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TO PARTIES OF RECORD IN APPLICATION 24-05-007:

This is the proposed decision of Administrative Law Judge Justin Regnier. It will appear on the Commission's December 19, 2024 agenda. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Pursuant to Rule 14.6(b), comments on the proposed decision must be filed within 7 days of its mailing and reply comments must be filed within 7 business days from the last day of filing comments.

Comments must be filed pursuant to Rule 1.13 electronically. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ Regnier at Justin.Regnier@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ MICHELLE COOKE

Michelle Cooke

Chief Administrative Law Judge

MLC: avs
Attachment

Decision PROPOSED DECISION OF ALJ REGNIER (Mailed 11/25/2024)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California
Edison Company (U338E) For
Approval of Its 2025 ERRRA Forecast
Proceeding Revenue Requirement.

Application 24-05-007

**DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S
2025 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED
FORECAST REVENUE REQUIREMENT**

TABLE OF CONTENTS

Title	Page
DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S 2025 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED FORECAST REVENUE REQUIREMENT	1
Summary	2
1. Background	5
1.1. Procedural Background.....	7
1.2. Submission Date	12
2. Jurisdiction	12
3. Issues Before the Commission	12
4. 2025 Forecast Overview and Methodology	14
5. SCE's Portfolio of Resources for 2025	16
5.1. Utility-Owned Generation and Purchased Power Contracts	17
5.1.1. Hydroelectric Resources	18
5.1.2. SCE Solar Photovoltaic Generation Program (SPVP).....	18
5.1.3. Combined Heat-and-Power (Co-Generation) and Renewables	19
5.1.4. Utility Owned Natural Gas Facilities	20
5.1.5. Santa Catalina Island Generation Fuel Costs	21
5.1.6. Utility Owned Storage (UOS)	22
5.1.7. Inter-Agency Contract Production.....	22
5.1.8. Inter-Utility Nuclear Contract Production.....	23
5.1.9. Resource Adequacy and Reliability Contracts.....	24
5.1.9.1. System Reliability Request for Offers	25
5.1.9.2. Emergency Reliability Procurement	25
5.1.9.3. Mid-Term Reliability (MTR).....	26
5.1.9.4. Imports Used for MTR and Diablo Canyon Replacement.....	27
5.1.9.5. Generic and Bilateral Resource Adequacy Contracts.....	27
5.1.9.6. Local Capacity Requirement Contracts	28
5.1.10. Public Purpose Program Charges	28
5.1.11. Green Tariff Shared Renewables Program	30
5.1.12. Discussion	31
5.2. Other SCE Resources and Programs	31
5.2.1. Nuclear Decommissioning.....	31
5.2.2. Demand Response	32
5.2.3. CAISO Costs, Load Procurement Charges, and Energy Revenue	33
5.3. Carrying and Financing Costs.....	34
5.3.1. Hedging Costs.....	34

5.3.2.	Gas Transportation and Storage.....	35
5.3.3.	Subscription Fees, Financing Costs, and Carrying Costs	36
6.	GHG Forecast Costs, Revenues, and Reconciliation.....	38
6.1.	2025 GHG Forecast Costs	38
6.2.	2025 Greenhouse Gas Forecast Revenues, Program Costs, and Returns..	40
6.2.1.	Revenues	40
6.2.2.	Reconciliation of Prior Period GHG Costs.....	41
6.2.3.	Administrative and Customer Outreach Expenses	41
6.2.4.	Clean Energy Programs Set Aside Funding - SOMAH, DAC-SASH, and CEOP.....	42
6.2.4.1.	Solar on Multifamily Affordable Housing Program	43
6.2.4.2.	SCE's Disadvantaged Community Programs.....	44
6.2.4.3.	Community Choice Aggregator DAC Programs	45
6.2.4.4.	Clean Energy Optimization Pilot.....	46
6.2.5.	GHG Revenue Returns	47
6.2.5.1.	Residential and Small Commercial Customers	47
6.2.5.2.	Emissions-Intensive and Trade-Exposed Customers	48
6.2.6.	Discussion	48
7.	SCE's Revenue Requirement and Ratemaking Proposal.....	49
7.1.	Generation Service Revenue Requirement.....	49
7.1.1.	ERRA Balancing Account.....	50
7.1.2.	Portfolio Allocation Balancing Account.....	51
7.1.3.	Energy Settlement Memorandum Account and Litigation Costs Tracking Account.....	52
7.1.4.	Discussion	53
7.2.	Delivery Service Revenue Requirement	53
7.2.1.	New System Generation Net Capacity CAM-Related Costs	55
7.2.2.	New System Generation Balancing Account (NSGBA).....	56
7.2.3.	System Reliability Modified Cost Mechanism-Related Costs	56
7.2.4.	Tree Mortality Contract Costs.....	57
7.2.5.	BioMAT Contract Costs	58
7.2.6.	Central Procurement Entity Related Costs	58
7.2.7.	Discussion of New System Generation Revenue Requirement.....	60
7.3.	Cost Responsibility Surcharges.....	60
7.3.1.	Competition Transition Cost Surcharge.....	62
7.3.2.	PCIA Revenue Requirement.....	62
7.3.2.1.	Updated RA Slice of Day Portfolio.....	64
7.3.2.2.	Updated Total Portfolio Costs.....	65

7.3.2.3. Updated Total Portfolio Market Value Forecast 65

7.3.2.4. Updated Energy Value..... 67

7.3.2.5. Updated RA Value(s) 67

7.3.2.6. Updated RPS Value 68

7.3.2.7. 2024 Year End PABA Balance 69

7.3.2.8. System Reliability Procurement Memorandum
Account Historical Costs..... 69

7.3.2.9. Utility Owned Storage – Separator Facility 70

7.4. Resource Adequacy Position and Assignment to MPB Subcategories 70

7.4.1. Interim Slice of Day Methodology 70

7.4.2. Assignment of Capacity to Local, System, and Flexible RA MPBs.... 72

7.4.3. Ensuring that the Full Volume of Excess RA is Sold..... 73

7.4.4. Need to revise the current MPB methodology..... 74

7.4.5. Discussion 76

8. 2025 ERRA Forecast Average Rates 77

9. PCIA Rates by Vintage 79

10. Safety Considerations and Environmental
and Social Justice Considerations 80

11. Compliance with the Authority Granted Herein..... 81

12. Summary of Public Comment..... 82

13. Procedural Matters 82

14. Reduction of Comment Period and Comments on Proposed Decision 82

15. Assignment of Proceeding..... 83

Findings of Fact..... 83

Conclusions of Law 87

ORDER 88

**DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S
2025 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED
FORECAST REVENUE REQUIREMENT**

Summary

This Decision approves, with modifications, Southern California Edison Company's (SCE) 2025 Energy Resource Recovery Account (ERRA) Forecast and approves a 2025 forecast revenue requirement of \$4.637 billion, representing a decrease of \$442.537 million as compared to the revenue requirement in rates today. As a result of the costs and other adjustments approved in this Decision, on January 1, 2025, SCE's system average rates for bundled customers will decrease by approximately 0.1 percent as compared to rates effective October 1, 2024, to 25.9¢/kilowatt hour in 2024. The Power Charge Indifference Adjustment (PCIA) rates will be negative for most customer vintages and will be negative system-wide in 2025, resulting in credits for customers in most PCIA vintages.

SCE's proposed revenue requirement, as given in the Alternate October Update on October 21, 2024, consists of both a generation service component and a delivery service component. This alternate update was provided by SCE in order to incorporate information updated one business day before the deadline for the initial document's submission and to assign capacity in alignment with how the prices for that capacity were computed.

SCE's proposed 2025 generation service revenue requirement totaled \$4.663 billion, reflecting a reduction of approximately \$725 million, or 13.5 percent, from what is being recovered in generation service rates in 2024. This Decision authorizes SCE to transfer the following 2024 account balances related to its generation service rates: -\$10.152 million from the 2024 ERRA Balancing Account (BA), \$587.214 million from the 2024 Portfolio Allocation

Balancing Account (PABA), and -\$295 million from the 2024 Energy Settlement Memorandum Account (ESMA).

Within SCE's forecasted 2025 delivery service revenue requirement, SCE is authorized to recover the following: (1) \$457.467 million for New System Generation and System Reliability fuel and purchase power contracts; (2) \$5.157 million in spent nuclear fuel costs; (3) -\$19.169 million for forecast Base Revenue Requirement Balancing Account – Distribution fuel and purchased power costs; (4) -\$641.624 million customer return of greenhouse gas (GHG) allowance proceeds; (5) \$21.610 million for the Public Purpose Program Charge; and (6) \$1.558 million for Modified Cost Allocation Mechanism (MCAM) fuel and purchased power.

SCE is also authorized to transfer the following delivery-service related account balances: (1) \$146.846 million in the 2024 year-end balance in the New System Generation BA; (2) \$19.110 million in the 2024 year-end balance for the Tree Mortality Non-Bypassable Charge BA; (3) -\$2.842 million in the 2024 year-end Bioenergy Market Adjusting Tariff Non-Bypassable Charge BA; and (4) \$2.849 million in the 2024 year-end Modified Cost Allocation Mechanism BA.

This decision approves SCE's forecast GHG costs, including \$436.214 million in GHG cap-and-trade costs. This decision also directs SCE to distribute \$58.183 million to Emissions-Intensive and Trade-Exposed (EITE) customers and \$583.441 million to residential and small business customers through the California Climate Credit. The semi-annual California Climate Credit for residential and small business customers of \$56 per eligible account is approved.

SCE's procurement-related revenue requirement will be updated to reflect 2024 year-end balances with recorded actuals through November 2024, if

available, and forecast for December 2024. SCE will update these figures in their initial Tier 1 Advice letter filed in conformance with this Decision, and implement the rate changes on January 1, 2025, in the Tier 1 Consolidated Revenue Requirement and Rate Change Advice Letter filed pursuant to Resolution E-5217.

A summary of SCE's 2025 ERRRA Forecast Revenue Requirement Changes is provided below:

Table S-1 – SCE 2025 ERRA Forecast Revenue Requirement Changes (\$000)¹

Rate Component	October Alternate Update – Estimated Revenue Requirement	In Rates ²	Revenue Requirement Change
2025 Generation Forecast Fuel and Purchased Power	4,085,868 ³	4,703,703	(619,835)
2024 Year End (YE) ERRA BA	(10,152)	179,952	(187,104)
2024 YE PABA	587,214	507,585	79,629
2024 YE ESMA	(295)	(375)	80
New System Generation	604,313	625,436	(21,124)
MCAM ⁴	4,407	2,362	2,045
Nuclear Decommissioning	5,157	4,958	200
Base Revenue Requirement BA-Distribution Fuel and Purchased Power	(19,169)	(3,582)	(15,588)
GHG Allowance Revenues	(641,624)	(955,105)	313,481
Public Purpose Program Charges	21,610	17,930	3,680
Total ERRA Revenue Requirement	4,637,329	5,079,566	(442,537)

Application 24-05-007 is closed.

1. Background

In Decision (D.) 02-10-062, the Commission established the Energy Resource Recovery Account (ERRA), the power procurement balancing account required by Public Utilities (Pub. Util.) Code Section 454.5(d)(3). Pursuant to

¹ Exhibit SCE-09 at 15, Table II-3.

² The 2024 ERRA Forecast revenue requirement was authorized in D.23-11-096 and implemented in rates on January 1, 2024, via Advice Letter 5175-E.

³ Exhibit SCE-09 at 15, Table II-3 lines 3-5.

⁴ Reflects three-year amortization adjustment pursuant to Resolution E-5240.

D.02-10-062 and D.02-12-074, the purpose of the ERRA is to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power (F&PP), utility retained generation, California Independent System Operator (CAISO) related costs, and costs associated with the residual net short procurement requirements to Southern California Edison Company's (SCE's) bundled electric service customers.

The ERRA regulatory process includes: (1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the upcoming year; (2) an annual compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least cost dispatch (LCD), prudent maintenance of Utility Owned Generation (UOG) and the ERRA Balancing Account (BA); and (3) the quarterly compliance report where Energy Division reviews procurement transactions "to ensure the prices, types of products, and quantities of each product conform to the approved plan."

The Commission adopted the Cost Responsibility Surcharge in D.02-11-022 (as modified by D.03-07-030), which consisted of the Competition Transition Charge (CTC). The CTC is used to recover the above-market costs of resources procured prior to market restructuring after the 2000-2001 Energy Crisis.

In D.06-07-030 (as modified by D.07-01-030 and subsequently refined in D.11-12-018, D.14-10-045, D.18-10-019, D.19-10-001, D.20-01-030, D.20-03-019, D.20-08-004, D.21-05-030, D.22-01-023, and D.23-06-006), the Commission adopted the Power Charge Indifference Adjustment (PCIA) for determining the above-market costs associated with the utility/California Department of Water Resources (CDWR) Power Charge as an element of the Cost Responsibility Surcharge. The PCIA applies to departing load customers who are responsible

for a share of the CDWR power contracts or new generation resource commitments. The PCIA is intended to ensure that departing load customers pay their share of the above-market portion of the CDWR contract and generation resource costs incurred on their behalf, and that bundled customers remain indifferent to customer departures.

The electric utilities are also required to incorporate greenhouse gas costs into the generation component of electricity rates through the ERRA process.⁵

1.1. Procedural Background

SCE filed the instant Application on May 15, 2024, seeking approval of a \$3.768 billion revenue requirement for 2025, a decrease of approximately \$1.312 billion relative to the revenue provided by rates effective at that time.⁶

On May 30, 2024, SCE filed Application (A.) 24-05-025 notifying the Commission of an overcollection in rates and requesting authority to decrease bundled service rates. This expedited Trigger application was approved by D.24-08-015. In order to avoid double counting the impact of the 2024 ERRA Trigger implementation, SCE is removing the portion of the balance that is already approved for recovery in the ERRA Trigger line item of SCE's consolidated revenue requirement from its estimate of the 2024 year-end ERRA BA balance.⁷

On June 17, 2024, the California Community Choice Association (CalCCA) and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed protests to SCE's Application.

⁵ D.12-12-033 OP 3; D.14-10-033 at 5.

⁶ Application 24-05-007 at 1-2.

⁷ Exhibit SCE-09 at 6.

Also on June 17, 2024, the Direct Access Customer Coalition (DACC) filed a response to the Application.

On June 27, 2024, SCE filed a reply to the intervenors' protests and response. CalCCA, Cal Advocates, and DACC were granted party status given their timely response to SCE's Application.

A prehearing conference (PHC) was held on July 26, 2024, to discuss the issues of law and fact and determine the need for hearing and schedule for resolving the matter. No other parties requested party status in this proceeding during the PHC.

On August 14, 2024, the assigned Commissioner issued the Scoping Memorandum and Ruling (Scoping Memo).

On August 17, 2024, SCE filed Supplemental Testimony addressing how it intends to integrate the new 24-hour Slice of Day (SOD) Resource Adequacy (RA) framework into this ERRA forecast ratemaking and how it proposes to allocate large hydroelectric and nuclear energy.

On September 3, 2024, CalCCA filed testimony objecting to SCE's SOD approach, suggesting changes to RA sales forecasts and allocation, and asserting several spreadsheet errors.

On September 19, 2024, SCE filed rebuttal testimony addressing CalCCA's testimony by articulating its rationale to continue with a SOD approach, committing to correct the identified spreadsheet errors, and clarifying their proposed RA and RPS treatment.

On September 16, 2024, the assigned Administrative Law Judge (ALJ) issued a ruling acknowledging reduced comment and reply periods of seven days and directing parties to respond.

On September 23, 2024, SCE filed a prehearing conference statement on behalf of SCE, CalCCA, Cal Advocates, and DACC (Joint Parties), confirming (1) the reduced comment and reply comment periods and (2) that there are no disputed material issues of fact.

On October 2, 2024, the Commission's Energy Division (ED) published the 2025 Market Price Benchmark (MPB) for the Energy Index and Renewable Portfolio Standard (RPS), noting that there has been an unforeseen delay to the release of the Resource Adequacy (RA) MPBs.

On October 4, 2024, ED published an addendum to the MPBs to include the RA MPBs. This addendum contained additional information regarding transaction volumes and noted that the overall number is driven by the summer versus winter differential. 2025 flexible and system MPB forecast values are based upon a transaction volume that is approximately five and seven times smaller, respectively, than the transaction volumes used to forecast 2024 flexible and system MPB values.

On October 4, 2024, SCE filed a motion requesting a three-day extension of time for the October Update and all subsequent filings enumerated in the Scoping Memo, due to the delay⁸ in publication of the MPB values.

On October 7, 2024, the assigned ALJ issued a ruling extending the due date for filings enumerated in the Scoping Memo schedule two days.

On October 8, 2024, the assigned ALJ issued a ruling requesting party comment on procedural mechanisms that should be considered to avoid an over-collection or under-collection as a result of the current MPB methodology.

⁸ D.22-01-023 Ordering Paragraph 1 dictates that these values be released by October 1 or the following business day.

On October 11, 2024, ED published errata updating the 2024 (final) and 2025 (forecast) RPS MPBs. The 2024 value was reduced by fourteen percent and the 2025 value was increased by six percent.

On October 14, 2024, CalCCA filed a response to the October 8, 2024, ALJ Ruling. This response asserts that no procedural mechanisms are appropriate at this time as the RA and RPS MPBs are doing precisely what the Commission intended, including the prevention of cost shifts among customers.

On October 14, 2024, SCE timely filed both its initial October Update and response to the October 8, 2024, ALJ Ruling. SCE's response clarifies that it did not seek to impact the existing methodology used to calculate MPBs, but strongly supports a future rulemaking for evaluation of this methodology and other outstanding PCIA ratemaking issues.⁹ SCE's response notes that the 2024 RA MPBs released on October 1 have an impact of shifting \$900 million of costs, recorded as a debit in the ERRA BA and a credit in the PABA BA.¹⁰ In both documents, it notes a need to (1) reflect a change in how it assigns RA to align with its attributes and (2) incorporate the RPS MPB values issued three days earlier.

On October 15, 2024, the assigned ALJ issued a ruling directing SCE to file an Alternate October Update (AOU) by October 21, 2021, and providing timelines for response and reply to SCE's proposal. Direction to file this update was given to allow for the incorporation of the updated RPS MPB and the assignment of RA capacity in the same manner as was used to generate the MPBs.

⁹ SCE's October 14, 2024 response to ruling at 2.

¹⁰ SCE's October 14, 2024 response to ruling at 5 and footnote 8.

On October 17, 2024, CalCCA filed a response to the October 15, 2024, ALJ ruling, requesting that SCE be directed to provide a revised October Update utilizing the October 11, 2024, errata RPS MPB and that parties be allowed to comment on SCE's methodologies in comments and briefs.

On October 17, 2024, the assigned ALJ issued a ruling directing SCE to file and serve a Revised October Update (ROU) and clarifying that party discussion of the ROU and AOU methodologies is permissible within Comment on October Update and briefing filings. Direction to file this update was given to allow for the incorporation of the updated MPBs and the assignment of RA capacity in the same manner as SCE had done in the most recent applications.

On October 21, 2024, SCE timely filed and served the AOU to its 2025 ERRRA forecasted revenue requirement.

On October 23, 2024, SCE timely filed and served the ROU to its 2025 ERRRA forecasted revenue requirement.

On October 24, 2024, SCE timely filed and served a joint motion to offer prepared testimonies into evidence and to seal the parties' confidential exhibits.

On October 28, 2024, AReM and DACC timely filed and served joint comment on the October Updates.

On October 28, CalCCA timely filed and served its Opening Brief and Comments on the October Update.

On October 28, SCE timely filed and served its Opening Brief.

On November 4, 2024, SCE and CalCCA timely filed and served Reply Briefs.

On November 5, 2024, ED issued a further Errata to the 2024 final and 2025 forecast MPBs. This errata reduces the MPB value for SCE's 2024 System RA by eight percent and increases SCE's 2025 Flexible RA MPB value by 20%. It also

reduces the following values by less than five percent; SCE and SDG&E's 2024 Local RA MPB, SCE's 2024 Flexible RA MPB, SCE's 2025 System RA MPB.

Finally, it increases SCE's 2025 Local RA MPB by approximately one percent.

On November 18, 2024, the assigned ALJ issued a ruling moving exhibits into evidence, sealing confidential exhibits, and submitting the record.

1.2. Submission Date

This matter was submitted on November 18, 2024, upon the issuance of the assigned ALJ's ruling.

2. Jurisdiction

The ERRA process was established pursuant to California Public Utilities Code (Pub. Util. Code) § 454.5(d), Rules 2.1 and 3.2 of the Commission's Rules of Practice and Procedure, and D.02-10-062.

3. Issues Before the Commission

The issues to be determined or otherwise considered are:

1. Whether SCE's requested 2025 ERRA forecast revenue requirement is reasonable, including but not limited to consideration of the following:
 - a. SCE's forecast of electric sales and electric load;
 - b. SCE's forecast costs for fuel and purchase power expenses;
 - c. SCE's forecast costs for spent nuclear fuel interim storage;
 - d. SCE's forecast greenhouse gas (GHG) costs; and
 - e. Annual true-ups for balancing accounts such as the Portfolio Allocation Balancing Account (BA), New System Generation BA, Energy Settlements Memorandum Account, ERRA BA, Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge, and Tree Mortality Non-Bypassable Charge BA;
2. Whether SCE's forecast of GHG allowance revenue return allocations for energy-intensive trade-exposed customers,

- small business customers, and the residential customer California Climate Credit is reasonable;
3. Whether SCE's forecast of GHG revenues and expenses set aside for (a) clean energy and energy efficiency programs and GHG administration, and (b) customer education and outreach plan costs are reasonable;
 4. Whether SCE's forecast of Central Procurement Entity related costs is reasonable;
 5. Whether the Cost Allocation Mechanism rates are reasonable;
 6. Whether SCE's calculations of the Power Charge Indifference Adjustment (PCIA) and Competition Transition Charge are reasonable, including discussion of the following:
 - a. Treatment of RA resources and associated costs in the PCIA;
 - b. Treatment of RPS resources with excess RPS value and allocation of RPS sales across vintages;
 - c. Calculation of the indifference amount;
 - d. Calculation of the year-end Portfolio Allocation BA balance; and
 - e. Allocation of indifference charges among vintages and customer classes;
 7. Whether SCE's request and methods used to determine the issues described above comply with all applicable rules, regulations, resolutions, and decisions for all customer categories; and
 8. Whether there are any safety concerns, or environmental or social justice considerations raised by the Application.

Arguments raised by intervenors

4. **2025 Forecast Overview and Methodology**

SCE's AOU forecast F&PP costs are associated with its UOG resources, purchased power contracts, financing, various carrying costs, and procurement contracts to meet reliability requirements set by the Commission. SCE forecasts a 2025 total F&PP revenue requirement of \$ 4,085,868 million, a decrease of 20 percent¹¹ from the 2024 forecast.¹²

On April 30, 2024, SCE's ERRA Trigger Balance exceeded SCE's ERRA Trigger Point and Threshold, resulting in the filing of A.24-05-025. On August 1, 2024, the Commission adopted D.24-08-015, granting SCE's Application. On September 20, 2024, SCE submitted Advice 5371-E, decreasing bundled service customer generation rates by \$742.426 million over the 12-month period from October 1, 2024, through September 30, 2025. To avoid double counting the impact of this decrease, SCE removed this amount from its estimate of the 2024 year-end ERRA BA balance.¹³

SCE indicated it based its revenue requirement on a forecast of total electricity sales and customers for its service territory that was completed in December 2023,¹⁴ which it adjusts to account for the bundled customer portion of load. The proportion of bundled customers as a proportion of total sales increased slightly in its October Update to account for CCA load returning to bundled service.¹⁵

¹¹ Exhibit SCE-09 at 15, Table II-3.

¹² D.23-11-094 at 4, ($\$4,085,868 / \$5,118,545 = 0.8$).

¹³ Exhibit SCE-09 at 6.

¹⁴ Exhibit SCE-09 at 18.

¹⁵ Exhibit SCE-06 at 18.

SCE's total retail electricity sales volume in 2023 was 80,846 gigawatt hours (GWh). SCE's forecast of total electricity sales in 2024 is 81,758 GWh, and its forecast of total electricity sales in 2025 is 82,901 GWh¹⁶. This represents an annual increase in annual total retail sales of 1.13% in 2024 and 1.41% in 2025 as compared to 2023. SCE attributes this increased load mainly to climate driven need for increased cooling and increased levels of transportation electrification. SCE's retail sales forecast is influenced by historical trends in employment growth, residential housing starts, the economic outlook, weather assumptions and other factors¹⁷ (e.g. energy efficiency savings, transportation electrification, building electrification, and behind the meter generation). SCE forecasts the total number of retail customers to increase by 0.5 percent in 2024 and 0.6 percent in 2025.¹⁸

SCE calculates the revenue requirement necessary for procuring bundled customer energy in 2025 using energy need at the CAISO interface, which allows SCE to account for line losses¹⁹ inherent in transporting energy from the CAISO interface to bundled service customers' meters. SCE also adjusts the sales forecast downward 4.5%²⁰ to adjust for the difference between billed and delivered energy for Net Energy Metering (NEM) customers.

Finally, SCE's 2025 forecast of total bundled service customer load accounts for departed load. This departed load includes the increase in the load

¹⁶ Exhibit SCE-09 at 19.

¹⁷ Exhibit SCE-01 at 19.

¹⁸ Exhibit SCE-01 at 24.

¹⁹ D.21-03-051, OPs 1 and 2.

²⁰ Exhibit SCE-01 at 14 and footnote 26. The NEM adjustment is 4.5 percent for retail sales and 5.7 percent for bundled sales.

cap for Direct Access customers. It also includes Energy Service Providers and Community Choice Aggregators (CCA) that meet one of the following criteria: (1) file a binding notice of intent to begin community choice aggregation service; (2) file an initial RA filing; (3) start community choice aggregation service; or (4) formally submit an April RA forecast pursuant to Pub. Util. Code Section 380.

No parties directly addressed SCE's testimony and workpapers related to its forecast of electric sales and electric load. After reviewing the Opening Testimony, Rebuttal Testimony, workpapers, AOU, comments, Opening Brief, and Reply Brief documents, we find SCE's forecasted 2025 electric sales and electric load to be reasonable, and therefore approve them as proposed.

5. SCE's Portfolio of Resources for 2025

SCE's portfolio of resources includes a variety of UOG and contracted resources, which are discussed in Sections 5.1.1-5.1.12 below. SCE's UOG includes hydroelectric, renewable generation, fossil fueled (natural gas, propane, and diesel) generation, nuclear generation, and energy storage resources. SCE's contracted resources include combined heat-and-power (CHP), renewable generation, inter-utility and bilateral contracts, and anticipated future solicitations and market purchases (represented by proxy costs).²¹ Each subsection that follows describes the costs associated with a particular resource that was proposed in SCE's 2025 ERRA Forecast Application and Testimony as amended by its AOU. As noted in Section 1 above, SCE forecasted dispatch of its portfolio of resources using an LCD approach.

²¹ Exhibit SCE-01 at 28.

5.1. Utility-Owned Generation and Purchased Power Contracts

SCE's UOG and purchased power contract resources consist of hydroelectric, renewable, nuclear generation, fossil fueled (natural gas, propane, and diesel) generation, and energy storage.

The 2025 costs forecasted for this portfolio were amended downward from 2024 estimates both in the initial forecast and in the AOU based on the balance of increases and decreases within the cost categories, with major changes summarized here.

SCE's net bundled service load forecast decreased approximately 6.8 percent for 2025.²² Both power and gas prices decreased and outages on gas fired UOG units decreased the amount of generation from the PABA portfolio.²³ Large increases in 2025 RPS MPB resulted in approximately double the revenue from SCE's Voluntary Allocation Sales as had been originally forecast, and there were additional sales from SCE's BioRAM portfolio.²⁴

Large increases in the 2025 forecast RPS MPB increased revenues from SCE's Voluntary Allocation and Renewable Energy Certificates (REC) sales. Large increases in the 2025 RA MPBs and incorporation of SCE's interim proposal for SOD both decreased RA sales and increased the price of RA purchases. Both contractual changes and the retirement of hedging reduced financing costs. Finally, the addition of new RA purchases and contractual arrangements related to mid-term reliability (MTR) procurement increased costs.

²² Exhibit SCE-09 at 26.

²³ Exhibit SCE-09 at 25.

²⁴ Exhibit SCE-09 at 26.

5.1.1. Hydroelectric Resources

SCE's hydroelectric resources consist of 32 hydro generating facilities in Central and Southern California that provide a combined 1,164 megawatts (MW) of nameplate capacity. SCE forecasts average hydrological conditions in 2025 and incorporates SCE's best estimate of upcoming outages and unavailability in predicting 2025 generation.²⁵

SCE's 2025 forecast optimizes the use of the full 1,015 MW of capacity from the nine-unit Big Creek Project, located about 50 miles east of Fresno, California (when operationally feasible) during the highest economic value hours.²⁶

The other 24 powerhouses are in SCE's Eastern Division. Its Eastern Division powerhouses are in the Sierra Nevada, San Bernadino, and San Gabriel mountains and provide 161 MW of predominantly run-of-the-river, non-dispatchable resources.²⁷ SCE has applied for approval to sell two sets²⁸ of hydroelectric production facilities, with a requested final decision date of March 2025. SCE notes that these sales, if approved, would remove 15.09 MW from its portfolio. As these sales have not been approved, SCE has not reduced its energy and capacity forecast to reflect the loss of these facilities.²⁹

5.1.2. SCE Solar Photovoltaic Generation Program (SPVP)

D.13-05-033 authorized SCE to install, own, and operate up to 91 MW of solar photovoltaic generation on commercial rooftop space and ground sites

²⁵ Exhibit SCE-01 at 38.

²⁶ Exhibit SCE-09 at 35.

²⁷ Exhibit SCE-01 at 38.

²⁸ A.24-08-012 and A.24-09-008.

²⁹ Exhibit SCE-09 at 36.

within its service territory. SCE notes that these sites were largely decommissioned in 2023. SCE expects the sole remaining site, site 42, will be de-energized in 2026.³⁰ This site is rated at approximately 9 MW³¹ and its production is reflected in SCE's 2025 energy forecast.³²

5.1.3. Combined Heat-and-Power (Co-Generation) and Renewables

SCE forecasted the power deliveries from its co-generation and renewable resources as “must-take” energy, measured at the generators’ meters. The projects SCE included in its 2025 forecast AOU total approximately 10,007 MW of contracted capacity, representing historical performance of existing resources. Four additional solar projects are expected to begin delivering energy between January and December 2025, but the contractual expectation of deliveries from those new projects was adjusted to account for their expected probability of successful development and commercial operation.³³

SCE's renewable and CHP projects typically have contract-specific energy prices, but it also has several qualifying facility (QF) projects that are paid at the posted avoided cost of energy price under standard offer contracts (SOC). The SOC is either based on the New QF SOC adopted in D.20-05-006, which is based on a three-year average of CAISO locational marginal prices, or the QF SOC adopted in the QF Summit settlement, which is based on average 12-month forward heat rates for the resource type.³⁴

³⁰ Exhibit SCE-09 at 37.

³¹ D.23-11-094 at 20.

³² Exhibit SCE-01 at 39.

³³ Exhibit SCE-01 at 39.

³⁴ Exhibit SCE-01 at 43.

SCE's AOU forecasted the annual capacity factors for its CHP and renewable energy projects as follows:

Table 5-1: Annual Capacity Factors by Technology³⁵

Technology Type	Percent Capacity Factor
Biomass	75.7%
Cogeneration	24.3%
Geothermal	90.2%
Small Hydro	14.2%
Solar	28.8%
Wind	28.7%

SCE noted that its energy and capacity prices for each of the CHP and renewable energy projects in its portfolio are based on their individual contracts and that its forecast includes estimated curtailments from its solar and wind portfolios due to economic reasons, which are reflected in SCE's energy and payment forecasts.³⁶

5.1.4. Utility Owned Natural Gas Facilities

SCE includes the natural gas procurement costs for its five black-start capable, dispatchable peakers within its 2025 ERRRA forecast. The five natural gas peakers have a combined capacity of 245 MW.³⁷ The capacity and non-fuel variable costs associated with these peakers are included in SCE's general rate case (GRC) revenue requirement.³⁸

³⁵ Exhibit SCE-09 at 39, Table IV-11.

³⁶ Exhibit SCE-01 at 43 - 45.

³⁷ Exhibit SCE-01C at 45; The Commission ordered SCE to build up to 250 MW of black-start capable, dispatchable generation capacity within its service area through an August 15, 2006 Assigned Commissioner's Ruling.

³⁸ Exhibit SCE-01 at 45.

Additionally, SCE owns the Mountainview Generating Station and proposes to continue recovering capital and fuel costs, pursuant to D.18-10-019.³⁹ SCE does not state the current capacity of this generation station, but prior filings indicate a capacity of 1,056 MW.⁴⁰

In both its initial forecast⁴¹ (\$5.48/MMBtu) and its AOU⁴² (\$4.75/MMBtu), SCE noted that gas prices for 2025 are expected to be lower than previously forecasted.

5.1.5. Santa Catalina Island Generation Fuel Costs

SCE uses six diesel generators and 23 propane-fired micro-turbines at the Pebbly Beach Generating Station to provide electricity service to Santa Catalina Island. Based on historical usage rates in 2023-2024 and the island's storage capacity, SCE's forecast indicated it will need to acquire 48,386 barrels of diesel fuel throughout 2025 in the Los Angeles market, at a cost of approximately \$183.20/barrel, or \$7.988 million total.⁴³ SCE also estimated it will need to procure approximately \$1.019 million of propane fuel.⁴⁴ Both the diesel and propane cost projections were based on the IHS Global Insight Variable for Gasoline and Fuels and collectively comprise \$9.007 million in fuel costs to service Catalina Island in 2025.⁴⁵

³⁹ Exhibit SCE-06 at 42.

⁴⁰ D.23-11-094 OP 5.

⁴¹ Exhibit SCE-01 at 30.

⁴² Exhibit SCE-09 at 29.

⁴³ Exhibit SCE-09 at 62.

⁴⁴ Exhibit SCE-01 at 61-63 and Table IV-16.

⁴⁵ Exhibit SCE-09 at 65-66.

No parties addressed SCE's forecasted 2024 fuel costs for its service to Santa Catalina Island in comments or testimony. Upon review, we find the forecasted propane and diesel fuel costs to be reasonable and appropriately modeled using market-based pricing and authorize SCE to recover them as proposed.

5.1.6. Utility Owned Storage (UOS)

SCE also forecasted that its DESI 2, or UOS Titanium project, will be a CAISO market resource of 1.4 MW/ 3.7 MWh, and stated it will recover storage charging costs and market revenues associated with this resource through its New System Generation Balancing Account (NSGBA).⁴⁶ Titanium has an anticipated CAISO market start date of December 2024.⁴⁷

5.1.7. Inter-Agency Contract Production

SCE has a contract through September 2067 to purchase and/or exchange capacity and associated energy with the Western Area Power Administration (WAPA) and the U.S. Bureau of Reclamation. For 2025, SCE has an entitlement of 280.245 MW of contingent capacity and 238.16 GWh of firm energy. These contracted quantities originate from the Boulder Canyon Project at Hoover Dam.

To account for the ongoing drought conditions affecting the Hoover power plant, the monthly capacity and firm energy available to SCE from this source may be curtailed. Monthly capacity contingent on conditions is forecast to range between 108 and 192 MW. Monthly firm energy is contingent on conditions and is forecast to range between 9 and 21 GWh.⁴⁸ During periods when Hoover is unable to provide energy in amounts equal to the firm energy, the WAPA is

⁴⁶ Exhibit SCE-01 at 48.

⁴⁷ Exhibit SCE-06 at 45.

⁴⁸ Exhibit SCE-01 at 47, table IV-14.

obligated to provide any deficit, if requested by the purchaser, at a rate equal to the WAPA's cost to acquire.⁴⁹

SCE does not include "Fringe Service" agreement totals in its forecast. These agreements provide for small amounts of energy exchange among neighboring utilities. SCE holds agreements with the Department of Defense, detailed in Advice Letters 2686-E and 1777-E.⁵⁰

5.1.8. Inter-Utility Nuclear Contract Production

SCE owns a 15.8 percent share, or 213 MW per unit, of the three-unit Palo Verde Nuclear Generation Station (PVNGS), which is operated by Arizona Public Service Company (APS).⁵¹ SCE forecasts assume that PVNGS will operate as baseload capacity. PVNGS Units 1 and 3 will experience refueling outages in 2025.⁵² SCE, through contracts with APS and other suppliers, incurs a share of the nuclear fuel management costs for PVNGS, from the mining of the uranium necessary to fabricate the fuel to spent fuel transportation, safe interim storage, and permanent disposal. SCE projected that its share of the PVNGS nuclear fuel expense for 2025 will be \$29.2 million.⁵³ The costs to transfer fuel to, and store it in, the on-site Independent Spent Fuel Storage Installation (ISFSI) are considered operating costs for PVNGS, and therefore not included in the 2025 ERRA forecast. However, SCE forecasted it will incur \$2.93 million in spent nuclear fuel storage costs associated with PVNGS, approximately \$2.92 million of which

⁴⁹ Exhibit SCE-01 at 46, footnote 51.

⁵⁰ Exhibit SCE-01 at 46, footnote 50.

⁵¹ Exhibit SCE-06 at 57.

⁵² Exhibit SCE-06 at 59-60.

⁵³ Exhibit SCE-06 at 59.

would be offset by credits from the U.S. Department of Energy spent fuel litigation. Therefore, SCE included a net cost associated with PVNGS spent fuel storage of \$0.01 million.

No parties addressed SCE's PVNGS cost forecast for 2025. Upon review, we find SCE's proposed costs associated with fuel storage and procurement for PVNGS to be reasonable and in accordance with state laws and regulations. SCE's forecasted PVNGS fuel procurement and spent fuel costs are approved.

5.1.9. Resource Adequacy and Reliability Contracts

D.06-07-029, as modified by D.10-12-035 and Senate Bill 695 (Kehoe), Stat. 2009, Ch.337, adopted a cost allocation mechanism (CAM) to allocate the costs electric utilities incur to meet Resource Adequacy requirements on behalf of customers in an electric utility's service territory. In D.10-12-035, the Commission also allowed SCE to allocate costs associated with CHP generation procured on behalf of Direct Access customers' Electric Service Providers and CCAs.

Under a Joint Party Proposal adopted in D.07-09-044, SCE will hold the dispatch rights for all New Generation contracts in 2025, but the energy from these contracts will not be used to meet forecasted bundled customer load.⁵⁴ Instead, SCE forecasts the energy revenue benefits from these resources to be allocated to all customers, and energy revenues from these resources were based on LCD.

D.20-06-002 identifies SCE as the central procurement entity for its distribution area, tasking them with multi-year local RA procurement beginning with the 2023 compliance year. That decision adopts CAM as the cost recovery mechanism for the procured RA and the associated administrative costs.

⁵⁴ Exhibit SCE-01 at 47-48.

5.1.9.1. System Reliability Request for Offers

SCE forecasted 2025 costs associated with resources procured in accordance with D.19-11-016's order directing utilities to conduct System Reliability Request for Offers (SRRFO). D.19-11-016 directed SCE to procure 1,184.7 MW of incremental RA capacity, including seven "Fast Track" contracts for new energy storage resources (totaling approximately 678 MW of incremental RA system capacity) that were approved in Resolution E-5101, and an additional five "Standard Track" contracts that were approved in Resolution E-5142 (totaling approximately 590 MW of nameplate capacity).⁵⁵ Pursuant to Resolution E-5240, SCE accounted for emergency system reliability MCAM-eligible costs and revenues in its 2025 forecast.⁵⁶

SCE also included contract costs from and revenues from the SRRFO in its 2025 forecast. SCE segmented these costs across its PABA, Modified Cost Allocation Mechanism BA (MCAMBA), and NSGA accounts.⁵⁷

5.1.9.2. Emergency Reliability Procurement

D.21-02-028 authorized the investor-owned utilities (IOU) to contract for emergency reliability capacity that is available to serve peak and net peak demand in the summer of 2021, and seek approval for recovery of rates through CAM. In D.21-03-056, the Commission further authorized the IOUs to procure resources to meet the summer 2021 and 2022 effective planning reserve margin of 17.5 percent. In D.21-12-015, the Commission adopted requirements for summers 2022 and 2023.

⁵⁵ Exhibit SCE-01 at 49.

⁵⁶ Exhibit SCE-01 at 49.

⁵⁷ Exhibit SCE-06 at 47.

5.1.9.3. Mid-Term Reliability (MTR)

D.21-06-035 addressed MTR needs across CAISO's operating system, and SCE launched its Mid-Term Reliability Request for Offers (MTRRFO) for incremental resources to come online in 2023-2026 on July 30, 2021.⁵⁸

SCE has executed contracts for eleven energy storage and renewable energy projects to address MTR needs, which were approved in Resolutions E-5205, E-5225, E-5234, E-5251, E-5253, E-5271, E-5307, E-5309, E-5313, E-5316, and E-5333⁵⁹.

In addition to advice letters solely requesting approval of contracts for new MTR, SCE notes in its AOU that two advice letters that modify the online date and/or pricing for known resources have been approved.

On April 10, 2024, SCE submitted 5257-E-A, seeking approval of an amended and restated Phase I contract. On June 10, 2024, SCE submitted Advice 5316-E seeking approval of 750 MW of new nameplate capacity for 2026-2027 MTR, and the modification of the terms for 100 MW of 2024 MTR approved in its first contract. These advice letters were approved by Resolutions E-5334 and E-5344, respectively.⁶⁰

SCE asserts in its AOU that it has updated its F&PP cost assumptions and PCIA workpaper to reflect these changes in commercial operation date.

⁵⁸ D.21-06-035 required at least 11,500 MW of additional net qualifying capacity (NQC) to be procured by all of the LSEs subject to the Commission's integrated resource planning (IRP) authority. SCE's portion of that capacity is 4,052 MW: 705 MW online by August 1, 2023; 2,114 MW by June 1, 2024; 529 MW by June 1, 2025, and 705 MW of long lead time resources by 2026.

⁵⁹ Exhibit SCE-06 at 50.

⁶⁰ Exhibit SCE-09 at 52.

5.1.9.4. Imports Used for MTR and Diablo Canyon Replacement

In its AOU, SCE includes firm resources and has identified other potential imports for possible use as a bridge for MTR compliance. These purchases may have implications for both the ERRRA and PABA BA, depending on how the volumes are ultimately used.

D.24-09-006 allows for any LSE with obligations in Ordering Paragraph 6 of D.21-06-035 to procure Diablo Canyon Power Plant Replacement resources to procure certain bridge resources to meet that requirement. Some of these resources are procured pursuant to D.24-09-006.

5.1.9.5. Generic and Bilateral Resource Adequacy Contracts

SCE forecasts its 2025 RA purchase costs for generic RA contracts using the 2025 RA MPBs in conjunction with SCE's SOD position. It calculated its 2025 month-ahead RA position based on its RA requirements and the available supply it has contracted to meet them, plus a buffer. It pro-rates its generic procurement between System, Local, and Flexible RA in the same proportions as its excess sold and unsold forecast and applies the appropriate MPB to each proportion.⁶¹

The MPB calculates the market value of the three revenue streams in the IOU portfolio – the Energy Index, Renewable Portfolio Standard (RPS) MPB, and Resource Adequacy (RA) MPB. The RA MPB is the MPB that reflects the estimated value of each unit of capacity in an IOU's PCIA-eligible portfolio that can be used to satisfy Resource Adequacy obligations, in dollars per kilowatt-month (\$/kW-month), based on a weighted average of all RA transactions of the LSEs subject to the PCIA.

⁶¹ Exhibit SCE-09 at 54.

The RA MPB has three subcomponents. For purposes of Energy Division's annual RA MPB calculation, for which Energy Division compiles information on RA transactions through data requests to the LSEs, these three types of RA are counted according to the following rules:⁶²

- RA that provides both system and flexible capacity shall be counted as flexible capacity.
- RA that provides both system and local capacity shall be counted as local RA capacity.
- If the RA provides all three types of RA capacity, it shall be counted as local capacity.⁶³

SCE utilizes a framework to attempt to monetize any amounts of RA exceeding its calculated position.

5.1.9.6. Local Capacity Requirement Contracts

SCE also included forecasted costs associated with its local capacity requirements (LCR) contracts in the Western LA Basin and Moorpark local reliability areas.⁶⁴

5.1.10. Public Purpose Program Charges

SCE forecasts procurement-related expenses for the four programs it recovers through the Public Purpose Program charge (PPPC) in 2025.

First, SCE includes forecasted capacity costs and estimated in-front-of-the-meter production of resources procured through its Preferred Resource Pilot

⁶² SCE Opening Brief at 15.

⁶³ Decision 18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, at 74. Issued in Rulemaking (R.) 17-06-026

⁶⁴ Exhibit SCE-01 at 54-55.

(PRP) #2.⁶⁵ These resources were procured pursuant to D.18-07-023 which authorized SCE's second PRP. SCE proposes to recover the costs of the PRP behind-the-meter energy storage contracts from customers through the PPPC.⁶⁶

Second, SCE includes in its AOU a forecast of \$19.110 million in fuel and purchased power costs to be recorded in the Tree Mortality Non Bypassable Charge Balancing Account (TMNBCBA), including the Franchise Fee and Uncollectible Factor (FF&U) and BioRAM audit expenses.⁶⁷

Third, pursuant to Resolutions E-4805 and E-4770, SCE forecasted audit expenses for its BioRAM contracts to total \$0.018 million in 2025, but the actual audit expenses will be recorded in its TMNBCBA.⁶⁸

Fourth, SCE projects in its AOU the fuel and purchased power costs related to its Bioenergy Market Adjusting Tariff BioMAT Resources or Contracts to total \$5.642 million in 2025, including FF&U.⁶⁹

Upon review of SCE's testimony, Alternate October Update, and Workpapers, the Commission finds SCE's forecasted 2024 PRPBA, TMNBCA, and BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA) amounts reasonable. SCE is authorized to recover its costs associated with the programs described in Section 5.1.10 through the PPPC.

⁶⁵ Exhibit SCE-01 at 55; SCE includes the following Preferred Resources: Demand Response, Renewable Distributed Generation, Energy Storage, Renewable Distributed Generation paired with Energy Storage and Permanent Load Shifting.

⁶⁶ Exhibit SCE-01 at 56 and footnote 62.

⁶⁷ Exhibit SCE-09 at 124.

⁶⁸ Exhibit SCE-01 at 123.

⁶⁹ Exhibit SCE-09 at 126.

5.1.11. Green Tariff Shared Renewables Program

SCE included the costs of implementing its Green Tariff Shared Renewables (GTSR) Program, pursuant to Public Util. Code § 2831-2833, D.15-01-051, and D.24-05-065. SCE provides customers with two options to be served with a larger mix of renewable energy, relative to SCE's other tariff options. As per D.24-05-065, however, the GTSR-ECR Program option is closed to new procurement not currently under negotiation or contract.⁷⁰ One of the projects serving the GTSR-ECR program is currently online, and the other three are expected to be online and producing power in 2025.⁷¹ The unprocured capacity for the GTSR-ECR option has been reassigned to the modified Green Tariff Program.⁷² SCE has procured Green Tariff-specific projects to serve GTSR customers; these are online and expected to be producing power in 2025. The Green Tariff total capacity is capped at 562 MW with subscriptions capped at 40 MW per customer.

The customer discounts provided by SCE's DAC Green Tariff Program will also be funded through Public Purpose Programs Charge, and more detail on this Program is provided in Section 6.2.4.2 below.

For 2025, SCE forecasts that participation in its Green Tariff programs will equal approximately 122,774 MWh and ECR participation will be 112,448 MWh.⁷³ This is an increase from 2024.⁷⁴ The forecasted MWh required to serve Green

⁷⁰ D.24-05-065 Ordering Paragraph 5(b).

⁷¹ Exhibit SCE-09 at 57.

⁷² Exhibit SCE-09 at 56.

⁷³ Exhibit SCE-09 at 58.

⁷⁴ D.23-11-094 OP 10 lists 2024 GTSR participation as 171,220 MWh.

Tariff customers are removed from the CHP and Renewables energy and shown separately.⁷⁵

No party directly referenced SCE's Green Tariff programs in their testimony or briefs. Upon review of SCE's testimony, October Update, and Workpapers, the Commission finds SCE's forecasted 2025 GTSR BA amount accurate, reasonable, and in compliance with applicable rules and Commission orders.

5.1.12. Discussion

No parties directly addressed SCE's testimony and workpapers related to its Utility Owned Generation fuel and Purchased Power Contracts, with the exception of SCE's assignment of RA capacity to local, system and flexible MPBs. After reviewing the Opening Testimony, Rebuttal Testimony, workpapers, AOU, comments, Opening Brief, and Reply Brief documents, we find SCE's forecasted 2025 portfolio of UOG fuel and purchased power resources to be reasonable pursuant to Pub. Util. Code § 454.5 and therefore approve them as proposed.

Further discussion of the assignment of RA capacity to local, system, and flexible MPBs is found in Section 7.4.2

5.2. Other SCE Resources and Programs

5.2.1. Nuclear Decommissioning

SCE is the majority owner and decommissioning agent for the San Onofre Nuclear Generating Station (SONGS) Units 1, 2, and 3. SONGS Unit 1 was retired on November 30, 1992, and SONGS Units 2 and 3 were permanently retired on June 7, 2013.⁷⁶ All three SONGS units are being decommissioned, and the fuel from the units has been transferred to its on-site ISFSI. The costs for storing spent

⁷⁵ Exhibit SCE-09 at 58.

⁷⁶ Exhibit SCE-09 at 58.

fuel at the on-site ISFSI are covered by the SONGS Nuclear Decommissioning Trusts and were not included in the 2025 ERRRA forecast. However, SCE includes \$5.157 million in off-site interim storage costs⁷⁷ for SONGS Unit 1 spent fuel assemblies in its 2025 ERRRA forecast.

No parties addressed SCE's SONGS-related cost forecasts for 2025. Upon review of the Opening Testimony, Rebuttal Testimony, workpapers, AOU, comments, Opening Brief, and Reply Brief documents, we find SCE's proposed costs associated with off-site interim storage costs for SONGS to be reasonable and in accordance with state laws and regulations. SCE is authorized to recover up to \$5.157 million in SONGS spent nuclear-fuel storage related costs in 2025.

5.2.2. Demand Response

SCE forecasted an estimated 5 GWh of energy reductions in 2025 through several price-responsive demand-response (DR) programs: Summer Discount Plan (SDP), Smart Energy Program (SEP), and Capacity Bidding Program (CBP). SDP and SEP are bid into the CAISO markets as Reliability Demand Response Resource (RDRR) and CBP as Proxy Demand Resource (PDR).⁷⁸ The impact of these programs is based on past customer performance and enrollment, which can vary month-to-month. Pursuant to D.23-12-005, SCE records all demand response incentives in its Demand Response Program Balancing Account (DRPBA), and the annual balances are transferred to the Base Revenue Requirement Balancing Account (BRRBA). SCE's 2025 DR forecast was based on its Load Impact Protocols and opportunity costs that factor in the maximum

⁷⁷ Exhibit SCE-09 at 127.

⁷⁸ Exhibit SCE-09 at 66.

available hours for customers to participate in specific programs per day, month, and year.⁷⁹

No parties directly contested SCE's forecasted DR energy reductions or its forecast calculations. Upon review of Commission precedent and SCE's filings in this proceeding, we find its DR forecasts for 2025 to be reasonable and therefore adopt them.

5.2.3. CAISO Costs, Load Procurement Charges, and Energy Revenue

SCE separated CAISO-related costs into (1) non-energy related costs; (2) load-procurement charges; and (3) energy-related revenues associated with SCE's PABA- and CAM-eligible resources.⁸⁰

SCE stated that non-energy-related CAISO costs are not sensitive to short-term energy market prices, and therefore its 2025 forecast for such costs will be equal to the most recent 12-month period.⁸¹

SCE calculated load-procurement charges for 2024 by multiplying the hourly load by the hourly SP-15 prices for each hour. Pursuant to Resolution E-5183, SCE contracted to develop 537.5 MW of energy storage at three sites to address summer reliability. Pursuant to Resolution E-5259, one of these three sites (referred to as the "Separator" project) is now counted toward SCE's MTR procurement requirements. Separator had a commercial online date of September 24, 2024.⁸² SCE stated it will credit energy benefits associated with the remaining two projects (referred to as the "Anode" and "Cathode" projects)

⁷⁹ Exhibit SCE-09 at 66.

⁸⁰ Exhibit SCE-01 at 66.

⁸¹ Exhibit SCE-01 at 66-67.

⁸² Exhibit SCE-06 at 67.

against the costs that are recovered through distribution charges and reduce load-procurement charges that apply to bundled service customers to reflect the net benefits.

Finally, SCE estimated its energy revenue from the dispatch of these resources by multiplying the forecasted hourly production from its PABA-, ERRA-, BMNBCBA-, CGST-, and CAM-eligible portfolios by the SP-15 price at that hour. The energy revenues are used to offset forecasted PABA, ERRA, BMNBC, CGST, and NSGBA revenue requirements.⁸³

No party directly addressed SCE's forecasted 2025 CAISO costs, load procurement charges, or energy revenue. Upon review of SCE's testimony, rebuttal testimony, AOU, workpapers, Comments, Opening briefs, and reply briefs we find its forecasted 2025 CAISO-related costs to be reasonable and therefore approve them as proposed.

5.3. Carrying and Financing Costs

SCE uses a variety of financial mechanisms to control cost risk and ensure reliable energy supply. This section addresses the cost of both those mechanisms and the market data and reporting service that inform its strategy for deploying them.

5.3.1. Hedging Costs

SCE's costs of power and natural gas for its UOG, purchased power contracts, and QF contracts are hedged using the underlying commodities trading markets to offset risks of market volatility. The hedging costs for 2025 initially included brokerage fees and options premiums. Due to a lack of liquidity, however, SCE retired its option-based budget for hedging.⁸⁴ No party

⁸³ Exhibit SCE-01 at 61 and Table IV-8.

⁸⁴ Exhibit SCE-09 at 9 and 81.

addressed this issue. Upon the Commission's review of SCE's documents, we find the hedging costs forecasted for 2024 to be reasonable.

5.3.2. Gas Transportation and Storage

SCE forecasted it will maintain its current gas transportation agreements through 2025. These agreements have an estimated fixed cost of \$15.532 million for SCE-owned gas fired resources. This cost is based on an estimated daily reservation charge for Backbone Transportation Service (BTS) rights.⁸⁵

Separately, SCE has month-to-month capacity contracts with Southern California Gas Company under Rate Schedule GT-TLS for gas transportation to its (1) Mountainview Plant and (2) Barre, Center, Grapeland, McGrath, and Mira Loma peaker plants. SCE expects that these contracts will auto-renew each month in 2025.⁸⁶

SCE also has a BTS contract with Southern California Gas Company for firm rights of 60,000 MMBtu/day for a three-year contract (October 2023-September 2026). SCE forecasted that the total fixed costs for this contract in 2025 will be \$15.530 million⁸⁷, and the tariff-based reservation charge is currently \$0.70913/MMBtu per day.⁸⁸

Finally, SCE has a gas storage contract for interruptible gas storage under Rate Schedule G-TBS, a modified fixed variable rate with a reservation charge of

⁸⁵ Exhibit SCE-09 at 81.

⁸⁶ Exhibit SCE-09 at 82. These gas transportation contracts do not have any fixed components, so the charges will vary by month.

⁸⁷ Exhibit SCE-09 at 82.

⁸⁸ Exhibit SCE-09 at 82. These rates and SCE's forecasted costs reflect Southern California Gas Company's Rate Schedule G-BTS2.

\$1.65/MMBtu. This contract confers a capacity of 150,000 MMBtu/day between April 2024 and March 2025 at a total fixed cost of \$0.062 million.⁸⁹

No party addressed SCE's gas transportation and storage forecasts directly in filings. Upon the Commission's review of SCE's documents, we find its forecasted 2024 gas transportation and storage costs to be reasonable and therefore approve them as proposed in A.24-05-007 and updated in SCE's October Update.

5.3.3. Subscription Fees, Financing Costs, and Carrying Costs

SCE forecasts that it will spend up to \$835,000 on subscription fees to access market data, risk analysis, reports on power, gas, and GHG allowance price forecasts, and other industry news in 2025.

Separately, SCE is authorized to recover actual fuel inventory financing costs and actual collateral costs, pursuant to D.93-01-027, D.02-10-062, and D.04-01-048. The latter Decision directs SCE to apply the three-month commercial paper rate index to under-collected balances. SCE forecasted it will use a portion of a \$3.35 billion multi-year revolving credit facility (revolver) to provide capacity for collateral and supporting account balances and requested to recover various fees and upfront costs associated with that portion in its 2025 ERRR proceeding-related balancing accounts. In 2024, SCE exercised an option to extend this revolver one additional year⁹⁰ with the following features:

- \$3.35 billion borrowing capacity;
- May 2028 maturity;

⁸⁹ SCE-09 at 83. SCE has pro-rated the cost of this contract to the ERRR BA, PABA, and NSGBA based on the cost-share of each cost recovery mechanism.

⁹⁰ Exhibit SCE-09 at 84.

- \$20,000 annual administrative fee;
- 17.5 basis point annual facility fee;
- 107.5 basis point participation fee on any outstanding letters of credit;
- 20 basis point issuer fees on any letters of credit; and
- Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points loan rate.⁹¹

If SCE's collateral requirements exceed the revolver capacity, it has an accordion option that would allow it to increase the limit to \$4.00 billion.

SCE also stated it will use its \$3.00 billion commercial paper program to finance fuel inventories in 2025, assuming the market for A2/P2/F3 commercial paper remains stable and SCE can use this program for short-term borrowing needs.⁹²

SCE separately forecasted fuel inventory, GHG procurement compliance, and power procurement collateral requirement carrying costs. Fuel inventory carrying costs account for ownership interests and storage of in core nuclear fuel, natural gas, and diesel, using short-term debt to finance the inventory. Greenhouse gas (GHG) procurement compliance carrying costs are computed using the historical inventory balances and the commercial paper rate. Power procurement carrying costs are based on average collateral requirements and the projected terms of SCE's revolvers; these costs will be updated with actual requirements and terms as requirements change in 2025.

No party directly addressed SCE's forecasted subscription fees, financing costs, or carrying costs as described in its testimony, workpapers, and October

⁹¹ Exhibit SCE-09 at 86.

⁹² Exhibit SCE-09 at 86.

Update documents. Upon review, we find its 2025 forecasts for subscription fees; financing costs; and carrying costs for 2025 as described above to be reasonable and therefore approved for 2025.

6. GHG Forecast Costs, Revenues, and Reconciliation

In D.14-10-033, the Commission adopted standard procedures for electric utilities to request GHG forecast revenue and reconciliation requirements filed after 2013; adopted Confidentiality Protocols for Cap-and-Trade-related data; and required the utilities to use a proxy price in their forecasts. The IOUs were also required to submit GHG Forecast Revenue and Reconciliation Applications annually within their ERRA forecast filings.⁹³ In Advice Letter 4587-E, SCE submitted updated GHG templates (Templates D-1 through D-5), as directed by D.21-08-026.⁹⁴ We therefore apply the standards adopted in D.21-08-026 to review SCE's current forecast and determine the reasonableness of its revenue and reconciliation proposal.

6.1. 2025 GHG Forecast Costs

SCE and the other IOUs in California began incurring compliance costs related to Assembly Bill 32 and the California Air Resources Board's (CARB) GHG cap-and-trade program in January 2013. The program is intended to reduce California's economy-wide GHG emissions to 40 percent below 1990 levels by 2030. Because SCE still owns, operates, and procures power from GHG-emitting

⁹³ D.14-10-033 was modified by D.15-01.024 and D.15-07-001. Previously, the variables included Recorded and Forecast Volumetric Residential Return. However, in D.15-07-001, the Commission concluded that "The IOUs 2016 ERRA Forecast Filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016."

⁹⁴ D.21-08-026 at 3 and Ordering Paragraph 12.

resources, it incurs compliance costs associated with this program either directly or indirectly.

SCE proposes to allocate direct GHG costs to the customers who benefit from the resources to which the GHG costs are attributable, and to include the direct cost of the GHG compliance instruments in its proposed generation service through the ERRA BA, PABA and the ESMA.

Direct GHG costs are related to GHG-emitting resources from which SCE is the 'first deliverer' of electricity, such as in-state facilities that emit more than 25,000 metric ton (MT) of GHG, or out-of state facilities with unspecified emissions (assessed at a default rate of 0.428MT/MWh).⁹⁵ Based on CARB's calculations of SCE's resource portfolio, SCE must procure and surrender compliance instruments to CARB on annual and triennial deadlines.

SCE is also exposed to indirect GHG costs through its QF contracts and its wholesale market electricity purchases, each of which include an embedded GHG compliance price that is updated monthly and based on the heat rate of the resource. The gas equivalent value for energy purchased is multiplied by an emissions factor of 117 pounds of CO_{2e} per MMBtu.

For 2025, SCE forecasted a proxy price of \$35.46/MT of GHG emissions, using the Intercontinental Exchange (ICE) settlement price as of August 26, 2024. SCE forecasts \$436.214 million in costs⁹⁶ resulting from compliance with the California Cap-and-Trade program in 2025 across its direct and indirect costs, GHG costs associated with its QF contracts, and GHG costs associated with electricity purchased from the California wholesale market.

⁹⁵ GHG emissions are measured in carbon dioxide equivalent (CO_{2e}).

⁹⁶ Exhibit SCE-09 at 69, 77.

6.2. 2025 Greenhouse Gas Forecast Revenues, Program Costs, and Returns

Each year, CARB allocates GHG allowances to each of California's large electric IOUs as part of California's Cap-and-Trade program. The IOUs sell these allowances at quarterly auction and return the proceeds to ratepayers, as well as use a portion of the funds for specific clean energy programs. SCE forecasts each year's GHG allowance revenue by multiplying the total volume of allowances that the CARB has allocated to SCE for 2025 by a forecast proxy price meant to represent auction prices for these allowances. This allowance revenue has FF&U amounts deducted, then is adjusted by truing up the previous year's forecast with actual revenues. Forecast administrative expenses are the deducted, leaving a GHG Auction Revenue Subtotal amount for clean energy program costs and customer returns.

6.2.1. Revenues

GHG revenue is expected to be materially lower than previous forecasts for both 2024 and 2025 due to a significant drop in the GHG proxy price for the remainder of 2024 through 2025.⁹⁷

SCE estimates its 2025 GHG allowance revenue (including FF&U) will total \$825.968 million, as illustrated in Table 6-1.

SCE forecasts that California IOUs' combined allocation of forecast GHG allowance auction proceeds will total \$1.893 billion⁹⁸.

⁹⁷ Exhibit SCE-09 at 90.

⁹⁸ Exhibit SCE-09 at 97 and Table VII-32.

6.2.2. Reconciliation of Prior Period GHG Costs

As per the Alternate October Update, SCE estimated its GHG allowance proceeds will result in an undercollection of \$127.531 million in 2024.⁹⁹ This represents the 2024 consignment to auction of GHG allowances allocated to SCE by the State of California. The undercollection is due to a difference in forecast and actual auction allowance revenues and accrues within the Greenhouse Gas Revenue Balancing Account (GHGRBA).

6.2.3. Administrative and Customer Outreach Expenses

SCE forecasted it will spend approximately \$0.868 million to administer its California Climate Credit program in 2025,¹⁰⁰ which includes internal employee and customer-outreach related costs. This amount is slightly higher than in past years, which SCE asserts is due to system updates related to the delivery of EITE credits. The majority of administrative costs are associated with the disbursement of the California Climate Credit in April and October, and SCE's 2025 forecast aligns with what was approved in D.23-11-094 in its 2024 ERRA forecast proceeding.¹⁰¹

No parties opposed or commented on SCE's 2025 forecast of administrative and customer outreach expenses. Upon consideration, the Commission finds SCE's 2025 forecast GHG-revenue related administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission Decisions.

⁹⁹ Exhibit SCE-09 at 102.

¹⁰⁰ Exhibit SCE-09 at 103, Table VII-34 line 7.

¹⁰¹ Exhibit SCE-01 at 87-88.

Table 6-1. Summary of SCE 2024 GHG Allocated Allowance Auction Proceeds and Related Expenses¹⁰²

Program	SCE Proposed (Millions)
<u>GHG Auction revenues</u>	
1. 2025 Forecast GHG auction allowance revenues	- \$ 816.832
2. Associated FF&U	- \$ 9.136
3. 2024 GHG Auction revenue true-up	\$ 127.531
<u>2025 Forecast Administrative Expenses</u>	
4. 2025 Outreach and Administrative Expenses	\$ 0.868
5. 2025 Forecast FF&U	\$ 0.010
GHG Auction Revenue Subtotal	- \$ 641.624

6.2.4. Clean Energy Programs Set Aside Funding – SOMAH, DAC-SASH, and CEOP

Pub. Util. Code § 748.5(c) authorizes the Commission to allocate up to 15 percent of the revenue received by an electric corporation from its sales of allocated GHG allowances to specific clean energy and energy efficiency projects that are not funded by any other source and are already approved by the Commission. SCE noted that it has set aside \$55.936 million in allowance revenues to fund all of its Clean Energy Programs in 2025.¹⁰³

¹⁰² Exhibit SCE-09 at 103, Table VII-34.

¹⁰³ Exhibit SCE-09 at 103, Table VII-34 line 17.

6.2.4.1. Solar on Multifamily Affordable Housing Program

Assembly Bill 693 (Eggman) Stat. 2015, Ch. 582 created the Solar on Multifamily Affordable Housing (SOMAH) program, allocating 10 percent of GHG allowance auction proceeds, or up to \$100 million annually, whichever is less, for fiscal years 2016 through 2026. In D.17-12-022, the Commission required that 10 percent of forecast auction revenue be reserved for SOMAH through each IOU's ERRA applications and established that each IOU shall contribute its proportionate share of \$100 million, when necessary, based on its share of allowance sale proceeds from the previous four quarters.¹⁰⁴

D.20-01-022 clarified that prior-year GHG revenue allocations should be trued-up based on a 10 percent allocation of actual GHG revenues received. In D.20-04-012, the Commission extended SOMAH through June 2026, clarified existing requirements, and set additional requirements for the SOMAH budget true-up process.¹⁰⁵ D.22-09-009 modified the forecast budgeting process by adding a pathway for each IOU to request to set aside its proportionate share of a \$100 million budget and identifying a set allocation for each IOU's share.¹⁰⁶ This pathway is dependent on their ability to adequately demonstrate that the IOUs' combined forecast GHG allowances will equal or exceed \$1 billion.¹⁰⁷ As a result, IOUs may either propose setting aside 10 percent of their forecast revenue or their share of \$100 million.

¹⁰⁴ D.17-12-022 at OP 4 and OP 7.

¹⁰⁵ The SOMAH program funding is allocated on a fiscal year basis while the Forecast revenue requirement is set for the calendar year, in this case 2025.

¹⁰⁶ D.22-09-009 Table 1.

¹⁰⁷ D.22-09-009 OP 3.

In its 2025 ERRRA forecast, SCE sets aside \$46.528 million to cover its share of the \$100 million annual SOMAH cap. It also noted that its 2024 SOMAH true-up, which will be recorded in 2025, will result in an increase in SOMAH funding of \$3.681 million.¹⁰⁸

No parties commented on SCE's proposed SOMAH allocation. Upon review, the Commission finds SCE's SOMAH allocation reasonable and in compliance with applicable rules, orders and Commission Decisions. A summary of SCE's SOMAH forecasted allocation for 2025 is detailed below in Table 6-2.

6.2.4.2. SCE's Disadvantaged Community Programs

In D.18-06-027, the Commission created the Disadvantaged Communities (DAC) Single Family Solar Homes (SASH) program and set an annual \$10 million budget. SCE's proportionate share of that \$10 million annual budget is 46 percent, starting in 2019. In its 2025 ERRRA Forecast, SCE has allocated \$4.6 million to its DAC-SASH program (46 percent of \$10 million).¹⁰⁹

On January 24, 2024, the CPUC Executive Director granted SCE an extension to the February 1, 2024, deadline for submitting annual program budget estimates for the DAC Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT) Programs. This extension was due to the reliance of these programs on a final decision in the Green Access Program (GAP) proceeding. The GAP final decision, D.24-05-065, was issued on June 7, 2024 and discontinues the CSGT program and transfers all remaining unprocured capacity to the Modified DAC-GT program. SCE's Advice Letter 5329-E-A was approved on July 18, 2024 and states that SCE will target CSGT customer transition to the

¹⁰⁸ Exhibit SCE-09 at 97. See Advice Letter 5241-E, filed pursuant to OP 4 of D.22-09-009.

¹⁰⁹ Exhibit SCE-09 at 99.

DAC-GT program in early Q1 2025.¹¹⁰ The customer bill discounts for DAC-GT are funded through public purpose program rates, while procurement and other costs are funded through GHG revenues. SCE does not forecast additional funding for the latter category, thus does not request GHG funding for DAC-GT in 2025. SCE forecasts expenditures of \$16,960,000 for bill discounts in 2025 for DAC-GT, coming from the Public Purpose Programs.¹¹¹

6.2.4.3. Community Choice Aggregator DAC Programs

D.18-06-027, as clarified by Resolution E-4999, authorized CCAs to access these same program funding sources to run their own DAC-GT and CSGT programs. On July 8, 2024, Clean Power Alliance of Southern California (CPA) submitted Advice 0029-E which states that CPA elects to maintain its existing CSGT program in accordance with D.24-05-065 issued on June 7, 2024. The Decision allows Program Administrators to discontinue the CSGT program and transfer all remaining unprocured capacity to the Modified DAC-GT program. Therefore, CPA has requested a PY 2025 budget for its CSGT program.¹¹² Of the \$4.074 million requested, the above market generation portion of \$1.127 million will be funded through GHG allowance revenue, with the remainder of \$2.947 million recovered through PPP funds.¹¹³

Lancaster Choice Energy, Pico Rivera Innovative Municipal Energy, and San Jacinto Power, jointly as CalChoice, demonstrated surplus funding through

¹¹⁰ SCE AL 5329-E at 6.

¹¹¹ Exhibit SCE-09 at 100.

¹¹² CPA AL 0029-E at 3-4.

¹¹³ Exhibit SCE-09 at 100.

2025 and therefore will not require any GHG or public purpose funding.¹¹⁴ No parties commented on SCE's set aside for its own or the CCA's DAC programs. Upon consideration, the Commission finds SCE's 2025 forecast for DAC-SASH, DAC-GT and CSGT set-asides from GHG and public purpose program charge funding to be reasonable and in compliance with all rules, law and Commission orders.

6.2.4.4. Clean Energy Optimization Pilot

In D.19-04-010, the Commission approved a \$20.4 million Clean Energy Optimization Pilot (CEOP) designed to provide a pay-for-performance pilot project at University of California (UC) and California State University (CSU) schools, starting in 2019. D.20-01-002 authorized SCE to spend \$10 million for the CEOP. Due to the COVID-19 pandemic, UC and CSU schools transitioned to remote learning, drastically affecting on-campus energy use. As a result, a Petition to Modify (PFM) D.19-04-014 was filed in August 2020. D.20-12-035 approved a settlement agreement that modified the CEOP and authorized it to continue.¹¹⁵

D.22-01-003 separately authorized an additional \$10 million to fund CEOP. Because SCE already requested and attained approval for funding totaling \$20.4 million for the project, it forecasts that, as of 2025, its CEOP program is fully funded and did not request any further funding in the instant application.¹¹⁶

No parties commented on SCE's CEOP funding in this proceeding. Upon review, SCE's request is consistent with all rules, law and Commission orders, and no additional funding for the CEOP program is granted in this Decision.

¹¹⁴ Exhibit SCE-09 at 101.

¹¹⁵ D.20-12-035 at 39.

¹¹⁶ Exhibit SCE-09 at 101.

Table 6-2. Summary of SCE 2025 GHG Clean Energy Related Expenses

Program	SCE Proposed (Millions)
Clean Energy and Energy Efficiency Programs	
1. SCE 2025 Solar on Multifamily Affordable Housing Program (SOMAH)	\$ 46.528
2. SCE 2024 SOMAH True-Up	\$ 3.681
3. SCE 2025 Disadvantaged Communities – Single-family Solar Homes (DAC-SASH)	\$ 4.600
4. CPA 2025 DAC-GT and CSGT	\$ 1.127
Total Clean Energy and EE Program Set-Asides	\$ 55.936

6.2.5. GHG Revenue Returns

After deducting expenses and program set asides, GHG auction proceeds are returned to Residential, Small Commercial, and Emissions-Intensive and Trade-Exposed Customers.

6.2.5.1. Residential and Small Commercial Customers

SCE proposes to return \$583.441 million in GHG revenue¹¹⁷ in its residential and small commercial customers' 2025 California Climate Credit.¹¹⁸ This estimate accounts for administrative and customer outreach costs and will equal \$56 per eligible customer in bill credits forecasted to be distributed in April

¹¹⁷ Exhibit SCE-09 at 103, Table VII-34 line 24.

¹¹⁸ Exhibit SCE-09 at 90.

and October 2025. This amount is significantly below the 2024 credit of \$86¹¹⁹ and the May forecast of \$92¹²⁰ per Residential and Small Commercial Customer.

6.2.5.2. Emissions-Intensive and Trade-Exposed Customers

Customers operating EITE businesses are eligible to receive industry assistance in the form of a bill credit once annually, in April. SCE forecasted its 2025 EITE customer return costs to be \$58.183 million.¹²¹ No party commented on SCE's forecasted EITE costs for 2025, and upon review, the Commission finds them consistent with all rules, laws, and prior Commission orders. SCE is authorized to return the \$58.183 million allocated to industry assistance funds to eligible EITE customers in 2025, as proposed in its testimony, workpapers, and AOU documents.

Table 6-3. Summary of SCE 2025 California Clean Credit and EITE Refunds

Program	SCE Proposed (Millions)
Clean Energy and Energy Efficiency Programs	
1. SCE 2025 California Clean Credit Return	\$ 583.441
2. SCE 2025 EITE Return	\$ 58.183
Total GHG Returns	\$ 641.624

6.2.6. Discussion

No party directly addressed SCE's forecasted GHG revenues and expenses, forecasted allocated allowance auction proceeds, or other aspects

¹¹⁹ D.23-11-094 at 3.

¹²⁰ A.24-05-007 at 2.

¹²¹ Exhibit SCE-09 at 103, Table VII-34 line 23.

related to SCE's GHG accounting for its 2025 ERRRA forecast proceeding. Weighing the record, we find SCE's GHG revenues and expenses, set asides for clean energy and energy efficiency programs, returns for EITE and CCC eligible customers, and accounting are reasonable and approved.

7. SCE's Revenue Requirement and Ratemaking Proposal

SCE proposes a total 2025 revenue requirement of \$4.637 billion, comprised of the following generation and delivery service requirements.

7.1. Generation Service Revenue Requirement

The generation service revenue requirement recovers F&PP costs, along with the associated GHG costs of resources, recorded in SCE's (1) ERRRA BA; (2) PABA; and (3) the GTSR BA. SCE's 2025 forecast generation service requirement, as provided in its AOU, is \$4.663 billion, which is \$725.230 million,¹²² or 13.46 percent, below its generation service revenue requirement from rates in effect today.

¹²² Exhibit SCE-09 at 15.

Table 7-1. Summary of SCE’s Proposed 2025 ERRA Forecast Proceeding Generation Service Revenue Requirement¹²³

Description	SCE Proposed 2025 Revenue Requirement (millions)
2025 F&PP Costs (including GHG costs)	
• ERRA BA-related	\$ 2,830.024
• PABA-related	\$ 1,248.713
• Green Tariff Shared Renewables BA-related	\$ 7.132
2024 ERRA BA True-up	-\$ 10.152
2024 PABA True-Up	\$ 587.214
2024 ESMA True-Up	-\$ 0.295
Total Generation Service	\$ 4,662.635

7.1.1. ERRA Balancing Account

SCE’s ERRA BA records the difference between SCE’s ERRA-related revenue requirement and its F&PP expenses for bundled service customers during the prior year.¹²⁴ In its AOU, SCE estimates that the 2025 ERRA BA F&PP costs will be \$2,831 million, resulting in an overcollection of \$1,628 million¹²⁵ less than current rates. It further estimates that the 2024 ERRA year-end balance will be negative \$10.152 million, resulting in an end of 2024 overcollection of \$187.104 million (including FF&U) under current rates.¹²⁶ The estimate provided for the 2024 ERRA BA in the AOU was developed by adding the amount

¹²³ Exhibit SCE-09 at 106, Table V-III-36.

¹²⁴ SCE’s ERRA BA was established in D.02-10-062, effective January 1, 2003.

¹²⁵ Exhibit SCE-09 at 15.

¹²⁶ Exhibit SCE-01 at 112; Exhibit SCE-09C at 15 and table II-3.

forecasted to be recorded in the ERRA BA October-December 2024 to the amount already recorded as of September 30, 2024, which included the RA and RPS true-up amounts.¹²⁷

As discussed in Section 4 above, SCE removed the increased revenues associated with the 2024 ERRA Trigger revenue requirement when calculating its final ERRA BA balance in the AOU forecasts.

SCE notes that the initial estimates of overcollection are largely the result of unanticipated changes to the MPBs and lower-than-forecast power prices resulting in lower-than-forecast load procurement costs.

7.1.2. Portfolio Allocation Balancing Account

D.18-10-019 modified the balancing accounts to be considered in ERRA forecast proceedings and directed utilities to create new balancing accounts to track above-market costs and revenues associated with their electric portfolios.¹²⁸ The PABA records the above market costs of long term, fixed price contract costs and utility owned generation costs for bundled and departed load customers (*see* Section 5 above for specific resource types).

SCE's AOU forecasts a 2025 PABA revenue requirement of \$1,248.024 million, resulting in an undercollection of \$1,013 million,¹²⁹ including FF&U.

¹²⁷ Exhibit SCE-09, Appendix A at A-1.

¹²⁸ Pursuant to D.18-10-019 Ordering Paragraph 1 and page 42, the above-market costs of the CTC- and PCIA-eligible resources are defined as the actual costs less (1) actual revenues received through bilateral transactions, (2) actual energy and ancillary services revenues, (3) actual retained RPS value, and (4) actual retained RA value.

¹²⁹ Exhibit SCE-09 at 114.

In its AOU, SCE forecasts that the year-end balance in its 2024 PABA will be a \$587.214 million undercollection, of \$79.628 million more than current rates,¹³⁰ including FF&U, as of December 31, 2024.

SCE states this undercollection is largely due to the changes in MPBs and SCE's proposal to use its October Alternate Update methodology of applying the final 2024 RA and RPS MPB. Without this change in methodology, PABA would have been forecasted to end 2024 with an overcollection of \$877.513 million.¹³¹

Weighing the record, we find that SCE's forecast 2025 PABA revenue requirement and 2024 PABA year-end true-up reasonable and approved.

7.1.3. Energy Settlement Memorandum Account and Litigation Costs Tracking Account

SCE continues to pursue refunds from generators that overcharged it and other California IOUs for electricity during the 2000-2001 California Energy Crisis. In its 2025 AOU, SCE estimated a balance of negative \$0.295 million in its Energy Settlement Memorandum Account (ESMA), including FF&U.

Pursuant to Resolution E-3894, SCE is also required to maintain a Litigation Costs Tracking Account (LCTA) within its ESMA to track litigation costs associated with the pursuit of a settlement related to the California Energy Crisis. SCE forecasted its LCTA will have a balance of \$0 as of December 31, 2024.

The combined balance of the ESMA and the LCTA sums to an over collection of \$295,000, which will be returned to customers.¹³²

¹³⁰ Exhibit SCE-09 at 114.

¹³¹ Exhibit SCE-09 at 114.

¹³² Exhibit SCE-09 at 115.

No party directly raised any comments or testimony regarding SCE's forecast for its ESMA and LCTA in 2025. We find this forecast of ESMA and LCTA balances, including SCE's return of \$295,000 to customers, to be reasonable and is approved.

7.1.4. Discussion

In its AOU testimony, SCE forecasted a total 2025 ERRA Generation Service revenue requirement of \$4,663 million, \$725 million less than 2024, which will be incorporated into rates in January 2025.

Weighing the record, we find SCE's forecast ERRA BA revenue requirement and 2024 ERRA BA under/overcollection recovery proposal to be reasonable. SCE is authorized to recover the 2025 Generation Service revenue requirement as summarized in Table 7-1.

7.2. Delivery Service Revenue Requirement

SCE's delivery service revenue requirement is recovered from all bundled and departing load SCE customers through allocation mechanisms other than the Competition Transition Charge (CTC), PCIA, and the Wildfire Non-Bypassable Charge. SCE forecasts a total delivery service revenue requirement of negative \$25.306 million for 2025, which represents (1) a consolidation of New System Generation (NSG) forecast costs, including Central Procurement Entity (CPE)-related costs and the estimated year-end 2024 NSGBA balance; (2) 2025 System Reliability MCAM-related forecast costs and the estimated 2024 MCMABA balance; (3) 2025 Tree Mortality contract forecast costs and the estimated 2024 TMNBCBA balance; (4) 2025 BioMAT contract forecast costs and the estimated 2024 BMNBCBA balance; (5) 2025 forecast for spent nuclear fuel storage revenue requirement; (6) 2025 BRRBA-Distribution fuel and purchased power forecast costs; and the (7) estimated 2025 GHG allowance revenues to be returned to

eligible customers.^{133,134} This revenue requirement reflects an increase of \$282.694 million over current rates.

Table 7-2. Summary of SCE’s Proposed 2025 ERRA Forecast Delivery Service Revenue Requirement¹³⁵

Description	SCE Forecast 2025 Revenue Requirement (millions)
New System Generation <ul style="list-style-type: none"> • New System Generation F&PP 2025 Forecast¹³⁶ • Estimated YE NSGBA 2024 Balance • MCAM F&PP 2025 Forecast 	\$ 457.467 \$ 146.846 \$ 1.558
Spent Nuclear Fuel Storage	\$ 5.157
Distribution Rate Component <ul style="list-style-type: none"> • Base Revenue Requirement BA-Distribution F&PP • GHG Allowance Revenues 	-\$ 19.169 -\$ 641.624
Public Purpose Programs Charge <ul style="list-style-type: none"> • Public Purpose Program F&PP Charge 2024 Forecast • Tree Mortality Non-Bypassable Charge BA YE 2023 Balance • BioMAT Non-Bypassable Charge BA YE 2023 Balance 	\$ 5.341 \$ 19.110 -\$ 2.842
Total Delivery Service	-\$ 25.306

¹³³ GHG allowance revenues and associated costs are discussed further in Section 6.

¹³⁴ Exhibit SCE-09 at 115.

¹³⁵ Exhibit SCE-09 at 106 and Table VIII-36.

¹³⁶ Estimate includes indirect GHG costs.

7.2.1. New System Generation Net Capacity CAM-Related Costs

D.06-07-029 established a process to allocate the benefits and costs of new generation capacity to all benefiting customers in an IOU's service area for up to 10 years. Utilities were previously required to notify the Commission whether they intend to apply this CAM to new generation capacity contracts when they seek approval of each contract. In D.11-05-005, however, the Commission implemented a new process that authorizes IOUs to treat these new generation contracts as CAM-eligible for the duration of the underlying power purchase agreement, so long as the Commission finds that CAM is applicable to the contract.¹³⁷

Pursuant to D.20-06-022, SCE became the CPE responsible for procuring multi-year Local RA resources on behalf of all LSEs in its distribution service area, beginning in 2023. In Exhibit SCE-02C, as updated in Exhibit SCE-07C, SCE described administrative costs and other costs associated with its role as CPE, such as system-related costs, which are recorded in its Centralized Local Procurement Sub-Account and recovered under the CAM. SCE noted that the forecasted costs only relate to Grid Management Charges associated with the CPE's participation in the RA market, since the contracts were only active for a short period prior to filing this application.¹³⁸

D.23-06-029 adopted refinements to the RA program, including establishing a 17 percent Planning Reserve Margin for 2024 and 2025.¹³⁹

¹³⁷ D.11-05-005 at 6-7 and OP 17.

¹³⁸ Exhibit SCE-02 at 5-6 and Exhibit SCE-06 at 111-112.

¹³⁹ D.23-06-029 at OP 7.

7.2.2. New System Generation Balancing Account (NSGBA)

The NSGBA was established on January 16, 2009, pursuant to OP 2 of D.07-09-004. It is intended to record the costs and benefits of power purchase agreements associated with new generation resources, including SCE's CPE-related procurement. The NSGBA also accounts for the costs of compliance obligations due to another LSE's cessation of retail service due to bankruptcy or any other reason. SCE's AOU forecasts a 2025 NSGBA revenue requirement of \$457.467 million, which would result in an increase of \$54.471 million above current rates. It further estimates that the 2024 NSGBA will end this year overcollected by \$75.594 million, including FF&U.

7.2.3. System Reliability Modified Cost Allocation Mechanism-Related Costs

As discussed in Section 5.1.9.1 above, D.19-11-016 established specific requirements for IOUs to procure system-level RA capacity by August 2023.

Separately, D.22-05-015 authorized the use of non-bypassable customer charges to recover Modified Cost Allocation Mechanism (MCAM) costs from customers of LSEs that opt-out or do not comply with the RA adequacy requirements. Resolution E-5240 authorized SCE to complete transfers of its System Reliability Procurement Memorandum Account (SRPMA) balance and costs associated with D.22-05-016 are now recorded in its PABA, MCAMBA, and NSGBA, as of January 2023.

Finally, D.23-12-014 granted a petition for modification of D.22-05-015. This PFM allows non-utility load serving entities to purchase additional RA

capacity at the final 2023 RA year-ahead forecast price; any resulting sales revenue is recorded to the 2019 subaccount of the PABA.¹⁴⁰

SCE's AOU forecasts a 2025 MCAM F&PP revenue requirement of \$1.558 million, which would result in an undercollection of \$0.246 million at current rates. It further estimates that the 2024 MCAMBA will end this year undercollected by \$1.799 million.

After reviewing the Opening Testimony, Rebuttal Testimony, workpapers, AOU, comments, Opening Brief, and Reply Brief documents, we find SCE's forecasted 2025 MCAMBA costs to be reasonable therefore approve them as proposed.

7.2.4. Tree Mortality Contract Costs

SCE's tree mortality non-bypassable charge was applied to all procurement that has occurred pursuant to Resolution E-4770 and E-4805. As discussed in Section 5.1.10 above, SCE's AOU forecasts a 2025 TMNBCBA F&PP revenue requirement of \$19.110 million. SCE's forecasted BioRAM audit costs, which are also recorded in the TMNBCBA, are forecasted to total \$18,000 in 2025.¹⁴¹ It further estimates that the 2024 TMNBCBA will end this year undercollected by \$2.978 million.¹⁴²

No party directly raised any comments or testimony regarding SCE's 2025 forecast for its TMNBCBA and true up of 2024 TMNBCBA balances. We find this forecast of TMNBCBA balances to be reasonable and in compliance with applicable rules, orders, and Commission decisions.

¹⁴⁰ Exhibit SCE-09 at 123.

¹⁴¹ Exhibit SCE-09 at 124.

¹⁴² Exhibit SCE-09 at 15 and Table II-3 at line 28.

7.2.5. BioMAT Contract Costs

Senate Bill 1122 (Rubio), Stat. 2012, Ch.612, created a bioenergy feed-in tariff to procure renewable resources from small-scale bioenergy projects, the Bioenergy Market Adjusting Tariff (BioMAT). In accordance with OP 3 of D.20-08-043, on October 1, 2020, SCE submitted Advice Letter 4306-E to establish the BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA) to record these net costs. D.23-11-084 set rules to enable CCAs to participate in the BioMAT program.

SCE's AOU forecasts a 2025 BMNBCBA revenue requirement of \$5.642 million.¹⁴³ The CCA portion of 2025 BMNBCBA costs is \$0. It further estimates that the 2024 BMNBCBA will end this year overcollected by \$2.842 million.¹⁴⁴

No party submitted any comments or testimony regarding SCE's 2025 forecast for its BMNBCBA and true up of 2024 BMNBCBA balances. We find this forecast of BMNBCBA balances to be reasonable and in compliance with applicable rules, orders, and Commission decisions.

7.2.6. Central Procurement Entity Related Costs

D.20-06-002 identifies SCE as the CPE for its distribution service area and directs SCE to procure multi-year local RA contracts on behalf of all LSEs in its distribution service area beginning in 2023. D.22-03-034 requires that CPE procurement costs be forecast and implemented through rates in the ERRA proceeding and documented in a separate confidential chapter of ERRA forecast

¹⁴³ Exhibit SCE-09 at 126.

¹⁴⁴ Exhibit SCE-09 at 15 and Table II-3 at line 29.

testimony.¹⁴⁵ D.23-06-029 adopted additional reporting that allows LSEs to manage RA procurement and assess the need for potential CAISO backstop.¹⁴⁶

As already noted, the CAM is the cost recovery mechanism for CPE procurement of local RA. SCE has a Centralized Local Procurement Balancing sub-account within its NSGBA BA to facilitate the cost recovery process.¹⁴⁷ SCE has several CPE-related purchased and self-show procurement agreements entered into through separate CPE Local RA request for offers, spanning 2024 through 2027, each of which include CAISO costs under its scheduling coordinator identification number, SCE8.¹⁴⁸

SCE-CPE notes that its Big Creek Ventura local area will be short in May 2025 and other shoulder months in 2026 and 2027. It states that it was reasonable to decline high priced offers that would have helped fill the May 2025 short position given their price and lack of material impact on the May 2025 short position. SCE-CPE further states that it is confident of meeting future shortfalls in subsequent RFOs.¹⁴⁹

Pursuant to D.22-03-034, SCE also forecasted \$250,000 for 2024 administrative costs for utilizing independent evaluators to review its solicitation documentation for future CPE-related contracts, which was based on its most

¹⁴⁵ D.22-03-034 OP 19

¹⁴⁶ D.23-06-029 FoF7

¹⁴⁷ D.20-06-002 OP 17 and Exhibit SCE-07C at 1.

¹⁴⁸ Exhibit SCE-07 at 7-10.

¹⁴⁹ Exhibit SCE-07 at 6.

recent CPE solicitation evaluator costs.¹⁵⁰ It further forecasts confidential procurement net costs and FF&U.¹⁵¹

No parties opposed SCE's CPE proposed revenue requirement. Weighing the record, we find SCE's forecasted 2025 CPE costs to be reasonable and are therefore approve as proposed.

7.2.7. Discussion of New System Generation Revenue Requirement

No parties opposed SCE's proposed revenue requirement for New System Generation and System Reliability contracts, including those discussed in its CPE forecasted costs.

Weighing the record, we find SCE's total requested delivery service revenue requirement for New System Generation and System Reliability contracts, along with SCE's request to true-up the NSGBA, to be reasonable and are therefore authorized.

7.3. Cost Responsibility Surcharges

The Cost Responsibility Surcharge (CRS) Indifference Amount is the difference between the total portfolio cost and the forecast value of the portfolio; it includes the CTC and the Power Charge Indifference Adjustment (PCIA) charges.¹⁵²

The CTC rate is used to recover the above market costs of pre-restructuring resources such as eligible QFs and is the same for all vintages. The

¹⁵⁰ Exhibit SCE-02C at 7, Exhibit SCE-07C at 8.

¹⁵¹ Exhibit SCE-07C at 12.

¹⁵² The Commission adopted the Cost Responsibility Surcharge Indifference Charge in D.02-11-022, as modified by D.03-07-030, D.06-07-030, D.08-09-012, D.11-12-018, Resolution E-4475, D.18-10-019 and D.19-10-001, and D.21-03-051 and D.23-06-006.

PCIA rates are used to recover the above-market costs of all non-CTC-eligible resources which vary by vintage based on the generation resources included in that vintage.

In D.08-09-012, the Commission adopted the practice of vintaging the utility's generation portfolio to ensure that departed load customers are held responsible only for generation procured prior to the date of their departure from bundled service. Accordingly, SCE calculated indifference amounts for each "vintage year" based on the generation resources that were committed in each calendar year.

In D.18-10-019, the commission articulated the following overall goals of the PCIA:¹⁵³

The Commission shall ensure that bundled retail customers of an electrical corporation shall not experience any cost increases as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) the implementation of a community choice aggregator program.

The Commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

SCE noted that both its and the Santa Catalina Island general rate case (GRC) may have an impact on the final 2025 CRS rates proposed. One component of SCE's 2025 GRC Phase I A.23-05-010¹⁵⁴ is the Authorized Generation Base Revenue Requirement, which is recovered from customers via the PABA on a vintaged basis. Within the Application for Authority to Increase Rates for its Catalina Gas Utility (A.23-12-011), SCE proposed a rate increase and

¹⁵³ D.18-10-019 at 14.

¹⁵⁴ Exhibit SCE-09 at 145.

to recover costs associated with the production of electricity. The approval or denial¹⁵⁵ of SCE's proposal will impact the 2025 CRS.¹⁵⁶

7.3.1. Competition Transition Charge

The Competition Transition Charge (CTC) recovers all above-market costs associated with contracts previously necessary to serve departing customers, regardless of their date of departure from investor-owned utility generation service. For 2025, SCE's AOU October Update and its associated errata forecasted the following average CTC costs: (1) -\$0.00061/kWh for Domestic (D); (2) - \$0.00056/kWh for Street Lighting customers; (3) -\$0.00046 for TC-1, TOU-GS-2 and Standby-Sec; (4) -\$0.00045 for TOU-PA-2; (5) -\$0.00044 for TOU-GS-3 and TOU-PA-3; (6) -\$0.00043 for TOU-GS-1, TOU-8-Sec, and Standby-Pri; (7) - \$0.00042 for TOU-8-Pri; (8) -\$0.00040 for TOU-8-Sub and Standby-Sub. customers of all vintages.¹⁵⁷

No parties addressed SCE's CTC-related cost forecasts for 2025. Weighing the record, we find SCE's proposed CTC costs to be reasonable and therefore approve as proposed.

Weighing the record, we find SCE's forecasted 2025 electric sales and electric load to be reasonable and therefore approved as proposed.

7.3.2. PCIA Revenue Requirement

The PCIA recovers the above-market costs of all non-CTC eligible resources and varies by the generation resources in that vintage. PCIA costs are determined by the date of a customer's departure from bundled customer

¹⁵⁵ The March 27, 2024 Scoping Memo anticipates a decision in the first quarter of 2025.

¹⁵⁶ Exhibit SCE-09 at 146.

¹⁵⁷ Exhibit SCE-09 Appendix B at B-8.

service. Customers who depart in the first half of each year are assigned to the prior year's "vintage" and customers who depart in the second half of each year are assigned to the current year's "vintage."¹⁵⁸ SCE calculated its indifference amount for its 2025 PCIA by first estimating the above- and below-market costs of its portfolio, and then accounting for true-ups and adjustments in its portfolio balancing accounts.¹⁵⁹ SCE forecasted that its generation portfolio is below market for 2025, resulting in an indifference amount of negative \$1,928 million which will result in a PCIA credit on most departed load customers' bills.¹⁶⁰

Weighing the record, we find SCE's calculation of the indifference amount to be reasonable and are therefore approved as proposed.

In addition to the indifference amount, SCE's total 2024 PCIA revenue requirement forecast accounts for applicable balancing account true-ups and other adjustments, including: (1) annual true-ups in the ERRA BA and PABA; (2) the removal of one-third of the PABA-eligible portion of the historical costs related to System Reliability procurement originally recorded in the SRPMA to effectuate the 36-month amortization recovery period adopted in Resolution E-5240; (3) and the UOS Separator project.

For 2025, SCE calculated a total PCIA revenue requirement of -\$1,343 million. The 2025 PCIA revenue requirement is illustrated in Table 6.4

¹⁵⁸ For example, 2020 vintage departing load customers are those who departed SCE's bundled customer service between July 1, 2020, and June 30, 2021. SCE's vintages include 2001-2003, 2004-2008, and annually starting in 2009.

¹⁵⁹ D.21-03-015.

¹⁶⁰ SCE-09 Appendix B at B-4.

and a list of SCE's forecasted system average PCIA rates by vintage year is provided in Table 6-5.¹⁶¹

Table 7-3. Summary of SCE's 2024 ERRA Forecast Portfolio Costs, Portfolio Market Value, Balancing Account True-Ups, and Total PCIA Revenue Requirement¹⁶²

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	\$4,130.980
Market Value	-\$6,058.423
• Energy Value	-\$1,546.403
• RPS Value	-\$2,049.023
• RA Value	-\$2,462.997
One-Time Adjustments	-\$ 295.000
Total 2024 Indifference Amount	-\$1,928.345
Balancing and Memorandum Account True-Ups	
• 2024 YE PABA Balance	\$ 587.926
• 2024 YE ERRA Balance	-\$ 10.040
• SRPMA Historical Costs Amortization	-\$ 7.208
• Emergency Reliability Utility-Owned Storage (UOS) Separator	\$ 17.396
2024 PCIA Revenue Requirement	-\$1,340.270
2024 PCIA Revenue Requirement with Uncollectibles Factor	-\$1,342.687

7.3.2.1. Updated RA Slice of Day Portfolio

D.23-04-010 affirmed that the Commission intended to move forward with SOD implementation in 2025. D.24-06-004 confirmed the SOD framework will

¹⁶¹ SCE's final revenue requirement and its associated PCIA rates will be updated in its Advice Letter implementing this Decision.

¹⁶² Exhibit SCE-09 at 129 and Table IX-43.

start in 2025. This framework transitions RA from a compliance requirement based on the worst hour in the year to one based on every hour of the “worst day” for each month. Additionally, this framework requires charging sufficiency for storage resources.

SCE created its hourly position under the SOD framework utilizing the ED’s showing tool and the Commission’s master resource database. This hourly position is fulfilled by generation resources forecast to be used to serve bundled customers in 2025.

7.3.2.2. Updated Total Portfolio Costs

Portfolio Costs for each vintage are determined by their resources’ forecast fixed and variable costs. The Total Portfolio costs do not include any costs associated with CAM, TMNBCBA, BMNBCBA, MCAMBA, and LCR-eligible resources, ISO-load related costs, or Residual Net Position spot market (*i.e.*, “short-term”) purchases.¹⁶³ The AOU to SCE’s forecast for total portfolio cost is \$4,130 million, a 4% reduction from its May Forecast.¹⁶⁴

7.3.2.3. Updated Total Portfolio Market Value Forecast

The total portfolio market value forecast of PABA-eligible resources is calculated using the three forecast MPBs in accordance with D.18-10-019 and D.19-10-001. Increases in MPB values have the effect of decreasing the CTC and vintaged rates.¹⁶⁵

The first forecast MPB is the Energy Index and reflects the estimated dollar value of each megawatt hour (MWh) in SCE’s PABA-eligible portfolio. The

¹⁶³ Exhibit SCE-09 at 131-132.

¹⁶⁴ Exhibit SCE-09 at 129 and Table IX-43. Exhibit SCE-11C at 128 and Table IX-43.

¹⁶⁵ Exhibit SCE-09 at 132.

second forecast MPB is the RA MPB and reflects the estimated dollar value of each unit of forecast retained and forecast sold capacity in SCE's PABA portfolio that can be used to satisfy RA obligations, given in units of kilowatt-month. Each unit of capacity is allocated to one of the three subcomponents of the MPB, the system RA MPB, the local RA MPB, or the flexible RA MPB.¹⁶⁶ The third forecast MPB is the RPS MPB and reflects the estimated incremental dollar value of each unit of Forecast Retained and Forecast Sold RPS-eligible MWh.

Each of these MPBs and their subcomponents underwent significant changes between the forecast values included in the May testimony and the early October issuance of updated values by ED. These MPB changes are summarized in Table IX-44 of the October Updates, reproduced as Table 7-4 below:

Table 7-4. Comparison of Forecast PCIA Market Price Benchmarks

Market Price Benchmark (MPB)	2024 ERRA Forecast June Submittal	2024 ERRA Forecast October Submittal	2025 ERRA Forecast May Submittal	2025 Forecast October Submittal*	Percent Change between May and October
Energy Index**	\$71.87/MWh	\$61.50/MWh	\$55.98/MWh	\$41.67/MWh	-26%
RPS MPB	\$12.63/MWh	\$31.73/MWh	\$31.73/MWh	\$71.24/MWh	125%
RA MPBs	(intentionally left blank)				
System	\$88.68/kW-yr	\$182.76/kW-yr	782.76/kW-yr	510.48/kW-yr	179%
Local	80.88	105.72	105.72	133.20	26%
Flexible	85.80	109.44	109.44	169.22	55%
* These figures reflect the October 4 addendum but do not consider the November 5 revision					
** This value is the weighted Energy Index computed pursuant to D.23-06-006.					

¹⁶⁶ Exhibit SCE-09 at 132.

SCE's AOU forecast of the total market value of the PABA-eligible portfolio increased to \$6,058 million, which is a 41% increase relative to the May Forecast. SCE states that this increase is primarily the result of the updated 2025 forecast MPBs.¹⁶⁷

This increase was mitigated both by the reduction in Energy Index MPBs and the assignment of RA capacity to all three RA MPBs. The PABA total market value would have been further increased by 13.43% if the Energy Index MPB had remained at its May forecast level.¹⁶⁸ The PABA total market value would have been further increased by 13.48% if SCE had continued assigning all of its RA to the system subcategory.¹⁶⁹

7.3.2.4. Updated Energy Value

D.23-06-006 adopted an updated methodology for the first forecast MPB, the Energy Index. This updated methodology applies a time weighting to account for the differing energy prices during on-peak and off-peak periods, portfolio weighting to represent the actual value that the PCIA portfolio receives in the CAISO market, and removes data for any resources that are 300 MW or larger. For its 2025 analysis, SCE utilized historical data from its PCIA-eligible portfolio for the years 2021-2023.¹⁷⁰

7.3.2.5. Updated RA Value(s)

The effect of the assignment of capacity to all three RA MPBs is a reduction in the market value of RA capacity. This substitution of less valuable local and

¹⁶⁷ Exhibit SCE-09 at 128.

¹⁶⁸ Exhibit SCE-09 at 129 and table IX-43.

¹⁶⁹ Exhibit SCE-09 at 129 and table IX-43, Exhibit SCE-11C at 128 and table IX-43.

¹⁷⁰ Exhibit SCE-09 at 133-135.

flexible RA capacity for more valuable system RA has a direct impact on portfolio value.

Weighing the record, we find SCE's treatment of RA resources and associated costs in the PCIA to be reasonable and therefore approve them as proposed in SCE's AOU.

7.3.2.6. Updated RPS Value

The RPS Value is the estimated dollar value that is attributed to the renewable energy component of SCE's PABA-eligible portfolio in a given year. SCE's forecast of the RPS value increased compared to SCE's May testimony, primarily as a result of the 125 percent increase in the updated 2025 forecast RPS MPB.¹⁷¹

SCE's RPS volumes are the result of previously held RECs, added to by PABA eligible generation and decreased by RECs surrendered to achieve SCE's compliance obligation or sold via market offer or voluntary allocation (VA). SCE is not holding a Voluntary Allocation or Market Offer process for 2025 but will continue to allocate long term VA RECs from contracts signed in 2024.¹⁷²

SCE notes that the question of how to value banked RECs used to meet RPS compliance requirements has been a persistent issue, and that issue has now been resolved by D.24-08-008.¹⁷³ We agree with SCE's conclusion that this issue was settled by D.24-08-008 and is no longer contested.

SCE notes that starting in June 2023, it experienced REC creation issues in the Western Renewable Energy Generation Information System, affecting approximately 45 percent of its REC volume. SCE has identified the required

¹⁷¹ Exhibit SCE-09 at 138-139.

¹⁷² Exhibit SCE-09 at 140-141.

¹⁷³ SCE Opening Brief at 9-10.

adjustments for invoices and REC transfers in 2023 and does not expect there to be additional changes for 2023. Not all the billing data for 2024, however, has been finalized, and SCE warns that there may still be some adjustments to these numbers.¹⁷⁴

Weighing the record, we find SCE's treatment of RPS resources to be reasonable and therefore approve them as proposed.

7.3.2.7. 2024 Year End PABA Balance

SCE's PABA, which has subaccounts for each vintage portfolio, is used to record the actual costs, market revenues, actual retained RA and RPS values, and billed customer revenues associated with the CTC and PCIA-eligible resources. The 2024 year-end PABA balance thus reflects the difference between the actual 2024 above-market costs of SCE's CTC-and PCIA-eligible portfolio and the amount collected from customers' CTC, PCIA and generation rates in 2024. Pursuant to D.18-10-019 and D.19-10-001, these year-end balances are then either recovered from or returned to customers in 2025 rates. SCE's current estimate of the 2024 year-end balance results in a return to customers of \$587.926 million.¹⁷⁵

Weighing the record, we find SCE's calculation of the year-end PABA to be reasonable and therefore approve it as proposed.

7.3.2.8. System Reliability Procurement Memorandum Account Historical Costs

The System Reliability Procurement Memorandum Account tracks the costs of procuring capacity for Opt-Out and deficient LSEs that have required backstop procurement, as directed in D.19-11-016 and D.21-06-035. These incurred costs are being amortized over the 2024-2026 time-frame in compliance

¹⁷⁴ Exhibit SCE-09 at 142.

¹⁷⁵ Exhibit SCE-09 at Attachment A at A-2.

with D.22-05-015. SCE's Alternate October Update includes \$7.208 million in these costs.

7.3.2.9. Utility Owned Storage – Separator Facility

SCE's UOS Separator facility began counting towards MTR procurement, effective August 1, 2023. As per Resolution E-5259, Separator's costs and benefits will be recovered via the 2021 subaccount of the PABA in 2025.

7.4. Resource Adequacy Position and Assignment to MPB Subcategories

The contested issues in this proceeding involve how SCE addresses its RA obligations.¹⁷⁶ Each of these issues involve SCE's implementation of methodologies for which the Commission's guidance is not explicit.

The Commission has repeatedly found that policy and rule changes are beyond the scope of the ERRA forecast proceedings.¹⁷⁷ The October 8, 2024 assigned ALJ ruling clarifies that issues such as whether the MPB methodology should be changed are outside the scope of this proceeding.¹⁷⁸ AReM and DACC note that ERRA proceedings are not the appropriate vehicle for major policy changes.¹⁷⁹ CalCCA notes that the Commission generally does not allow policymaking in ERRA Forecast cases.¹⁸⁰

7.4.1. Interim Slice of Day Methodology

SCE proposes a methodology for forecasting its 2025 RA position based on the slice of day framework that takes effect in 2025.

¹⁷⁶ SCE Opening brief at 12; CalCCA Opening brief at iii-iv, 13-25.

¹⁷⁷ See Scoping Memo in A.13-05-015 at 3; D.18-01-009 at 10.

¹⁷⁸ Assigned ALJ's October 8, 2024 ruling requesting party comment on procedural mechanisms at 3.

¹⁷⁹ AReM and DACC comments on SCE's Revised ERRA October Update at 4.

¹⁸⁰ Exhibit SCE-01 at 11.

CalCCA objects to this methodology, asserting that it does not adequately (1) comply with the authorized PCIA methodology, (2) comprehensively address assignment of RA quantity and price, or (3) provide a price that is granular enough to reflect the specific value of resources under the SOD framework.¹⁸¹ SCE characterizes its SOD framework as a reasonable interim approach to account for a known compliance obligation¹⁸² and clarifies that (1) it is not proposing that this framework be a precedential methodology and (2) the framework may be refined in future years.¹⁸³ SCE asserts that this methodology is being employed to align the RA quantity calculation to account for CPUC-adopted changes in how RA resources are counted for compliance purposes.¹⁸⁴

Both SCE and CalCCA acknowledge that both (1) the effect that the SOD framework has on the valuation of storage and hybrid resources and (2) the methodology for characterizing these resources within the SOD are not settled issues and will likely evolve over time.¹⁸⁵

Both SCE and CalCCA recognize that there is no current methodology to obtain an hourly structured price curve and that implementing such a curve would require action by the Commission that cannot reasonably occur prior to the setting of 2025 forecast rates.¹⁸⁶ CalCCA asserts that the impact of SOD on the value of the IOUs' capacity portfolios deserves the Commission's full

¹⁸¹ Exhibit CalCCA-01 at 2 and 12.

¹⁸² SCE Opening Brief at 30.

¹⁸³ Exhibit SCE-05 at 3.

¹⁸⁴ SCE Opening Brief at 33.

¹⁸⁵ Exhibit SCE-04 at 8-10; SCE Opening Brief at 28-9.

¹⁸⁶ Exhibit SCE-04 at 8; Exhibit CalCCA-01 at 13 and footnote 32.

consideration.¹⁸⁷ CalCCA observes that the Commission's Energy Division will likely need to gather more transactional data than it currently does to understand and quantify the impact of SOD in the market, including whether RA prices vary based on the underlying resource technologies.¹⁸⁸ CalCCA argues that the Commission should further consider these issues in separate ratemaking.¹⁸⁹

7.4.2. Assignment of Capacity to Local, System, and Flexible RA MPBs

SCE's AOU and ROU forecasts differ only in that the AOU assigns RA capacity to each of the three subcategories according to the D.18-10-019 MPB methodology while the ROU attributes RA capacity between the system and flex subcategories in alignment with their calculated Month-Ahead RA position.¹⁹⁰

CalCCA objects to SCE's proposal to reassign RA to the local category in late October, noting that it had ample opportunity to do so earlier in the process.¹⁹¹ They further object to SCE's rationale for doing so, asserting that this proposal ceases to value SCE's PCIA portfolio according to how SCE's customers actually benefit from it¹⁹² and that the 1.1% increase relative to current bundled rates does not constitute rate volatility.¹⁹³

¹⁸⁷ CalCCA Reply Brief at 13.

¹⁸⁸ Exhibit CalCCA-01 at 11.

¹⁸⁹ CalCCA Opening Brief at 28.

¹⁹⁰ Exhibit SCE-09 at 2; Exhibit SCE-11 at 2; SCE OB at 14; Exhibit SCE-01 at 34.

¹⁹¹ CalCCA Opening Brief at 24.

¹⁹² CalCCA Opening Brief at iv.

¹⁹³ CalCCA Opening Brief at 16.

SCE notes that it made this change in methodology in prior ERRA forecast proceedings and assert that this proceeding allows it the discretion to revert to its prior methodology.¹⁹⁴

The D.18-10-019 language cited clearly establishes the process for assigning RA capacity to RA subcategories. The decision language preceding this assignment process clearly articulates that it is adopting parties' proposals for estimating and refining the RA MPB.¹⁹⁵ As the decision language is silent on both the rationale behind the order of assignment to RA subcategories within this process and on the assignment of RA capacity to these MPBs for the purpose of valuation, D.18-10-019 does not provide guidance on these questions. There is currently no policy or rule governing the methodology for assigning capacity to RA subcategories for the purpose of valuation. Establishing such a policy or rule is outside the scope of this proceeding.

7.4.3. Ensuring that the Full Volume of Excess RA is Sold

CalCCA raises the issue of ensuring that the volume of excess RA is properly forecast and sold when possible.¹⁹⁶ SCE makes corrections and adopts some CalCCA proposals.¹⁹⁷ SCE further notes that their methodology for forecasting sold RA is the same as it has used in at least the past four ERRA

¹⁹⁴ SCE Opening Brief at 22 and 23.

¹⁹⁵ D.18-10-019 at 73-74.

¹⁹⁶ Exhibit SCE-01 at 23-27.

¹⁹⁷ Exhibit SCE-05 at 2-9.

forecast proceedings¹⁹⁸ and provides a detailed reply to CalCCA's arguments.¹⁹⁹ Ultimately, both SCE and CalCCA omit this from their list of contested issues.²⁰⁰

7.4.4. Need to revise the current MPB methodology

The creation of the CPE for the purpose of Local RA has affected the RA markets that D.18-10-019 and D.19-10-001 worked to quantify. The implementation of SOD may further change these markets.

The Commission's Energy Division notes a reduction in transaction volume used to compute the year ahead RA MPB of approximately 80% between 2024 and 2025. Energy Division further notes the presence of affiliate and swap transactions, which may not be arm's length transactions, within this already low transaction volume. Finally, Energy Division staff notes that the nearly threefold increase in the System RA MPB as being driven by the summer versus winter differential.²⁰¹

CalCCA notes that the PABA balance has been both a major contributor to the PCIA revenue and has also been unpredictable, citing the variation in Brown Market Power²⁰² values as the main contributor.²⁰³

SCE notes that the 2024 Final and 2025 Forecast RA MPBs are irregular and abnormally high.²⁰⁴ In reference to the changes created by MPBs, SCE observes

¹⁹⁸ SCE Opening Brief at 33.

¹⁹⁹ SCE Opening Brief at 33-37.

²⁰⁰ SCE reply brief at 1-2; CalCCA reply brief at 2.

²⁰¹ Energy Division's October 4, 2024 Addendum to the Market Price Benchmark Calculations.

²⁰² "Brown Power" is now referred to as Energy Index. This value is reliant upon the Energy Index MPB.

²⁰³ Exhibit CalCCA-01 at 38-41.

²⁰⁴ SCE Opening Brief at 16.

that this extreme level of volatility benefits no party or ratepayers and suggests reforms are needed to the PCIA ratemaking framework.²⁰⁵ SCE strongly supports a future rulemaking to evaluate the current methodology for calculating the RA and RPS MPBs, among other outstanding PCIA ratemaking issues that require resolution, and urges the Commission to open the proceeding no later than Q1 2025.²⁰⁶

CalCCA states that the Commission should defer consideration of SCE's proposed modifications to the PCIA RA methodology to a rulemaking, noting that precedential policies will also have impacts in PG&E and SDG&E service territories.²⁰⁷

AReM and DACC identify the need for future rulemaking on the RA MPB, suggesting that any problems with the calculation or application of the RA MPB should be addressed in either a new rulemaking or a re-opened Rulemaking 17-06-026.²⁰⁸

²⁰⁵ Exhibits SCE-09 at 128 and footnote 144.

²⁰⁶ SCE October 14, 2024, comments on ruling regarding procedural mechanisms at 2 and footnote 2 - SCE notes that such issues include consideration of whether the existing PCIA methodology is working as intended or if a different approach (and interim tracking mechanisms for potential future true-ups to ensure customer indifference) is warranted, potential modifications to the PCIA methodology to account for RA slice of day (SOD) implementation, and potential changes to the trigger mechanism applicable to bundled service customer generation rates to additionally include changes to departing load customer PCIA rates.

²⁰⁷ Exhibit CalCCA-01 at 13.

²⁰⁸ AReM and DACC comments on SCE's Revised ERRRA October Update at 4-6.

7.4.5. Discussion

The standard in this proceeding is a preponderance of the evidence.²⁰⁹ As the scope of this proceeding does not encompass the creation of new policy and rule changes, the question before us is whether SCE has shown by a preponderance of the evidence that its proposals are a reasonable execution of prior commission guidance.

In the case of SCE's interim SOD methodology, the Commission finds that SCE's proposed methodology is a reasonable execution of guidance given to account for how Resource Adequacy is counted for compliance purposes. The Commission finds SCE's use of their SOD methodology reasonable for the purposes of the 2025 ERRA forecast. The issues of whether hourly RA MPB prices are needed and how to achieve proper accounting for storage and hybrid resources under SOD are both ripe for consideration in a rulemaking proceeding.

SCE's proposal to assign RA capacity to Local, System, and Flexible RA is not a novel approach. SCE has interpreted the guidance given to Energy Division for assigning RA capacity in generating MPBs as an appropriate method for it to assign RA for the purposes of valuation in past ERRA Forecast proceedings. Their proposal to do so again in this proceeding is not a policy nor rule change. The Commission finds SCE's proposal for assignment of RA capacity to Local, System, and Flexible RA reasonable for the purposes of the 2025 ERRA forecast. The methodology for assigning RA capacity to RA subcategories for the purpose of valuation is ripe for consideration within a rulemaking proceeding.

²⁰⁹ Re Pacific Bell, D.87-12-067, p. 25, 27 CPUC 2d 1, 22. See also Universal Studios Inc. v. Southern California Edison Co., D.04-04-074, p 32, 2004 Cal. PUC LEXIS 173; Re Golden State Water Co., D.07-11-037, p. 101, 2007 Cal. PUC LEXIS 648

The need to review or modify SCE's methodology for forecasting sold RA has been omitted from all parties' reply brief listing of contested issues. As that is no longer a contested issue, we do not address it here.

All of the parties to this proceeding have noted variation in the MPBs that have the potential to create harmful price volatility, and Energy Division has noted anomalies in the forecast data that warrant an evaluation of whether the methodology used to assess prices remains adequate to ensure indifference.

Due to issues identified above regarding affiliate and swap transactions, the Commission's Energy Division should conduct an inquiry and provide a report on transactions that should not be included in the calculation of the MPB. More broadly, revisiting the methodology for computing the MPBs is an issue that is ripe for consideration within a rulemaking proceeding.

Due to the issues described above, the Commission may in another proceeding consider revisions to the MPB methodology that may impact the adopted 2025 Final MPBs.

8. 2025 ERRA Forecast Average Rates

SCE calculates the impact on its bundled customer groups associated with this proposed revenue requirement. The results of this calculation are detailed in the following table:

Table 8-1. Summary of SCE's Bundled Customer Rates

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	% Change from 10/1/2024
Domestic				
• D	0.22557	0.11462	0.34019	2.4%
• D-CARE	0.10217	0.11461	0.21678	4.0%
• DE	0.13957	0.11456	0.25412	2.1%
• DM	0.13667	0.11494	0.25161	20.5%
• DMS-1	0.23474	0.11492	0.34967	1.1%
• DMS-2	0.22962	0.11506	0.34469	-0.3%
Lighting-Small, Med. Power				
• GS-1	0.16462	0.10981	0.27444	0.5%
• GS-2	0.20234	0.09998	0.30232	-2.1%
• TC-1	0.25194	0.08913	0.34107	-1.2%
• TOU-GS	0.16099	0.08925	0.25023	0.9%
Large Power				
• TOU-8-S	0.13921	0.08390	0.22311	-1.0%
• TOU-8-P	0.12153	0.08009	0.20162	-3.1%
• TOU-8-T	0.04873	0.07440	0.12313	-1.1%
• TOU-8-S-S	0.14327	0.08947	0.23273	-1.0%
• TOU-8-S-P	0.14074	0.08537	0.22612	-0.8%
• TOU-8-S-T	0.05544	0.07693	0.13237	-0.9%
Agricultural & Pumping				
• TOU-PA-2	0.15545	0.09111	0.24656	-1.2%
• TOU-PA-3	0.12340	0.07723	0.20063	-2.0%
Street & Area Lighting				
• LS-1	0.64317	0.06093	0.70410	0.0%
• LS-2	0.20582	0.06086	0.26668	0.1%
• LS-3	0.10028	0.06096	0.16124	-1.4%
• DTL	0.49845	0.06093	0.55938	0.1%
• OL-1	0.37082	0.06093	0.43175	0.1%
Average Rate – All Groups	0.16008	0.09894	0.25901	-0.1%

9. PCIA Rates by Vintage

Pursuant to D.18-10-019, the vintaged Indifference Amounts are allocated to rate groups using the system generation revenue allocation factors, then divided by the forecast billing determinants to set the final PCIA rates. In accordance with D.19-10-001, SCE applied forecast vintage-specific billing determinants to set the final PCIA rates. Pursuant to D.08-09-012, customers are assigned a vintage based on the date of their departure. If they departed on or before June 30 of a given year, they are assigned to the prior year's vintage. Alternatively, if they departed on or after July 1 of a given year, they are assigned that year's vintage. PCIA rates by vintage are detailed in the following table.

Table 9-1. Summary of SCE PCIA Rates by Vintage

2001	(0.00000)
2004	(0.00000)
2009	0.00127
2010	0.00045
2011	(0.00086)
2012	(0.00106)
2013	(0.00103)
2014	(0.00231)
2015	(0.00750)
2016	(0.01017)
2017	(0.00968)
2018	(0.01126)
2019	(0.01122)

2020	(0.00991)
2021	(0.00971)
2022	(0.01706)
2023	(0.02167)
2024	(0.02063)
2025	(0.02149)

Weighing the record, we find SCE's allocation of indifference charges among vintages and customer classes to be reasonable and therefore approve them as proposed.

10. Safety Considerations and Environmental and Social Justice Considerations

The California Legislature enacted AB 32 (Nunez) Stat. 2006, Ch. 488, in part to address the health and safety impacts of GHG emissions, which pose "a serious threat to the economic well-being, public health, natural resources, and the environment of California." The Legislature found that GHG emissions could result in "the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious disease, asthma, and other human health related problems."

This Decision approves SCE's forecast of GHG costs and allocation of GHG allowance proceeds because it helps achieve a main goal of AB 32 and Pub. Util. Code § 748.5 and will therefore improve the health and safety of California residents.

The provision of F&PP inherently assumes that all power providers are fully compliant with laws, rules, regulations, and internally-managed controls to help ensure that their generating facilities are operated and maintained in a safe working condition.

No party raised any Environmental or Social Justice concerns related to the Application.

11. Compliance with the Authority Granted Herein

We authorize SCE to update the final 2024 year-end balances with recorded actual values (actuals) through October 2024 and forecast for November and December 2024. These balances shall utilize the most updated MPB values available. If SCE has its November 2024 actuals available in time for submitting its Advice Letter, those should be included rather than a November forecast.

SCE shall submit a Tier 1 Advice Letter to the Commission's Energy Division within 30 days of the date of issuance of this Decision to implement the revenue requirements adopted in this Decision. The tariff sheets filed in this Advice Letter shall be effective on or after the date filed, subject to the Commission's Energy Division determining that SCE's Advice Letter complies with this Decision.

SCE is further authorized to implement the revenue requirement adopted in this proceeding, as updated to reflect October – November 2024 actuals and forecasts for December 2024, in its advice letter for rates to be effective starting January 1, 2025.²¹⁰

²¹⁰ If SCE's November 2024 actual numbers are not available at the time the utility files its implementation advice letter, it may use November 2024 forecasts.

Weighing the record, we find SCE's request and methods used to determine the issues described above for all customer categories are reasonable and therefore approve them as proposed.

12. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

There was a total of 8 written comments. Written comments largely supported affordability and advocated for rate reduction, both at the level proposed by this application and at a higher level than contemplated here. Other themes expressed in public comment were frustration with high energy prices, noting the profitability and dividends associated with SCE stock, and finding it more appropriate to reward energy savers than to discount prices for residents using more than 500kWh per month.

13. Procedural Matters

This decision affirms all rulings made by the ALJ and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

14. Reduction of Comment Period and Comments on Proposed Decision

The proposed decision of ALJ Justin Regnier in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code. In developing the schedule for the proceeding, parties stipulated to reduce the 30-day public review and comment period required by Pub. Util. Code

Section 311 to 7 days for opening comments and 7 days for reply comments.²¹¹

Comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

15. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Justin Regnier is the assigned ALJ in this proceeding.

Findings of Fact

1. SCE's 2024 total forecast ERRR is \$4.637 billion, which is a decrease of \$442.537 million when compared to rates currently recovered from customers today.
2. SCE forecasted an increase in total retail electricity sales from a forecasted 81,758 GWh in 2024 to a forecast of 82,901 GWh in 2025.
3. SCE forecasted a 0.5 percent increase in its number of customers in 2024 and a 0.6 percent increase in 2025.
4. SCE's forecast of utility-owned generation and purchased power contract deliveries in 2024 consisted of 1,164 MW nameplate capacity of hydroelectric power, approximately 9 MW of nameplate capacity in solar photovoltaic resources, 10,007 MW from co-generation and renewable resources, 245 MW of natural gas peaker resources, and approximately 1 GW from its Mountainview Generating Station.
5. SCE holds one (1) inter-utility capacity contract for 2025, consisting of an entitlement of 280 MW of contingent capacity and 238 GWh of firm energy from the Hoover Dam project.

²¹¹ The reduced comment period on the proposed decision was articulated in the assigned ALJ ruling of September 16, 2024, and affirmed in the September 23, 2024 joint PHCstatement.

6. SCE forecasted costs associated with 5 GWh of energy reductions in 2025 to provide economic demand response programs, including the Summer Discount Plan, Smart Energy Program, and Capacity Bidding Program.

7. SCE forecasted a revenue requirement of \$21.610 million resulting in a net increase of \$3.680 million in procurement-related Public Purpose Program Charge funds to recover (1) behind-the-meter resources associated with its Preferred Resource Pilot #2 contracts; (2) net costs associated with biomass generation associated with the Tree Mortality Non-Bypassable Charge; (3) net charges for the BioMAT program; and (4) volumetric electricity service subsidies through the GTSR, DAC-GT and CSGT programs.

8. SCE forecasted 122,774 MWh of participation through the Green Tariff Shared Renewable (GTSR) program and 122,448 MWh of participation through the GTSR-Enhanced Community Renewables program in 2025.

9. SCE forecasted \$5.157 million in off-site interim spent nuclear fuel costs for SONGS Unit 1 assemblies in 2025.

10. SCE forecasted \$29.2 million in nuclear fuel expenses, and \$0.01 million in net interim spent nuclear fuel expenses at PVNGS in 2024.

11. SCE forecasted a total cost of \$9.007 million in fuel costs to provide electricity service to Catalina Island, which includes \$7.988 million in diesel fuel and \$1.019 million for propane in 2025.

12. SCE forecasted 2025 hedging costs for energy-related transaction fees and for hedging SCE's open energy position in workpapers for 2025 and these costs were reduced due to a lack of liquidity and its subsequent retirement of option-based hedging.

13. SCE holds a \$3.35 billion multi-year revolving credit facility with a May 2028 maturity, also called the “revolver,” to serve short-term borrowing requirements.

14. SCE forecasted costs associated with the revolving credit facility, including: (1) \$20,000 in administrative fees; (2) 17.5 basis point annual facility fee; (3) 107.5 basis point participation fee on any outstanding letters of credit; (4) 20 basis point issuer fee on any letters of credit; and (5) Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points borrowing (loan) rate.

15. SCE forecasted GHG procurement compliance carrying costs for 2024, which SCE estimated using historical GHG inventory balances and the ERRA BA interest rates in workpapers for 2025.

16. SCE’s 2025 forecast, as modified by the AOU, proposes the bundled service customer rates detailed in Table 8-1.

17. SCE’s 2024 forecast Generation Service revenue requirement is \$4.663 billion, which will be allocated in balancing accounts as detailed in Table 7-1.

18. SCE forecasts a 2025 Green Tariff Shared Renewables BA amount of \$7.132 million.

19. In total, SCE forecasted an overcollection of \$295,000 in the Energy Settlement MA and Litigation Costs TA in 2024.

20. SCE’s total 2024 forecast Delivery Service revenue requirement is negative \$25.306 million, with included costs as detailed in Table 7-2.

21. SCE forecasted its 2024 GHG allowance revenue using a proxy price of \$39.36/MT, will apply the proxy price of \$35.72/MT to forecast November 2024 allowance revenue, and forecasts 2025 GHG allowance revenue using a proxy price of \$35.46/MT.

22. SCE's net forecasted revenue proceeds (including FF&U) from GHG allowances granted by CARB in 2025 is \$825.968 million.

23. SCE's 2025 forecast administrative and customer outreach expenses to be set aside is \$868,000 including FF&U.

24. SCE anticipates the IOUs' combined allocation of forecast GHG allowance auction proceeds for 2025 will total \$1.893 billion.

25. SCE's GHG allocated allowance auction proceeds to be set aside for SOMAH program funding in 2025 is \$46.528 million.

26. SCE has allocated \$4.6 million in 2025 to its DAC-SASH program.

27. SCE has allocated \$16,490 in 2025 for its DAC-GT and CSGT programs, to be recovered from its public purpose rate component.

28. CPA's total 2024 program forecast for its DAC-GT and CSGT programs includes a funding request of \$4.074 million for 2025; the above market generation portion of \$1.127 million will be funded through GHG allowance revenue, with the remainder of \$2.947 million recovered through PPP funds.

29. CalChoice demonstrated surplus funding through 2025 and therefore will not require any GHG or public purpose funding.

30. SCE has been previously authorized to allocate \$20.4 million to implement the CEOP and is not requesting additional funding in 2025.

31. SCE's 2024 forecast EITE customer return is \$58.183 million.

32. SCE's 2025 forecast semi-annual California Climate Credit is \$56.00 per eligible residential and small commercial account, based on a forecast of 5,200,294 eligible recipients.

33. SCE's 2025 California Climate Credit is significantly below the 2024 credit of \$86 and the May forecast for 2024 of \$92.

34. For 2025, CTC costs are as follows: (1) $-\$0.00061/\text{kWh}$ for Domestic (D); (2) $-\$0.00056/\text{kWh}$ for Street Lighting customers; (3) $-\$0.00046$ for TC 1, TOU GS 2 and Standby Sec; (4) $-\$0.00045$ for TOU PA 2; (5) $-\$0.00044$ for TOU GS 3 and TOU PA 3; (6) $-\$0.00043$ for TOU GS 1, TOU 8 Sec, and Standby Pri; (7) $-\$0.00042$ for TOU 8 Pri; (8) $-\$0.00040$ for TOU 8 Sub and Standby Sub. customers of all vintages.

35. For 2025, the SCE Wildfire Non-Bypassable Charge will be the latest Commission-approved value for all customer classes in all vintages.

36. SCE's forecasted 2025 PCIA revenue requirement is as detailed in Table 7-3.

37. SCE's forecasted 2025 PCIA rates by vintage are as detailed in Table 9-1.

38. Challenges to facts supporting SCE's proposed 2025 forecast of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; and bundled customer electric sales and year-end balancing accounts were waived by parties in this proceeding by virtue of stipulation to waive evidentiary hearing.

39. As referenced in the AOU, Energy Division issued the MPB calculations for the RA MPB on October 4, 2024, and noted anomalies in the MPBs, including low transaction volumes relative to overall size of the portfolio, the inclusion of swap and affiliate transactions, and the nearly threefold increase in the System RA MPB.

Conclusions of Law

1. SCE's 2025 forecast, as modified in this Decision, of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; and bundled customer electric sales and year-end balancing account balances are reasonable.

2. SCE's proposed 2025 cost responsibility surcharges are reasonable and should be approved.
3. SCE should implement the revenue requirement adopted in this proceeding, as updated to reflect October – November 2024 actuals and forecasts for November – December 2024, in its advice letter for rates to be effective starting January 1, 2025.
4. Advice Letters to implement changed tariff sheets in accordance with this Decision should be filed as Tier 1 Advice Letters.
5. All rulings issued by the assigned Commissioner and the assigned ALJ should be confirmed.
6. The Commission orders adopted in D.24-08-015, authorizing SCE's 2024 ERRRA Trigger Application (A.24-05-025) are unchanged by this Decision.
7. All motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, should be denied.
8. Application 24-05-007 should be closed.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is authorized to recover a total 2025 Energy Resource Recovery Account electric procurement cost revenue requirement forecast of \$4,637.329 million, consisting of both a generation service component and a delivery service component.
2. Within Southern California Edison Company's (SCE) 2025 generation service revenue requirement of \$4,662.635 million, SCE is authorized to recover a total of \$4,085.868 million in fuel and purchased power costs and transfer the following 2024 account balances: (1) -\$10.152 million from the Energy Resource Recovery Account Balancing Account (BA); (2) \$587.214 million from the

Portfolio Allocation BA; and (3) -\$295,000 from the Energy Settlement Memorandum Account.

3. Within Southern California Edison Company's (SCE) 2025 delivery service revenue requirement of negative \$25.306 million, SCE is authorized to recover the following: (1) \$457.467 million for the New System Generation and System Reliability fuel and purchase power contracts; (2) \$5.157 million in spent nuclear fuel costs; (3) negative \$19.169 million for forecast Base Revenue Requirement Balancing Account – Distribution fuel and purchased power costs; (4) negative \$641.624 million customer return of greenhouse gas allowance proceeds; (5) \$5.341 million for the Public Purpose Program Charge, which includes the Tree-Mortality Non-Bypassable Charge, SCE's Preferred Resources Pilot #2, Bioenergy Market Adjusting Tariff Non-Bypassable Charge, and a portion of the Disadvantaged Communities – Green Tariff and Community Solar Green Tariff program funding which provides volumetric subsidies to qualifying customer classes; and (6) \$1.558 million in Modified Cost Allocation Mechanism fuel and power purchase costs.

4. Southern California Edison Company is authorized to transfer the following account balances: (1) a \$146.846 million 2024 year-end balance in the New System Generation Balancing Account (BA); (2) \$19.110 million in the 2024 year-end balance for the Tree Mortality Non-Bypassable Charge BA; and (3) negative \$2.842 million in the 2024 year-end BioMAT Non-Bypassable Charge BA.

5. Southern California Edison Company is authorized to reconcile its 2025 greenhouse gas (GHG) costs, revenues and requirements as follows: (1) recover a revenue requirement to cover the actual interest and forecasted carrying costs associated with its GHG Cap-and-Trade compliance; and (2) distribute

\$641.624 million in forecast 2025 GHG allowance auction proceeds to its customers, with \$55.936 million set aside for clean energy and energy efficiency projects, and \$868,000 set aside for outreach and administrative expenses.

6. Southern California Edison Company shall return \$583.441 million in greenhouse gas allowance auction revenues to residential and small commercial customers through the forecasted amount of \$56.00 in April and October 2025 for the California Climate Credit program.

7. Southern California Edison Company shall return a forecast of \$58.183 million in greenhouse gas allowance auction revenues to its Emissions-Intensive and Trade-Exposed customers in April 2025.

8. Southern California Edison Company (SCE) shall file a Tier 1 Advice Letter and revised tariff sheets within 30 days of the issuance of this Decision to implement this Decision. The Advice Letter shall include supporting documentation for:

- (a) Residential rate schedules (including master-metered rate schedules) to include the authorized 2025 Climate Credit amount;
- (b) Small business rate schedules to include the authorized 2025 Climate Credit amount;
- (c) The updated November 2024 revenue requirement actuals and forecasts for November and/or December 2024, depending on the availability of November revenue requirement actuals at the time of the Advice Letter filing; and
- (d) The usage of Renewable Energy Certificates banked in or after 2019 for 2024 Renewables Portfolio Standard compliance for SCE's bundled customers.

9. Southern California Edison Company must file a separate Tier 1 Consolidated Revenue Requirement and Rate Change Advice Letter no later than

December 31, 2024, pursuant to Resolution E-5217. This Tier 1 Advice Letter must contain tariff sheet revisions as necessary to implement the rate changes authorized in this Decision.

10. All rulings issued by the assigned Commissioner and Administrative Law Judge (ALJ) associated with Application (A.) 24-05-007 are affirmed herein; and all motions associated with A.24-05-007 not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, are denied.

11. Application 24-05-007 is closed.

This order is effective today.

Dated _____, at San Francisco, California