

Application No.: A.23-05-XXX
Exhibit No.: SCE-07 Vol. 01
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(U 338-E)

2025 General Rate Case

Results of Operations

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 12, 2023

SCE-07 Vol. 01: Results of Operations

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I.

INTRODUCTION

The chapters that comprise Volume 1 of Southern California Edison Company's (SCE) Results of Operations (RO) exhibit address several related subjects. First, Chapter II summarizes SCE's revenue requirement for the 2025-2028 forecast period. Next, Chapter III summarizes SCE's GRC-related and total company revenue requirement change in 2025 through 2028.

Then, Chapter IV presents SCE's methodology to separate, or "functionalize," the CPUC-jurisdictional base-related revenue requirement between distribution, generation, and new system generation (*e.g.*, Peakers and Energy Storage). Chapter IV also presents SCE's Transmission & Distribution (T&D) Jurisdictional Study, which is used to split total forecast costs between the jurisdiction of the California Public Utilities Commission (Commission or CPUC) and the Federal Energy Regulatory Commission (FERC).

Chapter V discusses various GRC-related ratemaking proposals associated with SCE's requested CPUC-jurisdictional base-related revenue requirements.¹ Chapter VI presents SCE's forecasts of: (i) electricity sales, (ii) customer accounts, and (iii) new meter connections in SCE's service area for 2023-2028. Chapter VII presents SCE's estimates of the revenues that would result from application of SCE's currently authorized rates to the sales forecast. Chapter VIII presents SCE's 2018-2022 recorded and 2023-2028 forecasts of cost escalation rates.

Chapter IX presents SCE's estimates of Other Operating Revenue (OOR), which offsets the base revenue requirement to be collected from SCE's customers. Chapter X summarizes the O&M expense forecast development process and the total O&M expenses presented throughout this application. Finally, Chapter XI presents SCE's proposed Administrative and General (A&G) and Pensions and Benefits (P&B) capitalization rates.

¹ Chapter V also includes the review of Mobilehome Park (MHP) Costs incurred through 2022 as required by D.14-03-021.

1 II.

2 **RESULTS OF OPERATIONS AT PRESENT AND PROPOSED RATES**

3 Part A of this chapter presents SCE's base-related² total company Results of Operations (RO)
4 summary of earnings for the recorded year 2022 and forecast years 2023 through 2028 at present rates.³
5 This chapter also presents SCE's base-related CPUC-jurisdictional RO summary of earnings for the
6 forecast years 2025 through 2028 at present rates. The RO summary of earnings at present rates
7 identifies the expected rate of return on SCE's operations, absent the rate relief requested in this
8 Application. Part B of this chapter sets forth the RO summary of earnings at proposed rates.

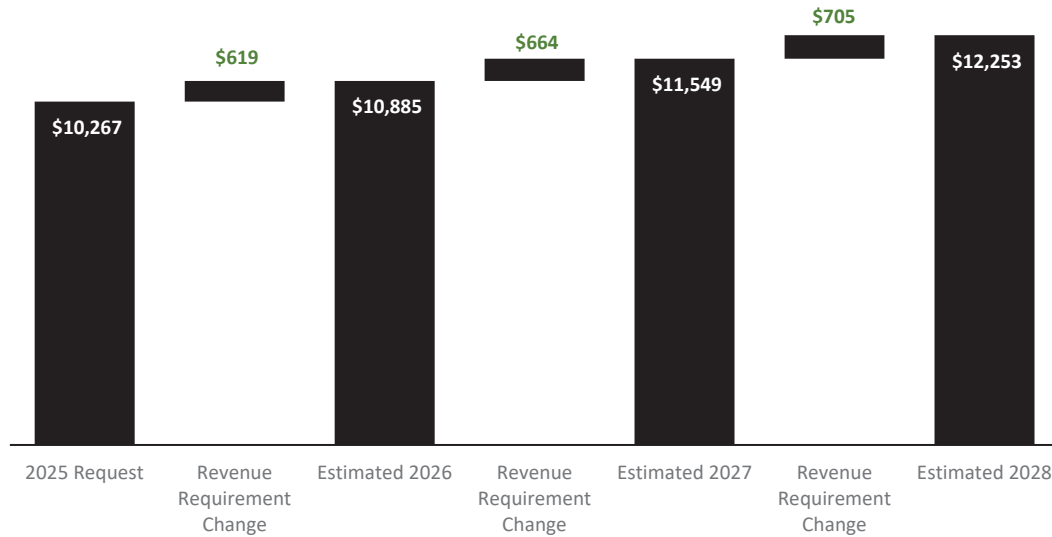
9 Figure II-1 below summarizes SCE's requested CPUC-jurisdictional revenue requirements in
10 2025 through 2028 and the associated incremental revenue requirement changes for the forecast years
11 2026 through 2028.

12 The requested revenue requirement gives SCE a reasonable opportunity to recover anticipated
13 O&M expenses (including A&G expenses) and capital costs associated with expected rate base amounts,
14 providing SCE a reasonable opportunity to realize earnings at the current Commission-authorized rate of
15 return.

² Base-related costs include distribution, transmission, and generation O&M, A&G, depreciation, return, and taxes (excluding fuel and purchased power costs recovered through the Energy Resource Recovery Account (ERRA) and the Portfolio Allocation Balancing Account (PABA)).

³ Refer to WP SCE-07, Vol. 01, Book A, pp. 1-23, Results of Operations.

Figure II-1
Southern California Edison Company
Requested CPUC-Jurisdictional Revenue Requirements⁴
(\$millions)



In addition to the revenue requirement shown above, SCE is also requesting the one-time recovery of \$96.7 million (including Franchise Fees & Uncollectibles) in 11 memorandum accounts as discussed in Chapter V of this testimony.

A. Results of Operations at Present Rates

SCE's RO at present rates is presented in Table II-1. The amounts shown reflect total base-related revenue requirements including FERC-jurisdictional transmission-related revenues, operating costs, and capital costs.

For the year 2022, Table II-1 shows the base-related total company RO including:

⁴ Operating expenses included in the RO tables presented in this chapter for the years 2026 through 2028 were calculated based on the Post-Test Year Ratemaking Mechanism described in SCE-07, Volume 4. The final 2026 through 2028 revenue requirements will be determined through the operation of the Commission-approved Post-Test Year Ratemaking Mechanism and submitted to the Commission by December 1 of each year prior to implementation in 2026, 2027, and 2028, respectively. As such, the revenue requirements shown for years 2026, 2027, and 2028 are estimated and will change upon implementation pursuant to the authorized Post-Test Year Ratemaking Mechanism.

- 1) 2022 Authorized Base Revenue Requirement (ABRR);⁵ and
- 2) recorded FERC-jurisdictional base transmission revenues.

For the current year 2023, Table II-1 shows the base-related total company RO including:

- 1) currently effective ABRR; and
- 2) estimated FERC-jurisdictional base transmission revenues based on present rate levels.

For the forecast years 2024 and 2025, Table II-1 shows the base-related total company RO including:

- 1) estimated 2024 and 2025 ABRR; and
- 2) estimated FERC-jurisdictional base transmission revenues based on present rate levels.

The estimated CPUC-jurisdictional RO for the years 2025 through 2028 all utilize the forecast ABRR for base-related operating revenues.⁶ Table II-2 supports the CPUC-jurisdictional base-related operating revenues (*i.e.*, ABRR) used in the RO calculations for the years 2022 through 2028 on Table II-1. Table II-3 shows the ABRR and FERC-jurisdictional base transmission revenues that comprise the Operating Revenues in Table II-1.

To determine the ABRR at present rates in Table II-1, the Authorized Distribution Base Revenue Requirement (ADBRR) under the Base Revenue Requirement Balancing Account (BRRBA), the Authorized Generation Base Revenue Requirement (AGBRR) under the Portfolio Allocation Balancing Account (PABA), and both the Authorized Peaker Generation Revenue Requirement (APGRR) and the Authorized Energy Storage Revenue Requirement (AESRR) under the New System Generation Balancing Account (NSGBA) ratemaking mechanisms are used in place of the forecast base-related revenues at present rate levels as contained in Chapter VII of this volume. This is because the general purpose of the BRRBA, and to some extent the PABA and NSGBA, is to reflect in rates any differences between the recorded level of base-related revenue and the ADBRR/AGBRR/APGRR/AESRR.

⁵ The ABRR is comprised of the Authorized Distribution Base Revenue Requirement (ADBRR), the Authorized Generation Base Revenue Requirement (AGBRR), the Authorized Peaker Generation Revenue Requirement (APGRR) and the Authorized Energy Storage Revenue Requirement (AESRR) pursuant to D.21-08-036 and as set forth in Advice 4586-E.

⁶ SCE's methodology to determine the base-related CPUC-jurisdictional revenue requirement is described in Chapter IV of this exhibit.

To determine the CPUC-jurisdictional RO at present rates in Table II-1, SCE has removed all FERC-jurisdictional transmission-related revenues and costs,⁷ arriving at the forecast ABRR for base-related operating revenues.⁸ Table II-2 and Table II-3 provide further details on the CPUC-jurisdictional base-related operating revenues (*i.e.*, ABRR) and FERC-jurisdictional base transmission revenues.

Table II-1
Southern California Edison Company
Results Of Operations At Present Rates
Excluding Rate Requests Included In This Filing⁹
(\$000)

Line Item	Authorized	Estimated (Total Company)			Estimated (CPUC)			
	2022	2023	2024	2025	2025	2026	2027	2028
1. Total Operating Revenues	8,671,709	8,983,312	9,804,911	9,820,777	8,371,337	8,371,337	8,371,337	8,371,337
2. Operating Expenses:								
3. Production								
4. Steam	4,210	3,560	3,466	2,643	2,643	2,643	2,643	2,643
5. Nuclear	75,076	76,431	76,428	76,453	76,453	76,453	76,453	76,453
6. Hydro	44,264	52,628	52,952	60,237	60,237	60,237	60,237	60,237
7. Other	84,919	84,385	89,298	101,018	101,018	101,018	101,018	101,018
8. Total Production O&M	208,469	217,003	222,144	240,351	240,351	240,351	240,351	240,351
9. Transmission	253,467	248,151	261,778	266,362	142,901	142,901	142,901	142,901
10. Distribution	1,019,313	1,133,630	1,198,807	1,280,115	1,278,369	1,278,369	1,278,369	1,278,369
11. Customer Accounts	125,198	136,888	151,329	147,716	147,716	147,089	147,089	147,089
12. Uncollectibles	25,843	17,485	17,649	18,752	16,219	20,836	22,109	23,454
13. Customer Service & Information	78,911	105,120	106,075	106,410	106,410	106,410	106,410	106,410
14. Administrative & General	1,027,456	1,136,222	1,108,914	1,211,477	1,149,414	1,149,549	1,149,681	1,149,713
15. Franchise Requirements	62,438	83,194	90,803	91,237	78,912	101,385	107,584	114,125
16. Revenue Credits	(231,720)	(236,052)	(237,751)	(233,943)	(171,005)	(174,457)	(168,310)	(168,077)
17. Total O&M	2,569,374	2,841,641	2,919,748	3,128,477	2,989,286	3,012,432	3,026,184	3,034,334
18. Escalation	—	61,738	67,883	119,640	110,498	165,522	225,384	288,463
19. Depreciation	2,425,708	2,605,386	2,793,642	3,375,079	3,016,327	3,225,301	3,459,943	3,729,727
20. Taxes Other Than On Income	501,880	552,883	604,844	650,762	546,156	588,056	635,509	684,856
21. Taxes Based On Income	378,275	293,230	489,776	231,752	74,610	116,741	18,391	(96,689)
22. Total Taxes	880,155	846,113	1,094,620	882,514	620,766	704,798	653,900	588,166
23. Total Operating Expenses	5,875,237	6,354,878	6,875,892	7,505,710	6,736,877	7,108,053	7,365,411	7,640,691
24. Net Operating Revenue	2,796,471	2,628,435	2,929,019	2,315,067	1,634,460	1,263,284	1,005,926	730,647
25. Rate Base	37,618,479	42,166,688	45,074,299	47,860,519	40,367,724	43,552,417	46,917,482	50,340,183
26. Rate of Return	7.43%	6.23%	6.50%	4.84%	4.05%	2.90%	2.14%	1.45%

⁷ Chapter VII of this volume presents both base-related (*i.e.*, GRC-related) present rate revenues and total system (including SCE Fuel and Purchased Power) present rate revenues.

⁸ SCE's methodology to determine the base-related CPUC-jurisdictional revenue requirement is described in Chapter IV of this exhibit.

⁹ 2022 reflects the authorized total company revenues, also shown in Table II-3. As shown in Table II-1, SCE's actual rate of return at present rates in 2023 through 2028 is lower than in 2022 and lower than the currently authorized 7.44 percent rate of return.

Table II-2
Southern California Edison Company
Summary of Approved and Forecast ABRR Changes
Excluding Rate Requests Included In This Filing
(\$000)

Estimated Authorized Base Revenue Requirement			Authority
Line	Item	\$	
1.	2021 Authorized Base Revenue Requirement		
2.	Distribution	6,123,571	D.21-08-036, Advice Letter 4586-E
3.	Generation	686,975	D.21-08-036, Advice Letter 4586-E
4.	New System Generation (Peakers and Energy Storage)	63,564	D.21-08-036, Advice Letter 4586-E
5.	2021 Authorized Base Revenue Requirement	6,874,110	
6.	2022 Post Test Year Ratemaking Changes		
7.	Distribution	369,098	D.21-08-036, Advice Letter 4639-E
8.	Generation	16,935	D.21-08-036, Advice Letter 4639-E
9.	New System Generation (Peakers and Energy Storage)	(923)	D.21-08-036, Advice Letter 4639-E
10.	2022 Post Test Year Ratemaking Changes	385,110	
11.	2022 Authorized Base Revenue Requirement	7,259,220	
12.	2023 Post Test Year Ratemaking Changes		
13.	Distribution	419,003	D.22-12-031, Advice Letter 4933-E
14.	Generation	25,460	D.22-12-031, Advice Letter 4933-E
15.	New System Generation (Peakers and Energy Storage)	(826)	D.22-12-031, Advice Letter 4933-E
16.	Wildfire Self Insurance	(139,495)	PFM D.21-08-036
17.	2023 Post Test Year Ratemaking Changes	304,142	
18.	2023 Authorized Base Revenue Requirement	7,563,362	
19.	2024 Post Test Year Ratemaking Changes		
20.	Distribution	794,304	A.19-08-013 (Track 4 Errata 7.44 CoC)
21.	Generation	14,456	A.19-08-013 (Track 4 Errata 7.44 CoC)
22.	New System Generation (Peakers and Energy Storage)	(786)	A.19-08-013 (Track 4 Errata 7.44 CoC)
23.	Wildfire Self Insurance	(139,494)	PFM D.21-08-036
24.	2024 Post Test Year Ratemaking Changes	668,480	
25.	2024 Requested Base Revenue Requirement	8,371,337	
26.	Estimated 2025, 2026, 2027, 2028 Authorized Base Revenue Requirement	8,371,337	

Table II-3
Southern California Edison Company
Summary of Total Operating Revenues
Excluding Rate Requests Included In This Filing
(\$000)

Summary of Total Operating Revenues (Excluding Amounts Requested in this Filing)								Authority	
Line	Description	2022	2023	2024	2025	2026	2027	2028	-1
1.	ABRR	7,259,220	7,563,362	8,371,337	8,371,337	8,371,337	8,371,337	8,371,337	D.21-08-036, AL 4639-E
2.	FERC	1,412,489	1,419,951	1,433,574	1,449,440	1,476,789	1,511,156	1,546,053	2022 FERC: AL 4651-E
3.	Total	8,671,709	8,983,312	9,804,911	9,820,777	9,848,126	9,882,493	9,917,390	

B. Results of Operations at Proposed Rates

Table II-4 below presents SCE's requested revenue requirements for the years 2025 through 2028 at proposed rates. The RO summary of earnings shows that SCE will need \$10.267 billion, \$10.885 billion, \$11.549 billion, and \$12.253 billion in CPUC-jurisdictional base-related revenue in the years 2025, 2026, 2027, and 2028, respectively, to cover the costs of doing business and to have the

1 opportunity to realize earnings at the Commission-authorized rate of return. SCE's authorized rate of
2 return on rate base is 7.44 percent.¹⁰ The incremental revenue requirement (*i.e.*, ABRR) and associated
3 revenue changes to provide SCE with a reasonable opportunity to earn a 7.44 percent rate of return for
4 the years 2025 through 2028 are discussed in Chapter III of this volume.

¹⁰ SCE's currently effective rate of return was authorized by the Commission in D.22-12-031.

Table II-4
Southern California Edison Company
Results of Operations At Proposed Rates
CPUC-Jurisdictional¹¹
(\$000)

		GRC CPUC			
Line	Item	2025	2026	2027	2028
1.	Total Operating Revenues	10,266,672	10,885,338	11,548,972	12,253,484
2.	Operating Expenses:				
3.	Production				
4.	Steam	2,643	2,643	2,643	2,643
5.	Nuclear	76,453	76,453	76,453	76,453
6.	Hydro	60,237	60,237	60,237	60,237
7.	Other	101,018	101,018	101,018	101,018
8.	Total Production O&M	240,351	240,351	240,351	240,351
9.	Transmission	142,901	142,901	142,901	142,901
10.	Distribution ¹	1,258,369	1,258,369	1,258,369	1,258,369
11.	Customer Accounts	147,716	147,089	147,089	147,089
12.	Uncollectibles	19,650	20,831	22,099	23,444
13.	Customer Service & Information	106,410	106,410	106,410	106,410
14.	Administrative & General	1,149,414	1,149,549	1,149,681	1,149,713
15.	Franchise Requirements	95,605	101,355	107,523	114,070
16.	Revenue Credits	(171,005)	(174,457)	(168,310)	(168,077)
17.	Total O&M	2,989,410	2,992,397	3,006,111	3,014,270
18.	Escalation	110,498	165,522	225,384	288,463
19.	Depreciation	3,024,446	3,233,421	3,464,004	3,733,788
20.	Taxes Other Than On Income				
21.	Property Taxes	476,120	515,692	560,792	607,794
22.	Payroll Taxes & Misc	70,107	72,388	74,718	77,062
23.	Taxes Based On Income	593,709	666,334	727,913	787,452
24.	Total Taxes	1,139,936	1,254,415	1,363,422	1,472,308
25.	Total Operating Expenses	7,264,291	7,645,755	8,058,921	8,508,829
26.	Net Operating Revenue	3,002,381	3,239,583	3,490,051	3,744,655
27.	Rate Base	40,367,724	43,552,417	46,917,482	50,340,183
28.	Rate Of Return	7.44%	7.44%	7.44%	7.44%

¹ In this table, SCE has reflected a downward adjustment of \$20 million to its proposed 2025 revenue requirement, which is an estimated impact associated with a portion of the O&M-related errata.

¹¹ Refer to WP SCE-07, Vol. 01, Book A, p.16, Results of Operations at Proposed Rates.

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III.

GRC INCREMENTAL REVENUE AND RATE CHANGE PROPOSAL

In this Application, SCE requests that the Commission adopt a 2025 base-related CPUC-jurisdictional revenue requirement or ABRR of \$10.267 billion (as presented in Chapter II of this Exhibit). This amount represents an increase of \$1.895 billion above the 2024 Track 4 requested ABRR of \$8.371 billion estimated to be authorized prior to the increase requested in this proceeding.¹² After considering other forecast CPUC-jurisdictional base-related revenue changes between 2024 and 2025,¹³ the revenue change attributable to this Application is \$1.906 billion, or 22.76%.

Based on the operation of the Post-Test Year Ratemaking (PTYR) mechanism proposed by SCE in SCE-07, Volume 4, SCE projects a 2026 base-related CPUC-jurisdictional revenue requirement or ABRR of \$10.885 billion, a 2027 ABRR of \$11.549 billion, and a 2028 ABRR of \$12.253 billion (as presented in Chapter II of this Exhibit). The projected 2026 ABRR represents a \$618.666 million increase over SCE's requested 2025 ABRR, the projected 2027 ABRR represents a \$663.634 million increase over SCE's requested 2026 ABRR, and the projected 2028 ABRR represents a \$704.512 million increase over SCE's requested 2027 ABRR. After considering other forecast CPUC-jurisdictional base-related revenue changes, the estimated incremental revenue changes associated with the PTYR mechanism are \$373.123 million for 2026, \$476.544 million for 2027 and \$514.533 million for 2028.

Table III-5 below identifies the requested ABRR and other forecast CPUC-jurisdictional base-related revenue changes resulting from this Application.¹⁴

¹² See Table II-2. SCE's 2024 requested ABRR in the 2021 GRC Track 4 (A.19-08-013) is \$8.606 billion, after SCE's second errata. The 2024 requested ABRR in this volume reflects additional adjustments for authorized cost of capital (D.22-12-031) and wildfire self-insurance (PFM, D.21-08-036). The revenue requirement change from 2024 to 2025 in this volume assumes SCE's Track 4 adjusted request is adopted as filed.

¹³ Revenue growth is calculated based on base-related rate levels in effect as of Mar 01, 2023.

¹⁴ Refer to WP SCE-07, Vol. 01, Book A, p. 25, 2025-2028 Revenue Changes.

Table III-5
Southern California Edison Company
2025, 2026, 2027 and 2028 Revenue Changes Resulting From the
2025 Test Year and 2026, 2027 and 2028 PTYR GRC Request
CPUC-Jurisdictional
(\$000)

ABRR and Revenue Change Including Impact of Previously Approved & Forecast ABRR Changes						
Line	Item	2025	2026	2027	2028	Reference
1.	Proposed GRC Base Revenue Requirement	10,266,672	10,885,338	11,548,972	12,253,484	Table II-4
2.	Estimated Present (Prior Year) Revenue Requirement	8,371,337	10,266,672	10,885,338	11,548,972	2025: Table II-2
3.	Change in Authorized Base Revenue Requirement	1,895,334	618,666	663,634	704,512	
4.	Less Sales-Driven GRC Revenue Growth:					
5.	2024	83,762	7,804,322			Table VI-25
6.	2025	84,689	7,890,693			Table VI-25
7.	2025	84,689	7,890,693			Table VI-25
8.	2026	86,287	8,039,583			Table VI-25
9.	2026	86,287		8,039,583		Table VI-25
10.	2027	88,295		8,226,673		Table VI-25
11.	2027	88,295			8,226,673	Table VI-25
12.	2028	90,334			8,416,652	Table VI-25
13.	Sales-Driven GRC Revenue Growth	86,371	148,890	187,091	189,979	
14.	One-Time Memorandum Account Recovery (Including FF&U)					
15.	Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA)	3,440	(3,440)			Table V-13
16.	Customer Service Re-Platform Memorandum Account (CSRPMA)	35,637	(35,637)			Table V-13
17.	Service Center Modernization Projects Memorandum Account (SCMPMA)	24,556	(24,556)			Table V-13
18.	Distribution Deferral Administrative Costs Memorandum Accounts (DDACMA)	771	(771)			Table V-13
19.	Emergency Customer Protections Memorandum Account (ECPMA)	73	(73)			Table V-13
20.	Residential Disconnections Implementation Cost Memorandum Account (RDICMA)	7,640	(7,640)			Table V-13
21.	NEM Online Application System Memorandum Account (NEMOASMA)	1,267	(1,267)			Table V-13
22.	California Consumer Privacy Act Memorandum Account (CCPAMA)	4,893	(4,893)			Table V-13
23.	Avoided Cost Calculator Memorandum Account (ACCMA)	740	(740)			Table V-13
24.	Community Choice Aggregators Audit Memorandum Account (CCAAMA)	494	(494)			Table V-13
25.	Wildfire Mitigation Plan Memorandum Account (WMPMA)	17,143	(17,143)			Table V-13
26.	Balancing & Memorandum Account Recovery	96,653	(96,653)	-	-	
27.	GRC Revenue Change	1,905,616	373,123	476,544	514,533	
28.	Percent GRC Revenue Change	22.76%	3.63%	4.38%	4.46%	
29.	Total System Present Rate Revenues	16,367,266	16,578,703	16,960,119	17,356,678	Table VII-29
30.	2025 GRC Revenue Change		1,905,616	1,905,616	1,905,616	Line 27 (2025)
31.	2026 GRC Revenue Change			373,123	373,123	Line 27 (2026)
32.	2027 GRC Revenue Change				476,544	Line 27 (2027)
33.	Total System Present Rate Revenues (Including GRC Revenue Change)	16,367,266	18,484,319	19,238,859	20,111,961	Line 29 through Line 32
34.	Percent Total Revenue Change	11.64%	2.02%	2.48%	2.56%	Line 27 / Line 33

SCE proposes that the ABRR requested in this Application for the 2025 test year become effective on January 1, 2025. The 2025 ABRR adopted by the Commission in this proceeding should then be consolidated for revenue allocation and rate design purposes with the 2025 Energy Resource Recovery Account (ERRA) Forecast proceeding and other year-end consolidated revenue requirement and rate level changes anticipated to occur on January 1, 2025. It is appropriate to consolidate the 2025 GRC rate level change with other rate level changes anticipated to occur January 1, 2025, since it will reduce the number of rate level changes contributing to rate stability, customer understanding, and ease of administration.¹⁵

¹⁵ Pursuant to the Commission's Rate Case Plan adopted in D.93-07-030, rate design and other pricing issues are to be addressed in a separate Phase II of this GRC and are not addressed in this Application.

IV.

DEVELOPMENT OF THE CPUC-JURISDICTIONAL GRC REVENUE REQUIREMENT

A. Introduction

This chapter presents SCE's development of the proposed CPUC-jurisdictional GRC base-related revenue requirement beginning in 2025, including: (1) the derivation of the base-related revenue requirements to be recovered through rates authorized by the Commission as opposed to those authorized by the FERC; and (2) SCE's methodology to functionalize the CPUC-jurisdictional base-related revenue requirement requested in this proceeding between distribution, generation, and new system generation (e.g., peakers, energy storage) cost components.

B. CPUC-Jurisdictional Revenue Requirement

This section sets forth the CPUC-jurisdictional revenue requirement for 2025-2028. As discussed in Chapter II of this volume, the operating expenses and investment-related costs identified in this Application include base-related FERC-jurisdictional transmission-related operating and capital costs. To determine the CPUC-jurisdictional revenue requirement, SCE must split costs to be recovered through rates authorized by the Commission from those authorized by FERC. SCE determines the split using the methodology that resulted in the jurisdictional factors adopted by the Commission in D.04-07-022.¹⁶ The Commission also adopted jurisdictional factors derived from this methodology in the following subsequent proceedings: D.06-05-016, D.09-03-025, D.12-11-051, D.15-11-021, D.19-05-020, and D.21-08-036 (SCE's prior general rate cases). Table IV-6 below sets forth the jurisdictional split methodology for each cost component of the Results of Operations (RO).

¹⁶ The jurisdictional factors adopted by the Commission in D.04-07-022 relied, in part, on the Transmission and Distribution (T&D) Jurisdictional Study that SCE submitted to the FERC as part of SCE's 2002 FERC rate case filed on January 31, 2002 (Amended February 13, 2002 – Docket No. ER02-925-000). An updated T&D Jurisdictional Study was prepared for subsequent cases, and for use in this Application, based on updated sets of historical cost values and asset statistics.

Table IV-6
Jurisdictional Split Methodology by RO Cost Component

Line No.	Item	Jurisdictional Allocation Base
1.	Operating Expenses	
2.	Production	100% CPUC-related (Direct Assigned)
3.	Transmission	T&D Jurisdictional Study/FERC Settlement
4.	Distribution	T&D Jurisdictional Study/FERC Settlement
5.	Customer Accounts	100% CPUC-related (Direct Assigned)
6.	Uncollectibles	Calculated based on resultant CPUC-Jurisdictional amounts
7.	Customer Service & Information	100% CPUC-related (Direct Assigned)
8.	Administrative & General	Labor Allocator
9.	Property Insurance	Gross Plant Allocator
10.	Franchise Requirements	Calculated based on resultant CPUC-Jurisdictional amounts
11.	Revenue Credits	Direct Assigned; Labor Allocator, and T&D Jurisdictional Study
12.	Escalation	Calculated based on resultant CPUC-Jurisdictional amounts
13.	Depreciation	Direct Assigned
14.		T&D Jurisdictional Study; and
15.		Labor Allocator
16.	Taxes Other Than on Income:	
17.	Property Taxes	Gross Plant Allocator
18.	Payroll Taxes & Misc	Labor Allocator
19.	Taxes Based on Income	Residual Tax After Fully Normalized FERC Income Tax Formula Calculation
20.	Rate Base	Direct Assigned
21.		T&D Jurisdictional Study; and
22.		Labor Allocator

As shown in Table IV-6 above, SCE developed composite jurisdictional percentages by GRC activity for the CPUC and FERC jurisdictions (*i.e.*, jurisdictional factors) utilizing 2022 recorded data. The CPUC-jurisdictional factors were then applied to SCE's requested 2025, 2026, 2027, and 2028 O&M expenses to determine the CPUC-jurisdictional base-related revenue requirements for each year. Table IV-7 below sets forth the CPUC-jurisdictional factors and CPUC-jurisdictional base-related revenue requirements requested in the Application for each year from 2025 through 2028.¹⁷

¹⁷ Refer to WP SCE-07, Vol. 01, Book A, pp. 27-32, CPUC-Jurisdictional Factors & Revenue Requirements with Adjustments.

Table IV-7
CPUC-Jurisdictional Factors and Revenue Requirements
(\$000)

Line Item	2025 GRC - CPUC		2026 GRC - CPUC		2027 GRC - CPUC		2028 GRC - CPUC	
	\$	%	\$	%	\$	%	\$	%
1. Total Operating Revenues	10,266,672	88.56%	10,885,338	88.90%	11,548,972	89.21%	12,253,484	89.17%
2. Operating Expenses:								
3. Production								
4. Steam	2,643	100.00%	2,643	100.00%	2,643	100.00%	2,643	100.00%
5. Nuclear	76,453	100.00%	76,453	100.00%	76,453	100.00%	76,453	100.00%
6. Hydro	60,237	100.00%	60,237	100.00%	60,237	100.00%	60,237	100.00%
7. Other	101,018	100.00%	101,018	100.00%	101,018	100.00%	101,018	100.00%
8. Total Production O&M	240,351	100.00%	240,351	100.00%	240,351	100.00%	240,351	100.00%
9. Transmission	142,901	53.65%	142,901	53.65%	142,901	53.65%	142,901	53.65%
10. Distribution	1,258,369	99.86%	1,258,369	99.86%	1,258,369	99.86%	1,258,369	99.86%
11. Customer Accounts	147,716	100.00%	147,089	100.00%	147,089	100.00%	147,089	100.00%
12. Uncollectibles	19,650	88.58%	20,831	88.92%	22,099	89.23%	23,444	89.19%
13. Customer Service & Information	106,410	100.00%	106,410	100.00%	106,410	100.00%	106,410	100.00%
14. Administrative & General (Excluding Property Insurance)	1,128,609	95.14%	1,128,609	95.14%	1,128,609	95.14%	1,128,609	95.14%
15. Administrative & General (Property Insurance)	20,805	82.68%	20,940	83.21%	21,072	83.74%	21,104	83.87%
16. Administrative & General	1,149,414	94.88%	1,149,549	94.89%	1,149,681	94.90%	1,149,713	94.90%
17. Franchise Requirements	95,605	88.58%	101,355	88.92%	107,523	89.23%	114,070	89.19%
18. Revenue Credits	(171,005)	73.10%	(174,457)	73.49%	(168,310)	72.78%	(168,077)	72.76%
19. Subtotal	2,989,410	95.55%	2,992,397	95.55%	3,006,111	95.56%	3,014,270	95.54%
20. Escalation	110,498	92.36%	165,522	92.79%	225,384	93.04%	288,463	93.20%
21. Depreciation	3,024,446	89.40%	3,233,421	89.72%	3,464,004	90.02%	3,733,788	90.11%
22. Taxes Other Than On Income								
23. Taxes Other Than On Income - Property	476,120	82.68%	515,692	83.21%	560,792	83.74%	607,794	83.87%
24. Taxes Other Than On Income - Payroll	70,107	93.51%	72,388	93.51%	74,718	93.51%	77,062	93.51%
25. Taxes Based On Income	593,709	79.07%	666,334	80.63%	727,913	81.77%	787,452	81.88%
26. Total Taxes	1,139,936	81.33%	1,254,415	82.34%	1,363,422	83.14%	1,472,308	83.24%
27. Total Operating Expenses	7,264,291	90.43%	7,645,755	90.61%	8,058,921	90.79%	8,508,829	90.74%
28. Net Operating Revenue	3,002,381	84.34%	3,239,583	85.10%	3,490,051	85.76%	3,744,655	85.79%
29. Rate Base	40,367,724	84.34%	43,552,417	85.10%	46,917,482	85.76%	50,340,183	85.79%
30. Rate Of Return	7.44%		7.44%		7.44%		7.44%	

Consistent with D.04-07-022, Administrative and General (A&G) expense and General and Intangible plant costs are allocated to the CPUC-jurisdictional revenue requirements on the basis of labor cost ratios. The testimony that follows describes the Transmission and Distribution (T&D) Jurisdictional Study performed by SCE to derive various CPUC-jurisdictional factors as identified in Table IV-7 above. Determination of the labor cost ratios and the T&D Jurisdictional Study are included in the workpapers that support this Chapter.¹⁸

1. Transmission and Distribution Jurisdictional Study

This testimony presents SCE's methodology for separating T&D operation and maintenance (O&M) expenses, other operating revenue (OOR), and capital expenditures between FERC

¹⁸ Refer to WP SCE-07, Vol. 01, Book A, pp. 27-32, CPUC-Jurisdictional Factors & Revenue Requirements with Adjustments.

jurisdiction (California Independent System Operator (CAISO) facilities), and CPUC jurisdiction (non-CAISO facilities).

a) Introduction

In April 1996, SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) filed a joint petition for a declaratory order at FERC seeking to clarify whether certain facilities serve a transmission- or distribution-related function, making the facilities subject to either FERC's jurisdiction or the CPUC's, respectively.¹⁹ "Whether facilities are used in local distribution or transmission raises a question of fact, which [FERC] has jurisdiction to determine."²⁰ FERC applied the following seven factors to determine whether facilities perform a distribution or transmission function:

1. Local distribution facilities are normally near retail customers.
2. Local distribution facilities are primarily radial.
3. Power flows into local distribution systems and rarely, if ever, flows out.
4. When power enters a local distribution system, it is not re-consigned or transported on to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be of reduced voltage.²¹

Transmission and distribution facilities meeting the seven-factor test are distribution and not subject to CAISO's operational control, regardless of voltage.

When California's electric industry restructuring program was implemented in 1998, SCE transferred operational control of its transmission facilities to the CAISO. The facilities determined to be performing a transmission function for SCE, PG&E, and SDG&E were placed under the operational control of the CAISO and deemed to be under the jurisdiction of FERC. In addition, the generation step up transformers and radial lines that connect generating plants to our transmission

¹⁹ Pac. Gas & Elec. Co., San Diego Gas & Elec. Co. & S. California Edison Co., 77 FERC ¶ 61,077 (1996).

²⁰ S. California Edison Co., 153 FERC ¶ 61,384 (2015) (internal citation omitted).

²¹ Pac. Gas & Elec. Co., San Diego Gas & Elec. Co. & S. California Edison Co., 77 FERC ¶ 61,077, 61,318 (1996).

1 network were deemed to perform a generation function, and are therefore not subject to the CAISO's
2 operational control.²² While nearly all of PG&E and SDG&E's transmission facilities over 50 kV are
3 under CAISO control, SCE's lower voltage sub-transmission systems between 50 kV and 200 kV are
4 configured to not operate in parallel with the CAISO-controlled transmission system with exceptions.
5 SCE's CAISO-controlled facilities include all line positions of 500 kV or greater and 161 kV line, most
6 230 kV lines, and certain 115 kV, 66 kV, and 55 kV lines. Also included are substations at 500 kV/230
7 kV and 230 kV/161 kV and portions of substations that transform power from 230 kV/115 kV, 230
8 kV/66 kV, and 115 kV/55 kV. All other facilities are non-CAISO controlled and are under the
9 jurisdiction of the CPUC.

10 **b) Cost Separation Methodology**

11 **(1) CAISO/Non-CAISO O&M Cost Separation Methodology**

12 To determine the amount of SCE's O&M costs attributable to CPUC
13 versus FERC jurisdictions, SCE analyzes recorded transmission and distribution expenses, and applies
14 various metrics and ratios to separate the costs between CAISO and non-CAISO related O&M.
15 This O&M cost separation study is consistent with the methodology prescribed in the protocols for
16 SCE's FERC formula rate tariff,²³ which determines the O&M attributable to SCE's FERC jurisdictional
17 facilities that will then be reflected in SCE's annual FERC formula rate.²⁴ SCE used this general cost
18 separation methodology to determine the CPUC jurisdictional factors applicable to transmission and
19 distribution O&M used in this 2025 GRC.

20 The cost separation study that SCE performs to determine O&M
21 attributable to its FERC jurisdictional facilities is done annually. SCE has followed the same
22 methodology to determine O&M costs attributable to the CPUC jurisdiction for this 2025 GRC.
23 To perform its O&M cost separation study, SCE uses the recorded transmission and distribution O&M

²² The five sets of radial lines: Cool Water-Kramer (two lines), Huntington Beach-Ellis (four lines), Mandalay-Santa Clara (two lines), Ormond Beach-Moorpark (four lines), and Mojave Solar connect the generators located at Cool Water, Huntington Beach, Mandalay, Ormond Beach, and Mojave Solar to the transmission system.

²³ Refer to WP SCE-07, Vol. 01, Book A, pp. 40-41, FERC Formula Rate Protocols.

²⁴ SCE's FERC formula rate recovers the costs of SCE's FERC jurisdictional facilities and was filed on November 18, 2022.

costs reported in FERC Form 1 as the starting point. The results, by FERC account, are shown in Table IV-8.²⁵

²⁵ Refer to WP SCE-07 Vol. 01, Book A, pp. 42-68, Transmission and Distribution Operations and Maintenance Expense Details by GRC Activity.

Table IV-8
2025 O&M Jurisdictional Factors by GRC Activity²⁶

GRC Activities with ISO Related Components	ISO	ISO	ISO	Non-ISO	Non-ISO	Non-ISO
	Labor	Non-Labor	Other	Labor	Non-Labor	Other
TRANSMISSION EXPENSES:						
Alternative Technologies	47.6%	47.6%	0%	52.4%	52.4%	0%
Circuit Breaker Inspections and Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Develop and Manage Policy and Initiatives	40.0%	40.0%	0%	60.1%	60.1%	0%
Distribution Support Activities	40.0%	40.0%	0%	60.1%	60.1%	0%
Environmental Programs	40.0%	40.0%	0%	60.1%	60.1%	0%
Equipment Washing	40.0%	40.0%	0%	60.1%	60.1%	0%
Facility and Land Operations	40.0%	40.0%	0%	60.1%	60.1%	0%
Grid Engineering	84.5%	42.7%	0%	15.5%	57.3%	0%
High Fire Risk Inspections and Remediations	47.6%	47.6%	0%	52.4%	52.4%	0%
Implement Ratemaking Cost Recovery	40.0%	40.0%	0%	60.1%	60.0%	0%
Informational Meetings	40.0%	40.0%	0%	60.1%	60.1%	0%
Infrared Inspection Program	47.6%	47.6%	0%	52.4%	52.4%	0%
Insulator Washing	47.6%	47.6%	0%	52.4%	52.4%	0%
Interconnection, Added Facilities and Special Contracts	40.0%	40.0%	0%	60.1%	60.1%	0%
Monitoring and Operating Substations	40.0%	40.0%	0%	60.1%	60.1%	0%
Monitoring Bulk Power System	40.0%	40.0%	0%	60.1%	60.1%	0%
Other Substation Equipment Inspections and Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
PSPS Execution	47.6%	47.6%	0%	52.4%	52.4%	0%
Relay Inspections and Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Roads and Rights of Way	47.6%	47.6%	0%	52.4%	52.4%	0%
Safety Activities - Transmission & Distribution	40.0%	40.0%	0%	60.0%	60.0%	0%
Substation - Inspections and Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Substation Maintenance Oversight	40.0%	40.0%	0%	60.1%	60.1%	0%
Substation Minor Equipment and Supplies	40.0%	40.0%	0%	60.1%	60.1%	0%
Substation O&M Breakdown Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Supplemental System Hardening Activities	47.6%	47.6%	0%	52.4%	52.4%	0%
Technology Assessment	40.0%	40.0%	0%	60.1%	60.1%	0%
Technology Infrastructure Maintenance and Replacement	40.0%	40.0%	0%	60.1%	60.1%	0%
Telecommunication Storm Response O&M	40.0%	40.0%	0%	60.1%	60.1%	0%
Training Delivery and Development - Transmission and Distribution	40.0%	40.0%	0%	60.1%	60.1%	0%
Training Seat-Time - Transmission and Distribution	40.0%	40.0%	0%	60.1%	60.1%	0%
Transformer Inspections and Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Transmission Capital Maintenance	40.0%	40.0%	0%	60.1%	60.1%	0%
Transmission Intrusive Pole Inspections	47.6%	47.6%	0%	52.4%	52.4%	0%
Transmission Joint Pole Operations	40.0%	40.0%	0%	60.1%	60.1%	0%
Transmission Line Patrols	47.6%	47.6%	0%	52.4%	52.4%	0%
Transmission Line Rating Remediation (TLRR)	47.3%	47.6%	0%	52.7%	52.4%	0%
Transmission Line Rents	0%	55.7%	47.9%	0%	44.3%	52.1%
Transmission O&M Maintenance	46.0%	44.6%	0%	54.0%	55.4%	0%
Transmission Pole Loading Assessments	40.0%	39.6%	0%	60.1%	60.4%	0%
Transmission Pole Loading Repairs	47.6%	47.6%	0%	52.4%	52.4%	0%
Transmission Pole Loading Work Order Related Expense	47.6%	47.6%	0%	52.4%	52.4%	0%
Transmission Request for Attachment Inspections	40.0%	40.0%	0%	60.1%	60.1%	0%
Transmission Routine Vegetation Management	47.3%	47.5%	0%	52.7%	52.5%	0%
Transmission Support Activities	40.0%	40.6%	0%	60.0%	59.4%	0%
Transmission Underground Structure Inspection	2.6%	2.4%	0%	97.4%	97.6%	0%
Transmission/Substation Storm Response O&M	40.2%	68.2%	0%	59.8%	31.8%	0%
Transmission/Substation Work Order Related Expense	47.2%	60.7%	0%	52.8%	39.3%	0%
Transmission/Substation Work Order Write-Off	40.0%	40.0%	0%	60.1%	60.1%	0%
Utility Joint Ownership Obligations	47.6%	84.8%	0%	52.4%	15.2%	0%
Wildfire Vegetation Management	47.6%	47.6%	0%	52.4%	52.4%	0%
Wildfire Work Order Related Expense	47.6%	47.6%	0%	52.4%	52.4%	0%

²⁶ Refer to WP SCE-07, Vol. 01, Book A, pp. 69-72, FERC – CPUC O&M and OOR Jurisdictional Allocation.

1 The costs recorded to transmission FERC accounts 560-573 and
2 distribution FERC accounts 580-598 are separated by Final Cost Centers. Separating costs at the Final
3 Cost Center level allows SCE to group the O&M costs into sub-accounts that reflect similar activities
4 and to apply a metric or allocation factor appropriate for that set of activities. For example, SCE records
5 all of its substation equipment maintenance to FERC account 570 in its FERC Form 1. By examining
6 these costs at the Final Cost Center level, SCE can separate the maintenance by type of equipment
7 (*i.e.*, overhead and underground transmission lines, transmission and distribution circuit breakers) and
8 allocate the O&M cost to jurisdictions based on the ratio of equipment under CAISO control to the total
9 population of that type of equipment.

10 Transmission and Distribution O&M expenses are assigned to one of two
11 categories: (1) those costs that are attributable to either CAISO or non-CAISO facilities and/or activities
12 and are therefore directly assignable to one of those jurisdictions; and (2) dual-use O&M costs that apply
13 to both CAISO and non-CAISO facilities, but for which particular metrics can allocate the expenses
14 between jurisdictions. O&M costs in these categories are allocated as follows:

- 15 • O&M expenses directly assignable to non-CAISO facilities and/or
16 activities are allocated 100 percent to CPUC. An example of this
17 would be station equipment maintenance expenses on equipment not
18 under CAISO control. Expenses associated with O&M attributable to
19 CAISO facilities/or activities are allocated 100 percent to FERC.
- 20 • Dual use O&M expenses attributable to both CAISO and non-CAISO
21 facilities/or activities are allocated by four asset-driven metrics. SCE
22 used 2022 recorded statistical information for these metrics to better
23 represent expected operations in the test year.²⁷ To develop the four
24 metric-based allocators, SCE determined the number of overhead and
25 underground transmission line miles and number of transmission and
26 distribution circuit breakers associated with CAISO-controlled versus
27 non-CAISO facilities. An example of this would be Account 570
28 (Maintenance of Station Equipment), which is divided into several
29 facilities/activities including, circuit breaker, transformer, and voltage

²⁷ Refer to WP SCE-07, Vol. 01, Book A, pp. 73-75, ISO Allocators.

control equipment maintenance. These facilities/activities use equipment counts for cost allocation purposes. A ratio of CAISO-controlled circuit breakers to total circuit breakers is calculated and used to allocate the costs in this sub-account.

After all Final Cost Centers have been allocated between CPUC and FERC, SCE divides the CPUC-jurisdictional O&M expense by total company O&M expense to determine an aggregate CPUC-jurisdictional factor for transmission O&M and distribution O&M. These factors are shown in Table IV-8 above.

(2) CAISO/Non-CAISO Other Operating Revenue (OOR) Separation Methodology

To separate the OOR, SCE derived forecasts of revenue by account. These forecasts were separated between CAISO and non-CAISO based on assignment of the nature of each activity. For example, revenues for firm transmission services using facilities under the operational control of CAISO were assigned to CAISO. For added/interconnection facilities, a detailed review of each contract was performed assigning the assets between CAISO and non-CAISO.²⁸

(3) CAISO/Non-CAISO Plant Cost Separation Methodology

SCE performs an annual study to determine recorded transmission and distribution plant reported in SCE's prior year FERC Form 1 filing that should be classified as CAISO or non-CAISO. Generally, once the plant is recorded and the assets are classified, the classification remains the same from year to year. The exception would be if assets at a particular location changed from non-CAISO to CAISO control or vice versa. SCE then adds the forecast capital expenditures for the test period to arrive at a forecast of CAISO and non-CAISO gross plant.

The plant study is performed by substation and line location. If all assets at a particular location are not under CAISO control, then SCE directly classifies those plant costs as non-CAISO. The converse is true for assets under CAISO control. Where it is not possible to directly classify the assets for a particular location, SCE analyzes the individual components of the substation to determine the jurisdiction that has operational control of the component. For example, in a 230/115 kV substation, the high side of the substation may be under CAISO control, while the low side is under

²⁸ Refer to WP SCE-07, Vol. 01, Book A, pp. 76-77, 2025 Tariffed OOR.

1 CPUC jurisdiction. For a mixed-use transmission line, SCE analyzes the number of line miles for each
2 jurisdiction.

3 To classify forecast capital expenditures, SCE identified the expenditures
4 by budget element. Often, these budget elements identify capital replacements as CAISO or non-CAISO
5 based on the defined scope of work and the assets involved. Blanket capital expenditures²⁹ cannot be
6 readily separated because they are for jobs on the system each year, but for which details and locations
7 are not known in advance. So costs for blanket expenditures were allocated between CAISO and non-
8 CAISO based on 2018-2022 recorded costs. Blankets include:

- 9 1. Overhead line additions and retirements.
- 10 2. Repair of storm damage or damage caused by others.
- 11 3. Circuit breaker and transformer additions and replacements.
- 12 4. Replacement of failed substation equipment.
- 13 5. Purchases of portable tools, spare parts, store equipment, lab
14 equipment, furniture and office equipment.

15 The assignment of each forecast blanket work order between CAISO and
16 non-CAISO is based on identifying and classifying the respective 2018-2022 recorded system and
17 blanket work order costs. The classification is based on identifying the historical blanket work order
18 items to assets on the transmission system. These assets were classified as CAISO and non-CAISO
19 based on SCE's internal single-line diagrams detailing the separation of the transmission system.

20 **2. Allocation of Income Taxes Between the FERC and CPUC**

21 The allocation of income taxes between FERC and CPUC jurisdictions entails the
22 allocation between a regulatory agency that requires full normalization tax treatment (*i.e.*, FERC) and a
23 regulatory agency that requires both flow-through and normalization tax treatments (*i.e.*, CPUC).
24 Under full normalization, income tax expense can be computed using an income tax formula.
25 SCE utilizes a normalized income tax formula in this GRC to compute the income tax expense allocable
26 to the FERC jurisdiction. The normalized income tax formula used in this proceeding is the same
27 methodology SCE proposed in its 2021 GRC and the Commission adopted in D.21-08-036.
28 The normalized income tax formula is equal to the equity rate of return on the FERC portion of rate base

²⁹ Refer to WP SCE-07, Vol. 01, Book A, pp. 78-79, ISO Allocators for T&D PWRD Blanket Capital.

multiplied by the income tax rate, grossed-up to a revenue requirement.³⁰ The FERC-jurisdictional income tax expense (using the normalized income tax formula) is then subtracted from Total Taxes Based on Income to derive the CPUC-jurisdictional income tax expense.

Using the full normalization tax calculation to derive FERC-jurisdictional income tax expense yields the appropriate flow-through tax benefits to the CPUC jurisdiction. SCE continues to use normalized and flow-through tax treatment in this GRC proceeding to calculate Total Taxes Based on Income. The CPUC-jurisdictional income tax expense is:

$$\text{Total Taxes Based on Income} - \text{FERC normalized income tax expense} = \text{CPUC- Jurisdictional Taxes Based on Income}$$

C. Functionalization of CPUC-Jurisdictional Revenue Requirement

To have separate rate components for distribution, generation, and new system generation, SCE must separate or “functionalize” its requested CPUC-jurisdictional base-related revenue requirements. In this Application, SCE proposes no change to the functionalization methodology adopted by the Commission in D.04-07-022, modified in D.06-05-016, and affirmed in D.09-03-025, D.12-11-051, D.15-11-021, D.19-05-020, and D.21-08-036. The following testimony summarizes the Commission-adopted functionalization approach.

The majority of SCE’s CPUC-jurisdictional base-related revenue requirement can be functionalized between generation, distribution, and new system generation through direct assignment by the FERC Uniform System of Accounts and SCE’s physical location identifiers. The remainder of SCE’s CPUC-jurisdictional base-related revenue requirement comprising A&G and general plant costs that support overall company activities cannot be directly assigned between generation, distribution, and new system generation, so an allocation is utilized.

To functionalize SCE’s 2025 CPUC-jurisdictional base-related revenue requirement, SCE first directly assigns O&M costs and rate base amounts between generation, distribution, and new system generation. The O&M costs and rate base amounts that cannot be directly assigned to generation, distribution, and new system generation (*e.g.*, A&G and general plant) are then functionalized based on a labor cost allocator.³¹ SCE next functionalizes the other components of its 2025 revenue requirement,

³⁰ The calculation also includes adjustments to the Equity Rate of Return amount for any permanent differences (*e.g.*, non-deductible business meals) and for book depreciation on the AFUDC-Equity portion of plant assets.

³¹ SCE developed the labor cost allocator on 2025 labor as forecast in this proceeding.

including income taxes, property taxes, and payroll taxes. Income and property taxes are functionalized using the ratio of the generation, distribution, and new system generation rate base to CPUC-jurisdictional rate base; payroll taxes are functionalized by using a labor cost allocator.

Table IV-9 shows the functionalization of SCE's 2025 CPUC-jurisdictional base-related revenue requirement request.³²

Table IV-9
2025 Results of Operation at Proposed Rates – Functionalized
(\$000)

2025 Summary of Earnings		CPUC by Function Including Adjustments			
Line Description	Distribution	Generation	Peakers	Energy Storage	Total
1. Total Operating Revenues	9,251,013	941,076	59,353	15,231	10,266,672
2. Operating Expenses:					
3. Production					
4. Steam	–	2,368	240	35	2,643
5. Nuclear	–	76,453	–	–	76,453
6. Hydro	–	60,237	–	–	60,237
7. Other	–	91,915	8,276	827	101,018
8. Total Production O&M	–	230,973	8,516	862	240,351
9. Transmission	142,901	–	–	–	142,901
10. Distribution	1,257,292	–	–	1,077	1,258,369
11. Customer Accounts	147,716	–	–	–	147,716
12. Uncollectibles	17,710	1,797	113	29	19,650
13. Customer Service & Information	104,400	1,321	65	623	106,410
14. Administrative & General (Excluding Property Insurance)	1,017,103	104,650	5,158	1,698	1,128,609
15. Administrative & General (Property Insurance)	18,491	2,113	172	29	20,805
16. Administrative & General	1,035,594	106,763	5,330	1,726	1,149,414
17. Franchise Requirements	86,165	8,746	552	142	95,605
18. Revenue Credits	(165,630)	(5,044)	(249)	(82)	(171,005)
19. Total O&M	2,626,146	344,558	14,328	4,378	2,989,410
20. Escalation	84,942	24,267	974	315	110,498
21. Depreciation	2,733,226	267,851	18,213	5,156	3,024,446
22. Taxes Other Than On Income					
23. Property Taxes	423,103	49,909	2,707	402	476,120
24. Payroll Taxes & Misc	60,700	9,395	11	–	70,107
25. Taxes Based On Income	527,372	57,838	6,591	1,908	593,709
26. Total Taxes	1,011,175	117,142	9,309	2,311	1,139,936
27. Total Operating Expenses	6,455,489	753,818	42,824	12,159	7,264,291
28. Net Operating Revenue	2,795,523	187,258	16,528	3,071	3,002,381
29. Rate Base	37,580,805	2,523,440	222,191	41,288	40,367,724
30. Rate of Return	7.44%	7.42%	7.44%	7.44%	7.44%

³² Refer to WP SCE-07, Vol. 01, Book A, pp. 80-84 for support of Table IV-9, Table IV-10, Table IV-11 and Table IV-12, Results of Operations at Proposed Rates – Functionalized 2025-2028 with Adjustments.

Using the same functionalization methodology, Table IV-10, Table IV-11 and Table IV-12 provide the functionalization for SCE's requested 2026, 2027 and 2028 CPUC-jurisdictional base-related revenue requirements

Table IV-10
2026 Results of Operation at Proposed Rates - Functionalized
(\$000)

2026 Summary of Earnings		CPUC by Function Including Adjustments				
Line Description	Distribution	Generation	Peakers	Energy Storage	Total	
1. Total Operating Revenues	9,839,322	970,096	59,333	16,588	10,885,338	
2. Operating Expenses:						
3. Production						
4. Steam	—	2,368	240	35	2,643	
5. Nuclear	—	76,453	—	—	76,453	
6. Hydro	—	60,237	—	—	60,237	
7. Other	—	91,915	8,276	827	101,018	
8. Total Production O&M	—	230,973	8,516	862	240,351	
9. Transmission	142,901	—	—	—	142,901	
10. Distribution	1,257,292	—	—	1,077	1,258,369	
11. Customer Accounts	147,089	—	—	—	147,089	
12. Uncollectibles	18,833	1,853	113	32	20,831	
13. Customer Service & Information	104,400	1,321	65	623	106,410	
14. Administrative & General (Excluding Property Insurance)	1,017,103	104,650	5,158	1,698	1,128,609	
15. Administrative & General (Property Insurance)	18,707	2,039	163	30	20,940	
16. Administrative & General	1,035,810	106,689	5,322	1,728	1,149,549	
17. Franchise Requirements	91,633	9,016	551	154	101,355	
18. Revenue Credits	(169,082)	(5,044)	(249)	(82)	(174,457)	
19. Total O&M	2,628,875	344,809	14,319	4,394	2,992,397	
20. Escalation	131,401	32,407	1,296	419	165,522	
21. Depreciation	2,931,566	277,558	18,601	5,696	3,233,421	
22. Taxes Other Than On Income						
23. Property Taxes	460,678	52,021	2,574	419	515,692	
24. Payroll Taxes & Misc	62,676	9,701	12	—	72,388	
25. Taxes Based On Income	595,004	62,657	6,598	2,076	666,334	
26. Total Taxes	1,118,358	124,378	9,184	2,495	1,254,415	
27. Total Operating Expenses	6,810,199	779,152	43,400	13,004	7,645,755	
28. Net Operating Revenue	3,029,123	190,944	15,933	3,583	3,239,583	
29. Rate Base	40,721,127	2,568,930	214,190	48,170	43,552,417	
30. Rate Of Return	7.44%	7.43%	7.44%	7.44%	7.44%	

Table IV-11
2027 Results of Operation at Proposed Rates - Functionalized
(\$000)

2027 Summary of Earnings		CPUC by Function Including Adjustments			
Line Description	Distribution	Generation	Peakers	Energy Storage	Total
1. Total Operating Revenues	10,474,022	996,615	60,052	18,284	11,548,972
2. Operating Expenses:					
3. Production					
4. Steam	—	2,368	240	35	2,643
5. Nuclear	—	76,453	—	—	76,453
6. Hydro	—	60,237	—	—	60,237
7. Other	—	91,915	8,276	827	101,018
8. Total Production O&M	—	230,973	8,516	862	240,351
9. Transmission	142,901	—	—	—	142,901
10. Distribution	1,257,292	—	—	1,077	1,258,369
11. Customer Accounts	147,089	—	—	—	147,089
12. Uncollectibles	20,045	1,904	115	35	22,099
13. Customer Service & Information	104,400	1,321	65	623	106,410
14. Administrative & General (Excluding Property Insurance)	1,017,103	104,650	5,158	1,698	1,128,609
15. Administrative & General (Property Insurance)	18,914	1,970	155	32	21,072
16. Administrative & General	1,036,017	106,620	5,314	1,730	1,149,681
17. Franchise Requirements	97,532	9,263	558	170	107,523
18. Revenue Credits	(162,935)	(5,044)	(249)	(82)	(168,310)
19. Total O&M	2,642,340	345,037	14,319	4,415	3,006,111
20. Escalation	182,230	40,993	1,633	528	225,384
21. Depreciation	3,152,886	285,620	19,122	6,376	3,464,004
22. Taxes Other Than On Income					
23. Property Taxes	503,370	54,493	2,448	481	560,792
24. Payroll Taxes & Misc	64,693	10,013	12	—	74,718
25. Taxes Based On Income	653,134	65,356	7,140	2,283	727,913
26. Total Taxes	1,221,197	129,862	9,600	2,764	1,363,422
27. Total Operating Expenses	7,198,652	801,511	44,674	14,083	8,058,921
28. Net Operating Revenue	3,275,369	195,103	15,377	4,201	3,490,051
29. Rate Base	44,031,473	2,622,816	206,721	56,472	46,917,482
30. Rate Of Return	7.44%	7.44%	7.44%	7.44%	7.44%

Table IV-12
2028 Results of Operation at Proposed Rates - Functionalized
(\$000)

2028 Summary of Earnings		CPUC by Function Including Adjustments			
Line Description	Distribution	Generation	Peakers	Energy Storage	Total
1. Total Operating Revenues	11,142,420	1,030,150	60,920	19,994	12,253,484
2. Operating Expenses:					
3. Production					
4. Steam	—	2,368	240	35	2,643
5. Nuclear	—	76,453	—	—	76,453
6. Hydro	—	60,237	—	—	60,237
7. Other	—	91,915	8,276	827	101,018
8. Total Production O&M	—	230,973	8,516	862	240,351
9. Transmission	142,901	—	—	—	142,901
10. Distribution	1,257,292	—	—	1,077	1,258,369
11. Customer Accounts	147,089	—	—	—	147,089
12. Uncollectibles	21,322	1,968	116	38	23,444
13. Customer Service & Information	104,400	1,321	65	623	106,410
14. Administrative & General (Excluding Property Insurance)	1,017,103	104,650	5,158	1,698	1,128,609
15. Administrative & General (Property Insurance)	19,027	1,896	147	34	21,104
16. Administrative & General	1,036,130	106,546	5,306	1,732	1,149,713
17. Franchise Requirements	103,744	9,574	566	186	114,070
18. Revenue Credits	(162,702)	(5,044)	(249)	(82)	(168,077)
19. Total O&M	2,650,175	345,338	14,321	4,436	3,014,270
20. Escalation	235,963	49,877	1,983	640	288,463
21. Depreciation	3,405,411	301,443	19,822	7,112	3,733,788
22. Taxes Other Than On Income					
23. Property Taxes	547,985	56,958	2,316	535	607,794
24. Payroll Taxes & Misc	66,722	10,327	12	—	77,062
25. Taxes Based On Income	709,745	67,553	7,650	2,505	787,452
26. Total Taxes	1,324,452	134,838	9,978	3,039	1,472,308
27. Total Operating Expenses	7,616,001	831,496	46,105	15,228	8,508,829
28. Net Operating Revenue	3,526,420	198,654	14,815	4,766	3,744,655
29. Rate Base	47,406,396	2,670,551	199,167	64,069	50,340,183
30. Rate Of Return	7.44%	7.44%	7.44%	7.44%	7.44%

V.

GRC RATEMAKING PROPOSALS

This chapter provides (1) a brief overview of SCE's approved ratemaking structure, including the recovery of SCE's authorized CPUC-jurisdictional base-related revenue requirements through the operation of the BRRBA, PABA and the NSGBA, and (2) SCE's GRC-related balancing and memorandum account proposals, which include:

1. Continuation and modification of the Wildfire Risk Mitigation Balancing Account (WRMBA) / Grid Hardening Balancing Account (GHBA);
2. Continuation and modification of the Vegetation Management Balancing Account (VMBA);
3. Continuation of the Risk Management Balancing Account (RMBA);
4. Continuation and modification of the Z-Factor Memorandum Account (ZFMA);
5. Continuation of the Rule 20 Balancing Account (Rule 20 BA);
6. Continuation and modification of the Medical Programs Balancing Account (MPBA);
7. Continuation and modification of the Pensions Cost Balancing Account (PCBA);
8. Continuation and modification of the Post-Employment Benefit Other than Pensions Balancing Account (PBOP BA);
9. Continuation of the 2018 Tax Accounting Memorandum Account (TAMA 2018);
10. Continuation of the Safety and Reliability Investment Incentive Mechanism (SRIIM);
11. Continuation, modification and recovery of the Service Center Modernization Projects Memorandum Account (SCMPMA);
12. Continuation of the Distributed Energy Resources-Driven Grid Reinforcement Program Memorandum Account (DER-DGRPMA);
13. Continuation of the Short-Term Incentive Program Memorandum Account (STIPMA);
14. Continuation and modification of the Catalina Repower Memorandum Account (CRMA);
15. Establishment of the General Liability Insurance Balancing Account (GLIBA);
16. Establishment of the Next Gen ERP SAP Memorandum Account (NGESMA);
17. Establishment of the AMI 2.0 Memorandum Account (AMIMA);
18. Establishment of the Historic Sporting Events Cost Tracking Memorandum Account (HSECTMA);
19. Establishment of the Cybersecurity Compliance Memorandum Account (CCMA);
20. Establishment of the Renewable Transmission Projects Memorandum Account (RTPMA);

21. Elimination of the Underground Structures Replacement Balancing Account (USRBA);
22. Elimination of the Pole Loading and Deteriorated Poles Programs Balancing Account (PLDPBA);
23. Elimination and recovery of the Customer Service Re-Platform Memorandum Account (CSRPMMA);
24. Elimination and recovery of the Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA);
25. Elimination and recovery of the NEM Online Application System Memorandum Account (NEMOASMA);
26. Modification of the Electric Vehicle Infrastructure Memorandum Account (EVIMA);
27. Recovery of the Distribution Deferral Administrative Costs Memorandum Account (DDACMA);
28. Recovery of the Emergency Customer Protections Memorandum Account (ECPMA);
29. Recovery of the Residential Disconnections Implementation Cost Memorandum Account (RDICMA);
30. Recovery of the California Consumer Privacy Act Memorandum Account (CCPAMA);
31. Recovery of the Avoided Cost Calculator Memorandum Account (ACCMA);
32. Recovery of the Community Choice Aggregators Audit Memorandum Account (CCAAMA);
and,
33. Recovery of the Fusing Mitigation Costs within the Wildfire Mitigation Plan Memorandum Account (WMPMA).

A. Current Ratemaking Structure Overview

For SCE's bundled service customers, SCE's current rate structure comprises the following rate components:

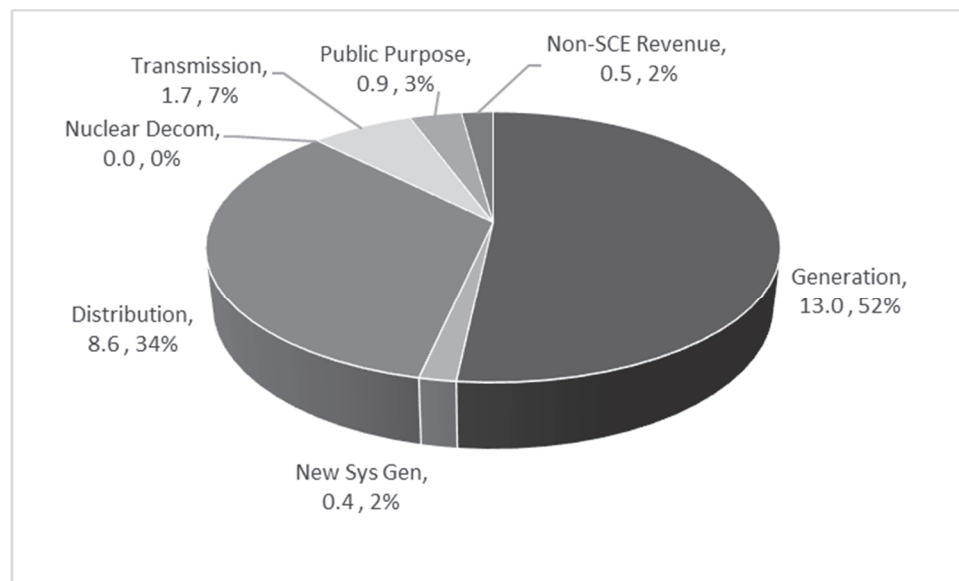
1. Distribution;³³
2. Transmission (includes all FERC-jurisdictional cost and revenue components);

³³ Revenues from the Distribution rate component recover: (1) ADBRR costs approved by the Commission through the GRC proceeding, and (2) other Distribution costs as approved by the Commission in various proceedings such as Charge Ready and Demand Response Program costs.

3. SCE Generation;³⁴
4. New System Generation;³⁵
5. Nuclear Decommissioning;
6. Public Purpose Programs;
7. Wildfire Fund Non-Bypassable Charge; and
8. Fixed Recovery Charges.

Figure V-2 shows the relative magnitude of each rate component for bundled service customers as of March 1, 2023.³⁶

Figure V-2
Southern California Edison Company
Bundled Service Customers Average Rates
As of March 1, 2023
(cents/kWh)



³⁴ Revenues from the SCE Generation rate component recover: (1) AGBRR costs as approved by the Commission through GRC proceedings, and (2) fuel and purchased power costs as approved by the Commission in ERRA proceedings.

³⁵ Revenues from the SCE New System Generation rate component recover: (1) authorized base-related New System Generation costs (e.g., SCE's Peaker and Energy Storage Revenue Requirement) as approved by the Commission through the GRC proceeding, and (2) net purchased power costs that the Commission has deemed to be considered New Generation or Emergency Reliability and as approved by the Commission through ERRA proceedings.

³⁶ Present rates are those rates implemented in Advice 4977-E submitted on February 27, 2023.

1 Authorized CPUC-jurisdictional base-related revenue requirements are recovered from
2 customers through the Distribution, Generation, and New System Generation rate components and the
3 operation of the BRRBA, PABA, and NSGBA mechanisms. SCE proposes to continue the BRRBA,
4 PABA and NSGBA mechanisms in the 2025 test year and 2026, 2027 and 2028 post-test years.

5 D.04-07-022 established the BRRBA to ensure that SCE would recover no more and no less than
6 its authorized CPUC-jurisdictional distribution base-related revenue requirement, or ADBRR.
7 The portion of the ABRR functionalized as new system generation associated with SCE's peakers and
8 energy storage is recovered from all benefiting customers through the New System Generation rate
9 component. As a result of D.07-09-044, SCE established the NSGBA, which ensures SCE recovers no
10 more and no less than its CPUC-jurisdictional New System Generation costs. A component of the New
11 System Generation costs is the CPUC-jurisdictional peaker and energy storage revenue requirement.³⁷
12 D.18-10-019 established the PABA, with subaccounts for each vintaged portfolio, to record the costs,
13 market revenues, imputed Resource Adequacy (RA) and Renewable Energy Credit (REC) revenues, and
14 billed customer revenues associated with its eligible resources. The portion of the ABRR functionalized
15 as generation, the AGBRR, is recovered through the operation of the PABA.

16 A fundamental purpose of the BRRBA, PABA and NSGBA is to compare portions of the
17 monthly ABRR to retail revenues from distribution, generation, and new system generation rates.
18 The BRRBA tracks under-collections and over-collections to be recovered or refunded through
19 distribution rates. Similarly, the NSGBA and PABA track under-collections and over-collections to be
20 recovered or refunded through the New System Generation rate and generation rate components,
21 respectively. The balances in SCE's balancing accounts, such as the BRRBA, PABA and NSGBA, are
22 consolidated into rate levels annually in SCE's year-end consolidated revenue requirement and rate
23 change advice letter.³⁸ In addition, SCE sets forth the entries recorded in the BRRBA, PABA and
24 NSGBA for Commission review for each calendar year in its annual April 1 ERRR Review applications.

³⁷ Pursuant to D.18-06-009, SCE is also authorized to include in its New System Generation (NSG) rates the approved costs for SCE's Aliso Canyon Energy Storage Utility Owned Generation Tesla and GE projects. The 535.7 MW of utility-owned storage projects approved in Resolution E-5183 are not currently part of the AESRR portion of the ABRR that records to the NSGBA.

³⁸ Distribution over or under-collections are consolidated into distribution rate levels. Generation over or under-collections are consolidated into generation or Power Charge Indifference Adjustment (PCIA) rate levels. New System Generation over or under-collections are consolidated into New System Generation rate levels.

1 **B. GRC-Related Balancing and Memorandum Account Proposals**

2 **1. Continuation and Modification of Balancing and Memorandum Accounts**

3 **a) Wildfire Risk Mitigation Balancing Account (WRMBA)/Grid Hardening**
4 **Balancing Account (GHBA)**

5 In the 2021 GRC, the Commission authorized the establishment of the two-way
6 WRMBA to track the difference between authorized and recorded capital expenditures associated with
7 SCE's Wildfire Covered Conductor Program (WCCP) over the 2019-2023 period.³⁹ Pursuant to the
8 2021 GRC Decision, SCE is authorized to recover the revenue requirement associated with the
9 authorized WCCP capital expenditures, including a 110 percent reasonableness threshold. The capital-
10 related revenue requirements for actual WCCP expenditures in excess of the 110 percent reasonableness
11 threshold are subject to additional reasonableness review prior to recovery from customers. All entries in
12 the WRMBA are recorded on a CPUC-jurisdictional basis.⁴⁰

13 In this GRC, SCE proposes to (1) expand the scope of the WRMBA to include
14 additional grid hardening capital expenditures over the 2025 through 2028 period, in addition to the
15 WCCP; (2) change the name of the account from the WRMBA to the GHBA to reflect this expanded
16 scope; and (3) eliminate or increase the threshold that requires additional reasonableness review.
17 Specifically, SCE proposes to record the capital-related revenue requirement associated with the
18 following programs/activities in the GHBA:

- 19 • WCCP, which consists of expenditures associated with: (i) the installation of
20 covered conductor (i.e., aluminum or copper wire covered by three layers of
21 insulation designed to withstand incidental contact from foreign objects),
22 (ii) associated pole replacements/upgrades (using either composite poles or
23 fire-resistant wraps on wood poles) to account for the additional weight and

³⁹ In Track 4 of the 2021 GRC, SCE proposed to extend the WRMBA through the end of 2024 to track, in a new separate subaccount, capital expenditures associated with an additional 1,200 miles of covered conductor to be installed in 2024. SCE proposed the continued ability to seek cost recovery through a separate reasonableness review for expenditures above 110 percent of the authorized revenue requirement associated with the capital expenditures threshold for those authorized 1,200 miles. *See* Track 4, Exhibit SCE-01, pp. 20-21.

⁴⁰ The WRMBA contains two sub-accounts: (1) WCCP Costs Not Subject to AB 1054 and (2) WCCP Costs Subject to AB 1054. This subaccount structure is no longer necessary in 2025 because SCE has already incurred the \$1.575 billion of wildfire mitigation-related capital expenditures that are subject to AB 1054 and has issued (or has the authority to issue) Recovery Bonds to finance these costs.

1 higher wind loading associated with covered conductor and to ensure ongoing
2 compliance with General Order 95, (iii) associated replacement of outdated
3 secondary conductor (i.e., installation of multiplex conductors on the
4 secondary lines per SCE's most recent Distribution Design Standards),
5 (iv) the remediation of tree attachments (i.e., the elimination of instances in
6 which existing electrical equipment is attached to trees), (v) installation of
7 new vibration dampers or vibration damper retrofits (i.e., install vibration
8 dampers on covered conductor installed prior to the standard being published
9 for vibration susceptibility in late 2020), and (vi) installation of fire-resistant
10 wrap retrofit (i.e., install fire-resistant wrap on wood poles that passed pole
11 loading and were not replaced during prior covered conductor installations);

- 12 • Targeted Undergrounding Program (TUG), which consists of expenditures
13 associated with converting overhead miles to underground miles (i.e., civil
14 construction, electrical work, and work associated with panel conversions to
15 accommodate the underground system);
- 16 • Rapid Earth Fault Current Limiter (REFCL) activities, which consist of
17 capital expenditures associated with the installation of ground fault
18 neutralizers, pole tops and isobanks to detect ground faults and rapidly reduce
19 the fault current to a level much lower than traditional powerline designs; and,
- 20 • Long Span Initiative (LSI) activities, which consist of capital expenditures
21 associated with the installation of (i) line spacers, which are insulated pieces
22 of equipment that separate the lines to reduce the possibility of wire-to-wire
23 contact, (ii) alternate construction, including ridge pin, box construction,
24 wider crossarms, and intersect poles to increase phase spacing or reduce sag,
25 and (iii) covered conductor.

26 As a result of the additional uncertainty associated with forecasting this expanded
27 scope of work, SCE proposes to eliminate or increase the cost threshold that requires additional
28 reasonableness review within the GHBA. Currently, SCE is required to seek additional reasonableness
29 review to recover the capital-related revenue requirement associated with WCCP direct capital
30 expenditures over the 2019-2023 period that exceed 110 percent of the authorized amount. SCE is
31 authorized to submit a Tier 2 advice letter to recover the capital-related revenue requirement associated

1 with capital expenditures that are 110 percent or less of the authorized amount and to return any over-
2 collection associated with authorized capital expenditures. As a result of the expanded scope and to
3 allow for more streamlined and efficient cost recovery of the more expansive grid hardening approach, it
4 is appropriate to eliminate the reasonableness review threshold. If the Commission feels some level of
5 threshold remains appropriate, SCE proposes to increase the threshold to 125 percent.

6 Therefore, for the reasons explained above and as discussed and supported in
7 Exhibit SCE-04, Vol. 05 Pt. 2, SCE proposes to continue, with modifications, the WRMBA/GHBA over
8 the 2025 GRC cycle.

9 **b) Vegetation Management Balancing Account (VMBA)**

10 In the 2021 GRC, the Commission authorized the establishment of the two-way
11 VMBA to record the difference between authorized and recorded O&M expenses for vegetation
12 management activities.⁴¹ Pursuant to the 2021 GRC Decision, SCE is required to submit a Tier 2 advice
13 letter to recover an under-collection that is less than 115 percent of the authorized VMBA revenue
14 requirement as well as return any over-collection at the end of each year. Recorded VMBA expenses in
15 excess of 115 percent of the annual authorized VMBA revenue requirement are subject to additional
16 reasonableness review in a separate proceeding prior to recovery from customers. All entries recorded in
17 the VMBA are entered on a CPUC-jurisdictional basis.

18 In this GRC, SCE proposes to continue the two-way VMBA and (1) requests an
19 expanded scope for vegetation management activities consistent with SCE's proposal in its 2021 GRC
20 Track 4 and (2) proposes to eliminate the reasonableness review threshold or increase it to 125 percent.
21 Specifically, in its Track 4 request, SCE requested the Commission's clarification that it is reasonable
22 for SCE to record vegetation management-related Environmental Services Department (ESD) costs in
23 the VMBA.⁴² The inclusion of activities that support vegetation management in the VMBA is
24 reasonable because these costs result directly from vegetation management work and therefore are
25 correlated with changes in the level of vegetation management work.

⁴¹ In the 2021 GRC, "vegetation management activities" were defined to specifically include (but not necessarily be limited to) routine Transmission and Distribution vegetation management; dead, dying, and diseased tree removal; and wildfire vegetation management through SCE's Hazard Tree Management Program (HTMP).

⁴² A.19-08-013, Exhibit SCE-Tr. 4, Vol. 01, p. 20.

1 It is also reasonable to eliminate or increase the VMBA reasonableness review
2 threshold. As more fully described in SCE-02, Vol. 10, vegetation management costs are subject to
3 variability based on changes in inspection practices, compliance requirements, risk-based assessments
4 and other exogenous factors, such as state-mandated changes to compensation practices. For example, as
5 a result of D.17-12-024 (the High Fire Threat Decision, or HFTD), SCE made significant changes to its
6 vegetation management procedures to comply with new fire-safety regulations, which modified the
7 minimum clearance from 18 inches to a minimum of four feet between vegetation and SCE's electric
8 distribution facilities, and increased the recommended clearance at time of trim to 12 feet in high fire
9 areas. In addition, SCE was required to pay its vegetation contractors higher wages in accordance with
10 Senate Bill (SB) 247, which combined with the new policy changes from the HFTD contributed to SCE
11 incurring \$212.786 million in incremental costs above the current VMBA threshold of 115 percent in
12 2021.⁴³ Given the uncertainty of future California legislative and regulatory policymaking, potential
13 changes to compliance requirements and the contractor labor market, it is reasonable to maintain a two-
14 way balancing account for vegetation management costs. For the reasons outlined above regarding
15 variability, SCE requests that the existing cap on the VMBA be eliminated or, at a minimum, increased
16 to 125 percent to allow for more timely recovery of these pass-through costs.⁴⁴

17 Therefore, for the reasons explained above and as discussed and supported in
18 Exhibit SCE-02, Vol. 10, SCE proposes to continue, with modifications, the VMBA over the 2025 GRC
19 cycle.

20 **c) Risk Management Balancing Account (RMBA)**

21 In the 2021 GRC, the Commission authorized the establishment of the one-way
22 Risk Management Balancing Account (RMBA) to record the difference between actual insurance
23 premium expenses for wildfire liability coverage, including the costs of alternative risk transfer

⁴³ See A.22-06-003, Exhibit SCE-01, Table V-40.

⁴⁴ The consideration of timely recovery of pass-through costs has much more significance relative to the environment in which the 115 percent VMBA cap was originally established in 2021 when interest rates were still near 0 percent. That reality has changed. In 2023, Commercial Paper rates (which set the interest rate component for all CPUC-authorized MAs and BAs, including the VMBA) are likely to be at or above 5 percent (on average) over the duration of the year (based on S&P Global Market Intelligence's forecast for 2023 as of March 6, 2023). That means that for every \$20 million in under-collected balances, customers will have to pay an additional \$1 million in interest on an annual basis. To put this in perspective, as of year-end 2022 SCE's VMBA was under-collected by approximately \$492 million, which translates into *approximately \$25 million in additional interest* that customers will need to pay per year until the balance is eliminated.

1 instruments, and the authorized insurance premium expenses for wildfire liability coverage adopted in
2 the 2021 GRC Decision. The year-end balance in the RMBA, if an over-collection, is transferred on an
3 annual basis to the distribution subaccount of the BRRBA to be returned to customers in distribution
4 rates. Actual RMBA expenses exceeding the authorized RMBA revenue requirement are eligible for
5 tracking in SCE's Wildfire Expense Memorandum Account (WEMA) and are subject to a
6 reasonableness review prior to recovery from customers.

7 On February 22, 2023, SCE filed a Joint Petition for Modification (PFM) of the
8 2021 GRC Decision with Cal Advocates and The Utility Reform Network (TURN) to establish a
9 customer-funded wildfire liability self-insurance program for SCE covering: (1) the 2023-2024 wildfire
10 liability insurance renewal period (i.e., July 1, 2023 to June 30, 2024) and (2) the first half of SCE's
11 2024-2025 wildfire liability insurance renewal period (covering July 1, 2024 to December 31, 2024), in
12 lieu of purchasing wildfire liability insurance from the commercial insurance market. The parties filing
13 the PFM agreed to support continuation of the customer-funded wildfire liability self-insurance program
14 in SCE's 2025 GRC cycle to provide customers additional savings.

15 If the PFM is granted by the Commission, SCE will modify the RMBA effective
16 July 1, 2023 to effectuate the customer-funded wildfire liability self-insurance program.⁴⁵ In the 2025
17 GRC cycle, SCE proposes to continue the RMBA consistent with the modifications proposed in the
18 PFM, for the reasons stated therein.

19 Therefore, for the reasons explained above and as discussed and supported in
20 Exhibit SCE-06, Vol. 03, SCE proposes to continue the RMBA, as modified by the pending PFM, over
21 the 2025 GRC cycle.

22 **d) Z-Factor Memorandum Account (ZFMA)**

23 In the 2021 GRC, the Commission authorized SCE to establish the ZFMA to track
24 costs associated with events that are potential Z-Factors.⁴⁶ SCE included the establishment of the ZFMA
25 as part of its Post-Test Year Ratemaking Mechanism. In this GRC, SCE proposes to continue the ZFMA

⁴⁵ On April 14, 2023, a Proposed Decision was issued granting the PFM. The Proposed Decision is expected to be adopted at the Commission's May 18, 2023 voting meeting.

⁴⁶ The existing Z-Factor mechanism allows SCE to seek recovery of costs associated with exogenous events that result in a major cost impact for SCE. SCE is responsible for any events that do not have a financial impact of more than \$10 million. There is a \$10 million "deductible amount" applied on a one-time basis to the first year's revenue requirement associated with any approved Z-Factors. SCE is not proposing any changes to these mechanics of the Z-Factor mechanism.

1 and to expand the applicability to include the GRC test year, as opposed to only GRC attrition years.
2 This proposal is consistent with the Commission’s determination in SDG&E’s 2019 GRC that
3 SDG&E’s Z-Factor should apply to the test year as well as attrition years. The reasoning the
4 Commission applied in that decision – that “a Z-Factor event is just as likely to occur during the [test
5 year] as it does during the attrition years” – applies equally to SCE.⁴⁷ As a result, SCE proposes to
6 remove the ZFMA from the Post-Test Year Ratemaking Mechanism and operate it instead as a
7 standalone memorandum account throughout the 2025 GRC cycle.

8 **e) Rule 20 Balancing Account (Rule 20 BA)**

9 In the 2018 GRC Decision, the Commission authorized establishment of the one-
10 way Rule 20A Balancing Account (Rule 20A BA) to track the annual capital and expense costs for Rule
11 20A undergrounding projects on a forecast and recorded basis and to record any over-collected balances
12 in the account for future Rule 20A projects. In the 2021 GRC Decision, the Commission approved
13 SCE’s request to continue the Rule 20A one-way balancing account.⁴⁸ On June 3, 2021, the Commission
14 issued D.21-06-013, revising the Rule 20 program and directing SCE to include subaccounts for tracking
15 Rule 20B and 20C expenses in its existing Rule 20A one-way balancing account. Additionally,
16 D.21-06-013 directed that any funds authorized in the GRC for the purpose of a Rule 20 Program are to
17 be reserved exclusively for the purpose and benefit of the Rule 20 Programs as authorized in SCE’s Rule
18 20 tariff. The Rule 20 program funds cannot be reallocated for any other purpose without the express
19 authorization of the Commission.⁴⁹ On July 1, 2021, SCE submitted Advice 4531-E to modify the Rule
20 20A BA to include subaccounts to track Rule 20B and 20C and rename the account the Rule 20 BA.⁵⁰

21 Exhibit SCE-02, Vol. 08 provides the recorded Rule 20 BA capital expenditure
22 and expense amounts through 2022 and the forecast amounts for 2023 through 2024 compared to the
23 amounts authorized in the 2021 GRC. SCE proposes to carry over any December 31, 2024 balance in
24 the Rule 20 BA to fund Rule 20 projects during the 2025 GRC cycle.

⁴⁷ D.19-09-051, p. 712.

⁴⁸ D.21-08-036, p. 153.

⁴⁹ D.21-06-013, OP 13.

⁵⁰ Advice 4531-E was approved with an effective date of July 1, 2021.

1 Therefore, for the reasons explained above and as discussed and supported in
2 Exhibit SCE-02, Vol. 08, SCE proposes to continue the one-way Rule 20 BA over the 2025 GRC cycle
3 to account for future Rule 20A, 20B and 20C projects.

4 f) **Medical Programs Balancing Account (MPBA)**

5 The purpose of the two-way Medical Programs Balancing Account (MPBA) is to
6 record the difference between: (1) medical, dental and vision expenses authorized by the Commission,
7 and (2) recorded medical, dental and vision expenses, after capitalization. The balance in the MPBA is
8 carried forward each month through the end of each year. The balance recorded in the MPBA at the end
9 of each year is transferred to the BRRBA and PABA and consolidated into rate levels annually.

10 SCE's current practice is to transfer the December 31 balance from the MPBA to the BRRBA and the
11 PABA in January of the following calendar year. Effective with the start of the 2025 GRC cycle, SCE
12 proposes to make this transfer in December (instead of January) to provide for more timely recovery or
13 return of the recorded over- or under-collection amounts consistent with annual transfers in the majority
14 of SCE's other cost balancing accounts.⁵¹ Transferring the balances in December will reduce interest
15 expense to be paid by SCE's customers. Entries recorded in the MPBA in each calendar year are
16 reviewed in SCE's ERRA Review applications filed on April 1 of each subsequent year.

17 Therefore, SCE proposes to continue the use of the two-way MPBA during the
18 2025 GRC cycle, with a modification to the timing of the transfer to the BRRBA and PABA described
19 above, as these costs can vary significantly from the forecast. If this proposal is approved, in the advice
20 letter submitted in compliance with a final Commission decision in this proceeding, SCE will modify
21 Preliminary Statement Part VV as required (e.g., include the 2025 authorized revenue requirement).

22 For more information on the MPBA, please see Exhibit SCE-06, Vol. 04.

23 g) **Pensions Costs Balancing Account (PCBA)**

24 The purpose of the two-way Pensions Costs BA (PCBA) is to record the
25 difference between: (1) pension expenses authorized by the Commission, and (2) recorded pension
26 expenses, after capitalization. The balance in the PCBA is carried forward each month through the end
27 of each year. The balance recorded in the PCBA at the end of each year is transferred to the BRRBA and
28 PABA and consolidated into rate levels annually. SCE's current practice is to transfer the December 31

⁵¹ For example, SCE will transfer the December 31, 2025 balance in the MPBA to the BRRBA and the PABA in December 2025 for consolidation into January 1, 2026 rate levels. Under SCE's current practice, the December 31, 2025 balance would not start to be recovered in rate levels until January 1, 2027.

1 balance from the PCBA to the BRRBA and the PABA in January of the following calendar year.
2 Effective with the start of the 2025 GRC cycle, SCE proposes to make this transfer in December (instead
3 of January) to provide for more timely recovery or return of the recorded over- or under-collection
4 amounts consistent with annual transfers in the majority of SCE's other cost balancing accounts.⁵²
5 Transferring the balances in December will reduce interest expense to be paid by SCE's customers.
6 Entries recorded in the PCBA in each calendar year are reviewed in SCE's ERRA Review applications
7 filed on April 1 of each subsequent year.

8 Therefore, SCE proposes to continue the use of the two-way PCBA during the
9 2025 GRC cycle, with a modification to the timing of the transfer to the BRRBA and PABA described
10 above, as pension expenses can vary significantly from the forecast. If this proposal is approved, in the
11 advice letter submitted in compliance with a final Commission decision in this proceeding, SCE will
12 modify Preliminary Statement Part OO as required (e.g., include the 2025 authorized revenue
13 requirement).

14 For more information on the PCBA, please see Exhibit SCE-06, Vol. 04.

15 **h) Post-Employment Benefits Other than Pensions Balancing Account**
16 **(PBOPBA)**

17 The purpose of the two-way Post-Employment Benefit Other than Pensions BA
18 (PBOPBA) is to record the difference between: (1) Post-Employment Benefit Other than Pensions
19 (PBOP) expenses authorized by the Commission, and (2) recorded PBOP expenses, after capitalization.
20 The balance in the PBOPBA is carried forward each month through the end of each year. The balance
21 recorded in the PBOPBA at the end of each year is transferred to the BRRBA and PABA and
22 consolidated into rate levels annually. SCE's current practice is to transfer the December 31 balance
23 from the PBOPBA to the BRRBA and the PABA in January of the following calendar year.
24 Effective with the start of the 2025 GRC cycle, SCE proposes to make this transfer in December (instead
25 of January) to provide for more timely recovery or return of the recorded over- or under-collection
26 amounts consistent with annual transfers in the majority of SCE's other cost balancing accounts.⁵³

⁵² For example, SCE will transfer the December 31, 2025 balance in the PCBA to the BRRBA and the PABA in December 2025 for consolidation into January 1, 2026 rate levels. Under SCE's current practice, the December 31, 2025 balance would not start to be recovered in rate levels until January 1, 2027.

⁵³ For example, SCE will transfer the December 31, 2025 balance in the PBOPBA to the BRRBA and the PABA in December 2025 for consolidation into January 1, 2026 rate levels. Under SCE's current practice, the December 31, 2025 balance would not start to be recovered in rate levels until January 1, 2027.

Transferring the balances in December will reduce interest expense to be paid by SCE's customers. Entries recorded in the PBOPBA in each calendar year are reviewed in SCE's ERRA Review proceedings filed on April 1 of each subsequent year.

Therefore, SCE proposes to continue the use of the two-way PBOPBA during the 2025 GRC cycle, with a modification to the timing of the transfer to the BRRBA and PABA described above, as PBOB expenses can vary significantly from the forecast. If this proposal is approved, in the advice letter submitted in compliance with a final Commission decision in this proceeding, SCE will modify Preliminary Statement Part PP as required (e.g., include the 2025 authorized revenue requirement).

For more information on the PBOP BA, please see Exhibit SCE-06, Vol. 04.

i) Tax Accounting Memorandum Account 2018 (TAMA 2018)

In the 2015 GRC Decision, the Commission authorized establishment of the Tax Accounting Memorandum Account (TAMA) effective January 1, 2015. In Advice 3314-E submitted on November 25, 2015, SCE included Preliminary Statement Part N.28, TAMA, which is a two-way memorandum account that tracks the impact on the authorized CPUC-jurisdictional revenue requirement resulting from: (1) any income tax accounting method change associated with the Internal Revenue Service (IRS) or California Franchise Tax Board (CFTB) for tax year 2015-2017, (2) any changes in federal or California tax law, final or temporary regulations or other administrative guidance that impact the determination of depreciation and/or repair deductions for tax years 2015-2017, (3) the difference between authorized and recorded federal and California non-pole loading net repair deductions for 2015-2017, (4) any adjustments arising from audits, administrative appeals proceedings or litigation affecting items 1-3 above, and (5) a change in authorized revenue requirements as determined by the CPUC resulting from an IRS private letter ruling regarding compliance with normalization regulations. The TAMA must remain open until the IRS and CFTB audit periods for tax years 2015-2017 are closed statutorily.

On March 18, 2016, SCE submitted Advice 3314-E-B to modify the TAMA at the direction of the Commission's Energy Division to add: (1) changes between authorized and recorded deductions resulting from the Tax Increase Prevention Act of 2014, (2) the impact from the Protecting Americans from Tax Hikes Act of 2015, (3) that the TAMA may only be closed upon Commission approval, (4) that the TAMA balance will be transferred to the BRRBA only upon Commission

1 approval, (5) that the annual TAMA advice letter shall have a Tier 2 designation, and (6) that SCE shall
2 propose how to address the future activities in the TAMA in the 2018 GRC Proceeding.

3 In the 2018 and 2021 GRCs, SCE proposed to continue the TAMA. In the 2018
4 GRC Decision,⁵⁴ the Commission agreed that the TAMA should be extended; however, the Commission
5 found extension of the TAMA in its then current form would limit the effectiveness of the account.
6 The 2018 GRC Decision mandated that the new TAMA, the “TAMA 2018,” must have separate line
7 items detailing the difference between income tax expenses forecasted and income tax expenses
8 incurred, specifically resulting from (1) net revenue changes, (2) mandatory tax law changes, tax
9 accounting changes, tax procedural changes, or tax policy changes, and (3) elective tax law changes, tax
10 accounting changes, tax procedural changes or tax policy changes.⁵⁵ In the 2021 GRC Decision, the
11 Commission authorized SCE to continue use of the two-way 2018 TAMA for years 2021 through 2024
12 to aid the Commission’s review of the reasonableness of SCE’s implementation of various tax
13 changes.⁵⁶

14 For the 2025 GRC period, SCE proposes to continue the use of the two-way
15 TAMA 2018 account.⁵⁷ Please see Exhibit SCE-07, Vol. 02 for further discussion. SCE proposes to
16 extend all applicable provisions of TAMA 2018 to include 2025 through 2028 and to have the
17 memorandum account remain open until the IRS and CFTB audit periods for those years are closed.

18 **j) Safety and Reliability Investment Incentive Mechanism (SRIIM)**

19 The 2015 GRC Decision⁵⁸ replaced the Reliability Investment Incentive
20 Mechanism (RIIM) authorized in prior GRCs with the Safety and Reliability Investment Incentive
21 Mechanism (SRIIM). The SRIIM was adopted to encourage SCE to spend its authorized capital forecast
22 on key programs to meet the SRIIM goals and to retain employees in classifications responsible for the
23 programs. The SRIIM includes two components: capital spending and staffing. The SRIIM determines
24 the difference between: (1) actual (recorded) safety and reliability-related capital additions, and (2) the

⁵⁴ D.19-05-020.

⁵⁵ On June 14, 2019, SCE submitted Advice 4016-E to establish the TAMA 2018 as Preliminary Statement Part N.63 with all the provisions as ordered in D.19-05-020.

⁵⁶ D. 21-08-036, pp. 467, 643 (OPs 746, 747).

⁵⁷ The TAMA 2018 must remain open and the balance in the account is reviewed in every subsequent GRC until a Commission decision closes the account.

⁵⁸ D.15-11-021.

1 authorized level of safety and reliability-related capital additions adopted in the most recent GRC
2 decision. Additionally, the SRIIM tracks the SRIIM staffing target.

3 SCE proposed to maintain the SRIIM over the 2018 GRC cycle, with proposed
4 modifications. Based on SCE's agreements with the Coalition of California Utility Employees (CUE), in
5 the 2018 GRC Decision,⁵⁹ the Commission authorized enhancements to the capital mechanism and the
6 workforce mechanism. SCE also proposed to maintain the SRIIM over the 2021 GRC cycle, with
7 proposed modifications. As adopted in the 2021 GRC Decision, SCE was authorized to maintain the
8 SRIIM with adjustments to (1) headcount classifications⁶⁰ and (2) headcount targets.⁶¹

9 SCE is again proposing to maintain the SRIIM over the 2025 GRC cycle, with an
10 updated headcount target as discussed in Exhibit SCE-02, Vol. 02. If this proposal to continue the
11 SRIIM is adopted, SCE will update Preliminary Statement Part LL, SRIIM, to include the updated
12 headcount target, in addition to any other necessary changes to the tariff associated with the
13 continuation.

14 **k) Service Center Modernization Projects Memorandum Account (SCMPMA)**

15 As discussed in Exhibit SCE-06, Vol. 7, SCE proposes to maintain the SCMPMA
16 over the 2025 GRC cycle to continue to record costs associated with the Redlands and Santa Barbara
17 service center modernization projects, which are not currently projected to be completed by the end of
18 2024. SCE also proposes to include incremental costs associated with the Arrowhead service center
19 modernization project within the SCMPMA over the 2025 GRC cycle, given the uncertainty associated
20 with whether a suitable parcel of land can be acquired and the follow-on construction schedule if the
21 land is acquired. Similar to other projects recorded to the SCMPMA, SCE will not seek recovery of the
22 Arrowhead service center costs recorded in the SCMPMA until the modernization project for that
23 service center is completed. Additionally, SCE will no longer record the costs associated with the
24 Bishop, Kernville, Ridgecrest, San Joaquin and Santa Ana service center modernization projects in the
25 SCMPMA because those projects are expected to be completed by the end of 2024. In Chapter V.B.5
26 below, SCE seeks recovery of the costs associated with the completed projects that have recorded to the

⁵⁹ D.19-05-020.

⁶⁰ In D.21-08-036, SCE was authorized to remove the Distribution Groundman and Transmission Apprentice Groundman and add the Distribution Apparatus Technician and Distribution Apparatus Foreman to the headcount classification of the SRIIM.

⁶¹ In D.21-08-036, SCE was authorized to increase the headcount target from 2,175 to 2,465.

SCMPMA; any ongoing revenue requirements for those projects are included in the ADBRR beginning in 2025. Chapter V.B.5 below also includes additional information on the background and mechanics of this account, which are not repeated here. If this proposal to continue and modify the SCMPMA is adopted, SCE will update Preliminary Statement Part N.54, SCMPMA, to include any necessary changes to the tariff, including the elimination of the service center modernization projects that have been completed and the addition of the Arrowhead service center modernization project.

I) Distributed Energy Resources-Driven Grid Reinforcement Program
Memorandum Account (DER-DGRPMA)

In the 2021 GRC, SCE presented a forecast for its Load Growth Business Planning Element (BPE). The Load Growth BPE covered the capital expenditures needed to support customer load and DER growth throughout SCE's electrical grid, which encompassed programs within the Distribution Substation Plan, DER-Driven Grid Reinforcement, Transmission Substation Plan, System Improvement Programs, and Land Rights Management. Due to uncertainty in the timing and the potential magnitude of DER-driven reliability needs, SCE and Cal Advocates recommended removal of the DER-Driven Grid Reinforcement costs from SCE's Load Growth forecast in the 2021 GRC and to instead record the revenue requirement associated with the actual capital expenditures within the program in a new memorandum account. In the 2021 GRC Decision, the Commission adopted this recommendation and authorized the establishment of the DER-DGRPMA.⁶² The purpose of the DER-DGRPMA is to record the capital-related revenue requirements associated with actual DER-Driven Grid Reinforcement capital expenditures and includes activities to upgrade the distribution system to enable the integration of DERs. These activities include but are not limited to: DER-driven distribution circuit upgrades, DER-drive 4 kV cutovers, DER-driven new circuits, DER-drive circuit breaker upgrades, and DER-drive substation transformer upgrades.

SCE's 2021 distribution planning process did not include a DER-driven needs analysis due to tool development delays. Thus, SCE's 2021 Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) filings do not contain any DER-driven needs or projects and the DER-DGRPMA has only recorded minimal amounts.⁶³ SCE continues to develop software tools and processes to support this analysis but continues to face challenges to complete it in

⁶² D.21-08-036, p. 132.

⁶³ As of December 31, 2022, the recorded balance in the DER-DGRPMA was \$0.014 million. For this reason, SCE is not seeking recovery of the 2021 GRC cycle DER-DGRPMA balance in this Application.

1 conjunction with annual distribution planning process timelines. To improve the accuracy and speed
2 necessary to produce study results, SCE has prioritized efforts to deploy software tools utilized for these
3 studies.

4 Given the continued uncertainty in the timing and magnitude of these types of
5 projects, SCE did not include a forecast of DER-driven grid reinforcement capital expenditures in this
6 GRC. Instead, for the 2025 GRC cycle, SCE proposes to maintain the DER-DGRPMA and continue to
7 track costs for future reasonableness review and recovery associated with SCE's DER-Driven Grid
8 Reinforcement Program. The continued use of the memorandum account reflects that SCE's DER-
9 Driven Grid Reinforcement Program will continue to be subject to a high degree of uncertainty around
10 the timing and magnitude of DER-driven reliability reinforcement needs, similar to the 2021 GRC cycle.
11 If this proposal to continue the DER-DGRPMA is adopted, SCE will update Preliminary Statement Part
12 N.31, DER-DGRPMA, to include any necessary changes to the tariff to reflect the continuation.

13 **m) Short-Term Incentive Program Memorandum Account (STIPMA)**

14 The purpose of the STIPMA is to compare the authorized and actual Short Term
15 Incentive Program (STIP) expenses paid out, after capitalization. If authorized amounts exceed actual
16 payout amounts (*i.e.*, over-collections), the over-collection is returned to customers through the BRRBA
17 and the PABA. If the actual payout amounts exceed the authorized amounts (*i.e.*, under-collections), the
18 under-collection is not recoverable in customer rates. The Commission has required SCE to use the
19 STIPMA during the 2009, 2012, 2015, 2018 and 2021 GRC cycles.⁶⁴ Therefore, SCE proposes to
20 continue the use of the STIPMA in the 2025 GRC cycle. In the advice letter submitted in compliance
21 with a final Commission decision in this proceeding, SCE will update Preliminary Statement Part N.8 as
22 required to reflect the continuation (*e.g.*, include the 2025 authorized revenue requirement).

23 For more information on the STIPMA, please see Exhibit SCE-06, Vol. 04.

24 **n) Catalina Repower Memorandum Account (CRMA)**

25 The Catalina Repower Project included the replacement of six diesel electric
26 generators to meet new emissions requirements set forth by the South Coast Air Quality Management
27 District (SCAQMD). To maintain reliability and serve load for the service area, in the 2021 GRC, SCE
28 proposed to replace the generators in three phases with two of the existing generators being replaced
29 with two new SCAQMD compliant generators during each phase. Due to the timing uncertainty of

⁶⁴ Prior to 2018, the STIPMA was known as the Results Sharing Memorandum Account (RSMA).

1 implementing Phase 1 and the need for additional scrutiny of the proposed project, the Commission
2 directed SCE to submit a standalone application with an updated version of the Catalina Repower
3 Project proposal within 60 days of the issuance of the 2021 GRC Decision. In addition, the Commission
4 authorized SCE to establish the Catalina Repower Memorandum Account to track costs related to the
5 project for possible future recovery following a reasonableness review in the 2025 GRC.

6 On October 15, 2021, SCE filed A.21-10-005, requesting authority to proceed
7 with its proposal to install six new diesel generation units at the existing Pebbly Beach Generating
8 Station to replace existing units. On November 3, 2022, the Commission issued D.22-11-007 approving
9 an all-party settlement regarding SCE's proposed Catalina Repower Project. The settlement agreement
10 established a process for SCE to obtain future Commission review and approvals for the project once the
11 SCAQMD completes its rulemaking on air emissions requirements impacting the project and issues the
12 necessary permits for the project. Section D.3 of the approved settlement agreement specifies that SCE
13 should continue to track Catalina Repower Project costs in the CRMA, for recovery in SCE's next GRC.

14 However, as of the filing date of this Application, the Catalina Repower Project is
15 not complete and is not expected to be placed in service prior to 2025, as further described in Exhibit
16 SCE-05, Vol. 01. Therefore, it is premature in this GRC for SCE to seek cost recovery of the amounts
17 that are recorded and will record in the CRMA over the next few years. Instead, SCE proposes to
18 maintain the CRMA during the 2025 GRC cycle but modify the disposition section of the tariff to allow
19 SCE to seek cost recovery via the submission of a Tier 3 advice letter upon project completion instead of
20 carrying these capital costs without recovery (and accumulating interest expense for customers) until
21 2029 (i.e., SCE's next GRC after 2025). If this proposal to continue and modify the CRMA is adopted,
22 SCE will update Preliminary Statement Part N.26, CRMA, to include the necessary changes to the
23 disposition section of the tariff.

24 **2. Proposed New Balancing and Memorandum Accounts**

25 **a) Establishment of the General Liability Insurance Balancing Account** 26 **(GLIBA)**

27 As discussed in Exhibit SCE-06, Vol. 03, there are many factors that affect
28 insurance premiums, and certain factors are outside of SCE's control or are difficult to foresee,
29 including the market fluctuations in the cost of general liability insurance. This, in turn, makes it
30 difficult to provide an accurate forecast. For this reason, in this GRC cycle, SCE seeks to establish a new
31 two-way interest-bearing balancing account, the General Liability Insurance Balancing Account

1 (GLIBA), to record and recover/return on an annual basis the difference between SCE's authorized non-
2 wildfire general liability insurance premiums costs that are included on a forecast basis in customers'
3 distribution rates and the actual costs incurred by SCE for non-wildfire general liability insurance
4 premiums. SCE will transfer any over/under-collection recorded in the GLIBA as of December 31 to the
5 distribution sub-account of the BRRBA to be returned to or collected from customers in the following
6 year's distribution rates via SCE's year-end consolidated revenue requirement and rate change process.
7 SCE will include the recorded operation of the GLIBA in its annual ERRA Review application for
8 review by the Commission to ensure that the entries made in the GLIBA are stated correctly and are
9 consistent with applicable Commission decisions.

10 SCE's proposal to establish the two-way GLIBA is substantially consistent and
11 aligned with the general liability insurance ratemaking authorized for the Sempra utilities and PG&E.
12 In A.17-10-007, SDG&E and SoCalGas requested authority to establish a Liability Insurance Premium
13 Balancing Account (LIPBA), a two-way balancing account for liability insurance premiums, citing to
14 the uncertainty regarding the possible need for and cost of additional insurance because of market
15 fluctuations in the cost of liability insurance.⁶⁵ The Commission approved this request in D.19-09-051,
16 with the modification that SDG&E and SoCalGas be required to submit a Tier 2 advice letter for
17 recovery of costs of additional liability insurance coverage that were not requested in the GRC
18 application.⁶⁶ In D.20-12-005, the Commission authorized PG&E to establish the Risk Transfer
19 Balancing Account (RTBA) for general liability insurance premium costs for coverage up to \$1.4 billion
20 and also granted PG&E the authority to submit a Tier 2 advice letter to recover costs for coverage in
21 excess of \$1.4 billion.⁶⁷

22 Therefore, for the reasons outlined above and in Exhibit SCE-06, Vol. 03, SCE
23 proposes to establish the GLIBA, effective January 1, 2025, for use during the 2025 GRC cycle. In the
24 advice letter submitted in compliance with a final Commission decision in this proceeding, SCE will
25 include all necessary tariff changes to implement this new balancing account.

⁶⁵ D.19-09-051, p. 533.

⁶⁶ D.19-09-051, pp. 535-536. SCE is not requesting additional general liability coverage beyond what is included in Exhibit SCE-06, Vol. 03.

⁶⁷ D.20-12-005, pp. 249-250. This decision also granted PG&E's request regarding the implementation of self-insurance, which also utilizes the RTBA.

1 **b) Establishment of the NextGen ERP SAP Memorandum Account (NGESMA)**

2 SCE's core business data and functions – including its financial operations,
3 human resources, asset and work management, and supply chains – run or flow through SAP. As the
4 SAP Business Suite Enterprise Resource Planning (ERP) Platform reaches the end of its life cycle, SCE
5 faces increasing risk that added complexity and customizations, with the emergence of new
6 technological advancements, will not be supported by the current platform. To help mitigate this risk,
7 SCE plans to replace its current SAP with newer SAP technology to broaden its digital capabilities
8 across its business data and function.

9 In this proceeding, SCE intends to file a motion to establish a new memorandum
10 account, the NextGen ERP SAP Memorandum Account (NGESMA), with a January 1, 2024 effective
11 date, to record the revenue requirements associated with O&M expenses and capital expenditures for
12 activities related to the implementation phase of the NextGen ERP project as discussed in Exhibit SCE-
13 06, Vol. 02.⁶⁸ SCE proposes to address the reasonableness and recovery approach for the amounts
14 recorded in the NGESMA in its forthcoming 2024 NextGen ERP standalone application. Upon a finding
15 of reasonableness by the Commission, SCE proposes to transfer the balance in the NGESMA, including
16 accrued interest, to the distribution sub-account of the BRRBA to be recovered in customers'
17 distribution rates, or to a NextGen ERP-related balancing account and then to BRRBA, depending on
18 the cost recovery framework included in the standalone NextGen ERP application.

19 **c) Establishment of the Advanced Metering Infrastructure 2.0 Memorandum**
20 **Account (AMIMA)**

21 As discussed in Exhibit SCE-02, Vol. 03, by 2028 approximately 80 percent of
22 SCE's existing Advanced Metering Infrastructure (AMI) meters will have been installed in the field for
23 more than 15 years. As SCE's meter fleet has aged, SCE has been experiencing an increase in failures
24 year-over-year. This increasing failure rate impacts SCE's ability to provide its customers reliable,
25 timely, and accurate billing and results in higher manual billing costs, and increased costs for personnel
26 to troubleshoot and replace failed meters. The AMI 1.0-meter population is also experiencing
27 technology obsolescence. Given the increasing meter failures, the risk of meter obsolescence, and
28 inability to update the associated and necessary software, it is imperative that SCE begins the

⁶⁸ Given the anticipated project size, these costs may also include facility-related costs associated with modifying existing SCE workspaces to accommodate the collaboration efforts of the project teams.

1 replacement process for its meter fleet and associated infrastructure to provide customers adequate
2 billing services and avoid additional operational costs. Since SCE is planning to spend significant
3 resources on replacement of the existing AMI system, it is prudent for SCE to build in capabilities that
4 will be required during the life span of the new metering infrastructure. The next generation of AMI
5 must not only be able to provide the capabilities the current infrastructure supports and address the
6 known failure modes of the current assets and lessons learned from the previous deployment, but also
7 incorporate technology improvements that will help SCE and its customers realize the State's and the
8 Commission's goals of decarbonization, climate change resilience, and transition to a clean energy
9 economy. In this GRC, SCE is seeking review and recovery for the base-level planning capital
10 expenditures. For the base-level planning O&M, SCE intends to file a motion in this proceeding seeking
11 authority to establish a memorandum account for tracking these costs for future review and recovery
12 with an effective date of May 12, 2023, the filing date of this Application. SCE currently estimates that
13 it will incur \$4.432 million and \$0.585 million in O&M expenses in 2023 and 2024, respectively, for
14 pre-deployment base-level planning costs for the new AMI system.⁶⁹ Subsequently, SCE plans to file a
15 standalone application in the 2025 timeframe with a comprehensive business case and funding request
16 for a full AMI deployment.

17 Therefore, in this Application, SCE proposes to establish a new memorandum
18 account, the Advanced Metering Infrastructure 2.0 Memorandum Account (AMIMA), to record the
19 revenue requirements for the O&M expenses associated with the pre-deployment base-level planning
20 costs for the new AMI project. SCE proposes to seek recovery of the amounts recorded in the AMIMA
21 in the forthcoming 2025 standalone AMI 2.0 application and, upon a finding of reasonableness by the
22 Commission, SCE will transfer the balance in the AMIMA, including accrued interest, to the
23 distribution sub-account of the BRRBA to be recovered in customers' distribution rates (or to an AMI
24 2.0-related balancing account and then to BRRBA depending on the cost recovery framework included
25 in the standalone AMI 2.0 application).

⁶⁹ SCE anticipates spending approximately \$4.432 million of O&M for the Market Assessment Stage of the AMI 2.0 pre-deployment activities, which includes the costs for both in-house technical resources as well as internal vendor support. \$0.585 million of O&M is anticipated to be spent on Proof-of-Concept Stage work.

1 d) **Establishment of the Historic Sporting Events Cost Tracking Memorandum**
2 **Account (HSECTMA)**

3 SCE's costs and services will be impacted by the 2028 Summer Olympics,
4 occurring in July 2028, and the 2026 World Cup, taking place in June and July of 2026. Olympic events
5 will take place at multiple venues within Los Angeles County and the SCE service area. Specifics on
6 event and facility locations and times have not been finalized. Venue planning and energy needs are
7 being planned by a Los Angeles Department of Water & Power-led energy council to start in 2023-
8 2024. O&M impacts are expected in the 2027-2028 timeframe for inspection and repairs, business
9 resiliency and security, work crews (including overtime) and equipment. World Cup tournament
10 matches will occur at SoFi Stadium in Inglewood and other adjacent facilities within SCE's service area.
11 The anticipated (but yet unknown) order of magnitude is in the same range as the Super Bowl.

12 Given the lack of specifics for the energy needs for these sporting events and the
13 corresponding forecasting uncertainty, SCE proposes to establish the HSECTMA, effective January 1,
14 2025, to record the revenue requirements associated with the incremental O&M expenses and capital
15 expenditures that would not have been incurred "but for" serving the electrical requirements of these
16 upcoming historic sporting events. This will align with policymakers' efforts to bring these events to the
17 greater Los Angeles region and the expectation that all supporting institutions will be able to deliver
18 services necessary to support these events even if these services are beyond what is typically provided.
19 SCE will present the costs recorded in the HSECTMA for reasonableness review and recovery in SCE's
20 2029 GRC. Upon a finding of reasonableness by the Commission, SCE will transfer the amounts
21 recorded in the HSECTMA, plus accrued interest, to the distribution subaccount of the BRRBA for
22 recovery in customers' distribution rates.

23 e) **Establishment of the Cybersecurity Compliance Memorandum Account**
24 **(CCMA)**

25 SCE is closely monitoring a variety of emerging mandatory cybersecurity
26 standards that are at various stages of development and that would require additional investment to
27 comply with. The federal government has on many occasions highlighted the significant cyber and
28 physical security risks to critical infrastructure that utilities must be prepared to meet, and these
29 comments have more recently been accompanied by calls to expand regulation for utility cybersecurity.
30 For example, President Biden in March 2022 sent a letter to governors calling on public utilities
31 commissions to explore the introduction of distribution-level cybersecurity mandates. Similar calls have

1 been echoed by officials in various public appearances and the President's National Cybersecurity
2 Strategy from March 2023 highlighted the importance of cybersecurity for the distribution system and
3 distributed energy resources.⁷⁰ Meanwhile, other federal agencies have introduced rulemakings on other
4 cybersecurity mandates, such as increased reporting to the Cybersecurity and Infrastructure Security
5 Agency (CISA) and the Securities and Exchange Commission. The Department of Defense has also
6 notified the sector that we will likely be subject to its forthcoming Cybersecurity Maturity Model
7 Certification (CMMC). Various members of congress have also expressed their desire to expand
8 cybersecurity regulations, such as those for distribution cybersecurity and systemically important critical
9 infrastructure (SICI). In light of this potential -- but still undefined -- wave of regulation, SCE expects to
10 incur additional costs to comply with regulatory requirements. However, due to the uncertainty in the
11 magnitude, scope, and timing, SCE is unable to accurately forecast these costs for inclusion in its 2025
12 GRC request.⁷¹

13 Therefore, in this Application, SCE proposes to establish a new memorandum
14 account, the Cybersecurity Compliance Memorandum Account (CCMA), to record the revenue
15 requirements associated with the incremental O&M expenses and capital expenditures that are incurred
16 to adhere to new cybersecurity regulations and requirements. SCE intends to file a motion in this
17 proceeding seeking authority to establish this memorandum account for tracking these costs for future
18 review and recovery with an effective date of May 12, 2023, the filing date of this Application. SCE will
19 present the costs recorded in the CCMA for reasonableness review and recovery in either SCE's annual
20 ERRR Review proceeding or in a subsequent GRC. Upon a finding of reasonableness by the
21 Commission, SCE will transfer the amounts recorded in the CCMA, plus accrued interest, to the
22 distribution subaccount of the BRRBA for recovery in customers' distribution rates.

23 **f) Establishment of the Renewable Transmission Projects Memorandum**
24 **Account (RTPMA)**

25 As discussed in Exhibit SCE-02, Vol. 07, SCE finalized its GRC forecast for
26 Renewable Transmission Projects in March 2023. Subsequently, in April 2023, the CAISO issued a new
27 draft Transmission Planning Process (TPP) plan⁷² that, if adopted, would require SCE to spend

⁷⁰ See <https://www.whitehouse.gov/wp-content/uploads/2023/03/National-Cybersecurity-Strategy-2023.pdf>.

⁷¹ Amounts recorded in the CCMA would be incremental to the authorized amount for Cybersecurity costs requested in Exhibit SCE-04, Vol. 3 and ultimately approved by the Commission.

⁷² See <http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf>.

1 significantly more on Renewable Transmission Projects during the 2025 GRC cycle than previously
2 anticipated. Specifically, this plan would require SCE to sponsor multiple large Renewable
3 Transmission Projects not previously contemplated, with total spend on these required projects during
4 the 2025 GRC cycle estimated at around \$2 billion (total company). In addition, the draft plan also
5 includes three competitive projects within or adjacent to SCE's service area. SCE expects a final TPP
6 plan to be adopted by the CAISO in May 2023. Because of the potential for significant cost increases
7 during the 2025 GRC cycle that are both outside of SCE's control and unable to be reflected in SCE's
8 forecast due to timing reasons, SCE proposes to establish the Renewable Transmission Projects
9 Memorandum Account (RTPMA), effective January 1, 2025. The RTPMA will track the CPUC-
10 jurisdictional capital-related revenue requirement and capital-related expense associated with costs spent
11 on Renewable Transmission Projects that are incremental to the amounts authorized in the 2025 GRC
12 based on SCE's March 2023 forecast. SCE will submit these costs to the Commission for reasonableness
13 review and recovery in either SCE's ERRR Review application or in a subsequent GRC application
14 depending on the timing of when the projects are completed to minimize the amount of interest expense
15 that accrues on the recorded amounts. Upon a finding of reasonableness, SCE will transfer the approved
16 amounts, plus accrued interest, from the RTPMA to the distribution subaccount of the BRRBA to be
17 recovered in customers' distribution rates.

18 **3. Elimination of Balancing and Memorandum Accounts**

19 **a) Underground Structures Replacement Balancing Account (USRBA)**

20 In the 2021 GRC Decision, the Commission ordered the establishment of the
21 Underground Structures Replacement Balancing Account (USRBA), effective January 1, 2021.
22 In Advice 4586-E, SCE established Preliminary Statement Part DDDD, USRBA, which is a two-way
23 balancing account for recording the difference between: (1) recorded capital revenue requirements for
24 actual capital expenditures associated with SCE's Underground Structures Replacement Program
25 (USRP), and (2) the USRBA revenue requirement authorized in the 2021 GRC Decision. The USRP is a
26 program to replace certain high risk underground structures.⁷³ SCE annually transfers any over- or

⁷³ Specifically, the USRP includes underground structure replacements that are classified as Grade F (at risk of failing with expected remaining life of 1-5 years) with either Code E (emergency, recommend replacing as soon as possible) or Code 1 (recommend replacing within the next three years) and rated very high or high in terms of population proximity, population density, traffic rate, and falling debris hazard; or underground structures that are classified as Grade D (poor, with a remaining life of 5-15 years) but with a Code 2

(Continued)

under-collection in the USRBA to the distribution sub-account of the BRRBA as of December 31 to be returned to or recovered from customers. The recorded operation of the USRBA is reviewed by the Commission in SCE's annual ERRA Review proceeding.

SCE proposes to close the USRBA once the December 31, 2024 balance is transferred to the distribution subaccount of the BRRBA because SCE expects to complete the work needed to upgrade the Grade F and D structures identified for balancing account treatment in the 2021 GRC cycle, prior to 2025 – as more fully discussed in Exhibit SCE-02, Vol. 01. Any ongoing capital-related revenue requirement associated with the work completed in the 2021 GRC cycle (including in 2024) and any additional underground structure replacement work is included in SCE's 2025 ADBRR and will not be subject to two-way balancing account treatment in the 2025 GRC cycle. SCE will seek to eliminate the USRBA in its 2024 ERRA Review application, which is submitted on April 1, 2025, after the final year of the USRBA (2024) is reviewed by the Commission.

b) Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA)

In the 2015 GRC Decision,⁷⁴ the Commission authorized a Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA) effective January 1, 2015. In Advice 3314-E/E-A/E-B, SCE established Preliminary Statement Part J, PLDPBA, which is a two-way balancing account to record the difference between: (1) recorded capital-related revenue requirements for the Pole Loading Program and the Deteriorated Pole Program, (2) O&M expenses for the Pole Loading Program, and (3) the authorized Pole Programs revenue requirement as adopted in the 2015 GRC Decision. The level of expenditures to be recovered in the PLDPBA in 2016 and 2017 was capped at 15 percent above the authorized levels. There was no cap on 2015 expenditures. SCE annually transfers any over- or under-collection in the PLDPBA to the distribution sub-account of the BRRBA as of December 31 to be returned to or recovered from customers. The recorded operation of the PLDPBA is reviewed by the Commission in SCE's annual ERRA Review proceedings.

In the 2018 GRC Decision, the Commission found that no changes in the structure of the PLDPBA were warranted. Therefore, the level of expenditures to be recovered in the PLDPBA over the 2018 GRC period was capped at 15 percent above the authorized levels. In the 2021 GRC Decision, SCE proposed to maintain the two-way PLDPBA consistent with the 2018 GRC Decision.

(recommend installing shoring within the next 3 years) and rated very high or high in terms of population proximity, population density, traffic rate, and falling debris hazard.

⁷⁴ D.15-11-021.

1 In the 2025 GRC, SCE proposes to close the PLDPBA effective January 1, 2025
2 as the pole loading assessment programs are concluding prior to 2025 and the work is transitioning back
3 to a forecastable compliance program, as more fully described in Exhibit SCE-02, Vol. 09. Therefore,
4 there is no longer a need for two-way balancing account treatment in the 2025 GRC cycle. SCE will
5 seek to eliminate the PLDPBA in its 2024 Erra Review application, which is submitted on April 1,
6 2025, after the final year of the PLDPBA (2024) is reviewed by the Commission.

7 **c) Customer Service Re-Platform Memorandum Account (CSRPMA)**

8 In the 2018 GRC Decision, the Commission authorized the establishment of a
9 Customer Service Re-Platform Memorandum account (CSRPMA) to record the revenue requirements
10 associated with capital expenditures from project inception to project close⁷⁵ and O&M expenses and
11 benefits from the beginning of the 2018 Test Year until these expenses begin to be recovered in rates.
12 The 2018 GRC Decision also stated that SCE is to continue to use the CSRPMA until such time as
13 recovery of the approved Customer Service Re-Platform revenue requirement is included in a GRC
14 revenue requirement.

15 On July 22, 2021, SCE filed A.21-07-009 to begin recovery of the costs recorded
16 in the CSRPMA. The proceeding was segmented into two tracks: in Track 1, the Commission
17 considered recovery of CSRP costs recorded through April 2021; and in Track 2, the Commission
18 considered recovery of costs incurred from May 2021 through December 2021. As discussed in Exhibit
19 SCE-03, Vol. 01, in its decision in Track 1, D.22-09-015, the Commission authorized SCE to recover an
20 initial revenue requirement of \$12.851 million associated with Track 1 costs incurred through April
21 2021 and approximately \$375.479 million for the on-going Track 1 capital-related revenue requirement
22 through 2024 (after which time the ongoing capital-related revenue requirement associated with
23 approved Track 1 capital expenditures is included in the 2025 ADBRR). On March 16, 2023, the
24 Commission adopted D.23-03-019 (Track 2 Decision) in Track 2, authorizing SCE to recover
25 approximately \$65 million, which is comprised of the recorded balance in the CSRPMA of \$20.8
26 million for the revenue requirement through December 31, 2021, and recovery, on an annual basis, of a
27 total forecast capital-related revenue requirement of \$44.3 million for January 2022 through December

⁷⁵ On December 2, 2021, SCE submitted Advice 4656-E to modify the CSRPMA to allow SCE to record the revenue requirement associated with the capital expenditures related to deferred CSRP scope and necessary upgrades to the new systems until the on-going revenue requirement can be included in SCE's next GRC. Advice 4656-E was approved by the Commission's Energy Division on December 30, 2021 with a December 2, 2021 effective date.

2024 (after which time the ongoing capital-related revenue requirement associated with approved Track 2 capital expenditures is included in the 2025 ADBRR). The Track 2 Decision also authorized SCE to seek review and recovery of the post-Track 2 2022 through 2024 CSRP costs and reimbursable benefits in this Application.⁷⁶

In Exhibit SCE-03, Vol. 01, SCE sets forth an estimate of the remaining capital expenditures and O&M costs and reimbursable benefits that have been or are expected to be incurred or realized from January 2022 through December 2024. As described in Chapter V.B.5 below, SCE sets forth the estimated revenue requirement associated with this spend for recovery in this proceeding.

Because SCE is including all 2025 and forward costs in its forecast ADBRR, SCE proposes to close and eliminate the CSRPMA once the final amounts recorded in the CSRPMA have been transferred to the distribution subaccount of the BRRBA for recovery in customers' rates.⁷⁷ Beginning with the 2025 GRC cycle, the ongoing revenue requirement associated with all approved CSRP spend will be included in the ADBRR.

d) Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA)

In the 2021 GRC Decision,⁷⁸ the Commission authorized the establishment of the Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA), effective January 1, 2021. In Advice 4586-E, SCE established Preliminary Statement Part N.37, SRNEFMA, which records incremental capital-related revenue requirements above those authorized in Track 1 of SCE's 2021 GRC associated with seismic retrofits of SCE's non-electric facilities for future cost recovery in SCE's next GRC. In Chapter V.B.5 below, SCE seeks recovery of the incremental capital-related revenue requirements recorded in the SRNEFMA over the 2021 GRC cycle, which are discussed more fully in Exhibit SCE-06, Vol. 07. Any ongoing capital-related revenue requirement associated with the work completed in the 2021 GRC cycle (including 2024) and all additional amounts for SCE's seismic work on non-electric facilities is included in SCE's 2025 ADBRR.

⁷⁶ See D.23-03-019, OP 2.

⁷⁷ The final transfer of the Track 1 and Track 2-related revenue requirements from the CSRPMA to BRRBA-D will occur on December 31, 2024. The revenue requirements associated with the 2022 through 2024 spend will record in the CSRPMA through December 31, 2024 and then transfer to BRRBA-D upon the issuance of a final decision in this proceeding.

⁷⁸ D.21-08-036.

1 Therefore, SCE proposes to eliminate the SRNEFMA once the December 31,
2 2024 balance is transferred to the distribution subaccount of the BRRBA because the rationale for
3 utilizing the memorandum account (i.e., that SCE lacks historical experience for these types of seismic
4 projects and therefore is not authorized full forecast funding) no longer applies in the 2025 GRC cycle.
5 As discussed in Exhibit SCE-06, Vol. 07, SCE has completed all assessments for its remaining seismic
6 work for non-electric facilities through 2028, which allows SCE to forecast the amount of funding
7 needed to complete this work. Both our customers and SCE benefit from recovering these ongoing
8 2025-2028 costs on a forecast basis to avoid the accumulation of four years of interest expense in a
9 memorandum account.

10 e) **NEM Online Application System Memorandum Account (NEMOASMA)**

11 On November 6, 2014, the Commission issued D.14-11-001 (Decision to Transfer
12 Responsibility for Collecting Solar Statistics From the California Solar Initiative To The Net Energy
13 Metering Interconnection Process) in Rulemaking 12-11-005, which ordered SCE to update the
14 customer Net Energy Metering (NEM) interconnection application to include additional data fields and
15 transfer the collected data to the California Solar Statistics contractor on a regular basis for processing
16 and posting to the California Solar Statistics website. OP 4 of D.14-11-001 provides: “Costs incurred by
17 Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San
18 Diego Gas and Electric Company (SDG&E) in developing an online Net Energy Metering
19 interconnection application portal may be tracked through a memorandum account. PG&E, SCE, and
20 SDG&E may seek recovery through their respective general rate cases.” In response, on January 12,
21 2015, SCE submitted Advice 3162-E to establish Preliminary Statement Part N.6, the NEM Online
22 Application System Memorandum Account (NEMOASMA), to track the costs SCE incurs to establish
23 an online application system for processing applications for interconnection under SCE’s NEM tariffs.

24 In D.16-01-044 (“Decision Adopting Successor To Net Energy Metering Tariff”),
25 issued February 16, 2015, the Commission implemented the new NEM 2.0 (or NEM-ST). On February
26 29, 2016, SCE submitted Advice 3371-E (“Implementation of Southern California Edison Company’s
27 Net Energy Metering Successor Tariffs in Accordance with Decision 16-01-044”). In that advice letter,
28 SCE made updates to the NEMOASMA to record costs associated with the implementation of the new
29 NEM tariff.

30 SCE has now completed the implementation of its NEM Online Application
31 System and will no longer need to record incremental costs in the NEMOASMA as of January 1, 2025.

1 Therefore, SCE proposes to close the NEMOASMA effective January 1, 2025 and eliminate the
2 NEMOASMA in the advice letter implementing a final decision in this proceeding. Additionally, in this
3 GRC, SCE is seeking recovery of the balances in the NEMOASMA as of December 31, 2024 as
4 discussed in Chapter V.B.5 below.

5 **4. Modification (But Not Continuation) of Memorandum Accounts**

6 **a) Modification of the Electric Vehicle Infrastructure Memorandum Account**
7 **(EVIMA)**

8 Pursuant to Assembly Bill (AB) 841 (Stats. 2020, Ch 3.72), in 2022, SCE
9 established the EVIMA to track the SCE-incurred costs of all electrical distribution infrastructure on the
10 utility side of the customer's meter for all customers installing separately metered infrastructure to
11 support charging stations, other than those in single-family residences.⁷⁹ The EVIMA applies to costs
12 incurred by SCE related to electric vehicle infrastructure installed under the provisions of SCE's Electric
13 Rule 29 between January 1, 2021 and the implementation date of SCE's next GRC (i.e., January 1,
14 2025). Costs that are eligible for recovery as part of the ratemaking approved in SCE's current
15 Transportation Electrification Programs, such as Charge Ready Transport and Charge Ready 2
16 Programs, do not apply to this account.

17 The disposition section of SCE's EVIMA tariff provides that the costs tracked in
18 the EVIMA shall be separately reviewed for reasonableness in SCE's next GRC (i.e., its 2025 GRC) or
19 any other proceeding deemed appropriate by the Commission.⁸⁰ However, as of December 31, 2022,
20 SCE had not yet recorded any costs in the EVIMA. Therefore, there are no recorded amounts to review
21 for reasonableness; however, as discussed in Exhibit SCE-02, Vol. 08, SCE does expect to record costs
22 in the EVIMA in 2023 and 2024. Beginning January 1, 2025, costs that currently would record to the
23 EVIMA will be included in SCE's ADBRR. Therefore, given this timing issue, SCE requests that the
24 final decision in this proceeding authorize SCE to modify its EVIMA tariff to allow SCE to submit the
25 2023 and 2024 costs recorded in the EVIMA for reasonableness review and recovery via a Tier 3 advice
26 letter. This proposal will limit the amount of interest expense that will accumulate in the EVIMA that is
27 ultimately recovered from customers by facilitating more timely recovery of these costs as opposed to

⁷⁹ See Advice 4429-E and Resolution E-5167.

⁸⁰ See Section c of SCE's Preliminary Statement Part N.50.

having to wait to submit these costs for reasonableness review and recovery in SCE's 2029 GRC – a full six years after they will have started to be incurred.

5. Recovery of Memorandum Account Balances

The purpose of this section is to support SCE's requested recovery of the December 31, 2024 balances recorded in the memorandum accounts summarized in Table V-13. As further discussed below, SCE's tariffed Preliminary Statements either direct or permit SCE to seek recovery of the balances in these accounts in SCE's GRC. To facilitate SCE's request, SCE is providing recorded amounts for each of these accounts through December 31, 2022 and an estimate of the costs and resulting revenue requirement that SCE expects to record in these accounts through December 31, 2024. SCE will include updated recorded balances in its Update Testimony. Ultimately, SCE proposes to recover the actual December 31, 2024 balances recorded in these accounts, as further described in each section below.

Table V-13
Recovery of Memorandum Accounts Summary⁸¹
(Nominal \$000)

Line No.	Item Description	RECOVERY REQUEST (\$000)											Total Rec Req
		SRNEFMA	CSRPM	SCMPMA	DDACMA	ECPMA	RDICMA	NEMOASMA	CCPMA	ACCMA	CCAAMA	WMPMA	
1	Beginning Balance as of 1/1/22		(21)	10,690	84	16	1,645	1,192	3,239	322		8,432	25,598
2	O&M Expense		23,922	0	106	1	2,069		376	132			26,606
3	Capital Related												
4	Depreciation		1,180	1,336								545	3,062
5	Income Taxes		(573)	947								151	525
6	Property Taxes		-	558								145	703
7	Return		660	3,963								800	5,423
8	Total Capital Related	-	1,268	6,804	-	-	-	-	-	-	-	1,641	9,713
9	Total Capital Related Expense		1,268	6,804	-	-	-	-	-	-		1,641	9,713
10	Subtotal	-	25,189	6,804	106	1	2,069	-	376	132	-	1,641	36,318
11	Adjustments		(7,069)										(7,069)
12	Interest		270	267	2	0	58	20	60	7		138	824
13	Recorded Balance 12/31/2022	-	18,369	17,761	192	18	3,771	1,213	3,675	462	-	10,212	55,671
14	Estimated Balance 12/31/2024	3,401	35,238	24,281	762	72	7,554	1,253	4,838	732	488	16,951	95,570

a) Seismic Retrofit for Non-Electric Facilities Memorandum Account (SRNEFMA)

In the 2021 GRC, SCE proposed a capital expenditure forecast for its Seismic Assessment and Mitigation program. The program included (1) assessment of SCE's electric

⁸¹ Refer to WP SCE-07, Vol. 01, Book A, p. 86, Recovery of Memorandum Accounts.

1 infrastructure, non-electric facilities, generation infrastructure and telecommunications/IT infrastructure
2 to identify what seismic mitigations are needed, and (2) implementation of the necessary retrofits and
3 improvements. In the 2021 GRC Decision,⁸² the Commission found that SCE had not sufficiently
4 justified including certain larger office buildings in the cost-per-square-foot calculation for its non-
5 electric facilities in the program. The Commission removed an \$11 million large office building from
6 the calculation and authorized a memorandum account to track seismic retrofit costs for SCE's non-
7 electric facilities because SCE lacked historic expenditure data for projects of that size. The Commission
8 authorized SCE to seek recovery of any costs above the 2021 GRC authorized amounts in the 2025
9 GRC.

10 Pursuant to OP 26 of the 2021 GRC Decision, SCE submitted Advice 4586-E to
11 establish Preliminary Statement Part N.37, the Seismic Retrofit for Non-Electric Facilities Memorandum
12 Account (SRNEFMA). SCE tracks the incremental capital-related revenue requirements above those
13 authorized in Track 1 of SCE's 2021 GRC associated with seismic retrofits of SCE's non-electric
14 facilities for future cost recovery. For comparison purposes, SCE includes the authorized capital-related
15 revenue requirements associated with the seismic retrofit for non-electric facilities capital expenditure
16 funding levels adopted in the 2021 GRC Decision.⁸³

17 The purpose of SCE's Seismic Resiliency Program is to ensure business
18 continuity in the case of a catastrophic, severe, or moderate earthquake. The costs recorded in the
19 SRNEFMA provide for seismic mitigations/retrofits to strengthen office buildings and other critical
20 facilities. As background, SCE retains experienced and qualified contractors to assess its existing
21 building portfolio relative to Federal Emergency Management Agency (FEMA) and American Society
22 of Civil Engineers (ASCE) standards, both for structural and non-structural seismic risk reduction, and
23 to perform mitigations and monitor expenditures. Assessments include gathering and synthesizing
24 seismic hazard data, running analysis of the hazards against SCE's infrastructure to evaluate potential
25 damage to assets and the range of consequences if such events were to occur, and determining
26 engineering improvements to mitigate the possible damage. These assessments on SCE's infrastructure

⁸² D.21-08-036, pp. 332-333.

⁸³ SCE was authorized the following amounts in the 2021 GRC Decision for the Seismic Retrofit for Non-Electric Facilities in 2021, 2022 and 2023, respectively: \$2.211 million, \$3.027 million, and \$3.712 million (the 2023 amount includes the Cost of Capital adjustment adopted in D.22-12-031). In Track 4, SCE's proposed authorized amount is \$4.493 million.

1 and facilities help inform the seismic exposure and impacts of seismic events and the functionality and
2 stability of the infrastructure in the event of a significant earthquake. Once assessments are completed,
3 SCE prioritizes projects based on risk ranking, occupancy, and the criticality of the asset. Projects with
4 the greatest safety and reliability impact are given the highest priority, using the tranche approach
5 described in SCE's 2022 RAMP.⁸⁴ Projects are planned and executed to minimize service interruptions.
6 Mitigation work varies based upon the type and condition of the non-electric facility. In many cases, the
7 seismic retrofit work entails strengthening of the walls themselves, and of the attachment of the walls to
8 the roof.

9 To-date in this GRC cycle, SCE has performed work to support nine seismic
10 retrofit projects,⁸⁵ two of which were completed in 2022 (Dominguez Hills Building D garage and the
11 San Joaquin Valley Service Center).⁸⁶ The seven additional projects are still underway, with 11 detailed
12 facility assessments now in progress. As more fully discussed in Exhibit SCE-04, Vol. 01, at year-end
13 2022, there was approximately \$36.7 million of capital expenditures in Construction Work-In-Progress
14 (CWIP) status and SCE estimates that it will incur additional capital expenditures totaling \$51.696
15 million in 2023 and 2024 to complete this work, with the incremental capital-related revenue
16 requirements associated with these capital expenditures recording to the SRNEFMA. SCE estimates that
17 the incremental capital-related revenue requirements associated with these incremental capital
18 expenditures in 2023 and 2024 will be approximately \$3.401 million,⁸⁷ which would result in a
19 December 31, 2024 SRNEFMA balance of the same amount. SCE will provide the most recent
20 SRNEFMA recorded activity in the Update Phase of this GRC proceeding, with a final recorded
21 December 31, 2024 balance provided in the advice letter implementing the 2025 GRC decision.

22 Therefore, upon the issuance of a final decision in this proceeding, SCE proposes
23 to transfer the December 31, 2024 recorded balance in the SRNEFMA, including accrued interest, to the

⁸⁴ A.22-05-013, Chapter 8.

⁸⁵ One example of an ongoing seismic retrofitting project involves welding and damper installations at SCE's General Office complex in Rosemead, California.

⁸⁶ However, as of the end of 2022, SCE had not recorded any incremental amounts in the SRNEFMA because the recorded capital-related revenue requirements had not yet exceeded the authorized capital-related revenue requirements already included GRC base rates.

⁸⁷ This estimate only includes the capital-related revenue requirements that exceed the amounts already authorized for recovery in GRC base rates.

1 distribution subaccount of the BRRBA to be recovered in customers' distribution rates and close the
2 SRNEFMA.⁸⁸

3 **b) Customer Service Re-Platform Memorandum Account (CRPMA)**

4 On March 16, 2023, the Commission adopted D.23-03-019, which, in pertinent
5 part, authorized SCE to seek review and recovery of the 2022 through 2024 CRP-related costs and
6 reimbursable benefits in this Application.⁸⁹ In 2022 through 2024, SCE incurred or expects to incur
7 costs to continue post-stabilization of the CRP platform, such as addressing system performance issues
8 and providing additional training and support. A more detailed discussion of the 2022 through 2024
9 spend, and any associated benefits, is included in Exhibit SCE-03, Vol. 01. Table V-14 summarizes the
10 entries recorded in the CRPMA as of December 31, 2022 that are associated with this CRP-related
11 spend that occurred beginning in January 2022.

⁸⁸ The recorded operation of the BRRBA, which would include the SRNEFMA transfer, would then be reviewed in SCE's 2024 ERRR Review proceeding (SCE files this application on April 1, 2025).

⁸⁹ See D.23-03-019, OP 2.

Table V-14
Customer Service Re-Platform Memorandum Account⁹⁰
(CSRPMA)

Line No.	Description	(\$000)
1	Beginning Balance	-
2	Capital Revenue Requirement	(21)
3	Adjusted Beginning Balance (Line 1 : Line 2)	(21)
	Operation and Maintenance	
4	Labor	7,230
5	Non-Labor	15,655
6	Indirect Labor Costs	1,036
7	Total Operations and Maintenance (Line 4 : Line 6)	23,922
	Capital-Related Revenue Requirement	
8	Depreciation	1,180
9	Income Taxes	(573)
10	Property Taxes	-
11	Rate of Return	660
12	Total Capital-Related Revenue Requirement (Line 8 : Line 11)	1,268
13	Benefits	(7,069)
14	(Over)/Under Collection (Line 7 + Line 12 + Line 13)	18,120
15	Interest	270
16	Ending Balance (Line 3 + Line 14 + Line 15)	18,369

In 2022, SCE incurred \$23.92 million in incremental O&M expenses⁹¹ and \$11.9 million in incremental direct capital expenditures. In 2023 and 2024, SCE estimates that it will incur \$14.4 million in incremental O&M expenses and \$17.5 million in incremental direct capital expenditures. Together, SCE estimates this will result in a December 31, 2024 recorded balance in the

⁹⁰ Refer to WP SCE-07, Vol. 01, Book A, p. 87, Customer Service Re-Platform Memorandum Account.

⁹¹ In 2022, SCE inadvertently recorded \$0.200 million in the CSRPMA that should have been recorded to the RDICMA. The corrective entry was recorded in 2023.

1 CSRPMA of \$35.238 million.⁹² Support for this incremental revenue requirement is included in Exhibit
2 SCE-03, Vol. 01. SCE will provide the most recent CSRPMA recorded activity for the 2022 through
3 2024 spend in the Update Phase of this GRC proceeding, with a final recorded December 31, 2024
4 balance provided in the advice letter implementing the 2025 GRC decision.

5 Therefore, upon the issuance of a final decision in this proceeding, SCE proposes
6 to transfer the December 31, 2024 recorded balance in the CSRPMA associated with the 2022 through
7 2024 spend, including interest, to the distribution subaccount of the BRRBA to be recovered in
8 customers' distribution rates.⁹³ SCE proposes to then eliminate this account, as discussed in Chapter
9 V.B.3(c) above.

10 c) **Service Center Modernization Projects Memorandum Account (SCMPMA)**

11 In the 2018 GRC, SCE requested approval of Service Center Modernization
12 Projects to properly support current work processes and equipment. Service centers function as the
13 operational base for crews in steady-state, storm, and emergency conditions and include general
14 administrative offices, logistics buildings, materials storage areas and structures, vehicle maintenance
15 facilities, and interior and outside training areas. Pursuant to the 2018 GRC Decision, SCE was
16 authorized to record costs associated with six projects⁹⁴ in a memorandum account. On August 27, 2019,
17 SCE submitted Advice 4012-E-A modifying the SCMPMA consistent with the 2018 GRC Decision.

18 In the 2021 GRC, SCE requested authorization of capital expenditures for
19 Enterprise Operations for Facility, Land Operations, and Transportation Services over the 2021 GRC
20 period. Within the requested amount were the following infrastructure upgrade and IT
21 infrastructure/equipment projects: Blythe Service Center, Santa Barbara Service Center, T&D Training
22 Center, Camp Edison Buildings, Vehicle Maintenance Facilities, General Office 1 (GO1) and 4 (GO4)
23 Workplace Upgrades, GO1 Electrical Upgrades, Fleet Charging Program, Employee Charging
24 Infrastructure Program, Materials Supply Warehouse, Covina Customer Service Automated System
25 Building Remodel, and CSRP training rooms. In the 2021 GRC Decision, the Commission authorized

⁹² The estimated revenue requirement is calculated by adding the O&M amounts (\$14.400 million) to the capital-related revenue requirement (\$2.669 million). The capital-related revenue requirement is calculated by using the Revenue Requirement Multiplier of 15.25 percent as specified in Preliminary Statement Part LL.

⁹³ The recorded operation of the BRRBA, which would include the CSRPMA transfer, would then be reviewed in SCE's 2024 ERRRA Review proceeding.

⁹⁴ Projects approved for recording in the SCMPMA include Bishop, Kernville, Redlands, Ridgecrest, San Joaquin, and Santa Ana, including the IT infrastructure and equipment.

1 funding for all the projects with the exception of the Santa Barbara Service Center.⁹⁵ The Commission
2 confirmed SCE had demonstrated a need for the Santa Barbara Service Center, which consists of
3 relocating the existing Santa Barbara service center from its present location to a new location south of
4 the city, but denied funding for the project because a final site for the service center had not yet been
5 secured.⁹⁶ On October 4, 2021, SCE submitted Advice 4586-E to modify the SCMPMA to include the
6 Santa Barbara Service Center project to allow the tracking of costs related to the new service center once
7 a site has been secured.

8 Table V-15 summarizes the completed project entries recorded in the SCMPMA
9 as of December 31, 2022.⁹⁷

⁹⁵ D.21-08-036, COL 209.

⁹⁶ D.21-08-036, FOF 572.

⁹⁷ Costs associated with the Redlands and Santa Barbara service center projects are not included because SCE is not seeking recovery of those recorded costs in this Application due to SCE's assumption that those projects will not be completed during the 2021 GRC cycle.

Table V-15
Service Center Modernization Projects Memorandum Account⁹⁸
(SCMPMA)

Line No.	Description	(\$000)
1	Beginning Balance	10,690
2	Rounding Adjustment	(0)
3	Adjusted Beginning Balance (Line 1 : Line 2)	10,690
Operations and Maintenance		
4	Labor	0
5	Non-Labor	0
6	Total Operation and Maintenance (Line 4 + Line 5)	0
Capital-Related Revenue Requirement		
7	Depreciation	1,336
8	Income Taxes	947
9	Property Taxes	558
10	Rate of Return	3,963
11	Total Capital-Related Revenue Requirement (Line 7 : Line 10)	6,804
12	(Over)/Under Collection (Line 6 + Line 11)	6,804
13	Interest	267
14	Ending Balance (Line 3 + Line 12 + Line 13)	17,761

The ending balance recorded in the SCMPMA as of December 31, 2022 is a debit of \$17.761 million, as shown on Line 14 of Table V-15. These recorded costs reflect completed projects for SCE's Bishop, Kernville, Ridgecrest, Santa Ana, and San Joaquin service centers. As discussed in Exhibit SCE-06, Vol. 07, SCE constructed, upgraded, or remodeled administrative buildings, logistics building and vehicle maintenance facilities to support office space, support assembly and staging of T&D materials as well as maintenance and services needed for T&D vehicles. In addition, SCE has completed site plans and secured sites that will allow safe vehicular access, circulation, and parking for

⁹⁸ Refer to WP SCE-07, Vol. 01, Book A, pp. 88-89, Service Center Modernization Projects Memorandum Account.

1 crew vehicles, employees, as well as customers. In 2023, SCE estimates that it will incur \$42.73 million
2 in capital expenditures that results in an estimated capital-related revenue requirement of \$6.52 million
3 to complete these projects,⁹⁹ resulting in a December 31, 2024 SCMPMA balance of \$24.281 million.
4 SCE will provide the most recent SCMPMA recorded activity in the Update Phase of this GRC
5 proceeding, with a final recorded December 31, 2024 balance provided in the advice letter implementing
6 the 2025 GRC decision.

7 Therefore, effective upon a final decision in this proceeding, SCE proposes to
8 transfer the December 31, 2024 recorded balance in the SCMPMA to the distribution subaccount of the
9 BRRBA to be recovered from all customers via distribution rates.¹⁰⁰

10 **d) Distribution Deferral Administrative Costs Memorandum Accounts**

11 The Distribution Deferral Administrative Costs Memorandum Account
12 (DDACMA) records the incremental solicitation-related administrative costs associated with the Utility
13 Regulatory Incentive Pilot program as adopted in D.16-12-036 and the Distribution Resources Plan
14 (DRP) Distribution Investment Deferral Framework (DIDF) adopted in D.18-02-004. As outlined in the
15 Disposition and Review Procedures section of SCE's Preliminary Statement Part N.32, the recorded
16 solicitation-related administrative costs in the DDACMA are considered pre-approved for recovery
17 through the Tier 3 advice letters requesting Commission approval of the estimated administrative costs.
18 These costs are pre-approved for recording and recovery and will be reviewed by the Commission in
19 SCE's GRC. Administrative costs exceeding the estimate approved in the Tier 3 advice letters are
20 subject to a reasonableness review.

21 On May 23, 2019, SCE submitted Advice 4003-E to make modifications to three
22 existing IDER Incentive Pilot ratemaking accounts and to repurpose those accounts to Distribution
23 Deferral balancing accounts. Through the advice letter, the IDER Administrative Costs Memorandum
24 Account (IDERACMA) was repurposed as the DDACMA with the intended use of tracking and
25 recovering incremental administrative costs associated with DIDF RFO-related procurement activities.

26 On February 11, 2021, the Commission issued D.21-02-006 that adopted pilot
27 programs to test varying frameworks for procuring distributed energy resources that would either avoid

⁹⁹ SCE used the Revenue Requirement Multiplier of 15.25 percent as specified in Preliminary Statement Part LL to estimate the capital-related revenue requirement for 2023 and 2024.

¹⁰⁰ The recorded operation of the BRRBA, which would include the SCMPMA transfer, would then be reviewed in SCE's 2024 EERRA Review proceeding.

or defer utility capital investments. Pursuant to OPs 8 and 9 of D.21-02-006 (as corrected in D.21-05-037), SCE was directed to develop a page on its company website that describes the partnership pilot, advertises the launch of the pilot subscription and notices availability of procurement tranches within 30 days of the tranche opening, identifies monthly updated procurement goals for each deferral opportunity, and provides notice that aggregators will be looking for customers to enroll in the pilot. Once aggregators have passed prescreening, SCE must include prescreened aggregator contact information on the website no later than September 15 so that customers can contract the aggregator directly to enroll. SCE was authorized to track the costs associated with this work in the DDACMA and seek recovery in the GRC.

Table V-16 summarizes the entries recorded in the DDACMA as of December 31, 2022.

Table V-16
Distribution Deferral Administrative Costs Memorandum Account¹⁰¹
(DDACMA)

Line No.	Description	(\$000)
1	Beginning Balance	84
	Expenses	
2	IDER Admin Expenses	42
3	DIDF Admin Expenses	64
4	Total Expenses (Line 2 : Line 3)	106
5	(Over)/Under Collection (Line 4)	106
6	Interest	2
7	Ending Balance (Line 1 + Line 5 + Line 6)	192

¹⁰¹ Refer to WP SCE-07, Vol. 01, Book A, p. 90 Distribution Deferral Administrative Costs Memorandum Account.

1 The ending balance recorded in the DDACMA as of December 31, 2022 is a debit
2 of \$0.192 million, as shown on Line 7 in Table V-16.¹⁰² The recorded IDER Admin Expenses shown on
3 Line 2 of Table V-16 resulted from the use of Merrimack Energy consulting, who serves as an
4 independent evaluator to ensure fair and equitable administration of the solicitation process to avoid
5 discrimination, bias, or favoritism in the identification of winning bids for the Standard Offer Contract
6 (SOC) and DIDF RFO for 2021 and 2022.¹⁰³ The recorded DIDF Admin expenses shown on Line 3 of
7 Table V-16 include costs related to the development and maintenance of the public-facing solicitation
8 website. In 2023, SCE corrected an accounting error that inadvertently recorded \$0.021 million in the
9 DDACMA that should have recorded to SCE's Distribution Resources Plan Memorandum Account
10 (DRPMA); therefore, SCE is reducing its DDACMA-related cost recovery request by \$0.021 million.

11 SCE currently estimates that the balance in the DDACMA as of December 31,
12 2024 will be a debit of \$0.762 million. This is due to an expected increase in administrative costs related
13 to the DIDF program, an increase in Merrimack Energy consulting costs, and additional Pacific
14 Consulting Group vendor and survey costs for work that is scheduled to start in 2023. SCE will provide
15 the most recent DDACMA recorded activity in the Update Phase of this GRC proceeding, with a final
16 recorded December 31, 2024 balance provided in the advice letter implementing the 2025 GRC
17 decision. Therefore, effective upon a final decision in this proceeding, SCE proposes to transfer the
18 December 31, 2024 recorded balance in the DDACMA, including accrued interest, to the distribution
19 subaccount of the BRRBA to be recovered in customers' distribution rates.¹⁰⁴

20 **e) Emergency Customer Protections Memorandum Account (ECPMA)**

21 In late September and early October 2017, major wildfires broke out across
22 California impacting the lives of many residents and disrupting multiple utility services. On November
23 9, 2017, in response to the Governor's state of emergency proclamations, the Commission, on its own

¹⁰² The Beginning Balance shown on Line 1 is the recorded balance as of year-end 2021. In 2021, SCE recorded \$0.058 million of IDER-related administrative expenses in the IDER sub-account and \$0.025 million of DIDF-related administrative expenses in the DIDF sub-account.

¹⁰³ On November 16, 2020, SCE submitted Advice 4342-E to seek approval from the Commission to launch a DIDF RFO to procure distributed energy resources (DERs) that can defer specific traditional distribution projects, which was approved on December 16, 2020. However, on July 17, 2021, SCE submitted Advice 4523-E to conclude the 2020-2021 DIDF RFO without selecting any offers from DER providers due to offers not being able to meet the needs of the area or being cost effective.

¹⁰⁴ The recorded operation of the BRRBA, which would include the DDACMA transfer, would then be reviewed in SCE's 2024 ERRR Review proceeding.

1 motion, adopted Resolutions M-4833 and M-4835 to implement emergency consumer protections for
2 one year to assist residential and non-residential customers affected by the California wildfires.
3 Resolutions M-4833 and M-4835 offered the following consumer protections for electric and natural gas
4 customers affected by the 2017 wildfires: (1) waiver of deposit requirements for residents seeking to re-
5 establish service for one year and expedited move-in and move-out service requests; (2) cease estimating
6 energy usage for billing attributed to the time period when the home/unit was unoccupied as a result of
7 the wildfires; (3) create payment plan options; (4) suspend disconnection for non-payment and
8 associated fees, waiver of deposit and late fee requirements; and (5) provide support for low-income
9 customers. These protections were adopted in the resolutions to ensure that customers who experienced
10 housing or financial crises due to a disaster or state of emergency do not lose access to vital utility
11 services. On August 9, 2018, the Commission issued D.18-08-004 to affirm the emergency customer
12 protections for residential and non-residential customers.

13 On August 24, 2018, SCE submitted Advice 3852-E to establish the Wildfires
14 Customer Protections Memorandum Account (WCPMA) to record costs associated with protections
15 ordered in D.18-08-004. On September 10, 2018, SCE submitted Advice 3862-E to re-name the
16 WCPMA to the Emergency Customer Protections Memorandum Account (ECPMA) pursuant to OP 3 of
17 D.18-08-004. The ECPMA records costs related to providing emergency customer protections for
18 customers affected by disasters declared a state of emergency by the Governor.

19 On July 11, 2019, the Commission issued D.19-07-015, which ordered SCE to
20 make modifications to the ECPMA to further extend the customer protections for all disasters in which
21 the Governor of California or the President of the United States has declared a state of emergency.¹⁰⁵
22 On July 19, 2019, SCE submitted Advice 4040-E to modify its ECPMA tariff to include the expansion.

23 In the 2021 GRC Decision, the Commission authorized SCE to recover the
24 December 31, 2020 recorded balance in the ECPMA by transferring this amount to the distribution
25 subaccount of the BRRBA for recovery in customers' distribution rates.¹⁰⁶ SCE implemented this
26 authorization in Advice 4586-E. Therefore, in this GRC, SCE is seeking recovery of costs recorded in
27 the ECPMA beginning January 1, 2021.

¹⁰⁵ D.19-07-015, OP 4.

¹⁰⁶ D.21-08-036, pp. 464-465.

Table V-17 summarizes the entries recorded in the ECPMA as of December 31, 2022, which includes amounts recorded in both 2021 and 2022.

Table V-17
Emergency Customer Protections Memorandum Account¹⁰⁷
(ECPMA)

Line No.	Description	(\$000)
1	Beginning Balance	16
	Expenses	
2	Bill Forgiveness	1
3	Total Expenses	1
4	Interest	0
5	Ending Balance (Line 1 + Line 3 + Line 4)	18

The ending balance recorded in the ECPMA as of December 31, 2022 is a debit of \$0.018 million, as shown on Line 5 of Table V-17.¹⁰⁸ This amount results from Emergency Customer Protections (ECP), specifically customer bill forgiveness, provided in relation to nine fires, including the 2017 Thomas Fire,¹⁰⁹ the 2020 Apple Fire,¹¹⁰ the 2020 Bobcat Fire,¹¹¹ the 2020 Bond Fire,¹¹² the 2020

¹⁰⁷ Refer to WP SCE-07, Vol. 01, Book A, p. 91, Emergency Customer Protections Memorandum Account.

¹⁰⁸ The Beginning Balance shown on Line 1 is the recorded balance as of year-end 2021. All amounts recorded in 2021 were for customer bill forgiveness.

¹⁰⁹ See Advice 3733-E. SCE acknowledges that it provided approximately \$0.008 million of bill forgiveness to customers impacted by the 2017 Thomas Fire in 2021 and 2022, which exceeds the standard one-year timeframe referenced in the ECPMA. This bill forgiveness is primarily associated with situations where temporary facilities were installed so work on the main lines could be completed.

¹¹⁰ See Advice 4282-E.

¹¹¹ See Advice 4295-E.

¹¹² SCE did not submit an ECP advice letter for the Bond Fire. However, \$3.84 was recorded to the ECPMA in January 2021 associated with this fire. SCE is not seeking to recover this amount, but this would not be apparent due to rounding so SCE is including this footnote for transparency.

1 Castle Fire,¹¹³ the 2020 Creek Fire,¹¹⁴ the 2020 Lake Fire,¹¹⁵ the 2020 Silverado Fire,¹¹⁶ and the 2020 El
2 Dorado Fire.¹¹⁷ The activation of the ECP was the result of an Emergency Proclamation issued by
3 Governor Newsom for each of the events. SCE submitted advice letters for each event that provide
4 detailed information, including the dates of each event, eligibility of billing and credit protections for
5 customers and a list of customer protections offered for impacted customers.

6 SCE estimates that the balance in the ECPMA as of December 31, 2024 will be a
7 debit of \$0.072 million based on the average amount of costs recorded in the ECPMA annually over the
8 last five years.¹¹⁸ SCE will provide the most recent ECPMA recorded activity in the Update Phase of
9 this GRC proceeding, with a final recorded December 31, 2024 balance provided in the advice letter
10 implementing the 2025 GRC decision.

11 Therefore, effective upon the issuance of a final decision in this proceeding
12 finding that the ECPMA recorded costs are reasonable, SCE proposes to transfer the December 31, 2024
13 recorded balance in the ECPMA, plus accrued interest, to the distribution sub-account of the BRRBA to
14 be recovered in customers' distribution rates.¹¹⁹

15 **f) Residential Disconnections Implementation Cost Memorandum Account**
16 **(RDICMA)**

17 On June 11, 2020, the Commission issued D.20-06-003 in R.18-07-005, which
18 authorized the expansion of additional protections to reduce the number of residential customer
19 disconnections and to improve reconnection processes for disconnected customers. Specifically, the
20 decision provided additional protections by requiring SCE to enroll eligible customers in all applicable

¹¹³ See Advice 4295-E.

¹¹⁴ See Advice 4295-E.

¹¹⁵ See Advice 4282-E.

¹¹⁶ SCE did not submit an ECP advice letter for the Silverado Fire. However, \$23.67 was recorded to the ECPMA in January 2021 associated with this fire. SCE is not seeking to recover this amount, but this would not be apparent due to rounding so SCE is including this footnote for transparency.

¹¹⁷ See Advice 4295-E.

¹¹⁸ SCE has already activated ECPs for disasters declared in 2022 and 2023, which increases the likelihood that additional amounts will record to the ECPMA by the end of 2024. For example, in August 2022, SCE activated ECPs for the Route Fire; in September 2022, SCE activated ECPs for the Fairview Fire and Tropical Storm Kay; in January 2023, SCE activated ECPs for the severe winter storms.

¹¹⁹ The recorded operation of the BRRBA, which would include the ECPMA transfer, would then be reviewed in SCE's 2024 ERRR Review proceeding.

1 benefit programs administered by SCE, offer 12-month payment plans, prohibit disconnections if there
2 is a Low-Income Home Energy Assistance Program (LIHEAP) pledge, and cease requiring service
3 deposits or reconnection fees. In addition, the decision required SCE to establish new procedures to
4 better inform customers who are in danger of having their utilities disconnected of applicable benefit
5 programs that are available. For cost recovery, the decision authorized the establishment of the
6 RDICMA to track incremental implementation costs associated with billing system upgrades,
7 development of the LIHEAP online portal, customer outreach costs, arrearage management plan (AMP)
8 and other costs, and required that costs recorded in the RDICMA be reviewed for reasonableness and
9 recovery in SCE's GRC.¹²⁰

10 On October 7, 2021, the Commission issued D.21-10-012 to adopt the Percentage
11 of Income Payment Plan (PIPP) pilot program. On November 30, 2021, SCE submitted Advice 4653-E
12 to modify the RDICMA to track PIPP pilot program-related administrative costs on a temporary basis
13 and transfer the applicable costs recorded in the RDICMA to the PIPP memorandum account (PIPPMA)
14 once the PIPPMA was approved. On November 16, 2022, SCE submitted Advice 4906-E to further
15 modify the RDICMA to track incremental costs associated with reconnection fees eliminated in D.20-
16 06-003 until these costs are included in SCE's 2025 ABRR.

17 Table V-18 summarizes the entries recorded in the RDICMA as of December 31,
18 2022.

¹²⁰ D.20-06-003, OP 95.

Table V-18
Residential Disconnections Implementation Cost Memorandum Account¹²¹
(RDICMA)

Line No.	Description	(\$000)
1	Beginning Balance	1,645
	Operations and Maintenance	
2	Labor	104
3	Non-Labor	1,965
4	Total Expenses (Line 2 : Line 3)	2,069
5	(Over)/Under Collection (Line 4)	2,069
6	Interest	58
7	Ending Balance (Line 1 + Line 5 + Line 6)	3,771

The ending balance recorded in the RDICMA as of December 31, 2022 is a debit of \$3.771 million, as shown on Line 7 in Table V-18.¹²² This balance is comprised of costs recorded in 2021 and 2022 associated with the 12-month payment extension/installment plan and the implementation of SCE's AMP program, which is a debt forgiveness payment plan option for residential CARE and FERA customers who have past due bills totaling \$500 or greater that are at least 90 days old. In addition, SCE recorded costs for the development of its LIHEAP portal from a third-party vendor.

SCE estimates that the balance in the RDICMA as of December 31, 2024 will be a debit of \$7.554 million because of continuing work on the further development and administration of the LIHEAP online portal and for waived reconnection fees in 2023 and 2024. SCE will provide the most recent RDICMA recorded activity in the Update Phase of this GRC proceeding, with a final recorded December 31, 2024 balance provided in the advice letter implementing the 2025 GRC decision.

¹²¹ Refer to WP SCE-07, Vol. 01, Book A, p. 92, Residential Disconnections Implementation Cost Memorandum Account.

¹²² The Beginning Balance shown on Line 1 is the recorded balance as of year-end 2021. Additionally, approximately \$0.238 million of PIPP-related costs originally recorded to the RDICMA in 2022 were subsequently transferred to the PIPMA in January 2023.

1 Therefore, effective upon a final decision in this proceeding, SCE proposes to
2 transfer the December 31, 2024 recorded balance in the RIDCMA, plus accrued interest, to the PPPAM
3 to be recovered in customers' public purpose program rates.¹²³

4 **g) NEM Online Application System Memorandum Account (NEMOASMA)**

5 On November 6, 2014, the Commission adopted D.14-11-001, which, in pertinent
6 part, authorized the establishment of a memorandum account to track costs associated with developing
7 an online NEM interconnection application portal for processing NEM interconnection requests and to
8 seek recovery of these costs in the GRC.¹²⁴ On January 12, 2015, SCE submitted Advice 3162-E to
9 establish the NEMOASMA. On January 28, 2016, the Commission adopted D.16-01-044, which
10 authorized the establishment of a successor tariff to SCE's existing NEM program. On February 29,
11 2016, SCE submitted Advice 3371-E to modify the NEMOASMA to additionally track the costs
12 associated with modifying its NEM interconnection application portal to implement the new
13 interconnection and verification requirements adopted in D.16-01-044.

14 SCE's interconnection portal is hosted by a 3rd party (Clean Power Research)
15 using their PowerClerk Interconnection (PCI) platform. PCI is a workflow automation software that
16 provides flexible, no-code configuration that streamlines design and management of programs to meet
17 customer satisfaction and process optimization. SCE's first PCI module was implemented on July 1,
18 2015 to support the NEM program available at that time. A second module was later created to support
19 the second generation of NEM (known as NEM 2.0). The majority of the costs recorded in the
20 NEMOASMA were incurred between November 2014 and June 2015 when the initial PCI module was
21 deployed for the NEM program. The original costs recorded during this period total \$0.898 million,
22 which include the PCI initial subscription fee of \$0.456 million, IT changes to develop adequate
23 Application Programming Interface (APIs) to communicate with the platform while maintaining
24 cybersecurity requirements (\$0.184 million), and workflow development, NEM forms creation and
25 handoff automation (\$0.258 million). Other maintenance-type work was recorded as additional charges
26 in subsequent periods. Interest on the balance in the NEMOASMA has accrued monthly, in accordance
27 with SCE's tariff.

¹²³ The recorded operation of the PPPAM, which would include the RIDCMA transfer, would then be reviewed in SCE's 2024 ERRA Review proceeding.

¹²⁴ D.14-11-001, OP 4.

SCE now seeks recovery of the December 31, 2024 balance in the NEMOASMA and to close and eliminate this memorandum account as of January 1, 2025. Table V-19 summarizes the entries recorded in the NEMOASMA as of December 31, 2022.

Table V-19
Net Energy Metering Online Application System Memorandum Account¹²⁵
(NEMOASMA)

Line No.	Description	(\$000)
1	Beginning Balance	1,192
2	Interest	20
3	Ending Balance (Line 1 + Line 2)	1,213

The ending balance recorded in the NEMOASMA as of December 31, 2022 is a debit of \$1.213 million, as shown on Line 3 in Table V-19.¹²⁶ SCE is not expecting to record any additional costs in the NEMOASMA in 2023 and 2024 other than interest expense. Therefore, SCE estimates that the balance in the NEMOASMA as of December 31, 2024 will be a debit of \$1.253 million. SCE will provide the most recent NEMOASMA recorded activity in its Update Testimony, with a final recorded December 31, 2024 balance provided in the advice letter implementing the 2025 GRC decision.

Therefore, effective upon a final decision in this proceeding, SCE proposes to transfer the December 31, 2024 recorded balance in the NEMOASMA, plus accrued interest, to the distribution subaccount of the BRRBA to be recovered in customers' distribution rates.¹²⁷ SCE will then eliminate this account, as discussed in Chapter V.B.3(e) above.

h) California Consumer Privacy Act Memorandum Account (CCPAMA)

On March 29, 2019, SCE filed A.19-03-025 requesting authority to establish Preliminary Statement Part N.64, the CCPAMA, to track incremental costs related to compliance with the California Consumer Privacy Act of 2018 (CCPA). The CCPA is a privacy statute impacting

¹²⁵ Refer to WP SCE-07, Vol. 01, Book A, p. 93, Net Energy Metering Online Application System Memorandum Account.

¹²⁶ The Beginning Balance shown on Line 1 is the recorded balance as of year-end 2021.

¹²⁷ The recorded operation of the BRRBA, which would include the NEMOASMA transfer, would then be reviewed in SCE's 2024 ERRR Review proceeding.

companies doing business with California consumers that include gross revenues in excess of \$25 million. The CCPA generally requires the utilities, on consumers' request, to disclose what data they collect of them, to whom the data is disclosed, and how to opt out. Due to the uncertainty around the costs that SCE would incur, such as upgrades to customer data, IT and privacy systems, compliance requirements and training, SCE was authorized to establish a memorandum account to track these incremental costs for recovery in SCE's GRC.

On November 3, 2020, the CCPA was amended by the California Privacy Rights Act of 2020 (CPRA), which became effective on January 1, 2023. The CPRA modifies the scope of the CCPA and the underlying statutes in California Civil Code Sections 1798.100 – 1798.199.100. On July 12, 2021, SCE submitted Advice 4517-E to modify the existing CCPAMA to include the modification of the CPRA.

As stated above, the purpose of the CCPAMA is to track incremental costs related to compliance with the CCPA and the CPRA. Table V-20 summarizes the entries recorded in the CCPAMA as of December 31, 2022.

Table V-20
California Consumer Privacy Act Memorandum Account¹²⁸
(CCPAMA)

Line No.	Description	(\$000)
1	Beginning Balance	3,239
2	Operation and Maintenance Costs	376
3	Interest	60
4	Ending Balance (Line 1 + Line 2 + Line 3)	3,675

The ending balance recorded in the CCPAMA as of December 31, 2022 is a debit of \$3.675 million, as shown on Line 4 in Table V-20.¹²⁹ These recorded costs resulted from the approval of the CPRA in November 2020, which required that SCE take on additional responsibilities. Specifically, the inclusion of employment-related requests required changes to the SCE.com intake form

¹²⁸ Refer to WP SCE-07, Vol. 01, Book A, p. 94, California Consumer Privacy Act Memorandum Account.

¹²⁹ The Beginning Balance shown on Line 1 is the recorded balance as of year-end 2021.

1 and costs to update the existing code to systematically search for information and consolidate the
2 information into the report. To track the requests to meet reporting compliance obligations, a tracking
3 tool was created. In 2023, SCE expects to record approximately \$0.763 million in capital-related
4 revenue requirements into the CCPAMA for the associated IT costs. In addition, SCE expects to
5 continue to record labor and non-labor costs into the CCPAMA through the end of 2024 of \$0.100
6 million and \$0.300 million, respectively. This results in an estimated December 31, 2024 balance in the
7 CCPAMA of \$4.838 million. SCE will provide the most recent CCPAMA recorded activity in Update
8 Testimony in this GRC proceeding, with a final recorded December 31, 2024 balance provided in the
9 advice letter implementing the 2025 GRC decision.

10 Therefore, effective upon a final decision in this proceeding, SCE proposes to
11 transfer the December 31, 2024 recorded balance in the CCPAMA, plus accrued interest, to the PPPAM
12 to be recovered in customers' public purpose program rates.¹³⁰

13 **i) Avoided Cost Calculator Memorandum Account (ACCMa)**

14 The Avoided Cost Calculator estimates the costs of traditional resources that will
15 be avoided when a distributed energy resource is procured instead. On June 15, 2016, the Commission
16 issued D.16-06-007, *Decision to Update Portions of Commission's Current Cost-Effectiveness*
17 *Framework*. In the decision, the Commission authorized the agency's executive director to hire
18 contractors to perform annual updates to the Avoided Cost Calculator and to provide technical assistance
19 or research. The Commission approved funding up to \$100,000 annually in reimbursable funds for the
20 Avoided Cost Calculator update process. In addition, the Commission approved \$400,000 annually, for
21 three years beginning in fiscal year 2016-17, in reimbursable funds for ongoing technical assistance to
22 support future phases of cost-effectiveness work. Unspent funds from the calculator update may be used
23 to supplement technical assistance funds, and vice versa, within an overall cap of \$500,000 annually for
24 the first three years. Beginning in fiscal year 2019-20, the authorization went to \$100,000 per year and
25 any unspent funds may be carried over to subsequent fiscal years on a going-forward basis until or
26 unless the Integrated Distributed Energy Resources or a successor proceeding determines that updates to
27 the Avoided Cost Calculator are no longer needed. This funding is allocated among utilities based on the
28 energy efficiency allocation, as determined in R.13-11-005. This results in SCE receiving an allocation

¹³⁰ The recorded operation of the PPPAM, which would include the CCPAMA transfer, would then be reviewed in SCE's 2024 ERRa Review proceeding.

of 36.56 percent of the authorized funding. On February 28, 2017, SCE submitted Advice 3566-E to establish the ACCMA. The purpose of the ACCMA is to record SCE's portion of costs reimbursed to the Commission or their contractor for updating the Avoided Cost Calculator and providing technical assistance or research for the purpose of advancing future refinement of cost-effective methods pursuant to D.16-06-007.

Table V-21 summarizes the entries recorded in the ACCMA as of December 31, 2022, which date back to 2017 when the account became effective.

Table V-21
Avoided Cost Calculator Memorandum Account¹³¹
(ACCMA)

Line No.	Description	(\$000)
1	Beginning Balance	322
2	Operation and Maintenance Costs	132
3	Interest	7
4	Ending Balance (Line 1 + Line 2 + Line 3)	462

The ending balance recorded in the ACCMA as of December 31, 2022 is a debit of \$0.462 million, as shown on Line 4 in Table V-21. The \$0.462 million of recorded costs are SCE's portion of the costs reimbursed to the Commission for its work as well as its contractors' work to update the Avoided Cost Calculator. The amount recorded covers work completed since 2017. SCE estimates that the December 31, 2024 balance in the ACCMA will be a debit of \$0.732 million, which is the result of SCE reimbursing the Commission \$0.135 million in both 2023 and 2024 to exhaust the amount authorized for this work through the end of 2024. SCE will provide the most recent ACCMA recorded activity in Update Testimony, with a final recorded December 31, 2024 balance provided in the advice letter implementing the 2025 GRC decision.

¹³¹ Refer to WP SCE-07, Vol. 01, Book A, p. 95, Avoided Cost Calculator Memorandum Account.

1 Therefore, effective upon a final decision in this proceeding, SCE proposes to
2 transfer the December 31, 2024 recorded balance in the ACCMA, plus accrued interest, to the
3 distribution subaccount of the BRRBA to be recovered in customers' distribution rates.¹³²

4 **j) Community Choice Aggregators Audit Memorandum Account (CCAAMA)**

5 On December 28, 2012, the Commission issued D.12-12-036, which adopted a
6 Community Choice Aggregator (CCA) Code of Conduct applicable to the Investor-Owned Utilities
7 (IOUs). The purpose of the Code of Conduct is to provide CCAs the opportunity to compete on a fair
8 and equal basis with other load serving entities. Accordingly, the decision required independent audits of
9 each IOU every two years to ensure that each IOU is abiding by the limitations on marketing and
10 lobbying activities that qualify the IOU for non-marketing status. The decision allowed the IOUs to
11 establish memorandum accounts to record the costs associated with these audits and to recover the
12 recorded costs in their GRCs.¹³³ On December 7, 2018, SCE submitted Advice 3912-E to establish the
13 Community Choice Aggregation Audit Memorandum Account (CCAAMA), which became effective on
14 January 6, 2019.

15 As of December 31, 2022, SCE had not recorded any amounts in the CCAAMA.
16 However, SCE received three invoices from the Commission related to these audits dated November 29,
17 2022, January 10, 2023, and January 11, 2023 for \$0.015 million, \$0.006 million and \$0.038 million,
18 respectively, which will be recorded to the CCAAMA in 2023. These invoices seek reimbursement for
19 services rendered by Sjoberg Evashenk Consulting related to audit planning, administrative and field
20 work analysis. Additionally, on January 12, 2023, SCE received notification from the Commission's
21 Energy Division that the current contract for the audit had 18 months remaining with a balance of \$1.3
22 million, of which SCE is responsible for 33 percent, or approximately \$0.429 million. Therefore, SCE
23 estimates that the amount recorded in the CCAAMA as of December 31, 2024 will be a debit of \$0.488
24 million. SCE will provide the most recent CCAAMA recorded activity in the Update Phase of this GRC
25 proceeding, with a final recorded December 31, 2024 balance provided in the advice letter implementing
26 the 2025 GRC decision.

¹³² The recorded operation of the BRRBA, which would include the ACCMA transfer, would then be reviewed in SCE's 2024 ERRR Review proceeding.

¹³³ D.12-12-036, p. 29.

1 Therefore, effective upon a final decision in this proceeding, SCE proposes to
2 transfer the December 31, 2024 recorded balance in the CCAAMA, plus accrued interest, to the
3 distribution subaccount of the BRRBA to be recovered in customers' distribution rates.

4 **k) Wildfire Mitigation Plan Memorandum Account (WMPMA)**

5 **(1) Fusing Mitigation**

6 On June 23, 2022, the Commission adopted D.22-06-032 addressing Track
7 3 of SCE's 2021 GRC for the recovery of wildfire mitigation memorandum and balancing account
8 balances. In pertinent part, Conclusion of Law 10 found that SCE had failed to meet its burden of
9 demonstrating that the fusing mitigation costs incremental to the authorized Grid Safety and Resiliency
10 Program (GSRP) budget included in Track 3 were reasonable and should be recovered from ratepayers.

11 In response to the findings in D.22-06-032, in Exhibit SCE-04, Vol. 05
12 Pt. 1 SCE provides information regarding the installation of the fuses in question to support a
13 Commission finding that SCE acted prudently and should recover the \$24.6 million (2020\$)¹³⁴ of total
14 incremental capital costs. SCE is currently recording the capital-related revenue requirement associated
15 with these incremental fusing mitigation capital costs in its Wildfire Mitigation Plan Memorandum
16 Account (WMPMA), with the revenue requirement beginning in November 2019. The recorded balance
17 in the WMPMA related to the fusing mitigation capital costs as of December 31, 2022 is a debit of
18 \$10.212 million. SCE estimates that the recorded amount will increase to \$16.951 million as of
19 December 31, 2024. SCE will provide the most recent recorded activity (i.e., the ongoing capital-related
20 revenue requirement) in the Update Phase of this GRC proceeding, with a final recorded December 31,
21 2024 balance provided in the advice letter implementing the 2025 GRC decision.

22 Therefore, upon a finding of reasonableness of the fusing mitigation-
23 related capital expenditures, SCE proposes to transfer the associated recorded capital-related revenue
24 requirement through December 31, 2024, including accrued interest, to the distribution subaccount of
25 the BRRBA to be recovered in customers' distribution rates.¹³⁵ In the event SCE receives recovery from
26 the manufacturer or supplier for any of the incremental costs sought herein, in accordance with
27 Conclusion of Law 11 in D.22-06-032, SCE will provide an accounting of the recovery and reduce the

¹³⁴ See footnote 86 of D.22-06-032. Refer to WP SCE-07, Vol. 01, Book A, p. 96, Wildfire Mitigation Plan Memorandum Account (Fusing Mitigation).

¹³⁵ The 2025 and forward ongoing capital-related revenue requirement would be included in the ADBRR.

1 associated capital-related revenue requirement request so that customers do not fund the recovery of
2 costs that SCE has recovered from a third-party.

3 **C. Review of Mobilehome Park Costs**

4 In Decision (D.) 14-03-021, the Commission authorized an initial three-year pilot program to
5 convert master-metered mobilehome parks and manufactured housing communities (collectively,
6 MHPs) to direct utility service. The Commission subsequently extended the program through 2021 with
7 the issuance of resolution E-4958.¹³⁶ On April 16, 2020, the Commission issued D.20-04-004,
8 establishing the current version of the program: a 10-year MHP Utility Conversion Program beginning
9 on January 1, 2021 that primarily adopts the requirements established for the pilot program, but with
10 certain adjustments to eligibility, annual target conversion rates, and cost targets. D.20-04-004 also
11 continued the cost recovery method adopted in the pilot, through which the utilities are authorized to
12 record actual program costs for the Mobilehome Park Utility Conversion Program in a balancing
13 account and recover prudently incurred costs in a GRC. “Review for reasonableness of ‘to the meter’
14 [or TTM] costs will occur in the GRC where those costs are put into rate base. Review for
15 reasonableness of ‘beyond the meter’ [or BTM] costs will occur in the first GRC case after system cut
16 over to direct utility service is completed.”¹³⁷

17 In compliance with the cost recovery method approved in D.14-03-021, SCE presents
18 justification for \$71.518 million of costs recorded to plant for completed Mobilehome Park Utility
19 Upgrade Program (Pilot, Transition year, and Conversion programs) conversions from January 1, 2019
20 through December 31, 2022. This is the first GRC in which the TTM costs are put into rate base and is
21 the first GRC after the systems associated with the BTM costs were cut over to direct utility service.
22 Section 1 below provides an overview of the procedural history and scope of the program. Section 2
23 explains program performance and why SCE’s pilot program was a success. Section 3 sets forth a
24 summary of costs and initiatives to keep costs down.

25 **1. Overview of Procedural History and Program Scope**

26 D.14-03-021 approved a three-year “living” pilot program to incentivize voluntary
27 conversions of mobilehome parks and manufactured housing communities with master-metered natural
28 gas and electricity to direct utility service. The Commission concluded in that decision, in part due to the

¹³⁶ Resolution E-4958, *Authorization to extend the Mobile Home Park Utility Upgrade Pilot Program (MHP Pilot) to December 31, 2021, for currently participating electric and gas utilities*, issued March 14, 2019.

¹³⁷ D.14-03-021, OP 2.

1 fact very few conversions were completed in the seventeen years following establishment of the
2 statutory conversion process,¹³⁸ expansion of BTM construction was necessary to achieve significant
3 conversions. After noting the “very minimal monthly rate impacts” of the projected costs of the pilot
4 program for the years 2015 through 2017, the Commission concluded that the program “is both
5 affordable and fair”¹³⁹ and that approximately 10% of the MHP spaces within each utility’s service
6 territory should be converted over the term of the pilot program.¹⁴⁰ Resolution E-4878 extended the pilot
7 program through December 31, 2019 and directed the utilities to continue to complete all Category 1¹⁴¹
8 MHP conversions (equal to approximately 10% of all 106,000 eligible MHP spaces identified in SCE’s
9 service territory, as established in D.14-03-021) and work on Category 2 and 3 MHPs.

10 On May 22, 2015, SCE implemented the pilot program when it received a prioritized
11 category list of selected MHPs from the Commission’s Safety and Enforcement Division (SED).
12 SCE was directed to complete Category 1 parks. SCE finished all of the Category 1 parks as well as
13 portions of the Category 2 list as defined in Resolution E-4878. Thereafter, Resolution E-4958
14 authorized the extension of the MHP Pilot to the earlier of December 31, 2021 or the issuance of a
15 Commission decision approving the continuation, expansion, or modification of the program.

16 SCE successfully partnered with MHP Owners/Operators, SoCalGas, and Southwest Gas
17 to complete utility upgrades for participating MHPs. Once the project list was determined, SCE worked
18 jointly with the gas utilities to schedule parks for conversion. Location, size, and park availability were
19 additional determining factors used by both SCE and the gas companies. From inception of the MHP
20 Pilot through December 31, 2022, SCE converted a combined total of 17,877 spaces. This is
21 approximately 17% of all master-meter/sub-metered mobilehome park spaces in SCE’s service territory

¹³⁸ Chapter 6.5 of the Public Utility Code, *Transfer of Facilities in Master-Metered Mobilehome Parks and Manufactured Housing Communities to Gas or Electric Corporation Ownership*.

¹³⁹ D.14-03-021, p. 2.

¹⁴⁰ D.14-03-021, FOF 26, OP 2.

¹⁴¹ During the Commission’s open application period, mobilehome park owners submitted applications and completed questionnaires describing park-owned infrastructure conditions, including safety information. Depending on the detail and thoroughness of submitted questionnaires, SED prioritized parks into Categories 1, 2 or 3 based on high to lower safety risk. IOUs were instructed by SED to convert parks in Category 1 (highest risk) for the initial three-year pilot, followed by additional bridge parks from Category 2 and Category 3 in pilot extensions.

1 previously identified and provided to SCE by the SED.¹⁴² D.20-04-004 preserves the current MHP
2 annual target conversion rate at 3.33 percent with a cumulative target of converting 50 percent of
3 eligible MHP spaces by 2030 with a priority to maximize conversion of higher risk master-
4 meter/submeter systems that supply natural gas to mobilehome parks or manufactured housing
5 communities and where possible, to prefer dual conversions (natural gas and electric). D.20-04-004 also
6 expands eligibility to include sub-metered and non-sub-metered mobilehomes.¹⁴³ Prioritization should
7 continue to be based on safety, reliability, dual conversions, and capacity improvements consistent with
8 D.14-03-021.¹⁴⁴

9 **2. Program Performance**

10 The initial purpose of implementing the Pilot Program was to conduct a pilot during
11 which the investor-owned utilities (IOUs) and the Commission could assess the feasibility and
12 effectiveness of a mobilehome park conversion program as outlined in D.14-03-021. SCE's Pilot
13 Program was a success due to the achievement of the performance indicators listed below. SCE will
14 continue the use of the same indicators to continue to define success for the 10-year program.

15 **a) System Safety and Reliability**

16 Safe and reliable utility service is central to the MHP Pilot Program. To assist in
17 prioritizing MHPs for conversion, SED developed a Form of Intent (FOI) and required all MHPs
18 interested in participating in the MHP Pilot Program to complete the FOI. In that FOI, SED requested
19 information on the age and amperage of current electric assets serving the MHP. It is SCE's
20 understanding that this information was partly used to determine which MHPs were in greater need for
21 conversion in order to prioritize safety and reliability upgrades. Upon conversion, all utility distribution
22 infrastructure up to and including the meter becomes owned and maintained by SCE and subject to
23 SCE's standards. Included in these standards are: 1) installation of utility infrastructure at the proper
24 depth and separation from other facilities; 2) utilization of appropriate fill material and compaction
25 within trenches to meet industry standards; 3) safe placement of electric pedestals and meters; 4) proper
26 documentation and mapping of these facilities so they are readily located and marked prior to any future
27 digging and excavation; and (5) inclusion of the converted MHPs' TTM portion in SCE's Distribution

¹⁴² In addition, SCE completed planning efforts for approximately 3,800 spaces but did not complete the work because the park owners ultimately opted out of the program.

¹⁴³ D.20-04-004, p. 43.

¹⁴⁴ D.20-04-004, p. 49.

1 Inspection Maintenance Program (DIMP).¹⁴⁵ Best practices for safety, efficiency, and economic benefit
2 are monitored, explored, and encouraged during interaction with SCE inspectors, project managers, and
3 planning and program managers.

4 Replacement of aging distribution systems with new, professionally installed
5 systems underscores one of the broad issues of “undisputed merit” set forth in the D.14-03-021 to help
6 ensure “the safety of utility service at MHPs, or safety and reliability.”¹⁴⁶ The MHP Pilot Program
7 included the installation of new, up-to-current-standard distribution systems to replace aging
8 infrastructure.¹⁴⁷ There is a safety enhancement and benefit to SCE installing these facilities and
9 performing the subsequent operation and maintenance of the MHP distribution systems because SCE
10 has sufficient resources, expertise, and experience. Included with the new electrical infrastructure and
11 routine maintenance schedules, residents experience a newly efficient system that improves voltage drop
12 and flicker,¹⁴⁸ as well as, transformer loading management (TLM).¹⁴⁹ For example, prior to conversion,
13 MHP panels were aged and limited with many spaces utilizing panels 50amp or less. Smaller outdated
14 panels typically relay breakers when maximized under higher loading conditions. After cutover, newer
15 panels are 100 amp-rated and can allow for breaker upgrades to accommodate additional appliances,
16 such as air conditioning, which improve comfort and safety during elevated temperature months.

17 In both the pilot program and permanent program, the Commission recognized the
18 safety benefits of the conversion from master-meter/submeter natural gas and/or electric service to direct
19 service, for mobilehome parks and manufactured housing communities:

¹⁴⁵ See SCE-02, Vol. 02 - Distribution Inspections and Maintenance and Capital-Related.

¹⁴⁶ D.14-03-021 p. 6.

¹⁴⁷ The decision cited anecdotal evidence about aging MHP infrastructure, including (1) a spike in MHP construction in California in approximately 1950 and 1960; (2) common conditions in which electrical amperage was lower than 100 amps; and (3) the presence of many MHP owners who want to get out of the utility business without taking prompt steps to do so. See D.14-03-021, pp. 19-20.

¹⁴⁸ Voltage drop criteria is based on the calculated percent voltage drop for the secondary and service cable/conductors from the transformer to the customer’s meter.

¹⁴⁹ TLM refers to SCE’s internal tracking of customers assigned to each transformer for purpose of transformer load tracking and customer outage management.

1 Clearly, safety has improved through the installation of new,
2 reliable, distribution systems, consisting of modern materials and
3 construction methods. Going forward after the conversions, the
4 distributions systems are now and will continue to be operated and
5 maintained by the utilities indefinitely. In addition, the utilities will
6 have primary responsibility for emergency response to the parks
7 and their residents.¹⁵⁰

8 The Commission also reasoned that the upgrades would increase capacity for
9 customers, providing “immediate opportunity for residents to install air conditioning and/or heating
10 which, until conversion under the program, was generally impossible.”¹⁵¹

11 **b) SCE’s Customer Program Access**

12 Prior to conversion, MHP residents had relied on park managers, property
13 managers or park owners to provide residents information about SCE customer programs.
14 Upon conversion of the MHP, residents now have direct access to SCE customer programs and services,
15 such as California Alternative Rates for Energy (CARE), Family Electric Rate Assistance (FERA), and
16 Medical Baseline. Residents can also now take advantage of time-of-use rates and/or energy-efficiency
17 rebates, which give MHP customers more opportunities to potentially save on their electric bills. As of
18 December 31, 2022, 8,279 MHP residents were directly enrolled in SCE’s CARE program and 262 were
19 enrolled in SCE’s Medical Baseline program. Customers can contact SCE’s customer service
20 representatives with billing inquiries or questions regarding other aspects of their utility service,
21 including outage notifications. MHP residents can also access SCE’s online tools and services to
22 monitor their energy usage directly and discover additional ways to save energy and money.

23 **c) Collection of MHP Conversion Cost Data**

24 D.14-03-021 required annual reporting on the living pilot, in part to inform a
25 decision about whether continuation of the program beyond three years was warranted. The Commission
26 reasoned, “should actual costs prove much greater than anticipated . . . we will be able to bring the
27 program to an early end.” Thus, another main purpose of the MHP Pilot was to provide the IOUs and the
28 Commission with information necessary to assess the feasibility and effectiveness of a comprehensive
29 MHP conversion program as outlined in D.14-03-021.¹⁵² Among other things, the Commission required
30 SCE to report on its implementation timeline, the number of applications received, any problems

¹⁵⁰ Resolution E-4878, p. 14.

¹⁵¹ Resolution E-4878, p. 15.

¹⁵² D.14-03-021, OP 2 and OP 8, respectively, on pp. 75 and 77.

1 experienced with prioritizing the conversions, information about each selected MHP, and cost
2 information for both TTM and BTM construction/cut-over. In addition to the original reporting
3 requirements, D.20-04-004¹⁵³ also instructed SCE to provide:

- 4 1. More detailed MHP physical configuration and layout detail including
5 common use structures, and residential buildings with permanent foundations;
- 6 2. Annual number of common use space conversions and average of spaces
7 converted per park;
- 8 3. Additional information about what non-energy service and communication
9 providers service the Applicants' MHP;
- 10 4. Disclosure of potential issues (e.g., cultural, environmental, endangered
11 species) that could impact the design phase of the project program (or risk removal of the program); and
- 12 5. DAC, CARE/FERA, and Medical Baseline Information (also provided in
13 Annual Reports).

14 SCE continues to file its annual status reports each February 1 of the calendar
15 year, since filing the first report on February 1, 2016.¹⁵⁴

16 As indicated above, the initial pilot was successful, and the Commission extended
17 it with modifications in Resolution E-4878.¹⁵⁵ Subsequently, D.21-04-004 agreed with the January 2020
18 Staff Evaluation that the MHP Pilot achieved the intended safety improvements. Although actual cost of
19 the MHP Pilot were higher in some cases than the original estimates anticipated in D.14-03-021, the rate
20 impact data provided by the utilities shows the rate increases required to fund the program were
21 generally in line with Commission expectations.¹⁵⁶ For these reasons, the Commission established the
22 ten-year program.

23 **3. Summary of Costs**

24 Throughout the life of the MHP Pilot and two subsequent extensions, SCE has
25 successfully converted 17,877 spaces at an average cost of \$14,326 per space as reported in SCE's 2022

¹⁵³ D.20-04-004, p. 142.

¹⁵⁴ Refer to WP SCE-07, Vol. 01, Book A, pp. 97-125, SCE Annual MHP Conversion Pilot Program Report.

¹⁵⁵ Resolution E-4878, p. 8, p. 14.

¹⁵⁶ D.20-04-004, p. 2.

1 MHP Annual Report.¹⁵⁷ Thus, its average recorded cost per space is well below the projected \$22,319
2 forecast that the Commission considered when adopting the pilot program in D.14-03-021.¹⁵⁸

3 SCE considers an MHP fully converted when system cutover has occurred, the original
4 master meter has been removed, and all financial obligations have been fulfilled. In accordance with OP
5 10 of D.14-03-021, SCE submitted annual reports regarding, among other things, construction costs
6 (TTM and BTM), and incurred costs per space, which are provided as workpapers to this testimony.¹⁵⁹
7 Costs may vary depending on multiple factors, including availability of contractors, geographic location,
8 field conditions, etc. TTM includes the cost for the portion paid by SCE to contractors for TTM
9 construction activities. BTM Contractor Costs are costs associated with construction and installation of
10 materials beyond the meter.

11 Table V-22 shows the MHP Pilot closing costs from January 1, 2019 to December 31,
12 2022. Costs are shown for both BTM and TTM and further categorized into capital and O&M breakouts.
13 Capital costs include civil work/trenching, labor, material, structures, design, construction, property tax,
14 and other fees such as permitting and traffic control. O&M costs include costs for program outreach,
15 labor such as program startup cost for supporting organizations, and non-labor such as tool expenses,
16 mileage, and travel.

¹⁵⁷ Average cost per space only includes capital related costs. O&M costs do not contribute to the average cost per space since costs are associated with program outreach, program startup costs, and non-labor such as tool expenses, mileage, and travel.

¹⁵⁸ D-14-03-21, Appendix B.

¹⁵⁹ SCE is also providing work orders for two project examples—one large-size park space conversion (identified as Park “A”) and one medium-sized park space conversion (which is identified as Park “B”). Refer to WP SCE-07, Vol. 01, Book A, pp. 126-127, MHP Pilot Program Two Park Conversion Examples.

Table V-22
MHP Closings Costs from January 1, 2019 to December 31, 2022¹⁶⁰

Line No.	Item Description	2019	2020	2021	2022	Total Cost Review
1	O&M Expense	\$ 218,700	\$ 69,430	\$ 89,917	\$ 107,643	\$ 485,690
2	Capital Related Revenue Requirement					
3	Depreciation	8,846,610	11,129,518	9,716,450	5,438,368	35,130,946
4	Income Taxes	1,734,731	2,703,713	2,456,373	1,697,941	8,592,759
5	Property Taxes	692,007	1,001,100	1,016,119	309,939	3,019,165
6	Return	8,235,393	10,688,690	9,768,656	6,632,204	35,324,943
7	Total Capital Related Revenue Requirement	19,508,741	25,523,021	22,957,599	14,078,452	82,067,813
8	Total Capital Related Expense	\$ 19,508,741	\$ 25,523,021	\$ 22,957,599	\$ 14,078,452	82,067,813
9	Adjusted Beginning Balance	\$ (26,437)	\$ -	\$ (11,250,881)	\$ -	(11,277,318)
10	Subtotal	\$ 19,701,003	\$ 25,592,451	\$ 11,796,636	\$ 14,186,095	71,276,185
11	Interest	\$ 194,308	\$ 41,800	\$ 6,006	\$ 171,037	\$ 242,114
12	Subtotal	\$ 194,308	\$ 41,800	\$ 6,006	\$ 171,037	\$ 242,114
13	Total Cost Review	\$ 19,895,311	\$ 25,634,251	\$ 11,802,642	\$ 14,357,133	\$ 71,518,299

Even though SCE's recorded costs are well below what it initially projected (and what the Commission considered to be "affordable and fair" when it adopted the pilot program),¹⁶¹ SCE implemented cost management practices to control and minimize costs of on-going BTM¹⁶² and TTM¹⁶³ work. For BTM project work, the park owner ultimately selects the contractor. Since the park owner has authority over contractor selection, to control BTM costs, SCE and SoCalGas implemented a three-bid review process where park owners must submit their top three bids to SCE for reasonableness review. Previously, park owners would submit only one bid to SCE for review, which would make it difficult to assess relative costs among competitors. Upon reviewing the three bids, SCE does not automatically just choose the lowest bid; rather, it takes additional factors into consideration. To ensure reasonableness and

¹⁶⁰ Refer to WP SCE-07, Vol. 01, Book A, pp. 128-134, MHP Closing Costs.

¹⁶¹ D.14-03-021, p. 2.

¹⁶² TTM Costs include costs for the portion paid by SCE for TTM activities which are shared with other participating utilities where service territories overlap. These costs include trenching and paving, company labor in support of the program, including TTM work for selected MHPs, meter installation and master meter removal.

¹⁶³ BTM Contractor Costs are paid directly to the BTM Contractor to perform the BTM construction work. These costs include installation of the residential pedestal, connection to the mobilehome and all associated permit fees.

1 feasibility, SCE reviews the bids to ensure the contractor can meet project timelines, complete work
2 within SCE's design construction standards, and do so with a demonstrated safety track record.

3 For TTM work, SCE has authority over contractor selection. In order to control TTM
4 costs and help ensure reasonableness, SCE conducts a competitive bidding process where several
5 contractors are invited to bid. To be eligible for bidding, contractors must be selected from SCE's master
6 services agreement list, demonstrate acceptable safety rankings, provide reasonable pricing, be
7 subscribed to ISNetworld,¹⁶⁴ and be available to complete project work within participating geographic
8 locations. A Request for Proposal (RFP), which outlines the bidding process, contract terms, and scope
9 requirements, is sent to the eligible contractors and they will be invited to join a bidder conference,
10 which is a public meeting hosted for all of the selected participating bidders. The bidder conference
11 ensures that all contractors have a common understanding of the procurement requirements and that no
12 potential contractor receives any special treatment. Additionally, the bidder conference allows each of
13 the contractors to have access to the same information regarding the project which they can use to
14 prepare their proposals. Pre-identifying bidders, providing a robust RFP, and hosting bidder conferences
15 help ensure that SCE selects quality contractors to execute TTM project work at reasonable costs.

16 In addition to the competitive bidding process in place, SCE rebids every three years to
17 re-negotiate since contractors will not typically extend their unit pricing beyond three years. The rebid
18 also allows SCE to update any contract or procedural requirements to account for any lessons learned,
19 re-defined scope requirements, and adjust labor and/or material costs owing to inflation. SCE and
20 contract crews incorporated lessons learned and developed efficiencies after completing tasks
21 throughout the first phase of the MHP Pilot program. Moreover, new unit pricing encompassed these
22 efficiencies, lessons learned, and items not previously included, such as shoring and jacks, which
23 normally drove Field Change Orders (FCO)¹⁶⁵ prior to rebid. Any FCO requires approval by SCE staff
24 and is sometimes accompanied by field visits that sometimes result in additional but still reasonable
25 personnel time and other administrative costs. Additionally, during rebid, trench configurations were
26 adjusted to fewer ducts than initially proposed, which reduced SCE's joint trench percentage from 54%
27 to 52%. Increased planner and contractor experience resulted in thorough site walks that improved

¹⁶⁴ ISNetworld is an online platform service that connects SCE with qualified contractors meeting SCE's safety rating criteria - <https://www.isnetworld.com/en/>.

¹⁶⁵ Field change orders are unidentified field conditions driving changes to design and/or additional material not included in the contractor's original bid.

1 prospective design accuracy. Collaborative IOU focus of proper meter placement also minimized costly
2 TTM FCO impacts. Contractor best practices for efficiency are continuously encouraged, and SCE
3 exercises oversight over all projects by inspecting them and ensuring that they are consistent with all
4 current SCE design standards.

5 **4. Conclusion**

6 SCE respectfully requests that in its final decision in this proceeding, the Commission
7 find reasonable approximately \$71.518 million that SCE incurred for projects completed in the MHP
8 Pilot, MHP transition period, and the MHP Utility Conversion Program between January 1, 2019
9 through December 31, 2022.¹⁶⁶ After recording meter cutovers and work orders closed to plant in
10 service from inception to December 31, 2022, a total of 17,877 spaces were converted, averaging a cost
11 of approximately \$14,326 per space excluding O&M. SCE's original proposal before issuance of the
12 Decision projected average costs per space could be \$22,319 with approximately \$14,000 for TTM and
13 \$8,300 for BTM. SCE subsequently demonstrated cost containment, ratepayer stewardship, and
14 continuous improvement over the course of the pilot in converting parks, resulting in average recorded
15 costs of \$14,326 per space for a customer service and safety program the Commission encouraged and
16 monitored via SCE's annual reports.

¹⁶⁶ SCE recovered the revenue requirements associated with the MHP Pilot-related O&M and capital additions over this time period in the Mobilehome Park Master Meter Balancing Account (MMMBA).

VI.

FORECASTS OF SALES, CUSTOMERS, AND NEW METER CONNECTIONS

This chapter presents the forecasts of: (i) retail electricity sales,¹⁶⁷ (ii) customers, and (iii) new meter connections in SCE's service area for 2023-2028.¹⁶⁸ It comprises a summary of the forecasts and a brief description of the methodology used to produce each forecast. This section also briefly describes the major factors and assumptions that influence each forecast.

A. Sales Forecast

This retail forecast reflects SCE's latest sales forecast developed in the 4th quarter of 2022. It incorporates the latest economic vendor forecast outlooks as well as the state's long-term decarbonization policy impacts, especially on the accelerating electrification load growth. Total SCE retail sales were 85,870 GWh in 2022. SCE retail sales are forecasted to be 82,966 GWh in 2023, 84,689 GWh in 2025, and 90,334 GWh in 2028. The projected average annual growth in energy sales is about 1.7% for years 2025 to 2028. Continuous growth of total energy consumption due to customer additions and increasing cooling degree days from climate impact combined with accelerated growth from transportation and building electrification load, among other factors, contributed to the growth of SCE's retail sales forecast over the forecast period.¹⁶⁹

1. Methodology

SCE uses econometric models to forecast monthly retail electricity sales by customer class. Retail sales include final sales to bundled, direct access, and Community Choice Aggregation customers within the SCE service area. Retail sales do not include sales to public power customers, contractual sales, or inter-changes with other utilities since these are not considered final sales to SCE's customers.

The retail sales forecast represents the sum of sales to seven customer classes: (1) residential; (2) commercial; (3) industrial; (4) other public authority; (5) agricultural; (6) street lighting; and (7) inter-department transfers (IDT). Each customer class forecast (except IDT) is itself the product of two separate forecasts: (1) a forecast of electricity consumption per customer or per building-square-feet, and (2) a forecast of the number of customers or total building square feet. The IDT

¹⁶⁷ Retail sales captured in this chapter reflects total energy delivered by SCE.

¹⁶⁸ Reference herein to customers refers to customer accounts.

¹⁶⁹ Refer to WP SCE-07, Vol. 01, Book A, pp. 136-182, Sales and Customer Forecast Methodology.

1 forecast, which represents a very small percentage of total retail sales, is based upon the average of
2 recorded monthly sales over the most recent 12-month period.

3 Econometric models employ statistical techniques to quantify the relationship between
4 electricity consumption and the various economic, demographic, and other factors that influence
5 electricity consumption. Examples of such variables are weather, electricity rates, billing days,
6 employment, personal income, and building floor stock. Historical data is used to determine these
7 relationships. The typical estimation procedure used to construct the models is ordinary least squares
8 (OLS). Model-generated forecasts may be modified based on current trends, judgment, or events that are
9 not specifically modeled in the econometric equations.

10 Once a satisfactory statistical relationship is established, SCE uses historical average
11 values of weather (specifically, cooling and heating degree days) and the number of billing days to
12 represent typical or normal conditions in future periods. Forecasts of economic drivers such as
13 employment, regional output, and building square footage, with the typical weather and billing day
14 variables, are then added to the models to derive forecast values of electricity consumption per customer
15 and per building square foot. Economic data vendors, such as Moody's Analytics and S&P Global
16 Market Intelligence,¹⁷⁰ California Economic Development Department (EDD), and Dodge Data &
17 Analytics, are the principal sources of employment, personal income, and floor stock data, both
18 historical and forecast.

19 **2. Historical Trends**

20 On a recorded basis, SCE's total electricity sales remained relatively flat between 2019
21 and 2021 despite the impact of the COVID-19 pandemic. SCE saw stronger- and sooner-than-expected
22 economic recovery as the country emerged from the pandemic, with businesses reopening and near-full
23 employment, in addition to extreme summer weather from accelerated climate change led to higher sales
24 (more than 2.5% year-over year growth) in 2022.

25 Customer growth, which is measured by the number of SCE customer accounts, has
26 remained positive, averaging 0.58% annual growth between 2016 and 2022. Continuous population

¹⁷⁰ S&P Global Market Intelligence acquired IHS Markit in March 2022 and is currently undergoing a re-branding. IHS Markit was previously known as IHS Global Insight. S&P Global Market Intelligence's fourth-quarter 2022 publication, upon which this testimony relies was still titled "IHS Markit Power Planner" when this testimony was prepared, but all references in this testimony will be to "S&P Global Market Intelligence" or "S&P Global, or "S&P Global Market Intelligence Power Planner".

1 growth within SCE's service territory, especially the Inland Empire area, is one of the main drivers for
2 future customer growth.

3 The year-over-year percent change in the total non-farm employment in the counties
4 served by SCE during the years 2014 to 2028 is shown in Figure VI-3. Employment growth peaked in
5 2022, a rapid increase from the pandemic era lows in 2020. Employment growth is expected to slow
6 down but remain positive in the future.

7 Unlike during the Great Recession, as documented between 2007-2009, the housing
8 market exhibited strong growth since the pandemic, driven by pent-up demand, shortages of housing
9 supply, and delayed housing construction activities from prior years. As shown in Figure VI-3 below,
10 improvements in the housing sector have continued in recent years. Housing starts in SCE's service
11 territory had a large increase of 40% in 2019. In the years following, housing starts stayed at a similarly
12 high level above the pre-pandemic average until the Federal Reserve started to increase interest rates in
13 2022. Despite recent interest rate increases, the housing market is expected to have moderate growth
14 (about 3.6% average annual growth) over years 2023 through 2026, then stay relatively flat through
15 2028. SCE's forecasts of both residential and non-residential customers are based on econometric
16 models that correlate changes in the number of customers to a change in economic activity.
17 For example, in the case of residential customers, population growth is used as the leading economic
18 variable to forecast the number of customers. Changes in the number of commercial customers are
19 assumed to be influenced by changes in the number of residential customers, while changes in the
20 number of industrial customers are dependent upon changes in manufacturing employment.

Figure VI-3
Total Non-Farm Employment Growth in the Counties Served by SCE
2014 to 2028

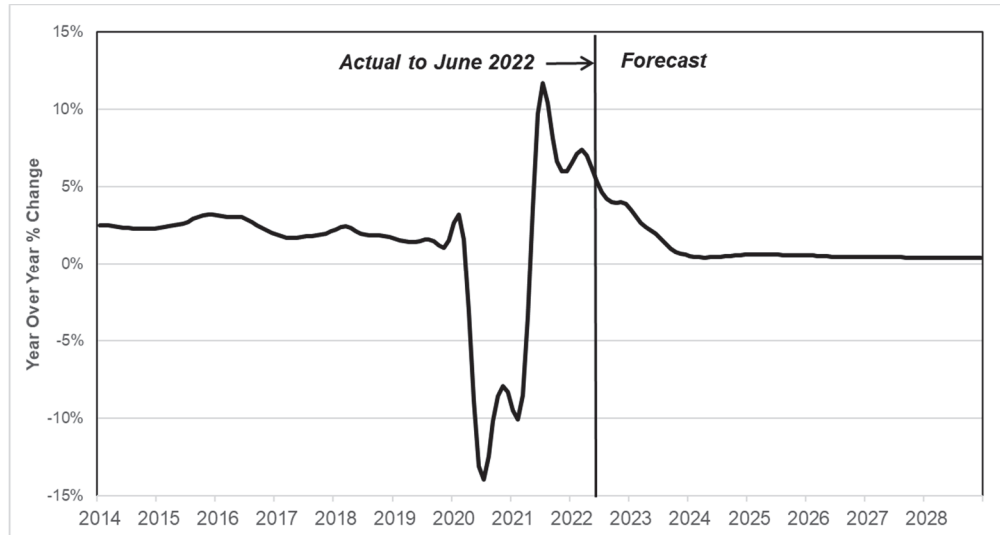
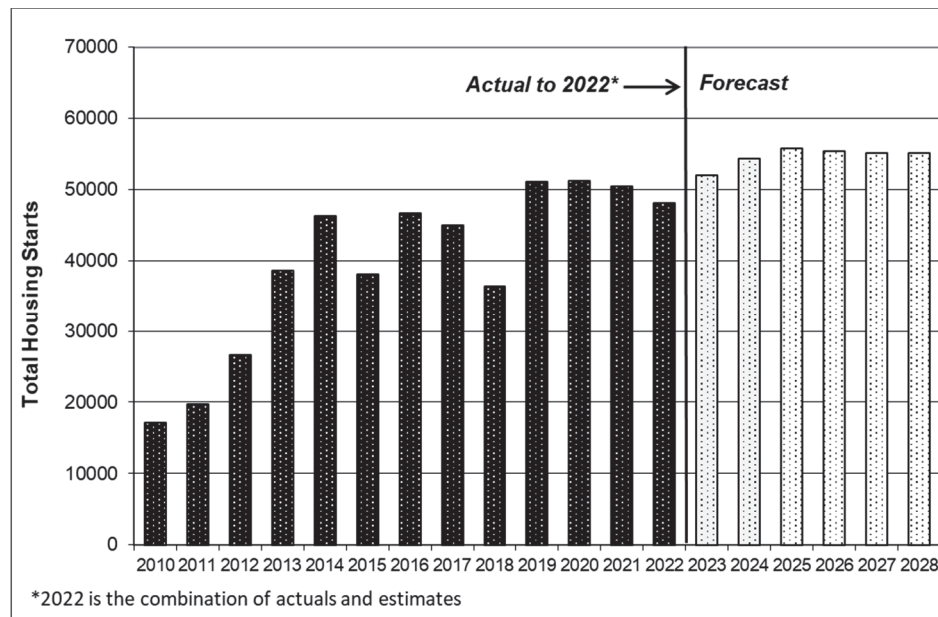


Figure VI-4
Housing Starts in the Counties Served by SCE

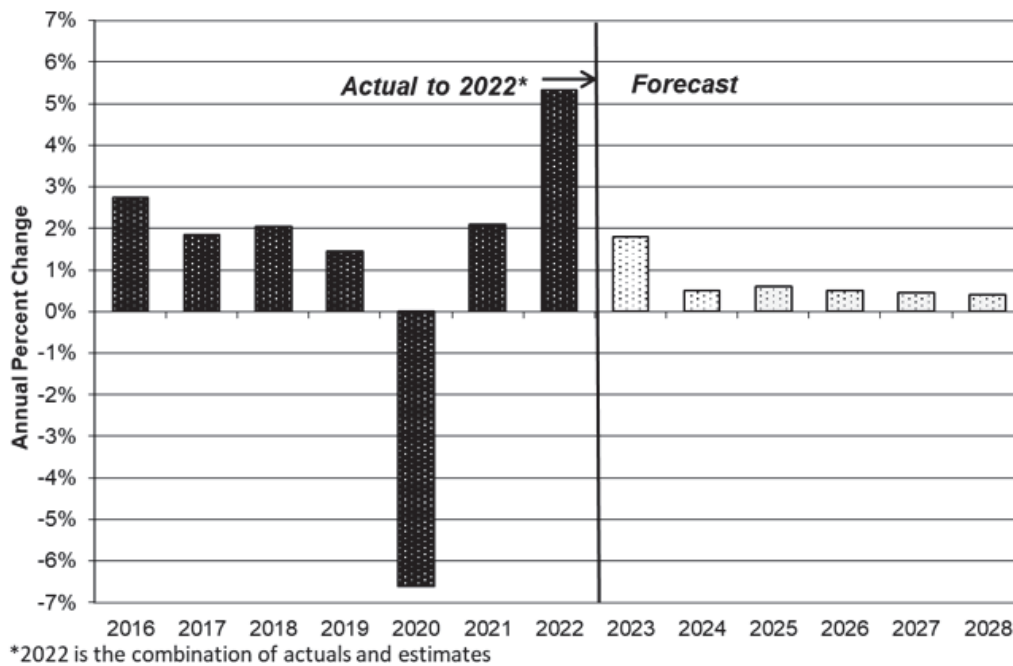


3. Economic Outlook

Based on the average outlooks from Moody's Analytics and S&P Global Market Intelligence, the economy is expected to slow down in 2023 due to short-term economic impacts from

high inflation and interest rate increases, among other reasons. However, it is expected that the economy will show positive growth starting in 2024. The total employment in SCE's service territory is expected to increase 1.8 percent in 2023 and an additional 0.5 percent in 2024, as displayed in Figure VI-4. Housing starts are expected to increase by 8.1 percent and 4.6 percent in 2023 and 2024 respectively, as displayed in Figure VI-4 above. The increases are driven by the expected gain in household formation and the limited availability of existing homes.

Figure VI-5
Total Non-Farm Employment Growth in Counties Served by SCE



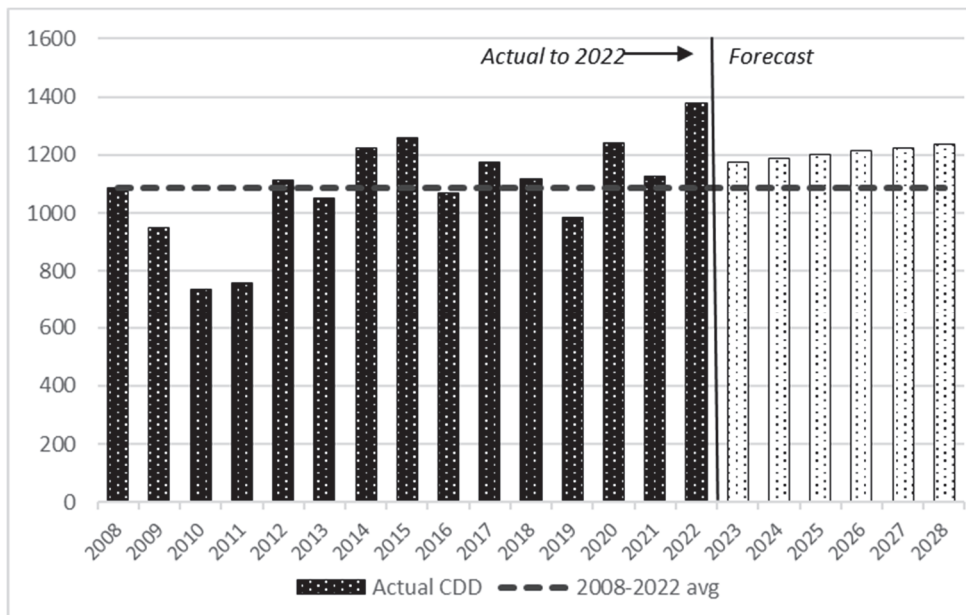
4. Weather Assumptions

SCE uses estimated monthly heating degree days (HDDs) and cooling degree days (CDDs) as inputs to the energy forecast (through consumption/usage forecast models). SCE estimates future temperatures through leveraging historical observed weather data and daily temperature projections from climate models¹⁷¹ to incorporate the long-term climate impact on load. SCE calibrates the General Circulation Model (GCM) results to the observed temperature data. Then SCE fits the calibrated GCM temperature data with a linear trend to extrapolate the future impact of climate change

¹⁷¹ SCE utilizes the daily minimum and maximum temperature projections associated with the RCP 8.5 scenario10 GCMs.

on temperatures (decreasing HDDs and increasing CDDs) from 2022 to 2050. As shown in Figure VI-6 below, SCE's service territory experienced higher-than-normal CDDs in the past 10 years, which reflects the accelerated impact of climate change over that period. Therefore, SCE's forecasted temperatures reflect the warming trend as a result from climate change.

Figure VI-6
Recorded and Forecast Cooling Degree Days¹⁷²



5. Other Factors Influencing the Forecast

Other factors influencing total retail sales during the 2023-2028 period include energy efficiency programs, transportation electrification load (including electric vehicle-charging load), self-generation (such as residential rooftop solar and combined-heat and power installations), behind-the-meter energy storage installations, and building electrification (BE).¹⁷³

a) Energy Efficiency

Energy Efficiency (EE) savings represent electricity consumption that would have taken place in the absence of specific utility-funded programs. In other words, historic retail sales would

¹⁷² Refer to WP SCE-07, Vol. 01, Book A, p. 136-182, Sales and Customer Forecast Methodology, for additional explanation of how cooling degree days is calculated.

¹⁷³ SCE has also incorporated electricity rates in its forecast, but it does not materially drive the sales forecast due to the impacts from the other factors mentioned above.

1 have been higher in the absence of these programs holding all other factors the same. SCE leveraged the
2 California Energy Commission’s (CEC) Integrated Energy Policy Report (IEPR) Additional Achievable
3 Energy Efficiency (AAEE) scenario forecasts to develop its EE forecast. SCE’s EE forecast reflects the
4 reasonably expected EE impact in the future, which is bounded by CEC’s 2021 IEPR “Mid-Mid” and
5 “Mid-High” AAEE scenario forecasts.

6 **b) Transportation Electrification Load**

7 SCE forecasts future transportation electrification (TE) load growth for both light
8 duty vehicle (LDV) load and non-LDV load. Non-LDV load includes medium and heavy duty vehicle,
9 bus, and off-road transportation electrification.

10 SCE’s forecasts incorporate expected decarbonization funding, mandates, and
11 other supportive policies. For LDVs, policies such as the California Air Resource Board’s (CARB)
12 Advanced Clean Cars II and the state’s 100% zero-emission-vehicle (ZEV) sales goal were considered.
13 For medium and heavy-duty vehicles and buses, policies such as CARB’s Innovative Clean Transit,
14 Advanced Clean Trucks, and Advanced Clean Fleet rules were considered. SCE’s forecast also aligns
15 with CARB’s 2022 Scoping Plan for achieving carbon neutrality in the long-term.¹⁷⁴

16 The growth of transportation electrification to date has been profound, and that
17 growth is accelerating. According to the Electric Power Research Institute (EPRI), California EV sales
18 have accounted for 20% of new car sales in 2022, up from 12.6% in 2021.¹⁷⁵ SCE expects the
19 cumulative number of light duty EVs will reach 1,970,060 by 2028, as shown in Table VI-23.

¹⁷⁴ CARB’s 2022 Scoping Plan for achieving carbon neutrality report:
<https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf>.

¹⁷⁵ As of December 2022, data from the Electric Power Research Institute (EPRI) on annual light-duty vehicle sales, based on third-party registration data, is available via subscription.

Table VI-23
Transportation Electrification Load (GWh) and Annual Cumulative Light Duty
Electric Vehicles in SCE's Service Territory

Year	# of Light Duty EVs	Light Duty EVs GWh	Non-Light Duty EV GWh	TE GWh
2022*	436,248	1,809	640	2,449
2023**	581,968	2,405	758	3,163
2024**	769,585	3,190	907	4,096
2025**	988,498	4,059	1,098	5,157
2026**	1,266,426	5,159	1,309	6,469
2027**	1,624,876	6,513	1,562	8,075
2028**	1,970,060	7,777	1,921	9,698

*estimate: Sep 2022 is the latest actual data use for Light Duty EVs.

**forecast

For the medium and heavy-duty forecast, SCE utilizes CEC's 2021 Integrated Energy Policy Report (IEPR) Interagency High Electrification Scenario, which reflects the CARB's Advanced Clean Trucks and Advanced Clean Fleet rules.¹⁷⁶ For bus and off-road transportation electrification, SCE bases its service area forecasts on CEC's 2021 high case forecast.¹⁷⁷

c) Building Electrification

SCE forecasts future building electrification (BE) load growth for residential and commercial space and water heating. SCE's BE forecast incorporates impacts from expected federal and statewide decarbonization policies and funding as well as BE programs. The main impacts to the forecast come from existing or applied for BE programs, increasing electrification requirements in Title 24 building codes and standards, and policy impacts from the federal Inflation Reduction Act (IRA) and the California Air Resource Board's (or CARB's) State Implementation Plan (SIP), among others. SCE expects the BE load to reach 2,028 GWh by 2028.

d) Solar PV

SCE models both the residential and non-residential customer adoptions of solar photovoltaic systems through generalized Bass diffusion models. In general, the residential model

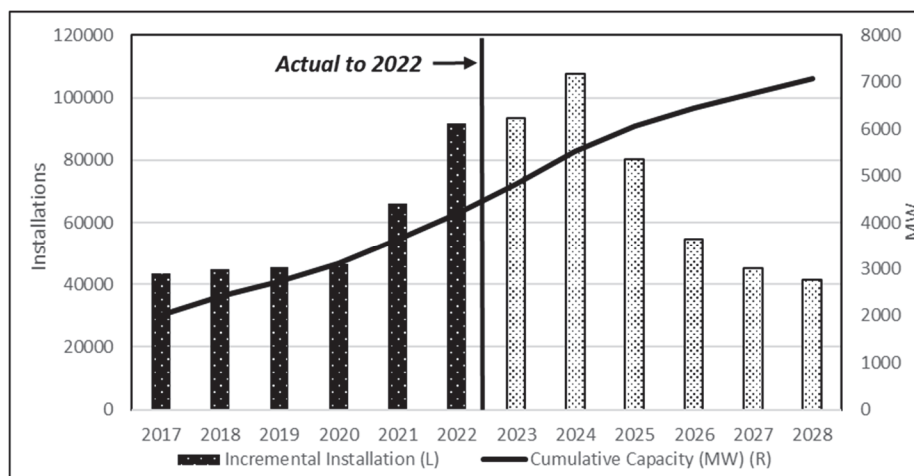
¹⁷⁶ CEC's IEPR Commissioner Workshop on the Electricity and Natural Gas Demand Forecast for 2021–2035: Transportation Forecast and Demand Scenarios Project. Available at <https://www.energy.ca.gov/event/workshop/2021-12/session-2-iepr-commissioner-workshop-electricity-and-natural-gas-demand>.

¹⁷⁷ Javanbakht, Heidi, Cary Garcia, Ingrid Neumann, Anitha Rednam, Stephanie Bailey, and Quentin Gee. 2022. Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast. California Energy Commission. Publication Number: CEC-100-2021-001-V4. Available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581>.

incorporates the most recent solar PV system prices from Bloomberg with adjustments for the existing Federal Income Tax Credit and extension driven by the IRA starting in 2023. Non-residential solar photovoltaic adoption is modeled using a simulated Bass diffusion model calibrated to historical installs.

Additional post-model adjustments were made to account for future incremental PV growth driven by Title 24 building code requirements for both residential and non-residential new constructions. SCE also incorporates the estimated impact of the DG Successor Tariff, which is partially offset by impact from SCE’s recent customer rate increases. Figure VI-7 below shows the historical total PV annual installations and cumulative capacities and forecasts over the period of 2023 to 2028.

Figure VI-7
Total (Res + Non-Res) Solar PV Annual Incremental Installations and Cumulative Installed Capacity Forecast



e) Energy Storage

SCE forecasts adoption of paired solar PV and energy storage systems as well as standalone energy storage systems for residential and non-residential customers in SCE’s service territory.

SCE’s residential battery adoption forecast is based on the Bass diffusion model¹⁷⁸ with estimated market potential and other specified parameters simulated from NREL’s System Advisor Model (SAM) model. Additional post-model adjustments are made to account for incremental system installations funded by the Self Generation Incentive Program Equity Resiliency Incentive

¹⁷⁸ The Bass diffusion model is a standard technology adoption model originally developed in 1969.

Program and the Energy Storage Pilot Program. The non-residential energy storage forecast is modeled separately with a simple trend analysis based on historical adoptions.

The historical accelerated growth of behind-the-meter battery storage installations is expected to continue for both residential and nonresidential sectors. The total annual storage system installations are estimated to increase by about 46% on average for residential and nonresidential sectors between years 2022 to 2025. The forecasted adoption and capacity are shown in Table VI-24 below.

Table VI-24
Total (Res + Non-Res) Cumulative Energy Storage Annual Installation and Capacity Forecast

Year	Annual Installation	Annual Capacity (MW)
2022*	31,663	457
2023**	45,442	620
2024**	59,767	798
2025**	75,316	995
2026**	91,188	1,203
2027**	108,231	1,428
2028**	126,440	1,670

*2022 is the combination of actual installation through June and estimates for remaining months.

**forecast

6. **Total Retail Sales Forecast by Customer Class**

Table VI-25 below presents SCE's forecast of total electricity sales by customer class. The table shows actual sales in 2021 and 2022 and forecast numbers from 2023 to 2028. The projected average annual growth in total retail sales is 1.7 percent from 2024-2028 based on recorded retail sales in 2022.

Table VI-25
Annual Retail Sales by Customer Class (GWh)

	2021	2022	2023*	2024*	2025*	2026*	2027*	2028*
Residential	30,758	31,604	28,530	28,900	29,186	30,168	31,515	32,670
Agricultural	1,904	1,692	1,755	1,754	1,769	1,783	1,799	1,804
Commercial	41,454	43,838	43,835	44,703	45,706	46,725	47,782	48,877
Industrial	4,696	4,145	4,672	4,256	3,923	3,538	3,158	2,973
Public Authorities**	4,519	4,592	4,174	4,149	4,105	4,073	4,041	4,010
Total Retail Sales	83,331	85,870	82,966	83,762	84,689	86,287	88,295	90,334

*Forecast

**Includes public authorities - other, street lighting, special contracts, railways and interdepartmental

B. Customer and New Meter Connection Forecasts

Table VI-26 and Table VI-27 present the forecasts of total electricity customers and new meter connections by customer class, respectively, for 2023-2028 and 2022 recorded. Both residential new customers and new meter connections are closely tied to activity in the residential construction sector, with lags of up to 12 months, meaning that a change in the number of new meter connections or new customers is typically a result of a change in the number of housing starts that occurred up to 12 months earlier. For this reason, our forecast of new customers and new meter connections follows closely the housing market cycle described above. Over the period from 2024 to 2028, total customer growth is projected to average about 0.65 percent per year, which is slightly higher than the 0.58 percent average annual growth recorded from 2018 to 2022.¹⁷⁹

Table VI-26
Year-End Customers by Customer Class

	2021	2022	2023*	2024*	2025*	2026*	2027*	2028*
Residential	4,498,761	4,541,114	4,564,681	4,595,175	4,626,593	4,658,452	4,690,292	4,722,159
Agricultural	19,551	18,856	18,760	18,703	18,573	18,408	18,245	18,082
Commercial	604,964	608,757	613,766	617,392	621,063	624,756	628,458	632,158
Industrial	6,932	5,650	5,723	5,625	5,515	5,438	5,362	5,294
Public Authorities*	70,619	69,163	70,617	70,033	70,062	69,939	69,752	69,519
Total	5,200,827	5,243,540	5,273,546	5,306,928	5,341,806	5,376,993	5,412,109	5,447,212

*Forecast

**Includes public authorities - other, street lighting, special contracts, railways and interdepartmental

Similar to the residential new customer forecast, SCE's residential new meter installation activities are closely tied to activities in the residential construction sector, with lags of up to 12 months, meaning that a change in the number of residential new meter connections is typically a result of a change in the number of housing starts that occurred up to 12 months earlier. Table VI-27 presents the forecast of total new meter connections by customer class for 2023-2028 and 2022 recorded.

¹⁷⁹ Although the historical average of customer growth is close to the average of SCE's forecasted customer growth, it should not be considered a substitute for the forecast. Historical averages are not economic forecasts and produce results that are inconsistent with historical correlations between new meter connections and residential construction. In addition, the historical average covers the period of the COVID-19 pandemic, and therefore reflects the significant, once-in-a-generation economic impact of the pandemic.

Table VI-27
New Meter Connections

	2022	2023*	2024*	2025*	2026*	2027*	2028*
Residential	31,201	33,330	31,573	33,421	36,084	36,768	36,154
Agricultural	147	184	184	184	184	184	184
Non-Residential	3,395	3,918	3,918	3,918	3,918	3,918	3,918
Total New Meters	34,743	37,432	35,675	37,523	40,186	40,870	40,256

*Forecast

As highlighted in the Historical Trend section above (section VI.A.2), housing starts have shown strong positive growth since 2019 despite the COVID-19 pandemic. However, housing starts began to fall after the Federal Reserve began tightening its monetary policy. Moderate growth is still expected for SCE housing starts in the next few years given the housing demand and supply conditions as well as the tempered economic growth outlooks from economic forecast vendors. Given increasing housing market volatility in recent months, SCE establishes its most-up-to-date housing starts outlooks by averaging the January 2023 forecasts from Moody's Analytics and S&P Global Market Intelligence.

The compound annual growth rate (CAGR) of projected annual housing starts is expected to be 2.8% over years 2023 to 2028, lower than the 5.2% CAGR over the past 5 years (or from 2018 to 2022). Given the established housing starts outlooks, SCE expects the number of new residential meter connections to reach 33,421 in 2025, 36,084 in 2026, and 36,768 in 2027, and to decrease slightly to 36,154 in 2028. SCE considers this forecast to be conservative due to additional impacts not necessarily captured in the vendors' top-down economic forecasts. Those include regional housing development impacts from California policies such as the Affordable Housing Act and large sport events such as the 2028 Summer Olympics in Los Angeles.

Per the final decision in SCE's 2021 GRC (D.21-08-036), SCE agreed to reexamine its commercial/industrial new meter forecast model and propose a new or improved method to better reflect the commercial new meter growth. Based on this further investigation, SCE has decided to adopt a new approach in forecasting commercial new meter growth. SCE's new method is a simple linear trend projection leveraging most recent installation history as well as data and knowledge from SCE's local planning and operation organizations. SCE had previously utilized the statistical model to forecast commercial new meter growth. However, given the changing dynamics in commercial development, SCE has recognized the limitation of applying the statistical approach currently due to lack of strong indicator(s) SCE analyzed so far. SCE will continue exploring and validating the statistical modeling

1 approach, and may propose a different method to forecast commercial new meter installations in its next
2 GRC.

VII.

PRESENT RATE REVENUE

This chapter supports the development of both the Total System Present Rate Revenue (TSPRR) and the GRC Related Present Rate Revenue (GRCPRR) and discusses the differences between the two amounts. As explained below, the GRCPRR is a subset of the TSPRR and is used to determine the estimated revenue change requested in this proceeding for 2025, 2026, 2027, and 2028.

A. Total System Present Rate Revenue

TSPRR is based on the kilowatt hour (kWh) sales forecast included in Chapter VI of this volume and rate levels effective March 1, 2023 pursuant to Advice 4977-E submitted on February 27, 2023. This section provides the forecast TSPRR for Test Year 2025, and post-test years 2026, 2027 and 2028.¹⁸⁰

1. Methodology for the Development of Total System Present Rate Revenue Estimates

a) Forecast of Sales

Chapter VI of this volume forecasts SCE's net kWh sales by revenue class through 2028. The five defined revenue classes are: Residential, Commercial, Industrial, Agricultural, and Other Public Authorities (OPA). These forecasts include customers by revenue class as well. The determination of the TSPRR requires converting these revenue class forecasts to forecasts of billing determinants by rate group. The TSPRR is then the product of present rates and the forecast billing determinants. The basic rate groups that we use to develop the TSPRR are defined in subsection (b) below.

b) Revenue Class and Rate Group Statistical Data

Individual customer usage statistics generally are aggregated and summarized by two broad categories: revenue class and rate schedule. Revenue class data aggregate usage statistics by similar end use criteria. Rate schedule data aggregate usage statistics by groupings with relatively homogeneous load characteristics and methods of service.

In nearly all Company-sponsored publications, statistical data is compiled and reported by revenue class, consistent with our procedures for reporting to FERC.

The five classifications, identified above, are widely used and broadly understood and, as a result, are generally accepted by the electric utility industry for statistical reporting. In addition,

¹⁸⁰ Refer to WP SCE-07, Vol. 01, Book B, pp. 1-430, Present Rate Revenue Workpapers.

many government and industry statistical series are gathered and reported on this basis. Data aggregated by these classifications provide information that tends to be predictable with some degree of confidence.

Statistical data is also gathered by rate schedule and is grouped and compiled according to rate group for ratemaking purposes. Rate groups are designated as follows:

- Domestic
- TOU-GS-1: Lighting – Small and Medium Power, Time Of Use Non-Demand Metered
- TOU-GS-2: Lighting – Small and Medium Power, Time Of Use Demand Metered
- TOU-GS: Lighting – Small and Medium Power, Time Of Use
- TC-1: Traffic Control
- Large Power – Secondary Voltage
- Large Power – Primary Voltage
- Large Power – Sub-transmission Voltage
- Large Power – Secondary Voltage - Standby
- Large Power – Primary Voltage – Standby
- Large Power – Sub-transmission Voltage – Standby
- TOU-PA-2: Agricultural and Pumping, whose monthly kW is below 200
- TOU-PA-3: Agricultural and Pumping, whose monthly kW is above 200
- Street and Area Lighting

These groupings enable costs to be allocated to groups of customers with relatively homogeneous load characteristics and methods of service, and provide a link between incurrence of costs, development of rates, and recovery of revenues across revenue classes. For example, nondomestic customers who, as a group, use relatively small amounts of energy and have relatively small demands are grouped together as the Lighting Small and Medium Power, Time of Use Non-Demand Metered Rate Group. The rate groups listed above, with some modification, have been retained over time to generally provide for consistency of data from one GRC to the next.

The interrelationship between revenue class and rate group can be demonstrated by describing how these classifications relate to individual rate schedules through an example.

Assume there are only two revenue classes of customers, Commercial and Industrial, and only two rate groups: (1) Lighting-Small and Medium Power, Non-Demand-Metered,

and, (2) Large Power-Secondary Voltage, that take service under rate schedules TOU-GS-1 and TOU-8-S, respectively. Commercial and Industrial customers would be allowed to take service in either of these rate schedules, but customers on Schedule TOU-GS-1 would be included in the Lighting-Small and Medium Power, Non-Demand-Metered Rate Group, while customers on Schedule TOU-8-S would be included in the Large Power Group-Secondary Voltage Rate Group. This situation is illustrated in Table VII-28.

Table VII-28
Illustrative Revenue Classes By Rate Group

Line No.	Revenue Class		Rate Group	
1.	Commercial	Industrial	Lighting-Small & Medium Power—Non-Demand	Large Power—Secondary Voltage
2.	TOU-GS-1	TOU-GS-1	TOU-GS-1	
3.	TOU-8-S	TOU-8-S		TOU-8-S

c) **Forecast of Billing Determinants by Rate Schedule**

(1) **Description of Forecasting Methodology**

SCE uses statistical methods to analyze time-series data to forecast kWh sales by revenue class by rate schedule, based in part upon five years of recorded data. Other related billing determinants by rate schedule, such as usage by time-period, are derived from the forecast kWh sales and historical usage patterns.

The statistical models forecast kWh and average customers for each rate schedule within each revenue class. These independent forecasts of kWh by rate schedule by revenue class are then normalized to the total revenue class kWh forecasts described in Chapter VI of this exhibit.

(2) **Forecast of Billing Determinants**

Using the above-described method, rate schedule bill month forecasts are also normalized to match the revenue class forecasts. Kilowatt month forecasts are tied to the kWh and bill month forecasts based on both a direct forecast of billing demand by rate schedule and by historical load factors. The final output of the model is a forecast of billing determinants in total for each rate

schedule. These billing determinants are then spread to the appropriate rate group and/or time period based on historical relationships to develop the billing determinants by rate schedule necessary to estimate the TSPRR.

2. Total System Present Rate Revenue Forecast

The billing determinants (customer usage data, such as: net kWh sales, billing kilowatt months, billing horsepower, bill months, number and type of lamps, voltage and power factor adjustment data, and other miscellaneous customer usage data) developed for each rate schedule are then multiplied by the various billing factors for each rate schedule. In addition, SCE forecasts both Bundled and Departing Load (DL) customer billing determinants separately since these customers pay different generation-related charges.

This product of billing factors and billing determinants, for both Bundled and DL customers is, in fact, developed separately for generation, as well as PCIA charges, distribution, transmission, nuclear decommissioning, public purpose programs, and other miscellaneous revenue components. The sum of these component revenues is the TSPRR.

TSPRR is the revenue that is estimated to be billed for service rendered during a particular forecast period. The TSPRR has been estimated for the forecast years 2023 through 2028.¹⁸¹ Table VII-29 below shows the average number of customers, GWh sales, TSPRR, for base year 2022 and for forecast years 2023 through 2028.

***Table VII-29
Average Customers, Sales And Total System Present Rate Revenue
2022 through 2028***

Line No.	Year	Customers	Sales (GWh)	TSPRR (\$000)
1	2022	5,227,646	85,996	\$16,009,690
2	2023	5,259,793	82,966	\$16,452,532
3	2024	5,291,686	83,762	\$16,444,674
4	2025	5,325,820	84,689	\$16,367,266
5	2026	5,360,866	86,287	\$16,578,703
6	2027	5,396,014	88,295	\$16,960,119
7	2028	5,431,123	90,334	\$17,356,678

¹⁸¹ Refer to WP SCE-07, Vol. 01, Book C, pp. 1-310, Retail Sales and Customer Forecast.

1 **B. GRC Present Rate Revenue**

2 As discussed above, the TSPRR reflects the total amount of revenue associated with currently
3 adopted rate levels. However, in this proceeding, SCE is not requesting a revenue requirement
4 associated with the total cost of providing service to retail customers, so comparing the TSPRR to the
5 GRC requested revenue requirement is not appropriate. Therefore, as discussed in this section, in order
6 to determine the appropriate amount of revenue change requested in this proceeding, the GRC-related
7 Present Rate Revenue (GRCPRR) must be determined. This section provides the forecast of the
8 GRCPRR for the 2025 test year and post-test years 2026, 2027 and 2028.

9 **1. Determination of the GRC Present Rate Revenue**

10 Consistent with past GRC applications, SCE's requested revenue requirement in this
11 proceeding is only a subset of the total costs to serve its customers. For example, SCE is not seeking
12 revenue required with the recovery of fuel and purchased power costs. Therefore, the GRCPRR excludes
13 revenue associated with recovery of fuel and purchased power costs. Table VII-30 shows a comparison
14 between Total System cost categories included in each rate component, and cost categories included in
15 the GRCPRR.

Table VII-30
TSPRR and GRCPRR
Cost Components

Rate Component	Cost Components	
	TSPRR	Included in GRC Revenue Requirement and GRCPRR
Generation/PCIA	1) Base Generation 2) Fuel 3) Purchased Power	1) Base Generation
Distribution	1) Base Distribution 2) Other Distribution	1) Base Distribution
New System Generation	1) Base NSG (Peakers/Energy Storage) 2) Purchased Power	1) Base NSG
Transmission	1) Base Transmission 2) TRBAA 3) RSBAA 4) TACBA	N/A
Nuclear Decommissioning	1) Trust (currently \$0) 2) Spent Nuclear Fuel	N/A
Public Purpose Programs	1) CPUC-Authorized Public Purpose Programs	N/A
DWR	1) Power Charge (currently \$0) 2) WF Fund NBC	N/A
Fixed Recovery Charges	1) CPUC-Authorized AB 1054 FRCs	N/A

2. GRC Present Rate Revenue Forecast

To determine the GRCPRR for each forecast year, SCE first determined the GRC-related rate in present rate levels, which is based on the GRC-related revenue requirements and adopted kWh sales used to set rate levels as of March 1, 2023.¹⁸² The GRCPRR shown in Table VII-31 below is determined by applying the calculated present GRC-related rates to the kWh forecast set forth in Chapter V of this volume. Table VII-31 also sets forth the average number of customers and kWh sales forecast for 2024 through 2028. As discussed in Chapter III of this volume, when determining the total GRC-related revenue change requested in this proceeding, SCE includes annual GRCPRR sales growth

¹⁸² Present rates are those rates implemented in Advice 4977-E submitted on February 27, 2023.

amounts that equal the change in the GRCPRR from one year to the next. For example, the GRC Revenue Growth amount shown on Table III-5 for 2025 in the amount of a \$86.371 million is equal to the difference between the 2025 GRCPRR and the 2024 GRCPRR.¹⁸³

Table VII-31
Average Customers, Sales and GRC Present Rate Revenue
2024 through 2028

Line No.	Year	Customers	Sales (GWh)	GRCPRR (\$000)
1	2024	5,306,928	83,762	7,804,322
2	2025	5,341,806	84,689	7,890,693
3	2026	5,376,993	86,287	8,039,583
4	2027	5,412,109	88,295	8,226,673
5	2028	5,447,212	90,334	8,416,652

¹⁸³ Refer to WP SCE-07, Vol. 01, Book C, pp. 311-312, Average Customers, Sales and GRC Present Rate Revenue, for support of the development of the GRCPRR.

1 **VIII.**

2 **COST ESCALATION**

3 This chapter estimates the effects of inflation on the labor, non-labor, and capital costs of an
4 electric utility in California. In this chapter SCE explains and supports the escalation rates used to
5 deflate recorded O&M and administrative and general (A&G) recorded expenses from 2018 - 2022 and
6 inflate forecast O&M and A&G expenses for 2023 - 2028. SCE also explains and supports the escalation
7 rates used to forecast the inflationary effects on capital expenditures. SCE requests to include in its
8 revenue requirement the expenses it expects to incur from 2025-2028 for labor, materials, and services.

9 Section 1 of this chapter summarizes the O&M and A&G escalation rates that SCE developed
10 for use in this proceeding. Section 2 provides the methodology and sources SCE used to develop the
11 O&M and A&G escalation rates. In this section, SCE also presents the escalation rates developed for
12 Palo Verde Nuclear Generating Station (Palo Verde) O&M escalation. In Section 3, SCE summarizes
13 and explains the capital escalation rates used in this proceeding. In Section 4, SCE presents testimony on
14 the GRC update testimony it intends to file after the hearings. Section 5 demonstrates the difference
15 between S&P Global Market Intelligence escalation rate components and the components used to
16 estimate CPI-U and why CPI-U is an inappropriate index to use for estimating inflation impacts upon an
17 electric utility in California.

18 **A. O&M and A&G Escalation Rates**

19 SCE estimates the labor escalation rate for all represented and non-represented employees. SCE
20 estimates the non-labor escalation rates with the functional categories that have been authorized by the
21 Commission in previous GRC decisions:¹⁸⁴ steam production, hydro production, other power
22 production, transmission plant, distribution plant, customer accounts, customer service and information
23 (CS&I), administrative and general (A&G), and nuclear production. These escalation rates are
24 summarized in the below “Labor” and “Non-Labor” sections.

25 **1. Labor**

26 Labor price indices and escalation rates are shown in Table VIII-32 below.¹⁸⁵

¹⁸⁴ D.21-08-036, p. 540.

¹⁸⁵ Refer to WP SCE-07, Vol. 01, Book D, p. 3, Labor O&M Escalation Rates.

Table VIII-32
Labor O&M Escalation Rates

Label	Description	SCE AHE					S&P Global Blended Escalation					
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SCE Labor O&M Blended Escalation - 2022 Base Year	Inflation Index	0.901	0.927	0.936	0.961	1.000	1.055	1.088	1.120	1.152	1.184	1.217
	Deflation Index	1.110	1.078	1.068	1.041	1.000	0.948	0.919	0.893	0.868	0.844	0.822
	Percent Change	2.28%	2.89%	0.94%	2.65%	4.09%	5.50%	3.15%	2.92%	2.85%	2.81%	2.78%

a) Non-labor

Non-labor price indices and escalation rates are shown in Table VIII-33 below.¹⁸⁶

Table VIII-33
Non-Labor O&M Escalation Rates

SCE Variable Name	Description	S&P Global Non-Labor O&M Escalation Rates										
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Steam Generation	Inflation Index	0.806	0.826	0.828	0.889	1.000	1.008	0.994	1.001	1.016	1.033	1.052
	Deflation Index	1.241	1.211	1.207	1.125	1.000	0.992	1.006	0.999	0.985	0.968	0.951
	Percent Change	3.72%	2.47%	0.35%	7.27%	12.52%	0.84%	-1.42%	0.69%	1.47%	1.69%	1.84%
Hydro Generation	Inflation Index	0.803	0.821	0.814	0.875	1.000	1.013	0.993	0.996	1.008	1.024	1.041
	Deflation Index	1.245	1.218	1.229	1.143	1.000	0.988	1.008	1.004	0.992	0.977	0.960
	Percent Change	5.92%	2.21%	-0.89%	7.47%	14.34%	1.25%	-1.97%	0.34%	1.20%	1.60%	1.70%
Other Generation	Inflation Index	0.826	0.846	0.847	0.887	1.000	1.020	1.006	1.013	1.027	1.044	1.062
	Deflation Index	1.211	1.181	1.181	1.127	1.000	0.980	0.994	0.987	0.974	0.958	0.942
	Percent Change	4.53%	2.50%	0.02%	4.81%	12.69%	2.03%	-1.39%	0.71%	1.38%	1.60%	1.73%
Transmission	Inflation Index	0.818	0.836	0.838	0.888	1.000	1.004	0.980	0.983	0.994	1.007	1.022
	Deflation Index	1.223	1.196	1.193	1.126	1.000	0.996	1.020	1.017	1.006	0.993	0.978
	Percent Change	2.92%	2.25%	0.22%	6.01%	12.55%	0.44%	-2.44%	0.35%	1.08%	1.34%	1.45%
Distribution	Inflation Index	0.757	0.775	0.775	0.856	1.000	0.992	0.958	0.959	0.967	0.979	0.993
	Deflation Index	1.321	1.290	1.290	1.168	1.000	1.008	1.044	1.043	1.034	1.021	1.007
	Percent Change	3.70%	2.40%	0.04%	10.41%	16.80%	-0.83%	-3.38%	0.05%	0.91%	1.25%	1.43%
Customer Accounts	Inflation Index	0.826	0.850	0.844	0.895	1.000	1.032	1.028	1.048	1.071	1.092	1.115
	Deflation Index	1.211	1.176	1.184	1.117	1.000	0.969	0.973	0.954	0.934	0.915	0.897
	Percent Change	3.15%	2.95%	-0.67%	6.01%	11.74%	3.15%	-0.32%	1.90%	2.17%	2.05%	2.08%
Customer Service and Information	Inflation Index	0.811	0.834	0.820	0.872	1.000	1.019	0.998	1.012	1.030	1.048	1.067
	Deflation Index	1.233	1.199	1.220	1.147	1.000	0.982	1.002	0.988	0.971	0.954	0.937
	Percent Change	3.29%	2.84%	-1.70%	6.41%	14.66%	1.86%	-2.00%	1.40%	1.73%	1.75%	1.80%
Administration and General	Inflation Index	0.880	0.899	0.907	0.946	1.000	1.027	1.037	1.054	1.074	1.095	1.117
	Deflation Index	1.137	1.112	1.103	1.057	1.000	0.974	0.964	0.949	0.931	0.913	0.895
	Percent Change	1.77%	2.20%	0.87%	4.34%	5.69%	2.70%	0.97%	1.64%	1.87%	1.97%	2.00%
Nuclear Generation	Inflation Index	0.817	0.836	0.834	0.893	1.000	1.012	1.001	1.011	1.027	1.046	1.065
	Deflation Index	1.224	1.196	1.200	1.120	1.000	0.988	0.999	0.989	0.974	0.956	0.939
	Percent Change	3.45%	2.35%	-0.32%	7.12%	11.97%	1.18%	-1.05%	0.97%	1.59%	1.80%	1.90%

¹⁸⁶ Refer to WP SCE-07, Vol. 01, Book D, p. 4, Non-Labor O&M Escalation Rates.

2. O&M Methodology and Estimates

The following sections explain how SCE used the rates from the tables above to develop labor and non-labor escalation rates for the recorded period (2018 - 2022) and the forecast period (2023 - 2028).

a) Labor Escalation

SCE developed the labor escalation rates in Table VIII-32 using four sources of information:

1. Average Hourly Earnings (AHE) based on recorded SCE payroll data for 2018-2022.
2. Actual labor escalation rates for both represented and non-represented employees for 2023.
3. Collective Bargaining Agreements based on in-force collective bargaining agreements that specify straight time wage increases for represented employees for 2024-2025.
4. S&P Global Market Intelligence forecasts of labor escalation rates for U.S. electric utilities for Professional and Technical workers and Managers and Administrators (non-represented) for 2024-2028, and for Physical Workers (represented) from 2026-2028.

(1) Recorded Period - 2018 - 2022 - Recorded SCE Payroll Data

SCE recorded labor escalation is based on calculating actual AHE for non-executives across the company. The AHE calculation utilizes actual hourly wages paid and corresponding hours for straight time, overtime and double-time labor. To calculate the AHE, effective hours are calculated as the sum of: (i) straight-time hours, (ii) overtime hours, and double-time hours. Wages are summarized across three categories, dividing overtime wages by 1.5, and dividing double-time wages by 2. Then the total effective wages are divided by total hours worked to calculate average hourly earnings. This method removes the effect of year-to-year variations in overtime and double-time hours worked.

(2) Forecast Period - 2023 – 2028 ¹⁸⁷

(a) Collective Bargaining Agreements

For 2023, SCE's represented employees received a wage increase of 5.50 percent based on the collective bargaining agreement with the International Brotherhood of

¹⁸⁷ Refer to WP SCE-07, Vol. 01, Book D, p. 3, Labor O&M Escalation Rates.

1 Electrical Workers (IBEW). For 2024 and 2025, SCE’s represented employees will receive wage
2 increases of 3.25 percent and 3.00 percent, respectively, based on the aforementioned collective
3 bargaining agreement with IBEW. For 2026 – 2028, SCE has no collective bargaining agreement in
4 place, therefore the represented employee labor escalation rate is based on S&P Global Market
5 Intelligence forecasts, as explained below.

6 (b) **S&P Global Market Intelligence Forecasts of Labor Escalation**

7 SCE purchases economic projection data from S&P Global Market
8 Intelligence, one of the largest and most respected economic forecasting services in the world. S&P
9 Global Market Intelligence provides projections of wage increases for professional and technical
10 workers (non-represented), managers and administrators (non-represented), and physical workers
11 (represented). The SCE physical workers represented category includes electric power generation,
12 transmission, and distribution workers. The S&P Global Market Intelligence labor cost projections are
13 national projections and are not specific to the Western U.S. or Southern California.

14 For 2023, SCE represented and non-represented employees have
15 received an average actual wage increase of 5.50 percent. To estimate total company labor escalation for
16 2024 - 2028, SCE constructed a weighted average of forecast labor escalation rates provided by S&P
17 Global Market Intelligence¹⁸⁸ publication and the negotiated and ratified labor rate escalation for
18 physical workers set forth in the current collective bargaining agreement for 2024 through 2025. No
19 ratified collective bargaining agreement is in place for 2026 forward.

20 The respective weights for the different labor escalation forecasts
21 from S&P Global Market Intelligence for “Professional and Technical Workers” and “Managers and
22 Administrators” and 2023 IBEW collective bargaining agreement for “Physical Workers” are detailed in
23 Table VIII-34 below.¹⁸⁹ The weighting is based on the total wages paid by the specified employee
24 categories in 2022.

¹⁸⁸ S&P Global Market Intelligence Power Planner, Fourth-quarter 2022, published January 2023.

¹⁸⁹ Refer to WP SCE-07, Vol. 01, Book D, pp. 5-6, Labor O&M Wage Escalation Composite.

Table VIII-34
Labor O&M Escalation Weighting

Employee Category	S&P Global Variable	Share of Total Wages
Professional and Technical Workers	ECIPWPARN.S.A.FOP2 - United States, Wages and Salaries, Private, Professional and Related	44.32%
Managers and Administrators	ECIPWMBFNS.A.FOP2 - United States, Wages and Salaries, Private, Management, Business, Financial	17.65%
Physical Workers (represented employees)	CEU4422110008.A.FOP2 - United States, Average Hourly Earnings, Electric Power Generation Transmission and Distribution	38.03%
Total		100.00%

b) Non-labor O&M Escalation

(1) S&P Global Market Intelligence Indices

For recorded and forecast non-labor O&M escalation, SCE uses indices provided by S&P Global Market Intelligence's¹⁹⁰ publication. S&P Global provides indices of O&M combined materials and services costs by the functional O&M categories of steam production, hydro production, other power production, transmission plant, distribution plant, customer accounts, customer service information (CS&I), administrative and general (A&G), and nuclear production. To develop the respective escalation factors for each forecast year, 2023-2028, SCE re-bases the indices to equal 1.000 in 2022, the last recorded year. SCE's non-labor indices and non-labor escalation rates are shown above in Table VIII-33.

c) Blended O&M Escalation For Palo Verde

SCE does not operate Palo Verde, rather it is operated by Arizona Public Service (APS). APS bills SCE for its proportional share of operating costs, including both labor and non-labor costs. SCE books payments sent to APS as a non-labor expense. To properly escalate these O&M costs, SCE develops a weighted average labor and non-labor O&M escalation rate specific for Palo Verde. The current labor weighting for Palo Verde is 55.87% and the non-labor weighting is 44.13%. In order to provide relevant indices, SCE re-bases the indices to equal 1.000 in 2022, so the base year of the

¹⁹⁰ S&P Global Market Intelligence Power Planner, Fourth-quarter 2022, published January 2023.

index is equal to 1.000 during the last recorded year (2022). SCE illustrates the Palo Verde escalation rates below in Table VIII-35.¹⁹¹

Table VIII-35
Palo Verde Blended O&M Escalation Rates

Label	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SCE Palo Verde O&M	Inflation Index	0.866	0.869	0.879	0.923	1.000	1.030	1.046	1.069	1.093	1.119	1.145
Blended Escalation -	Deflation Index	1.154	1.151	1.138	1.083	1.000	0.971	0.956	0.936	0.915	0.894	0.873
2022 Base Year	Percent Change	1.65%	0.31%	1.11%	5.09%	8.30%	2.96%	1.56%	2.20%	2.29%	2.35%	2.37%

d) Health Care Escalation

In Exhibit SCE-06, Volume 04, Chapter VIII, SCE presents estimates of test year health care costs that do not incorporate the non-labor escalation rates discussed here. Because SCE treats health care cost trends separately, the effect of health care changes is removed from the A&G non-labor escalation rates in this chapter. This was done by utilizing A&G non-labor escalation rates from S&P Global Market Intelligence that exclude health care cost escalation. Therefore, there is no double-counting of escalation between the health care escalation rates in Exhibit SCE-06, Volume 04, and the escalation rates illustrated within this chapter.

3. Capital Cost Escalation

a) Purpose

This section presents the forecast capital escalation rates that will be used to escalate capital additions for attrition years as discussed further in SCE-07 Volume 4. Forecast capital escalation rates for all variables, except General Plant, are based on the S&P Global Market Intelligence Construction Costs Indices.¹⁹² Table VIII-36 summarizes the capital escalation rates developed for this case.¹⁹³

SCE estimated capital escalation rates for the following functional categories:

- Nuclear – Palo Verde
- Generation – Hydro
- Generation – Other (Gas Peaker Plants and Mountainview)

¹⁹¹ Refer to WP SCE-07, Vol. 01, Book D, pp. 7-9, Palo Verde O&M Labor and Non-Labor Blended Escalation Rates.

¹⁹² S&P Global Market Intelligence Power Planner, Fourth-quarter 2022, published January 2023.

¹⁹³ Refer to WP SCE-07, Vol. 01, Book D, pp. 10-13, Capital Escalation Rates.

- Transmission
- Distribution
- General Plant

b) Capital Escalation Rates

SCE's capital escalation rates, except for General Plant, are based on the S&P Global Market Intelligence forecasts of the Handy-Whitman Index of Public Utility Construction Costs.¹⁹⁴ For 2022 - 2028, SCE used the S&P Global Market Intelligence Forecast of Handy-Whitman Construction Cost Indices for the Pacific and Plateau Region.¹⁹⁵

For General Plant capital escalation, SCE built an index to estimate General Plant inflation.¹⁹⁶ The weighting of the General Plant cost categories that comprise the General Plant index is based on average recorded General Plant costs for 2018-2022 as recorded in SCE's FERC Form 1.

The General Plant cost categories are assigned the appropriate S&P Global Market Intelligence variables¹⁹⁷ and weighted by the General Plant average recorded costs for 2018-2022.

¹⁹⁴ The Handy-Whitman Indices are published by Whitman, Requardt, and Associates, LLP, located in Baltimore, Maryland, as they have been since 1924. SCE has used Handy-Whitman indices in various General Rate Cases. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company use various Handy-Whitman indices in constructing their respective escalation indices in their General Rate Cases.

¹⁹⁵ S&P Global Market Intelligence Power Planner, Fourth-quarter 2022, published January 2023 - Cost Trends of Electric Utility Construction: Pacific Region, Table A14.

¹⁹⁶ Refer to WP SCE-07, Vol. 01, Book D, p. 11, Capital Escalation Rates.

¹⁹⁷ S&P Global Market Intelligence Short Term Macro Forecast January 2023. Refer to WP SCE-07, Vol. 01, Book D, p. 13, Capital Escalation Rates.

Table VIII-36
Capital Escalation Rates

SCE Variable Name	Description	S&P Global Capital Escalation Rates						
		2022	2023	2024	2025	2026	2027	2028
Nuclear Palo Verde	Inflation Index	1.000	1.019	1.019	1.020	1.017	1.013	1.018
	Deflation Index	1.000	0.981	0.982	0.980	0.984	0.987	0.983
	Percent Change	7.54%	1.90%	-0.01%	0.13%	-0.36%	-0.36%	0.49%
Hydro Generation	Inflation Index	1.000	1.001	0.993	0.991	0.993	0.997	1.004
	Deflation Index	1.000	0.999	1.007	1.009	1.007	1.003	0.996
	Percent Change	12.15%	0.07%	-0.76%	-0.22%	0.25%	0.36%	0.74%
Other Generation	Inflation Index	1.000	1.082	1.155	1.215	1.236	1.226	1.202
	Deflation Index	1.000	0.924	0.866	0.823	0.809	0.816	0.832
	Percent Change	11.80%	8.22%	6.71%	5.21%	1.75%	-0.86%	-1.89%
Transmission	Inflation Index	1.000	1.040	1.065	1.069	1.067	1.065	1.069
	Deflation Index	1.000	0.961	0.939	0.936	0.937	0.939	0.935
	Percent Change	10.49%	4.04%	2.33%	0.39%	-0.13%	-0.24%	0.40%
Distribution	Inflation Index	1.000	1.069	1.128	1.148	1.151	1.159	1.176
	Deflation Index	1.000	0.935	0.886	0.871	0.869	0.863	0.850
	Percent Change	9.78%	6.92%	5.52%	1.76%	0.28%	0.63%	1.53%
General Plant	Inflation Index	1.000	1.032	1.036	1.042	1.054	1.066	1.078
	Deflation Index	1.000	0.969	0.965	0.960	0.949	0.938	0.928
	Percent Change	10.22%	3.19%	0.40%	0.59%	1.12%	1.17%	1.10%

4. Escalation Rates Shall be Updated During GRC Update Phase

In accordance with the Rate Case Plan, following hearings, escalation rates shall be updated to reflect current escalation rates and known cost changes, such as ratified collective bargaining agreements.¹⁹⁸

5. Handy-Whitman Public Utility Construction Costs, S&P Global Market Intelligence Forecasts, and SCE Labor Indices are More Appropriate Indices to Estimate Utility Cost Escalation than CPI-U

The Handy-Whitman Index of Public Utility Construction Costs, S&P Global Market Intelligence, and SCE labor indices are the most appropriate cost indices to forecast cost escalation when estimating O&M and capital cost escalation for an electric utility in California. The Handy-Whitman Index of Public Utility Construction Costs and S&P Global Market Intelligence forecasts for O&M and capital cost escalation have been relied upon by the Commission in numerous regulatory proceedings

¹⁹⁸ D.07-07-004.

regarding O&M and capital escalation and are a reliable source for historical utility construction cost information.¹⁹⁹ The Handy-Whitman index utilized in this chapter is based on actual construction cost data for utility capital projects in the Pacific region.

CPI-U is based on costs that are unrelated to the costs of performing utility capital projects and utility O&M in California and Arizona. According to the U.S. Bureau of Labor Statistics (BLS) website,²⁰⁰ “[t]he Consumer Price Index (CPI) is a measure of the average change over time in the prices paid by urban consumers for a market basket of consumer goods and services.” The basket of goods for households is not representative of utility expenses and investments related to transmission, distribution, generation, and O&M projects in California and Arizona.

This is evidenced by the BLS “[r]elative importance of components in the Consumer Price Indices: U.S. city average”²⁰¹ where the BLS lists the components of CPI-U, which are as follows:

Table VIII-37
Components of CPI-U

Line No.	CPI-U Component	Share/Weight
1	Food and beverages	14.38%
2	Housing	44.38%
3	Apparel	2.48%
4	Transportation	16.74%
5	Medical Care	8.11%
6	Recreation	5.39%
7	Education and communication	5.85%
8	Other goods and services	2.68%
9	Total	100.00%

The cost components of running an electric utility are not represented in CPI-U. For example, listed below are the cost components of S&P Global Market Intelligence’s Transmission

¹⁹⁹ For instance, SCE has used IHS Markit indices in all general rate cases since at least the early 1980s. Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Gas Company also use various IHS Markit indices in their general rate cases. S&P Global Market Intelligence acquired IHS Markit in March 2022.

²⁰⁰ Bureau of Labor Statistics, Consumer Price Index. <https://www.bls.gov/cpi/> (as of February 15, 2023).

²⁰¹ Bureau of Labor Statistics, Consumer Price Index Table 1 (2021 Weights). Relative importance of components in the Consumer Price Indices: U.S. city average, December 2022 <https://www.bls.gov/cpi/tables/relative-importance/2022.htm> (accessed March 8, 2023).

1 Production Plant – Pacific region index. These variables represent the cost components for performing
2 transmission capital projects in California.

Table VIII-38
S&P Global Market Intelligence Transmission Capital Components

Line No.	Utility Cost Component - Transmission Capital
1	Materials, Transformers & Station Equipment - Pacific
2	Overhead Conductor - Transmission - All Regions
3	Tower Steel
4	Insulators
5	Treated Pine Poles - All Regions
6	Materials, Underground Conductors & Devices - Pacific
7	Construction Equipment - All Regions
8	Building Material - Ready-Mix Concrete - Pacific
9	Standard Cross Arms - All Regions
10	Standard Galvanized Steel Guy Wire - All Regions
11	Building Material - Steel Bars For Reinforced Concrete - Pacific

IX.

OTHER OPERATING REVENUE

Part A of this chapter presents SCE's total company Other Operating Revenue (OOR) for recorded year 2022 and forecast years 2023 through 2028. OOR is revenue received by SCE from transactions not directly associated with the sale of electric energy and is recorded in FERC accounts 450 through 456. OOR is subtracted from total operating costs to determine the test year revenue requirement because it reduces the revenue that must be collected through customer rate levels. Part B of this section discusses SCE's Added Facilities rates used for the 2025 test year.

A. Account-By-Account Summary Of OOR

OOR recorded amounts for 2022 and forecast amounts for 2023 through 2028 are summarized in Table IX-39 below.²⁰²

Table IX-39
Other Operating Revenue
Nominal (\$000)

FERC Line Description	Recorded 2022	2023	2024	Forecast 2025	2026	2027	2028	Exhibit Reference
1. 450.000 - Forfeited Discounts								
2. Customer Service Operations OOR	17,164	11,754	11,706	11,307	11,307	11,307	11,307	SCE-03, Vol.1
3. 451.000 - Miscellaneous Service Revenues								
4. Customer Service Operations OOR	13,839	16,294	16,341	6,793	6,793	6,793	6,793	SCE-03, Vol.1, SCE-02, Vol.11
5. Transmission & Distribution OOR	1,781	1,287	1,278	1,253	1,253	1,253	1,253	SCE-03, Vol.1, SCE-02, Vol.11
6. Financial and Other Miscellaneous Revenues	117	290	290	635	635	635	635	SCE-03, Vol.1
7. Total 451.000	15,737	17,871	17,909	8,682	8,682	8,682	8,682	
8. 453.000 - Sales of Water & Water Power								
9. Financial and Other Miscellaneous Revenues	819	760	760	760	760	760	760	SCE-07, Vol.1
10. 454.000 - Rent from Electric Property								
11. Transmission & Distribution OOR	38,802	45,334	45,334	45,334	45,334	45,334	45,334	SCE-02, Vol.11
12. Financial and Other Miscellaneous Revenues	16,840	12,005	12,499	13,387	13,387	13,387	13,387	SCE-02, Vol.11
13. Total 454.000	55,642	57,339	57,833	58,721	58,721	58,721	58,721	
14. 456.000 - Other Electric Revenue								
15. Customer Service Operations OOR	(0)	9,569	9,569	9,569	9,569	9,569	9,569	SCE-03, Vol.1
16. CS&I Tariffed Products and Services OOR	47,357	46,877	47,598	49,301	52,753	46,606	46,373	SCE-07, Vol.2, SCE-02, Vol.11, SCE-03, Vol.1
17. Transmission & Distribution OOR	71,233	72,228	72,191	75,566	75,566	75,566	75,566	SCE-07, Vol.2, SCE-02, Vol.11, SCE-03, Vol.1
18. Financial and Other Miscellaneous Revenues	585	815	800	762	762	762	762	SCE-02, Vol.11, SCE-07, Vol.1
19. Gains/Losses on Sale of Property	6,028	1,607	1,607	1,607	1,607	1,607	1,607	SCE-07, Vol.2
20. Securitization Administration Fee	481	561	1,106	997	997	997	997	SCE-07, Vol.1
21. Gross Revenue Sharing Mechanism Authorized Thres	16,672	16,672	16,672	16,672	16,672	16,672	16,672	SCE-07, Vol.1
22. Total OOR	231,720	236,052	237,751	233,943	237,395	231,248	231,015	

1. Revenue Account 450 – Forfeited Discounts

This account includes fees imposed on customers because of failure to pay bills. Such fees include forfeited discounts and late payment charges. Forecasts of revenues and descriptions

²⁰² Refer to WP SCE-07, Vol. 01, Book D, pp. 15-61, for Other Operating Revenue- summarized by FERC Account.

1 within this FERC account, with support for the estimating method used, are contained in Exhibit
2 SCE-03, Volume 01. The 2025 test year estimate for FERC account 450 is \$11.307 million.

3 **2. Revenue Account 451 – Miscellaneous Service Revenues**

4 This account includes revenues for all miscellaneous services and charges billed to
5 customers not specifically provided for in other accounts. Such fees include returned check charges and
6 connection charges. Forecasts of revenues and descriptions for each sub-account within the FERC
7 account, with support for the estimating method used, are contained in Exhibit SCE-02, Volume 11, and
8 Exhibit SCE-03, Volume 1. The 2025 test year estimate for FERC account 451 is \$8.682 million.

9 **3. Revenue Account 453 – Sales of Water and Power**

10 This account includes the annual payment SCE receives from PG&E for maintaining
11 SCE's upstream dams, which benefit PG&E's downstream powerhouses. The 2025 test year estimate for
12 FERC account 453 is \$0.760 million.

13 **4. Revenue Account 454 – Rent From Electric Property**

14 This account includes rents received for the use by others of land, buildings and other
15 property devoted to electric operations. The majority of the revenues recorded in FERC account 454 are
16 generated from company-financed added and interconnection facilities. Exhibit SCE-02, Volume 11
17 supports the forecast of the Company-financed added and interconnection facilities revenues. Part B of
18 this Chapter supports the development of added facilities rates for the 2025 Test Year. The total 2025
19 test year estimate for FERC account 454 is \$58.721 million.

20 **5. Revenue Account 456 – Other Electric Revenues**

21 The account includes revenues recorded that are generated from customer-financed added
22 and interconnection facilities. Exhibit SCE-02, Volume 11 supports the forecast of the Customer-
23 financed added facilities revenues. Part B of this Chapter supports the development of added facilities
24 rates for the 2025 Test Year. In addition, the revenues associated with the tax gross-up on Contributions
25 in Aid of Construction and Solar Grant Amortization are included in this account as supported in Exhibit
26 SCE-07, Volume 2. This account also includes various customer service and CS&I Tariffed Products
27 and Services OOR not included in other accounts. The total 2025 test year estimate for FERC account
28 456, including various other miscellaneous sub-accounts as supported in workpapers, is \$135.198
29 million.

1 **6. Other OOR**

2 **a) Revenues with Specific Treatment**

3 In various decisions and resolutions, the Commission has established specific
4 ratemaking treatment for revenues generated from a variety of programs. Since these revenues are
5 returned to customers directly through the operation of memorandum or balancing accounts established
6 to track the programs, they are not included in the GRC. Specific ratemaking treatment includes, but is
7 not limited to, programs such as Research, Development and Demonstration Royalties (RDDR) and
8 revenues related to the labor markup billed to non-utility affiliates and returned to customers through a
9 credit recorded in the BRRBA.

10 **b) Gain or Loss on Sale of Property**

11 In past GRCs, the Commission ordered SCE to include in OOR the gain or loss on
12 the sale of property originating in utility plant FERC accounts 101 and 103 and transferred to FERC
13 account 121 (Non-Utility Property) prior to sale. This revenue is to be shared between shareholders and
14 customers based on the time the property was included in rate base. The 2025 test year estimate of
15 revenues attributable to the gain or loss on sale of property is \$1.607 million and is supported and
16 developed in Exhibit SCE-07, Volume 02.²⁰³

17 **c) Securitization Servicing Administration Fee**

18 The Financing Orders in D.20-11-007, D.21-10-025, and D.23-02-023 grant
19 SCE's request for authority under Assembly Bill (AB) 1054 and Public Utilities (Pub. Util.) Code 850.1
20 to issue Recovery Bonds to finance fire risk mitigation capital expenditures. The Recovery Bonds will
21 be issued by a legally separate Special Purpose Entity, which will transfer the Recovery Bond proceeds
22 to SCE in exchange for the right to receive revenues to repay the Recovery Bonds' principal, interest,
23 and related costs. As servicer, SCE would be responsible for determining Consumers' electricity usage,
24 billing, collecting, and remitting the Fixed Recovery Charge to the Bond Trustee, and submitting
25 Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters.
26 The Bond Trustee will pay SCE for these servicing and administration services. The Financing Orders
27 provide that SCE will periodically credit back to customers through BRRBA all periodic servicing and

²⁰³ The gains and losses on minor sales of property are allocated between customers and shareholders pursuant to D.06-05-041 as modified by D.06-12-043.

administration fees in excess of SCE's incremental cost of performing the servicer and administration functions.²⁰⁴

Beginning with this GRC, SCE's servicing and administration fees are included as a cost of service, capturing both the costs of providing servicing and administration services and the revenue received from collections as the servicer/administrator of the Recovery Bonds.²⁰⁵ In each base rate case, SCE will include a revenue credit of the administration and servicing fees that SCE collects as the servicer/administrator of the Recovery Bonds (to the extent not previously credited back through the BRRBA).²⁰⁶

d) Non-Tariffed Products and Services

In D.99-09-070, the Commission adopted SCE's Gross Revenue Sharing Mechanism (GRSM) for Other Operating Revenue (OOR) generated from Non-Tariffed Products and Services (NTP&S).²⁰⁷ NTP&S are products and services (other than traditional electric utility services) that SCE offers to third parties that make secondary or complementary use of temporarily available capacity in certain utility assets that have been pre-approved by the Commission.²⁰⁸ The Commission has authorized the specific categories of products and services that SCE can offer to third parties as NTP&S,²⁰⁹ but the prices, terms, and other conditions of these products and services are not regulated by the Commission.

As recognized by the Commission, the utility's offering of NTP&S furthers the Commission's important policy goal of encouraging the use of temporarily available utility capacity and underutilized utility assets that were funded by ratepayers. That is, rather than let temporarily available utility capacity and assets remain idle (which a utility could do) or not fully utilized, the Commission authorized utilities like SCE to offer NTP&S for non-traditional electric utility products and services to

²⁰⁴ D.21-10-025, pp. 111-112 (Ordering Paragraph 57), and D.23-02-023, p. 121 (Ordering Paragraph 55).

²⁰⁵ See Exhibit SCE-06, Vol. 03, section V.B.2.(a).

²⁰⁶ SCE Advice 4416-E and 4717-E – Issuance Advice Letter.

²⁰⁷ The revenue sharing mechanism applies to all of SCE's OOR derived from SCE's approved NTP&S categories, except revenue that is: (1) derived from tariffs, fees, or charges established by the Commission or FERC; and (2) subject to other established ratemaking procedures or mechanisms.

²⁰⁸ "NTP&S are products and services other than traditional electric services offered by SCE that rely on secondary or complementary use of available capacity in utility assets or personnel." June 17, 2020 ALJ Ruling in SCE's 2021 GRC Application 19-08-018.

²⁰⁹ D.99-09-070, Attachment A.

1 encourage their secondary or complementary use. Therefore, the Commission also recognizes the
2 importance of incentivizing utilities to offer temporarily available capacity to third parties through
3 NTP&S:

4 It is Commission policy to encourage the use of excess utility capacity
5 and underutilized utility assets through non-tariffed products and
6 services (NTP&S).²¹⁰

7 The overall concept of a revenue sharing mechanism for revenues
8 from non-tariffed products and services is in the public interest
9 because it provides the utility with incentives to use utility property
10 for other productive purposes without interfering with the utility's
11 operation or affecting service to utility customers.²¹¹

12 As an example, SCE is authorized to lease and license land as an NTP&S under a
13 transmission tower for horticultural purposes, such as nurseries or tree farms.²¹² The land under the
14 tower would be idle, but the Commission allows and encourages SCE to lease and license the land as an
15 NTP&S and receive additional gross revenues that benefit ratepayers. Under the GRSM, ratepayers
16 receive 100% of the first \$16.672 million in gross revenues from NTP&S each year.²¹³ As such, the
17 CPUC jurisdictional portion of the \$16.672 million threshold amount (\$11.25 million) is included in the
18 OOR 2025 test year estimate.²¹⁴ Once the GRSM threshold amount is met, then additional gross

²¹⁰ Resolution G-3456, p. 3.

²¹¹ D.99-09-070, 1990 Cal. PUC LEXIS 653, at *47-48. See also D.11-03-038 at 6 (March 29, 2011) (“[T]he agreement makes productive use of what is currently vacant conduit space. It makes eminent good sense for California’s energy utilities, with their extensive easements, rights of way, and underground conduits, to cooperate in this manner with the telecommunication utilities who are seeking to build the fiber optic network. Joint use of the utility franchises has obvious economic and environmental benefits. The public interest is served when utility property is used for other productive purposes without interfering with the utility’s operations or affecting service to utility customers.” (quoting D.93-04-019, 1993 Cal. PUC LEXIS 275 at *4)). See also Resolution G-3456 where the Commission stated on page 3, “It is Commission policy to encourage the use of excess utility capacity and underutilized utility assets through non-tariffed products and services (NTP&S).”

²¹² D.99-09-070, Attachment A, p. A-1.

²¹³ D.99-09-070, footnote 4, p. 4.

²¹⁴ The current threshold, as adopted in D.99-09-070, is based on the level of OOR from non-tariffed products and services reflected as a revenue credit in SCE’s 1995 Test Year GRC (D.96-01-011). From the inception of the GRSM program, ratepayers have received total gross revenues of more than \$638.1 million. This revenue is generated without an increase to ratepayer utility costs, and the business risks are borne by shareholders.

1 revenues are divided between shareholders and customers. The customers' share is distributed annually
2 via Advice Letter in the Electric Deferred Refund Account balance.²¹⁵

3 SCE tracks the incremental costs incurred in providing NTP&S, which are paid
4 for by SCE's shareholders. Incremental costs are funded by shareholders because these products and
5 services are an ancillary form of revenue and outside of standard electric utility operations. In contrast,
6 ratepayers are responsible for the *costs that* are incurred in providing electric service to ratepayers.
7 If existing utility assets and personnel (funded by the ratepayers for utility services) have temporarily
8 available capacity, SCE is able to leverage this available capacity at no additional cost to ratepayers.
9 The work in providing utility service must always take precedence over NTP&S.²¹⁶ However, when not
10 in use for, and in support of, utility operations, these assets and personnel may temporarily be used to
11 support NTP&S.²¹⁷ Indeed, since NTP&S are provided by the utility (and not an affiliate), NTP&S must
12 make use of existing utility assets to qualify as a NTP&S.²¹⁸ And, the Commission-approved Rule VII of
13 the Affiliate Transaction Rules allow SCE to utilize utility resources as long as the cost, quality or
14 reliability of electric service is not affected. Leveraging these utility resources optimize the use of the
15 resource and are done without increasing the costs to the utility.²¹⁹ This Commission-approved
16 framework provides ratepayers with significant revenues through the GRSM,²²⁰ which is achieved only

²¹⁵ After ratepayers receive the first \$16.7 million in gross revenues, SCE's shareholders can receive 70% or 90% of gross revenues from passive and active investments, respectively, while ratepayers receive an additional 30% or 10% depending upon the investment classification. D.99-09-070, p. 4.

²¹⁶ Rule VII C.4.c. of the Affiliate Transaction Rules D.12-06-029, an NTP&S must not affect, the cost, quality or reliability of electric service.

²¹⁷ "The Commission has historically encouraged energy utilities to offer non-tariffed products and services that enhance the utilization of utility assets." D.99-09-070 p. 3 incremental costs would be borne entirely by shareholders.

²¹⁸ Rule VIIc4. of D.06-12-029 "Products and services which are offered on a nontariffed basis and which meet the following conditions: a. The nontariffed product or service utilizes a portion of a utility asset or capacity; b. such asset or capacity has been acquired for the purpose of and is necessary and useful in providing tariffed utility services; c. the involved portion of such asset or capacity may be used to offer the product or service on a nontariffed basis without adversely affecting the cost, quality or reliability of tariffed utility products and services."

²¹⁹ Rule VII C.4.c. of the Affiliate Transaction Rules D.12-06-029, an NTP&S must not affect, the cost, quality or reliability of electric service.

²²⁰ Since the inception of the GRSM program, ratepayers have received total gross revenues of more than \$638.1 million, which represents 73% of gross revenues (compared to 27% of the net revenues for shareholders). Revenues for ratepayers are generated without an increase to ratepayer utility costs, and the business risks are borne by shareholders.

1 when SCE has the incentive to provide NTP&S using temporarily available capacity funded by the
2 ratepayers for utility services.

3 To help SCE determine whether a cost is incremental (and thus charged to the
4 shareholders) since the inception of NTP&S in 1999, SCE uses the “but for” test. In summary, if SCE
5 would *not* have incurred the cost *but for* the NTP&S, then the cost is deemed *incremental* (and charged
6 to SCE’s shareholders). On the other hand, if SCE *would have* incurred the cost, regardless of the
7 NTP&S, then the cost is deemed *non-incremental*. The intent of Decisions 99-09-070 and 98-12-083
8 (which granted SCE the authority to offer certain telecommunications services) is to apportion to
9 ratepayers the capital expenditures and operating expenses incurred to support utility operations and
10 apportion to shareholders those new capital expenditures and operating expenses incurred to increase the
11 capacity or usefulness of the utility assets in order to generate additional OOR. These decisions
12 recognize that the utility workforce and assets are relatively fixed costs that, due to cyclical
13 requirements, may have temporarily available capacity that may be utilized in the performance of
14 NTP&S activities. In return, ratepayers receive a share of gross revenue in accordance with the GRSM.
15 To the extent there are no additional costs incurred by the utility, and that the employees and assets
16 having temporarily available capacity remain fully capable of performing the functions necessary to
17 provide undiminished electrical service, the ratepayers will continue to pay for employees and assets
18 temporarily utilized in the delivery of NTP&S. To help ensure proper recording and tracking of
19 incremental costs, which are shareholder funded, SCE provides training for identified employees.

20 The Commission has affirmed on numerous occasions, including in SCE’s 2021
21 GRC proceeding, that any proposed changes to SCE’s GRSM is subject to a separate rulemaking
22 proceeding.²²¹ Therefore, as in SCE’s past GRC applications, SCE is not proposing any changes to the
23 GRSM in this direct testimony. SCE is also not proposing any changes to its NTP&S offerings or
24 processes in this proceeding as well.

²²¹ “We reject TURN’s recommendation that the Commission consider modification of the NTP&S revenue sharing mechanism in the next GRC. As provided in the Assigned ALJs’ June 17, 2020 email ruling in this proceeding and in past Commission decisions, a rulemaking is the appropriate venue for reviewing SCE’s NTP&S revenue sharing mechanism.” D.21-08-036, p. 481 (citing the Assigned Administrative Law Judge’s (ALJ) June 17, 2020 email ruling in SCE’s 2021 GRC application 19-08-013), S.09-03-025 at 301-302, D.12-11-051 at 657, and D.18-09-009 at 5. In the June 17, 2020 email ruling, the ALJ also made clear that whether SCE’s existing NTP&S offerings satisfy the conditions of D.98-08-035 (Section III.A) is also not within the scope of SCE’s GRC application. June 17, 2020 email ruling in A19-08-013.

1 **(1) Accounting, Reporting, and Auditing of NTP&S**

2 While the Commission has made clear that changes to SCE's GRSM is not
3 the subject of SCE's GRC applications, the Administrative Law Judge (ALJ) in SCE's 2021 GRC
4 proceeding determined that the issue of whether SCE's incremental NTP&S costs were properly
5 accounted for related to the reasonableness of SCE's requested revenue requirement and thus within the
6 scope of the GRC.²²² Therefore, SCE provides the following testimony on SCE's accounting, reporting,
7 and auditing processes of NTP&S.²²³

8 Accounting: SCE has established accounting procedures and mechanisms
9 to identify and record the incremental costs associated with NTP&S, as required by Affiliate Transaction
10 Rule VII.D.1²²⁴ to identify and record the incremental costs (for which shareholders are responsible)
11 associated with NTP&S. SCE has processes and procedures (including training) to apply a "but for" test
12 to determine whether costs are incremental. If SCE would not have incurred the cost "but for" the
13 offering of any NTP&S, the cost is deemed incremental and allocated to shareholders. Thus, any
14 incremental costs to support SCE's NTP&S activities are charged directly to that business unit and there
15 is no need to "credit" or "reimburse" the utility for this work as these costs were never borne by the
16 utility. Because these incremental costs are charged to those business unit's work orders and cost
17 objects, these cost objects are excluded from the GRC historical results or forecasts. Similarly,
18 embedded assets that have been acquired to provide utility services that may be leveraged by those
19 business units that provide NTP&S offerings do not result in any additional costs for ratepayers.
20 Thus, there is no need or requirement to "credit" or "reimburse" the utility for maximizing the use of a
21 utility assets. The accounting treatment for incremental costs is all fully consistent with the Affiliate
22 Transaction Rules and NTP&S requirements and has been reviewed in several Affiliate Transaction
23 Rules audits.

²²² June 17, 2020 email ruling in A.19-08-013. The ALJ also determined that issue of whether SCE's NTP&S offerings are driving proposed and unnecessary investments in the GRC was also within the scope of SCE's GRC application. Id.

²²³ There are additional internal processes for Edison Carrier Solutions (ECS), which are discussed in Section IX.6.d(1) below.

²²⁴ Rule VII.D.1 of the Affiliate Transaction Rules (D.06-12-09) requires "A mechanism or accounting standard for allocating costs to each new product or service to prevent cross-subsidization between services a utility would continue to provide on a tariffed basis and those it would provide on a nontariffed basis"

1 Reporting: SCE’s NTP&S and GRSM are subject to annual reporting
2 requirements. Under Rule VII H of the Affiliate Transaction Rules, SCE is required to annually submit
3 its Periodic Report of Utility Non-Tariffed Products and Services where SCE provides the costs and
4 revenues associated with SCE’s NTP&S.²²⁵ SCE’s most recent report, for calendar year 2021, was
5 submitted on July 8, 2022. The Commission has indicated its preference to address NTP&S concerns in
6 the Energy Division’s affiliate transaction audits.²²⁶

7 Auditing: The Commission has a right to review and audit SCE’s books
8 and records,²²⁷ including those related to the provision of NTP&S, which is governed under Section VII
9 of the Affiliate Transaction Rules. As a result of SCE’s 2015 GRC Decision (D.15-11-021), the Energy
10 Division retained the independent auditing firm Baker Tilly Virchow Krause, LLP (Baker Tilly) to
11 comprehensively audit SCE’s compliance with the California Affiliate Transaction Rules for the years
12 2010-2011 and, in August 2015, the State Controller’s Office, on behalf of the Energy Division,
13 commenced an audit of SCE’s affiliate transactions for years 2012-2013.²²⁸ The 2012-2013 Affiliate
14 Transaction Rules Audit was completed in March 2018, and there were no findings from the auditors
15 related to Rule VII.²²⁹ The most recent Affiliate Transaction Rules Audit for 2016 – 2017 commenced in
16 June 2019 was completed in June 2020, and there were similarly no findings from the auditors related to
17 Rule VII.²³⁰

²²⁵ Rule VII.H of the Affiliate Transaction Rules (D.06-12-09) Periodic Reporting of Nontariffed Products and Services: Any utility offering nontariffed products and services shall file periodic reports with the Commission’s Energy Division twice annually for the first two years following the effective date of these Rules, then annually thereafter unless otherwise directed by the Commission. The utility shall serve periodic reports on the service list of this proceeding. The periodic reports shall contain the following information: 1) A description of each existing or new category of nontariffed products and services and the authority under which it is offered; 2) A description of the types and quantities of products and services contained within each category (so that, for example, “leases for agricultural nurseries at 15 sites” might be listed under the category “leases of land under utility transmission lines,” although the utility would not be required to provide the details regarding each individual lease); 3) The costs allocated to and revenues derived from each category; and 4) Current information on the proportion of relevant utility assets used to offer each category of product and service.

²²⁶ D.12-11-051.

²²⁷ Public Utilities Code Section 314.5.

²²⁸ ATR VII governs utilities’ provision of NTP&S.

²²⁹ “Southern California Edison Audit Report Affiliate Transaction Rules for Calendar Years 2012 and 2013” conducted by the California State Controller, dated March 2018.

²³⁰ Years 2020 and 2021 are being audited as of October 2022.

1 e) **Compliance Requirement from D. 21-08-036 – SCE’s Accounting of NTP&S**

2 In the Commission’s decision in SCE’s 2021 GRC proceeding, Decision No. 21-
3 08-036, the Commission determined that:

- 4 • Changes to the CPUC’s approved GRSM in the GRC are outside the scope of
5 a GRC application.²³¹
- 6 • SCE has established accounting procedures and processes to identify and
7 record incremental costs associated with NTP&S.²³²
- 8 • There was no evidence that SCE was improperly allocating incremental costs
9 to ratepayers.²³³

10 Notwithstanding the above, the Commission left open the possibility of making
11 “ongoing improvements to SCE’s established accounting procedures”²³⁴ in SCE’s 2021 GRC
12 proceeding because The Utility Reform Network (TURN) made a late proposal in its Opening Brief that
13 SCE keep a record of each of the “but for” tests it conducts for its NTP&S offerings and that SCE keep
14 time logs and other appropriate records concerning NTP&S offerings’ use of ratepayer funded (i.e., non-
15 incremental) utility resources.²³⁵ The Commission recognized that SCE raised legitimate concerns about
16 the resource impacts of TURN’s late proposal and whether TURN’s proposal would be unduly costly
17 and administratively burdensome.²³⁶ But, because of the limited record, the Commission directed SCE to
18 respond to four inquiries relating to the accounting of NTP&S in this 2025 GRC application:

- 19 • The level/number of utility resources that would be impacted, an associated
20 cost estimate, as well as the supporting calculations, if TURN’s “but for” and

²³¹ D.21-08-036, p. 481. See also discussion above in Section 6(c).

²³² These processes included trainings with shared service partners to ensure employees understand their obligations to identify incremental costs that would be incurred “but for” ECS to help limit instances where incremental costs are not properly identified. D.21-08-036, p. 480.

²³³ D.21-08-036, p. 480.

²³⁴ D.21-08-036, p. 481.

²³⁵ D.21-08-036, p. 479.

²³⁶ For example, the Commission indicated that it was unclear how many shared SCE employees would need to be equipped with, and trained to use, a time tracking software to be able to implement TURN’s recommendation, what this overall effort would cost, and how long it would take SCE to implement TURN’s proposal. (D.21-08-036, p. 480).

time log tracking recommendations were implemented for SCE's ECS Department.

- Alternatives to TURN's "but for" and time log tracking recommendations that would achieve similar objectives at a lower cost.
- How ECS employee questions are assigned to and addressed by HR personnel.
- Whether ECS pays for office-related expenses (including utilities), why/why not, and how SCE's current approach is consistent with the requirement that all incremental costs for NTP&S be the sole responsibility of shareholders.²³⁷

The Commission's focus on SCE's ECS Department in its inquiries is understandable because of ECS' significant provision of NTP&S. Moreover, as noted by the Commission in SCE's 2021 GRC proceeding, TURN's proposal was limited to ECS, and TURN did not provide information on the type and level of SCE resources used by other NTP&S offerings outside of ECS.²³⁸ Thus, before responding to the Commission's four inquiries, SCE provides the following brief background on ECS, which will provide a greater context for SCE's responses.

(1) Background of ECS

SCE is the only electric Investor Owned Utility (IOU) in California that has a CPUC-approved Certificate of Public Convenience and Necessity (CPCN) to operate a commercial telecommunications carrier.²³⁹ As such, SCE is in the unique position to further three important Commission policy goals. First, SCE has fulfilled the Commission's goal of providing competition in the telecommunications market. During the 1990s, the CPUC sought to increase competition in the telecommunications market by allowing Competitive Local Exchange Carriers (CLECs) to compete against the existing Incumbent Local Exchange Carriers (ILECs). SCE stepped in to meet this challenge, and the CPUC's goal was achieved when it granted CPCNs to companies, like

²³⁷ D.21-08-036, p. 479.

²³⁸ D.21-08-036, p. 480.

²³⁹ D.98-12-083.

1 SCE, who could compete as CLECs and provide commercial telecommunication services to customers
2 in direct competition of the ILECs.²⁴⁰

3 Second, ECS is not an affiliate nor subsidiary of SCE. Rather, SCE (not
4 ECS) is the owner of the Commission-authorized telecommunications CPCN. SCE created a department
5 called Edison Carrier Solutions within SCE's Information Technology Organizational Unit that uses
6 SCE's temporarily available excess capacity on SCE's fiber network to provide commercial
7 telecommunication non-voice services to non-residential customers.²⁴¹ As such, by creating the ECS
8 department, SCE furthers the Commission's goal to make use of temporarily available capacity and
9 underutilized utility assets through NTP&S.²⁴²

10 Finally, through SCE's ECS Department, SCE is playing an important role
11 in the Commission's efforts to bridge the digital divide so that underserved and unserved communities
12 will have greater access to broadband services. SCE has been an active participant in OIR 20-09-001
13 which addresses the Commission's efforts to bridge the digital divide and provide broadband to
14 underserved and disadvantaged communities. In the OIR, the Commission has been encouraging the
15 California energy IOUs to make temporary excess capacity on their fiber optic networks (which were
16 built for and paid by utility customers) to further broadband to underserved and disadvantaged
17 communities. Like the other electric IOUs, SCE has a fiber optic network that is built for electric utility
18 operations to serve SCE's entire service territory, and thus SCE has unique routes or locations in areas
19 where service is not readily available or where other CLECs or ILECS may not find economic to serve.
20 In addition, because of SCE's CPCN, SCE's shareholder can elect to make additional investments to
21 build and expand SCE's fiber network (at shareholder expense and risk) for commercial
22 telecommunication purposes that can be used to further broadband to undeserved and disadvantaged

²⁴⁰ Under SCE's CPCN, SCE is not permitted to sell telephone or dial service, and SCE cannot sell services to residential customers. Rather, SCE is authorized to act as an open access, non-discriminatory facilitator of local telecommunication services. *See* D.98-12-083.

²⁴¹ In addition, because the Commission authorized SCE's telecommunications CPCN (which no other California electric IOU possess), SCE's shareholders can make capital investments (at their own expense and risk) and build telecommunications networks for commercial telecommunication purposes. Excess capacity on SCE's shareholder funded telecommunications network can be used by SCE's ratepayers at no cost.

²⁴² *See* discussion in Section 6(c) on NTP&S in this testimony. *See* also the Governor's Executive Order N-73-20.

1 communities.²⁴³ Through ECS, SCE is able to use temporarily available capacity on its existing
2 ratepayer funded fiber network and also build (at shareholder's expense) additional dark fiber, which
3 can be used to provide middle mile service for internet service providers, governmental agencies, and
4 others to facilitate broadband.

5 As indicated above, ECS is a department within SCE, and, as of December
6 31, 2022, ECS had a staff of 57 employees who are all funded by shareholders and which represents
7 only .4% of SCE's total population of 12,893 full-time employees.²⁴⁴ ECS' assets are not in SCE's rate
8 base, and thus SCE's electric ratepayers do not fund this department although they benefit from the
9 GRSM. Because ECS's staff and assets are shareholder funded, SCE does not seek funding for ECS in
10 the company's general rate case proceedings. SCE ratepayers also benefit from ECS because the utility
11 can use ECS's shareholder funded fiber-optic cables for utility operations at no charge to ratepayers
12 other than initial set up costs (not including ECS engineering labor). As of December 31, 2022, SCE
13 uses strands on roughly 295 shareholder funded cable segments, or roughly 415 miles of shareholder

²⁴³ SCE has been an active participant in OIR 20-09-001 which addresses the Commission's efforts to bridge the digital divide and provide broadband to underserved and disadvantaged communities. In the OIR, the Commission has been encouraging the California energy IOUs to make temporary excess capacity on their fiber optic networks (which were built for and paid by utility customers) to further broadband to underserved and disadvantaged communities. Like the other electric IOUs, SCE has a fiber optic network that is built for electric utility operations to serve SCE's entire service territory, and thus SCE has unique routes or locations in areas where service is not readily available or where other CLECs or ILECS may not find economic to serve. In addition, because of SCE's CPCN, SCE's shareholder can elect to make additional investments to build and expand SCE's fiber network (at shareholder expense and risk) for commercial telecommunication purposes that can be used to further broadband to underserved and disadvantaged communities. In OIR 20-09-001, SCE provided information on potential pilot programs, and in 2022, SCE (through ECS) successfully provided middle mile service to an internet service provider to facilitate broadband services to underserved and disadvantaged areas in Palm Desert and Cathedral Hills. In prior years, ECS provided similar middle mile services to the same company to serve underserved areas in Phelan, California. SCE's use of its ratepayer funded fiber network was acknowledged in OIR 20-09-001 by parties such as the California Energy Technology Fund, who indicated that "should an IOU have unlit dark fiber that extends to unserved broadband areas, it should strongly be encouraged to form a subsidiary like SCE's ECS to provide middle mile services to [Internet Service Provider] and local jurisdictions interested in serving these areas. ECS can be a model for such subsidiaries." [Note: ECS is a department of SCE and not a subsidiary] TURN also recognized the benefits of SCE's efforts through ECS of making ratepayer funded utility assets available to third parties: "SCE states that the County may partner with a local ISP or neighboring cities to provide broadband to residents or businesses. SCE provides a detailed description of the project's elements, including the County's efforts to pursue grant funding. This is a good example of a project that leverages IOU infrastructure with work undertaken by local governments." See CETF's August 30, 2021 Opening Comments, p. 2, and TURN's August 30, 2021 Opening Comments, p. 11 in R.20-09-001.

²⁴⁴ Refer to WP SCE-07, Vol. 01, Book D, pp. 62-63, Edison Carrier Solutions Staff, for additional details.

1 funded cables, saving ratepayers the cost of building these cable segments or acquiring the services
2 externally.

3 In its provision of NTP&S, ECS relies primarily on its own dedicated staff
4 or direct charges to ECS (shareholder) to perform day-to-day work (which is 100 percent funded by
5 shareholders). However, as discussed earlier in Section IX.6(c) of this testimony on NTP&S, the
6 Commission-approved Affiliate Transaction Rules allow ECS to make use of non-incremental utility
7 resources (SCE employees and assets) without reimbursing the utility (this is referred to “temporarily
8 available excess capacity”). ECS’ use of such employees is minimal, does not interfere with utility
9 operations work, and is thus considered non-incremental.²⁴⁵ As with other NTP&S work, ECS uses the
10 “but for” test (described in Section IX.6(c)) to determine whether a cost is incremental or non-
11 incremental. While ECS is permitted to use temporarily available capacity of utility resources,
12 ratepayers always have priority if there are competing demands for support. If capacity is unavailable,
13 ECS will use outside resources paid for by shareholders.

14 SCE’s accounting, reporting, and auditing requirements for NTP&S are
15 covered in Section IX.6.c(1) above. SCE has implemented additional internal processes for its ECS
16 department. Incremental costs to support ECS are charged directly to shareholders and thus excluded
17 from the GRC. ECS has in place separate accounting for costs related to work performed for ECS by
18 shared service partners that would not be incurred “but for” ECS. ECS provides these accounts (Work
19 Orders and SAP Cost Objects) to each shared service partner that employees charge to when performing
20 ECS specific work. As part of CPUC-mandated reporting related to its CPCN, ECS annually submits a
21 list of capital work orders (including work order numbers, description of the work, and total dollars
22 charged) to the CPUC as part of its annual report intended to show SCE’s compliance with cost
23 allocation rules.

24 **(2) SCE’s Response to the Commission’s Inquiry on Impacts from Time**
25 **Logs and “But For” Records**

26 In the 2021 GRC, TURN made a late proposal in its brief that SCE keep a
27 record of each of the “but for” tests it conducts for its NTP&S offerings, even if the work or activity is
28 non-incremental. In addition, even though SCE tracks incremental costs and does not include them in

²⁴⁵ When work is determined to add up to one or more FTE, labor costs are deemed incremental and charged to shareholders.

1 ratepayer costs (because they are paid for by shareholders), TURN also proposed that SCE keep time
2 logs and other appropriate records concerning NTP&S offerings' use of ratepayer funded (i.e., non-
3 incremental) utility resources.²⁴⁶ SCE responded that TURN's proposal was costly and burdensome.

4 The Commission recognized SCE's legitimate concerns over additional
5 recording requirements²⁴⁷ and that SCE already has established accounting procedures and processes to
6 identify and record incremental costs associated with NTP&S.²⁴⁸ However, because of TURN's late
7 proposal and the limited record in SCE's 2021 GRC proceeding,²⁴⁹ the Commission requested testimony
8 in this 2025 GRC proceeding on SCE's concerns. Thus, the Commission directed SCE to address in this
9 GRC Application the Commission's first inquiry: "Assuming TURN's 'but for' and time log tracking
10 recommendations were implemented for ECS, provide an estimate of the level/number of utility
11 resources that would be impacted, an associated cost estimate, as well as the supporting calculations."²⁵⁰
12 SCE welcomes the opportunity to respond now to the Commission's inquiry on the cost and resource
13 impacts of recording each "but for" test and also keeping time logs and records concerning SCE's use of
14 non-incremental, ratepayer funded utility resources associated with NTP&S offerings.

15 As a threshold matter, SCE believes that recording every "but for"
16 decision and recording non-incremental resources goes well beyond existing requirements, is
17 unnecessary, costly, and time consuming, and would impose burdens that far outweigh any perceived
18 benefits. For example, SCE tracks incremental costs related to its NTP&S because they are paid for by
19 shareholders and reporting of these costs is required annually under Rule VII.H.3,²⁵¹ while tracking use

²⁴⁶ D.21-08-036, p. 479.

²⁴⁷ "Therefore, there is a limited record on these issues and SCE raises legitimate concerns regarding whether TURN's recommendations would be unduly costly and administratively burdensome." D.21-08-036, p. 479.

²⁴⁸ These processes included annual trainings with shared service partners to ensure employees understand their obligations to identify incremental costs that would be incurred "but for" Edison Carriers Solutions (ECS) to help limit instances where incremental costs are not properly identified. D.21-08-036, p. 480.

²⁴⁹ The Commission, for example, indicated that due to the limited record, "it is unclear how many shared SCE employees would need to be equipped with, and trained to use, the time tracking software to be able to implement TURN's recommendation, what this overall effort would cost, and how long it would take SCE to implement." D.21-08-036, pp. 479-480.

²⁵⁰ D.21-08-036, p. 479.

²⁵¹ D.06-12-029 Rule VII H. Periodic Reporting of Nontariffed Products and Services: Any utility offering nontariffed products and services shall file periodic reports with the Commission's Energy Division twice annually for the first two years following the effective date of these Rules, then annually thereafter unless

(Continued)

1 of non-incremental resources that leverage temporary excess capacity of existing utility assets (as the
2 Commission is inquiring about) lacks purpose. As indicated earlier in Section IX.6(c), ECS may use
3 available utility resources subject to the GRSM and Rule VII.H.3. And, as indicated earlier, the
4 Commission has encouraged NTP&S because the utility workforce and assets are relatively fixed costs
5 that, due to cyclical requirements, and may have temporarily available capacity that may be utilized and
6 made productive in the performance of NTP&S activities.

7 While ECS tracks incremental costs for allocation to shareholders, ECS
8 does not have established processes/systems to track non-incremental.²⁵² Likewise, ECS does not log
9 every time a non-ECS employee performs a “but for” test and determines the work or resource is non-
10 incremental. SCE provides proper training, so that employees can determine whether the work or
11 activity they performed is incremental or non-incremental. ECS is small enough department
12 (representing less than 0.4% of all SCE employees) and with sufficient internal staff that its time impact
13 on a non-incremental resource’s normal day is negligible.

14 Because SCE does not currently track use of non-incremental use of utility
15 resources, SCE contracted with KPMG,²⁵³ at shareholder cost, to respond to the Commission’s inquiry
16 and estimate the cost and time to develop, implement, and maintain the use of a “non-incremental”
17 resource tracking system.²⁵⁴ Below is a summary of the results:

otherwise directed by the Commission. The utility shall serve periodic reports on the service list of this proceeding. The periodic reports shall contain the following information: 1. A description of each existing or new category of nontariffed products and services and the authority under which it is offered; 2. A description of the types and quantities of products and services contained within each category (so that, for example, “leases for agricultural nurseries at 15 sites” might be listed under the category “leases of land under utility transmission lines,” although the utility would not be required to provide the details regarding each individual lease); 3. The costs allocated to and revenues derived from each category; 4. Current information on the proportion of relevant utility assets used to offer each category of product and service.

²⁵² For example, shareholders fund two employees in SCE’s Network Operation Center (NOC) because the employees receive calls from both electric customers and telecommunications customers that may be experiencing a service quality issue. These employees at the NOC may open a trouble ticket, and employees that service a telecommunications customer record track their time which is considered incremental.

²⁵³ Klynveld Peat Marwick Goerdeler (KPMG). Refer to WP SCE-07, Vol. 01, Book D, pp. 64-114, KPMG Study.

²⁵⁴ As indicated in the KPMG report, the scope of KPMG’s engagement included “developing protocols that include Timekeepers tracking each non-incremental interaction with ECS, along with estimates of effort required to deploy and execute those processes. We referenced KPMG’s Target Operating Model framework to define the protocols, processes, and other organizational aspects required to implement such a process. This Target Operating Model framework includes six layers: Service Delivery Model, People, Functional

(Continued)

Table IX-40
Table of summary of KPMG Study²⁵⁵
Costs to implement non-incremental resource tracking

Employee needs role	Estimated total resources	Annual cost per resource (\$ millions)	Total annualized cost (\$ millions)
Dedicated Timekeeper	26	\$0.10–\$0.14	\$2.6–\$3.64
Nondedicated Timekeeper	8	\$0.10–\$0.14	\$0.80–\$1.12
Timekeeper Resource Manager	6	\$0.16	\$0.96
Grand total	40	—	\$4.36–\$5.72

As seen above in Table IX-40, the KPMG study concluded that:

(1) dedicated time keeping would require 26 additional resources throughout the company, at an estimated annualized cost of \$2.6-\$3.6 million (2) non-dedicated time keeping would require 8 additional resources and an estimated annualized cost of \$0.8-\$1.2 million, and (3) timekeeping resource management would require 6 additional resources and an estimated annualized cost of \$0.96 million, resulting in a total estimated annualized cost of \$4.4-\$5.7 million.²⁵⁶ With a year-end staff at ECS of 57 employees, if these 40 resources were added to ECS, this would almost double ECS’s head count in order to track non-incremental time and analyze “but for” tests and would be economically and administratively burdensome.

It is important to note again that the incremental resources and costs in Table IX-40 would be to track non-incremental resources which have no cost impact to ratepayers as employees provide work or resources for ECS only when such work will not interfere with utility work. Thus, the utility would need to incur new and additional costs and resources to track time that otherwise

Process, Supporting Technology, Performance Insights & Data, and Governance. This section describes the Target Operating Model design along with assumptions and level of effort estimates to implement.”

²⁵⁵ Refer to WP SCE-07, Vol. 01, Book D, p. 85, KPMG Study.

²⁵⁶ If the Commission requires SCE to track these non-incremental costs (which it should not, for the reasons SCE has stated in this testimony), then SCE respectfully requests funding in this GRC for the additional resources as outlined in the KMPG study.

1 does not cost the utility or customer anything. Please note, impacts of the distractions to the day-to-day
2 work from logging and time tracking were not included in the above estimates.

3 As noted above, for incremental costs, SCE has established accounting
4 procedures and mechanisms to identify and record the incremental costs (for which shareholders are
5 responsible) associated with non-tariffed products and services and exclude them from ratepayer cost
6 recovery. Thus, any incremental costs to support ECS are charged directly to shareholders or ECS.
7 Creating tracking mechanisms for non-incremental resources would create costs and administrative
8 burden without any incremental value.

9 Also, as noted above, SCE pays ratepayers for use of non-incremental
10 resources by contributing 100% of its gross revenues to the \$16.7 million GRSM threshold and 10-30%
11 of total gross revenues thereafter. In 2021, ECS contributed about \$11 million of the \$16.7 million, then
12 contributed an additional ~\$6 million of the 10-30% remaining gross revenue sharing. This is pure
13 margin for ratepayers as there are no incremental costs or risks being borne by ratepayers. ECS bears the
14 burden of the operating costs and capital investments to generate NTP&S revenues in order to cover
15 these costs.

16 As indicated in Decision No, 21-08-036, the Commission found that there
17 was no evidence that SCE was improperly allocating incremental costs to ratepayers.²⁵⁷ Ultimately,
18 training and awareness is key in making sure its employees recognize when they must apply the “but
19 for” test, understand the impact of NTP&S and how it relates to their jobs, understand the importance of
20 compliance with regulatory requirements, and have resources available if they have questions. To that
21 end, SCE requires additional training beyond what is required from the Affiliate Transaction Rules for
22 NTP&S as described in Section 6(c)(1). In 2022 SCE instituted a web-based training program that will
23 allow impacted employees to take training on a regular basis. In 2022 119 employees were trained via
24 web-based training. SCE has been improving and enhancing the effectiveness of its training.
25 Today, training for the “but for” test is part of the ECS’s computer-based training program that is
26 assigned as appropriate and is well-produced and easy to understand training with a knowledge check at
27 the end to get credit for course. Training and awareness is a superior alternative to burdensome and
28 unnecessary reporting requirements and will achieve the Commission’s objective in a more cost
29 effective manner.

²⁵⁷ D.21-08-036, p. 480.

(3) **SCE’s Response to the Commission’s Inquiry on Alternatives to Time Logs and “But For” Records**

The Commission’s second inquiry is as follows: “Are there alternatives to TURN’s ‘but for’ and time log tracking recommendations that would achieve similar objectives at a lower cost?”²⁵⁸

Similar to the above on the question on how to track non-incremental time and “but for” tests, ECS, at shareholder costs, contracted with KPMG to evaluate potential alternatives to the above. Below Table IX-41 reflects a summary of the results:

***Table IX-41
Table of Summary of KPMG Study²⁵⁹
Alternatives (\$ millions)***

Alternative	Description	Estimated one-time cost (\$ millions)	Estimated annual operating cost (\$ millions)
1. Time Sheets	This time-tracking alternative mandates that all SCE employees submit timesheets that will not be used for billing or accounting. Those timesheets would be used to log time spent specifically on ECS related activities. This would be an active tracking of time by each employee into a system.	\$1.50	\$0.20
2. Allocations	SCE can enhance the existing Cost Allocation Manual that determines how costs for shared services are allocated among departments and affiliates to further break out non-incremental and incremental costs. Allocations can be defined by analyzing actual time spent or by conducting a time study. A sample time study methodology is included in a subsequent section. This would be an active tracking of time over the span of the survey, and will entail tracking <u>both non-incremental and incremental time</u> in order to derive the associated costs.	\$0.50–\$1.00	\$0.06
3. Process Mining	This time-tracking alternative uses process mining technology to track digital activities across the company. It enables SCE to passively monitor activities across technology landscape and collect utility personnel time spent supporting ECS.	\$2.50–\$3.00	\$0.35

²⁵⁸ D.21-08-036, p. 479.

²⁵⁹ Refer to WP SCE-07, Vol. 01, Book D, pp. 71-72, Summary of KPMG Study- Alternatives.

1 As seen in the table below, each of these alternatives have significant
2 disadvantages which make them unreasonable and noncompliant alternatives, and they would not lead to
3 data that is accurate or independently verified. The alternative of regular training as discussed earlier,
4 would be less burdensome, intrusive, time consuming, and costly.²⁶⁰

5 SCE is providing the alternatives in the KPMG report in this testimony in
6 compliance with the Commission's inquiry. It is important to note that KPMG does not make a
7 recommendation on any of these alternatives. Given the significant disadvantages with each of these
8 alternatives, SCE urges the Commission to not adopt any of them. Rather, given that there have been no
9 findings of improper tracking of incremental costs, the Commission should continue to allow SCE to use
10 the "but for" test and train employees. Rigorous training is the key for compliance and places the
11 responsible on employees to do the right thing and record their incremental costs so that these costs can
12 be properly borne by shareholders.

²⁶⁰ If the Commission requires SCE to track these non-incremental costs (which it should not, for the reasons SCE has stated in this testimony), then SCE respectfully requests funding in this GRC for the additional resources (including the necessary capital resources) as outlined in the KPMG study.

Table IX-42
Table of Summary of KPMG Study²⁶¹
Alternatives Disadvantages and Advantages

Alternative Name	Advantages	Disadvantages
1. Time Sheets	<ul style="list-style-type: none"> Places the accountability to the employees that have already been trained. Provides a direct linkage between time spent and reimbursements to SCE. Offers the potential to be the most accurate alternative as employees would be responsible for recording their actual time spent. 	<ul style="list-style-type: none"> Requires a change in company culture as time sheets are not widely used across the company especially for non-incremental support, and employees may not submit time for all interactions without a comprehensive change management effort in addition to on-going training. Cost to implement timekeeping system as current systems in place are not set up to support regular time sheets.
2. Allocation	<ul style="list-style-type: none"> Common in the utility industry, predominately for time between affiliates. A one-time process where representative individuals who are skilled in their role are used as the benchmark for the job standard. Has the potential to be less accurate because ECS operates in a dynamic environment and resource needs can change rapidly, thus the need for “but for” tests by non-incremental resources. As a result, allocations may under-state or over-state non-incremental time and would require a true-up mechanism. 	<ul style="list-style-type: none"> ECS is a department and not an affiliate, and allocations are less common between departments than between affiliates. Allocation percentages are often set for the year and need to be reevaluated and reconfirmed by managers. Assumptions do not adjust for real-time changes, and there may be a margin of error due to the delay in confirming where time was actually spent.
3. Process Mining	<ul style="list-style-type: none"> Allows for the ability to create automated event logs/records from business processes. Passive function that works on top of existing systems. Provides immediate insights/analytics from data gathered. Allows for the ability to find and fix inefficiencies swiftly. 	<ul style="list-style-type: none"> Cost to acquire and implement the new system and hire or train staff to manage. May not capture activities outside of existing systems such as phone calls and texts. Technology is complicated and likely not well understood within SCE; change management efforts may be required.

²⁶¹ Refer to WP SCE-07, Vol. 01, Book D, pp. 101-104, Summary of KPMG Study - Alternatives Disadvantages and Advantages for additional details.

1 (4) **SCE’s Response to the Commission’s Inquiry on ECS’ use of SCE’s**
2 **Human Resources Department**

3 The Commission’s third inquiry is as follows: “Concerning the HR
4 services provided to ECS, provide a description of how ECS employee questions are assigned to, and
5 addressed by, HR personnel (i.e., do ECS employees have an assigned HR specialist, and if so, does that
6 HR specialist also oversee utility employees?).”²⁶²

7 For context, ECS employees are SCE employees. SCE employees who
8 work on ECS matters are assigned HR personnel based on their Organizational Unit (e.g., Information
9 Technology).

10 As noted above, per the NTP&S rules, ECS can use HR’s temporarily
11 available capacity, as long as utility work is always the priority, and these costs are non-incremental.
12 ECS uses shared resources and excess capacity of HR personnel. Thus, ECS employees have an
13 assigned HR specialist that also oversees utility employees. This HR specialist would exist whether ECS
14 existed or not, and thus is considered non-incremental. For example, in 2022, ECS transitioned to the
15 Information Technology Organizational Unit from Customer Service Organizational Unit. ECS, which
16 had approximately 64 employees at the end of 2021, did not impact the IT HR support function
17 sufficiently to require any incremental resources, and ECS’s departure from the Customer Service
18 Organizational Unit did not impact (i.e., decrease) headcount in the Customer Service HR support
19 function.

20 Another example to illustrate the point that ECS is too small to impact HR
21 resource staffing is to compare the HR staffing department per SCE employee per capita and compare to
22 ECS. Based on this ratio, ECS does not warrant an incremental HR resource, as illustrated in Table IX-
23 43.

²⁶² D.21-08-036, p. 479.

Table IX-43
Human Resources Ratio²⁶³

As of 12/31/2022

a	Total HR Business Partners Dept. Staffing	48
b	Total SCE Employees	12,893
c	Per Capita Business Partner Head Count (b/a)	269
d	ECS Staffing	57
e	Incremental BP Headcount (d/c)	0

(5) SCE’s Response to the CPUC’s Inquiry on ECS’ Use of Office Related Expenses.

The Commission’s fourth inquiry is as follows: “Discuss whether ECS pays for office-related expenses (including utilities), why/why not, and how SCE’s current approach is consistent with the requirement that all incremental costs for NTP&S be the sole responsibility of shareholders.”²⁶⁴

SCE’s shareholders pay for all office-related expenses for ECS except utilities, such as electricity and water. Office related expenses such as paper, pens, computers, etc., are considered incremental costs and thus tracked separately and paid for by shareholders. Utilities, such as electricity and water are considered *non*-incremental costs, as they would exist whether ECS existed or not as ECS is using temporary excess capacity in the building. An example is that ECS has relocated several times during the past several years (e.g., from Rosemead to Irwindale to Pomona and Irvine) as the utility operations needed space capacity in certain locations, and ECS found locations with excess space. ECS also has rented WeWork space as needed.²⁶⁵ Finally, as noted above, ECS pays the ratepayers for use of non-incremental resources by contributing 100% of its gross revenues to the \$16.7 million GRSM threshold and 10-30% of total gross revenues thereafter.

B. Added Facilities Rates

SCE’s revenue requirement recovers the costs of owning, operating, and maintaining standard facilities. Customers may request facilities in addition to, or in substitution for, the standard facilities

²⁶³ Refer to WP SCE-07, Vol. 01, Book D, pp. 115-116, Human Resources Ratio.

²⁶⁴ D.21-08-036, p. 479.

²⁶⁵ Further, ECS’ use of SCE’s space is limited. Since March 2020, ECS employees have been mostly working remotely from their homes, coming into the office approximately one day per week beginning in May 2022.

that SCE would normally install. SCE may accommodate these requests by building such additional facilities, which are called Added Facilities. Customers are charged for the cost of these additional facilities through Added Facilities rates. Table IX-44 below summarizes the proposed Added Facilities rates.

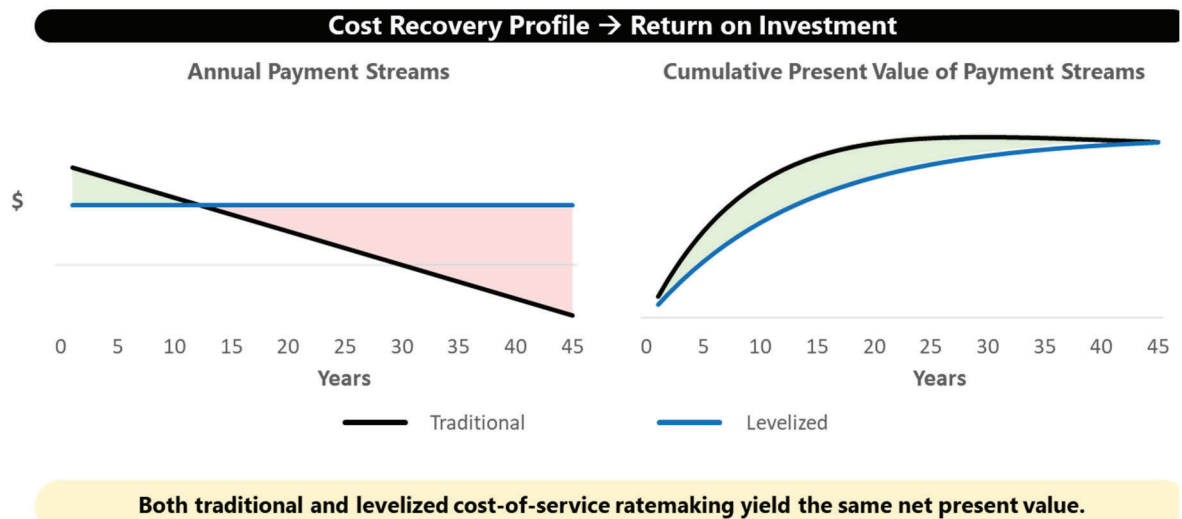
Table IX-44
Added Facilities Rate Components²⁶⁶

Added Facilities Rates				SCE Financed			Customer Financed		
Line	Component	No Coverage	20-Year Coverage	Perpetual Coverage	No Coverage	20-Year Coverage	Perpetual Coverage	No Coverage	20-Year Coverage
1	Capital (Depreciation, Return, Taxes)	9.07%	9.07%	9.07%	—	—	—	1.93%	1.93%
2	Overhead (A&G, Property Taxes, Insurance)	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.77%	1.77%
3	O&M	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	—	0.21%
4	Total Capital, Overhead, and O&M	12.76%	12.76%	12.76%	3.70%	3.70%	3.70%	0.31%	0.33%
5	Replacement	—	0.21%	1.03%	—	0.21%	1.03%	—	0.21%
6	Annual Total	12.76%	12.97%	13.79%	3.70%	3.90%	4.73%	0.31%	0.33%
7	Monthly Total	1.06%	1.08%	1.15%	0.31%	0.33%	0.39%	0.31%	0.33%
8	One-Time Payment Factor	N/A	132.85%	185.29%	N/A	39.98%	63.50%	N/A	39.98%

The Added Facilities rates reflect the costs of owning, operating, and maintaining the Added Facilities. The methodology for calculating the Added Facilities rates is based on portfolio-derived levelized rates. That is, Added Facilities rates are calculated to equal the net present value of a traditional declining rate base revenue requirement stream. In the calculation of Added Facilities rates, SCE models the revenue requirement stream for a portfolio of its transmission and distribution Added Facilities over their average service lives. SCE then converts this declining revenue stream into a levelized rate, which produces a levelized revenue stream that yields the same net present value as a traditional declining rate base revenue requirement stream.

²⁶⁶ Refer to WP SCE-07, Vol. 01, Book D, pp. 117-151, Added Facilities Rate Components.

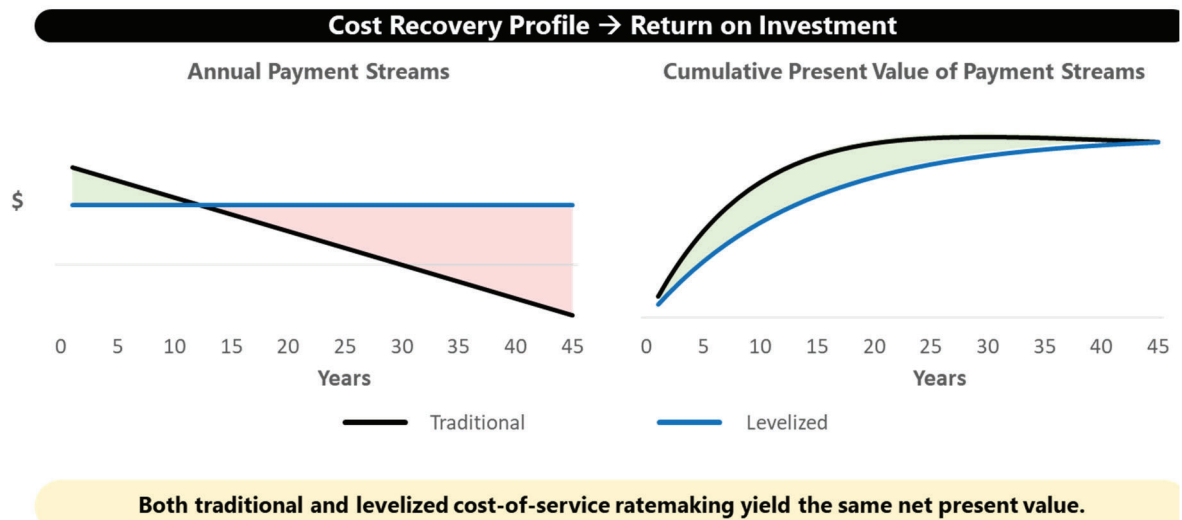
Figure IX-8
Illustration of Traditional vs. Levelized Cost Recovery²⁶⁷



The assumptions used to derive Added Facilities rates are divided into two cost components:
(1) capital-related (or costs of ownership); and (2) O&M-related. The capital-related cost component is

²⁶⁷

Figure IX-8
Illustration of Traditional vs. Levelized Cost Recovery



illustrates the relationship between traditional and levelized cost-of-service ratemaking. Under traditional cost-of-service ratemaking, SCE's return on investment declines as SCE recovers its initial investment through

(Continued)

1 based on SCE's currently authorized rate of return (7.44%) and depreciation and salvage rates, current
2 statutory Federal income tax (21.00%) and State income tax (8.84%) rates, 2021 Administrative and
3 General (A&G) expenses (0.81%), and proposed property tax (1.47% of Assessed Value) and Insurance
4 (0.32%). The rate component for O&M has been calculated as the ratio of the most recent ten years'
5 historical O&M expense and plant-in-service relevant to the Added Facilities.

6 Added Facilities are provided under several tariff provisions, depending on the facilities. Under
7 Rule 2, Section H, SCE provides additional transmission and distribution facilities. SCE may either
8 finance Added Facilities (SCE-financed option) or require the customer to finance the Added Facilities
9 (Customer-financed option). The cost of these Added Facilities is recovered through a monthly charge
10 equal to the installed cost of the facilities times the monthly Added Facilities rate applicable to the
11 financing and replacement option.

12 SCE provides Added Facilities with and without replacement coverage. As shown in Table IX-
13 44, the current rates have the following options: (1) SCE-financed with replacement at additional cost,
14 (2) SCE-financed with limited replacement for a 20-year term at no additional cost, (3) SCE-financed
15 with perpetual replacement at no additional cost, (4) Customer-financed with replacement at additional
16 cost, (5) Customer-financed with limited replacement for a 20-year term at no additional cost, and
17 (6) Customer-financed with perpetual replacement at no additional cost. These replacement options
18 address utility and customer obligations to pay for new facilities when the originally installed facilities
19 require replacement. If a customer chooses the rate with replacement at additional cost option, the
20 customer must pay for replacement facilities when needed. If a customer chooses the limited 20-year
21 replacement option, SCE provides replacement with no additional cost to the customer for a period up to
22 20 years. Finally, if a customer chooses the perpetual replacement option, SCE provides replacement
23 facilities at no additional cost to the customer if the customer continues to pay for the Added Facilities.

24 As provided in Rule 2, Section H, when SCE determines the collection of monthly charges to be
25 impractical, the Added Facilities customer must make an equivalent one-time payment in lieu of the

depreciation accruals. Since SCE's depreciation accruals account for the cost of removing and disposing of an asset at the end of its service life, there comes a point when the sum of the depreciation accruals will exceed the initial investment of an asset. At that point, the return on investment is negative because applying a rate of return to a negative investment balance produces a negative return on investment. As SCE's Added Facilities rates are levelized based on a traditional declining revenue requirement, those rates account for the negative return on investment described and illustrated above. In other words, the present value calculations include the negative return in the later years and are incorporated in SCE's Added Facilities rates.

1 monthly charges. The one-time payment equals the net present value of the future payments the
2 customer would otherwise be obligated to pay multiplied by the installed cost of the Added Facilities to
3 calculate a one-time equivalent payment.

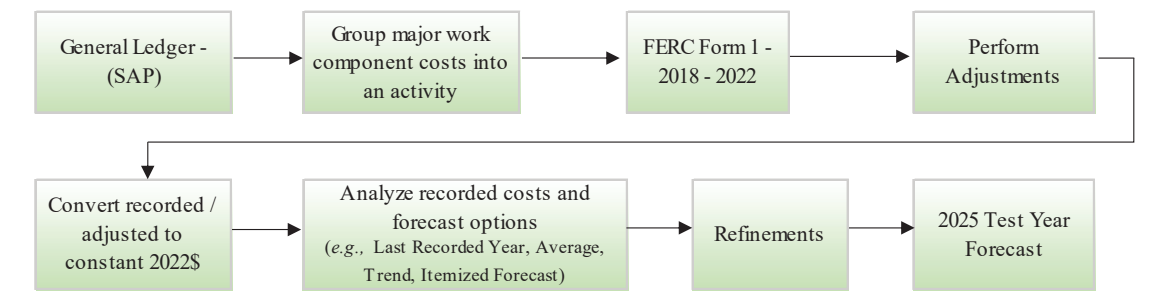
4 Under Rule 2, Section J, SCE may finance the monthly capital-related charge of Interval
5 Metering and/or Metering Facilities not part of other transmission and distribution facilities installed as
6 Added Facilities under Rule 2, Section H. The rate for the monthly capital-related charge of Interval
7 Metering and/or Metering Facilities under Rule 2, Section J, is 1.24 percent per month. The rate is
8 multiplied by the investment amount of the Interval Metering and/or Metering Facilities. Under Rule 21,
9 SCE may either finance generation interconnection facilities (SCE-financed option) or require the
10 customer to advance the cost of interconnection facilities (Customer-financed option).

X.

OPERATION AND MAINTENANCE EXPENSE FORECAST DEVELOPMENT

In preparing the O&M expense estimates for this GRC Application, SCE used the following step-by-step process to develop and support the 2025 Test Year O&M expenses. The purpose of this methodology as reflected in Figure X-9 below, was to achieve a consistent analytical approach by the respective subject matter experts that prepared the O&M expense estimates.

***Figure X-9
Expense Forecast Development***



SCE's O&M expense forecast development process complies with the Commission's Rate Case Plan decision, D.89-01-040, in that it: (1) includes five years of recorded data for each FERC account, by labor, non-labor, and other, used in developing the Test Year revenue requirement, including the most current recorded year available when the GRC application is filed, (2) provides base year (2022) recorded and estimated data for subsequent forecast years, (3) states all expenses in recorded base year (2022) and nominal dollars, and (4) makes sure that all forecast amounts have a clear tie back to base data.²⁶⁸

In summary, the O&M expense forecast development process comprised the following steps, as illustrated in Figure X-9 above:

- Five years of recorded O&M data (2018-2022) was extracted from SCE's SAP system for the period January 1, 2018 through December 31, 2022.
- The extracted five years of recorded FERC Form 1 O&M data is the basis or starting point for the recorded O&M. This data was then organized into activity groups by FERC account

²⁶⁸ D.89-01-040, Appendix B, Standard Requirement List of Documentation Supporting an NOI, specifically item numbers 6 and 7.

for analysis and forecasting. This effort not only supported the level of expenses for 2025 but required a companywide review of recorded expenses and activities.

- Recorded expenses were adjusted for unique or abnormal expenses, and to remove expenses which are recovered through other ratemaking mechanisms. After adjustments were made, the recorded-adjusted expenses were converted to constant 2022 dollars.
- Developing the 2023 through 2025 forecast O&M expenses included a review of various standard forecasting methodologies accepted by the Commission, including: (1) use of last recorded year; (2) averaging of recorded data; (3) trending of recorded data; and (4) development of an “itemized forecast” approach. These are the standard forecasting methodologies accepted by the Commission. Other methodologies are also used in SCE’s showing. For instance, forecasts may be tied to units of work and some associated unit cost. Forecasts may be prepared based on specialized expertise, such as pension costs, which are based on an actuarial methodology. In all cases, SCE recognizes that, as the applicant, its witnesses must prove and must demonstrate the reasonableness of the methodology and the resulting forecast.
- A 2025 Test Year forecast for each O&M activity was selected. Each witness supports and justifies the method chosen and discusses the reasons other methodologies were not used to determine the 2025 forecast for each O&M activity.

A. GRC O&M Data Management

The starting point to develop SCE’s 2025 Test Year O&M expense estimates involved collecting and analyzing recorded data for the five-year historical period 2018-2022.²⁶⁹ The originating source for the recorded O&M expense data for the base five-year period is SAP.²⁷⁰ The FERC requires that all electric utilities file an annual comprehensive financial and operating report, known as the FERC Form 1 (FF1). Reporting recorded costs in the FF1 follows FERC’s established Uniform System of Accounts (USOA). Recorded O&M expenses in the FF1 are reported by FERC account and are derived from SAP.

²⁶⁹ Since SCE is filing its 2025 GRC application in 2023, the 2018 through 2022 recorded data will be the five-year recorded period used, with 2022 designated as the “base year,” and 2018 through 2022 referred to as the “historical period.”

²⁷⁰ SCE implemented the SAP accounting system on July 1, 2008. The SAP system was installed with the goal of replacing separate systems with a single solution that integrates the basic enterprise business processes, *e.g.*, accounting, payroll, procurement, material management, and work management in a single, integrated application that uses a centralized database.

1 The total recorded amounts in each O&M FERC account for the years 2018 through 2022 in this GRC
2 filing are identical to the amounts in SCE's FF1 filings for those years.

3 SCE's Corporate Finance Department (Finance) aggregates the GRC O&M historical and
4 forecast data on a total company basis in a financial database. Within the financial database, the O&M
5 costs are assigned Business Planning Groups (BPGs), BPEs and GRC activities by final cost centers
6 (FCCs) for review throughout the year. Finance provides each O&M witness a standardized workpaper
7 package (which can also be complemented with supplemental workpapers) in order to: (1) help ensure
8 all base O&M costs are being forecast in the GRC, (2) prevent double recovery of costs, and (3) provide
9 a consistent and simplified O&M showing across FCCs. Recorded 2018 through 2022 O&M expenses
10 were extracted from SAP and loaded in the financial database to begin the GRC forecasting process.

11 To help facilitate the O&M forecast process, FERC accounts have been aggregated into GRC
12 activity groupings that track closely with the purpose of the work. Separation into activities allows SCE
13 to isolate the cause of certain variations in historical data and helps establish a basis for the forecasting
14 method selected. At SCE, O&M budgets are assigned to functional and cross-functional managers
15 responsible for the expenses and are evaluated throughout the year for performance and cost control.
16 In SAP, cost centers are used to capture expenses for similar types of work, grouped to facilitate their
17 effective tracking and management. Also, with the use of cost elements, FCCs are used in the cost
18 accounting system to identify and record the costs to the appropriate FERC accounts.

19 O&M costs are bifurcated into one of two categories: labor or non-labor. For the GRC, portions
20 of the non-labor costs that are not subject to traditional non-labor escalation or that require special
21 trending rates are reclassified as "other" expenses. Examples of these types of costs include rents and
22 health care expenses.

23 **B. Adjustments Included in GRC Activities** ²⁷¹

24 Certain types of adjustments were made to recorded labor and non-labor expenses for the base
25 year 2022 and prior years (2018 through 2021) in the historical period.²⁷² These adjustments were made
26 to remove: (a) costs recovered through other ratemaking (non-GRC) mechanisms, such as Public

²⁷¹ Refer to WP SCE-07, Vol. 01, Book D, pp. 153-166, Summary of Ratemaking Adjustments.

²⁷² All of the forecast O&M and capital-related costs included in this GRC filing are on a total Company-wide, or total system basis, which includes both base-related CPUC-jurisdictional costs and base-related FERC-jurisdictional transmission-related operating and capital costs. Based on a methodology, as described in Chapter IV of this Exhibit, the total system O&M and capital-related forecasts are then separated into CPUC and FERC-jurisdictional amounts.

Purpose Programs costs, (b) costs that are non-ratepayer expenses or non-utility, such as costs that are the responsibility of shareholders, and (c) costs that have been disallowed by the Commission, such as costs related to SCE's Directors and Officers liability insurance expense. In addition, expenses for services provided by SCE to support Edison International (EIX) and associated non-utility affiliates were added back to the base year and historical period.

1. Ratemaking Treatment for Non-Utility-Related Expenses

Regarding expenses in support of EIX and associated non-utility affiliates and their relationship to the ratemaking process, this filing adheres to Commission precedent in the Holding Company Decision (D.88-01-063), the Affiliate Transaction Rulemaking Decision (D.97-12-088) and all subsequent GRCs. These decisions established guidelines and methodologies SCE must follow when incurring expenses to support non-utility affiliates.

Under these decisions, such expenses incurred by the utility are charged to EIX and non-utility affiliates. The payments from EIX and non-utility affiliates for these services are recorded as a credit to SCE's BRRBA and returned to customers through the operation of the BRRBA. Current Commission-approved ratemaking provides that SCE reverses these credits from forecast test year expenses. Forecast test year expenses are reflected at the level the utility will incur them excluding the credit.²⁷³ Then, recorded utility expenses to support EIX and non-utility affiliates are credited to customers through the BRRBA. This procedure helps ensure that utility customers do not subsidize services provided by SCE to EIX and non-utility affiliates.

Except for the two cases that are discussed below, SCE has reflected its forecast test year expenses on a "gross" basis. It is necessary to forecast on a gross basis because otherwise SCE's customers would receive the benefit of charges to EIX and non-utility affiliates twice: once through a reduction in test year expenses, and a second time through credits recorded in the BRRBA.

Consistent with the principles of the Holding Company Decision, costs incurred by SCE on behalf of EIX and non-utility affiliates not included in the forecast Test Year expense estimates will not be credited to the BRRBA. SCE removed from its forecast Test Year expenses those non-utility affiliate costs identified as incremental expenses and that are associated with personnel or activities 100 percent dedicated to non-utility functions. These costs include: (1) Corporate Communications outside

²⁷³ SCE uses the term "gross basis" (*i.e.* 100% level) to indicate the level of costs excluding the credit. We use the term "net basis" for the level of costs including the credit.

1 services costs associated exclusively with EIX and non-utility affiliates, and (2) EIX and non-utility
2 affiliate's pensions and benefits costs. These costs are not included in the forecast test year expense
3 estimates (*i.e.*, they have been reflected on a net basis). Therefore, they will not be credited to the
4 BRRBA.

5 **2. Disallowances or Regulatory Settlement Agreements**

6 SCE recognizes that there are historical costs that were recorded but excluded from the
7 recorded base data and forecasts as directed by the Commission. For example, in D.13-09-028, *Decision*
8 *Conditionally Approving the Southern California Edison Company Settlement Agreement Regarding the*
9 *Malibu Canyon Fire*, the Commission ordered SCE to pay \$37 million from Shareholder funds.
10 This included a \$20 million fine, plus an additional \$17 million to inspect SCE-owned poles in Malibu
11 Canyon for compliance with GO 95 safety factors and SCE internal standards. In compliance with this
12 decision, SCE identified \$41.231 million of recorded costs between 2018 and 2022 that were removed
13 from the base and 2025 Test Year.

14 **3. Other Adjustments**

15 SCE performed select adjustments that do not fall into the categories as discussed above.
16 Other adjustments performed largely fall in the category of aligning historical costs to SCE's forecast in
17 areas where the current accounting structure or one-time, non-recurring items made it difficult to
18 perform a reasonable comparison.

19 After all adjustments are made to the recorded 2018 through 2022 expenses, labor and
20 non-labor escalation rates for the recorded period are applied to the recorded-adjusted amounts to
21 remove the effect of inflationary changes in the costs of labor and goods in order to facilitate year-to-
22 year comparisons. The 2018 through 2021 recorded amounts are escalated and restated in base year, or
23 2022, dollars, using escalation rates developed and supported in Chapter VIII of this Exhibit.²⁷⁴

24 **C. Analyze Costs**

25 After the historical 2018 through 2022 data is adjusted and converted into constant 2022 dollars,
26 the data is used to make initial estimates for 2023, 2024, and the 2025 test year O&M forecasts.
27 The Finance database calculates the following forecasting methodologies for recorded-adjusted O&M
28 costs at the GRC activity level by labor, non-labor and other:

²⁷⁴ Refer to WP SCE-07, Vol.01, Book D, pp. 167-325, FERC Account Recorded with Escalation.

- 1 • **Last Recorded Year:** the 2025 Test Year estimate could be based on the last recorded year
2 (*i.e.*, 2022 base year) of recorded-adjusted O&M expenses.²⁷⁵
- 3 • **Averaging:** the 2025 Test Year estimate could be based on two, three, four, or five years
4 (2018-2022) of recorded-adjusted O&M expenses which are arithmetically averaged.
- 5 • **Linear Trending:** the 2025 Test Year estimate could be based on three, four, or five years
6 (2018-2022) of recorded-adjusted O&M expenses trended using standard regression analysis.
- 7 • **Itemized Forecast:** the 2025 Test year estimate could be based on a detailed analysis of
8 costs expected to be incurred in the Test Year. This approach may use 2022 recorded-
9 adjusted, an average of recorded years, or a historical trend as a base plus a detailed estimate
10 of additional future costs and/or savings. In addition, a forecast may be built from zero
11 dollars to estimate Test Year expense (*i.e.*, a “bottoms-up” forecast). Some itemized forecasts
12 will tie directly to an underlying causal variable. For example, meter-related expenses are
13 tied directly to the number of meters, and the forecast of Test Year expenses for meter-
14 related activities is tied to the forecast number of meters.²⁷⁶

15 This standardized approach used to estimate future O&M funding levels for an activity is a
16 structured and systematic process. Ultimately, the method used is a matter of judgment. Often, year-to-
17 year changes in recorded data are a complex mix of events that cannot always be fully explained, or they
18 are explained as natural or cyclical events, which may recur one or more times over the five-year
19 recorded history. This could be due to weather conditions or may be due to a business or economic cycle
20 longer than one year in duration. This variation in recorded data should not be adjusted but should be
21 considered when deciding the estimating method to be used for that activity. In such an instance, a
22 historical average may be more appropriate than a trend. As year-to-year variations are understood, it is
23 determined whether a historical average or trend is appropriate, or whether the 2022 base year recorded
24 level should be the basis from which future estimates are made.

25 Not all activities lend themselves to a mathematical estimating method based on historical data.
26 Wide variations in recorded expense levels would reduce the use of trending or averaging methods as
27 accurate predictors of test year expenses. These types of activities may be better estimated using a

²⁷⁵ Some forecast will also reflect Last Recorded Year (LRY) + Adjustments; these methods are based on LRY but are adjusted to capture any identifiable changes in the test year that are in addition to or less than last recorded year. These adjustments are then explained in each corresponding testimony.

²⁷⁶ See Exhibit SCE-02, Vol. 03.

1 special study approach, a “bottoms-up” calculation of resources required, or an addition or subtraction of
2 some incremental costs to a base level of expense given some expected future change in workload or
3 scope of activity.

4 **D. 2025 O&M Forecast**

5 Each O&M witness considered the results obtained from each of the forecasting methods and
6 discusses such in their respective testimony and accompanying workpapers, documents the validity of
7 these methods in determining their 2025 test year forecast. Based on their analyses of recorded costs,
8 and their understanding of the activities they anticipate for the test year, SCE’s O&M witnesses forecast
9 their estimates for test year 2025 O&M expenses. The selected forecast for each O&M activity is then
10 summarized up to the FERC account level and included in the 2025 test year revenue requirement
11 request.

12 **E. Summary of Results**

13 The following tables summarize the O&M expense amounts for the recorded year 2022 and
14 estimated years 2023 through 2025, both in constant 2022 dollars and nominal dollars.²⁷⁷

²⁷⁷ Refer to WP SCE-07, Vol. 01, Book E, pp. 1-258, Total Company O&M Expense.

Table X-45
Southern California Edison Company
Test Year 2025 General Rate Case
Operations & Maintenance Expenses
Category: Total O&M Expenses
(\$000)

Line	Description	Recorded/Adj		Estimated (in Constant 2022\$)				
		2022	2023	2024	2025	2026	2027	2028
1.	Production							
2.	Steam	4,210	3,560	3,466	2,643	2,643	2,643	2,643
3.	Nuclear	76,030	77,768	77,931	78,349	78,349	78,349	78,349
4.	Hydro	44,264	52,628	52,952	60,237	60,237	60,237	60,237
5.	Other	83,965	83,048	87,795	99,123	99,123	99,123	99,123
6.	Total Production	208,469	217,003	222,144	240,351	240,351	240,351	240,351
7.	Transmission	253,467	248,151	261,778	266,362	266,362	266,362	266,362
8.	Distribution	1,019,313	1,133,630	1,198,807	1,280,115	1,280,115	1,280,115	1,280,115
9.	Customer Accounts	130,570	135,530	151,032	149,016	149,016	149,016	149,016
10.	Interest Offset on Customer Deposits	(5,372)	1,358	297	(1,300)	(1,927)	(1,927)	(1,927)
11.	Uncollectibles (Account 904)	25,843	17,485	18,714	22,188	23,432	24,777	26,296
12.	Customer Service and Informational and Sales	78,911	105,120	106,075	106,410	106,410	106,410	106,410
13.	Administrative and General	1,027,456	1,136,222	1,108,914	1,211,477	1,211,477	1,211,477	1,211,477
14.	Franchise Requirements (Account 927)	62,438	89,960	96,283	107,968	114,017	120,563	127,954
15.	Total O&M	2,801,094	3,084,459	3,164,043	3,382,586	3,389,253	3,397,144	3,406,053
16.	Escalation	–	61,738	67,883	119,640	178,393	242,253	309,499
17.	Total O&M (Including Escalation)	2,801,094	3,146,196	3,231,926	3,502,226	3,567,646	3,639,396	3,715,552
18.	Less: Franchise Fees and Uncollectibles (FF&U)	(88,281)	(107,445)	(114,996)	(130,156)	(137,449)	(145,340)	(154,249)
19.	Total O&M (Excluding FF&U)	2,712,813	3,038,751	3,116,929	3,372,071	3,430,197	3,494,056	3,561,303
20.	Labor, Non-labor, and Other Expense Detail (Constant 2022\$):							
21.	Labor	860,483	836,347	874,406	943,415	943,415	943,415	943,415
22.	Non-Labor	1,297,581	1,606,784	1,693,844	1,769,741	1,769,741	1,769,741	1,769,741
23.	Other	643,031	641,328	595,794	669,431	676,097	683,988	692,898
24.	Total O&M	2,801,094	3,084,459	3,164,043	3,382,586	3,389,253	3,397,144	3,406,053
25.	Escalation:							
26.	Labor	–	45,996	77,161	113,223	143,372	173,895	204,951
27.	Non-Labor	–	9,882	(21,059)	(10,617)	12,398	39,911	70,039
28.	Other	–	5,859	11,780	17,034	22,623	28,447	34,509
29.	Total Escalation	–	61,738	67,883	119,640	178,393	242,253	309,499
30.	Total O&M (Including Escalation)	2,801,094	3,146,196	3,231,926	3,502,226	3,567,646	3,639,396	3,715,552
31.	Less : Franchise Fees and Uncollectibles (FF&U)	(88,281)	(107,445)	(114,996)	(130,156)	(137,449)	(145,340)	(154,249)
32.	Total O&M (Excluding FF&U)	2,712,813	3,038,751	3,116,929	3,372,071	3,430,197	3,494,056	3,561,303

Table X-46
Southern California Edison Company
Test Year 2025 General Rate Case
Operation & Maintenance Expenses
Category: Generation Expenses
(\$000)

Line	Account	Description	Recorded/Adj	Estimated (in Constant 2022\$)					
			2022	2023	2024	2025	2026	2027	2028
1.		Steam:							
2.	500	Operation Supervision and Engineering	3,869	3,334	3,245	2,299	2,299	2,299	2,299
3.	501	Fuel	-	-	-	-	-	-	-
4.	502	Steam Expenses	-	-	-	-	-	-	-
5.	505	Electric Expenses	-	-	-	-	-	-	-
6.	506	Miscellaneous Steam Power Expenses	218	225	221	210	210	210	210
7.	507	Rents	-	-	-	-	-	-	-
8.	509	Allowances	-	-	-	-	-	-	-
9.	510	Maintenance Supervision and Engineering	124	-	-	134	134	134	134
10.	511	Maintenance of Structures	-	-	-	-	-	-	-
11.	512	Maintenance of Boiler Plant	-	-	-	-	-	-	-
12.	513	Maintenance of Electric Plant	-	-	-	-	-	-	-
13.	514	Maintenance of Miscellaneous Steam Plant	-	-	-	-	-	-	-
14.		Total Steam	4,210	3,560	3,466	2,643	2,643	2,643	2,643
15.		Nuclear:							
16.	517	Operation Supervision and Engineering	16,614	17,958	18,147	18,655	18,655	18,655	18,655
17.	518	Nuclear Fuel Expense	-	-	-	-	-	-	-
18.	519	Coolants and Water	9,137	9,413	9,411	9,409	9,409	9,409	9,409
19.	520	Steam Expenses	3,862	5,150	5,127	5,039	5,039	5,039	5,039
20.	523	Electric Expenses	5,702	4,474	4,474	4,474	4,474	4,474	4,474
21.	524	Miscellaneous Nuclear Power Expenses	20,429	23,465	23,465	23,465	23,465	23,465	23,465
22.	525	Rents	-	-	-	-	-	-	-
23.	528	Maintenance Supervision and Engineering	3,485	2,982	2,982	2,982	2,982	2,982	2,982
24.	529	Maintenance of Structures	1,458	569	569	569	569	569	569
25.	530	Maintenance of Reactor Plant Equipment	6,258	9,147	9,147	9,147	9,147	9,147	9,147
26.	531	Maintenance of Electric Plant	7,219	3,806	3,806	3,806	3,806	3,806	3,806
27.	532	Maintenance of Miscellaneous Nuclear Plant	1,866	804	804	804	804	804	804
28.		Total Nuclear	76,030	77,768	77,931	78,349	78,349	78,349	78,349
29.		Hydro:							
30.	535	Operation Supervision and Engineering	1,726	82	85	90	90	90	90
31.	536	Water for Power	4,049	5,422	5,422	5,422	5,422	5,422	5,422
32.	537	Hydraulic Expenses	2,369	983	995	1,290	1,290	1,290	1,290
33.	538	Electric Expenses	2,004	-	-	-	-	-	-
34.	539	Miscellaneous Hydraulic Power Generation Expenses	18,672	29,457	28,796	33,268	33,268	33,268	33,268
35.	540	Rents	1,504	-	-	-	-	-	-
36.	541	Maintenance Supervision and Engineering	4,221	-	-	-	-	-	-
37.	542	Maintenance of Structures	666	-	-	1,135	1,135	1,135	1,135
38.	543	Maintenance of Reservoirs, Dams and Waterways	2,555	423	439	668	668	668	668
39.	544	Maintenance of Electric Plant	5,328	-	-	-	-	-	-
40.	545	Maintenance of Miscellaneous Hydraulic Plant	1,171	16,261	17,215	18,366	18,366	18,366	18,366
41.		Total Hydro	44,264	52,628	52,952	60,237	60,237	60,237	60,237
42.		Other:							
43.	546	Operation Supervision and Engineering	2,963	1,340	1,508	2,410	2,410	2,410	2,410
44.	547	Fuel	-	-	-	-	-	-	-
45.	548	Generation Expenses	7,162	-	-	460	460	460	460
46.	549	Miscellaneous Other Power Generation Expenses	11,636	20,131	21,073	20,177	20,177	20,177	20,177
47.	550	Rents	3,159	3,213	3,587	4,640	4,640	4,640	4,640
48.	551	Maintenance Supervision and Engineering	2,943	-	-	223	223	223	223
49.	552	Maintenance of Structures	1,972	-	-	121	121	121	121
50.	553	Maintenance of Generating and Electric Plant	20,774	868	856	6,417	6,417	6,417	6,417
51.	554	Maintenance of Miscellaneous Other Power Generation Plant	2,093	22,278	24,210	24,431	24,431	24,431	24,431
52.	555	Purchased Power	-	-	-	-	-	-	-
53.	556	System Control and Load Dispatching	992	1,142	1,142	1,142	1,142	1,142	1,142
54.	557	Other Expenses	30,273	34,075	35,420	39,102	39,102	39,102	39,102
55.		Total Other	83,965	83,048	87,795	99,123	99,123	99,123	99,123
56.		Total Production	208,469	217,003	222,144	240,351	240,351	240,351	240,351
57.		Escalation	-	7,640	10,747	15,932	21,520	27,462	33,631
58.		Total O&M (Including Escalation)	208,469	224,643	232,892	256,283	261,871	267,813	273,982
59.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):							
60.		Labor	73,972	79,523	81,932	85,393	85,393	85,393	85,393
61.		Non-Labor	134,020	136,892	139,624	151,215	151,215	151,215	151,215
62.		Other	476	588	588	3,743	3,743	3,743	3,743
63.		Total O&M	208,469	217,003	222,144	240,351	240,351	240,351	240,351
64.		Escalation:							
65.		Labor	-	4,371	7,226	10,243	12,970	15,731	18,541
66.		Non-Labor	-	3,269	3,521	5,689	8,550	11,731	15,090
67.		Other	-	-	-	-	-	-	-
68.		Total Escalation	-	7,640	10,747	15,932	21,520	27,462	33,631
69.		Total O&M (Including Escalation)	208,469	224,643	232,892	256,283	261,871	267,813	273,982

Table X-47
Southern California Edison Company
Test Year 2022 General Rate Case
Operation & Maintenance Expenses
Category: Transmission Expenses
(\$000)

Line	Account	Description	Recorded/Adj		Estimated (in Constant 2022\$)				
			2022	2023	2024	2025	2026	2027	2028
1.		Operation:							
2.	560	Operation Supervision and Engineering	5,846	6,290	5,682	7,222	7,222	7,222	7,222
3.	561	Load Dispatching	15,115	16,505	16,865	19,116	19,116	19,116	19,116
4.	562	Station Expenses	24,301	31,238	34,635	26,573	26,573	26,573	26,573
5.	563	Overhead Line Expenses	21,619	29,679	28,499	33,450	33,450	33,450	33,450
6.	564	Underground Line Expenses	2,970	2,160	2,452	2,431	2,431	2,431	2,431
7.	565	Transmission of Electricity by Others	336	380	389	336	336	336	336
8.	566	Miscellaneous Transmission Expenses	39,719	51,251	51,557	52,232	52,232	52,232	52,232
9.	567	Rents	17,882	16,533	17,641	20,270	20,270	20,270	20,270
10.		Total Operation	127,789	154,037	157,720	161,630	161,630	161,630	161,630
11.		Maintenance:							
12.	568	Maintenance Supervision and Engineering	2,006	1,101	1,211	1,530	1,530	1,530	1,530
13.	569	Maintenance of Structures	44,224	2,689	2,820	3,740	3,740	3,740	3,740
14.	570	Maintenance of Station Equipment	9,990	6,981	8,141	11,473	11,473	11,473	11,473
15.	571	Maintenance of Overhead Lines	67,157	80,448	89,007	85,649	85,649	85,649	85,649
16.	572	Maintenance of Underground Lines	411	721	733	640	640	640	640
17.	573	Maintenance of Miscellaneous Transmission Plant	1,889	2,173	2,145	1,700	1,700	1,700	1,700
18.		Total Maintenance	125,679	94,114	104,058	104,732	104,732	104,732	104,732
19.		Total O&M	253,467	248,151	261,778	266,362	266,362	266,362	266,362
20.		Escalation	-	5,228	4,241	9,262	13,972	19,124	24,518
21.		Total O&M (Including Escalation)	253,467	253,379	266,019	275,624	280,334	285,486	290,880
22.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):							
23.		Labor	84,444	83,149	84,388	97,795	97,795	97,795	97,795
24.		Non-Labor	151,579	148,469	159,749	148,735	148,735	148,735	148,735
25.		Other	17,444	16,533	17,641	19,832	19,832	19,832	19,832
26.		Total O&M	253,467	248,151	261,778	266,362	266,362	266,362	266,362
27.		Escalation:							
28.		Labor	-	4,573	7,447	11,737	14,863	18,027	21,246
29.		Non-Labor	-	655	(3,206)	(2,476)	(891)	1,097	3,272
30.		Other	-	-	-	-	-	-	-
31.		Total Escalation	-	5,228	4,241	9,262	13,972	19,124	24,518
32.		Total O&M (Including Escalation)	253,467	253,379	266,019	275,624	280,334	285,486	290,880

Table X-48
Southern California Edison Company
Test Year 2022 General Rate Case
Operation & Maintenance Expenses
Category: Distribution Expenses
(\$000)

Line	Account	Description	2022	2023	2024	2025	2026	2027	2028
1.		Operation:							
2.	580	Operation Supervision and Engineering	14,663	16,366	13,356	14,636	14,636	14,636	14,636
3.	582	Station Expenses	37,544	40,224	40,924	51,559	51,559	51,559	51,559
4.	583	Overhead Line Expenses	108,787	124,790	122,994	168,592	168,592	168,592	168,592
5.	584	Underground Line Expenses	9,425	10,764	9,137	9,779	9,779	9,779	9,779
6.	585	Street Lighting and Signal System Expenses	361	—	68	378	378	378	378
7.	586	Meter Expenses	22,613	25,376	25,420	25,019	25,019	25,019	25,019
8.	587	Customer Installations Expenses	25,938	24,747	25,181	25,573	25,573	25,573	25,573
9.	588	Miscellaneous Distribution Expenses	109,301	117,299	123,187	149,384	149,384	149,384	149,384
10.	589	Rents	3,197	6,041	6,962	4,398	4,398	4,398	4,398
11.		Total Operation	331,828	365,607	367,229	449,317	449,317	449,317	449,317
12.		Maintenance:							
13.	590	Maintenance Supervision and Engineering	1,735	1,101	1,211	1,318	1,318	1,318	1,318
14.	591	Maintenance of Structures	82	649	554	682	682	682	682
15.	592	Maintenance of Station Equipment	9,649	11,319	11,921	21,464	21,464	21,464	21,464
16.	593	Maintenance of Overhead Lines	593,477	674,872	726,732	715,768	715,768	715,768	715,768
17.	594	Maintenance of Underground Lines	49,984	46,866	56,632	58,858	58,858	58,858	58,858
18.	595	Maintenance of Line Transformers	4,989	5,568	5,581	4,498	4,498	4,498	4,498
19.	596	Maintenance of Street Lighting and Signal Systems	4,191	4,170	4,180	3,519	3,519	3,519	3,519
20.	597	Maintenance of Meters	5,854	6,348	7,035	7,835	7,835	7,835	7,835
21.	598	Maintenance of Miscellaneous Distribution Plant	17,523	17,131	17,733	16,854	16,854	16,854	16,854
22.		Total Maintenance	687,485	768,024	831,578	830,797	830,797	830,797	830,797
23.		Total O&M	1,019,313	1,133,630	1,198,807	1,280,115	1,280,115	1,280,115	1,280,115
24.		Escalation	-	9,217	(10,522)	(1,371)	16,969	38,662	62,380
25.		Total O&M (Including Escalation)	1,019,313	1,142,847	1,188,284	1,278,744	1,297,084	1,318,776	1,342,495
26.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):							
27.		Labor	389,065	293,352	302,394	315,992	315,992	315,992	315,992
28.		Non-Labor	627,198	834,238	889,450	949,306	949,306	949,306	949,306
29.		Other	3,050	6,041	6,962	14,816	14,816	14,816	14,816
30.		Total O&M	1,019,313	1,133,630	1,198,807	1,280,115	1,280,115	1,280,115	1,280,115
31.		Escalation:							
32.		Labor	—	16,134	26,686	37,926	48,024	58,248	68,651
33.		Non-Labor	—	(6,917)	(37,208)	(39,296)	(31,055)	(19,586)	(6,271)
34.		Other	—	—	—	—	—	—	—
35.		Total Escalation	—	9,217	(10,522)	(1,371)	16,969	38,662	62,380
36.		Total O&M (Including Escalation)	1,019,313	1,142,847	1,188,284	1,278,744	1,297,084	1,318,776	1,342,495

Table X-49
Southern California Edison Company
Test Year 2022 General Rate Case
Operation & Maintenance Expenses
Category: Customer Accounts Expenses
(\$000)

Line	Account	Description	Recorded/Adj.		Estimated (in Constant 2022\$)				
			2022	2023	2024	2025	2026	2027	2028
1.	901	Supervision	16,327	17,512	19,292	18,586	18,586	18,586	18,586
2.	902	Meter Reading Expenses	2,229	4,821	4,879	5,051	5,051	5,051	5,051
3.	903	Customer Records and Collection Expenses	102,987	105,506	119,491	119,461	119,461	119,461	119,461
4.	904	Uncollectible Accounts	25,843	17,485	18,714	22,188	23,432	24,777	26,296
5.	905	Miscellaneous Customer Accounts Expenses	9,027	7,691	7,369	5,919	5,919	5,919	5,919
6.		Interest Offset on Customer Deposits	(5,372)	1,358	297	(1,300)	(1,927)	(1,927)	(1,927)
7.		Total O&M	151,041	154,373	170,043	169,904	170,520	171,866	173,384
8.		Escalation	-	6,170	9,796	13,852	18,098	22,339	26,676
9.		Total O&M (Including Escalation)	151,041	160,542	179,839	183,756	188,618	194,204	200,061
10.		Less: Account 904 (Uncollectible Accounts)	(25,843)	(17,485)	(18,714)	(22,188)	(23,432)	(24,777)	(26,296)
11.		Total O&M (Less Account 904)	125,198	143,057	161,125	161,568	165,187	169,428	173,765
12.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):							
13.		Labor	81,279	80,858	92,171	93,177	93,177	93,177	93,177
14.		Non-Labor	49,290	54,672	58,860	55,839	55,839	55,839	55,839
15.		Other	20,471	18,843	19,011	20,888	21,504	22,850	24,368
16.		Total O&M	151,041	154,373	170,043	169,904	170,520	171,866	173,384
17.		Escalation:							
18.		Labor	-	4,447	8,134	11,183	14,161	17,176	20,243
19.		Non-Labor	-	1,722	1,662	2,669	3,937	5,163	6,433
20.		Other	-	-	-	-	-	-	-
21.		Total Escalation	-	6,170	9,796	13,852	18,098	22,339	26,676
22.		Total O&M (Including Escalation)	151,041	160,542	179,839	183,756	188,618	194,204	200,061
23.		Less: Account 904 (Uncollectible Accounts)	(25,843)	(17,485)	(18,714)	(22,188)	(23,432)	(24,777)	(26,296)
24.		Total O&M (Less Account 904)	125,198	143,057	161,125	161,568	165,187	169,428	173,765

Table X-50
Southern California Edison Company
Test Year 2022 General Rate Case
Operation & Maintenance Expenses
Category: Customer Service and Information and Sales Expenses
(\$000)

Line	Account	Description	2022	2023	2024	2025	2026	2027	2028
1.	907	Supervision	1,049	1,055	1,124	1,237	1,237	1,237	1,237
2.	908	Customer Assistance Expenses	61,330	83,886	78,048	76,627	76,627	76,627	76,627
3.	909	Informational and Instructional Advertising Expenses	13,519	13,835	20,501	21,739	21,739	21,739	21,739
4.	910	Miscellaneous Customer Service and Informational Expenses	—	—	—	—	—	—	—
5.	912	Demonstrating and Selling Expenses	3,012	6,344	6,402	6,807	6,807	6,807	6,807
6.	913	Advertising Expenses	—	—	—	—	—	—	—
7.		Total Customer Service & Information	78,911	105,120	106,075	106,410	106,410	106,410	106,410
8.	916	Miscellaneous Sales Expenses	—	—	—	—	—	—	—
9.		Total Sales Expense	—	—	—	—	—	—	—
10.		Total O&M	78,911	105,120	106,075	106,410	106,410	106,410	106,410
11.		Escalation	—	3,570	3,968	6,864	9,475	12,134	14,865
12.		Total O&M (Including Escalation)	78,911	108,690	110,042	113,273	115,884	118,544	121,275
13.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):							
14.		Labor	37,436	44,318	46,118	51,591	51,591	51,591	51,591
15.		Non-Labor	41,475	60,803	59,957	54,819	54,819	54,819	54,819
16.		Other	—	—	—	—	—	—	—
17.		Total O&M	78,911	105,120	106,075	106,410	106,410	106,410	106,410
18.		Escalation:							
19.		Labor	—	2,437	4,070	6,192	7,841	9,510	11,208
20.		Non-Labor	—	1,132	(102)	672	1,634	2,624	3,657
21.		Other	—	—	—	—	—	—	—
22.		Total Escalation	—	3,570	3,968	6,864	9,475	12,134	14,865
23.		Total O&M (Including Escalation)	78,911	108,690	110,042	113,273	115,884	118,544	121,275

Table X-51
Southern California Edison Company
Test Year 2022 General Rate Case
Operation & Maintenance Expenses
Category: Administrative and General Expenses
(\$000)

Line	Account	Description	Recorded/Ad		Estimated (in Constant 2022\$)			
			2022	2023	2024	2025	2026	2027
1.		Operation:						
2.	920	Administrative and General Salaries	185,398	245,599	257,715	289,289	289,289	289,289
3.	921	Office Supplies and Expenses	174,253	243,429	252,552	281,906	281,906	281,906
4.	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-
5.	923	Outside Services Employed	46,276	47,406	51,872	49,195	49,195	49,195
6.	924	Property Insurance	14,779	20,841	22,336	25,193	25,193	25,193
7.	925	Injuries and Damages	487,667	423,946	348,713	356,119	356,119	356,119
8.	926	Employee Pensions and Benefits	44,439	76,874	98,622	133,625	133,625	133,625
9.	927	Franchise Requirements	62,522	89,960	96,283	107,968	114,017	120,563
10.	928	Regulatory Commission Expenses	2,811	2,298	2,298	2,298	2,298	2,298
11.	930	General Advertising Expenses-Miscellaneous General Expenses	37,693	39,071	38,920	37,688	37,688	37,688
12.	931	Rents	9,268	9,272	7,852	10,725	10,725	10,725
13.		Reduction for A&G Credit for Catalina Utilities	-	-	-	-	-	-
14.		Total Operation	1,065,705	1,204,696	1,177,762	1,294,005	1,300,054	1,306,600
15.		Maintenance:						
16.	935	Maintenance of General Plant	24,188	21,486	27,435	25,440	25,440	25,440
17.		Total Maintenance	24,188	21,486	27,435	25,440	25,440	25,440
18.		Total O&M	1,089,893	1,226,182	1,205,197	1,319,445	1,325,495	1,332,041
19.		Escalation	-	29,913	49,653	75,102	98,360	122,531
20.		Total O&M (Including Escalation)	1,089,893	1,256,095	1,254,850	1,394,547	1,423,854	1,454,572
21.		Less: Account 927 (Franchise Requirements)	(62,522)	(89,960)	(96,283)	(107,968)	(114,017)	(120,563)
22.		Total O&M (Less Account 927)	1,027,371	1,166,135	1,158,567	1,286,579	1,309,837	1,334,009
23.		Labor, Non-labor, and Other Expense Detail (Constant 2018\$):						
24.		Labor	194,287	255,147	267,401	299,467	299,467	299,467
25.		Non-Labor	294,018	371,711	386,203	409,826	409,826	409,826
26.		Other	601,588	599,324	551,592	610,152	616,202	622,748
27.		Total O&M	1,089,893	1,226,182	1,205,197	1,319,445	1,325,495	1,332,041
28.		Escalation:						
29.		Labor	-	14,033	23,598	35,942	45,513	55,202
30.		Non-Labor	-	10,021	14,274	22,125	30,223	38,882
31.		Other	-	5,859	11,780	17,034	22,623	28,447
32.		Total Escalation	-	29,913	49,653	75,102	98,360	122,531
33.		Total O&M (Including Escalation)	1,089,893	1,256,095	1,254,850	1,394,547	1,423,854	1,454,572
34.		Less: Account 927 (Franchise Requirements)	(62,522)	(89,960)	(96,283)	(107,968)	(114,017)	(120,563)
35.		Total O&M (Less Account 927)	1,027,371	1,166,135	1,158,567	1,286,579	1,309,837	1,334,009

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XI.

OVERHEAD ALLOCATION

A. Capitalized A&G Expense

This section provides SCE's estimated capitalization rate for Administrative and General (A&G) expenses.²⁷⁸ Capitalized A&G is calculated by multiplying the A&G capitalization rate by the A&G expense in FERC account 920 (A&G Salaries) and eligible portions of account 921 (Office Supplies and Expenses).²⁷⁹ SCE records the total capitalized A&G as a credit to account 922 (Administrative Expenses Transferred) and a debit to account 107 (Construction Work in Progress), and ultimately includes it in Plant-in-Service.

SCE performs an A&G Effort Study to determine the A&G capitalization rate for costs that are not already directly recorded to capital work orders.²⁸⁰ This study is conducted in accordance with FERC Electric Plant Instruction No. 4²⁸¹ and the National Association of Regulatory Utility Commissioners' (NARUC) interpretation of that instruction.²⁸² Each department incurring expenses charged to accounts 920 and 921 estimates the portion of its A&G costs that supports construction activities. Estimates are developed by reviewing employees' time and expenses related to construction activities, and by reviewing the relationship between departmental functions and construction activities. SCE proposed this methodology in its 2015, 2018, and 2021 GRCs and it was undisputed each time. Thus, SCE is using the same approach in the 2025 RO Model.

Based on these departmental estimates, a company-wide composite weighted average A&G capitalization rate of 32.4 percent was computed. SCE applies this rate of 32.4 percent to the Test Year 2025 forecast of applicable A&G expenses.

²⁷⁸ To properly reflect the total costs of construction, administration and general costs supporting construction activities, that are not directly charged to construction work orders, are included in capital and simultaneously removed from expense.

²⁷⁹ A&G expense in SCE's Short-Term Incentive Program is capitalized by applying the Pension and Benefits (P&B) capitalization rate. *See* SCE-06, Vol. 04, Ch. III for details on SCE's Short Term Incentive Program (STIP).

²⁸⁰ Refer to WP SCE-07, Vol. 01, Book E, pp. 308-350, Capitalized A&G Effort Study.

²⁸¹ Refer to WP SCE-07, Vol. 01, Book E, pp. 332-333, FERC Instruction No. 4.

²⁸² Refer to WP SCE-07, Vol. 01, Book E, pp. 334-339, NARUC Interpretation.

1 **B. Capitalized P&B Expense**

2 This section provides SCE's estimated capitalization rate for P&B expenses. SCE uses this
3 capitalization rate to establish the amount of P&B expenses that will be capitalized.²⁸³ Capitalized P&B
4 cost is calculated by multiplying the P&B capitalization rate by the estimate of P&B expenses to be
5 recorded in account 925 (Injuries and Damages) and account 926 (Employee P&B), before recording the
6 credit mentioned below. The amount of P&B expense to be capitalized is recorded as a credit to account
7 926 and a debit to account 107 (Construction Work In Progress) and ultimately included in Plant-in-
8 Service.

9 P&B expense is correlated with labor expense; as labor costs are incurred, P&B costs are also
10 incurred. Therefore, the rate of P&B capitalization follows the rate of labor capitalization. The total
11 2022 recorded wages paid for construction divided by the total 2022 recorded wages paid by SCE
12 (excluding below-the-line wages) results in a P&B capitalization rate of 52.9 percent. This methodology
13 was proposed in SCE's 2009, 2012, 2015, 2018 and 2021 GRCs and was undisputed. Thus, it is being
14 consistently applied in the 2025 RO Model. Utilizing this methodology, SCE is proposing to use 52.9
15 percent for the Test Year 2025 forecast of P&B capitalization.²⁸⁴

²⁸³ To properly reflect the total costs of construction, these P&B costs associated with construction labor must be included in capital (and simultaneously removed from expense).

²⁸⁴ In D.09-03-025, the Commission's Decision on SCE's 2009 GRC, the Commission adopted TURN's proposal to assign P&B costs below-the-line before the capitalized P&B rate is applied to this net amount. SCE has incorporated this adjustment into its 2025 forecast for Accounts 925 and 926.