STATE OF CALIFORNIA GAVIN NEWSOM, ~~Governor~~

~~PUBLIC UTILITIES COMMISSION~~

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

~~November 24, 2025~~ **~~Agenda ID # 23883~~**
~~Ratesetting~~

~~TO PARTIES OF RECORD IN APPLICATION 25-05-008:~~

~~This is the proposed decision of Administrative Law Judge Eileen Odell. It will appear on the Commission's December 18, 2025 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 10 days of its mailing and reply comments must be filed within 5 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 Odell at Eileen.Odell@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 ODELL (Mailed 11/24/2025)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its 2026 ERRA Forecast Proceeding Revenue Requirement.	Application 25-05-008

DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S 2026 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED REVENUE REQUIREMENT FORECAST

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DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S 2026 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED REVENUE REQUIREMENT FORECAST

Summary

This Decision approves, with modifications, Southern California Edison Company's (SCE) amended 2026 Energy Resource Recovery Account (ERRA)[1] revenue requirement request of $4.689 billion - an increase of $228.250 million, roughly 5.1 percent, above the adopted 2025 ERRA revenue requirement.

While SCE's overall ERRA revenue requirement will increase from what is included in current rates, the ERRA portion of SCE's system average generation rates for bundled service customers will decrease by approximately 11.9 percent as compared to rates effective on October 1, 2025, to 10.01¢/kilowatt hour. SCE's Power Charge Indifference Adjustment (PCIA) rates for unbundled service customers will increase for all customer vintages in 2026.

The ERRA process allows SCE to recover its electricity procurement costs, including expenses for fuel and purchased power, utility-owned generation, California Independent System Operator related costs, related greenhouse gas (GHG) costs, and the remaining costs of residual net short procurement requirements necessary to serve bundled customers. SCE is also authorized to propose a forecast of GHG allowance revenue return allocations, estimated costs SCE will incur as a central procurement entity (that contracts for resources on

[1] Contrasted with general rate cases in which the California Public Utilities Commission (Commission or CPUC) reviews a utility's forecasts of capital infrastructure, labor, operations and maintenance, and other categories of costs, the Energy Resource Recovery Account (ERRA) Forecast processes focuses largely, though not exclusively, on the "pass through costs" a utility incurs specifically to procure power to provide to customers (*i.e.*, the utility's actual costs), for which the utility does not earn a profit. *See* the CPUC website, Energy Resource Recovery Account, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/what-is-an-energy-resource-recovery-account-proceeding (last visited Sept. 15, 2025).

behalf of other load serving entities in its service territory), and common cost allocation proposals. Amounts adopted by this Decision will be implemented in rates in 2026, and any over- or under-charges compared with actual expenses incurred by SCE in 2026 will be collected from or returned to customers.

This Decision approves, as modified, SCE's 2026 ERRA forecast revenue requirement, comprised of its forecast generation service revenue requirement and delivery service revenue requirement, as shown in Table S-1, below. This Decision also approves the transfer of certain balances, including year-end 2025 balances, to their appropriate balancing accounts.

Included within the amounts authorized for recovery or return listed below, this Decision approves SCE's forecast 2026 GHG Cap-and-Trade compliance costs, totaling $349.789 million. This Decision approves GHG allowance revenue allocations and directs SCE to distribute $58.908 million to Emissions-Intensive and Trade-Exposed customers and $384.371 million to residential and small business customers through the California Climate Credit, for a total of $443.279 million in revenue returns to customers.

SCE will update its ERRA revenue requirement to reflect 2025 year-end balances with recorded actual amounts through November 2025, if available, and a forecast for December 2025. SCE will update these figures in its initial Tier 1 Advice Letter filed in conformance with this Decision, and implement the rate changes on January 1, 2026, in the Tier 1 Consolidated Revenue Requirement and Rate Change Advice Letter filed pursuant to Resolution E-5217.

Table S-1, below, provides a summary of the revenue requirement adopted by this Decision and the corresponding amounts authorized for SCE's 2025 ERRA revenue requirement.

Table S-1: 2026 ERRA Forecast Revenue Requirement ($000)

Description	Authorized	Amount in	

	Amount	Current Rates[2]	Revenue Requirement Change
2026 Forecast Fuel and Purchased Power	$4,723,179	$4,538,709	$184,470
Year-End 2025 ERRA Balancing Account (BA)	$(898,645)	$(276,313)	$(622,331)
Year-End 2025 Portfolio Allocation BA	$1,318,350	$740,627	$577,723
Year-End 2025 Energy Settlements Memorandum Account	$1,314	$(294)	$1,608
Year-End 2025 New System Generation BA	$(24,718)	$78,024	$(102,742)
Year-End 2025 Modified Cost Allocation BA	$2,522	$3,151	$(628)
Year-End 2025 Tree Mortality Non-Bypassable Charge (NBC) BA	$14,240	$21,243	$7,003
Year-End 2025 BioMAT NBCBMA	$(3,764)	$(2,842)	$(921)
GHG Allowance Revenues	$(443,279)	$(641,624)	$198,345
Total ERRA Forecast Revenue Requirement	$4,689,200	$4,460,681	$228,520

Application 25-05-008 is closed.

1. Background

This section briefly describes the Energy Resource and Recovery Account (ERRA) regulatory background and the costs authorized for recovery via the ERRA process. This section also describes the procedural history of Southern California Edison Company's (SCE) 2026 ERRA forecast application.

1.1. Energy Resource and Recovery Account Regulatory Background

[2] The Commission authorized the ERRA component of Southern California Edison Company's (SCE's) current rates in Decision (D.) 24-12-039, which resolved SCE's 2025 ERRA forecast proceeding. SCE implemented these rates on January 1, 2025, via Advice Letter (AL) 5448-E, which contained the required end-of-year updates. This Decision cites to the final 2025 ERRA revenue requirement implemented via AL 5448. *See* Amended Exhibit SCE-05A, Table II-2 [hereinafter SCE-05A; all citations to documents with this naming convention are references to proceeding exhibits, unless otherwise stated]. This chart reflects only the ERRA-related component of SCE's 2025 adopted and forecast 2026 revenue requirements.

Public Utilities (Pub. Util.) Code Section 454.5 (d) set standards by which the California Public Utilities Commission (Commission) must evaluate electric utilities' procurement plans when these utilities resumed full procurement responsibilities after the 2000-2001 California energy crisis. Subsequently, the Commission created the ERRA process in Decision (D.) 02-10-062 to provide for recovery of procurement costs.[3] The Commission also adopted procurement policy priorities and minimum standards of utility behavior, including the responsibility to prudently administer contracts and generation resources, and to dispatch energy in a least-cost manner,[4] considering priorities including reliability and environmental sensitivity.[5]

The ERRA process consists of: (1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement for the upcoming year;[6] (2) an annual compliance proceeding to review the utility's compliance in the prior year regarding energy resource contract administration, least-cost dispatch (LCD), fuel procurement, and prudent maintenance of utility-owned generation (UOG) and the ERRA Balancing Account (BA); and (3) a quarterly compliance report by which the Commission's Energy Division reviews utility procurement transactions "to ensure the prices, types of products, and quantities of each product conform to the approved plan."[7]

[3] D.02-10-062, *Interim Decision* at 1 [hereinafter D.02-10-062].

[4] D.02-10-062 at 52.

[5] D.02-10-062 at 17-18.

[6] Electric utilities generally file ERRA forecast applications in May (May Filings). Each October, the Commission's Energy Division releases a set of Market Price Benchmarks (MPBs), representing actual costs benchmarks for the prior year and forecast price benchmarks for the upcoming year. The utilities file updates to their May Filings incorporating the Commission's MPBs as well as updated actual cost data on which their forecasts are based (October Updates).

[7] D.02-10-062 at 73.

As a part of ERRA forecast proceedings, utilities forecast their Cost Responsibility Surcharges (CRS), which originally included the Competition Transition Charge (CTC).[8] The CTC is used to recover the above-market costs of resources procured prior to market restructuring after the 2000-2001 energy crisis. In 2006, the Commission adopted an additional CRS component: the Power Charge Indifference Adjustment (PCIA).[9] Today, the PCIA is used to determine and allocate across bundled and Departing Load (DL) customers the above-market costs of resources procured in part on behalf of unbundled customers before they left utility generation service.[10] Utilities recover bundled customers' share of these costs via generation rates and recover departed customers' share via the PCIA methodology.[11]

Finally, electric utilities must include in their ERRA forecasts estimates of the costs they will incur to comply with Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006.[12] The utilities must also forecast GHG

[8] The Commission adopted the Cost Responsibility Surcharges (CRS) and Competition Transition Charge (CTC) in D.02-11-002 (as modified by D.03-07-030), *Opinion* [hereinafter D.02-11-002]. These charges are discussed in Section 8 of this Decision. The CTC recovers costs authorized by Pub. Util. Code 367(a)(1)-(6).

[9] The Commission adopted the Power Charge Indifference Adjustment (PCIA) in D.06-07-030, *Decision Regarding Direct Access and Departing Load Cost Responsibility Surcharge Obligations*, (as modified by D.07-01-030 and as refined by 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, D.23-06-006, and D.25-06-025) [hereinafter D.06-07-030].

[10] "Bundled customers" or "bundled service customers" receive energy generation and delivery service from SCE; "unbundled" or "departing load" customers receive only energy delivery service from SCE.

[11] In its testimony, SCE refers to the PCIA and the CTC as "the Cost Responsibility Surcharges." Unless otherwise specified and reflecting recent Commission decision terminology, for the purposes of this Decision, we refer to the PCIA and the CTC collectively, as "PCIA Charges" that recover the "PCIA Revenue Requirement," pursuant to the "PCIA methodology."

[12] While SCE's Application in this proceeding was pending, the California Legislature amended AB 32 via AB 1207. Among other changes, AB 1207 (1) directed changes to the way

allowance revenues, intended to be returned to customers to offset the costs of GHG program compliance, and must propose clean energy program funding set-asides and customer revenue return amounts.

1.2. Procedural Background

SCE filed Application (A.) 25-05-008 (Application) on May 15, 2025 (May Filing), requesting Commission adoption of a 2026 ERRA forecast revenue requirement totaling $4.385 billion, representing a decrease of $75.555 million from the revenue requirement in rates at that time.[13]

On June 18, 2025, the Direct Access Customer Coalition (DACC) filed a timely response to the Application and the California Community Choice Association (CalCCA) and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed timely protests to the Application. On June 30, 2025, SCE filed a timely reply to parties' protests and response.

On July 10, 2025, the assigned Administrative Law Judge (ALJ) held a prehearing conference (PHC) to discuss the issues of law and fact and determine the need for hearing and a schedule for resolving the Application. At the PHC, parties stipulated to a reduced comment period for the proposed decision in this

amended AB 32 via AB 1207. Among other changes, AB 1207 (1) directed changes to the way the Commission and utilities must allocate allowance revenues across customers and (2) as of July 1, 2026, eliminated the Commission's authority to allocate allowance revenues to clean energy programs. Because these and AB 1207's other provisions have not yet been implemented by the Commission, this Decision reflects Cap-and-Trade program rules as they existed prior to the passage of AB 1207. These issues may be addressed in Rulemaking (R.) 25-07-013, the Commission's Order Instituting Rulemaking to Improve the California Climate Credit.

[13] Application (A.) 25-05-008, Application of Southern California Edison Company for Approval of its 2026 ERRA Forecast Proceeding Revenue Requirement at 1 [hereinafter A.25-05-008].

proceeding.[14] Also at the PHC the ALJ asked SCE whether it had incorporated data center demand into its 2026 ERRA forecast.[15]

On July 14, 2025, SCE responded via email to the ALJ's question regarding data center demand. On July 15, 2025, the ALJ issued an email ruling that included SCE's data center demand email and provided opportunity for party comment. No party provided comment on SCE's data center demand forecast.

The assigned Commissioner issued a Scoping Memo on July 17, 2025.

On July 18, 2025, SCE filed and served its Proof of Compliance with Rules 3.2 (B), (C), and (D) of the Commission's Rules of Practice and Procedure (Rules); these Rules require SCE to provide the public with notice of its Application.

On August 15, 2025, CalCCA served intervenor testimony which objected to or proposed corrections for aspects of SCE's proposed 2026 PCIA revenue requirement. On September 8, 2025, SCE served rebuttal testimony.

On September 8, 2025, the ALJ issued a ruling providing notice of and instructions for an in-person evidentiary hearing scheduled for September 22, September 26, and September 30-October 2, 2025.

On September 15, 2025, SCE filed and served a public version of a joint case management statement (JCM Statement) on behalf of itself, Cal Advocates, CalCCA, and DACC (the parties); SCE also filed and served an accompanying motion requesting leave to file a Confidential JCM Statement under seal. In the JCM Statement, CalCCA requested one hour of evidentiary hearings.[16] SCE opposed CalCCA's request for hearings and stated that evidentiary hearings

[14] A.25-05-008, Reporter's Transcript (RT) Vol. 1 at 31, 23:24.

[15] A.25-05-008, RT Vol. 1 at 11.

[16] A.25-05-008, Joint Case Management Statement (Public) at 4 and Attachment A: Cross Examination Matrix, September 15, 2025 [hereinafter JCM Statement].

were not necessary. Cal Advocates stated that it did not believe hearings were necessary but did not oppose hearings requested by other parties. DACC stated that it did not oppose hearings requested by other parties.[17]

On October 1, 2025, the Commission's Energy Division published its Market Price Benchmarks (MPB) Calculations 2025.

SCE served its October Update, Exhibit SCE-05, on October 15, 2025. SCE provided a complete version of its public October Update on October 16, 2025. SCE's October Update increased SCE's proposed 2026 ERRA revenue requirement from $4.385 billion to $4.759 billion. SCE's October Update included significant changes to the projected year-end 2025 balances in SCE's ERRA BA and PABA, largely driven by the decreases in the 2025 Final Resource Adequacy (RA) and Renewable Portfolio Standard (RPS) MPBs. SCE's October Update also noted that it had exceeded its Trigger Balance as of September 30, 2025, again, largely as a result of application of the Final 2025 MPBs.

After the close of business on October 27, 2025, SCE served an Amended October Update, Exhibit SCE-05A, containing what SCE describes as two corrections to its October Update, discussed below. SCE's Amended October Update proposed a $4.689 billion 2026 revenue requirement, 1.5 percent less than that proposed in SCE's October Update. SCE requested that SCE-05A replace SCE-05 in its entirety. This Decision relies on SCE's Amended October Update.

On October 28, 2025, CalCCA served Exhibit CalCCA-02, and CalCCA and SCE filed and served a Joint Motion to Offer Prepared Testimonies and Exhibit into Evidence and a Joint Motion to Seal a Portion of the Evidentiary Record.

On October 29, 2025, SCE filed and served an Opening Brief and CalCCA

[17] JCM Statement at 4.

filed and served a document combining comments on SCE's Amended October Update and an Opening Brief. Both parties filed and served motions requesting leave to file confidential versions of these documents under seal.

On October 30, 2025, SCE filed Advice Letter (AL) 5664-E, notifying the Commission that its ERRA Trigger Balance had exceeded its four percent Trigger Point as of September 30, 2025. In this AL, SCE states that its Trigger Balance will self-correct within 120 days due to adoption of the rates at issue in this Decision. SCE requested no rate changes to address the Trigger Balance exceedance.

On November 4, 2025 SCE and CalCCA filed reply briefs.

1.3. Submission Date

This matter was submitted on November 4, 2025, upon filing of reply briefs.

2. Jurisdiction

The ERRA process was established pursuant to Pub. Util. Code Section 454.5(d), Commission Rules 2.1 and 3.2, and D.02-10-062.

3. Issues Before the Commission

The issues to be determined or otherwise considered are:

1. Whether SCE's requested 2026 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 of costs for fuel and purchased power expenses (F&PP);
   c. SCE's forecast of costs for nuclear fuel expenses;
   d. SCE's forecast of greenhouse gas (GHG) costs;
   e. Annual true ups for certain memorandum accounts (MAs) and balancing accounts (BAs);
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 program 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 resource adequacy (RA) resources and associated costs in the PCIA;
    b. Treatment of Renewable Portfolio Standard (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 across vintages and customer classes;
7. Whether SCE's requests and methods used to determine the issues described above comply with all applicable rules, regulations, and decisions for all customer categories; and
8. Whether there are any safety concerns, or environmental or social justice considerations raised by the Application.

The disputed issues in this case relate to Issues 1, 6, and 7, above, and concern SCE's proposed PCIA revenue requirement.[18] This Decision discusses disputed issues in Sections 7 and 8.

4. 2026 Energy Resource Recovery Account Forecast Overview and Sales Forecast Methodology

SCE's 2026 ERRA forecast revenue requirement costs are associated with the F&PP costs of SCE's UOG, purchased power contracts, financing, various carrying costs, and procurement contracts to meet reliability requirements set by the Commission. SCE's F&PP revenue requirement forecast is developed to provide sufficient energy to meet customer demand, *i.e.*, the number of customers and energy sales per customer that SCE forecasts for 2026. SCE forecasts customer sales as described below.

As noted above, on October 27, 2025, SCE served an Amended October Update, Exhibit SCE-05A, containing what SCE describes as two corrections to its October Update. First, the Amended October Update corrects SCE's omission of general rate case (GRC) revenues into its Billed Revenue Allocation Table (BRAT), which is used to determine how applicable customer revenues are distributed to generation related balancing accounts. SCE also includes two 2026 RA contracts in its Amended October Update that had been included in SCE's May Filing but inadvertently omitted from the October Update.[19] SCE's Amended October Update also included an update to SCE's RA Optimizer. These corrections and updates impacted the forecast 2026 and 2025 true-up ERRA BA and PABA balances. Separately, SCE's Amended October Update also updates the authorized revenue forecast for October-December 2025 to reflect the updated authorized amount from SCE's test-year (TY) 2025 general rate case

[18] CalCCA-01 at 1-2.

[19] SCE-05A at 3-4.

(GRC) Decision.[20]

4.1. 2026 Electric Sales and Electric Load Forecast Methodology

The Commission adopts SCE's proposed 2026 forecasts of electric sales and electric load. SCE forecasts total retail net electricity sales of 78,773 gigawatt hours (GWh) in 2025 and 80,447 GWh in 2026; recorded sales totaled 79,502 GWh in 2024.[21] SCE's forecasts represent a slight decrease in total retail sales of roughly one percent in 2025 and an increase of 2.2 percent in 2026. SCE states that the slight decrease in projected 2025 sales compared to 2024 actual sales results from normal weather assumption for 2025 relative to the hot weather conditions experienced in 2024. SCE states that the anticipated increase in 2026 is mainly due to a projected increase in electricity use from increased space cooling load and transportation electrification loads.

SCE bases its bundled service customer sales forecast on a total retail sales forecast developed in December 2024.[22] SCE projects its total retail sales forecast using econometric models.[23] SCE states that the retail sales forecast represents the sum of forecast sales in seven customer classes, measured at the customer meter. The sales forecast for each class is the product of two separate forecasts: a forecast of electricity consumption per customer or per building square foot, and a forecast of the total number of customers or total building square feet. [24, 25]

[20] *See* D.25-09-030, Decision on Test Year 2025 General Rate Case for Southern California Edison Company [hereinafter D.25-09-030].

[21] SCE-05A at 20.

[22] SCE-05A at 20.

[23] SCE states that the typical estimation procedure used to construct the models is Ordinary Least Squares. SCE-05A at 22.

[24] SCE-05A at 21.

[25] SCE estimates 200 MW incremental growth in demand in 2025-2028 due to data centers and incorporated a proportion of that demand in its 2026 ERRA forecast. SCE states that this

SCE testifies that the econometric modelling that creates its retail sales forecast considers variables including weather projections, electricity rates, number of billing days, employment, personal income indices, and building stock.[26] SCE adjusts the model results to reflect current trends, including, for example, to reflect forecasted strong behind-the-meter solar generation growth expected due to building code requirements.[27]

SCE forecasts residential customer growth based primarily on population growth and assumes commercial customer growth is tied to residential customer growth, while industrial customer growth is related to changes in manufacturing employment.[28] SCE forecasts its total retail customer count to increase by 0.6 percent in 2025 and 0.7 percent in 2026.[29]

SCE determines hourly bundled service customer loads by applying an hourly load shape to the annual bundled energy forecast. The hourly load shapes are created using econometric modelling.[30]

No intervenors addressed SCE's forecast electric sales or electric load testimony or workpapers. After reviewing SCE's testimony and workpapers, we

incorporated a proportion of that demand in its 2026 ERRA forecast. SCE states that this represents approximately one percent of SCE's forecasted total retail demand during those years. *July 17, 2025 Email Ruling on Southern California Edison Company's 2026 ERRA Forecast, Replies to Response to ALJ Inquiry During July 10 PHC* at 4.

[26] SCE-05A at 22.

[27] SCE-05A at 26.

[28] SCE-05A at 22.

[29] SCE-05A at 27.

[30] SCE-05A at 19. "Monthly bundled energy is then derived by summing the hourly load for each calendar month. Monthly bundled service customer peak demand is determined by selecting the maximum hourly load in each calendar month."

find SCE's forecast 2026 electric sales and electric load to be reasonable and therefore approve them.

5. Southern California Edison Company's Portfolio of Resources and Procurement Cost Forecast Methodology

This section discusses the portfolio of resources SCE intends to use to satisfy customer demand in 2026 and the methods and factors SCE uses to forecast capacity, production, and related costs and revenues. SCE's resources include UOG, including UO nuclear generation, UO hydroelectric generation, UO fossil fuel generation (*e.g.*, natural gas), UO renewable generation resources, and UO storage.[31] SCE's purchased power resources include combined heat-and-power (CHP) and renewable resources, inter-utility and bilateral contracts, and anticipated future solicitations and market purchases estimated based on proxy capacity costs.[32] Finally, SCE's 2026 forecast includes the costs of procurement contracts SCE entered into to meet Commission reliability requirements.[33] After describing SCE's portfolio of resources, this section describes the other F&PP-related costs for which recovery is requested, including CAISO costs, carrying costs, and hedging costs.

5.1. 2026 Energy Production and Cost Forecast Methodology

SCE develops its production and cost forecasts using PLEXOS software. SCE's PLEXOS software models (1) forecast the least-cost dispatch (LCD) of

[31] SCE-05A at 30.

[32] *See* SCE-05A at n.64, explaining that SCE applies the updated capacity price of $138.36 /kW-year for all RA products, which is the 2026 Forecast RA Adder.

[33] SCE-05A at 30.

dispatchable resources in SCE's portfolio; (2) optimize hydroelectric dispatch; and (3) perform Monte Carlo simulations of forced outage rates of individual units.[34] SCE states that "[t]he simulated dispatch is based on a forecast of power,[35] gas,[36] and GHG prices, physical constraints of each generating unit, and contractual limitations."[37]

The discussions throughout this section contain factors that influence the availability of a given resource to serve customer demand in 2026, *i.e.*, the factors that shape SCE's development of its LCD modelling inputs. The information that SCE provides regarding its portfolio (and that we summarize here) helps the Commission determine the reasonableness of the projected 2026 costs of these resources, which the Commission reviews in full in Sections 7 and 8, below.

5.2. Utility-Owned Generation and Purchased Power

SCE forecasts a total 2026 F&PP cost of $4.723 billion. SCE states that its 2026 forecast of F&PP costs will be greater than the $4.539 billion in F&PP costs adopted in SCE's 2025 ERRA forecast, based on increases and decreases in various cost categories.[38]

In its Amended October Update, SCE summarizes trends that impact its 2026 production and cost forecast, noting that its projected 2026 net bundled load

[34] SCE-05A at 32.

[35] SCE bases its 2026 power price forecast on the forward power broker quotes for 2026 in effect as of August 25, 2025. The applicable 24-hour flat price was $43.24/MWh. SCE-05A at 33.

[36] SCE bases its daily natural gas price forecast on monthly NYMEX forward prices at the SoCal Citygate in effect as of August 25, 2025, plus intrastate transportation charges from Southern California Gas Company (SoCalGas), as applicable. The 12-month average NYMEX forward gas price as of August 25, 2025 was $5.00/MMBtu for 2026. SCE-05A at 34.

[37] SCE-05A at 33. SCE does not use the PLEXOS models to develop forecasts of GHG prices. *Id.* at n.41.

[38] *See* SCE-05A at Table II-2 ($184,470/$4,538,709).

forecast increased roughly three percent from 2025 projected load, increasing forecast procurement costs.[39] Lower projected SP-15 power prices and higher projected gas prices cause the implied market heat rate to drop, decreasing generation forecasts from SCE's gas dispatchable portfolio; this will increase load procurement costs and decrease market revenues.[40] SCE projects additional fuel and GHG costs due to energy put-option rights to be exercised in 2026 for local capacity requirement dispatchable units; this will increase gas and direct GHG costs, increase market revenues, and decrease hedging costs. Finally, SCE notes that procurement for reliability purposes in 2026 will increase costs, offset by related higher forecast RA sales revenues and energy benefits.

SCE's Amended October Update maintains these overall trends, and explains the overall increase in projected costs between its May Filing and Amended October Update F&PP estimates as follows: additional Mid-Term Reliability (MTR) solar and energy storage contracts, the removal of terminated resources, changes in commercial online dates, and lower contractual prices due to federal tax credits all net to an increase in RA procurement costs; the removal of forecast bridge energy exports due to elimination of the option for LSEs to use bridge contracts for the procurement requirements discussed in Section 5.2.10 of this Decision results in decreased direct GHG costs and decreased hedging costs; decreases in the MPBs leads to lower revenues from Modified Cost Allocation Mechanism (MCAM) sales and lower revenues from Voluntary Allocation sales, which decreases projected RA sales and REC sales revenue; and finally, updated forecast outage information and resource characteristics for SCE's gas-fired UOG

[39] SCE-05A at 31.

[40] SCE-05A at 32.

ultimately decrease SCE's projected UOG and CAM fuel costs, and decrease PABA and CAM market revenues. SCE's Amended October Update forecast also updates its RA position in response to final 2026 requirements.[41]

5.2.1. Utility-Owned Generation and Purchased Power: Hydroelectric Generating Facilities

SCE includes in its 2026 ERRA forecast the forecast energy production from and capacity related to a subset of its hydroelectric generation facilities. SCE operates 32 hydroelectric generating facilities in California, providing approximately 1,164 megawatts (MW) of nameplate capacity. SCE divides its hydroelectric generation into two regions: SCE's Northern Division, known as the Big Creek Project, produces 1,015 MW of nameplate capacity while SCE's Eastern Division produces 161 MW of nameplate capacity.[42]

SCE operates the Big Creek Project at full capacity (when possible) during the highest economic value hours. The Big Creek Project provides ancillary services to the CAISO market when not operating at full capacity, serving as a flexible, dispatchable resource for most of the year.[43] SCE's Eastern Division facilities, on the other hand, are "predominantly run-of-the-river, non-dispatchable resources[,]" with output highly dependent on hydrological conditions.[44] SCE states that its forecast energy production assumes an average hydrological year for 2026 and incorporates SCE's best estimate of upcoming outages and unavailability in 2026.

[41] SCE-05A at 31-32.

[42] SCE-05A at 40.

[43] SCE-05A at 40.

[44] SCE-05A at 41.

SCE's forecast of hydroelectric production in 2026 differs from its 2025 forecast in that SCE excludes from its 2026 forecast the energy and capacity forecasts typically associated with facilities SCE intends to sell. Since August 2024, SCE has filed three applications requesting authority from the Commission to sell ten hydrogeneration facilities with a combined capacity of roughly 17.5 MW. As of October 16, 2025, one application has been approved, and the others are pending, as described in Section 8.2.5.[45]

5.2.2. Utility-Owned Generation and Purchased Power: Solar Photovoltaic Generation

SCE includes in its 2026 ERRA forecast the anticipated energy production from its last remaining Solar Photovoltaic Program (SPVP) site: Site 42. D.13-05-033 authorized SCE to install, own, and operate up to 91 MW of SPV generation on commercial rooftop space and ground sites within its service territory.[46] In 2022, SCE analyzed its SPVP portfolio and determined that retirement of the sites was the least-cost option considering safety issues and declining revenues that failed to recoup the costs of needed upgrades. SCE has been de-energizing its SPVP sites over time; however, Site 42 will not be fully

[45] SCE-05A at 41. *See* D.25-09-012, *Decision Authorizing Southern California Edison Company To Sell Certain Hydroelectric Power Plants To San Bernardino Valley Municipal Water District Under Public Utilities Code Section 851*. The Commission has not yet resolved A.24-09-008, Application of Southern California Edison Company (U338E) for Approval Under Public Utilities Code Section 851 to Sell the Fontana Union Water Company or A.25-03-001, Application of Southern California Edison Company (U338E) for Approval Under Public Utilities Code Section 851 to Sell the Lower Tule Hydroelectric Power Plant to Lower Tule Hydro LLC.

[46] D.13-05-033, *Partially Granting Southern California Edison Company's Petition for Modification of Decision 12-02-035 (Solar Photovoltaic Program)* at 1. SCE-05A at n.48.

de-energized until year-end 2026.[47] Site 42 is rated at approximately 9 MW.[48] Its confidential 2026 production forecast is based on the previous year's project capacity factor.[49]

5.2.3. Utility-Owned Generation and Purchased Power: Combined Heat and Power and Renewables

SCE includes in its 2026 ERRA forecast the anticipated energy production, energy costs, and capacity costs of its combined heat and power (CHP) and renewables projects. The energy deliveries from SCE's CHP and renewables projects are measured at the generators' meters and are effectively "must take" energy. SCE's CHP and renewables projects that deliver energy have approximately 11,045 MW of contract capacity.[50]

SCE forecasts monthly energy deliveries from CHP and renewables projects based on the historical performance of each project.[51] SCE's average annual capacity factors for the six renewable technologies are as follows:

Table 5-1: SCE's Annual Capacity Factors by Technology[52]

Technology	Capacity Factor
Biomass	70.6%

[47] SCE-05A at 43.

[48] D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement* at 18 [hereinafter D.24-12-039].

[49] SCE-05A at 43.

[50] SCE-05A at 43-44.

[51] SCE-05A at 44.

[52] SCE-05A at Table IV-11. SCE states:

> Average annual capacity factors are based on expected annual energy (adjusted for curtailment) and contract capacity for each project aggregated by technology. …[F]or new, undeveloped projects, both the energy and capacity are weighted by each project's respective probability of successful development. *Id.* at 44.

Technology	Capacity Factor
Cogeneration	26.9%
Geothermal	51.0%
Small hydrogeneration	20.6%
Solar	27.2%
Wind	27.8%

SCE expects 13 solar projects to begin delivering energy during 2026. Because new projects lack historical performance data, SCE bases their projected deliveries on contractually expected deliveries, discounted by the projects' expected probabilities of successful development.[53] SCE's production and cost forecasts incorporate estimated curtailments from its solar and wind portfolios.[54]

Many of SCE's renewables and CHP projects have contract-specific energy and capacity prices.[55] Most of SCE's qualifying facility (QF) projects are paid at the posted avoided cost of energy price under standard offer contracts (SOC)[56] while the project's forecast capacity price is either the firm or as-available avoided capacity price depending on the project's specific dedicated capacity.

5.2.4. Utility-Owned Generation and Purchased Power: Utility-Owned Natural Gas Facilities

[53] SCE-05A at 44.

[54] SCE-05A at 48.

[55] SCE-05A at 46.

[56] SCE explains that the posted avoided cost of energy for QF projects is set under either the New QF SOC, adopted in D.20-05-006, or the QF SOC adopted in the QF Summit Settlement. The New QF SOC short run avoided cost is based on CAISO locational marginal prices, while the avoided cost of energy under the QF Summit Settlement is based on the average 12-month forward heat rates. SCE-05A at 46. *See also* D.20-05-006, *Decision Adopting a New Standard Offer Contract for Qualifying Facilities of 20 Megawatts or Less Pursuant to the Public Utility Regulatory Policies Act of 1978*.

SCE includes the estimated production from and natural gas costs of its five black-start capable, dispatchable Peaker units in its 2026 ERRA forecast. These units have a combined capacity of 245 MW. The capacity and non-fuel variable costs associated with these Peakers are included in SCE's GRC revenue requirement and so are not included in this ERRA forecast.[57]

In addition to amounts related to the Peaker units, SCE includes the forecast energy production, as well as capital, natural gas, and GHG costs relating to Mountainview Generating Station in its 2026 ERRA forecast, pursuant to D.18-10-019.[58] SCE ~~does not state~~ states that the current capacity of this generation station~~, but prior filings indicate a capacity of 1,056~~ is 1,110 MW.[59] As noted above, SCE projects gas prices to be five percent higher in 2026 compared to those it projected for 2025, ultimately lowering forecast volumes of generation from SCE's gas dispatchable portfolio.[60]

5.2.5. Utility-Owned Generation and Purchased Power: Inter Utility Contract Production

SCE includes in its 2026 ERRA forecast the anticipated energy and capacity costs of forecast deliveries from a fifty-year agreement executed with the Western Area Power Administration (WAPA) and the U.S. Bureau of Reclamation. Under the terms of this agreement, SCE has a 2026 entitlement of

[57] SCE-05A at 48.

[58] SCE-05A at 48. *See also* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology* at 56 and Conclusions of Law (COL) 13 and COL 14, removing the 10-year limit on recovery of UOG costs from DL customers [hereinafter D.18-10-019].

[59] ~~D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast* at 83, Finding of Fact (FOF) 5 [hereinafter D.23-11-094].~~ SCE, Opening Comments on the Proposed Decision at A-2.

[60] SCE-05A at 32.

280.245 MW of contingent capacity and 238.16 GWh of firm energy generated by the Boulder Canyon Project at the Hoover Dam.[61]

SCE states that due to ongoing drought conditions in the Rocky Mountains, and subsequent lower surface elevation levels in Lake Mead, the amounts of capacity and firm energy available to SCE will be curtailed from those entitlement amounts, potentially reaching as low as 100 MW and 9 GWh, respectively. SCE forecasts inter-utility contract purchases of 156 GWh in 2026, and inbound capacity averaging approximately 151 MW per month.[62] SCE states: "[d]uring periods when Hoover is unable to provide energy in amounts equal to the firm energy, the WAPA is obligated to provide any deficit, if requested by the purchaser, at a rate equal to the WAPA's cost to acquire."[63]

5.2.6. Utility-Owned Generation and Purchased Power: New System Generation Cost Allocation Method Contracts

SCE includes in its 2026 ERRA forecast the anticipated energy costs, energy revenues, and capacity costs of New System Generation resources.[64] In 2006, the Commission required SCE to procure "New System Generation" through long-term power purchase agreements (PPA) entered on behalf of bundled and unbundled customers across its service territory.[65]

[61] SCE-05A at 49.

[62] SCE-05 at 49-50.

[63] SCE-05A at n.52.

[64] SCE-05A at 50.

[65] D.06-07-029, as modified by D.10-12-035, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation* at Ordering at OP 1 [hereinafter D.06-07-029]. After California's electric market restructuring and the energy crisis of 2000-2001, developers were reticent to construct new generation facilities without securing long term purchase contracts that were, at the time, unattractive to IOUs. In particular, IOUs found long term contracts risky given market reforms that allowed customers to opt in and out of bundled IOU service. The Commission adopted its requirements for new generation procurement in D.06-07-029 to address these issues. *See id.* at 1-5. *See also* Senate Bill (SB) 695 (Kehoe), Stat. 2009, Ch.337.

In the same decision, the Commission unbundled the capacity rights for these New System Generation resources from the energy components;[66] the load serving entities (LSEs) in the IOUs respective service territories are allocated the capacity rights that can then be applied to each LSE's resource adequacy requirements.[67] The Commission adopted the Cost Allocation Mechanism (CAM) to allocate the costs and benefits of these resources: the costs and benefits of the resource adequacy capacity component[68] are socialized to all customers connected to the utility's distribution system; the costs and benefits of the energy component are assigned "to those that value the energy the most."[69]

To effectuate this distribution of energy rights, pursuant to D.07-09-44 and the Joint Party Proposal adopted therein, SCE holds the dispatch rights for all New System Generation contracts and distributes the energy rights via auction.[70] SCE forecasts 2026 energy revenues from these resources based on LCD.[71] The costs and revenues related to these resources are tracked in the New System Generation Balancing Account (NSGBA).[72]

[66] D.06-07-029 at 14.

[67] D.06-07-029 at OP 1.

[68] Benefitting customers are charged only the "net capacity costs" of the resource, defined as "a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract." D.06-07-029 at OP 1.

[69] D.06-07-029 at 31. SCE states that the energy rights are not used to meet SCE's bundled customer load. *See* SCE-05A at 50-51.

[70] D.07-09-044, *Opinion Adopting Joint Settlement Agreement, as Clarified, Regarding Principles for the Energy Auction Process and Products*, as modified by D.12-11-008, Appendix A at 1 [hereinafter D.07-09-044]. *See also* SCE-05A at n.53.

[71] SCE-05A at 51. *See also* Sections 5.1 (for a description of LCD modelling) and 5.4.2 (for a description of the impact of anticipated energy revenues on forecast costs).

[72] SCE-05A at 51. *See also* Section 7.2.1.

Commission decisions have since (1) expanded the scope of resources to which the CAM may apply and (2) modified CAM processes. For example, in D.10-12-035, the Commission allowed SCE to allocate via the CAM the net capacity costs associated with CHP generation procured on behalf of Direct Access customers' Electric Service Providers (ESPs) and CCAs.[73] In D.11-05-005, the Commission modified the CAM process, in part by expanding CAM treatment to UOG if the Commission determines a UOG resource is needed for system or local area reliability.[74] Lastly, the capacity costs of certain bankrupt non-IOU LSEs (or of those LSEs that cease to provide retail service) revert to the relevant IOU for CAM recovery, if those costs were originally recovered under the Modified Cost Allocation Mechanism (MCAM, discussed below).[75]

SCE describes three decisions in which the Commission (1) required the IOUs to address summer emergency reliability by contracting for additional capacity and (2) authorized CAM recovery for these contracts.[76] SCE lists the

[73] D.10-12-035, *Decision Adopting Proposed Settlement* at 56 and COL 14; *see also* SCE-05A at 126. The net capacity costs of these resources are recovered from all benefitting customers via the CAM. *See* SCE-05A at 129.

[74] D.11-05-005, *Decision Modifying New Generation and Long-Term Cost Allocation Mechanism Pursuant to Senate Bill 695* at OPs 1-3 [hereinafter D.11-05-005]. *See also* SCE-05A at 128 and n.134.

[75] SCE-05A at 131-132, citing D.22-05-015, *Decision on Modified Cost Allocation Mechanism*, and D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process* [hereinafter D.22-05-015]. The defunct LSEs must have had capacity obligations under D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023* [hereinafter D.19-11-016] or D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)* [hereinafter D.21-06-035] for this reversion to apply.

[76] SCE-05A at 129, citing D.21-02-028, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Seek Contracts for Additional Power Capacity for Summer 2021 Reliability* [hereinafter D.21-02-028], D.21-03-056, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022* [hereinafter D.21-03-056], and D.21-12-015, *Phase 2 Decision Directing*

contracts and UOG resources for which the Commission has authorized CAM cost recovery in testimony.[77]

5.2.6.1. New System Generation: Central Procurement Entity Costs for Local Resource Adequacy

SCE includes the forecast net procurement and administrative costs related to its role as a Central Procurement Entity (CPE) in its 2026 ERRA forecast. In D.20-06-002, the Commission designated SCE as the CPE for its distribution area, tasking SCE with multi-year local resource adequacy (Local RA) procurement obligations starting with the 2023 compliance year. That decision adopts CAM as the cost recovery mechanism for the resources and the administrative costs of acting as CPE.[78] D.23-06-029 adopted additional local and flexible capacity procurement requirements.[79] All procurement conducted by SCE as the CPE is separate from procurement conducted by SCE for SCE's bundled service customers.[80] D.22-03-034 requires that CPE procurement costs be forecast and implemented through rates in the ERRA proceeding and documented in a separate chapter of a utility's ERRA forecast.[81]

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023 [hereinafter D.21-12-015].

[77] SCE-05A at Table VIII-39.

[78] D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program*, at OPs 2 and 16. *See also* SCE-07 at 1.

[79] D.23-06-029, *Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Requirements* at COL 8.

[80] SCE-07 at 1.

[81] D.22-03-034, *Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure* at OP 19.

In Exhibit SCE-02, as updated in Exhibit SCE-07, SCE describes its 2026 CPE cost forecast as including: (1) the net procurement costs of resources from SCE's 2021 and 2022 Local RA Requests for Offers (RFO),[82] (2) non-energy related CAISO costs and credits, and (3) administrative costs of $250,000.[83] CPE-related procurement costs are forecast to have increased slightly from 2025, and administrative costs are forecast as the standard expenses SCE incurs to use an independent evaluator to participate in its CPE RFOs, based on the cost of SCE's most recent CPE solicitation.[84] The non-energy costs of the related procurement described by SCE include only Grid Management Charges, which are costs related to SCE-CPE's participation in the market, and two small, related credits. SCE uses the Centralized Local Procurement Sub-Account (CLPSA) of the NSGBA to track CPE costs.[85]

SCE's Amended October Update includes information on two CAISO market enhancements CAISO expects to roll out throughout 2026: Day-Ahead Market Enhancements (DAME) and the Extended Day-Ahead Market (EDAM). These initiatives are intended to improve both system reliability and market efficiency. However, because these are new variables, SCE does not include any anticipated related costs or revenues in its 2026 ERRA forecast.[86] SCE also notes in its Amended October Update that SCE-CPE did not select any offers for its 2025 SCE-CPE Local RA RFO, as SCE determined LSEs had contracted for

[82] SCE-07 at 10 and Table IV-3.

[83] SCE-07 at 13 and Table IV-3.

[84] SCE-07 at 13.

[85] SCE-07 at 14-15

[86] SCE-07 at 11-12.

sufficient local resources in the Local Area Basin and Big Creek-Ventura local areas that met 2026 through 2028 compliance requirements.[87]

No party has opposed SCE's forecast of CPE-related costs. We find SCE's forecasts of 2026 CPE-related procurement and administrative costs to be forecast and allocated consistent with Commission rules. SCE's CPE cost forecast is reasonable and approved.

5.2.6.2. New System Generation: Utility-Owned Storage

SCE includes its 2026 ERRA forecast the anticipated storage costs and market revenues related to energy storage authorized as part of its 2015 GRC.[88] This utility-owned storage (UOS) resource, known as DESI 2, or the UOS Titanium project, will be a CAISO market resource of 1.4 MW/ 3.7 MWh, and has an estimated CAISO market start date in the fourth quarter of 2025. SCE tracks storage charging costs and revenues associated with this resource through the NSGBA.[89]

5.2.7. Utility-Owned Generation and Purchased Power: System Reliability Modified Cost Allocation Method-Related Costs

SCE includes in its 2026 ERRA forecast the capacity costs of and related revenues from resources procured pursuant to D.19-11-016, in which the Commission directed utilities to conduct System Reliability Requests for Offers (SRRFO) for incremental system resource adequacy capacity for 2021-2023. D.19-11-016 directed SCE to procure 1,184.7 MW of incremental system RA

[87] SCE-07 at 8.

[88] *See* D.15-11-021, *Decision on Test Year 2015 General Rate Case for Southern California Edison Company* at 47.

[89] SCE-05A at 51.

capacity on behalf of its bundled customers, and similarly adopted "self-procurement" requirements for other LSEs.[90] D.19-11-016 also directed the incumbent IOUs to procure additional generation capacity on behalf of other LSEs in their service territories that either (a) elected to opt out of self-procurement ("opt-out procurement") or (b) failed to acquire their share of required capacity after electing to do so ("backstop procurement"). SCE's additional procurement requirement related to opt-out LSE elections was 56.6 MW.[91] This decision deferred creating the cost recovery mechanism for this procurement.[92]

After initiating its 2019 SRRFO, SCE procured the capacity required by D.19-11-016 via seven "Fast Track" contracts for new energy storage resources (totaling approximately 678 MW of incremental RA system capacity, 770 MW nameplate capacity) that were approved in Resolution (Res.) E-5101, and an additional five "Standard Track" contracts that were approved in Res. E-5142 (totaling approximately 590 MW of nameplate capacity).[93]

In D.22-05-015, the Commission adopted the MCAM to ensure that the net costs of the opt-out procurement and backstop procurement required by

[90] D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023* at 41 [hereinafter D.19-11-016]. The Commission also required SCE to procure 140.3 MW for its Direct Access customers.

[91] SCE-05A at n.56, citing April 15, 2020 *Administrative Law Judge's Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual 2020 Integrated Resource Plan Filings and Assigning Procurement Obligations Pursuant to Decision 19-11-016* at 9, in Rulemaking (R.) 16-02-007.

[92] D.19-11-016 at 37, and 74-75, COL 13.

[93] SCE-05A at 52.

D.19-11-016 and the backstop procurement required by D.21-06-035[94] are allocated fairly, economically, and in accordance with the law.[95] D.22-05-015 authorized the use of non-bypassable customer charges to recover those costs, as well as the costs of any backstop procurement associated with any future Integrated Resource Planning (IRP)-related procurement orders made by the Commission.[96] Finally, D.22-05-015 also adopted a one-time provision allowing non-IOU LSEs to negotiate purchasing the portion of D.19-11-016 capacity that the IOU had procured on behalf of customers who, after 2019, left IOU service for the purchasing LSE's service.[97]

SCE's costs associated with system reliability resources procured pursuant to D.19-11-016 were initially recorded in the System Reliability Procurement Memorandum Account (SRPMA).[98] However, once the Commission adopted the MCAM and the MCAM Balancing Account (MCAMBA), SCE was authorized to allocate and transfer the SRPMA's recorded costs between the PABA, MCAMBA, and NSGBA, as appropriate, based on which customers were responsible for the costs of the required procurement. SCE completed this transfer in January 2023, and has, since that time, segmented SRRFO costs to its PABA, MCAMBA, and NSGBA.[99]

[94] D.21-06-035 required LSEs to procure an additional 11,500 MW of Net Qualifying Capacity that would come online between 2023 and 2026. "Unlike D.19-11-016, D.21-06-035 did not allow LSEs to opt-out of self-procurement. However, D.21-06-035 requires the IOUs to backstop any LSEs that fail to procure and bring-online their required share of reliability resources." Resolution (Res.) E-5240 at 2.

[95] D.22-05-015, *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations* at 1 [hereinafter D.22-05-015].

[96] D.22-05-015 at Ordering Paragraphs (OPs) 2 and 3.

[97] D.22-05-015 at OP 4.

[98] SCE-05A at 52.

[99] Res. E-5240 lists the customer groups on whose behalf SCE procured resources pursuant to D.19-11-016 (and D.21-06-035, discussed further in Section 5.2.9) and, in some cases, where

Unlike CAM-eligible costs recorded in the NSGBA, which are collected from all benefitting customers, MCAM costs are recovered only from the customers of LSEs that opted out of or failed to meet procurement obligations.[100]

5.2.8. Utility-Owned Generation and Purchased Power: Emergency Reliability Procurement

SCE includes in its 2026 ERRA forecast the remaining capacity costs of summer emergency reliability procurement authorized by D.21-02-028, D.21-03-056, and D.21-12-015.[101] These costs are tracked in the NSGBA.[102] D.21-02-028 directed IOUs to contract for capacity to serve peak and net peak demand in the summer of 2021, and to seek approval for recovery of the costs via the CAM.[103]

In D.21-03-056, the Commission authorized supply and demand-side measures to address reliability issues in the summers of 2021 and 2022, including authorizing the IOUs to procure the resources needed to meet the summer 2021 and 2022 effective planning reserve margin (PRM) of 17.5 percent, with cost recovery of the incremental procurement above SCE's own 15 percent PRM coming from all benefitting customers via the CAM.[104]

D.19-11-016 (and D.21-06-035, discussed further in Section 5.2.9) and, in some cases, where these costs will be transferred to from the SRPMA: bundled customers (PABA), Opt-Out LSE customers (MCAMBA), non-operational Opt-Out LSE customers (NSGBA), bundled customers who departed to non-IOU and non-Opt Out LSEs between November 2019 and May 2022 (PABA), and Backstop/Deficient LSE customers (MCAMBA). *Id*. at 3-4. *See also* SCE-05A at 52 and Table IV-9, in which SCE notes the applicable balancing account associated with each of the "System Reliability RFO" (or "SR RFO") line items.

[100] D.22-05-10 at 8.

[101] SCE-05A at 53-54.

[102] SCE-05A at 129; *see also* SCE-05A at Table IV-9.

[103] D.21-02-028 at 11 and OP 1; SCE-05A at 53.

[104] D.21-03-056 at 1 and FOF 77.

In D.21-12-015, the Commission adopted several supply and demand-side requirements to address resource reliability for summer in 2022 and 2023, including additional incremental procurement requirements.[105] The Commission authorized CAM recovery of the net costs of the incremental procurement required by this decision.[106]

5.2.9. Utility-Owned Generation and Purchased Power: Mid-Term Reliability Procurement

In its 2026 ERRA forecast, SCE includes the estimated remaining capacity costs of contracts secured to meet mid-term reliability (MTR) requirements adopted in D.21-06-035 and D.23-02-040.[107] D.21-06-035 addressed MTR needs across CAISO's operating system by requiring at least 11,500 MW of additional net qualifying capacity (NQC) to be procured by all LSEs subject to the Commission's integrated resource planning (IRP) authority.[108] SCE's portion of the required capacity was 4,052 MW.[109] SCE launched its MTR Request for Offers (MTRRFO) for resources to come online in 2023-2026 on July 30, 2021.[110]

In D.23-02-040, the Commission required supplemental MTR procurement of 4,000 MWs of NQC in addition to the amounts ordered in D.21-06-035, based on updated California Energy Commission load forecasting suggesting additional capacity was needed due to increased demand, the impacts of climate change, unexpected fossil fuel generation system retirements, and the likelihood of delays in the procurement of long lead time resources required by

[105] D.21-12-015 at 1, OP 2 and OP 3; SCE-05A at 54.

[106] D.21-12-015 at OP 70.

[107] SCE-05A at 54-55.

[108] D.21-06-035 at 1 and OP 1; SCE-05A at 54.

[109] D.21-06-035 at Table 6 and OP 3; SCE-05A at 54.

[110] SCE-05A at 55.

D.21-06-035.[111] SCE's bundled customer share of this required procurement was 1,367 MW, and its Direct Access share was 172 MW.[112]

SCE states that, through its phased MTRRFOs, it has executed contracts for a number of energy storage and renewable energy projects that were approved in Res. E-5205, E-5225, E-5234, E-5251, E-5253, E-5271, E-5307, E-5309, E-5313, E-5316, and E-5333, E-5334, E-5344, E-5365, and E-5419.[113] Seven of SCE's MTR ALs were approved without an accompanying resolution (ALs 5336-E, 5386-E, 5446-E, 5470-E, 5517-E, 5537-E, and 5593-E).[114] SCE has one AL requesting approvals related to MTR contracts pending before the Commission. SCE's 2026 forecast of the capacity costs for the MTR resources listed above are tracked in the PABA.[115]

In its Amended October Update, SCE revises its cost recovery for two MTR contracts due to the reallocation of capacity to meet MTR requirements, as authorized in Res. E-5240 and E-5365.[116]

5.2.10. Utility-Owned Generation and Purchased Power: Imports Used for Mid-Term Reliability and Diablo Canyon Replacement

[111] D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process* at 1 [hereinafter D.23-02-040]; SCE-05A at 54-55.

[112] D.23-02-040 at 31 and OP 3. D.23-02-040 was modified by D.24-02-047. Compliance mechanisms for the procurement required by these decisions were modified in D.25-09-007, *Decision Granting, with Modifications, Southern California Edison Company's Petition for Modification of Decisions 23-02-040 and 24-02-047* [hereinafter D.25-09-007].

[113] SCE-05A at 55-60.

[114] SCE-05A at 58-60.

[115] SCE-05A at 60.

[116] SCE-05A at 61.

SCE's May Filing included in its 2026 ERRA forecast cost assumptions related to MTR bridge procurement and Diablo Canyon Replacement procurement costs, originally required under D.21-06-035 and D.23-02-040 (as modified by D.24-02-047), discussed in Section 5.2.9 above.[117] SCE noted in its May Filing that these assumptions may change based on its then-pending petition for modification (PFM) of D.23-02-040 and D.24-02-047.[118]

Pursuant to D.25-09-007, which adopted SCE's PFM in part, SCE's Amended October Update removes assumptions relating to this bridge procurement and Diablo Canyon Replacement from its 2026 ERRA forecast. D.25-09-007 eliminated the option for LSEs to use additional bridge contracts as compliance mechanisms for the procurement required by D.21-06-035 and D.23-02-040 (as modified by D.24-02-040).[119] D.25-09-007 further states that LSEs will be deemed compliant with procurement obligations noted above if they (1) have sufficient executed long-term (ten years or more) contracts (for capacity and/or energy, as applicable) to meet the applicable MTR procurement obligation and (2) have met their month-ahead system RA obligations for all months in which their procurement is delayed, by the final deadline for curing any RA deficiency.[120]

SCE's removal of additional bridge contract costs in its Amended October Update suggests SCE believes it is compliant or will be compliant with its procurement obligations pursuant to the alternative compliance mechanism adopted in D.25-09-007. Implementation of D.25-09-007 is intended to decrease

[117] SCE-01 at 52-53.

[118] SCE-01 at 149.

[119] D.25-09-007 at OP 2.

[120] D.25-09-007 at OP 6.

ratepayer costs as bridge contracts are among the most expensive contracts entered into by any LSE on a per-MWh and per-kW-month basis for MTR compliance.[121]

5.2.11. Utility-Owned Generation and Purchased Power: Generic and Bilateral Resource Adequacy Contracts

SCE includes in its 2026 ERRA forecast the monthly capacity costs for generic and bilateral contracts secured to meet estimated remaining 2026 RA needs. SCE's final 2026 RA requirements, less the capacity represented by RA contracts already procured, equals SCE's forecast remaining 2026 RA need.[122] For the months in which SCE forecasts an incremental RA need, SCE forecasts costs for generic and bilateral RA contracts to meet that need based on a "quantity x price" formula. The "quantity" variable is produced by SCE's Slice-of-Day methodology, described in Section 8.2.2.3.1, below. SCE multiplies this forecast quantity by a proxy price to develop forecast costs. SCE uses the Commission's 2026 Forecast RA Market Price Benchmark (RA MPB or RA Adder) as the proxy price in its Amended October Update. SCE's Amended October Update incorporates the impacts of D.25-06-049, which modified the Commission's RA valuation methodology, combining the former three RA Adders (specific to local, system, and flexible capacity) into one RA Adder.[123] D.25-06-049 and the RA Adder are also described in Section 8.2.2.3, below.

[121] D.25-09-007 at 2 and FOF 4.

[122] SCE-05A at 62. The Commission adopted SCE's final 2026 RA requirements in D.25-06-048, *Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements* [hereinafter D.25-06-048]. These requirements include an 18 percent planning reserve margin (PRM) and an effective PRM procurement target ranging from 1,260 to 2,300 MW for the months of June through October. SCE-05A at 153.

[123] SCE-05A at 63; D.25-06-048 at 20.

Finally, SCE states that any available supply that exceeds the amount needed to satisfy RA requirements, plus a buffer, is assumed to be excess RA. SCE uses a framework to try to monetize the value of its excess RA.[124]

5.2.12. Utility-Owned Generation and Purchased Power: Local Capacity Requirement Costs

SCE includes in its 2026 ERRA forecast the estimated capacity costs, and when applicable, the gas, GHG, and energy costs associated with its local capacity requirement (LCR) contracts in the Western Los Angeles Basin (LA Basin) and Moorpark local reliability areas. SCE includes the estimated production from the in-front-of-the-meter LCR resources in its production forecast, while the behind-the-meter LCR resources decrease the bundled service customer load requirement.[125]

The Commission authorized SCE to procure between 1,400 MW and 1,800 MW for the LA Basin and between 215 MW and 290 MW in the Moorpark sub-area to meet LCR in D.13-02-015.[126] The Commission ordered SCE to procure an additional 500 MW to 700 MW by 2021 to address local capacity needs resulting from the retirement of the San Onofre Nuclear Generating Station (SONGS) in D.14-03-004.[127]

SCE launched its LCR RFO in September 2013 to procure the amounts of preferred resources, energy storage, and gas-fired capacity the Commission required via the decisions noted above. In D.15-11-041, the Commission granted

[124] SCE-05A at 63.

[125] SCE-05A at 64.

[126] SCE-05A at 63; D.13-02-015, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements* at OPs 1 and 2.

[127] SCE-05A at 63; D.14-03-004, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due to Permanent Retirement of the San Onofre Nuclear Generating Stations* at OP 1.

in part SCE's request for approval of 63 contracts executed because of the 2013 LCR RFO.[128] As suggested above, SCE notes that the LCR contracts included in its 2026 ERRA forecast represent both behind-the-meter and in-front-of-the-meter resources.[129]

5.2.13. Utility-Owned Generation and Purchased Power: Preferred Resources Pilot

SCE includes in its 2026 ERRA forecast the estimated production from and forecast net costs of its Preferred Resource Pilot (PRP) Program. SCE launched its PRP RFO#2 in 2015 to solicit electrical energy, capacity, and renewable attributes from eligible resources such as demand response (DR), renewable distributed generation, energy storage, renewable distributed generation paired with energy storage and permanent load shifting.[130] The Commission approved 19 contracts secured via this RFO in D.18-07-023.[131] While some PRP-RFO procurement net costs are recovered via the PABA,[132] SCE notes that it recovers the net costs of the DR component of SCE's PRP contracts via its Distribution rate component, and PRP behind-the-meter energy storage contract costs from customers through the Public Purpose Program Charge (PPPC).[133]

[128] SCE-05A at 63; D.15-11-041, *Decision Approving, in Part, Results of Southern California Edison Company Local Capacity Requirements Request for Offers for the Western LA Basin Pursuant to Decisions 13-02-015 and D.14-03-004* at OP 1.

[129] SCE-05A at 64.

[130] SCE-05 at 62.

[131] D.18-07-023, *Decision Approving the Results of Southern California Edison Company's Second Preferred Resources Pilot Procurement* at OP 1.

[132] SCE-05A at Table VII-9, ln. 105: "Resource Adequacy – Purchases," "PRP RFO."

[133] *See* SCE-05A, n.66 for reference to recovery of PRP costs via the PPPC. *See* SCE-05A at Table VIII-36, n.3, for reference to recovery of PRP costs via the Base Revenue Requirement Balancing Account-Distribution (BRRBA-D) rate component. *See* SCE-05A at Table IV-9, ln. 105, for reference to a portion of PRP costs tracked via the PABA.

5.2.14. Utility-Owned Generation and Purchased Power: Green Tariff Shared Renewables

SCE's 2026 ERRA forecast includes the estimated costs of SCE's Green Tariff Shared Renewables (GTSR) Program.[134] Originally authorized in D.15-01-015, SCE's GTSR program provides customers with two options to be served with a larger mix of renewable energy, relative to SCE's other tariff options.[135] Under the first option, SCE's Green Rate program, customers may choose either a 50 percent or 100 percent mix of renewable energy, with a corresponding increase in their generation rate. Under the second option, SCE's Enhanced Community Renewables (ECR) program, customers may support local renewable energy projects through agreements with third-party developers. SCE's GTSR BA tracks the F&PP costs of resource contracts for which the Commission has approved GTSR recovery.[136]

The Commission modified the Green Tariff and ECR programs in 2024 by closing the ECR tariff to new procurement and reassigning the unprocured capacity under the ECR tariff to the modified Disadvantaged Communities Green Tariff (DAC-GT), among other program changes.[137] The Commission

[134] SCE-05A at 65. D. 15-01-015, *Decision Approving Green Tariff Shared Renewables Program for San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company Pursuant to Senate Bill 43*. *See also* Pub. Util. Code §§ 2831-2833.

[135] The Commission adopted further guidelines for the GTSR Program in: D.16-05-006, *Addressing Participation of Enhanced Community Renewables Projects in the Renewable Auction Mechanism and other Refinements to the Green Tariff Shared Renewables Program*; D.17-07-007, *Decision Modifying the AmLaw 100 Securities Opinion Requirement for Enhanced Community Renewables Projects under the Green Tariff Shared Renewables Program in D.15-01-051*, and D.19-05-031, *Decision Dismissing the Application for Approval of Green Energy Programs*, and Res. E-4734 and E-5028. SCE-05A at 65-66.

[136] SCE-05A at 67.

[137] D.24-05-065, *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Program* at OP 2 [hereinafter D.24-05-065]. The DAC-GT program is discussed in Section 6.3.2 of this Decision. *See also* SCE-05A at 66.

further capped the total capacity for the modified Green Tariff program at 562 MW with subscriptions capped at 40 MW per customer.[138]

SCE forecasts Green Tariff participation in 2026 to be 123,556 MWh and ECR participation to be 143,283 MWh, which is an increase from the demand seen in 2025.[139] SCE's forecast incorporates an increase in demand for these tariffed services that began in May 2022; since then, SCE has identified more interested customers that, if enrolled, would have exceeded SCE's available Green Tariff capacity of 60 MW. SCE describes six approved GT projects to serve this demand in its forecast, including the costs of at least five solar photovoltaic projects.[140] Costs related to the modified Green Tariff are recovered by participating customer subscribers.[141]

5.2.15. Utility-Owned Generation and Purchased Power: Nuclear Costs

SCE includes in its 2026 ERRA forecast the anticipated production, and costs of generation-related nuclear fuel expenses and interim spent fuel storage costs associated with its partial ownership of Palo Verde Nuclear Generating Station (PVNGS).[142] As a minority owner of PVNGS Units 1, 2, and 3, SCE owns a 15.8 percent share that provides a maximum dependable capacity to SCE of 207 MW, 208 MW, and 208 MW per unit, respectively. For forecasting purposes, SCE assumes that PVNGS will operate in a baseload manner. Units 1 and 2 will experience refueling and maintenance outages in 2026.[143]

[138] D.25-05-065 at 144 and n.378, OPs 5(b) and 5(c)

[139] SCE-05A at 67.

[140] SCE-05A at 65-66.

[141] SCE-05A at 66.

[142] SCE-05A at 69.

[143] SCE-05A at 70-71.

SCE incurs a share of the nuclear fuel management costs for PVNGS, including costs for the mining of the uranium, uranium conversion, design and fabrication of the fuel assemblies, spent fuel transportation costs, safe interim storage costs, and permanent disposal costs.[144] SCE forecasts $29.356 million in nuclear fuel expenses related to PVNGS. SCE's projected nuclear fuel expense for PVNGS is based on four factors: the amortization of the remaining costs for each reactors' current batch of nuclear fuel assemblies; the forecast of electrical generation from each unit; the U.S. Department of Energy (DOE) spent fuel disposal charges mandated by the 1982 Waste Policy Act; and (4) interim storage costs for spent fuel assemblies in the dry cask Independent Spent Fuel Storage Installation (ISFSI) located on site at PVNGS.[145]

The costs to transfer fuel to the on-site ISFSI are considered operating costs for PVNGS, and therefore not included in the 2026 ERRA forecast. For item (4) above, SCE forecasts $40,000 in net interim used fuel storage charges at PVNGS, after accounting for a $3.03 million damages award payment from the DOE from litigation to recover spent fuel storage costs.[146]

In addition to having an ownership interest in PVNGS, SCE is the majority owner and decommissioning agent for 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.[147] All three SONGS units are being decommissioned, and some of the spent fuel from these units has been transferred to its on-site ISFSI.[148]

[144] SCE-05A at 69.

[145] SCE-05A at 70.

[146] SCE-05A at 71.

[147] SCE-05A at 69.

[148] SCE-05A at 71.

SCE states that the costs for storing spent fuel at the on-site ISFSI are covered by the SONGS Nuclear Decommissioning Trusts and so are not included in the 2026 ERRA forecast.[149] Some spent fuel, however, has historically been stored off-site. In its May Filing, SCE forecast that, beginning in 2026, the costs for the SONGs Unit 1 off-site spent fuel storage would be paid from the Non-Qualified Nuclear Decommissioning Trust (NQNDT), into which SCE will deposit litigation proceeds attributable to the cost of SONGS spent fuel storage.[150] However, SCE's Amended October Update no longer forecast that SONGS off-site spent fuel storage would be paid from litigation proceeds, and instead forecast $5.234 million in interim storage costs during 2026 for the SONGS Unit 1 spent fuel assemblies temporarily stored off-site. SCE states that it has not received the expected litigation proceeds from DOE and has no expectation of when it will receive these funds.[151]

Scoping Memo Issue 1(c) requires us to assess the reasonableness of SCE's forecast nuclear fuel expenses. We find that SCE's forecast of nuclear fuel related production and costs, including the forecast costs of SCE's interim spent fuel storage, reflect current conditions at SONGS and PVNGS, are consistent with applicable law, Commission decisions, and prior year forecasts, and so are reasonable and adopted. To effectuate D.24-08-001's directive that, to the extent possible, applicable nuclear storage costs should be paid from DOE litigation funds, rather than ratepayers, once SCE receives and deposits applicable DOE

[149] SCE-05A at 71.

[150] SCE-01 at 61-62, citing D.24-08-001, *Decision Approving the 2021 Nuclear Decommissioning Cost Triennial Proceeding Costs of Southern California Edison Company and San Diego Gas & Electric Company* at 27, 36, and OP 3.

[151] SCE-05A at 72.

litigation funds in the SONGS 1 NQNDT, SCE must propose a refund of these 2026 SONGS 1 forecast costs in its next ERRA forecast or compliance proceeding.

5.2.16. Utility-Owned Generation and Purchased Power: Santa Catalina Island Fuel Costs

SCE includes in its 2026 ERRA forecast the updated projected fuel costs of operating six diesel generators and 23 propane-fired microturbines to provide electric service to Santa Catalina Island (Catalina or Catalina Island).[152] SCE bases its diesel cost forecast on a forecast of consumption (based on 2024-2025 recorded actuals) and a forecast of diesel prices (also based on average 2024-2025 recorded data while incorporating a projected decrease based on the IHS Global Insight Variable for Gasoline and Fuels).[153] Based on the estimated 50,921 barrels to be consumed by SCE on Catalina Island in 2026 and an average cost of $157.29 per barrel (including the costs of transporting the fuel), SCE forecast its 2026 Catalina-related diesel fuel cost to be $7.998 million.[154]

SCE's Amended October Update revises its estimate for propane fuel costs for Catalina Island to reflect adoption of D.25-06-010, in which the Commission resolved SCE's test year (TY) 2025 Catalina Island general rate case (GRC).[155] SCE

[152] SCE-05A at 72.

[153] SCE-05A at 73. SCE-01 (at 62) refers to this adjustment as a decrease while SCE-05 refers to this adjustment as an increase, despite the figures in Table IV-17 being identical in each document. Because each of the monthly per-barrel costs forecast in 2026 is less than the corresponding per-barrel recorded costs, we characterize this adjustment as a decrease.

[154] SCE-05A at Table IV-17. Note, however that this total does not match the total SCE provides in the body of SCE-05A at 75 and 77 ($7.988 million). Given that the $7.988 figure is not supported by SCE's data provided in Table IV-17, and SCE's remaining references to the Santa Catalina diesel fuel costs all refer to a $7.998 million total (*e.g.*, SCE-01 at 63 and 64, Table IV-16 and Table IV-8; SCE-05A at Table IV-17, SCE-05A at Table IV-9), we assume that $7.998 million is the correct figure and references to $7.988 million are typos.

[155] *Compare* SCE-05A at 75 and SCE-01 at 64. D.25-06-010, *Decision Adopting Settlement Agreement, as Modified, and Resolving Undisputed Issues in a General Rate Case for Southern California Gas Company's Santa Catalina Gas Utility Operations*.

bases its forecast for propane fuel costs on actual cubic feet delivered in 2023 and 2024; SCE then converts this forecast usage to therms and applies the Catalina Gas G-2 rate schedule. SCE incorporates into its projection an expected nearly 53 percent increase in propane prices (also based on the IHS Global Insight Variable for Gasoline and Fuels). This produces a total 2026 forecast propane cost of $1.478 million.[156] Combining the diesel and propane projections, SCE forecasts a total fuel cost of $9.476 million for 2026 Catalina Island generation.[157] These costs are tracked in SCE's PABA.[158]

SCE's October Update contains the following footnote, relating to its Catalina Island propane forecast:

> Prior to setting up SCE Electric as a customer of Catalina Gas, SCE Electric (and by extension electric customers) only paid for the cost of propane and transportation to fuel the microturbines. Pursuant to Gas Tariff Rule 17, SCE intends to backbill SCE Electric back to January 2024 or earlier. SCE has not completed this backbilling at the time of filing this October Update and thus has not included these costs in its forecast. SCE anticipates the backbill amount minus propane and transportation costs already paid for could be an additional $1.0 to 3.0 million.[159]

In testimony submitted in support of its TY 2025 Catalina Island GRC application, SCE informed the Commission that, at the time, SCE's Electric Plant paid "for the cost of gas (including transportation) used for the microturbines but [did] not pay any of the costs of gas facilities the electric plant also uses."[160] SCE

[156] SCE-05A at 75.

[157] SCE-05A at 77.

[158] SCE-05A at Table IV-9, lns. 89-90.

[159] SCE-05A at n.72.

[160] A.23-12-011, Exhibit SCE-01, Direct Testimony Supporting Southern California Edison Company's Application for Authority to Increase Rates for its Catalina Gas Utility at 110 [hereinafter A.23-12-011, SCE-01].

stated that "SCE Catalina Gas will begin billing SCE Electric on March 1, 2024 for gas service to the microturbines."[161] D.25-06-010 notes that SCE proposed to charge its SCE Electric generation operations the G-2 non-residential rate to "[r]educe … bill impacts on customers[.]"[162] D.25-06-010 does not discuss backbilling SCE Electric for any costs.

SCE's Gas Tariff Rule 17 allows for bill adjustments when: (1) unauthorized use has occurred; (2) billing errors have been made; and/or (3) there has been a meter error.[163] SCE hasn't clearly alleged unauthorized use, meter error, or billing error. We require more information about SCE's proposal.

Commission General Order (GO) 96-B states that an advice letter is an appropriate vehicle for a utility to request Commission authorization to deviate from its tariffs. A utility may also request relief by means of an advice letter when the utility has been authorized or required by Commission order to seek relief by means of an advice letter.

Within 60 days of the adoption of this Decision, SCE is ordered to submit an Information-Only advice letter explaining to the Commission:

1. The legal authority supporting SCE Catalina Gas's intention to backbill SCE Electric "to January 2024 or earlier;"
2. An accounting of the amounts for which SCE Catalina Gas has backbilled SCE Electric and/or intends to backbill SCE Electric, including accounting of any "propane and transportation costs already paid for" that SCE asserts will be subtracted from the amounts subject to backbilling; and

[161] A.23-12-011, SCE-01 at 86.

[162] D.25-06-010 at 14, citing A.23-12-011, SCE-01 at 110.

[163] SCE Gas Rule 17, Section A. Adjustment of Bills, Cal. P.U.C. Sheet No. 1346-G et seq., effective Dec. 22, 2010.

3. Direct citations to the Commission decisions or orders authorizing recovery of the revenue requirements underlying those amounts.

SCE is required to serve this Information-Only advice letter on the service list for this proceeding and on the most recently updated service list for A.23-12-011. SCE did not request and this Decision does not provide authority for SCE Catalina Gas to backbill SCE Electric in any amount.

5.2.17. Utility-Owned Generation and Purchased Power: Tree Mortality Contracts

SCE includes the forecast net costs of its two Tree Mortality Program contracts in its 2026 ERRA forecast, as well as the forecast program audit costs, totaling $21.567 million, including FF&U.[164] California experienced a tree mortality crisis due to prolonged drought conditions and bark beetle infestations that were exacerbated by the drought.[165] To address these conditions, Res. E-4770 and SB 859 required the large IOUs to procure generating capacity from biomass generation facilities that use designated proportions of dead and dying trees located in designated high-hazard zones as feedstock. Pursuant to Pub. Util. Code Section 399.30.3(f), also codified as part of SB 859, the Commission adopted D.18-12-003, authorizing the large IOUs to recover the net costs of these contracts via a non-bypassable charge (TMNBC); SCE includes this NBC in its PPPC.[166] Related costs are tracked in the TMNBC BA.[167]

[164] SCE-05A at 135.

[165] *See* the Proclamation of a State of Emergency on Tree Mortality declared by Governor Edmund G. Brown Jr. on October 30, 2015, available at the California State Library website, https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-Proc-2015-10-30.pdf (last visited Aug. 7, 2025).

[166] D.18-12-003, *Decision Establishing a Non-Bypassable Charge for Costs Associated with Tree Mortality Biomass Energy Procurement*, at OP 9.

[167] SCE-05A at 135.

Res. E-4805 authorized the large IOUs to procure additional biofuel capacity via the Renewable Auction Mechanism (RAM) authorized in Res. E-4770, via a second biomass RAM (BioRAM), or via bilateral contracting.[168] SCE's forecast includes $0.018 million in audit costs, as then-Commission President Picker's concurrence of Res. E-4805 is read as requiring the large IOUs to conduct audits of the biomass facilities from which the required capacity is procured.[169]

5.2.18. Utility-Owned Generation and Purchased Power: Bioenergy Market Adjusting Tariff Contracts

SCE includes the updated 2026 estimated net costs of its Bioenergy Market Adjusting Tariff (BioMAT) program contracts in its 2026 ERRA forecast. The Commission authorized allocation of BioMAT costs via a non-bypassable charge (BM NBC) in D.20-08-043, and authorized collection of the BMNBC from all customers via the PPPC.[170] SCE includes in its 2026 ERRA forecast projected net BioMAT F&PP costs of $4.383 million, (including FF&U).[171] While SCE does not forecast CCA BioMAT costs in its 2026 ERRA forecast, SCE explains how it will include such costs in rates, should the Commission approve those costs via authorizations other than this Decision.[172]

5.3. Discussion of Southern California Edison Company's Portfolio of Resources and Procurement Cost Forecast Methodology

168 Res. E-4805.

169 SCE-05A at 135.

170 D.20-08-043, *Decision Revising the BioEnergy Market Adjusting Tariff Program* at OP 3. *See also* SCE-05A at 136.

171 SCE-05A at 137.

172 SCE-05A at 137.

No parties directly addressed SCE's testimony and workpapers related to its UOG and purchased power forecast components or methodologies, aside from CalCCA's two proposed corrections to SCE workpapers, accepted by SCE in its Amended October Update, as discussed in Section 8, below.[173] After reviewing the testimonies and workpapers, we find SCE's forecasts to be based on reasonable methods of least-cost dispatch modelling, incorporating relevant forecasts of power and gas prices, the physical constraints of each of SCE's generating units, and contractual limitations. SCE's procurement plan was made consistent with the Commission procurement directives and approvals described above. We therefore find SCE's characterizations of its 2026 portfolio of UOG F&PP resources and procurement forecasting methodology to be reasonable, consistent with Pub. Util. Code section 454.5, D.02-10-062, and other authorities described above, and so we approve them.

5.4. Other Southern California Edison Company Programs and Costs

5.4.1. Other Programs and Costs: Demand Response

SCE includes in its 2026 ERR forecast the estimated incentive costs and impacts on projected customer load of the following 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 Resources (RDRR) and CBP as Proxy Demand Resources (PDR). SCE states that these economic- or price-response-based DR programs provide SCE an opportunity *(i.e.*, option) to request the participating customers to curtail their load when the market price

[173] *See also* CalCCA-01 at 1.

reaches a certain threshold or in hours when it is expected that market prices will reach a certain threshold due to temperature or load conditions.[174]

SCE projects that these programs will lead to 5 GWh of energy reductions in 2026. SCE's 2026 DR forecast was based on its Load Impact Protocols and opportunity costs factoring in the maximum hours customers may participate in specific programs per day, month, and year, with load impact estimates based on past customer performance and forecast enrollment rates for program participation.[175] Per D.23-12-005, SCE records all DR incentives in its Demand Response Program Balancing Account (DRPBA), and the annual balances are transferred to the Base Revenue Requirement Balancing Account (BRRBA).[176]

No parties addressed SCE's forecast DR energy reductions or incentive costs. Upon review of Commission precedent and SCE's filings in this proceeding, we find its DR forecasts for 2026 to be reasonable and therefore adopt them.

5.4.2. Other Programs and Costs: CAISO Costs, Load Procurement Charges, and Energy Revenues

SCE's 2026 ERRA forecast includes certain costs and revenues associated with its participation in the CAISO market. SCE's forecast "CAISO costs" are separated into three categories: (1) non-energy related costs; (2) load-procurement charges; and (3) energy-related revenues associated with resources in SCE's portfolio.[177]

[174] SCE-05A at 77.

[175] SCE-05A at 77.

[176] D.23-12-005, *Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027* at 183. SCE-05A at 78. *See also* Section 7.2.4, below.

[177] SCE-05A at 78.

SCE describes its forecast 2026 non-energy related CAISO costs as the net costs of grid management charges, Federal Energy Regulatory Commission fees, congestion revenue rights auction-related costs, ancillary services, CAISO uplift costs, standard capacity product costs, and other non-energy related CAISO costs. SCE states that it considers these non-energy related CAISO costs to be "non-energy related" because they are not sensitive to short-term energy market prices. SCE forecasts these charges based on actual costs incurred in the most recent calendar year (here, 2024).[178]

SCE's Amended October Update includes information on the Day-Ahead Market Enhancements (DAME) and Extended Day-Ahead Market (EDAM) CAISO initiatives, which are "aimed at significantly strengthening system reliability and driving market efficiency," and which should begin producing revenues in May 2026. SCE forecasts no costs related to these initiatives but will record such costs in the CAISO costs section of future ERRA forecast filings.[179]

SCE projects load-procurement charges for its bundled customers "based on multiplying the hourly load net of NEM export adjustments with the hourly SP-15 prices for that hour."[180] These load procurement charges are included in SCE's proposed 2026 ERRA forecast revenue requirement.

Pursuant to Res. E-5183, SCE contracted to develop 537.5 MW of energy storage at three sites to address summer reliability, two of which will be operated in such a way as to offset SCE's load procurement charges in 2026. SCE describes two energy storage sites that will be operated as distribution assets: "Anode" and "Cathode." The energy benefits (revenues) from the resources are debited

[178] SCE-05A at 78-79.

[179] SCE-05A at 79.

[180] SCE-05A at 80.

from the ERRA load procurement charge category, and credited to the distribution subaccount of the BRRBA, where project costs are recorded.[181]

Pursuant to Res. E-5259, the third site (referred to as the "Separator" project) is now counted toward SCE's MTR procurement requirements, and so the costs and benefits of the Separator project are recovered via the 2021 subaccount of the PABA in 2026.[182]

Finally, SCE estimates energy revenue from the dispatch of its portfolio of resources in 2026 by multiplying forecast hourly production by the SP-15 price at that hour. SCE accounts for energy revenues from its PABA-, ERRA-, BMNBC-, CGST-, and CAM-eligible portfolios separately, offsetting the forecast PABA, ERRA, BMNBC, CGST, and NSGBA revenue requirements.[183]

No party directly addressed SCE's forecast 2026 CAISO costs, load procurement charges, or energy revenues. Upon review of SCE's testimonies and workpapers, we find its forecast 2026 CAISO-related costs, load procurement charges, and energy revenue to be reasonable and therefore approve them as proposed.

5.4.3. Other Programs and Costs: Hedging Costs

SCE includes in its 2026 ERRA forecast the estimated costs of SCE's hedging program. SCE hedges its open energy position, which includes both power and the natural gas utilized by SCE's UOG, purchased power contracts, and QF contracts, by purchasing the underlying commodities using a

[181] SCE-05A at 80.

[182] SCE-05A at 80, citing D.21-06-035 and Res. E-5259. *See also* Section 8.2.4, below.

[183] SCE-05A at 80-81.

market-based approach and, when reasonable, call options on the commodities, using a budget-based approach. SCE's projected costs include energy-related transaction fees (clearing and exchange fees, as well as brokerage fees) and option premiums for hedging SCE's open energy position in 2026.[184] Upon review of SCE's testimony and workpapers, we find its hedging costs forecast for 2026 to be reasonable.

5.4.4. Other Programs and Costs: Gas Transportation and Storage

SCE includes no fixed costs related to gas transportation and storage in its 2026 ERRA Forecast. SCE states that it does not expect to incur fixed costs associated with gas transportation agreements due to a change in Southern California Gas Company's (SoCalGas) G-BTS2 rate structure from a fixed reservation charge to a volumetric based charge.[185]

For example, SCE has executed three Backbone Transportation Service (BTS) agreements with SoCalGas, effective October 1, 2023 through September 2026, for transportation capacity under Rate Schedule G-BTS2, a modified fixed variable rate. SCE acquired firm rights for 60,000 MMBtu/day for the entire three-year term of the contract. Due to the change in the G-BTS2 charge from reservation-based to volumetric-based usage starting December 1, 2024, SCE projects no cost associated with its BTS rights.[186]

However, SCE continues to hold month-to-month contracts for gas transportation capacity under rate schedule GT-TLS under volumetric rates for

[184] SCE-05A at 93.

[185] SCE-05A at 93, citing D.24-07-009, *Decision Adopting an All-Party Settlement Agreement and Granting San Diego Gas & Electric Company and Southern California Gas Company Authority to Revise Their Natural Gas Rates and Implement Storage Proposals*.

[186] SCE-05A at 94.

its Mountainview Generating Station, and for its Barre, Center, Grapeland, McGrath, and Mira Loma Peakers. SCE expects these contracts to auto-renew each month in 2026. [187]

SCE's forecast natural gas price used in its PLEXOS LCD simulation (which, as discussed in Section 5.1, is the basis of SCE's procurement cost forecast) is based on monthly NYMEX forward prices at the SoCal Citygate in effect as of August 25, 2025, plus intrastate transportation charges from SoCalGas, as applicable.[188] In this way, forecast volumetric gas transportation costs are incorporated into its 2026 ERRA forecast.

SCE has no gas storage contracts for 2026.[189]

No intervenors addressed SCE's gas transportation and storage costs forecast. Upon the Commission's review of SCE's testimonies, we find its proposed 2026 gas transportation and storage costs to be incorporated into its procurement cost forecast consistent with relevant data and Commission rules, and so we find them reasonable, and approve them as proposed in SCE's Amended October Update.

5.4.5. Other Programs and Costs: Subscription Fees, Financing Costs, and Carrying Costs

SCE includes in its 2026 ERRA forecast the updated estimated costs of subscriptions SCE will use to access independent market data, risk analysis reports, reports on power prices, gas prices, emissions prices, and industry news in 2026. These subscriptions are also used to calculate the short-run avoided cost (SRAC) energy prices for QF projects (*see* Section 5.2.3). For 2026, SCE is

[187] SCE-05A at 94.

[188] SCE-05A at 34.

[189] SCE-05A at 94.

forecasting non-labor expenses related to these subscription fees in the amount of $1.042 million.[190]

SCE includes in its 2026 ERRA forecast updated estimated fuel inventory financing costs and collateral costs. D.93-01-027 authorized SCE to recover actual fuel inventory financing costs[191] and D.02-10-062, which established the ERRA BA, provides for recovery of fuel and credit costs including collateral costs.[192] D.04-01-048 authorizes recovery of financing costs associated with ERRA forecast proceeding under-collections, holding that the three-month commercial paper rate index should be applied to under-collected balances.[193]

SCE anticipates that it will use a $3.35 billion multi-year credit facility (referred to as a revolver) to meet projected collateral requirements, balancing account under-collections, and short-term, general-purpose borrowing needs in 2026.[194] SCE notes that the revolver allows for liquidity support for its commercial paper program, letters of credit, and cash collateral for power procurement needs. The revolver carries only a marginal facility fee if no borrowing or other usage is required. SCE dedicates a minimum amount of the revolver to providing collateral on short notice to requesting counterparties, representing the maximum collateral draw that may be made. The remainder of the revolver is free for general working capital needs.[195]

[190] SCE-05A at 94.

[191] SCE-05A at 96, citing D.93-01-027, *Opinion* at FOF 23-26, 28, 30-32 and COL 14.

[192] SCE-05A at 96, citing D.02-10-062, FOF 23.

[193] SCE-05A at 96, citing D.04-01-048, *Opinion on Southern California Edison Company's Energy Resource Recovery Account* at 10 and OP 4.

[194] SCE-05A at 96. SCE states that, in 2025, it exercised an option to extend the revolver one additional year.

[195] SCE-05A at 97.

SCE's updated proposal would recover a pro-rata share of the costs of the revolver, corresponding to the capacity required to support potential collateral requirements and balancing account under-collections in 2026.[196] The revolver has the following features and fee provisions:

1. a $20,000 annual administrative fee;
2. a 17.5 basis point annual facility fee;
3. a 107.5 basis point participation fee on any outstanding letters of credit;
4. a 20 basis point issuer fee on any letters of credit; and
5. an Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points borrowing (loan) rate.[197]

SCE states that its $3 billion commercial paper program will finance fuel inventories. SCE's 2026 updated ERRA forecast assumes that the market for A3/P2 commercial paper will continue to remain stable and that SCE will be able to utilize the commercial paper program for its short-term borrowing needs. In addition to the $3 billion borrowing capacity, SCE's October Update states that its commercial paper program has A3/P2/F3 rating and a five basis point annualized dealer fee for each issue.[198]

SCE testifies that it will provide letters of credit as collateral for most counterparties.[199] SCE intends to charge the participation and issuer fees associated with each letter of credit issued under the revolver or via bilateral uncommitted agreements to the appropriate balancing accounts.

[196] SCE-05A at 97.

[197] SCE-05A at 96-97. The revolver has a May 2029 maturity date.

[198] SCE's Amended October Update indicated a change in ratings for its commercial paper program, from A2/P2 to A3/P2. *Compare* SCE-01 at 86 and SCE-05A at 98.

[199] SCE-05A at 98.

SCE separately forecasts fuel inventory, GHG procurement compliance, and power procurement collateral requirement carrying costs for its updated 2026 ERRA forecast. First, SCE states that its fuel inventory carrying costs consist of the carrying costs related to (1) its in-core nuclear fuel associated with its ownership interest in the PVNGS, (2) natural gas storage and imbalance, and (3) diesel fuel for the diesel generators on Catalina Island. The projected costs are based on forecast average monthly inventory balances for these resources and the 2026 forecast carrying cost rate. Because short-term debt is assumed to finance the total forecast fuel inventory, the carrying cost forecast is calculated as the interest on the debt necessary to fund the inventory.[200]

SCE also includes an updated forecast of its GHG procurement compliance carrying costs. SCE is authorized to recover the actual interest expense associated with the cash outlays to meet GHG procurement compliance costs.[201] To forecast these costs, SCE uses historical GHG inventory amounts and the applicable interest rate (here, the 90-Day non-financial Commercial Paper Rate).[202]

Finally, SCE forecasts the carrying costs associated with its collateral requirements necessary to procure power, based on average collateral requirements and the projected terms of SCE's revolver, described above.[203]

No intervenor addressed SCE's forecast subscription fees, financing costs, or carrying costs as described in its testimony, workpapers, and Amended October Update documents. Upon review, we find SCE's 2026 forecasts for

[200] SCE-05A at 99.

[201] SCE-05A at 100 and n.95, citing D.14-10-033, *Phase 2 Decision Adopting Standard Procedures for Utilities to File Greenhouse Gas Forecast and Revenue Reconciliation Requests* at Attachment B, Section G - GHG Accounting Procedures for Ratesetting Purposes [hereinafter D.14-10-033].

[202] SCE-05A at 100 and n.96.

[203] SCE-05A at 100.

subscription fees, financing costs, and carrying costs for 2026 as described above to be consistent with Commission decisions authorizing recovery of such costs, reasonable, and therefore approve them for inclusion in SCE's 2026 revenue requirement.

6. Greenhouse Gas Forecast Emissions Costs, Allowance Revenues, Program Allocations, and Customer Returns

AB 32 authorized the California Air Resources Board (CARB) to create a market-based program to reduce California's GHG emissions, leading CARB to create the Cap-and-Trade program. Cap-and-Trade program rules establish a cap on the total emissions that certain emitters can produce each year, measured in metric tons of carbon dioxide equivalent; the cap decreases each year. Utilities must surrender enough compliance instruments to the State each year to equal their specific compliance obligation based on their expected emissions. The program is intended to reduce California's economy-wide GHG emissions to 40 percent below 1990 levels by 2030.[204] Because SCE still owns, operates, and procures power from GHG-emitting resources, it continues to incur emissions costs associated with the program. SCE's forecast 2026 GHG emissions costs are discussed in Section 6.1.

In addition to its own emissions compliance activities, SCE engages in the processes used to help Californians offset the increase in energy costs that result from Cap-and-Trade.[205] Each year, CARB allocates GHG allowances to each of

[204] Information on California's Cap-and-Trade program can be found on the CARB website. California Air Resources Board, Cap-and-Trade Program, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/about (last visited Aug. 7, 2025).

[205] D.12-12-033, *Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor Owned Utilities* at 2-3 [hereinafter D.12-12-033]. D.14-10-033 at 5.

California's electric IOUs as part of the Cap-and-Trade program. The IOUs sell these allowances at quarterly auctions and return the proceeds to ratepayers after program administration costs are deducted and after dedicating a portion of the funds for specific clean energy programs. The elements of SCE's forecast of 2026 GHG allowance revenue returns are discussed in Sections 6.2-6.5.

The Commission adopted standard procedures for electric utilities to forecast GHG emissions costs and to request approval of GHG forecast revenues and revenue returns in D.14-10-033. D.14-10-033 included a series of standard templates for utilities to use to structure their requests and demonstrate compliance with the Commission's approved methodologies (Templates D1-D5).[206] D.14-10-033 also adopted Confidentiality Protocols for Cap-and-Trade-related data. In D.21-08-026, the Commission adopted standards for updates to the GHG cost and revenue allocation templates.[207] Other Commission decisions have made changes to components of this analysis, as described below. We apply the standards adopted in these decisions to determine the reasonableness of SCE's forecast costs, revenues, and proposed return allocations.

6.1. Greenhouse Gas Forecasts: Emissions Costs

SCE includes in its updated ERRA forecast $349.789 million in costs SCE expects to incur to comply with the Cap-and-Trade program in 2026.[208] SCE and other IOUs in California began incurring costs related to the Cap-and-Trade program in January 2013.

[206] D.14-10-033 at Attachment D, GHG Revenue and Reconciliation Application Form.

[207] *See* D.21-08-026, *Decision Adopting Customer Climate Credit Updates* [hereinafter D.21-08-026]. This decision also removed the requirement to include Templates D4 and D5.

[208] SCE-05A at 81.

D.14-10-033 states that GHG emissions costs are forecast, at a high level, by multiplying a forecast of GHG allowances needed (which, in turn, is based on a volume of expected GHG emissions) by a forecast GHG emissions proxy price.[209] SCE's emissions costs can be broken into direct GHG emissions costs and indirect GHG emissions costs. While a split of forecast total GHG emissions costs into direct and indirect costs is confidential per Commission rules,[210] we describe the general methodologies SCE uses to develop these subtotals below.

SCE calculates the first component of the equation, emissions volumes, differently for different resource types.[211] First, SCE incurs direct GHG costs that are either the cost of a compliance instrument (*e.g.,* an allowance or an offset) SCE is required to surrender to CARB (compliance costs)[212] or the reimbursement for compliance instruments that third party generators with whom SCE has procurement contracts must surrender to CARB (procurement contract costs).[213]

209 D.14-10-033 at 14. *See also* SCE-05A at 81.

210 *See* D.14-10-033, Attachment A, Confidentiality Protocols, at 2. *See also* D.06-06-066, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission*.

211 SCE's methodologies for estimating GHG emissions volumes for the direct GHG costs of UOG, procurement contracts, and out of state imports and the indirect GHG costs of in state market power purchases and QF are described in full at SCE-05A at 84-87.

212 Resources for which SCE incurs direct compliance costs are those for which it is the "First Deliverer" of electricity: SCE's UOG in California in-state facilities that emit more than 25,000 metric ton (MT) of GHG, and power SCE imports from out of state as unspecified market power, non-zero specified source power (assessed at a CARB-assigned GHG emissions rate specific to the generating facility), or Asset-Controlling Supplier power (assessed at a CARB-assigned GHG emissions rate specific to the entity that supplies the power). SCE-05A at 82.

213 SCE-05A at 82. SCE notes that, under most of its tolling agreements with in-state gas-fired power generators, SCE bears the responsibility of reimbursing the generator for the GHG costs of the resources for which SCE is under contract. These costs are calculated based on the quantity of gas fired during the contract period and a contract-specific emissions factor. CARB may reimburse the generator financially or with SCE's allowances or offsets. *Id*. *See also* D.14-10-033 at 7.

Consistent with D.14-10-033, SCE forecasts emissions volumes associated with sources of direct GHG costs "as a simple function of the volume of energy SCE expects to generate or purchase from each source and the emissions intensity of the energy produced."[214]

Indirect GHG costs, on the other hand, generally reflect GHG costs embedded in the price of power purchased on the open market or through contracts that do not include GHG settlement terms.[215] In other words, SCE's indirect GHG costs can come from (1) QF contracts or (2) wholesale market purchases of electricity, each of which include price terms that are recalculated monthly and that contain an embedded GHG premium price.[216] D.14-10-033 requires that utilities forecast indirect costs "using a reasonable methodology that is consistent with D.12-12-033, the utility's own ERRA […] filing, and any applicable [C]ARB [C]ap-and-[T]rade program rules." Because the GHG costs for these resources are embedded in market prices that vary over time, SCE states that it uses simplifying assumptions to forecast indirect GHG emissions costs and the volumes associated with them (which we do not describe here, but which are described at length in Exhibit SCE-05A).[217]

SCE uses a forecast proxy price as the second part of the general "volume x price" GHG cost forecast methodology noted above. Consistent with guidance provided in D.14-10-033, SCE uses the ICE settlement price of a 2026-vintage

[214] SCE-05A at 84; D.14-10-033 at 14.

[215] D.14-10-033 at 7.

[216] SCE-05A at 86-87.

[217] SCE's methodologies for estimating GHG emissions volumes for the direct GHG costs of UOG, out of state imports, and procurement contracts and the indirect GHG costs of in-state QFs and wholesale market purchases are described in full detail at SCE-05A at 84-87.

GHG allowance as the basis for its 2026 GHG price forecast.[218] The applicable ICE settlement price for 2026, as of August 25, 2025, was $30.57/MT.[219, 220]

6.1.1. Greenhouse Gas Forecasts: Discussion of Southern California Edison Company's Forecast Greenhouse Gas Emissions Costs

SCE's 2026 forecast GHG emissions costs are calculated consistent with D.14-10-033 and the updated templates provided by D.21-08-026. SCE uses reasonable simplifying methods for calculating indirect GHG emissions volumes and costs that are particular to the type of resource for which the volumes are estimated. SCE proposed methods are consistent with the methods previously approved by this Commission.[221] No intervenors have commented on or opposed SCE's forecast of 2026 GHG emissions costs. We find SCE's forecast 2026 GHG emissions costs to be reasonable and approve them.

6.2. Greenhouse Gas Forecasts: Calculation of 2026 Greenhouse Gas Allowance Revenues and Revenue Returns

This section describes the factors and calculations SCE uses to forecast its updated 2026 GHG allowance revenues, clean energy program revenue set-asides, Emissions-Intensive Trade-Exposed (EITE) facility returns, and the 2026 California Climate Credits. As noted above, each year CARB allocates allowances for utilities to sell at auction and return the resulting revenues to ratepayers. SCE proposes setting aside $33.094 million for clean energy

218 SCE-05A at n.79. D.14-10-033 at 12.

219 SCE-05A at 81.

220 Pursuant to D.14-10-033, actual GHG costs are trued up as a part of the overall true up of SCE's procurement balancing accounts. D.14-10-033 at 4; SCE-05A at 91.

221 *See e.g.*, D.24-12-039 at 38-39.

programs[222] and returning $443.279 million[223] in net GHG allowance revenues to eligible EITE, small business and residential customers in 2026. Based on these updated estimates, residential and small commercial customers can expect a semi-annual 2026 California Climate Credit of $36.00.[224] SCE's program administration costs and GHG allowance revenues are recorded in SCE's Greenhouse Gas Revenues Balancing Account (GHGRBA).

6.2.1. Greenhouse Gas Forecasts: 2026 Forecast Allowance Auction Revenues and 2025 Revenues True Up

SCE forecasts 2026 GHG allowance revenues totaling $682.214 million, before accounting for FF&U.[225] Consistent with direction provided in D.14-10-033, SCE forecasts each year's GHG allowance revenue by multiplying the total volume of allowances that CARB has allocated to SCE for 2026 by a forecast proxy price that is meant to represent auction price for these allowances.[226]

SCE forecasts a 2026 CARB consignment of allowance volumes equaling 22,316,439 metric tons of carbon dioxide (CO_2) equivalent emissions.[227] SCE multiplies this allowance forecast by its forecast proxy price, the ICE settlement price for 2026 vintage allowances with delivery in December 2026 as of August 25, 2025, $30.57/MT, to calculate its forecast 2026 Cap-and-Trade revenues.[228]

[222] SCE-05A at Table VII-34, ln. 14.

[223] SCE-05A at Table VII-34, ln. 17.

[224] SCE-05A at Table VII-34, ln. 28.

[225] SCE-05A at Table VII-34, ln. 5.

[226] SCE-05A at 103. *See also* D.14-10-033 at 13.

[227] SCE-05A at Table VII-34, ln. 2.

[228] SCE-05A at 103. *See also* D.14-10-033 at 13.

SCE incorporates anticipated FF&U to arrive at an updated 2026 GHG allowance auction revenue forecast of $690.069 million.[229] SCE's Amended October Update forecasts less GHG allowance revenue in 2026 due to a lower applicable proxy price than was forecast in its May Filing.[230]

SCE's forecast of 2026 GHG allowance auction revenues as described in testimony and depicted in workpapers is calculated consistent with Commission rules provided in D.14-10-033 and D.21-08-026. No party has objected to SCE's forecast of GHG allowance auction revenues. We find SCE's forecast to be reasonable and adopt it.

6.2.1.1. Greenhouse Gas Forecasts: 2025 Allowance Auction Revenue True Up

D.14-10-033 states that any amount of over- or under-forecast GHG revenues is added to or subtracted from the total GHG revenue return for the next forecast year. Because this assessment of prior-year actual revenues occurs via ERRA forecast proceedings for which the evidentiary record typically closes in October or November, this true up should be based on actual auction revenues and GHG revenues returned to customers through the end of the third quarter, and on forecasts for the fourth quarter.[231]

SCE forecasts an over-estimate of 2025 auction revenues of $178.472 million,[232] meaning that SCE disbursed more revenue than it actually received in 2025. As of its October Update, SCE's 2025 GHG allowance revenues true up includes actual proceeds from SCE's February, May, and August 2025 auctions,

[229] SCE-05A at Table VII-34, sum of lns. 5 and 7.

[230] SCE-05A at 102.

[231] D.14-10-033 at 36-37.

[232] SCE-05A at Table VII-34, ln. ~~8~~5, difference between 2025 forecast and actual values.

and a forecast for the remaining December auction. The forecast was created by, again, multiplying the remaining portion of the total allowances allocated to SCE for 2025 by a proxy price. SCE's proxy price is $28.81/MT, the ICE futures settlement price for December 2025 deliveries as of August 25, 2025, in accordance with D.14-10-033.[233]

No party has commented on SCE's true up of 2025 allowance revenues. SCE's forecast is calculated consistent with Commission rules and so is reasonable and adopted.

6.2.2. Greenhouse Gas Forecasts: 2026 Greenhouse Gas Administrative Costs and True Up of 2025 Administrative Costs

SCE provides an updated estimate of $0.386 million in costs that it will incur to administer the California Climate Credit program in 2026.[234] SCE notes that most of these costs are related to its biannual disbursements of the California Climate Credit in April and October, including production and postage costs.[235] SCE forecasts approximately $4,443 in related FF&U, for a total 2026 administrative cost forecast of $0.390 million.[236]

The updated forecast 2026 total is lower than that presented for 2025, in part because SCE's 2025 forecast costs include the whole-project IT-related costs SCE states it incurred to update its billing system to implement Res. E-5339, issued in August 2024 to modify the eligibility rules for the Small Business Climate Credit, discussed further below. In its Amended October Update, however, SCE states that most of the costs of this billing system upgrade will be

[233] SCE-05A at ~~100~~103; D.14-10-033 at 12.

[234] SCE-05A at Table VII-34, ln. 10.

[235] SCE-05A at 106 and n.102. *See also* SCE-05A at Table VII-30.

[236] SCE-05A at Table VII-34, lns. 11 and 13.

absorbed through SCE's normal IT budget, "with only a minimal incremental amount of $0.049 million to be recorded in the Greenhouse Gas Administrative Costs Memorandum Account (GHGACMA)."[237] For this reason, SCE recorded significantly less than the forecast of IT system upgrade costs in 2025. The difference rolls over, increasing SCE's 2026 GHG allowance revenue returns.

On review of SCE's testimony and workpapers, we find SCE's updated forecast of the costs it will incur to administer the California Climate Credit program in 2026 to be reasonable and adopt it. No party has commented on SCE's forecast of administrative costs.

6.2.2.1. Greenhouse Gas Forecasts: True Up of 2025 Administrative Costs

D.14-10-033 requires that utilities true up their prior-year forecasts of administrative costs incurred to administer the California Climate Credit program with actual costs and carry the balance forward into the calculation of the current forecast California Climate Credit.[238] SCE projects that it over-forecast administrative and outreach costs in 2025. The decision resolving SCE's 2025 ERRA forecast adopted a $0.868 million forecast of GHG administration and outreach costs.[239] SCE states in its Amended October Update that it expects the actual year-end total administrative costs to be $0.413 million, based on costs recorded through August 31, 2025.[240]

SCE's updated 2025 Climate Credit administrative costs true up is calculated consistent with Commission rules and so is reasonable and we adopt it.

[237] *See* SCE-05A at Table VII-30. *See also* SCE-05A at 105-106.

[238] D.14-10-033 at 26.

[239] D.24-12-039 at 40-41; SCE-05A at 105.

[240] SCE-05A at 102.

Combining the forecast over-disbursement of allowance revenues in 2025 and the overcollection of 2025 administrative costs, a year-end 2025 balance of $213.307 million in the GHGRBA carries forward,[241] decreasing the revenues available for 2026 clean energy programs and customer returns. Accounting for the 2026 and 2025 forecasts and actual allowance auction revenues and administrative expenses, SCE projects a net total of $476.372 million to allocate to clean energy programs and customer returns in 2026, as illustrated in Table 6.1, below.[242]

Table 6.1: Summary of 2026 GHG Allowance Auction Revenues Forecast and Related Expenses[243]

Program	SCE Proposed (millions)
GHG Auction Revenues	
2026 Forecast GHG Auction Revenues	$682.214 million
2026 Forecast GHG Auction Revenue Associated FF&U	$7.856 million
2025 GHGRBA Revenue True Up	- $213.307 million
Administrative Expenses	
2026 Forecast Administrative and Outreach (A&O) Costs	-$0.386 million
2026 Forecast A&O Associated FF&U	-$.004 million
GHG Auction Revenue Available for Clean Energy Programs and Customer Returns in 2026	$476.372 million[244]

6.3. Greenhouse Gas Forecasts: 2026 Clean Energy Program Set-Asides

[241] SCE-05A at Table VII-34, ln. 4.

[242] SCE-05A at Table VII-34, sum of the absolute values in lns. 14 and 17.

[243] Figures are derived from SCE-0A5 at Table VII-34.

[244] Values may not add up to total due to rounding.

As noted above, Public Utilities Code section 748.5 authorizes the Commission to allocate up to 15 percent of GHG allowance revenues for otherwise-unfunded clean energy and energy efficiency projects and requires the Commission to return the remaining GHG allowance revenues to customers.[245]

SCE proposes a $33.094 million total set-aside for clean energy programs in 2026, comprised of forecasts of expenses for the following programs, as described below: Solar on Multifamily Affordable Housing Program (SOMAH) and Disadvantaged Community (DAC) Programs.[246]

6.3.1. 2026 Clean Energy Program Set-Asides: Solar on Multifamily Affordable Housing Program

SCE proposes an updated $23.264 million set-aside for its SOMAH program in 2026.[247] AB 693 (Eggman) Stat. 2015, Ch. 582 created the SOMAH program, and allocated up to the lesser of $100 million or 10 percent of all IOU GHG allowance revenues for SOMAH program costs for fiscal years 2016 through 2026. In D.17-12-022, the Commission required that 10 percent of allowance auction proceeds be reserved for SOMAH through each IOU's ERRA applications and established that each IOU must contribute its proportionate share of the $100 million, when necessary, based on its share of allowance sale proceeds from the previous four quarters.[248] D.20-01-022 clarified that prior-year

[245] AB 1207 amended Pub. Util. Code § 748.5 to render the provision obligating the Commission to direct this set-aside inoperative as of July 1, 2026.

[246] SCE-05A at Table VII-34, ln. 14.

[247] SCE-05A at Table VII-34, ln. 14a.

[248] D.17-12-022, *Decision Adopting Implementation Framework for Assembly Bill 693 and Creating the Solar on Multifamily Affordable Housing Program* at OP 4 and OP 7.

SOMAH set-aside of 10 percent of forecast GHG allowance revenues should be trued-up based on actual GHG allowance revenues received.[249]

In D.20-04-012, the Commission extended SOMAH through June 2026, clarified existing budgeting requirements, and set additional reporting requirements.[250] 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 the $100 million budget and by identifying a set allocation for each IOU's share (rather than modifying the percentage shares each year based on prior four quarters' revenues). This pathway is dependent on the IOUs' ability to adequately demonstrate that their combined forecast GHG allowances will equal or exceed $1 billion.[251] As a result, IOUs may propose setting aside 10 percent of their forecast GHG revenue or their share of $100 million.

Pursuant to OP 3 of D.22-09-009, after confirming that the combined 2026 SOMAH Program budget would exceed $100 million, SCE proposes to set aside its approved share of the $100 million cap, $23.264 million, to fund SOMAH through D.20-04-012's June 2026 program extension, and based on SCE's share of funding for a six-month budget as shown in Table 2 of D.22-09-009.[252]

SCE notes that its 2024 SOMAH true up revealed a $3.328 million difference between SCE's share of the $100 million cap based on actual GHG revenues recorded in 2024, and its previously approved set-aside in the 2024

[249] D.20-01-022, *Decision Adopting Southern California Edison Company's 2020 Electric Procurement Cost Revenue Requirement Forecast and 2020 Forecast of Greenhouse-Gas-Related Costs* at COL 15.

[250] D.20-04-012, *Decision Determining Revenue Availability and Adequacy of Participation and Interest in the Solar on Multifamily Affordable Housing* at OP 6, OP 5, and OPs 2-4, respectively.

[251] D.22-09-009, *Decision Modifying Decision (D.) 17-12-022 and D.20-04-012 Regarding Process for Solar on Multifamily Affordable Housing Program Funding* at OP 1 and OP 3.

[252] SCE-05A at 108-109 and n.109. SCE notes that its set-aside is for the first half of 2026 and so the set-aside amount represents half of SCE's annual share adopted in D.22-09-009. *Id.*

ERRA filings.[253] This extra funding rolls over to be available in 2026, yielding a total available SOMAH budget of approximately $26.592 million.[254]

6.3.2. 2026 Clean Energy Program Set-Asides: Disadvantaged Community Programs

SCE proposes a 2026 set-aside for the DAC-Single Family Solar Homes (SASH) program of $4.60 million. In D.18-06-027, the Commission implemented AB 327[255] by creating the DAC Single Family Solar Homes (SASH) program, which provides financial incentives towards the installation of solar generating systems on the homes of low-income homeowners. In the same decision, the Commission set an annual, all-IOU $10 million budget for DAC-SASH, to be funded first via GHG allowance revenues, and through PPP funds, should GHG allowance revenues be exhausted. SCE's proportionate share of that $10 million annual budget is 46 percent, starting in 2019.[256] Thus, in its 2026 ERRA forecast, SCE has allocated $4.60 million of its projected GHG allowance revenues to its DAC-SASH program (46 percent of $10 million).[257]

In addition to creating the DAC-SASH program, D.18-06-027 created Green Tariff options for DACs, including the DAC-GT and Community Solar Green Tariff (CSGT).[258] SCE proposes a zero dollar set-aside for its DAC-GT and

[253] SCE-05A at 109-110, citing AL 5482-E-B.

[254] SCE-05A at Table VII-34, sum of lns. 14a and 14b.

[255] AB 327 (Perea), Stats. 2013, ch. 611.

[256] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities* at 1 and OP 8 [hereinafter D.18-06-027].

[257] SCE-05A at 111.

[258] D.18-06-027 at OP 11 and OP 12.

CSGT programs, as the set-aside funds anticipated to be available through the end of 2025 remain greater than forecast costs through 2026.[259]

Finally, D.18-06-027, as clarified by Res. E-4999, allowed authorized CCAs to access these same program funding sources to run their own Green Tariff programs, including DAC-GT and CSGT programs. On April 1, 2025, Clean Power Alliance of Southern California (CPA) submitted AL 0035-E, showing a FY 2026 funding request of $5.142 million, which is reduced for prior year unspent amounts. SCE states that, of the total funding requested, the above market generation portion of $1.902 million will be funded through GHG allowance revenue, with the remainder of $3.240 million recovered through the PPP Charge.[260] On April 1, 2025, Lancaster Choice Energy, Pico Rivera Innovative Municipal Energy, and San Jacinto Power, jointly as CalChoice, submitted a joint advice letter demonstrating surplus funding through program year 2026 of $0.119 million. Therefore, SCE requests no additional funding to be set aside for this program through GHG allowance revenues (or PPP funds).[261]

In its Amended October Update, SCE notes that on August 14, 2025, Orange County Power Authority (OCPA) submitted AL 13-E to establish and implement their DAC-GT program and is requesting approval of its initial 2026 and 2027 budgets. If OCPA's request is granted, SCE states it will include these budgets in its 2027 ERRA forecast.[262]

[259] SCE-05A at 112. Green Tariff programs are described generally in Section 5.2.14 of this Decision.

[260] SCE-05A at 113.

[261] SCE-05A at 113-114 and n.119, citing Lancaster Choice Energy, AL 34-E, Pico Rivera Innovative Municipal Energy, AL 29-E, and San Jacinto Power AL 27-E.

[262] SCE-05A at 113-114.

SCE's proposed GHG allowance set-asides for clean energy and efficiency programs are calculated consistent with governing statutes and applicable Commission decisions. No party commented on SCE's proposals. We find these proposals reasonable and adopt them.

6.4. Greenhouse Gas Forecasts: 2026 California Climate Credit Calculation

SCE proposes to return $443.279 million in GHG allowance proceeds to customers in 2026. From that amount, SCE proposes to set aside $58.908 million in revenues for recipients of California Industry Assistance, available to EITE facilities, who receive credits to minimize leakage associated with Cap-and-Trade program costs in purchased energy.[263] The Commission adopted methodologies for calculating EITE returns in D.14-12-037, as modified by D.15-08-006 and D.16-07-007,[264] and updated these methodologies in D.21-08-026.[265] The Commission calculates EITE returns[266] for each eligible facility using emissions-efficiency benchmarks, while the utility is responsible for disbursement.[267]

Once EITE facilities receive credits, the remaining amount ($384.371 million) flows through to small business and residential customers.[268]

[263] SCE-05A at Table VII-34, at ln. 19. Customers operating EITE businesses are eligible to receive industry assistance in the form of a bill credit each April.

[264] *See* D.14-12-037, *Decision Adopting Greenhouse Gas Allowance Revenue Allocation Formulas and Distribution Methodologies for Emissions-Intensive and Trade Exposed Customers* [hereinafter D.14-12-037].

[265] D.21-08-026 at OP 3-OP 5.

[266] D.14-12-037 at OP 3.

[267] CPUC website, "California Industry Assistance," https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-industry-assistance, last visited Sept. 8, 2025.

[268] SCE-05A at Table VII-34, ln. 29. D.21-08-096 at 7.

D.15-07-001 removed the volumetric component of the residential credit adopted in D.12-12-033, based on customer usage, and adopted a flat rate credit that is the same for all residential customers starting January 1, 2016.[269] D.21-08-026 changed the small business credit from the volumetric credit set forth in D.12-12-033 to a flat rate credit equal to the residential credit. Based on the estimated number of small commercial and residential customers in 2026, SCE proposes a $36 California Climate Credit, to appear on and offset residential and small commercial customer bills twice in 2026.[270]

6.5. Greenhouse Gas Forecasts: Discussion

No intervenor addressed SCE's proposed EITE returns or small business and residential California Climate Credits for 2026. Upon review of SCE's testimony and workpapers, we find SCE's proposed customer returns to be calculated pursuant to applicable Commission decisions, consistent with the law, and reasonable and so we approve them.

Table 6-2: SCE's Updated 2026 Allowance Auctions Revenue Allocations and Related Costs

Description	2026 Forecast ($000)
Year-End 2025 GHGRBA Carry-Over	($213,307)

[269] D.15-07-001, *Decision on Residential Rate Reform For Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates* at 254; D.12-12-033 at OP 1. D.21-08-026 at OP 6; D.12-12-033 at OP 1.

[270] SCE-05A at Table VII-34, ln. 28.

2026 GHG Allowance Revenues • Franchise Fees and Uncollectibles (FF&U)	$682,214 $7,856
GHG Administrative Expenses • FF&U	$386 $4
Subtotal 2026 GHG Allowance Revenues	**$476,372**
• AB 693/SB 9 Set-Aside for SOMAH • AB 693/SB 9 Set-Aside SOMAH True up • AB 327 SCE's DAC-SASH Program • AB 327 SCE's DAC-GT and CSGT Programs • AB 327 CPA's DAC-GT and CSGT Programs • AB 327 Cal Choice's DAC-GT and CSGT Programs **Subtotal Clean Energy Program Set-Asides**	($23,264) ($3,328) ($4,600) $ - ($1,902) $ - **($33,094)**
Net GHG Revenues Available for Returns	**$443,279**
EITE Returns	$58,908
Revenues Remaining for Small Business and Residential Returns	$384,371
Estimated Number Eligible for Small Business and Residential Credits	5,288,762
Estimated 2026 Semi-Annual California Climate Credit	**$36.00**

7. Southern California Edison Company's 2026 Energy Resource Recovery Account Revenue Requirement Forecasts, as Modified

SCE proposes an updated 2026 ERRA forecast revenue requirement of $~~4.68~~4.689 billion and a F&PP revenue requirement sub-component of $~~4.824~~4.723 billion in its Amended October Update.[271] The proposed customer returns from GHG allowance revenues allows the total ERRA revenue requirement to be less than the F&PP revenue requirement. Table 7-1, below, summarizes the ERRA revenue requirement subtotals in current rates, those in

[271] SCE-05A at ~~118-119 and n.119~~Table II-1.

SCE's May Filing and Amended October Update, and the amounts approved in this Decision.[272]

The biggest changes in revenue requirement between SCE's May Filing and the Amended October Update are (1) the impacts of the application of the Commission's Final 2025 MPBs, which caused a large decrease in the year-end 2025 ERRA BA balance and a large increase in the YE 2025 PABA balance, and (2) a large decrease in anticipated GHG allowance revenues, increasing the delivery service revenue requirement and decreasing expected customer returns in 2026.

[272] *See* SCE-01 at Table II-2; SCE-05A at Table II-3.

Table 7-1: 2026 ERRA Forecast Revenue Requirement (RR, $000)

	Description	Amount in Current Rates	May Filing Forecast	Amended October Update Forecast and Adopted Amount
1	***Generation Service RR***			
2	2026 F&PP*:			
3	ERRA BA-related	$2,831,352	$2,759,015	$2,710,124
4	PABA-related	$1,249,871	$1,538,984	$1,494,274
5	GTSRBA-related	$7,132	$7,552	$7,308
6	2025 YE ERRA BA Balance	($276,313)	$69,234	($898,645)
7	2025 YE PABA Balance	$740,627	$61,792	$1,318,350
8	2025 YE ESMA Balance (net)	($249)	$185	$1,314
9	**Total ERRA Forecast Generation Service RR**	**$4,552,375**	**$4,436,731**	**$4,632,727**
10	***Delivery Service RR***			
11	New System Generation Rate Component:*			
12	2026 NSG F&PP	$457,467	$473,358	$473,047
13	2025 YE NSGBA Balance	$78,024	($20,859)	($24,718)
14	MCAM Rate Component:			
15	2026 MCAM F&PP	$1,558	$1,322	$3,682
16	2025 YE MCAMBA Balance	$3,151	$1,602	$2,522
17	Nuclear Decommissioning Rate Component:			
18	2026 Spent Nuclear Fuel	$5,157	$7	$5,332
19	Distribution Rate Component			
20	2026 BRRBA-D F&PP	($19,169)	($18,971)	($2,684)
21	GHG Allowance Revenues	($641,624)	($528,071)	($433,279)
22	Public Purpose Programs Charge:^			
23	2026 PPPC F&PP	$5,314	$34,054	$32,095
24	2025 YE TMNBCBA Balance	$21,243	$7,473	$14,240
25	2025 YE BMNBCBA Balance	($2,842)	($1,521)	($3,764)
26	**Total ERRA Forecast Delivery Service RR**	**($91,694)**	**($51,605)**	**$56,464**
27	**TOTAL ERRA PROCEEDING RR**	**$4,460,681**	**$4,385,126**	**$4,689,200**

* Includes Direct GHG costs. ^ includes forecast 2026 PPPC costs related to the TMNBC, the BMNBC, the LCR-PPP, and DAC-GT/CSGT PPPC amounts, as further described below.

7.1. Updated Generation Service Revenue Requirement

SCE proposes an updated 2026 generation service revenue requirement of $4.633 billion, including FF&U.[273] This forecast is $80.352 million more than the forecast included in current rates. SCE's 2026 ERRA forecast generation service revenue requirement includes the estimated 2026 F&PP costs (including the related GHG costs) tracked in the ERRA BA, the PABA, GTSR BA.[274]

SCE's proposed generation service revenue requirement also includes the estimated year-end 2025 balances of the ERRA BA, the PABA, and SCE's Energy Settlement Memorandum Account (ESMA) and the Litigation Costs Tracking Account (LCTA, a subaccount of the ESMA),[275] representing F&PP cost over-collections, which would be returned to customers, or F&PP costs incurred but not recovered in prior years (under-collections), and offset by actual revenues.[276]

7.1.1. Generation Service: Updated 2026 Energy Resource Recovery Account Balancing Account Forecast

SCE proposes an updated $2.710 billion 2026 ERRA BA revenue requirement.[277] Pursuant to Pub. Util. Code section 454.5 (d)(3), the Commission adopted the ERRA BA as the mechanism by which utilities would track actual procurement costs against forecast amounts.[278] Amounts recorded to the ERRA

[273] SCE-05A at 122.

[274] SCE-05A at Table II-3.

[275] The year-end 2025 balance of the LCTA-ESMA contains estimated costs related to the net generator refund items stemming from the 2000-2001 California Energy Crisis. SCE-05A at 123.

[276] SCE-05A at 122-123.

[277] SCE-05A at 123.

[278] D.02-10-062 at OP 14.

BA are recovered from bundled customers through generation service rates.[279]

As noted by SCE, it was later authorized to:

> modif[y] the ERRA BA to record only the costs associated with SCE's wholesale short-term market purchases (*i.e.*, the costs of meeting remaining bundled service customers' full energy and ancillary services requirements through the CAISO market with contract terms of less than one year in duration), the fuel and purchased power costs of any contracted resources that are not eligible for recovery in the PABA or the NSGBA (or any other balancing account), and the actual retained RPS and RA value from SCE's [PABA] eligible resources (calculated using the Commission-provided Forecast and Final RPS and RA Adders) used to meet bundled service customer requirements.[280]

The 2026 ERRA BA forecast is impacted by the disputed issues in this case regarding the valuation of certain RPS instruments that may be used for bundled service customer compliance, discussed in Section 8 of this Decision.

7.1.1.1. Updated Year-End 2025 Energy Resource Recovery Account Balance

SCE also requests approval of an updated estimated $898.645 million over-collection in the ERRA BA as of December 31, 2025. SCE estimates its year-end 2025 ERRA BA balance using recorded amounts from January through September 30, 2025, and prior-year authorized forecasts of the remaining months' activity, adjusted by market forwards as of October 3, 2025.[281] SCE states

[279] SCE-05A at 13-14.

[280] SCE-05A at 125, citing AL 3914-E. SCE identifies the specific resources and costs that are tracked in the ERRA BA in SCE-05A, Table IV-9 and describes how the production and costs of each resource are estimated in SCE-05A, as summarized in Sections 4, 5, and 6 of this Decision.

[281] SCE-05A at 124-125. Because SCE's YE 2025 ERRA Forecast is based on actual revenues received through September 2025, SCE's 2026 ERRA forecast needs no adjustment to reflect the results of SCE 2024 Trigger Exceedance, which was amortized and returned to customers up through September 30, 2025. SCE-05A at 5-6.

that the forecast over-collection "is largely the result of the true up and application of the 2025 Final RA and RPS Adders to actual retained RA and RPS in the ERRA BA."[282]

SCE's request to true up its 2025 ERRA BA is a component of its request to true up its 2025 PCIA Surcharges, discussed holistically in Section 8.2.4.1. Section 8 also illustrates how the year-end 2025 ERRA BA could be impacted by the disputed issues in this case, should SCE use or have used certain RPS instruments for bundled customer compliance in 2025. Finally, SCE's trued-up forecast year-end 2025 ERRA Trigger Balance exceeded SCE's ERRA Trigger Point and Threshold as of September 30, 2025. SCE's 2025 trigger exceedance is also addressed in Section 8.2.4.1.

Upon consideration of the Application, testimonies, comments, briefs, and workpapers in our record, and consistent with our determinations in Section 8, we find SCE's proposed updated 2026 ERRA BA revenue requirement and estimated year-end 2025 ERRA BA balance reasonable and forecast consistent with applicable rules, orders, and Commission decisions. SCE is authorized to transfer its year-end 2025 ERRA balance to the 2025 vintage subaccount of the PABA.

7.1.2. Generation Service: Updated 2026 Portfolio Allocation Balancing Account Forecast

SCE proposes a 2026 PABA revenue requirement of $1.494 billion, including FF&U.[283] D.18-10-019 modified the balancing accounts to be considered in ERRA forecast proceedings and directed utilities to create PABAs - new

[282] SCE-05A at 125.

[283] SCE-05A at 123.

vintaged balancing accounts to track above-market costs and revenues associated with their PCIA-eligible electric portfolios, discussed in Section 8, below.[284, 285]

The PABA addresses the issue of costs incurred, in part, on behalf of customers that no longer receive power generation from SCE; these resources are generally long-term, fixed-price contract costs and certain utility-owned generation costs.[286] As discussed further in Section 8 of this Decision, the 2026 PABA forecast is impacted by the disputed issues in this case.

7.1.2.1. Updated Year-End 2025 Portfolio Allocation Balancing Account Balance

In addition to the forecast 2026 PABA revenue requirement, SCE requests recovery of the estimated remaining PABA balance as of December 31, 2025. SCE projects that the remaining balance in the PABA at year's end will be an under-collection of $1.318 billion (including FF&U).[287] SCE estimates its year-end 2025 PABA balance using recorded amounts from January through September 30, 2025, and prior-year authorized forecasts of the remaining months' activity.[288]

Like SCE's request to true up its 2025 ERRA BA, SCE's request to true up its year-end 2025 PABA balance is a component of its request to true up its 2025 PCIA revenue requirement. The calculation of the 2025 year-end PABA balance could also be impacted by disputed issues, as addressed in Section 8 of this

[284] SCE defines "above-market costs of PABA-eligible resources" 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." SCE-05A at n.129, citing D.18-10-019 at 42 and OP 1.

[285] SCE identifies the resources tracked in its PABA in SCE-05A, Table IV-9 and describes how the production and costs of each resource are estimated in Exhibit SCE-05A, as summarized in Sections 4, 5, and 6 of this Decision.

[286] SCE-05A at 123-124.

[287] SCE-05A at 126.

[288] SCE-05A at 124.

Decision. Finally, SCE's true up of the year-end 2025 PABA contributed to SCE's 2025 ERRA Trigger exceedance, also discussed in Section 8.

Upon consideration of the Application, testimonies, comments, briefs, and workpapers submitted in this proceeding, and consistent with our reasoning and findings related to disputed issues as expressed in Section 8, we find SCE's proposed 2026 PABA revenue requirement and year-end 2025 PABA balance, as proposed in its Amended October Update, to be based on reasonable interpretations of applicable rules and Commission decisions, and so we approve them.

7.1.3. Generation Service: Updated 2026 Green Tariff Shared Renewables Balancing Account Forecast

SCE requests an updated 2026 GTSR revenue requirement of $7.308 million, including FF&U.[289] D.15-01-015 authorized SCE to track the actual costs of contracts procured pursuant to SCE's GT program, which allows customers opportunities to purchase more power from renewable sources.[290] Costs tracked in the GTSRBA are recovered from SCE's bundled service customers.[291]

No party has opposed or commented on SCE's proposed 2026 GTSR revenue requirement. Upon consideration of the Application, testimonies, and workpapers, we find SCE's proposed 2026 GTSRBA revenue requirement reasonable and consistent with applicable rules, orders, and Commission decisions, and approve it.

[289] SCE-05A at 124.

[290] SCE's GTSR purchased power contracts are discussed in Section 5.2.14 of this Decision.

[291] SCE-05A at 13-14.

7.1.4. Generation Service: Estimated Energy Settlement Refunds and Litigation Costs Tracking Account Year-End 2025 Balance

SCE requests to put into 2026 rates an estimated $0 in settlement refunds remaining in the ESMA and recorded litigation costs of $1.314 million remaining in the LCTA-ESMA as of December 31, 2025, including FF&U.[292] SCE is pursuing refunds from generators who overcharged SCE (and the other California IOUs) for electricity during the 2000-2001 California Energy Crisis. SCE tracks such settlement funds in the ESMA and returns them to customers. In Res. E-3894, the Commission required SCE to maintain an LCTA within the ESMA to track the litigation costs that are set aside in the Federal Energy Regulatory Commission investigation settlement agreements and actual litigation costs incurred by SCE.[293] These costs are netted against any settlement refunds before the remaining balance is returned to ratepayers.[294]

No party commented on SCE's forecasts of remaining year-end 2025 ESMA/LCTA costs. Upon review of SCE's Application, testimonies, and workpapers, we find SCE's forecasts of these costs reasonable and consistent with applicable rules and Commission decisions and therefore approve them.

7.2. Delivery Service Revenue Requirement

SCE proposes a delivery service revenue requirement of $56.474 million.[295] This total delivery service revenue requirement forecast is $148.168 million more than the forecast included in current rates (negative $91.694 million).[296] SCE's

[292] SCE-05A at 126.

[293] SCE-05A at 126.

[294] SCE-05A at Table VIII-35, n.1.

[295] SCE-05A at 127.

[296] SCE-05A at Table II-3.

delivery service revenue requirement is recovered from all bundled and departing load SCE customers through allocation mechanisms other than the CTC, the PCIA, and the Wildfire Non-bypassable Charge (NBC).[297, 298]

The delivery service revenue requirement includes, in total: (1) 2026 NSG forecast F&PP and GHG costs (including CPE-related costs) and the estimated year-end 2025 NSGBA balance; (2) 2026 System Reliability MCAM-related forecast costs and the estimated year-end 2025 balance in the MCAMBA; (3) 2026 forecast spent nuclear fuel storage costs; (4) the 2026 Base Revenue Requirement Balancing Account, Distribution sub account (BRRBA-Distribution) F&PP forecast costs; (5) GHG allowance revenues; (6) 2026 Public Purpose Programs Charge (PPPC) forecast F&PP costs, including those related to the Tree Mortality NBC (TMNBC), the BioMAT NBC (BMNBC), Local Capacity Requirement (LCR)-PPP costs, and the Disadvantaged Communities-Green Tariff/Community Solar Green Tariff (DAC-GT/CSGT) PPPC and (7) the estimated year-end 2025 balances in the TMNBCBA and the BMNBCBA.[299]

The largest change between SCE's May Filing and its Amended October Update's forecast 2026 delivery service revenue requirement is the impact of the updated anticipated 2026 GHG proxy price, as discussed below.

7.2.1. Delivery Service: Updated New System Generation Balancing Account 2026 Forecast and Year-End 2025 Balance

[297] D.24-12-039 at 52.

[298] The CTC, PCIA, and Wildfire Mitigation Non-Bypassable Charge are discussed in Section 8 of this Decision.

[299] SCE-05A at Table II-3.

SCE forecasts updated 2026 F&PP costs to be tracked in the NSGBA[300] totaling $473.047 million, including direct GHG costs and FF&U; this represents a $15.580 million increase from what is currently in rates.[301] Pursuant to the authorities discussed in Section 5.2.6 of this Decision, in addition to the net capacity costs of New System Generation contracts,[302] costs tracked in the NSGBA include the respective portion of system reliability costs previously recorded to the SRPMA,[303] the emergency summer reliability procurement ordered by D.21-02-028, D.21-03-056, D.21-12-015,[304] the emergency reliability procurement required by D.23-06-029,[305] the storage charging costs and market revenues of the UOS DESI 2,[306] certain CHP contract costs,[307] and Central Procurement Entity procurement and administration costs.[308] The costs tracked in the NSGBA are recovered from all benefitting customers (bundled service customers and unbundled customers) via the NSG rate component.[309]

SCE forecasts an updated 2025 year-end over-collection balance in the NSGBA of $24.718 million, including FF&U, representing a $102.742 million

[300] D.07-09-044 established the NSGBA at OP 2.

[301] SCE-05A at Table II-3.

[302] SCE lists the contracts and authorizing documents for its CAM-eligible resources in SCE-05A at Table VIII-39. *See also* Section 5.2.6.

[303] SCE-05A at 133 and n.151. *See also* Section 5.2.7.

[304] SCE-05A at 129.

[305] SCE-05A at 131.

[306] SCE-05A at 51. *See also* Section 5.2.6.2.

[307] SCE-05A at 128 and 131. *See also* Section 5.2.6.

[308] *See* SCE-05A at 128-129 and n.24 and SCE-07, detailing SCE's forecast of procurement and administrative costs incurred to serve as a CPE. *See also* Section 5.2.6.1 of this Decision.

[309] SCE-05A at 127-128.

decrease from what is currently in rates.[310] To estimate the year-end NSGBA balance, SCE uses recorded amounts from January 1, 2025 through September 30, 2025, plus a forecast of the activity SCE expects to record in the NSGBA during October through December 31, 2025.[311]

No party has disputed SCE's proposed 2026 NSGBA forecast or estimated NSGBA year-end 2025 balance. Upon review of SCE's Application, party testimonies, and SCE's workpapers, we find SCE's proposed NSGBA 2026 forecast and 2025 year-end balance to include costs authorized to be recovered via the CAM, to be calculated consistent with the law, and Commission decisions, and reasonable, and so authorize recovery as requested. The CAM rates resulting from this authorized revenue requirement are shown in Section 10, Table 9-2 of this Decision.

7.2.2. Delivery Service: Updated Modified Cost Allocation Mechanism Balancing Account 2026 Forecast and Year End 2025 Balance

SCE forecasts 2026 MCAM-related F&PP costs tracked in the MCAMBA totaling $3.682 million in its Amended October Update, including FF&U; this represents a roughly $2.124 million increase from what is currently in rates.[312] The resources that these costs represent are described in Section 5.2.7 of this Decision, and can be summarized as the net costs of the opt-out and backstop procurement secured on behalf of Departing Load customers for system reliability ordered by D.19-11-016 and D.22-05-015 (as modified by

[310] SCE-05A at Table II-3.

[311] SCE-05A at 132.

[312] SCE-05A at Table II-3.

D.23-12-014). The costs tracked in the MCAMBA are recovered only from the customers of LSEs that opted out of or failed to meet procurement obligations.[313]

SCE forecasts a $2.522 million under-collection balance in the MCAMBA as of December 31, 2025, $0.628 million less than what is currently in rates.[314]

No party has disputed SCE's proposed 2026 MCAMBA forecast or MCAMBA year-end 2025 balance. Upon review of SCE's Application, party testimonies, and SCE's workpapers, we find SCE's proposed 2026 MCAMBA forecast and 2025 year-end balance to be forecast consistent with the law and Commission decisions, and reasonable and so adopt these forecasts as requested.

7.2.3. Delivery Service: Updated 2026 Spent Nuclear Fuel Costs Forecast

As discussed in Section 5.3.1, SCE incurs costs for off-site interim storage of spent nuclear fuel. SCE projects $5.332 million, including FF&U, associated with spent nuclear fuel in its 2026 ERRA forecast delivery service revenue requirement.[315] SCE's spent nuclear fuel storage cost forecast increased between its May Filing and Amended October Update. In its May Filing, SCE projected that 2026 interim spent fuel offsite storage costs for SONGS unit 1 would be paid out of litigation proceeds deposited into the SONGS 1 Non-Qualified Nuclear Decommissioning Trust (NQNDT).[316] However, in its Amended October Update, SCE states that, as of October 2025, it had received no applicable litigation funds from the DOE, and so includes the forecast costs in rates.[317]

[313] SCE-05A at 133.

[314] SCE-05A at Table II-3.

[315] SCE-05A at Table II-3.

[316] SCE-01 at 61-62.

[317] SCE-05A at 71-72.

We note here that D.24-08-001 required that any applicable DOE litigation proceeds must be deposited into the SONGS Unit 1 NQNDT and must be used to pay spent fuel management and storage costs for that unit. Remaining proceeds must be returned to ratepayers.[318] To effectuate D.24-08-001's directive that, to the extent possible, applicable spent nuclear fuel storage costs should be paid from DOE litigation funds, rather than ratepayers, once SCE receives and deposits applicable DOE litigation funds in the SONGS 1 NQNDT, SCE must propose a refund of these 2026 SONGS 1 forecast costs recovered in rates in its next ERRA forecast or compliance proceeding.

No party has disputed SCE's proposed 2026 spent nuclear fuel interim storage cost forecast. Upon review of the record, we find SCE's proposed 2026 spent nuclear fuel interim storage cost forecast to be reasonable and authorize recovery as requested.

7.2.4. Delivery Service: Updated 2026 Base Revenue Requirement Balancing Account-Distribution Sub-Account Forecast

SCE forecasts an updated negative $2.684 million balance in 2026 F&PP costs recorded in the distribution subaccount of its Base Revenue Requirement Balancing Account (BRRBA-D),[319] a $16.486 million increase from the

[318] D.24-08-001, *Decision Approving the 2021 Nuclear Decommissioning Cost Triennial Proceeding Costs of Southern California Edison Company and San Diego Gas & Electric Company* at OP 3.

[319] SCE-05A at Table II-3. For the purposes of its 2026 ERRA Forecast requests, SCE records the forecasts of the following costs or credits in the BRRBA-D:

1. costs of and credits equaling the energy benefits of SCE's UOS Anode and Cathode (SCE-05A at 80);
2. administrative payment fees to the CARB, calculated to recover the costs of the State's implementation of AB 32 (SCE-05A at n.132);
3. Energy Imbalance Market Body of State Regulator (EIM BOSR) costs and

over-collection currently forecast in rates.[320]

No party has disputed SCE's proposed 2026 BRRBA-D forecast. After considering SCE's testimony and workpapers, we find SCE's proposed 2026 BRRBA-D forecast to be reasonable and so authorize recovery as requested.

7.2.5. Delivery Service: Greenhouse Gas Revenue Balancing Account

SCE forecasts a negative $443.279 million balance in its GHGRBA; this amount includes an estimated $213.307 million year-end 2025 undercollection and has been netted against forecast 2026 GHG revenues and administrative costs.[321] This amount also reflects deductions to the available GHG allowance revenue for clean energy and efficiency program funding. SCE's negative balance reflects that the amount is to be returned to ratepayers. As noted above, the change in forecast GHG prices, and the resulting change in GHG allowance revenues is a significant driver in the total revenue requirement change between SCE's May Filing and the Amended October Update. SCE forecast $528.071 million in GHG allowance revenues to return to customers in its May Filing.[322]

No intervenors have commented on SCE's proposed GHGRBA balance. Given the approvals conferred in Section 6, we find SCE's proposed 2026 GHGRBA forecast reasonable and adopt it.

DRAM costs (SCE-05A, Table VIII-36 at n.3 and n.6);

4. the net impacts of SCE's DR and PRP programs (*see* SCE-05A at 78 and Table VIII-36, n.3), and
5. transfer amounts from the Distribution sub-account of the Local Capacity Requirements Products Balancing Account (SCE-05A at Table VIII-36, n.3).

[320] SCE-05A at Table II-3, ln. 23.

[321] *See* SCE-05A at Table II-3 and Table VII-34.

[322] SCE-01 at Table II-2.

7.2.6. Delivery Service: 2026 Public Purpose Program Charge Component Forecasts and Related 2025 Year-End Balances

SCE forecasts $42.571 million in applicable ERRA costs to be recovered via the Public Purpose Program Charge (PPPC) in 2026. These costs include forecast 2026 costs for the TMNBC, forecast costs for the BMNBC, the confidential behind-the-meter energy storage contract costs of the Preferred Resources Pilot Program tracked in the LCR-PPP subaccount (Section 5.2.13),[323] and CCA DAC-GT/CSGT program costs (Section 6.6.2). The proposed PPPC also includes year-end 2025 balances for the TMNBCBA and the BMNBCBA.[324]

SCE estimates a 2026 tree mortality F&PP revenue requirement of $21.567 million, including FF&U, and including an estimated $0.018 million in audit costs.[325] SCE projects a 2025 year-end TMNBCBA balance of $14.240 million, $7.003 million less than the amount currently included in rates.[326] SCE forecasts $~~4.838~~4.383 million F&PP costs that will record to its BMNBCBA in 2026, including FF&U.[327] SCE estimates a year's-end 2025 over-collection of $3.764 million (including FF&U) in the BMNBCBA.[328] SCE forecasts $3.240 million in costs for its DAC-GT/CSGT programs in 2026, representing the forecast costs of the Clean Power Alliance of Southern California DAC-GT/CSGT program

323 SCE-05A at n.66.

324 SCE-05A at Table II-3, lns. 26-30 and n.2.

325 SCE-05A at 135; SCE notes that only actual audit costs will ultimately be recovered via the TMNBC. *See* Section 5.2.17.

326 SCE-05A at Table II-3, ln. 28.

327 SCE-05A at 137. *See* Section 5.2.18.

328 SCE-05A at 138.

funding that remains after allotted GHG allowance revenues are exhausted (Section 6.3.2).[329]

No party has disputed SCE's proposed 2026 PPPC revenue requirements, including the 2026 forecast and 2025 true-up amounts identified above. Upon review of the record, we find SCE's proposed 2026 PPPC component calculations to be reasonable and calculated consistent with applicable laws and Commission rules, and so we adopt them.

8. Power Charge Indifference Adjustment

This section discusses the Cost Responsibility Surcharges (CRS) SCE uses to recover the PCIA revenue requirement portion of its 2026 ERRA forecast revenue requirement.[330] This section provides a summary of the history of these charges, SCE's proposed calculations of the revenue requirements upon which the charges are based, party comments on and opposition to SCE's requests, and the Commission's determinations on the disputed issues in this proceeding.

This section also addresses other costs SCE requests be included in its 2026 PCIA: (1) the recovery of the 2025 year-end PABA balance; (2) the transfer of the 2025 year-end ERRA BA balance to the 2025 vintage sub-account of the PABA;[331] (3) 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

[329] SCE-05A at 113.

[330] As noted above, in its testimony, SCE refers to the PCIA and the CTC as "the Cost Responsibility Surcharges." Unless otherwise specified and reflecting recent Commission decision terminology, for the purposes of this Decision, we refer to the PCIA and the CTC collectively, as "PCIA Charges" that recover the "PCIA Revenue Requirement," pursuant to the "PCIA methodology."

[331] The remaining 2025 balances for the ERRA BA and the PABA are also addressed in Sections 7.1.1 and 7.1.2, above, as components of the proposed generation service revenue requirement. However, because these balances are collected via the PCIA, they are discussed here to complete the explanation of the final adopted CTC and PCIA surcharges.

effectuate the 36-month amortization recovery period adopted in Res. E-5240; and (4) costs related to the UOS Separator project. [332]

8.1. Power Charge Indifference Adjustment Background and Overview

The Commission is required by law to ensure that the movement of customers from bundled electric services to unbundled service does not shift costs to customers that remain with the utility or those that depart for Community Choice Aggregator (CCA) or Direct Access (DA) service, collectively, "unbundled customers" or Departing Load (DL).[333] In 2002, the Commission adopted a process to allocate costs to achieve this "indifference" to DL.[334] This process addresses the shift of costs between bundled and departed customers by ensuring that DL customers share in the above- or below-market costs of generation resources that were procured on their behalf prior to their opting out of IOU generation service. The resource costs and revenues that must be allocated to achieve this are tracked in the PABA, which is separated into vintaged subaccounts.[335] The practice of vintaging the PABA subaccounts by year ensures that DL customers are allocated *only* those costs and benefits that were incurred prior to when they left SCE's generation service.[336]

[332] SCE-05A at 158.

[333] *See* Pub. Util Code §§366.1, 366.2, 365.28 and 366.39.

[334] The Commission adopted the CRS in D.02-11-022, and it has been modified by decisions including D.03-07-030, D.06-07-030, D.08-09-012, D.11-12-018, Res. E-4475, D.18-10-019, D.19-10-001, D.20-08-004, D.21-05-030, D.22-01-023, D.22-07-008, and D.25-06-049.

[335] SCE's vintaged subaccounts are: a Pre-2002 CTC subaccount, a legacy UOG account, a subaccount for resources committed in 2004-2009, annual subaccounts for each year from 2010-2025, and a subaccount for New QF SOC. *See* SCE-05A, Appendix B at B-1. *See also* D.08-09-012, *Decision on Non-Bypassable Charges for New World Generation and Related Issues* at OP 10 [hereinafter D.08-09-012].

[336] SCE-05A at 142.

The Indifference Amount is the quantification of the difference between the forecast annual cost of the PABA-eligible generation portfolio (Total Portfolio Cost) and the forecast market value of that portfolio (Total Portfolio Market Value). The Total Portfolio Market Value is the forecast output of the resources in the generation portfolio multiplied by Market Price Benchmarks (MPBs), related to the energy value, resource adequacy (RA) value, and Renewable Portfolio Standard (RPS) value of the resources, discussed below.

Ultimately, the Indifference Amount is adopted via ERRA forecast proceedings on a forecast basis and is recovered from bundled customers via generation rates, and from DL customers via two separate charges: the Competition Transition Charge (CTC) and the Power Charge Indifference Adjustment (PCIA).[337] The CTC is used to recover the above-market costs of resources developed prior to the electricity market restructuring that occurred in California in the late 1990s and early 2000s, such as eligible QFs, and is the same for all vintages.[338]

Established in D.06-07-030, the PCIA recovers the above-market costs of non-CTC, PABA-eligible resources.[339] An Indifference Amount is calculated for each vintaged subaccount based on the generation resources committed in each calendar year. The sum of all CTC- and PCIA-vintaged Indifference Amounts

[337] SCE notes that its CRS also includes its Wildfire Fund Non-Bypassable Charge (NBC). The Wildfire Fund NBC incorporated into SCE's estimates in this case was approved for use in 2025 in D.24-12-001. On September 9, 2025, the assigned ALJ in R.23-03-007 issued a ruling requesting comment on the California Department of Water Resources' September 8, 2025, "90-day Notice Regarding 2026 Wildfire Non-Bypassable Charge." Pursuant to AB 1054, AB 111, and D.19-10-056, the Commission will authorize a Wildfire Fund NBC for 2026.

[338] *See* Pub. Util. Code § 367(a)(1)-(6) and D.02-11-002.

[339] D.06-07-030 at OP 16.

equals the total PCIA Indifference Amount.[340] Finally, D.18-10-019 authorized utilities to conduct a true up of the PCIA Indifference Amount to reflect actual costs incurred and actual revenues received.[341]

8.2. Updated Calculation of the 2026 Power Charge Indifference Adjustment

As noted above, the PCIA Indifference Amount is the difference between SCE's projected 2026 PCIA-eligible Total Portfolio Cost and its Total Portfolio Market Value. As illustrated in Table 8-1, below, SCE's forecast 2026 Indifference Amount decreased by 79 percent between its May Filing and Amended October Update, due largely to application of the Commission's Forecast 2026 MPBs, particularly the RA MPB, released on October 1, 2025.[342]

[340] SCE-05A at 142 and n.173, citing D.06-07-030.

[341] D.18-10-019 at OP 6.

[342] SCE-05A at 140.

Table 8-1: Summary of SCE's 2026 ERRA Forecast Portfolio Costs, Portfolio Market Value, and Total PCIA Revenue Requirement[343]

PCIA Revenue Requirement	May Filing (millions)	Amended October Update (millions)
Total Portfolio Cost[344]	$4,340,729	$4,474,429
Total Portfolio Market Value[345] • Energy Value • RPS Value • RA Value	($6,161,875) • ($1,513,697) • ($2,056,885) • ($2,591,293)	($4,863,806) • ($1,426,661) • ($1,983,575) • ($1,453,570)
One Time Adjustments[346]		

343 SCE-05A at Table IX-42.

344 SCE's Total Portfolio Cost as expressed here is the sum of the costs of its PCIA-eligible UOG Capital and O&M, its non-renewable UOG, QF-eligible CHP, Renewable QF and RPS, Conventional Contracts (Bilateral/RFO/IU), and Common Costs before netting out the impacts of sold or retained RA, RPS and energy revenues. *See* SCE-05A at Appendix B, Table: "IOU Portfolio by Resource Type[.]" Portfolio costs are offset by anticipated portfolio revenues as described in n.345, below.

345 For each revenue stream, the Total Portfolio Market Value is calculated by subtracting applicable anticipated revenues from the associated resource market value, *e.g.*, the total energy market value of SCE's energy resources is the forecast market value calculated using the Energy Index, as described below (Section 8.2.2.1), minus forecast energy revenues (Section 5.4.2).

346 SCE's $1.3 million adjustment in its Amended October Update reflects recovery of the year-end 2025 balance in the LCTA-ESMA.

PCIA Revenue Requirement	May Filing (millions)	Amended October Update (millions)
	$185	$1,300
Total 2026 Indifference Amount	($1,820,961)	($388,078)
Additions and Balancing and Memorandum Account True Ups		
• YE 2025 ERRA BA • YE 2025 PABA • SRPMA Amortization • UOS Separator	• $68,468 • $61,108 • - • $29,224	• ($888,414) • $1,303,342 • - • $29,224
2026 PCIA Revenue Requirement	($1,662,161)	$56,074
2026 PCIA Revenue Requirement with Uncollectibles Factor	($1,665,158)	$56,191

8.2.1. Updated Total Portfolio Cost

To calculate its Total Portfolio Cost, SCE sums the estimated costs of each vintage subaccount in its PABA; these forecast costs are based on the forecast fixed and variable costs of the CTC- and PCIA-eligible resources SCE anticipates using to serve bundled customers in 2026.[347] SCE states that these costs include:

> the authorized base generation capital revenue requirement [AGBRR, sic], as determined in SCE's [general rate case] Phase 1 proceeding;[348] fuel costs, and direct GHG costs for all eligible

[347] SCE-05A at 147, noting that the Total Portfolio Costs were calculated consistent with the costs outlined in SCE-05A, Table IV-9. Thus, SCE's Total Portfolio Cost was calculated using the methods described in Section 4 of this Decision, as refined by the information provided in Sections 5 and 6 of this Decision.

[348] SCE's test year (TY) 2025 GRC had not been resolved at the time of SCE's May Filing, and so SCE used the 2024 AGBRR as authorized in D.23-11-096 and modified with the approval of Advice 5406-E to forecast this value. However, on September 18, 2025, the Commission adopted D.25-09-030, resolving SCE's TY 2025 GRC, and which, among other authorizations, approved a Commission-jurisdictional base revenue requirement of $9.664 billion for the 2025 TY, effective January 1, 2025. SCE has incorporated the impacts of this Decision into their Amended October Update. SCE states that it will update the AGBRR for 2026 in its implementation advice letter. SCE-05A at 147 and n.175. *See also* SCE-05A at 162.

> UOG; RPS-eligible contract costs; QF and non-CAM-eligible CHP contract costs; all bilateral and RFO contract costs, including fuel costs and direct GHG costs if applicable; and any applicable one-time refunds or adjustments.[349]

In its Amended October Update, SCE forecasts Total Portfolio Costs equaling $4.474 billion, $134 million less than forecast in its May Filing.[350]

8.2.2. Updated Total Portfolio Market Value

Pursuant to D.18-10-019 and D.19-10-001, to forecast the Total Portfolio Market Value, SCE multiplies the forecast quantity output of the resources in each PABA vintage subaccount of SCE's PCIA-eligible generation portfolio by the Energy Index, RPS Adder, and RA Adder MPBs determined each year by the Commission.[351] In other words, the total estimated market value of each CTC or PCIA-vintaged subaccount is made up of the combined estimated market values of three possible streams of revenue each portfolio may yield: the energy value, the RA value, and the RPS value. All else kept constant, decreases to the MPBs increase the CTC and PCIA rates.[352]

In its Amended October Update, SCE incorporated the Commission's forecast 2026 MPBs, released on October 1, 2025, into its calculation of its 2026 forecast Total Portfolio Market Value. SCE projects a $4.864 billion updated Total Portfolio Market Value, a 21 percent decrease from its May Filing estimate.[353] As shown below, these MPBs were generally lower than the MPBs SCE used to

[349] SCE-05A at 147, citations omitted.

[350] SCE-05A at Table IX-42.

[351] *See* SCE-01 at Appendix B, B-4 for SCE's proposed 2026 Indifference Amount calculation as of its May Filing. *See* SCE-05A at Appendix B for SCE's updated forecast Indifference Amount calculation.

[352] SCE-05A at 148.

[353] SCE-05A at Table IX-42.

forecast the Total Portfolio Market Value in its May Filing, leading to a larger (less negative) forecast 2026 Indifference Amount than was first forecast. [354]

Table 8-2: Comparison of Forecast PCIA Market Price Benchmarks

<table>
<tr><th>Market Price Benchmark (MPB)</th><th>2025 ERRA Forecast May Submittal</th><th>2025 ERRA Forecast October Submittal[355]</th><th>2026 ERRA Forecast May Submittal</th><th>2026 ERRA Forecast October Submittal</th><th>Percent Change in 2026 May/October Submittals</th></tr>
<tr><td>Energy Index</td><td>$55.98/MWh</td><td>$41.67/MWh</td><td>$40.57/MWh</td><td>$40.00/MWh</td><td>-1%</td></tr>
<tr><td>RPS Adder</td><td>$31.73/MWh</td><td>$71.24/MWh</td><td>$71.24/MWh</td><td>$62.45/MWh</td><td>-12%</td></tr>
<tr><td>RA Adder(s)</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>System</td><td>$182.76/kW-yr</td><td>$483.72/kW-yr</td><td>$483.72/kW-yr</td><td rowspan="3">$138.36/kW-yr</td><td>-71%</td></tr>
<tr><td>Local</td><td>$105.72/kW-yr</td><td>$134.76/kW-yr</td><td>$134.76/kW-yr</td><td>3%</td></tr>
<tr><td>Flex</td><td>$109.44/kW-yr</td><td>$203.64/kW-yr</td><td>$203.64/kW-yr</td><td>-32%</td></tr>
</table>

8.2.2.1. Updated Total Portfolio Energy Value

[354] SCE-05A at Table IX-43. In SCE-05A, n.78, SCE states that a footnote in Energy Division's October 1, 2025 MPB Report is incorrect. Referring to the October MPBs released in 2024, the footnote states "Energy Division issued a subsequent set of revised MPB values to the service list on November 5th, 2024 for informational purposes, which was not used in the ERRA proceeding." SCE states "SCE believes Footnote 1 of October 1, 2025 MPBs to be incorrect as SCE was ordered on page 80 of D.24-12-039 (Final Decision for the 2025 ERRA Forecast) to 'utilize the most updated MPB values available' when updating its final 2024 year-end balances and 2025 forecasts." With this understanding, SCE used the November MPBs in its 2025 ERRA forecast implementation AL.

We read the October 1, 2025 MPB Report Footnote 1 as noting, for our purposes, that the decision resolving SCE's 2025 ERRA forecast did not use the November MPBs in its tables or listed authorizations. Therefore, we agree with Energy Division that the proceeding itself (*i.e.,* the decision resolving SCE's 2025 ERRA forecast proceeding) did not use the November MPBs, other than by directing SCE to use them in its implementation AL and we agree with SCE that it was, in fact, directed to use the November MPBs in its 2025 ERRA forecast implementation AL.

[355] Consistent with what is described in n.354, these MPBs are the MPBs released in November 2024 rather than the October Addendum 2024 MPBs listed in D.24-12-039, the decision resolving SCE's last ERRA forecast case. *See* D.24-12-039 at Table 7-4 and at 80.

SCE proposes a $1.427 billion updated 2026 Total Portfolio Energy Value, roughly six percent lower than SCE forecast in its May Filing.[356] The Total Portfolio Energy Value is the estimated financial value of the energy components of SCE's PCIA-eligible portfolio for a given year. It is forecast by multiplying the weighted Energy Index MPB, as described below and presented in dollars per MWh, by the estimated amount of energy produced by resources in SCE's PCIA-eligible portfolio.[357]

In 2023, the Commission adopted an updated methodology to increase the accuracy of the forecast Energy Index.[358] Utilities use Energy Division MPBs in their calculations, as follows. Utilities use historical data from their own sales to determine a portfolio weight – that is, to measure how close to the actual SP-15 price SCE's energy was sold at, on average, in prior years. To do this, SCE calculates the annual average price of its PABA portfolio resources in each year from 2022 through 2024. SCE compares those average prices to the actual SP-15 to find a portfolio weight for each year. SCE's average portfolio weight for 2022-2024 was 92 percent.

SCE applies time-weights (reflecting how much of SCE's power is purchased in on-peak hours vs. off-peak hours) to its Commission-calculated, SCE-specific on-peak and off-peak 2026 Forecast Energy MPBs. SCE then applies the portfolio weight developed per the process described above to produce portfolio- and time-weighted on-peak and off-peak MPBs. These are combined to

[356] SCE-05A at Table IX-42.

[357] SCE-05A at 149.

[358] *See* D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* at COL 11 [hereinafter D.23-06-006]. SCE-05A at 150-151. SCE-05A at 150-151 illustrates these calculations.

create a final forecast energy benchmark, here $40.00/MWh, by which SCE multiplies its estimated energy production to determine the Energy Market Value of its PABA-eligible portfolio. SCE notes that the change in its Energy Market Valuations between May and October is primarily due to the slight change in MPBs used ($40.56/MWh in May vs. $40.00/MWh in October).[359]

No party disputes SCE's proposed updated 2026 Energy Value.

8.2.2.2. Updated Total Portfolio Renewable Portfolio Standard Value

SCE proposes a $1.984 billion updated 2026 Total Portfolio RPS Value, roughly four percent less than what SCE proposed in its May Filing primarily due to use of the Commission's RPS MPB.[360] The RPS Value is the estimated value, measured in dollars per megawatt hour, of the renewable energy component of SCE's PCIA-eligible portfolio each year.[361] Except as described below, this value is forecast by multiplying the Forecast RPS Adder by the estimated volume of RPS-eligible resources in SCE's PCIA-eligible portfolio and by incorporating the actual prices of recent RPS sales.[362]

SCE's proposed forecast RPS quantities are its previously held RECs, added to by any RECs related to PCIA-eligible generation, and decreased by RECs surrendered to achieve SCE's compliance obligation or sold via market offer (MO) or voluntary allocation (VA), pursuant to D.18-10-019. SCE is not holding a short-term VAMO process for 2026 but will continue to allocate long term VA RECs from contracts signed in 2024, based on the accepted bid price.

[359] SCE-05A at 149.

[360] SCE-05A at 154.

[361] SCE-05A at 148 and Table IX-42

[362] SCE-05A at Table IX-47.

SCE states that all volumes not allocated in either long-term VA or MO processes are forecast to be used by SCE towards its 2026 RPS compliance target.[363]

In its May Filing and Amended October Update, SCE values these RECs either at (1) the 2026 Forecast RPS Adder calculated by the Energy Division, (2) at the actual prices for sales up to 45 days prior to ERRA forecast filings, or, (3) at $0, for Forecast Unsold RPS and any Pre-2019 Banked RECs forecast to be needed for bundled customer compliance.[364] SCE's proposed valuation of Pre-2019 Banked Recs that it may retire for bundled customer RPS compliance in 2026 (or that it has retired for bundled customer compliance in 2025) is a disputed issue in this case, as discussed below.

8.2.2.2.1. Pre-2019 Banked RECs – Valuation and Order of Retirement

Pre-2019 Banked RECs are RECs that were generated and banked prior to January 1, 2019, but used for utility bundled customer RPS compliance obligations in later years. Here, CalCCA and SCE disagree as to whether SCE must value Pre-2019 Banked RECs at the applicable RPS Adder or at $0, if SCE forecasts it will use such RECs for bundled customer RPS compliance in 2026 or if SCE has used such RECs for bundled customer compliance in 2025.

D.19-10-001 modified the method used to value banked RECs expected to be used for bundled customer compliance when forecasting PCIA rates. In that decision, the Commission evaluated proposals put forth by Working Groups

[363] SCE-05A at 155-156.

[364] SCE-05A at Table IX-47. SCE proposes valuing RPS quantities as follows: RECs that cannot be allocated, SCE's portion of VAMO RECs, non-SCE Voluntary Allocations, and Post-2018 Banked RECs forecast to be used for bundled customer compliance are forecast at the prior years' Forecast RPS Adder. RPS sold through Market Offers and Actual Sold RPS are valued at actual prices and Forecast Unsold and Pre-2019 Banked RECs are valued at $0.

made of party representatives.[365] Among other proposals, one Working Group proposed that, if a utility expects to retain and retire a REC for bundled customer compliance in a forecast year, the REC should be valued at the then-current Forecast RPS Adder, as calculated by Energy Division staff, and credited to DL customers via the PCIA.[366] Any RECs that are unsold are valued at $0 until they are used for bundled customer compliance or sold, at which point they become Actual Sold (valued at the actual price) or Actual Retained RECs (valued at the RPS Adder, as described above).[367] The Commission adopted this Working Group proposal.[368] However, the Commission also noted in a Finding of Fact for that decision that "[t]he methods adopted in this Decision apply to RECs generated commencing January 1, 2019 and going forward."[369]

Prior to D.19-10-001, bundled customers credited DL customers the market value of all forecast unsold/retained banked RECs at the time the RECs were generated and banked, based on the then-current RPS MPB. The RECs were valued at $0 thereafter regardless of whether and when they were used for bundled customer compliance.[370]

As noted above, SCE proposes that, if it must use Pre-2019 Banked RECs for bundled customer compliance, those RECs should be valued at $0 because D.19-10-001 excludes Pre-2019 Banked RECs from the updated forecast methodology by virtue of the Finding of Fact cited above.[371] Substantively, SCE

[365] D.19-10-001 at 4-5, 12.

[366] D.19-10-001 at 13.

[367] D.19-10-001 at 35.

[368] D.19-10-001 at OP 2 and Attachment B, Table I.

[369] D.19-10-001 at FOF 8.

[370] SCE-04 at 5; CalCCA-01 at 17.

[371] SCE-05A at 156-157 and n.186; SCE-04 at 3 (ln. 15-17) and 4 (ln. 5-9). SCE notes that in response to its PFM of D.23-06-006, which modified to the PCIA methodology, the Commission

argues that, because its bundled customers already paid market value for those RECs at the time they were generated and banked under the prior PCIA methodology, to require them to pay again ("pay twice") for the RECs at issue would make bundled service customers no longer "indifferent" to departed load in violation of Pub. Util. Code section 366.2(g).[372] SCE further argues that CalCCA's proposed methodology is "underdeveloped," and that it relies on a misunderstanding of how SCE allocates the credits of Banked RECs that are used for bundled customer compliance and so "would misalign costs and benefits."[373] The Commission adopted SCE's proposed methodology on an interim basis in ~~its last two~~SCE's 2024 ERRA forecast ~~decisions~~decision and approved it in SCE's 2025 ERRA forecast decision for that proceeding.[374]

response to its PFM of D.23-06-006, which modified to the PCIA methodology, the Commission found that D.23-06-006 did not modify D.19-10-001 with respect to the treatment of Pre-2019 Banked RECs. SCE-04 at 5 and n.10, citing D.24-08-004, *Decision Denying Petition for Modification of Decision* 23-06-006 at 4.

372 SCE Opening Brief at 21.

373 SCE Reply Brief at 9. SCE states in testimony that it "does not track which resources (and thereby which PABA vintage) produce the RECs that are used for compliance versus those that are banked[,]" and that that information would be needed to implement CalCCA's proposal. SCE-04 at 8. CalCCA responds that its proposal is agnostic as to the date the REC's original generating resource or contract went into service. What matters is the year in which a REC is generated, as that is the customer vintage into which CalCCA's proposed credit flows, and so its proposal can be implemented based on information SCE has. CalCCA Opening Brief at 37-38. SCE does not state in briefs that it does not track RECs in a way that would allow it to implement its proposal; as noted above, SCE concludes that it results in a misalignment of costs and benefits. SCE Reply Brief at 9.

374 D.24-12-039 at 68: "Weighing the record, we find SCE's treatment of RPS resources to be reasonable and therefore approve them as proposed for this proceeding." *See also*, A.24-05-007, Exhibit SCE-09 at 114: "However, should the post-2018 banked RECs be exhausted, SCE will then use pre-2019 banked RECs and value those pre-2019 banked RECs at zero." D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast* at 60 [hereinafter D.23-11-094]: "Should SCE determine that the use of RECs banked in or before 2018 is necessary for its bundled service RPS compliance, it should value those RECs at zero, as it proposed."

CalCCA argues in testimony and briefs that any Pre-2019 Banked RECs projected to be used for SCE's bundled customer RPS compliance in 2025 or 2026 should be valued at the current RPS Adder, consistent with the new methodology adopted in D.19-10-001 and that SCE should retire RECs on a "first-in, first-out" basis.[375] CalCCA proposes that the value of the REC should be logged as a credit to the PCIA in the vintage year in which the REC was generated, with a corresponding debit to the ERRA BA, to be paid by bundled customers through generation rates.[376]

CalCCA argues that the methodology adopted in D.19-10-001 is appropriate for valuing Pre-2019 Banked RECs because otherwise, DL customers (who, as bundled customers, paid for Pre-2019 Banked RECs at the time they were generated and banked) would not receive credit for the full market value of the RPS resource to which they contributed when it is used for bundled customer compliance after the DL customer's date of departure from bundled service.[377] This, CalCCA argues, is a cost shift that means DL is no longer "indifferent," which runs contrary to Pub. Util. Code section 366.2(g).[378] CalCCA states that bundled service customers would not be "paying twice" and would be indifferent under its proposal because they would only be paying DL customers

[375] CalCCA's "first-in, first-out" proposal is intended to allow DL customers who paid for RECs earlier to be compensated first. CalCCA-01 at 25.

[376] CalCCA-01 at 25. *See also* CalCCA Opening Brief at 6-7~~27~~.

[377] CalCCA-01 at 32. CalCCA Opening Brief at 20-21.

[378] CalCCA Opening Brief at 6. Pub. Util. Code § 366.2(g) states:

> Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.

an additional amount that is proportional to the portion of the REC for which DL customers originally paid as bundled customers.[379]

In support of its position, CalCCA cites D.19-10-001's OP 2 and Appendix B, which summarize the valuation methodology adopted by the decision.[380] Based on the lack of demarcation between RECs in those portions of D.19-10-001, CalCCA argues in testimony that "D.19-10-001 does not draw any distinction between the treatment of Pre-2019 Banked RECs and Post-2018 Banked RECs (*i.e.*, Unsold RPS) when those RECs are eventually applied towards bundled customer compliance."[381] While acknowledging that the Commission has previously adopted SCE's $0 valuation method,[382, 383] CalCCA argues that SCE's 2024 and 2025 ERRA forecast decisions did not resolve the issue because they adopted the proposal on an interim basis.[384]

Regarding the Finding of Fact noted above, CalCCA argues in briefs that the January 1, 2019 effective-date is applicable only to the portion of D.19-10-001 that modified the treatment of Unsold RECs and that "what the Commission now labels as 'Retained RPS' has been treated the same since the Commission created a new MPB to reflect the RPS value of certain RPS-eligible resources in 2011."[385] D.19-10-001 created the category of Unsold RECs, CalCCA argues, and

379 CalCCA-01 at 29. CalCCA Opening Brief at 30.

380 CalCCA-01 at n.36.

381 CalCCA-01 at 21, citing D.19-10-001, at Attachment B.

382 CalCCA-01 at 19 and n.42, citing D.23-11-094 at 53.

383 CalCCA-01 at 20 and n.45, citing D.24-12-039 at 68: "Weighing the record, we find SCE's treatment of RPS resources to be reasonable and therefore approve them as proposed for this proceeding."

384 CalCCA-01 at 20.

385 CalCCA Opening Brief at 19. *See also id.* at 22: "[D.]19-10-001, however, left intact the fundamental requirement, created by D.11-12-018, that for RPS-eligible resources retained by bundled customers, the indifference calculation must reflect the incremental RPS value."

applies a $0 valuation to those RECs, but did not change the way that Retained RECs are valued, at the RPS Adder.[386] Thus, the effective date does not apply.

SCE disagrees, arguing that prior to D.19-10-001, all excess RECs were valued at the then-current RPS Adder in the year they were generated and banked, and it was not until D.19-10-001 that the Commission created the category of "Retained RECs," which are valued at the RPS Adder and credited to the PCIA in the year of use, rather than in the generation year. The change in the timing of the credit to DL customers, SCE states, is a new method adopted in D.19-10-001 and so is subject to the January 1, 2019 effective date.[387]

SCE states that it would be procedurally inappropriate to adopt what it characterizes as a "new policy" (CalCCA's proposal) in an ERRA forecast proceeding applicable to only one IOU, a contention with which SCE states CalCCA generally agrees, at times.[388] SCE notes that the former PCIA methodology did not true up market values, so when the forecasted market values were higher than actual values, DL customer retained those higher values at the expense of bundled service customers. This is an example, SCE states, of how "[t]he former PCIA methodology contained its own balance of customer interests" and that the methodology "should not be revisited now, and certainly not in a piecemeal fashion to favor one group of customers over another."[389]

[386] CalCCA Opening Brief at 22-23.

[387] SCE Reply Brief at 4-5.

[388] SCE-04 at 3 and n.3, citing CalCCA-01 at 13:

> In my experience, the Commission generally does not allow policymaking in ERRA Forecast cases. Proposals to change the PCIA ratemaking framework are first reviewed in other proceedings, such as the PCIA Rulemaking Proceeding initiated this year, so that all interested parties have an opportunity to evaluate and respond to those proposals.

[389] SCE-04 at 6-7.

8.2.2.2.2. Discussion

Under the Commission's preponderance of the evidence standard, SCE's proposal to value Pre-2019 Banked RECs used for bundled customer compliance in 2025 and forecast to be used as such in 2026 at $0 continues to be a reasonable methodology unless and until the Commission addresses the issue on an industry-wide basis. As noted by SCE, we have previously found that "[w]e agree with SCE that the Commission has not, to this date, found that SCE's bundled service customers owe additional credits to [DL] customers when SCE uses RECs banked in or before 2018."[390] The Commission has not provided further guidance as to a reading of D.19-10-001 that would suggest this obligation stems from that decision, notwithstanding the Finding of Fact noted above. Therefore, we find that SCE's proposal is, more likely than not, a reasonable interpretation of existing Commission guidance.

Given the outstanding questions of fact and policy related to the mechanics and equity of CalCCA's proposal and the different ways these questions might be responded to on an industry-wide basis, it is reasonable for SCE to continue to use the procedure the Commission has previously found reasonable ~~on an interim basis~~in SCE's prior two ERRA forecast proceedings.

The proposal to address conflicting understandings regarding the valuation of Pre-2019 Banked RECs is appropriate for consideration in a rulemaking. SCE is directed to file a Tier 2 advice letter by February 1, 2026 to propose how it will track the quantity of Pre-2019 Banked RECs used to meet 2026 compliance obligations and the years in which each of those RECs was generated. The advice letter shall explain how SCE intends to track the quantity

[390] SCE-04 at 5, n.9, citing D.23-11-094 at 53.

and generation year of all Pre-2019 Banked RECs it will use to meet 2026 compliance requirements through September 30, 2026. The advice letter shall also explain how SCE intends to forecast how many and which RECs SCE intends to use for bundled customer compliance from October 1, 2026, through December 31, 2026.

This information will allow any updated guidance from the Commission regarding the treatment of Pre-2019 Banked RECs to apply to Pre-2019 Banked RECs used for bundled compliance in 2026. Should the Commission issue updated guidance on the appropriate valuation of Pre-2019 Banked RECs prior to September 1, 2026, SCE will be required to incorporate that guidance into its 2026 October Update. SCE's proposal to value any Pre-2019 Banked RECs used for bundled customer compliance in 2025 at $0 is a reasonable application of existing Commission guidance and will not be revisited.

8.2.2.2.3. First-in-First-Out

Relatedly, CalCCA also argues that "Pre-2019 Banked RECs should be utilized on a first-in-first-out basis so that credit [resulting from CalCCA's proposed REC valuation methodology, above] is provided to now-departed customers who paid for the banked RECs earliest."[391] CalCCA's first-in-first-out proposal is a component of its proposed Pre-2019 Banked REC valuation methodology, in which DL customers are provided a credit in the vintage year a REC used for bundled customer compliance was generated. SCE's methodology, on the other hand, provides all eligible DL customers a pro rata share of the value of RECs used for bundled customer compliance at the same time.[392] SCE has confirmed that it intends to retire all Post-2018 Banked RECs before retiring

[391] CalCCA-01 at 25.

[392] SCE-04 at 8.

Pre-2019 Banked RECs and we make this a requirement here.[393] Because we decline to adopt CalCCA's proposed valuation methodology and because CalCCA has provided no other justification for its first-in-first-out proposal, we decline to adopt it.

8.2.2.3. Updated Total Portfolio Resource Adequacy Value

SCE proposes an updated 2026 Total Portfolio RA Value of $1.453 billion, a roughly 44 percent decrease from the value forecast in its May Filing.[394] The RA Value is the estimated financial value, measured in dollars per kilowatt, of the RA component of SCE's PCIA-eligible portfolio in a given year. [395] SCE multiplies the forecast RA Adder (or actual sales prices, when applicable), presented in dollars per kilowatt-year, by the estimated volume of RPS-eligible capacity of the resources in SCE's PCIA-eligible portfolio, determined using SCE's Slice-of-Day (SOD) methodology, discussed below. SCE forecasts the costs of any excess RA that it may sell in 2026, valued at the Forecast RA Adder. SCE values forecast unsold RA at $0.[396]

SCE states that the decrease between its May Filing and Amended October Update forecast RA Value is driven by application of the 2026 Forecast RA Adder and an update SCE made to the forecast quantity of capacity from energy storage resources.[397] CalCCA states that SCE corrected its excess RA

[393] SCE-01 at Table IX-45, noting that the quantity of Pre-2019 Banked RECs SCE forecasts equals its "Forecast RPS compliance if short, required to use bank, and all Post-2018 RECs are exhausted."

[394] SCE-05A at Table IX-42.

[395] SCE-05A at 148.

[396] SCE-05A at 152-153.

[397] SCE-05A at 151.

quantification after CalCCA issued discovery on the topic to SCE.[398] CalCCA states that as SCE was addressing its discovery request, SCE identified a second error in its RA calculations. SCE identifies this error as the omission of two RA resources from SCE's position forecast. SCE has corrected both issues in its Amended October Update.[399] SCE also incorporates its final 2026 RA allocations and requirements assigned by the Commission in September 2026, including an 18 percent PRM and an effective PRM procurement target ranging from 1,260 to 2,300 MW for June through October 2026.[400]

In its May Filing, SCE forecast the RA Adders and Total Portfolio RA Value according to then-established Commission methodologies. This included segmenting RA quantities into Local RA, System RA, and Flexible RA into subgroups, and multiplying each of the three subgroup quantities by an RA Adder specific to the type of RA provided.[401] However, after SCE filed its May Filing, the Commission issued D.25-06-049 which consolidated the three RA Adders into one RA Adder.[402] Pursuant to D.25-06-049, the Commission's Energy Division included a single Final 2025 RA Adder and single Forecast 2026 RA Adder in its Market Price Benchmark Calculations for 2025, released on October 1, 2025. SCE incorporates the single MPB in its forecast 2026 and final 2025 PCIA calculations.[403]

398 CalCCA Opening Brief at 59.

399 SCE-05A at 4-5.

400 SCE-05A at 153, citing D.25-06-048, *Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements* [hereinafter D.25-06-048].

401 SCE-01 at 137-138.

402 D.25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark* at OP 1. The decision also changed the pool of data Energy Division is to use to calculate the forecast RA Adder. *Id.*

403 *See* SCE-05A at Table IX-45.

8.2.2.3.1. Slice of Day Methodology

SCE determines the forecast costs and market values of its RA resources using a "price X quantity" formula, using the 2026 Forecast RA MPB or actual sales as the "price" variable. SCE proposes to forecast its RA position, *i.e.*, the "quantity" portion of its 2026 forecast, using a SOD Methodology.[404] The Commission has adopted the SOD methodology for use in determining IOU RA compliance,[405] but has not provided direction on or rules for IOU use of SOD when calculating a forecast Indifference Amount.[406]

SOD Overview

SOD transitions the Commission's RA program from a compliance requirement based on a single net qualifying capacity (NQC) check in the peak hour to a capacity check in every hour of the "worst day" (24 total hours) for each month.[407] SCE created its hourly RA position under the SOD framework using its internal RA Optimizer tool and the Commission's Master Resource Database.[408]

To account for RA values in the PCIA, SCE converts its hourly position to a monthly position. "To represent SCE's RA position as a single monthly number, SCE converts its hourly position into a monthly position by taking an average of its hourly optimized supply and creating a 'baseload equivalent' position."[409] SCE states that it normalizes the baseload-equivalent RA quantity for a resource

[404] SCE-05A at 63, 142; *see also* Section 5.2.11 of this Decision.

[405] *See* D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track* at OP 2 and D.24-06-004 at OP 5.

[406] CalCCA-01 at 12.

[407] SCE-05A at 143.

[408] SCE-05A at 146. *See also* Section 5.2.11.

[409] SCE-05A at 143.

by the capacity of the resource, signifying the effective contribution of the resource towards meeting the SOD requirement, *i.e.*, a resource's "SOD RA Effectiveness Factor."[410] In testimony, SCE describes the methodologies it uses to estimate RA quantity by resource type: baseload resources, intermittent resources, stand-alone storage, and hybrid co-located sources.[411]

CalCCA questions SCE's use of the SOD framework for the purpose of calculating the PCIA, arguing that it should continue to be treated as an interim methodology given the unknowns surrounding the "full impact of SOD on RA value."[412] CalCCA recommends that this issue be evaluated in the current PCIA rulemaking.[413] SCE does not oppose CalCCA's recommendation, noting that it has consistently identified its SOD framework as an interim approach.[414]

While CalCCA does not dispute the RA quantity forecast SCE's method produces,[415] CalCCA argues that, between its May Filing and October Update, SCE updated its RA Optimizer tool it uses to calculate its SOD position. SCE's introduction of an updated RA Optimizer in its October Update, CalCCA argues, led to input errors in SCE's calculations that were only uncovered due to CalCCA's discovery requests.[416] SCE corrected these issues in its Amended October Update.[417] However, CalCCA states, SCE's RA Optimizer update is procedurally improper, this late in an ERRA forecast proceeding, as it denies

[410] SCE-05A at 144.

[411] SCE-05A at 144-147.

[412] CalCCA-01 at 12.

[413] CalCCA-01 at 13 and n.26.

[414] SCE-04 at 11.

[415] CalCCA Opening Brief at 57, 60.

[416] CalCCA Opening Brief at 59.

[417] SCE-05A at 4.

intervenors "and the Commission the opportunity to fully explore the impacts of this change in the two weeks before Comments were due.[418]

This situation leads CalCCA to request:

> that the Commission clearly instruct SCE (and other IOUs in their cases) that the October Update is not an appropriate forum in which to introduce substantive changes to its models or methods and explicitly find that including updates this late into the ERRA process prejudices non-utility parties.[419]

October Updates, CalCCA argues, are for updates of prior estimates and not the appropriate forum for substantive methodological changes.[420]

8.2.2.3.2. Discussion

We agree with CalCCA that any remaining questions regarding the impact of SOD on PCIA calculations are appropriate for exploration via a rulemaking in which all LSEs can participate. Consistent with our holding in D.24-12-039, we also find "that SCE's proposed methodology is a reasonable execution of guidance given to account for how Resource Adequacy is counted for compliance purposes."[421] The Commission finds SCE's use of its SOD methodology to forecast PCIA charges reasonable for the purposes of the 2026 ERRA forecast.

CalCCA does not dispute the outcome of the changes SCE made to its RA value forecast methodology between SCE's May Filing and its Amended October Update. We agree that large, substantive methodological changes between a utility's May Filing and October Update can present challenges for the

[418] CalCCA Opening Brief at 60.

[419] CalCCA Opening Brief at 60-61.

[420] CalCCA Opening Brief at 59.

[421] D.24-12-039 at 75.

Commission and intervenors and may ultimately be prejudicial. However, CalCCA cites to no Commission authority that supports its request to preemptively declare all substantive utility changes between May and October to be prejudicial. CalCCA does not allege, and we do not find prejudice here and so we decline to adopt CalCCA's request.

8.2.3. Other Proposed Modifications to Southern California Edison Company's Calculation of its 2026 Indifference Amount

In testimony, CalCCA notes what it considers to be two corrections to SCE's 2026 Indifference Amount calculation: CalCCA states that SCE failed to allocate the sale revenue related to one contract in a REC swap transaction to the proper PABA vintage proposed in SCE's AL 5487-E. CalCCA also states that an error in SCE's workpapers resulted in the impacts of neither of the two contracts in the swap transaction appearing in the Indifference Calculation.[422]

CalCCA also recommends that SCE update the vintage assignment of any MTR contract that is shifted between program obligations. Specifically, CalCCA recommends that contract number 12078, which is projected to be online during 2026, be updated to reflect the expected update to meet both the 2025 (2021 PABA vintage subaccount) and 2026 (2023 PABA vintage subaccount) MTR compliance tranches.[423] SCE does not dispute these recommendations[424] and incorporates them into its Amended October Update.

8.2.4. Other Items Included in Southern California Edison Company's Proposed 2026 Power Charge Indifference Adjustment Rates

[422] CalCCA-01 at 36-37.

[423] CalCCA-01 at 39-40.

[424] SCE-04 at 11-12.

SCE proposes to include the following additional items in its 2026 PCIA rates forecast:[425]

a. A true up of the year-end 2025 PABA balance, pursuant to D.18-10-019 and D.19-10-001;

b. A transfer of the year-end 2025 ERRA balance to the 2025 PABA vintage subaccount, pursuant to OP 4 of D.22-01-023;

c. Amortization of the system reliability costs incurred pursuant to D.19-11-016, tracked in the PABA, and authorized for recovery pursuant to Res. E-5240 (described in Section 5.2.7);

d. Costs of the UOS Separator, to be recovered via the 2021 subaccount of the PABA pursuant to D.21-06-035 and Res. E-5259 (described in Section 5.4.2);

e. Amortization of its January 1, 2025 – September 30, 2025, General Rate Case Revenue Requirement Memorandum Account (GRCRRMA) balance, pursuant to D.25-09-030.

SCE's requested amortization of the remaining D.19-11-016 system reliability costs in the PABA and recovery of UOS Separator costs via the PABA continue to be proposed in compliance with Commission directives and are therefore reasonable and authorized.

SCE's test year 2025 GRC decision was not adopted until September of that test year. Thus, SCE's rates for most of 2025 did not reflect the base revenue requirement ultimately adopted for that period, resulting in an undercollection. SCE's GRCRRMA balance is not included in the revenue requirement amounts adopted in this decision.[426] However, the decision resolving that GRC directed SCE to amortize over 24 months the difference between billed revenues received

[425] SCE-05A at 158.

[426] *See* SCE-05A at 160.

during the test year and the adopted 2025 base revenue requirement "beginning October 1, 2025, or as soon thereafter as it may be effected."[427] SCE's presentation of the year-end 2025 PABA balance in its Amended October Update is different from its May Filing, in part, because in the May Filing, all of SCE's forecast year-end 2025 PABA undercollection was included in its proposed 2026 ERRA Revenue requirement. Now, because the GRCRRMA portion is to be amortized over 24 months rather than 12, the GRCRRMA portion of the forecast year-end 2025 PABA undercollection has been removed from the PABA undercollection and the portion that is to be amortized over the 12 months beginning January 1, 2025 has been tracked as a standalone revenue requirement item incorporated into the 2026 PCIA revenue requirement.[428, 429]

8.2.4.1. 2025 Power Charge Indifference Adjustment True Up and 2025 Trigger Exceedance

SCE's requests to (1) transfer the year-end 2025 ERRA balance to the 2025 PABA vintage subaccount and (2) incorporate a true up of its 2025 PABA balance into the 2026 PCIA revenue requirement are reasonable and adopted. D.18-10-019 requires utilities to propose in their ERRA forecasts a true up of prior-year PCIA surcharges, by which utilities compare the forecast PCIA surcharge amounts with the actual amounts utilities received for their PCIA-eligible resources over the forecast period.[430] This true up can change the

[427] D.25-09-030 at 2, OP 2.

[428] SCE-05A at 170, n.215, and Appendix A at Table 2.

[429] SCE adjusts the year-end 2025 NSGBA in a similar way, removing the full year-end 2025 overcollection of NSGBA resources, and including only the portion that is to be returned over the first 12 months of the 24 month amortization period. *See* SCE-05A at Appendix A, Table 4.

[430] D.18-10-019, as refined by D.19-10-001 and D.25-06-049. *See also* SCE-05A at 152.

total value of the PCIA revenue requirement (by showing that the actual market value of resources was greater or less than forecast in the prior year).[431]

D.19-10-001 created processes by which forecast RA and RPS MPBs are trued-up. Following this decision, the Commission has authorized SCE's retained RA and RPS quantities to be valued at the applicable prior-year Final MPBs (which Energy Division develops based on actual sales prices realized) or at $0 (in the case of Pre-2019 Banked RECs), unsold quantities of Post-2018 Banked RECs are valued at $0, and actual sold quantities are valued at the actual sales prices.[432] Energy values are trued-up using actual sales. The true up allows any variations from the forecast, that is, any over- or under-collections, to be returned to or recovered from ratepayers. D.25-06-049 modified the RA MPB and required the modified RA to be used not only to forecast 2026 RA values, but also to true up 2025 RA values.[433]

As shown in Table 8-3, below, SCE's proposed true ups of the values of Retained RA and RPS recorded in these balancing accounts changed significantly from its May Filing to its Amended October Update, primarily due to incorporation of the 2025 Final MPBs. The Commission's Final 2025 MPBs indicate that retained RPS and retained System and Flex RA resources were overvalued in the 2025 ERRA forecast. Practically speaking, this means that bundled customers "reimbursed" or credited DL customers for more than the retained quantities were worth in the market in 2025. DL customers' PCIA rates

[431] *See* SCE-05 at n.152.

[432] D.19-10-001 at OPs 3 and 4. D.23-11-094 at 60: "Should SCE determine that the use of RECs banked in or before 2018 is necessary for its bundled service RPS compliance , it should value those RECs at zero, as proposed[;]" D.24-12-0 at 68: "we find SCE's treatment of RPS resources to be reasonable and therefore approve them as proposed for this proceeding."

[433] D.25-06-049 at COL 10.

will increase in 2026 and bundled customer rates will decrease to reverse this over-valuation.

Table 8-3: Change in PCIA-Related Year-End 2025 Balances between SCE's May Filing and Amended October Update[434]

Account	May Filing ($000)	Amended October Update ($000)	Change ($000)
Year-End 2025 PABA Balance	$69,234	$1,318,350	($1,249,116)
Year-End 2025 ERRA BA Balance	$61,792	($898,645)	$960,437

Table 8-4: Comparison of 2025 Forecast to Final PCIA Market Price Benchmarks[435]

Market Price Benchmark	2025 Forecast Adders (In Rates/May Filing)	2025 Final Adders (October 2025)	Percent Change
Energy Index	$40.56/MWh	N/A (actuals used)	N/A
RPS Adder	$71.24/MWh	$63.86/MWh	-10%
RA Adders			
System	$483.72/kW-yr	$134.52/kW-yr	-72%
Local	$134.76/kW-yr	$134.52/kW-yr	0%
Flex	$203.64/kW-yr	$134.52/kW-yr	-34%

CalCCA initially disagreed with SCE's proposed PCIA true up, arguing that SCE's use of the Final 2025 RA MPB true-up method adopted by D.25-06-049 constitutes retroactive ratemaking.[436] CalCCA filed an application for rehearing (AFR) of D.25-06-049 on July 28, 2025, alleging that the Commission's application of the new RA MPB to 2025 PCIA true ups constituted impermissible retroactive

434 May Filing data is taken from SCE-01 at Table II-2; Amended October Update data is taken from SCE-05A at Table II-3.

435 SCE-05A at Table X-50.

436 CalCCA Opening Brief at 39.

ratemaking. CalCCA's AFR was denied by the Commission at its October 30, 2025 voting meeting.[437] CalCCA notes that its arguments in this area are therefore moot.[438]

SCE's forecast 2025 PCIA surcharge true ups have been calculated consistent with D.18-10-019, D.19-10-001, and D.25-06-049. SCE's proposed year-end 2025 ERRA BA and PABA balances are adopted. SCE is authorized to transfer the 2025 year-end ERRA balance to the 2025 subaccount of the PABA. Incorporation of these costs in the 2026 PCIA rates is reasonable and approved as requested.

Finally, SCE also notes that its true ups of year-end 2025 ERRA BA and PABA balances caused its ERRA Trigger Balance to exceed its ERRA Trigger Point and Threshold as of September 30, 2025, "[p]rimarily as a result of the retained RA and RPS true-up."[439, 440] SCE submitted AL 5664-E on October 30, 2025, notifying the Commission of its Trigger Point Exceedance, but requested no rate changed because the exceedance undercollection would self-correct by virtue of implementation of forecast 2026 ERRA rates on January 1, 2026.

8.2.5. Other Proceedings that May Impact the 2026 Power Charge Indifference Adjustment

[437] *See* D.25-10-061, *Order Denying Rehearing of Decision 25-06-049*.

[438] CalCCA Reply Brief at 12.

[439] SCE-05A at 4.

[440] The Commission's resolution of SCE's 2024 ERRA Trigger application decreased SCE's bundled service customer rates from October 1, 2024-September 30, 2025. While the impacts of SCE's 2024 ERRA Trigger Application were included in SCE's estimates of its 2025 year-end balance forecasts in SCE-01, by the time SCE served SCE-05A, the impacts of the Trigger application had lapsed. SCE's year-end 2025 balancing account forecasts now incorporate the impacts of the 2024 ERRA Trigger by virtue of being based on recorded amounts through September 30, 2025. *See* SCE-01 at 3-4 and SCE-05A at 5-6.

In its May Filing, SCE lists the proceedings below as potentially impacting the 2026 PCIA.[441] Updates to the statuses of those proceedings and additional proceedings that may impact the 2026 PCIA are also listed below.

a. Phase 1 of SCE's 2025 General Rate Case (GRC, A.23-05-101)

On September 18, 2025, the Commission adopted D.25-09-030, which, among other authorizations: (1) approved a Commission-jurisdictional base revenue requirement of $9.664 billion for TY 2025[442]; and (2) authorized recovery of certain memorandum and balancing accounts, including the January 1, 2025 through September 30, 2025 balance in the GRCRRMA, which represents the difference between the actual revenue received in those months in 2025 and the actual rates adopted by the decision for 2025.[443] As noted above, these approvals have been factored into SCE's Amended October Update.

D.25-09-030 also adopted a Post-Test Year Ratemaking (PTYR) mechanism that would adjust SCE's Authorized Base Revenue Requirement on an annual basis in non-test years. To implement this, SCE plans to submit an AL before December 1, 2025, that will include an update to the 2026 AGBRR that SCE will use in its implementation of 2026 ERRA Forecast rates on January 1, 2026.[444]

D.25-09-030 also authorized the establishment of the two-way Palo Verde Non-Labor Operations and Maintenance (O&M) Expense Balancing Account (PVNLOMBA) to record both actual Palo Verde operating costs and authorized funding related to Palo Verde non-labor O&M expenses. Cost recovery is automatic for up to 110 percent of the authorized amounts in any year, and

[441] SCE-01 at 147-150.

[442] D.25-09-030 at 1.

[443] D.25-09-030 at OP 2.

[444] D.25-09-030 at OP 3. SCE-05A at 162.

amounts above that level are subject to a reasonableness review. SCE is authorized to transfer year-end balances in the PVNLOMBA to the Legacy UOG PABA subaccount. SCE forecasts transferring a year-end 2025 balance of $10.832 million to the Legacy UOG subaccount of the PABA and will update the final amount in its 2026 ERRA forecast implementation advice letter.[445]

Finally, D.25-09-030 approved the continuation of the existing two-way Post Employment Benefits Other than Pensions Balancing Account (PBOPBA), Pension Costs Balancing Account (PCBA), and Medical Programs Balancing Account (MPBA) through the 2025 GRC cycle and the modification of the schedule for transferring the year-end PBOPBA, PCBA, and MPBA balances to the BRRBA and PABA to occur in December instead of January the following year. SCE forecast December 2025 transfers of $0.822 million, $1.040 million, and $4.490 million for the PBOPBA, PCBA, and MPBA to PABA. SCE will update this amount in its 2026 ERRA forecast implementation advice letter.[446]

b. <u>2025 Santa Catalina Island GRC (A.23-12-011)</u>

The Commission issued D.25-06-010, resolving SCE's Catalina Island GRC, in June 2025, after SCE filed its May Application. SCE incorporates the impact of this decision in its Amended October Update. This decision decreased SCE's forecast 2026 Catalina Island fuel costs, as described in Section 5.2.16.

[445] D.25-09-030 at OP 21. SCE-05A at 177-178

[446] SCE-05A at 178.

c. Applications for the sales of various hydroelectric plants (A.24-08-012, A.24-09-008, and A.25-03-001)

A.24-08-012 was resolved by D.25-09-012, *Decision Authorizing Southern California Edison Company to Sell Certain Hydroelectric Power Plants to San Bernardino Valley Municipal Water District Under Public Utilities Code Section 851*. Neither A. 24-09-008 nor A.25-01-001 has been resolved as of October 1, 2025. SCE's 2026 forecasts remain unchanged by this decision because SCE had factored in decreased production related to these systems in its May Filing.

d. Track 1 of the ERRA PCIA Order Instituting Rulemaking (R.25-02-005)

As noted above, SCE incorporated the updated RA MPB ordered by the Track 1 decision in the PCIA rulemaking (D.25-06-049) into its Amended October Update, as described in Section 8.2.2.3.

e. SCE's Petition for Modification of D.23-02-040 and D.24-02-047

SCE's PFM of these decisions, relating to bridge procurement, was granted in part by D.25-08-007 as discussed in Section 5.2.10 of this Decision. This decision likely decreased procurement costs for ratepayers.

f. SCE's Measure Long Beach Surcharge Balancing Account Advice Letter

On April 4, 2025, SCE submitted Advice 5510-E, requesting authority to implement a surcharge to recover the costs of a new utility users' tax (UUT) imposed by the City of Long Beach on certain SCE natural gas purchases. If Advice 5510-E is approved, SCE will remove the forecast costs for Measure LB UUT from New System Generation forecast costs.[447]

g. SCE's 2021 ERRA Review

[447] SCE-05A at 162.

SCE's May Filing noted that a proposed decision in its 2021 ERRA Review proceeding was pending before the Commission.[448] On June 19, 2025, the Commission issued D.25-06-006, *Approving Southern California Edison Company 2021 Energy Resource Recovery Account Compliance Application*. This decision orders SCE to implement a vintage-specific sur-credit to the PCIA rates to refund $3.7 million of double-collected franchise fees to applicable DL customers. SCE incorporates this adjustment into its Amended October Update. SCE will account for the sur-credit to ensure it is borne by shareholders, rather than ratepayers.[449]

h. Track 3 of the RA OIR (R.23-10-011)

SCE's May Filing noted that a forthcoming Track 3 decision in R.23-10-011, the Resource Adequacy rulemaking, could impact its Indifference Amount calculation. After SCE submitted its May filing, the Commission issued D.25-06-048, *Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*. As noted above, SCE has incorporated the impacts of this decision in its Amended October Update.

8.3. Approval of Southern California Edison Company's 2026 Indifference Amount

Based on our review of the Application, testimonies, workpapers, and briefs, and Commission decisions, we resolve the disputed issues as noted above and find all other aspects of SCE's calculations of the 2026 Indifference Amount forecast, including its treatment of RA and RPS resource values, to be consistent with current Commission guidance and so reasonable, as specified herein.

8.4. 2026 Competition Transition Charges

448 SCE-01 at 150.

449 SCE-05A at 162.

SCE's proposed 2026 CTC rates are approved. The history of the CTC is described in Section 8.1, above. The final CTC (and PCIA) rates are determined by allocating the vintaged PABA revenue requirements to rate groups using generation revenue allocation factors approved in SCE's GRC Phase 2 proceeding, normalized to account for each rate group's kWh sales forecast by vintage and divided by forecast sales by vintage (also referred to as billing determinants).[450] No party has disputed or commented upon SCE's proposed 2026 CTC rates. SCE's proposed CTC rates were calculated consistent with Commission decisions and so are reasonable and approved for recovery as proposed. Based on the calculation of the 2026 Indifference Amount, above, SCE's updated 2026 Competition Transition Charges are as follows:

Table 8-3: 2026 Competition Transition Charges ($/kWh)[451]

Rate Group	2026 CTC	Rate Group (cont'd)	2026 CTC (cont'd)
Domestic	0.00017	TOU-8-Sub	0.00011
TOU-GS-1	0.00012	TOU-PA-2	0.00012
TC-1	0.00013	TOU-PA-3	0.00012
TOU-GS-2	0.00013	St. Lighting	0.00016
TOU-GS-3	0.00012	Standby-Sec	0.00013
TOU-8-Sec	0.00012	Standby-Pri	0.00012
TOU-8-Pri	0.00012	Standby-Sub	0.00011
System Average		0.00014	

8.5. 2026 Power Charge Indifference Adjustment Rates by Vintage

[450] SCE-05A at 142.

[451] SCE-05A, Appendix B, Table: "ERRA CRS Rates - Vintaged Specific Sales Rate Design."

SCE calculated proposed 2026 PCIA rates pursuant to the methodology described for CTC rates, above.[452] Because SCE has calculated PCIA rates consistent with the Commission's prescribed methodology, we find SCE's calculation of the vintaged PCIA rates reasonable and approve them for recovery as requested.

Table 8-4: 2025 & 2026 Average PCIA Rates Across Classes ($/kWh)

Vintage	2025 Rate[453]	2026 Rate[454]
2001	0.00001	0.00005
2004	0.00001	0.00005
2009	0.00162	0.01256
2010	0.00125	0.01504
2011	0.00041	0.01749
2012	0.00028	0.01845
2013	0.00036	0.01885
2014	(0.00115)	0.02140
2015	(0.00698)	0.01628
2016	(0.00975)	0.01934
2017	(0.00927)	0.01837
2018	(0.01077)	0.02098
2019	(0.01194)	0.01680
2020	(0.01148)	0.01756
2021	(0.00973)	0.01636

[452] SCE-05A at 142.

[453] SCE AL 5448E Attachment C, "ERRA CRS Rates - Vintaged Specific Sales Rate Design."

[454] SCE-05A, Appendix B, Table: "ERRA CRS Rates - Vintaged Specific Sales Rate Design."

2022	(0.01441)	0.02324
2023	(0.01962)	0.02299
2024	(0.02363)	0.00921
2025	(0.02467)	(0.00639)

9. Approval of Southern California Edison Company's 2026 Energy Resource Recovery Account Forecast Revenue Requirement

Upon review of the record, including intervenor submissions and SCE's filings submitted in support of the inputs and assumptions that underlie SCE's ERRA procurement cost forecast and requests for recovery of other costs, we find SCE's 2026 ERRA forecast revenue requirement, as updated by SCE's Amended October Update, to be reasonable and adopt it.

10. 2026 Energy Resource Recovery Account Forecast Average Rates

SCE calculates the incremental impact on its bundled customer group rates associated with this proposed revenue requirement. The results of this calculation are detailed in Table 9-1, below. Table 9-2, below shows the portion of those rates related to the New System Generation Balancing Account, allocated via the Cost Allocation Mechanism, as described in Sections 5.2.6 and 7.2.1, and as required by Scoping Memo Issue 5. Because we find the underlying forecast revenue requirements reasonable, and because we find the calculation of rates stemming from those revenue requirements to be consistent with Commission rules and practice, we find SCE's ERRA-related bundled customer group rates and the New System Generation rate component reasonable.

Table 9-1: Summary of the 2026 ERRA Forecast Portion of SCE's Bundled Customer Rates[455]

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	Change from October 1, 2025 Rates
Domestic				
• D	0.25929	0.11567	0.37496	-3.0%
• D-CARE	0.10856	0.11565	0.22421	-3.8%
• DE	0.16532	0.11561	0.28093	-3.4%
• DM	0.16884	0.11599	0.28483	-3.0%
• DMS-1	0.25948	0.11600	0.37548	-4.7%
• DMS-2	0.25379	0.11612	0.36991	-5.0%
Lighting-Small, Med. Power				
• GS-1	0.18477	0.11132	0.29609	-4.8%
• GS-2	0.21500	0.10031	0.31531	-5.1%
• TC-1	0.27593	0.08995	0.36588	-4.2%
• TOU-GS	0.17795	0.09057	0.26852	-5.4%
Large Power				
• TOU-8-S	0.15817	0.08638	0.24455	-5.7%
• TOU-8-P	0.13680	0.08189	0.21869	-5.9%
• TOU-8-T	0.05953	0.07639	0.13592	-8.2%
• TOU-8-S-S	0.16793	0.09268	0.26061	-5.6%
• TOU-8-S-P	0.13344	0.08080	0.21424	-6.0%
• TOU-8-S-T	0.05176	0.07230	0.12406	-8.0%
Agricultural & Pumping				
• TOU-PA-2	0.17764	0.09388	0.27152	-5.4%
• TOU-PA-3	0.12933	0.07722	0.20655	-5.9%
Street & Area Lighting •				
• LS-1	0.69630	0.06150	0.75780	-1.2%
• LS-2	0.19878	0.06143	0.26021	-3.3%
• LS-3	0.11198	0.06152	0.17350	-5.3%
• DTL	0.49603	0.06150	0.55753	-1.6%
• OL-1	0.39056	0.06150	0.45206	-1.9%
Average Rate – All Groups	0.17818	0.10008	0.27825	-4.5%

Table 9-2: 2026 ERRA Forecast Cost Allocation

[455] SCE Amended October Update Workpapers, 2026 ERRA Forecast Chapter XI tables October Amended.xlsx, tab: 2026 ERRA October Amended. The "Total" column includes the Public Utilities Commission Regulatory Fee.

Mechanism Rate Component[456]

Rate Schedule by Customer Group	Total Delivery (¢/kWh)
Domestic	
• D	0.00832
• D-CARE	0.00832
• DE	0.00832
• DM	0.00832
• DMS-1	0.00832
• DMS-2	0.00832
Lighting-Small, Med. Power	
• GS-1	0.00645
• GS-2	0.00626
• TC-1	0.00442
• TOU-GS	0.00583
Large Power	
• TOU-8-S	0.00543
• TOU-8-P	0.00491
• TOU-8-T	0.00390
• TOU-8-S-S	0.00543
• TOU-8-S-P	0.00491
• TOU-8-S-T	0.00390
Agricultural & Pumping	
• TOU-PA-2	0.00474
• TOU-PA-3	0.00449
Street & Area Lighting	
• LS-1	0.00449
• LS-2	0.00449
• LS-3	0.00449
• DTL	0.00449
• OL-1	0.00449
Average Rate – All Groups	0.00651

[456] SCE Amended October Update Workpapers, 2026 ERRA Forecast Chapter XI tables October Amended.xlsx, tab: 2026 ERRA October Amended.

11. Safety 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.

12. Compliance with the Authority Granted Herein

We authorize SCE to update the final 2025 year-end balances with recorded actual values (actuals) through October 2025 and forecasts for November and December 2025. These balances, as well as the 2026 forecasts, shall utilize the most updated MPB values available. If SCE has its November 2025 actuals available in time for submitting its Advice Letter, those should be included rather than a November forecast.[457]

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 2025 actuals and forecasts for December 2025, in its advice letter for rates to be effective starting January 1, 2026.

13. 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.

As of October 27, 2025, the Commission has received six public comments on the Docket Card for this proceeding. Some commenters welcome the rate decrease proposed by SCE's May Filing. Some commenters welcome the rate decrease proposed by the May Filing and state that if the October Update results in a rate increase, they oppose approval. Some commenters state that they do not know how the rate increase or decrease is calculated and question whether the

[457] If SCE's November 2025 actual numbers are not available at the time the utility files its implementation advice letter, it may use November 2025 forecasts.

Commission knows how the rate increase or decrease is calculated. One commenter requested an SCE balance sheet.

14. Procedural Matters: Motions for Entry of Testimony and to Seal Portions of the Record

On September 16, 2025, SCE filed a motion requesting leave to file a confidential version of the September 16, 2025 Joint Case Management Statement.

On October 28, 2025, SCE and CalCCA filed a Joint Motion to Offer Prepared Testimonies and Exhibits into Evidence pursuant to Rules 11.1, 13.8, and 13.11 of the Commission's Rules, as well as a Joint Motion to Seal a Portion of the Evidentiary Record. SCE requests that the Commission admit Exhibits SCE-01, SCE-02, SCE-03, SCE-04, SCE-05, SCE-05A, SCE-06, and SCE-07 into the evidentiary record. SCE requests that the Commission seal Exhibits SCE-01C, SCE-02C, SCE-05C, SCE-05AC, and SCE-07C. CalCCA requests that the Commission admit Exhibits CalCCA-01 and CalCCA-02 in the evidentiary record; CalCCA requests that we seal CalCCA-01C and CalCCA-02C.

On October 29, 2025, SCE and CalCCA each filed motions requesting leave to file confidential versions of their Opening Brief or Opening Briefs/Comments on SCE's Amended October Update, respectively, under seal. On November 4, 2025, SCE and CalCCA each filed motions requesting leave to file confidential versions of their Reply Briefs under seal.

No party has opposed these motions. Good cause having been shown and given compliance with procedural requirements, these motions are granted. This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

15. Comments on Proposed Decision

The proposed decision of Administrative Law Judge (ALJ) Eileen Odell was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. ~~Comments~~Opening comments were filed on December 4, 2025 by CalCCA and SCE, and reply comments were filed on ~~by~~ December 9, 2025 by CalCCA and SCE.

We have considered opening and reply comments on the proposed decision and the following modifications have been made. In response to comments on the proposed decision, we have modified Section 8 to replace the language "in its last two ERRA forecast decisions" with "in SCE's 2024 ERRA forecast decision and approved it in SCE's 2025 ERRA forecast decision for that proceeding." In the same section, we have replaced the language "on an interim basis" with "in SCE's prior two ERRA forecast proceedings." Finding of Fact 126 was also modified to align with these changes.[458]

In response to comments on the proposed decision, we have corrected the nameplate capacity of SCE's Mountainview Generation Station in Section 5 and in Finding of Fact 13.[459]

Finally, we have corrected typographical errors and page and line citations to the record noted in comments on the proposed decision.[460]

[458] SCE, Opening Comments on the Proposed Decision at A-1.

[459] SCE, Opening Comments on the Proposed Decision at A-1 through A-2.

[460] SCE, Opening Comments on the Proposed Decision at A-1 through A-2.

16. Assignment of Proceeding

Commissioner John Reynolds is the assigned Commissioner and Eileen Odell is the assigned ALJ in this proceeding.

Findings of Fact

1. SCE's proposed 2026 ERRA forecast revenue requirement includes its 2026 forecasts of electricity procurement costs, including expenses associated with F&PP, UOG, CAISO related costs, and costs associated with the residual net short procurement requirements to serve bundled electric service customers. The forecast also includes a true up of these costs incurred in 2025, as well as a forecast of GHG emissions costs, and SCE's proposed GHG allowance revenue returns. Finally, SCE's forecast includes its calculation of the 2026 Indifference Adjustment.

2. SCE's 2026 total forecast ERRA revenue requirement is $4.689 billion, which is $228.520 million greater than the 2025 ERRA-related revenue requirement in current rates.

3. SCE used econometric modelling to forecast its 2026 total retail sales estimate, from which it deducted estimated DL sales to arrive at its 2026 bundled customer sales forecast. The resulting forecast is adjusted for line losses and to account for NEM energy exports.

4. SCE forecasts hourly loads by applying a modeled hourly load shape to the annual bundled energy forecast.

5. SCE forecast a slight decrease in total retail electricity sales in 2025, from 79,502 GWh recorded in 2024 to a forecast of 78,773 GWh in 2025. SCE forecasts a slight increase in 2026, for a total retail sales forecast of 80,447 GWh.

6. SCE forecasts residential customer growth based primarily on population growth; commercial customer growth is assumed to be tied to residential

customer growth, while industrial customer growth is related to changes in manufacturing employment.

7. SCE forecasts a 0.6 percent increase in its number of customers in 2025 and a 0.7 percent increase in 2026.

8. SCE develops its production and cost forecasts using PLEXOS software that (1) forecasts the least-cost dispatch of dispatchable resources in SCE's portfolio; (2) optimizes hydroelectric dispatch; and (3) performs Monte Carlo simulations of forced outage rates of individual units.

9. SCE develops the production and cost forecast inputs for its PLEXOS models based on forecasts of power, gas, and GHG prices, the physical constraints of each generating unit, and contractual limitations.

10. SCE's forecast of energy prices is based on the forward power broker quotes for 2026 in effect as of August 25, 2025; SCE's natural gas price forecast is based on monthly NYMEX forward prices at the SoCal Citygate in effect as of August 25, 2025, plus intrastate transportation charges from Southern California Gas Company, as applicable. SCE used the ICE settlement price of a 2026-vintage GHG allowance, as of August 25, 2025, as the basis for its 2026 GHG price forecast.

11. SCE's portfolio of resources available in 2026 includes UOG, including UO nuclear generation, UO hydroelectric generation, UO fossil fuel generation (*e.g.*, natural gas), UO renewable generation resources, and UO storage. SCE's purchased power resources include CHP and renewable resources, inter-utility and bilateral contracts, and anticipated future solicitations and market purchases. Finally, SCE's 2026 forecast includes the costs of procurement contracts SCE entered into to meet Commission reliability requirements.

12. SCE's resource-specific energy production forecasts from SCE's portfolio of resources are listed in Exhibit SCE-05A, Table IV-8, "Updated 2026 Energy Forecast of the SCE Portfolio," and are confidential unless provided publicly elsewhere in SCE's testimony.

13. SCE's forecast of UO generation and purchased power contract capacity in 2026 includes 1,164 MW of hydroelectric power nameplate capacity, approximately 9 MW of nameplate capacity in solar photovoltaic resources, 11,045 MW from CHP and renewable resources, 245 MW of natural gas Peaker resources, and approximately ~~1,056~~1,110 MW from its Mountainview Generating Station. SCE's forecast also includes forecasts of inbound capacity available via SCE's inter-utility contract with the WAPA and the U.S. Bureau of Reclamation, averaging 151 MW per month in 2026.

14. SCE's forecast includes the expected production from and revenues related to SCE's UOG hydrogeneration facilities; SCE's forecast assumes an average hydrological year for 2026 and incorporates SCE's best estimate of upcoming outages and unavailability in 2026.

15. SCE's forecast includes the anticipated energy production from SCE's last remaining SPVP site, Site 42; this production forecast is based on the previous year's project capacity factor.

16. SCE's forecast includes the anticipated energy production, energy costs, and capacity costs of CHP and renewables projects; SCE forecasts monthly energy deliveries from CHP and renewables projects based on the historical performance of each project, adjusted to reflect anticipated curtailments from solar and wind projects. For new CHP projects without performance data, energy production and capacity forecasts are based on contractual expectations discounted by their expected probabilities of successful development.

17. SCE's forecast includes the estimated production from and natural gas costs of its five dispatchable Peaker units; it includes the projected energy production, as well as capital and natural gas costs from the Mountainview Generating Station in its 2026 forecasts of energy deliveries and costs.

18. SCE's forecast includes the anticipated energy and capacity costs of forecast deliveries from a fifty-year agreement executed with the WAPA and the U.S. Bureau of Reclamation. Ongoing drought conditions cause SCE to reduce its estimates to levels below its 2026 entitlement of 280.245 MW of contingent capacity and 238.16 GWh of firm energy generated by the Boulder Canyon Project at the Hoover Dam. SCE forecasts related net inter-utility contract purchases of 156 GWh in 2026.

19. SCE's 2026 ERRA forecast includes anticipated energy costs, energy revenues, and capacity costs of New System Generation resources, including the storage costs and market revenues associated with its utility-owned storage facility, UOS Titanium. These costs are recovered via the Commission's CAM to ensure all benefitting customers pay the costs of the resources. These costs are tracked in SCE's NSGBA. SCE's CAM-eligble contracts are listed in Exhibit SCE-05A at Table VIII-39, "CAM Applicable Resources."

20. SCE includes in its forecast the anticipated net procurement costs of resources from SCE's 2021 and 2022 SCE-CPE Local RA RFOs, CAISO costs, and $250,000 in administrative costs related to its role as a CPE. Projected administrative costs are based on the costs of the independent evaluator used for SCE's last CPE solicitation. These costs are tracked in the CPE subaccount of the NSGBA and are recovered under the CAM.

21. SCE's forecast includes the capacity costs and net revenues of approximately 1,360 MW of total nameplate capacity secured via seven "Fast

Track" and five "Standard Track" contracts entered into following SCE's SRRFO, held pursuant to D.19-11-016. These costs are allocated across the PABA, the NSGBA, and the MCAMBA, which allows applicable costs to be recovered from Departed Load customers using the MCAM.

22. SCE includes in its forecast the remaining capacity costs of summer emergency reliability incremental procurement required by D.21-02-028, D.21-03-056, and D.21-12-015; these costs are tracked in the NSGBA and recovered from all benefitting customers via the CAM.

23. SCE includes in its forecast the estimated remaining capacity costs of contracts secured to meet MTR requirements adopted in D.21-06-035 and D.23-02-040. D.21-06-035 required SCE to procure 4,052 MW of nameplate capacity; D.23-02-040 required SCE to procure a combined 1,539 MW.

24. SCE includes in its forecast the estimated monthly capacity costs of generic contracts SCE projects it will need to secure to satisfy its RA obligations in 2026. SCE forecasts this incremental need using Slice-of Day methodology and applies the Commission's Forecast RA MPB as the proxy price for these contracts.

25. SCE's final 2026 RA requirements include an 18 percent PRM and an effective PRM procurement target ranging from 1,260 to 2,300 MW for the months of June through October.

26. Relating to its RA position, SCE's Amended October Update: (1) includes two resources in its RA position that had been included in its May Filing but omitted from its October Update and (2) includes corrections to SCE's excess energy storage position identified by CalCCA, reducing SCE's projected 2026 ERRA revenue requirement by $99.700 million.

27. SCE includes in its forecast the estimated capacity costs, and when applicable, the gas, GHG, and energy costs associated with its 63 LCR contracts in the LA Basin and Moorpark local reliability areas, procured pursuant to D.13-02-015. SCE includes the estimated production from its in-front-of-the-meter LCR resources in its production forecast, while its behind-the-meter LCR resources decrease the bundled service customer load requirement.

28. SCE includes in its 2026 ERRA forecast the estimated front-of-the-meter production from and capacity costs of its PRP Program, which consists of 19 contracts approved by the Commission in D.18-07-023.

29. SCE includes in its forecast the estimated costs of SCE's modified GTSR Program projects. SCE forecasts Green Tariff participation in 2026 to be 123,556 MWh and ECR participation to be 143,283 MWh, which is an increase from the demand seen in 2025.

30. SCE includes in its forecast the anticipated costs of generation-related nuclear fuel expenses and interim spent fuel storage costs associated with its partial ownership of PVNGS. These forecasts reflect planned outages. SCE forecasts $29.356 million in nuclear fuel expenses related to PVNGS. The PVNGS interim spent fuel costs included in that estimate will be offset by a credit of $3.03 million stemming from a damages award from DOE spent fuel litigation, leaving a remaining cost of $40,000.

31. While SCE initially forecast that the costs for the SONGS Unit 1 off-site interim spent fuel storage would be paid from the NQNDT, SCE's Amended October Update noted that SCE had not received applicable litigation proceeds as of October 2025 and so forecast $5.234 million in costs in rates.

32. D.24-08-001 requires that any applicable DOE litigation proceeds must be deposited into the NQNDT and must only be used for spent fuel management and storage costs for the SONGS. Remaining proceeds must be returned to ratepayers.

33. SCE forecasts a total cost of $9.476 million in fuel costs to provide electricity service to Catalina Island in 2026, which includes $7.998 million in diesel fuel and $1.478 million for propane. These forecast diesel costs are based on 2024-2025 actual fuel purchases, actual fuel costs, and unused fuel, with an adjustment to the diesel price to incorporate a projected decrease based on the IHS Global Insight Variable for Gasoline and Fuels; the propane cost forecast was based on applying SCE's Catalina Gas G-2 rate schedule to forecast propane quantities (estimated based on actual 2023 and 2024 usage).

34. SCE did not request approval of its plan for Catalina Gas to backbill SCE Electric for costs incurred as far back as January 2024 or earlier.

35. SCE includes in its forecast the anticipated net costs and BioRAM audit costs related to two contracts funded by SCE's Tree Mortality NBC, pursuant to D.18-12-003. These forecast costs total $21.567 million in 2026.

36. SCE includes the 2026 estimated net costs of its BioMAT program contracts totaling $4.383 million including FF&U in its 2026 ERRA forecast. D.20-08-043 authorized recovery of such contracts via a non-bypassable charge.

37. SCE's forecast includes the impacts of its economic DR programs, which, combined, are expected to result in an estimated 5 GWh of energy reductions.

38. SCE forecasts the non-energy costs related to SCE's participation in the CAISO market in 2026. SCE's forecast is based on actual costs incurred in 2024.

39. SCE's forecast includes estimated load procurement charges, forecast by multiplying the hourly load net of NEM export adjustments with the hourly

SP-15 prices for that hour. SCE incorporates expected load procurement charge reductions resulting from SCE's operation of two energy storage sites, Anode and Cathode, as distribution assets.

40. A third energy storage site, Separator, is used as MTR procurement and so its related costs and revenues are tracked in the 2021 subaccount of the PABA.

41. SCE's forecast of F&PP costs it will incur in 2026 is offset by anticipated revenues from the dispatch of SCE's portfolio. These revenues are forecast based on multiplying forecast hourly production by the forecast SP-15 price at that hour; resource revenues are tracked in and reduce the revenue requirements of the same balancing accounts in which the applicable resource costs are tracked.

42. SCE includes in its forecast the estimated costs of SCE's hedging program. These fees include energy-related transaction fees and option premiums for hedging SCE's open energy position in 2026.

43. SCE includes no fixed gas transportation or storage costs in its 2026 ERRA forecast. SCE includes volumetric gas transportation costs in its modelling using a forecast natural gas rate that incorporates intrastate gas transportation charges.

44. SCE includes $1.042 million in subscription fees in its 2026 forecast. SCE relies on subscriptions to access independent market data, risk analysis reports, reports on power prices, gas prices, emissions prices, and industry news.

45. D.04-01-048 requires that the three-month commercial paper rate index should be applied to under-collected balances in ERRA forecast proceedings, and that the financing costs of such balances may be recovered.

46. D.93-01-027 allows SCE to recover its actual fuel inventory financing costs.

47. D.02-10-062 allows SCE to recover collateral costs.

48. SCE holds a $3.35 billion multi-year revolving credit facility with a May 2029 maturity, also called the "revolver," to serve short-term borrowing

requirements. Specifically, SCE anticipates that it will use the revolver to meet projected collateral requirements, balancing account under-collections, and short-term, general-purpose borrowing needs in 2026. SCE dedicates a minimum amount of the credit availability in the revolver to providing collateral to counterparties on short notice; the reserved amount is equal to the maximum collateral draw that could be required.

49. SCE includes in its forecast financing costs a pro-rata share of the costs of the revolver corresponding to the capacity required to support potential collateral requirements and balancing account under-collections in 2026.

50. SCE will provide letters of credit as collateral for most counterparties; SCE will charge the associated participation and issuer fees to the balancing account of the applicable underlying resource.

51. SCE's forecast includes fuel inventory carrying costs stemming from its ownership interest in PVNGS, its natural gas storage, and the diesel fuel for SCE's diesel generators on Catalina Island. The projected costs are based on forecast average monthly inventory balances for these resources and the 2026 carrying cost rate, which, here, is SCE's interest rate on short-term debt.

52. SCE includes a forecast of GHG procurement compliance carrying costs based on its historical GHG inventory balances and the 90-Day Non-Financial Commercial Paper Rate.

53. SCE's forecast of the carrying costs associated with its collateral requirements necessary to procure power is based on average collateral requirements and the projected terms of SCE's revolver.

54. Because SCE still owns, operates, and procures power from GHG-emitting resources, it continues to incur emissions costs associated with the California Cap-and-Trade program.

55. D.14-14-033 and D.21-08-026 provide the Commission's rules for forecasting GHG emissions costs.

56. SCE forecasts GHG emissions costs by multiplying the estimated volume of GHG emissions of its 2026 procurement by a forecast proxy price.

57. SCE uses the ICE settlement price of a 2026-vintage GHG allowance as its 2026 GHG forecast proxy price for the purpose of estimating emissions costs. The applicable ICE settlement price for 2026, as of August 25, 2025, was $30.57/MT.

58. SCE forecast emissions volumes for direct GHG costs, *i.e.*, the GHG costs of SCE's UOG and procurement contract costs, as a function of the volume of energy SCE expects to generate or purchase from each source and the emissions intensity of the energy produced.

59. SCE's indirect GHG costs are the GHG costs of QF contracts and wholesale purchases for which the power price and the GHG premium embedded therein change over time. SCE uses simplifying assumptions, discussed in testimony, to forecast the emissions costs stemming from indirect sources of GHG emissions.

60. SCE forecasts 2026 GHG emissions costs of $349.789 million.

61. SCE's GHG emissions costs are trued up as a part of SCE's overall procurement balancing account true ups.

62. D.14-14-033 and D.21-08-026 provide the Commission's rules for forecasting GHG allowance revenues.

63. SCE forecasts 2026 GHG allowance revenues totaling $682.214 million.

64. SCE forecasts 2026 GHG allowance revenues by multiplying its expected 2026 consignment of allowances by a forecast proxy price.

65. SCE uses the ICE settlement price of a 2026-vintage GHG allowance as of August 25, 2025 ($30.57/MT) as its 2026 GHG allowance proxy price.

66. SCE's forecast of actual 2025 GHG revenue is based on the actual revenues received via SCE's 2025 auctions held thus far, and the product of remaining allocations to be auctioned multiplied by the ICE futures settlement price for December 2025 deliveries as of August 25, 2025 as a proxy for remaining 2025 auction clearing prices. This price is $28.81/MT. SCE forecasts an over-estimate of 2025 auction revenues of $178.472 million.

67. SCE estimates $0.386 million in costs that it will incur to administer the GHG revenue return program in 2026. SCE forecasts approximately $4,443 in related FF&U, for a total 2026 administrative cost forecast of $0.390 million. Most of these costs are related to its biannual disbursements of the California Climate Credit, including production and postage costs.

68. Because much of the forecast costs of a 2025 billing system upgrade can be absorbed by SCE's IT budget, SCE's 2025 actual administrative costs for its customer return program will ultimately be $0.460 million less than forecast, increasing revenues available for customer returns in 2026.

69. Combining the forecast over-disbursement of allowance revenues in 2025 and the overcollection of 2025 administrative costs, a year-end 2025 GHGRBA balance of $213.307 million carries forward, decreasing revenues available for 2026 customer returns. Accounting for the 2026 and 2025 forecast and actual auction revenues and program expenses, SCE projects a net total of $476.372 million to allocate to clean energy programs and customer returns in 2026.

70. Until June 30, 2026, Pub. Util. Code section 748.5 authorizes the Commission to allocate up to 15 percent of GHG allowance revenues for otherwise-unfunded clean energy and energy efficiency projects and requires the Commission to return the remaining GHG allowance revenues to customers.

71. SCE proposes to set aside $33.094 million for clean energy and energy efficiency program funding in 2026.

72. AB 693 created the SOMAH program allocated up to the lesser of $100 million or 10 percent of all IOU GHG allowance revenues for SOMAH program costs for fiscal years 2016 through 2026.

73. D.17-12-022 required that 10 percent of allowance auction proceeds be reserved for SOMAH through each IOU's ERRA applications and established that each IOU must contribute its proportionate share of the $100 million based on its share of allowance sale proceeds from the previous four quarters.

74. D.20-01-022 clarified that prior-year SOMAH set-aside of 10 percent of forecast GHG allowance revenues should be trued-up based on actual GHG allowance revenues received.

75. In D.20-04-012, the Commission extended SOMAH through June 2026.

76. D.22-09-009 modified the SOMAH forecast budgeting process by adding a pathway for each IOU to request to set aside its proportionate share of the 100 million budget and by identifying a set allocation for each IOU's share.

77. SCE proposes to set aside $23.264 million to fund the SOMAH program through June 2026. This amount is SCE's set proportionate share of the total 50 million (half-year) program budget.

78. SCE's 2024 SOMAH true up revealed a $3.328 million difference between SCE's share of the $100 million cap based on actual GHG revenues recorded in 2024, and its previously approved set-aside in the 2024 ERRA or ECAC filings. This extra funding rolls over to be available in 2026, yielding a total available SOMAH budget of approximately $26.592 million.

79. Among other requirements, AB 327 requires the Commission to ensure that all eligible low-income electricity and gas customers are given the

opportunity to participate in low-income energy efficiency programs, including customers occupying multi-unit residential structures.

80. Pursuant to AB 327, the Commission created the DAC-SASH program in D.18-06-027, setting an annual, all-IOU $10 million budget for DAC-SASH, to be funded first via GHG allowance revenues, and through PPP funds, should GHG allowance revenues be exhausted. SCE's proportionate share of that $10 million annual budget is 46 percent, starting in 2019.

81. SCE has allocated $4.6 million of its projected GHG allowance revenues to its DAC-SASH program (46 percent of $10 million).

82. D.18-06-027 allowed CCAs to access GHG allowance revenues to run their own Green Tariff programs, including DAC-GT and CSGT programs.

83. On April 1, 2025, CPA submitted AL 0035-E, requesting $5.142 million in FY 2026 funding for its CCA-DAC program, which includes prior year unspent amounts. Due to CARB's limits on volumetric-based allowance revenue returns, SCE proposes to fund the above market generation portion of $1.902 million through GHG allowance revenue, with the remaining $3.240 million recovered through the PPP Charge.

84. After the proposed $33.094 million set-aside for clean energy programs is deducted, SCE estimates $443.279 million remaining for customer returns.

85. From GHG allowance revenue, EITE facilities receive California Industry Assistance credits to minimize leakage associated with Cap-and-Trade program costs in purchased energy. The Commission adopted methodologies for calculating EITE returns in D.14-12-037, as modified by D.15-08-006 and D.16-07-007, and updated these methodologies in D.21-08-026.

86. The Commission calculates EITE returns for each eligible facility using emissions-efficiency benchmarks, while SCE is responsible for disbursement.

87. SCE proposes to set-aside $58.908 million in revenues for EITE facilities.

88. Once EITE facilities receive credits, the remaining allowance revenue ($384.371 million) flows through to small business and residential customers.

89. D.15-07-001 removed the volumetric portion of the residential credit from the credit methodology adopted in D.12-12-033, based on customer usage, and adopted a flat rate credit that is the same for all residential customers starting January 1, 2016. D.21-08-026 changed the small business credit from the volumetric credit set forth in D.12-12-033 to a flat rate credit equal to the residential credit.

90. Based on the estimated number of eligible customers in 2026, SCE proposes a $36 biannual California Climate Credit to offset residential and small commercial customer bills twice in 2026.

91. SCE proposes a $4.689 billion updated and amended 2026 ERRA forecast revenue requirement, including a F&PP revenue requirement of $4.724 billion.

92. SCE's 2026 ERRA forecast is made up of a generation service revenue requirement and a delivery service revenue requirement.

93. SCE's requests the recovery of the balancing and memorandum account balances, costs, charge components, and forecast GHG allowance revenues that make up its 2026 ERRA forecast revenue requirement, as listed in Table 7-1.

94. Pursuant to Pub. Util. Code section 454.5 (d)(3), D.02-10-062 adopted the ERRA BA as the mechanism by which utilities would track actual procurement costs against forecast amounts. Amounts recorded to the ERRA BA are recovered from bundled customers through generation service rates.

95. SCE's estimates of the 2025 year-end balances in the ERRA BA and PABA are based on the forecast costs adopted in SCE's 2025 ERRA Forecast proceeding in D.24-12-039 except that January through September 30, 2025 have been

updated with recorded actuals and October through December 2025 incorporate updated market forwards as of October 3, 2025.

96. SCE's year-end 2025 ERRA BA forecast also incorporates the impacts of SCE's 2024 ERRA Trigger Application, which anticipated a $742.426 million over-collection. SCE requests to transfer the remaining year-end 2025 ERRA BA balance to the 2025 vintage subaccount of the PABA.

97. The 2026 ERRA BA and year-end 2025 ERRA forecast are impacted by the disputed issues in this case regarding the valuation of certain RPS instruments that may be used for bundled service customer compliance.

98. D.18-10-019 modified the balancing accounts considered in ERRA forecast proceedings and directed utilities to create new balancing accounts with vintaged subaccounts to track above-market costs and revenues associated with their electric portfolios. The PABA tracks and accounts for recovery from responsible bundled service and Departing Load customers their respective shares of the "above-market" costs of all generation resources that are eligible for cost recovery through the CTC and PCIA.

99. The calculation of the 2026 forecast and 2025 year-end PABA balances are impacted by the disputed issues in this proceeding.

100. SCE's year-end 2025 ERRA BA and PABA balances changed significantly between SCE's May Filing and its Amended October Update, mostly due to application of the Final 2025 and Forecast 2026 MPBs.

101. SCE's Amended October Update, Exhibit SCE-05A, contains updated ERRA BA and PABA balances that SCE states correct for mistakes in its allocation of generation revenues received from bundled customers across balancing accounts. The errors were caused by its failure to incorporate authorized GRC revenues into the calculation of allocation percentages.

102. D.15-01-015 authorized SCE to track the actual costs of contracts procured pursuant to SCE's GT program, which allows customers opportunities to purchase more power from renewable sources. Costs tracked in the GTSRBA are recovered from customers participating in the GT program.

103. SCE is pursuing refunds from power generators who overcharged SCE for electricity during the 2000-2001 California Energy Crisis. SCE tracks such settlement funds in the ESMA. In Res. E-3894, the Commission required SCE to maintain a LCTA within the ESMA to track the litigation costs that are set-aside in the FERC investigation settlement agreements and actual litigation costs incurred by SCE. These costs are netted against any settlement refunds before the remaining ESMA balance is returned to ratepayers.

104. Costs tracked in the NSGBA include the net capacity costs of New System Generation contracts entered into pursuant to D.06-07-029 and D.07-08-044, a portion of system reliability costs previously recorded to the SRPMA (pursuant to D.19-11-016, D.21-12-015, and D.22-05-015), summer reliability procurement costs (pursuant to D.21-02-028, D.21-03-056, and D.21-12-015), the storage charging costs and market revenues of the UOS DESI 2 (pursuant to D.15-11-021), certain CHP contract costs (pursuant to D.10-12-035), and local capacity requirement procurement (pursuant to D.23-06-029) and Central Procurement Entity procurement and administration costs (pursuant to D.20-06-002, D.22-03-034). The costs tracked in the NSGBA are allocated via the CAM and are recovered from all benefitting customers (bundled service customers and unbundled customers) via the NSGNBC.

105. To estimate the year-end 2025 NSGBA balance, SCE uses recorded amounts from January 1, 2025 through September 30, 2025, plus a forecast of the activity SCE expects to record in the NSGBA through December 31, 2025.

106. Pursuant to D.22-01-015, SCE's MCAMBA tracks the costs of procurement authorized to be recovered via the MCAM, including the opt-out and backstop system reliability procurement required by D.19-11-016 and the backstop procurement required by D.21-06-035. The costs tracked in the MCAMBA are recovered from the customers of LSEs that opted out of or did not meet procurement obligations.

107. For the purposes of its 2026 ERRA Forecast requests, SCE records the forecasts of the following costs or credits in the BRRBA-D: cost of and credits equaling the energy benefits of SCE's UOS Anode and Cathode (pursuant to Res. E-5183); administrative payment fees to the CARB calculated to recover the costs of the State's implementation of AB 32; EIM BOSR and DRAM costs; the impacts of SCE's DR programs, and transfer amounts from the distribution sub-account of the LCRPBA.

108. Pursuant to D.14-10-033, SCE's proposed 2026 GHGRBA forecast includes SCE's forecast GHG allowance revenues, an estimated year-end 2025 undercollection, and forecast administrative costs.

109. SCE's proposed PPPC components are forecast 2026 costs for the TMNBC, including audit costs (pursuant to D.18-12-003), forecast costs for the BMNBC (pursuant to D.20-08-043), the forecast contract capacity costs of the PRP tracked in the LCR-PPP subaccount (pursuant to D.18-07-023), and CCA DAC-GT/CSGT (pursuant to D.18-06-027.) The proposed PPPC also includes year-end 2025 balances for the TMNBCBA and the BMNBCBA.

110. The first component of the CRS is the CTC. Pursuant to Pub. Util. Code § 367 and D.02-11-002, the CTC recovers the above-market costs of pre-energy market restructuring and other eligible resources (e.g., resources procured prior to December 20, 1995, and others as defined by the Public Utilities Code or

Commission decision) and is the same for each customer within a class, regardless of a customer's date of departure from bundled service.

111. The second component of the CRS is the PCIA. Established in D.06-07-030, the PCIA implements procedures to fulfill Commission responsibilities incurred pursuant to Public Utilities Code Sections 366.1, 366.2, 365.28 and 366.39. Under these provisions, the Commission has an obligation to ensure that (1) bundled service IOU customers do not experience any cost increases due to the departure of retail customers, and (2) customers who depart IOU service do not experience any cost increases due to an allocation of costs that were not incurred on their behalf. D.08-09-012 adopted the practice of vintaging a utility's portfolio subject to the PCIA. This Decision refers to the CTC and PCIA, collectively as "PCIA charges," recovering the "PCIA revenue requirement."

A third CRS component, the Wildfire Mitigation NBC, is not determined in the ERRA forecast proceeding.

Odell, Eileen [EO1]
~~Antonina, I cannot get this FOF to join this numbered list!~~

112. The CTC and the PCIA recover the annual PCIA Indifference Amount, or the difference between the forecast Total Portfolio Costs and Total Portfolio Market Values of SCE's PCIA-eligible portfolio. The market values of the applicable portfolio fit into three categories based on the three revenue streams a resource may produce: energy values, RA values, and RPS values.

113. The 2026 Forecast MPBs are as stated in Table 8-2 of this Decision; the Final 2025 MPBs are as stated in Table 8-4.

114. D.18-10-019 authorized utilities to conduct a true up of the PCIA Indifference Amount to reflect actual costs incurred and actual revenues received.

115. SCE calculates Total Portfolio Costs in 2026 based on the forecast fixed and variable costs of SCE's CTC- and PCIA-eligible resources as a part of its overall ERRA procurement cost forecast. These costs are SCE's authorized base generation capital revenue requirement, as determined in SCE's GRC Phase 1 proceeding; fuel costs, and direct GHG costs for all eligible UOG; RPS-eligible contract costs; QF and non-CAM-eligible CHP contract costs; all bilateral and RFO contract costs, including fuel costs and direct GHG costs if applicable; and any applicable one-time refunds or adjustments.

116. Pursuant to D.18-10-019 and D.19-10-001, the Total Portfolio Market Value is defined as the forecast output of the three streams of revenue produced by CTC- and PCIA eligible resources multiplied by the applicable MPBs (Energy Index, RA Ader, RPS Adder), calculated by the Commission and released in October of each year. D.25-06-049 recently updated the way the Commission calculates the RA MPB, referred to as the RA Adder; among other changes, instead of using separate adders to value local, flexible, and system capacity all relevant capacity is now valued at the same RA Adder.

117. The Commission denied CalCCA's AFR of D.25-06-049 on Oct. 30, 2025.

118. Total Portfolio Cost and Total Portfolio Market Value calculations can be simplified to "price x quantity" formulas. SCE's "quantity" calculation for its RA resource is based on its Slice-of-Day position. The Commission has adopted Slice-of-Day as the mechanism by which utilities measure RA compliance; the Commission has not addressed whether the methodology should be used for PCIA purposes on an industry-wide basis.

119. In. D.24-12-039, the Commission found SCE's use of Slice-of-Day for PCIA valuations to be reasonable on an interim basis.

120. The application of Slice-of-Day methodology to portfolio value calculation is ripe for consideration in a rulemaking.

121. SCE is not holding a short-term VAMO process for 2026 but will continue to allocate long term VA RECs from contracts signed in 2024, based on the accepted bid price. SCE states that all RPS volumes not allocated in either long-term VA or MO processes are forecast to be used by SCE towards its 2026 RPS compliance target.

122. SCE's proposed valuation of a category of RPS resources referred to as "Pre-2019 Banked RECs" that it may retire for bundled customer RPS compliance in 2026 or may have retired for bundled service customer compliance in 2025, is a disputed issue in this case.

123. Prior to D.19-10-001, bundled service customers credited DL customers the market value of all retained RECs at the time the RECs were generated and banked, based on the then-current RPS MPB, and the RECs were valued at $0 thereafter regardless of whether and when they were used for bundled customer RPS compliance. D.19-10-001 changed this, stating that retained RECs forecast to be used for bundled customer compliance in the following year should be valued at the Forecast RPS Adder, as calculated by Energy Division staff, and credited to the PCIA. D.19-10-001 contained a Finding of Fact that states: "[t]he methods adopted in this Decision apply to RECs generated commencing January 1, 2019 and going forward."

124. SCE proposes to value any RECs used in 2025 or 2026 for bundled customer compliance at $0 if those RECs were generated prior to 2019.

125. SCE intends to retire all Post-2018 Banked RECs before retiring Pre-2019 Banked RECs.

126. The Commission found SCE's proposed method of valuing Pre-2019 Banked RECs it may use for bundled service customer compliance at $0 to be reasonable on an interim basis in D.23-11-094 ~~and D.24-12-039,~~ (the ~~decisions~~decision resolving SCE's 2024 ~~and~~ERRA forecast application) and also approved the treatment in D.24-12-039 (the decision resolving SCE's 2025 ERRA forecast ~~applications~~application)..

127. The proposal to address conflicting understandings of the valuation of Pre-2019 banked RECs is ripe for consideration in a rulemaking.

128. SCE provided an Amended October Update that forecasts its Total Portfolio Market Value for its 2026 Indifference Amount and that trues-up its 2025 Indifference Amount based on updated Forecast 2026 MPBs and Final 2025 MPBs released by the Commission's Energy Division on October 1, 2025.

129. SCE forecasts an updated 2026 Indifference Amount of negative $388.078 million, comprised of an updated Total Portfolio Cost of $4.474 billion and a Total Portfolio Market Value of $4.864 billion. The Total Portfolio Market Value forecast is comprised of an updated Total Energy Value of $1.427 billion, updated Total RPS Value of $1.984 billion, and an updated total RA value of $1.454 billion.

130. In addition to the 2026 Indifference Amount, SCE requests to include the following costs in its 2026 PCIA revenue requirement: (1) the 2025 year-end PABA balance (pursuant to D.18-10-019); (2) the 2025 year-end ERRA BA balance, after transferring this balance to the 2025 vintage sub-account of the PABA (pursuant to D.22-01-023); (3) the remainder 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 Res. E-5240; (4) costs related to the UOS Separator project; and (5)

recovery of the applicable amounts of the amortization of SCE's GRCRRMA balance over 24 months, beginning on October 1, 2025.

131. SCE updated its 2026 PCIA Indifference Amount in its October Update to incorporate the following decisions: D.25-09-030, D.25-06-006, D.25-06-010, D.25-09-012, D.25-06-048, and D.25-06-049. SCE's Amended October Update made corrections to the proposed 2026 Indifference Amount.

132. SCE's Indifference Amount revenue requirement is recovered from DL customers via the CTC and PCIA and from bundled service customers via generation rates.

133. SCE's true up of its year-end 2025 PABA and ERRA balances using the Final 2025 MPBs caused SCE's Trigger Balance to exceed its Trigger Point as of September 30, 2025. SCE determined that the balance would self-correct within 120 days by virtue of the adoption of this Decision. SCE filed AL 5664-E on October 30, 2025, requesting no rate changes resulting from the Trigger Exceedance, given that the undercollection representing the exceedance amount will be incorporated and recovered via the rates adopted by this Decision.

134. SCE's proposed CTC and PCIA rates are determined by allocating the vintaged PABA revenue requirements to rate groups using generation revenue allocation factors approved in SCE's GRC Phase 2 proceeding normalized to account for each rate group's kWh sales forecast by vintage and divided by forecast sales by vintage (also referred to as billing determinants).

135. SCE's proposed 2026 CTC rates are as stated in Table 8-3.

136. SCE's proposed 2026 PCIA rates are as stated in Table 8-4.

137. The average bundled customer rates representing SCE's proposed 2026 ERRA forecast are as stated in Table 9-1 of this Decision.

138. SCE's proposed CAM rate components are as stated in Table 9-2.

139. SCE's proposed GHG costs and revenues accounting and allowance allocations help achieve a main goal of AB 32 and Pub. Util. Code § 748.5, reducing GHG emissions, and will therefore improve the health and safety of California residents.

140. 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.

Conclusions of Law

1. SCE's 2026 forecasts of customers, retail sales, bundled sales, and electric load are reasonable and should be approved.

2. SCE's 2026 forecasts of energy prices, natural gas prices, and greenhouse gas prices are reasonable and should be approved.

3. SCE's PLEXOS modelling of simulated least cost dispatch 2026 forecast of its F&PP costs is reasonably based on SCE's forecasts of power, gas, and GHG prices, the physical constraints of each relevant generating unit, and contractual limitations, and the resulting forecasts should be approved.

4. SCE should be required to file an Information Only Advice Letter within 60 days of the adoption of this decision to provide more information about its plan for Catalina Gas to backbill SCE Electric, explaining to the Commission:

    1. The legal authority supporting SCE Catalina Gas's intention to backbill SCE Electric "to January 2024 or earlier;"
    2. An accounting of the amounts for which SCE Catalina Gas has backbilled SCE Electric and/or intends to backbill SCE Electric, including accounting of any "propane and

transportation costs already paid for" that SCE asserts will be subtracted from the amounts subject to backbilling; and

3. Direct citations to the Commission decisions or orders authorizing recovery of the revenue requirements underlying those amounts.

5. SCE's 2026 forecast of costs for nuclear fuel expenses is reasonable and should be adopted.

6. Once SCE receives and deposits applicable DOE litigation funds in the SONGS 1 NQNDT, SCE should be required to propose a refund of 2026 SONGS 1 forecast costs in its next ERRA forecast or compliance proceeding.

7. SCE's forecast 2026 GHG emissions costs are reasonable and should be adopted.

8. SCE's 2026 forecast of GHG revenues and true up of 2025 GHG revenues are reasonable and should be adopted.

9. SCE's 2026 forecast of administrative expenses it will incur to administer GHG revenue returns and true up of 2025 costs of the same are reasonable and should be adopted.

10. SCE's clean energy program set-asides from GHG allowances are reasonable and should be adopted.

11. SCE's calculations of its proposed California Climate Credit, and its proposed EITE customer assistance budget are reasonable and should be adopted.

12. SCE's forecast balancing and memorandum account balances, proposed balance true ups, and forecast rate components as depicted in Table 7-1 are reasonable and should be approved.

13. SCE's proposal to use its Slice-of-Day methodology to forecast the quantity of RA need to calculate the 2026 Indifference Amount is reasonable and should be approved on an interim basis.

14. SCE's proposal to value Pre-2019 Banked RECs that it may use for bundled service customer compliance in 2025 or 2026 at $0 is a reasonable interim methodology.

15. Because the Commission intends to address conflicting understandings of D.19-10-001's impacts in the current PCIA Rulemaking, SCE should be required to file a Tier 2 advice letter to explain how it intends to track the quantity and generation year of each Pre-2019 Banked REC SCE uses for bundled customer compliance in 2026.

16. CalCCA's proposal to require SCE to use a "first-in-first-out" methodology for using banked RECs should not be adopted at this time given that (1) SCE has already committed to using Post-2018 Banked RECs before Pre-2019 Banked RECs, and (2) CalCCA has not articulated a need for its proposal beyond its proposal to value Pre-2019 Banked RECs forecast to be used for bundled compliance at the Forecast RPS Adder and credited to the PCIA vintage in which the REC was generated, which we have rejected.

17. SCE's proposed 2026 CRS charges are reasonable and should be approved.

18. SCE's proposed 2026 CAM rate components are reasonable and should be adopted.

19. SCE should implement the revenue requirement adopted in this proceeding, as updated to reflect October – November 2025 actuals and forecasts for November – December 2025, as available, in its advice letter for rates to be effective starting January 1, 2026.

20. Advice letters to implement changed tariff sheets in accordance with this Decision should be filed as Tier 1 Advice Letters.

21. SCE's and CalCCA's joint motion to admit testimony and exhibits into evidence should be granted.

22. SCE's and CalCCA's joint motion to seal Exhibits SCE-01C, SCE-02C, SCE-05C, SCE-05AC, SCE-07C, CalCCA-01C and CalCCA-02C should be granted for a period of three years after the effective date of this Decision.

23. The parties' joint motion to seal a confidential version of the Joint Case Management Statement should be granted for a period of three years after the effective date of this Decision.

24. SCE's and CalCCA's motions to seal confidential versions of their Opening Briefs and Reply Briefs should be granted for a period of three years after the effective date of this Decision.

25. All rulings issued by the assigned Commissioner and the assigned ALJ should be confirmed.

26. All motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ should be denied.

27. Application 25-05-008 should be closed.

ORDER

IT IS ORDERED that:

1. Southern California Edison Company is authorized to recover a total 2026 Energy Resource Recovery Account electric procurement cost revenue requirement forecast of $4.689 billion, consisting of both a generation service component and a delivery service component.

2. Within Southern California Edison Company's (SCE) 2026 generation service revenue requirement of $4.633 billion, SCE is authorized to recover the following: (1) $2.710 billion forecast 2026 Energy Resource Recovery Account Balancing Account (ERRA BA) costs and a negative $898.645 million year-end 2025 ERRA BA balance; (2) $1.494 billion forecast 2026 Portfolio Allocation Balancing Account (PABA) costs and a $1.318 billion year-end 2025 PABA undercollection; (3) $7.308 million in forecast 2026 Green Tariff Shared Renewables Program costs; and (4) $1.314 million in actual litigation costs incurred in 2025 and tracked in the Energy Settlement Memorandum Account. SCE is authorized to transfer the 2025 year-end ERRA BA balance to the vintage 2025 subaccount of the PABA.

3. Within Southern California Edison Company's (SCE) 2026 delivery service revenue requirement of $56.474 million, SCE is authorized to recover or return to customers the following: (1) $473.047 million for the New System Generation and other Cost Allocation Mechanism (CAM) fuel and purchased power (F&PP) costs, representing a 2026 forecast (2) 2025 New System Generation overcollection of $24.718 million; (3) $6.204 million in Modified CAM F&PP costs, representing a combined 2026 forecast and a 2025 undercollection; (3) $5.332 million in spent nuclear fuel costs; (4) negative $2.684 million for forecast Base Revenue Requirement Balancing Account — Distribution F&PP costs; (5) negative $443.279 million in returns of greenhouse gas allowance proceeds to customers; and (6) $42.571 million for the 2026 Public Purpose Program Charge.

4. Once Southern California Edison Company (SCE) receives and deposits applicable Department of Energy litigation funds in the San Onofre Nuclear Generating Station (SONGS) Unit 1 Non-Qualified Nuclear Decommissioning

Trust, SCE must propose a refund of 2026 SONGS Unit 1 forecast costs in its next Energy Resource Recovery Account forecast or compliance proceeding.

5. Southern California Edison Company is authorized to reconcile its 2026 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 $443.279 million in forecast 2025 GHG allowance auction proceeds to its customers, after setting aside $33.094 million for clean energy and energy efficiency projects and $390,285 for outreach and administrative expenses.

6. Southern California Edison Company shall return $384.371 million in greenhouse gas allowance auction revenues to residential and small commercial customers through the forecasted amount of $36.00 in April and October 2026 for the California Climate Credit program.

7. Southern California Edison Company shall return a forecast of $58.908 million in greenhouse gas allowance auction revenues to its Emissions-Intensive and Trade-Exposed customers in April 2026.

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 2026 Climate Credit amount;

(b) Small business rate schedules to include the authorized 2026 Climate Credit amount;

(c) The updated November 2025 revenue requirement actuals and forecasts for November and/or December 2025, 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 before 2019 for 2025 Renewables Portfolio Standard compliance for SCE's bundled customers.

9. Southern California Edison Company shall file a separate Tier 1 Consolidated Revenue Requirement and Rate Change Advice Letter no later than December 31, 2025, 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. In a subsequent Energy Resource Recovery Account forecast or compliance application, whichever occurs first, Southern California Edison Company (SCE) shall propose a refund of the 2026 San Onofre Nuclear Generating Station unit 1 (SONGS 1) offsite interim spent fuel storage costs adopted in this Decision that, by the time of the application, have been recovered in rates, following receipt and deposit of applicable Department of Energy SONGS 1 interim spent nuclear fuel storage litigation proceeds into the Non-Qualified Nuclear Decommissioning Trust for SONGS 1.

11. Southern California Edison Company (SCE) shall file an Information-Only Advice Letter within 60 days of the adoption of this Decision. SCE shall serve this Advice Letter on the service list in Application (A.)25-05-008 and on the most recently updated service list for A.23-12-011. This Advice Letter shall contain:

a. The legal authority supporting SCE Catalina Gas's intention to backbill SCE Electric "to January 2024 or earlier;"

b. An accounting of the amounts for which SCE Catalina Gas has backbilled SCE Electric and/or intends to backbill SCE Electric, including accounting of any "propane and transportation costs already paid for" that SCE asserts will be subtracted from the amounts subject to backbilling; and

c. Direct citations to the Commission decisions or orders authorizing recovery of the revenue requirements underlying those amounts.

12. Southern California Edison Company shall file a Tier 2 Advice Letter by February 1, 2026, to propose how it will track the quantity of Pre-2019 Banked Renewable Energy Credits (RECs) used to meet bundled customer compliance in 2026. The Advice Letter shall explain how SCE intends to track the quantity and generation year of all Pre-2019 Banked RECs it will use to meet 2026 compliance requirements through September 30, 2026. The Advice Letter shall also explain how SCE intends to forecast how many and which RECs SCE intends to use for bundled customer compliance from October 1, 2026, through December 31, 2026.

13. Southern California Edison Company's (SCE) September 15, 2025 Motion for Leave to File the Confidential Version of the Joint Case Management Statement Under Seal is granted. The confidential version of the Joint Case Management Statement shall remain under seal for a period of three years from the effective date of this decision, consistent with Decision 06-06-066. During this three-year period, the information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If SCE believes that it is necessary for this information to remain under seal for longer than three years, it may file a new motion owing good cause for extending this order no later than 30 days before the expiration of this order.

14. Southern California Edison Company and California Community Choice Association's October 28, 2025 Joint Motion to Admit Prepared Testimony and Exhibits into the record is granted.

15. Southern California Edison Company (SCE) and California Community Choice Association's (Cal-CCA) October 28, 2025 Joint Motion to Seal a Portion of the Evidentiary Record is granted. The confidential versions of SCE's Exhibits SCE-01, SCE-02, SCE-05, SCE-05A, and SCE-07 and the confidential versions of CalCCA-s Exhibit CalCCA-01 and CalCCA-02 shall remain under seal for a period of three years from the effective date of this decision, consistent with Decision 06-06-066. During this three-year period, the information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If SCE or CalCCA believes that it is necessary for this information to remain under seal for longer than three years, it may file a new motion owing good cause for extending this order no later than 30 days before the expiration of this order.

16. Southern California Edison Company's (SCE) October 29, 2025 Motion for Leave to File a Confidential Version of its Opening Brief Under Seal and November 4, 2025 Motion for Leave to File a Confidential Version of its Reply Brief Under Seal are granted. The confidential version of SCE's Opening and Reply Briefs shall remain under seal for a period of three years from the effective date of this decision, consistent with Decision 06-06-066. During this three-year period, the information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If SCE believes that it is necessary for this information to remain under seal for longer than three years, it may file a new motion owing good cause for extending this order no later than 30 days before the expiration of this order.

17. California Community Choice Association's (CalCCA) October 29, 2025 Motion for Leave to File a Confidential Version of its Opening Brief Under Seal and November 4, 2025 Motion for Leave to File a Confidential Version of its

Reply Brief Under Seal are granted. The confidential version of CalCCA's Opening and Reply Briefs shall remain under seal for a period of three years from the effective date of this decision, consistent with Decision 06-06-066. During this three-year period, the information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If CalCCA's believes that it is necessary for this information to remain under seal for longer than three years, it may file a new motion owing good cause for extending this order no later than 30 days before the expiration of this order.

18. Application 25-05-008 is closed.

This order is effective today.

Dated____________________, at Sacramento, California.

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