Docket		A.25-04-001
Exhibit Number	:	CA-01
Commissioner	:	John Reynolds
Admin. Law Judge	:	Elaine Lau
Public Advocates	:	
Office Project Mgr.	:	Stanley Kuan
Witnesses	:	S. Kuan, M. Ammermuller, M. Yeo, K. Lutes, B. Lui, C. Jenquin

PUBLIC ADVOCATES OFFICE

CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY ON APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY FOR A COMMISSION FINDING THAT ITS PROCUREMENT-RELATED AND OTHER OPERATIONS FOR THE RECORD PERIOD JANUARY 1 THROUGH DECEMBER 31, 2024 COMPLIED WITH ITS ADOPTED PROCUREMENT PLAN; FOR VERIFICATION OF ITS ENTRIES IN THE ENERGY RESOURCE RECOVERY ACCOUNT AND OTHER REGULATORY ACCOUNTS; AND FOR AN INCREASE OF $3.992 MILLION IN REVENUE REQUIREMENT DUE TO A NET UNDERCOLLECTION RECORDED IN SIX ACCOUNTS

PUBLIC VERSION

San Francisco, California
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CHAPTER 1: EXECUTIVE SUMMARY

(Witness: Stanley Kuan)

I. EXECUTIVE SUMMARY

This testimony presents the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) review of Southern California Edison Company's (SCE) Energy Resource Recovery Account (ERRA) Compliance Application (A.) 25-04-001 (Application) for the Record Period from January 1, 2024 through December 31, 2024 (2024 Record Period).[1] SCE filed its Application pursuant to Decision (D.) 02-10-062.[2] In that Decision, the California Public Utilities Commission (Commission) required the annual review of certain utility procurement activities in the ERRA proceeding.[3]

Pursuant to D.02-10-062, D.02-12-074, and California Public Utilities Code (PU Code) § 454.5(d)(3), the purpose of the ERRA is to allow certain electric investor-owned utilities (IOUs) to record and recover their power costs and to provide for the timely recovery of each IOU's incurred procurement costs consistent with the IOU's approved procurement plan.[4] PU Code § 454.5(d)(3) authorizes the Commission to establish balancing accounts to track the differences between recorded revenues and costs incurred related to the approved procurement plan.[5]

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[1] A.25-04-001, *Application of Southern California Edison Company (U 338-E) for a Commission Finding that its Procurement-Related and Other Operations for the Record Period January 1 Through December 31, 2024 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for an increase of $3.992 million in revenue requirement due to a net undercollection recorded in six accounts.*

[2] D.02-10-062, *Interim Opinion,* October 24, 2002; issued in Rulemaking (R.) 01-10-024 et al.

[3] D.02-10-062 at 76-79, Ordering Paragraphs 5-17.

[4] D.02-10-062 at 71 – 72, Finding of Fact 23, 26.

[5] PU Code §454.5(d)(3) states: "The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission."

SCE filed its Application on April 1, 2025, requesting Commission approval for costs associated with activities that occurred during the 2024 Record Period. The scope of Cal Advocates' review of SCE's Application includes a review of utility-owned generation operations, fuel expenses and procurement, contract administration, least-cost dispatch, demand response, and an audit of balancing account entries.

In this testimony, Cal Advocates presents its analyses and recommendations associated with SCE's request. This testimony focuses exclusively on the 2024 Record Period and is based on Cal Advocates' analysis of information submitted by SCE that includes, but is not limited to, SCE's testimony and workpapers submitted with its application and responses to data requests.

The issues that Cal Advocates reviewed for the 2024 Record Period are listed in the table below and summarized in this chapter. For those issues or topic areas for which no testimony is filed, Cal Advocates does not have any recommendations or disallowances. The qualifications of Cal Advocates witnesses and their testimony declarations are contained in Appendix A of this report.

List of Cal Advocates Witnesses and Respective Chapters

Chapter #	Description	Witness
1	Executive Summary	Stanley Kuan
2	Least-Cost Dispatch and Demand Response Programs	Michael Ammermuller
3	Utility-Owned Generation – Natural Gas	Michael Yeo
4	Contract Administration	Kayla Lutes
5	Compliance Audit of the Energy Resource Recovery Account (ERRA) and Other Balancing and Memorandum Accounts	Brian Lui, Craig Jenquin, and Michael Ammermuller
6	Greenhouse Gas Compliance Instruments	Tom Gariffo

II. SUMMARY OF FINDINGS & RECOMMENDATIONS

The following summary provides an overview of each chapter presented in the testimony and identifies Cal Advocates' sponsoring witnesses for that chapter of testimony for the 2024 Record Period.

1. Executive Summary (Stanley Kuan)

2. Least-Cost Dispatch and Demand Response Programs (Michael Ammermuller)

Cal Advocates does not object to SCE's least-cost dispatch and demand response program activities for the 2024 Record Period. Cal Advocates recommends that the Commission hold a workshop with the IOUs and other interested parties to set out revised Least Cost Dispatch (LCD) filing rules that account for changes to the electricity market, including widespread adoption of rooftop solar and expanded use of energy storage resources since the rules were first developed in 2015.

3. Utility Owned Generation – Natural Gas (Michael Yeo)

Cal Advocates recommends the Commission order SCE to a) establish a procedure to ensure that it would receive equipment advisories from manufacturers for all plant equipment (not just 86RE relays) that are critical for operational readiness; (b) contact Electro Switch Corporation, the manufacturer of the failed 86RE relay, to find out whether there had been advisories that it did not receive prior to July 11, 2024, and report in its 2026 ERRA Compliance filing the list of those outstanding advisories and SCE's actions on those advisories; and (c) repair the Beckwith M-3425A relay, which could not be tested currently due to technical issues with the testing software.

4. Contract Administration (Kayla Lutes)

Cal Advocates does not object to SCE's contract administration activities and practices for Record Period 2024.

5. Compliance Audit of the Energy Resource Recovery Account (ERRA) and Other Balancing and Memorandum Accounts (Brian Lui, Craig Jenquin, and Michael Ammermuller)

Cal Advocates recommends that the Commission disallow the calculated interest of $91,412.54 on the California Air Resources Board (CARB) transactions recorded to the Base Revenue Requirement Balancing Account (BRRBA) because the interest amount recovers costs incurred that are inappropriate due to SCE's error, and result in an overstatement of SCE's revenue requirement. Cal Advocates does not object to the accounting entries recorded for Record Period 2024 in the other 32 balancing and memorandum accounts that were reviewed.

6. Greenhouse Gas Compliance Instruments (Tom Gariffo)

As an emitter of greenhouse gas (GHG) in California, SCE is obligated to comply with the requirements of CARB's Cap-and-Trade program. During the 2024 Record Period, SCE recorded [redacted] worth of GHG compliance costs from utility-owned generation (UOG) and [redacted] worth of GHG compliance costs from tolling contracts for a total [redacted].[6] SCE provided workpapers reporting these costs and demonstrating its calculations in compliance with the methodologies detailed in D.21-05-004.[7] SCE appears to have accurately recorded and demonstrated its 2024 Record Period GHG compliance costs in accordance with Commission requirements.

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[6] SCE-02C Testimony, Table VII-72, at 216.

[7] D.21-05-004, *Decision Modifying Decision 19-04-016*, May 6, 2021 at OP 1, Attachment A; issued in A.13-08-002 et al.

CHAPTER 2: LEAST-COST DISPATCH AND DEMAND RESPONSE PROGRAMS

(Witness: Michael Ammermuller)

I. INTRODUCTION AND SUMMARY

This chapter reviews Southern California Edison Company's (SCE) energy bidding and demand response activities for the 2024 Record Period between January 1, 2024, and December 31, 2024, and determines whether SCE met the California Public Utilities Commission's (Commission) least-cost dispatch (LCD) standard. The Public Advocates Office (Cal Advocates) reviewed SCE's 2024 Record Period Energy Resource Recovery Account (ERRA) Compliance Application (A.) 25-04-001 and testimony. Cal Advocates analyzed data requests and reviewed current and past ERRA testimony and relevant Commission decisions. Finally, Cal Advocates compared SCE's performance and conduct against the Commission's LCD standard to determine if operations were in accordance with the Commission's Standard of Conduct (SOC) 4.

II. RECOMMENDATIONS

Cal Advocates does not object to SCE's LCD and demand response (DR) program activities for the 2024 Record Period. Cal Advocates recommends that the Commission hold a workshop with the investor-owned utilities (IOUs) and other interested parties to set out revised LCD filing rules that account for the electricity market changes since the rules were first developed in 2015.

III. REGULATORY BACKGROUND

The procurement and dispatch of electricity by California's investor-owned utilities (IOUs) are guided by past Commission decisions:

- Decision (D.) 02-10-062 set minimum standards of behavior and established SOC 4, which states, "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[8]

- D.02-12-074 further defined SOC 4 and LCD principles, stating, "[LCD] refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services…."[9]

Cal Advocates and the IOUs developed LCD reporting standards in 2015, which the Commission adopted in D.15-05-007.[10] This Decision and those described above direct SCE to demonstrate that it achieved LCD in the ERRA Compliance process. D.15-05-007 also recognized that the dispatch of demand response programs should be reviewed as a part of LCD compliance.[11]

IV. DISCUSSION AND ANALYSIS

A. Forecast Accuracy: Price and Demand

1. SCE's Forecast and Bid Strategy

SCE submits bids to the California Independent System Operator (CAISO) for the volume of hourly demand it expects to serve its bundled customers.[12] SCE forecasts its hourly demand for the next day and purchases most of that hourly volume from CAISO's day-ahead market (DAM). That demand will be delivered using resources selected by CAISO, which may or may not include SCE-owned resources that SCE bids separately into the market as supply. The real-time market (RTM) will adjust supply to ensure the

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[8] D.02-10-062, *Interim Opinion,* October 24, 2002 at 52; issued in R.01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*.

[9] D.02-12-074, *Interim Opinion,* December 19, 2002 at 54; issued in R.01-10-024.

[10] D.15-05-007, *Decision Adopting Methodology and Closing Proceeding,* May 7, 2015 at 17-18; issued in Application (A.) 11-04-001, *Application of Southern California Edison Company for a Commission Finding that its Procurement-Related and Other Operations for the Record Period January 1 Through December 31, 2010 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for Recovery of $25.613 Million Recorded in Three Memorandum Accounts.*

[11] D.15-05-007, Ordering Paragraph 3.

[12] A.25-04-001, SCE-03C Testimony at 9.

actual bundled demand in SCE's territory is met. SCE [redacted].[13]

SCE also calculates a bid price for each resource that SCE operates or otherwise schedules into the market to generate energy for the market, reduce load (such as for DR), or to charge energy storage.[14] The majority of resource price bids reflect the cost of fuel and generation but may also consider the [redacted].[15] Accurate price forecasts allow SCE to create bids that minimize ratepayer costs by offering resources at prudent prices that recover the costs of generation or opportunity costs at optimal hours of operation.

2. Analysis of SCE Load and Price Forecasting

SCE must maintain accurate load forecasts to avoid purchasing excessive load. Over-forecasted load can lead SCE to purchase more energy than is needed on the CAISO DAM. Any excess load purchased on the DAM is credited back to SCE by the CAISO at RTM prices. DAM and RTM prices typically converge with one another, but it is possible for the RTM to experience price volatility or even sustained price divergence from DAM prices.

SCE must also strive to accurately forecast the price of energy on the DAM. This is critical for accurately pricing SCE's use-limited resources which have opportunity costs depending on values that shift over time due to market conditions. For example, SCE is only allocated a certain volume of generation from the Hoover Dam and should optimize the energy bid prices for that resource so that it is only dispatched when energy prices maximize potential revenue. If the bid price is too low, generation will be

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[13] SCE-03C Testimony at 9.

[14] Self-scheduled resources are an exception since they are offered to the market at any price. SCE-03C Testimony at 6.

[15] SCE-03C Testimony at 7-8.

dispatched at a lower price and may not be available later for dispatch at a higher energy price.

Cal Advocates used SCE data to measure the mean absolute percentage error (MAPE) and variance of SCE's demand and price forecasts in the 2024 Record Period. Price forecasts are represented by the Default Load Aggregation Point (DLAP), the average Local Marginal Price (LMP) across SCE's service area . The MAPE measures the difference between SCE's forecasted price/demand and the actual price/demand cleared in the market.[16] The variance[17] reported in Tables 1 and 2 demonstrates the actual market price (or load delivered) minus the forecasted price (or load awarded); it is not an absolute value. A negative variance would indicate that SCE tended to overestimate the price/load, i.e., that the actual price (or load) experienced was less than the forecasted price (or load). Calculations for price forecast accuracy use daily data and are presented below for both the top 100 highest-LMP days of the 2024 Record Period, as well as for all days of the 2024 Record Period. Demand forecast accuracy summarized here was measured only for the top 100 highest-LMP days using both daily and hourly data.[18]

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[16] The mean absolute percentage error equation is the absolute value of [(Actual Price or Demand) – (Forecast Price or Demand)] / (Actual Price or Demand).

[17] Variance in this context is a measurement of forecast error magnitude.

[18] Cal Advocates and the IOUs jointly agreed previously to such forecast reporting metrics. D.15-05-007, Appendix A.

Table 1: Price Forecast Comparison between 2021-2024 Record Periods[19]

(Confidential)

		MAPE		Variance	
Year	**Data Range**	**Median**	**Average**	**Median**	**Average**
2024	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2023	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2022	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2021	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2024	All 366 Days	[redacted]	[redacted]	[redacted]	[redacted]
2023	All 365 Days	[redacted]	[redacted]	[redacted]	[redacted]
2022	All 365 Days	[redacted]	[redacted]	[redacted]	[redacted]
2021	All 365 Days	[redacted]	[redacted]	[redacted]	[redacted]

Table 1 shows that the median and average MAPEs for the top 100 LMP days in the 2024 Record Period [redacted]. For all 366 days of the 2024 Record Period, the median and average price MAPEs [redacted]. The magnitude of the variances of the full year ("All 366 Days") [redacted]

[19] Cal Advocates' analysis is based on the SCE workpaper in Attachment 2.1, "SCE ERRA 2024 Section D_Price Forecast_CONFIDENTIAL."

[20] There are [redacted] days where the calculated average daily MAPE exceeded 100%. [redacted] of these instances occurred because the average daily energy prices were 1) negative values (resulting in an excessively larger numerator than the denominator in the MAPE calculation) and/or 2) between -$1.00 and $1.00 (resulting in a denominator less than 1 in the MAPE calculation). However, all [redacted] of all energy price days, and coincidental to the [redacted] (see Figure 1, below). As such, inclusion of these [redacted] outliers resulted in the overall average daily MAPE for 2024 of [redacted] rather than the [redacted] (as shown in Table 1). Therefore, since these [redacted] days skewed the overall MAPE despite the dollar value, Cal Advocates adjusted these [redacted] daily MAPEs to 100% to diminish their effect on the overall MAPE. See Attachment 2.1.

[redacted] while the magnitude of the variances [redacted]. A positive variance would indicate that SCE tended to forecast prices lower than actual DAM prices, while a negative variance means that SCE forecasted prices higher than actual DAM prices. Deviations from forecast accuracy generally have a higher potential cost impact during the highest energy value days, so [redacted]

Table 2: Demand Forecast Comparison between 2021-2024 Record Periods[21]

(Confidential)

		MAPE		Variance (MWh)	
Year	**Data Range**	**Median**	**Average**	**Median**	**Average**
2024	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2023	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2022	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2021	Top 100 Days	[redacted]	[redacted]	[redacted]	[redacted]
2024	All Hours of 100	[redacted]	[redacted]	[redacted]	[redacted]
2023	All Hours of 100	[redacted]	[redacted]	[redacted]	[redacted]
2022	All Hours of 100	[redacted]	[redacted]	[redacted]	[redacted]
2021	All Hours of 100	[redacted]	[redacted]	[redacted]	[redacted]

Table 2 shows SCE's demand forecast accuracy. SCE's overall median and average MAPE values [redacted], indicating [redacted] in SCE's demand forecasting accuracy. The median and average MAPEs also [redacted] from the 2023 Record Period for all hours in the top 100 days. Additionally, the variances for the 2024 Record Period [redacted], indicating that SCE [redacted] the demand it would need to serve the next day's load in the top

[21] Cal Advocates' analysis is based on SCE workpapers in Attachment 2.2, "SCE ERRA 2024 Section D_DLAP Awards and Prices_CONFIDENTIAL." The data for previous years was calculated in the same manner and is recorded in Cal Advocates' previous ERRA Compliance testimonies.

100 highest priced days, causing SCE to [redacted] day-ahead demand than was necessary to provide service.

Figure 1: Demand Forecast and Actual Load Comparison with Average LMP for the 2024 Record Period (Confidential)[22]

[redacted]

Figure 1 further illustrates that SCE [redacted] demand during the 2024 Record Period.[23] However, in response to a data request, SCE provided supplemental data including hourly net usage, rather than hourly demand data, to account for other factors, such as rooftop solar, in determining forecast accuracy because "SCE procures

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[22] See Attachments 2.1 and 2.2

[23] An additional note from Figure 1 is the [redacted] January [redacted] below-average temperatures in the Pacific Northwest and Intermountain West regions [redacted] in the other Western U.S. balancing authorities and CAISO. See "Q1 2024 Report on Market Issues and Performance" October 11, 2024, https://www.caiso.com/documents/2024-first-quarter-report-on-market-issues-and-performance-oct-11-2024.pdf and "Winter Conditions Report for January 2024" March 6, 2024, https://www.caiso.com/documents/wintermarketperformancereportforjan2024.pdf.

demand in the CAISO market to serve *net* load."[24] SCE's recommendation of net usage of MWh in the RTM as opposed to delivered MWh in the RTM does create a smaller variance (i.e. the MAPE numerator), as illustrated in Figure 2.

Figure 2: Actual and Forecasted Load Comparisons to Net Load for Top 100 Energy Price Days in the 2024 Record Period (Confidential)[25]

[redacted]

While, as SCE states, this may be a more "appropriate comparison to the Hourly Award data,"[26] incorporating it into the analysis of this proceeding complicates both year-to-year and cross-utility MAPE comparisons due to different baseline measurements between the MAPE calculations. However, if this net usage better represents SCE's, or any other IOU's, delivery obligation it may be worth further review of this variance

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[24] Emphasis added. SCE provided supplemental workpapers to Attachment 2.2 introducing the variance of load delivered net of other factors (e.g. rooftop solar). See Attachment 2.3 "SCE Responses to Cal Advocates Data Requests" at 1 and 2, and Attachment 2.4 "SCE ERRA 2024 Section D_DLAP Awards and Prices_DR02-Q1_SUPPLEMENT_CONFIDENTIAL"

[25] Cal Advocates' analysis is based on SCE workpapers in Attachments 2.1 and 2.4.

[26] See Attachment 2.3 at 1.

calculation to reflect the expanded influence of rooftop solar or other customer-side generation on load (or price) forecast and demand since LCD reporting standards were decided in 2015. Therefore, the issue of updating reporting metrics to determine a utility's forecast accuracy would be best addressed in a separate proceeding that addresses changes to the LCD standards so that all relevant stakeholders may provide input, not just those in the current proceeding.

Nevertheless, the [redacted] as shown in the original data set provided with SCE's testimony (and as reflected in Figure 1) is reasonable.

3. Conclusion on Demand and Price Forecasting in the 2024 Record Period

Tables 1 and 2 show that SCE's demand and price forecasting were [redacted] in the 2024 Record Period than in the previous year. While Cal Advocates determined that SCE's price forecasting was reasonable and, thus, does not object to SCE's price and load forecasting in the 2024 Record Period, the measurement of this accuracy may be improved using the alternative measure introduced by SCE. Therefore, Cal Advocates recommends that the Commission hold a workshop with the IOUs and other interested parties to set out revised LCD metrics to reflect changes in the electric market, such as the wide adoption of rooftop solar, since reporting standards were decided in 2015.

B. SCE's Supply Bidding Strategy

SCE offers its resources for dispatch in the CAISO markets by [redacted].[27] Self-schedules are also known as "price-taker" bids since the resource will be paid the price of energy at the time of dispatch. Self-scheduling is inherently at odds with LCD principles but is appropriate for must-run resources, such as run-of-the-river hydro, or resources with minimal costs of operation and/or fuel, such as solar power plants. Dispatchable

[27] SCE-03C Testimony at 6.

thermal units may also be appropriately self-scheduled when the unit must generate energy during certain testing or maintenance periods.

Most dispatchable resources, like natural gas-fired power plants, have fuel and operational costs whenever they generate. Appropriate economic bids consider those costs and any other costs of generation as inputs to the final bid price. Economic bidding and LCD principles ensure that the resource only runs when its market payment is at or above the cost of operation, ensuring full market cost recovery of generation costs.

1. Review of Economic Bids for Thermal Resources

Cal Advocates reviewed the economic bids of resources for which SCE held schedule coordinator duties during the Record Period. Thermal dispatchable resources are appropriately dispatched when the cost of energy (the LMP at the resource's price node) exceeds the costs of resource generation. While the CAISO ultimately makes resource dispatch decisions, SCE must construct economic bids for its resources to accurately state the cost of generation and offer them to the market for dispatch. A properly constructed economic bid does not guarantee dispatch, as the CAISO considers overall demand needs as well as regional constraints such as transmission congestion.

Figure 3: Thermal Generation Scheduled by SCE and Average Day-Ahead LMP in the 2024 Record Period (Confidential)[28]

[redacted]

Figure 3 above shows the dispatch of natural gas resources scheduled by SCE. In general, SCE received awards in correlation with its monthly demand. As the figure demonstrates, [redacted].[29] Figure 3 illustrates [redacted]; the latter is when the CAISO experienced peak load.[30] Nevertheless, the generation shown in Figure 3 would be complemented by other forms of supply such as non-thermal resources scheduled by SCE, contracted energy that SCE does not schedule, imported energy, and energy purchases from the CAISO energy markets.

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[28] The LMP (right-vertical axis) includes negative prices for the sake of visual clarity of the Average Day Ahead LMP line. Resources with multiple units are aggregated, except for resources with individual units above 100MW nameplate capacity. (Cal Advocates's analysis is based on SCE workpaper in Attachment 2.5, "SCE ERRA 2024 Section H_Disp Awards-Bids_CONFIDENTIAL"

[29] [redacted].

[30] See "Q3 2024 Report on Market Issues and Performance" December 23, 2024 at 19, https://www.caiso.com/documents/2024-third-quarter-report-on-market-issues-and-performance-dec-23-2024.pdf.

2. Review of Energy Storage Bids

SCE's testimony and workpapers include reports of bid and dispatch behavior of energy storage resources for which it acted as Scheduling Coordinator with CAISO.[31] Energy storage resources are use-limited, given they would exhaust their fuel (stored energy) after four or eight consecutive hours of full dispatch, depending on their full capacity. Energy storage resources also often have daily and/or annual charge/discharge limits. This means LCD principles are met when the resources are scheduled for dispatch during the most expensive LMP hours of the day and scheduled to charge during the least expensive LMP hours of the day.

SCE creates economic bids for its energy storage resources using opportunity cost principles. [redacted] this strategy [redacted].[32]

[31] See Attachment 2.3, at 4 to 6.

[32] See Attachment 2.3, at 3.

Figure 4: Hourly Sum of Discharge and Charge Awards (MW) and Average Hourly LMP ($/MWh) in the 2024 Record Period (Confidential)[33]

[redacted]

Figure 5: Hourly Count of Discharge and Charge Awards and Average Hourly LMP in the 2024 Record Period (Confidential)[34]

[redacted]

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[33] See Attachment 2.5 and Cal Advocates analysis is based on SCE workpapers in Attachment 2.6 "Storage Bids CONF." This graph excludes the data for Separator at Etiwanda Substation, addressed separately as a Reliability Utility Owned Energy Storage (RUOES) resource.

[34] See Attachment 2.5 and Attachment 2.6. Charge awards are shown as negative values for visual distinction in the graph. The absolute value on the primary/left vertical axis indicates the number of days SCE received either a charge or discharge award for a given hour in the 2024 Record Period. This graph excludes the data for Separator at Etiwanda Substation, addressed separately as a RUOES resource.

As illustrated in Figure 4, SCE's overall storage bidding resulted in [redacted] Similarly, Figure 5 shows [redacted]. So like Figure 4, Figure 5 shows a pattern of [redacted]

In its testimony, SCE includes a section on Reliability Utility Owned Energy Storage (RUOES) citing Resolution E-5183.[35] This Resolution clarifies the LCD standards apply for a prudency review of SCE's operations, including RUOES resources, in its ERRA Compliance proceedings. As stated in the Resolution the Commission expects "that least cost dispatch *may* be reviewed using meter data reflecting the timing of the resources' charging and discharging and whether SCE is bidding load reasonably in the day ahead market given historical load patterns."[36] In the current proceeding, SCE provided data in its workpapers for the two operational RUOES resources,[37] which like the energy storage analysis above, showed consistency with the LCD principles. Yet, the Commission only outlined a potential expectation for a prudent review of RUOES resources.

Presently, there is no explicit requirement for the IOUs to submit their energy storage bidding and scheduling activities in their ERRA compliance applications, only this outline for RUOES resources in Resolution 5183-E. While SCE provided reports on the bid and dispatch data for the energy storage resources in its workpapers for this

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[35] SCE-03C Testimony at 9.

[36] *Resolution E-5183. Southern California Edison request for approval of Emergency Reliability Engineering, Procurement, Construction, and Maintenance Contract for Utility-Owned Storage Resources*, issued December 17, 2021, at 24, emphasis added.

[37] See SCE Workpaper Attachment 2.7 "SCE ERRA 2024 Section D_RUOES_CONFIDENTIAL (check).xlsx" for Cathode, and Cal Advocates' analysis based on SCE Workpaper in Attachment 2.6, "ETIWND_2' tab, for Separator at Etiwanda analysis.

proceeding (and has done so in previous ERRA Compliance proceedings) the Commission has yet to rule on how SCE and other IOUs should report on the energy storage resources to ensure compliance with LCD requirements. Since the LCD filing requirements were codified in 2015, there have been numerous changes to the electricity market, such as expanded use of energy storage resources.[38] As stated previously in this chapter, Cal Advocates recommends that the Commission hold a workshop with the IOUs and other interested parties to set out revised LCD filing rules that account for these market changes.

3. Self-Scheduling Activity

In 2024, SCE [redacted],[39] [redacted]

[redacted].[40]

During the Record Period, CAISO awarded [redacted] MWh of SCE's non-dispatchable must-take resources such as wind and solar resources.[41]

SCE submitted [redacted] MWh of self-scheduled energy from thermal resources in the Record Period for non-discretionary purposes.[42] [redacted]

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[38] For example, nameplate capacity of energy storage in California increased from 200 MW to 2.5 GW from 2017 to 2021. See Chapter 1 of Aydin, Mariko Geronimo, and Cevat Onur Aydin. 2023. California Public Utilities Commission Energy Storage Procurement Study. Lumen Energy Strategy, LLC. Prepared for the California Public Utilities Commission. May 31, 2023, at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-storage/2023-05-31_lumen_energy-storage-procurement-study-report.pdf.

[39] SCE-03C Testimony at 14.

[40] SCE-03C Testimony at 7.

[41] SCE-03C Testimony, at 20.

[42] SCE Workpaper in Attachment 2.8 "SCE ERRA 2024 Section H_SS and Market Awards_CONFIDENTIAL."

[redacted].[43] Self-schedule volumes of other dispatchable thermal resources are consistent with historical patterns for testing SCE's thermal fleet.

4. Incremental Bid Cost Formulation and Variances

SCE formulates bids for each resource it possesses dispatch rights to and submits them to the CAISO's Integrated Forward Market (IFM), which is made up of the DAM for energy and ancillary services, as well as the Residual Unit Commitment (RUC) process.[44] Bid variances may arise when SCE's calculation of resource bids (calculated bids) varies from the price that is ultimately submitted to the CAISO markets (clean bids).[45]

SCE reports that of the 105,185 bids for dispatchable thermal resources it submitted to CAISO during the 2024 Record Period, "with zero bids found to have a variance due to incorrect values, and zero hours where dispatchable thermal resources were not bid into the CAISO."[46] SCE also reports 11 solar resource DAM bid variances that stemmed from a single "bid submittal issue which resulted in no Day Ahead bids being submitted for the resource on that day"[47]; SCE estimates no cost impact from these bid variances.[48] This low-error rate supports SCE's compliance with the reasonable manager standard for its dispatchable resource bidding activity.

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[43] See SCE Advice Letter 4767-E.

[44] SCE-03C Testimony at 12.

[45] SCE-03C Testimony, at 13.

[46] SCE-03C Testimony, at 13.

[47] SCE-03C Testimony at 13.

[48] SCE-03C Testimony at 13.

C. Hydro Management

Dispatchable hydro, specifically reservoir-fed systems and pumped storage facilities, is a type of use-limited generation constrained by available water and various local, state, and federal water-use constraints. SCE bids these resources into the market with consideration for the opportunity cost of running the resource at particular times, subject to those constraints.[49] Hydro resources provide the highest value to customers when they are dispatched during high energy price periods, maximizing market revenues and mitigating the cost of dispatching more expensive resources.

In Record Period 2024, SCE operated five dispatchable hydro resources/systems. The Big Creek hydroelectric system is made up of six reservoirs and nine powerhouses, representing 1,015 MW of combined capacity.[50] This complex includes the John S. Eastwood Power Station (Eastwood), a 200 MW pumped hydro resource.[51] SCE also owns and operates the Poole[52] and Rush Creek[53] hydroelectric resources, 11.25 MW and 13.01 MW, respectively. SCE also holds a contract with the Western Area Power Administration and the Bureau of Reclamation for 280.2 MW of Hoover Dam generation.[54] Finally, SCE operates several relatively smaller non-dispatchable hydro assets totaling 149 MW.[55]

Cal Advocates reviewed SCE's hydro dispatch over the course of the Record Period, with additional focus on energy dispatched during the highest-value energy hours of the year for each resource. SCE's hydro facilities were awarded for energy dispatches

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[49] SCE-03C Testimony at 7, 9.

[50] SCE-03C Testimony at 11.

[51] SCE-03C Testimony at 11-12.

[52] "Southern California Edison Lee Vining Hydroelectric Project Draft License Application, Volume 1," September 2024 at A-11, accessed at https://www.sce.com/sites/default/files/custom-files/PDF_Files/_Lee_Vining_P-1388_DLA_Volume-I_Combined.pdf. Note: the Poole Powerhouse is part of the Lee Vining Hydroelectric Project.

[53] "Rush Creek Project Relicensing," last updated January 2025, accessed at https://www.sce.com/regulatory/hydro-licensing/rush-creek.

[54] SCE-03C Testimony at 63.

[55] SCE-03C Testimony at 11.

and/or ancillary services [redacted][56] of 2024 in which the hydro resource was operational.[57]

Table 3: Dispatch and Ancillary Service Awards for SCE's Hydro Resources During the Top 500 Highest LMP Hours of the 2024 Record Period (Confidential)[58]

Hydro Resource	Percent total available capacity utilized by the market	Hours of no generation[59]
Big Creek	[redacted]	
Eastwood		
Hoover Dam		
Rush Creek		
Poole		

Cal Advocates finds SCE's bidding of its hydroelectric resources in the Record Period reasonable.

1. Eastwood Pumped Hydro

The Eastwood hydroelectric resource has pump-back capabilities that allow the resource to consume energy to pump water from Shaver Lake and store it at the higher-altitude forebay, Balsam Meadow.[60] This stored water may be used for generation during hours with high energy prices to offset the high costs of generating electricity.[61] Pump-back operations are less efficient than generation. Therefore, pumping into Eastwood's forebay adds value only when performed during hours of relatively low energy prices. This enables Eastwood to generate revenue via price arbitrage: by buying low

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[56] Cal Advocates' analysis is based on SCE Workpaper in Attachment 2.9, "SCE ERRA 2024 Section D_Hydro Awards-LMPs_CONFIDENTIAL"

[57] Operability may be reduced by forced or planned outages, water availability, transmission outages, reservoir work, and water use constraints determined by county, state, or federal agencies.

[58] See Attachment 2.9.

[59] Table 3 excludes periods when the unit was unavailable to the market, such as during an outage.

[60] SCE-03C Testimony at 19.

[61] SCE-03C Testimony at 19-20.

(consuming energy through pump-back) and selling high (using the pumped water for generation).

On September 15, 2022 Eastwood's main unit circuit breaker "experienced a critical in-service failure"[62] and forced Eastwood offline. It returned to service on July 17, 2024.[63] Eastwood went offline for scheduled outages in late August and from October 1 through November 24, 2024,[64] and experienced additional outages in September and December of 2024.[65] Despite these incidents, [redacted].

As illustrated in Figure 6, Eastwood, when operational, shows a general pattern of [redacted].

[62] SCE-03C Testimony at 28.

[63] SCE-03C Testimony at 29.

[64] Scheduled more than 45 days prior to the commencement of the outage, see Attachment 2.10, "SCE Response to Master Data Request," at 1-5.

[65] Scheduled 45 days or fewer prior to the commencement of the outage, SCE-03C Testimony, Table II-8, at 28 and Attachment 2.10, at 6-9.

Figure 6: Eastwood Generation and Pump-back MW with Average Hourly LMP for 2024 Record Period (Confidential)[66]

[redacted]

D. Demand Response Management

1. Least-Cost Dispatch Principles

SCE's economically-triggered DR resources may be dispatched by CAISO when the LMP is above the resource's economic bid or during periods of emergency reliability. Cal Advocates reviewed SCE's DR resource bid price calculations and SCE's decisions to offer or withhold the resources to the market to ensure that SCE met LCD principles and utilized the most cost-effective portfolio of resources.

SCE's DR programs include the Capacity Bidding Program (CBP), Summer Discount Plan (SDP), Smart Energy Program (SEP), and three Local Capacity Requirement (LCR) resources. These programs are further categorized by day-of versus day-ahead scheduling, the sector served, and/or how many hours the program may be active per day. SCE formulated bids for its 1,035 MW[67] of economically-triggered DR

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[66] See Attachment 2.9.

[67] SCE-03 Testimony at 19.

resources based on [redacted], [redacted][68]

2. Dispatch in the Record Period

SCE meets LCD principles when its DR programs are dispatched as much as possible during high-price energy hours, with consideration for program and contract limitations, such as maximum monthly dispatches, and other opportunity costs. For example, DR programs SDP and SEP are [redacted][69] [redacted]. Optimized DR programs mitigate the dispatch of higher-priced resources on the grid and help to offset the fixed monthly costs of the DR programs. SCE pays DR subscribers or contracted program managers a fixed rate per month regardless of whether the program is dispatched or not.

[68] See SCE Workpapers Attachments 2.11 through 2.16, "SCE ERRA 2024 Section I_DR-CBP-DA_CONFIDENTIAL," "SCE ERRA 2024 Section I_DR-LCR_ACES_CONFIDENTIAL," "SCE ERRA 2024 Section I_DR-LCR_AMS_CONFIDENTIAL "SCE ERRA 2024 Section I_DR-LCR_STEM_CONFIDENTIAL," "SCE ERRA 2024 Section I_DR-SDP_CONFIDENTIAL," "SCE ERRA 2024 Section I_DR-SEP_CONFIDENTIAL."

[69] See Attachments 2.15 and 2.16, 'Notes' tab.

Figure 7: Monthly DR Program Dispatch Count with Average LMP in Record Period 2024 (Confidential)[70]

[redacted]

Figure 7 shows the number of dispatches of each DR program compared with the average monthly LMP. As seen in Figure 7, and as evidenced in the analyses in this testimony chapter, the average LMP in [redacted]. In the 2023 Record Period, as illustrated in Figure 8, [redacted].[71] However, [redacted] as illustrated in both Figures 7 and 8, there was not a similar [redacted] As illustrated in Figure 8, the average LMP in [redacted]. This is

[70] See Attachment 2.17, "SCE ERRA 2024 CalAdv WP DR Combined CONFIDENTIAL."

[71] [redacted]. See Attachments 2.12 through 2.14.

largely due to [redacted].[73]

Figure 8: Monthly DR Dispatch Count with Average Monthly LMP for Record Periods 2022 – 2024 (Confidential)[74]

[redacted]

Although the 2024 Record Period [redacted] as shown in Figure 8, [redacted] so it is reasonable that [redacted]

[72] See Attachment 2.18, "2023 SCE-03 Ch I. Section D.1_DLAP Awards and Prices_CONFIDENTIAL"

[73] See Attachment. 2.2. See also Attachments 2.11 through 2.16, 'Notes' tabs and Attachment 2.17.

[74] See Attachment 2.17.

3. Cal Advocates' Assessment of Demand Response Administration

Cal Advocates concludes that SCE's economically-triggered DR resources were made available during high-price hours at reasonable bid prices in the 2024 Record Period. Throughout the year, DR resources were dispatched with respect to their use limitations and program design, helping to mitigate the dispatch of more expensive resources.

II. CONCLUSION

Overall, Cal Advocates does not object to SCE's conduct, procedures, and market results of economic bidding and scheduling in the 2024 Record Period. Cal Advocates recommends that the Commission hold a workshop with the IOUs and other interested parties to set out revised LCD filing rules that account for the electricity market changes, such as the wide adoption of rooftop solar and expanded use of energy storage resources, since the rules were first developed in 2015.

LIST OF ATTACHMENTS FOR CHAPTER 2

#	Attachment	Description
1	Attachment 2.1 (Confidential)	SCE ERRA 2024 Section D_Price Forecast_CONFIDENTIAL.xlsx **(Available via e-mail)**
2	Attachment 2.2 (Confidential)	SCE ERRA 2024 Section D_DLAP Awards and Prices_CONFIDENTIAL.xlsx **(Available via e-mail)**
3	Attachment 2.3 (Confidential)	SCE Responses to Cal Advocates Data Requests CONF.pdf
4	Attachment 2.4 (Confidential)	SCE ERRA 2024 Section D_DLAP Awards and Prices_DR02-Q1_SUPPLEMENT_CONFIDENTIAL.xlsx **(Available via e-mail)**
5	Attachment 2.5 (Confidential)	SCE ERRA 2024 Section H_Disp Awards-Bids_CONFIDENTIAL.xlsx **(Available via e-mail)**
6	Attachment 2.6 (Confidential)	Storage Bids CONF.xlsx **(Available via e-mail)**
7	Attachment 2.7 (Confidential)	SCE ERRA 2024 Section D_RUOES_CONFIDENTIAL (check).xlsx **(Available via e-mail)**
8	Attachment 2.8 (Confidential)	SCE ERRA 2024 Section H_SS and Market Awards_CONFIDENTIAL.xlsx **(Available via e-mail)**
9	Attachment 2.9 (Confidential)	SCE ERRA 2024 Section D_Hydro Awards-LMPs_CONFIDENTIAL.xlsx **(Available via e-mail)**
10	Attachment 2.10	SCE Response to Master Data Request.pdf
11	Attachment 2.11 (Confidential)	SCE ERRA 2024 Section I_DR-CBP-DA_CONFIDENTIAL.xlsx **(Available via e-mail)**
12	Attachment 2.12	SCE ERRA 2024 Section I_DR-LCR_ACES_CONFIDENTIAL.xlsx **(Available via e-mail)**

#	Attachment	Description
13	Attachment 2.13 (Confidential)	SCE ERRA 2024 Section I_DR-LCR_AMS_CONFIDENTIAL.xlsx **(Available via e-mail)**
14	Attachment 2.14 (Confidential)	SCE ERRA 2024 Section I_DR-LCR_STEM_CONFIDENTIAL.xlsx **(Available via e-mail)**
15	Attachment 2.15 (Confidential)	SCE ERRA 2024 Section I_DR-SDP_CONFIDENTIAL.xlsx **(Available via e-mail)**
16	Attachment 2.16 (Confidential)	SCE ERRA 2024 Section I_DR-SEP_CONFIDENTIAL.xlsx **(Available via e-mail)**
17	Attachment 2.17 (Confidential)	SCE ERRA 2024 CalAdv WP DR Combined CONFIDENTIAL.xlsx **(Available via e-mail)**
18	Attachment 2.18 (Confidential)	2023 SCE-03 Ch I. Section D.1_DLAP Awards and Prices_CONFIDENTIAL.xlsx **(Available via e-mail)**

CHAPTER 3: UTILITY-OWNED GENERATION – NATURAL GAS

(**Witness**: Michael Yeo)

I. INTRODUCTION AND RECOMMENDATION

This chapter addresses the operation and management of SCE's utility-owned natural gas facilities, and the outages that occurred at those facilities during the 2024 Record Period (January 1, 2024 to December 31, 2024).

After reviewing SCE's testimony and responses to data requests, Cal Advocates recommends the Commission order SCE to

(a) establish a procedure to ensure that it would receive equipment advisories from manufacturers for all plant equipment (not just 86RE relays) that are critical for operational readiness,

(b) contact Electro Switch Corporation, the manufacturer of the failed 86RE relay, to find out whether there had been advisories that it did not receive prior to July 11, 2024. SCE is to report, in its next ERRA Compliance filing in 2026, the list of those outstanding advisories and SCE's actions on those advisories.

(c) repair the Beckwith M-3425A relay, which could not be tested currently due to technical issues with the testing software.

II. GENERATION FACILITIES[75]

SCE owns, operates, and maintains five natural gas-fired peaking generating plants (Peakers) and one combined-cycle gas-fired generating station called Mountainview Generating Station.

A. SCE Peaker Facilities

As a result of heat and power-demand conditions experienced in Southern California during July and August 2006, the Commission directed SCE to develop five SCE-owned black-start-capable Peaker units[76] of up to 250 MW total generating capacity to provide the urgently

[75] Information about SCE's natural gas generation facilities was provided in Chapter III (Natural Gas Generation) of SCE Direct Testimony SCE-01, SCE-06, and from SCE data request responses.

[76] Black start is the ability to start or restore a power generator to operation without relying on external energy sources. (https://ieeexplore.ieee.org/document/5469492).

needed capacity and grid reliability for its entire transmission and distribution system.[77] The objective was to reduce the risk of shortages and blackouts during peak demand periods and other system emergencies. SCE filed Application (A.) 07-12-029 to recover costs associated with acquiring and installing the five Peakers, four of which became operational in August 2007, and the fifth in November 2012.[78]

The fifth Peaker, the McGrath Peaker Generating Station (McGrath Peaker), became operational on November 1, 2012. SCE then filed A.12-12-028 on December 31, 2012, to demonstrate the reasonableness of the costs incurred to install the McGrath Peaker and requested recovery of the revenue requirement associated with it. The Commission approved SCE's request in D.14-06-043.

Each of SCE's five Peakers consist of a single, simple-cycle, aeroderivative combustion turbine generator of approximately 49 MW-rated net capacity.[79] Together, the five Peakers offer 245 MW of generating capacity.[80]

The Peakers contribute to bulk power grid reliability with quick starting and rapid ramping capabilities and can run several times per day if necessary.[81] Because of their relatively low startup costs and ability to start up and shut down quickly, the Peakers can run when necessary to help reduce overall customer costs.[82]

SCE states that the power from its Peakers is used for the CAISO energy and ancillary services markets, where the units run to meet unexpected customer demand when needed, respond to unplanned system contingencies, or provide required system operating reserves by remaining off-line but immediately available.[83] Because of the Peakers' black-start capability,

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[77] August 15, 2006, *Assigned Commissioner's Ruling Addressing Electric Reliability Needs in Southern California for Summer 2007* (ACR) issued in Rulemaking (R.) 05-12-013 and R.06-02-013, at 2, and 6.

[78] SCE testimony, SCE-01, at 46, line 11 to 12.

[79] SCE testimony, SCE-01, at 46, line 9 to 10.

[80] SCE testimony, SCE-01, at 46, line 10 to 11.

[81] SCE testimony, SCE-01, at 46, line 15 to 16.

[82] SCE testimony, SCE-01, at 46, line 16 to 18.

[83] SCE testimony, SCE-01, at 46, line 18 to 21.

they can be used to help restore power if the grid experiences a total shutdown or "black-out."[84] However, there is a limitation on each Peaker's daily and annual use as Peakers are not allowed to exceed their respective daily and annual air emissions permit limits.[85]

The five SCE Peakers are:

1. Barre Peaker

The Barre Peaker is located at SCE's Barre Substation in Stanton, California (CA), with an operation date of August 2007.[86]

2. Center Hybrid Peaker

The Center Hybrid Peaker is located at SCE's Center Substation in Norwalk, CA, with an operation date of August 2007.[87] Pursuant to the Commission's May 26, 2016, Resolution E-4791, authorizing expedited procurement of storage resources, and D.18-06-009,[88] the Center Hybrid Peaker underwent Enhanced Gas Turbine upgrades in 2016, that included the integration of a 10 MW battery energy storage system into the Peaker.[89] Henceforth, it became a hybrid unit. The cost recovery for the upgrade was approved in D.18-06-009.[90]

3. Grapeland Hybrid Peaker

The Grapeland Hybrid Peaker is located at SCE's Etiwanda Substation in Rancho Cucamonga, CA, with an operation date of August 2007.[91] In 2016, pursuant to Commission Resolution E-4791 and D.18-06-009, the Grapeland Peaker also underwent Enhanced Gas Turbine upgrades that included the integration of a 10 MW battery energy storage system into the

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[84] SCE testimony, SCE-01, at 46, line 21 to at 47, line 2.

[85] SCE testimony, SCE-01, at 46, footnote 70.

[86] SCE testimony, SCE-01, at 46, line 5 and line 11.

[87] SCE testimony, SCE-01, at 46, line 5 to 6 and line 11.

[88] D.18-06-009, *Decision Granting Cost Recovery for Utility-Owned Energy Storage Projects Pursuant to Resolution E-4791*, issued in A.17-03-020.

[89] SCE testimony, SCE-01, at 46, footnote 69.

[90] D.18-06-009, *Decision Granting Cost Recovery for Utility-Owned Energy Storage Projects Pursuant to Resolution E-4791*, issued in A.17-03-020.

[91] SCE testimony, SCE-01, at 46, line 6 to 7 and line 11.

Peaker.[92] Like the aforementioned Center Hybrid Peaker, it became a hybrid unit. The cost recovery for the upgrade was approved in D.18-06-009.[93]

4. McGrath Peaker

The McGrath Peaker is located next to NRG Energy's Mandalay Generating Station in Oxnard, CA, with a commercial operation date of November 2012.[94]

5. Mira Loma Peaker

The Mira Loma Peaker is located at SCE's Mira Loma Substation in Ontario, CA, with an operation date of August 2007.[95] Pursuant to Commission Resolution E-4791 and D.18-06-009, SCE added 2 10 MW, 4-hour battery energy storage systems adjacent to the Mira Loma Peaker.[96] Unlike the enhancements at the Center Hybrid Peaker and the Grapeland Hybrid Peaker, these battery system additions were not integrated into the Mira Loma Peaker.[97] Therefore, the Mira Loma Peaker is not considered a hybrid generating facility.

B. Mountainview Generating Station

Background

The Mountainview Generating Station (Mountainview Station) is a two-unit (named Unit 3 and Unit 4) combined-cycle gas turbine power plant located in Redlands, CA.[98] Each unit consists of two combustion turbines (CTs) and one steam turbine (ST) and generates

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[92] SCE-01, at 46, footnote 69.

[93] D.18-06-009, *Decision Granting Cost Recovery for Utility-Owned Energy Storage Projects Pursuant to Resolution E-4791*, issued in A.17-03-020.

[94] SCE testimony, SCE-01, at 46, line 8 to 9 and line 11 to 12.

[95] SCE testimony, SCE-01, at 46, line 7-8 and line 11.

[96] SCE testimony, SCE-01, at 46, footnote 69.

[97] SCE testimony, SCE-01, at 46, footnote 69.

[98] SCE testimony, SCE-01, at 57, line 24 to 25 and SCE response to Cal Advocates Data Request 17, Question 004.

approximately 555 MW of power per unit.[99] The two units yield a nominal 1,110 MW net for the plant.[100]

The current Mountainview Station was built on the site of SCE's former San Bernardino Generating Station that consisted of two units, Unit 1 and 2, both of which were retired and decommissioned several years ago.[101] SCE decommissioned the two units in 2009 and sold the San Bernardino Generating Station to Thermo Ecotek Corporation as part of its generation divestiture during electric restructuring.[102] The sale to Thermo Ecotek Corporation was approved by the Commission in D.97-12-106.[103] Thermo Ecotek subsequently changed the name of the facility to Mountainview.[104]

Thermo Ecotek subsequently filed an Application for Certification for Mountainview Units 3 and Unit 4 with the California Energy Commission (CEC) on February 1, 2000.[105] The CEC approved the Application for Certification on March 21, 2001.[106] The AES Corporation purchased Thermo Ecotek from Ecotek's parent company, Thermo Electron Corporation, on July 31, 2001, and the sale included the Mountainview power plant.[107] In April 2003, Intergen bought the Mountainview Project from AES.[108]

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[99] SCE testimony, SCE-01, at 57, line 25 to 26, at 59, line 1 to 3, and SCE response to Cal Advocates Data Request 17, Question 004 and 013.

[100] SCE testimony, SCE-01, at 57, line 26 and SCE's response to Cal Advocates Data Request 17 Question 004.

[101] SCE response to Cal Advocates Data Request 17, Question 004 and 017.

[102] The divestiture was undertaken by Decision 95-12-063, as modified by Decision 96-01-009, Assembly Bill 1890, and Decision 03-02-028.

[103] Interim Order, issued on December 16, 1997, in A.96-11-046, *In the Matter of the Application of Southern California Edison Company (U-338-E) for authority to sell gas-fired electrical generation facilities.*

[104] Powermag.com 8/15/2006 article on Mountainview. http://www.powermag.com/mountainview-power-plant-redlands-california/?pagenum=2.

[105] https://www.energy.ca.gov/powerplant/combined-cycle/mountainview-generating-station

[106] https://www.energy.ca.gov/powerplant/combined-cycle/mountainview-generating-station

[107] Thermo Electron Corporation's New Release on July 31, 2001: https://ir.thermofisher.com/investors/news-and-events/news-releases/news-release-details/2001/Thermo-Electron-Completes-Final-Phase-of-Thermo-Ecotek-Sale/default.aspx?print=1

[108] https://www.energy.ca.gov/powerplant/combined-cycle/mountainview-generating-station

In A.03-07-032,[109] filed on July 21, 2003, SCE sought the Commission's authorization to acquire the Mountainview Power Company either (1) as a wholly owned subsidiary to enter into a power purchase agreement (PPA) with the Mountainview Power Company for electricity from the Mountainview Power Project, or (2) as a utility-owned generation facility. On December 18, 2003, the Commission approved A.03-07-032 in D.03-12-059[110] and authorized SCE to execute the PPA. D.03-12-059 was modified by two subsequent Decisions, (D.)04-03-037[111] and D.04-04-019.[112] Through D.04-03-037 and D.04-04-019, the Mountainview Power Company became a wholly-owned subsidiary of SCE and held a PPA with SCE.

In D.09-03-025,[113] the Commission approved SCE's request to operate Mountainview Station as a utility-owned generation facility rather than as a PPA lessee. D.09-03-025, "…approve[d] the transfer of ownership,"[114] and "…allow[ed] SCE to acquire direct ownership of Mountainview, and to include its capital costs in rate base and recover its operating costs through the Test Year 2009 revenue requirement."[115]

Unit 3 of the Mountainview Station began commercial operation on December 9, 2005, and Unit 4 began commercial operation on January 19, 2006.[116]

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[109] A.03-07-032, *In the Matter of the Application of Southern California Edison Company (U 338-E) for Approval of a Power Purchase Agreement under PUHCA Section 32(k) Between the Utility and a Wholly Owned Subsidiary and Authority to Recover the Costs of Such Power Purchase Agreement in Rates.*

[110] D.03-12-059, *Opinion Granting Southern California Edison Company's Application to Acquire Mountainview Power Company, LLC (MVL) Either as a Wholly Owned Subsidiary and to Enter into a Power Purchase Agreement with MVL For Electricity from the Mountainview Power Project, or as a Utility-Owned Generation Facility,* December 18, 2003 at 67-68; issued in A.03-07-032.

[111] D.04-03-037, *Opinion Adopting Federal Energy Regulatory Commission's Changes to The Mountainview Power Purchase Agreement Approved by This Commission in Decision 03-12-059*, March 16, 2004; issued in A.03-07-032.

[112] D.04-04-019, *Order Modifying Decision 03-12-059 And Denying Rehearing of Decision, As Modified*, April 1, 2004; issued in A.03-07-032.

[113] D.09-03-025, *Alternate Decision Of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Company*, March 12, 2009; issued in A.07-11-011.

[114] D.09-03-025 , at 33.

[115] D.09-03-025, at 365.

[116] https://www.energy.ca.gov/powerplant/combined-cycle/mountainview-generating-station

In May 2016, the two Mountainview Station units underwent CT system upgrades which increased the nominal generating unit output from 536 MW to 555 MW.[117] After the upgrade, each CT was rated at 182 MW each, and the ST was rated at 191 MW.[118] Therefore, the total nominal generating unit rating for Unit 3 and Unit 4 is 555 MW each (2x182 MW + 191 MW), or 1,110 MW net (2x555 MW) for the entire Mountainview Station.[119]

However, due to constraints on the San Bernardino 220 kilovolt (kV) transmission line, the maximum generation output at Mountainview Station is limited to 536 MW.[120] Subsequently, a new interconnection agreement executed in April 2019 allowed Mountainview Station to officially increase the nominal rated capacity to 1,110 MW.[121]

Although Unit 3 and Unit 4 each have a nominal net capacity rating of 555 MW, the actual power output varies above and below this number because of ambient weather effects, such as temperature and humidity.[122] Each of the two units can operate independently from one another.[123] However, for a unit to operate and prevent the heat recovery steam generator (HRSG) from overheating, at least one of its two CTs and its ST must be in service.[124] This is because when a CT is operating, it produces hot CT exhaust gas that flows through the HRSG attached to that CT.[125] To keep the HRSG from overheating, water must flow through that HRSG.[126] The

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[117] SCE response to Cal Advocates Data Request 17, Question 004.

[118] SCE response to Cal Advocates Data Request 17, Question 004, 009 and 010.

[119] SCE testimony, SCE-01, at 57, line 25 to 26, at 59, line 1 to 3, and SCE response to Cal Advocates Data Request 17, Question 004 and 013.

[120] SCE response to Cal Advocates Data Request 17, Question 004.

[121] SCE response to Cal Advocates Data Request 17, Question 004.

[122]SCE response to Cal Advocates Data Request 17, Question 004.

[123] SCE response to Cal Advocates Data Request 17, Question 004.

[124] SCE testimony, SCE-01, at 59, line 4 to 5, and SCE response to Cal Advocates Data Request 17, Question 014a, 015a, and 016.

[125] SCE testimony, SCE-01, at 60, line 3 to 4, and SCE response to Cal Advocates Data Request 17, Question 014a.

[126] SCE testimony, SCE-01, at 60, line 4 to 5, and SCE response to Cal Advocates Data Request 17, Question 014a.

resulting steam produced by that HRSG must then be routed to that unit's operating ST, otherwise the HRSG will overheat.[127]

The nominal rated output for a Mountainview Station unit when it is operating with a single CT and the ST is 250 MW,[128] versus the 555 MW[129] when both CTs and the ST are in service.[130]

In practice, Mountainview Station is not operated as a "base-load" plant (i.e., it is not constantly operated at its full-rated output level).[131] It is instead operated as an "intermediate duty" plant, meaning that the power output depends on the required California Independent System Operator (CAISO) dispatch orders to meet current power requirements and changing market conditions. Therefore, its energy production fluctuates in real-time.[132] Moreover, Mountainview Station, as a dispatchable resource, should only run when its variable costs can be expected to be recovered from the market.[133]

Physical Properties and Operational Characteristics

For either Unit 3 or Unit 4 to operate, at least one of the unit's two CTs, as well as that unit's ST, must be in service.[134] The unit is typically started with a single CT and its ST in service (i.e., its "1+1" configuration or C1 configuration[135]).[136] Following a unit start-up, if more

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[127] SCE testimony, SCE-01, at 60, line 5 to 6, and SCE response to Cal Advocates Data Request 17, Question 014a.

[128] SCE testimony, SCE-01, at 66, footnote 95, at 67, footnote 98, at 70, footnote 107, and SCE response to Cal Advocates Data Request 17, Question 014a.

[129] SCE testimony, SCE-01, at 57, line 25 to 26, at 59, line 1 to 3, and SCE response to Cal Advocates Data Request 17, Question 004 and 013.

[130] SCE testimony, SCE-01, at 59, line 1 to 3, and SCE response to Cal Advocates Data Request 17, Question 004.

[131] SCE testimony, SCE-01, at 60, line 12 to 13, and SCE response to Cal Advocates Data Request 17, Question 004.

[132] SCE testimony, SCE-01, at 60, line 13 to 15, and SCE response to Cal Advocates Data Request 17, Question 004.

[133] SCE testimony, SCE-03, at 3, line 17 to 18.

[134] SCE testimony, SCE-01, at 59, line 4 to 5, and SCE response to Cal Advocates Data Request 17, Question 014a, 015a, and 016.

[135] CE testimony, SCE-01, at 60, line 24 to 27, at 70, footnote 107, and SCE response to Cal Advocates Data Request 17, Question 158.

[136] SCE response to Cal Advocates Data Request 17, Question 016.

output is needed, the unit is then transitioned to having both CTs and its ST in service (i.e., its "2+1" configuration).[137]

While in operation, the unit can be transitioned from its 1+1 configuration to its 2+1 configuration (and vice versa) as needed, without coming offline.[138] Unit startups and shutdowns, as well as transitions from 1+1 to 2+1 configurations (and vice versa) while operating, are based on CAISO dispatch instructions.[139]

Occasionally, a unit's operations are restricted to its 1+1 configuration, to perform maintenance on one of that unit's CTs.[140] Depending on the exact scope of the maintenance work involved, it is often possible for a unit to operate in its 1+1 configuration while the non-operating CT is undergoing maintenance.[141]

When a unit is started up after being offline, the exact timing of when the CT and ST are synchronized to the power grid can vary, but typically the ST is placed online within approximately 30 minutes after that unit's first CT is placed online.[142]

The normal unit shutdown process is to first ramp down the CT (or both CTs, if both are operating) to its rated minimum load condition, and to then take the CT offline (or to sequentially ramp down and take both CTs offline, if both were running).[143] The ST ramps down at the same time the CT (or both CTs) are ramping down, and the ST is then taken offline simultaneously with the last CT going offline (i.e., of the two CTs, if both were running).[144] Forced outages can (but do not always) result in the ST and CT (or both CTs) coming offline faster than during a normal shutdown (for example, a forced outage can cause the turbines to suddenly trip, and the

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[137] SCE response to Cal Advocates Data Request 17, Question 016.

[138] SCE response to Cal Advocates Data Request 17, Question 016.

[139] SCE response to Cal Advocates Data Request 17, Question 016.

[140] SCE response to Cal Advocates Data Request 17, Question 016.

[141] SCE response to Cal Advocates Data Request 17, Question 016.

[142] SCE response to Cal Advocates Data Request 17, Question 016.

[143] SCE response to Cal Advocates Data Request 17, Question 016.

[144] SCE response to Cal Advocates Data Request 17, Question 016.

turbines are not progressively ramped down such as when the offline occurs in a normal shutdown).[145]

Figure 3-1 Mountainview Station – Aerial View of Unit 3 and Unit 4[146, 147]

[145] SCE response to Cal Advocates Data Request 17, Question 016.

[146] SCE testimony, SCE-01, at 59, Figure III-3, and SCE response to Cal Advocates Data Request 17, Question 003, 018 and 019.

[147] SCE response to Cal Advocates Data Request 17, Question 004 and 017: Unit 1 and Unit 2 were located on the same plant site, formerly named San Bernardino Generating Station; they were retired and decommissioned several years ago.

<u>Legend – Figure 3-1</u>

3A: Gas Turbine

3A HRSG: Heat Recovery Steam Generator

3B: Gas Turbine

3B HRSG: Heat Recovery Steam Generator

3ST: U3 Steam Turbine

4A: Gas Turbine

4A HRSG: Heat Recovery Steam Generator

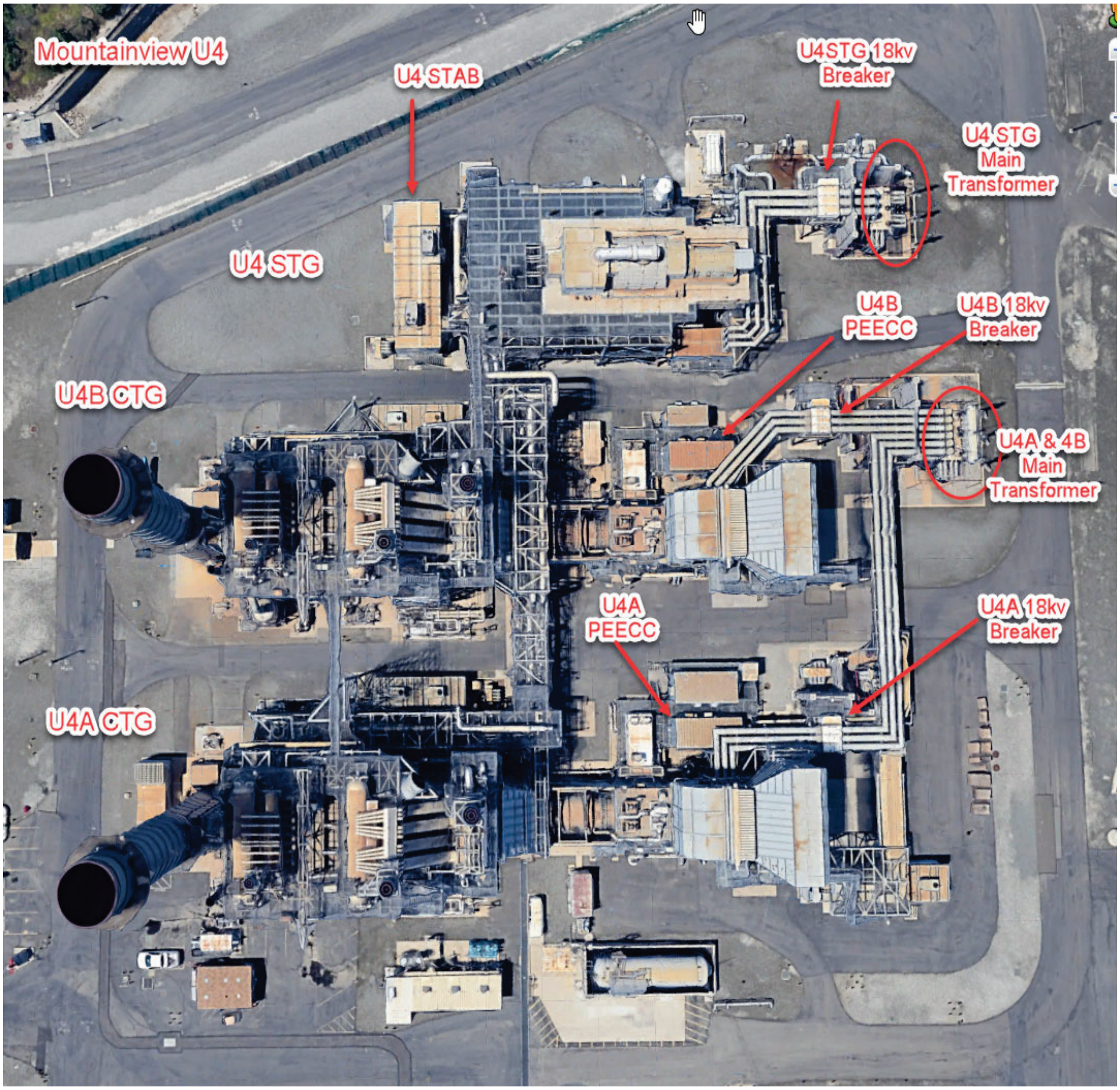
4B: Gas Turbine

4B HRSG: Heat Recovery Steam Generator

4ST: U4 Steam Turbine

Water Treatment: Steam and Cooling tower water processing plant.

Figure 3-2 Mountainview Station – Aerial View Showing Major Electrical Equipment[148]



[148] SCE response to Cal Advocates Data Request 17 Question 045.

Legend – Figure 3-2

STG Steam Turbine Generator
CTG Combustion Turbine Generator
STAB Steam Turbine Accessory Building
PEECC Package Electronic Electrical Control Center

Legend – Figure 3-2 (continued)

PEECC 18kv protective relays,

- SEL 300G
- Beckwith M3425A
- Basler BE1-25 (sync check)
- GE DBF Digital Breaker Fail
- GE IFV51 Ground protection

Lock out Relays

- 86RE Reverse Energization
- 86BN Bus Ground
- 86G-3 Backup Generator Protection
- 86G-4 Second Backup Generator Protection
- 86BF Breaker Fail
- 86G-1 Generator Lockout
- 86G-2 Second Generator Lockout

U4 STAB 18KV protective relays

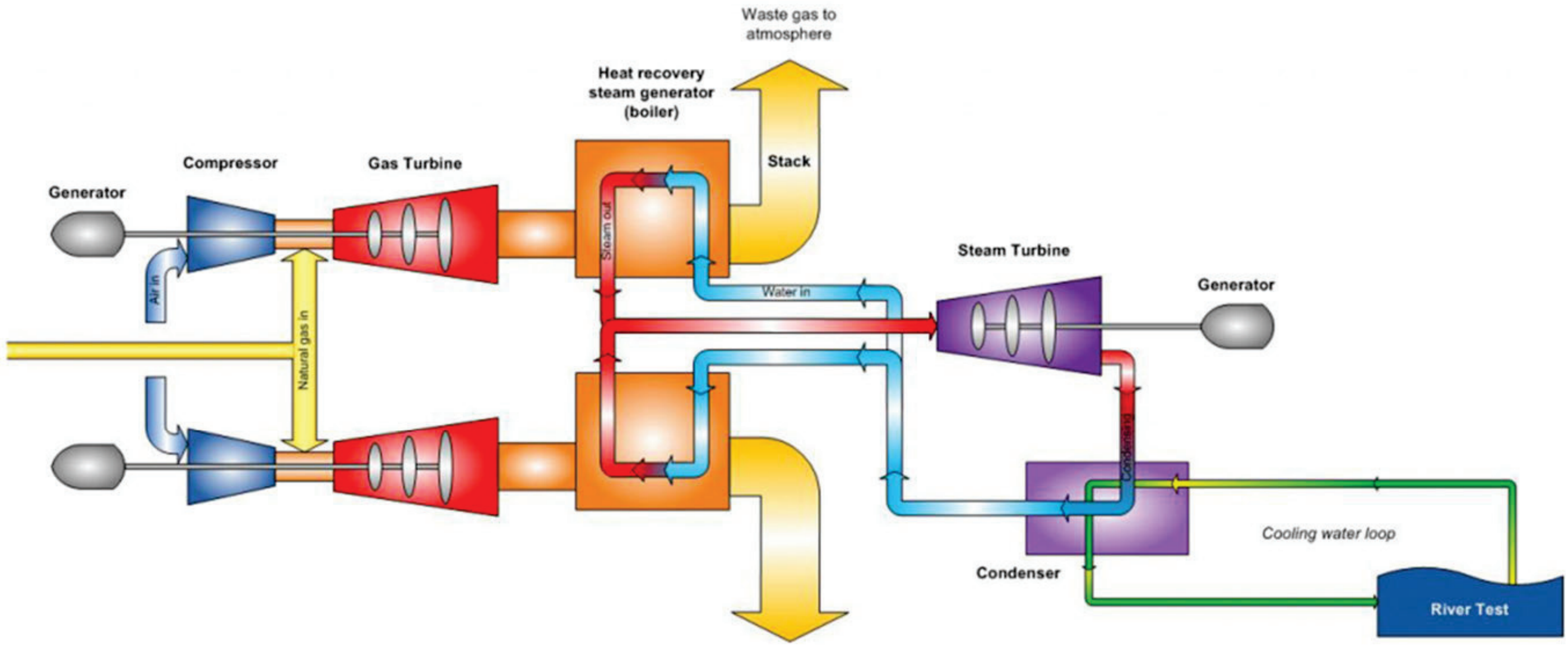
- SEL 300G
- Beckwith M3425A
- Basler BE1-25 (sync check)
- GE DBF Digital Breaker Fail
- GE MIV Ground protection

Lock out Relays

- 86RE Reverse Energization

- 86BN Bus Ground
- 86BF Breaker Fail
- 86G-1 Generator Lockout
- 86G-2 Second Generator Lockout

Figure 3-3 Schematic View of a Combined Cycle Gas Generator[149,150]



[149] The schematic view is that of the Marchwood Power Plant (https://www.marchwoodpower.com/ccgt/); it represents a typical equipment arrangement in a two-combustion turbine, combined-cycle generator. The diagram shows the relative locations of the two Combustion Turbines (CTs) shown as “Gas Turbine” above, the two Heat Recovery Steam Generators (HRSGs), and the single Steam Turbine (ST).

[150] SCE response to Cal Advocates Data Request 17, Question 008 – A Gas Turbine and a CT are standard industry nomenclature utilized interchangeably to describe a turbine that's propelled through the combustion of one of the following fuel sources; natural gas, propane, or hydrogen.

III. OUTAGE

For the 2024 Record Period, Cal Advocates reviewed the Mountainview Generating Station Unit 4B outage which started on July 9, 2025 at 16:56[151] and ended on July 13, 2024 at 11:06, for a total of 3.757 days (3 days, 18 hours, and 10 minutes).[152] The outage was caused by an issue with the Electroswitch relay.[153]

The descriptions of the activities, parts, and systems affected and/or referenced in the forced outage are as follows:

1. 18 kilo Volt (kV): the nominal voltage level at which the Mountainview Station generator produces electrical power.[154] This voltage is used to transfer power from the generator to the main transformer via the 18 kV generator output breaker.[155] The breaker serves as the primary isolation point between the generator and the rest of the electrical system.[156]

   The 18 kV feeder cable carries the generated power from the generator terminals through the breaker and onward to the main step-up transformer, where the voltage is increased for transmission across the grid.[157] The 18 kV system includes associated buss work, protection relays, and control circuitry that ensure safe and reliable operation of the generator and its connection to the grid.[158]

   At Mountainview Station, 18 kV is considered a distribution-level voltage. It is used internally to connect the generator to the main transformer and auxiliary systems.[159] It is not part of the high-voltage transmission network, which operates at significantly higher voltages

[151] The time convention used is the 24-hour clock.

[152] SCE testimony, SCE-01, at 66, Table III-17, line 5, and SCE response to Cal Advocates Data Request 17, Question 024 to 027.

[153] SCE testimony, SCE-01, at 70, line 17.

[154] SCE response to Cal Advocates Data Request 17, Question 041.

[155] SCE response to Cal Advocates Data Request 17, Question 041.

[156] SCE response to Cal Advocates Data Request 17, Question 041.

[157] SCE response to Cal Advocates Data Request 17, Question 041.

[158] SCE response to Cal Advocates Data Request 17, Question 041.

[159] SCE response to Cal Advocates Data Request 17, Question 042.

(e.g., 220 kV or above).[160] The 18 kV system is part of the plant's internal power infrastructure and is classified accordingly.[161]

2. Breaker: an electrical device that interrupts the flow of electricity when it detects a dangerous level of current to prevent overheating, fire, and damage to appliances and wiring.

   In the Mountainview Station Unit 4B outage incident, the 18 kV breaker is a high-voltage circuit breaker installed between a generator and the power grid.[162] Its primary role is to connect or disconnect the generator from the rest of the electrical system.[163] Its equipment designation is 4BENEYM-GB, which is based off the construction prints as well as the matching DCS (Digital Control System) designations.[164]

   <u>Breaker Trip</u>

   A breaker trip means the circuit breaker's closed main contacts were commanded to trip open.[165]

   A "breaker trip at full load" refers to the unit circuit breaker opening while the generator is operating at its maximum MW output.[166] At full load, the generator is producing its rated voltage and current, which flows through the closed main contacts of the unit breaker.[167]

   In this scenario, the breaker is commanded to open (trip) while still conducting a full load current.[168] The breaker is specifically designed to handle this condition and safely interrupt the current without damage or failure.[169]

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[160] SCE response to Cal Advocates Data Request 17, Question 042.

[161] SCE response to Cal Advocates Data Request 17, Question 042.

[162] SCE response to Cal Advocates Data Request 17, Question 039 and 043.

[163] SCE response to Cal Advocates Data Request 17, Question 039.

[164] SCE response to Cal Advocates Data Request 17, Question 047.

[165] SCE response to Cal Advocates Data Request 17, Question 052.

[166] SCE response to Cal Advocates Data Request 17, Question 053 and 159.

[167] SCE response to Cal Advocates Data Request 17, Question 053 and 159.

[168] SCE response to Cal Advocates Data Request 17, Question 053 and 159

[169] SCE response to Cal Advocates Data Request 17, Question 053.

The breaker can trip at any load if a fault or abnormal condition is detected by the protection relays.[170] Trips are not limited to full load operation.[171]

Under normal operating procedures, the unit's output is typically reduced to a minimal level before the breaker is tripped.[172] However, in certain situations, such as protection trips or emergency shutdowns, the breaker may be required to open under full load conditions.[173]

During a trip event, the main contacts of the breaker open and the voltage and current flow are interrupted.[174] The path for electrical energy to flow is broken.[175]

When a trip event occurs, the other main components of the generating unit are also commanded to shut down immediately.[176]

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[170] SCE response to Cal Advocates Data Request 17, Question 160.

[171] SCE response to Cal Advocates Data Request 17, Question 160.

[172] SCE response to Cal Advocates Data Request 17, Question 053.

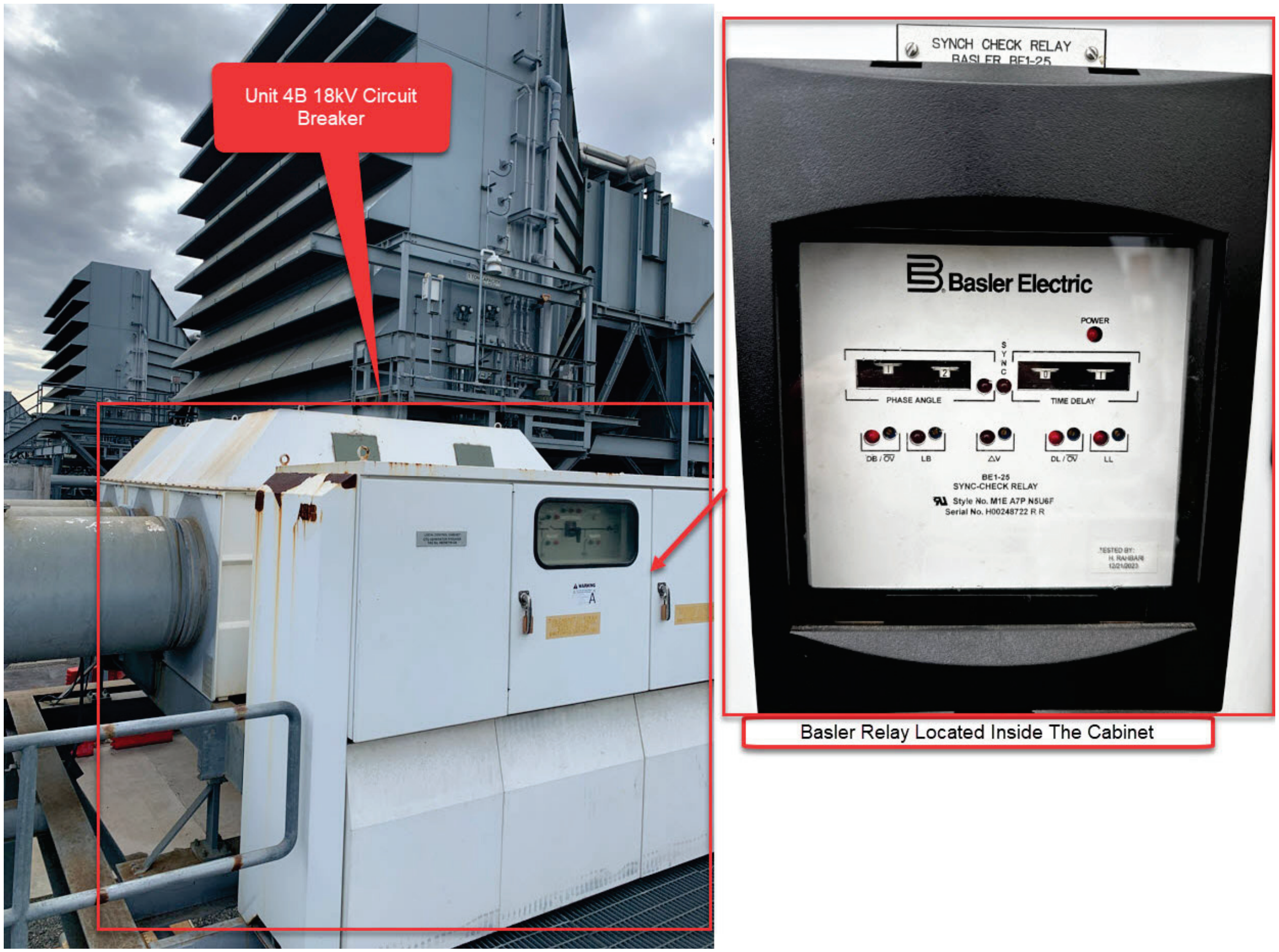
[173] SCE response to Cal Advocates Data Request 17, Question 053 and 159.

[174] SCE response to Cal Advocates Data Request 17, Question 054.

[175] SCE response to Cal Advocates Data Request 17, Question 054.

[176] SCE response to Cal Advocates Data Request 17, Question 054.

Figure 3-4 Photo of the Mountainview Station Unit 4B 18kV Circuit Breaker[177]



177 SCE response to Cal Advocates Data Request 21, Question 002.

3. Combustion Turbine (CT) versus Combustion Turbine Generator (CTG):[178]

The term, Combustion Turbine Generator (CTG), denotes the operating unit (combustion turbine and generator) as a whole, whereas Combustion Turbine (CT) is utilized when speaking specifically of the prime mover by itself.

The prime mover is the object that "turns" another object. For example, an electrical generator cannot produce energy by itself; it needs something that has the force to turn its shaft. Whatever is attached to that shaft that turns it is considered the prime mover. In the case above, it is the CT.

4. Heat Recovery Steam Generator (HRSG):[179] An energy recovery heat exchanger that recovers heat from a hot gas stream, such as a combustion turbine exhaust. It produces steam that is used to drive the steam turbine (i.e., combined cycle). There are four HRSGs at Mountainview Station (see Figure 3-1).

5. North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS):[180] GADS, which is part of NERC, is an electric industry-initiated data system introduced in 1982 to expand data collection activities that began in 1963.[181] Since 1982, SCE has utilized the NERC GADS to classify and track outage events (i.e., scheduled and unscheduled outages) at its generation facilities.[182] The GADS program was established for compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment.[183] SCE provides information annually to the Western Electricity Coordinating Council (WECC).[184]

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[178] SCE response to Cal Advocates Data Request 17, Question 005 to 007.

[179] SCE response to Cal Advocates Data Request 17, Questions 012.

[180] SCE response to Cal Advocates Data Request 17, Questions 032.

[181] SCE testimony, SCE-01, at 25, line 2 to 4, and SCE response to Cal Advocates Data Request 17, Question 029, 032, 033 and 035.

[182] SCE testimony, SCE-01, at 25, line 2 to 4, and SCE response to Cal Advocates Data Request 17, Question 029, 032, 033 and 035.

[183] SCE response to Cal Advocates Data Request 17, Question 029, 032 and 035.

[184] SCE response to Cal Advocates Data Request 17, Question 035.

GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry.[185] The objective of the GADS program is the compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment.[186]

Today, GADS maintains operating information on conventional generating units, wind plants, and solar plants.[187]

Through GADS, NERC collects information about the performance of electric generating equipment and supports equipment availability analyses.[188]

GADS reporting is mandatory for NERC-registered entities with conventional generating units that are 20 MW or more, wind plants with a total installed capacity of 75 MW or more, and a commercial operation date of January 1, 2005 or later:[189]

Effective January 1, 2025, solar plants with a total installed capacity of 20 MW or more, regardless of interconnection, are required to report to GADS.[190] When reporting events to GADS, there are numerous reporting requirements,[191] two of which are Event Type and Cause Code:[192, 193]

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[185] SCE testimony, SCE-01, at 25 line 4 to 5.

[186] SCE testimony, SCE-01, at 25, line 6 to 8, and SCE response to Cal Advocates Data Request 17, Questions 032.

[187] SCE response to Cal Advocates Data Request 17, Questions 033.

[188] SCE response to Cal Advocates Data Request 17, Questions 033.

[189] SCE response to Cal Advocates Data Request 17, Questions 033.

[190] SCE response to Cal Advocates Data Request 17, Questions 033.

[191] SCE response to Cal Advocates Data Request 17, Questions 033.

[192] SCE response to Cal Advocates Data Request 17, Questions 031 and 033: A complete list of the Event Codes and their definitions are provided in Exhibit SCE -06.

[193] SCE response to Cal Advocates Data Request 17, Questions 033: NERC GADS Data Reporting Instructions (GADS_DRI_2024.pdf)

a. The Event Type is a two-letter code describing a unit's operational state.[194] For example, an Event Type, D1, is an unplanned (Forced) derating.[195] This is a derating that requires an immediate reduction in capacity.[196]

b. The Cause Code identifies the cause of the event; the codes are created and defined by NERC GADS.[197]

6. Relay: a device used in power generation for equipment protection, automation, and control.[198]

a. A protective/protection relay is an electrically operated device used to control or protect electrical circuits.[199] Protective relays monitor electrical parameters and trigger circuit breakers to isolate faults: the fault isolation is to prevent equipment damage and ensure plant and personnel safety.[200] (See Figure 3.5 for a schematic diagram of the generator protection relay and the equipment it monitors.)

Protection relay logic refers to the programmed conditions and sequences that determine when a relay will issue a trip signal.[201] It includes inputs, thresholds, timing, and output actions based on electrical parameters like current, voltage, and frequency.[202]

Protection relay settings are configuration parameters that define the operating thresholds and behavior of the relay.[203] These include overcurrent limits, voltage ranges, time delays, and coordination settings used to detect and isolate faults.[204]

Protection relay wiring refers to the physical electrical connections between the relay and associated equipment, including current transformers (CTs), potential transformers (PTs), breakers, and

[194] SCE response to Cal Advocates Data Request 17, Questions 033.

[195] SCE response to Cal Advocates Data Request 17, Questions 029, 030 and 033.

[196] SCE response to Cal Advocates Data Request 17, Questions 029, 030 and 033.

[197] SCE response to Cal Advocates Data Request 17, Questions 033.

[198] SCE response to Cal Advocates Data Request 17, Question 038.

[199] SCE response to Cal Advocates Data Request 17, Question 038 and 067.

[200] SCE response to Cal Advocates Data Request 17, Question 038 and 067.

[201] SCE response to Cal Advocates Data Request 17, Question 123.

[202] SCE response to Cal Advocates Data Request 17, Question 123.

[203] SCE response to Cal Advocates Data Request 17, Question 125.

[204] SCE response to Cal Advocates Data Request 17, Question 125.

control circuits.[205] It ensures proper signal flow for monitoring and tripping.[206]

b. A breaker relay is a type of protective relay used in electrical systems to monitor and control circuit breakers.[207] Its primary function is to detect abnormal conditions—such as overcurrents, short circuits, or faults—and initiate the opening (tripping) of the circuit breaker to isolate the affected section of the electrical system.[208]

18 kV Breaker Relay

The 18 kV breaker relay at Mountainview Station is designated as 86RE where "86" is an Institute of Electrical and Electronics Engineers (IEEE) designation for a lockout relay and "RE" refers to Reverse Energization.[209] The 86RE relay is an 86 lockout relay that has been configured for Reverse Energization protection.[210] Functionally, it is a lockout relay, but its application and logic are tailored to detect and respond to reverse power flow.[211]

Reverse energization refers to the condition where electrical power flows in the opposite direction from normal operation, such as from the grid back into the generator.[212] This is different from normal energization, where power flows from the generator to the grid. Reverse energization can damage equipment and is typically detected and isolated by protection relays.[213]

At Mountainview Station, SCE uses the 86RE, the relay to detect and respond to reverse power flow, because it is designed to react to reverse energization fault conditions.[214] Protection relays will trip under a reverse energization condition to prevent damage to the generator and associated equipment from an abnormal power flow

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205 SCE response to Cal Advocates Data Request 17, Question 127.

206 SCE response to Cal Advocates Data Request 17, Question 127.

207 SCE response to Cal Advocates Data Request 17, Question 040 and 062.

208 SCE response to Cal Advocates Data Request 17, Question 040 and 062.

209 SCE response to Cal Advocates Data Request 17, Question 048.

210 SCE response to Cal Advocates Data Request 17, Question 063, 069 and 118.

211 SCE response to Cal Advocates Data Request 17, Question 040, 049 and 063.

212 SCE response to Cal Advocates Data Request 17, Question 064.

213 SCE response to Cal Advocates Data Request 17, Question 064.

214 SCE response to Cal Advocates Data Request 17, Question 040, 049, 065 and 069.

direction, which can occur due to faults or operational errors.[215] This protection capability promotes safe operation and system integrity.[216]

Mountainview Station utilizes six types of 18 kV breaker relays, each serving a specific protective or control function within the generator output breaker system.[217] They are all protection relays: some serve as protection elements while others also serve control or synchronization functions.[218] The six types and their functions are:

(1) Schweitzer Engineering Laboratory (SEL) 300G multifunction generator protective relay – Provides comprehensive generator protection, including monitoring of voltage, current, frequency, and synchronism.[219] It detects faults and initiates breaker trips when abnormal conditions are present.[220]

The SEL 300G relay is a multifunction generator protection relay that monitors a generator to ensure it is working safely and correctly.[221] If something fails, like a short circuit, overheating, or power flowing in the wrong direction, it can automatically implement a shutdown to prevent damage or danger.[222] It monitors electrical signals like voltage, current, and frequency, and detects problems such as:[223]

(a) Ground faults (electricity flowing where it should not)

(b) Overheating

(c) Power flowing backwards

(d) Generator losing sync with the power grid

It can also send alerts, record events, and trigger protective actions like opening a breaker.[224]

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[215] SCE response to Cal Advocates Data Request 17, Question 065.

[216] SCE response to Cal Advocates Data Request 17, Question 065.

[217] SCE response to Cal Advocates Data Request 17, Question 040, 049, 073, 074, 076 and 079.

[218] SCE response to Cal Advocates Data Request 17, Question 108.

[219] SCE response to Cal Advocates Data Request 17, Question 049, 070, 071,104, 105 and 108.

[220] SCE response to Cal Advocates Data Request 17, Question 049, 070 and 071.

[221] SCE response to Cal Advocates Data Request 17, Question 071.

[222] SCE response to Cal Advocates Data Request 17, Question 071.

[223] SCE response to Cal Advocates Data Request 17, Question 071.

[224] SCE response to Cal Advocates Data Request 17, Question 071.

(2) Beckwith M-3425A multifunction relay – Serves as a backup generator protection relay.[225] It monitors electrical parameters and provides redundancy for fault detection and trip initiation.[226]

(3) Basler BE1-25 Sync Check relay – Ensures proper synchronization between the generator and the grid before the 18 kV breaker is closed; it prevents damage due to out-of-phase closing.[227]

(4) Electroswitch 86-series lockout relay – Provides latching trip functionality.[228] Electro Switch Corporation[229] is the manufacturer of the 86-series lockout relays, as well as the generator breaker control switch, used at Mountainview Station.[230]

The 86 lockout relay is a latching device that isolates equipment during fault conditions.[231] Once actuated, it locks in the tripped state until manually reset, ensuring faults are not reintroduced without inspection.[232]

(5) General Electric DBF (Digital Breaker Failure) relay – Monitors breaker status and current flow.[233] If the breaker fails to open after receiving a trip command, this relay initiates backup tripping of upstream breakers to isolate the fault.[234]

(6) General Electric IFV51 Ground Protection relay – Provides dedicated ground fault protection by monitoring for abnormal current flow to ground.[235]

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[225] SCE response to Cal Advocates Data Request 17, Question 049, 072, 104, 105 and 108.

[226] SCE response to Cal Advocates Data Request 17, Question 049 and 072.

[227] SCE response to Cal Advocates Data Request 17, Question 049, 078 and 108.

[228] SCE response to Cal Advocates Data Request 17, Question 049.

[229] SCE response to Cal Advocates Data Request 17, Question 111, 132, 136 and 174: Electro Switch Corporation, 180 King Avenue, Weymouth, MA 02188.

[230] SCE response to Cal Advocates Data Request 17, Question 077 and 133.

[231] SCE response to Cal Advocates Data Request 17, Question 040, 049, and 099.

[232] SCE response to Cal Advocates Data Request 17, Question 040, 049, 066 and 099.

[233] SCE response to Cal Advocates Data Request 17, Question 049 and 078.

[234] SCE response to Cal Advocates Data Request 17, Question 049 and 078.

[235] SCE response to Cal Advocates Data Request 17, Question 049 and 078.

These relays collectively support a wide range of protective functions, including overcurrent protection, over/under voltage protection, reverse power detection, neutral overcurrent/overvoltage protection, over/under excitation monitoring, unit status indication, and breaker status monitoring.[236]

Together, they form a coordinated protection scheme that ensures safe, reliable operation of the generator and its connection to the grid.[237]

SCE did not select the specific generator output breaker and the specific breaker relay used at Mountainview Station.[238] The facility's design and engineering and its procurement of all major equipment, including the 18 kV breaker and 18 kV breaker relay, were completed prior to SCE's acquisition of the plant.[239] The 18 kV breaker and the 18 kV breaker relay in question were part of the original construction, and the commissioning scope was performed by the previous owner.[240]

[236] SCE response to Cal Advocates Data Request 17, Question 049.

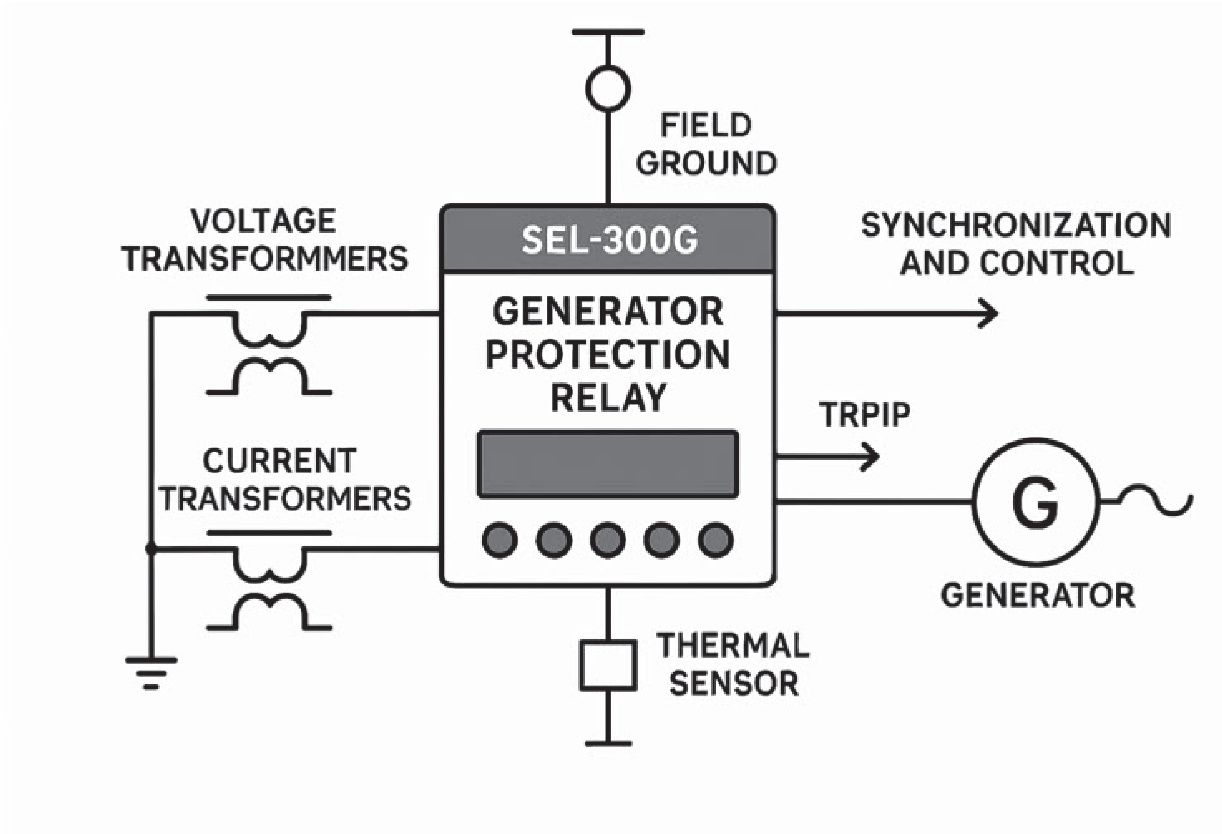
[237] SCE response to Cal Advocates Data Request 17, Question 049.

[238] SCE response to Cal Advocates Data Request 17, Question 050 and 051.

[239] SCE response to Cal Advocates Data Request 17, Question 050 and 051.

[240] SCE response to Cal Advocates Data Request 17, Question 050 and 051.

Figure 3-5 Diagram of the Generator Protection Relay and Connecting Equipment[241]

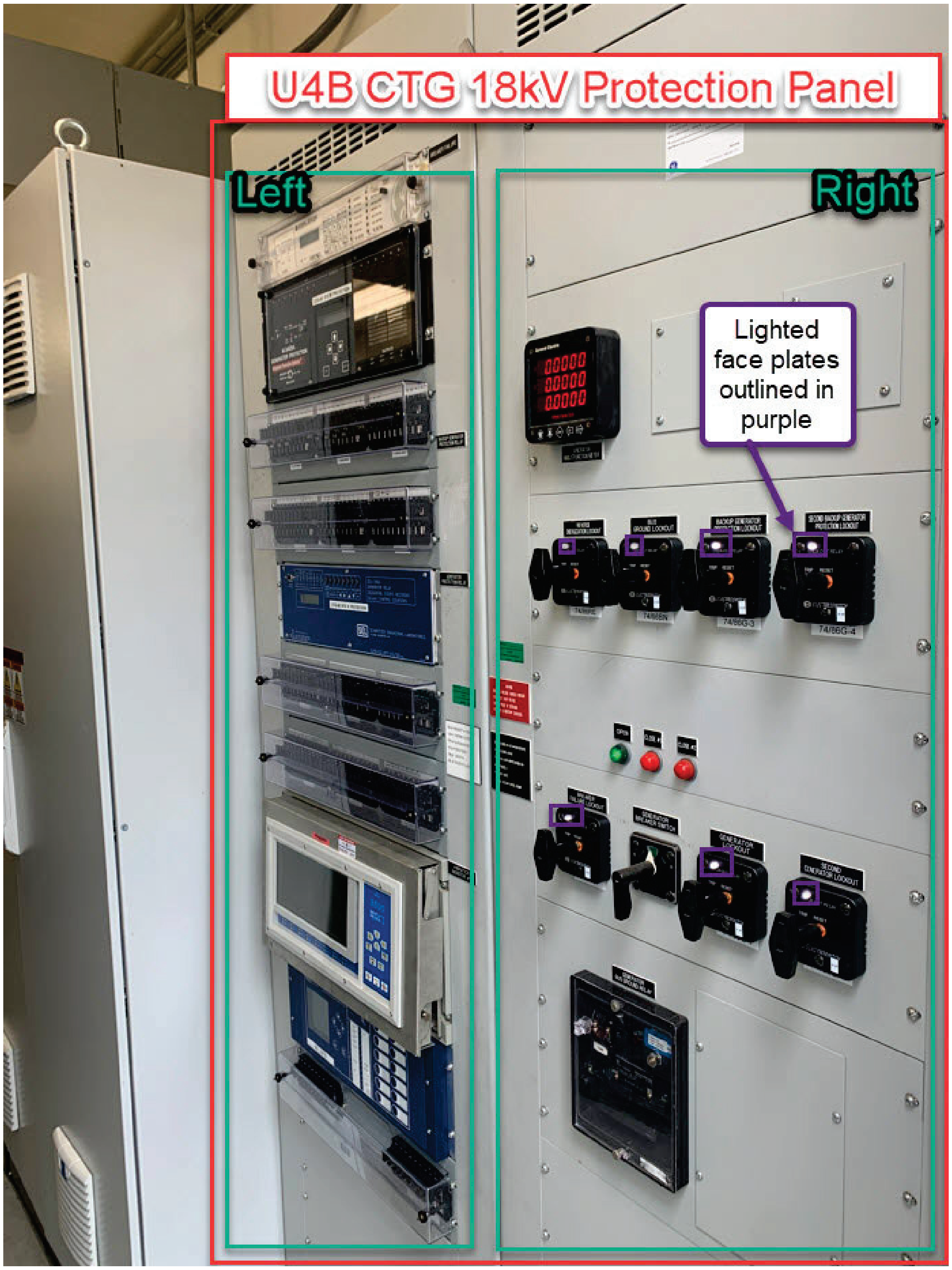


This visual shows the basic connections:

- **Generator**: Produces electrical power.
- **CTs (Current Transformers)**: Measure current flowing from the generator.
- **PTs (Potential Transformers)**: Measure voltage levels.
- **SEL-300G Relay**: Monitors signals and detects faults.
- **Breaker**: Disconnects the generator if a fault is detected.
- **Control Panel**: Interface for settings, alarms, and status.

[241] SCE response to Cal Advocates Data Request 17, Question 040, 045 and 046.

Figure 3-6 Photo of the Unit 4B 18 kV Protection Relay Panels (Left and Right Panel)[242]



242 SCE response to Cal Advocates Data Request 17, Question 040, 068, 069 and 075, and Data Request 21, Question 002.

Figure 3-7 Photo of the Unit 4B 18 kV Protection Relay Left Panel Showing the GE, Beckwith and SEL 300G Relay[243]

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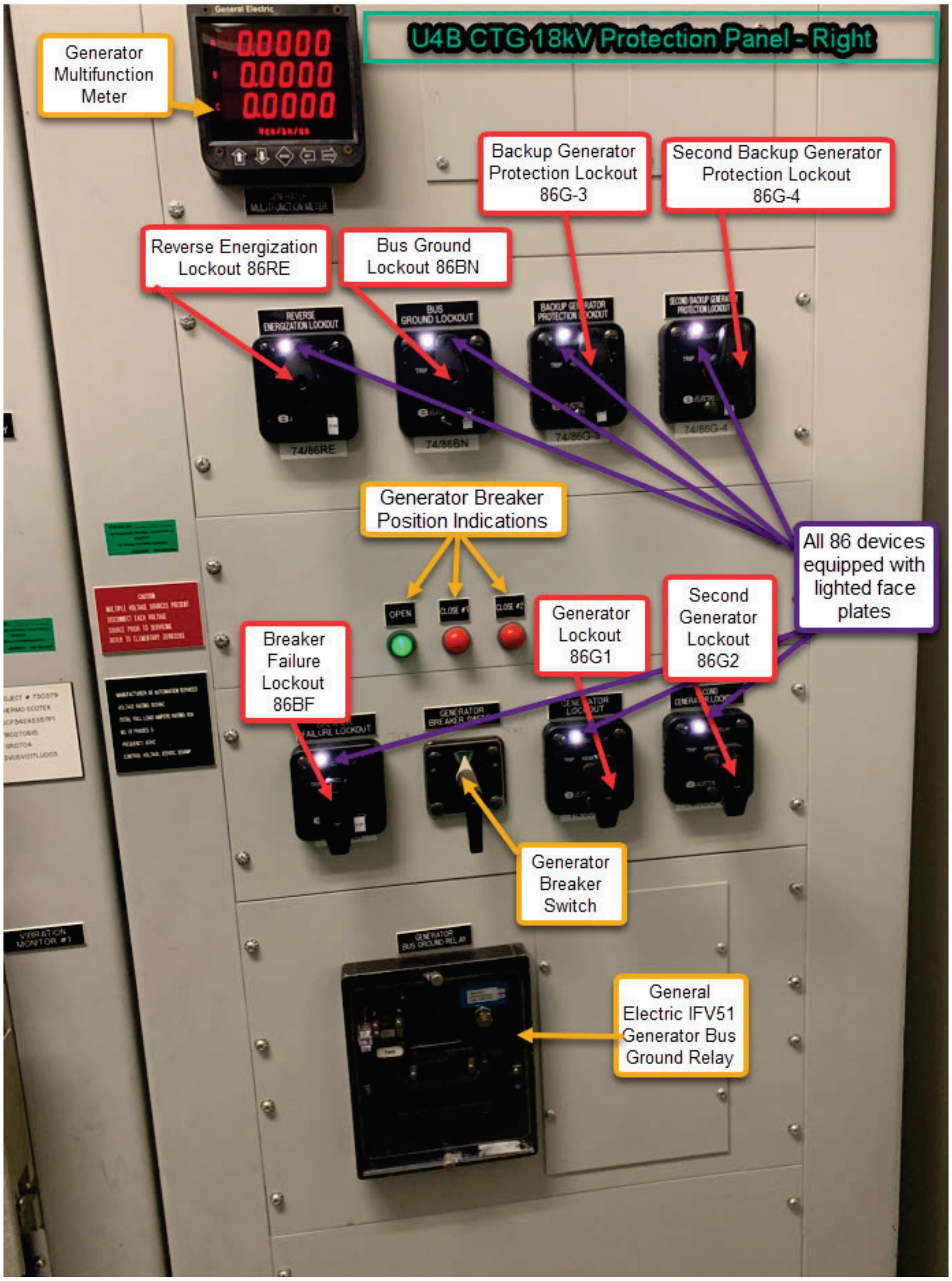
[243] SCE response to Cal Advocates Data Request 17, Question 040, and Data Request 21, Question 002.

Figure 3-8 Photo of the Unit 4B 18 kV Protection Relay Right Panel Showing Lighted Face Plates[244]



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[244] SCE response to Cal Advocates Data Request 17, Question 040, 068, 069 and 075, and Data Request 21, Question 002.

At Mountainview Station, the protective relays monitor the 18 kV system, which includes the generator, buss (solid metal conductor) work between the generator and the 18 kV breaker, and the buss work from the 18 kV breaker to the main transformer.[245] When the protective relays sense abnormal conditions, they send a trip signal either directly to the equipment to be tripped or to an *86 device,*[246] the ANSI/IEEE appellative for a lockout relay. The *86 device* then sends multiple trip signals to different pieces of equipment, including the 18 kV breaker, to isolate the generator from the rest of the system and shut down the unit.[247]

Protective relays generally have limited output contacts with low voltage and current carrying capabilities.[248] The *86 devices* have a high number of output contacts with high voltage and current carrying capability.[249] This allows for a single output of a protective relay to send a trip signal to an *86 device* that can then send multiple trip signals to multiple devices.[250] The *86 device* is then physically "locked" in the tripped position requiring a physical reset.[251]

There are 56 protective relays designated as 18 kV relays, all of which will trip the 18 kV breaker.[252] These relays are a combination of multifunction microprocessor relays, electro-mechanical relays, and sudden and over pressure relays.[253] They are all protecting the 18 kV

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[245] SCE response to Cal Advocates Data Request 17, Question 040 and 044.

[246] SCE response to Cal Advocates Data Request 17, Question 048.

Other References: https://control.com/textbook/electric-power-measurement-and-control/auxiliary-and-lockout-86-relays/: the lockout relay is designated by the American National Standards Institute (ANSI)/ Institute of Electrical and Electronics Engineers (IEEE) device number code 86. The purpose of an 86 relay is to serve as an intermediary element between one or more protective relays and one or more control devices, and

Common IEEE Device Numbers (https://www.basler.com/Common-device-numbers): Device 86, or lockout relay, is an electrically-operated hand, or electrically-reset relay or device that functions to shut down or hold equipment out of service upon the occurrence of abnormal conditions.

[247] SCE response to Cal Advocates Data Request 17, Question 040.

[248] SCE response to Cal Advocates Data Request 17, Question 040.

[249] SCE response to Cal Advocates Data Request 17, Question 040.

[250] SCE response to Cal Advocates Data Request 17, Question 040.

[251] SCE response to Cal Advocates Data Request 17, Question 040.

[252] SCE response to Cal Advocates Data Request 17, Question 046 and 079.

[253] SCE response to Cal Advocates Data Request 17, Question 046.

system including the generator, breaker, main transformer, auxiliary transformers, and 18 kV buss.[254]

In Mountainview Station, there are 38 lockout relays (*86 devices*) associated with those 56 relays.[255] Of the 38 lockout relays, seven are in each of the four Packaged Electronic/Electrical Control Compartments (PEECCs) and five are in each of the two Steam Turbine Accessory Buildings (STABs).[256]

7. Steam Turbine (ST):[257] Equipment that converts the thermodynamic energy in the steam supplied by the HRSGs into mechanical energy at its shaft. Mountainview Station has two STs.

8. Steam Turbine Auxiliary Building (STAB):[258] a secure, environmentally controlled facility that houses critical electrical and control systems for the steam turbine and generator. It typically contains generator and transformer protection equipment, switchgear and circuit breakers, turbine and excitation control systems, battery and DC power systems, UPS units, and communication and monitoring infrastructure. These systems ensure reliable operation, protection, and control of the turbine-generator unit and its associated electrical components. There is a total of two STABs at Mountainview: Unit 3 STAB and Unit 4 STAB.

9. Steam Turbine Generator (STG):[259] Equipment that converts the mechanical energy at the ST shaft into electrical energy at the generator terminals. Each ST is attached to an electrical generator; Mountainview Station has two STGs.

10. Steam Turbine (ST) versus Steam Turbine Generator (STG):[260]

The term, "Steam Turbine Generator" (STG), is used to describe the operating unit (steam turbine and generator) as a whole, whereas the term, "Steam Turbine" (ST), is used when speaking specifically of the prime mover by itself.

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[254] SCE response to Cal Advocates Data Request 17, Question 046.

[255] SCE response to Cal Advocates Data Request 17, Question 046, 049 and 079.

[256] SCE response to Cal Advocates Data Request 17, Question 046, and SCE response to Cal Advocates Data Request 21, Question 04.

[257] SCE response to Cal Advocates Data Request 17, Question 012.

[258] SCE response to Cal Advocates Data Request 21, Question 004.

[259] SCE response to Cal Advocates Data Request 17, Question 012.

[260] SCE response to Cal Advocates Data Request 17, Question 011.

The prime mover is the object that "turns" another object. In this case the object being turned is an electrical generator, which cannot produce energy by itself – the generator needs something that has the force to turn its shaft. Whatever is attached to that shaft that turns it is considered the prime mover, which in the case above is the ST. Hence, the "Steam Turbine" is a component of the "Steam Turbine Generator."

11. Unit Designation and Operation:

The term, "Unit 4," used at Mountainview Station refers to that specific unit with the numeric designation "4;" while Unit 4A refers to Unit 4's "A" block, which includes the "A" combustion turbine/generator, its associated HRSG, and accessory equipment for unit "A" (see Figure 3-3).[261] Similarly, Unit 4B refers to Unit 4's "B" block; as such, the two terms, Unit 4 and Unit 4B, are not used interchangeably.[262]

Each of the two generating units, Unit 3 and Unit 4, has two CTs (see Figure 3-3); as such, each of the two CTs, are assigned either "A" or "B" as well.[263] For example, Unit 4A CT refers to Unit 4's "A" CT, and Unit 4B CT refers to Unit 4's "B" CT.[264] There is no CT Unit 4C, or 4D, etc.[265]

In its Testimony, SCE uses the term, "Unit 4B," and the term, "the 4B," interchangeably.[266]

Operation of either Unit 3 or Unit 4 requires that at least one of its 2 CTs and its ST be in operation.[267] The CT exhaust gases flow through HRSGs, two of which are installed on each unit (i.e., one HRSG per CT).[268] When a CT is operating, hot CT exhaust gas is produced and flows through the HRSG attached to that CT.[269] To keep the HRSG from over-heating, water must flow through that HRSG.[270] The resulting

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[261] SCE response to Cal Advocates Data Request 17, Question 018 and 019.

[262] SCE response to Cal Advocates Data Request 17, Question 021 and 022.

[263] SCE response to Cal Advocates Data Request 17, Question 018 and 019.

[264] SCE response to Cal Advocates Data Request 17, Question 018 and 019.

[265] SCE response to Cal Advocates Data Request 17, Question 018 and 019.

[266] SCE response to Cal Advocates Data Request 17, Question 021.

[267] SCE response to Cal Advocates Data Request 17, Question 014 and 015.

[268] SCE response to Cal Advocates Data Request 17, Question 014.

[269] SCE response to Cal Advocates Data Request 17, Question 014.

[270] SCE response to Cal Advocates Data Request 17, Question 014.

> steam that is produced by that HRSG must then be routed to that unit's operating ST or the HRSG will overheat.[271]
>
> The nominal rated output for a Mountainview Station unit (Unit 3 or 4), when that unit is operating with a single CT and its ST in service, is 250 MW.[272] To achieve the full rated 555 MW output[273] from the ST, both CTs on a generating unit must be in-service (i.e., both HRSGs must be in-service).[274]

A component failure within the 86RE lockout relay control circuit caused the lockout relay to actuate and trip the unit offline.[275] Initially, SCE detected that the outage was due to a reverse energization trip; however, upon investigation, SCE determined that the component failure of the 86RE caused a false reverse energization signal.[276]

SCE operators are alerted via digital control system (DCS) alarms in the control room.[277] The operators did not have to manually shut down Unit 4B because the facility automatically tripped via the DCS.[278] Protection relays, interlocks, and control system logic coordinate shutdowns, and the Instrumentation and Controls (I&C) devices monitor parameters and initiate trips as needed.[279] The set points for shutting down the facility are established by engineering staff and are based on equipment ratings, protection coordination studies, and manufacturer recommendations to ensure safe operation and timely fault isolation.[280]

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[271] SCE response to Cal Advocates Data Request 17, Question 014.

[272] SCE response to Cal Advocates Data Request 17, Question 014.

[273] SCE testimony, SCE-01, at 57, line 25 to 26, at 59, line 1 to 3, and SCE response to Cal Advocates Data Request 17, Question 004 and 013.

[274] SCE Testimony, SCE-01, at 66, footnote 95, and at 73, footnote 114; and SCE response to Cal Advocates Data Request 17, Question 013 and 014.

[275] SCE response to Cal Advocates Data Request 17, Question 055 and 109.

[276] SCE response to Cal Advocates Data Request 17, Question 055.

[277] SCE response to Cal Advocates Data Request 17, Question 162 and 163.

[278] SCE response to Cal Advocates Data Request 17, Question 164 and 165.

[279] SCE response to Cal Advocates Data Request 17, Question 169.

[280] SCE response to Cal Advocates Data Request 17, Question 170.

During the trip, only Unit 4B shut down automatically while Unit 4A and Unit 4 STG remained online.[281]

SCE's Direct Testimony and its data request responses on the July 9, 2024 outage are focused on the issues and activities of three relays: the 86RE lockout relay, a specific type of the *86 device*, whose faceplate failure caused the outage; and two related relays, the Beckwith M-3425A and the Schweitzer Engineering Laboratory (SEL) 300G relay. In its narrative, SCE uses the terms, "nameplate" and "faceplate," interchangeably.[282]

Initial investigations were focused on the 86RE relay due to indications or alarms related to reverse energization or lockout conditions, which are critical for fault isolation and protection.[283] During this event, the 86RE relay was the only lockout relay (8*6 device*) that was actuated, and there were no alarm or event indications on any of the other protective relays.[284] Therefore, no other relays were initially investigated.[285]

An SCE Test Technician and SCE's vendor, Electrical Systems Testing, conducted the initial investigations.[286] SCE has previously hired Electrical Systems Testing for various assignments, including Catalina Generation Station: Electrical testing, protective relay testing, equipment installations, and commissioning support.[287] SCE's assessment of Electrical Systems Testing's performance has consistently been positive.[288]

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[281] SCE response to Cal Advocates Data Request 17, Question 166.

[282] SCE response to Cal Advocates Data Request 17, Question 096 and 097: With reference to the Electroswitch unit described in SCE's testimony, the terms, "nameplate" and "faceplate," are used interchangeably.

[283] SCE response to Cal Advocates Data Request 17, Question 080, 083, 085 and 086.

[284] SCE response to Cal Advocates Data Request 17, Question 080.

[285] SCE response to Cal Advocates Data Request 17, Question 081.

[286] SCE response to Cal Advocates Data Request 17, Question 084, 107, 131, 171 and 183: Electrical Systems Testing , 16458 Bolsa Chica Road, Suite 233, Huntington Beach, CA 92649.

[287] SCE response to Cal Advocates Data Request 17, Question 185.

[288] SCE response to Cal Advocates Data Request 17, Question 185.

The vendor has demonstrated technical competence, reliability, and professionalism in all prior engagements.[289]

For this outage work, Electrical Systems Testing was selected based on their existing service agreement and prior experience with Mountainview GS relay systems.[290] Electrical Systems Testing was selected under an existing Blanket Purchase Order (BPO) agreement.[291] This BPO provides electrical testing services across SCE facilities, including routine testing and maintenance procedures, protective relay inspections, testing and commissioning, and troubleshooting services.[292] The vendor was, in accordance with SCE's standard procurement and contracting procedures, engaged for technical services, such as specialized electrical support across its generation facilities.[293]

For the initial investigation, Electrical System Engineering was engaged to assist station Test Technicians in troubleshooting the cause of the 86RE relay trip, and to test and verify proper operation of protective relays associated with the 86RE relay trip.[294]

Following the trip, SCE personnel began to troubleshoot the 86RE protection relay logic, settings, and wiring.[295] Initial findings were that the 86RE relay had tripped.[296] The 86RE relay was the only lockout relay that actuated during the event.[297] No protective relay elements were triggered, and no trip signals were issued from the SEL

[289] SCE response to Cal Advocates Data Request 17, Question 185.

[290] SCE response to Cal Advocates Data Request 17, Question 172.

[291] SCE response to Cal Advocates Data Request 17, Question 184, 187 and 189.

[292] SCE response to Cal Advocates Data Request 17, Question 184 and 187.

[293] SCE response to Cal Advocates Data Request 17, Question 184 and 187.

[294] SCE response to Cal Advocates Data Request 17, Question 188.

[295] SCE response to Cal Advocates Data Request 17, Question 085.

[296] SCE response to Cal Advocates Data Request 17, Question 085 and 086.

[297] SCE response to Cal Advocates Data Request 17, Question 129.

300G and the Beckwith M-3425A relay.[298] This led investigators to focus on the 86RE relay as the source of the trip.[299]

However, SCE's standard practice is to investigate all related relays.[300] Priority was given to the 86RE relay, but further steps included checking the SEL 300G and the Beckwith M-3425A relay before returning the unit to service.[301]

Details of the inspections and tests performed by SCE included the following:

(a) SCE reviewed the relay settings and logic diagrams, verified input/output mappings, and analyzed event records to confirm that no protection elements were triggered during the trip.[302] Point-to-point wiring checks were also performed.[303]

(b) SCE reviewed the configured settings in the SEL 300G and the Beckwith M-3425A relay, compared them against design standards, and confirmed that no trip conditions were met during the event.[304]

SCE utilized the Dobel F6150 Power System Simulator to simulate voltage and current inputs so as to test the operation of the relays' programmed protective functions at their specified setpoints and the resulting output signals.[305]

The settings were verified to be within expected ranges.[306]

While the SEL 300G passed all tests, the Beckwith M-3425A relay could not be tested due to technical issues with the testing software, but was returned to AUTO mode.[307]

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[298] SCE response to Cal Advocates Data Request 17, Question 129.

[299] SCE response to Cal Advocates Data Request 17, Question 129.

[300] SCE response to Cal Advocates Data Request 17, Question 130.

[301] SCE response to Cal Advocates Data Request 17, Question 082 and 130.

[302] SCE response to Cal Advocates Data Request 17, Question 124.

[303] SCE response to Cal Advocates Data Request 17, Question 124.

[304] SCE response to Cal Advocates Data Request 17, Question 126.

[305] SCE response to Cal Advocates Data Request 17, Question 151.

[306] SCE response to Cal Advocates Data Request 17, Question 126.

[307] SCE response to Cal Advocates Data Request 17, Question 085, 151, 154, 156 and 177.

(c) SCE performed point-to-point wiring checks from the SEL and the Beckwith relay to the 86RE lockout relay.[308] The investigation confirmed that no other circuits were connected to the 86RE and that the wiring was intact and properly terminated.[309] SCE, in its data requestion response, provided copies of its Systems, Applications, and Products (SAP) inspection notes and its SEL 300G test results to substantiate its 86RE circuit connections inspection and relay testing.[310] No anomalies were found during the inspections.[311]

SCE personnel found, during additional troubleshooting, that the manufacturer of the 86RE relay had issued an advisory for the Lighted Nameplate.[312] The manufacturer stated that the switch (CAT # 78PA07LA), manufactured prior to 2008, had known issues with false trips.[313] As a temporary solution, the lighted faceplate[314] aspect of the switch was disabled.[315] Faceplate lighting is standard for visibility and operational awareness, especially in control rooms. However, the lighting, in this case, was bypassed due to reliability concerns after the tripping event took place.[316]

The reliability concerns are based on the manufacturer advisory indicating that older illuminated models could cause false trips due to internal faults.[317] The trip was

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[308] SCE response to Cal Advocates Data Request 17, Question 082, 128, 150 and 175.

[309] SCE response to Cal Advocates Data Request 17, Question 082, 128, 150 and 175.

[310] SCE response to Cal Advocates Data Request 17, Question 150 and 153.

[311] SCE response to Cal Advocates Data Request 17, Question 176.

[312] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[313] SCE response to Cal Advocates Data Request 17, Question 085.

[314] SCE response to Cal Advocates Data Request 17, Question 087: A faceplate is the front panel of a relay or control device, which includes indicators, and identification labels.

SCE response to Cal Advocates Data Request 17, Question 088, 090 to 092: A lighted faceplate includes illuminated indicators to show operational status, or trip conditions, to aid the operators in real-time monitoring on equipment status. Unlike an unlighted faceplate, which only provides physical labels and controls, a lighted faceplate provides illuminated indicators that display operational status and trip conditions –the lit information thus aids the operators in real-time monitoring. The lighted faceplate can be disabled by removing power from its illumination circuit.

[315] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[316] SCE response to Cal Advocates Data Request 17, Question 093.

[317] SCE response to Cal Advocates Data Request 17, Question 085 and 094 and 095.

caused by a component failure in the 86RE lockout relay control circuit.[318] The lighted nameplate,[319] part of the Electroswitch relay under advisory, was identified as a potential source of false trip signals due to its design.[320] There was an issue with older illuminated models which could potentially cause unintended actuation of the lockout relay, leading to a false trip.[321]

Therefore, disconnecting the lighted faceplate control wiring from the 86RE lockout relay prevented unintended actuation of the solenoid.[322] SCE determined that the failed part was the 86RE lockout relay faceplate, originally manufactured by Electro Switch Corporation.[323] The relay was installed during the original construction of Mountainview Generating Station in 2005.[324] It had not been replaced prior to the July 9, 2024 outage.[325]

In addition, two temporary inputs to the Generator SEL were run to facilitate 86RE monitoring and 86RE mechanical monitoring.[326] Also, a power quality meter was installed to monitor running voltage and current in case another trip occurred.[327] The 86RE circuit, coming from both the SEL 300G and the Beckwith M-3425A relay, was also checked point to point, and it was verified that no other wiring or connections were made to the 86RE from other circuits or equipment.[328]

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[318] SCE response to Cal Advocates Data Request 17, Question 095 and 109.

[319] SCE response to Cal Advocates Data Request 17, Question 096 and 097: With reference to the Electroswitch unit described in SCE's testimony, the terms, "nameplate" and "faceplate," are used interchangeably.

[320] SCE response to Cal Advocates Data Request 17, Question 095.

[321] SCE response to Cal Advocates Data Request 17, Question 085 and 094 and 095.

[322] SCE response to Cal Advocates Data Request 17, Question 098.

[323] SCE response to Cal Advocates Data Request 17, Question 194.

[324] SCE response to Cal Advocates Data Request 17, Question 194.

[325] SCE response to Cal Advocates Data Request 17, Question 194.

[326] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[327] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[328] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

The trip was isolated to the 86RE relay due to its specific control circuit and vintage; no other relays were affected.[329] Other relays did not actuate and showed no fault indications.[330] However, similar relays were identified and included in a replacement plan due to shared design risks.[331]

The 86RE relay (an 86 lockout relay that has been configured for reverse energization protection)[332] is an Electroswitch lockout relay with an expected operational life of 20–25 years under standard conditions.[333] Its depreciation life follows the plant's asset schedule, which is 35 years, as authorized in D.15-11-021, issued in SCE's 2015 General Rate Case .[334],[335] In general, life expectancy reflects physical reliability and expected operational lifespan, while depreciation life is an accounting measure tied to the broader facility's financial schedule and does not necessarily reflect actual wear or failure risk.[336]

All 86 Lockout relays, including the affected 86RE, were installed during original plant construction and have been in service since 2005.[337]

SCE personnel, working with Electrical Systems Testing contractors, tested the 4B Primary and Backup Protection Relays (SEL 300G and Beckwith M-3425A).[338] The SEL 300G was tested and found to be satisfactory.[339] The Beckwith Relay could not be

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[329] SCE response to Cal Advocates Data Request 17, Question 119.

[330] SCE response to Cal Advocates Data Request 17, Question 119.

[331] SCE response to Cal Advocates Data Request 17, Question 119.

[332] SCE response to Cal Advocates Data Request 17, Question 063, 069 and 118.

[333] SCE response to Cal Advocates Data Request 17, Question 112 and 115.

[334] D.15-11-021, *Decision on Test Year 2015 General Rate Case for Southern California Edison Company*, November 12, 2015; issued in A.13-11-003.

[335] SCE response to Cal Advocates Data Request 17, Question 113 and 116.

[336] SCE response to Cal Advocates Data Request 17, Question 114 and 117.

[337] SCE response to Cal Advocates Data Request 17, Question 050, 059 and 111.

[338] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[339] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

tested due to technical issues with the testing software.[340] Both relays were placed back into "AUTO" mode, and final preparations were made to perform a test run with operations personnel.[341] During the test run SCE personnel observed that the correct signals were being logged in the sequence of events recorder (SER) on inputs 207 and inputs 208 on the SEL 300G.[342] After the above steps were completed, Unit 4B was tested and ran normally without issues.[343] Unit 4B was then released for service.[344]

As stated above, during the course of the July 9, 2024 outage, two other protection relays, besides the 86RE lockout relay, were also investigated: the Beckwith M-3425A (backup generator protection) and the SEL 300G (primary generator protection) relay.[345] They were tested, following the Unit 4B trip, to confirm proper operation and absence of faults due to misconfiguration or hardware issues.[346]

Monitoring SEL 300G relays allows operators to track relay status, log trip events, verify protection logic, and support fault diagnostics and post-event analysis.[347] Completing SEL monitoring involves configuring and verifying inputs on the SEL 300G relay to track the 86RE relay's coil and contact status.[348] The purpose is to log trip events and confirm relay behavior during operation, aiding in diagnostics, and preventing recurrence.[349] Upon completion of the SEL 300G monitoring and the installation of a power quality meter, SCE was able to confirm that the SEL 300G relay was correctly logging trip-related signals (e.g., 86COILMON and 86CONTACTMON) and in stable

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[340] SCE response to Cal Advocates Data Request 17, Question 085, 151, 154, 156 and 177.

[341] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[342] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[343] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[344] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[345] SCE response to Cal Advocates Data Request 17, Question 082, 121, 122 and 151.

[346] SCE response to Cal Advocates Data Request 17, Question 104 and 105.

[347] SCE response to Cal Advocates Data Request 17, Question 103 and 106.

[348] SCE response to Cal Advocates Data Request 17, Question 100 and 102.

[349] SCE response to Cal Advocates Data Request 17, Question 100, 102 and 106.

operation.[350] The SEL 300G therefore passed all tests using simulated inputs.[351] SCE did not require any follow-up actions.[352]

The Beckwith M-3425A relay could not be tested due to software issues but was returned to service in AUTO mode after verifying wiring and absence of fault indications.[353]

The 18 kV current breaker relay performed as designed, protecting the breaker and electrical system, by initiating a trip signal when abnormal conditions were detected.[354] The July 9, 2024 trip was not triggered by any operation setpoints, such as electrical current or equipment temperature; the trip was caused by the failure of the faceplate.[355]

The 18 kV feeder breaker is the original breaker from the construction of the plant, circa 2005.[356] Similarly, the 18 kV feeder breaker relay is original equipment from the construction of the plant, circa 2005.[357] No other equipment failed during the July 9, 2024 trip.[358]

SCE successfully tested the generator, and returned it to service without further issues.[359] The outage ended on July 13, 2024 at 11:06.[360]

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[350] SCE response to Cal Advocates Data Request 17, Question 101 and 106.

[351] SCE response to Cal Advocates Data Request 17, Question 082.

[352] SCE response to Cal Advocates Data Request 17, Question 106.

[353] SCE response to Cal Advocates Data Request 17, Question 082, 151, 154, 156 and 177.

[354] SCE response to Cal Advocates Data Request 17, Question 040, 055 and 056.

[355] SCE response to Cal Advocates Data Request 17, Question 055, 057, 058, 095, 146 and 194.

[356] SCE response to Cal Advocates Data Request 17, Question 050, 059 and 111.

[357] SCE response to Cal Advocates Data Request 17, Question 051, 060 and 111.

[358] SCE response to Cal Advocates Data Request 17, Question 061.

[359] SCE response to Cal Advocates Data Request 17, Question 101.

[360] SCE-01, at 66, Table III-17, SCE Workpapers, A2504001 SCE-01 Workpapers.pdf, at 231, and SCE response to Cal Advocates Data Request 01 (MDR), Question 1.1.4 to 1.1.13, and Data Request 17, Question 027.

The incident did not violate any in-house SCE procedures and operating instructions, or any other requirements, such as those of the American Society of Mechanical Engineers (ASME) Codes and Standards.[361]

Manufacturer's Advisory on the Electroswitch Relay

During the July 9, 2024 outage, SCE maintenance discovered an issue with the Electroswitch 86 lockout relay (Electroswitch relay).[362] The Electroswitch relay has been under a manufacturer's advisory regarding the lighted nameplate (or faceplate).[363] Electro Switch Corporation, the manufacturer,[364] had issued the advisory on September 19, 2014 (see Figure 3-9).[365] It was only on July 11, 2024, two days after the outage, that SCE received the advisory.[366] According to SCE, it immediately acted upon the information contained in the advisory to further its investigation.[367]

The information contained in the advisory furthered SCE's investigation of the 86RE relay tripping event; the investigation helped SCE conclude that a component failure in the lighted faceplate led to a false reverse-energization signal.[368] Given the component failure in the 86RE relay faceplate, SCE acted on the recommendation in the advisory to consider replacement.[369]

[361] SCE response to Cal Advocates Data Request 17, Question 201.

[362] SCE testimony, SCE-01, at 70, line 7, and at 71, line 5 to 6.

[363] SCE testimony, SCE-01, at 71, line 6 to 7, and SCE response to Cal Advocates Data Request 17, Question 142 and 143.

[364] SCE response to Cal Advocates Data Request 17, Question 111, 132, 136 and 174: Electro Switch Corporation, 180 King Avenue, Weymouth, MA 02188.

[365] SCE response to Cal Advocates Data Request 17, Question 134. 138 and 139.

[366] SCE response to Cal Advocates Data Request 17, Question 141.

[367] SCE response to Cal Advocates Data Request 17, Question 145.

[368] SCE response to Cal Advocates Data Request 17, Question 146.

[369] SCE response to Cal Advocates Data Request 17, Question 146.

SCE explained the applicability of the Electroswitch relay advisory as follows:[370]

"The advisory letter was issued by Electro Switch Corporation on September 19, 2014 (reference attachment "Electroswitch Pre 2009 LNP Product Advisory Note 9-19-14.pdf"). As described in the advisory, customers using Model 658 Lighted Nameplate (LNP) relays were advised to consider replacement of units that may have been exposed to elevated voltage conditions or were exhibiting symptoms such as LEDs [light-emitting diodes] not lit or flashing, intermittent SCADA [Supervisory Control and Data Acquisition] contact alarms, or unintended breaker trips.

"The advisory states:

'Based on the Model 658 LNP data accumulated and the field and lab test performance of the Model 748 LNP, Electroswitch suggests that customers with LNP Model 658 consider replacement where their nameplates may have been exposed to elevated voltage conditions or are exhibiting LNP symptoms as described above.'

"Prior to the 2024 outage, SCE has no record of the nameplate being exposed to elevated voltage or exhibiting other symptoms identified in the advisory that would have supported a recommended replacement. Prior to the outage, the relay had passed all previous testing performed during routine maintenance and was operating within normal expected parameters. As such, SCE does not believe the conditions noted in the advisory were triggered."

SCE added that the advisory was discretionary, and it only recommended considering replacement under certain circumstances; those conditions noted in the advisory were not met.[371] Also, the advisory was discretionary in not specifying a timeline as to when to begin and end the work to be performed.[372] There were no other instruction items in the Electroswitch advisory.[373]

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[370] SCE response to Cal Advocates Data Request 17, Question 134.

[371] SCE response to Cal Advocates Data Request 17, Question 134, 135 and 137.

[372] SCE response to Cal Advocates Data Request 17, Question 134, and 140.

[373] SCE response to Cal Advocates Data Request 17, Question 144.

However, SCE did not explain why it did not receive the Electroswitch advisory until July 11, 2024, two days after the start of the outage on July 9, 2024.[374] SCE stated that it had no record of the 86RE relay being exposed to elevated voltage or exhibiting symptoms related to the lighted nameplate and does not believe such conditions were triggered.[375] Also, SCE argued that it did not discover the problem with the 86RE relay prior to the outage because the relay had passed all previous testing and was operating within normal expected parameters.[376] In addition, SCE added that it tests protective relays on a routine basis, every 6 years. Part of its routine testing included the associated lockout relay and the circuit breaker trip testing; SCE provided two such testing reports.[377]

In its data response on corrective actions, SCE did not state whether it had reached out to other equipment manufacturers as to whether there are outstanding advisories that it did not receive, especially in light of what had happened: there could be other urgent advisories that need paramount attention to prevent equipment failures and/or power outages.

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[374] SCE response to Cal Advocates Data Request 17, Question 141.

[375] SCE response to Cal Advocates Data Request 17, Question 148.

[376] SCE response to Cal Advocates Data Request 17, Question 204.

[377] SCE response to Cal Advocates Data Request 17, Question 205.

Figure 3-9 Electroswitch Product Advisory [378]

ELECTROSWITCH · SWITCHES & RELAYS
UNIT OF ELECTRO SWITCH CORP.

180 King Avenue
Weymouth, MA 02188
Telephone: (781) 335-5200
Fax: (781) 335-4253

<u>Product Advisory Note – Sept 19, 2014</u>

<u>Regarding Lighted Nameplates [LNP] Manufactured Prior to December 2008</u>

LNP Model 658 installed on Lock Out Relays with switch numbers starting with 78P and Breaker Control Switch numbers starting with 24P, 74P and 88P. [Date codes up to and including 0848, the 48th week of 2008]

Electroswitch has received a few isolated reports of incidents concerning Lock Out Relays and Breaker Control Switches with 48VDC and 125VDC Lighted Nameplates (LNPs), Model 658, manufactured in years 2000-2008. Reported LNP symptoms have included the nameplate LEDs not lit or flashing, the SCADA contact alarm on or intermittent and in a very few reported instances, failures resulting in an unintended breaker "trip/open" operation.

High voltage lab testing, well over the maximum allowable ANSI/IEEE C37.90 requirements, concluded that the Model 658 LNPs can be susceptible to circuit damage under these elevated voltages and could in some cases fail resulting in a "trip/open" breaker operation.

Additional lab testing of customer provided in-service Model 658 LNPs, with 10+ years of service with no reported symptoms was completed. All of these units were found to be operating within original specification, still meeting the ANSI/IEEE C37.90 and C37.90.1 requirements, but with some showing circuit discoloration. Evaluation of other returned Model 658 LNPs with reported symptoms have also displayed evidence of similar circuit discoloration. This discoloration, the result of circuit heating, was reproduced in our lab after extended exposure to elevated temperature and high voltage greater than the requirements established by IEEE C37.90.

The Electroswitch LNP Model 748, released in Dec. 2008, has demonstrated reliable performance and durability in the field. In lab tests significantly exceeding the ANSI/IEEE C37.90 requirements, all units tested continued to operate within specification with no evidence of circuit heating or discoloration. Further testing was completed under extreme high voltage test conditions that damaged the Model 748 LNP with none resulting in an unintended "trip/open" operation.

Based on the Model 658 LNP data accumulated and the field and lab test performance of the Model 748 LNP, Electroswitch suggests that customers with LNP Model 658 consider replacement where their nameplates may have been exposed to elevated voltage conditions or are exhibiting LNP symptoms as described above.

Users with Model 658 LNPs with the Molex connector feature may also consider a resistor pack option. The resistor pack when added protects against an unintended breaker "trip/open" operation in the event of a LNP failure, however will not extend the life of the LNP.

Please contact Jackie Carlson at Electroswitch Sales at (781) 607-3333 for further information.

[378] SCE response to Cal Advocates Data Request 17, Question 134.

NERCGADS Cause Code

SCE classified the July 9, 2024 forced outage event as a NERC Event Type D1.[379] A D1 event is one when there is a forced/unplanned derating that requires an immediate reduction in capacity.[380]

SCE followed NERC GADS protocol when classifying the outage event type as D1, Unplanned (Forced) Derating, that requires an immediate reduction in capacity of Unit 4B.[381] Because the outage only affected the Unit 4B Combustion Gas Turbine (CGT), the Unit 4A CGT and Steam Turbine were not affected and remained in operation, and Unit 4A was not derated.[382]

SCE also classified this outage with Cause Code 4810,[383] described as "generator output breaker" because the unit's 18kV generator circuit breaker tripped, resulting in the forced outage.[384] Although the root cause of the trip was traced to a component failure within the Electroswitch 86RE lockout relay, the direct operational impact was the opening of the generator output breaker.[385]

In accordance with NERC GADS guidance, when reporting an event, utilities are instructed to "select the code which best describes the cause or component responsible for the event."[386] According to SCE, GADS Cause Code 4810 most closely aligns with the observable effect of the event - the breaker trip - which is the basis for categorizing

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[379] SCE testimony, SCE-01, at 66, Table III-17, and SCE response to Cal Advocates Data Request 01 (MDR), Question 1.1.13: Excel File 2024 A2304XXX PAO-SCE-MDR-001 Q1.1.4-Q1.1.13 Fossil-fueled-CONFIDENTIAL.xlsx, and Data Request 017, Question 030.

[380] SCE response to Cal Advocates Data Request 17, Question 029, 030 and 033 [North American Electric Reliability Corporation Generating Availability Data System (NERC GADS) Data Reporting Instructions (33_NERC GADS Data Reporting Instructions.pdf)].

[381] SCE response to Cal Advocates Data Request 17, Question 029.

[382] SCE response to Cal Advocates Data Request 17, Question 029.

[383] SCE response to Cal Advocates Data Request 01 (MDR), Question 1.1.13: Excel File 2024 A2404XXX PAO-SCE-MDR-001 Q1.1.4-Q1.1.13 Fossil-fueled-CONFIDENTIAL.xlsx.

[384] SCE response to Cal Advocates Data Request 17, Question 032.

[385] SCE response to Cal Advocates Data Request 17, Question 032.

[386] SCE response to Cal Advocates Data Request 17, Question 032.

GADS events.[387] The relay failure initiated the trip, but the breaker actuation was the proximate cause of the unit derate and outage.[388] SCE adds that this classification ensures consistency with GADS reporting standards and allows for accurate benchmarking and performance tracking across similar events industry-wide.[389]

In addition to reporting the Event Types and GADS Cause Codes to NERC, SCE currently shares its NERC GADS information with the WECC and in SCE's annual ERRA Compliance proceeding.[390] Besides WECC and the CPUC, SCE did not state that it had provided or shared its NERC GADS information to any other party/person for the 2024 Record Period.[391]

Besides outages, there are no other events for which SCE must assign and report NERC Event Types and GADS Cause Codes.[392] SCE added that it did not receive any request from any entity for follow-up documentation for the 2024 Record Period.[393]

Unit Restoration

Cal Advocates requested that SCE explain why the repair and restoration of the unit took 3.757 days.[394] In addition to providing a timeline of the time spent on the July 9, 2025 outage, as shown in Table 3-1, SCE adds the following explanations:[395]

The duration of the July 9, 2024 outage was driven by the need to identify and resolve a component failure within the Unit 4B 86RE lockout relay control circuit.[396] The trip occurred unexpectedly at full load, and the source of the trip was not

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[387] SCE response to Cal Advocates Data Request 17, Question 032.

[388] SCE response to Cal Advocates Data Request 17, Question 032.

[389] SCE response to Cal Advocates Data Request 17, Question 032.

[390] SCE response to Cal Advocates Data Request 17, Question 035.

[391] SCE response to Cal Advocates Data Request 17, Question 035.

[392] SCE response to Cal Advocates Data Request 17, Question 034 and 035.

[393] SCE response to Cal Advocates Data Request 17, Question 036 and 037.

[394] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[395] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[396] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

immediately evident.[397] SCE prioritized safety, reliability, and thorough investigation over speed, acting prudently to ensure system integrity before returning Unit 4B to service.[398]

SCE's response included methodical testing, wiring verification, coordination with the relay manufacturer, and implementation of temporary monitoring solutions.[399] The outage duration reflects the time required to complete these activities and to validate the unit's readiness for safe operation.[400]

The contractor or vendor assisting SCE during the outage was Electrical Systems Testing.[401] Their work included working with SCE Test Technicians in troubleshooting the 86RE relay trip, in performing protective relay testing, wiring verification, and coordination of SEL monitoring setup.[402]

All post-outage work was performed by SCE Test Technicians.[403] Their work included final verification of relay logic and wiring, completion of SEL monitoring configuration, and operational testing of Generator 4B prior to release for service.[404]

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[397] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[398] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[399] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[400] SCE response to Cal Advocates Data Request 17, Question 179, 180 and 210.

[401] SCE response to Cal Advocates Data Request 17, Question 084, 107, 131, 171 and 183: Electrical Systems Testing , 16458 Bolsa Chica Road, Suite 233, Huntington Beach, CA 92649.

[402] SCE response to Cal Advocates Data Request 17, Question 183.

[403] SCE response to Cal Advocates Data Request 17, Question 183.

[404] SCE response to Cal Advocates Data Request 17, Question 183.

Table 3-1 Unit 4B Trip Timeline[405]

Date & Time	Activity Description	Duration
07/09/2024 17:00	Unit 4B GT 18kV breaker tripped at full load. Initial alarm: 'Load Reject – Generator Breaker Trip via 86RE.'	
07/10/2024 16:23	Began troubleshooting relay logic, settings, and wiring. 86RE relay found tripped. Further investigation initiated.	23 hrs
07/11/2024 15:13	Identified Electroswitch relay under manufacturer advisory. Disabled lighted nameplate. Installed temporary SEL monitoring and power quality meter. Verified 86RE circuit wiring.	28 hrs
07/12/2024 20:12	Coordinated with Electrical Systems Testing. SEL 300G tested and passed. Beckwith relay review attempted but not completed due to software issues.	13 hrs
07/13/2024 08:59	Completed SEL monitoring setup. Verified signal logging. Conducted operational test run with Generator 4B.	2 hrs
07/13/2024 11:06	Unit 4B released for service.	

SCE annotated Table 3-1 with the following comments:

(a) The outage response was timely and thorough. The trip source was not immediately evident, and SCE prioritized safety and reliability over speed in its investigation.

(b) The affected relay was original equipment from 2005 and had not been flagged for replacement prior to the outage. While standard relay components are stocked, temporary bypass solutions were implemented to expedite restoration once the issue was identified. Replacement parts were ordered for the replacement program and received in October 2024, and replacements were completed between October 12, 2024 and April 27, 2025.

(c) SCE did not perform a formal benefit/cost study specific to this component. The failure was due to a manufacturer defect. SCE has since initiated a proactive replacement program for similar relays to mitigate future risk.

SCE Cal Advocates finds the expended outage time and explanation provided by SCE to be reasonable.

[405] SCE response to Cal Advocates Data Request 17, Question 179 and 210.

Post-Mortem and Corrective Actions

SCE undertook the following steps and actions before returning Unit 4 to service:[406]

(a) Completed SEL monitoring setup and verified signal logging (86COILMON and 86CONTACTMON).

(b) Installed Fluke Power Quality Analyzer to monitor voltage and current.

(c) Performed point-to-point wiring checks on the 86RE circuit.

(d) Tested SEL 300G relay and reviewed Beckwith relay logic.

(e) Verified no additional faults or trip signals.

(f) Conducted operational test run with Generator Unit? 4B.

(g) Released the generator back to operations.

The activities regarding the parts/equipment that were replaced were:[407]

(a) The 86RE lockout relay Lighted Name Plate (LNP) was identified as the source of the trip and was replaced.

(b) All affected Electroswitch LNPs of the same model and vintage at Mountainview were also replaced as a precaution, given the false tripping event.

In addition, to prevent the recurrence of similar incidents, SCE acted on the following:[408]

(a) Configuring SEL 300G inputs to monitor 86RE coil and contact status.

(b) Installing a Fluke Power Quality Analyzer to monitor voltage and current.

(c) Verifying 86RE circuit wiring and relay logic.

(d) Testing SEL 300G; Beckwith relay reviewed but not tested due to software issues.

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[406] SCE response to Cal Advocates Data Request 17, Question 157.

[407] SCE response to Cal Advocates Data Request 17, Question 213.

[408] SCE response to Cal Advocates Data Request 17, Question 212.

(e) Replacing all affected Electroswitch relays with lighted nameplates.

(f) SCE requested that Electroswitch update their distribution list to include critical key SCE stakeholders when advisories are issued.

The information contained in the Electroswitch advisory furthered SCE's investigation of the 86RE relay tripping event; the investigation helped SCE conclude that a component failure in the lighted faceplate led to a false reverse-energization signal.[409] Given the component failure in the 86RE relay faceplate, SCE acted on the recommendation in the advisory to consider replacement.[410]

Only the 86RE relay, and no others, actuated during the event.[411] However, multiple relays of the same type and vintage were identified across the Mountainview Station.[412] Following this event, SCE initiated a replacement plan to proactively address the risk of false trips in similar units.[413]

All of the Electroswitch relays at Mountainview were inspected and those of the same model and vintage as the affected 86RE relay that tripped had their lighted name plate replaced.[414] SCE initiated a replacement program for all lighted nameplates for Electroswitch 86 relays of the same vintage (pre-2008) as the 86RE relay that tripped.[415]

The program included scheduled replacement, verification of wiring, and bypassing illumination circuits where necessary to prevent false trips.[416] New LNPs were ordered and received in August 2024, and the replacements were completed between August 17, 2024 and April 27, 2025.[417] All remaining replacements were completed

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[409] SCE response to Cal Advocates Data Request 17, Question 146.

[410] SCE response to Cal Advocates Data Request 17, Question 146.

[411] SCE response to Cal Advocates Data Request 17, Question 110.

[412] SCE response to Cal Advocates Data Request 17, Question 110.

[413] SCE response to Cal Advocates Data Request 17, Question 110.

[414] SCE response to Cal Advocates Data Request 17, Question 146 and 206.

[415] SCE response to Cal Advocates Data Request 17, Question 120.

[416] SCE response to Cal Advocates Data Request 17, Question 120.

[417] SCE response to Cal Advocates Data Request 17, Question 146 and 147.

between October 12, 2024 and April 27, 2025.[418] SCE provided an Excel spreadsheet showing the affected relays and their replacement dates.[419]

As an additional precaution, all supervisors and electrical Test Technicians within other areas of the Generation Department were informed of the situation and provided a copy of the advisory.[420]

However, SCE did not explain why it did not receive the September 19, 2014 Electroswitch advisory till July 11, 2024, two days after the start of the outage on July 9, 2024.[421] SCE only became aware, during additional troubleshooting, that the manufacturer of the 86RE relay had issued an advisory for the LNP.[422] Had SCE received the notification shortly after September 19, 2014, the date of the Electroswitch advisory, SCE alluded that it would not have acted on it because the circumstances mentioned in the Electroswitch advisory did not prevail. SCE stated that it had no record of the 86RE relay being exposed to elevated voltage or exhibiting symptoms related to the lighted nameplate and does not believe such conditions were triggered.[423] Also, SCE argued that it did not discover the problem with the 86RE relay prior to the outage because the relay had passed all previous testing and was operating within normal expected parameters.[424] In addition, SCE added that it tests protective relays on a routine basis, every 6 years. Part of its routine testing included the associated lockout relay and the circuit breaker trip testing; SCE provided two such testing reports.[425]

In Cal Advocates' data request on SCE's post-mortem and corrective action activities, SCE did not identify all relevant actions comporting to the Commission's

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[418] SCE response to Cal Advocates Data Request 17, Question 208.

[419] SCE response to Cal Advocates Data Request 17, Question 206.

[420] SCE response to Cal Advocates Data Request 17, Question 206.

[421] SCE response to Cal Advocates Data Request 17, Question 141.

[422] SCE response to Cal Advocates Data Request 17, Question 085 and 177.

[423] SCE response to Cal Advocates Data Request 17, Question 148.

[424] SCE response to Cal Advocates Data Request 17, Question 204.

[425] SCE response to Cal Advocates Data Request 17, Question 205.

Reasonable Manager Standard. SCE did not mention whether it had reached out to Electro Switch Corporation or other manufacturers as to whether there are outstanding advisories that it did not receive, especially in light of what had happened: there could be other urgent advisories that need paramount attention to prevent equipment failures and/or power outages. In addition, SCE did not mention whether its in-house purchasing and operational procedures should be changed/modified to require communication between SCE and all of its equipment manufacturers to receive equipment advisories.

When Cal Advocates asks whether SCE's current operation and maintenance practices failed to prevent this outage and what SCE had done to revise the operation and maintenance practices to prevent its recurrence, SCE responded that its SCE's operation and maintenance practices were not the cause of the July 9, 2024 outage.[426] Post-mortem actions require proactive and not just reactive remedial solutions.

SCE's reactive post-mortem response activities to this July 9, 2024 incident were to:

(a) initiate a replacement program for all Electroswitch relays with lighted nameplates matching the model and vintage of the affected 86RE relay.[427]

(b) inform all supervisors and electrical Test Technicians within other areas of the Generation Department of the situation and provide a copy of the advisory.[428]

(c) reinforce its oversight protocols following the July 2024 Unit 4B outage by ensuring that all relay testing, wiring verification, and equipment commissioning activities were reviewed and approved by Generation Management.[429]

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[426] SCE response to Cal Advocates Data Request 17, Question 207.

[427] SCE response to Cal Advocates Data Request 17, Question 208.

[428] SCE response to Cal Advocates Data Request 17, Question 206.

[429] SCE response to Cal Advocates Data Request 17, Question 211, 214 and 215.

(d) coordinate closely with Electrical Systems Testing to validate relay logic, perform point-to-point wiring checks, and confirm proper operation before returning Unit 4B to service.[430]

(e) initiate a station-wide inspection and replacement program for all affected Electroswitch relays.[431] and

(f) request that the manufacturer [Electro Switch Corporation] update its advisory distribution list to include key SCE stakeholders.[432] SCE did not state that it would ask Electro Switch for any past advisories that it had not received.

Some proactive actions, for example, would be for SCE to find out why it never did receive Electro Switch Corporation's said advisory, to consider whether its purchase orders for equipment purchases should be changed to mandate mandatory advisory notifications, and to ascertain, from all its equipment manufacturers, not just Electro Switch Corporation, whether there are advisories that SCE had not received.

SCE should compile a list of all plant equipment (not just relays) that are critical for operational readiness, and develop a communication protocol with the manufacturers to ensure that SCE is promptly notified of any equipment advisories. The communication protocol could be mandated as part of SCE's equipment purchase orders and/or service contracts.

Finally, SCE did not mention, in its corrective actions, any commitment to repair the Beckwith M-3425A relay, which could not be tested due to technical issues with the testing software.[433] If the relay needs to be tested, then it must be important for the integrity of plant operations.

Post-mortem corrective actions are not just correcting the known problems, but also to institute proactive actions to preclude their recurrences. SCE's lapses in post-mortem actions do not comport to the Commission's Reasonable Manager Standard.

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[430] SCE response to Cal Advocates Data Request 17, Question 211 and 214.

[431] SCE response to Cal Advocates Data Request 17, Question 211.

[432] SCE response to Cal Advocates Data Request 17, Question 211.

[433] SCE response to Cal Advocates Data Request 17, Question 085, 151, 154, 156 and 177.

SCE did not prepare any Root Cause Evaluation (RCE) Report for this event; however, SCE provided the Generation Incident Report in its Workpapers A.25-04-001 ERRA Review of Operations 2024.[434]

Depreciation and Life Expectancy

Mountainview Station has a 35-year depreciable life that was authorized in D.15-11-021, issued in SCE's 2015 General Rate Case .[435] Its 35-year depreciation life follows the plant's asset schedule.[436] This 35-year life is from the in-service date of 2005, resulting in a terminal date of December, 2040 and a remaining life of 16 years (as of year-ending for the 2024 Record Period).[437] SCE depreciates the entire facility and its assets over this lifespan and the individual parts in question do not have a separate depreciable life from the rest of the facility.[438]

The Electroswitch lockout relay has an expected operational life of 20–25 years under standard conditions.[439] In general, life expectancy reflects physical reliability and expected operational lifespan while depreciation life is an accounting measure tied to the broader facility's financial schedule and does not necessarily reflect actual wear or failure risk.[440]

Cost of Outage

The trip was not due to non-compliance with the advisory.[441] As discussed in response to Cal Advocates' Data Request Questions 134 and 137, the manufacturer's advisory was not a mandatory compliance requirement but rather a conditional

[434] SCE response to Cal Advocates Data Request 17, Question 202 and 203.

[435] SCE response to Cal Advocates Data Request 17, Question 197 and 198.

[436] SCE response to Cal Advocates Data Request 17, Question 113 and 116.

[437] SCE response to Cal Advocates Data Request 17, Question 197 and 198.

[438] SCE response to Cal Advocates Data Request 17, Question 197 and 198.

[439] SCE response to Cal Advocates Data Request 17, Question 112 and 115.

[440] SCE response to Cal Advocates Data Request 17, Question 114 and 117.

[441] SCE response to Cal Advocates Data Request 17, Question 148 and 149.

recommendation to consider replacement if certain circumstances had been met.[442] SCE has no record of the 86RE relay being exposed to elevated voltage or exhibiting symptoms related to the LNP and does not believe such conditions were triggered.[443]

The 86RE relay is an Electroswitch lockout relay with an expected operational life of 20–25 years under standard conditions.[444] Its depreciation life follows the plant's asset schedule, which is 35 years, as authorized in SCE's 2015 General Rate Case D.15-11-021.[445], [446]

All 86 Lockout relays, including the affected 86RE, were installed during original plant construction, and have been in service since 2005.[447]

The cost of the outage consists of two components: 1) the cost of energy purchased to replace the unavailable generation facility, and 2) the cost of the repair work at Unit 4B.

The July 9, 2024 Unit 4B forced outage resulted in a replacement power cost of $852,053 to ratepayers.[448] SCE objected to Cal Advocates' query as to whether SCE sought reimbursement from any vendor for that cost.[449] Instead, SCE responded, "SCE does not believe there is any contractor at fault for the 86RE relay trip event. SCE is not aware of any instance in which power plant component suppliers, or providers of power plant maintenance services, offer direct reimbursement of costs as part of their routine product offerings to their customers after over 20 years of service."[450] While SCE did not

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[442] SCE response to Cal Advocates Data Request 17, Question 148.

[443] SCE response to Cal Advocates Data Request 17, Question 148.

[444] SCE response to Cal Advocates Data Request 17, Question 112 and 115.

[445] *Decision on Test Year 2015 General Rate Case for Southern California Edison Company* issued in A.13-11-003.

[446] SCE response to Cal Advocates Data Request 17, Question 113 and 116.

[447] SCE response to Cal Advocates Data Request 17, Question 050, 059 and 111.

[448] SCE response to Cal Advocates Data Request 17, Question 181.

[449] SCE response to Cal Advocates Data Request 17, Question 182 and 196.

[450] SCE response to Cal Advocates Data Request 17, Question 182 and 196.

answer the question that was asked, Cal Advocates infers from that statement that SCE did not seek any reimbursement.[451]

Bechtel Corporation[452] was the original contractor that performed the engineering, procurement, and construction (EPC) contract for Mountainview Station around 2005.[453] SCE had no record of previous work performed by contractors on the 86RE relay, and did not mention whether it had any active warranty with Bechtel Corporation to defray part of the repair and replacement power cost.[454]

Another original contractor was General Electric Company (GE).[455] Its role was to install and commission original equipment, including combustion turbines and associated control systems around 2005.[456] SCE had no record of previous work performed by contractors on the 86RE relay, and did not mention whether it had any active warranty with GE to cover part of the repair and replacement power cost.[457]

The warranty period for the failed 86RE relay was one year from the date of shipment, and it was installed during the original construction of Mountainview Station around 2005.[458] It had not been replaced prior to the July 9, 2024 outage.[459] Therefore, SCE had no basis to seek any compensation from Electro Switch Corporation.

The 86RE relay was in service from 2005[460] until its failure in 2024, a service life of 19 years. In general, Electroswitch lockout relays have an expected operational life of

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[451] SCE response to Cal Advocates Data Request 17, Question 182 and 196.

[452] SCE response to Cal Advocates Data Request 17, Question 183: Address: 707 Wilshire Blvd, Suite 3088, Los Angeles, CA 90017.

[453] SCE response to Cal Advocates Data Request 17, Question 183.

[454] SCE response to Cal Advocates Data Request 17, Question 183, 190, 191 and 192.

[455] SCE response to Cal Advocates Data Request 17, Question 183: Address: 3601 E. La Palma Ave, Anaheim, CA 92806.

[456] SCE response to Cal Advocates Data Request 17, Question 183.

[457] SCE response to Cal Advocates Data Request 17, Question 183, 190, 191 and 192.

[458] SCE response to Cal Advocates Data Request 17, Question 194 and 195.

[459] SCE response to Cal Advocates Data Request 17, Question 194.

[460] SCE response to Cal Advocates Data Request 17, Question 051, 060 and 111.

20–25 years under standard conditions.[461] Its depreciation life follows the plant's asset schedule, which is 35 years, as authorized in SCE's 2015 General Rate Case D.15-11-021[462], [463] The plant's 35-year depreciation life is more appropriate for major equipment, such as generators and turbines. While the 19-year service life fell slightly short of the 20-25 expected operational life, Cal Advocates contends that the replacement date after the outage was close to the useful-service life period. However, the 86RE relay faceplate failure was not an expected wear-and-tear breakage over time but was due to its design causing false trip signals.[464]

SCE hired Electrical Systems Testing to perform the outage work.[465] The work was performed under the terms of the existing Blanket Purchase Order agreement.[466] SCE's direct repair cost of the outage was $8,764 while SCE's Operation and Maintenance cost was $29,046.39 (labor and materials).[467] SCE's repair cost is recovered through its authorized funding in set forth in D.21-08-036, issued in SCE's 2021 GRC .[468]

Therefore, the total cost of this outage from both replacement power and SCE's direct and contractor cost is $889,863.39 ($852,053 + $29,046.39 + $8,764).

IV. CONCLUSIONS AND RECOMMENDATIONS

After reviewing SCE's testimony and responses to data requests, Cal Advocates recommends the Commission order SCE to:

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[461] SCE response to Cal Advocates Data Request 17, Question 112 and 115.

[462] *Decision on Test Year 2015 General Rate Case for Southern California Edison Company* issued in A.13-11-003.

[463] SCE response to Cal Advocates Data Request 17, Question 113 and 116.

[464] SCE response to Cal Advocates Data Request 17, Question 095.

[465] SCE response to Cal Advocates Data Request 17, Question 186 and 199.

[466] SCE response to Cal Advocates Data Request 17, Question 184, 187 and 189.

[467] SCE response to Cal Advocates Data Request 17, Question 186 and 199.

[468] D.21-08-036 at finding of fact number 438, at 610; issued in A.19-08-013; *see also* SCE response to Cal Advocates Data Request 28, Question 139 and 140.

(a) establish a procedure to ensure that it would receive equipment advisories from manufacturers for all plant equipment (not just 86RE relays) that are critical for operational readiness,

(b) contact Electro Switch Corporation, the manufacturer of the failed 86RE relay, to find out whether there had been advisories that it did not receive prior to July 11, 2024. SCE is to report, in its next ERRA Compliance filing in 2026, the list of those outstanding advisories and SCE's actions on those advisories.

(c) repair the Beckwith M-3425A relay, which could not be tested currently due to technical issues with the testing software.

LIST OF ATTACHMENTS FOR CHAPTER 3

#	Attachment	Description
1	Attachment 3.1 (Confidential)	SCE's Response to Cal Advocate's Data Request #17, Questions 1-32.
2	Attachment 3.2 (Confidential)	SCE's Response to Cal Advocate's Data Request #17, Questions 34-215.
3	Attachment 3.3	SCE's Response to Cal Advocate's Data Request #21, Questions 1-4.

CHAPTER 4: CONTRACT ADMINISTRATION

(Witness: Kayla Lutes)

I. INTRODUCTION AND SUMMARY

This chapter of testimony presents the Public Advocates Office's (Cal Advocates) review of Southern California Edison Company's (SCE) contract administration for Record Period 2024. SCE reported its contract administration activities in its Energy Resource Recovery Account (ERRA) Compliance Application (A.) 25-04-001 (Application) testimony and associated workpapers. Cal Advocates reviewed SCE's administration, modification, and termination of its capacity and energy resource contracts and agreements. Cal Advocates also reviewed SCE's reported contract disputes and any contract modifications that resulted in a notional change in the underlying value of the contract. Cal Advocates conducted its analysis to ensure that SCE prudently administered its contracts for the benefit of ratepayers and in compliance with the California Public Utilities Commission's (Commission) Standard of Conduct 4 (SOC 4).

II. RECOMMENDATIONS

Based on the information SCE provided and Cal Advocates' review and analysis under the standards of review described below in Section IV, Cal Advocates does not object to SCE's contract administration activities and practices for Record Period 2024.

III. REGULATORY BACKGROUND

California Public Utilities Code Section 454.5(d)(2) established "a regulatory process to verify and ensure that each contract was administered in accordance with terms of the contract, and contract disputes that may arise are reasonably resolved." Cal Advocates' review and analysis of an investor-owned utility's (IOU) energy procurement contracts are guided by two major ERRA decisions: Decision (D.) 02-10-062 and

D.02-12-074 (the October and December Decisions, respectively).[469] The October Decision set forth the guidelines for California's three largest IOUs[470] to resume procurement responsibilities following the energy crisis of 2000-2001.[471] The October Decision orders the IOUs to comply with minimum standards of conduct, including SOC 4, which states that, "the utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[472] SOC 4 was modified by the December Decision to include specific terms regarding contract administration:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts... In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs… The utility bears the burden of proving compliance with the standard set forth in its plan.[473]

Commission review and enforcement of SOC 4 helps ensure that the IOUs have "operated [their] resources to produce the lowest possible cost for customers."[474]

IV. DISCUSSION AND ANALYSIS

A. New Contracts

SCE executed 81 conventional and natural gas contracts in the Record Period,[475] one Public Utility Regulatory Policies Act (PURPA) and Combined Heat and Power

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[469] D.02-10-062, *Interim Opinion*, October 24, 2002; issued in Rulemaking (R.) 01-10-024 (the October Decision); D.02-12-074, Interim Opinion, December 19, 2002; issued in R.01-10-024 (the December Decision).

[470] Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and SCE.

[471] D.02-12-074, at 54.

[472] D.02-12-074, at 54.

[473] D.05-01-054, at 5.

[474] D.05-01-054, at 14.

[475] SCE Energy Resource Recovery Account (ERRA) Review of Operations, 2024, Chapters I-II, April 1, 2025, at 78.

(CHP) contract,[476] 11 Renewables Portfolio Standard (RPS) contracts,[477] eight Battery Energy Storage System(s) (BESS) contracts,[478] and zero Central Procurement Entity (CPE) contracts.[479] SCE continued to manage a total of 21 Energy Efficiency (EE), seven Demand Response (DR), 10 Renewable Distributed Generation (DG), and four Permanent Load Shifting (PLS) contracts for a total of 42 Behind the Meter (BTM) contracts.[480] All SCE contracts executed in the Record Period were approved through separate Commission processes; SCE is not seeking approval of any new contracts through the present ERRA Application.

B. Contract Amendments and Modifications

During the 2024 Record Period, SCE executed five BTM contract amendments, two Conventional and Natural Gas contract amendments, five PURPA and CHP contract amendments, 42 RPS contract amendments, and 74 BESS contract amendments.[481] Cal Advocates reviewed SCE's contract amendments and other modifications to determine if SCE met the following criteria:

- Did SCE adequately justify the rationale for the contract amendment?
- Is the contract amendment necessitated by operational needs?
- Is the contract amendment in the best interest of SCE's ratepayers?
- What is the actual or notional value of the contract amendment?
- How is the actual and/or notional value of the amendment accounted for in SCE's expense and/or revenue account?

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[476] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 88.

[477] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 102.

[478] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 133.

[479] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 170.

[480] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 63.

[481] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 42, 58, 67, 82 to 84, and 113 to 117.

Contract amendments that resulted in appreciable changes to the underlying notional value of the contract or other substantive changes are summarized below.

1. Watson Cogen Company LLC (ID 10839)

Watson Cogen Company LLC (Watson Cogen) is a 305 megawatt (MW) cogeneration facility located in Carson, California.[482] SCE executed a Power Purchase Agreement (PPA) with Watson Cogen on April 2, 2022, which the Commission approved in Advice Letter 4767-E. The PPA includes a provision that requires each party to consent to renew the contract for each additional year throughout the 51-month term. SCE and Watson Cogen executed Amendment No. 2 on September 20, 2024, in which both parties agreed to renew the contract [redacted] while maintaining a Net Present Value (NPV) of [redacted].[484]

2. MM Tulare Energy, LLC, LLC (ID 1254)

MM Tulare Energy, LLC is a 1.5 MW biomass facility located in Visalia, California.[485] SCE executed a PPA with MM Tulare Energy, LLC on March 14, 2017 as part of SCE's Renewable Market Adjusting Tariff (ReMAT) program. SCE and MM Tulare Energy, LLC executed a Letter Agreement on February 12, 2024, to [redacted]

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[482] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 68.

[483] [redacted] SCE's Response to Cal Advocate's Data Request Set PubAdv-SCE-020, October 30, 2025, Question 2, Attachment 3.4.

[484] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 68.

[485] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 88.

[redacted].[486] The production damages occurred as a result of a 1.93 GWh shortfall during a 24-month performance measurement period.[487]

The total amount of Guaranteed Energy Production Damages assessed for Performance Measurement Period 5, prior to the amendment, was [redacted].[488] Under the Letter Agreement, SCE shall [redacted] per month from the amounts that would otherwise be due to MM Tulare Energy, LLC for [redacted] SCE shall subtract a final payment of the remaining balance of [redacted] from the amount that would otherwise be due to MM Tulare Energy, LLC for [redacted].[489] SCE states that its customers benefit from this amendment because it supports project viability.[490]

3. Antelope DSR 3, LLC (ID 5262)

Antelope DSR 3, LLC is a 20 MW solar PV facility located in Lancaster, California.[491] SCE executed the PPA with Antelope DSR 3, LLC on August 4, 2016, as part of SCE's 2015 RPS solicitation. SCE and Antelope DSR 3 executed a Letter Agreement on May 14, 2024 to [redacted].[492] The damage amount occurred as result of a 27.46 GWh shortfall during a 24-month performance measurement period.[493]

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[486] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 88.

[487] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 101.

[488] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 2, Attachment 3.1.

[489] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 2, Attachment 3.1.

[490] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 88.

[491] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 93

[492] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 93.

[493] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 104.

The total Product Replacement Damages amount assessed prior to execution of the amendment was [redacted][494] This amount was collected over 11 months following execution of the amendment, commencing with the final payment in April 2024. Applicable interest was also assessed subsequent to execution of the amendment in the amount of [redacted] with the final 11th payment.[495] Cal Advocates supports this amendment because it protects ratepayers by ensuring SCE collects its damages owed by Antelope DSR 3, LLC.[496]

4. Peregrine Energy Storage, LLC (ID 12047)

Peregrine Energy Storage LLC (Peregrine) is a 100 MW battery energy storage facility located in San Diego, California.[497] SCE executed the PPA with Peregrine on December 6, 2021 as part of SCE's Mid-Term Reliability for Offers. SCE and Peregrine executed Amendment No. 5 on May 29, 2024 to address (1) [redacted],[498] (2) an extension of the Expected Initial Delivery Date to June 1, 2025 and an extension of the Initial Delivery Deadline to October 1, 2025, (3) an agreement to share the value of bonus tax credits via price reductions, and (4) a Commission penalty indemnification structure.[499] This amendment was approved on August 22, 2024 via Advice Letter 5316-E.[500]

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[494] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 3, Attachment 3.2.

[495] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 3, Attachment 3.2.

[496] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 3, Attachment 3.2.

[497] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 122.

[498] [redacted] SCE's Response to Cal Advocate's Data Request Set PubAdv-SCE-020, October 30, 2025, Question 3, Attachment 3.5.

[499] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 122.

[500] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 122.

5. Condor Energy Storage, LLC (ID 12046)

Condor Energy Storage, LLC (Condor) is a 200 MW battery energy storage facility located in Grand Terrace, California.[501] SCE executed the PPA with Condor on December 6, 2021, as part of SCE's Minimum Target Requirement Request for Offers (MTR RFO). SCE and Condor executed Amendment No. 4 on May 31, 2024, to provide for the following: (1) to extend the Expected Initial Delivery Date by the provision of Proxy RA Capacity, (2) to require the Seller to achieve the Initial Delivery Date by August 1, 2024, (3) for the Seller to pay liquidated damages for each day of the Proxy RA Period in lieu of Daily Delay Liquidated Damages, (4) for the Seller to provide Notice of its election to extend the Expected Initial Delivery Date by providing Proxy RA Capacity, and (5) for that Seller to deliver 200 MW of Proxy RA Capacity beginning on June 1, 12 2024, and to deliver such Proxy RA Capacity throughout the Proxy RA Delivery Period.[502] Cal Advocates finds these amendments to be reasonable because they support grid reliability by providing additional RA during summer months, impose an enforceable deadline, and protect ratepayers from the cost of a delay.[503]

6. Sonoran West Solar Holdings, LLC (ID 12042)

Sonoran West Solar Holdings, LLC (Sonoran) is a 200 MW battery energy storage project located in Blythe, California.[504] SCE executed Amendment No. 4 with Sonoran on October 28, 2020 as part of SCE's Short-Term Reliability Request for Offers. SCE and Sonoran executed the amendment on August 29, 2024 to document that the parties shall share any net economic benefit resulting from the Federal Tax Credit Legislation.[505] Cal Advocates finds this amendment to be reasonable because it ensures that ratepayers receive their fair portion of any benefit resulting from the Federal Tax Credit.

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[501]SCE ERRA 2024, Ch. I-II, April 1, 2025, at 124.

[502] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 124.

[503] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 124.

[504] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 130.

[505] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 130

C. Contract Terminations

During the 2024 Record Period, SCE terminated eleven BTM contracts, twelve Conventional and Natural Gas contracts, four PURPA and CHP contracts, six RPS contracts, and two BESS contracts.[506] The majority of terminations were due to the contracted terms of obligation expiring. In addition, one BTM contract was terminated when an Event of Default occurred.[507] One Conventional and Natural Gas contract was terminated and consolidated.[508] One CHP contract was terminated when an event of default occurred due to the facility no longer meeting the requirement of an Eligible CHP Facility under the PPA.[509] Finally, two BESS contracts were terminated early due to an Event of Default and a Termination Agreement of contract to remove a nonviable project from SCE's portfolio.[510]

Cal Advocates reviewed SCE's contract terminations described in SCE's testimony and workpapers and issued discovery, as necessary. Cal Advocates concludes that SCE's conduct for contract terminations in the 2024 Record Period was prudent.

D. Disputes and Other Contracting Issues

During the Record Period, SCE had no contract disputes with its counterparties for reasons other than Force Majeure.

E. Force Majeure and Uncontrollable Force Claims

Generally speaking, a force majeure claim is a claim by a party to a contract that seeks to excuse a change in deliveries or availability due to circumstances beyond the party's control. SCE works with parties who make Force Majeure claims to determine

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506 SCE ERRA 2024, Ch. I-II, April 1, 2025, at 48, 61, 72, 108, and 145.

507 SCE ERRA 2024, Ch. I-II, April 1, 2025, at 48.

508 SCE ERRA 2024, Ch. I-II, April 1, 2025, at 61.

509 SCE ERRA 2024, Ch. I-II, April 1, 2025, at 72.

510 SCE ERRA 2024, Ch. I-II, April 1, 2025, at 145.

whether to accept such a claim. Negotiations and third-party arbitration are commonly conducted to resolve a Force Majeure claim.[511]

SCE identified one Conventional, two RPS, and eight BESS counterparties that submitted Force Majeure claims that may have begun or been resolved during the 2024 Record Period.[512] Cal Advocates concludes SCE's administration of Force Majeure claims to be prudent and reasonable. The following paragraphs analyze a selection of force majeure claims resolved in the Record Period that involved protracted discussions among counterparties and/or major resources.

1. Calleguas Municipal Water District (ID 4252)

Calleguas Municipal Water District (Calleguas MWD) is a 1 MW hydroelectric facility located in Camarillo, California.[513] SCE executed the PPA with Calleguas MWD on December 11, 2013 as part of SCE's ReMAT program. On October 28, 2023, Calleguas MWD notified SCE of a potential force majeure event involving droughts, societal behavioral adaptations to climate change, and regulatory requirements and requested to terminate the contract due to force majeure. On March 14, 2024, SCE gave notice to the seller that its claim was rejected because the occurrence was not covered under the definition of force majeure. On May 23, 2024, Calleguas MWD notified SCE of its disagreement with SCE's rejection of Calleguas MWD's potential force majeure claim. SCE is currently reviewing the situation further.[514]

On March 19, 2025, SCE presented an option for Calleguas MWD to shift the project from the existing Re-MAT contract to a PURPA Standard Offer Contract, which does not contain a guaranteed energy production damages provision.[515]

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[511] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 59.

[512] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 99, and 141.

[513]SCE ERRA 2024, Ch. I-II, April 1, 2025, at 100.

[514] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 100.

[515] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 4, Attachment 3.3.

The shift would be effectuated by executing a new PURPA standard offer contract concurrently with the mutual termination of the existing Re-MAT contract. On April 21, 2025, Calleguas MWD confirmed that it desired to move forward with this option, and is currently collecting the information necessary to submit a PURPA application to SCE to initiate the contracting process.[516]

2. Nova Power, LLC (ID 12059)

Nova Power, LLC (Nova II) is a 230 MW battery energy storage facility located in Menifee, California.[517] SCE executed the PPA with Nova II on September 29, 2022 as part of SCE's 2021 MTR RFO. On February 9, 2024, Nova II notified SCE of a force majeure event due to extreme rain on January 22, 2024, causing project schedule delays. On April 9, 2024, Nova II sent an update to the force majeure claim, extending the claim due to additional severe weather episodes through April 5, 2024. On May 3, 2024, Nova II sent a force majeure claim, requesting nine days of schedule relief based on a statistically abnormal number of rain events, which made it difficult for Nova II to make timely progress on multiple construction activities.[518]

On May 13, 2024, SCE sent a notification to Nova II denying the Force Majeure claim due to lack of historical average rain event data to substantiate the claim. Nova II replied on May 23, 2024, disputing SCE's analysis of the weather events experienced at the site and provided expanded historical weather data during the relevant historical and construction periods.[519] On September 5, 2024, based on the additional data provided, SCE acknowledged the weather event was not anticipated and accepted Nova II's Force Majeure claim [redacted]

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[516] SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, October 14, 2025, Question 4, Attachment 3.3.

[517] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 142.

[518] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 142.

[519] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 142.

[redacted][520] SCE considers this claim closed.[521]

F. Energy Delivery Performance Administration

During the Record Period, there were 25 contracts who failed to meet their required targets during the Record Period or had prior period replacement damage amounts settled during the Record Period.[522] Cal Advocates finds these contracts to be reasonable, and all energy replacement damage amounts were paid to SCE or netted from SCE's payment to the seller.[523]

G. Other Contract Administration Activities

1. California Independent System Operator Corporation (CAISO)

No CAISO System Emergencies were experienced that required action during the Record Period.

2. Western Community Energy Bankruptcy

On May 24, 2021, Western Community Energy (WCE) declared a fiscal emergency and filed for federal bankruptcy protection.[524] On July 12, 2021, SCE submitted Advice Letter 4541-E to set forth the re-entry fee calculation pursuant to SCE's Rule 23. On February 15, 2022, a settlement agreement was approved requiring WCE to pay SCE $6 million for SCE's secured claims in the bankruptcy case, 50 percent (%) of which was allocated to the re-entry fee claim. SCE began billing former WCE customers for the unrecovered re-entry fee amount pursuant to Advice Letter 4813-E in October 2022.[525]

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[520] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 142.

[521] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 142.

[522] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 71 and 101 to 107.

[523] SCE ERRA 2024, Ch. I-II, April 1, 2025, at 71 and 101 to 107.

[524] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 146-147.

[525] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 146-147.

In January 2024, SCE determined that it recovered a total of $6,232,698 in 18 Residual Re-Entry Fees from the former WCE customer service accounts with cost responsibility.[526] Applying the final Residual Re-Entry Fee amount of $5,220,043, SCE recovered $1,012,655 more than needed to satisfy the final WCE Residual Re-Entry Fee amount.[527] Starting in March 2024, SCE issued bill credits totaling $1,012,655 plus interest to the former WCE customer service accounts that paid the Residual Re-Entry Fees.[528] SCE used the same allocation methodology authorized in Advice Letter 4813-E to issue the bill credits.[529] SCE added a bill message to applicable customers' bills to explain the bill credit.[530] SCE anticipates no further activity on its claims and cost recovery related to the WCE Bankruptcy.[531]

3. Central Procurement Entity (CPE)

Beginning in 2023 and pursuant to D.20-06-002, SCE served as the CPE within its Transmission Access Charge area, procuring local RA requirements on behalf of Load Serving Entities (LSE) therein.[532] The CPE contracts administered by SCE during the Record Period include local RA transactions contracted under short-term RA Confirmation Letters. SCE received three new declarations submitted by the participating LSEs during the Record Period to show local RA attributes to the CPE for the 2025 through 2027 compliance periods for no compensation (the LSE was to retain system and flexible RA attributes).

However, the Commission's Decision on Track 2 Issues (D.24-12-003) issued on December 12, 2024, in Rulemaking 23-10-011, eliminated the non-compensated self-

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[526] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 147.

[527] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 147.

[528] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 147.

[529] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 147.

[530] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 147.

[531] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 148.

[532] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 149-150.

showing option from the CPE framework and required the CPEs to send a letter to LSEs with active self-show attestations nullifying any remaining commitments in future years.[533] SCE sent the required letters to comply with D.24-12-003.[534] There were zero CPE contracts, zero amendments, two consents, and zero terminations to report during the Record Period. CPE contracts executed during the Record Period were filed through either the 2024 Annual Compliance Report in conformance with the guidelines in SCE's Assembly Bill 57 Bundled Procurement Plan or through the advice letter or application processes. [535]

V. CONCLUSION

To determine the reasonableness of SCE's actions as a contract manager, Cal Advocates analyzed SCE's testimony, issued data requests, and gathered information about specific contracts in SCE's portfolio that were modified, terminated, or involved in contract disputes. Cal Advocates also reviewed SCE's general contract administration activities. Following this review and analysis, Cal Advocates does not object to SCE's contract administration activities and practices for Record Period 2024.

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[533] D.24-12-003, Issued in Rulemaking (R.) 23-10-011, *Decision on Track 2 Issues,* December 5, 2024.

[534] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 149.

[535] SCE ERRA 2024, Ch. I-II, April 3, 2025, at 149-150.

LIST OF ATTACHMENTS FOR CHAPTER 4

#	Attachment	Description
1	Attachment 4.1 (Confidential)	SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, Question 2.
2	Attachment 4.2 (Confidential)	SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, Question 3.
3	Attachment 4.3 (Confidential)	SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-016, Question 4.
4	Attachment 4.4 (Confidential)	SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-020, Question 2.
5	Attachment 4.5 (Confidential)	SCE's Response to Cal Advocate's Data Request Set CalAdv-SCE-020, Question 3.

CHAPTER 5: COMPLIANCE AUDIT OF THE ENERGY RESOURCE RECOVERY ACCOUNT (ERRA) AND OTHER BALANCING/MEMORANDUM ACCOUNTS

(**Witnesses**: Brian Lui, Craig Jenquin, and Michael Ammermuller)

I. INTRODUCTION:

In its Application,[536] SCE requests that the California Public Utilities Commission (CPUC or Commission) find its recorded entries into the submitted regulatory accounts (i.e., balancing and memorandum accounts), from January 1, 2024, through December 31, 2024 (2024 Record Period) are appropriate, correctly stated, and in compliance with Commission decisions.[537,538] In addition, SCE requests the Commission approve the recovery or refund of certain regulatory account over- or under-collections.[539] SCE's balancing and memorandum accounts include the Energy Resource Recovery Account Balancing Account (ERRA BA) and forty-four (44) other regulatory accounts.[540]

Cal Advocates selected and reviewed 33 balancing and memorandum accounts submitted in A.25-04-001 based on assessments of internal control environment, financial impact, results of prior reviews, and changes to accounting practices. This chapter presents Cal Advocates' review of the 33 balancing and memorandum accounts selected for the 2024 Record Period.

II. SUMMARY AND RECOMMENDATIONS

Cal Advocates does not object to the accounting entries recorded for Record Period 2024 in the 32 balancing and memorandum accounts listed below:

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[536] Application (A.)25-04-001, *Application of Southern California Edison Company (U 338-E) In Its 2024 Record Period Annual Energy Resource Recovery Account (ERRA) Review Proceeding*, April 1 2025.

[537] A.25-04-001, SCE Confidential Direct Testimony Exhibit SCE-02, Chapter IV (SCE-02C, Ch.4) at 24 lines 10-12.

[538] A.25-04-001, SCE Direct Testimony Exhibit SCE-04 (SCE-04), at 6 lines 21-22.

[539] SCE-02C, Ch.4 at 24 lines 13-15.

[540] SCE-02C, Ch.4 Table IV-13 at 28.

- Energy Resource Recovery Account Balancing Account (ERRA BA)
- Public Purpose Programs Adjustment Mechanism (PPPAM)
- California Alternative Rates for Energy (CARE) Balancing Account (CBA)
- Medical Programs Balancing Account (MPBA)
- Pension Costs Balancing Account (PCBA)
- Post-Employment Benefits Other Than Pensions Balancing Account (PBOP BA)
- Short-term Incentive Programs Memorandum Account (STIPMA)
- Charge Ready Program Balancing Account (CRPBA)
- Green Tariff Marketing, Education, & Outreach Memorandum Account (GTME&OMA)
- Enhanced Community Renewables Marketing, Education, & Outreach Memorandum Account (ECRMA&OMA)
- Green Tariff Shared Renewables Administrative Costs Memorandum Account (GTSRACMA)
- Green Tariff Shared Renewables Balancing Account (GTSRBA)
- Local Capacity Requirement Products Balancing Account (LCRPBA)
- Transportation Electrification Portfolio Balancing Account (TEPBA)
- Underground Structures Replacement Balancing Account (USRBA)
- Portfolio Allocation Balancing Account (PABA)
- Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA)
- Emergency Load Reduction Program Balancing Account (ELRPBA)
- Emergency Reliability Energy Storage Balancing Account (ERESBA)
- AB1X Balancing Account (AB1XBA)
- Faily Electric Rate Assistance Balancing Account (FERABA)
- High Distributed Energy Resources Consulting Fund Balancing Account (HiDERCFBA)
- Modified Cost Allocation Mechanism Balancing Account (MCAMBA)
- San Joaquin Valley Data Gathering Plan Memorandum account (SJVDGPMA)

- Residential Rate Implementation Memorandum Account (RRIMA)
- Integrated Resource Planning Costs Memo Account (IRPCMA)
- Summer Reliability Demand Response Program Memorandum Account (SRDRPMA)
- Percentage of Income Payment Plan Memorandum Account (PIPPMA)
- Interruption Cost Estimate 2.0 Calculator Development Memorandum Account (ICE2MA)
- Climate Adaptation Vulnerability Assessment Memorandum Account (CAVAMA)
- Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA)
- New System Generation Balancing Account (NSGBA)

However, Cal Advocates recommends that the Commission disallow the calculated interest of $91,412.54 on the California Air Resources Board (CARB) transactions recorded to the Base Revenue Requirement Balancing Account (BRRBA) because the interest amount recovers costs incurred that are inappropriate due to SCE's error, and result in an overstatement of SCE's revenue requirement.

III. REGULATORY BALANCING AND MEMORANDUM ACCOUNTS

A. Applicable Ratemaking Accounts

The revenues, expenses, and ending balances of 33 ratemaking accounts reported by SCE and reviewed by Cal Advocates for the 2024 Record Period are summarized in Table 5-1 below:

Table 5-1[541]
Ratemaking Accounts Reviewed by Cal Advocates
Record Period Ending December 31, 2024

SCE Testimony Reference	Account	Beginning Balance ($000)	Ending Balance ($000)	Balance Change ($000s)
SCE-02C, Table IV-14	ERRA BA	$(195,548)	$(886,481)	$(690,933)
SCE-02C, Table IV-15	BRRBA	$1,452,624	[redacted]	[redacted]
SCE-02C, Table IV-17	PPPAM	$107,781	$198,266	$90,485
SCE-02C, Table IV-18	CBA	$59,410	$103,279	$43,869
SCE-02C, Table IV-19	MPBA	$9,933	$24,992	$15,059
SCE-02C, Table IV-20	STIPMA	$(1,044)	$(0)	$1,044
SCE-02C, Table IV-22	PCBA	$(68,647)	$(65,563)	$3,084
SCE-02C, Table IV-23	PBOP BA	$(15,457)	$(13,218)	$2,239
SCE-02C, Table IV-27	CRPBA	$0	$28,034[542]	$0
SCE-02C, Table IV-30	GTME&OMA	$22	$(85)	$(107)
SCE-02C, Table IV-31	ECRME&OMA	$49	$51	$2
SCE-02C, Table IV-33	GTSRACMA	$554	$2,494	$1,940
SCE-02C, Table IV-34	GTSRBA	$870	$(1,164)	$(2,034)

[541] Table 5-1 summarizes data provided by SCE in SCE-02C, Ch.4 and SCE-04.

[542] Prior to the annual transfer to the BRRBA, NSGBA, and PPPAM.

SCE Testimony Reference	Account	Beginning Balance ($000)	Ending Balance ($000)	Balance Change ($000s)
SCE-02C, Table IV-35	LCRPBA	$0	[redacted][543]	$0
SCE-02C, Table IV-36	TEPBA	$0	$21,196[544]	$0
SCE-02C, Table IV-44	USRBA	$0	$4,136[545]	$0
SCE-02C, Table IV-45	PABA	$617,032	$800,619	$183,587
SCE-02C, Table IV-48	TMNBCBA	$19,111	$24,650	$5,539
SCE-02C, Table IV-51	ELRPBA	$0	$(9,794)[546]	$0
SCE-02C, Table IV-53	ERESBA	$0	$34,192[547]	$0
SCE-02C, Table IV-54	AB1XBA	$0	69[548]	$0
SCE-02C, Table IV-55	FERABA	$0	$14,265[549]	$0
SCE-02C, Table IV-56	HiDERCFBA	$0	$396[550]	$0

[543] Prior to the annual transfer to the BRRBA, NSGBA, and PPPAM.

[544] Prior to the annual transfer to the BRRBA Distribution subaccount.

[545] Prior to the annual transfer to the BRRBA Distribution subaccount.

[546] Prior to the annual transfer to the BRRBA Distribution subaccount.

[547] Prior to the annual transfer to the BRRBA Distribution subaccount and transfer to PABA vintage-2021.

[548] Prior to the annual transfer to the BRRBA Distribution subaccount.

[549] Prior to the annual transfer to the BRRBA and the PPPAM.

[550] Prior to the annual transfer to the BRRBA Distribution subaccount. Cal Advocates notes that in its review of this account that SCE incorrectly included $19,163 in "Overhead" as an expense. SCE acknowledged the error and processed a correction, along with applicable interest calculation (see Attachment 5.1, "SCE Responses to Data Requests" at 1 and 2, and Attachment 5.2 "DR18 Q1 –

(continued on next page)

SCE Testimony Reference	Account	Beginning Balance ($000)	Ending Balance ($000)	Balance Change ($000s)
SCE-02C, Table IV-58	MCAMBA	$3,354	$4,298	$944
SCE-02C, Table IV-59	SJVDGPMA	$0	$644[551]	$0
SCE-02C, Table IV-61	RRIMA	$43,790	$45,976	$2,186
SCE-02C, Table IV-62	IRPCMA	$3,537	$5,434	$1,897
SCE-02C, Table IV-64	SRDRPMA	$35,882	$38,195	$2,313
SCE-02C, Table IV-65	PIPPMA	$770	$1,013	$243
SCE-02C, Table IV-66	ICE2MA	$0	$311	$311
SCE-02C, Table IV-67	CAVAMA	$3,633	$3,824	$191
SCE-02C, Table V-68	PLDPBA	$(13,917)	$4,637	$18,554
SCE-04, Table I-1	NSGBA	$224,876	$54,107	$(170,769)

B. Requested Revenue Requirement Change

SCE seeks a net revenue requirement increase of $3.992 million,[552] including franchise fees & uncollectible (FF&U) amounts associated with the following six accounts: the Residential Rate Implementation Memorandum Account (RRIMA), Integrated Resource Planning Costs Memorandum Account (IRPCMA), Summer

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HIDERCFBA.xlsx." Cal Advocates notes this exception as it otherwise does not object to the other recorded entries to this regulatory account.

[551] Prior to the annual transfer to the PPPAM.

[552] SCE SCE-02C, Ch.4 , Table IV-12 at 25.

Reliability Demand Response Program Memorandum Account (SRDRPMA), Percentage of Income Payment Plan Memorandum Account (PIPPMA), Interruption Cost Estimate 2.0 Calculator Development Memorandum Account (ICE2MA), and Climate Adaptation Vulnerability Assessment Memorandum Account (CAVAMA). During the 2024 Record Period, all six accounts authorized by the Commission were undercollected. A summary of SCE's requested net revenue requirement increase is shown in Table 5-4 below.

Table 5-4[553]
Summary of Requested Revenue Requirement Change

Balancing / Memorandum Accounts	**Requested Revenue Change ($000)**
Residential Rate Implementation Memorandum Account (RRIMA)	$ 1,169
Integrated Resource Planning Costs Memorandum Account (IRPCMA)	$ 1,668
Summer Reliability Demand Response Program Memorandum Account (SRDRPMA)	$ 416
Percentage of Income Payment Plan Memorandum Account (PIPPMA)	$ 197
Interruption Cost Estimate 2.0 Calculator Development Memorandum Account (ICE2MA)	$ 303
Climate Adoption Vulnerability Assessment Memorandum Account (CAVAMA)	$ 195
Net Under-Collected Balance:	$ 3,948
FF&U:	$ 44
Total Revenue Requirement Change:	$ 3,992

[553] SCE SCE-02C, Ch. 4, Table IV-12 at 25.

IV. AUDIT OBJECTIVES, SCOPE, AND PROCEDURES

Cal Advocates conducted its review to determine whether entries recorded in the 33 balancing accounts were appropriate, correctly stated, and compliant with applicable Commission decisions, advice letters, and resolutions. Cal Advocates' audit procedures included, but were not limited to, the following:

- Review of SCE's application testimony, exhibits, workpapers, and data request responses.
- Review of pertinent advice letters and Commission decisions.
- Review of monthly interest rates used for the accounts in question and verification of the interest calculations.
- Review of sample entries recorded in the selected balancing and memorandum accounts. Cal Advocates' sample was judgmentally selected based on the auditors' knowledge, judgment, and opinion.
- Review of source documents, including the examination of invoices and ledger entries, that support the revenues and expenses recorded in the balancing and memorandum accounts.
- Virtual meetings with SCE to review and verify accuracy of account entries and supporting documentation.

V. FINDINGS AND RECOMMENDATIONS

A. BRRBA

SCE recorded a $1.276 million debit (expense) in the Distribution subaccount of the BRRBA (BRRBA-D) for CARB administrative costs approved in its ERRA Forecast. Regarding this expense, SCE states it "inadvertently neglected to record CARB administration costs into the BRRBA-D for 2021 through 2023."[554] From 2021 through 2023, SCE recorded these CARB administrative costs in the ERRA BA and NSGBA prior to the transfer to the BRRBA-D in 2024.[555] As shown in its workpapers, the 2021 CARB administrative costs were initially recorded in the ERRA BA in November 2021,

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[554] SCE-02C, Ch. 4 at 41, lines 20-21.

[555] Attachment 5.1, at 3 and Attachment 5.3, "Response to 2024 ERRA Review DR8 Q2-BRRBA" '1-Summary' tab.

and accrued a total of $37,819.67 in interest before the transfer to the BRRBA-D in 2024.[556] Similarly, the two CARB administrative cost entries in the NSGBA, one in October 2022 and the other in October 2023, accrued a total of $61,532.44 in interest before the transfer to BRRBA-D in 2024.[557] The accrued interest of these "inadvertently recorded" CARB costs were included in the $1.276 million transfer to the 2024 Record Period BRRBA-D.[558]

The BRRBA-D, as a subaccount of the BRRBA, is included in the estimated year-end balances of select regulatory accounts to be collected in future rates for SCE's estimated, on-going revenue requirement; these year-end balances and rates are approved in the relevant ERRA Forecast proceeding.[559] For example, if the 2021 CARB administrative costs recorded in November 2021 in the ERRA BA were correctly recorded to the BRRBA-D, interest would have only been calculated through December 31, 2021 as part of the BRRBA year-end balance, and then collected in rates the following year (i.e. 2022) with final approval by the Commission. Therefore, no additional interest would have accrued beyond December 31, 2021 for the 2021 CARB administrative costs, and thus not included in the revenue requirement for future rates. However, these CARB administrative costs were entered in incorrect accounts, and SCE accrued interest in the ERRA BA beyond December 31, 2021, as well as in the NSGBA beyond December 31 of both 2022 and 2023 (respectively). These costs and accrued

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[556] Attachment 5.3, '1-Summary' tab, and Attachment 5.4, "BRRBA Closing Sheet - Confidential", cells N56 and N57.

[557] Attachment 5.3, '1-Summary' tab, and Attachment 5.4, cells N56 and N57.

[558] Attachment 5.4, cell N57.

[559] The year-end regulatory account balances are estimated in the year-ahead Forecast proceedings for collection in future rates. The final approval of the regulatory account balance though is in the ERRA Compliance proceeding, such as the current proceeding, since all activity in the regulatory accounts submitted for review are included in the ERRA Compliance proceeding. See also Rulemaking (R).25-02-005, *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, issued February 26, 2025, at 3-10.

interest were then transferred to the BRRBA-D in [redacted] of 2024,[560] to be approved as a part of SCE's revenue requirement.[561, 562]

Based on SCE's own processes, both accountants and their manager verify the accuracy of monthly costs and revenues recorded to regulatory accounts.[563] Therefore, these CARB administrative costs should have been recognized as incorrectly recorded in the ERRA BA and NSGBA during the months they were initially recorded, or soon after. If so, these CARB administrative costs and any relevant accrued interest would have been transferred to the BRRBA-D, incorporated as part of the relevant estimated BRRBA year-end balances, and appropriately collected in rates in the subsequent years as part of SCE's revenue requirement. Yet SCE failed to recognize these errors, despite its own internal practices, and continued to imprudently and inappropriately accrue interest on these incorrectly recorded CARB administrative costs in these regulatory accounts.

While Cal Advocates recognizes the CPUC-authorized collection of the CARB administrative costs themselves,[564] plus the relevant interest,[565] the calculated interest outside of the relevant months is inappropriate and is effectively an overstatement of SCE's revenue requirement. SCE should not be permitted to collect the inappropriate

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[560] Attachment 5.4, cells N56 and N57.

[561] Attachment 5.3., "1-Summary" tab.

[562] See SCE Advice Letter 5449-E: *Final Implementation of Southern California Edison Company's Consolidated Revenue Requirement and Rate Change on January 1, 2025*, and also the request for the BRRBA in the current proceeding, namely that the entries in the account are "appropriate."

[563] Attachment 5.1, at 4-6.

[564] See D.20-12-035, *Decision Adopting Southern California Edison Company's 2021 Electric Procurement Cost Revenue Requirement Forecast, 2021 Forecast of Greenhouse Gas-Related Costs, and Power Charge Indifference Adjustment Trigger Mechanism Surcharge*, December 21, 2020, issued in A.20-07-004 et al.; D.22-01-003, *Decision Approving Southern California Edison Company's 2022 Energy Resource Recovery Account-related Forecast Revenue Requirement and 2021 Trigger Mechanism Balance*, January 14, 2022, issued in A.21-06-003 et al.; and D.22-12-012, *Decision Approving Southern California Edison Company's 2023 Energy Resource Recovery Account-related Forecast Revenue Requirement and 2022 Trigger Mechanism Balance*, December 5, 2022, issued in A.22-05-014 et al.

[565] The calculated interest in Nov – Dec 2021 in the ERRA BA ($32.04), and the calculated interest from Oct-Dec 2022 ($3,536.01), and Oct-Dec in 2023 ($4,371.46) in the NSGBA for each year's CARB administrative cost entry; see Attachment 5.3, 'CalAd Interest calcs' tab.

accrued interest from its imprudent monitoring and recording of the 2021, 2022, and 2023 CARB administrative costs at the expense of ratepayers. Therefore, due to SCE's demonstrated imprudent account monitoring, Cal Advocates recommends a disallowance of $91,412.54 from the BRRBA for the inappropriate calculated interest from the inadvertently recorded CARB administrative costs in the ERRA BA and NSGBA.[566]

VI. CONCLUSION

Cal Advocates recommends a disallowance of $91,412.54, the calculated interest from the inadvertently recorded CARB administrative costs in the ERRA BA and NSGBA, from the BRRBA. Cal Advocates does not object to the 2024 accounting entries recorded in the 32 balancing and memorandum accounts listed in Table 5-1. In addition, Cal Advocates does not oppose SCE's requested Revenue Requirement increase of $ 3.992 million related to the undercollection of the RRIMA, IRPCMA, SRDRPMA, PIPPMA, ICE2MA, and CAVAMA.

[566] Attachment 5.3, 'CalAd Interest calcs' tab, cell U17.

LIST OF ATTACHMENTS FOR CHAPTER 5

#	Attachment	Description
1	Attachment 5.1	SCE Responses to Data Requests.pdf
2	Attachment 5.2	DR18 Q1 – HIDERCFBA.xlsx (Available via Email)
3	Attachment 5.3	Response to 2024 ERRA Review DR8 Q2-BRRBA.xlsx (Available via Email)
4	Attachment 5.4 (Confidential)	BRRBA Closing Sheet – Confidential (Available via Email)

CHAPTER 6: GREENHOUSE GAS COMPLIANCE INSTRUMENTS

Cal Advocates is not serving testimony on this chapter.

APPENDIX A
Qualifications of Witnesses

PREPARED TESTIMONY AND QUALIFICATIONS
OF
STANLEY KUAN

Q1. Please state your name, business address, and position with the California Public Utilities Commission ("Commission").

A1. My name is Stanley Kuan and my business address is 505 Van Ness Avenue, San Francisco, California. I work in the Electricity Planning and Policy Branch of the Public Advocate Office of the California Public Utilities Commission (Cal Advocates) as a Regulatory Analyst.

Q2. Please summarize your education background and professional experience.

A2. I graduated from University of California, San Diego with a B.A. in Economics. I also obtained a law degree from the George Washington University Law School. I have been employed by Cal Advocates on the Procurement Cost Recovery team of the Electricity Planning and Policy Branch for five years. Before that, I was an analyst with the Cal Advocates on the Customer Programs team of the Electric Pricing and Customer Programs Branch for four years. I have worked on the Energy Resources Recovery Account (ERRA), the Power Charge Indifference Adjustment (PCIA) Rulemaking (R.17-06-026) and ERRA and PCIA Update and Reform Rulemaking (R.25-02-005), San Joaquin Valley (SJV) DAC proceeding (R.15-03-010), Demand Response Auction Mechanism (DRAM) (Application (A.) 17-01-012, SDG&E Maritime Rate Application (A.17-09-005).

Q3. What is your responsibility in this proceeding?

A3. I am responsible for Chapter 2: Least Cost Dispatch and Demand Response.

Q4. Does this conclude your prepared direct testimony?

A4. Yes, it does.

PREPARED TESTIMONY AND QUALIFICATIONS
OF
MICHAEL AMMERMULLER

Q1. Please state your name, business address, and position with the Commission.

A1. My name is Michael Ammermuller. My business address is 505 Van Ness Ave, San Francisco, California, 94102. I am employed as a Public Utilities Regulatory Analyst in the Public Advocates Office, Electricity Planning & Policy Branch.

Q2. Please summarize your education background and professional experience.

A2. I hold a Master of Science in Economics from the State University of New York – at Buffalo. I joined the CPUC in 2017 and worked in both Energy and Communications Divisions prior to joining the Electricity Policy and Planning Branch at the Public Advocates Office in 2023. My experience at the CPUC includes implementing consumer protection and broadband deployment programs and participating in proceedings for telephone General Rate Cases, Diablo Canyon Power Plant Extended Operations Cost Recovery, and Energy Resource Recovery Account (ERRA) Compliance. My other relevant experience includes three years with Citigroup Inc. (trade settlement, risk management) and 19 months at an Iowa-based electric and gas utility MidAmerican Energy Co. (accounting and finance).

Q3. What is your responsibility in this proceeding?

A3. I am responsible for Chapter 4: Contract Administration, and co-witness for Chapter 5: Compliance Review of the Energy Resource Recovery Account (ERRA) and Other Balancing / Memorandum Accounts.

Q4. Does this conclude your prepared direct testimony?

A4. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
MICHAEL YEO

Q.1 Please state your name, business address, and position with the Commission.

A.1 My name is Michael Yeo. My business address is 505 Van Ness Avenue, San Francisco, California. I am employed by the California Public Utilities Commission as a Senior Utilities Engineer in the Public Advocates Office.

Q.2 Briefly state your educational background and experience.

A.2 I graduated from the University of Toronto with a Bachelor of Applied Science in Civil Engineering, and am a registered Professional Engineer. Since joining the Commission in 1992, I have worked in various assignments in Public Advocates Office, Energy Division and the Consumer Protection and Safety Division. Immediately prior to joining the Commission, I worked for the California Department of Transportation.

Q.3 What is the scope of your responsibility in this proceeding?

A.3 I am responsible for Chapter 3: Utility-Owned Generation – Natural Gas.

Q.4 Does this complete your testimony currently?

A.4 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
KAYLA LUTES

Q.1 Please state your name, business address, and position with the Commission.

A.1 My name is Kayla Lutes. My business address is 505 Van Ness Avenue, San Francisco, CA 94102. I am employed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) as a Public Utilities Regulatory Analyst I in the Electricity Planning and Policy branch.

Q.2 Briefly state your educational background and experience.

A.2 I hold a Master's degree in Public Policy from the University of California San Diego, specializing in Inequality and Social Policy and Environmental Policy. I received my Bachelor of Arts in Political Science from California Polytechnic State University San Luis Obispo. Since joining Cal Advocates, I have sponsored testimony in A. 24-05-020, Bear Valley Electric Service, Inc.'s application to acquire, own, and operate the Bear Valley Solar Energy and Battery Storage. I've also sponsored testimony in A. 25-04-015, SDG&E's application to establish a ratemaking mechanism for energization projects pursuant to Senate Bill 410.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for Chapter 4: Contract Administration.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
BRIAN LUI

Q.1 Please state your name, business address, and position with the Commission.

A.1 My name is Brian Lui. My business address is 505 Van Ness Ave, San Francisco, California, 94102. I am employed by the California Public Utilities Commission (CPUC) as a Public Utilities Financial Examiner in the Public Advocates Office, Electricity Planning & Policy Branch.

Q.2 Please describe your educational and professional experience.

A.2 I hold a Masters Degree in Accounting from Golden Gate University in San Francisco. I also received a Bachelors of Science Degree in Biochemistry from the University of California, Riverside. I joined the Commission on January 7, 2014 in the Public Advocates Office's Electricity Planning and Policy Branch. In the Public Advocates Office, I am involved in the ERRA Forecast and ERRA Compliance proceedings. Immediately prior to joining the Commission, I worked for the California State Board of Equalization as a tax auditor. I have over 9 years of experience working as an auditor in the public sector.

Q.3 What is the scope of your responsibility in this proceeding?

A.3 I am responsible for Chapter 5: Compliance Review of the Energy Resource Recovery Account (ERRA) and Other Balancing / Memorandum Accounts.

Q.4 Does this complete your testimony at this time?

A.4 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
CRAIG JENQUIN

Q.1 Please state your name and business address.

A.1 My name is Craig Jenquin. My business address is 320 4th St, Los Angeles, California, 90013. I am employed by the California Public Utilities Commission (CPUC) as a Public Utilities Regulatory Analyst in the Public Advocates Office, Electricity Planning & Policy Branch.

Q.2 Please describe your educational and professional experience.

A.2 I hold a Bachelors of Science in Applied Mathematics and a Bachelors of Arts in Linguistics from the University of California, San Diego (UCSD). I joined the Commission in August, 2022 in the Electricity Planning and Policy branch of Public Advocates Office in the Procurement Cost Recovery Department. At the Public Advocates Office, I have provided analysis in ERRA Forecast and Compliance proceedings, focused on reviews of balancing accounts, load forecasting, and least-cost dispatch.

Q.3 What is the scope of your responsibility in this proceeding?

A.3 I am co-sponsoring Chapter 5: Compliance Review of the Energy Resource Recovery Account (ERRA) and Other Balancing / Memorandum Accounts

Q.4 Does this complete your testimony at this time?

A.4 Yes, it does.