jan 2017	-\$472	\$3,470	\$32,492	\$308,019	-\$53,553	-\$10,526	\$250,896	\$150,473	\$52,608	-\$96,329	\$637,077	
42 Feb 2017	\$15,369	\$453,669	\$330,610	\$1,007,507	\$1,798,385	\$111,151	\$162,386	\$461,566	\$765,122	\$1,577,200	\$6,682,963	
43 Mar 2017	-\$1,780	-\$14,803	\$416,086	-\$541,233	\$240,701	\$575,024	\$4,041,873	\$232,457	\$685,021	-\$454,675	\$5,178,669	
44 Apr 2017	\$11,283	\$570	\$226,974	\$32,487,033	\$444,125	-\$318,433	\$801,454	\$223,187	\$78,030	\$129,434	\$34,083,658	
45 May 2017	\$13,664	-\$43	\$7,516,533	\$7,920,288	\$1,795,504	-\$192,522	-\$2,226,610	\$505,965	\$176,895	\$6,435,427	\$21,945,099	
46 Jun 2017	-\$761	\$761	\$170,780	-\$63,431	-\$75,029	\$55,521	\$1,315,801	\$1,366,286	\$477,679	-\$316,437	\$2,931,169	
47 Jul 2017	\$12,350	\$761	-\$38,332	\$108,511	\$381,557	\$60,184	\$232,398	\$227,468	\$75,900	\$189,532	\$1,250,328	
48 Aug 2017	\$453,134	-\$452,616	-\$322,840	\$399,588	\$488,428	\$79,970	\$323,941	\$328,970	\$109,768	\$119,905	\$1,528,249	
49 Sep 2017	\$11,821	-\$1,180	\$10,511	\$28,470	-\$1,610,011	\$1,774,213	\$580,546	\$327,557	\$109,294	\$159,002	\$1,390,223	
50 Oct 2017	\$11,839	-\$594	\$134,055	\$670,383	\$655,866	\$296,131	\$10,632	\$628,442	\$314,405	\$195,516	\$2,916,673	
51 Nov 2017	\$1,653,095	\$204,541	\$35,216	\$13,767	\$360,544	\$38,809	-\$3,103,026	\$83,416	\$41,735	\$154,301	-\$517,602	
52 Dec 2017	<u>\$10,092</u>	<u>-\$189</u>	<u>\$25,355</u>	<u>\$40,429</u>	<u>\$791,795</u>	<u>\$77,359</u>	<u>\$329,882</u>	<u>\$115,202</u>	<u>\$57,634</u>	<u>\$202,454</u>	<u>\$1,650,013</u>	
53 Total:	\$2,189,633	\$194,346	\$8,537,439	\$42,379,331	\$5,218,313	\$2,546,880	\$2,720,172	\$4,650,989	\$2,944,091	\$8,295,329	\$79,676,521	

3) Total Transmission Activity Not Including Incentive Plant Activity (See Note 5):

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u> Sum C2 - C11
<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>	
54 Jan 2017	\$1,862,153	\$0	-\$4,229,183	\$1,288,541	-\$2,155,979	\$40,179,967	-\$10,805,168	\$46,090	-\$1,149,426	-\$18,568,418	\$6,468,578	
55 Feb 2017	-\$54	\$0	\$8,727,472	\$13,052,909	-\$14,439,745	\$14,579,252	\$6,934,217	-\$21,022	\$2,471,233	\$5,575	\$31,309,838	
56 Mar 2017	-\$154,588	\$81,070	-\$3,816,423	\$9,310,983	\$9,214,239	\$7,717,474	\$6,336,701	-\$234,023	-\$956,806	\$169,199	\$27,667,825	
57 Apr 2017	\$0	-\$13	\$11,191,794	-\$4,664,717	\$18,804,320	\$7,635,660	\$6,878,169	-\$649,632	\$1,449,496	\$14,473	\$40,659,549	
58 May 2017	-\$98	\$68,763	\$1,394,625	\$10,571,790	\$3,159,263	\$3,378,310	\$1,318,502	-\$308	-\$30,035	\$267,094	\$20,127,905	
59 Jun 2017	\$395,111	\$390,635	\$4,752,999	\$25,391,960	\$2,457,185	\$6,853,509	\$3,043,928	-\$187,249	-\$963,027	-\$192,813	\$41,942,238	
60 Jul 2017	\$2	\$768,283	\$3,222,965	\$17,513,038	\$1,417,802	\$9,374,209	-\$2,998,213	\$2,270,474	-\$1,874,401	-\$132,809	\$29,561,349	
61 Aug 2017	\$0	\$43,317	\$6,907,615	\$67,142,326	\$683,649	\$2,065,605	\$5,234,459	-\$221,076	\$3,360,494	\$199,885	\$85,416,274	
62 Sep 2017	\$0	\$39,925	\$2,728,941	\$7,683,804	-\$334,146	\$5,689,843	\$3,397,025	\$7,139	-\$1,388,305	\$387,196	\$18,211,422	
63 Oct 2017	\$0	\$291	-\$3,874,754	-\$39,548,378	\$2,442,368	\$10,133,009	-\$1,467,530	-\$464,081	\$1,583,416	\$5,009	-\$31,190,650	
64 Nov 2017	-\$1,657,268	\$12,322	\$2,396,063	\$5,090,314	\$1,019,819	\$17,713,334	\$1,624,614	-\$2,081,812	-\$35,475	\$1,695,232	\$25,777,143	
65 Dec 2017	<u>\$0</u>	<u>\$15,224</u>	<u>\$15,903,849</u>	<u>\$161,490,448</u>	<u>\$10,160,040</u>	<u>\$6,670,447</u>	<u>\$2,503,033</u>	<u>\$12,243</u>	<u>\$2,564,419</u>	<u>\$1,093,225</u>	<u>\$200,412,927</u>	
66 Total:	\$445,258	\$1,419,817	\$45,305,962	\$274,323,018	\$32,428,813	\$131,990,619	\$21,999,736	-\$1,523,258	\$5,031,584	-\$15,057,152	\$496,364,397	

4) Calculation of change in Non-Incentive ISO Plant:

A) Change in ISO Plant Balance December to December (See Note 6)											
	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
67	\$1,030,500	-\$425,809	\$38,115,412	\$160,272,325	\$49,389,689	\$40,165,853	\$10,029,896	\$4,714,292	\$2,969,302	-\$9,386,201	\$296,875,259
B) Change in Incentive ISO Plant (See Note 7)											
	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
68	\$2,189,633	\$194,346	\$8,537,439	\$42,379,331	\$5,218,313	\$2,546,880	\$2,720,172	\$4,650,989	\$2,944,091	\$8,295,329	\$79,676,521
C) Change in Non-Incentive ISO Plant (See Note 8)											
	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
69	-\$1,159,134	-\$620,155	\$29,577,973	\$117,892,994	\$44,171,377	\$37,618,973	\$7,309,724	\$63,303	\$25,211	-\$17,681,529	\$217,198,738

5) Other ISO Transmission Activity without Incentive Plant Activity (See Note 9):

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
	Sum C2 - C11											
<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>	
70 Jan 2017	-\$4,847,719	\$0	-\$2,761,020	\$553,763	-\$2,936,665	\$11,451,792	-\$3,590,170	-\$1,915	-\$5,759	-\$21,804,789	-\$23,942,483	
71 Feb 2017	\$141	\$0	\$5,697,725	\$5,609,615	-\$19,668,417	\$4,155,269	\$2,303,992	\$874	\$12,382	\$6,547	-\$1,881,872	
72 Mar 2017	\$402,437	-\$35,410	-\$2,491,550	\$4,001,486	\$12,550,740	\$2,199,576	\$2,105,459	\$9,726	-\$4,794	\$198,689	\$18,936,359	
73 Apr 2017	\$0	\$6	\$7,306,557	-\$2,004,708	\$25,613,416	\$2,176,258	\$2,285,369	\$26,997	\$7,263	\$16,996	\$35,428,155	
74 May 2017	\$256	-\$30,035	\$910,480	\$4,543,330	\$4,303,240	\$962,860	\$438,091	\$13	-\$150	\$313,647	\$11,441,732	
75 Jun 2017	-\$1,028,588	-\$170,623	\$3,102,993	\$10,912,442	\$3,346,939	\$1,953,336	\$1,011,388	\$7,782	-\$4,825	-\$226,419	\$18,904,423	
76 Jul 2017	-\$5	-\$335,575	\$2,104,111	\$7,526,399	\$1,931,192	\$2,671,766	-\$996,199	-\$94,356	-\$9,392	-\$155,957	\$12,641,985	
77 Aug 2017	\$0	-\$18,920	\$4,509,632	\$28,855,070	\$931,200	\$588,723	\$1,739,223	\$9,187	\$16,838	\$234,724	\$36,865,679	
78 Sep 2017	\$0	-\$17,439	\$1,781,588	\$3,302,190	-\$455,142	\$1,621,676	\$1,128,710	-\$297	-\$6,956	\$454,682	\$7,809,012	
79 Oct 2017	\$0	-\$127	-\$2,529,631	-\$16,996,301	\$3,326,756	\$2,888,034	-\$487,608	\$19,286	\$7,934	\$5,882	-\$13,765,775	
80 Nov 2017	\$4,314,345	-\$5,382	\$1,564,268	\$2,187,612	\$1,389,098	\$5,048,521	\$539,801	\$86,516	-\$178	\$1,990,702	\$17,115,304	
81 Dec 2017	\$0	-\$6,650	\$10,382,819	\$69,402,096	\$13,839,018	\$1,901,161	\$831,668	-\$509	\$12,849	\$1,283,768	\$97,646,221	
82 Total:	-\$1,159,134	-\$620,155	\$29,577,973	\$117,892,994	\$44,171,377	\$37,618,973	\$7,309,724	\$63,303	\$25,211	-\$17,681,529	\$217,198,738	

Notes:

- 1) Amounts on Line 13 from corresponding account Schedule 7, column 2.
Amounts on Line 1 must match corresponding account Schedule 7, Column 2 for previous year.
The amounts for each month on the remaining lines are calculated by summing the following values:
 - a) Other ISO Transmission Activity without Incentive Plant Activity on Lines 70-81 for the same month;
 - b) ISO Incentive Plant Activity on Lines 41 to 52 for the same month; and
 - c) The previous month balance of the Transmission Plant - ISO amounts on Lines 1-13.
 For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:
 - a) the "Other ISO Transmission Activity without Incentive Plant Activity" for May of the Prior Year (on Line 74, Column 5);
 - b) the "ISO Incentive Plant Activity" for May of the Prior Year (on Line 45, Column 5),
 - c) and the "Transmission Plant - ISO" amount for April of the Prior Year (on Line 5, Column 5)."
- 2) Amounts on Line 15 must match 6-Plant Study amounts for Distribution Plant - ISO for previous year.
Amounts on Line 16 must match amounts on 6-Plant Study for Distribution Plant - ISO.
- 3) Includes recorded Transmission Plant-In-Service additions, retirements, transfers and adjustments. From SCE internal accounting records.
- 4) Column 12 matches 'Activity for Incentive Projects' on 14-IncentivePlant, Lines 40 to 53. Other columns from SCE internal accounting records.
- 5) Amount in matrix on lines 28 to 39 minus amount in matrix on lines 41 to 52
- 6) Amount on Line 13 less amount on Line 1 for each account.
- 7) Line 53
- 8) Amount on Line 67 less amount on Line 68 for each account.
- 9) For each column (FERC Account) divide Line 69 by Line 66 to arrive at a ratio for each column.
Apply the ratio of each column to each monthly value from Lines 54-65 to calculate the values for the corresponding months listed in Lines 70-81.

Transmission Plant Study

Input cells are shaded yellow

A) Plant Classified as Transmission in FERC Form 1 for Prior Year:

Prior Year: 2017

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	Substation					
3	352	\$879,621,910	FF1 207.49g	\$569,698,023	64.77%	
4	353	\$5,902,949,228	FF1 207.50g	\$3,409,447,774	57.76%	
5	Total Substation	\$6,782,571,138	L 3 + L 4	\$3,979,145,796	58.67%	
6						
7	Land					
8	350	\$343,195,020	FF1 207.48g	\$252,777,321	73.65%	
9						
10	Total Substation and Land	\$7,125,766,158	L 5 + L 8	\$4,231,923,117	59.39%	
11						
12	Lines					
13	354	\$2,343,145,352	FF1 207.51g	\$2,283,380,922	97.45%	
14	355	\$1,292,702,467	FF1 207.52g	\$364,424,080	28.19%	
15	356	\$1,524,531,167	FF1 207.53g	\$1,245,933,686	81.73%	
16	357	\$256,348,021	FF1 207.54g	\$190,222,489	74.20%	
17	358	\$376,710,004	FF1 207.55g	\$84,920,374	22.54%	
18	359	\$193,773,411	FF1 207.56g	\$172,640,885	89.09%	
19	Total Lines	\$5,987,210,422	Sum L13 to L18	\$4,341,522,436	72.51%	
20						
21	Total Transmission	\$13,112,976,580	L 10 + L 19	\$8,573,445,553	65.38%	Note 1

B) Plant Classified as Distribution in FERC Form 1:

Line	Account	Total Plant	Data Source	Distribution Plant - ISO	ISO % of Total	Notes
22						
23	Land:					
24	360	\$125,242,449	FF1 207.60g	\$0	0.00%	
25	Structures:					
26	361	\$644,469,720	FF1 207.61g	\$0	0.00%	
27	362	\$2,539,477,720	FF1 207.62g	\$0	0.00%	
28	Total Structures	\$3,183,947,440	L 26 + L 27	\$0	0.00%	
29						
30	Total Distribution	\$3,309,189,889	L 24 + L 28	\$0	0.00%	Note 2

Notes:

- Total transmission does not include account 359.1 "Asset Retirement Costs for Transmission Plant" Total on this line is also equal to FF1 207.58g (Total Transmission Plant) less FF1 207.57g (Asset Retirement Costs for Transmission Plant).
- Only accounts 360-362 included as there is no ISO plant in any other Distribution accounts.

Instructions:

- Perform annual Transmission Study pursuant to instructions in tariff.
- Enter total amounts of plant from FERC Form 1 in Column 1, "Total Plant".
- Enter ISO portion of plant in Column 2, "Transmission Plant - ISO, or "Distribution Plant - ISO".

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Prior Year: 2017

Balances for Transmission Depreciation Reserve - ISO during the Prior Year, including December of previous year (See Note 1):

Line	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
	FERC Account:											=Sum C2 to C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	Dec 2016	\$0	\$18,079,939	\$72,260,283	\$439,653,028	\$465,353,602	\$46,058,792	\$407,738,326	\$839,659	\$2,896,108	\$14,910,822	\$1,467,790,558
2	Jan 2017	\$0	\$18,283,074	\$73,627,073	\$446,326,175	\$469,783,097	\$46,771,081	\$411,072,225	\$1,077,878	\$3,343,627	\$15,147,898	\$1,485,432,127
3	Feb 2017	\$0	\$18,491,562	\$75,140,143	\$453,003,079	\$476,560,306	\$47,636,155	\$402,185,495	\$1,311,598	\$3,570,987	\$15,359,991	\$1,493,259,318
4	Mar 2017	\$0	\$18,700,677	\$77,454,665	\$459,647,499	\$479,223,452	\$47,811,229	\$403,962,631	\$2,161,365	\$4,982,805	\$15,572,879	\$1,509,517,203
5	Apr 2017	\$0	\$18,909,668	\$78,699,446	\$466,347,421	\$483,567,402	\$48,267,189	\$407,039,637	\$2,402,701	\$5,263,331	\$15,782,988	\$1,526,279,783
6	May 2017	\$0	\$19,118,620	\$80,036,364	\$473,096,345	\$485,004,798	\$47,597,525	\$407,318,599	\$2,633,859	\$5,506,958	\$15,994,174	\$1,536,307,242
7	Jun 2017	\$0	\$19,327,525	\$81,886,320	\$479,864,477	\$480,069,078	\$49,424,853	\$407,916,408	\$2,808,959	\$5,656,064	\$16,219,697	\$1,543,173,380
8	Jul 2017	\$0	\$19,535,939	\$83,209,698	\$486,678,422	\$484,602,130	\$49,566,102	\$411,148,567	\$3,043,681	\$5,912,707	\$16,438,962	\$1,560,136,208
9	Aug 2017	\$0	\$19,743,389	\$84,460,037	\$493,515,293	\$488,634,546	\$50,204,820	\$414,201,934	\$3,298,127	\$6,201,499	\$16,657,071	\$1,576,916,716
10	Sep 2017	\$0	\$19,949,988	\$87,149,817	\$500,380,751	\$496,124,235	\$45,310,593	\$414,179,542	\$3,118,477	\$6,331,117	\$16,925,640	\$1,589,470,161
11	Oct 2017	\$0	\$20,156,605	\$88,391,525	\$507,287,057	\$500,349,205	\$46,259,392	\$416,574,500	\$3,355,895	\$6,557,520	\$17,145,720	\$1,606,077,419
12	Nov 2017	\$0	\$20,363,790	\$89,640,731	\$514,150,751	\$504,670,195	\$46,878,036	\$417,410,165	\$3,589,936	\$6,782,544	\$17,366,006	\$1,620,852,154
13	Dec 2017	\$0	\$20,570,771	\$90,912,860	\$521,029,731	\$508,793,023	\$46,422,546	\$417,546,825	\$3,830,318	\$6,981,972	\$17,589,054	\$1,633,677,100
14	13-Mo. Avg:	\$0	\$19,325,504	\$81,759,151	\$480,075,387	\$486,364,236	\$47,554,486	\$410,638,066	\$2,574,804	\$5,383,634	\$16,239,300	\$1,549,914,567

2) Distribution Depreciation Reserve - ISO (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5	Total	Notes	
	FERC Account:						=Sum C2 to C4	
	Mo/YR	360	361	362				
15	Dec 2016	\$0	\$0	\$0	\$0	\$0	Beginning of Year ("BOY") amount	
16	Dec 2017	\$0	\$0	\$0	\$0	\$0	End of Year ("EOY") amount	
17	BOY/EOY Average:	\$0	\$0	\$0	\$0	\$0	Average of Line 15 and Line 16	

3) General and Intangible Depreciation Reserve

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	
			=C4+C5			
			Total			
			Gen. and Int.	General	Intangible	
			Depreciation	Depreciation	Depreciation	
	<u>Mo/YR</u>		<u>Reserve</u>	<u>Reserve</u>	<u>Reserve</u>	<u>Source</u>
18	Dec 2016	BOY:	\$1,917,414,678	\$1,073,416,375	\$843,998,303	FF1 219.28c and 200.21c for previous year
19	Dec 2017	EOY:	\$1,736,829,507	\$1,094,912,964	\$641,916,543	FF1 219.28c and 200.21c
20		BOY/EOY Average:	\$1,827,122,093			Average of Line 18 and Line 19

a) Average BOY/EOY General and Intangible Depreciation Reserve

		<u>Amount</u>	<u>Source</u>
21	Total G+I Dep. Reserve on Average BOY/EOY basis:	\$1,827,122,093	Line 20
22	Transmission W&S Allocation Factor:	5.6290%	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	\$102,849,091	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

		<u>Amount</u>	<u>Source</u>
24	Total G+I Dep. Reserve on Average EOY basis:	\$1,736,829,507	Line 19
25	Transmission W&S Allocation Factor:	5.6290%	27-Allocators, Line 9
26	G + I Plant Dep. Reserve (EOY):	\$97,766,503	Line 24 * Line 25

Transmission Activity Used to Determine Monthly Transmission Depreciation Reserve - ISO Balances

1) Total Transmission Activity by Account (See Note 3)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
												Sum C2 - C11
	<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
27	Jan 2017	\$0	306,343	1,828,211	11,991,735	4,315,317	(127,444)	3,368,094	329,314	(1,106,927)	258,165	\$21,162,809
28	Feb 2017	\$0	290,108	2,281,929	11,279,778	9,042,366	379,373	(11,020,299)	350,234	541,964	400,428	\$13,545,880
29	Mar 2017	\$0	290,738	4,676,994	27,884,284	806,326	(2,423,623)	1,535,387	(2,359,872)	(8,300,886)	340,605	\$22,449,953
30	Apr 2017	\$0	290,835	1,454,328	10,481,720	4,159,881	(1,324,044)	3,063,220	321,925	183,974	220,634	\$18,852,472
31	May 2017	\$0	290,954	1,700,063	15,489,338	(1,738,324)	(5,849,776)	(232,892)	368,620	462,436	264,158	\$10,754,576
32	Jun 2017	\$0	290,930	3,213,461	17,834,290	(14,566,250)	4,144,771	143,358	619,300	1,174,652	545,138	\$13,399,650
33	Jul 2017	\$0	291,471	1,608,515	9,406,835	4,467,319	(2,627,232)	3,244,280	366,888	382,806	272,756	\$17,413,638
34	Aug 2017	\$0	292,532	1,378,925	6,827,735	3,455,861	(659,744)	3,034,095	281,001	144,031	214,158	\$14,968,593
35	Sep 2017	\$0	292,479	5,709,308	18,269,617	10,405,006	(22,827,946)	(588,569)	2,195,606	1,338,710	2,660,700	\$17,454,911
36	Oct 2017	\$0	292,323	1,326,972	6,044,361	3,844,384	544,911	2,257,111	360,949	617,197	250,239	\$15,538,447
37	Nov 2017	\$0	290,594	1,359,996	9,252,252	4,029,281	(806,780)	421,244	380,637	636,340	247,754	\$15,811,317
38	Dec 2017	\$0	292,325	1,422,319	5,386,485	3,627,210	(5,155,955)	(400,684)	353,971	829,025	249,266	\$6,603,961
39	Total:	\$0	\$3,511,631	\$27,961,020	\$150,148,429	\$31,848,376	-\$36,733,489	\$4,824,346	\$3,568,572	-\$3,096,678	\$5,924,001	\$187,956,207

Schedule 8
Accumulated Depreciation

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

2) Depreciation Expense (See Note 4)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
												Sum C2 - C11
	<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
40	Jan 2017	\$0	\$228,702	\$1,138,473	\$6,687,886	\$4,542,449	\$991,690	\$3,141,255	\$255,074	\$264,292	\$236,635	\$17,486,456
41	Feb 2017	\$0	\$228,707	\$1,132,629	\$6,689,660	\$4,536,369	\$1,026,681	\$3,132,768	\$255,278	\$264,443	\$208,164	\$17,474,699
42	Mar 2017	\$0	\$229,335	\$1,145,540	\$6,703,280	\$4,500,033	\$1,039,729	\$3,139,037	\$255,914	\$266,951	\$210,223	\$17,490,041
43	Apr 2017	\$0	\$229,265	\$1,141,095	\$6,710,403	\$4,526,042	\$1,048,215	\$3,154,661	\$256,247	\$269,144	\$209,890	\$17,544,962
44	May 2017	\$0	\$229,266	\$1,157,229	\$6,773,145	\$4,579,026	\$1,053,897	\$3,162,507	\$256,591	\$269,420	\$210,080	\$17,691,161
45	Jun 2017	\$0	\$229,224	\$1,175,277	\$6,798,800	\$4,591,427	\$1,056,253	\$3,157,961	\$257,287	\$269,990	\$218,854	\$17,755,072
46	Jul 2017	\$0	\$228,989	\$1,182,288	\$6,821,131	\$4,598,080	\$1,062,396	\$3,163,876	\$259,176	\$271,514	\$218,148	\$17,805,599
47	Aug 2017	\$0	\$228,526	\$1,186,713	\$6,836,846	\$4,602,782	\$1,070,752	\$3,161,935	\$259,359	\$271,729	\$218,192	\$17,836,833
48	Sep 2017	\$0	\$227,874	\$1,195,679	\$6,897,062	\$4,605,669	\$1,072,797	\$3,167,179	\$259,824	\$272,137	\$218,653	\$17,916,873
49	Oct 2017	\$0	\$227,848	\$1,199,517	\$6,903,917	\$4,601,470	\$1,083,182	\$3,171,523	\$260,274	\$272,467	\$219,451	\$17,939,650
50	Nov 2017	\$0	\$227,847	\$1,194,387	\$6,870,313	\$4,609,568	\$1,092,921	\$3,170,311	\$261,165	\$273,507	\$219,713	\$17,919,730
51	Dec 2017	\$0	\$228,123	\$1,197,812	\$6,874,844	\$4,613,125	\$1,108,479	\$3,163,796	\$261,398	\$273,641	\$222,501	\$17,943,720
52	Total:	\$0	\$2,743,707	\$14,046,640	\$81,567,286	\$54,906,038	\$12,706,990	\$37,886,809	\$3,097,586	\$3,239,236	\$2,610,503	\$212,804,795

3) Total Transmission Activity less Depreciation Expense (See Note 5)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
												Sum C2 - C11
	<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
53	Jan 2017	\$0	\$77,641	\$689,739	\$5,303,848	-\$227,132	-\$1,119,134	\$226,839	\$74,240	-\$1,371,219	\$21,530	\$3,676,352
54	Feb 2017	\$0	\$61,401	\$1,149,300	\$4,590,118	\$4,505,997	-\$647,308	-\$14,153,067	\$94,956	\$277,520	\$192,264	-\$3,928,819
55	Mar 2017	\$0	\$61,403	\$3,531,454	\$21,181,003	-\$3,693,707	-\$3,463,352	-\$1,603,649	-\$2,615,786	-\$8,567,837	\$130,383	\$4,959,912
56	Apr 2017	\$0	\$61,570	\$313,233	\$3,771,318	-\$366,161	-\$2,372,259	-\$91,441	\$65,678	-\$85,171	\$10,744	\$1,307,510
57	May 2017	\$0	\$61,688	\$542,833	\$8,716,193	-\$6,317,350	-\$6,903,673	-\$3,395,399	\$112,029	\$193,017	\$54,077	-\$6,936,585
58	Jun 2017	\$0	\$61,706	\$2,038,184	\$11,035,490	-\$19,157,677	\$3,088,519	-\$3,014,603	\$362,013	\$904,662	\$326,284	-\$4,355,422
59	Jul 2017	\$0	\$62,482	\$426,227	\$2,585,704	-\$130,761	-\$3,689,628	\$80,404	\$107,713	\$111,291	\$54,607	-\$391,961
60	Aug 2017	\$0	\$64,006	\$192,212	-\$9,111	-\$1,146,922	-\$1,730,496	-\$127,840	\$21,642	-\$127,698	-\$4,034	-\$2,868,240
61	Sep 2017	\$0	\$64,605	\$4,513,628	\$11,372,555	\$5,799,337	-\$23,900,742	-\$3,755,748	\$1,935,782	\$1,066,573	\$2,442,047	-\$461,962
62	Oct 2017	\$0	\$64,475	\$127,455	-\$859,556	-\$757,085	-\$538,271	-\$914,412	\$100,675	\$344,729	\$30,788	-\$2,401,203
63	Nov 2017	\$0	\$62,747	\$165,609	\$2,381,939	-\$580,287	-\$1,899,700	-\$2,749,066	\$119,472	\$362,833	\$28,041	-\$2,108,413
64	Dec 2017	\$0	\$64,202	\$224,507	-\$1,488,360	-\$985,915	-\$6,264,435	-\$3,564,480	\$92,573	\$555,384	\$26,765	-\$11,339,759
65	Total:	\$0	\$767,924	\$13,914,380	\$68,581,143	-\$23,057,663	-\$49,440,479	-\$33,062,463	\$470,986	-\$6,335,914	\$3,313,498	-\$24,848,588

4) Calculation of Other Transmission Activity

A) Change in Depreciation Reserve - ISO (See Note 6)											
66	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
	\$0	\$2,490,832	\$18,652,577	\$81,376,703	\$43,439,421	\$363,754	\$9,808,498	\$2,990,659	\$4,085,865	\$2,678,232	\$165,886,542
B) Total Depreciation Expense (See Note 7)											
67	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
	\$0	\$2,743,707	\$14,046,640	\$81,567,286	\$54,906,038	\$12,706,990	\$37,886,809	\$3,097,586	\$3,239,236	\$2,610,503	\$212,804,795
C) Other Activity (See Note 8)											
68	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
	\$0	-\$252,875	\$4,605,937	-\$190,583	-\$11,466,617	-\$12,343,237	-\$28,078,311	-\$106,926	\$846,629	\$67,729	-\$46,918,253

5) Other Transmission Activity (See Note 9)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
												Sum C2 - C11
	<u>Mo/YR</u>	<u>350.1</u>	<u>350.2</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Total</u>
69	Jan 2017	\$0	-\$25,567	\$228,317	-\$14,739	-\$112,953	-\$279,401	\$192,643	-\$16,854	\$183,228	\$440	\$155,113
70	Feb 2017	\$0	-\$20,219	\$380,441	-\$12,756	\$2,240,840	-\$161,606	-\$12,019,498	-\$21,558	-\$37,083	\$3,930	-\$9,647,509
71	Mar 2017	\$0	-\$20,220	\$1,168,982	-\$58,861	-\$1,836,887	-\$864,655	-\$1,361,900	\$593,853	\$1,144,867	\$2,665	-\$1,232,156
72	Apr 2017	\$0	-\$20,275	\$103,686	-\$10,480	-\$182,093	-\$592,255	-\$77,656	-\$14,911	\$11,381	\$220	-\$782,382
73	May 2017	\$0	-\$20,314	\$179,689	-\$24,222	-\$3,141,630	-\$1,723,561	-\$2,883,544	-\$25,434	-\$25,792	\$1,105	-\$7,663,701
74	Jun 2017	\$0	-\$20,319	\$674,679	-\$30,667	-\$9,527,147	\$771,075	-\$2,560,153	-\$82,187	-\$120,884	\$6,669	-\$10,888,934
75	Jul 2017	\$0	-\$20,575	\$141,090	-\$7,186	-\$65,028	-\$921,147	\$68,283	-\$24,454	-\$14,871	\$1,116	-\$842,771
76	Aug 2017	\$0	-\$21,077	\$63,626	\$25	-\$570,366	-\$432,033	-\$108,568	-\$4,913	\$17,063	-\$82	-\$1,056,325
77	Sep 2017	\$0	-\$21,274	\$1,494,101	-\$31,604	\$2,884,021	-\$5,967,024	-\$3,189,570	-\$439,474	-\$142,520	\$49,916	-\$5,363,428
78	Oct 2017	\$0	-\$21,231	\$42,190	\$2,389	-\$376,500	-\$134,384	-\$776,565	-\$22,856	-\$46,064	\$629	-\$1,332,391
79	Nov 2017	\$0	-\$20,662	\$54,820	-\$6,619	-\$288,578	-\$474,276	-\$2,334,646	-\$27,123	-\$48,483	\$573	-\$3,144,995
80	Dec 2017	\$0	-\$21,141	\$74,316	\$4,136	-\$490,297	-\$1,563,969	-\$3,027,136	-\$21,016	-\$74,213	\$547	-\$5,118,774
81	Total:	\$0	-\$252,875	\$4,605,937	-\$190,583	-\$11,466,617	-\$12,343,237	-\$28,078,311	-\$106,926	\$846,629	\$67,729	-\$46,918,253

Notes:

- 1) Amounts on Line 13 based on current year Plant Study. Amounts on Line 1 shall be based previous year Plant Study, and shall match amounts on Line 13 in previous year Annual Update.
 - The amounts for each month on the remaining lines are calculated by summing the following values:
 - a) Depreciation Expense (on Lines 40 to 51) for the same month;
 - b) Other Transmission Activity (on Lines 69 to 80) for the same month; and
 - c) Balances for Transmission Depreciation Reserve (on Lines 1 to 13) for the previous month.
 - For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:
 - a) Depreciaton Expense for May of the Prior Year (on Line 44, Column 5);
 - b) Other Transmission Activity for May of the Prior Year (on Line 73, Column 5); and
 - c) The balances for Transmission Depreciation Reserve for April of the Prior Year (on Line 5, column 5).
 - 2) Amounts on Line 15 derived from Plant Study for previous year Prior Year.
 - Amounts on Line 16 derived from Plant Study for Prior Year.
 - 3) Total Transmission Activity by Account represents accumulated depreciation changes for all Transmission plant.
 - 4) From 17-Depreciation, Lines 24 to 35.
 - 5) Amount in matrix on lines 27 to 38 minus amount in matrix on lines 40 to 51.
 - 6) Line 13 - Line 1.
 - 7) Line 52.
 - 8) Line 66 - Line 67.
 - 9) For each column (FERC Account) divide Line 68 by Line 65 to arrive at a ratio for each column.
- Apply the ratio of each column to each monthly value from Lines 53-64 to calculate the values for the corresponding months listed in Lines 69-80.

Accumulated Deferred Income Taxes

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes

a) End of Year Accumulated Deferred Income Taxes

<u>Line</u>	<u>Account</u>	<u>Col 1</u>	<u>Col 2</u>	<u>Source</u>
			<u>Total ADIT</u>	
1	Account 190		\$38,585,681	Line 353, Col. 2
2	Account 282		-\$1,090,207,015	Line 452, Col. 2
3	Account 283		-\$15,673,913	Line 803, Col. 2
4	Excess Deferred Tax Liability - 2017 TCAJA		-\$582,299,547	FF1 278.9, Row 1, Column e (Act 254)
5	Total Accumulated Deferred Income Taxes		-\$1,649,594,793	Sum of Lines 1 to 4

b) Beginning of Year Accumulated Deferred Income Taxes

<u>Line</u>	<u>Account</u>	<u>BOY ADIT</u>	<u>Source</u>
10	Total Accumulated Deferred Income Taxes	-\$1,551,362,350	Previous Year Informational Filing, Line 5, Col. 2

c) Average of Beginning and End of Year Accumulated Deferred Income Taxes

<u>Line</u>	<u>Account</u>	<u>Average ADIT</u>	<u>Source</u>
15	Average BOY/EOY ADIT:	-\$1,600,478,572	Average of Line 5 and Line 10

2) Account 190 Detail

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>
<u>ACCT 190</u>	<u>DESCRIPTION</u>	<u>END BAL</u>	<u>Gas, Generation</u>	<u>ISO Only</u>	<u>Plant Related</u>	<u>Labor</u>	<u>(Instructions 1&2)</u>
		<u>per G/L</u>	<u>or Other Related</u>			<u>Related</u>	<u>Description</u>
Electric:							
100	190.000 Amort of Debt Issuance Cost	\$649,241	\$506		\$648,735		C: Relates to all Regulated Electric Property
101	190.000 Executive Incentive Comp	\$3,146,087	\$1,577,551			\$1,568,536	C: Relates to employees in all functions
102	190.000 Bond Discount Amort	\$771,695	\$602		\$771,093		C: Relates to all Regulated Electric Property
103	190.000 Executive Incentive Plan	\$1,536,403	\$770,403			\$766,000	C: Relates to employees in all functions
104	190.000 Ins - Inj/Damages Prov	\$29,451,918	\$84,386			\$29,367,532	C: Relates to employees in all functions
105	190.000 Accrued Vacation	\$11,617,959	\$33,288			\$11,584,671	C: Relates to employees in all functions
106	190.000 PBOP 401H Amortization	\$34,717,749	\$99,474			\$34,618,275	C: Relates to employees in all functions
107	190.000 EMS	\$1,247,125	\$973		\$1,246,152		C: Relates to all Regulated Electric Property
108	190.000 Amortization of Debt Expense	\$955,103	\$745		\$954,358		C: Relates to all Regulated Electric Property
109	190.000 Decommissioning	\$421,953,973	\$421,953,973				Relates to Nuclear Decommissioning Costs
110	190.000 Balancing Accounts	-\$9,045,539	-\$9,045,539				Relates Entirely to CPUC Balancing Account Recovery
111	190.000 CIAC/ITCC	\$0	\$0				Non-Rate Base FAS 109 Tax - CIAC
112	190.000 Pension & PBOP	\$9,082,254	\$26,023			\$9,056,231	C: Relates to employees in all functions
113	190.000 Property/Non-ISO	\$6,708,625	\$6,708,625				Non-Rate Base Property
114	190.000 Regulatory Assets/Liab	\$9,519,058	\$9,519,058				Relates to Nonrecovery Balancing Account
115	190.000 Temp - Other/Non-ISO	\$1,027,410,561	\$1,027,410,561				Not Component of Rate Base
116	190.000 Net Operating Losses DTA	\$172,664,412	\$0		\$172,664,412		NOL/DTA
117	...						

Continuation of Account 190 Detail

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>
<u>ACCT 190</u>	<u>DESCRIPTION</u>	<u>END BAL</u>	<u>Gas, Generation</u>	<u>ISO Only</u>	<u>Plant Related</u>	<u>Labor Related</u>	<u>(Instructions 1&2)</u>
		<u>per G/L</u>	<u>or Other Related</u>				<u>Description</u>
Electric:							
118	...						<u>Source</u>
250	Total Electric 190	\$1,722,386,624	\$1,459,140,628	\$0	\$176,284,750	\$86,961,245	Sum of Above Lines beginning on Line 100

Account 190 Gas and Other Income:

(Instructions 1&2)

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>
300	190.000	Temp - Other/Non-ISO - Gas	-\$910	-\$910			Gas Related Costs
301	190.000	Net Operating Losses DTA - Gas	\$118,747	\$118,747			Gas Related Costs
302	190.000	Balancing Accounts	\$2,738,775	\$2,738,775			Other Non-ISO Related Costs
303	190.000	Temp - Other/Non-ISO - Other	\$1,561,144	\$1,561,144			Not Component of Rate Base
304	190.000	Net Operating Losses DTA - Other	-\$15,234,903	-\$15,234,903			Not Component of Rate Base
305	...						

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Source</u>
350	Total Account 190 Gas and Other Income	-\$10,817,147	-\$10,817,147	\$0	\$0	\$0	Sum of Above Lines beginning on Line 300
351	Total Account 190	\$1,711,569,477	\$1,448,323,481	\$0	\$176,284,750	\$86,961,245	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				19.111%	5.629%	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	\$38,585,681		\$0	\$33,690,614	\$4,895,067	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
354	FERC Form 1 Account 190	\$1,711,569,477		Must match amount on Line 351, Col. 2			FF1 234.18c

3) Account 282 Detail

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Col 7</u>
<u>ACCT 282</u>	<u>DESCRIPTION</u>	<u>END BAL</u>	<u>Gas, Generation</u>	<u>ISO Only</u>	<u>Plant Related</u>	<u>Labor</u>	<u>Description</u>
		<u>per G/L</u>	<u>or Other Related</u>			<u>Related</u>	
400	282.000	Fully Normalized Deferred Tax	-\$1,090,207,015	-\$1,090,207,015			Property-Related FERC Costs
401	282.000	Property/Non-ISO	-\$5,756,860,298	-\$5,756,860,298			Property-Related CPUC Costs
402	282.000	Capitalized software	-\$25,491,012	-\$25,491,012			Property-Related CPUC Costs - Cap Software
403	282.000	Audit Rollforward	-\$865,727	-\$865,727			Property-Related CPUC Costs - Audit
404	282.000	Property/Non-ISO - Gas	-\$936,176	-\$936,176			Gas Related Costs
405	282.000	Property/Non-ISO - Other	-\$6,492,275	-\$6,492,275			Other Non-ISO Related Costs
406	...						

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Source</u>
450	Total Account 282	-\$6,880,852,503	-\$5,790,645,488	-\$1,090,207,015	\$0	\$0	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)				19.111%	5.629%	27-Allocators Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)	-\$1,090,207,015		-\$1,090,207,015	\$0	\$0	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282	\$6,880,852,503		Must match amount on Line 450, Col. 2			FF1 275.5k

4) Account 283 Detail

ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
500	Electric: 283.000 Ad Valorem Lien Date Adj-Electric	-\$42,051,267			-\$42,051,267		Relates to all Regulated Electric Property
501	283.000 Refunding & Retirement of Debt	-\$39,655,122	-\$30,927		-\$39,624,195		C: Relates to all Regulated Electric Property
502	283.000 Health Care - IBNR	-\$1,149,642	-\$3,294			-\$1,146,348	C: Relates to employees in all functions
503	283.000 Balancing Accounts	-\$158,026,051	-\$158,026,051				Relates Entirely to CPUC Balancing Account Recovery
504	283.000 Capitalized Software	\$0	\$0				Property-Related CPUC Costs - Cap Software
505	283.000 Decommissioning	-\$422,955,253	-\$422,955,253				Relates to Nuclear Decommissioning Costs
506	283.000 Property/Non-ISO	\$0	\$0				Property-Related CPUC Costs
507	283.000 Regulatory Assets/Liab	\$0	\$0				Relates to Nonrecovery Balancing Account
508	283.000 Temp - Other/Non-ISO	-\$83,907,538	-\$83,907,538				Non-Rate Base FAS 109 Tax Flow-Thru
509	...						

Continuation of Account 283 Detail

ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
510	Electric (continued): ...						
650	Total Electric 283	-\$747,744,873	-\$664,923,063	\$0	-\$81,675,462	-\$1,146,348	Sum of Above Lines beginning on Line 500
	Account 283 Gas and Other:						(Instructions 1&2)
700	283.000 Temp - Other/Non-ISO - Gas	-\$61,716	-\$61,716				Gas Related Costs
701	283.000 Temp - Other/Non-ISO - Other	-\$4,351,620	-\$4,351,620				Other Non-ISO Related Costs
702	...						

Schedule 9
ADIT

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>	<u>Source</u>
800	Total Account 283 Gas and Other	-\$4,413,336	-\$4,413,336	\$0	\$0	\$0	Sum of Above Lines beginning on Line 700
801	Total Account 283	-\$752,158,209	-\$669,336,399	\$0	-\$81,675,462	-\$1,146,348	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				19.111%	5.629%	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	-\$15,673,913		\$0	-\$15,609,385	-\$64,528	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	\$752,158,209	Must match amount on Line 801, Col. 2				FF1 277.19k

Instruction 1: For any "Company Wide" ADIT line item balance (i.e., that include Catalina Gas or Water costs), indicate in Column 7 with a leading "C:".

Instruction 2: For any Company Wide ADIT balance items, include a portion of the total Column 2 balance in Column 3 "Gas, Generation, or Other Related" based on the following percentages.

1) For Line items allocated based on the Wages and Salaries Allocation Factor:

	<u>FERC Form 1 Reference or Instruction</u>	<u>Prior Year Value</u>
A:Total Electric Wages and Salaries	FF1 354.28b	\$749,285,680
B:Gas Wages and Salaries	FF1 355.62b	\$615,045
C:Water Wages and Salaries	FF1 355.64b	\$1,537,997
D:Total Electric, Gas, and Water Wages and Salaries	A+B+C	\$751,438,722
E:Labor Percentage "Gas, Generation, or Other"	(B+C) / D	0.2865%

2) For Line items allocated based on the Transmission Plant Allocation Factor or "ISO Only":

	<u>FERC Form 1 Reference or Instruction</u>	<u>Prior Year Value</u>
F:Total Electric Plant In Service	FF1 207.104g	\$46,164,121,713
G:Total Gas Plant In Service	FF1 201.8d	\$6,268,777
H:Total Water Plant in Service	FF1 201.8e	\$29,763,069
I:Total Electric, Gas, and Water Plant In Service	F+G+H	\$46,200,153,559
J:Plant Percentage "Gas, Generation, or Other"	(G+H) / I	0.0780%

Instruction 3: For any balances in account 190 relating to "Executive Incentive Comp" or "Executive Incentive Plan", the amount included in Column 3 "Gas, Generation or Other Related" shall be 50% of the total balance in Column 1, plus an amount equal to the "Labor Percentage Gas, Generation, or Other" shown on Line E of Instruction 1 times 50% of the total balance in Column 1. The remaining amount shall be included in Column 6 "Labor Related".

Instruction 4: Classify any ADIT line items relating to refunding and retirement of debt as Plant related (Column 5).

Instruction 5: For any balances in account 190 relating to stock options, the entire amount is included in Column 3 "Gas, Generation or Other Related."

Prior Year CWIP and Forecast Period Incremental CWIP by Project

Prior Year CWIP is the amount of Construction Work In Progress for projects that have received Commission approval to include CWIP in Rate Base.

1) Prior Year CWIP, Total and by Project

			<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	<u>Col 6</u>
			= Sum of all columns					
<u>Line</u>	<u>Month</u>	<u>Year</u>	<u>Monthly Total CWIP</u>	<u>Tehachapi</u>	<u>Devers to Colorado River</u>	<u>South of Kramer</u>	<u>West of Devers</u>	<u>Red Bluff</u>
1	December	2016	\$115,749,706	\$14,915,548	\$0	\$4,204,927	\$69,685,245	\$0
2	January	2017	\$117,194,142	\$15,082,524	\$0	\$4,239,931	\$70,177,660	\$0
3	February	2017	\$119,164,541	\$15,117,127	\$0	\$4,296,863	\$71,031,101	\$0
4	March	2017	\$125,730,091	\$15,123,625	\$0	\$4,400,061	\$73,723,204	\$0
5	April	2017	\$95,419,244	\$15,192,634	\$0	\$4,461,541	\$75,120,416	\$0
6	May	2017	\$82,582,163	\$149,718	\$0	\$4,476,504	\$77,300,754	\$0
7	June	2017	\$84,504,679	\$149,718	\$0	\$4,697,238	\$78,966,264	\$0
8	July	2017	\$85,941,140	\$149,718	\$0	\$4,761,048	\$80,276,384	\$0
9	August	2017	\$89,338,929	\$150,129	\$0	\$4,777,853	\$83,585,450	\$0
10	September	2017	\$91,194,895	\$150,062	\$0	\$4,824,268	\$85,335,965	\$0
11	October	2017	\$91,967,696	\$150,062	\$0	\$4,844,918	\$86,972,716	\$0
12	November	2017	\$134,322,419	\$150,062	\$0	\$4,852,268	\$91,066,687	\$0
13	December	2017	<u>\$150,629,632</u>	<u>\$150,976</u>	<u>\$0</u>	<u>\$4,884,728</u>	<u>\$98,805,812</u>	<u>\$0</u>
14	13 Month Averages:		\$106,441,483	\$5,894,762	\$0	\$4,594,011	\$80,157,512	\$0

			<u>Col 7</u>	<u>Col 8</u>	<u>Col 9</u>	<u>Col 10</u>	<u>Col 11</u>	<u>Col 12</u>
			<u>Whirlwind Substation Expansion</u>	<u>Colorado River Substation Expansion</u>	<u>Mesa</u>	<u>Alberhill</u>	<u>ELM Series Caps</u>	
15	December	2016	\$26,943,987	\$0	\$0	\$0	\$0	
16	January	2017	\$27,694,027	\$0	\$0	\$0	\$0	
17	February	2017	\$28,719,449	\$0	\$0	\$0	\$0	
18	March	2017	\$32,483,202	\$0	\$0	\$0	\$0	
19	April	2017	\$644,653	\$0	\$0	\$0	\$0	
20	May	2017	\$655,187	\$0	\$0	\$0	\$0	
21	June	2017	\$691,460	\$0	\$0	\$0	\$0	
22	July	2017	\$753,990	\$0	\$0	\$0	\$0	
23	August	2017	\$825,497	\$0	\$0	\$0	\$0	
24	September	2017	\$884,600	\$0	\$0	\$0	\$0	
25	October	2017	\$0	\$0	\$0	\$0	\$0	
26	November	2017	\$0	\$0	\$38,253,401	\$0	\$0	
27	December	2017	<u>\$0</u>	<u>\$0</u>	<u>\$46,788,116</u>	<u>\$0</u>	<u>\$0</u>	
28	13 Month Averages:		\$9,253,542	\$0	\$6,541,655	\$0	\$0	---

2) Total Forecast Period CWIP Expenditures (see Note 1)

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
			See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2
			Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
29	December	2017	---	---	---	---	---	---	\$150,629,632	---
30	January	2018	\$9,351,204	\$701,340	\$10,052,544	\$5,037,315	\$4,098,417	\$70,417	\$155,574,443	\$4,944,811
31	February	2018	\$10,204,202	\$765,315	\$10,969,517	\$1,615,948	\$0	\$121,196	\$164,806,816	\$14,177,184
32	March	2018	\$22,153,491	\$1,661,512	\$23,815,003	\$1,024,177	\$0	\$76,813	\$187,520,829	\$36,891,197
33	April	2018	\$9,357,335	\$701,800	\$10,059,135	\$116,255	\$0	\$8,719	\$197,454,990	\$46,825,358
34	May	2018	\$14,954,818	\$1,121,611	\$16,076,429	\$786,000	\$0	\$58,950	\$212,686,470	\$62,056,838
35	June	2018	\$17,718,219	\$1,328,866	\$19,047,085	\$3,410,370	\$2,447,558	\$72,211	\$228,250,974	\$77,621,342
36	July	2018	\$12,070,760	\$905,307	\$12,976,067	\$548,326	\$0	\$41,124	\$240,637,591	\$90,007,959
37	August	2018	\$16,798,571	\$1,259,893	\$18,058,464	\$297,663	\$0	\$22,325	\$258,376,067	\$107,746,435
38	September	2018	\$13,815,047	\$1,036,129	\$14,851,175	\$349,971	\$0	\$26,248	\$272,851,024	\$122,221,392
39	October	2018	\$24,263,780	\$1,819,783	\$26,083,563	\$77,673	\$0	\$5,825	\$298,851,088	\$148,221,457
40	November	2018	\$22,781,801	\$1,708,635	\$24,490,436	\$47,000	\$0	\$3,525	\$323,290,999	\$172,661,367
41	December	2018	\$27,803,219	\$2,085,241	\$29,888,461	\$20,677,884	\$8,513,638	\$912,318	\$331,589,257	\$180,959,625
42	January	2019	\$10,509,601	\$788,220	\$11,297,821	\$185,930	\$0	\$13,945	\$342,687,203	\$192,057,571
43	February	2019	\$18,429,548	\$1,382,216	\$19,811,764	\$204,643	\$0	\$15,348	\$362,278,976	\$211,649,344
44	March	2019	\$20,210,543	\$1,515,791	\$21,726,333	\$361,034	\$0	\$27,078	\$383,617,198	\$232,987,566
45	April	2019	\$18,395,093	\$1,379,632	\$19,774,725	\$373,816	\$0	\$28,036	\$402,990,071	\$252,360,439
46	May	2019	\$19,070,892	\$1,430,317	\$20,501,209	\$400,431	\$0	\$30,032	\$423,060,816	\$272,431,185
47	June	2019	\$34,328,459	\$2,574,634	\$36,903,093	\$413,213	\$0	\$30,991	\$459,519,706	\$308,890,074
48	July	2019	\$21,416,333	\$1,606,225	\$23,022,558	\$432,387	\$0	\$32,429	\$482,077,448	\$331,447,816
49	August	2019	\$22,238,370	\$1,667,878	\$23,906,247	\$14,427,934	\$8,470,083	\$446,839	\$491,108,922	\$340,479,290
50	September	2019	\$24,775,209	\$1,858,141	\$26,633,350	\$453,078	\$0	\$33,981	\$517,255,212	\$366,625,580
51	October	2019	\$23,310,193	\$2,891,632	\$41,446,725	\$19,987,218	\$9,341,864	\$798,402	\$537,916,317	\$387,286,685
52	November	2019	\$28,594,395	\$2,488,229	\$35,664,615	\$16,531,554	\$6,140,181	\$779,353	\$556,270,025	\$405,640,393
53	December	2019	\$33,982,790	\$2,548,709	\$36,531,499	\$5,786,285	\$2,531,642	\$244,098	\$586,771,142	\$436,141,510
54	13-Month Averages:									\$301,458,237

3) Forecast Period CWIP Expenditures by Project (see Note 1)

3a) Project:

Tehachapi

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
			Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
55	December	2017	---	---	---	---	---	---	\$150,976	---
56	January	2018	\$426,481	\$31,986	\$458,467	\$191,116	\$0	\$14,334	\$403,994	\$253,017
57	February	2018	\$659,259	\$49,444	\$708,703	\$891,972	\$0	\$66,898	\$153,827	\$2,851
58	March	2018	\$589,704	\$44,228	\$633,932	\$588,345	\$0	\$44,126	\$155,288	\$4,312
59	April	2018	\$82,255	\$6,169	\$88,424	\$80,255	\$0	\$6,019	\$157,438	\$6,462
60	May	2018	\$788,000	\$59,100	\$847,100	\$786,000	\$0	\$58,950	\$159,588	\$8,612
61	June	2018	\$703,326	\$52,749	\$756,075	\$862,313	\$150,976	\$53,350	\$0	-\$150,976
62	July	2018	\$503,326	\$37,749	\$541,075	\$503,326	\$0	\$37,749	\$0	-\$150,976
63	August	2018	\$252,663	\$18,950	\$271,613	\$252,663	\$0	\$18,950	\$0	-\$150,976
64	September	2018	\$304,971	\$22,873	\$327,844	\$304,971	\$0	\$22,873	\$0	-\$150,976
65	October	2018	\$2,000	\$150	\$2,150	\$2,000	\$0	\$150	\$0	-\$150,976
66	November	2018	\$2,000	\$150	\$2,150	\$2,000	\$0	\$150	\$0	-\$150,976
67	December	2018	\$2,161,291	\$162,097	\$2,323,388	\$2,161,291	\$0	\$162,097	\$0	-\$150,976
68	January	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
69	February	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
70	March	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
71	April	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
72	May	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
73	June	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
74	July	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
75	August	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
76	September	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
77	October	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
78	November	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
79	December	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$150,976
80	13-Month Averages:									-\$150,976

3b) Project:

Devers to Colorado River

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
			Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
81	December	2017	---	---	---	---	---	---	---	---
82	January	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
83	February	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
84	March	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
85	April	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
86	May	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
87	June	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
88	July	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
89	August	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
90	September	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
91	October	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
92	November	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
93	December	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
94	January	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
95	February	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
96	March	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
97	April	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
98	May	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
99	June	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
100	July	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
101	August	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
102	September	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
103	October	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
104	November	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
105	December	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
106	13-Month Averages:									

3c) Project:

South of Kramer

Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
			107	December	2017	---	---	---	---	---
108	January	2018	\$11,515	\$864	\$12,379	\$0	\$0	\$0	\$4,897,107	\$12,379
109	February	2018	\$11,776	\$883	\$12,659	\$0	\$0	\$0	\$4,909,766	\$25,038
110	March	2018	\$11,286	\$846	\$12,132	\$0	\$0	\$0	\$4,921,898	\$37,170
111	April	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$4,941,657	\$56,929
112	May	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$4,961,415	\$76,687
113	June	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$4,981,174	\$96,446
114	July	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$5,000,932	\$116,204
115	August	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$5,020,691	\$135,963
116	September	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$5,040,449	\$155,721
117	October	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$5,060,208	\$175,480
118	November	2018	\$18,380	\$1,379	\$19,759	\$0	\$0	\$0	\$5,079,966	\$195,238
119	December	2018	\$18,383	\$1,379	\$19,762	\$0	\$0	\$0	\$5,099,728	\$215,000
120	January	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,126,603	\$241,875
121	February	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,153,478	\$268,750
122	March	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,180,353	\$295,625
123	April	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,207,228	\$322,500
124	May	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,234,103	\$349,375
125	June	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,260,978	\$376,250
126	July	2019	\$25,000	\$1,875	\$26,875	\$0	\$0	\$0	\$5,287,853	\$403,125
127	August	2019	\$125,000	\$9,375	\$134,375	\$0	\$0	\$0	\$5,422,228	\$537,500
128	September	2019	\$250,000	\$18,750	\$268,750	\$0	\$0	\$0	\$5,690,978	\$806,250
129	October	2019	\$250,000	\$18,750	\$268,750	\$0	\$0	\$0	\$5,959,728	\$1,075,000
130	November	2019	\$250,000	\$18,750	\$268,750	\$0	\$0	\$0	\$6,228,478	\$1,343,750
131	December	2019	\$545,000	\$40,875	\$585,875	\$0	\$0	\$0	\$6,814,353	\$1,929,625
132	13-Month Averages:									

3d) Project:			West of Devers							
			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
133	December	2017	---	---	---	---	---	---	\$98,805,812	---
134	January	2018	\$588,167	\$44,113	\$632,280	\$0	\$0	\$0	\$99,438,091	\$632,280
135	February	2018	\$2,503,300	\$187,748	\$2,691,048	\$0	\$0	\$0	\$102,129,139	\$3,323,327
136	March	2018	\$4,798,387	\$359,879	\$5,158,266	\$0	\$0	\$0	\$107,287,405	\$8,481,593
137	April	2018	\$5,648,177	\$423,613	\$6,071,790	\$0	\$0	\$0	\$113,359,195	\$14,553,383
138	May	2018	\$5,573,177	\$417,988	\$5,991,165	\$0	\$0	\$0	\$119,350,360	\$20,544,549
139	June	2018	\$6,499,929	\$487,495	\$6,987,424	\$2,458,051	\$2,207,009	\$18,828	\$123,860,905	\$25,055,094
140	July	2018	\$5,781,065	\$433,580	\$6,214,645	\$45,000	\$0	\$3,375	\$130,027,175	\$31,221,363
141	August	2018	\$7,660,609	\$574,546	\$8,235,155	\$45,000	\$0	\$3,375	\$138,213,955	\$39,408,143
142	September	2018	\$7,537,297	\$565,297	\$8,102,594	\$45,000	\$0	\$3,375	\$146,268,174	\$47,462,362
143	October	2018	\$18,313,481	\$1,373,511	\$19,686,992	\$75,673	\$0	\$5,675	\$165,873,818	\$67,068,006
144	November	2018	\$19,079,066	\$1,430,930	\$20,509,996	\$45,000	\$0	\$3,375	\$186,335,438	\$87,529,627
145	December	2018	\$20,045,130	\$1,503,385	\$21,548,515	\$18,456,121	\$8,497,680	\$746,883	\$188,680,949	\$89,875,137
146	January	2019	\$4,609,602	\$345,720	\$4,955,322	\$185,000	\$0	\$13,875	\$193,437,396	\$94,631,585
147	February	2019	\$5,236,167	\$392,713	\$5,628,880	\$190,000	\$0	\$14,250	\$198,862,026	\$100,056,214
148	March	2019	\$11,290,424	\$846,782	\$12,137,206	\$340,000	\$0	\$25,500	\$210,633,731	\$111,827,920
149	April	2019	\$12,835,520	\$962,664	\$13,798,184	\$340,000	\$0	\$25,500	\$224,066,415	\$125,260,604
150	May	2019	\$13,428,006	\$1,007,100	\$14,435,106	\$340,000	\$0	\$25,500	\$238,136,022	\$139,330,210
151	June	2019	\$14,204,694	\$1,065,352	\$15,270,046	\$340,000	\$0	\$25,500	\$253,040,568	\$154,234,756
152	July	2019	\$14,472,486	\$1,085,436	\$15,557,922	\$340,000	\$0	\$25,500	\$268,232,990	\$169,427,179
153	August	2019	\$14,642,486	\$1,098,186	\$15,740,672	\$340,000	\$0	\$25,500	\$283,608,163	\$184,802,351
154	September	2019	\$15,213,790	\$1,141,034	\$16,354,824	\$340,000	\$0	\$25,500	\$299,597,487	\$200,791,675
155	October	2019	\$18,580,671	\$1,393,550	\$19,974,221	\$5,706,367	\$3,174,605	\$189,882	\$313,675,460	\$214,869,648
156	November	2019	\$13,761,026	\$1,032,077	\$14,793,103	\$290,000	\$0	\$21,750	\$328,156,813	\$229,351,001
157	December	2019	\$14,863,709	\$1,114,778	\$15,978,487	\$290,000	\$0	\$21,750	\$343,823,550	\$245,017,738
158	13-Month Averages:									\$158,421,232

3e) Project:			Red Bluff							
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
159	December	2017	---	---	---	---	---	---	\$0	---
160	January	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
161	February	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
162	March	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
163	April	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
164	May	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
165	June	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
166	July	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
167	August	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
168	September	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
169	October	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
170	November	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
171	December	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
172	January	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
173	February	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
174	March	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
175	April	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
176	May	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
177	June	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
178	July	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
179	August	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
180	September	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
181	October	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
182	November	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
183	December	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
184	13-Month Averages:									\$0

3f) Project: Whirlwind Substation Expansion

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	
			Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP	
185	December	2017	---	---	---	---	---	---	---	---	
			= C1 * 16-Plnt Add Line 74		= C1 + C2		= (C4 - C5) * 16-Plnt Add Line 74		= Prior Month C7 + C3 - C4 - C6		= C7 - Dec Prior Year C7
186	January	2018	\$10,309	\$773	\$11,082	\$10,309	\$0	\$773	\$0	\$0	
187	February	2018	\$6,204	\$465	\$6,669	\$6,204	\$0	\$465	\$0	\$0	
188	March	2018	\$6,687	\$502	\$7,189	\$6,687	\$0	\$502	\$0	\$0	
189	April	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
190	May	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
191	June	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
192	July	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
193	August	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
194	September	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
195	October	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
196	November	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
197	December	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
198	January	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
199	February	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
200	March	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
201	April	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
202	May	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
203	June	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
204	July	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
205	August	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
206	September	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
207	October	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
208	November	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
209	December	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
210	13-Month Averages:									\$0	

3g) Project: Colorado River Substation Expansion

Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
			211	December	2017	---	---	---	---	---
212	January	2018	\$728	\$55	\$783	\$728	\$0	\$55	\$0	\$0
213	February	2018	\$1,158	\$87	\$1,245	\$1,158	\$0	\$87	\$0	\$0
214	March	2018	\$780	\$59	\$839	\$780	\$0	\$59	\$0	\$0
215	April	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
216	May	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
217	June	2018	\$334	\$25	\$359	\$334	\$0	\$25	\$0	\$0
218	July	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
219	August	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
220	September	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
221	October	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
222	November	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
223	December	2018	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
224	January	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
225	February	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
226	March	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
227	April	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
228	May	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
229	June	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
230	July	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
231	August	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
232	September	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
233	October	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
234	November	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
235	December	2019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
236	13-Month Averages:									\$0

3h) Project:			Mesa							
Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2	Unloaded Total Plant Adds	Prior Period CWIP Closed	= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
			Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
237	December	2017	---	---	---	---	---	---	\$46,788,116	---
238	January	2018	\$6,150,625	\$461,297	\$6,611,922	\$4,835,162	\$4,098,417	\$55,256	\$48,509,620	\$1,721,504
239	February	2018	\$6,764,842	\$507,363	\$7,272,205	\$716,614	\$0	\$53,746	\$55,011,464	\$8,223,348
240	March	2018	\$6,728,747	\$504,656	\$7,233,403	\$428,365	\$0	\$32,127	\$61,784,375	\$14,996,259
241	April	2018	\$2,637,958	\$197,847	\$2,835,805	\$36,000	\$0	\$2,700	\$64,581,480	\$17,793,364
242	May	2018	\$7,602,991	\$570,224	\$8,173,216	\$0	\$0	\$0	\$72,754,696	\$25,966,580
243	June	2018	\$9,514,013	\$713,551	\$10,227,564	\$0	\$0	\$0	\$82,982,260	\$36,194,144
244	July	2018	\$4,760,538	\$357,040	\$5,117,579	\$0	\$0	\$0	\$88,099,839	\$41,311,723
245	August	2018	\$7,813,915	\$586,044	\$8,399,959	\$0	\$0	\$0	\$96,499,797	\$49,711,681
246	September	2018	\$4,860,922	\$364,569	\$5,225,491	\$0	\$0	\$0	\$101,725,289	\$54,937,173
247	October	2018	\$5,232,286	\$392,421	\$5,624,708	\$0	\$0	\$0	\$107,349,996	\$60,561,880
248	November	2018	\$3,062,453	\$229,684	\$3,292,137	\$0	\$0	\$0	\$110,642,133	\$63,854,017
249	December	2018	\$4,668,878	\$350,166	\$5,019,044	\$23,755	\$0	\$1,782	\$115,635,641	\$68,847,525
250	January	2019	\$5,133,736	\$385,030	\$5,518,766	\$0	\$0	\$0	\$121,154,407	\$74,366,291
251	February	2019	\$11,785,380	\$883,903	\$12,669,283	\$0	\$0	\$0	\$133,823,690	\$87,035,574
252	March	2019	\$7,424,715	\$556,854	\$7,981,568	\$0	\$0	\$0	\$141,805,258	\$95,017,142
253	April	2019	\$4,022,697	\$301,702	\$4,324,399	\$0	\$0	\$0	\$146,129,657	\$99,341,541
254	May	2019	\$3,957,356	\$296,802	\$4,254,158	\$0	\$0	\$0	\$150,383,815	\$103,595,699
255	June	2019	\$4,386,911	\$329,018	\$4,715,929	\$0	\$0	\$0	\$155,099,744	\$108,311,628
256	July	2019	\$5,763,632	\$432,272	\$6,195,905	\$0	\$0	\$0	\$161,295,649	\$114,507,533
257	August	2019	\$6,352,933	\$476,470	\$6,829,403	\$0	\$0	\$0	\$168,125,052	\$121,336,936
258	September	2019	\$8,352,169	\$626,413	\$8,978,581	\$0	\$0	\$0	\$177,103,633	\$130,315,517
259	October	2019	\$3,995,870	\$299,690	\$4,295,560	\$0	\$0	\$0	\$181,399,193	\$134,611,077
260	November	2019	\$14,262,524	\$1,069,689	\$15,332,214	\$0	\$0	\$0	\$196,731,407	\$149,943,291
261	December	2019	\$9,312,568	\$698,443	\$10,011,010	\$4,179,168	\$2,531,642	\$123,564	\$202,439,684	\$155,651,568
262	13-Month Averages:									\$110,990,871

3i) Project:			Alberhill							
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
263	December	2017	---	---	---	---	---	---	\$0	---
264	January	2018	\$15,725	\$1,179	\$16,904	\$0	\$0	\$0	\$16,904	\$16,904
265	February	2018	\$39,608	\$2,971	\$42,579	\$0	\$0	\$0	\$59,483	\$59,483
266	March	2018	\$43,160	\$3,237	\$46,397	\$0	\$0	\$0	\$105,880	\$105,880
267	April	2018	\$116,635	\$8,748	\$125,383	\$0	\$0	\$0	\$231,262	\$231,262
268	May	2018	\$89,340	\$6,700	\$96,040	\$0	\$0	\$0	\$327,303	\$327,303
269	June	2018	\$86,306	\$6,473	\$92,779	\$89,672	\$89,573	\$7	\$330,403	\$330,403
270	July	2018	\$126,591	\$9,494	\$136,085	\$0	\$0	\$0	\$466,488	\$466,488
271	August	2018	\$170,144	\$12,761	\$182,905	\$0	\$0	\$0	\$649,393	\$649,393
272	September	2018	\$147,617	\$11,071	\$158,688	\$0	\$0	\$0	\$808,081	\$808,081
273	October	2018	\$98,843	\$7,413	\$106,256	\$0	\$0	\$0	\$914,337	\$914,337
274	November	2018	\$315,182	\$23,639	\$338,821	\$0	\$0	\$0	\$1,253,157	\$1,253,157
275	December	2018	\$63,376	\$4,753	\$68,129	\$0	\$0	\$0	\$1,321,286	\$1,321,286
276	January	2019	\$273,333	\$20,500	\$293,833	\$0	\$0	\$0	\$1,615,119	\$1,615,119
277	February	2019	\$108,141	\$8,111	\$116,252	\$12,783	\$0	\$959	\$1,717,630	\$1,717,630
278	March	2019	\$189,544	\$14,216	\$203,760	\$19,174	\$0	\$1,438	\$1,900,777	\$1,900,777
279	April	2019	\$243,017	\$18,226	\$261,243	\$31,956	\$0	\$2,397	\$2,127,667	\$2,127,667
280	May	2019	\$323,230	\$24,242	\$347,472	\$51,131	\$0	\$3,835	\$2,420,174	\$2,420,174
281	June	2019	\$376,704	\$28,253	\$404,957	\$63,913	\$0	\$4,793	\$2,756,424	\$2,756,424
282	July	2019	\$456,915	\$34,269	\$491,183	\$83,087	\$0	\$6,232	\$3,158,289	\$3,158,289
283	August	2019	\$483,650	\$36,274	\$519,924	\$89,478	\$0	\$6,711	\$3,582,024	\$3,582,024
284	September	2019	\$483,650	\$36,274	\$519,924	\$89,478	\$0	\$6,711	\$4,005,759	\$4,005,759
285	October	2019	\$483,652	\$36,274	\$519,926	\$89,478	\$0	\$6,711	\$4,429,495	\$4,429,495
286	November	2019	\$320,845	\$24,063	\$344,908	\$76,696	\$0	\$5,752	\$4,691,956	\$4,691,956
287	December	2019	\$4,917,683	\$368,826	\$5,286,510	\$31,956	\$0	\$2,397	\$9,944,112	\$9,944,112
288	13-Month Averages:									\$3,359,286

3j) Project:			ELM Series Capacitors								
			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	
			= C1 * 16-Plnt Add Line 74		C1 + C2	Unloaded Total Plant Adds		= (C4 - C5) * 16-Plnt Add Line 74		= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP	
289	December	2017	---	---	---	---	---	---	\$0	---	
290	January	2018	\$2,147,654	\$161,074	\$2,308,728	\$0	\$0	\$0	\$2,308,728	\$2,308,728	
291	February	2018	\$218,055	\$16,354	\$234,409	\$0	\$0	\$0	\$2,543,137	\$2,543,137	
292	March	2018	\$9,974,740	\$748,106	\$10,722,846	\$0	\$0	\$0	\$13,265,983	\$13,265,983	
293	April	2018	\$853,930	\$64,045	\$917,975	\$0	\$0	\$0	\$14,183,958	\$14,183,958	
294	May	2018	\$882,930	\$66,220	\$949,150	\$0	\$0	\$0	\$15,133,108	\$15,133,108	
295	June	2018	\$895,930	\$67,195	\$963,125	\$0	\$0	\$0	\$16,096,232	\$16,096,232	
296	July	2018	\$880,860	\$66,065	\$946,925	\$0	\$0	\$0	\$17,043,157	\$17,043,157	
297	August	2018	\$882,860	\$66,215	\$949,075	\$0	\$0	\$0	\$17,992,231	\$17,992,231	
298	September	2018	\$945,860	\$70,940	\$1,016,800	\$0	\$0	\$0	\$19,009,031	\$19,009,031	
299	October	2018	\$598,790	\$44,909	\$643,699	\$0	\$0	\$0	\$19,652,730	\$19,652,730	
300	November	2018	\$304,720	\$22,854	\$327,574	\$0	\$0	\$0	\$19,980,304	\$19,980,304	
301	December	2018	\$846,161	\$63,462	\$909,623	\$36,717	\$15,958	\$1,557	\$20,851,653	\$20,851,653	
302	January	2019	\$467,930	\$35,095	\$503,025	\$930	\$0	\$70	\$21,353,678	\$21,353,678	
303	February	2019	\$1,274,860	\$95,615	\$1,370,475	\$1,860	\$0	\$140	\$22,722,153	\$22,722,153	
304	March	2019	\$1,280,860	\$96,065	\$1,376,925	\$1,860	\$0	\$140	\$24,097,078	\$24,097,078	
305	April	2019	\$1,268,860	\$95,165	\$1,364,025	\$1,860	\$0	\$140	\$25,459,103	\$25,459,103	
306	May	2019	\$1,337,300	\$100,298	\$1,437,598	\$9,300	\$0	\$698	\$26,886,703	\$26,886,703	
307	June	2019	\$15,335,150	\$1,150,136	\$16,485,286	\$9,300	\$0	\$698	\$43,361,992	\$43,361,992	
308	July	2019	\$698,300	\$52,373	\$750,673	\$9,300	\$0	\$698	\$44,102,667	\$44,102,667	
309	August	2019	\$694,300	\$47,573	\$741,873	\$13,998,456	\$8,470,083	\$414,628	\$30,371,455	\$30,371,455	
310	September	2019	\$475,600	\$35,670	\$511,270	\$23,600	\$0	\$1,770	\$30,857,355	\$30,857,355	
311	October	2019	\$15,244,900	\$1,143,368	\$16,388,268	\$14,191,373	\$6,167,259	\$601,809	\$32,452,441	\$32,452,441	
312	November	2019	\$4,581,991	\$343,649	\$4,925,640	\$16,164,858	\$6,140,181	\$751,851	\$20,461,372	\$20,461,372	
313	December	2019	\$4,343,830	\$325,787	\$4,669,617	\$1,285,160	\$0	\$96,387	\$23,749,443	\$23,749,443	
314	13-Month Averages:									\$28,209,776	

3k) Project:			add additional projects below this line (See Instruction 3)								
			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	
			= C1 * 16-Plnt Add Line 74		C1 + C2	Unloaded Total Plant Adds		= (C4 - C5) * 16-Plnt Add Line 74		= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP	
315	December	2017	---	---	---	---	---	---	\$0	---	
316	January	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
317	February	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
318	March	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
319	April	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
320	May	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
321	June	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
322	July	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
323	August	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
324	September	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
325	October	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
326	November	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
327	December	2018	---	\$0	\$0	---	---	\$0	\$0	\$0	
328	January	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
329	February	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
330	March	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
331	April	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
332	May	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
333	June	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
334	July	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
335	August	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
336	September	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	
337	October	2019	---	\$0	\$0	---	---	\$0	\$0	\$0	

Schedule 10
CWIP

338	November	2019	\$0	\$0	\$0	\$0	\$0
339	December	2019	\$0	\$0	\$0	\$0	<u>\$0</u>
340	13-Month Averages:						\$0

Notes:

- 1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).
- 2) Sum of project specific values from lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,...

Instructions:

- 1) Enter recorded amounts of CWIP during Prior Year on Lines 1-13, 15-27 (including December of year previous to Prior Year).
- 2) Enter forecast project specific values on lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,...
- 3) If Commission approval is granted to include CWIP in Rate Base for additional projects, include additional tables for each of those additional projects.

TRANSMISSION PLANT HELD FOR FUTURE USE

Inputs are shaded yellow

Transmission Plant Held for Future Use shall be amounts of Electric Plant Held for Future Use (account 105) intended to be placed under the Operational Control of the ISO, plus an allocated amount of any General Electric Plant Held for Future Use, with the allocation factor being the Transmission Wages and Salaries AF.

<u>Line</u>		<u>Beginning of Year Balance</u>	<u>End of Year Balance</u>	<u>Source</u>
1	Total Electric PHFU	\$16,261,841	\$15,781,292	FF1 page 214.47d

Plant intended to be placed under the Operational Control of the ISO:

	<u>Col 1</u>	<u>Col 2</u> Type	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>
	<u>Description</u>	<u>of Plant</u>	<u>Beginning of Year Balance</u>	<u>End of Year Balance</u>	<u>Source</u>
2a	Alberhill	Sub	\$9,942,155	\$9,942,155	SCE records
2b					
2c					
2d					
2e					
2f					
2g					
2h					
...					
3	Total:		\$9,942,155	\$9,942,155	Sum of above lines

		<u>Beginning of Year Balance</u>	<u>End of Year Balance</u>	<u>Source</u>
4	General Plant Held for Future Use	\$0	\$0	FF1 page 214
5	Wages and Salaries AF:	5.629%	5.629%	27-Allocators, L 9
6	Portion for Transmission PHFU:	\$0	\$0	L 4 * L 5

All other Electric Plant Held for Future Use not intended to be placed under the Operational Control of the ISO:

		<u>Beginning of Year Balance</u>	<u>End of Year Balance</u>	<u>Source</u>
7		\$6,319,686	\$5,839,137	Note 1
8	Transmission PHFU:	\$9,942,155	\$9,942,155	L 3 + L 6
9	Average of BOY and EOY Transmission PHFU:	\$9,942,155		Sum of Line 8 / 2

Calculation of Gain or Loss on Transmission Plant Held for Future Use -- Land

			<u>Source</u>
10	Gain or Loss on Transmission Plant Held for Future Use --- Land	\$0	SCE Records

Instructions:

- 1) For any Electric Plant Held for Future Use intended to be placed under the Operational Control of the ISO, list on lines 2a, 2b, etc. Provide description in Column 1. Note type of plant (land or other) in Column 2. Under "Source" (Column 5), state the line number on FERC Form 1 page 214 from which the amount is derived. BOY amount will be EOY value from previous year FERC Form 1, EOY amount will be in current year FF1.
- 2) For any Electric Plant Held for Future Use classified as General note amount on Line 4.
- 3) Add additional lines 2 i, j, k, etc. as necessary to include additional projects intended to be placed under the Operational Control of the ISO.
- 4) Gains and Losses on Transmission Plant Held for Future Use - Land is treated in accordance with Commission policy. Any gain or loss on non-land portions of Transmission Plant Held for Future Use is not included.

Notes:

- 1) Amount of Line 1 not intended to be placed under the Operational Control of the ISO.

Determination of amount of Abandoned Plant and Abandoned Plant Amortization Expense

Input data is shaded yellow

Initially Abandoned Plant Amortization Expense and Abandoned Plant are both zero.

Upon Commission approval of recovery of abandoned plant costs for a specific project or projects, SCE will complete this worksheet in accordance with that Order.

Orders Providing for Abandoned Plant Cost Recovery:	Project	Commission Order

Abandoned Plant for each project represents the amount of costs that the Order approves for inclusion in Rate Base.

Abandoned Plant Amortization Expense for each project represents the annual amortization of abandoned costs that the Order approves as an annual expense.

Line		Amount for Prior Year	Note:
1	Abandoned Plant Amortization Expense:	\$0	Sum of projects below for PY.
2	Abandoned Plant (BOY):	\$0	Sum of projects below for PY.
3	Abandoned Plant (EOY):	\$0	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	\$0	Average of Lines 2 and 3.

5 First Project: **Fill in Name** 2nd Project: **Fill in Name**

Year	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense
6						
7						
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Notes:

1) "EOY HV Abandoned Plant" is amount of "EOY Abandoned Plant" that would have been High Voltage (>= 200 kV).

Instructions:

- 1) Upon Commission approval of recovery of abandoned plant costs for a project:
 - a) Fill in the name the project in order (First Project, Second Project, etc.).
 - b) Fill in the table with annual End of Year ("EOY") Abandoned Plant, EOY HV Abandoned Plant, and Abandoned Plant Amortization Expense amounts in Accordance with the Order.
If table can not be filled out completely, fill out at least through the Prior Year at issue.
 - c) Sum project-specific amounts for each project and enter in lines 1, 2, and 3 for the Prior Year at issue.
(BOY value is EOY value from previous year)
- 2) Add additional projects if necessary in same format.
- 3) Add additional years past 2035 if necessary.

Calculation of Components of Working Capital

Inputs are shaded yellow

1) Calculation of Materials and Supplies

Materials and Supplies is the amount of total Account 154 Materials and Supplies times the Transmission Wages and Salaries AF

Line	Month	Year	Data Source	Total Materials and Supplies Balances	Notes
1	December	2016	FF1 227.12b	\$237,798,844	Beginning of year ("BOY") amount
2	January	2017	SCE Records	\$236,701,406	
3	February	2017	SCE Records	\$235,215,054	
4	March	2017	SCE Records	\$234,227,486	
5	April	2017	SCE Records	\$229,290,189	
6	May	2017	SCE Records	\$227,387,009	
7	June	2017	SCE Records	\$229,834,302	
8	July	2017	SCE Records	\$231,240,887	
9	August	2017	SCE Records	\$229,531,353	
10	September	2017	SCE Records	\$226,308,483	
11	October	2017	SCE Records	\$229,185,237	
12	November	2017	SCE Records	\$230,757,406	
13	December	2017	FF1 227.12c	\$238,006,741	
14	13-Month Average Value Account 154:			\$231,960,338	(Sum Line 1 to Line 13) / 13
15	Transmission Wages and Salaries AF:			5.629%	
16	Materials and Supplies EOY Value:			\$13,397,450	Line 13 * Line 15
17	13-Month Average Value:			\$13,057,097	Line 14 * Line 15

2) Calculation of Prepayments

Prepayments is an allocated portion of Total Prepayments based on the Transmission Wages and Salaries Allocation Factor.

	Month	Year	Data Source	Total Prepayments Balances	Notes	
18	December	2016	Note 1, c	\$99,369,073	See Note 1, c	
19	January	2017	SCE Records	\$120,656,391		
20	February	2017	SCE Records	\$110,804,401		
21	March	2017	SCE Records	\$169,364,348		
22	April	2017	SCE Records	\$230,958,817		
23	May	2017	SCE Records	\$190,396,526		
24	June	2017	SCE Records	\$135,529,209		
25	July	2017	SCE Records	\$144,680,436		
26	August	2017	SCE Records	\$136,252,209		
27	September	2017	SCE Records	\$306,743,337		
28	October	2017	SCE Records	\$290,763,947		
29	November	2017	SCE Records	\$295,532,251		
30	December	2017	Note 1, f	\$227,852,643		See Note 1, f
a) 13-Month Average Calculation						
31	13-Month Average Value:			\$189,146,429.82	(Sum Line 18 to Line 30) / 13	
32	Transmission Wages and Salaries AF:			5.6290%		27-Allocators, Line 9
33	Prepayments:			\$10,647,093		Line 31 * Line 32
b) EOY calculation						
34	EOY Value:			\$227,852,643	Line 30	
35	Transmission Wages and Salaries AF:			5.6290%	27-Allocators, Line 9	
36	Prepayments:			\$12,825,874	Line 34 * Line 35	

Notes:

1) Remove any amounts related to years prior to the effective date of the formula on b and e below.

Beginning of Year Amount		Prepayments Balances	Source
a	FERC Form 1 Acct. 165 Recorded Amount:	\$114,171,737	FF1 111.57d
b	Prior Period Adjustment:	\$14,802,664	Note 1
c	BOY Prepayments Amount:	\$99,369,073	a - b
End of Year Amount		Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	\$227,852,643	FF1 111.57c
e	Prior Period Adjustment:	\$0	Note 1
f	EOY Prepayments Amount:	\$227,852,643	d - e

Plant Balances For Incentive Projects Receiving either ROE Incentives ("Transmission Incentive Plant") or CWIP ("CWIP Plant")

Input data is shaded yellow

A) Summary of Incentive Project plant balances receiving ROE incentives ("Transmission Incentive Plant") and/or CWIP ("CWIP Plant") and calculation of balances needed to determine the following:

- 1) Rate Base in Prior Year
- 2) Prior Year Incentive Rate Base - End of Year
- 3) Prior Year Incentive Rate Base - 13-Month Average

Transmission Incentive Project plant balances and CWIP Plant may affect the following:

- a) CWIP Plant during the Prior Year is included in Rate Base (used in Prior Year TRR and True Up TRR).
- b) Forecast Period Incremental CWIP contributes to Incremental Forecast Period TRR
- c) CWIP Plant receiving an ROE adder contributes to Prior Year Incentive Rate Base - EOY, or Prior Year Incentive Rate Base - 13 Month Average as appropriate.
- d) "TIP Net Plant In Service" at EOY Prior Year is used to calculate the PY Incentive Rate Base (on EOY basis).
- e) "TIP Net Plant In Service" in PY is used to calculate the Prior Year Incentive Rate Base (on 13-month average basis).

1) Summary of CWIP Plant in Prior Year and Forecast Period

Line	Incentive Project	Col 1	Col 2	Col 3	Notes:
		Prior Year End-of-Year CWIP Plant Amount	Prior Year 13-Month Average CWIP Plant Amount	Forecast Period Incremental CWIP 13-Month Avg. Amount	
1	1) Tehachapi	\$150,976	\$5,894,762	-\$150,976	10-CWIP Lines 13, 14, and 80
2	2) Devers-Colorado River	\$0	\$0	\$0	10-CWIP Lines 13, 14, and 106
3	3) South of Kramer	\$4,884,728	\$4,594,011	\$628,048	10-CWIP Lines 13, 14, and 132
4	4) West of Devers	\$98,805,812	\$80,157,512	\$158,421,232	10-CWIP Lines 13, 14, and 158
5	5) Red Bluff	\$0	\$0	\$0	10-CWIP Lines 13, 14, and 184
6	6) Whirlwind Substation Exp.	\$0	\$9,253,542	\$0	10-CWIP Lines 27, 28, and 210
7	7) Colorado River Sub. Exp.	\$0	\$0	\$0	10-CWIP Lines 27, 28, and 236
8	8) Mesa	\$46,788,116	\$6,541,655	\$110,990,871	10-CWIP Lines 27, 28, and 262
9	9) Alberhill	\$0	\$0	\$3,359,286	10-CWIP Lines 27, 28, and 288
10	10) ELM Series Caps	\$0	\$0	\$28,209,776	10-CWIP Lines 27, 28, and 314
11	...	---	---	---	...
12					
13	Totals:	\$150,629,632	\$106,441,483	\$301,458,237	

2) Summary of Prior Year Incentive Rate Base amounts (EOY Values)

Line	Incentive Project	Col 1	Col 2	Col 3	Notes:
		= C2 + C3 Prior Year Incentive Rate Base	EOY CWIP Portion	EOY TIP Net Plant In Service	
14	1) Rancho Vista	\$150,232,043	\$0	\$150,232,043	Line 38, C4
15	2) Tehachapi	\$2,728,701,253	\$150,976	\$2,728,550,276	Line 1, C1, and Line 38, C2
16	3) Devers-Colorado River	\$687,752,340	\$0	\$687,752,340	Line 2, C1, and Line 38, C3
17	...	---	---	---	...
18					
19	Total PY Incentive Net Plant:	\$3,566,685,636			End of Year

3) Summary of Prior Year Incentive Rate Base amounts (13-Month Average values)

Line	Incentive Project	Col 1	Col 2	Col 3	Notes:
		= C2 + C3 Prior Year Incentive Rate Base	13-Month Avg. CWIP Portion	13-Month Avg. TIP Net Plant In Service Portion	
20	1) Rancho Vista	\$152,604,254	\$0	\$152,604,254	Line 39, C4
21	2) Tehachapi	\$2,756,592,235	\$5,894,762	\$2,750,697,473	Line 1, C2, and Line 39, C2
22	3) Devers-Colorado R	\$697,660,501	\$0	\$697,660,501	Line 2, C2, and Line 39, C3
23	...	---	---	---	...
24					
25	Total PY Incentive Net Plant:	\$3,606,856,990			13 Month Average

4) Prior Year TIP Net Plant In Service

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	
		Total TIP	L 54 to L 66, C3	L 80 to L 92, C3	L 67 to L 79, C3		
Prior Year	Month	Net Plant		Devers to	Rancho		
	Year	In Service	Tehachapi	Colorado River	Vista		Notes
26	December	2017	\$3,623,644,583	\$2,761,096,354	\$707,569,233	\$154,978,996	---
27	January	2018	\$3,615,880,495	\$2,755,369,096	\$705,927,339	\$154,584,059	---
28	February	2018	\$3,614,032,508	\$2,755,580,398	\$704,262,987	\$154,189,123	---
29	March	2018	\$3,610,703,590	\$2,754,293,881	\$702,621,120	\$153,788,590	---
30	April	2018	\$3,603,732,187	\$2,749,366,950	\$700,971,573	\$153,393,664	---
31	May	2018	\$3,617,080,147	\$2,764,751,667	\$699,329,740	\$152,998,739	---
32	June	2018	\$3,611,530,160	\$2,761,235,317	\$697,691,029	\$152,603,814	---
33	July	2018	\$3,604,314,877	\$2,756,061,325	\$696,044,662	\$152,208,889	---
34	August	2018	\$3,597,373,681	\$2,751,250,377	\$694,311,578	\$151,811,726	---
35	September	2018	\$3,590,313,710	\$2,746,221,604	\$692,675,301	\$151,416,805	---
36	October	2018	\$3,584,010,799	\$2,741,953,296	\$691,035,618	\$151,021,884	---
37	November	2018	\$3,573,357,571	\$2,733,336,611	\$689,393,997	\$150,626,964	---
38	December	2018	\$3,566,534,659	\$2,728,550,276	\$687,752,340	\$150,232,043	---
39	13 Month Averages:		\$3,600,962,228	\$2,750,697,473	\$697,660,501	\$152,604,254	

5) Total Transmission Activity for Incentive Projects

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	
		Total Transmission	Account	= C1 - C2	Source
Prior Year	Month	Activity for	360-362	Account 350-359	
	Year	Incentive	Activity	Activity for	
		Projects		Incentive	
				Projects	
40	December	2017	\$0	\$0	C1: Sum of below projects for each month
41	January	2018	\$637,077	\$0	
42	February	2018	\$6,682,963	\$0	
43	March	2018	\$5,178,669	\$0	
44	April	2018	\$34,083,658	\$0	
45	May	2018	\$21,945,099	\$0	
46	June	2018	\$2,931,169	\$0	
47	July	2018	\$1,250,328	\$0	
48	August	2018	\$1,528,249	\$0	
49	September	2018	\$1,390,223	\$0	
50	October	2018	\$2,916,673	\$0	
51	November	2018	-\$517,602	\$0	
52	December	2018	\$1,650,013	\$0	
53	Total		\$79,676,521	\$0	

6) Calculation of Prior Year Net Plant in Service amounts for each Incentive Project

a) Tehachapi

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
		Plant	Accumulated	= C1 - C2	= C1 - Previous	
Prior Year	Month	In-Service	Depreciation	Net Plant	Month C1	
	Year			In Service	Transmission	
					Activity	
54	December	2017	\$2,998,641,930	\$237,545,576	\$2,761,096,354	\$0
55	January	2018	\$2,999,220,787	\$243,851,690	\$2,755,369,096	\$578,857
56	February	2018	\$3,005,739,539	\$250,159,141	\$2,755,580,398	\$6,518,753
57	March	2018	\$3,010,773,105	\$256,479,225	\$2,754,293,881	\$5,033,566
58	April	2018	\$3,012,180,175	\$262,813,225	\$2,749,366,950	\$1,407,069
59	May	2018	\$3,033,901,664	\$269,149,997	\$2,764,751,667	\$21,721,489
60	June	2018	\$3,036,761,062	\$275,525,745	\$2,761,235,317	\$2,859,397
61	July	2018	\$3,037,969,275	\$281,907,950	\$2,756,061,325	\$1,208,213
62	August	2018	\$3,039,542,946	\$288,292,570	\$2,751,250,377	\$1,573,672
63	September	2018	\$3,040,901,421	\$294,679,817	\$2,746,221,604	\$1,358,475
64	October	2018	\$3,043,025,002	\$301,071,706	\$2,741,953,296	\$2,123,581
65	November	2018	\$3,040,804,627	\$307,468,016	\$2,733,336,611	-\$2,220,375
66	December	2018	\$3,042,408,308	\$313,858,031	\$2,728,550,276	\$1,603,681

b) Rancho Vista

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
				= C1 - C2	= C1 - Previous Month C1	
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>	
67	December	2017	\$191,508,708	\$36,529,712	\$154,978,996	\$0
68	January	2018	\$191,508,708	\$36,924,649	\$154,584,059	\$0
69	February	2018	\$191,508,708	\$37,319,585	\$154,189,123	\$0
70	March	2018	\$191,503,112	\$37,714,522	\$153,788,590	-\$5,596
71	April	2018	\$191,503,112	\$38,109,447	\$153,393,664	\$0
72	May	2018	\$191,503,112	\$38,504,373	\$152,998,739	\$0
73	June	2018	\$191,503,112	\$38,899,298	\$152,603,814	\$0
74	July	2018	\$191,503,112	\$39,294,223	\$152,208,889	\$0
75	August	2018	\$191,500,874	\$39,689,148	\$151,811,726	-\$2,238
76	September	2018	\$191,500,874	\$40,084,069	\$151,416,805	\$0
77	October	2018	\$191,500,874	\$40,478,989	\$151,021,884	\$0
78	November	2018	\$191,500,874	\$40,873,910	\$150,626,964	\$0
79	December	2018	\$191,500,874	\$41,268,831	\$150,232,043	\$0

c) Devers to Colorado River

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
				= C1 - C2	= C1 - Previous Month C1	
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>	
80	December	2017	\$773,686,037	\$66,116,803	\$707,569,233	\$0
81	January	2018	\$773,686,037	\$67,758,698	\$705,927,339	\$0
82	February	2018	\$773,663,579	\$69,400,592	\$704,262,987	-\$22,458
83	March	2018	\$773,663,560	\$71,042,441	\$702,621,120	-\$19
84	April	2018	\$773,655,861	\$72,684,289	\$700,971,573	-\$7,699
85	May	2018	\$773,655,861	\$74,326,121	\$699,329,740	\$0
86	June	2018	\$773,658,982	\$75,967,954	\$697,691,029	\$3,121
87	July	2018	\$773,654,455	\$77,609,792	\$696,044,662	-\$4,528
88	August	2018	\$773,563,195	\$79,251,617	\$694,311,578	-\$91,259
89	September	2018	\$773,568,549	\$80,893,248	\$692,675,301	\$5,354
90	October	2018	\$773,570,518	\$82,534,900	\$691,035,618	\$1,969
91	November	2018	\$773,570,554	\$84,176,557	\$689,393,997	\$35
92	December	2018	\$773,570,554	\$85,818,214	\$687,752,340	\$0

d) South of Kramer

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
				= C1 - C2	= C1 - Previous Month C1	
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>	
93	December	2017	\$0	\$0	\$0	\$0
94	January	2018	\$0	\$0	\$0	\$0
95	February	2018	\$0	\$0	\$0	\$0
96	March	2018	\$0	\$0	\$0	\$0
97	April	2018	\$0	\$0	\$0	\$0
98	May	2018	\$0	\$0	\$0	\$0
99	June	2018	\$0	\$0	\$0	\$0
100	July	2018	\$0	\$0	\$0	\$0
101	August	2018	\$0	\$0	\$0	\$0
102	September	2018	\$0	\$0	\$0	\$0
103	October	2018	\$0	\$0	\$0	\$0
104	November	2018	\$0	\$0	\$0	\$0
105	December	2018	\$0	\$0	\$0	\$0

e) West of Devers

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>
				= C1 - C2	= C1 - Previous Month C1
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>
106	December	2017	\$0	\$0	\$0
107	January	2018	\$0	\$0	\$0
108	February	2018	\$0	\$0	\$0
109	March	2018	\$0	\$0	\$0
110	April	2018	\$0	\$0	\$0
111	May	2018	\$0	\$0	\$0
112	June	2018	\$0	\$0	\$0
113	July	2018	\$0	\$0	\$0
114	August	2018	\$0	\$0	\$0
115	September	2018	\$0	\$0	\$0
116	October	2018	\$0	\$0	\$0
117	November	2018	\$0	\$0	\$0
118	December	2018	\$0	\$0	\$0

f) Red Bluff

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
				= C1 - C2	= C1 - Previous Month C1	
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>	
119	December	2017	\$235,590,583	\$19,587,100	\$216,003,483	\$0
120	January	2018	\$235,590,583	\$20,083,716	\$215,506,867	\$0
121	February	2018	\$235,596,527	\$20,580,331	\$215,016,196	\$5,944
122	March	2018	\$235,599,878	\$21,076,959	\$214,522,919	\$3,351
123	April	2018	\$235,602,997	\$21,573,594	\$214,029,403	\$3,119
124	May	2018	\$235,602,997	\$22,070,236	\$213,532,761	\$0
125	June	2018	\$235,604,618	\$22,566,878	\$213,037,740	\$1,621
126	July	2018	\$235,604,618	\$23,063,524	\$212,541,094	\$0
127	August	2018	\$235,604,618	\$23,560,169	\$212,044,449	\$0
128	September	2018	\$235,604,618	\$24,056,814	\$211,547,803	\$0
129	October	2018	\$235,604,618	\$24,553,460	\$211,051,158	\$0
130	November	2018	\$235,653,735	\$25,050,105	\$210,603,630	\$49,118
131	December	2018	\$235,653,723	\$25,546,854	\$210,106,869	-\$12

g) Whirlwind Substation Expansion

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	
				= C1 - C2	= C1 - Previous Month C1	
<u>Prior Year Month</u>	<u>Year</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>	
132	December	2017	\$53,627,431	\$3,026,415	\$50,601,016	\$0
133	January	2018	\$53,627,431	\$3,136,881	\$50,490,550	\$0
134	February	2018	\$53,627,431	\$3,247,348	\$50,380,084	\$0
135	March	2018	\$53,627,431	\$3,357,814	\$50,269,617	\$0
136	April	2018	\$86,255,712	\$3,468,280	\$82,787,432	\$32,628,281
137	May	2018	\$86,423,087	\$3,645,924	\$82,777,163	\$167,374
138	June	2018	\$86,465,217	\$3,823,912	\$82,641,305	\$42,131
139	July	2018	\$86,496,127	\$4,001,987	\$82,494,140	\$30,910
140	August	2018	\$86,531,254	\$4,180,126	\$82,351,128	\$35,127
141	September	2018	\$86,558,720	\$4,358,336	\$82,200,383	\$27,466
142	October	2018	\$87,524,371	\$4,536,604	\$82,987,767	\$965,651
143	November	2018	\$87,519,888	\$4,716,859	\$82,803,029	-\$4,483
144	December	2018	\$87,531,655	\$4,897,105	\$82,634,551	\$11,767

h) Colorado River Substation Expansion

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>
	<u>Prior Year Month</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>
	<u>Year</u>			= C1 - C2	= C1 - Previous Month C1
145	December	2017 \$71,091,079	\$5,992,602	\$65,098,477	\$0
146	January	2018 \$71,149,299	\$6,139,912	\$65,009,388	\$58,220
147	February	2018 \$71,330,024	\$6,287,341	\$65,042,683	\$180,724
148	March	2018 \$71,477,391	\$6,435,142	\$65,042,249	\$147,367
149	April	2018 \$71,530,278	\$6,583,246	\$64,947,031	\$52,887
150	May	2018 \$71,586,513	\$6,731,460	\$64,855,053	\$56,235
151	June	2018 \$71,611,412	\$6,879,789	\$64,731,623	\$24,900
152	July	2018 \$71,627,145	\$7,028,169	\$64,598,975	\$15,733
153	August	2018 \$71,640,094	\$7,176,582	\$64,463,511	\$12,949
154	September	2018 \$71,639,023	\$7,325,022	\$64,314,001	-\$1,071
155	October	2018 \$71,464,495	\$7,473,459	\$63,991,036	-\$174,528
156	November	2018 \$71,465,330	\$7,621,547	\$63,843,782	\$835
157	December	2018 \$71,499,907	\$7,769,637	\$63,730,269	\$34,577

i) Mesa

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>
	<u>Prior Year Month</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>
	<u>Year</u>			= C1 - C2	= C1 - Previous Month C1
158	December	2017 \$0	\$0	\$0	\$0
159	January	2018 \$0	\$0	\$0	\$0
160	February	2018 \$0	\$0	\$0	\$0
161	March	2018 \$0	\$0	\$0	\$0
162	April	2018 \$0	\$0	\$0	\$0
163	May	2018 \$0	\$0	\$0	\$0
164	June	2018 \$0	\$0	\$0	\$0
165	July	2018 \$0	\$0	\$0	\$0
166	August	2018 \$0	\$0	\$0	\$0
167	September	2018 \$0	\$0	\$0	\$0
168	October	2018 \$0	\$0	\$0	\$0
169	November	2018 \$1,657,268	\$0	\$1,657,268	\$1,657,268
170	December	2018 \$1,657,268	\$0	\$1,657,268	\$0

j) Alberhill

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>
	<u>Prior Year Month</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>
	<u>Year</u>			= C1 - C2	= C1 - Previous Month C1
171	December	2017 \$0	\$0	\$0	\$0
172	January	2018 \$0	\$0	\$0	\$0
173	February	2018 \$0	\$0	\$0	\$0
174	March	2018 \$0	\$0	\$0	\$0
175	April	2018 \$0	\$0	\$0	\$0
176	May	2018 \$0	\$0	\$0	\$0
177	June	2018 \$0	\$0	\$0	\$0
178	July	2018 \$0	\$0	\$0	\$0
179	August	2018 \$0	\$0	\$0	\$0
180	September	2018 \$0	\$0	\$0	\$0
181	October	2018 \$0	\$0	\$0	\$0
182	November	2018 \$0	\$0	\$0	\$0
183	December	2018 \$0	\$0	\$0	\$0

k) ELM Series Caps

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>
	<u>Prior Year Month</u>	<u>Plant In-Service</u>	<u>Accumulated Depreciation</u>	<u>Net Plant In Service</u>	<u>Transmission Activity</u>
	<u>Year</u>			= C1 - C2	= C1 - Previous Month C1
184	December	2017 \$0	\$0	\$0	\$0
185	January	2018 \$0	\$0	\$0	\$0
186	February	2018 \$0	\$0	\$0	\$0
187	March	2018 \$0	\$0	\$0	\$0
188	April	2018 \$0	\$0	\$0	\$0
189	May	2018 \$0	\$0	\$0	\$0
190	June	2018 \$0	\$0	\$0	\$0
191	July	2018 \$0	\$0	\$0	\$0
192	August	2018 \$0	\$0	\$0	\$0
193	September	2018 \$0	\$0	\$0	\$0
194	October	2018 \$0	\$0	\$0	\$0
195	November	2018 \$0	\$0	\$0	\$0
196	December	2018 \$0	\$0	\$0	\$0

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:			Cite:
184	CWIP:	Yes	121 FERC ¶ 61,168 at P 57	
185	ROE adder:	0.75%	121 FERC ¶ 61,168 at P 129	
186	100% Abandoned Plant:	No	-----	
	B) Tehachapi Incentives Received:			Cite:
187	CWIP:	Yes	121 FERC ¶ 61,168 at P 57	
188	ROE adder:	1.25%	121 FERC ¶ 61,168 at P 129	
189	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71	
	C) Devers to Colorado River Incentives Received:			Cite:
190	CWIP:	Yes	121 FERC ¶ 61,168 at P 57	
191	ROE adder:	1.00%	121 FERC ¶ 61,168 at 129; modified by ER10-160 Settlement, see	
192			P2 and P3	
193	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71	
	D) Devers to Palo Verde 2 Incentives Received:			Cite:
194	CWIP:	No	121 FERC ¶ 61,168 at P 57; modified by ER10-160 Settlement, see	
195			P2 and P3	
196	ROE adder:	0.00%	121 FERC ¶ 61,168 at P 129; modified by ER10-160 Settlement, see	
197			P 3 and P 7	
198	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71	
	E) South of Kramer Incentives Received:			Cite:
199	CWIP:	Yes	134 FERC ¶ 61,181 at P 79	
200	ROE adder:	0.00%	---	
201	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79	
	F) West of Devers Incentives Received:			Cite:
202	CWIP:	Yes	134 FERC ¶ 61,181 at P 79	
203	ROE adder:	0.00%	---	
204	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79	
	G) Red Bluff Incentives Received:			Cite:
205	CWIP:	Yes	133 FERC ¶ 61,107 at P 76	
206	ROE adder:	0.00%	133 FERC ¶ 61,107 at P 102	
207	100% Abandoned Plant:	Yes	133 FERC ¶ 61,107 at P 88	
	H) Whirlwind Substation Expansion Incentives Received:			Cite:
208	CWIP:	Yes	134 FERC ¶ 61,181 at P 79	
209	ROE adder:	0.00%	---	
210	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79	
	I) Colorado River Substation Expansion Incentives Received:			Cite:
211	CWIP:	Yes	134 FERC ¶ 61,181 at P 79	
212	ROE adder:	0.00%	---	
213	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79	
	J) Mesa			Cite:
214	CWIP:	Yes	161 FERC ¶ 61,107 at P35	
215	ROE adder:	0.00%	---	
216	100% Abandoned Plant:	No	---	
	K) Alberhill			Cite:
217	CWIP:	Yes	161 FERC ¶ 61,107 at P35	
218	ROE adder:	0.00%	---	
219	100% Abandoned Plant:	Yes	161 FERC ¶ 61,107 at P 21	
	L) ELM Series Caps			Cite:
220	CWIP:	Yes	161 FERC ¶ 61,107 at P35	
221	ROE adder:	0.00%	---	
222	100% Abandoned Plant:	Yes	161 FERC ¶ 61,107 at P 21	
	M) Future Incentive Projects			Cite:
223	CWIP:			
224	ROE adder:			
225	100% Abandoned Plant:			

Instructions:

1) Upon Commission approval of any incentives for additional projects, add additional projects and provide cite to the Commission decision.

Determination of Incentive Adders Components of the TRR

Input data is shaded yellow

Two Incentive Adders are calculated:

- a) The Prior Year Incentive Adder is a component of the Prior Year TRR.
- b) The True Up Incentive Adder is a component of the True Up TRR.

1) Calculation of Incremental Return on Equity Factor

The Incremental Return on Equity Factor is the incremental Prior Year TRR expressed per 100 basis points of ROE incentive, for each million dollars of Incentive Net Plant. It is calculated according to the following formula:

$$IREF = CSCP * 0.01 * (1/(1 - CTR)) * \$1,000,000$$

<u>Line</u>	where:	<u>Value</u>	<u>Source</u>
1	CSCP = Common Stock Capital Percentage	48.6129%	1-BaseTRR, L 46
2	CTR = Composite Tax Rate	40.7460%	1-BaseTRR, L 58
3	IREF =	\$8,204	Above formula

2) Determination of multiplicative factors for use in calculating Incentive Adders:

Multiplicative factors are used to calculate the Incentive Adders on an Transmission Incentive Project specific basis. Multiplicative factor for each project is the ratio of its ROE adder to 1%.

<u>Line</u>		<u>ROE Adder</u>	<u>Multiplicative Factor</u>	<u>Source</u>
4	1) Rancho Vista	0.75%	0.75	14-IncentivePlant, L 185
5	2) Tehachapi	1.25%	1.25	14-IncentivePlant, L 188
6	3) Devers to Col. River	1.00%	1.00	14-IncentivePlant, L 191
7				
8	...			

3) Calculation of Prior Year Incentive Adder (EOY)

- 1) Determine Prior Year Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million \$ of Prior Year Incentive Rate Base.
- 2) Sum project-specific Incentive Adders to yield the total Prior Year Incentive Adder.

<u>Line</u>		<u>Prior Year Incentive Rate Base</u>	<u>Multiplicative Factor</u>	<u>Prior Year Incentive Adder</u>	<u>Source</u>
9	1) Rancho Vista	\$150,232,043	0.75	\$924,395	14-IncentivePlant, L 14, Col. 1
10	2) Tehachapi	\$2,728,701,253	1.25	\$27,983,351	14-IncentivePlant, L 15, Col. 1
11	3) Devers to Col. River	\$687,752,340	1.00	\$5,642,425	14-IncentivePlant, L 16, Col. 1
12					
13	...				
14			Prior Year Incentive Adder =	\$34,550,171	Sum of above PY Incentive Adders for each individual project

4) Calculation of True-Up Incentive Adder

- 1) Determine True Up Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million \$ of True Up Incentive Net Plant.
- 2) Sum project-specific Incentive Adders to yield the total True Up Incentive Adder.

<u>Line</u>		<u>True-Up Incentive Net Plant</u>	<u>Multiplicative Factor</u>	<u>True-Up Incentive Adder</u>	<u>Source</u>
15	1) Rancho Vista	\$152,604,254	0.75	\$938,991	14-IncentivePlant, L 20, Col. 1
16	2) Tehachapi	\$2,756,592,235	1.25	\$28,269,378	14-IncentivePlant, L 21, Col. 1
17	3) Devers to Col. River	\$697,660,501	1.00	\$5,723,713	14-IncentivePlant, L 22, Col. 1
18					
19	...				
20			True-Up Incentive Adder =	\$34,932,083	Sum of above PY Incentive Adders for each individual project

5) Calculation of Total ROE for Plant-In Service in the True Up TRR

a) Transmission Incentive Plant Net Plant In Service

<u>Line</u>	<u>Incentive Project</u>	<u>13-Month Avg. TIP Net Plant In Service</u>	<u>Source</u>
21	1) Rancho Vista	\$152,604,254	14-IncentivePlant, L 20, Col. 3
22	2) Tehachapi	\$2,750,697,473	14-IncentivePlant, L 21, Col. 3
23	3) Devers to Col. River	\$697,660,501	14-IncentivePlant, L 22, Col. 3
24			
	...		

b) Calculation of ROE Adders on TIP Net Plant In Service

<u>Line</u>	<u>Incentive Project</u>	<u>Col 1 True Up Incentive Adder</u>	<u>Col 2 After-Tax True Up Incentive Adder</u>	<u>Source</u>
25	1) Rancho Vista	\$938,991	\$556,390	See Note 1
26	2) Tehachapi	\$28,208,926	\$16,714,917	See Note 1
27	3) Devers to Col. River	\$5,723,713	\$3,391,529	See Note 1
28				See Note 1
29	...			
30		Total:	\$20,662,836	

c) Equity Portion of Plant In Service Rate Base

<u>Line</u>		<u>Amount</u>	<u>Source</u>
31	Total Rate Base:	\$5,419,835,230	4-TUTRR, Line 17
32	CWIP Portion of Rate Base:	<u>\$106,441,483</u>	4-TUTRR, Line 14
33	Plant In Service Rate Base:	\$5,313,393,747	Line 31 - Line 32
34	Equity percentage:	48.6129%	1-BaseTRR, Line 46
35	Equity Portion of Plant In Service Rate Base:	\$2,582,993,951	Line 33 * Line 34

d) Total ROE for Plant In Service in the True Up TRR

<u>Line</u>			
36	Plant In Service ROE Adder Percentage:	0.80%	Line 30 / Line 35
37	Base ROE (Including 50 basis point		
38	CAISO Participation Adder):	<u>9.80%</u>	1-BaseTRR, Line 49
39	Total ROE for Plant In Service in True Up TRR:	10.60%	Line 36 + Line 38

Instructions:

1) If additional projects receive ROE adders, add to end of lists, and include in calculation of each Incentive Adder.

Notes:

1) Column 1: The True Up Incentive Adder for each Incentive Project equals the IREF on Line 3, times the applicable Multiplicative Factor on Lines 15 to 18, times the million \$ of TIP Net Plant In Service on Lines 21 to 24.

Column 2: The After Tax True Up Incentive Adder is derived by multiplying the amounts in Column 1 by (1 - CTR) (Where the CTR is on Line 2).

Forecast Plant Additions for In-Service ISO Transmission Plant

Yellow shaded cells are Input Data

Forecast Plant Additions represents the total increase in ISO Transmission Net Plant, not including CWIP, during the Rate Year, incremental to the year-end Prior Year amount. It is calculated on a 13-Month Average Basis during the Rate Year.

1) Total Plant Additions Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
			See Note 2 Unloaded Total Plant Adds	See Note 2 Prior Period CWIP Closed	See Note 2 Over Heads Closed to PIS	See Note 2 Cost of Removal	See Note 2 AFUDC Eligible Plant Additions	See Note 2 AFUDC	See Note 2 Incremental Gross Plant	See Note 2 Depreciation Accrual	See Note 2 Incremental Reserve	See Note 2 Net Plant	See Note 2 Unloaded Low Voltage Additions	See Note 2 Unloaded Low Voltage Additions
1	January	2018	\$19,115,721	\$4,132,901	\$1,123,712	\$1,207,777	\$13,889,440	\$416,683	\$19,448,339	\$0	\$0	\$19,448,339	\$548,711	\$557,820
2	February	2018	\$15,694,355	\$34,484	\$1,174,490	\$1,207,777	\$13,889,440	\$416,683	\$35,526,090	\$41,172	\$41,172	\$35,484,918	\$1,097,422	\$1,115,640
3	March	2018	\$15,102,583	\$34,484	\$1,130,107	\$1,207,777	\$13,889,440	\$416,683	\$50,967,686	\$75,209	\$116,381	\$50,851,305	\$1,646,134	\$1,673,459
4	April	2018	\$17,901,937	\$2,638,000	\$1,144,795	\$1,302,701	\$14,981,058	\$449,432	\$69,161,150	\$107,899	\$224,280	\$68,936,870	\$2,194,845	\$2,231,279
5	May	2018	\$14,864,406	\$34,484	\$1,112,244	\$1,207,777	\$13,889,440	\$416,683	\$84,346,706	\$146,414	\$370,694	\$83,976,012	\$2,743,556	\$2,789,099
6	June	2018	\$95,174,450	\$74,323,798	\$1,563,799	\$1,710,354	\$19,669,074	\$590,072	\$179,964,674	\$178,562	\$549,256	\$179,415,417	\$4,770,685	\$4,849,878
7	July	2018	\$14,713,160	\$70,912	\$1,098,169	\$1,212,077	\$13,938,890	\$418,167	\$194,982,092	\$380,986	\$930,242	\$194,051,850	\$5,319,396	\$5,407,698
8	August	2018	\$14,376,069	\$34,484	\$1,075,619	\$1,207,777	\$13,889,440	\$416,683	\$209,642,686	\$412,778	\$1,343,020	\$208,299,667	\$5,868,107	\$5,965,518
9	September	2018	\$14,428,377	\$34,484	\$1,079,542	\$1,207,777	\$13,889,440	\$416,683	\$224,359,512	\$443,814	\$1,786,834	\$222,572,678	\$6,416,818	\$6,523,337
10	October	2018	\$14,727,807	\$71,265	\$1,099,241	\$1,253,783	\$14,418,501	\$432,555	\$239,365,332	\$474,970	\$2,261,803	\$237,103,528	\$7,537,257	\$7,662,375
11	November	2018	\$14,125,406	\$34,484	\$1,056,819	\$1,207,777	\$13,889,440	\$416,683	\$253,756,463	\$506,737	\$2,768,540	\$250,987,923	\$8,085,968	\$8,220,195
12	December	2018	\$139,623,547	\$53,925,792	\$6,427,332	\$6,323,882	\$72,724,640	\$2,181,739	\$395,665,199	\$537,203	\$3,305,743	\$392,359,456	\$6,634,679	\$8,778,015
13	January	2019	\$14,345,567	\$0	\$1,075,918	\$1,217,729	\$14,003,881	\$420,116	\$410,289,072	\$837,624	\$4,143,368	\$406,145,704	\$9,251,670	\$9,405,248
14	February	2019	\$13,364,280	\$0	\$1,002,321	\$1,131,729	\$13,014,881	\$390,446	\$423,914,390	\$868,583	\$5,011,951	\$418,902,439	\$9,868,661	\$10,032,480
15	March	2019	\$13,520,671	\$0	\$1,014,050	\$1,131,729	\$13,014,881	\$390,446	\$437,707,829	\$897,428	\$5,909,379	\$431,798,450	\$10,485,651	\$10,659,713
16	April	2019	\$13,715,286	\$39,760	\$1,025,664	\$1,143,947	\$13,155,390	\$394,662	\$451,699,494	\$926,629	\$6,836,007	\$444,863,487	\$11,284,474	\$11,471,796
17	May	2019	\$19,727,727	\$460,898	\$1,445,012	\$1,622,510	\$18,658,868	\$559,766	\$471,809,489	\$956,249	\$7,792,256	\$464,017,232	\$11,901,465	\$12,099,029
18	June	2019	\$19,806,746	\$272,295	\$1,465,084	\$1,644,426	\$18,910,904	\$567,327	\$492,004,219	\$998,822	\$8,791,078	\$483,213,141	\$12,518,456	\$12,726,262
19	July	2019	\$47,944,709	\$12,901,858	\$2,628,214	\$2,976,500	\$34,229,749	\$1,026,892	\$540,627,534	\$1,041,574	\$9,832,652	\$530,794,882	\$13,135,446	\$13,353,495
20	August	2019	\$27,702,986	\$8,473,412	\$1,442,218	\$1,141,368	\$13,125,733	\$393,772	\$569,025,142	\$1,144,510	\$10,977,162	\$558,047,980	\$13,867,851	\$14,098,058
21	September	2019	\$13,612,716	\$0	\$1,020,954	\$1,131,729	\$13,014,881	\$390,446	\$582,917,529	\$1,204,628	\$12,181,790	\$570,735,739	\$14,484,842	\$14,725,290
22	October	2019	\$45,081,505	\$14,054,510	\$2,327,024	\$1,752,821	\$20,157,439	\$604,723	\$629,177,961	\$1,234,038	\$13,415,828	\$464,017,232	\$15,101,833	\$15,352,523
23	November	2019	\$31,728,969	\$7,464,449	\$1,819,839	\$1,193,091	\$13,720,543	\$411,616	\$661,945,294	\$1,331,971	\$14,747,799	\$647,197,495	\$15,718,823	\$15,979,756
24	December	2019	\$47,725,059	\$3,893,576	\$3,287,361	\$3,489,608	\$40,130,496	\$1,203,915	\$710,672,021	\$1,401,340	\$16,149,139	\$694,522,882	\$16,335,814	\$16,606,988
25	13-Month Averages:								\$521,342,706			\$512,181,617		\$12,714,512

2) Incentive Plant Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
			C4 10-CWIP L30-53 Unloaded Total Plant Adds	C5 10-CWIP L30-53 Prior Period CWIP Closed	C6 10-CWIP L30-53 Over Heads Closed to PIS	N/A Cost of Removal	N/A AFUDC Eligible Plant Additions	N/A AFUDC	= Prior Month C7 +C1+C3 Incremental Gross Plant	= Prior Month C7 * L91/12 Depreciation Accrual	= Prior Month C9 + C8 Incremental Reserve	=C7-C9 Net Plant	Unloaded Low Voltage Additions	Loaded Low Voltage Additions
26	January	2018	\$5,037,315	\$4,098,417	\$70,417	\$0	\$0	\$0	\$5,107,732	\$0	\$0	\$5,107,732	\$0	\$0
27	February	2018	\$1,615,948	\$0	\$121,196	\$0	\$0	\$0	\$6,844,877	\$10,813	\$10,813	\$6,834,064	\$0	\$0
28	March	2018	\$1,024,177	\$0	\$76,813	\$0	\$0	\$0	\$7,945,867	\$14,491	\$25,304	\$7,920,563	\$0	\$0
29	April	2018	\$116,255	\$0	\$8,719	\$0	\$0	\$0	\$8,070,841	\$16,821	\$42,125	\$8,028,716	\$0	\$0
30	May	2018	\$786,000	\$0	\$58,950	\$0	\$0	\$0	\$8,915,791	\$17,086	\$59,211	\$8,856,580	\$0	\$0
31	June	2018	\$3,410,370	\$2,447,558	\$72,211	\$0	\$0	\$0	\$12,398,371	\$18,875	\$78,086	\$12,320,285	\$0	\$0
32	July	2018	\$548,326	\$0	\$41,124	\$0	\$0	\$0	\$12,987,822	\$26,247	\$104,333	\$12,883,489	\$0	\$0
33	August	2018	\$297,663	\$0	\$22,325	\$0	\$0	\$0	\$13,307,810	\$27,495	\$131,829	\$13,175,981	\$0	\$0
34	September	2018	\$349,971	\$0	\$26,248	\$0	\$0	\$0	\$13,684,028	\$28,173	\$160,001	\$13,524,027	\$0	\$0
35	October	2018	\$77,673	\$0	\$5,825	\$0	\$0	\$0	\$13,767,527	\$28,969	\$188,970	\$13,578,557	\$0	\$0
36	November	2018	\$47,000	\$0	\$3,525	\$0	\$0	\$0	\$13,818,052	\$29,146	\$218,116	\$13,599,936	\$0	\$0
37	December	2018	\$20,677,884	\$8,513,638	\$912,318	\$0	\$0	\$0	\$35,408,255	\$29,253	\$247,369	\$35,160,886	\$0	\$0
38	January	2019	\$185,930	\$0	\$13,945	\$0	\$0	\$0	\$35,608,130	\$74,959	\$322,328	\$35,285,801	\$0	\$0
39	February	2019	\$204,643	\$0	\$15,348	\$0	\$0	\$0	\$35,828,120	\$75,383	\$397,711	\$35,430,409	\$0	\$0
40	March	2019	\$361,034	\$0	\$27,078	\$0	\$0	\$0	\$36,216,232	\$75,848	\$473,559	\$35,742,672	\$0	\$0
41	April	2019	\$373,816	\$0	\$28,036	\$0	\$0	\$0	\$36,618,084	\$76,670	\$550,229	\$36,067,855	\$0	\$0
42	May	2019	\$400,431	\$0	\$30,032	\$0	\$0	\$0	\$37,048,547	\$77,521	\$627,750	\$36,420,797	\$0	\$0
43	June	2019	\$413,213	\$0	\$30,991	\$0	\$0	\$0	\$37,492,751	\$78,432	\$706,181	\$36,786,570	\$0	\$0
44	July	2019	\$432,387	\$0	\$32,429	\$0	\$0	\$0	\$37,957,567	\$79,372	\$785,554	\$37,172,013	\$0	\$0
45	August	2019	\$14,427,934	\$8,470,083	\$446,839	\$0	\$0	\$0	\$52,832,340	\$80,356	\$865,910	\$51,966,430	\$0	\$0
46	September	2019	\$453,078	\$0	\$33,981	\$0	\$0	\$0	\$53,319,399	\$111,846	\$977,756	\$52,341,643	\$0	\$0
47	October	2019	\$19,987,218	\$9,341,864	\$798,402	\$0	\$0	\$0	\$74,105,019	\$112,877	\$1,090,633	\$73,014,386	\$0	\$0
48	November	2019	\$16,531,554	\$6,140,181	\$779,353	\$0	\$0	\$0	\$91,415,926	\$156,881	\$1,247,514	\$90,168,412	\$0	\$0
49	December	2019	\$5,786,285	\$2,531,642	\$244,098	\$0	\$0	\$0	\$97,446,309	\$193,528	\$1,441,042	\$96,005,267	\$0	\$0

3) Non-Incentive Plant Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
			Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Cost of Removal	Eligible Plant Additions	AFUDC	Incremental Gross Plant	Depreciation Accrual	Incremental Reserve	Net Plant	Unloaded Low Voltage Additions	Loaded Low Voltage Additions
50	January	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$14,340,607	\$0	\$0	\$14,340,607	\$548,711	\$557,820
51	February	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$28,681,213	\$30,359	\$30,359	\$28,650,854	\$1,097,422	\$1,115,640
52	March	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$43,021,820	\$60,718	\$91,077	\$42,930,742	\$1,646,134	\$1,673,459
53	April	2018	\$17,785,682	\$2,638,000	\$1,136,076	\$1,302,701	\$14,981,058	\$449,432	\$61,090,309	\$91,077	\$182,155	\$60,908,154	\$2,194,845	\$2,231,279
54	May	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$75,430,916	\$129,328	\$311,483	\$75,119,433	\$2,743,556	\$2,789,099
55	June	2018	\$91,764,081	\$71,876,240	\$1,491,588	\$1,710,354	\$19,669,074	\$590,072	\$167,566,302	\$159,687	\$471,170	\$167,095,132	\$4,770,685	\$4,849,878
56	July	2018	\$14,164,834	\$70,912	\$1,057,044	\$1,212,077	\$13,938,890	\$418,167	\$181,994,270	\$354,738	\$825,909	\$181,168,361	\$5,319,396	\$5,407,698
57	August	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$196,334,877	\$385,282	\$1,211,191	\$195,123,686	\$5,868,107	\$5,965,518
58	September	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$210,675,483	\$415,641	\$1,626,832	\$209,048,651	\$6,416,818	\$6,523,337
59	October	2018	\$14,650,134	\$71,265	\$1,093,415	\$1,253,783	\$14,418,501	\$432,555	\$225,597,805	\$446,001	\$2,072,833	\$223,524,972	\$7,537,257	\$7,662,375
60	November	2018	\$14,078,406	\$34,484	\$1,053,294	\$1,207,777	\$13,889,440	\$416,683	\$239,938,411	\$477,591	\$2,550,424	\$237,387,987	\$8,085,968	\$8,220,195
61	December	2018	\$118,945,662	\$45,412,154	\$5,515,013	\$6,323,882	\$72,724,640	\$2,181,739	\$360,256,944	\$507,950	\$3,058,374	\$357,198,570	\$8,634,679	\$8,778,015
62	January	2019	\$14,159,637	\$0	\$1,061,973	\$1,217,729	\$14,003,881	\$420,116	\$374,680,942	\$762,665	\$3,821,039	\$370,859,903	\$9,251,670	\$9,405,248
63	February	2019	\$13,159,637	\$0	\$986,973	\$1,131,729	\$13,014,881	\$390,446	\$388,086,270	\$793,201	\$4,614,240	\$383,472,030	\$9,868,661	\$10,032,480
64	March	2019	\$13,159,637	\$0	\$986,973	\$1,131,729	\$13,014,881	\$390,446	\$401,491,597	\$821,580	\$5,435,820	\$396,055,778	\$10,485,651	\$10,659,713
65	April	2019	\$13,341,469	\$39,760	\$997,628	\$1,143,947	\$13,155,390	\$394,662	\$415,081,410	\$849,959	\$6,285,778	\$408,795,632	\$11,284,474	\$11,471,796
66	May	2019	\$19,327,296	\$460,898	\$1,414,980	\$1,622,510	\$18,658,868	\$559,766	\$434,760,942	\$878,728	\$7,164,507	\$427,596,435	\$11,901,465	\$12,099,029
67	June	2019	\$19,393,533	\$272,295	\$1,434,093	\$1,644,426	\$18,910,904	\$567,327	\$454,511,468	\$920,390	\$8,084,897	\$446,426,571	\$12,518,456	\$12,726,262
68	July	2019	\$47,512,322	\$12,901,858	\$2,595,785	\$2,976,500	\$34,229,749	\$1,026,892	\$502,669,967	\$962,202	\$9,047,099	\$493,622,868	\$13,135,446	\$13,353,495
69	August	2019	\$13,275,052	\$3,330	\$995,379	\$1,141,368	\$13,125,733	\$393,772	\$516,192,802	\$1,064,154	\$10,111,252	\$506,081,549	\$13,867,851	\$14,098,058
70	September	2019	\$13,159,637	\$0	\$986,973	\$1,131,729	\$13,014,881	\$390,446	\$529,598,130	\$1,092,782	\$11,204,034	\$518,394,096	\$14,484,842	\$14,725,290
71	October	2019	\$25,094,287	\$4,712,650	\$1,528,623	\$1,752,821	\$20,157,439	\$604,723	\$555,072,942	\$1,121,161	\$12,325,195	\$542,747,747	\$15,101,833	\$15,352,523
72	November	2019	\$15,197,415	\$1,324,267	\$1,040,486	\$1,193,091	\$13,720,543	\$411,616	\$570,529,368	\$1,175,091	\$13,500,285	\$557,029,083	\$15,718,823	\$15,979,756
73	December	2019	\$41,938,774	\$1,361,933	\$3,043,263	\$3,489,608	\$40,130,496	\$1,203,915	\$613,225,712	\$1,207,812	\$14,708,098	\$598,517,614	\$16,335,814	\$16,606,988

4) ISO Corporate Overhead Loader

Line 74	ISO Corp OH Rate	7.50%
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5) ISO Cost of Removal Percent

Line 75	Cost of Removal Rate	8.00%
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6) AFUDC Loader Rate

Line 76	ISO AFUDC Rate	3.00%
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7) Calculation of ISO Depreciation Rate

December Prior Year plant balances and accrual rates are as shown on Schedule 17 Depreciation

Line	Acct	Col 1 December Prior Year Plant Balance	Col 2 Accrual Rate	Col 3 Annual Accrual	Col 4 C2*C3 Annual Accrual	Col 5 Accrual Rate Reference
77	350.1	\$87,876,203	0.00%	\$0	\$0	18 Dep Rates L1
78	350.2	\$164,901,118	1.66%	\$2,737,359	\$2,737,359	18 Dep Rates L2
79	352	\$569,698,023	2.57%	\$14,641,239	\$14,641,239	18 Dep Rates L3
80	353	\$3,409,447,774	2.47%	\$84,213,360	\$84,213,360	18 Dep Rates L4
81	354	\$2,283,380,922	2.44%	\$55,714,494	\$55,714,494	18 Dep Rates L5
82	355	\$364,424,080	3.67%	\$13,374,364	\$13,374,364	18 Dep Rates L6
83	356	\$1,245,933,686	3.05%	\$38,000,977	\$38,000,977	18 Dep Rates L7
84	357	\$190,222,489	1.65%	\$3,138,671	\$3,138,671	18 Dep Rates L8
85	358	\$84,920,374	3.87%	\$3,286,418	\$3,286,418	18 Dep Rates L9
86	359	\$172,640,885	1.56%	\$2,693,198	\$2,693,198	18 Dep Rates L10
87						
88		Sum of Depreciation Expense		\$217,800,081		Sum of C4 Lines 77 to 86
89		Sum of Dec Prior Year Plant		\$8,573,445,553		Sum of C2 Lines 77 to 86
90						
91		Composite Depreciation Rate	2.54%			Line 88 / Line 89

Notes:

- Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).
- Sum of Incentive Plant Calculations and Non-Incentive Calculations, lines 26-49 and lines 50-73

Depreciation Expense

Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO

Prior Year: 2017

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year: Source: 6-PlantInService, Lines 1-13.

Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
FERC Account:												
1	Dec 2016	\$86,845,703	\$165,326,927	\$531,582,611	\$3,249,175,449	\$2,233,991,232	\$324,258,228	\$1,235,903,791	\$185,508,197	\$81,951,072	\$182,027,086	\$8,276,570,295
2	Jan 2017	\$81,997,511	\$165,330,397	\$528,854,083	\$3,250,037,231	\$2,231,001,014	\$335,699,493	\$1,232,564,516	\$185,656,754	\$81,997,920	\$160,125,968	\$8,253,264,889
3	Feb 2017	\$82,013,020	\$165,784,066	\$534,882,418	\$3,256,654,353	\$2,213,130,982	\$339,965,913	\$1,235,030,894	\$186,119,194	\$82,775,424	\$161,709,715	\$8,258,065,980
4	Mar 2017	\$82,413,677	\$165,733,853	\$532,806,954	\$3,260,114,606	\$2,225,922,423	\$342,740,514	\$1,241,178,225	\$186,361,377	\$83,455,651	\$161,453,728	\$8,282,181,008
5	Apr 2017	\$82,424,960	\$165,734,429	\$540,340,485	\$3,290,596,932	\$2,251,979,965	\$344,598,339	\$1,244,265,048	\$186,611,561	\$83,540,944	\$161,600,158	\$8,351,692,820
6	May 2017	\$82,438,880	\$165,704,351	\$548,767,497	\$3,303,060,549	\$2,258,078,709	\$345,368,677	\$1,242,476,528	\$187,117,539	\$83,717,689	\$168,349,232	\$8,385,079,651
7	Jun 2017	\$81,409,531	\$165,534,488	\$552,041,270	\$3,313,909,561	\$2,261,350,618	\$347,377,534	\$1,244,803,717	\$188,491,607	\$84,190,542	\$167,806,375	\$8,406,915,243
8	Jul 2017	\$81,421,876	\$165,199,675	\$554,107,049	\$3,321,544,471	\$2,263,663,368	\$350,109,485	\$1,244,039,916	\$188,624,718	\$84,257,050	\$167,839,950	\$8,420,807,556
9	Aug 2017	\$81,875,011	\$164,728,138	\$558,293,842	\$3,350,799,129	\$2,265,082,996	\$350,778,178	\$1,246,103,080	\$188,962,876	\$84,383,656	\$168,194,579	\$8,459,201,484
10	Sep 2017	\$81,886,831	\$164,709,520	\$560,085,940	\$3,354,129,789	\$2,263,017,844	\$354,174,067	\$1,247,812,337	\$189,290,136	\$84,485,994	\$168,808,262	\$8,468,400,719
11	Oct 2017	\$81,898,670	\$164,708,798	\$557,690,365	\$3,337,803,870	\$2,267,000,466	\$357,358,231	\$1,247,335,361	\$189,937,864	\$84,808,333	\$169,009,660	\$8,457,551,618
12	Nov 2017	\$87,866,111	\$164,907,957	\$559,289,849	\$3,340,005,249	\$2,268,750,108	\$362,445,561	\$1,244,772,136	\$190,107,796	\$84,849,890	\$171,154,663	\$8,474,149,319
13	Dec 2017	\$87,876,203	\$164,901,118	\$569,698,023	\$3,409,447,774	\$2,283,380,922	\$364,424,080	\$1,245,933,686	\$190,222,489	\$84,920,374	\$172,640,885	\$8,573,445,553
14												
15	Depreciation Rates (Percent per year) See "18-DepRates" and Instruction 1.											

Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
17a	Dec 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17b	Jan 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17c	Feb 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17d	Mar 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17e	Apr 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17f	May 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17g	Jun 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17h	Jul 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17i	Aug 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17j	Sep 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17k	Oct 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17l	Nov 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17m	Dec 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%

18 Monthly Depreciation Expense for Transmission Plant - ISO by FERC Account: See Note 1 and Instruction 1

Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Month Total
24	Jan 2017	\$0	\$228,702	\$1,138,473	\$6,687,886	\$4,542,449	\$991,690	\$3,141,255	\$255,074	\$264,292	\$236,635	\$17,486,456
25	Feb 2017	\$0	\$228,707	\$1,132,629	\$6,689,660	\$4,536,369	\$1,026,681	\$3,132,768	\$255,278	\$264,443	\$208,164	\$17,474,699
26	Mar 2017	\$0	\$229,335	\$1,145,540	\$6,703,280	\$4,500,033	\$1,039,729	\$3,139,037	\$255,914	\$266,951	\$210,223	\$17,490,041
27	Apr 2017	\$0	\$229,265	\$1,141,095	\$6,710,403	\$4,526,042	\$1,048,215	\$3,154,661	\$256,247	\$269,144	\$209,890	\$17,544,962
28	May 2017	\$0	\$229,266	\$1,157,229	\$6,773,145	\$4,579,026	\$1,053,897	\$3,162,507	\$256,591	\$269,420	\$210,080	\$17,691,161
29	Jun 2017	\$0	\$229,224	\$1,175,277	\$6,798,800	\$4,591,427	\$1,056,253	\$3,157,961	\$257,287	\$269,990	\$218,854	\$17,755,072
30	Jul 2017	\$0	\$228,989	\$1,182,288	\$6,821,131	\$4,598,080	\$1,062,396	\$3,163,876	\$259,176	\$271,514	\$218,148	\$17,805,599
31	Aug 2017	\$0	\$228,526	\$1,186,713	\$6,836,846	\$4,602,782	\$1,070,752	\$3,161,935	\$259,359	\$271,729	\$218,192	\$17,836,833
32	Sep 2017	\$0	\$227,874	\$1,195,679	\$6,897,062	\$4,605,669	\$1,072,797	\$3,167,179	\$259,824	\$272,137	\$218,653	\$17,916,873
33	Oct 2017	\$0	\$227,848	\$1,199,517	\$6,903,917	\$4,601,470	\$1,083,182	\$3,171,523	\$260,274	\$272,467	\$219,451	\$17,939,650
34	Nov 2017	\$0	\$227,847	\$1,194,387	\$6,870,313	\$4,609,568	\$1,092,921	\$3,170,311	\$261,165	\$273,507	\$219,713	\$17,919,730
35	Dec 2017	\$0	\$228,123	\$1,197,812	\$6,874,844	\$4,613,125	\$1,108,479	\$3,163,796	\$261,398	\$273,641	\$222,501	\$17,943,720
36	Totals:	\$0	\$2,743,707	\$14,046,640	\$81,567,286	\$54,906,038	\$12,706,990	\$37,886,809	\$3,097,586	\$3,239,236	\$2,610,503	\$212,804,795
37	Total Annual Depreciation Expense for Transmission Plant - ISO:											\$212,804,795
38	(equals sum of monthly amounts)											

39 2) Calculation of Depreciation Expense for Distribution Plant - ISO

40						
41		<u>360</u>	<u>361</u>	<u>362</u>	<u>Source</u>	
42	Distribution Plant - ISO BOY	\$0	\$0	\$0	6-PlantInService Line 15.	
43	Distribution Plant - ISO EOY	\$0	\$0	\$0	6-PlantInService Line 16.	
44	Average BOY/EOY :	\$0	\$0	\$0		
45						
46	Depreciation Rates (Percent per year) See "18-DepRates".					
47		<u>360</u>	<u>361</u>	<u>362</u>		
48		1.67%	3.04%	3.13%		
49						
50	Depreciation Expense for Distribution Plant - ISO				See Note 2 and Instruction 2	
51						
52		<u>360</u>	<u>361</u>	<u>362</u>	<u>Total</u>	
53		\$0	\$0	\$0	\$0	Total is sum of Depreciation Expense for accounts
54						360, 361, and 362
55						

56 3) Calculation of Depreciation Expense for General Plant and Intangible Plant

57						
58	Total General Plant Depreciation Expense			236,723,303	FF1 336.10f	
59	Total Intangible Plant Depreciation Expense			238,988,799	FF1 336.1f	
60	Sum of Total General and Total Intangible Depreciation Expense			\$475,712,102	Line 58 + Line 59	
61	Transmission Wages and Salaries Allocation Factor			5.6290%	27-Allocators, Line 9	
62	General and Intangible Depreciation Expense			\$26,777,935	Line 60 * Line 61	
63						

64 4) Depreciation Expense

65					
66	Depreciation Expense is the sum of:	<u>Amount</u>	<u>Source</u>		
67	1) Depreciation Expense for Transmission Plant - ISO	\$212,804,795.14	Line 37, Col 12		
68	2) Depreciation Expense for Distribution Plant - ISO	\$0	Line 53		
69	3) General and Intangible Depreciation Expense	<u>\$26,777,935</u>	Line 62		
70	Depreciation Expense:	\$239,582,730.61	Line 67 + Line 68 + Line 69		

Notes:

- 1) Depreciation Expense for each account for each month is equal to the previous month balance of Transmission Plant - ISO for that same account, times the Monthly Depreciation Rate for that account. Monthly rate = annual rates on Line 17a etc. divided by 12.
- 2) Depreciation Expense for each account is equal to the Average BOY/EOY value on Line 44 times the Depreciation Rate on Line 48.

Instructions:

- 1) Depreciation rates on Lines 17a-17m input from Schedule 18. However, in the event of a mid-year change in depreciation rates approved by the Commission, the rates stated on Schedule 18 will represent end of Prior Year rates. To correctly calculate depreciation expense for Transmission Plant - ISO for the entire Prior Year, input depreciation rates from Schedule 18 only for those months during which the new rates were in effect, and input previous effective rates in the months for which they were in effect.
- 2) In the event that depreciation rates stated on Schedule 18 to be applied to Distribution Plant - ISO are revised mid-year, calculate Depreciation Expense for for Distribution Plant - ISO on Line 53 utilizing the weighted-average (by time) of the annual depreciation rates in effect in the Prior Year.

Depreciation Rates

1) Transmission Plant - ISO			Plant	Removal	
FERC			Less	Cost	Total
<u>Line</u>	<u>Account</u>	<u>Description</u>	<u>Salvage</u>	<u>Cost</u>	<u>Total</u>
1	350.1	Fee Land	0.00%	0.00%	0.00%
2	350.2	Easements	1.66%	0.00%	1.66%
3	352	Structures and Improvements	1.80%	0.77%	2.57%
4	353	Station Equipment	2.20%	0.27%	2.47%
5	354	Towers and Fixtures	1.35%	1.09%	2.44%
6	355	Poles and Fixtures	2.00%	1.67%	3.67%
7	356	Overhead Conductors and Devices	2.00%	1.05%	3.05%
8	357	Underground Conduit	1.65%	0.00%	1.65%
9	358	Underground Conductors and Devices	3.26%	0.61%	3.87%
10	359	Roads and Trails	1.56%	0.00%	1.56%
11					
2) Distribution Plant - ISO			Plant	Removal	
FERC			Less	Cost	Total
<u>Line</u>	<u>Account</u>	<u>Description</u>	<u>Salvage</u>	<u>Cost</u>	<u>Total</u>
12	360	Land and Land Rights	1.67%	0.00%	1.67%
13	361	Structures and Improvements	2.33%	0.71%	3.04%
14	362	Station Equipment	2.17%	0.96%	3.13%
3) General Plant			Plant	Removal	
FERC			Less	Cost	Total
<u>Line</u>	<u>Account</u>	<u>Description</u>	<u>Salvage</u>	<u>Cost</u>	<u>Total</u>
15	389	Land and Land Rights	1.67%	0.00%	1.67%
16	390	Structures and Improvements	2.41%	0.33%	2.74%
17	391.1	Office Furniture	5.00%	0.00%	5.00%
18	391.5	Office Equipment	20.00%	0.00%	20.00%
19	391.6	Duplicating Equipment	20.00%	0.00%	20.00%
20	391.2	Personal Computers	20.00%	0.00%	20.00%
21	391.3	Mainframe Computers	20.00%	0.00%	20.00%
22	391.7	PC Software	20.00%	0.00%	20.00%
23	391.4	DDSMS - CPU & Processing	14.29%	0.00%	14.29%
24	391.4	DDSMS - Controllers, Receivers, Comm.	10.00%	0.00%	10.00%
25	391.4	DDSMS - Telemetering & System	6.67%	0.00%	6.67%
26	391.4	DDSMS - Miscellaneous	5.00%	0.00%	5.00%
27	391.4	DDSMS - Map Board	4.00%	0.00%	4.00%
28	393	Stores Equipment	5.00%	0.00%	5.00%
29	395	Laboratory Equipment	6.67%	0.00%	6.67%
30	398	Misc Power Plant Equipment	5.00%	0.00%	5.00%
31	397	Data Network Systems	20.00%	0.00%	20.00%
32	397	Telecom System Equipment	14.29%	0.00%	14.29%
33	397	Netcomm Radio Assembly	10.00%	0.00%	10.00%
34	397	Microwave Equip. & Antenna Assembly	6.67%	0.00%	6.67%
35	397	Telecom Power Systems	5.00%	0.00%	5.00%
36	397	Fiber Optic Communication Cables	5.94%	0.12%	6.06%
37	397	Telecom Infrastructure	3.65%	0.10%	3.75%
38	392	Transportation Equip.	14.29%	0.00%	14.29%
39	394.4	Garage & Shop -- Equip.	10.00%	0.00%	10.00%
40	394.5	Tools & Work Equip. -- Shop	10.00%	0.00%	10.00%
41	396	Power Oper Equip	6.67%	0.00%	6.67%
4) Intangible Plant			Plant	Removal	
FERC			Less	Cost	Total
<u>Line</u>	<u>Account</u>	<u>Description</u>	<u>Salvage</u>	<u>Cost</u>	<u>Total</u>
42	302	Hydro Relicensing	2.52%	0.00%	2.52%
43	303	Radio Frequency	2.50%	0.00%	2.50%
44	301	Other Intangibles	5.00%	0.00%	5.00%
45	303	Cap Soft 5yr	20.58%	0.00%	20.58%
46	303	Cap Soft 7yr	14.93%	0.00%	14.93%
47	303	Cap Soft 10yr	12.45%	0.00%	12.45%
48	303	Cap Soft 15yr	6.78%	0.00%	6.78%

Notes: 1) Depreciation rates may only be revised as approved by the Commission pursuant to a Section 205 or 206 filing.

Operations and Maintenance Expenses

Cells shaded yellow are input cells

1) Determination of Adjusted Operations and Maintenance Expenses for each account (Note 1)

Line	Account/Work Activity Rev	Col 1	Col 2 = C3 + C4	Col 3	Col 4	Col 5 Note 2	Col 6 = C7 + C8	Col 7	Col 8	Col 9 = C10 + C11	Col 10 = C3 + C7	Col 11 = C4 + C8
		Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor	
Transmission Accounts												
1	560 - Operations Engineering	\$7,342,064	\$3,520,700	\$3,821,363	G&I		(\$209,296)	(\$1,000)	(\$208,296)	\$7,132,768	\$3,519,700	\$3,613,067
2	560 - Sylmar/Palo Verde	\$147,369	\$0	\$147,369			\$0			\$147,369	\$0	\$147,369
3	561.000 Load Dispatching	\$0	\$0	\$0			\$0			\$0	\$0	\$0
4	561.100 Load Dispatch-Reliability	\$633,250	\$355,803	\$277,446	G		(\$110,000)	(\$110,000)		\$523,250	\$245,803	\$277,446
5	561.200 Load Dispatch Monitor and Operate Trans. System	\$9,884,567	\$7,859,613	\$2,024,953			\$0			\$9,884,567	\$7,859,613	\$2,024,953
6	561.400 Scheduling, System Control and Dispatch Services	\$39,115,071	\$0	\$39,115,071	A		(\$39,115,071)		(\$39,115,071)	\$0	\$0	\$0
7	561.500 Reliability, Planning and Standards Development	\$5,180,971	\$3,963,546	\$1,217,425			\$0			\$5,180,971	\$3,963,546	\$1,217,425
8	562 - MOGS Station Expense	\$74	\$0	\$74	B		(\$74)		(\$74)	\$0	\$0	\$0
9	562 - Operating Transmission Stations	\$17,148,418	\$14,423,323	\$2,725,095			\$0			\$17,148,418	\$14,423,323	\$2,725,095
10	562 - Routine Testing and Inspection	\$4,002,506	\$2,841,206	\$1,161,300			\$0			\$4,002,506	\$2,841,206	\$1,161,300
11	562 - Sylmar/Palo Verde	\$1,032,205	\$0	\$1,032,205			\$0			\$1,032,205	\$0	\$1,032,205
12	563 - Inspect and Patrol Line	\$4,733,731	\$3,855,139	\$878,593			\$0			\$4,733,731	\$3,855,139	\$878,593
13	564 - Underground Line Expense	\$1,390,335	\$1,156,422	\$233,913			\$0			\$1,390,335	\$1,156,422	\$233,913
14	565 - Wheeling Costs	\$9,539,403	\$0	\$9,539,403	C		(\$9,539,403)	\$0	(\$9,539,403)	\$0	\$0	\$0
15	565 - WAPA Transmission for Remote Service	\$243,420	\$0	\$243,420			\$0			\$243,420	\$0	\$243,420
16	565 - Transmission for Four Corners	-\$267,657	\$0	(\$267,657)			\$0			(\$267,657)	\$0	(\$267,657)
17	566 - ISO/RSBA/TSP Balancing Accounts	-\$34,008,593	\$59,372	(\$34,067,965)	D		\$34,008,593	(\$59,372)	\$34,067,965	\$0	\$0	\$0
18	566 - Training	\$11,261,716	\$7,614,977	\$3,646,739			\$0			\$11,261,716	\$7,614,977	\$3,646,739
19	566 - Other	\$22,300,197	\$7,181,444	\$15,118,753	G&H		(\$14,261)	(\$10,752)	(\$3,509)	\$22,285,936	\$7,170,691	\$15,115,244
20	566 - NERC/CIP Compliance	-\$17,054	(\$14,126)	(\$2,928)			\$0			(\$17,054)	(\$14,126)	(\$2,928)
21	566 - Transmission Regulatory Policy	\$657,016	\$645,938	\$11,078			\$0			\$657,016	\$645,938	\$11,078
22	566 - FERC Regulation & Contracts	\$7,758,571	\$3,680,576	\$4,077,995			\$0			\$7,758,571	\$3,680,576	\$4,077,995
23	566 - Grid Contract Management	\$2,351,739	\$1,995,567	\$356,172			\$0			\$2,351,739	\$1,995,567	\$356,172
24	566 - Sylmar/Palo Verde/Other General Functions	\$944,338	\$0	\$944,338			\$0			\$944,338	\$0	\$944,338
25	567 - Line Rents	\$8,901,559	\$5,529	\$8,896,030			\$0			\$8,901,559	\$5,529	\$8,896,030
26	567 - Morongo Lease	\$6,500,000	\$0	\$6,500,000			\$0			\$6,500,000	\$0	\$6,500,000
27	567 - Eldorado	\$107,252	\$0	\$107,252			\$0			\$107,252	\$0	\$107,252
28	567 - Sylmar/Palo Verde	\$189,601	\$0	\$189,601			\$0			\$189,601	\$0	\$189,601
29	568 - Maintenance Supervision and Engineering	\$2,384,824	\$2,049,482	\$335,342			\$0			\$2,384,824	\$2,049,482	\$335,342
30	568 - Sylmar/Palo Verde	\$192,594	\$0	\$192,594			\$0			\$192,594	\$0	\$192,594
31	569 - Maintenance of Structures	\$158,593	\$39,767	\$118,826			\$0			\$158,593	\$39,767	\$118,826
32	569.100 - Hardware	\$7,271,761	\$0	\$7,271,761	F		(\$7,271,761)	\$0	(\$7,271,761)	(\$0)	\$0	(\$0)
33	569.200 - Software	\$18,769,249	\$25	\$18,769,224	F		(\$18,769,224)	\$0	(\$18,769,224)	\$25	\$25	\$0
34	569.300 - Communication	\$9,880,803	\$2,225	\$9,878,578	F		(\$6,876,266)	\$0	(\$6,876,266)	\$3,004,536	\$2,225	\$3,002,311
35	569 - Sylmar/Palo Verde	\$242,950	\$0	\$242,950			\$0			\$242,950	\$0	\$242,950
36	570 - Maintenance of Power Transformers	\$1,330,451	\$942,210	\$388,241			\$0			\$1,330,451	\$942,210	\$388,241
37	570 - Maintenance of Transmission Circuit Breakers	\$1,963,153	\$1,479,632	\$483,521			\$0			\$1,963,153	\$1,479,632	\$483,521
38	570 - Maintenance of Transmission Voltage Equipment	\$69,481	\$425,571	(\$356,090)			\$0			\$69,481	\$425,571	(\$356,090)
39	570 - Maintenance of Miscellaneous Transmission Equipment	\$1,952,398	\$1,230,390	\$722,008			\$0			\$1,952,398	\$1,230,390	\$722,008
40	570 - Substation Work Order Related Expense	\$5,512,531	\$970,207	\$4,542,324			\$0			\$5,512,531	\$970,207	\$4,542,324
41	570 - Sylmar/Palo Verde	\$1,655,073	\$744	\$1,654,329			\$0			\$1,655,073	\$744	\$1,654,329
42	571 - Poles and Structures	\$9,344,323	\$1,974,105	\$7,370,219	H		(\$4,213,792)	(\$7,564)	(\$4,206,228)	\$5,130,532	\$1,966,541	\$3,163,990
43	571 - Insulators and Conductors	\$4,912,678	\$2,815,367	\$2,097,312			\$0			\$4,912,678	\$2,815,367	\$2,097,312
44	571 - Transmission Line Rights of Way	\$17,986,496	\$2,655,913	\$15,330,583			\$0			\$17,986,496	\$2,655,913	\$15,330,583
45	571 - Transmission Work Order Related Expense	\$6,638,414	\$1,696,790	\$4,941,624			\$0			\$6,638,414	\$1,696,790	\$4,941,624
46	571 - Sylmar/Palo Verde	\$393,017	\$0	\$393,017			\$0			\$393,017	\$0	\$393,017
47	572 - Maintenance of Underground Transmission Lines	\$388,987	\$203,478	\$185,509			\$0			\$388,987	\$203,478	\$185,509
48	572 - Sylmar/Palo Verde	\$2,322	\$0	\$2,322			\$0			\$2,322	\$0	\$2,322
49	573 - Provision for Property Damage Expense to Trans. Fac.	\$2,970,934	\$1,053,187	\$1,917,747			\$0			\$2,970,934	\$1,053,187	\$1,917,747
50	...	---	---	---	---		\$0	---	---			
51	Transmission NOIC (Note 3)	-	-	-			\$8,201,574	\$8,201,574	\$0	\$8,201,574	\$8,201,574	\$0
52	Total Transmission O&M	\$221,093,098	\$76,684,121	\$144,408,977			(\$43,908,981)	\$8,012,886	-\$51,921,868	\$177,184,117	\$84,697,007	\$92,487,110
53												

Schedule 19
Operations and Maintenance

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

Col 1	Col 2 = C3 + C4	Col 3	Col 4	Col 5 Note 2	Col 6 = C7 + C8	Col 7	Col 8	Col 9 = C10 + C11	Col 10 = C3 + C7	Col 11 = C4 + C8
Account/Work Activity Rev	Total Recorded O&M Expenses			Reason	Adjustments			Adjusted Recorded O&M Expenses		
	Total	Labor	Non-Labor		Total	Labor	Non-Labor	Total	Labor	Non-Labor
Distribution Accounts										
54 582 - Operation and Relay Protection of Distribution Substation	24,220,560	\$17,289,915	\$6,930,645		-			\$24,220,560	\$17,289,915	\$6,930,645
55 582 - Testing and Inspecting Distribution Substation Equipmen	10,791,931	\$9,155,923	\$1,636,008		-			\$10,791,931	\$9,155,923	\$1,636,008
56 590 - Maintenance Supervision and Engineering	2,386,348	\$2,048,869	\$337,479		-			\$2,386,348	\$2,048,869	\$337,479
57 591 - Maintenance of Structures	72,359	\$7,390	\$64,969		-			\$72,359	\$7,390	\$64,969
58 592 - Maintenance of Distribution Transformers	857,666	\$603,961	\$253,705		-			\$857,666	\$603,961	\$253,705
59 592 - Maintenance of Distribution Circuit Breakers	2,677,958	\$2,302,750	\$375,208		-			\$2,677,958	\$2,302,750	\$375,208
60 592 - Maintenance of Distribution Voltage Control Equipment	981,244	\$848,245	\$132,999		-			\$981,244	\$848,245	\$132,999
61 592 - Maintenance of Miscellaneous Distribution Equipment	5,744,953	\$1,620,665	\$4,124,288		-			\$5,744,953	\$1,620,665	\$4,124,288
62 Accounts with no ISO Distribution Costs	475,672,744	\$203,269,818	\$272,402,926	G&H	(\$8,126,066)	(\$750,468)	(\$7,375,599)	\$467,546,678	\$202,519,351	\$265,027,327
63 Distribution NOIC (Note 3)	-	-	-		\$25,363,571	\$25,363,571	\$0	\$25,363,571	\$25,363,571	\$0
64 Total Distribution O&M	\$523,405,764	\$237,147,537	\$286,258,227		\$17,237,504	\$24,613,103	(\$7,375,599)	\$540,643,268	\$261,760,640	\$278,882,628
65										
66 Total Transmission and Distribution O&M	\$744,498,862	\$313,831,657	\$430,667,204		(\$26,671,477)	\$32,625,989	(\$59,297,466)	\$717,827,385	\$346,457,646	\$371,369,738
67										
68 Total Transmission O&M Expenses in FERC Form 1:	\$221,093,099	FF1 321.112b	Must equal Line 52, Column 2.							
69 Total Distribution O&M Expenses in FERC Form 1:	\$523,405,763	FF1 322.156b	Must equal Line 64, Column 2.							
70 Total TDBU NOIC	\$33,565,145	20-AandG, Note 2, f								

2) Determination of ISO Operations and Maintenance Expenses for each account (Note 5).

Line	Account/Work Activity Rev	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
			From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO	
		Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor	Reference	
71	560 - Operations Engineering	\$7,132,768	\$3,519,700	\$3,613,067	38.8%	\$2,765,373	\$1,364,587	\$1,400,785	Note 6, a	
72	560 - Sylmar/Palo Verde	\$147,369	\$0	\$147,369	100.0%	\$147,369	\$0	\$147,369	100% per Protocols	
73	561.000 Load Dispatching	\$0	\$0	\$0	34.9%	\$0	\$0	\$0	27-Allocators Line 30	
74	561.100 Load Dispatch-Reliability	\$523,250	\$245,803	\$277,446	34.9%	\$182,781	\$85,864	\$96,917	27-Allocators Line 30	
75	561.200 Load Dispatch Monitor and Operate Trans. System	\$9,884,567	\$7,859,613	\$2,024,953	34.9%	\$3,452,873	\$2,745,517	\$707,356	27-Allocators Line 30	
76	561.400 Scheduling, System Control and Dispatch Services	\$0	\$0	\$0	0.0%	\$0	\$0	\$0	0% per Protocols	
77	561.500 Reliability, Planning and Standards Development	\$5,180,971	\$3,963,546	\$1,217,425	100.0%	\$5,180,971	\$3,963,546	\$1,217,425	100% per Protocols	
78	562 - MOGS Station Expense	\$0	\$0	\$0	0.0%	\$0	\$0	\$0	0% per Protocols	
79	562 - Operating Transmission Stations	\$17,148,418	\$14,423,323	\$2,725,095	17.7%	\$3,036,993	\$2,554,378	\$482,616	27-Allocators Line 36	
80	562 - Routine Testing and Inspection	\$4,002,506	\$2,841,206	\$1,161,300	13.8%	\$551,531	\$391,508	\$160,023	27-Allocators Line 42	
81	562 - Sylmar/Palo Verde	\$1,032,205	\$0	\$1,032,205	100.0%	\$1,032,205	\$0	\$1,032,205	100% per Protocols	
82	563 - Inspect and Patrol Line	\$4,733,731	\$3,855,139	\$878,593	46.8%	\$2,213,224	\$1,802,444	\$410,780	27-Allocators Line 48	
83	564 - Underground Line Expense	\$1,390,335	\$1,156,422	\$233,913	1.4%	\$20,123	\$16,737	\$3,386	27-Allocators Line 54	
84	565 - Wheeling Costs	\$0	\$0	\$0	0.0%	\$0	\$0	\$0	0% per Protocols	
85	565 - WAPA Transmission for Remote Service	\$243,420	\$0	\$243,420	0.0%	\$0	\$0	\$0	0% per Protocols	
86	565 - Transmission for Four Corners	(\$267,657)	\$0	(\$267,657)	100.0%	(\$267,657)	\$0	(\$267,657)	100% per Protocols	
87	566 - ISO/RSBA/TSP Balancing Accounts	\$0	\$0	\$0	0.0%	\$0	\$0	\$0	0% per Protocols	
88	566 - Training	\$11,261,716	\$7,614,977	\$3,646,739	38.8%	\$4,366,165	\$2,952,325	\$1,413,840	Note 6, a	
89	566 - Other	\$22,285,936	\$7,170,691	\$15,115,244	38.8%	\$8,640,252	\$2,780,076	\$5,860,177	Note 6, a	
90	566 - NERC/CIP Compliance	(\$17,054)	(\$14,126)	(\$2,928)	65.4%	(\$11,150)	(\$9,236)	(\$1,914)	7-PlantStudy, Line 21, C3	
91	566 - Transmission Regulatory Policy	\$657,016	\$645,938	\$11,078	65.4%	\$429,566	\$422,323	\$7,243	7-PlantStudy, Line 21, C3	
92	566 - FERC Regulation & Contracts	\$7,758,571	\$3,680,576	\$4,077,995	65.4%	\$5,072,661	\$2,406,412	\$2,666,249	7-PlantStudy, Line 21, C3	
93	566 - Grid Contract Management	\$2,351,739	\$1,995,567	\$356,172	65.4%	\$1,537,599	\$1,304,729	\$232,870	7-PlantStudy, Line 21, C3	
94	566 - Sylmar/Palo Verde/Other General Functions	\$944,338	\$0	\$944,338	100.0%	\$944,338	\$0	\$944,338	100% per Protocols	
95	567 - Line Rents	\$8,901,559	\$5,529	\$8,896,030	68.2%	\$6,071,296	\$3,771	\$6,067,526	27-Allocators Line 60	
96	567 - Morongo Lease	\$6,500,000	\$0	\$6,500,000	90.8%	\$5,902,213	\$0	\$5,902,213	27-Allocators Line 66	
97	567 - Eldorado	\$107,252	\$0	\$107,252	100.0%	\$107,252	\$0	\$107,252	100% per Protocols	
98	567 - Sylmar/Palo Verde	\$189,601	\$0	\$189,601	100.0%	\$189,601	\$0	\$189,601	100% per Protocols	
99	568 - Maintenance Supervision and Engineering	\$2,384,824	\$2,049,482	\$335,342	33.8%	\$806,133	\$692,779	\$113,354	Note 6, c	
100	568 - Sylmar/Palo Verde	\$192,594	\$0	\$192,594	100.0%	\$192,594	\$0	\$192,594	100% per Protocols	
101	569 - Maintenance of Structures	\$158,593	\$39,767	\$118,826	20.9%	\$33,071	\$8,293	\$24,779	Note 6, b	
102	569.100 - Hardware	(\$0)	\$0	(\$0)	38.8%	(\$0)	\$0	(\$0)	Note 6, a	
103	569.200 - Software	\$25	\$25	\$0	38.8%	\$10	\$10	\$0	Note 6, a	
104	569.300 - Communication	\$3,004,536	\$2,225	\$3,002,311	38.8%	\$1,164,858	\$863	\$1,163,995	Note 6, a	
105	569 - Sylmar/Palo Verde	\$242,950	\$0	\$242,950	100.0%	\$242,950	\$0	\$242,950	100% per Protocols	
106	570 - Maintenance of Power Transformers	\$1,330,451	\$942,210	\$388,241	23.3%	\$309,712	\$219,334	\$90,377	27-Allocators Line 72	
107	570 - Maintenance of Transmission Circuit Breakers	\$1,963,153	\$1,479,632	\$483,521	36.6%	\$719,465	\$542,262	\$177,203	27-Allocators Line 74	
108	570 - Maintenance of Transmission Voltage Equipment	\$69,481	\$425,571	(\$356,090)	66.5%	\$46,230	\$283,159	(\$236,929)	27-Allocators Line 84	
109	570 - Maintenance of Miscellaneous Transmission Equipment	\$1,952,398	\$1,230,390	\$722,008	33.8%	\$659,962	\$415,904	\$244,058	Note 6, c	
110	570 - Substation Work Order Related Expense	\$5,512,531	\$970,207	\$4,542,324	25.3%	\$1,396,027	\$245,701	\$1,150,326	27-Allocators Line 90	
111	570 - Sylmar/Palo Verde	\$1,655,073	\$744	\$1,654,329	100.0%	\$1,655,073	\$744	\$1,654,329	100% per Protocols	
112	571 - Poles and Structures	\$5,130,532	\$1,966,541	\$3,163,990	46.8%	\$2,398,745	\$919,443	\$1,479,302	27-Allocators Line 48	
113	571 - Insulators and Conductors	\$4,912,678	\$2,815,367	\$2,097,312	46.8%	\$2,296,889	\$1,316,305	\$980,584	27-Allocators Line 48	
114	571 - Transmission Line Rights of Way	\$17,986,496	\$2,655,913	\$15,330,583	46.8%	\$8,409,463	\$1,241,754	\$7,167,709	27-Allocators Line 48	
115	571 - Transmission Work Order Related Expense	\$6,638,414	\$1,696,790	\$4,941,624	27.5%	\$1,827,708	\$467,165	\$1,360,543	27-Allocators Line 96	
116	571 - Sylmar/Palo Verde	\$393,017	\$393,017	\$0	100.0%	\$393,017	\$0	\$393,017	100% per Protocols	
117	572 - Maintenance of Underground Transmission Lines	\$388,987	\$203,478	\$185,509	1.4%	\$5,630	\$2,945	\$2,685	27-Allocators Line 54	
118	572 - Sylmar/Palo Verde	\$2,322	\$0	\$2,322	100.0%	\$2,322	\$0	\$2,322	100% per Protocols	
119	573 - Provision for Property Damage Expense to Trans. Fac.	\$2,970,934	\$1,053,187	\$1,917,747	45.2%	\$1,343,856	\$476,393	\$867,463	27-Allocators Line 102	
120	...	---	---	---	---	---	---	---		
121	Transmission NOIC (Note 4)	\$8,201,574	\$8,201,574	\$0		\$3,175,542	\$3,175,542	\$0		
122	Total Transmission - ISO O&M	\$177,184,117	\$84,697,007	\$92,487,110		\$78,644,834	\$32,793,575	\$45,851,259		

Schedule 19
Operations and Maintenance

Col 1 Account/Work Activity Rev	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
	From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
Adjusted Recorded O&M Expenses	Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO
	Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor	Reference
Distribution Accounts								
124 582 - Operation and Relay Protection of Distribution Substation	\$24,220,560	\$17,289,915	\$6,930,645	0.00%	-	-	-	Note 6, d
125 582 - Testing and Inspecting Distribution Substation Equipment	\$10,791,931	\$9,155,923	\$1,636,008	0.00%	-	-	-	Note 6, d
126 590 - Maintenance Supervision and Engineering	\$2,386,348	\$2,048,869	\$337,479	0.00%	-	-	-	Note 6, d
127 591 - Maintenance of Structures	\$72,359	\$7,390	\$64,969	0.00%	-	-	-	Note 6, d
128 592 - Maintenance of Distribution Transformers	\$857,666	\$603,961	\$253,705	0.0%	-	-	-	27-Allocators Line 108
129 592 - Maintenance of Distribution Circuit Breakers	\$2,677,958	\$2,302,750	\$375,208	0.0%	-	-	-	27-Allocators Line 114
130 592 - Maintenance of Distribution Voltage Control Equipment	\$981,244	\$848,245	\$132,999	0.0%	-	-	-	27-Allocators Line 120
131 592 - Maintenance of Miscellaneous Distribution Equipment	\$5,744,953	\$1,620,665	\$4,124,288	0.00%	-	-	-	Note 6, d
132 Accounts with no ISO Distribution Costs	\$467,546,678	\$202,519,351	\$265,027,327	0.00%	-	-	-	0% per Protocols
133 Distribution NOIC (Note 4)	\$25,363,571	\$25,363,571	\$0	0.00%	-	-	-	0% per Protocols
134 Total Distribution - ISO O&M	\$540,643,268	\$261,760,640	\$278,882,628		-	-	-	
135								
136								
137 Total ISO O&M Expenses (in Column 6)	\$717,827,385	\$346,457,646	\$371,369,738		\$78,644,834	\$32,793,575	\$45,851,259	
138 Line 122 + Line 134								

Notes:

1) "Adjusted Operations and Maintenance Expenses for each account" are the total amounts of O&M costs booked to each Transmission or Distribution account, less adjustments as noted.

2) Reasons for excluded amounts:

A: Exclude entire amount, all attributable to CAISO costs recovered in Energy Resource Recovery Account.

B: Exclude amount related to MOGS Station Expense.

C: Exclude amount attributable to CAISO costs recovered in Energy Resource Recovery Account.

D: Exclude amount recovered through to Reliability Services Balancing Account, the Transmission Access Charge Balancing Account Adjustment, and the American Reinvestment Recovery Act for the Tehachapi Wind Energy Storage Project.

E: Add NOIC annual payout.

F: Exclude amount of costs transferred to account from A&G Account 920 pursuant to Order 668.

G: Exclude any amount of ACE awards or Spot Bonuses in O&M accounts 560-592.

H: Excludes shareholder funded costs.

I: Exclude EEI & EPRI Dues Re-Mapped to FERC Account 930.2 Miscellaneous general expenses.

3) Total TDBU NOIC is allocated to Transmission and Distribution in proportion to labor in the respective functions. Transmission NOIC ("Non-Officer Incentive Compensation") equals Total TDBU NOIC times the Transmission NOIC Percentage calculated below. Distribution NOIC equals Total TDBU NOIC times the Distribution NOIC Percentage below.

Total TDBU NOIC is on Line: **70**

	Percentage	Calculation
Transmission NOIC Percentage:	24.4348%	Line 52, Col 3 / Line 66, Col 3
Distribution NOIC Percentage:	75.5652%	Line 64, Col 3 / Line 66, Col 3

4) NOIC attributable to ISO Transmission (Column 7) is calculated utilizing a percentage equal to the ratio of total ISO O&M Labor Expenses in column 7 (exclusive of NOIC) to the total labor expenses in column 3 (exclusive of NOIC). That allocator, which is identified below, is then applied to the value in Column 3 to arrive at the NOIC attributable to ISO Transmission in Column 7.

Resulting Percentage is: **38.72%**

5) "ISO Operations and Maintenance Expenses" is the amount of costs in each Transmission or Distribution account related to ISO Transmission Facilities.

6) "Percent ISO" percentages are calculated in accordance with the method set forth in SCE's TO Tariff protocols. See Column 9 for references to source of each Percent ISO.

Certain "Percent ISO percentages are calculable based on other "Percent ISO" amounts, as follows:

	Percent ISO
a) Accounts 560 - Operations Engineering, 566 - Training, 566-Other, 569.100 Hardware, 569.200 Software, and 569.300 Communication: Percent ISO for these accounts is equal to total ISO labor in accounts 561, 562, 563, 564, 566 (except Training and Other), 570, 571, and 572 (Column 7) divided by total labor in these same accounts (column 3):	38.8%
b) Account 569 - Maintenance of Structures Percent ISO for this account is equal to the total ISO labor in accounts 562 and 570 (Column 7) divided by total labor in this same account (Column 3).	20.9%
c) Account 570 - Maintenance of Miscellaneous Transmission Equipment and Account 568 -Maintenance Supervision and Engineering Percent ISO for this account is equal to the total ISO labor in accounts listed below (Column 7) divided by total labor in these same accounts (Column 3). 570 - Maintenance of Power Transformers 570 - Substation Work Order Related Expense 570 - Maintenance of Transmission Voltage Equipment 570 - Maintenance of Transmission Circuit Breakers	33.8%
d) Accounts 582, 590, 591, and 592 - Maintenance of Miscellaneous Distribution Equipment Percent ISO for these accounts is equal to the total ISO labor in account 592, exclusive of Maintenance of Miscellaneous Distribution Equipment (Column 7) divided by total labor in this same account (Column 3).	0.00%

7) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 19.

Schedule 20
Administrative and General Expenses

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

Calculation of Administrative and General Expense

Inputs are shaded yellow

Line	Acct.	Description	Col 1	Col 2	Col 3	Col 4	Notes
			FERC Form 1 Amount	Data Source	See Note 1 Total Amount Excluded	A&G Expense	
1	920	A&G Salaries	\$354,859,044	FF1 323.181b	\$69,867,001	\$284,992,043	
2	921	Office Supplies and Expenses	\$249,803,334	FF1 323.182b	\$5,868,285	\$243,935,049	
3	922	A&G Expenses Transferred	-\$145,897,634	FF1 323.183b	-\$48,972,720	-\$96,924,914	Credit
4	923	Outside Services Employed	\$54,121,017	FF1 323.184b	\$7,684,282	\$46,436,735	
5	924	Property Insurance	\$14,497,978	FF1 323.185b	\$0	\$14,497,978	
6	925	Injuries and Damages	\$117,581,984	FF1 323.186b	-\$694,137	\$118,276,121	
7	926	Employee Pensions and Benefits	\$142,806,958	FF1 323.187b	-\$15,693,853	\$158,500,811	
8	927	Franchise Requirements	\$110,632,750	FF1 323.188b	\$110,632,750	\$0	
9	928	Regulatory Commission Expenses	\$16,012,736	FF1 323.189b	\$17,351,998	-\$1,339,262	
10	929	Duplicate Charges	\$0	FF1 323.190b	\$0	\$0	
11	930.1	General Advertising Expense	\$5,718,074	FF1 323.191b	\$0	\$5,718,074	
12	930.2	Miscellaneous General Expense	\$34,422,373	FF1 323.192b	\$24,004,996	\$10,417,377	
13	931	Rents	\$6,627,867	FF1 323.193b	\$11,411,119	-\$4,783,252	
14	935	Maintenance of General Plant	\$13,296,044	FF1 323.196b	\$697,671	\$12,598,373	
15			\$974,482,525		Total A&G Expenses:	\$792,325,134	

		Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	\$792,325,134	Line 15
17	Less Account 924:	\$14,497,978	Line 5
18	Amount to apply the Transmission W&S AF:	\$777,827,156	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	5.6290%	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	\$43,784,056	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	19.1115%	27-Allocators, Line 22
22	Property Insurance portion of A&G:	\$2,770,777	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	\$46,554,833	Line 20 + Line 22

Note 1: Itemization of exclusions

Line	Acct.	Total Amount Excluded (Sum of Col 1 to Col 4)	Col 1	Col 2	Col 3	Col 4	Notes
			Shareholder Exclusions or Other Adjustments	Franchise Requirements	NOIC	PBOPs	
24	920	\$69,867,001	-\$11,516,850		\$81,383,851		See Instructions 2b, 3, and Note 2
25	921	\$5,868,285	\$5,868,285		\$0		
26	922	-\$48,972,720	-\$7,655,813		-\$41,316,907		
27	923	\$7,684,282	\$7,684,282		\$0		
28	924	\$0	\$0		\$0		
29	925	-\$694,137	-\$694,137		\$0		
30	926	-\$15,693,853	\$19,430,853		\$0	-\$35,124,706	See Note 3
31	927	\$110,632,750	\$0	\$110,632,750	\$0	\$0	See Note 4
32	928	\$17,351,998	\$17,351,998		\$0		
33	929	\$0	\$0		\$0		
34	930.1	\$0	\$0		\$0		
35	930.2	\$24,004,996	\$24,004,996		\$0		
36	931	\$11,411,119	\$11,411,119		\$0		
37	935	\$697,671	\$697,671		\$0		

Schedule 20
Administrative and General Expenses

Note 2: Non-Officer Incentive Compensation ("NOIC") Adjustment

(NOIC includes Results Sharing, Management Incentive Program, and Non-Officer Executive Incentive Compensation).
Adjust NOIC by excluding accrued NOIC Amount and replacing with the actual non-capitalized A&G NOIC payout.

	<u>Amount</u>	<u>Source</u>
a	Accrued NOIC Amount: \$103,811,325	SCE Records
b	Actual A&G NOIC payout: \$22,427,473	Note 2, d
c	Adjustment: \$81,383,851	

Actual non-capitalized NOIC Payouts:

	<u>Department</u>	<u>Amount</u>	<u>Source</u>
d	A&G	\$22,427,473	SCE Records and Workpapers
e	Other	\$10,140,103	SCE Records and Workpapers
f	Trans. And Dist. Business Unit	\$33,565,145	SCE Records and Workpapers
g	Total:	\$66,132,721	Sum of d to f

Note 3: PBOPs Exclusion Calculation

	<u>Amount</u>	<u>Note:</u>
a	Authorized PBOPs expense amount: \$40,171,333	See instruction #4
b	Prior Year FF1 PBOPs expense: \$5,046,627	SCE Records
c	PBOPs Expense Exclusion: -\$35,124,706	b - a

Note 4:

Amount in Line 31, column 2 equals amount in Line 8, column 1 because all Franchise Requirements Expenses are excluded Franchise Fees Expenses component of the Prior Year TRR are based on Franchise Fee Factors.

Schedule 20
Administrative and General Expenses

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

Instructions:

- 1) Enter amounts of A&G expenses from FERC Form 1 in Lines 1 to 14.
- 2) Fill out "Itemization of Exclusions" table for all input cells. NOIC amount in Column 3, Line 24 is calculated in Note 2. The PBOPs exclusion in Column 4, Line 30 is calculated in Note 3.
 - a) Exclude amount of any Shareholder Adjustments, costs incurred on behalf of SCE shareholders, from relevant account in Column 1.
 - b) Include as an adjustment in Column 1 for Account 920 any amount excluded from Accounts 569.100, 569.200, and 569.300 in Schedule 19 (OandM) related to Order 668 costs transferred.
 - c) Exclude entire amount of account 927 "Franchise Requirements" in Column 2, as those costs are recovered through the Franchise Fees Expense item.
 - d) Exclude any amount of Account 930.1 "General Advertising Expense" not related to advertising for safety, siting, or informational purposes in column 1.
 - e) Exclude any amount of expense relating to secondary land use and audit expenses not directly benefitting utility customers.
 - f) Exclude from account 930.2:
 - 1) Nuclear Power Research Expenses.
 - 2) Write Off of Abandoned Project Expenses.
 - 3) Any advertising expenses within the Consultants/Professional Services category.
 - g) Exclude the following costs included in any account 920-935:
 - 1) Any amount of "Provision for Doubtful Accounts" costs.
 - 2) Any amount of "Accounting Suspense" costs.
 - 3) Any penalties of fines.
 - 4) Any amount of costs recovered 100% through California Public Utilities Commission ("CPUC") rates.
 - h) Exclude the following amounts of employee incentive compensation from any account 920-935:
 - 1) Any Long Term Incentive Compensation ("LTI") costs.
 - 2) Beginning with Prior Year 2012, any amount of Officer Executive Incentive Compensation ("OEIC") in excess of the amount authorized by the CPUC in Decision D.12-11-051 or subsequent decision.
 - 3) Beginning with Prior Year 2012, any amount of Supplemental Executive Retirement Plan ("SERP") in excess of the amount authorized by the CPUC in Decision D.12-11-051 or subsequent decision.
 - 4) Beginning with Prior Year 2012, any amount of NOIC in excess of the amount authorized by the CPUC in Decision D.12-11-051 or subsequent decision.
 - 5) Any Spot Bonus costs.
 - 6) Any Awards to Celebrate Excellence ("ACE") costs.
- 3) NOIC adjustment in Column 3, Line 24 is made by determining the difference between the total accrued NOIC amount included in the FERC Form 1 recorded cost amounts and the actual A&G NOIC payout (see note 2). NOIC adjustment in column 3, Line 26 is made by entering the amount of accrued NOIC that is capitalized.
- 4) Determine the PBOPs exclusion. The authorized amount of PBOPs expense (line a) may only be revised pursuant to Commission acceptance of an SCE FPA Section 205 filing to revise the authorized PBOPs expense, in accordance with the tariff protocols. Accordingly, any amount different than the authorized PBOPs expense is excluded from account 926 (see note 3). Docket or Decision approving authorized PBOPs amount: ER16-2433
- 5) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 20.

Schedule 21
Revenue Credits

A		B		C		D	E	F			G		H	I	J	K		L	M	N
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Traditional OOR			GRSM			Other Ratemaking		Notes						
						Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total							
12a	456	4186114	Energy Related Services	3,857,356	Traditional OOR	3,857,356	0	3,857,356	0			0					0	0	1	
12b	456	4186118	Distribution Miscellaneous Electric Revenues	576	Traditional OOR	576	0	576	0			0					0	0	4	
12c	456	4186120	Added Facilities - One Time Charge	133,080	Traditional OOR	133,080	0	133,080	0			0					0	0	4	
12d	456	4186122	Building Rental - Nev Power/Mohave Cr	0	Traditional OOR	0	0	0	0			0					0	0	3	
12e	456	4186126	Service Fee - Optimal Bill Prd	160	Traditional OOR	160	0	160	0			0					0	0	1	
12f	456	4186128	Miscellaneous Revenues	803,911	Traditional OOR	803,911	0	803,911	0			0					0	0	1	
12g	456	4186130	Tule Power Plant - Revenue	0	Traditional OOR	0	0	0	0			0					0	0	3	
12h	456	4186142	Microwave Agreement	3,428	Traditional OOR	3,428	0	3,428	0			0					0	0	4	
12i	456	4186150	Utility Subs Labor Markup	0	Traditional OOR	0	0	0	0			0					0	0	7	
12j	456	4186155	Non Utility Subs Labor Markup	8,005	Other Ratemaking	474	474	0	0			0					7,531	0	6, 12	
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	1,447	Traditional OOR	1,447	0	1,447	0			0					0	0	4	
12l	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	14,522	Traditional OOR	14,522	0	14,522	0			0					0	0	4	
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etswana	4,388	Traditional OOR	4,388	0	4,388	0			0					0	0	4	
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	993	Traditional OOR	993	0	993	0			0					0	0	4	
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	845	Traditional OOR	845	0	845	0			0					0	0	4	
12p	456	4186194	Property License Fee revenue	173,880	Traditional OOR	173,880	0	173,880	0			0					0	0	4	
12q	456	4186512	Revenue From Recreation, Fish & Wildlife	1,965,774	GRSM	0	0	0	1,965,774	P	315,815	1,649,958	0				0	2		
12r	456	4186514	Mapping Services	161,225	GRSM	0	0	0	161,225	P	37,883	123,342	0				0	2		
12s	456	4186518	Enhanced Pump Test Revenue	40,875	GRSM	0	0	0	40,875	P	84	40,791	0				0	2		
12t	456	4186520	RTTC Revenue	0	GRSM	0	0	0	0	P	0	0	0				0	2		
12u	456	4186524	Revenue From Scrap Paper - General Office	0	GRSM	0	0	0	0	P	0	0	0				0	2		
12v	456	4186528	CTAC Revenues	1,700	GRSM	0	0	0	1,700	P	0	1,700	0				0	2		
12w	456	4186530	AGTAC Revenues	3,775	GRSM	0	0	0	3,775	P	2,775	1,000	0				0	2		
12x	456	4186536	Other Inc/erd Party DC-ESM	0	GRSM	0	0	0	0	P	0	0	0				0	2		
12y	456	4186538	3rd Party-Div Tmq-Cr PPD training	0	GRSM	0	0	0	0	P	0	0	0				0	2		
12z	456	4186716	ADT Vendor Service Revenue	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12aa	456	4186718	Read Water Meters - Irvine Ranch	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12bb	456	4186720	Read Water Meters - Rancho California	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12cc	456	4186722	Read Water Meters - Long Beach	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12dd	456	4186730	SSID Transformer Repair Services Revenue	56,262	GRSM	0	0	0	56,262	A	20,209	36,053	0				0	2		
12ee	456	4186815	Employee Transfer/Affiliate Fee	0	Other Ratemaking	0	0	0	0			0					0	6		
12ff	456	4186910	ITCC/CIAC Revenues	25,076,869	Traditional OOR	25,076,869	0	25,076,869	0			0					0	4		
12gg	456	4186912	Revenue From Decommission Trust Fund	(450,696,490)	Other Ratemaking	0	0	0	0			0					(450,696,490)	6		
12hh	456	4186914	Revenue From Decommissioning Trust FAS115	(11,397,579)	Other Ratemaking	0	0	0	0			0					(11,397,579)	6		
12ii	456	4186916	Offset to Revenue from NDT Earnings/Realized	450,696,234	Other Ratemaking	0	0	0	0			0					450,696,234	6		
12ij	456	4186918	Offset to Revenue from FAS 115 FMV	11,397,579	Other Ratemaking	0	0	0	0			0					11,397,579	6		
12kk	456	4186920	Revenue From Decommissioning Trust FAS115-1	38,748,032	Other Ratemaking	0	0	0	0			0					38,748,032	6		
12ll	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	(38,748,032)	Other Ratemaking	0	0	0	0			0					(38,748,032)	6		
12mm	456	4188712	Power Supply Installations - IMS	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12nn	456	4188714	Consulting Fees - IMS	0	GRSM	0	0	0	0	A	0	0	0				0	2		
12oo	456	4188818	FTR Auction Revenue	0	Other Ratemaking	0	0	0	0			0					0	6		
12pp	456	4196105	DA Revenue	137,952	Traditional OOR	137,952	0	137,952	0			0					0	1		
12qq	456	4196154	Direct Access Monthly Customer Charges	0	Traditional OOR	0	0	0	0			0					0	1		
12rr	456	4196158	EDBL Customer Finance Added Facilities	4,720,962	Traditional OOR	4,720,962	0	4,720,962	0			0					0	4		
12ss	456	4196162	SCE Energy Manager Fee Based Services	139,470	Traditional OOR	139,470	0	139,470	0			0					0	4		
12tt	456	4196166	SCE Energy Manager Fee Based Services Adj	0	Traditional OOR	0	0	0	0			0					0	4		
12uu	456	4196172	Off Grid Photo Voltaic Revenues	0	Traditional OOR	0	0	0	0			0					0	1		
12vv	456	4196174	Scheduling/Dispatch Revenues	0	Traditional OOR	0	0	0	0			0					0	4		
12ww	456	4196176	Interconnect Facilities Charges-Customer Financed	3,322,797	Traditional OOR	3,322,797	24,628	3,298,169	0			0					0	8		
12xx	456	4196178	Interconnect Facilities Charges - SCE Financed	15,018,441	Traditional OOR	15,018,441	0	15,018,441	0			0					0	4		
12yy	456	4196184	DMS Service Fees	2,757	Traditional OOR	2,757	0	2,757	0			0					0	4		
12zz	456	4196188	CCA - Information Fees	435,631	Traditional OOR	435,631	0	435,631	0			0					0	6		
12aaa	456	4206515	Operating Miscellaneous Land & Facilities	0	GRSM	0	0	0	0	P	0	0	0				0	2		
12bbb	456	-	Miscellaneous Adjustments	513	Traditional OOR	513	0	513	0			0					0	1		
12ccc	456	4186911	Grant Amortization	4,866,855	Other Ratemaking	0	0	0	0			0					4,866,855	6		
12ddd	456	4186925	GHG Allowance Revenue	384,894,152	Other Ratemaking	0	0	0	0			0					384,894,152	6		
12eee	456	4186132	Intercon One Time	1,589,445	Traditional OOR	1,589,445	0	1,589,445	0			0					0	4		
12fff	456	4186116	EV Charging Revenue	0	Traditional OOR	0	0	0	0			0					0	4		
12ggg	456	4186115	Energy Relt'd Srv-TSP	95,177	Traditional OOR	95,177	0	95,177	0			0					0	4		
12hhh	456	4186156	N/U Labor Mrkp-BRRBA	131,685	Other Ratemaking	7,794	7,794	0	0			0					123,890	6, 12		
12iii	456	4188720	LCFS CR 411.8	19,405,750	Traditional OOR	19,405,750	0	19,405,750	0			0					0	4		
12jjj	456	4186128	Miscellaneous Revenues - ISO	5,000	Traditional OOR	5,000	5,000	0	0			0					0	5		
12kkk	456	4186732	Power Quality C&I Customer Program	12,000	GRSM	0	0	0	12,000	P	0	12,000	0				0	2		
13	456	Total		467,087,400		74,953,617	37,896	74,915,721	2,241,611		376,767	1,864,844	389,892,172							
14		FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)		467,087,400																

Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Traditional OOR			GRSM			Other Ratemaking	Notes
						Total	ISO	Non-ISO	Total	A/P	Threshold [10]		
15a	456.1	4188112	Trans of Elec of Others - Pasadena		Traditional OOR	0	0	0	0		0	0	5
15b	456.1	4188114	FTS PPU/Non-ISO	296,028	Traditional OOR	296,028	0	296,028	0		0	0	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	930,163	Traditional OOR	930,163	0	930,163	0		0	0	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	151,885	Other Ratemaking	0	0	0	0		0	151,885	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	74,458,175	Other Ratemaking	0	0	0	0		0	74,458,175	6
15f	456.1	4188816	ISO-Congestion Revenue		Other Ratemaking	0	0	0	0		0	0	6
15g	456.1	4198110	Transmission of Elec of Others	46,329,301	Traditional OOR	46,329,301	46,329,301	0	0		0	0	5
15h	456.1	4198112	WDAT	5,560,313	Traditional OOR	5,560,313	0	5,560,313	0		0	0	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	(574,575)	Traditional OOR	(574,575)	0	(574,575)	0		0	0	4
15j	456.1	4198115	High Voltage Trans Access Rev (Existing Contracts)		Other Ratemaking	0	0	0	0		0	0	6
15k	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	1,080,948	Traditional OOR	1,080,948	0	1,080,948	0		0	0	4
15l	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	402,148	Traditional OOR	402,148	0	402,148	0		0	0	4
15m	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	209,706	Traditional OOR	209,706	0	209,706	0		0	0	4
15n	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	89,265	Traditional OOR	89,265	0	89,265	0		0	0	4
15o	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	651,331	Traditional OOR	651,331	0	651,331	0		0	0	4
15p	456.1	4198126	High Desert Tie-Line Rental Rev	264,133	Traditional OOR	264,133	0	264,133	0		0	0	4
15q	456.1	4198128	Scheduling/Dispatch Revenues (CSS)		Traditional OOR	0	0	0	0		0	0	4
15r	456.1	4198130	Inland Empire CRT Tie-Line EX	42,492	Traditional OOR	42,492	0	42,492	0		0	0	4
15s	456.1	4198910	Reliability Service Revenue - Non-PTO's	285,798	Other Ratemaking	0	0	0	0		0	285,798	6
15t	456.1	4198132	Radial Line Agreement-Base-Mojave Solr	90,533	Traditional OOR	90,533	0	90,533	0		0	0	4
15u	456.1	4198134	Radial Line Agreement-O&M-Mojave Solr	229,854	Traditional OOR	229,854	0	229,854	0		0	0	4
15v	456.1	4188716	ISO Non-Refundable Interconnection Deposit	3,708,123	Other Ratemaking	0	0	0	0		0	3,708,123	6
16	456.1 Total			134,205,621		55,601,640	46,329,301	9,272,339	0	0	0	78,603,981	
17	FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)			134,205,621									
18a													
19	457.1 Total			0		0	0	0	0	0	0	0	
20	FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)			0									
21a													
22	457.2 Total			0		0	0	0	0	0	0	0	
23	FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)			0									
Edison Carrier Solutions (ECS)													
24a	417	4863135	ECS - Pass Pole Attachments		GRSM	0	0	0	0	P		0	2
24b	417	4863130	ECS - Distribution Facilities	605,719	GRSM	0	0	0	605,719	P	138,132	467,587	2
24c	417	4862110	ECS - Dark Fiber	6,207,732	GRSM	0	0	0	6,207,732	A	1,179,301	5,028,431	2
24d	417	4862115	ECS - SCE Net Fiber	3,328,620	GRSM	0	0	0	3,328,620	A	648,086	2,680,534	2
24e	417	4862120	ECS - Transmission Right of Way	283,556	GRSM	0	0	0	283,556	A	55,208	228,348	2
24f	417	4862135	ECS - Wholesale FCC	21,488,152	GRSM	0	0	0	21,488,152	A	4,216,369	17,271,783	2
24g	417	4864110	ECS - Infrastructure Leasing		GRSM	0	0	0	0	A		0	2
24h	417	4864115	ECS - EU FCC Rev	(237,195)	GRSM	0	0	0	(237,195)	A	114,302	(351,497)	2
24i	417	4862125	ECS - Cell Site Rent and Use (Active)	13,328,277	GRSM	0	0	0	13,328,277	A	2,561,825	10,766,452	2
24j	417	4862130	ECS - Cell Site Reimbursable (Active)	4,452,839	GRSM	0	0	0	4,452,839	A	1,066,218	3,386,621	2
24k	417	4863120	ECS - Communication Sites	342,231	GRSM	0	0	0	342,231	P	71,854	270,376	2
24l	417	4863110	ECS - Cell Site Rent and Use (Passive)	3,528,304	GRSM	0	0	0	3,528,304	P	685,429	2,842,874	2
24m	417	4863115	ECS - Cell Site Reimbursable (Passive)	873,100	GRSM	0	0	0	873,100	P	325,605	547,495	2
24n	417	4863125	ECS - Micro Cell	1,970,237	GRSM	0	0	0	1,970,237	P	365,770	1,604,468	2
24o	417	4864120	ECS - End User Universal Service Fund Fee	(42,477)	GRSM	0	0	0	(42,477)	A	21,210	(63,687)	2
24p	417	4864116	ECS - Intrastate End User Revenue	1,330,785	GRSM	0	0	0	1,330,785	A	60,758	1,270,027	2
24q	417	4864121	ECS - Intrastate End User Fees	107,810	GRSM	0	0	0	107,810	A	4,665	103,145	2
24r	417	4864117	ECS - Interstate End User Tax Exempt	40,857	GRSM	0	0	0	40,857	A	0	40,857	2
24s	417	4864122	ECS - EU USAC E-Rate	27,607	GRSM	0	0	0	27,607	A	0	27,607	2
25	417 ECS Total			57,636,155		0	0	0	57,636,155		11,514,733	46,121,422	
26	417 Other			7,774,304									
27	FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)			65,410,459									

Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Traditional OOR			GRSM			Other Ratemaking	Notes
						Total	ISO	Non-ISO	Total	A/P	Threshold [10]		
Subsidiaries													
28a	418.1		ESI (Gross Revenues - Active)		GRSM	0	0	0	0	A		0	2.9
28b	418.1		ESI (Gross Revenues - Passive)		GRSM	0	0	0	0	P		0	2.9
28c	418.1		Southern States Realty		GRSM	0	0	0	0	P		0	2.15
28d	418.1		Mono Power Company	0	Traditional OOR	0	0	0	0			0	13
28e	418.1		SCE Capital Company	(45)	Traditional OOR	(45)	0	(45)	0			0	14
28f	418.1		Edison Material Supply (EMS)	(1,824,113)	Traditional OOR	(1,824,113)	(107,969)	(1,716,143)	0			0	7.17
29	418.1 Subsidiaries Total			(1,824,158)		(1,824,158)	(107,969)	(1,716,188)	0		0	0	
30	418.1 Other (See Note 16)			1,824,113									
31	FF-1 Total for Account 418.1 - Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)			(45)									
32	Totals			798,220,762		241,420,223	49,523,449	191,896,774	83,406,529		16,671,389	66,735,140	473,394,010

Line	Description	Amount	Calculation
33	Ratepayers' Share of Threshold Revenue	16,671,389	= Line 32K
34	ISO Ratepayers' Share of Threshold Revenue	5,425,127	Note 11
35			
36	Total Active Incremental Revenue	40,424,675	= Sum Active categories in column L
37	Ratepayers' Share of Active Incremental Revenue	4,042,467	= Line 36D * 10%
38	Total Passive Incremental Revenue	26,310,465	= Sum Passive categories in column L
39	Ratepayers' Share of Passive Incremental Revenue	7,893,139	= Line 38D * 30%
40	Total Ratepayers' Share of Incremental Revenue	11,935,607	= Line 37D + Line 39D
41	ISO Ratepayers' Share of Incremental Revenue (%)	32.54%	see Note 11
42	ISO Ratepayers' Share of Incremental Revenue	3,884,030	= Line 40D * Line 41D
43	Tot. ISO Ratepayers' Share NTP&S Gross Rev.	9,309,157	= Line 34D + Line 42D

44 **Total Revenue Credits:** Amount \$58,832,606 Calculation Sum of Column D, Line 43 and Column G, Line 32

- Notes:
- CPUC Jurisdictional service related.
 - Subject to sharing per the Gross Revenue Sharing Mechanism (GRSM), adopted in CPUC D.99-09-070. On an annual basis, once SCE obtains \$16,671,389.55 (Threshold Revenue) in NTP&S Revenues, any additional revenues (Incremental Gross Revenues) that SCE receives are shared between shareholders and ratepayers. For GRSM categories deemed Active, the Incremental Gross Revenues are shared 90/10 between shareholders and ratepayers. For those categories deemed Passive, the Incremental Gross Revenues are shared 70/30 between shareholders and ratepayers.
 - Generation related.
 - Non-ISO facilities related.
 - ISO transmission system related.
 - Subject to balancing account treatment
 - Allocated based on CPUC GRC allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year.
ISO Allocator = 0.05919 Source: CPUC D. 15-11-021
 - ISO portion of Traditional OOR relates to monthly revenues received from customers for facilities that are part of the ISO network.
 - Edison ESI is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for ESI are reported on Acct 418.1, pg 225.5e.
 - The first \$16,671,389 million in gross revenues generated by GRSM activities are automatically classified as Threshold Revenue.
 - Allocator is equal to the jurisdictional split of the Threshold Revenue, which is jurisdictionalized as \$5.425M to FERC ratepayers and \$11.246M to CPUC ratepayers per the 2009 CPUC General Rate Case (D. 09-03-025). The ISO ratepayers' share of ratepayer revenue is \$5.425M/\$16.671M = 32.54%.
 - Allocated based on the CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year. ISO portion of revenue is treated as traditional OOR.
ISO Allocator = 0.05919 Source: CPUC D. 15-11-021
 - Mono Power Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.11e. Revenues and costs shall be non-ISO.
 - SCE Capital Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.23e. Revenues and costs shall be non-ISO.
 - Southern States Realty is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for Southern States Realty are reported on Acct 418.1, pg 225.17e.
 - For subsidiaries that are subject to GRSM, Column D contains gross revenues. Input on Line 30D contains the associated expenses.
 - Per GRC Decision D.87-12-066, for ratemaking purposes EMS financials are consolidated with SCE's. See FERC Form 1 page 123.3 under "Equity Investment Differences". Consequently, net income of EMS is not reported separately in FERC Form 1 and is not a part of FERC Account 418.1 totals. To ensure that ratepayers receive the net income from this subsidiary SCE includes EMS net income in the formula on line 28f. This amount is reversed as part of line 30 to remain consistent with the totals reported in FERC Form 1.

NETWORK UPGRADE CREDIT AND INTEREST EXPENSE

Prior Year: **2017**

1) Beginning of Year Balances: (Note 1)

<u>Line</u>		<u>Balance</u>	<u>Notes</u>
1	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	\$119,779,556	See Note 1
2	Acct 252 Other	\$91,604,742	SCE Records
3	Total Acct 252	\$211,384,298	Line 1 + Line 2
4	(Must equal Line 3)	\$211,384,298	FF1 113.56d
2) End of Year Balances: (Note 2)			
5	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	\$93,345,105	See Note 3
6	Acct 252 Other	\$79,619,300	SCE Records
7	Total Acct 252	\$172,964,405	Line 5 + Line 6
8	(Must equal Line 7)	\$172,964,405	FF1 113.56c
9	Average Outstanding Network Upgrade Credits Beginning and End of Year	\$106,562,330	(Line 1 + Line 5) / 2
10	Interest On Network Upgrade Credits Recorded in FERC Acct 242	\$6,116,851	See Note 4
11	Acct 242 Other	\$664,223,662	SCE Records
12	Total Acct 242	\$670,340,513	Line 10 + Line 11
13	(Must equal Line 12)	\$670,340,513	FF1 113.48c

Notes:

- 1 Beginning of Year Balances are from December of the year previous to the Prior Year.
- 2 End of Year Balances are from December of the Prior Year.
- 3 Only projects that are in Rate Base in the year reported are included.
- 4 Interest relates to refund of facility and one-time payments by generator. For facility costs, pre-in-service date interest is excluded. For one-time costs, pre-in-service and post-in-service interest is included.

Determination of Regulatory Assets/Liabilities and Associated Amortization and Regulatory Debits/Credits

Line

1 Other Regulatory Assets/Liabilities are a component of Rate Base representing costs that are created resulting from the ratemaking
 2 actions of regulatory agencies. Pursuant to the Commission's Uniform System of Accounts, these items include amounts recorded
 3 in accounts 182.x and 254. This Schedule shall not include any costs recovered through Schedule 12.
 4
 5 SCE shall include a non-zero amount of Other Regulatory Assets/Liabilities only with Commission
 6 approval received subsequent to an SCE Section 205 filing requesting such treatment.
 7
 8 Amortization and Regulatory Debits/Credits are amounts approved for recovery in this formula transmission rate representing the
 9 approved annual recovery of Other Regulatory Assets/Liabilities as an expense item in the Base TRR, consistent
 10 with a Commission Order.

11			
12		Prior Year	
13		<u>Amount</u>	<u>Calculation or Source</u>
14	Other Regulatory Assets/Liabilities (EOY):	\$0	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	\$0	Avg. of Sum of Cols. 1 and 2 below
16	Amortization and Regulatory Debits/Credits:	\$0	Sum of Column 3 below

	Col 1	Col 2	Col 3	
	Prior Year	Prior Year	Prior Year	
Description of Issue	BOY	EOY	Amortization or	Commission Order
Resulting in Other Regulatory	Other Reg	Other Reg	Regulatory	Granting Approval of
<u>Asset/Liability</u>	<u>Asset/Liability</u>	<u>Asset/Liability</u>	<u>Debit/Credit</u>	<u>Regulatory Liability</u>
17 Issue #1				
18 Issue #2				
19 Issue #3				
20 Totals:	\$0	\$0	\$0	Sum of above

Instructions:

- 1) Upon Commission approval of recovery of Other Regulatory Assets/Liabilities, Amortization and Regulatory Debits/Credits costs through this formula transmission rate:
 - a) Fill in Description for issue in above table.
 - b) Enter costs in columns 1-3 in above table for the applicable Prior Year.
- 2) Add additional lines as necessary for additional issues.

Calculation of the Contribution of CWIP to the Base TRR

1) CWIP Contribution to the Prior Year TRR and True Up TRR

a) CWIP Balances:		Col 1	Col 2	Col 3	
		Prior Year	Prior Year	Forecast	
Line	Project	EOY Amount	Average Amount	Period Amount	Source
1	Tehachapi:	\$150,976	\$5,894,762	-\$150,976	10-CWIP, Lines 13, 14, 80
2	Devers to Colorado River:	\$0	\$0	\$0	10-CWIP, Lines 13, 14, 106
3	South of Kramer:	\$4,884,728	\$4,594,011	\$628,048	10-CWIP, Lines 13, 14, 132
4	West of Devers:	\$98,805,812	\$80,157,512	\$158,421,232	10-CWIP, Lines 13, 14, 158
5	Red Bluff:	\$0	\$0	\$0	10-CWIP, Lines 13, 14, 184
6	Whirlwind Sub Expansion:	\$0	\$9,253,542	\$0	10-CWIP, Lines 27, 28, 210
7	Colorado River Sub Expansion:	\$0	\$0	\$0	10-CWIP, Lines 27, 28, 236
8	Mesa:	\$46,788,116	\$6,541,655	\$110,990,871	10-CWIP, Lines 27, 28, 262
9	Alberhill:	\$0	\$0	\$3,359,286	10-CWIP, Lines 27, 28, 288
10	ELM Series Caps:	\$0	\$0	\$28,209,776	10-CWIP, Lines 27, 28, 314
11		\$0	---	\$28,209,776	10-CWIP, Lines 27, 28, 304
12	Totals:	\$150,629,632	\$106,441,483	\$329,668,013	Sum of Lines 1 to 11

b) Return:		EOY Amount	Average Amount	Source
13	CWIP Amount:	\$150,629,632	\$106,441,483	Line 12
14	Cost of Capital Rate:	7.2500%	7.2500%	1-BaseTRR, Line 53
15	Cost of Capital:	\$10,920,604	\$7,716,976	Line 13 * Line 14

c) Income Taxes		EOY Amount	Average Amount	Source
16	CWIP Amount:	\$150,629,632	\$106,441,483	Line 12
17	Equity ROR w Preferred Stock ("ER"):	5.2592%	5.2592%	1-BaseTRR, Line 54
18	Composite Tax Rate:	40.7460%	40.7460%	1-BaseTRR, Line 58
19	Income Taxes:	\$5,447,508	\$3,849,447	Formula on Line 21

20
21 Income Taxes = [(RB * ER) * (CTR/(1 - CTR))], or [(L13 * L17) * (L18 / (1 - L18))]
22 (No "Credits and Other" or "AFUDC" Terms, since these are not related to CWIP)
23

d) ROE Incentives:		Value	Source
24	IREF =	\$8,204	15-IncentiveAdder, Line 3

1) Tehachapi

	EOY Amount	Average Amount	
25	Tehachapi CWIP Amount:	\$150,976	Line 1
26	ROE Adder %:	1.25%	15-IncentiveAdder, Line 5
27	ROE Adder \$:	\$1,548	Formula on Line 32

2) Devers to Colorado River

	EOY Amount	Average Amount	
28	DCR CWIP Amount:	\$0	Line 2
29	ROE Adder %:	1.00%	15-IncentiveAdder, Line 6
30	ROE Adder \$:	\$0	Formula on Line 32

31
32 ROE Adder \$ = (Project CWIP Amount/\$1,000,000) * IREF * (ROE Adder % / 1%)

e) Total of Return, Income Taxes, and ROE Incentives contribution to PYTRR and True Up TRR

	PYTRR Amount	True Up TRR Amount	Source
33	Return:	\$10,920,604	Line 15
34	Income Taxes:	\$5,447,508	Line 19
35	ROE Adder Tehachapi:	\$1,548	Line 27
36	ROE Adder DCR:	\$0	Line 30
37	FF&U:	\$190,106	Note 1
38	Total:	\$16,559,766	Sum Lines 33 to 37

f) Contribution from each Project to the Prior Year TRR and True Up TRR

1) Contribution to the Prior Year TRR

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	
	<u>Project</u>	<u>Cost of Capital</u>	<u>Income Taxes</u>	<u>ROE Adder</u>	<u>FF&U</u>	<u>Total</u>	<u>Source</u>
39	Tehachapi:	\$10,946	\$5,460	\$1,548	\$209	\$18,163	Note 2
40	Devers to Colorado River:	\$0	\$0	\$0	\$0	\$0	Note 2
41	Eldorado Ivanpah:	\$354,141	\$176,656	\$0	\$6,164	\$536,961	Note 2
42	Lugo-Pisgah:	\$7,163,392	\$3,573,304	\$0	\$124,688	\$10,861,385	Note 2
43	Red Bluff:	\$0	\$0	\$0	\$0	\$0	Note 2
44	Whirlwind Sub Expansion:	\$0	\$0	\$0	\$0	\$0	Note 2
45	Colorado River Sub Expansion:	\$0	\$0	\$0	\$0	\$0	Note 2
46	South of Kramer:	\$3,392,125	\$1,692,088	\$0	\$59,044	\$5,143,258	Note 2
47	West of Devers:	\$0	\$0	\$0	\$0	\$0	Note 2
48		---	---	---	---	---	Note 2
49		---	---	---	---	---	Note 2
50	Totals:	\$10,920,604	\$5,447,508	\$1,548	\$190,106	\$16,559,766	Sum L 39 to L 49

2) Contribution to the True Up TRR

		<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Col 4</u>	<u>Col 5</u>	
	<u>Project</u>	<u>Cost of Capital</u>	<u>Income Taxes</u>	<u>ROE Adder</u>	<u>FF</u>	<u>Total</u>	<u>Source</u>
51	Tehachapi:	\$427,368	\$213,184	\$60,452	\$6,453	\$707,457	Note 3
52	Devers to Colorado River:	\$0	\$0	\$0	\$0	\$0	Note 3
53	Eldorado Ivanpah:	\$333,064	\$166,142	\$0	\$4,596	\$503,802	Note 3
54	Lugo-Pisgah:	\$5,811,396	\$2,898,890	\$0	\$80,184	\$8,790,470	Note 3
55	Red Bluff:	\$0	\$0	\$0	\$0	\$0	Note 3
56	Whirlwind Sub Expansion:	\$670,879	\$334,654	\$0	\$9,257	\$1,014,789	Note 3
57	Colorado River Sub Expansion:	\$0	\$0	\$0	\$0	\$0	Note 3
58	South of Kramer:	\$474,268	\$236,578	\$0	\$6,544	\$717,390	Note 3
59	West of Devers:	\$0	\$0	\$0	\$0	\$0	Note 3
60		---	---	---	---	---	Note 3
61		---	---	---	---	---	Note 3
62	Totals:	\$7,716,976	\$3,849,447	\$60,452	\$107,034	\$11,733,909	Sum of L 51 to 61

2) Contribution from the Incremental Forecast Period TRR

a) Total of all CWIP projects

		<u>Value</u>	<u>Source</u>
63	Forecast Period Incremental CWIP:	\$329,668,013	Line 12, Col 3
64	AFCRCWIP:	10.866%	2-IFPTRR, Line 16
65	CWIP component of IFPTRR without FF&U:	\$35,823,251	Line 63 * Line 64
66	FF&U:	\$416,026	Line 65 * (28-FFU, L5 FF Factor + U Factor)
67	CWIP component of IFPTRR including FF&U:	\$36,239,277	Line 65 + Line 66

b) Individual Project Contribution

	<u>Project</u>	<u>Amount wo FF&U</u>	<u>Amount with FF&U</u>	<u>Source</u>
68	Tehachapi:	-\$16,406	-\$16,596	Note 4
69	Devers to Colorado River:	\$0	\$0	Note 4
70	Eldorado Ivanpah:	\$68,247	\$69,039	Note 4
71	Lugo-Pisgah:	\$17,214,784	\$17,414,704	Note 4
72	Red Bluff:	\$0	\$0	Note 4
73	Whirlwind Sub Expansion:	\$0	\$0	Note 4
74	Colorado River Sub Expansion:	\$0	\$0	Note 4
75	South of Kramer:	\$12,060,781	\$12,200,847	Note 4
76	West of Devers:	\$365,035	\$369,275	Note 4
77		---	---	Note 4
78		---	---	Note 4
79	Totals:	\$29,692,441	\$30,037,268	Sum of Lines 68 to 78

3) Total Contribution of CWIP to the Retail and Wholesale Base TRRs:

a) Total of all CWIP projects

		<u>Value</u>	<u>Source</u>
80	PY Total Return, Taxes, Incentive:	\$16,369,661	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	\$35,823,251	Line 65
82	Total without FF&U:	\$52,192,911	Line 80 + Line 81
83	FF Factor:	0.9206%	28-FFU, Line 5
84	U Factor:	0.2408%	28-FFU, Line 5
85	Franchise Fees Amount:	\$480,472	Line 82 * Line 83
86	Uncollectibles Amount:	\$125,660	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	\$52,799,043	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	\$52,673,384	Line 82 + Line 85

b) Individual CWIP Project Contribution to the Retail Base TRR

	<u>Col 1</u> <u>PYTRR</u> <u>wo FF&U</u>	<u>Col 2</u> <u>IFPTRR</u> <u>wo FF&U</u>	<u>Col 3</u> <u>FF&U</u>	<u>Col 4</u> <u>Total</u>	<u>Source</u>	
89	Tehachapi:	\$17,954	-\$16,406	\$18	\$1,566	Note 5
90	Devers to Colorado River:	\$0	\$0	\$0	\$0	Note 5
91	Eldorado Ivanpah:	\$530,797	\$68,247	\$6,957	\$606,001	Note 5
92	Lugo-Pisgah:	\$10,736,696	\$17,214,784	\$324,609	\$28,276,089	Note 5
93	Red Bluff:	\$0	\$0	\$0	\$0	Note 5
94	Whirlwind Sub Expansion:	\$0	\$0	\$0	\$0	Note 5
95	Colorado River Sub Expansion:	\$0	\$0	\$0	\$0	Note 5
96	South of Kramer:	\$5,084,213	\$12,060,781	\$199,110	\$17,344,104	Note 5
97	West of Devers:	\$0	\$365,035	\$4,239	\$369,275	Note 5
98		---	---	---	---	Note 5
99		---	---	---	---	Note 5
100	Totals:	\$16,369,661	\$29,692,441	\$534,933	\$46,597,035	

c) Individual CWIP Project Contribution to the Wholesale Base TRR

	<u>Col 1</u> <u>PYTRR</u> <u>wo FF&U</u>	<u>Col 2</u> <u>IFPTRR</u> <u>wo FF&U</u>	<u>Col 3</u> <u>FF</u>	<u>Col 4</u> <u>Total</u>	<u>Source</u>	
101	Tehachapi:	\$17,954	-\$16,406	\$14	\$1,563	Note 6
102	Devers to Colorado River:	\$0	\$0	\$0	\$0	Note 6
103	Eldorado Ivanpah:	\$530,797	\$68,247	\$5,515	\$604,558	Note 6
104	Lugo-Pisgah:	\$10,736,696	\$17,214,784	\$257,313	\$28,208,793	Note 6
105	Red Bluff:	\$0	\$0	\$0	\$0	Note 6
106	Whirlwind Sub Expansion:	\$0	\$0	\$0	\$0	Note 6
107	Colorado River Sub Expansion:	\$0	\$0	\$0	\$0	Note 6
108	South of Kramer:	\$5,084,213	\$12,060,781	\$157,832	\$17,302,826	Note 6
109	West of Devers:	\$0	\$365,035	\$3,360	\$368,396	Note 6
110		---	---	---	---	Note 6
111		---	---	---	---	Note 6
112	Totals:	\$16,369,661	\$29,692,441	\$424,034	\$46,486,136	

Notes:

- (Sum Lines 33 to 36) * (FF + U Factors from 28-FFU) for Prior Year TRR
(Sum Lines 34 to 37) * (FF Factor from 28-FFU) for True Up TRR
- Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on 28-FFU.
- Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
ROE Adder is from Lines 35 and 36. FF Expenses is based on FF Factor on 28-FFU.
- Project contribution to total IFPTRR is based on fraction of Forecast Period CWIP Balances on Lines 1 to 12, Col 3.
- Column 1 is from Lines 39 to 49, Sum of Column 1-3 (no FF&U).
Column 2 is from Lines 68 to 78 (no FF&U).
Column 3 is the product of (C1 + C2) and the sum of FF and U factors (28-FFU, L5)
- Same as Note 5 except no Uncollectibles Expense in Column 3.

Calculation of Wholesale Difference to the Base TRR

Inputs are shaded yellow

The Wholesale Difference to the Base TRR represents the amount by which the Wholesale Base TRR differs as compared to the Retail Base TRR. This difference is attributable to differences in the following six items, as approved by Commission Order 86 FERC ¶ 63,014 in Docket No. ER97-2355.

These six items may affect the Base TRR by affecting Rate Base, or affecting an annual expense (amortization). If the annual amortization affects Income Taxes, there is an additional annual Income Tax Effect. The table summarizes these impacts for each item:

<u>Line</u>		<u>Rate Base Difference</u>	<u>Expense (Amortization) Difference</u>	<u>Expense Tax Impact</u>
1	a) Depreciation	Yes	Yes	No
2	b) Taxes Deferred -Make Up Adjustment (South Georgia)	Yes	Yes	Yes
3	c) Excess Deferred Taxes	Yes	Yes	Yes
4	d) Taxes Deferred - Acct. 282 ACRS/MACRS	Yes	Yes	No
5	e) Uncollectibles Expense	No	Yes	No
6	f) EPRI and EEI Expenses	No	Yes	No

1) Calculation of Wholesale Rate Base Difference and Wholesale Rate Base Adjustment

a) Quantification of the Initial 2010 Wholesale Rate Base Difference and annual change

The difference between Retail and Wholesale Rate Base is attributable to the following four items, with with the Initial Prior Year 2010 Rate Base differences and annual changes as follows:

	<u>Data Source</u>	<u>Col 1 2010 Rate Base Difference (Wholesale less Retail)</u>	<u>Col 2 Annual Change (Amortization)</u>
7	1) Accumulated Depreciation	Fixed values	\$31,556,000
8	2) Taxes Deferred - Make Up Adjustment	Fixed values	-\$35,044,000
9	3) Excess Deferred Taxes	Fixed values	-\$624,650
10	4) Taxes Deferred - Acct. 282 ACRS/MACRS	Fixed values	-\$7,410,000
11		Totals:	-\$11,522,650

b) Quantification of the Wholesale Rate Base Adjustment

The Wholesale Rate Base Adjustment represents the impact on the Wholesale Base TRR relative to the Retail Base TRR of the Wholesale Rate Base Difference for the Prior Year.

	<u>Data Source</u>	<u>Value</u>	<u>Notes/Instructions</u>
12	Fixed Charge Rate	2-IFPTRR Line 16	10.87%
13	Prior Year		2017
14	Wholesale Rate Base Difference for Prior Year		-\$5,355,650
15	Wholesale Rate Base Adjustment	Line 14 * Line 12	-\$581,970

2) Calculation of Wholesale Expense Difference

The annual Wholesale Expense Difference impact is the negative of amounts stated in Lines 7 to 10 above, Column 2. It represents the effect on expenses (Wholesale less Retail) of amortizing the associated balances each year. If an annual amortization amount affects Income Taxes, the expense difference must be grossed up for income taxes.

a) Calculation of the Wholesale South Georgia Income Tax Adjustment to the TRR

	<u>Source</u>	<u>Value</u>
16	South Georgia Amortization	Line 8
17	Composite Tax Rate ("CTR")	1-BaseTRR L 58
18	Tax Gross Up Factor	(1/(1-CTR))
19	Wholesale South Georgia	
20	Income Tax Adjustment to the TRR:	- Line 16 * Line 18

b) Calculation of "Excess Deferred Taxes" Grossed Up for Income Taxes

	<u>Source</u>	<u>Value</u>
21	Annual Amort. of "Excess Deferred Taxes":	Line 9
22	Tax Gross Up Factor	Line 18
23	Excess Deferred Taxes Grossed Up for Income Taxes:	- Line 21 * Line 22
24		

25 c) Calculation of EPRI and EEI Expense Exclusion

	<u>Source</u>		<u>Notes/Instructions</u>
26			
27	EPRI Expenses	SCE Records	\$200,769
28	EEI Expenses	SCE Records	\$1,529,649
29	Sum of EPRI and EEI Expenses	Line 27 + 28	\$1,730,418
30	Transmission Wages and Salaries Allocation Factor	27-Allocators, Line 9	5.6290%
31	EPRI and EEI Expense Exclusion	Line 29 * 30	\$97,406

d) Total Expense Difference

			<u>Notes/Instructions</u>
32	1) Wholesale Depreciation Difference	- Line 7, Col. 2	\$2,176,300
33	2) Taxes Deferred - Make Up Adjustment	Line 20	-\$4,224,187
34	3) Excess Deferred Taxes	Line 23	-\$72,738
35	4) Taxes Deferred - Acct. 282 ACRS/MACRS	- Line 10, Col. 2	-\$511,200
36	5) EPRI and EEI Expense Exclusion	- Line 31	-\$97,406
37	Total Expense Difference:		-\$2,729,231

3) Calculation of the Wholesale Difference to the Base TRR

	<u>Source</u>	<u>Value</u>	
38	Wholesale Rate Base Adjustment	Line 15	-\$581,970
39	Expense Difference	Line 37	-\$2,729,231
40	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 79	-\$2,443,195
41	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	-\$239,591
42	Subtotal:	Sum Line 38 to Line 41	-\$5,993,986
43	Franchise Fee Exclusion		-\$30,482
44	Wholesale Difference to the Base TRR:	Line 42 + Line 43	-\$6,024,468

Notes/Instructions:

- 1) Fixed Charge Rate of capital and income tax costs associated with \$1 of Rate Base is defined elsewhere in this formula as "AFCRCWIP".
- 2) Input Prior Year for this Informational Filing in Line 13.
- 3) Calculation: (Line 11, Col 1) + ((Line 11, Col 2) * (Line 13 - 2010)).
- 4) Franchise Fee Exclusion is equal to the Franchise Fee Factor on the 28-FFU Line 5 times Line 38 + 39.
- 5) Only exclude if not already excluded in Schedule 20.

Calculation of Income Tax Rates

1) Federal Income Tax rate

Inputs are shaded yellow

Line	Prior Year	Federal Income Tax Rate ("FITR")	Source
1	2017	35.00%	Note 1, c Column 2, see also Note 2
2			

2) Composite State Income Tax Rate

Line	Prior Year	Composite State Income Tax Rate ("CSITR")	Source
6	2017	8.8400%	1) See calculation below on Line 45 based on inputs for apportionment factors and state tax rates. for the applicable Prior Year
7			
8			
9			
10			
11			

Calculation of Composite State Income Tax Rate for the Prior Year:

Line	State	Apportionment Factors ("AFs")	Source
15			
16	California	100.0000%	1) Input most recent available Apportionment Factors.
17	New Mexico	0.0000%	
18	Arizona	0.0000%	
19	D.C.	0.0000%	
20			

Line	State	Statutory Tax Rate ("STR")	Source
21			
22			
23	California	8.8400%	2) Input STR for the Prior Year for each state. See Notes 1 and 3.
24	New Mexico	6.2000%	
25	Arizona	4.9000%	
26	D.C.	9.0000%	
27			

Line	State	Ratio of SCE State Taxable Income to SCE California Taxable Income	Source
28			
29			
30			
31			
32			
33	California	100.0000%	3) Input most recent available ratios based on taxable income from state return filings.
34	New Mexico	0.0000%	
35	Arizona	0.0000%	
36	D.C.	0.0000%	
37			

Line	State	Effective State Tax Rate	Source
38			
39			
40	California	8.8400%	Line 16 * Line 23 * Line 33
41	New Mexico	0.0000%	Line 17 * Line 24 * Line 34
42	Arizona	0.0000%	Line 18 * Line 25 * Line 35
43	D.C.	0.0000%	Line 19 * Line 26 * Line 36
44			

44	Composite State		
45	Income Tax Rate =	8.8400%	Sum of Lines 40 to 43
46			

3) Capitalized Overhead portion of Electric Payroll Tax Expense

Line	Description	Amount
47		
48		
49	Total Electric Payroll Tax Expense (From 1-BaseTRR, Line 30)	\$117,049,541
50	Capitalization Rate (Note 4)	39.8%
51	Capitalized Overhead portion of Electric Payroll Tax Expense (Line 49 * Line 50)	\$46,585,717
52	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 49 - Line 51)	\$70,463,824

Notes:

1) In the event that statutory marginal tax rates change during the Prior Year, the effective tax rate used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: $((.3500 \times 120) + (.4000 \times 245))/365 = .3836$.

Calculation of FITR for Prior Year:

	(Col 1) FITR	(Col 2) Days	Note
a	35.00%	365	Input FITR in effect for first part of year and number of days
b		365	Input FITR in effect for second part of year and number of days
c	FITR: $35.00\% = ((\text{Line a, C1}) \times (\text{Line a, C2}) + (\text{Line b, C1}) \times (\text{Line b, C2})) / 365$		
2) Federal Source Statute:	Internal Revenue Code Section 11(b)(1)(D)		
3) State Source Statutes (Enter Reference to each State Marginal Tax Rate Statute below):			
a) California:	California Rev. & Tax. Cd. § 23151		
b) New Mexico	New Mexico Statutes, ¶12,300 Rates in general		
c) Arizona	Arizona Rev. Stat. Ann. Statute, § 43-1111		
d) District of Columbia	DC Code Ann. §47-1807.02		
4) Capitalization Rate approved in:	CPUC D. 15-11-021		
For the following Prior Years:	2015-2017		

Calculation of Allocation Factors

Inputs are shaded yellow

1) Calculation of Transmission Wages and Salaries Allocation Factor

Line	Notes	FERC Form 1 Reference or Instruction	Prior Year Value
1	ISO Transmission Wages and Salaries	19-OandM Line 137, Col. 7	\$32,793,575
2	Total Wages and Salaries	FF1 354.28b	\$749,285,680
3	Less Total A&G Wages and Salaries	FF1 354.27b	\$210,410,528
4	Total Wages and Salaries wo A&G	Line 2 - Line 3	\$538,875,152
5	Total NOIC (Non-Officer Incentive Compensation)	20-AandG, Note 2	\$66,132,721
6	Less A&G NOIC	20-AandG, Note 2	\$22,427,473
7	NOIC wo A&G NOIC	Line 5 - Line 6	\$43,705,248
8	Total non-A&G W&S with NOIC	Line 4 + Line 7	\$582,580,400
9	Transmission Wages and Salary Allocation Factor	Line 1 / Line 8	5.6290%

2) Calculation of Transmission Plant Allocation Factor

Line	Notes	FERC Form 1 Reference or Instruction	Prior Year Value
14	Transmission Plant - ISO	7-PlantStudy, Line 21	\$8,573,445,553
15	Distribution Plant - ISO	7-PlantStudy, Line 30	\$0
16	Total Electric Miscellaneous Intangible Plant	6-PlantInService, Line 21, C2	\$1,324,870,316
17	Electric Miscellaneous Intangible Plant	Line 16 * Line 9	\$74,577,232
18	Total General Plant	6-PlantInService, Line 21, C1	\$3,102,162,333
19	General Plant	Line 18 * Line 9	\$174,621,378
20	Total Plant In Service	FF1 207.104g	\$46,164,121,713
22	Transmission Plant Allocation Factor	(L14 + L15 + L17 + L19) / L20	19.1115%

3) Schedule 19 "Percent ISO" Allocation Factors (Input values are from SCE Records)

Line	Notes	Values	Notes	Applied to Accounts
26	a) Outages			
27	ISO Outages	5,827		561.000 Load Dispatching
28	Non-ISO Outages	10,854		561.100 Load Dispatch-Reliability
29	Total Outages	16,681 = L27 + L28		561.200 Load Dispatch Monitor and Operate Trans. System
30	Outages Percent ISO	34.9% = L27 / L29		
31				
32	b) Circuits			
33	ISO Circuits	215		562 - Operating Transmission Stations
34	Non-ISO Circuits	999		
35	Total Circuits	1,214 = L33 + L34		
36	Circuits Percent ISO	17.7% = L33 / L35		
37				
38	c) Relay Routines			
39	ISO Relay Routines	529		562 - Routine Testing and Inspection
40	Non-ISO Relay Routines	3,310		
41	Total Relay Routines	3,839 = L39 + L40		
42	Relay Routines Percent ISO	13.8% = L39 / L41		
43				

Schedule 27
Allocation Factors

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

	<u>Values</u>	<u>Notes</u>	<u>Applied to Accounts</u>
44 d) Line Miles			
45 ISO Line Miles	5,683		563 - Inspect and Patrol Line
46 Non-ISO Line Miles	6,473		571 - Poles and Structures
47 Total Line Miles	12,156 = L45 + L46		571 - Insulators and Conductors
48 Line Miles Percent ISO	46.8% = L45 / L47		571 - Transmission Line Rights of Way
49			
50 e) Underground Line Miles			
51 ISO Underground Line Miles	5		564 - Underground Line Expense
52 Non-ISO Underground Line Miles	355		572 - Maintenance of Underground Transmission Lines
53 Total Underground Line Miles	360 = L51 + L52		
54 Underground Line Miles Percent ISO	1.4% = L51 / L53		
55			
56 f) Line Rents Costs			
57 ISO Line Rent Costs	6,071,296		567 - Line Rents
58 Non-ISO Line Rent Costs	2,830,263		
59 Total Line Rent Costs	8,901,559 = L57 + L58		
60 Line Rent Costs Percent ISO	68.2% = L57 / L59		
61			
62 g) Morongo Acres			
63 ISO Morongo Acres	377		567 - Morongo Lease
64 Non-ISO Morongo Acres	38		
65 Total Morongo Acres	416 = L63 + L64		
66 Morongo Acres Percent ISO	90.8% = L63 / L65		
67			
68 h) Transformers			
69 ISO Transformers	142		570 - Maintenance of Power Transformers
70 Non-ISO Transformers	468		
71 Total Transformers	610 = L69 + L70		
72 Transformers Percent ISO	23.3% = L69 / L71		
73			
74 i) Circuit Breakers			
75 ISO Circuit Breakers	1,205		570 - Maintenance of Transmission Circuit Breakers
76 Non-ISO Breakers	2,083		
77 Total Circuit Breakers	3,288 = L75 + L76		
78 Circuit Breakers Percent ISO	36.6% = L75 / L77		
79			
80 j) Voltage Control Equipment			
81 ISO Voltage Control Equipment	340		570 - Maintenance of Transmission Voltage Equipment
82 Non-ISO Voltage Control Equipment	171		
83 Total Voltage Control Equipment	511 = L81 + L82		
84 Voltage Control Equipment Percent ISO	66.5% = L81 / L83		
85			
86 k) Substation Work Order Cost			
87 ISO Substation Work Order Costs	1,396,027		570 - Substation Work Order Related Expense
88 Non-ISO Substation Work Order Costs	4,116,505		
89 Total Substation Work Order Costs	5,512,531 = L87 + L88		
90 Substation Work Order Costs Percent ISO	25.3% = L87 / L89		
91			
92 l) Transmission Work Order Cost			
93 ISO Transmission Work Order Costs	1,827,708		571 - Transmission Work Order Related Expense
94 Non-ISO Transmission Work Order Costs	4,810,706		
95 Total Transmission Work Order Costs	6,638,414 = L93 + L94		
96 Transmission Work Order Costs Percent ISO	27.5% = L93 / L95		
97			

Schedule 27
Allocation Factors

TO2019 Annual Update
Attachment 5
TO13 True Up TRR

	<u>Values</u>	<u>Notes</u>	<u>Applied to Accounts</u>
98 m) Transmission Facility Property Damage			
99 ISO Transmission Fac. Property Damage	1,343,856		
100 Non-ISO Transmission Fac. Property Damage	1,627,078		
101 Total Transmission Facility Property Damage	2,970,934	= L99 + L100	
102 Trans. Fac. Property Damage Percent ISO	45.2%	= L99 / L101	
103			
104 n) Distribution Transformers			
105 ISO Distribution Transformers	0		
106 Non-ISO Distribution Transformers	1,967		
107 Total Distribution Transformers	1,967	= L105 + L106	
108 Distribution Transformers Percent ISO	0.0%	= L105 / L107	
109			
110 o) Distribution Circuit Breakers			
111 ISO Distribution Circuit Breakers	0		
112 Non-ISO Distribution Circuit Breakers	8,853		
113 Total Distribution Circuit Breakers	8,853	= L111 + L112	
114 Distribution Circuit Breakers Percent ISO	0.0%	= L111 / L113	
115			
116 p) Distribution Voltage Control Equipment			
117 ISO Distribution Voltage Control Equipment	0		
118 Non-ISO Distribution Voltage Control Equip.	2,316		
119 Total Distribution Voltage Control Equipment	2,316	= L117 + L118	
120 Distribution Voltage Control Equip. Pct. ISO	0.0%	= L117 / L119	

Franchise Fees and Uncollectibles Expense Factors

1) Approved Franchise Fee Factor(s)

Inputs are shaded yellow

<u>Line</u>	<u>From</u>	<u>To</u>	<u>Days in Prior Year</u>	<u>FF Factor</u>	<u>Reference</u>
1	2017	Present	365	0.92057%	Schedule 28 - Workpaper, Line 3
2					

2) Approved Uncollectibles Expense Factor(s)

<u>Line</u>	<u>From</u>	<u>To</u>	<u>Days in Prior Year</u>	<u>U Factor</u>	<u>Reference</u>
3	2017	Present	365	0.24076%	Schedule 28 - Workpaper, Line 4
4					

3) FF and U Factors

<u>Line</u>	<u>Prior Year</u>	<u>FF Factor</u>	<u>U Factor</u>	<u>Notes</u>
5	2017	0.92057%	0.24076%	Calculated according to Instruction 3

Notes:

1) Franchise Fees represent payments that SCE makes to municipal entities for the right to locate facilities within the municipality.

Instructions:

- 1) Enter Franchise Fee and Uncollectibles Factors as approved by the California Public Utilities Commission ("CPUC") in modules 1 and 2 above pursuant to Instruction 2. If approved factors changed during Prior Year, enter both, and note period of time for which each applies in "From" and "To" columns, and number of days each was in effect during the Prior Year in "Days in Prior Year" Column.
- 2) Franchise Fees Factor is calculated from CPUC Decision by dividing adopted Franchise Fees by Total Operating Revenues less Franchise Fees. Uncollectibles Factor is calculated by dividing adopted Uncollectibles expense by Total Operating revenues less Uncollectibles Expense. Resulting FF & U Factors represent factors that, when applied to TRR without FF and U will correctly determine FF and U expense.
- 3) Calculate in module 3 the weighted average FF and U factors from the factors in modules 1 and 2 based on the number of days each FF and U factor was in effect during the Prior Year at issue.

	<u>Percent</u>	<u>Calculation</u>
Prior Year FF Factor:	0.92057%	((L1 FF Factor * L1 Days) + (L2 FF Factor * L2 Days))/365
Prior Year U Factor:	0.24076%	((L3 U Factor * L3 Days) + (L4 U Factor * L4 Days))/365

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

<u>Line</u>	<u>TRR Values</u>	<u>Notes</u>	<u>Source</u>
1	\$1,180,853,097 = Wholesale Base TRR		1-BaseTRR, Line 89
2	-\$121,378,713 = Total Wholesale TRBAA	Note 1	2018 TRBAA ER18-154
3	-\$120,967,080 = HV Wholesale TRBAA		2018 TRBAA ER18-154
4	-\$411,633 = LV Wholesale TRBAA		2018 TRBAA ER18-154
5	-\$8,897,435 = Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue
6	96.9981% = HV Allocation Factor		31-HVLV, Line 37
7	3.0019% = LV Allocation Factor		31-HVLV, Line 37

Inputs are shaded yellow

Calculation of Total High Voltage and Low Voltage components of Wholesale TRR

	<u>Col 1</u>	<u>Col 2</u>	<u>Col 3</u>	<u>Source</u>
	<u>TOTAL</u>	<u>High Voltage</u>	<u>Low Voltage</u>	
8	Wholesale Base TRR: \$1,180,853,097	\$1,145,404,984	\$35,448,113	See Note 3
9	CWIP Component of Wholesale Base TRR: \$52,673,384	\$52,673,384	\$0	See Note 4
10	Non-CWIP Component of Wholesale Base TRR: \$1,128,179,713	\$1,092,731,600	\$35,448,113	See Note 5
11	Wholesale TRBAA: -\$121,378,713	-\$120,967,080	-\$411,633	Lines 2 to 4
12	Less Standby Transmission Revenues: <u>-\$8,897,435</u>	<u>-\$8,630,342</u>	<u>-\$267,093</u>	See Note 6
13	Components of Wholesale Transmission Revenue Requirement: \$1,050,576,949	\$1,015,807,562	\$34,769,387	Sum of Lines 8, 11, and 12

Notes:

- 1) TRBAA is "Transmission Revenue Balancing Account Adjustment". The TRBAA is determined pursuant to SCE's Transmission Owner Tariff and may be revised each January 1, upon commission acceptance of a revised TRBAA amount, or upon the date the Commission orders.
- 2) From 33-RetailRates. See Line: **Line 17, column 3**
- 3) Column 1 is from Line 1.
Column 2 equals Column 1 * Line 6.
Column 3 equals Column 1 * Line 7.
- 4) From 24-CWIPTRR, Line 88. All High Voltage.
- 5) Line 8 - Line 9
- 6) Column 1 is from Line 5.
Column 2 equals Column 1 * Line 6.
Column 3 equals Column 1 * Line 7.

Calculation of SCE Wholesale Rates (See Note 1)

SCE's wholesale rates are as follows:

- 1) Low Voltage Access Charge
- 2) Low Voltage Wheeling Access Charge
- 3) High Voltage Utility-Specific Rate
- 4) HV Existing Contracts Access Charge
- 5) LV Existing Contracts Access Charge

Calculation of Low Voltage Access Charge:

<u>Line</u>				<u>Source</u>
1	LV TRR =	\$34,769,387		29-WholesaleTRRs, Line 13, C3
2	Gross Load =	86,694,873	MWh	32-Gross Load, Line 3
3	Low Voltage Access Charge =	\$0.00040	per kWh	Line 1 / (Line 2 * 1000)

Calculation of Low Voltage Wheeling Access Charge:

				<u>Source</u>
4	LV TRR =	\$34,769,387		29-WholesaleTRRs, Line 13, C3
5	Gross Load =	86,694,873	MWh	32-Gross Load, Line 3
6	Low Voltage Wheeling Access Charge =	\$0.00040	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Utility Specific Rate:

(used by ISO in billing of ISO TAC)

				<u>Source</u>
7	SCE HV TRR =	\$1,015,807,562		29-WholesaleTRRs, Line 13, C2
8	Gross Load =	86,694,873	MWh	32-Gross Load, Line 3
9	High Voltage Utility-Specific Rate =	\$0.0117170	per kWh	Line 7 / (Line 8 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

				<u>Source</u>
10	HV Wholesale TRR =	\$1,015,807,562		29-WholesaleTRRs, Line 13, C2
11	Sum of Monthly Peak Demands:	162,442	MW	32-Gross Load, Line 4
12	HV Existing Contracts Access Charge:	\$6.25	per kW	Line 10 / (Line 11 * 1000)

Calculation of Low Voltage Existing Contracts Access Charge:

				<u>Source</u>
13	LV Wholesale TRR =	\$34,769,387		29-WholesaleTRRs, Line 13, C3
14	Sum of Monthly Peak Demands:	162,442	MW	32-Gross Load, Line 4
15	LV Existing Contracts Access Charge:	\$0.21	per kW	Line 13 / (Line 14 * 1000)

Notes:

1) SCE's wholesale rates are subject to revision upon acceptance by the Commission of a revised TRBAA amount. See Note 1 on 29-WholesaleTRRs.

Derivation of High Voltage and Low Voltage Gross Plant Percentages

Determination of HV and LV Gross Plant Percentages for ISO Transmission Plant in accordance with ISO Tariff Appendix F, Schedule 3, Section 12.

Input cells are shaded yellow

HV and LV Components of Total ISO Plant on Lines 2, 3, 7, 8, and 9 are from the Plant Study, performed pursuant to Section 9 of Appendix IX:

A) Total ISO Plant from Prior Year								
Classification of Facility:	Total ISO Gross Plant	Land	Structures	HV Land	LV Land	HV Structures	LV Structures	HV/LV Transformers
Line 1	Lines:							
2	HV Transmission Lines	\$4,456,571,807	\$207,303,577	\$4,249,268,230	\$207,303,577	\$0	\$4,249,268,230	\$0
3	LV Transmission Lines	\$97,777,323	\$5,523,117	\$92,254,206	\$0	\$5,523,117	\$0	\$92,254,206
4	Total Transmission Lines (L 2 + L 3):	\$4,554,349,130	\$212,826,694	\$4,341,522,436	\$207,303,577	\$5,523,117	\$4,249,268,230	\$92,254,206
5								
Line 6	Substations:							
7	HV Substations (>= 200 kV)	\$3,527,998,671	\$39,632,449	\$3,488,366,223	\$39,632,449	\$0	\$3,488,366,223	\$0
8	Straddle Subs (Cross 200 kV boundary):	449,562,934	\$190,905	\$449,372,030	\$110,505	\$80,400	\$267,329,959	\$128,270,187
9	LV Substations (Less Than 200kV)	41,534,818	\$127,274	\$41,407,544	\$0	\$127,274	\$0	\$41,407,544
10	Total all Substations (L7 + L8 + L9)	\$4,019,096,424	\$39,950,627	\$3,979,145,797	\$39,742,953	\$207,674	\$3,755,696,182	\$169,677,731
11								
12	Total Lines and Substations	\$8,573,445,553	\$252,777,321	\$8,320,668,232	\$247,046,530	\$5,730,791	\$8,004,964,412	\$261,931,936
13								
14								
15	Gross Plant that can directly be determined to be HV or LV:							
16		High	Low		Notes:			
17		Voltage	Voltage	Total				
18	Land	\$247,046,530	\$5,730,791	\$252,777,321	From above Line 12			
19	Structures	\$8,004,964,412	\$261,931,936	\$8,266,896,348	From above Line 12			
20	Total Determined HV/LV:	\$8,252,010,942	\$267,662,727	\$8,519,673,669	Sum of lines 18 and 19			
21	Gross Plant Percentages (Prior Year):	96.858%	3.142%		Percent of Total			
22								
23	Straddling Transformers	\$52,082,532	\$1,689,352	\$53,771,884	Straddling Transformers split by Gross Plant Percentages on Line 21			
24	Abandoned Plant (EOY)	\$0	\$0	\$0	See Notes 1 and 2 below			
25	Total HV and LV Gross Plant for Prior Year	\$8,304,093,474	\$269,352,079	\$8,573,445,553	Line 20 + Line 23 + Line 24			
26								
27								
Line 28	B) Gross Plant Percentage for the Rate Effective Period:							
29								
30		High	Low		Notes:			
31		Voltage	Voltage	Total				
32	Total HV and LV Gross Plant for Prior Year	\$8,304,093,474	\$269,352,079	\$8,573,445,553	Line 25			
33	In Service Additions in Rate Effective Period:	\$508,628,194	\$12,714,512	\$521,342,706	13-Month Average: 16-PlantAdditions, Line 25, Cols 7 (for Total) and 12 (for LV). HV = C7 - C12.			
34	CWIP in Rate Effective Period	\$301,458,237	\$0	\$301,458,237	13 Month Average: 10-CWIP, Line 54, Col. 8			
35	Total HV and LV Gross Plant for REP	\$9,114,179,904	\$282,066,591	\$9,396,246,495	Line 32 + Line 33 + Line 34			
36								
37	HV and LV Gross Plant Percentages:	96.998%	3.002%		Percent of Total on Line 35			
38	(HV Allocation Factor and							
39	LV Allocation Factor)							

Notes:

- 1) For High Voltage Column, sum of EOY HV Abandoned Plant for all Projects on Schedule 12 for EOY of Prior Year
- 2) For Low Voltage Column, Sum of EOY Abandoned Plant less HV Abandoned Plant for all Projects on Schedule 12 for EOY of Prior Year.

Calculation of Forecast Gross Load

<u>Line</u>	<u>MWh</u>	<u>Calculation</u>	<u>Source</u>
1	86,680,005		Note 1
2	14,868		Note 2
3	86,694,873	Line 1 + Line 2	Sum of above
4	162,442		Note 1

Notes:

- 1) Latest SCE approved sales forecast as of April 15 of each year.
- 2) SCE pump load forecast as of April 15 of each year.
- 3) The load forecast used in Schedule 32 shall be for the calendar year in which the rates are to be in effect.

Calculation of SCE Retail Transmission Rates

Retail Base TRR: 1,186,877,565 Source: 1-BaseTRR WS, Line 86

Input cells are shaded yellow

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

Line	CPUC Rate Group	12-CP factors	Total Allocated costs	GWh	Backup GWh	NEM GWh	Maximum demand - MW	Standby demand - MW	Billing Determinants with NEM Adjustment	Total energy rate \$/kWh	Total demand rate - \$/kW-month	GWh	Maximum demand - MW	Standby demand - MW	Notes
1a	Domestic	41.72%	\$495,114,953	28,443		1,431	0	0		27,012	\$0.01833				
1b	GS-1	7.77%	\$92,247,651	5,911		11	0	0		5,900	\$0.01564				
1b2	GS-1 continued			0						0					
1c	TC-1	0.05%	\$579,454	58			0			58	\$0.01005				
1d	GS-2	16.51%	\$195,980,788	13,100		61	44,897	36		13,039					
1e	TOU-GS-3	9.11%	\$108,135,862	7,840		68	22,683	70							
1f	TOU-8-SEC	8.79%	\$104,285,197	8,055		37	20,531								
1g	TOU-8-PRI	5.83%	\$69,233,016	5,509		23	12,817								
1h	TOU-8-SUB	6.32%	\$75,040,538	5,868		0	11,894			5,868					
1i	TOU-8-Standby-SEC	0.09%	\$1,117,201	113	97		325	285		210					
1j	TOU-8-Standby-PRI	0.20%	\$2,410,868	534	243		1,310	1,373		778					
1k	TOU-8-Standby-SUB	0.42%	\$4,929,146	1,672	560		3,309	8,394		2,231					
1l	TOU-PA-2	1.57%	\$18,626,625	1,816		6	8,121	1		1,810					
1m	TOU-PA-3	1.19%	\$14,068,650	1,454		16	4,933	8		1,438					
1n	Street Lighting	0.43%	\$5,107,616	698			0			698					
1o	---									0					
2	Totals:	100.00%	\$1,186,877,565	81,070	900	1653	130,819	10,166		80,317					

2) Determination of Demand Rates for Large Power (TOU-8) Rate Groups

Line	CPUC Rate Group	Standby Allocated costs	Standby Demand - MW	Contracted Standby Demand Charge \$/kW	CPUC Rate Group	Non-Standby Allocated Costs	Sum of Standby and Non-Standby Demand	Supplemental kW demand Charge \$/kW
9a	TOU-8-Standby-SEC	\$1,117,201	285	\$3.92	TOU-8-SEC	\$104,285,197	20,856	5.00
9b	TOU-8-Standby-PRI	\$2,410,868	1,373	\$1.76	TOU-8-PRI	\$69,233,016	14,126	4.90
9c	TOU-8-Standby-SUB	\$4,929,146	8,394	\$0.59	TOU-8-SUB	\$75,040,538	15,203	4.94
9d	---				---			
10								

3) End-User Transmission Rates

12	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
13	= Col 2 + Col 3	= Line1:Col2 - Line16:Col3	= Line16:Col7 * Line1:Col7 *10^3		= Line16:Col2 / (Line1:Col8 * 10^6)	= Line16:Col2 / Line1:Col6 / 10^3	from Line9:Col3	= Line16:Col6 * 0.746	= Line16:Col7 * 0.746	
14	Note 12			Note 13		Note 14				
15	CPUC Rate Group	Total Revenues	Revenue associated with Supplemental Demand or Energy	Standby Demand Revenue	Energy Charge - \$/kWh	Supplemental Demand Charge - \$/kW-month	Contracted standby kW demand Charge - \$/kW-month	Supplemental Demand Charge - \$/HP-month	Contracted standby kW demand Charge - \$/HP-month	Notes
16a	Domestic	\$495,114,953	\$495,114,953		\$0.01833					
16b	GS-1	\$92,247,651	\$92,247,651	\$0	\$0.01564	\$3.19	\$3.19			Note 15
16c	TC-1	\$579,454	\$579,454		\$0.01005					
16d	GS-2	\$195,980,788	\$195,839,614	\$141,174		\$4.36	\$3.92			
16e	TOU-GS-3	\$108,135,862	\$107,861,357	\$274,505		\$4.76	\$3.92			
16f	TOU-8-SEC	\$102,661,321	\$102,661,321			\$5.00				
16g	TOU-8-PRI	\$62,813,823	\$62,813,823			\$4.90				
16h	TOU-8-SUB	\$58,708,358	\$58,708,358			\$4.94				
16i	TOU-8-Standby-SEC	\$2,741,077	\$1,623,875	\$1,117,201		\$5.00	\$3.92			
16j	TOU-8-Standby-PRI	\$8,830,061	\$6,419,193	\$2,410,868		\$4.90	\$1.76			
16k	TOU-8-Standby-SUB	\$21,261,326	\$16,332,180	\$4,929,146		\$4.94	\$0.59			
16l	TOU-PA-2	\$18,626,625	\$18,625,442	\$1,183		\$2.29	\$2.29	\$1.71	\$1.71	Note 16
16m	TOU-PA-3	\$14,068,650	\$14,045,294	\$23,357		\$2.85	\$2.85			
16n	Street Lighting	\$5,107,616	\$5,107,616		\$0.00731					
16o	---									
17	Totals:	\$1,186,877,565	\$1,177,980,130	\$8,897,435						

Notes:

- See Col 9 of Lines 35a, 35b, 35c, etc.
- Sales forecast in total Giga-watt hours usage, represents the customers' total annual GWh usage. Based on same forecast as Gross Load forecast in Schedule 32, Line 1, but at customer meter level. Does not include Backup GWh included in Column 4 (the sum of Column 3 and 4 equals total Sales Forecast).
- Backup GWh represents the amount of electric service that is provided by SCE to a customer who has an onsite generating facility during unscheduled outages of the customer's on-site generator. Only applies to TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups.
- Amount of energy included in the sales forecast that is not subject to transmission charges pursuant to the California Public Utilities Commission ("CPUC") approved Net Energy Metering Program.
- Sales forecast pertaining to the sum of monthly maximum supplemental Mega-watt demand, applies to demand charge schedules
- Sales forecast pertaining to the sum of monthly contracted standby Mega-watt demand, applies to standby schedules
- Net Forecast in total Giga-watt hours usage - represents the customers' annual Net GWh, applicable to Non-Demand Charge Schedules such as Residential or Small General Service
- Recorded sales from Sample meters adjusted for population - use to set the total demand rate for the optional time-of-use schedules within the GS-1 rate group
- Line 1b2, Col11 = Line 1b Col9 * Line 1b Col11 * 10^6
- Total demand rate for the optional time-of-use schedules within the GS-1 rate group, Line 1b2:Col10 = Line 1b2:Col12 (which = Line 1b2:Col11 / ((Line1b:Col12 + Line1b:Col13) * 10^3)
- Sum of the TOU-8 Standby and TOU-8 Non-Standby billing determinants in Line1:Col6
- For TOU-8 Rates revenue = Supplemental Demand Charge on Line 9 Column 8 * Maximum Demand on Lines 1 Column 6
- For optional time-of-use schedules within the GS-1 rate group (Line16b:Col6), = (Line1b2:Col11 - Line16:Col3) / Line1b:Col12 / 10^3
- For the non TOU-8-Standby rate group, it is the minimum of Line16i:Col7, or the total demand rate in Line1:Col109
- Applicable to time-of-use schedules within the GS-1 rate group
- Applicable to the optional schedules that contain horse power charge such as PA-1
- GWh for TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups are placed in TOU-8-SEC, TOU-8-PRI, TOU-8-SUB Rate Groups respectively.

20

21

Rate Schedules in each CPUC Rate Group:

22

23

24

25	CPUC Rate Group	Rate Schedules included in Each Rate Group in the Rate Effective Period
26a	Domestic	Includes Schedules D, D-CARE, D-FERA, TOU-D-T, TOU-EV-1, TOU-D-TEV, DE, D-SDP, D-SDP-O, DM, DMS-1, DMS-2, DMS-3, and DS.
	Domestic (cont)	D (Option CPP), D-CARE (Option CPP), TOU-D-Option A, TOU-D-Option B, TOU-D-3
26b	GS-1	Includes Schedules GS-1, TOU-EV-3, and TOU-GS-1 (Option A, B, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26c	TC-1	Includes Schedules TC-1, Wi-Fi-1, and WTR.
26d	GS-2	Includes Schedules GS-2, TOU-EV-4, and TOU-GS-2 (Option A, B, R, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26e	TOU-GS-3	Includes Schedules TOU-GS-3-CPP, and TOU-GS-3 (Option A, B, R, RTP, SOP, Standby, TOU-BIP, GS-APS, GS-APS-E, and ME).
26f	TOU-8-SEC	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26g	TOU-8-PRI	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26h	TOU-8-SUB	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26i	TOU-8-Standby-SEC	Includes Schedules TOU-8-Standby (Option B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26j	TOU-8-Standby-PRI	Includes Schedules TOU-8-Standby (Option A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26k	TOU-8-Standby-SUB	Includes Schedules TOU-8-Standby (Option A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).

26l TOU-PA-2 Includes Schedules PA-1, PA-2, TOU-PA-ICE, and TOU-PA-2 (Option A, B, RTP, SOP-1, SOP-2, CPP, Standby, and AP-I).
 26m TOU-PA-3 Includes Schedules TOU-PA-3-CPP, and TOU-PA-3 (Option A, B, RTP, SOP-1, SOP-2, Standby, and AP-I).
 26n Street Lighting Includes Schedules AL-2, AL-2-B, DWL, LS-1, LS-2, LS-3, LS-3-B, and OL-1.
 26o ---

27
28

29 **Recorded 12-CP Load Data by Rate Group (MW)**

30	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	
31				=							=	
32				Line35:(Col1+Col2 +Col3)/3			from Line1:Col3	from Line1:Col4	= Col 7 + Col 8	Line35:(Col4*Col5 /Col6*Col9)	= Line35:(Col10 / total of Col10)	
33	12-CP MW						Note 17					
34	CPUC Rate Group	2014	2015	2016	3-Year Average	Line losses	Recorded GWh (Average)	Standby Adjusted Sales Forecast - GWh	Backup GWh	Total Sales Forecast - GWh	Loss Adjusted Average 12-CP	12-CP Allocation factors
35a	Domestic	68,997	70,775	70,601	70,124	1.0905	29,557	28,443	0	28,443	73,588	41.72%
35b	GS-1	12,145	12,889	12,483	12,506	1.0909	5,881	5,911	0	5,911	13,711	7.77%
35c	TC-1	85	83	82	83	1.0917	61	58	0	58	86	0.05%
35d	GS-2	30,524	30,626	29,452	30,201	1.0905	14,811	13,100	0	13,100	29,128	16.51%
35e	TOU-GS-3	16,197	16,184	15,947	16,109	1.0900	8,565	7,840	0	7,840	16,072	9.11%
35f	TOU-8-SEC	15,190	14,907	14,707	14,935	1.0909	8,586	8,168	0	8,168	15,500	8.79%
35g	TOU-8-PRI	9,949	9,882	9,684	9,838	1.0644	6,150	6,043	0	6,043	10,290	5.83%
35h	TOU-8-SUB	11,843	10,984	11,021	11,283	1.0315	7,868	7,540	0	7,540	11,153	6.32%
35i	TOU-8-Standby-SEC	101	143	155	133	1.0911	85	0	97	97	166	0.09%
35j	TOU-8-Standby-PRI	294	311	373	326	1.0645	236	0	243	243	358	0.20%
35k	TOU-8-Standby-SUB	587	631	714	644	1.0316	508	0	560	560	733	0.42%
35l	TOU-PA-2	3,189	3,024	2,748	2,987	1.0910	2,138	1,816	0	1,816	2,768	1.57%
35m	TOU-PA-3	1,846	1,833	1,891	1,857	1.0896	1,406	1,454	0	1,454	2,091	1.19%
35n	Street Lighting	812	660	685	719	1.0938	723	698	0	698	759	0.43%
35o	---											
36	Totals:	171,759	172,933	170,545	171,746		86,575	81,070	900	81,970	176,404	100.00%

Determination of Unfunded Reserves

Line		Reference	Col 1 Prior Year BOY Unfunded Reserves	Col 2 Prior Year EOY Unfunded Reserves	Col 3 Prior Year Average Unfunded Reserves
1					
2					
3					
4					Prior Year Amount
5					
6	Unfunded Reserves (EOY):	(Line 17, Col 2)			-\$10,031,267
7	Unfunded Reserves (Average BOY/EOY):	(Line 17, Col 3)			-\$10,165,091
8					
9					
10					
11					
12	Description of Issue				
13	<u>Unfunded Reserves</u>				
14	Provision for Injuries and Damages	(Line 24)	-\$6,460,053	-\$6,036,960	-\$6,248,506
15	Provision for Vac/Sick Leave	(Line 29)	-\$3,309,219	-\$3,465,026	-\$3,387,123
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	-\$529,643	-\$529,281	-\$529,462
17	Totals:	(Line 14 + Line 15 + Line 16)	-\$10,298,915	-\$10,031,267	-\$10,165,091
18					
19	<u>Calculations</u>				
20					
21	<u>Injuries and Damages</u>		BOY	EOY	Average BOY/EOY
22	Injuries and Damages - Acct. 2251010	Company Records - Input (Negative)	-\$114,763,336	-\$107,247,069	
23	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	5.6290%	5.6290%	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	-\$6,460,053	-\$6,036,960	-\$6,248,506
25					
26	<u>Vacation Leave</u>				
27	Vacation and Personal Time Accruals - Acct. 2350080	Company Records - Input (Negative)	-\$58,788,541	-\$61,556,455	
28	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	5.6290%	5.6290%	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	-\$3,309,219	-\$3,465,026	-\$3,387,123
30					
31	<u>Supplemental Executive Retirement Plan</u>				
32	Supplemental Executive Retirement Plan	Company Records - Input (Negative)	-\$18,818,284	-\$18,805,421	
33	Times:	Applicable Rate Base Percentage	50%	50%	
34	Sub-Total Supplemental Executive Retirement Plan	(Line 32 x Line 33)	-\$9,409,142	-\$9,402,711	
35	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	5.6290%	5.6290%	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	-\$529,643	-\$529,281	-\$529,462

Determination of PBOPs Filing Requirement and PBOPs Filing Amounts

Complete Lines 1-9 of this Schedule every other Annual Update beginning with the Annual Update submitted in 2014 (for Rate Year 2015).
Complete Lines 10-14 every Annual Update beginning with the Annual Update submitted in 2014 (for Rate Year 2015).

Pursuant to Section 8.b of the formula rate protocols, SCE must make a filing to adjust the current Authorized PBOPs Expense Amount if the absolute value of the sum of the Cumulative PBOPs Recovery Difference and the Future PBOPs Recovery Difference is greater than 20% of the sum of SCE's forecast PBOPs expense for the current year and the following year.

Check of above-described condition:

Line		Years	Amount	Source
1	Cumulative PBOPs Recovery Difference	2015-2016	\$0	Note 1
2	Future PBOPs Recovery Difference	2017-2018	-\$80,342,666	Note 2
3	Absolute Value of sum of a and b:		\$80,342,666	Absolute Value (Sum of L1 and L2)
4	20% of Two-Year Forecast PBOPs Expenses		\$0	Note 2, Line i

If amount on Line 3 is greater than amount on Line 4, then SCE must make filing.
Is Filing Necessary? Yes

Calculation
If (L3>L4) then "Yes", else "No"

Amount of PBOPs Expenses that SCE must file for if filing is necessary:

Line	Year	(C1) Forecast PBOPs Expenses	(C2) 50% of Cumulative PBOPs Recovery Difference	(C3) Filing PBOPs Expense	Calculation for Columns 2 and 3
5	2017	\$0	\$0	\$0	C2 = L1 * 0.5, C3 = C1 + C2
6	2018	\$0	\$0	\$0	C2 = L1 * 0.5, C3 = C1 + C2
7	2019	\$0	---	\$0	C2 NA, C3 =Avg of L7,L8,L9, C1
8	2020	\$0	---	\$0	C2 NA, C3 =Avg of L7,L8,L9, C1
9	2021	\$0	---	\$0	C2 NA, C3 =Avg of L7,L8,L9, C1

Calculation of PBOPs True Up TRR Adjustment (See Note 3):

Line		Amount	Source
10	Authorized PBOPs Expense Amount for Prior Year:	\$40,055,779	Note 1 for Prior Year
11	Current Authorized PBOPs Expense Amount:	\$40,171,333	Sch. 20 Note 3, Line a
12	Reduction from previous year:	-\$115,554	Line 10 - Line 11
13	Wages and Salaries Allocation Factor:	5.6290%	27-Allocators, Line 9
14	PBOPs True Up TRR Adjustment:	-\$6,505	Line 12 * Line 13

Notes:

1) The Cumulative PBOPs Recovery Difference is the cumulative over-recovery or under-recovery of SCE's PBOPs expense amount during the period beginning on the date the currently-effective Authorized PBOB Expense Amounts became effective and ending on December 31 of the immediately preceding year ("Prior PBOPs Recovery Period")

	Year	Amount	Decision Reference
Current Authorized PBOPs Expense Amounts:	2016	\$37,714,779	ER16-2433, Order dated September 28, 2016
(See Instruction 1)	2017	\$40,055,779	ER16-2433, Order dated September 28, 2016
	2018	\$40,171,333	ER16-2433, Order dated September 28, 2016
	2019	\$40,171,333	ER16-2433, Order dated September 28, 2016
	2020	\$40,171,333	ER16-2433, Order dated September 28, 2016
	...		

Calculation of Cumulative PBOPs Recovery Difference (see Instruction 2):

	(C1)	(C2)	(C3)	(C4)	(C5)
			Previous Over (-) or Under (+) Recovery	= C2 - C3 Adjusted PBOPs Recovery	= C1 - C4 Over (-) or Under (+) Recovery
Year	PBOPs Expenses	PBOPs Recovery	Recovery	Recovery	Recovery
First Year currently-effective PBOPs Amounts became effective:				\$0	\$0
...				\$0	\$0
			Cumulative PBOPs Recovery Difference:	\$0	Sum of above

2) The Future PBOPs Recovery Difference is the difference between:

- a) The sum of SCE's Forecast PBOPs Expense for the current year and next year ("Projected Expense"); and
- b) The sum of SCE's PBOPs Expense amount to be recovered under its Formula Rate for the current year and the next year at the current Authorized PBOPs Expense Amount ("Projected Recovery").

Calculation of Future PBOPs Recovery Difference:

	Amount	Calculation
a	Projected Expense:	\$0 Sum of first two years of Forecast PBOPs Expenses
b	Projected Recovery:	\$80,342,666 Sum from Note 1 for current and next year.
c	Future PBOPs Recovery Difference:	-\$80,342,666 Projected Expense less Projected Recovery

Five Year Forecast PBOPs Expenses:

	Forecast PBOPs Expenses
d	Year
e	
f	
g	
h	

Twenty Percent of sum of forecast PBOPs Expense for current Rate Year and Immediately succeeding Rate Year: \$0 **Calculation** (d+e) * 0.2

- 3) The PBOPs True Up TRR Adjustment determines the amount by which the True Up TRR for the Prior Year should be adjusted in order to correctly reflect the Authorized PBOPs Expense Amount that was in effect for the Prior Year (rather than the stated amount that is in effect for the current year as shown on Schedule 20, Note 3, Line a).

Instructions:

- 1) "Current Authorized PBOPs Expense Amounts" in Note 1 are the amounts in effect beginning the first year these amounts were authorized.

This schedule is to be filled out (if required by the protocols) utilizing the amounts in effect at that time. If a filing to revise the Authorized PBOPs Expense Amounts is required, SCE shall make such filing after the Draft Annual Update is posted.

SCE shall request that the Commission make the revised Authorized PBOPs Expense Amounts (as determined on Lines 5-9) effective beginning on January 1 of the filing year.

If the Commission approves SCE's filing, the Authorized PBOPs Expense Amount on Schedule 20, Note 3, Line a for the subsequent Annual Update shall then correspond to the first "Filing PBOPs Expense" in Column 3, Line 5 above. Absent another filing, subsequent Authorized PBOPs Expense Amounts in subsequent Annual Updates will correspond to the amounts in lines 6-9.

- 2) Fill out table through the year immediately preceding the current calendar year in which the Annual Update is filed.

Enter in C1 "PBOPs Expenses" for each year equal to SCE's actual PBOPs expenses.

Enter in C2 PBOPs Recovery based on Commission-approved amounts from most recent PBOPs filing for each year in Prior PBOPs Recovery Period.

Enter in C3 "Previous Over (-) or Under (+) Recovery" from previous filing to revise PBOPs amounts (Lines 5 and 6, C2), if any. Enter with same sign, and corresponding to the years over which it was amortized.

C4 "Adjusted PBOPs Recovery" represents PBOPs Recovery with the previous period over or undercollection removed.