Attachment 2 to Appendix IX

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:

TRR Component	Amount
Prior Year TRR	$1,026,235,675
Incremental Forecast Period TRR	$100,660,991
True-Up Adjustment	$59,638,034
Cost Adjustment	$0
Base TRR (retail)	$1,186,534,700

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.

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

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	$248,940,422
3	Transmission Plant Held for Future Use		11-PHFU, Line 8	$9,942,155
4	Abandoned Plant		12-AbandonedPlant, Line 3	$0
	Working Capital amounts			
5	Materials and Supplies		13-WorkCap, Line 16	$13,383,569
6	Prepayments		13-WorkCap, Line 36	$12,812,585
7	Cash Working Capital		(Line 65 + Line 66) / 16	$7,807,795
8	Working Capital		Line 5 + Line 6 + Line 7	$34,003,950
	Accumulated Depreciation Reserve Balances			
9	Transmission Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 13, Col. 12	-$1,633,677,100
10	Distribution Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 16, Col. 5	$0
11	General + Intangible Plant Depreciation Reserve	Negative amount	8-AccDep, Line 26	-$97,665,209
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	-$1,731,342,309
13	Accumulated Deferred Income Taxes	Negative amount	9-ADIT, Line 5, Col. 2	-$1,649,600,327
14	CWIP Plant		14-IncentivePlant, L 13, Col 1	$150,629,632
15	Other Regulatory Assets/Liabilities		23-RegAssets, Line 14	$0
15a	Unfunded Reserves		34-UnfundedReserves, Line 6	-$10,020,874
16	Network Upgrade Credits	Negative amount	22-NUCs, Line 5	-$93,345,105
17	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L15a + L16	$5,532,653,097
OTHER TAXES				
18	Sub-Total Local Taxes	FF1 263.1, Row 30, Column i	FF1 263.2 (see note to left)	$298,376,268
19	Transmission Plant Allocation Factor		27-Allocators, Line 22	19.1109%
20	Property Taxes		Line 18 * Line 19	$57,022,434
21	Payroll Taxes Expense			
22	FICA		Line 23 + Line 24+ Line 25	$106,921,364
23	Fed Ins Cont Amt -- Current	FF1 263, Row 6, Column i	FF1 263 (see note to left)	$106,811,420
24	FICA/OASDI Emp Incntv.	FF1 263, Row 7, Column i	FF1 263 (see note to left)	$80,115
25	FICA/HIT Emp Incntv.	FF1 263, Row 8, Column i	FF1 263 (see note to left)	$29,829
26	CA SUI Current	FF1 263, Row 21, Column i	FF1 263 (see note to left)	$5,909,370
27	Fed Unemp Tax Act- Current	FF1 263, Row 9, Column i	FF1 263 (see note to left)	$2,620,285
28	CADI Vol Plan Assess	FF1 263.1, Row 1, Column i	FF1 263.1 (see note to left)	$1,555,582
29	SF Pyrl Exp Tx - SCE	FF1 263, Row 39, Column i	FF1 263.1 (see note to left)	$42,940
30	Total Electric Payroll Tax Expense		Line 22 + (Line 26 to Line 29)	$117,049,541
31	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 51	$46,585,717
32	Remaining Electric Payroll Tax Expense to Allocate		Line 30 - Line 31	$70,463,824
33	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9	5.6232%
34	Payroll Taxes Expense		Line 32 * Line 33	$3,962,314
35	Other Taxes		Line 20 + Line 34	$60,984,749

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
RETURN AND CAPITALIZATION CALCULATIONS				
	Debt			
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%
	Preferred Stock			
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%
	Equity			
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
	Capital Percentages			
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	48.6129%
			Line 44 + Line 45+ Line 46	100.0000%
	Annual Cost of Capital Components			
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%
	Calculation of Cost of Capital Rate			
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	4.7641%
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	$401,115,723
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%
	Calculation of Credits and Other:			
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		$2,606,000
62	Credits and Other		Line 59 + Line 60+ Line 61	$2,086,200
63	Income Taxes:		Formula on Line 64	$206,039,913
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

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT				
	Component of Prior Year TRR:			
65	O&M Expense		19-OandM, Line 137, Col. 6	$78,494,545
66	A&G Expense		20-AandG, Line 23	$46,430,177
67	Network Upgrade Interest Expense		22-NUCs, Line 10	$6,116,851
68	Depreciation Expense		17-Depreciation, Line 70	$239,554,987
69	Abandoned Plant Amortization Expense		12-AbandonedPlant, Line 1	$0
70	Other Taxes		Line 35	$60,984,749
71	Revenue Credits	Negative amount	21-Revenue Credits, Line 44	-$58,832,606
72	Return on Capital		Line 55	$401,115,723
73	Income Taxes		Line 63	$206,039,913
74	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	11-PHFU, Line 10	$0
75	Amortization and Regulatory Debits/Credits		23-RegAssets, Line 16	$0
76	Prior Year Incentive Adder		15-IncentiveAdder, Line 14	$34,550,171
77	Total without FF&U		Sum of Lines 65 to 76	$1,014,454,511
78	Franchise Fees Expense		L 77 * FF Factor (28-FFU, L 5)	$9,338,764
79	Uncollectibles Expense		L 77 * U Factor (28-FFU, L 5)	$2,442,401
80	Prior Year TRR		Line 77 + Line 78+ Line 79	$1,026,235,675
TOTAL BASE TRANSMISSION REVENUE REQUIREMENT				
	Calculation of Base Transmission Revenue Requirement			
81	Prior Year TRR		Line 80	$1,026,235,675
82	Incremental Forecast Period TRR		2-IFPTRR, Line 82	$100,660,991
83	True Up Adjustment	Note 3	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	$1,186,534,700
	Wholesale Base Transmission Revenue Requirement			
87	Base TRR (Retail)		Line 86	$1,186,534,700
88	Wholesale Difference to the Base TRR		25-WholesaleDifference, Line 44	-$6,023,550
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$1,180,511,149

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 line
Order approving revised ROE:
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		
11			**Reference**
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%	Line 12 + (Line 13 * (1/(1 - 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 = (Prior Year TRR - CWIP-related costs) / Net Plant		
24			
25	**Determination of Net Plant:**		
26			**Reference**
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 Adder $ = (CWIP/$1,000,000) * IREF * (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			

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:	$1,014,454,511	1-BaseTRR, Line 77
62	Prior Year TRR wo CWIP Related Costs:	$998,084,850	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	$93,693,542	(1-BaseTRR, Line 65 + Line 66) * .75
64	AFCR:	13.032%	(Line 62 - Line 63) / Line 31
65			
66	**2) Calculation of IFP TRR**		
67			
68			**Reference**
69	Forecast Plant Additions:	$512,181,617	16-PlantAdditions, L 25, C10
70	AFCR:	13.032%	Line 64
71	AFCR * Forecast Plant Additions:	$66,747,559	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:	$99,505,405	Line 71 + Line 75
78			
79	Franchise Fees Expense:	$916,017	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	$239,569	Line 77 * U (from 28-FFU, L 5)
81			
82	Incremental Forecast Period TRR:	$100,660,991	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										
1		True Up TRR:	$1,014,193,033	Source:	From 4-TUTRR,	Line 45				
2										
3		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
4	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
5								Cumulative		
6					One-Time and			Excess (-) or		Cumulative
7				Actual	Previous	Monthly		Shortfall (+)		Excess (-) or
8			Monthly	Retail Base	Period	Excess (-) or	Monthly	in Revenue	Interest	Shortfall (+)
9			True Up	Transmission	True Up	Shortfall (+)	Interest	wo Interest for	for Current	in Revenue
10	Month	Year	TRR	Revenues	Adjustment	in Revenue	Rate	Current Month	Month	with Interest
11	January	2017	$84,516,086.12	$88,876,406		-$4,360,320	0.29%	-$4,360,320	-$6,322	-$4,366,642
12	February	2017	$84,516,086.12	$76,214,394		$8,301,692	0.29%	$3,935,050	-$626	$3,934,424
13	March	2017	$84,516,086.12	$88,623,013		-$4,106,927	0.29%	-$172,503	$5,455	-$167,048
14	April	2017	$84,516,086.12	$83,996,142		$519,945	0.31%	$352,897	$288	$353,185
15	May	2017	$84,516,086.12	$92,695,249		-$8,179,163	0.31%	-$7,825,978	-$11,583	-$7,837,561
16	June	2017	$84,516,086.12	$104,845,652		-$20,329,566	0.31%	-$28,167,127	-$55,807	-$28,222,935
17	July	2017	$84,516,086.12	$123,594,050		-$39,077,964	0.33%	-$67,300,899	-$157,614	-$67,458,513
18	August	2017	$84,516,086.12	$125,785,396		-$41,269,309	0.33%	-$108,727,823	-$290,707	-$109,018,530
19	September	2017	$84,516,086.12	$106,851,758		-$22,335,672	0.33%	-$131,354,202	-$396,615	-$131,750,817
20	October	2017	$84,516,086.12	$100,653,472		-$16,137,386	0.35%	-$147,888,203	-$489,368	-$148,377,571
21	November	2017	$84,516,086.12	$88,159,107		-$3,643,021	0.35%	-$152,020,592	-$525,697	-$152,546,289
22	December	2017	$84,516,086.12	$89,149,113		-$4,633,027	0.35%	-$157,179,316	-$542,020	-$157,721,336
23	January	2018	---	---		$0	0.35%	-$157,721,336	-$552,025	-$158,273,360
24	February	2018	---	---		$0	0.35%	-$158,273,360	-$553,957	-$158,827,317
25	March	2018	---	---		$0	0.35%	-$158,827,317	-$555,896	-$159,383,213
26	April	2018	---	---		$0	0.37%	-$159,383,213	-$589,718	-$159,972,931
27	May	2018	---	---		$0	0.37%	-$159,972,931	-$591,900	-$160,564,831
28	June	2018	---	---		$0	0.37%	-$160,564,831	-$594,090	-$161,158,920
29	July	2018	---	---		$0	0.37%	-$161,158,920	-$596,288	-$161,755,208
30	August	2018	---	---		$0	0.37%	-$161,755,208	-$598,494	-$162,353,703
31	September	2018	---	---		$0	0.37%	-$162,353,703	-$600,709	-$162,954,411
32	October	2018	---	---		$0	0.37%	-$162,954,411	-$602,931	-$163,557,343
33	November	2018	---	---		$0	0.37%	-$163,557,343	-$605,162	-$164,162,505
34	December	2018	---	---		$0	0.37%	-$164,162,505	-$607,401	-$164,769,906
35										

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

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
38			See Note 8	See Note 9	See Note 10	=C3 + C4	See Note 11	=C5 + C6	= - C4
39-42		Year	Monthly Interest Rate	Month Beginning Balance	Amortization	Month Ending Balance wo Interest	Interest for Current Month	Month Ending Balance	True Up Adjustment Received (+)/ Returned (-)
43	January	2019	0.37%	-$164,769,906	-$4,969,836	-$169,739,742	-$610,480	-$170,350,222	$4,969,836
44	February	2019	0.37%	-$170,350,222	-$4,969,836	-$175,320,059	-$630,848	-$175,950,907	$4,969,836
45	March	2019	0.37%	-$175,950,907	-$4,969,836	-$180,920,743	-$651,291	-$181,572,034	$4,969,836
46	April	2019	0.37%	-$181,572,034	-$4,969,836	-$186,541,870	-$671,808	-$187,213,678	$4,969,836
47	May	2019	0.37%	-$187,213,678	-$4,969,836	-$192,183,514	-$692,400	-$192,875,914	$4,969,836
48	June	2019	0.37%	-$192,875,914	-$4,969,836	-$197,845,750	-$713,067	-$198,558,817	$4,969,836
49	July	2019	0.37%	-$198,558,817	-$4,969,836	-$203,528,653	-$733,810	-$204,262,463	$4,969,836
50	August	2019	0.37%	-$204,262,463	-$4,969,836	-$209,232,299	-$754,628	-$209,986,927	$4,969,836
51	September	2019	0.37%	-$209,986,927	-$4,969,836	-$214,956,763	-$775,522	-$215,732,285	$4,969,836
52	October	2019	0.37%	-$215,732,285	-$4,969,836	-$220,702,121	-$796,493	-$221,498,614	$4,969,836
53	November	2019	0.37%	-$221,498,614	-$4,969,836	-$226,468,450	-$817,540	-$227,285,990	$4,969,836
54	December	2019	0.37%	-$227,285,990	-$4,969,836	-$232,255,826	-$838,664	-$233,094,490	$4,969,836
55					-$59,638,034	Shortfall or Excess Revenue in Prior Year:			$59,638,034

56

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

58

59 **4) True Up Adjustment**

Line			Notes:
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).
63			Negative amount is to be returned to customers by SCE (included in Base TRR as a negative amount).

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

Line				
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%	
85				

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
86	**Transmission Revenues: (Note 12)**							
87								
88		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**
89		See Note 13	See Note 14					Sum of left
90								
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 to106, 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 corrresponding 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

Line	Rate Base Item	Calculation Method	Notes	FERC Form 1 Reference or Instruction	Amount
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	$251,836,564
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
	Working Capital Amounts				
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	$13,043,569
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	$10,636,062
7	Cash Working Capital	1/16 (O&M + A&G)		1-Base TRR Line 7	$7,807,795
8	Working Capital			Line 5 + Line 6 + Line 7	$31,487,425
	Accumulated Depreciation Reserve Amounts				
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	-$102,742,532
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	-$1,652,657,099
13	Accumulated Deferred Income Taxes	BOY/EOY Avg.		9-ADIT, Line 15	-$1,600,481,339
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	-$10,154,559
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	$5,419,646,618

B) Return on Capital

Line			Notes	Reference	Amount
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	$392,922,787

C) Income Taxes

Line			Notes	Reference	Amount
20	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)				$201,953,043
		Where:			
21		RB = Rate Base		Line 17	$5,419,646,618
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	$78,494,545
27	A&G Expense	1-Base TRR L 66	$46,430,177
27a	PBOPs True Up TRR Adjustment	35-PBOPs L 14	-$6,498
28	Network Upgrade Interest Expense	1-Base TRR L 67	$6,116,851
29	Depreciation Expense	1-Base TRR L 68	$239,554,987
30	Abandoned Plant Amortization Expense	1-Base TRR L 69	$0
31	Other Taxes	1-Base TRR L 70	$60,984,749
32	Revenue Credits	1-Base TRR L 71	-$58,832,606
33	Return on Capital	Line 19	$392,922,787
34	Income Taxes	Line 20	$201,953,043
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	$967,618,036
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	$1,002,550,118

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

Line			Reference:
40	True Up TRR wo FF:	$1,002,550,118	Line 39
41	Franchise Fee Factor:	0.921%	28-FFU, L 5
42	Franchise Fee Expense:	$9,229,176	Line 40 * Line 41
43	Uncollectibles Expense Factor:	0.241%	28-FFU, L 5
44	Uncollectibles Expense:	$2,413,740	Line 42 * Line 43
45	True Up TRR:	$1,014,193,033	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"

		Percentage	Reference:	From	To	Days ROE In Effect
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:

		Reference:
e	End of Prior Year	Settlement in ER11-3697
f	Beginning of Prior Year	Settlement in ER11-3697

		Percentage	Reference:
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:

	Percentage	Reference:
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

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
	RETURN AND CAPITALIZATION CALCULATIONS			
	Calculation of Long Term Debt Amount			
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
	Calculation of Cost of Long-Term Debt			
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%
	Calculation of Preferred Stock Amount			
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
	Calculation of Cost of Preferred Stock			
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%
	Calculation of Common Stock Equity Amount			
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
Year 2017

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:

Issue	Face Amount	Issuance Date	Issuance Costs	Amortization Period (Years)	Annual Amortization	Notes
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:

Issue/Event	Event Date	Amortization Amount	Amortization Period (Years)	Annual Amortization	Notes
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"

Line		Amount	Source
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

Line	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

Line		Amount	Source
22	Average BOY/EOY Value:	$4,478,536,208	Average of Line 20 and 21.
23	Transmission W&S Allocation Factor:	5.6232%	27-Allocators, Line 9
24	General + Intangible Plant:	$251,836,564	Line 22 * Line 23.

b) EOY G&I Plant

Line		Amount	Source
25	EOY Value:	$4,427,032,649	Line 21.
26	Transmission W&S Allocation Factor:	5.6232%	27-Allocators, Line 9
27	General + Intangible Plant:	$248,940,422	Line 25 * Line 26.

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

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

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 Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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)

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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	$10,092	-$189	$25,355	$40,429	$791,795	$77,359	$329,882	$115,202	$57,634	$202,454	$1,650,013
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):

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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	$0	$15,224	$15,903,849	$161,490,448	$10,160,040	$6,670,447	$2,503,033	$12,243	$2,564,419	$1,093,225	$200,412,927
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)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
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)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
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)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
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):

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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-PlantStudy for Distribution Plant - ISO.
3) Includes recorded Transmission Plant-In-Service additions, retirements, transfers and adjustments. From SCE internal acounting 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 corresponsing 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	
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:

1) 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).
2) Only accounts 360-362 included as there is no ISO plant in any other Distribution accounts.

Instructions:

1) Perform annual Transmission Study pursuant to instructions in tariff.
2) Enter total amounts of plant from FERC Form 1 in Column 1, "Total Plant".
3) 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):

	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 to C11
		FERC Account:										
Line	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	
		FERC Account:			=Sum C2 to C4	
	Mo/YR	360	361	362	Total	Notes
15	Dec 2016	$0	$0	$0	$0	Beginning of Year ("BOY") amount
16	Dec 2017	$0	$0	$0	$0	End of Year ("EOY") amount
17	BOY/EOY Average:	$0	$0	$0	$0	Average of Line 15 and Line 16

3) General and Intangible Depreciation Reserve

	Col 1	Col 2	Col 3	Col 4	Col 5	
			=C4+C5			
	Mo/YR		Total Gen. and Int. Depreciation Reserve	General Depreciation Reserve	Intangible Depreciation Reserve	Source
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

		Amount	Source
21	Total G+I Dep. Reserve on Average BOY/EOY basis:	$1,827,122,093	Line 20
22	Transmission W&S Allocation Factor:	5.6232%	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$102,742,532	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

		Amount	Source
24	Total G+I Dep. Reserve on Average EOY basis:	$1,736,829,507	Line 19
25	Transmission W&S Allocation Factor:	5.6232%	27-Allocators, Line 9
26	G + I Plant Dep. Reserve (EOY):	$97,665,209	Line 24 * Line 25

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

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

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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

2) Depreciation Expense (See Note 4)

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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)

	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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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)

Line	350.1	350.2	352	353	354	355	356	357	358	359	Total
66	$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)

Line	350.1	350.2	352	353	354	355	356	357	358	359	Total
67	$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)

Line	350.1	350.2	352	353	354	355	356	357	358	359	Total
68	$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)

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
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
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) Depreciaiton 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 Yeaer (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 corresponsing 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

	Col 1	Col 2	
Line	**Account**	**Total ADIT**	**Source**
1	Account 190	$38,579,624	Line 353, Col. 2
2	Account 282	-$1,090,207,015	Line 452, Col. 2
3	Account 283	-$15,673,389	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	-$1,649,600,327	Sum of Lines 1 to 4
6			
7	**b) Beginning of Year Accumulated Deferred Income Taxes**		
8		**BOY**	
9		**ADIT**	**Source**
10	Total Accumulated Deferred Income Taxes	-$1,551,362,350	Previous Year Informational Filing, Line 5, Col. 2
11			
12	**c) Average of Beginning and End of Year Accumulated Deferred Income Taxes**		
13		**Average**	
14		**ADIT**	**Source**
15	Average BOY/EOY ADIT:	-$1,600,481,339	Average of Line 5 and Line 10

2) Account 190 Detail

	ACCT 190	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
	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

	ACCT 190	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
	Electric:							
118	…							
								Source
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:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
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	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
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%	5.623%	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	$38,579,624		$0	$33,689,628	$4,889,995	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

	ACCT 282	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
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	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
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%	5.623%	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
	Electric:							
500	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
	Electric (continued):							
510	…							
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:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
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	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
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%	5.623%	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	-$15,673,389		$0	-$15,608,928	-$64,461	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:

	FERC Form 1 Reference or Instruction	Prior Year Value
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":

	FERC Form 1 Reference or Instruction	Prior Year Value
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

			Col 1 = Sum of all columns	Col 2	Col 3	Col 4	Col 5	Col 6
Line	**Month**	**Year**	**Monthly Total CWIP**	**Tehachapi**	**Devers to Colorado River**	**South of Kramer**	**West of Devers**	**Red Bluff**
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	$150,629,632	$150,976	$0	$4,884,728	$98,805,812	$0
14	13 Month Averages:		$106,441,483	$5,894,762	$0	$4,594,011	$80,157,512	$0

			Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
Line	**Month**	**Year**	**Whirlwind Substation Expansion**	**Colorado River Substation Expansion**	**Mesa**	**Alberhill**	**ELM Series Caps**	
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	$0	$0	$46,788,116	$0	$0	
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 See Note 2 Forecast Expenditures	Col 2 See Note 2 Corporate Overheads	Col 3 See Note 2 Total CWIP Exp	Col 4 See Note 2 Unloaded Total Plant Adds	Col 5 See Note 2 Prior Period CWIP Closed	Col 6 See Note 2 Over Heads Closed to PIS	Col 7 See Note 2 Forecast Period CWIP	Col 8 See Note 2 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 Forecast Expenditures	Col 2 = C1 * 16-Plnt Add Line 74 Corporate Overheads	Col 3 = C1 + C2 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 = (C4 - C5) * 16-Plnt Add Line 74 Over Heads Closed to PIS	Col 7 = Prior Month C7 + C3 - C4 - C6 Forecast Period CWIP	Col 8 = C7 - Dec Prior Year C7 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 Forecast Expenditures	Col 2 Corporate Overheads	Col 3 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 Over Heads Closed to PIS	Col 7 Forecast Period CWIP	Col 8 Forecast Period Incremental CWIP
				= 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
81	December	2017	---	---	---	---	---	---	$0	---
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:**									**$0**

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	---	---	---	---	---	---	$4,884,728	---
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:**									**$628,048**

3d) Project: West of Devers

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			= (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
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

			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**	**Unload Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
185	December	2017	---	---	---	---	---	---	$0	---
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	---	---	---	---	---	---	$0	---
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

			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**
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

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			= (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**
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	$634,300	$47,573	$681,873	$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)

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			= (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**
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

338	November	2019	$0	$0		$0	$0	$0
339	December	2019	$0	$0		$0	$0	$0
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.

Line		Beginning of Year Balance	End of Year Balance	Source
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:

	Col 1 Description	Col 2 Type of Plant	Col 3 Beginning of Year Balance	Col 4 End of Year Balance	Col 5 Source
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

		Beginning of Year Balance	End of Year Balance	Source
4	General Plant Held for Future Use	$0	$0	FF1 page 214
5	Wages and Salaries AF:	5.623%	5.623%	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:

		Beginning of Year Balance	End of Year Balance	Source
7		$6,319,686	$5,839,137	Note 1

		Beginning of Year Balance	End of Year Balance	Source
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

			Source
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.

	Project	Commission Order
Orders Providing for Abandoned Plant Cost Recovery:		
	…	…

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	2011						
7	2012						
8	2013						
9	2014						
10	2015						
11	2016						
12	2017						
13	2018						
14	2019						
15	2020						
16	2021						
17	2022						
18	2023						
19	2024						
20	2025						
21	2026						
22	2027						
23	2028						
24	2029						
25	2030						
26	2031						
27	2032						
28	2033						
29	2034						
30	2035						
31	…						

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	End of Year ("EOY") amount
14	13-Month Average Value Account 154:			$231,960,338	(Sum Line 1 to Line 13) / 13
15	Transmission Wages and Salaries AF:			5.623%	27-Allocators, Line 9
16	**Materials and Supplies**		EOY Value:	$13,383,569	Line 13 * Line 15
17			13-Month Average Value:	$13,043,569	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.

Line	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 AverageValue:	$189,146,429.82	(Sum Line 18 to Line 30) / 13
32			Transmission Wages and Salaries AF:	5.6232%	27-Allocators, Line 9
33			Prepayments:	$10,636,062	Line 31 * Line 32
	b) EOY calculation				
34			EOY Value:	$227,852,643	Line 30
35			Transmission Wages and Salaries AF:	5.6232%	27-Allocators, Line 9
36			Prepayments:	$12,812,585	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 Prior Year End-of-Year CWIP Plant Amount	Col 2 Prior Year 13-Month Average CWIP Plant Amount	Col 3 Forecast Period Incremental CWIP 13-Month Avg. Amount	Notes:
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		Col 1 = C2 + C3 Prior Year Incentive Rate Base	Col 2 EOY CWIP Portion	Col 3 EOY TIP Net Plant In Service	Notes:
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 = C2 + C3 Prior Year Incentive Rate Base	Col 2 13-Month Avg. CWIP Portion	Col 3 13-Month Avg. TIP Net Plant In Service Portion	Notes:
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

	Prior Year Month	Year	Col 1 Total TIP Net Plant In Service	Col 2 L 54 to L 66, C3 Tehachapi	Col 3 L 80 to L 92, C3 Devers to Colorado River	Col 4 L 67 to L 79, C3 Rancho Vista	Col 5	Notes
26	December	2017	$3,623,644,583	$2,761,096,354	$707,569,233	$154,978,996	---	←December of
27	January	2018	$3,615,880,495	$2,755,369,096	$705,927,339	$154,584,059	---	year previous
28	February	2018	$3,614,032,508	$2,755,580,398	$704,262,987	$154,189,123	---	to Prior Year
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

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

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

a) Tehachapi

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 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		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
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		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
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		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
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

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

f) Red Bluff

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
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

Line			
	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

Line	where:		Value	Source
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%.

Line		ROE Adder	Multiplicative Factor	Source
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.

Line		Prior Year Incentive Rate Base	Multiplicative Factor	Prior Year Incentive Adder	Source
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.

Line		True-Up Incentive Net Plant	Multiplicative Factor	True-Up Incentive Adder	Source
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

Line	Incentive Project	13-Month Avg. TIP Net Plant In Service	Source
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

Line	Incentive Project	Col 1 True Up Incentive Adder	Col 2 After-Tax True Up Incentive Adder	Source
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

Line		Amount	Source
31	Total Rate Base:	$5,419,646,618	4-TUTRR, Line 17
32	CWIP Portion of Rate Base:	$106,441,483	4-TUTRR, Line 14
33	Plant In Service Rate Base:	$5,313,205,136	Line 31 - Line 32
34	Equity percentage:	48.6129%	1-BaseTRR, Line 46
35	Equity Portion of Plant In Service Rate Base:	$2,582,902,261	Line 33 * Line 34

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

Line			
36	Plant In Service ROE Adder Percentage:	0.80%	Line 30 / Line 35
37	Base ROE (Including 50 basis point		
38	CAISO Participation Adder):	9.80%	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	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2
			Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Cost of Removal	AFUDC Eligible Plant Additions	AFUDC	Incremental Gross Plant	Depreciation Accrual	Incremental Reserve	Net Plant	Unloaded Low Voltage Additions	Loaded 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	$8,634,679	$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	$14,054,514	$2,327,024	$1,752,821	$20,157,439	$604,723	$629,177,961	$1,234,038	$13,415,828	$615,762,133	$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	C5 10-CWIP L30-53	C6 10-CWIP L30-53	N/A	N/A	N/A	= Prior Month C7 +C1+C3	= Prior Month C7 * L91/12	= Prior Month C9 + C8	=C7-C9		=C11* (1-L75) * (1+L74+L76)
			Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Cost of Removal	AFUDC Eligible Plant Additions	AFUDC	Incremental Gross Plant	Depreciation Accrual	Reserve	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 Unloaded Total Plant Adds	Col 2 Prior Period CWIP Closed	Col 3 =(C1-C2)*L74 Over Heads Closed to PIS	Col 4 =(C1-C2+C3)*L75 Cost of Removal	Col 5 =C1-C2+C3-C4 AFUDC Eligible Plant Additions	Col 6 =C5*L76 AFUDC	Col 7 = Prior Month C2 +C2+C5+C6 Incremental Gross Plant	Col 8 = Prior Month C7 * L91/12 Depreciation Accrual	Col 9 = Prior Month C9 + C8 Incremental Reserve	Col 10 =C7-C9 Net Plant	Col 11 Unloaded Low Voltage Additions	Col 12 =C11* (1-L75) * (1+L74+L76) 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%

5) ISO Cost of Removal Percent

Line		
75	Cost of Removal Rate	8.00%

6) AFUDC Loader Rate

Line		
76	ISO AFUDC Rate	3.00%

7) Calculation of ISO Depreciation Rate

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

Line	Col 1 Acct	Col 2 December Prior Year Plant Balance	Col 3 Accrual Rate	Col 4 C2*C3 Annual Accrual	Accrual Rate Reference
77	350.1	$87,876,203	0.00%	$0	18 Dep Rates L1
78	350.2	$164,901,118	1.66%	$2,737,359	18 Dep Rates L2
79	352	$569,698,023	2.57%	$14,641,239	18 Dep Rates L3
80	353	$3,409,447,774	2.47%	$84,213,360	18 Dep Rates L4
81	354	$2,283,380,922	2.44%	$55,714,494	18 Dep Rates L5
82	355	$364,424,080	3.67%	$13,374,364	18 Dep Rates L6
83	356	$1,245,933,686	3.05%	$38,000,977	18 Dep Rates L7
84	357	$190,222,489	1.65%	$3,138,671	18 Dep Rates L8
85	358	$84,920,374	3.87%	$3,286,418	18 Dep Rates L9
86	359	$172,640,885	1.56%	$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:

1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).

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.

	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:										
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

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15 Depreciation Rates (Percent per year) See "18-DepRates" and Instruction 1.

16	**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%

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

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21		FERC										
22		Account:										**Month**
23	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**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	
37								Total Annual Depreciation Expense for Transmission Plant - ISO:				$212,804,795
38								(equals sum of monthly amounts)				

Line	Description						Source
39	**2) Calculation of Depreciation Expense for Distribution Plant - ISO**						
40							
41		**360**	**361**	**362**			**Source**
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		**360**	**361**	**362**			
48		1.67%	3.04%	3.13%			
49							
50	Depreciation Expense for Distribution Plant - ISO		See Note 2 and Instruction 2				
51							
52		**360**	**361**	**362**	**Total**		
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					5.6232%	27-Allocators, Line 9
62	General and Intangible Depreciation Expense					$26,750,192	Line 60 * Line 61
63							
64	**4) Depreciation Expense**						
65							
66	Depreciation Expense is the sum of:			**Amount**	**Source**		
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			$26,750,192	Line 62		
70			Depreciation Expense:	$239,554,986.67	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

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
	1) Transmission Plant - ISO				
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					

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
	2) Distribution Plant - ISO				
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%

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
	3) General Plant				
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%

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
	4) Intangible Plant				
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)

	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 Recorded O&M Expenses			**Adjustments**				**Adjusted Recorded O&M Expenses**		
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**Reason**	**Total**	**Labor**	**Non-Labor**	**Total**	**Labor**	**Non-Labor**
Line	**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)	-	-	-		$7,813,419	$7,813,419	$0	$7,813,419	$7,813,419	$0
52	**Total Transmission O&M**	$221,093,098	$76,684,121	$144,408,977		($44,297,136)	$7,624,731	-$51,921,868	$176,795,962	$84,308,852	$92,487,110
53											

	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 Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor
	Distribution Accounts										
54	582 - Operation and Relay Protection of Distribution Substatio	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)	-	-	-		$24,163,193	$24,163,193	$0	$24,163,193	$24,163,193	$0
64	**Total Distribution O&M**	$523,405,764	$237,147,537	$286,258,227		$16,037,126	$23,412,725	($7,375,599)	$539,442,890	$260,560,262	$278,882,628
65											
66	**Total Transmission and Distribution O&M**	$744,498,862	$313,831,657	$430,667,204		($28,260,010)	$31,037,456	($59,297,466)	$716,238,852	$344,869,114	$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	$31,976,612	20-AandG, Note 2, f								

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

	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
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**ISO**	**Total**	**Labor**	**Non-Labor**	**Reference**
Line	**Transmission Accounts**								
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 78
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	$0	$393,017	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)	$7,813,419	$7,813,419	$0		$3,025,254	$3,025,254	$0	
122	**Total Transmission - ISO O&M**	$176,795,962	$84,308,852	$92,487,110		$78,494,545	$32,643,286	$45,851,259	
123									

	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
	Account/Work Activity Rev	Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor	Reference
	Distribution Accounts								
124	582 - Operation and Relay Protection of Distribution Substatioi	$24,220,560	$17,289,915	$6,930,645	0.00%	-	-	-	Note 6, d
125	582 - Testing and Inspecting Distribution Substation Equipmen	$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)	$24,163,193	$24,163,193	$0	0.00%	-	-	-	0% per Protocols
134	**Total Distribution - ISO O&M**	$539,442,890	$260,560,262	$278,882,628		-	-	-	
135									
136									
137	**Total ISO O&M Expenses (in Column 6)**	$716,238,852	$344,869,114	$371,369,738		$78,494,545	$32,643,286	$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 transfered 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 Comunication:	
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 acccount 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 acccount is equal to the total ISO labor in accounts listed below (Column 7) divided by total labor in these same accounts (Column 3).	33.8%
570 - Maintenance of Power Transformers	
570 - Substation Work Order Related Expense	
570 - Maintenance of Transmission Voltage Equipment	
570 - Maintenance of Transmission Circuit Breakers	
d) Accounts 582, 590, 591, and 592 - Maintenance of Miscellaneous Distribution Equipment	
Percent ISO for these acccounts 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.

Calculation of Administrative and General Expense

Inputs are shaded yellow

Line	Acct.	Description	Col 1 FERC Form 1 Amount	Col 2 Data Source	Col 3 See Note 1 Total Amount Excluded	Col 4 A&G Expense	Notes
1	920	A&G Salaries	$354,859,044	FF1 323.181b	$71,019,547	$283,839,497	
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	-$15,437,745	$158,244,703	
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:	$790,916,479	

Line	Description	Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	$790,916,479	Line 15
17	Less Account 924:	$14,497,978	Line 5
18	Amount to apply the Transmission W&S AF:	$776,418,501	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	5.6232%	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	$43,659,481	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	19.1109%	27-Allocators, Line 22
22	Property Insurance portion of A&G:	$2,770,696	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$46,430,177	Line 20 + Line 22

Note 1: Itemization of exclusions

Line	Acct.	Total Amount Excluded (Sum of Col 1 to Col 4)	Col 1 Shareholder Exclusions or Other Adjustments	Col 2 Franchise Requirements	Col 3 NOIC	Col 4 PBOPs	Notes
24	920	$71,019,547	-$11,425,726		$82,445,273		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	-$15,437,745	$19,686,961		$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		

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.

		Amount	Source
a	Accrued NOIC Amount:	$103,811,325	SCE Records
b	Actual A&G NOIC payout:	$21,366,051	Note 2, d
c	Adjustment:	$82,445,273	

Actual non-capitalized NOIC Payouts:

	Department		Amount	Source
d	A&G		$21,366,051	SCE Records and Workpapers
e	Other		$9,660,204	SCE Records and Workpapers
f	Trans. And Dist. Business Unit		$31,976,612	SCE Records and Workpapers
g		Total:	$63,002,868	Sum of d to f

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
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.

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.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
1a	450	4191110	Late Payment Charge- Comm. & Ind.	5,873,550	Traditional OOR	5,873,550	0	5,873,550	0			0	0	1
1b	450	4191115	Residential Late Payment	11,837,660	Traditional OOR	11,837,660	0	11,837,660	0			0	0	1
1c	450	4191120	Non-Residential Late Payment		Traditional OOR	0	0	0	0			0	0	1
2	**450 Total**			**17,711,210**		**17,711,210**	**0**	**17,711,210**	**0**		**0**	**0**	**0**	
3	**FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)**			**17,711,210**										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	113,379	Traditional OOR	113,379	0	113,379	0			0	0	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	364,706	Traditional OOR	364,706	0	364,706	0			0	0	1
4c	451	4192110	Miscellaneous Service Revenues	33,304,278	Traditional OOR	33,304,278	0	33,304,278	0			0	0	1
4d	451	4192115	Returned Check Charges	1,427,740	Traditional OOR	1,427,740	0	1,427,740	0			0	0	1
4e	451	4192125	Service Reconnection Charges	5,877	Traditional OOR	5,877	0	5,877	0			0	0	1
4f	451	4192130	Service Establishment Charge	456	Traditional OOR	456	0	456	0			0	0	1
4g	451	4192140	Field Collection Charges	340	Traditional OOR	340	0	340	0			0	0	1
4h	451	4192510	Quickcheck Revenue	44	GRSM	0	0	0	44	P		44	0	2
4i	451	4192910	PUC Reimbursement Fee-Elect	411,073	Other Ratemaking	0	0	0	0			0	411,073	6
4j	451	4182120	Uneconomic Line Extension	228	Traditional OOR	228	0	228	0			0	0	1
4k	451	4192152	Opt Out CARE-Res-Ini	1,560	Other Ratemaking	0	0	0	0			0	1,560	1
4l	451	4192155	Opt Out CARE-Res-Mo	34,655	Other Ratemaking	0	0	0	0			0	34,655	1
4m	451	4192158	Opt Out NonCARE-Res-Ini	45,600	Other Ratemaking	0	0	0	0			0	45,600	1
4n	451	4192160	Opt Out NonCARE-Res-Mo	251,230	Other Ratemaking	0	0	0	0			0	251,230	1
4o	451	4192135	Conn-Charge - Residential	5,815,681	Traditional OOR	5,815,681	0	5,815,681	0			0	0	1
4p	451	4192145	Conn-Charge - Non-Residential	2,178,888	Traditional OOR	2,178,888	0	2,178,888	0			0	0	1
4q	451	4192150	Conn-Charge - At Pole	22,027	Traditional OOR	22,027	0	22,027	0			0	0	1
5	**451 Total**			**43,977,762**		**43,233,600**	**0**	**43,233,600**	**44**		**0**	**44**	**744,118**	
6	**FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)**			**43,977,762**										
7a	453	4183110	Sales of Water & Water Power - San Joaquin		Traditional OOR	0	0	0	0			0	0	3
7b	453	4183115	Sales of Water & Water Power - Headwater		Traditional OOR	0	0	0	0			0	0	3
7c	453	-	Miscellaneous Adjustments		Traditional OOR	0	0	0	0			0	0	3
8	**453 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
9	**FF-1 Total for Acct 453 - Sales of Water and Power, p300.18b (Must Equal Line 8)**			**0**										
10a	454	4184110	Joint Pole - Tariffed Conduit Rental	548,369	Traditional OOR	548,369	0	548,369	0			0	0	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	3,349,084	Traditional OOR	3,349,084	0	3,349,084	0			0	0	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	426,320	Traditional OOR	426,320	0	426,320	0			0	0	4
10d	454	4184116	Joint Pole - Tariffed Process & Eng Fees - Conduit		Traditional OOR	0	0	0	0			0	0	4
10e	454	4184118	Joint Pole - Pl Attchmnt Audit - Undoc P&E Fee		Traditional OOR	0	0	0	0			0	0	4
10f	454	4184120	Joint Pole - Aud - Unauth Penalty	718,500	Traditional OOR	718,500	0	718,500	0			0	0	4
10g	454	4184510	Joint Pole - Non-Tariffed Pole Rental	146,982	GRSM	0	0	0	146,982	P	29,678	117,304	0	2
10h	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	9,240	GRSM	0	0	0	9,240	P	1,004	8,236	0	2
10i	454	4184514	Joint Pole - Non-Tariff Requests for Information	18,880	GRSM	0	0	0	18,880	P	17,840	1,040	0	2
10j	454	4184516	Oil And Gas Royalties	13,134	GRSM	0	0	0	13,134	P	2,112	11,022	0	2
10k	454	4184518	Def Operating Land & Facilities Rent Rev	(787,609)	Traditional OOR	(787,609)	0	(787,609)	0			0	0	4
10l	454	4184810	Facility Cost -EIX/Nonutility	60,454	Other Ratemaking	3,578	3,578	0	0			0	56,876	6, 12
10m	454	4184815	Facility Cost- Utility		Traditional OOR	0	0	0	0			0	0	7
10n	454	4184820	Rent Billed to Non-Utility Affiliates	1,344,451	Other Ratemaking	79,578	79,578	0	0			0	1,264,873	6, 12
10o	454	4184825	Rent Billed to Utility Affiliates		Traditional OOR	0	0	0	0			0	0	7
10p	454	4194110	Meter Leasing Revenue		Traditional OOR	0	0	0	0			0	0	1
10q	454	4194115	Company Financed Added Facilities	10,649,093	Traditional OOR	10,649,093	0	10,649,093	0			0	0	4
10r	454	4194120	Company Financed Interconnect Facilities	747,196	Traditional OOR	747,196	0	747,196	0			0	0	4
10s	454	4194130	SCE Financed Added Faclty	22,731,825	Traditional OOR	22,731,825	0	22,731,825	0			0	0	4
10t	454	4194135	Interconnect Facility Finance Charge	13,246,533	Traditional OOR	13,246,533	3,119,188	10,127,345	0			0	0	8
10u	454	4204515	Operating Land & Facilities Rent Revenue	21,987,089	GRSM	0	0	0	21,987,089	P	4,456,797	17,530,293	0	2
10v	454	4867020	Nonoperating Misc Land & Facilities Rent		Traditional OOR	0	0	0	0			0	0	4
10w	454	-	Miscellaneous Adjustments	(35,871)	Traditional OOR	(35,871)	0	(35,871)	0			0	0	1
10x	454	4206515	Op Misc Land/Fac Rev	1,353,393	GRSM	0	0	0	1,353,393	P	272,458	1,080,936	0	2
10y	454	4184122	T-Unauth Pole Rent		Traditional OOR	0	0	0	0			0	0	4
10z	454	4184124	T-P&E Fees	5,840	Traditional OOR	5,840	0	5,840	0			0	0	4
10aa	454	4184821	Rent Rev NU-NonBRRBA	84,600	Other Ratemaking	5,007	5,007	0	0			0	79,592	6, 12
10bb	454	4184811	Fac Cost N/U-BRRBA	960,791	Other Ratemaking	56,869	56,869	0	0			0	903,922	6, 12
10cc	454	4184515	NEM 2.0	1,848,475	Other Ratemaking	0	0	0	0			0	1,848,475	6
11	**454 Total**			**79,426,770**		**51,744,313**	**3,264,221**	**48,480,091**	**23,528,719**		**4,779,889**	**18,748,830**	**4,153,738**	
12	**FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)**			**79,426,770**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
12a	456	4186114	Energy Related Services	3,857,356	Traditional OOR	3,857,356	0	3,857,356	0			0	0	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	576	Traditional OOR	576	0	576	0			0	0	4
12c	456	4186120	Added Facilities - One Time Charge	133,080	Traditional OOR	133,080	0	133,080	0			0	0	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr		Traditional OOR	0	0	0	0			0	0	3
12e	456	4186126	Service Fee - Optimal Bill Prd	160	Traditional OOR	160	0	160	0			0	0	1
12f	456	4186128	Miscellaneous Revenues	803,911	Traditional OOR	803,911	0	803,911	0			0	0	1
12g	456	4186130	Tule Power Plant - Revenue		Traditional OOR	0	0	0	0			0	0	3
12h	456	4186142	Microwave Agreement	3,428	Traditional OOR	3,428	0	3,428	0			0	0	4
12i	456	4186150	Utility Subs Labor Markup		Traditional OOR	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	6, 12
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	1,447	Traditional OOR	1,447	0	1,447	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	4
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	4,388	Traditional OOR	4,388	0	4,388	0			0	0	4
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	993	Traditional OOR	993	0	993	0			0	0	4
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	845	Traditional OOR	845	0	845	0			0	0	4
12p	456	4186194	Property License Fee revenue	173,880	Traditional OOR	173,880	0	173,880	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	2
12r	456	4186514	Mapping Services	161,225	GRSM	0	0	0	161,225	P	37,883	123,342	0	2
12s	456	4186518	Enhanced Pump Test Revenue	40,875	GRSM	0	0	0	40,875	P	84	40,791	0	2
12t	456	4186520	RTTC Revenue		GRSM	0	0	0	0	P		0	0	2
12u	456	4186524	Revenue From Scrap Paper - General Office		GRSM	0	0	0	0	P		0	0	2
12v	456	4186528	CTAC Revenues	1,700	GRSM	0	0	0	1,700	P	0	1,700	0	2
12w	456	4186530	AGTAC Revenues	3,775	GRSM	0	0	0	3,775	P	2,775	1,000	0	2
12x	456	4186536	Other Inc/erd Party DC-ESM		GRSM	0	0	0	0	P		0	0	2
12y	456	4186538	3rd Party-Div Tmg-Cr PPD training		GRSM	0	0	0	0	P		0	0	2
12z	456	4186716	ADT Vendor Service Revenue		GRSM	0	0	0	0	A		0	0	2
12aa	456	4186718	Read Water Meters - Irvine Ranch		GRSM	0	0	0	0	A		0	0	2
12bb	456	4186720	Read Water Meters - Rancho California		GRSM	0	0	0	0	A		0	0	2
12cc	456	4186722	Read Water Meters - Long Beach		GRSM	0	0	0	0	A		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	2
12ee	456	4186815	Employee Transfer/Affiliate Fee		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
12jj	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		GRSM	0	0	0	0	A		0	0	2
12nn	456	4188714	Consulting Fees - IMS		GRSM	0	0	0	0	A		0	0	2
12oo	456	4188818	FTR Auction Revenue		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		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		Traditional OOR	0	0	0	0			0	0	4
12uu	456	4196172	Off Grid Photo Voltaic Revenues		Traditional OOR	0	0	0	0			0	0	1
12vv	456	4196174	Scheduling/Dispatch Revenues		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		GRSM	0	0	0	0	P		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		Traditional OOR	0	0	0	0			0	0	4
12ggg	456	4186115	Energy Reltd 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	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										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
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	0	2
24b	417	4863130	ECS - Distribution Facilities	605,719	GRSM	0	0	0	605,719	P	138,132	467,587	0	2
24c	417	4862110	ECS - Dark Fiber	6,207,732	GRSM	0	0	0	6,207,732	A	1,179,301	5,028,431	0	2
24d	417	4862115	ECS - SCE Net Fiber	3,328,620	GRSM	0	0	0	3,328,620	A	648,086	2,680,534	0	2
24e	417	4862120	ECS - Transmission Right of Way	283,556	GRSM	0	0	0	283,556	A	55,208	228,348	0	2
24f	417	4862135	ECS - Wholesale FCC	21,488,152	GRSM	0	0	0	21,488,152	A	4,216,369	17,271,783	0	2
24g	417	4864110	ECS - Infrastructure Leasing		GRSM	0	0	0	0	A		0	0	2
24h	417	4864115	ECS - EU FCC Rev	(237,195)	GRSM	0	0	0	(237,195)	A	114,302	(351,497)	0	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	0	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	0	2
24k	417	4863120	ECS - Communication Sites	342,231	GRSM	0	0	0	342,231	P	71,854	270,376	0	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	0	2
24m	417	4863115	ECS - Cell Site Reimbursable (Passive)	873,100	GRSM	0	0	0	873,100	P	325,605	547,495	0	2
24n	417	4863125	ECS - Micro Cell	1,970,237	GRSM	0	0	0	1,970,237	P	365,770	1,604,468	0	2
24o	417	4864120	ECS - End User Universal Service Fund Fee	(42,477)	GRSM	0	0	0	(42,477)	A	21,210	(63,687)	0	2
24p	417	4864116	ECS - Instrastate End User Revenue	1,330,785	GRSM	0	0	0	1,330,785	A	60,758	1,270,027	0	2
24q	417	4864121	ECS - Intrastate End User Fees	107,810	GRSM	0	0	0	107,810	A	4,665	103,145	0	2
24r	417	4864117	ECS - Interstate End User Tax Exempt	40,857	GRSM	0	0	0	40,857	A	0	40,857	0	2
24s	417	4864122	ECS- EU USAC E-Rate	27,607	GRSM	0	0	0	27,607	A	0	27,607	0	2
25	**417 ECS Total**			**57,636,155**		**0**	**0**	**0**	**57,636,155**		**11,514,733**	**46,121,422**	**0**	
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**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	**FERC ACCT**	**ACCT**	**ACCT DESCRIPTION**	**DOLLARS**	**Category**	**Total**	**ISO**	**Non-ISO**	**Total**	**A/P**	**Threshold [10]**	**Incremental**	**Total**	**Notes**
	Subsidiaries													
28a	418.1		ESI (Gross Revenues - Active)		GRSM	0	0	0	0	A		0	0	2,9
28b	418.1		ESI (Gross Revenues - Passive)		GRSM	0	0	0	0	P		0	0	2,9
28c	418.1		Southern States Realty		GRSM	0	0	0	0	P		0	0	2, 15
28d	418.1		Mono Power Company	0	Traditional OOR	0	0	0	0			0	0	13
28e	418.1		SCE Capital Company	(45)	Traditional OOR	(45)	0	(45)	0			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	0	7, 17
29	**418.1 Subsidiaries Total**			**(1,824,158)**		**(1,824,158)**	**(107,969)**	**(1,716,188)**	**0**		**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	D	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

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

Notes:

1- CPUC Jurisdictional service related.

2- 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.

3- Generation related.

4- Non-ISO facilities related.

5- ISO transmission system related.

6- Subject to balancing account treatment

7- 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

8- ISO portion of Traditional OOR relates to monthly revenues received from customers for facilities that are part of the ISO network.

9- 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.

10- The first $16,671,389 million in gross revenues generated by GRSM activities are automatically classified as Threshold Revenue.

11- 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%.

12- 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

13- 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.

14- 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.

15- 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.

16- For subsidiaries that are subject to GRSM, Column D contains gross revenues. Input on Line 30D contains the associated expenses.

17- 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)

Line		Balance	Notes
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.

Schedule 23
Regulatory Assets and Liabilities

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		**Amount**	**Calculation or Source**
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

Line	**Description of Issue Resulting in Other Regulatory Asset/Liability**	**Col 1 Prior Year BOY Other Reg Asset/Liability**	**Col 2 Prior Year EOY Other Reg Asset/Liability**	**Col 3 Prior Year Amortization or Regulatory Debit/Credit**	**Commission Order Granting Approval of Regulatory Liability**
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:

Line	Project	Col 1 Prior Year EOY Amount	Col 2 Prior Year Average Amount	Col 3 Forecast 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:

Line		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

Line		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:

Line		Value	Source
24	IREF =	$8,204	15-IncentiveAdder, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	Source
25	Tehachapi CWIP Amount:	$150,976	$5,894,762	Line 1
26	ROE Adder %:	1.25%	1.25%	15-IncentiveAdder, Line 5
27	ROE Adder $:	$1,548	$60,452	Formula on Line 32

2) Devers to Colorado River

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

Line		PYTRR Amount	True Up TRR Amount	Source
33	Return:	$10,920,604	$7,716,976	Line 15
34	Income Taxes:	$5,447,508	$3,849,447	Line 19
35	ROE Adder Tehachapi:	$1,548	$60,452	Line 27
36	ROE Adder DCR:	$0	$0	Line 30
37	FF&U:	$190,106	$107,034	Note 1
38	Total:	$16,559,766	$11,733,909	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

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF&U	Col 5 = Sum C1 to C4 Total	Source
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

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF	Col 5 = Sum C1 to C4 Total	Source
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

		Value	Source
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

	Project	Amount wo FF&U	Amount with FF&U	Source
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

		Value	Source
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

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF&U	Col 4 Total	Source
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

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF	Col 4 Total	Source
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:

1) (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
2) 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.
3) 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.
4) Project contribution to total IFPTRR is based on fraction of Forecast Period CWIP Balances on Lines 1 to 12, Col 3.
5) 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)
6) 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:

Line		Rate Base Difference	Expense (Amortization) Difference	Expense Tax Impact
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:

		Data Source		Col 1 2010 Rate Base Difference (Wholesale less Retail)	Col 2 Annual Change (Amortization)
7	1) Accumulated Depreciation	Fixed values		$31,556,000	-$2,176,300
8	2) Taxes Deferred - Make Up Adjustment	Fixed values		-$35,044,000	$2,503,000
9	3) Excess Deferred Taxes	Fixed values		-$624,650	$43,100
10	4) Taxes Deferred - Acct. 282 ACRS/MACRS	Fixed values		-$7,410,000	$511,200
11			Totals:	-$11,522,650	$881,000

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.

		Data Source	Value	Notes/Instructions
12	Fixed Charge Rate	2-IFPTRR Line 16	10.87%	1
13	Prior Year		2017	2
14	Wholesale Rate Base Difference for Prior Year		-$5,355,650	3
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

		Source	Value
16	South Georgia Amortization	Line 8	$2,503,000
17	Composite Tax Rate ("CTR")	1-BaseTRR L 58	40.746%
18	Tax Gross Up Factor	(1/(1-CTR))	1.6876
19	Wholesale South Georgia		
20	Income Tax Adjustment to the TRR:	- Line 16 * Line 18	-$4,224,187.40

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

		Source	Value
21	Annual Amort. of "Excess Deferred Taxes":	Line 9	$43,100
22	Tax Gross Up Factor	Line 18	1.6876
23	Excess Deferred Taxes Grossed Up for Income Taxes:	- Line 21 * Line 22	-$72,738
24			

Line		Source		Notes/Instructions
25	**c) Calculation of EPRI and EEI Expense Exclusion**			
26		**Source**		**Notes/Instructions**
27	EPRI Expenses	SCE Records	$200,769	Note 5
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	5.6232%	
31	EPRI and EEI Expense Exclusion	Line 29 * 30	$97,305	
	d) Total Expense Difference			**Notes/Instructions**
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	-$97,305	
37		Total Expense Difference:	-$2,729,130	

3) Calculation of the Wholesale Difference to the Base TRR

Line		Source	Value	
38	Wholesale Rate Base Adjustment	Line 15	-$581,970	
39	Expense Difference	Line 37	-$2,729,130	
40	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 79	-$2,442,401	
41	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	-$239,569	
42	Subtotal:	Sum Line 38 to Line 41	-$5,993,069	
43	Franchise Fee Exclusion		-$30,481	Note 4
44	Wholesale Difference to the Base TRR:	Line 42 + Line 43	-$6,023,550	

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

Line				
	1) Federal Income Tax rate		Inputs are shaded yellow	
	Prior Year	**Federal Income Tax Rate ("FITR")**	**Source**	
1	2017	35.00%	Note 1, c Column 2, see also Note 2	
2				
3	**2) Composite State Income Tax Rate**			
4				
5		**Composite State**		
6	**Prior**	**Income Tax**		
7	**Year**	**Rate ("CSITR")**	**Source**	
8	2017	8.8400%	1) See calculation below on Line 45 based on inputs	
9			for apportionment factors and state tax rates.	
10			for the applicable Prior Year	
11				
12	**Calculation of Composite State Income Tax Rate for the Prior Year:**			
13				
14		**Apportionment**		
15	**State**	**Factors ("AFs")**	**Source**	
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				
21		**Statutory**		
22	**State**	**Tax Rate ("STR")**		
23	California	8.8400%	2) Input STR for the Prior Year	
24	New Mexico	6.2000%	for each state. See Notes 1 and 3.	
25	Arizona	4.9000%		
26	D.C.	9.0000%		
27				
28		**Ratio of SCE**		
29		**State Taxable**		
30		**Income to SCE**		
31		**California**		
32	**State**	**Taxable Income**		
33	California	100.0000%	3) Input most recent available ratios based on	
34	New Mexico	0.0000%	taxable income from state return filings.	
35	Arizona	0.0000%		
36	D.C.	0.0000%		
37				
38		**Effective State**		
39	**State**	**Tax Rate**		
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	**Composite State**			
45	**Income Tax Rate =**	8.8400%	Sum of Lines 40 to 43	
46				
47	**3) Capitalized Overhead portion of Electric Payroll Tax Expense**			
48				**Amount**
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 x 120) + (.4000 x 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%	= ((Line a, C1)*(Line a, C2)+ (Line b, C1)*(Line b, C2))/365

2) Federal Source Statute: Internal Revenue Code Section 11(b)(1)(D)

3) State Source Statues (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	$32,643,286
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	$63,002,868
6	Less A&G NOIC		20-AandG, Note 2	$21,366,051
7	NOIC wo A&G NOIC		Line 5 - Line 6	$41,636,816
8	Total non-A&G W&S with NOIC		Line 4 + Line 7	$580,511,968
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	5.6232%
10				
11	**2) Calculation of Transmission Plant Allocation Factor**			
12			**FERC Form 1 Reference**	**Prior Year**
13		**Notes**	**or Instruction**	**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	$74,499,964
18	Total General Plant		6-PlantInService, Line 21, C1	$3,102,162,333
19	General Plant		Line 18 * Line 9	$174,440,457
20	Total Plant In Service		FF1 207.104g	$46,164,121,713
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	19.1109%
23				

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

Line		Values		Notes	Applied to Accounts
25					
26	a) Outages	**Values**		**Notes**	**Applied to Accounts**
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	**Values**		**Notes**	**Applied to Accounts**
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	**Values**		**Notes**	**Applied to Accounts**
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					

Line	Description	Values	Notes	Applied to Accounts
44	d) Line Miles	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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 Undergound Line Miles	360	= L51 + L52	
54	Underground Line MIles Percent ISO	1.4%	= L51 / L53	
55				
56	f) Line Rents Costs	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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	**Values**	**Notes**	**Applied to Accounts**
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				

		Values	Notes	Applied to Accounts
98	m) Transmission Facility Property Damage	Values	Notes	Applied to Accounts
99	ISO Transmission Fac. Property Damage	1,343,856		573 - Provision for Property Damage Expense to Trans. Fac.
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	Values	Notes	Applied to Accounts
105	ISO Distribution Transformers	0		592 - Maintenance of Distribution Transformers
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	Values	Notes	Applied to Accounts
111	ISO Distribution Circuit Breakers	0		592 - Maintenance of Distribution Circuit Breakers
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	Values	Notes	Applied to Accounts
117	ISO Distribution Voltage Control Equipment	0		592 - Maintenance of Distribution Voltage Control Equipment
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

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

2) Approved Uncollectibles Expense Factor(s)

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

3) FF and U Factors

	Prior Year	FF Factor	U Factor	Notes
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.

	Percent	Calculation
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

Inputs are shaded yellow

Line	TRR Values		Notes	Source	
1	$1,180,511,149	= 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	-$8,894,864	= 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	

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

		Col 1	Col 2	Col 3	
		TOTAL	High Voltage	Low Voltage	Source
8	**Wholesale Base TRR:**	$1,180,511,149	$1,145,073,301	$35,437,848	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:**	$1,127,837,766	$1,092,399,918	$35,437,848	See Note 5
11	**Wholesale TRBAA:**	-$121,378,713	-$120,967,080	-$411,633	Lines 2 to 4
12	**Less Standby Transmission Revenues:**	-$8,894,864	-$8,627,849	-$267,016	See Note 6
13	**Components of Wholesale Transmission Revenue Requirement:**	$1,050,237,572	$1,015,478,372	$34,759,199	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:

Line				Source
1	LV TRR =	$34,759,199		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:

				Source
4	LV TRR =	$34,759,199		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)

				Source
7	SCE HV TRR =	$1,015,478,372		29-WholesaleTRRs, Line 13, C2
8	Gross Load =	86,694,873	MWh	32-Gross Load, Line 3
9	High Voltage Utility-Specific Rate =	$0.0117132	per kWh	Line 7 / (Line 8 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

				Source
10	HV Wholesale TRR =	$1,015,478,372		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:

				Source
13	LV Wholesale TRR =	$34,759,199		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:

Line	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
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	$0
3	LV Transmission Lines	$97,777,323	$5,523,117	$92,254,206	$0	$5,523,117	$0	$92,254,206	$0
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	$0
5									
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	$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	$53,771,884
9	LV Substations (Less Than 200kV)	41,534,818	$127,274	$41,407,544	$0	$127,274	$0	$41,407,544	$0
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	$53,771,884
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	$53,771,884
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant that can directly be determined to be HV or LV:				
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					

28 **B) Gross Plant Percentage for the Rate Effective Period:**

Line		High Voltage	Low Voltage	Total	Notes:
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

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	86,680,005		Note 1
2	Pump Load forecast:	14,868		Note 2
3	Forecast Gross Load:	86,694,873	Line 1 + Line 2	Sum of above
4	Forecast 12-CP Retail Load:	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

		Source	
Retail Base TRR:	1,186,534,700	1-BaseTRR WS, Line 86	Input cells are shaded yellow

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

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
		Note 1		Note 2	Note 3	Note 4	Note 5	Note 6	Note 7		Note 8	Note 8	Note 8		
				Sales Forecast Billing Determinants:											
			= Retail Base TRR * Line1:Col1	Sales Forecast (Not Including Backup)	Sales Forecast (Backup)	NEM Adjustment	Applies to supplemental kW demand charges	Applies to contracted standby kW demand charges	= (Line1:Col3 + Line1:Col4) - Line1:Col5	= Line1:Col2 / (Line1:Col8*10^6)	= Line1:Col2 / ((Line1:Col6 + Line1:Col7)*10^3)	Recorded Billing Determinants: to be applied to the Supplemental kW demand charges, and the Contracted Standby kW demand charges			
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%	$494,971,924	28,443		1,431	0	0	27,012	$0.01832					
1b	GS-1	7.77%	$92,221,003	5,911		11	0	0	5,900	$0.01563		5,942	29,137	0	
$1b_2$	GS-1 continued			0					0		$3.19	$92,886,353	$3.19		Notes 9,10
1c	TC-1	0.05%	$579,287	58			0		58	$0.01005					
1d	GS-2	16.51%	$195,924,173	13,100		61	44,897	36	13,039		$4.36				
1e	TOU-GS-3	9.11%	$108,104,624	7,840		68	22,683	70	7,772		$4.75				
1f	TOU-8-SEC	8.79%	$104,255,071	8,055		37	20,531		8,018		$5.08				
1g	TOU-8-PRI	5.83%	$69,213,016	5,509		23	12,817		5,486		$5.40				
1h	TOU-8-SUB	6.32%	$75,018,860	5,868		0	11,894		5,868		$6.31				
1i	TOU-8-Standby-SEC	0.09%	$1,116,879	113	97		325	285	210		$1.83				
1j	TOU-8-Standby-PRI	0.20%	$2,410,172	534	243		1,310	1,373	778		$0.90				
1k	TOU-8-Standby-SUB	0.42%	$4,927,722	1,672	560		3,309	8,394	2,231		$0.42				
1l	TOU-PA-2	1.57%	$18,621,244	1,816		6	8,121	1	1,810		$2.29				
1m	TOU-PA-3	1.19%	$14,064,586	1,454		16	4,933	8	1,438		$2.85				
1n	Street Lighting	0.43%	$5,106,140	698			0		698	$0.00731					
1o	---								0						
2	Totals:	100.00%	$1,186,534,700	81,070	900	1653	130,819	10,166	80,317						
3															
4															

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

6		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
7		from Line1:Col2	from Line1:Col7	= Col1 / Col2 / 10^3			from Line1:Col2	Note 11	= Col 6 / (Col 7 * 10^3)
8									
9	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	$1,116,879	285	$3.92		TOU-8-SEC	$104,255,071	20,856	5.00
9b	TOU-8-Standby-PRI	$2,410,172	1,373	$1.76		TOU-8-PRI	$69,213,016	14,126	4.90
9c	TOU-8-Standby-SUB	$4,927,722	8,394	$0.59		TOU-8-SUB	$75,018,860	15,203	4.93
9d	---					---			
10									

11 **3) End-User Transmission Rates**

Line		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	$494,971,924	$494,971,924			$0.01832					
16b	GS-1	$92,221,003	$92,221,003	$0		$0.01563	$3.19	$3.19			Note 15
16c	TC-1	$579,287	$579,287			$0.01005					
16d	GS-2	$195,924,173	$195,783,040	$141,133			$4.36	$3.92			
16e	TOU-GS-3	$108,104,624	$107,830,198	$274,426			$4.75	$3.92			
16f	TOU-8-SEC	$102,631,665	$102,631,665				$5.00				
16g	TOU-8-PRI	$62,795,677	$62,795,677				$4.90				
16h	TOU-8-SUB	$58,691,398	$58,691,398				$4.93				
16i	TOU-8-Standby-SEC	$2,740,285	$1,623,406	$1,116,879			$5.00	$3.92			
16j	TOU-8-Standby-PRI	$8,827,510	$6,417,339	$2,410,172			$4.90	$1.76			
16k	TOU-8-Standby-SUB	$21,255,184	$16,327,462	$4,927,722			$4.93	$0.59			
16l	TOU-PA-2	$18,621,244	$18,620,061	$1,183			$2.29	$2.29	$1.71	$1.71	Note 16
16m	TOU-PA-3	$14,064,586	$14,041,236	$23,350			$2.85	$2.85			
16n	Street Lighting	$5,106,140	$5,106,140			$0.00731					
16o	---										
17	Totals:	$1,186,534,700	$1,177,639,835	$8,894,864							

18

19 **Notes:**

1) See Col 9 of Lines 35a, 35b, 35c, etc.
2) 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).
3) 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.
4) 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.
5) Sales forecast pertaining to the sum of monthly maximum supplemental Mega-watt demand, applies to demand charge schedules
6) Sales forecast pertaining to the sum of monthly contracted standby Mega-watt demand, applies to standby schedules
7) 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
8) 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
9) Line 1b2, Col11 = Line 1b Col9 * Line 1b Col11 * 10^6
10) 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)
11) Sum of the TOU-8 Standby and TOU-8 Non-Standby billing determinants in Line1:Col6
12) For TOU-8 Rates revenue = Supplemental Demand Charge on Line 9 Column 8 * Maximum Demand on Lines 1 Column 6
13) For optional time-of-use schedules within the GS-1 rate group (Line16b:Col6), = (Line1b$_2$:Col11 - Line16:Col3) / Line1b:Col12 / 10^3
14) For the non TOU-8-Standby rate group, it is the minimum of Line16i:Col7, or the total demand rate in Line1:Col109
15) Applicable to time-of-use schedules within the GS-1 rate group
16) Applicable to the optional schedules that contain horse power charge such as PA-1
17) 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

22 **Rate Schedules in each CPUC Rate Group:**

23

24

Line	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 (con't)	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)**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
31					= Line35:(Col1+Col2 +Col3)/3						= Line35:(Col4*Col5 /Col6*Col9)	= Line35:(Col10 / total of Col10)
32								from Line1:Col3 Note 17	from Line1:Col4	= Col 7 + Col 8		
33		12-CP MW										
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			
1					
2					
3					**Prior Year**
4		**Reference**			**Amount**
5					
6	**Unfunded Reserves (EOY):**	(Line 17, Col 2)			-$10,020,874
7	**Unfunded Reserves (Average BOY/EOY):**	(Line 17, Col 3)			-$10,154,559
8					
9			**Col 1**	**Col 2**	**Col 3**
10			**Prior Year**	**Prior Year**	**Prior Year**
11			**BOY**	**EOY**	**Average**
12	**Description of Issue**		**Unfunded**	**Unfunded**	**Unfunded**
13	**Unfunded Reserves**		**Reserves**	**Reserves**	**Reserves**
14	Provision for Injuries and Damages	(Line 24)	-$6,453,360	-$6,030,706	-$6,242,033
15	Provision for Vac/Sick Leave	(Line 29)	-$3,305,791	-$3,461,436	-$3,383,613
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	-$529,094	-$528,732	-$528,913
17	Totals:	(Line 14 + Line 15 + Line 16)	-$10,288,244	-$10,020,874	-$10,154,559
18					
19	**Calculations**				
20					Average
21	**Injuries and Damages**		BOY	EOY	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)	5.6232%	5.6232%	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	-$6,453,360	-$6,030,706	-$6,242,033
25					
26	**Vacation Leave**				
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)	5.6232%	5.6232%	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	-$3,305,791	-$3,461,436	-$3,383,613
30					
31	**Supplemental Executive Retirement Plan**				
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)	5.6232%	5.6232%	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	-$529,094	-$528,732	-$528,913

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) Note 2, d-h 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:	5.6232%	27-Allocators, Line 9
14	PBOPs True Up TRR Adjustment:	-$6,498	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: (See Instruction 1)	2016	$37,714,779	ER16-2433, Order dated September 28, 2016
	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):

	Year	(C1) PBOPs Expenses	(C2) PBOPs Recovery	(C3) Previous Over (-) or Under (+) Recovery	(C4) = C2 - C3 Adjusted PBOPs Recovery	(C5) = C1 - C4 Over (-) or Under (+) 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:

	Year	Forecast PBOPs Expenses
d		
e		
f		
g		
h		

			Calculation
i	Twenty Percent of sum of forecast PBOPs Expense for current Rate Year and Immediately succeeding Rate Year:	$0	(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 preceeding 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.