Application No.:	A.23-04-003
Exhibit No.:	SCE-01
Witnesses:	T. Cameron S. DiBernardo D. Golden R. Hite T. Maddox

SOUTHERN CALIFORNIA EDISON®

(U 338-E)

Energy Resource Recovery Account (ERRA) Review of Operations, 2022 Chapters I-V

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California

April 3, 2023

SCE-01C: Testimony of Southern California Edison Company in Support of its Energy Resource Recovery Account (ERRA) Review of Operations, 2022
Chapters I-V

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EXECUTIVE SUMMARY

In this testimony, SCE:

1. Demonstrates that the 2022 Energy Resource Recovery Account (ERRA) Record Period[1] Fuel and Purchased Power (F&PP) expenses were reasonably incurred;
2. Presents explanations of variances between 2022 forecast and recorded F&PP expenses;
3. Demonstrates that the dispatch of generation resources and related spot market transactions complied with SCE's 2014 Assembly Bill (AB) 57 Commission-approved Bundled Procurement Plan (BPP) and Standard of Conduct 4;
4. Shows that SCE's contract administration activities and management of Utility-Retained Generation (URG) outages were reasonable;
5. Presents the operation of various regulatory accounts (*i.e.*, balancing accounts (BA) and memorandum accounts (MA)). Most of these accounts, *e.g.*, ERRA BA, are audited by the Commission to ensure that recorded entries are accurate and consistent with Commission decisions;
6. Provides support for the recovery of the net under-collected balance of $51.442 million (excluding interest) recorded in the Residential Rate Implementation Memorandum Account (RRIMA), Integrated Resource Planning Costs Memorandum Account (IRPCMA), Summer Reliability Demand Response Program Memorandum Account (SRDRPMA), Climate Adaptation Vulnerability Assessment Memorandum Account (CAVAMA), and the Percentage of Income Payment Plan Memorandum Account (PIPPMA); and,
7. Presents a review of other procurement-related activities and expenses and/or activities and expenses that the Commission has deemed within the scope of ERRA Review proceedings.

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[1] January 1, 2022 through December 31, 2022.

I.

INTRODUCTION

In compliance with Decision (D.) 02-10-062, D.03-07-029, and D.04-01-048, SCE submits its 2022 ERRA Review Application (Application) on April 3, 2023, which sets forth SCE's operations for the Record Period.[2] SCE's supporting testimony is included in Exhibits (Ex.) SCE-01, SCE-02, SCE-03, and SCE-04. SCE's testimony demonstrates, *inter alia*, that for the Record Period: (1) dispatch of generation resources and related spot market transactions complied with SCE's 2014 Commission-approved BPP and Standard of Conduct 4 (SOC 4); (2) procurement expenses eligible to be recovered through the Energy Resource Recovery Account (ERRA) Balancing Account (BA) and Portfolio Allocation Balancing Account (PABA) were accurately recorded; and (3) SCE's contract administration activities and Utility Retained Generation (URG) outage-management operations were reasonable.

D.02-10-062 determined that certain procurement operations should be reviewed annually through the ERRA review proceeding. The review contemplated in D.02-10-062 and D.02-12-074 includes URG expenses and contract administration of existing Qualifying Facility (QF) contracts, bilateral contracts, inter-utility power contracts, and renewable resource contracts. Additionally, D.02-10-062 and D.02-12-074 require a compliance review of the utilities' least-cost dispatch operations of its generation portfolio.

Pursuant to D.02-10-062, SCE is required to set forth the entries recorded in the ERRA BA for review. These entries, along with entries recorded in the Base Revenue Requirement Balancing Account, the Nuclear Decommissioning Adjustment Mechanism, the Public Purpose Programs Adjustment Mechanism, and the California Alternate Rates for Energy Balancing Account, are discussed in Section B of Ex. SCE-02, Chapter IV.[3] The entries recorded in the New System Generation Balancing Account (NSGBA) are discussed in Ex. SCE-04. Sections C through E of Ex. SCE-02,

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[2] SCE is submitting its ERRA Review Application on April 3, 2023, because April 1, 2023 falls on a weekend this year.

[3] SCE's preliminary statements require that the recorded entries be reviewed in SCE's annual ERRA Review proceedings.

Chapter IV discuss the 2022 operations of 38 accounts.[4] Ex. SCE-02, Chapter V, supports the 2022 operations of the Pole Loading and Deteriorated Pole Programs Balancing Account. As summarized in Table IV-12 of Ex. SCE-02, SCE seeks to recover from customers the net under-collected balance, including Franchise Fees & Uncollectibles (FF&U), of $51.442 million (excluding interest)[5] recorded in the Residential Rate Implementation Memorandum Account (RRIMA), Integrated Resource Planning Costs Memorandum Account (IRPCMA), Summer Reliability Demand Response Program Memorandum Account (SRDRPMA), Climate Adaptation Vulnerability Assessment Memorandum Account (CAVAMA), and the Percentage of Income Payment Plan Memorandum Account (PIPPMA).

Pursuant to OP 10 of D.20-12-006, "[f]or the Energy Resource Recovery Account (ERRA) compliance filings, the central procurement entity (CPE) shall: (1) include confidential, market-sensitive information in either a separate chapter of testimony or supplemental testimony, (2) redact the information from public filings, and (3) only allow CPE personnel and support personnel (including contract management, law, and regulatory compliance) to sponsor, prepare, and view non-public versions of the filing."[6] As such, the chapters related to Least Cost Dispatch and Contract Administration is now included in Ex. SCE-03 and the Operation of the New System Generation Balancing Account (NSGBA) is included in Ex. SCE-04.

In June 2021, the Commission issued D. 21-06-014 (PSPS OII Decision) directing the utilities to: (1) agree on one methodology to rely upon in calculating these estimated unrealized volumetric sales and unrealized revenue, (2) include the amount of estimated unrealized volumetric sales and unrealized revenue resulting from Public Safety Power Shutoff (PSPS) events in the ERRA Review proceedings addressing the years in which the PSPS events occurred, (3) detail the method of calculating the amounts of estimated unrealized sales and unrealized revenue in the ERRA Review proceedings, and (4)

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[4] *See* Ex. SCE-02, Table IV-13, lines 7-44, for a list of these accounts. SCE's preliminary statements require that these accounts be reviewed in SCE's annual ERRA review proceeding.

[5] In accordance with SCE's tariffed Preliminary Statements for these accounts, SCE will transfer the interest recorded in these accounts upon issuance of final decision in this proceeding to the applicable revenue balancing accounts to be recovered in rates from customers.

[6] D.20-12-006, p. 50.

report these estimated amounts unrealized sales and unrealized revenue in an annual PSPS report, as directed by the Commission in Rulemaking (R.) 18-12-005. Regarding the submission of this information in any pending ERRA Review or future ERRA Review proceeding, the utility shall request via an email to the Administrative Law Judge (and the service list) whether additional testimony is required on this topic and establish a procedure for submitting this information on an ongoing basis in the ERRA Review proceeding.[7] As such, this requirement is addressed at the end of Exhibit SCE-02.

Finally, SCE requests a net revenue requirement increase of $51.442 million (excluding interest)[8] in 2024 and/or 2025 rate levels upon a Commission finding in this proceeding that the balances in the five accounts, shown in SCE-02, Table IV-12, are reasonable and appropriately recorded in compliance with applicable Commission decisions and resolutions.

A. Organization of Testimony

Exhibits SCE-1 through SCE-6 are organized as follows:

Ex. SCE-01

Chapter I – Introduction
Chapter II – Hydroelectric Generation
Chapter III – Natural Gas Generation
Chapter IV – Other Generation
Chapter V – Nuclear Generation and Fuel

Ex. SCE-02

Chapter I – Natural Gas Procurement
Chapter II – Inventory and GHG Carrying Cost Rates, Collateral Costs, Security and Performance Assurance

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[7] D.21-06-014, OP 1. As described in Exhibit SCE-02, a proposed decision is currently pending Commission approval in Phase 2 of SCE's 2019 ERRA Review proceeding. The final decision may provide specific direction on how SCE is to proceed in this proceeding regarding the PSPS unrealized sales and revenues methodology and implementation.

[8] Includes FF&U.

Chapter III – CAISO Related Costs
Chapter IV – Operation of Ratemaking Accounts
Chapter V – Operation of PLDPBA
Chapter VI – 2021 ERRA Review – ERRA-Related Audit Testimony
Chapter VII – Greenhouse Gas Compliance Instrument Procurement
Chapter VIII – Tehachapi Storage Project
Chapter IX – Public Safety Power Shutoff (PSPS) Unrealized Revenues

Ex. SCE-03

Chapter I – Least Cost Dispatch
Chapter II – Contract Administration and Costs

Ex. SCE-04

Chapter I – Operation of the New System Generation Balancing Account (NSGBA)

Ex. SCE-05

Witness Qualifications and Confidentiality Declarations

Ex. SCE-06

Appendices for Exhibits SCE-01, SCE-02, and SCE-03.

B. Comparison Between the Forecast and Recorded Fuel and Purchased Power Revenue Requirement

In SCE's Record Year 2013 ERRA Review, SCE provided a table that documented the difference between its 2013 forecast ERRA-related costs and SCE's actual recorded 2013 ERRA-related costs.[9] SCE continues to provide this information and this reconciliation has become standard in ERRA Review proceedings. This data is provided for informational purposes only and is not relevant to any compliance or reasonableness review of SCE's actual recorded costs. In Table I-1 below, SCE provides an explanation for variances exceeding plus or minus 10 percent and greater than $5 million.

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[9] This table was provided in response to a request from then-Commissioner Florio at the Commission's Least-Cost Dispatch workshop in A.11-04-001, held on February 25, 2014.

Table I-1
2022 Forecast & Recorded Fuel and Purchased Power Revenue Requirement ($000)

Line	Category	Forecast	Recorded	Variance	Var %	Variance Explanation
1	Utility-Owned Generation (Fuel, Nuclear, and Carrying Costs)	[redacted]	[redacted]	$ 298,949	149%	Lower dispatch from Peakers and Mountainview offset by higher costs related to higher prices for fuel
2	Renewables and QF	[redacted]	[redacted]	$ (100,715)	-4%	Not applicable
3	GTSR Contracts	[redacted]	[redacted]	$ -	0%	Not applicable
4	Conventional Contracts (incl Compliance RA Bilateral Contracts)	[redacted]	[redacted]	$ (116,365)	-11%	Significantly lower generation than forecasted from tolling and dispatchable units
5	ACES	[redacted]	[redacted]	$ (480)	-6%	Costs are lower due to a change in contract start dates of a portion of the portfolio (one contract now starts in 2023)
6	CAM Portfolio CHP	[redacted]	[redacted]	$ 76,797	39%	Costs are higher due to significantly higher prices on fuel, specifically in the summer months and in December
7	LCR	[redacted]	[redacted]	$ 488,315	91%	Higher costs due to higher energy generation from gas fired units and higher fuel prices
8	Direct GHG Costs	[redacted]	[redacted]	$ (46,412)	-30%	Lower than forecasted dispatch from GHG-eligible gas fired units
9	Hedging Costs	[redacted]	[redacted]	$ (179,188)	-280%	Hedges performed better than forecasted and resulted in gains (due to the value of the hedges versus market price) instead of costs
10	ISO Costs	[redacted]	[redacted]	$ 141,091	3348%	Forecast assumed historical 12 month ISO costs would be the same as the current year Actual 2022 ISO costs were higher due to lower revenue from CRR Rents and RA charges offset by variable market neutrality charges (which are based on market activities)
11	Load Procurement Costs	[redacted]	[redacted]	$ 2,019,223	63%	Load was higher than forecasted coupled with higher than forecasted SP15 prices, with most of the additional costs occurring in December
12	RA Sales	[redacted]	[redacted]	$ (509)	0%	Not applicable
13	RPS Sales	[redacted]	[redacted]	$ 17,868	-20%	Actual sales of excess RPS (in Gwh) is lower than forecasted
14	Market Revenues	[redacted]	[redacted]	$ (752,914)	23%	Overall higher dispatch in addition to higher SP15 power prices in the CAISO market
15	Common	[redacted]	[redacted]	$ (367)	-5%	Not applicable
16	Other	[redacted]	[redacted]	$ (45,813)	-4496%	Actual costs contain items that are not forecasted in the ERRA proceeding such as Gas Sales, credit facility upfront fees, consulting services, interest, etc
17	**Grand Total**	[redacted]	[redacted]			

C. **Disallowance Cap**

D.15-11-011 requires SCE to set forth the calculation of the SOC 4 disallowance cap in its ERRA Review applications, and to provide a breakdown of the disallowance cap administrative expenses by procurement functional category.

Pursuant to D.02-12-074, the maximum risk of potential disallowance is set at twice the annual expenditures on administrative expenses for all procurement activities as established in a General Rate Case (GRC). The 2022 administrative expenses for procurement activities that the Commission approved in SCE's 2021 GRC (D.21-08-036) is $23.046 million. Therefore, the maximum potential disallowance for SOC-4 related violation(s) is twice $23.046 million, for a total of $46.092 million, in the 2022 Record Period.[10]

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[10] *See* D.03-06-067.

Table I-2
Standard of Conduct (SOC) 4 Disallowance Cap
($000)

No.	**Administration Expenses for all Procurement Functions**	**2021 GRC Authorized 2022$ (D. 21-08-036) Total**
1	DWR Contract Admin	–
2	URG	2,695
3	Renewables	6,604
4	QFs (including CHP)	1,617
5	Demand-side Resources	1,752
6	Other Admin Exp 1 (includes Tolls, RA Financial, Transmission, CAISO/AFA Activities	10,377
7	Other Admin Exp 2	–
8	Expenses Not Requested in 2021 GRC (e.g. Balancing / Memorandum Accounts)	–
9	All Procurement Activities	**23,046**
		x2
10	Standard of Conduct 4 Disallowance Cap	**46,092**

D. **Safety**

D.16-01-017 approved an amendment to Rule 2.1(c) of the Commission's Rules of Practice and Procedure (Title 20, Division 1, of the California Code of Regulations) to require all applications to identify all relevant safety considerations implicated by the application. One of SCE's core values is to ensure public and employee safety. As such, SCE's dispatch of generation inherently assumes that all power providers are fully compliant with laws, rules, regulations and internally-managed controls to assure that the generating facilities (*i.e.* whether SCE-owned, Power Purchase Agreements (PPA) generation, Resource Purchase Agreements (RPA), or purchased through the California Independent System Operator (CAISO) or other power exchanges) are operated and maintained in a safe working condition. Likewise, SCE's purchasing decisions regarding fuel, SCE's management of air emissions costs (*e.g.*, Greenhouse Gas Cap and Trade costs and other similar costs) and transmission capacity procurement activities also assume the counter-parties to these transactions are fully compliant with laws, rules, regulations and internally-managed controls to assure that their facilities are operated and maintained in a safe working condition.

The safety performance of the contracted counterparties is of concern to SCE but not directly related to SCE's activities at issue in this proceeding, which include sales and purchases of power, fuel, transmission capacity, and air emissions credits and allowances. Nevertheless, these activities do support public and employee safety, as these transactions are an inherent part of assuring a reliable supply of electricity to SCE customers. Costs incurred by SCE to operate and maintain the SCE office and public spaces, shops, warehouses, transmission, distribution, and power plants in a safe condition are reviewed in SCE's GRC Application. In addition, pursuant to D.14-12-025 and D.16-08-018, SCE filed its first Risk Assessment Mitigation Phase (RAMP) on November 15, 2018. On May 13, 2022, SCE filed its 2022 RAMP application pursuant to D.18-12-014 and D.21-11-009, covering the assessment and mitigation of key safety risks facing the company for years 2025-2028. The RAMP reports "provide Commission staff and other parties with the opportunity to analyze and understand the various models and methodologies that the energy utilities will be using to prioritize safety in their GRC proceedings. This prioritization of safety is to be achieved through models and methodologies to assess the energy utility's risk, and the mitigation measures the energy utility plans to take to reduce and minimize such risks."[11]

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[11] D.14-12-025, p. 24.

II.

HYDROELECTRIC GENERATION

SCE operated and maintained 32 hydroelectric generating plants (powerhouses) including 33 dams, 43 stream diversions, and approximately 143 miles of tunnels, conduits, flumes, and flow lines during the Record Period.[12] These resources have an aggregate 1,164 MW of nameplate generating capacity. This chapter demonstrates that SCE's hydro facilities were operated in a reasonable and prudent manner during the Record Period.

A. Characteristics of SCE's Hydro Generation Resources

Hydroelectric generation facilities can be roughly divided into two categories: (1) water storage and conveyance facilities; and (2) powerhouses and associated auxiliary equipment. Hydroelectric storage and conveyance facilities capture, store, and direct water to powerhouse facilities using a series of reservoirs, forebays, flumes, canals, conduits, flowlines, and penstocks. The water arrives at the powerhouse under pressure after having dropped from the forebay elevation, through the penstock, to the powerhouse elevation. At the powerhouse, the potential energy of the pressurized water turns the turbine wheels, causing the turbine and generator to rotate and produce electricity.

Figure II-1 illustrates a typical hydroelectric generating station.

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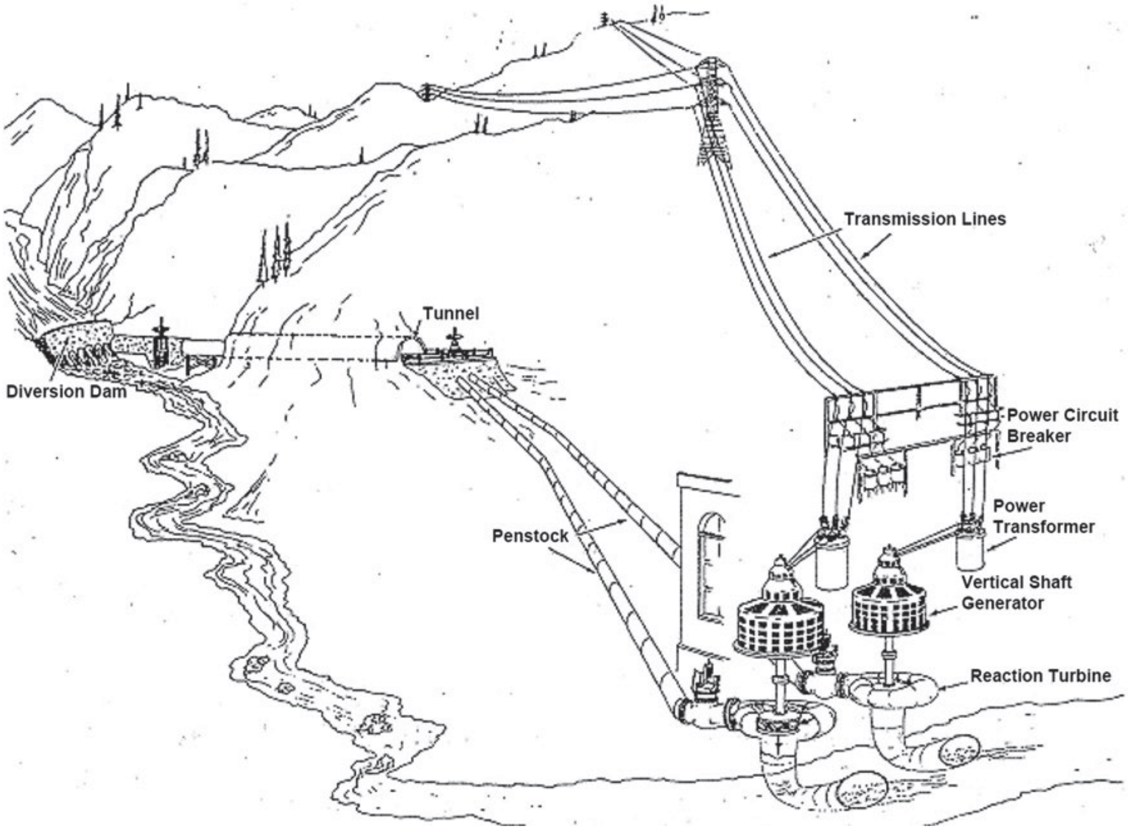
[12] SCE currently has 35 hydroelectric powerhouses of which three, Borel, San Gorgonio 1, and San Gorgonio 2, are no longer in operation. SCE is in negotiations with the Federal Energy Regulatory Commission (FERC) to relinquish the licenses of these facilities.

Figure II-1
Typical Hydroelectric Generating Station



SCE has three types of hydroelectric powerhouses: (1) stream flow or "run-of the-river;"[13] (2) reservoir storage; and (3) pumped storage (powerhouses where the water can be pumped back to a storage facility for reuse during peak hours).

Run-of-the-river facilities operate when water is available in the streams and rivers associated with the project. Water is diverted to the turbine-generators through various water conduits such as open flumes and canals, flowlines, tunnels, and finally into the penstock where it drops to the elevation of the turbine. The water pressure in the penstock is greatest at the bottom where the water turns the turbine.

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[13] A run-of-the-river project typically does not have control of a storage reservoir as part of the project. Although these projects generally have dams that divert water from the river into the hydro project water conveyance facility, the dam impoundment does not store significant amounts water.

Hydroelectric projects with storage facilities extend the window of opportunity for generation months beyond the runoff period by storing water and then releasing it during higher-priced peak power periods.

SCE has one pumped storage facility, the John S. Eastwood Power Station, which is operated as a reservoir storage facility with the added value of pump-back. The pump-back capabilities are used when available water for generation has dropped below full reservoir levels and lower-cost, off-peak power is available to pump back water to the upper reservoir. This operation allows reuse of limited water resources to generate during higher-priced peak operating hours.

B. <u>SCE Hydro Assets</u>

For discussion purposes, SCE's Hydro assets can be divided into two groups, Big Creek and all others. Big Creek encompasses all SCE Hydro facilities in the upper San Joaquin River watershed. These assets are located in the western Sierra Nevada Mountains, across an area that is centered approximately 50 miles northeast of Fresno. Big Creek hydroelectric system includes six major reservoirs, sixteen tunnels through solid granite, and nine powerhouses. Most Big Creek facilities directly connect to the bulk, 220kV power transmission system. In aggregate, the system represents approximately 1,015 MW, or about 87 percent of SCE's total Hydro generation. Most Big Creek facilities have been in service since the early to mid-twentieth century, and some equipment is more than 100 years old.

SCE's remaining small hydro assets are in the Bishop and Mono Basin areas of the eastern Sierra Nevada Mountains, the Kern, Kaweah, and Tule River areas in the southern Sierra Nevada Mountains, and the Ontario, San Bernardino, and Banning areas in the San Gabriel and San Bernardino Mountains. These powerhouses are connected to SCE's sub-transmission or distribution systems and collectively total approximately 149 MW of generating capacity, or about 13 percent of SCE's hydro generation capacity. Most of these assets are run-of-the-river powerhouses, and most have operated since the late-nineteenth and early-twentieth centuries.

Table II-3 below provides the rated MW rated capacity to the nearest one tenth of a MW for SCE's Large Hydro Powerhouses containing units that either by themselves, or in combination, equal or exceed 25 MW. These "large" powerhouses account for approximately 1,071 MW, or 92 percent, of SCE's total Hydro generating capacity.[14]

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[14] Throughout this chapter, SCE defines "large" hydro powerhouses as those having capacities exceeding 25 MW, consistent with the ERRA Review UOG outage reporting requirements established in D.15-03-023. However, note that in other forums "large" powerhouses are defined as those with capacities exceeding 30 MW (*e.g.,* powerhouses with capacities of 30 MW or less qualify as renewable resources under the Renewables Portfolio Standard while those exceeding 30 MW do not). As shown in Table II-3, SCE has one powerhouse that has a capacity between 25 MW and 30 MW*,* Kern River 1.

Table II-3
SCE Large Hydro Powerhouses

Line No.	Powerhouse	Unit	Nameplate Capacity (MW)
1	Big Creek 1	1	19.8
2		2	15.8
3		3	21.6
4		4	31.2
5		Total	88.4
6	Big Creek 2	3	15.8
7		4	15.8
8		5	17.5
9		6	17.5
10		Total	66.5
11	Big Creek 2A	1	55.0
12		2	55.0
13		Total	110.0
14	Big Creek 3	1	34.0
15		2	34.0
16		3	34.0
17		4	36.0
18		5	36.5
19		Total	174.5
20	Big Creek 4	1	50.0
21		2	50.0
22		Total	100.0
23	Big Creek 8	1	30.0
24		2	45.0
25		Total	75.0
26	Eastwood	1	199.8
27		Total	199.8
28	Mammoth Pool	1	95.0
29		2	95.0
30		Total	190.0
31	Kern River 1	1	6.6
32		2	6.6
33		3	6.6
34		4	6.6
35		Total	26.4
36	Kern River 3	1	20.5
37		2	19.7
38		Total	40.2

1. Big Creek

Big Creek utilizes six major reservoirs for water storage, as well as smaller reservoirs that supply some of the powerhouses. The maximum storage for the six major reservoirs is approximately 560,000 acre-feet. Due to operational planning and contractual constraints, the reservoirs are typically lowered during the winter months to minimum levels and filled to maximum levels during spring runoff from melting snowpack. The average annual runoff (with significant yearly variations) from the Big Creek watershed is approximately 1,830,000 acre-feet, with the majority of the runoff occurring during the months of April through August.[15] This creates a challenge for Big Creek to utilize as much of the runoff as possible for generation, while minimizing spill.[16] Once a reservoir reaches a full level, inflows that exceed the hydraulic capacity of the downstream powerhouse will bypass the powerhouse as controlled spill. If an outage occurs at the powerhouse during this time, it will cause an increase of water bypassing the powerhouse as controlled spill. SCE defines the energy in MWh lost due to water bypassing a powerhouse due to an outage as "outage bypassed energy." It is additional generation production that would have been possible had the hydro unit not been out of service.

In the case of a unit outage when reservoirs levels are not at full capacity, SCE can either store the water for later use, or utilize a standby unit. This action does not result in outage bypassed energy. Therefore, many of the unit outages that occur in the fall, winter, or spring may not have associated outage bypassed energy because the water has been routed to other available generating units or stored for generation production at a later date.

a) Powerhouse Arrangement

Big Creek consists of nine powerhouses arranged in essentially three parallel chains in the upper elevations, which then join together in the lower elevations. Water stored in Lake Edison and Florence Lake is channeled to Huntington Lake through the Portal Powerhouse, where it is then divided between the Huntington Chain[17] of powerhouses and the Shaver Chain[18] of powerhouses, which includes Eastwood. Water passing through the Shaver Chain collects in Shaver Lake and is then fed to Dam 5 where it rejoins water passing through the Huntington Chain. Below Dam 5, the water joins flow from the Mammoth Pool Chain at Dam 6, and continues down the mountain through

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[15] California Department of Water Resources, water flow summaries *available at* http://cdec.water.ca.gov/snow/current/flow/index2.html.

[16] Spill is water that is discharged downstream, around or past a given powerhouse, rather than being used by that powerhouse to generate electricity. It is a normal operation that does not pose any incremental risks to safety.

[17] The Huntington Chain utilizes the Big Creek 1, 2, 3, 4, and 8 plants.

[18] The Shaver Chain utilizes the Eastwood, Big Creek 2A, 3, 4, and 8 plants.

Powerhouse 3 to Redinger Lake.[19] The Big Creek system ends at Powerhouse 4, which is fed from Redinger Lake and is at the edge of PG&E's Kerckhoff Reservoir.

b) Environmental/Regulatory Requirements and Constraints Affecting Water Flow, Storage, Release, Etc.

Operation of Big Creek is subject to environmental and regulatory constraints. The overriding objective for using all the SCE Hydro powerhouses and water storage facilities is the prudent use of the water resource, and safety. Water management on the project is governed by FERC licenses, U.S. Forest Service agreements, water rights, and contractual commitments, which include provisions for water releases and storage levels.[20] Each reservoir has required storage levels at particular times of the year. The summer season typically requires nearly full levels to satisfy recreational interests. Additionally, there are limits on seasonal carry-over storage that apply to the whole Big Creek project that relate to downstream water users (largely for agricultural irrigation).

Water management includes the necessity to lower reservoir levels for spring runoff, the conveyance of water downstream pursuant to contractual agreements, and the desire to create power when it is most beneficial for SCE customers. The total reservoir capacity of the Big Creek system is only about one-third of the average annual runoff of the watershed. The majority of the peak runoff occurs within two to three months when late spring temperatures start to rise. A large volume of water must be moved downhill within a specific period to either meet obligations or reduce the potential of causing spill at various reservoirs that would reduce total generation. During instances when reservoirs are full and negative market prices occur it can be more economical to spill than generate.

The runoff during the 2022 water year was approximately 58 percent of a normal (*i.e.*, average) year.[21] Given the fleet's high reliability and the effective management of fuel (water)

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[19] The Mammoth Pool Chain utilizes the Mammoth Pool Powerhouse, BC 3, and BC 4 plants.

[20] Revenue received by SCE from water purveyors or water rights holders, given in exchange for SCE agreeing to operate in a manner which benefits the purveyor or rights holder, but is beyond the contractual obligations governing SCE's water operations, is credited to PABA.

[21] Unless otherwise noted, annual statistics provided herein are on a calendar year basis. While calendar year statistics are used it should also be noted that, per industry convention, precipitation statistics are often given

available, generation levels during the Record Period were approximately 66 percent of the 20-year historical average (2002-2021).

c) System Operation to Fulfill Requirements/Constraints

Water planning largely depends upon the runoff volume of the present and prior water year. Ample snowpack and high reservoir levels are indicative of large quantities of generation available for the market. There is a relationship between one water year and the next, with many reservoirs being lowered by the spring prior to the runoff from snowmelt, yet possibly retaining water depending upon the projected runoff forecast. This is always a balancing act with some uncertainty associated with the decisions. For example, the Mammoth Pool watershed is large when compared with the capacity of the Mammoth Pool powerhouse. The Mammoth Pool reservoir will spill even in a normal water year and must be lowered to a minimum level in the spring.

Florence, Edison, Huntington, and Shaver Lakes have much smaller watershed areas than Mammoth Pool. Therefore, these reservoirs do not have as high a potential for spill as Mammoth Pool. All reservoirs have certain restrictions affecting the water levels at certain times of the year. Generally, the levels of Edison and Shaver reservoirs are more flexible than Huntington and Florence reservoirs. The Big Creek reservoir inflows are monitored continually to maintain required contract water flows. Contractual water releases are determined by reservoir inflows and are monitored for daily compliance. The monitoring also identifies reservoir levels for controlling the required maximum and/or minimum storage levels with minimal storage level fluctuations. The Big Creek generation schedules are adjusted daily to provide the best use of the required water releases for generating during periods when it is most economic, and to meet water release requirements as established in the FERC licenses for fish, water and wildlife enhancement.

d) Factors Affecting Operations

The amount of generation available in a given year depends upon the precipitation received plus carryover reservoir storage from the previous year, less the required storage commitments.

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on a "water year" basis, which runs from October through September (*e.g.,* October 1, 2021 through September 30, 2022, for the 2022 water year).

During the 2022 water year, flow in the San Joaquin River was approximately 1,060 thousand acre-feet, or approximately 58% percent of an average year, following 2021, which had a runoff of approximately 25 percent of an average year. Long-term planning is used to generate a forecast of power available for scheduling each month during the year and includes consideration of:

- Current reservoir storage levels and capacities;
- Operational constraints including water contracts, environmental commitments, and recreational requirements;
- Plant and unit capabilities and efficiencies;
- Plant and unit outage planning data; and
- Hydrological forecasts including precipitation and snow surveys.

During the likely runoff period of May through July, and if market electricity prices are positive, there may be little Big Creek Project flexibility, as most of the powerhouses will be at full load or the water would otherwise be spilled. At most other times of the year, generally there is flexibility to allow the CAISO to economically dispatch the project. The Big Creek automation system schedules the most efficient units to operate to deliver the amount of generation requested. By combining the most efficient plant equipment with the optimum operational schedule, SCE hydro maximizes the value of available water resources. Outages are planned to minimize the impact on generation schedules and are therefore typically scheduled to occur during the fall and winter months when water for generation is least available.

2. Other SCE Hydro Assets

As mentioned above, in addition to Big Creek, SCE hydro assets include another 23 powerhouses with a total capacity of approximately 149 MW with a range in capacity from less than one MW at several, up to approximately 40 MW at Kern River 3. These assets are in the Bishop and Mono Basin areas, the Kern, Kaweah, and Tule River areas, and the Ontario, San Bernardino, and Banning areas in the San Gabriel and San Bernardino Mountains. Some of these powerhouses utilize flow from diversion dams on rivers, whereas others utilize flow from relatively small (*i.e.*, as compared to Big Creek) storage reservoirs.

Due to the smaller size of the reservoirs and operational constraints, most of these powerhouses are operated as run-of the-river powerhouses. In those cases, the diversions will route from the stream to the powerhouse the volume of water available to maximize generation. However, as noted above, if the unit is in an outage, this will result in outage bypassed energy. If the flow in the stream or volume available from the reservoir is less than the maximum capacity of the powerhouse, or a unit is on standby due to low water flow, the unit outage does not result in outage bypassed energy.

The Bishop Creek and Mono Basin areas have reservoir storage capacities to assist in seasonally leveling the operation of the powerhouses in those locations. Additionally, storage released from Isabella Reservoir, operated by the U.S. Army Corps of Engineers based on the requests of the Kern River Watermaster, often allows the Kern River 1 powerhouse to produce power during naturally occurring low river flows.

a) Environmental/Regulatory Requirements and Constraints

These 23 powerhouses are subject to various environmental and regulatory constraints. Many of the FERC licenses specify minimum releases from diversion dams to maintain fish life and riparian habitat. Powerhouses located along rivers with heavy recreational use such as the Kern are also subject to boating (rafting) release requirements.

b) Transmission System Operational Constraints in the Bishop/Mono Basin Area

To keep the local electrical system stable, generation must be curtailed when transmission capacity that normally delivers power from the Bishop/Mono Basin area to Southern California is reduced below normal. Curtailment is accomplished by reducing local generation resources (including SCE local generation) until total output matches area load requirements and the remaining transmission capacity out of the area.

c) Factors Affecting Operations

Like Big Creek, the amount of generation available each year from these 23 powerhouses depends upon precipitation during that year. However, for the diversion pools and reservoirs associated with these powerhouses, there is no carryover or target for storage to consider.

Therefore, hydrology planning activities are considerably less than needed at Big Creek, but incorporate the following similar parameters:

- Current reservoir storage levels and capacities;
- Operational constraints including water contracts, environmental commitments, and recreational requirements;
- Plant and unit capabilities and efficiencies;
- Plant and unit outage planning data; and
- Hydrological forecasts including precipitation and snow surveys.

However, and again compared to Big Creek, these powerhouses have much more limited flexibility in how they are run because they are either run of river or have limited storage capacity.

d) Storm Debris

Due to the river geology of many of these 23 powerhouses, there is high debris loading during storms that typically does not occur in the granite-walled canyons of Big Creek. This often requires taking a plant off-line during this period until the intakes can be cleared or until water turbidity decreases to an acceptable level. High turbidity indicates sand or silt in the water, which will cause damage to hydro turbines and associated equipment such as cooling systems. High turbidity water that flows past a powerhouse is not considered bypassed energy, because it is not suitable water for operation of the powerhouse. No records are kept on the amount of high turbidity water that bypasses powerhouses.

e) Eastwood Pumped Storage

Eastwood is SCE's largest hydroelectric generating unit and the only one with pump back capability. It consists of an underground powerhouse at Shaver Lake with a single pump/turbine rated at 200 MW. The powerhouse is fed water from a small reservoir known as the Balsam Meadow forebay. This forebay is located geographically and in elevation between Huntington Lake and Shaver Lake. Balsam Meadow forebay has a maximum storage capacity of approximately 1,547 acre-feet of water. The forebay is fed primarily by a water conveyance tunnel bringing water from Huntington Lake. In addition, some water is diverted from Pitman Creek into the Balsam Meadow forebay. Water exiting the forebay to Eastwood enters another tunnel which later transitions into a penstock that feeds the Eastwood turbine. When generating, water from the Balsam Meadow forebay flows through Eastwood and is discharged into Shaver Lake. This is the customary way for water to flow from Huntington Lake to Shaver Lake.

Over its history, much of Eastwood's operation has been in the conventional manner, generating electricity during peak periods by capturing the potential energy of the water resource as it flows from higher to lower elevations, as described above. Eastwood also provides pumped storage capacity, whereby the generator can also be operated as a motor.[22] This turns the turbine in the reverse direction, which allows the turbine to operate as a pump. When used in this manner for pumped storage, Eastwood consumes electric power during low or negative-priced hours to pump water uphill to the Balsam Meadow forebay, so it can generate power during higher-priced hours. Under typical operations, Eastwood Pump schedules are determined by SCE's Short-Term Market Planning group to maximize the value of Eastwood's Pumped Storage capabilities. For pump operations to add value to Eastwood, the on-peak/off-peak differential must be large enough so the cost to pump is less than the value of generation.[23] In recent years, peak and off-peak prices have evolved with the increased penetration of renewable resources leading to lower market prices for electricity during peak periods as well as higher price uncertainty. SCE continues to monitor changing market conditions and will continue to utilize Eastwood, so it maximizes value for SCE customers.

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[22] Pump-back mode operation also requires the use of a "pony motor" that is mounted above the generator. This pony motor assists in accelerating the generator to operating speed at the initiation of each pump-back mode operating cycle.

[23] Pump-back operation is approximately 75 percent efficient and consumes approximately 1.33 MWh of electricity for each 1.0 MWh of electricity subsequently generated when that same volume of water is later released back through the generator.

C. Recorded Hydro Production

Table II-4 below summarizes SCE's Hydro generation for the 2022 Record Period, as well as the average annual generation recorded during 2002 through 2021 on a calendar-year basis.[24]

Table II-4
SCE Hydro – 2022 Recorded Hydro Production

Line No.	Region	2002-2021 Average Net Generation (MWh)	2022 Net Generation (MWh)
1	Big Creek	2,862,407	2,228,358
2	Other Assets	510,884	337,405
3	TOTAL	3,373,291	2,565,763

As shown, the combined 2022 generation of Big Creek and the Other Assets was 2,565,763 MWh, approximately 76 percent of the previous 20-year period average. This mainly reflects the fact that there was lower than average water available for generation resulting from the persisting drought conditions that occurred during the year.

D. Large Hydro Performance During the Record Period

The efficient use and availability of SCE hydro generation resources are ensured through attentive management of the facilities. This includes minimizing, to the extent practical and cost effective, the number and duration of powerhouse outages (*i.e.,* thereby maximizing the availability of the powerhouses for generation service). Powerhouse availability is tracked using two primary metrics – equivalent availability factor (EAF) and forced outage factor (FOF). This section provides data on these metrics, along with summary information for the outages that affect these metrics, for SCE's large powerhouses.[25]

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[24] SCE hydro-transmitted load statistics comprise the net metered generation from the hydro plants as documented in FERC Form 1 and in other regulatory filings.

[25] See Table II-3 for a list of SCE's large powerhouses (*i.e.,* those with capacities exceeding 25 MW). D.15-03-023, p. 3, requires that SCE provide certain information in its annual ERRA review filing for outages exceeding 24 hours, where the outage affected a generating unit with a rated capacity exceeding 25 MW, or affected multiple generating units at a given power plant having a combined capacity exceeding 25 MW.

1. Equivalent Availability Factor Results

EAF is expressed as the percentage of time that a generating unit was available for service (regardless of whether it was in service) during the time period in question. EAF is reduced by scheduled outages, forced outages, and derates (*i.e.*, partial outages). EAF is not reduced by outages or derates resulting from issues that were external to the SCE-managed powerhouse, reservoir, dam site and flowline equipment including: (a) transmission system constraints or outages that impact the powerhouse, and (b) insufficient water flows to operate the turbines, or time periods when the water contains excessive levels of storm debris (whereby using the water would damage the turbine). EAF is calculated monthly for each powerhouse, which is then combined into a total aggregate EAF. Generally, the higher the EAF the better; however, SCE also considers the costs (non-labor and labor, including overtime) and benefits (including the value of electricity) when deciding how quickly to repair a given asset and return it to service.[26] As shown in Table II-5 below, the recorded EAF for 2022 was approximately 75.27 percent, in large part because 2 of SCE's powerhouses had Units that remained offline the entire year and the main circuit breaker failure experienced at Eastwood in September, which is significantly lower than SCE's five-year average of 85.12 percent (2016-2020).[27]

Table II-5
SCE Large Hydro – Equivalent Availability Factor (EAF)

Line No.	Year	SCE	Industry
1	2017	93.88	81.99
2	2018	88.38	79.57
3	2019	84.95	81.73
4	2020	89.08	81.87
5	2021	69.33	80.35
6	Avg.	85.12	81.10
7	2022	75.27	Unavailable

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[26] Because many maintenance activities require outages, it is not practical to achieve an EAF of 100 percent. Consistent with previous years, EAF calculations do not include Out of Management Control outages (e.g., Creek Fire).

[27] Historical industry EAF and FOF performance data is provided in Appendix III-B through III-F. (Source data was obtained from http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).

2. **Forced Outage Factor Results**

FOF is calculated by dividing the hours that the generating unit was forced off-line, due to equipment problems or other plant maintenance related issues, by the total hours in the year. Therefore, the ideal FOF level is a low percentage. FOF is calculated for each powerhouse and combined (*i.e.*, pro-rated by each powerhouse's rated MW output) into an overall total for the SCE Hydro fleet. As with EAF, FOF does not include outages due to issues that are external to the SCE-managed hydro assets and equipment.

As shown in Table II-6 below, the recorded FOF for the 2022 Record Period was approximately14.2 percent.[28] This value is significantly higher than SCE's prior five-year average of 7.05 percent (2017-2021) and is discussed in greater detail in Section 3.

Table II-6
SCE Large Hydro – Forced Outage Factor (FOF)

Line No.	Year	SCE	Industry
1	2017	1.02	3.55
2	2018	1.65	6.15
3	2019	2.69	4.01
4	2020	6.40	4.02
5	2021	23.50	3.78
6	Avg.	7.05	4.30
7	2022	14.2	Unavailable

3. **Outages and Outage Bypass Energy Loss**

Since 1982, SCE has utilized the North American Electric Reliability Corporation (NERC) GADS (Generating Availability Data System) to classify and track outage events (*i.e.,* scheduled and unscheduled outages) at its hydro facilities.[29] GADS was developed by utility designers,

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[28] Consistent with previous years, FOF calculations do not include Out of Management Control outages (e.g., Creek Fire).

[29] NERC GADS (the North American Electric Reliability Corporation's Generation Availability Data System) is a group of databases used to collect, record, and retrieve operating information from power plants in North America. The data is used to improve performance of electric generating equipment, and to support equipment reliability and availability analysis by GADS data users. For information on outage report code

operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, the following objectives for the GADS program were established: compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment.

Periodic production outages are required to perform maintenance on SCE's dams, flowlines and powerhouses. Planned maintenance outages are generally scheduled in the fall or winter when the lowest amount of water is available for generation. This practice minimizes outage bypass energy loss. However, relatively long outages are occasionally needed to complete major planned work (*e.g.,* dam improvements). Therefore, it is not uncommon to incur some amount of outage bypass energy loss during one or more of the planned outages undertaken in a typical year.

In addition to planned outages, unplanned repairs (*i.e.*, unscheduled forced outages) are also usually needed each year, particularly given the large size of SCE's hydro fleet. Such unplanned repairs can often be performed without incurring outage bypass energy loss, particularly during years of average or below average water availability. However, some amount of outage bypass energy loss is incurred due to unplanned outages in most years.

While SCE achieved a high level of reliability during the 2022 record period, there were three outages that resulted in bypass energy event at SCE's large powerhouses. These outages are discussed further in the following sections of testimony.

a) <u>Scheduled Outages</u>

Scheduled outages include planned maintenance outages as well as planned maintenance outage extensions. Planned outages are typically scheduled at the start of each year. For example, it is common for planned outages to occur in the spring to prepare for the summer peak season, and in the fall to address issues observed during the summer peak season. During the year, maintenance outages are scheduled when needed to perform non-emergency repairs, typically during a time better

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definitions, please refer to Appendix III-A and the NERC-GADS Data Reporting Instructions, *available at* http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Entire%20GADS%20Data%20Reporting%20Instructions%20Effective%20January%201,%202015.pdf.

suited for the bulk power grid (*e.g.,* on weekends).[30] As summarized in Table II-7, there were 69 scheduled outages (with zero outage extensions) at SCE's large powerhouses during the Record Period.

Table II-7
SCE Large Hydro – 2022 Scheduled Outages

Line No.	Outage Classification	Quantity
1	Planned (PO)	46
2	Planned Extension (PE)	0
3	Maintenance Outage (MO)	1
4	Maintenance Outage Extension (ME)	0
5	TOTAL	47

Forty-one of these scheduled outages exceeded 24 hours in duration. Three of these 47 scheduled outages continued into 2023, and none of these 47 were extended by more than one week past the scheduled end date that was in place at the start of the outage. Additional details regarding Hydro scheduled outages are provided in SCE's response to the Master Data Request for this proceeding.[31]

b) Unscheduled Outages

An unscheduled outage occurs when either equipment suddenly fails or must be removed from service relatively quickly because of control problems or to prevent damage. The unit either immediately trips or a shutdown is initiated, at which time the required repair proceeds.

During the Record Period, there were a total of 41 unscheduled (*i.e.*, forced) outages on SCE Hydro generating units. Twenty-nine of these outages affected a total generation capacity of less than 25 MW and/or had a duration of less than 24 hours. The other 12 outages lasted longer than 24 hours, and either occurred on a generating unit larger than 25 MW or affected a

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[30] For information on outage report code definitions, please refer to Appendix III-A and the NERC-GADS Data Reporting Instructions, available at http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Entire%20GADS%20Data%20Reporting%20Instructions%20Effective%20January%201,%202015.pdf.

[31] See SCE response to MDR A.23-04-XXX Q.1.1.12.b.

generation capacity of greater than 25 MW.[32] These 12 outages are summarized in Table II-8 and are discussed in more detail below. As shown, three of these 12 outages incurred outage bypassed energy, which led to water bypassing the powerhouse instead of generating electricity.[33]

Table II-8
SCE Large Hydro – 2022 Unscheduled Outages
(Lasting Longer than 24 Hours on Units Greater Than 25MW)

Line No.	Plant and Unit	NERC Event Type	MW Affected	Beginning Date/Time	Ending Time/Date	Outage Length (hrs:mins)	Bypassed Energy (MWh)	Incident Report
1	Big Creek PH 2A Unit 1	U1	55.0	11/19/2021 16:27	2/25/2022 14:17	2349:50	0	Yes
2	Mammoth Pool Unit 1	U1	95.0	12/21/2021 12:19	1/6/2022 7:07	378:48	0	Yes
3	Big Creek PH 3 Unit 5	U1	36.5	6/16/2022 13:56	6/18/2022 18:05	52:09	887	Yes
4	Eastwood	U1	198.0	6/16/2022 18:00	6/30/2022 12:22	330:22	6,609	Yes
5	Big Creek PH 3 Unit 2	U1	55.0	8/20/2022 19:15	8/22/2022 11:57	40:42	0	Yes
6	Mammoth Pool Unit 1	U1	95.0	8/29/2022 14:54	8/30/2022 14:58	24:04	0	Yes
7	Big Creek PH 2A Units 1 & 2	U1	55.0	9/20/2022 9:43	9/22/2022 15:19	53:36	0	Yes
8	Mammoth Pool Unit 1 & 2	U1	95.0	10/1/2022 8:04	10/5/2022 12:00	99:56	0	Yes
9	Big Creek PH 3 Unit 2	U1	34.0	12/4/2022 9:53	12/15/2022 8:19	262:26	886	Yes
10	Big Creek PH 8 Unit 2	U1	45.0	9/5/2020 15:49	Extended into 2023	TBD	TBD	TBD
11	Big Creek PH 3 Unit 3	U1	34.0	10/27/2021 11:00	Extended into 2023	TBD	TBD	TBD
12	Eastwood	U1	199.8	9/15/2022 10:59	Extended into 2023	TBD	TBD	TBD

(1) Big Creek 2A Unit 1 – Low Field to Ground

On November 19, 2021, Big Creek 2A Unit 1 was taken offline because the generator excitation field circuit to ground resistance reading was low. This means that the field ground detector indicated a decreasing winding resistance to ground indicative of contamination or failing insulation. The unit was removed from service to prevent the ground from worsening, or a second ground from occurring, which could have resulted in significant damage and trip of the unit. Following removal from service, the unit was de-energized to safely conduct inspections to determine the source of the ground.

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[32] D.15-03-023, p. 3, requires that SCE provide certain information in its annual ERRA review filing for forced outages exceeding 24 hours, where the forced outage affected a generating unit with a rated capacity exceeding 25 MW, or affected multiple generating units at a given power plant having a combined capacity exceeding 25 MW.

[33] SCE calculates the replacement power costs per the methodology described in the August 14, 2015 Settlement Agreement between SCE and Cal Advocates (Article 2 and Exhibit D), which was adopted in D.15-11-011. The methodology has been updated per the CAISO market design changes, replacing the Standard Capacity Product (SCP) with the successor Resource Adequacy Availability Incentive Mechanism (RAAIM).

The generator excitation field had a low resistance reading caused by pit flooding, which created excessive humidity in the generator. The generator sits horizontally on the turbine deck floor. Only the top half is visible from the turbine deck. The bottom half, which is not visible, sits below the turbine deck in a pit. Although water had accumulated in the pit, the generator was not submerged in the water.

The cause for the water accumulation in the pit is from coolers, also in the pit, used to cool the ambient air around the generator. The generator is air cooled to maintain acceptable operating temperatures. Condensation develops on the cooler surfaces and accumulates in a sump.[34] Water in the sump is removed with one of two pumps. The flooding in the pit was caused by the failure of both pit sump drain pumps. When each drain pump failed, they tripped their respective circuit breakers, which also deenergized the sump high level alarm. Therefore, the operators were unaware there was an issue until the generator low resistance (ground) reading was observed.

Corrective actions taken as a result of this outage include the replacement of the drain pumps and ordering of additional spare parts. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(2) Mammoth Pool Unit 1 – Low Field to Ground

On December 21, 2021, Mammoth Pool Powerhouse, Unit 1, was taken offline because the magnetic field circuit to ground resistance reading was low. The unit was removed from service to prevent the ground from worsening, or a second ground from occurring, which could have resulted in significant damage and an automatic trip of the unit. Normal ground resistance readings can range from 150 to 500 kohms (thousand ohms) and the unit was taken offline when the resistance reading had dropped to less than 30 kohms. The low ground reading is caused by dirt and carbon buildup on the field windings and bus work. Normally the field to ground reading decays slowly over time, allowing for the scheduling of a maintenance or planned outage to perform a thorough cleaning of

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[34] A sump is a low space, or pit, that collects liquids, in this case water.

the field and excitation components. In this case the field ground reading took a quicker than expected decrease and the unit was taken offline to avoid damage.

Previous to this time, the unit had been operating normally and within design parameters. The plant operators noticed the field to ground reading was decaying quicker than expected (within weeks as opposed to months). With the unit operating, the maintenance crew attempted to improve the reading by blowing off carbon buildup and debris from the unit using pressurized nitrogen. Although the readings improved slightly it became clear that the unit needed to be taken offline to safely perform a thorough cleaning.

Upon inspection it was determined that a technician had previously added epoxy to the insulation pucks,[35] as a temporary repair, until replacement pucks could be ordered and replaced at a later date. The unit was then started prior to the epoxy fully curing, which caused carbon dust to become trapped in the pucks. This led to the low ground readings necessitating removal of the unit from service.

The unit was taken offline for a thorough cleaning of the field and excitation components. The affected epoxy on the repaired pucks was also cleaned off. New insulation pucks were subsequently ordered and installed during the next opportunity outage, which occurred in March 2022. Additional corrective actions included training of personnel on the proper methods of cleaning and maintaining generator insulation, with specific discussion on proper application and curing of epoxy on the insulation pucks prior to installation. This training was completed in March 2022. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(3) Big Creek 3 Unit 5 – Broken Shear Pin

On June 16, 2022, the Hydro Operator on shift received indication in the Control Room of excessive vibration on Big Creek 3, Unit 5. The unit was then shut down and cleared to safely investigate the cause of the vibration — a broken shear pin on a wicket gate linkage. The shear pin was replaced and tested by operating the wicket gates. During testing, the replacement pin broke

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[35] Pucks are electrical insulators made of a material that inhibits the flow of electricity. They are installed between energized metal and non-energized metal surfaces to prevent electrical flow between each.

again indicating that the wicket gate was bound up. SCE personnel drained the penstock so that Technicians (Techs) could safely enter and inspected the turbine, where they found evidence of rock debris scaring to the wicket gate. No rock debris was found; therefore, it is likely the rock debris broke up passing through the wicket gate and out of the unit. Upon failure of the second shear pin, the wicket gate linkage was found to be out of adjustment. The wicket gate was then adjusted, and test stroked with a new shear pin for proper operation. With the issue resolved, the unit was returned to service.

Wicket gates are a series of adjustable vanes that regulate the flow of water to the turbine. The wicket gate shear pin is designed to shear or fail in the event of a mechanical overload on the wicket gate and is a sacrificial part that prevents more expensive parts from being damaged. The shear pin worked as intended and failed, requiring minimal parts and labor to fix it, rather than replacing a complete wicket gate or Servo link mechanism that controls the wicket gate's motion. Per the Tech inspection, rock debris is suspected to have caused the initial shear pin failure. The Tech found the eccentric pin for the wicket gate out of adjustment, misaligning the wicket gate.[36] The debris is also suspected to have caused this misalignment, resulting in the replacement shear pin failure. Once the gate was re-aligned and a new shear pin installed, the gate mechanism functioned properly. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(4) Eastwood – TSO Bypass Valve Failure

On June 14, 2022, at 3 PM, during an inspection at the Big Creek Eastwood Powerhouse, a needle valve on the 'automated' turbine shut off (TSO) bypass valve was observed to have a visible crack in the body. This needle valve is threaded into the body of the bypass valve, which typically contains water at 600 pounds per square inch (psi) of pressure. SCE continued to monitor the crack and on June 16, the issue was elevated to a safety concern. The concern was that the small crack could enlarge, potentially fracturing the valve body, causing injury to personnel, or flooding the governor cabinet circuitry rendering the unit unavailable.

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[36] The eccentric pin is different than the shear pin. The eccentric pin is designed to allow for adjustment to the Wicket gates. The shear pin is a designed failure point, whereby the pin fails in unfavorable conditions, this protecting the unit from damage

On June 16, 2022, the unit was placed in a forced outage to safely facilitate repairs of the TSO valve. While closing a separate 8-inch bypass isolation gate valve, necessary to depressurize the piping system connected to the TSO valve, a valve stem broke, which prevented further operation of the valve and operation of the unit.

In order to remove the bypass isolation valve to perform repairs it was necessary for SCE to dewater the power tunnel providing water to the powerhouse, which took approximately ten days. Following the dewatering process, SCE replaced both valves and placed the unit back in-service. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(5) <u>Big Creek 3 Unit 2 – Relay Trip</u>

On August 20, 2022, the BC302 tripped offline at 19:15 with no indication of cause from the dispatcher's Ovation view. When the Operator arrived on-site to investigate, he discovered that a number of failed protective devices had tripped the unit. SCE test-men created a safe work-around so as to bring the Unit back on-line while replacement relays were ordered. This work-around enabled SCE to bring the unit back online on August 22nd, at 11:57. SCE ordered and subsequently placed into inventory an additional relay as a back-up spare. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(6) <u>Mammoth Pool Unit 1 – Draft Tube Leak</u>

At 2:45 PM, on August 29, 2022, the plant operator was notified by the area utility worker that there was water leaking from the No.1 unit draft tube at the Mammoth Pool Powerhouse. The draft tube is a water conveyance that directs water exiting the water turbine to the tailrace. The tailrace is a water channel that takes water out of the power plant back to its source. The plant operator went downstairs and observed that there was a large amount of water leaking from a hole where a threaded stud should have been. The plant operator called the area manager and informed him of the issue. The decision was made to shut down the unit to investigate and determine the source of the leak. At 2:54, PM a unit "stop sequence" was initiated. The unit shut down normally. The next morning the operations crew made the unit safe to work on so that the mechanical crew could determine what had happened. The mechanical crew discovered that the adjustment nut on one of the draft tube wedges had unthreaded itself from the wedge. The wedges are used to create the seal between the upper and lower draft tube sections. Essentially, the wedges force the topside of the lower draft tube section up against the bottom side of the upper draft tube section, sealed by an O-ring. The loss of the adjustment nut allowed the wedge to work its way out of its slot and subsequently, the wedge was discharged out of the unit and into the afterbay (back into the water source).

When these units are run in the "rough loading zone", the draft tube sections tend to vibrate and move around quite forcefully.[37] SCE believes that over time these vibrations caused the wedge adjustment nut to vibrate and work its way off the stud.

Maintenance personnel plugged the hole to mitigate water from leaking out of draft tube and ensured that all the nuts on the other 21 wedges were tight. As there was no risk to running the unit with one wedge missing, the decision was made to put the unit back online. SCE personnel has completed fabrication of a new wedge for installation, which will occur during the the next planned outage of this unit. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(7) Big Creek 2A Units 1 & 2 – Turbine Shut-off Valve Leak

The Big Creek 2A Unit 1 Left hand[38] Turbine Shutoff Valve (TSOV) Control Valve developed a leak[39]. Repair of the leak required the team to drain the penstock to isolate the high-pressure source of the water. The penstock directs water from the source to the hydro power plant. Units #1 and #2 at this powerhouse utilize a common penstock. In order to clear the penstock to for Unit 1, Unit 2 was also forced into an outage.[40]

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[37] A Rough Loading Zone is a load range where the unit experiences vibrational forces.

[38] This hydro unit has two turbine runners, a Left Hand and a Right hand. The runner captures the energy of the penstock water flow to be converted into electrical energy.

[39] TSO Valve"-Turbine Shut-Off Valve. The TSO Valve is the main valve used to shut off the water supply used to drive the turbine.

[40] BC2A Unit 2, GADS U1 Outage was from 9/20/2022 9:57:00 AM through 9/22/2022 3:06:00 PM.

The TSOV is operated by using a control valve that pressurizes one side of the valve or the other to either push it closed or open. The control valve for this TSOV was no longer functioning properly due to a failed weld. The TSOV control valve was replaced, and the unit was returned to service. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(8) Mammoth Pool Units 1 & 2 – Turbine Shutoff Valve (TSOV) Failure

At the end of scheduled shutdown sequence of Mammoth Pool Unit #2, the TSOV failed to fully close.[41] As a result, the unit was taken offline, but remained spinning at approximately 67 RPM. To prevent damage to the unit, the team closed the penstock valve and drained the penstock, which directs water from the source to the hydro power plant. This isolated the unit from the water source and stopped the unit from spinning. Units #1 and #2 at this powerhouse utilize a common penstock. Therefore Unit #1 was also not available for operation as a result of draining the penstock.[42] After the TSOV on Unit #2 had been closed manually, the penstock was refilled, which allowed Unit #1 to be put back online. Unit #1 was returned to service on 10/3/2022 @ 17:20. Further troubleshooting was performed on the Unit #2 TSOV, and unit was returned to service on 10/5/2022 at 12:00.

This TSOV has exhibited similar events previously. These TSOVs utilize penstock water to operate an actuator that controls the opening and closing of the valve. As the forebay water (upstream water source) flows into the penstock, levels in the forebay lower, as does the pressure of the water in the penstock. SCE suspected that the penstock water pressure lowered to a level that was insufficient to properly operate the Unit #2 TSOV.

SCE personnel are developing a procedure to close the TSOV manually if this type of event were to occur again. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

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[41] TSO Valve”-Turbine Shut-Off Valve. The TSO Valve is the main valve used to shut off the water supply used to drive the turbine.

[42] Mammoth Pool Unit 1, GADS U1 Outage from 10/2/2022 at 0804 through 10/3/2022, 1720 hours.

(9) Big Creek 3 Unit 2 – Excessive Wicket Gate Leakage

On December 4, 2022, the Operations team observed excessive water leaking from Big Creek 3 Unit 2 wicket gates. For some hydroelectric turbines, a wicket gate helps to control the flow of water as it reaches the water turbine, which in turn determines how much power can be generated. The unit was taken offline to perform repairs. During the maintenance activity the team determined the wicket gate seals had failed in service. The maintenance team made temporary repairs by applying additional packing material within the seal valley. The leak was then slowed down enough to operate the unit safely until permanent repairs could be completed. During a planned outage two weeks later, the seals were replaced, and the unit was returned to service. SCE plant engineering, and operations and maintenance personnel have reviewed the Wicket Gate preventive maintenance program and adjusted the maintenance activities as necessary to prevent future in-service failures. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(10) Big Creek 8 Unit 2 - Creek Fire

(a) Background

On Friday September 4, 2020, at 6:33 PM, the Creek Fire was reported near Camp Sierra Road and Redding Road, approximately four miles North/East of Shaver Lake.[43] Shortly after midnight on September 5, source power to the Big Creek 1 powerhouse was lost as the 220 kV transmission lines were removed from service due to the close proximity of the fire. By daylight, on Saturday, September 5, the SCE transmission operator and the Big Creek Operations Center had lost communications with nine Big Creek Powerhouses (1, 2, 2A, 3, 4, 8, Eastwood, Portal, and Mammoth Pool). As fire conditions worsened, Cal Fire issued evacuation orders to the town of Big Creek (where SCE's Big Creek administrative offices are located, including company housing, maintenance and warehouse facilities, and the Big Creek 1 Powerhouse) and all other occupied Big Creek powerhouses. At some Big Creek powerhouses, the danger of fire overtaking the facility was so

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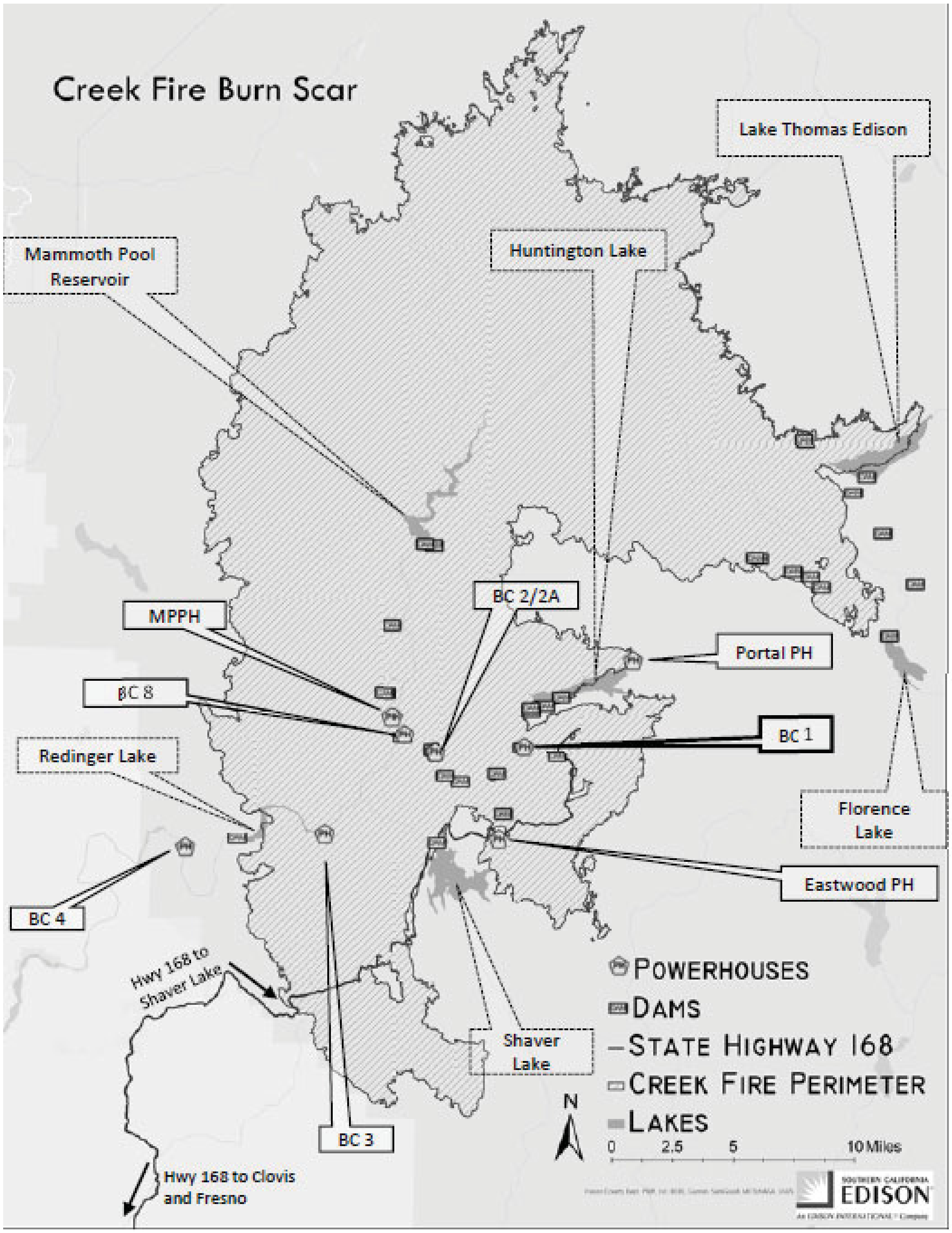
[43] The Creek Fire was the largest single fire (not a complex of two or more fires that merged over time) and the fourth largest overall fire in California history and was not declared 100 percent contained until December 24, 2020.

imminent that operators had little or no time to properly shut down the facilities prior to evacuating. SCE personnel were not permitted to return to the area(s) until evacuation orders were lifted by Cal Fire on September 10, 2020.

Figure II-2
2020 Creek Fire Burn Scar



Following the lifting of evacuation orders on September 10, 2020, SCE personnel began to perform damage assessments of the Big Creek Powerhouses in areas that were deemed safe. Powerhouse 8 Unit 2 was found to have severe damage while three other powerhouses, Powerhouse 2, 2A, and Mammoth Pool, sustained moderate damage. In addition to the Big Creek powerhouses, many of the operational support structures (*e.g*., company housing and garages, machine/electrical/carpenter shops) and appurtenant facilities and equipment (including transmission lines offtaking power, distribution lines providing station light and power and energizing key equipment, fiber optic lines and microwave equipment providing communication to control the power houses, etc.) were also damaged or destroyed by the fire. In order to re-establish generation operations, many of these structures and facilities must first be restored to safe and effective condition.

In September 2020, SCE began restoration efforts of the Big Creek Powerhouses, support structures and appurtenant facilities. This effort is ongoing with the goal of ultimately restoring Big Creek's full 1,015 MW of hydroelectric generating capacity and reinstating SCE's ability to perform regulatory mandated water management activities within the upper San Joaquin River watershed.

Restoration efforts for the remainder of September 2020 and well into October 2020 were extremely limited as most, if not all, morning inspection shifts could not be safely performed due to continued hazardous air quality from heavy smoke from the ongoing fire. While full powerhouse restoration was not possible at that time due to the ongoing fire, restoration activities on key services and facilities were initiated. Key areas of concern regarding restoration efforts were:

1. Return electrical services to each facility to facilitate fire-related hazard inspections and facility condition assessments.
2. Return key utilities to service, such as water treatment and wastewater treatment services.
3. Identify areas of high erosion risk near roadways leading to and from SCE generation, transmission, distribution, telecommunications, and administration infrastructure

for the safety of people traveling on those roadways. A secondary priority was to ensure the safety of SCE infrastructure (penstocks, forebays, buildings, etc.).

4. Inspect, test, and return powerhouses to service to provide needed power to undamaged portions of the grid. As a result of the fire, communication links were destroyed along with the transmission and distribution infrastructure. Powerhouses 3 and 4 were operated at limited load levels while the IT telecommunications infrastructure was being restored (accomplished by staffing these powerhouses around the clock) while the remaining seven powerhouse required telecommunication infrastructure to be restored as well as transmission and distribution before they were placed back in service.

(b) 2022 Creek Fire Status Update

As previously stated, Big Creek Powerhouse 8 Unit 2 (BC8U2) suffered severe damage as a result of the Creek Fire while three other powerhouses, Powerhouse 2, 2A, and Mammoth Pool, sustained moderate damage. With the exception of BC8U2, all Big Creek units have been fully restored to operation. Due to the extensive damage incurred to BC8U2 from the Creek Fire, efforts to fully restore BC8U2 will extend into 2023. SCE will provide an update in its next ERRA Review filing.[44]

Because the cause of the Creek Fire was a natural disaster,[45] an Incident Report (IR) describing the fire's cause was not created.

(11) Big Creek 3 Unit 3 – Failed Field Poles

The Big Creek 3 Unit 3 unplanned outage was the result of failed field poles on the generator that occurred on October 27, 2021. To reestablish generation operations, the field poles needed to be restored to safe and effective condition. When SCE attempted to replace the field poles, it was discovered that the poles had to be cut from the laminated plates, requiring removal of the

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[44] This is consistent with Public Advocate's Office's proposal in SCE's 2017 ERRA Review proceeding (A.18-03-016). In that proceeding, Public Advocate's Office proposed (see Public Advocate's Office report, pp. 3-17) that SCE, in future ERRA Review applications, disclose whether there are any pending outages and indicate when testimonies for those outages will be submitted.

[45] The United States Forest Service determined that the most probable cause of the Creek Fire was a lightning strike. Sierra National Forest - News & Events (usda.gov).

entire rotor assembly. During this removal process, the station crane was damaged. Repairs to the crane were completed in late September 2022 and the crane was used to remove the rotor assembly. Shortly thereafter, the field poles were cut out and shipped to a vendor for repair/refurbishment. SCE is forecasting BC3U3 to return to operation in the second quarter of 2023. SCE will provide an update in its next ERRA Review filing.[46]

(12) Eastwood – Main Circuit Breaker

In September 2022, the main unit circuit breaker for Eastwood Power Station (EPS) reached the end of its useful life and experienced a critical in-service failure. This failure caused the breaker to explode, damaging the breaker and surrounding concrete walls. The failure of this breaker has made EPS nonfunctional, and the station is currently in a forced outage state. Due to the extensive damage incurred to Eastwood, efforts to fully restore Eastwood to service will extend into 2023. SCE will provide an update in its next ERRA Review filing.[47]

4. **Summary**

SCE personnel investigated all unscheduled outages during the Record Period. Specialists (*e.g.*, engineers from the Generation Department home office) assist in these investigations where needed. Often, the cause of the outage, as well as the needed repairs and other corrective actions, are readily apparent and a more extensive analysis of the outage (such as a root cause analysis) is not needed and conducted. Outage repairs are summarized in the Hydro maintenance data base, and if the outage involved extensive repairs, additional documentation is typically also prepared (*e.g.*, a contractor repair report). As explained above, SCE management determined that during the Record Period all of the Hydro generation forced outages required additional investigation into the cause of the outage, including the preparation of Incident Reports.

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[46] See fn. 41, supra.

[47] See fn. 41, supra.

III.

NATURAL GAS GENERATION

A. SCE Peaker Introduction

SCE owns and operates five natural gas-fired peaking generating plants (known as the SCE Peakers). The five Peakers are: (1) Barre Peaker at SCE's Barre Substation in Stanton, CA; (2) Center Hybrid Peaker at SCE's Center Substation in Norwalk, CA; (3) Grapeland Hybrid Peaker at SCE's Etiwanda Substation in Rancho Cucamonga, CA; (4) Mira Loma Peaker at SCE's Mira Loma Substation in Ontario, CA; and (5) McGrath Peaker next to the GenOn Mandalay Generating Station in Oxnard, CA. Each Peaker plant consists of a single, simple cycle combustion turbine generator of approximately 49 MW rated net capacity, for an aggregate 245 MW of generating net capacity for the five plants. The first four Peakers became operational in August 2007 and the fifth Peaker (McGrath) became operational in November 2012.[48] During 2016, two of the Peakers (Center and Grapeland) were converted into Hybrid units involving integration of battery energy storage technology into the combustion turbine operating regime.

The SCE Peaker units contribute to bulk power grid reliability with quick starting and rapid ramping capabilities and can run several times per day if necessary. Their relatively low startup costs and ability to start up and shut down quickly means the Peakers can be run only when necessary, helping to reduce overall customer costs.[49] SCE offers the Peakers to the CAISO energy and AS markets where the units can be run to meet unexpected customer demand, respond to unplanned system contingencies, or simply provide required system operating reserves by remaining off-line but immediately available. Because the onsite power needs of each of the Peakers can be supplied by small internal combustion engine driven generators (fueled by natural gas) that are installed at each site, the Peakers are designed

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[48] Pursuant to Commission Resolution E-4791, two of the Peakers (*i.e.*, the Grapeland and Center Peakers) underwent Electric Gas Turbine upgrades during 2016, which included the integration of a 10 MW battery energy storage system into each of these Peakers. SCE also added two 10 MW 4-Hour battery energy storage systems adjacent to (but not integrated into) the Mira Loma Peaker facility. These four systems were approved in D.18-06-009.

[49] However, Peaker operating hours per day and per year must be managed such that their respective daily and annual air emissions do not exceed their respective air permit limits.

to assist power grid restoration by providing "black start" capability if the grid experiences a total shutdown or "black-out." The operation of the SCE Peakers during the Record Period and the related fuel costs for these facilities is described below.

B. SCE Peakers Performance During the Record Period

The five SCE Peakers provided 99,043 MWh of energy and were started an aggregate 1,089 times during the Record Period as shown in Table III-9. This yields an average capacity factor of 4.5 percent, an average of approximately 4.2 starts per Peaker per week, and an average of approximately 1.9 hours of run-time per Peaker start.

Table III-9
SCE Peakers - 2022 Generation and Starts

Line No.	Peaker Site	Generation (MWh)	Starts
1	Barre	23,165	193
2	Center	6,864	196
3	Grapeland	10,218	259
4	Mira Loma	30,425	212
5	McGrath	28,370	229
6	TOTAL	99,043	1,089

1. Fuel Usage Cost

The SCE Peakers consumed 1,085,945 MMBtu of natural gas at a cost of approximately $10,658,756 during the Record Period. Table III-10 shows the monthly sums of fuel usage and cost for all five Peakers.[50]

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[50] Each monthly accounting entry for fuel cost includes a forecast of the cost expected to be incurred in that month, as well as an entry which reconciles the prior month's cost forecast with the prior month's actual recorded cost. The cost data provided herein reflects this accounting practice and does not include fuel delivery (*i.e.*, transportation) costs, while the fuel usage data provided herein is the actual fuel consumed as recorded at the end of each month.

Table III-10
SCE Peakers - 2022 Fuel Usage & Cost

Line No.	Month	Usage (MMBtu)	Cost ($)
1	January	60,836	404,219
2	February	59,521	444,037
3	March	92,011	588,354
4	April	145,805	1,090,683
5	May	93,527	816,381
6	June	115,825	1,177,937
7	July	190,120	1,703,010
8	August	133,940	1,504,022
9	September	64,428	802,848
10	October	35,524	244,669
11	November	43,386	400,272
12	December	51,025	1,482,324
13	TOTAL	1,085,945	10,658,756

2. Results of Operation

The efficient use and reliability of SCE Peaker generation resources are ensured through attentive management of the facilities. Reliability is demonstrated using power generation industry performance metrics, including Commercial Availability, EAF, and FOF. This section provides data on these metrics for the Peaker facilities.

a) Equivalent Availability Factor Results

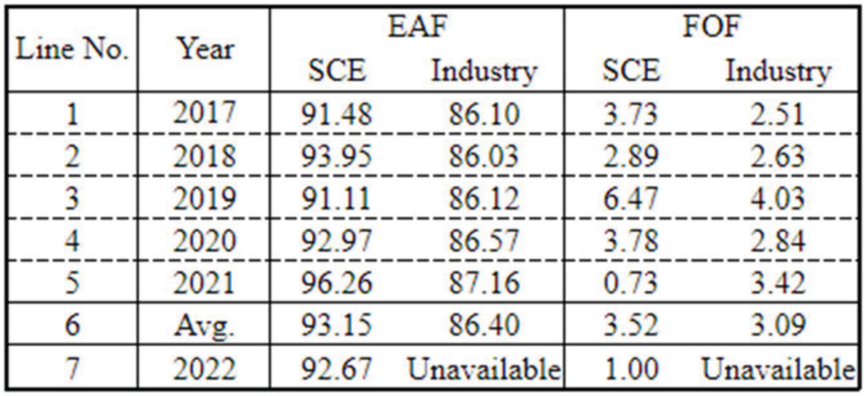
EAF is a measure of plant reliability that reflects the percentage of time that the generating unit is available for rated production. EAF is reduced by full outages and derates and includes both scheduled and unscheduled outages. EAF is not reduced by activities external to the Peaker plant that cause the Peaker to be out of service, such as transmission or gas pipeline outages.

The combined average EAF for the five Peakers for the 2022 Record Period was 92.67 percent as shown in Table III-11 below. This is slightly lower than the SCE Peaker average annual EAF of 93.15 for the prior five years, and significantly higher than the five-year industry average of approximately 86.40 percent (2017-2021),[51] reflecting the continued reliability of the SCE Peakers.[52] As discussed in more detail below, Record Period EAF was impacted by several factors, including the planned spring outages at the five Peakers.

b) Forced Outage Factor Results

FOF is a measure of plant reliability that reflects the extent of unscheduled (*i.e.*, forced) unit outages during the Record Period. Specifically, FOF is the percent of time a Peaker was not available for service due to an unscheduled outage. The ideal FOF level is a low percentage.[53] As shown in Table III-11 below, the combined average FOF for the five Peakers during the 2022 Record Period was 0.9 percent. In contrast with EAF performance, 2022 FOF was lower (*i.e.,* better) than that recorded by the SCE Peakers during the prior five years and the industry average.

Table III-11
SCE Peakers - 2022 Reliability



Line No.	Year	EAF		FOF	
		SCE	Industry	SCE	Industry
1	2017	91.48	86.10	3.73	2.51
2	2018	93.95	86.03	2.89	2.63
3	2019	91.11	86.12	6.47	4.03
4	2020	92.97	86.57	3.78	2.84
5	2021	96.26	87.16	0.73	3.42
6	Avg.	93.15	86.40	3.52	3.09
7	2022	92.67	Unavailable	1.00	Unavailable

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[51] Historical industry EAF and FOF performance data is provided in Appendices III-B through III-F. (Source data was obtained from http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).

[52] The Industry Average EAF and FOF provided herein are computed from all simple cycle combustion turbine power plant generating units reporting into the NERC GADS data base. There is not a distinct GADS category for "Peaker" power plants. While it is common for simple cycle combustion turbine power plants to be used for Peaking service, other technologies can also be used for Peaking service, such as diesel generators.

[53] Although the ideal FOF is a low percentage, in practice the power industry has not been able to eliminate all forced outages while sustaining cost-effective maintenance practices.

3. **Outage Events**

Since 2007 (the first year of operation for four of the five Peaker plants), SCE has utilized NERC GADS to track outage events (scheduled and unscheduled outages) at its Peaker facilities.[54] GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, specific objectives for the GADS program were established – compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment. The following sections discuss outage events that occurred during the Record Period.

a) Scheduled Outages

Scheduled outages include planned and maintenance outages as well as planned and maintenance outage extensions. Planned outages are typically scheduled at the start of each year. During the year, maintenance outages are scheduled when needed to perform non-emergency repairs, typically during a time better suited for the bulk power grid (*e.g.,* on weekends).

As shown in Table III-12 below, there were two annual maintenance inspection outages performed on the five Peakers during the Record Period, which accounted for approximately 1,001 outage hours, or approximately 22 percent, of the 2,276 total scheduled outage hours.[55] Additional scheduled outages included approximately 904 hours to perform the Barre Peaker Digital Control System (DCS) Upgrade, 201 hours for to perform the Grapeland Hybrid Peaker Generator Voltage

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[54] For information on outage report code definitions, please refer to Appendix III-A and the NERC-GADS Data Reporting Instructions, *available at* http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Entire%20GADS%20Data%20Reporting%20Instructions%20Effective%20January%201,%202015.pdf.

[55] Annual maintenance inspections are typically performed during the spring and fall time periods (*i.e.,* two inspections a year per Peaker); however, factors such as run time between maintenance inspections may allow for the deferral of an annual maintenance inspection.

Control upgrade, and 132 hours for "Misc." other planned maintenance activities such as black start testing and fire protection instrumentation and controls testing.[56]

Table III-12
SCE Peakers - 2022 Scheduled Outage Results

Line No.	Outage Purpose	Number	Hours:Mins
1	Annual Maintenance Inspections	2	1001:41
2	Barre Peaker DCS Upgrades	1	940:20
3	Grapeland Peaker Generator Voltage Control	1	201:30
4	Other - Misc.	16	132:48
5	TOTAL	20	2276:18

b) Unscheduled Outages

An unscheduled outage occurs when either equipment suddenly fails or must be removed from service relatively quickly because of control problems or to prevent damage. The unit either immediately trips or a shutdown is initiated, at which time the required repair proceeds. There were 51 unscheduled outages during the Record Period, which totaled approximately 934 hours. Many of the unexpected equipment problems that arose were diagnosed and quickly corrected. Two of the 51 unscheduled outages exceeded a duration of 24 hours.[57] These two outages are summarized in Table III-13 and discussed in further detail thereafter.

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[56] Those Out of Management Control (OMC) outages that include transmission system outages, gas supply line repair outages and black start testing outages are not included in either the EAF or FOF computations presented herein.

[57] D.15-03-023, p. 3, requires that SCE provide certain information in its annual ERRA Review filings for forced outages exceeding 24 hours, where the forced outage affected a generating unit with a rated capacity exceeding 25 MW, or affected multiple generating units at a given power plant having a combined capacity exceeding 25 MW.

Table III-13
SCE Peakers - 2022 Unscheduled Outages Exceeding 24 Hours

Line No.	Plant	NERC Event Type	MW's Affected	Beginning Date/Time	Ending Time/Date	Outage Length (hrs mins)	Incident Report
1	Center Peaker	U1	49.0	11/7/2022 9:03	11/9/2022 15:45	34:27	Yes
2	Grapeland Peaker	U1	49.0	12/20/2022 5:33	12/21/2022 16:00	54:42	Yes

(1) Center Hybrid Peaker – Failed Water Injection Pump

On November 7, 2022, while operating the plant the Operator noticed he could not maintain the plant within CO (Carbon Monoxide) emissions limits. Each Peaker power plant must be operated in accordance with the strict air permit requirements set by the South Coast Air Quality Management District. The Operator accomplishes this by adjusting how much ammonia is injected into the system for NOX (Oxides of Nitrogen) limits and by controlling how much water is injected into the system for CO (Carbon Monoxide) limits.

The maintenance team determined through troubleshooting activities that the CO emissions reduction water injection pump coupling had failed in service. The water injection pump pressurizes the water that is injected into the system to control CO emissions. The coupling is a small component that connects the pump mechanism to its motor.

A new coupling and new shim packs were installed. The shim packs ensure that the pump and its motor are aligned properly and level. The Operations team then test-ran the pump to ensure proper check vibration readings and proper discharge water pressure. The pump performed as expected and the plant was returned to service. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(2) Grapeland Hybrid Peaker – "LO-LO" Turbine Lubricating Oil Pressure Alarm

On December 20, 2022, during a plant startup, Grapeland Hybrid Electric Gas Turbine (EGT) Peaker tripped offline. The Operator observed a "LO-LO" Turbine Lubricating oil pressure alarm condition had tripped the unit. This is a protective function that ensures the turbine is not operated without sufficient lubricating oil present. If the turbine were operated without sufficient oil, the resulting friction and heat could cause severe damage to the turbine. The operator observed the control system was showing Turbine Lubricating oil pressure switching between 30 psi and 0 psi and then back to 30 psi. A technician was called to troubleshoot the problem. The technician inspected the Turbine Lubricating oil LO-LO pressure switch but did not detect any damage or malfunction. The technician cleaned the switch and made minor adjustments to ensure optimized operation. The plant was then returned to service. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

C. SCE Mountainview Generating Station

Mountainview is a two-unit (Units 3 and 4) combined cycle natural gas-fired power plant in Redlands, California. Each unit has a nominal rating of 555 MW and consists of two combustion turbines and one steam turbine for a combined total nominal capacity of 1,110 MW.[58]

Mountainview was originally owned by Mountainview, LLC (MVL), a wholly owned subsidiary of SCE. In D.09-03-025, the Commission ordered SCE to transfer ownership of Mountainview from MVL to SCE. Ownership was transferred in 2009 and, as a result, the MVL PPA was terminated. Since this transfer of ownership, Mountainview capital and O&M recorded costs are recovered through SCE's GRC-authorized base rates, and the fuel costs through the annual ERRA proceedings.

In this chapter, SCE discusses Mountainview operations and recorded fuel costs for the Record Period.

1. Mountainview Performance During the Record Period

As shown in Table III-14, Mountainview Units 3 and 4 started a combined total of 234 times and provided 3,735,152 MWh of energy during the Record Period (*i.e.*, a capacity factor of

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[58] In mid-2016, the Mountainview combustion turbines were upgraded during a routine overhaul, which raised the plant's California Energy Commission specified net nominal rating from 1,050 MW to 1,110 MW. The plant's actual maximum MW output varies above and below this value as a function of ambient temperature, and is also constrained by the plant's transmission limit of 1,110 MW.

approximately 38 percent). While outages occurring within the Record Period were contributors to the historically low capacity factor, the main driver was changes in the CAISO dispatch.[59]

Table III-14
SCE Mountainview - 2022 Generation

Line No.	Unit	Generation (MWh)	Starts
1	3	1,861,946	112
2	4	1,873,206	122
3	TOTAL	3,735,152	234

2. **Fuel Usage and Cost**

During the Record Period, the Mountainview units consumed 27,327,121 MMBtu of natural gas at a cost of approximately $295,899,975 million. Table III-15 below provides the monthly fuel usage and fuel cost for the Record Period.[60]

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[59] Mountainview capacity factor averaged 65 percent from 2007 through 2015. It was 53 percent in 2016, 44 percent in 2017, 21 percent in 2018, and 33 percent in 2019. Although outages played a part in lowering the capacity factors in both 2016 and 2017, it appears that significant increases in new renewables coming online is increasing energy supply during certain periods, lowering market clearing prices and causing Mountainview to be economic to run fewer hours during the year. This trend will likely continue as more renewables are brought on-line to meet increasing Renewables Portfolio Standard requirements.

[60] Each monthly accounting entry for fuel cost includes a forecast of the cost expected to be incurred in that month, as well as an entry which reconciles the prior month's cost forecast with the prior month's actual recorded cost. The cost data provided herein reflects this accounting practice and does not include fuel delivery (*i.e.*, transportation) costs, while the fuel usage data provided herein is the actual fuel consumed as recorded at the end of each month.

Table III-15
SCE Mountainview – 2022 Fuel Usage & Cost

Line No.	Month	Usage (MMBtu)	Cost ($000)
1	January	256,534	1,596
2	February	429,977	2,585
3	March	0	9
4	April	1,396,329	9,475
5	May	1,993,127	15,417
6	June	1,912,429	16,886
7	July	2,890,847	22,780
8	August	4,523,619	46,649
9	September	3,908,416	44,326
10	October	3,968,553	26,576
11	November	2,915,880	26,623
12	December	3,131,409	82,979
13	TOTAL	27,327,121	295,900

3. Mountainview Reliability During the Record Period

The efficient use and reliability of Mountainview is ensured through attentive management of the facilities. Reliability is demonstrated using power generation industry performance metrics, including Commercial Availability, EAF, and FOF. This section provides data on these metrics for Mountainview.

a) Equivalent Availability Factor (EAF) Results

EAF is a measure of plant reliability that reflects the percentage of time that the generating unit is available for rated production. EAF is reduced by full outages and derates and includes both scheduled and unscheduled outages. EAF is not reduced by activities external to the plant that cause the unit(s) to be out of service, such as transmission or gas pipeline outages.

The combined average EAF for Mountainview during the 2022 Record Period was 81.90 percent as shown in Table III-16 below. This is approximately 6.0 percent lower than the average annual EAF for the prior five years and the five-year industry average of approximately 84.40

percent (2017-2021),[61] [62] As discussed in more detail below, Record Period EAF was impacted by several factors, including the planned spring outages.

b) Forced Outage Factor (FOF) Results

FOF is a measure of plant reliability that reflects the extent of unscheduled (*i.e.*, forced) unit outages during the Record Period. Specifically, FOF is the percent of time Mountainview was not available for service due to an unscheduled outage. As shown in Table III-16 below, the FOF during the 2022 Record Period was 3.10% percent, which was lower (*i.e.,* better) than the prior five-year average recorded by Mountainview and slightly higher the industry average during that same five-year period.[63]

Table III-16
SCE Mountainview – 2022 Reliability

Line No.	Year	EAF		FOF	
		SCE	Industry	SCE	Industry
1	2017	83.46	84.17	12.71	2.35
2	2018	81.50	85.13	7.11	2.19
3	2019	89.36	85.08	7.09	2.21
4	2020	88.08	85.05	2.60	2.84
5	2021	93.29	82.55	0.29	3.29
6	Avg.	87.14	84.40	5.96	2.58
7	2022	81.90	Unavailable	3.10	Unavailable

4. Outage Events

Since 2005 (the year Mountainview began operation), SCE has utilized the NERC GADS to track outage events (scheduled and unscheduled outages) at Mountainview. GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, specific objectives for the GADS program were established:

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[61] Historical industry EAF and FOF performance data is provided in Appendices III-B through III-F. (Source data was obtained from http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).

[62] The Industry Average EAF and FOF provided herein are computed from all simple cycle combustion turbine power plant generating units reporting into the NERC GADS data base.

[63] Historical industry EAF and FOF performance data is provided in Appendices III-B though III-F. (Source data was obtained from http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).

compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment. The following sections discuss outage events that occurred during the Record Period.

a) Scheduled Outages

Scheduled outages include planned and maintenance outages as well as planned and maintenance outage extensions. Mountainview typically schedules a planned outage for both units in the spring to prepare for the summer peak season and then schedules a planned outage for both units in the fall to address issues observed during the summer peak season. During the year, additional maintenance outages are scheduled when needed to perform non-emergency repairs, typically during a time of lower power prices (*e.g.,* on weekends).

During the Record Period, and across units 3 and 4, Mountainview scheduled two outages, zero planned outage extensions, four planned derates, one maintenance outages, and no maintenance outage extensions. One of the two planned outages was initiated to perform annual maintenance activities. Combined, the 12 outages totaled approximately 1,481 outage hours.

b) Unscheduled Outage Events

The two generating units at Mountainview experienced a combined total of 37 unscheduled (*i.e.*, forced) outages, totaling approximately 730 hours during the Record Period, nine of these outages exceeded a duration of 24 hours as summarized in Table III-17 and as further explained herein.[64]

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[64] D.15-03-023 requires that SCE provide certain information in its annual ERRA Review filings for forced outages exceeding 24 hours, where the forced outage affected a generating unit with a rated capacity exceeding 25 MW or affected multiple generating units at a given power plant having a combined capacity exceeding 25 MW.

Table III-17
Mountainview – 2022 Unscheduled Outages
(Lasting Longer than 24 Hours)

Line No.	Unit	Event Type	MW Affected	Beginning Date/Time	Ending Time/Date	Length (hrs:mins)	Incident Report
1	4B	D1	305.0	12/30/2021 16:28	1/3/2022 10:20	89:52	Yes
2	4A	D1	305.0	2/23/2022 15:40	2/25/2022 3:43	36:03	Yes
3	3	U1	555.0	2/24/2022 7:45	2/25/2022 9:52	26:07	Yes
4	3	U1	555.0	4/29/2022 11:30	5/7/2022 18:26	198:99	Yes
5	3A	D1	305.0	5/8/2022 8:21	5/9/2022 14:57	30:36	Yes
6	3B	D1	305.0	6/4/2022 7:58	6/5/2022 8:27	24:29	Yes
7	4	D1	305.0	11/4/2022 17:30	11/7/2022 18:48	73:18	Yes
8	3	D1	305.0	11/10/2022 0:00	11/12/2022 23:15	71:15	Yes
9	4	D1	305.0	11/19/2022 13:53	11/21/2022 21:21	55:28	Yes

(1) Mountainview Unit 4B – Fuel Gas Heater Skid Leak

On December 30, 2021, while Mountainview Unit 4 was offline because it was not required for generation by the California Independent System Operator, an Operator Mechanic while performing unit rounds discovered a gas leak emanating from the Unit 4B Fuel Gas heater skid inlet flange (North/Lower). As this was both a safety and unit reliability concern, the unit was placed in a forced outage to facilitate repairs.

Each gas turbine at Mountainview requires fuel gas to be heated to 365 degrees F. Heating of the fuel is performed by Fuel Gas Heaters, sometimes referred to as a Performance Heaters, that use Intermediate Pressure (IP) Economizer Outlet Water from the Heat Recovery Steam Generator (HRSG) to accomplish this heating. The Fuel Gas Heaters are made up of 3 modular shell and tube heat exchangers that are stacked in series to achieve the needed heat transfer. Starting in 2019, Mountainview Unit 4A and 4B have experienced 17 documented cases of gas leaks from the Fuel Gas Heaters.

Heated gas is required for operation of the gas turbines and a fuel gas heater leak results in a forced outage of the associated gas turbine. SCE's analysis revealed that these leaks were not the result of a single cause, but instead were caused by several different contributing factors, explained below. The evaluation team developed corrective actions designed to address each of these factors and to mitigate continued recurrence of gas leaks at the Fuel Gas Heaters.

- Cyclic Operation (pressure and temperature cycles): Mountainview was designed to operate in baseload mode. This means that the plant would come online and remain at full power output for long periods of time. To support the growth of intermittent renewable energy sources, Mountainview has been required to cycle off and on regularly. The IP Economizer water pressure to the Fuel Gas Heaters drops when the unit is off and the fuel gas pressure from Southern California Gas Company remains relatively constant. The difference in pressure between the IP Economizer water and fuel gas while the plant is in operation results in a ~18,000 lb. force pushing on the gas seal in a favorable direction to prevent leaks. When the unit is off with 450-500 psi fuel gas and 0 psi IP Economizer water, there is a ~28,000 lb. force pushing the gas seal open. The bolts on the Fuel Gas Heater closure system are sized to prevent any movement and loss of sealing that could result in a leak path for fuel gas. All of the fuel gas leaks that have occurred have happened with the unit offline. Thermal cycles and differential temperatures between the hottest and coldest parts of the system can also impact these seals. The gas leaks always occur on the lower left head (end cover) of the heat exchanger, which is also the hottest head of these multi-pass heat exchangers. Both pressure and temperature cycles are contributing to the cause of these leaks. However, because 3A and 3B have not had any gas leaks and experience the same fluctuations, cyclic operation at Mountainview cannot be the root cause of these gas leaks.
- Pipe Strain: Another potential issue and difference between 3A and 3B Fuel Gas Heaters is the piping systems. Due to a fuel gas leak into the closed cooling water system on Unit 4, the fuel gas coolers had to be isolated by removing the fuel gas cooler isolation valves on both 4A and 4B (FGHV-623 and FG-HV-624). Removal of these valves may have created pipe strain that contributed to the Fuel Gas Heater leaks on 4A and 4B. The IP Economizer water supply to the Fuel Gas Heaters is supported by a rigid support with a U bolt to hold the pipe in place and prevent pipe strain from this pipe on the Fuel Gas Heater head.

Improper alignment or strain from this pipe could also contribute to movement and provide a leak path.

- Age: Wear was identified on both the Shell Flange and Tube Fitting gas sealing surfaces. This wear was not sufficient enough to prevent the sealing surfaces from sealing following maintenance but as the units went through thermal and pressure cycles it allowed relative motion between the sealing surfaces and provided a leak path.

Because a single cause is not able to be determined, corrective actions to address all potential causes will be implemented as appropriate. Cyclic operation is unavoidable due to current operating conditions, so the heat exchangers must be able to accommodate frequent temperature and pressure cycles without developing leaks. RW Holland (Original Equipment Manufacturer) provided recommendations for new upgraded Closure Bolt Stud Material and Belleville Style Washers to ensure the clamping force on the sealing surfaces is maintained during pressure and temperature cycles. Pipe strain will be addressed by ensuring the IP Economizer Hot Water Supply Pipe is supported and the pipe U bolt clamp is intact. Additionally, new FG-HV-623 and 624 valves were installed on 4A and 4B to mitigate any pipe strain from them being out of the piping system from contributing to future pipe strain that could contribute to gas leaks. All the maintenance done during these gas leaks has increased the wear and effective age of these heat exchangers. RW Holland recommends blending any high spots or inconsistencies on the Shell Flange and Tube Fitting gas sealing surfaces by grinding with an 80-grit flapper wheel, install modified Shell-side Sealing Rings, and install modified Split Rings. This was completed on 4A and 4B during the spring 2022 planned outages. Additionally, RW Holland has a separated head design that they specify for combined cycle power plants with cyclic operation run profiles.

A Common Cause Evaluation and an Incident Report (IR) were created for this outage and have been provided in testimony workpapers.

(2) Mountainview Unit 4A – Fuel Gas Heater Skid Leak

On February 23, 2022, prior to startup of the Unit, an SCE operator mechanic noticed a natural gas leak emanating from the bottom of the Mountainview Unit 4A gas heater skid. This is a reoccurring issue similar to that discussed in the previous section of testimony. A Common Cause Evaluation and an Incident Report (IR) were created for this outage and have been provided in testimony workpapers.

(3) Mountainview Unit 3 – Trip

On February 24, 2022 at 7:45 AM, the Mountainview Units 3A and 3B combustion turbine generators (CTGs) and Unit 3 steam turbine generator (STG) simultaneously tripped offline. Upon investigation by SCE Test Techs, the probable cause was believed to be a failed fiber optic temperature sensor on the main CTG transformer. However, when the suspected fiber optic temperature sensor was checked, no issues were found, and the unit was returned to service. The trip has not repeated since this occurrence. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(4) Mountainview Unit 3A – Generator Breaker Failure

On April 29, 2022, just after 8:00 am at the request of the California Independent System Operator (CAISO), generator 3A[65] was in the process of being shut down. During shutdown, the Generator 3A 18 kV generator breaker failed to open resulting in the breaker failure protection system opening the 220 kV breakers in the San Bernardino Substation. SCE ICE (Instrumentation, Control & Electrical) and Test technicians investigated the incident and discovered that the generator breaker operating linkage was broken. Generator 3A 18 kV generator breaker was switched out electrically and the unit was placed in a derate outage through May 2, 2022, at 23:59.

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[65] Mountainview Unit 3 consists of two gas turbines (3A and 3B) and one steam turbine (3S). The discharge heat from the gas turbines is used to generate steam in the heat recovery steam generator to drive the steam turbine. The unit can operate in two configurations, 2x1, consisting of the operation of two gas turbines and one steam turbine for full generating capability of the unit, or the unit configuration can be 1x1 (C1), the operation of one gas turbine and one steam turbine. The C1 configuration results in a curtailed output to the grid.

As a result of this outage SCE has begun the process of sending all breakers (one at a time) to Hitachi for maintenance/repair and overhaul of the drive mechanisms. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(5) Mountainview Unit 3A – Steam Line Leak

On May 8, 2022, an Operator reported there was a steam leak above the Mountainview Unit 3A heat recovery steam generator (HRSG) main steam attemperator “1 TO 2” pipe. The leak occurred on a 1" vent pipe located off the top of the attemperator line just before two vent pipe block valves. The unit was placed in a forced outage to facilitate repairs by a welder.

After conferring with the Operations Supervisor, the operators crank cooled[66] 3A HRSG to expedite the cooling of the unit. Following unit cooling, SCE maintenance personnel discovered that a pipe support had restricted the vent piping's ability to compensate for expansion and contraction of the attemperator line during temperature variances that occur when the unit is online versus offline. Over time, this continual expansion and contraction had caused the piping to fail open. The piping was repaired, and the pipe support was moved in a manner to reduce future stresses on this vent piping. The other units were inspected, and no additional pipe support issues were found. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(6) Mountainview Unit 3B – High-Pressure (HP) Bypass Warming Line Steam Leak

On June 4, 2022, during a plant walkdown, an SCE Operator discovered a steam leak emanating from the flow orifice flange on the Mountainview Unit 3B high pressure (HP) steam warming line.[67] This warming line is used to preheat the steam system downstream of the bypass

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[66] The term “crank cooled” means that the generator operated like a motor to spin the shutdown gas turbine and push cold air through the HRSG to cool it down

[67] High pressure (HP) steam is developed in the heat recovery steam generator (HRSG) to rotate the steam turbine. The HP bypass line is used during startup, shutdown, and unit trip to divert HP steam from the steam turbine. It can also control the main steam pressure during normal on-line operation. The diverted steam is exhausted to the steam condenser where it is cooled to a liquid state and pumped back to the HRSG. Without a bypass system, steam from the HRSG would have to be exhausted to the atmosphere until the steam turbine generator is available to accept steam.

control valve prior to introducing the HP steam to the system; preventing rapid steam condensation and rapid thermal expansion of the colder HP bypass steam system. The flow orifice restricts the flow of steam to the steam system downstream.

Due to more frequent unit starting/stopping to match energy market demand, Mountainview has begun experiencing higher levels of equipment age and thermal stress.[68] The steam leak is due to its age and operation. SCE maintenance personnel replaced gaskets and flange bolts, and the unit was returned to service. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(7) Mountainview Unit 4 - Generator Breaker (52G) Control Wiring

On November 4, 2022, SCE maintenance personnel were troubleshooting a low pressure alarm on the main output breaker (52G) on Unit 4A.[69] During troubleshooting, the team discovered damaged control wiring inside the control cabinet. The maintenance team determined the cause of the damage to be a relay, designated "AN," which had suffered an in-service failure causing damage to adjacent components. The plant was placed in a forced outage and made safe for maintenance personnel to make repairs. Following replacement of the failed relay and all the damaged components, the operations team returned the unit to service. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(8) Mountainview Unit 3 – Combustion Turbine Flex Seals

Mountainview Generating Station was designed to operate in baseload mode, which means that the plant would come online and remain near full power output for long periods of time. In order to support the growth of intermittent renewable energy sources, and meet the increased cyclic operation resulting from CAISO system operating demands, Mountainview is now required to

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[68] Cyclic Operation (pressure and temperature cycles): Mountainview was designed to operate in baseload mode. This means that the plant would come online and remain at full power output for long periods of time. To support the growth of intermittent renewable energy sources, Mountainview has been required to cycle off and on regularly. Thermal cycles and differential temperatures between the hottest and coldest parts of the system affects bolted connections in piping systems.

[69] The main output breaker connects the Generator output to the rest of the electrical system (Grid).

cycle on and off with higher frequency. Cycling refers to the operation of electric generating units at varying load levels (power demand), including on/off and low load variations, in response to changes in system load (demand) requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which can cause damage.

The combustion turbines at Mountainview have exhaust flex seals which are located between the outer barrel and the structure of the combustion turbine exhaust frame. These seals allow for expansion between the two components while preventing hot gasses from entering the exhaust frame cooling air space. The seal is made of multiple thin layers of stainless-steel sheets that can slide in slots to account for this movement. This sliding motion wears the sheets and allows pieces to come loose and potentially contact the turbines 3rd stage blades. A borescope inspection of the Unit 3B flex seals performed during the 2022 annual maintenance outage showed some component distress and a follow-up borescope inspection was scheduled from November 6 through November 9 to verify the condition of the flex seals following the summer run. This second inspection showed further deterioration of the 3B flex seals and because SCE had last replaced the flex seals in 2019, plant engineering recommended replacement of this flex seals in order to prevent damage to the turbine 3rd stage blades. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

(9) Mountainview Unit 4 - Turning Gear Rotation Speed Sensor Failure

On November 18, following a normal shut down of Unit 4A, the unit was placed on turning gear and approximately 1 hour later the unit showed 0 RPM.[70] During inspection of the turning gear assembly the operations team visually observed that the shaft continued to rotate while the control system indicated it had stopped. The team timed the shaft rotation speed at 6 RPM, but the unit still indicated 0 RPM. Upon further inspection SCE Technicians discovered that two of the three

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[70] A turning gear is a device placed on the main shaft of an engine or the rotor of a turbine. The turning gear slowly rotates the shaft or rotor and associated machinery (such as reduction gears and main steam or gas turbines), to ensure uniform cool-down.

speed sensing probes had failed in-service and were no longer transmitting signals to the control system [71].

The unit was subsequently placed in a forced outage as two failed probes would have prevented a Start Permissive of the unit, which requires at least two of the three speed probes to be functioning correctly. Safe replacement of the failed speed probes required scaffolding and mechanical support. Following replacement of the two speed probes the unit was returned to service. An Incident Report (IR) was created for this outage and has been provided in supporting workpapers.

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[71] Speed probes detect the speed of the shaft and transmit data to the controls system.

IV.

OTHER GENERATION

A. Catalina Diesel Fuel / Liquefied Petroleum Gas (LPG) and Transportation

SCE purchased 50,052 barrels of ultra-low sulfur #2 red-dyed diesel fuel and burned approximately 49,944 barrels of diesel fuel for electric generation on Santa Catalina Island during the Record Period. The average cost of diesel fuel per barrel was $183.44, for an average annual cost of approximately $9.182 million. The average transportation cost for the truck and barge delivery was $19.91 per barrel, for an average annual cost of $996,535 million. When the total transportation cost is applied to the total fuel cost, the total average annual cost for diesel fuel is $10.178 million.

SCE has 23 LPG-fired combustion turbines for electric generation on the Island for which, during the Record Period, SCE purchased 894,176 gallons of LPG. The average total cost per gallon was $1.95, for an average annual cost of approximately $1.740 million. The average transportation cost for the truck and barge delivery was $0.27 per gallon, for an average annual cost of $241,475. When the total transportation cost is applied to the total fuel cost, the total average annual cost for LPG fuel is $1.982 million.

The isolated nature of Santa Catalina Island, limited storage capacity footprint, and complexity of delivery make it imperative that diesel fuel and LPG supplies are reliable. Therefore, a dedicated supplier is contracted to meet ongoing demand for Santa Catalina Island. Considering the contract structure (which is the lowest competitive pricing available) and the integrity of the supply provided under the contract (which is essential to providing an uninterrupted supply of utility services to Catalina Island), SCE's diesel and LPG purchases for the Record Period should be found reasonable.

In 2022, SCE extended an existing contract with AAA Oil, Inc., DBA California Fuels and Lubricants, to provide diesel, LPG, and associated delivery services (subcontracted to Avalon Freight Services) to the Pebbly Beach Generating Station for diesel, LPG, and urea based on their lowest price qualified bid, which were negotiated to remain unchanged from their pre-RFP contract rates.

Diesel is provided at the Oil Price Information Services wholesale contract rack average price, less $0.02 per gallon, plus all applicable taxes and fees. Diesel delivery service is performed at $795.00

per truck load plus the cost of the CPUC-regulated barge service subcontracted to Avalon Freight Services.

LPG is provided at the Oil Price Information Services wholesale contract rack average price, plus $0.30 per gallon, plus all applicable taxes and fees. LPG delivery is performed at $475.00 per truck load plus the cost of the CPUC-regulated barge service subcontracted to Avalon Freight Services.

SCE's costs for diesel and LPG fuel for the Record Period are summarized below in Table IV-18 and Table IV-19. SCE's diesel fuel, LPG gas, and transportation costs conform to industry pricing information and regulatory-approved rates, and therefore should be found reasonable.

Table IV-18
Catalina Operations Diesel Fuel
2022 Recorded Delivered Diesel Costs

Date	Gallons Purchased	Barrels Purchased	Gallons Burned	Barrels Burned	Cost per Barrel	Invoice Total	Shipping Fee	Delivery Fee	Total Transport. Cost	Transport. Cost per Barrel	Total Diesel Cost	Cost/Gal
Jan-22	179,705	4,279	170058	4049	$144 06	$616,367 13	$64,418 10	$19,080 00	$83,498 10	$19 51	$699,865 23	$3.43
Feb-22	119,753	2,851	152712	3636	$154 03	$439,189 30	$42,785 94	$12,720 00	$55,505 94	$19 47	$494,695 24	$3.67
Mar-22	186,865	4,449	167958	3999	$181 13	$805,881 96	$66,552 96	$19,875 00	$86,427 96	$19 43	$892,309 92	$4.31
Apr-22	171,239	4,077	164724	3922	$192 69	$785,625 36	$60,892 98	$18,285 00	$79,177 98	$19 42	$864,803 34	$4.59
May-22	164,045	3,906	174720	4160	$202 97	$792,775 60	$58,403 16	$17,490 00	$75,893 16	$19 43	$868,668 76	$4.83
Jun-22	171,348	4,080	171612	4086	$214 39	$874,635 29	$61,159 20	$18,285 00	$79,444 20	$19 47	$954,079 49	$5.10
Jul-22	156,131	3,717	190050	4525	$193 40	$718,959 68	$58,844 76	$16,695 00	$75,539 76	$20 32	$794,499 44	$4.60 **
Aug-22	215,379	5,128	201978	4809	$185 30	$950,256 20	$81,232 72	$23,055 00	$104,287 72	$20 34	$1,054,543 92	$4.41
Sep-22	215,118	5,122	193830	4615	$192 26	$984,707 10	$81,787 37	$23,055 00	$104,842 37	$20 47	$1,089,549 47	$4.58
Oct-22	185,803	4,424	172620	4110	$202 68	$896,647 66	$70,153 66	$19,875 00	$90,028 66	$20 35	$986,676 32	$4.83
Nov-22	127,053	3,025	160608	3824	$184 47	$558,034 61	$47,989 06	$13,515 00	$61,504 06	$20 33	$619,538 67	$4.39
Dec-22	209,757	4,994	176778	4209	$153 89	$768,563 02	$79,278 99	$22,260 00	$101,538 99	$20 33	$870,102 01	$3.66
Totals	2,102,196	50,052	2,097,648	49,944		$9,191,642 91	$773,498 90	$224,190 00	$997,688 90		$10,189,331 81	
Averages					$183 44	$9,181,581 62				$19 91		
								Ann Transp. Cost	$996,535 32		$10,178,116 94	

** Effective 6/29/22 CPUC approved 6% fuel charge on all deliveries via Avalon Freight Services

Table IV-19
Catalina Operation Propane Fuel
2022 Recorded Delivered Propane Costs

Date	Gallons Purchased	Gallons Used	Cost per Gallon	Invoice Total	Shipping Fee	Delivery Fee	Total Transport. Cost	Transport. Cost per Gallon	Total Propane Cost
Jan-22	72,862	56,306	$2.00	$145,954.05	$15,679.44	$3,800.00	$19,479.44	$0.27	$165,433.49
Feb-22	54,276	53,119	$2.16	$117,023.02	$11,695.32	$2,850.00	$14,545.32	$0.27	$131,568.34
Mar-22	90,438	56,905	$2.26	$204,426.20	$19,506.48	$4,750.00	$24,256.48	$0.27	$228,682.68
Apr-22	45,438	60,289	$2.08	$94,284.00	$9,783.84	$2,375.00	$12,158.84	$0.27	$106,442.84
May-22	63,566	57,275	$1.86	$118,161.19	$13,654.74	$3,325.00	$16,979.74	$0.27	$135,140.93
Jun-22	80,635	56,463	$1.89	$152,134.93	$17,393.04	$4,275.00	$21,668.04	$0.27	$173,802.97
Jul-22	90,487	64,024	$1.85	$166,955.83	$21,270.88	$4,750.00	$26,020.88	$0.29	$192,976.71 **
Aug-22	89,476	56,400	$1.78	$159,236.11	$20,459.55	$4,750.00	$25,209.55	$0.28	$184,445.66
Sep-22	62,046	45,990	$1.81	$112,184.31	$14,137.77	$3,325.00	$17,462.77	$0.28	$129,647.08
Oct-22	63,233	56,644	$1.81	$114,345.81	$14,317.25	$3,325.00	$17,642.25	$0.28	$131,988.06
Nov-22	91,360	58,690	$1.82	$166,000.65	$20,779.58	$4,750.00	$25,529.58	$0.28	$191,530.23
Dec-22	90,359	62,047	$2.05	$185,573.33	$16,482.89	$3,800.00	$20,282.89	$0.22	$205,856.22
Totals	894,176	684,152		$1,736,279.43	$195,160.78	$46,075.00	$241,235.78		$1,977,515.21
Averages			$1.95	$1,740,073.14			241,475.87	0.27	1,981,500.66

** Effective 6/29/22 CPUC approved 6% fuel charge on all deliveries via Avalon Freight Services

B. <u>SCE Solar Photovoltaic (SPV) Program</u>

1. <u>Introduction</u>

SCE owns and operates 24 SPV facilities in its service area.[72] The 24 sites include one ground-mounted and 23 rooftop solar facilities, ranging in size from 0.5 MW to 6 MW AC. The total size of SCE's solar fleet is 59.5 MW AC (or 81.3 MW DC). Facility locations and rated capacity for each solar facility is summarized in Table IV-20 below.

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[72] Prior to 2019, there were 25 sites. One of the sites (Perris SPVP 044) was decommissioned in 2019.

Table IV-20
SCE-Owned Solar PV Plants

Line No.	Site Name	Location	Online Date	MW AC Capacity	MW DC Capacity
1	SPVP 002	Chino	9/24/2009	1	1.2
2	SPVP 003	Rialto	7/19/2010	1	1.2
3	SPVP 005	Redlands	12/27/2010	2.5	3.4
4	SPVP 006	Ontario	1/10/2011	2	2.6
5	SPVP 007	Redlands	12/29/2010	2.5	3.2
6	SPVP 008	Ontario	12/30/2010	2	2.9
7	SPVP 009	Ontario	1/10/2011	1	1.4
8	SPVP 010	Fontana	5/18/2011	1.5	2.3
9	SPVP 011	Redlands	11/10/2011	3.5	5.0
10	SPVP 012	Ontario	12/29/2010	0.5	0.8
11	SPVP 013	Redlands	9/15/2011	3.5	4.9
12	SPVP 015	Fontana	12/19/2011	3.5	4.7
13	SPVP 016	Redlands	5/18/2011	1.5	1.8
14	SPVP 017	Fontana	12/14/2011	3.5	4.5
15	SPVP 018	Fontana	5/23/2011	1.5	1.9
16	SPVP 022	Redlands	11/15/2010	2	3.1
17	SPVP 023	Fontana	5/12/2011	2.5	3.9
18	SPVP 026	Rialto	8/26/2011	6	8.6
19	SPVP 027	Rialto	11/27/2012	2	2.6
20	SPVP 028	San Bernardino	12/20/2011	3.5	4.9
21	SPVP 032	Ontario	12/22/2011	1.5	1.7
22	SPVP 033	Ontario	12/12/2011	1	1.3
23	SPVP 042	Porterville	12/28/2010	5	6.8
24	SPVP 048	Redlands	8/12/2013	5	6.8
25	Total MW AC			59.5	81.3

As approved by the Commission on June 18, 2009, the goal of SCE's Solar Photovoltaic Program (SPVP) was to drive installation costs down, improve technology and pricing of certain components, increase installation efficiency, and improve installation methods for solar photovoltaic technology.[73] In approving the SPVP, the Commission articulated that this program was "about driving

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[73] D.09-06-049.

the costs of deploying an existing technology down by creating a new market opportunity."[74] SPVP has contributed to these objectives, and the performance of the SCE-owned solar plants during the Record Period was reasonable as discussed in further detail below.

2. <u>Solar Performance Tracking</u>

SCE has adopted capacity factor as a primary indicator of SPV plant and fleet performance. Following the same convention as used by other types of power plants, SCE computes solar plant capacity factor as the percentage of actual generation as compared to the theoretical maximum generation that could be produced by a site (or by the entire fleet of sites) assuming the plant (or fleet) operated at rated MW output for all hours of the year.

Although solar plants do not operate after dark, the capacity factor computations discussed include night-time hours in the denominator (*i.e.,* achieving a capacity factor of even 50 percent would be impossible, even if all other parameters that limit capacity factor could be economically solved). Also, SCE computes capacity factor using AC measurements (*i.e.*, on the distribution grid side of the inverter), whereas others might use DC measurements (*i.e.,* on the panel side of the inverter), which would yield a higher computed capacity factor because it would exclude the inherent efficiency losses caused by the plant's inverters. There are numerous other factors that limit the economically achievable capacity factor of solar plants. These include:

- <u>Time of year and available daylight hours</u>: The time of year and associated daylight hours affect the cumulative output of SPV projects. There are more daylight hours during summer months than in the winter months, offering increased opportunity for the panels to generate electricity.
- <u>Weather and cloud cover</u>: Weather and varying degrees of cloud cover can also affect the output of the SPV projects. SPV modules generate the most electricity on cool, sunny days, and become less efficient as they heat up on hot days. Partially cloudy skies can also cause rapid swings in solar facility output.

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[74] *Id*, p. 53.

- Changes in temperature: Changes in temperature can affect the generating efficiency of solar panels. Most SPV panels have a rating between 20 and 25 degrees Celsius (*i.e.*, between 68- and 77-degrees Fahrenheit). Panel's generating efficiency decreases when the air temperature surrounding the panel (known as ambient temperature) is warmer than the panel's rating.
- Panel soiling: During extended periods without rain, the SPV panels become soiled with dust, emissions, and other particulates in the air. This panel soiling can cause decreased panel efficiency.
- Panel age: The efficiency of SPV panels degrades with age. Newly installed panels will generate electricity more efficiently than panels operating for several years.
- Aerosol scattering: Aerosol scattering occurs when direct light from the sun passes through small aerosol particles in the air. Aerosol particles can include dust, saltwater droplets, smog, or smoke. Sunlight hits the particles and reflects off in many directions, becoming scattered light. SPV panels produce electricity most efficiently with direct light. In inland areas where air pollution is more prevalent (and where all of SCE's SPV plants are located), aerosol scattering has a degrading effect on the ability of panels to generate electricity. The Porterville area where the ground-mounted facility (SPVP #042) is located experienced approximately five weeks of severe filtration of the sun due to smoke from local fires.
- Outages for Maintenance Activities: While solar plants do not have moving parts nor the associated maintenance activities required for other types of generating plants, some maintenance is required, including repairs to equipment components that fail. Such maintenance often requires the plant to be disconnected from the grid (*i.e.,* to incur an outage). Outages are also occasionally needed to perform plant modifications made in response to events that occur.

3. SPV Generating Facilities Performance During the Record Period

When the SPVP was initiated, based on conversations with panel suppliers and other research, SCE forecasted that, once constructed, the SCE-owned SPV would operate with a 20 percent system capacity factor.[75] The SCE-owned SPV plants have operated slightly below this forecast, having recorded an overall capacity factor of 16.8 percent from the inception of the program through 2022. During the Record Period, the SCE-owned SPV plant fleet capacity factor was 9.8 percent (*i.e.*, the fleet recorded 51,507 MWh AC of generation).

The Record Period capacity factor performance was approximately 7.0 percent lower than the historic average because: (a) ongoing normal panel efficiency degradation over time, and (b) the de-energization of 8 SPVP sites.

a) Panel Efficiency Degradation

An analysis of studies that examined the long-term degradation rates of various PV panels was performed by the National Renewable Energy Laboratory.[76] The results showed that for monocrystalline silicon, the most used panel for commercial and residential SPV panels, the degradation rate per year is less than 0.5 percent for panels made before 2000, and less than 0.4 percent for panels made after 2000. While this is a relatively low annual rate, it does result in some level of degradation over the expected life of solar installations. The SCE SPVP initial installation commenced in 2009 and all sites now exceed a decade of operation. The majority of SCE's SPV units are in the Inland Empire area of Southern California, where high temperatures occur in the summer months, increasing the rate of potential degradation of the units.

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[75] *See* A.08-03-015, Solar Photovoltaic (PV) Program Testimony, March 27, 2008, p. 7, line 23; and A.08-03-015, Reply of Southern California Edison Company's (U-338-E) to Responses or Protests of DRA, TURN, IEP, CAL SEIA, CC Energy, Joint Solar Parties, Recurrent Energy, and A-1 Sun, Inc. May 8, 2008, Appendix B, "Declaration of Rudy Perez," Declaration 3.

[76] https://www.engineering.com/DesignerEdge/DesignerEdgeArticles/ArticleID/7475/What-Is-the-Lifespan-of-a-Solar-Panel.aspx.

b) De-energization

While SCE Generation department has been operating and maintaining the SPVP facilities utilizing prudent industry practices and targeting to maintain a 20 percent capacity factor, maintenance practices have evolved over the years to optimize the O&M expense and keep it below the combined values of energy revenue, Renewable Energy Credits ("REC") and Resource Adequacy ("RA") with the intention of assuring a net positive value to SCE customers. However, with declining energy prices around the time of the day when SPVP generates electricity, because of oversupply of energy relative to demand, energy revenue has declined significantly in recent years. The RA value has also declined because of a reduction in Net Qualifying Capacity ("NQC") of the facilities. In addition, the REC prices have declined significantly over the last few years. The overall reduction in value from these facilities has influenced a reduction in maintenance expense targets.

Aging infrastructure and manufacturer/installer design deficiencies have resulted in a surge in expenditure necessary to assure safe and compliant operation of the facilities. Although the facilities were designed and constructed per industry standards at the time of installation, given the infancy of solar photovoltaic technology, deficiencies in construction existed and have been gradually discovered over the years. For example, in late 2021, a damaged connector/cable became an ignition source causing a localized rooftop fire of an installation site. The incident evaluation attributed the damage to a design deficiency in the panel string connector. Following this event, SCE performed a fleet wide evaluation which resulted in the de-energization of the top eight high risk sites to mitigate the risks of further rooftop hotspots, fire and asset failures.

SCE has been operating the portfolio for over 10 years and has successfully demonstrated solar photovoltaic technology as a new market opportunity. As solar SPVP costs have come down in recent years, SCE has successfully achieved the objectives of the SPVP program. SCE has determined, however, that continued operation of the facilities is no longer in the best interests of SCE customers because an increase in maintenance expenses and safety risks, coupled with declining value, has turned the operating economics unfavorable to SCE customers.

4. Summary

During the Record Period, SCE's SPV fleet performed at a capacity factor consistent with the unit's age and the operating characteristics of the ground fault protection systems installed to increase site safety. SCE continues to manage its SPV generating units in a manner that achieves an appropriate balance between fleet performance, economic value for customers, and O&M costs.

C. SCE Fuel Cell Demonstration Program

1. Introduction

SCE's Fuel Cell Demonstration Program is a partnership between SCE and the University of California Santa Barbara (UC Santa Barbara) and California State University San Bernardino (CSU San Bernardino) for educational and demonstration purposes.[77] The program consists of the installation and operation of two utility-owned fuel cell generating facilities with a combined capacity of 1.6 megawatts (MW) at UC Santa Barbara and CSU San Bernardino.

a) UC Santa Barbara

UC Santa Barbara's fuel cell facility is a 200-kW facility. This fuel cell uses a solid oxide fuel cell technology manufactured by Bloom Energy and is an electric-only fuel cell.[78] The Bloom Energy fuel cell converts natural gas to electricity, providing electricity to SCE's local distribution electrical grid. The unit became operational on September 6, 2012. SCE has a ten (10) year Lease Agreement with UC Santa Barbra that ceased in September 2022. Per that lease agreement, UC Santa Barbra had the right to obtain ownership and operate the facility at their request. SCE discussed turning the assets over to the University, but UC Santa Barbara declined to exercise their contractual right to retain the assets beyond the lease terms. SCE is therefore obligated under the terms of the contracts to remove the assets. SCE has successfully concluded the ten-year demonstration program and has discontinued operation of the facility at the expiration of the contract.

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[77] D.10-04-028, p. 27.

[78] The UCSB fuel cell is an electric-only fuel cell and does not provide any thermal output.

b) CSU San Bernardino

CSU San Bernardino's fuel cell facility is a 1.4 MW facility. This fuel cell uses a molten carbonate fuel cell technology manufactured by Fuel Cell Energy. The Fuel Cell Energy unit converts natural gas to electricity and heat, providing electricity to SCE's local distribution grid and heat for CSU San Bernardino's use in its campus heating operations. The unit has been operational since October 3, 2013.

D. Fuel Cell Operations During the Record Period

The two SCE Fuel Cell projects provided 8,154 MWh of energy during the Record Period as shown in Table IV-21.

Table IV-21
SCE Fuel Cells – 2021 Performance

Line No.	Annual Values	USC Santa Barbara Electric Only	CSU San Bernadino Combined Heat and Power	Total
1	Electrical Output (kWh)	900,290	7,529,701	8,429,991
2	Fuel Consumption (mmBtu)	9,768	73,268	83,036
3	Fuel Costs	100,497	880,466	980,963
4	Capacity Factor (Electrical)	51%	61%	

1. Fuel Usage and Cost

During the Record Period, SCE Fuel Cells consumed 83,036 MMBtu of natural gas at a cost of $0.98 million. Table IV-22 below shows the monthly sums of fuel usage and cost for both fuel cell projects.[79]

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[79] Each monthly accounting entry for fuel cost includes a forecast of the cost expected to be incurred in that month, as well as an entry which reconciles the prior month's cost forecast with the prior month's actual recorded cost. The cost data provided herein reflects this accounting practice, while the fuel usage data provided herein is the actual fuel consumed as recorded at the end of each month.

Table IV-22
SCE Fuel Cell – 2022 Fuel Cell Usage and Cost

Line No.	Month	Usage (mmBtu)	Cost ($)
1	January	7,839	65,068
2	February	7,149	64,752
3	March	7,822	63,350
4	April	6,985	61,416
5	May	8,142	81,037
6	June	3,698	45,900
7	July	7,024	72,073
8	August	8,355	107,497
9	September	7,488	103,345
10	October	7,598	68,584
11	November	5,031	56,095
12	December	5,906	191,848
13	TOTAL	83,036	980,963

2. <u>Record Period Performance Summary</u>

The Record Period capacity factors (*i.e.*, for electrical generation only, relative to the rated kW electrical output of the fuel cell) for the UC Santa Barbara and CSU San Bernardino generating facilities were 51 percent and 61 percent, respectively.

For the Record Period, the UC Santa Barbara facility did not experience any full site outages of 24 hours or greater. As mentioned above, SCE has concluded the ten-year demonstration program and decommissioning of the facility commenced in September of 2022.

The CSU San Bernardino Fuel Cell capacity factor for 2022 was 61 percent, an 8 percent increase when compared to 53 percent in 2021. The fuel cell experienced no major outages in 2022 which contributed to the higher capacity factor.

SCE will continue to monitor and report on the operations of the CSU San Bernardino Fuel Cell and will continue to share the results as part of SCE's annual ERRA Review proceeding and through other appropriate venues. The cost incurred for fuel during the Record Period is a reasonable and unavoidable expense to achieve these program goals, consistent with the Commission’s approval of this demonstration program.

V.

NUCLEAR GENERATION AND FUEL

A. Introduction

SCE owns 15.8 percent of Palo Verde Nuclear Generating Station (Palo Verde) Units 1, 2, and 3, located approximately 50 miles west of Phoenix, Arizona. Arizona Public Service Company (APS) is the operating agent for Palo Verde, which is currently the nation's largest nuclear installation.[80] The rated net electrical generating capacities of Palo Verde Units 1, 2, and 3 are 1,346 MW per unit.

This chapter sets forth Palo Verde Nuclear Generating Station (Palo Verde) generation and nuclear fuel expenses incurred by SCE during the Record Period. In addition, this chapter also summarizes SCE's oversight responsibilities: the planning, procurement, and scheduling of nuclear fuel materials and services, and the reasonableness of nuclear fuel material and services purchased by SCE during the Record Period for its ownership share in Palo Verde.

B. SCE Oversight Responsibilities for Palo Verde

As a minority owner that is neither the operating agent nor the Nuclear Regulatory Commission (NRC) license holder for Palo Verde, SCE participates in various committees to oversee APS' administration of Palo Verde as described below.

- The Palo Verde Administrative Committee is chaired by an APS officer, the Executive Vice President, Nuclear. The Administrative Committee also consists of other members as appointed by the co-owner utilities. SCE's member of the Palo Verde Administrative Committee is SCE's Vice President and Chief Nuclear Officer. The Palo Verde Administrative Committee meets quarterly to focus on strategy and planning for the station.
- The Palo Verde Engineering and Operations (E&O) Committee is responsible for final review and approval of the annual O&M budget as prepared by APS, review of O&M budget status and variance reports, review of recommended corrective actions to budget variances,

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[80] The Alvin W. Vogtle Electric Generating Plant, also known as Plant Vogtle, is a four-unit nuclear power plant located near Waynesboro, Georgia. On March 6, 2023, Vogtle Unit 3 reached initial reactor criticality. Upon completion of Units 3 and 4 later in 2023, Vogtle will become the largest nuclear power station in the United States.

and approval of those actions as necessary. The E&O Committee also provides for oversight of engineering and plant operations, and outage schedule review and approval. SCE's Nuclear Generation Senior Project Manager represents SCE on the E&O Committee. SCE's Project Manager actively participates in E&O Committee meetings discussing and approving significant cost, schedule, and resource issues, and confirms that the development, approval, monitoring, and control of the O&M budget is acceptable to SCE. The Palo Verde E&O Committee typically meets eight times per year.

SCE receives routine reports from Palo Verde and reviews plant information at routine meetings, usually at the Palo Verde site or at APS headquarters in Phoenix. SCE also provides input and oversight of nuclear fuel purchases, audits, and decommissioning funding through its involvement in other committees. As a minority owner that is not the Palo Verde operating agent, SCE does not review or have access to all reports and documents generated from or to each of the disciplines in the plant and does not routinely receive the NRC quarterly inspection reports regarding Palo Verde. Instead, SCE relies on APS, the Palo Verde operating agent and NRC license holder, to inform SCE of relevant, material information regarding Palo Verde operations.

C. <u>Types of Nuclear Outage Activities</u>

1. <u>Refueling and Maintenance Outages</u>

A fossil-fueled unit can be refueled continually while it is operating; therefore, fossil unit outages are scheduled around the necessity to maintain the unit. A nuclear unit, however, can only be refueled when it is off-line. After a nuclear unit is refueled, it contains a finite quantity of fuel to consume during that fuel cycle before it must again be refueled. The forecasted rate of consumption for this quantity of fuel determines the scheduling of the next refueling outage. Maintenance work required to be performed while a nuclear unit is off-line is performed during scheduled refueling outages (RFOs).

Planning the duration of each RFO is a complex task. Every scheduled refueling outage has work activities similar in scope and outage time requirements including: (1) shutdown and cooldown of the reactor; (2) disassembly of the reactor; (3) fuel replacement; and (4) reassembly of the reactor, followed by heat up and startup of the plant. During these periods, scheduled maintenance is conducted, surveillance tests[81] are performed, and plant modifications are completed. Because the three Palo Verde units do not shut down routinely for non-refueling outages (as do fossil fueled units when maintenance is required), a great deal of maintenance work is planned for these scheduled refueling outages.

2. Forced Outage Activities

When an unplanned or forced outage to a nuclear unit occurs, the primary objective is to repair the item that led to the outage. While minimizing the outage period is important, a certain amount of work is required for every forced shutdown. This includes surveillance testing and complying with all regulatory requirements and emergent maintenance requirements that cannot be deferred to a later planned outage.

D. Palo Verde Record Period Performance

1. Palo Verde Generation

The capacity factor and net generation for the Record Period for Palo Verde Units 1, 2, and 3 are shown in Table V-23.

Table V-23
2022 Record Period Generation

Line No.	Palo Verde Unit	Capacity Factor	Generation MWh (Net)
1	1	90.72%	10,418,477
2	2	97.20%	11,192,856
3	3	89.80%	10,321,364
4	Total		31,932,697
5	Site Avg	92.57%	10,644,232
SCE's 15.8% Share			5,045,366

The EAFs and FOFs for five years of plant generation for Palo Verde are shown in Table V-24. As previously stated in Chapter III Hydroelectric Generation, the EAF considers scheduled outages and forced outages. The ideal percentage is as high a level as possible. The FOF is calculated using the hours that the generating unit was forced off-line. The ideal percentage is as low as possible.

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[81] These tests are required by NRC-approved technical specifications.

As shown below, Palo Verde's Record Period and five-year averages for both factors were better than the industry averages.[82]

Table V-24
2017-2022 EAF and FOF Palo Verde Generation

		EAF		FOF	
Line No.	Year	Palo Verde	Industry	Palo Verde	Industry
1	2017	91.95%	90.00%	0.51%	1.43%
2	2018	88.57%	91.58%	1.12%	0.58%
3	2019	90.82%	90.01%	0.34%	1.57%
4	2020	89.48%	90.05%	1.15%	2.03%
5	2021	89.88%	89.48%	2.07%	2.96%
6	Avg.	90.14%	90.22%	1.04%	1.71%
7	2022	90.74%	Not Available	1.33%	Not Available

Table V-25 shows that for the Record Period, Palo Verde Unit 2 generated 778,561 MWh more than the five-year average, and Palo Verde Units 1 and 3 generated 555,486 MWh less than the five-year average.[83]

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[82] The industry values were obtained from the NERC GADS database for All Units Reporting, Nuclear Pressurized Water Reactor Plants Greater than 1,000 MW.

[83] 291,210 MWh (Palo Verde Unit 1) + 264,276 MWh (Palo Verde Unit 3) = 555,486 MWh (Palo Verde Units 1 and 3).

Table V-25
2022 Palo Verde Generation (Net MWh, 100% Share)

Line No.	Period	Palo Verde 1	Palo Verde 2	Palo Verde 3
1	2017	10,477,953	10,588,603	11,273,582
2	2018	11,220,878	9,458,026	10,427,448
3	2019	10,515,168	11,434,510	9,969,691
4	2020	9,818,478	10,466,373	11,267,585
5	2021	11,515,959	10,123,961	9,989,894
6	5 Year Average	10,709,687	10,414,295	10,585,640
7	2022	10,418,477	11,192,856	10,321,364
8	2022 Delta from Average	(291,210)	778,561	(264,276)

During the Record Period, Palo Verde Units 1 and 3 each had one scheduled refueling outage. Palo Verde Unit 2 had one unscheduled short notice outage during the Record Period.

a) Palo Verde Outages

(1) Palo Verde Unit 1

The capacity factor for Palo Verde Unit 1 was 90.72 percent during the Record Period. As shown in Table V-26 below, the unit was shut down for 35.1 days in 2022.

Table V-26
2022 Palo Verde Unit 1 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	4/9/2022	S	Unit 1 Cycle 23 RFO	35.1

(a) Unit 1 Cycle 23 Scheduled RFO[84]

Palo Verde Unit 1 was manually shut down for a scheduled 30-day refueling outage on April 9, 2022. In addition to routine scheduled refueling outage activities such as offloading and loading fuel, the work included scheduled preventative maintenance tasks on the primary, secondary, and electrical systems. The outage also included, but was not limited to: (1) in-core instrumentation replacement; (2) steam generator eddy current testing and foreign object search and retrieval; (3) reactor bottom mounted instrument inspection; (4) digital positioner installation on pressurizer spray valves; (5) motor operated valve pressure locking; (6) essential cooling water system heat exchanger "B" inspection and eddy current testing; (7) steam generator chemical cleaning and sludge lancing; (8) high pressure turbine inspection; (9) low pressure feedwater heater "1B" replacement; (10) water box divider plate repairs; (11) spray pond 10-inch and 24-inch piping inspection; (12) 13.8 kV non-class switchgear outage; (13) "NBNX04" engineered safety features 13.-4.16kV transformer replacement; and, (14) other equipment repairs and replacements. The unit was returned to service on May 14, 2022 after having been off-line for 35.1 days.

The five-day extension over the planned outage duration occurred due to a combination of: (1) polar crane reliability challenges; (2) steam generator eddy current testing delays; (3) main turbine project expanded work scope; (4) in-core instrumentation replacement issues; and, (5) instrumentation and controls resource challenges. The NRC reviewed the outage but did not identify any violations.[85]

(2) Palo Verde Unit 2

The capacity factor for Palo Verde Unit 2 was 97.20 percent during the Record Period. As shown in Table V-27 below, the unit was shut down for 15 days in 2022.[86]

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[84] The NERC Cause Code for the Unit 2 Cycle 23 RFO is 2070.

[85] *See* Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Integrated Inspection Report, May 09, 2022, p. 3.

[86] Palo Verde Unit 2 ranked third in the United States for electrical generation (MWh) from January 1, 2022 through October 30, 2022. *See* the U.S. Department of Energy, Energy Information Administration (EIA) U.S. Nuclear Generation and Generating Capacity, Capacity and Generation by State and Reactor Report "2022 P," *available at* https://www.eia.gov/nuclear/generation/ [accessed on January 19, 2023].

Table V-27
2022 Palo Verde Unit 2 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	1/24/2022	U	Unit 2 Short Notice Outage	13.5

(a) Unit 2 Unscheduled Short Notice Outage[87]

On January 24, 2022, Palo Verde Unit 2 was operating at full power reactor power was reduced to 0 percent for an unscheduled short notice outage to repair a nitrogen leak on safety injection tank 1A and to perform repairs on high pressure feedwater heater 5A. The unit was returned to full power on February 8, 2022, after having been off-line for 13.5 days.

(3) Palo Verde Unit 3

The capacity factor for Palo Verde Unit 3 was 89.80 percent during the Record Period. As shown in Table V-28 below, the unit was shut down for 33.4 days in 2022.[88]

Table V-28
2022 Palo Verde Unit 3 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	10/8/2022	S	Unit 3 Cycle 23 RFO	33.4

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[87] The NERC Cause Code for the January 24, 2022 Unit 2 Unscheduled Short Notice Outage is 3440.

[88] Palo Verde Unit 3 ranked seventh in the United States for electrical generation (MWh) from January 1, 2022 through October 30, 2022. *See* the U.S. Department of Energy, Energy Information Administration (EIA) U.S. Nuclear Generation and Generating Capacity, Capacity and Generation by State and Reactor Report "2022 P," *available at* https://www.eia.gov/nuclear/generation/ [accessed on January 19, 2023].

(a) Unit 3 Cycle 23 Scheduled RFO[89]

Palo Verde Unit 3 was manually shut down for a scheduled 35-day refueling outage on October 8, 2022. In addition to routine scheduled refueling outage activities such as offloading and loading fuel, the work included scheduled preventative maintenance tasks on the primary, secondary, and electrical systems. The outage also included, but was not limited to: (1) in-core instrument replacements; (2) coil stack replacements; (3) emergent steam generator eddy foreign object search and retrieval; (4) reactor bottom mounted instrument inspection; (5) digital positioner installation on pressurizer spray valves; (6) essential cooling water system heat exchanger "B" inspection and eddy current testing; (7) emergent pressurizer heater replacements; (8) low pressure turbine inspection; (9) main feedwater pump "A" overhaul; (10) high pressurizer feedwater heater inspection and repairs; (11) spray pond 10-inch and 24-inch piping inspection; (12) atmospheric dump valve "185" trim kit installation; (13) emergent plant cooling water "A" discharge sleeve repair; (14) 13.8KV non-class switchgear outage; (15) unit auxiliary transformer "MANX02" replacement; (16) "NBNX04" engineered safety features transformer 13.8-4.16 kV replacement; and, (17) other equipment repairs and replacements. The unit was returned to service on November 10, 2022 after having been off-line for 33 days.

E. Nuclear Fuel Expense

1. Overview

Nuclear fuel expenses incurred during the Record Period are dictated by unit operations and previous purchases of nuclear fuel materials and services. The nuclear fuel materials and services purchased during the Record Period are described in Section F of this chapter. The generation and fuel expense data related to Palo Verde are summarized in and discussed in Section E.2 of this chapter. SCE's share of nuclear fuel utilized at Palo Verde produced a net electrical generation of 5,045 gigawatt-hours (GWh) at an overall fuel expense of $31.5 million, equivalent to $6.25/MWh.

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[89] The NERC Cause Code for the Unit 3 Cycle 23 RFO is 2070.

Table V-29
Nuclear Fuel Energy Production and Expense[90]

Line No.	Station	GWh	$Millions	$/MWh
1	Palo Verde	5,045	31.52	6.25

2. Generation Related Nuclear Fuel Expense

a) Palo Verde Generation Related Expenses

Palo Verde Units 1, 2, and 3 nuclear fuel expenses for the Record Period were related to both generation and non-generation expenses. Palo Verde Unit 2 was in Cycle 23 throughout the entire Record Period. Palo Verde Unit 1 and Unit 3 experienced refueling outages during the Record Period.

Palo Verde Unit 1 was in Cycle 23 until April 9, 2022 when it began its 23rd refueling, returning to service on May 14, 2022, and operating thereafter in Cycle 24 through the end of the Record Period. Palo Verde Unit 2 was in Cycle 23 throughout the Record Period. Palo Verde Unit 3 was in Cycle 23 until October 7, 2022, when it began its 23rd refueling, returning to service on November 18, 2022, and operating thereafter in Cycle 24 through the end of the Record Period.

The generation-related fuel expense related to SCE's 15.8 percent ownership interest in Palo Verde was $31.5 million.

3. Non-Generation-Related Expenses

During a reactor refueling, depleted fuel assemblies are removed from a reactor core and replaced with new fuel assemblies. Because the depleted assemblies are highly radioactive, they must be stored and isolated from the environment. The United States Department of Energy (DOE) retains the ultimate responsibility for the permanent disposal of high-level radioactive waste and used nuclear fuel under the authority of the Nuclear Waste Policy Act of 1982. Until DOE implements a program for the disposal of used fuel, utilities must provide interim used fuel storage. After the DOE licenses and constructs facilities for the storage and permanent disposal of used fuel, the used fuel being stored on an

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[90] Does not include monthly non-generation-related expenses.

interim basis will be transferred to the DOE for disposition. Interim storage is being provided for Palo Verde Units 1, 2, and 3 in their respective used fuel pools and at the Palo Verde ISFSI[91] located on-site.

SCE's share of non-generation-related expenses during the Record Period for Palo Verde is a credit of $0.03 million (SCE share, 2022 $) for a dry cask storage system to store used fuel assemblies at the Palo Verde ISFSI located on-site. This included a credit from funds from the DOE spent fuel litigation damages award.

F. **Nuclear Fuel Purchases**

Nuclear fuel management consists of a sequence of activities involving the procurement and scheduling of materials and services required to manufacture nuclear fuel assemblies suitable for a nuclear power plant and the disposal of used fuel assemblies after their discharge from the reactor. These activities described below encompass: (a) mining and milling of natural uranium concentrates (U_3O_8), (b) conversion to uranium hexafluoride (UF_6), (c) enrichment, (d) design and fabrication of fuel assemblies, and (e) interim storage and permanent disposal of used nuclear fuel discussed in Section E.3 of this chapter. Scheduling materials and services required to manufacture finished fuel assemblies when needed is a critical aspect of managing SCE's nuclear fuel supply. Table V-30 presents typical scheduling lead times established by contract terms and SCE's practices for reload batches.[92] The range in lead times covers simple material transfers via "book transfer" to and from existing on-site inventory accounts at the various suppliers, to physical material deliveries which may require many months of lead time to prepare and ship.

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[91] Independent Spent Fuel Storage Installation (a.k.a., spent nuclear fuel dry storage facility).

[92] Nuclear fuel assemblies loaded together into the core of a nuclear generating unit at the beginning of an operating cycle and later removed together at the end of their operating life are referred to as a batch. At the conclusion of each operating cycle, one or more batches of fuel are discharged and the fuel assemblies in the remaining batches are relocated within the reactor core. A batch typically remains in the reactor for at least two operating cycles. An operating cycle, also known as a fuel cycle, begins with a unit's return to operation following a refueling and maintenance outage.

Table V-30
Typical Reload Nuclear Fuel Procurement Schedule – Months

Line No.	Activity	Months	Cumulative Months
1	Uranium Procurement[1]	12	12 to 29
2	Uranium Delivery	0 to 6	0 to 17
3	Conversion or UF_6	0 to 2	0 to 11
4	Enrichment or EUP	0 to 4	0 to 9
5	Fabrication	0 to 5	0 to 5
6	Scheduled Shipment Date[2]	0	0

[1] In the case of a long-term supply contract, uranium procurement may have occurred several years in advance of uranium delivery.

[2] Shipment date of the last fuel assembly to the plant.

The scheduling begins by establishing the scheduled shipment date for the last fuel assembly and then determining the lead-time required for each stage. The discussion below begins with the earliest process (the purchase of natural uranium concentrates), and then works forward.

1. <u>Natural Uranium Concentrates U_3O_8</u>

To begin the overall manufacturing process, Palo Verde's general practice is to have the U_3O_8 required for a reload batch in inventory or under contract to be delivered to a conversion facility during the six-month period before conversion to UF_6. This ensures that the U_3O_8 will be at the converter in time to meet converter contractual requirements. The minimum decision-making period for uranium procurement is about one year prior to its delivery for conversion where uranium is not already under contract. With long-term uranium supply contracts, the actual planning and procurement process may have taken place many years prior to the scheduling of deliveries under the contract. Requirements planning and procurement activity, including contract negotiation, must precede delivery.

2. <u>Conversion</u>

The conversion process converts impure U_3O_8 into high purity UF_6 suitable for the uranium enrichment process. U_3O_8 can be delivered to the converter two days to two months prior to

UF_6 delivery, depending on contract provisions.[93] Conversion of U_3O_8 to UF_6 is available in the United States only from the ConverDyn plant near Metropolis, Illinois. Outside the United States, conversion service is available from two suppliers: Cameco in Canada and Comurhex (Orano) in France. Material may be purchased as UF_6 (purchasing both the U_3O_8 and conversion services as one) from many sources, such as conversion suppliers, brokers, and others.

3. **Enrichment**

Uranium as found in nature consists principally of two isotopes, U-235 and U-238. The fission of the U-235 isotope is the primary heat source in the nuclear reactor. Natural uranium contains only 0.711 percent of U-235 by weight; however, most nuclear power plants are designed to use nuclear fuel containing uranium having approximately 3 percent-5 percent U-235. The enrichment process is therefore necessary to increase the concentration of the U-235 isotope to 3 percent-5 percent as required by the fuel design. Natural uranium feed UF_6 is typically delivered to the enrichment facility two days to four months prior to enriched UF_6 delivery to the fabrication facility. Services to enrich UF_6 from the natural state to the required design enrichment is available in the United States from Louisiana Energy Services (LES), in Europe from Urenco and Areva (Orano), and in China from CNEIC. The enrichment process is measured in separative work units (SWU). Enrichment services may be purchased with the UF_6 as enriched uranium product (EUP).

4. **Design and Fabrication**

Fuel fabrication is the last step in the manufacturing process. The enriched UF_6 is delivered to the fabricator who converts it to enriched uranium dioxide (UO_2) pellets, provides fuel rod blanks and other necessary hardware, assembles the rods containing UO_2 pellets into fuel assemblies, and delivers the finished fuel assemblies to the plant site. Enriched UF_6 can be delivered to the fabricator on the date the last fuel assembly is delivered to the plant site, or up to five months earlier, depending on contract provisions.

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[93] U_3O_8 must be provided at the converter at least two months prior to UF_6 delivery to the enrichment facility if the U_3O_8 requires weighing, sampling, and analysis. A two-day lead-time results if a book transfer is made at the conversion facility. A book transfer may occur if weighing, sampling and analysis of the supplier U_3O_8 have been previously performed and only a material title change from the supplier's account to SCE's account at the conversion facility is required.

Nuclear fuel must meet the operating requirements of each operating cycle. The fuel fabricator or the utility is responsible for the reactor core design of new fuel batches to be loaded into the reactor core at the start of each operating cycle. APS provides the reactor core design for Palo Verde. Reactor core design establishes the number of fuel assemblies for the new batches, the U_3O_8, conversion and enrichment required, and the configuration of the reactor core with both the old and new fuel batches. Fuel fabrication services for Palo Verde are available in the United States from Westinghouse and Framatome.

G. Palo Verde Nuclear Fuel Purchases

1. Uranium Purchases

During the Record Period, SCE purchased 135,000 pounds of U_3O_8 for SCE's share of Palo Verde requirements under contracts with Quasar; MacQuarie Physical Commodities UK Limited; Itochu; MTM Trading, LLC; and Energy USA. These contracts were awarded using strict competitive commercial processes.

2. Conversion to and/or Purchase of UF_6

During the Record Period, SCE purchased 41,870 KgU of conversion services for SCE's share of Palo Verde requirements under a contract with ConverDyn. SCE also purchased 60,621 KgU as UF_6 (U_3O_8 and conversion services together) for SCE's share of Palo Verde requirements under a contract with Cameco, Orano, and LES. These contracts were awarded using strict competitive processes.

3. Enrichment

During the Record Period, SCE purchased 103,919 SWU for SCE's share of Palo Verde under an enrichment uranium supply contract with Urenco and LES. These contracts were awarded using strict competitive commercial processes.

4. Enrichment Uranium Product - EUP

During the Record Period, SCE purchased 0 KgU of EUP.