Application No.:	A.23-05-010
Exhibit No.:	SCE-05 Vol. 01
Witnesses:	K. Billapati T. Cameron C. Fanous D. Golden A. Hernandez T. Maddox

(U 338-E)

2025 General Rate Case

Generation

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 12, 2023

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I.

INTRODUCTION

A. Content and Organization of Volume

SCE owns and operates approximately 2,600 MW of generating facilities composed of 32 hydroelectric plants (Hydro);[1] five gas-fired peaking units (Peakers), of which two are battery/combustion turbine Hybrid "Electric Gas Turbine" (EGT) configuration; two standalone Battery Energy Storage Systems (BESS);[2] one combined cycle gas plant (Mountainview); a largely diesel-driven electric generating plant (some of which may be supplanted by resources obtained via an upcoming clean energy, all-source RFO, which SCE anticipates will provide resources that will be available online after the 2025 test year) (Catalina Pebbly Beach); 23 rooftop solar photovoltaic (SPV) plants; and one ground-based SPV plant.[3] SCE also has a 15.8 percent interest (approximately 591 MW) in Palo Verde Nuclear Generating Station Units 1, 2, and 3 (Palo Verde) located in Arizona and operated by Arizona Public Service.

SCE's Generation Department operates and maintains all these facilities and plants, except for Palo Verde. The Generation Department also manages SCE's oversight of the demonstration Fuel Cell power plants located on the campuses of California State University, San Bernardino (CSUSB) and the University of California at Santa Barbara (UCSB). Generation "home office" functions support these efforts, and consist of the Asset Management & Generation Strategy, Major Projects & Engineering, and Regulatory Support Services groups. As discussed further in this volume, the Generation Business Planning Group (BPG) includes four Generation Business Planning Elements (BPE): Hydro, Fossil Fuel, Solar, and Nuclear.

SCE's Large Hydro plants continue to be among our most cost-effective generating resources. SCE's Hydro operation and maintenance (O&M) expense and Capital expenditure forecasts presented in

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[1] SCE currently has 35 hydroelectric power houses, of which three (San Gorgonio 1, San Gorgonio 2, and Borel) are no longer in operation and have been disconnected from the grid. SCE is in the process of relinquishing the FERC licenses of these facilities.

[2] The O&M and Capital forecast for SCE's Energy Storage facilities is presented in Exhibit SCE-02, Vol. 06.

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

this GRC are increasing from past recorded costs due to the expected issuance of the Big Creek licenses and decommissioning activities at two smaller Hydro facilities. SCE's forecast includes funding to continue operating its Hydro assets at historical levels of reliability for the duration of their Federal Energy Regulatory Commission ("FERC") license terms, many of which are in the process of being renewed.

The funding request for our gas-fueled Mountainview plant includes the ongoing operations and maintenance expenses for that plant, consistent with recorded costs. SCE's Mountainview request includes annualized costs (i.e., the average annual costs during 2025 through 2028) associated with Major Inspection outages forecasted to occur starting in 2023 and completed in 2027. Major Inspections are conducted at Mountainview units periodically based on unit run hours and starts. SCE averages the cost of major inspection outages over the four-year rate case cycle of 2025 through 2028 consistent with how similar Mountainview outage costs were averaged in SCE's previous GRC requests.[4]

Four of our five gas-fueled Peaker plants began commercial operation in July 2007, and the fifth, McGrath, became operational in November 2012. Our Peaker O&M expense forecast includes costs for permits; air quality monitoring; reporting and testing; chemicals and other consumables; water; water treatment; wastewater disposal; repair parts; and other related items.

The O&M and capital forecast for Catalina Island ("Catalina" or "the island," based at Pebbly Beach Generating Station) will continue to provide electric service for approximately 4,000 permanent residents and over one million annual visitors.[5] Since 1962, SCE has served as the regulated utility provider to the island, located twenty-six miles off the southern California coast, where SCE offers electric, water, and gas service. The electric service covers the entire island, approximately 22 miles long, 8 miles wide, (roughly 76 square miles), including the communities of Avalon and Two Harbors, as well as rural areas located throughout the island's interior.

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4 D.09-03-025, pp. 31-33.

5 United States Census Bureau, 2017 Population Estimates.

In 2012, SCE completed the construction of the UCSB Fuel Cell and, in 2013, SCE completed construction of the CSUSB Fuel Cell. These 10-year demonstration projects will be completed and head into decommissioning in 2023. The capital forecast will request funding required for the planned decommissioning of these demonstration plants. SCE's original funding for these fuel cells was approved by the Commission in D.10-04-028 and D.12-04-011.

SCE also is responsible for the operations and maintenance of 91 MW direct current (DC) of capacity from its Solar Photovoltaic Program (SPVP) power plants,[6] which largely have been operational for the past 10 years. During this time, SCE has demonstrated solar photovoltaic technology to be a new market opportunity, successfully achieving the original objectives of the SPVP program. However, as solar costs have decreased in recent years, SCE has determined that continued operation of the facilities is no longer in the best interests of SCE customers. This is because an increase in maintenance expenses and safety risks, coupled with declining value, has turned the operating economics unfavorable to SCE customers. As such SCE's capital forecast will request funding required for the decommissioning of the remaining SPVP sites.

SCE also owns 15.8 percent of Palo Verde Units 1, 2, and 3, which is located approximately 50 miles west of Phoenix, Arizona. Arizona Public Service Company ("APS") is the operating agent for Palo Verde, the nation's largest nuclear installation. The rated electrical net generating capacities of Palo Verde Units 1, 2, and 3 are approximately 1,346 MW per unit. SCE's approximately 591 MW share of Palo Verde has provided SCE customers with a safe, clean, reliable, and economic source of baseload generation since the mid-1980s. As a minority owner of Palo Verde, SCE is contractually responsible for compensating APS for SCE's 15.8 percent share.[7]

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[6] D.13-05-033.

[7] SCE owns a 15.8% interest in PVNGS. APS owns a 29.10% interest in PVNGS and is the operating agent. The remaining non-operating owners are Salt River Project (17.49%), El Paso Electric Company (15.80%), Public Service Company of New Mexico (10.20%), the Southern California Public Power Authority (5.91%), and Los Angeles Department of Water and Power (5.70%). On January 1, 2023, Salt River Project (SRP) will acquire 104 MWe of Public Service Company of New Mexico's (PNM) share of Palo Verde Unit 1. Additionally, on January 1, 2024, SRP will acquire 10 MWe of PNM's share of Palo Verde Unit 2. As a result of these ownership transfers, as of January 1, 2024, SRP will own 25.4233% of PVNGS Unit 1, 18.233% of

(*Continued*)

B. Summary of O&M Request

The 2025 Test Year O&M expense forecast for the Generation Business Planning Group totals $178.384 million, as summarized in Table I-1 and Figure I-1 below.[8], [9] The table also summarizes the recorded expenses incurred during 2018 through 2022.

Table I-1
Generation Business Planning Group - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)

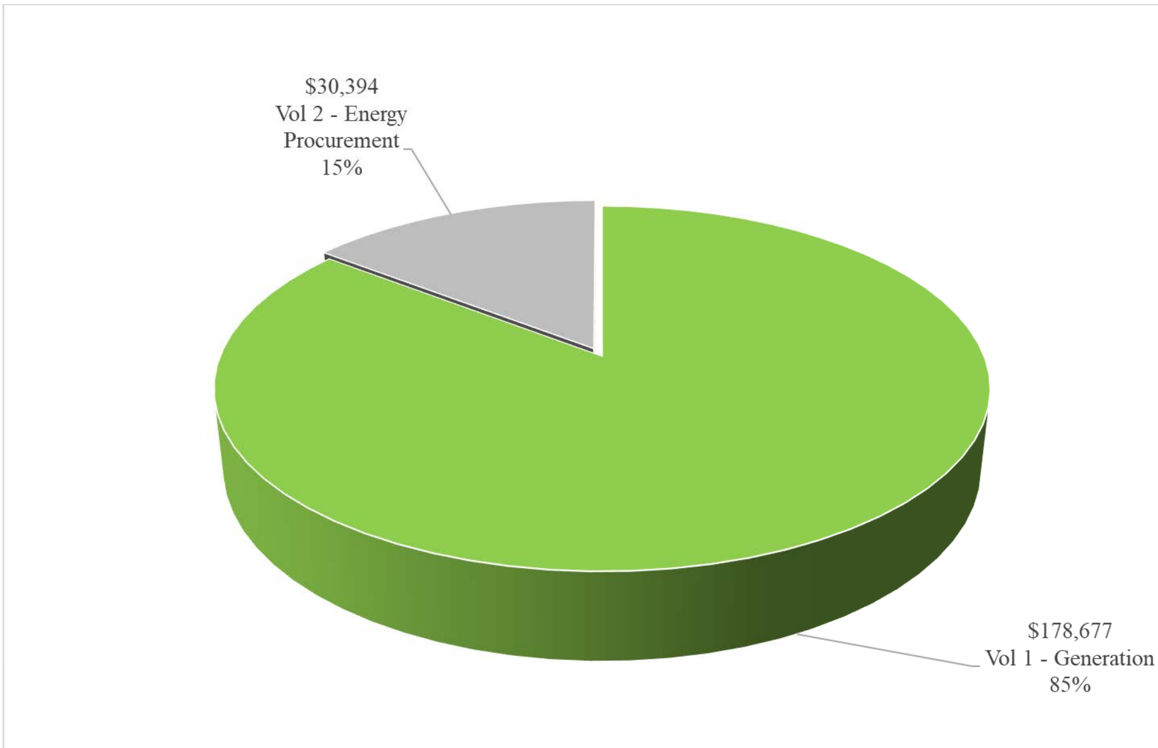
Line No.	Generation BPE/Year	Recorded 2018	2019	2020	2021	2022	Forecast 2023	2024	2025
1	Hydro	51,979	47,352	50,528	36,663	39,800	46,282	47,812	53,475
2	Fossil Fuel	44,606	32,905	40,803	39,002	43,869	38,825	41,734	44,109
3	Solar	4,588	4,417	3,797	4,513	4,515	3,517	3,476	4,347
4	Nuclear	94,495	91,222	87,944	81,783	75,076	76,431	76,428	76,453
5	**TOTAL**	**195,668**	**175,896**	**183,072**	**161,961**	**163,260**	**165,055**	**169,450**	**178,384**

PVNGS Unit 2, 10.20% of PVNGS Unit 3, and 20.3965% of PVNGS Common assets. Also as of January 1, 2024, PNM will own 2.2667% of PVNGS Unit 1, 9.4570% of PVNGS Unit 2, 10.20% of PVNGS Unit 3, and 7.2935% of the PVNGS Common assets.

[8] An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

[9] Numbers presented throughout this volume of testimony may have minor differences due to rounding and/or know errata as referenced.

Figure I-1
2025 Generation & Energy Procurement O&M Expenses
(Constant 2022 $000)



SCE's 2025 Test Year O&M expense forecasts for the continued operation and maintenance of our Generation Large Hydro, Fossil Fuel (Mountainview, Peakers, and Catalina) and Nuclear BPEs are consistent with recent past recorded costs, with appropriate adjustments for recent and future events. Future events include the portfolio optimization of Generation assets with planned exits of assets that are of low value to customers (small Hydro and rooftop solar PV), modernizing with new battery storage, reliability focused investments at Mountainview, cleaning the fleet including Catalina and pilots to burn hydrogen in Peakers, and extending the life of valuable/legacy Large Hydro assets. Approval of our Test Year forecast will fund these future events and provide for the continued safe and reliable operation of these power generating assets, in compliance with environmental objectives and other regulatory requirements.

C. Summary of Capital Request

As summarized in Table I-2 and Figure I-2 below, the 2023 through 2028 forecast capital expenditures for our Hydro, Fossil Fuel, Solar, and Nuclear BPEs total $858.517 million.[10], [11] This is $401.991 million more (approximately 89 percent) than the $456.526 million of capital expenditures recorded during the 2018 to 2022 time period. The main reasons for this increase are additional capital improvements identified through a maturing asset management program, work necessitated by the new Hydro FERC licenses that are expected to be issued in early 2023 and the decommissioning of SCE's SPVP fleet.

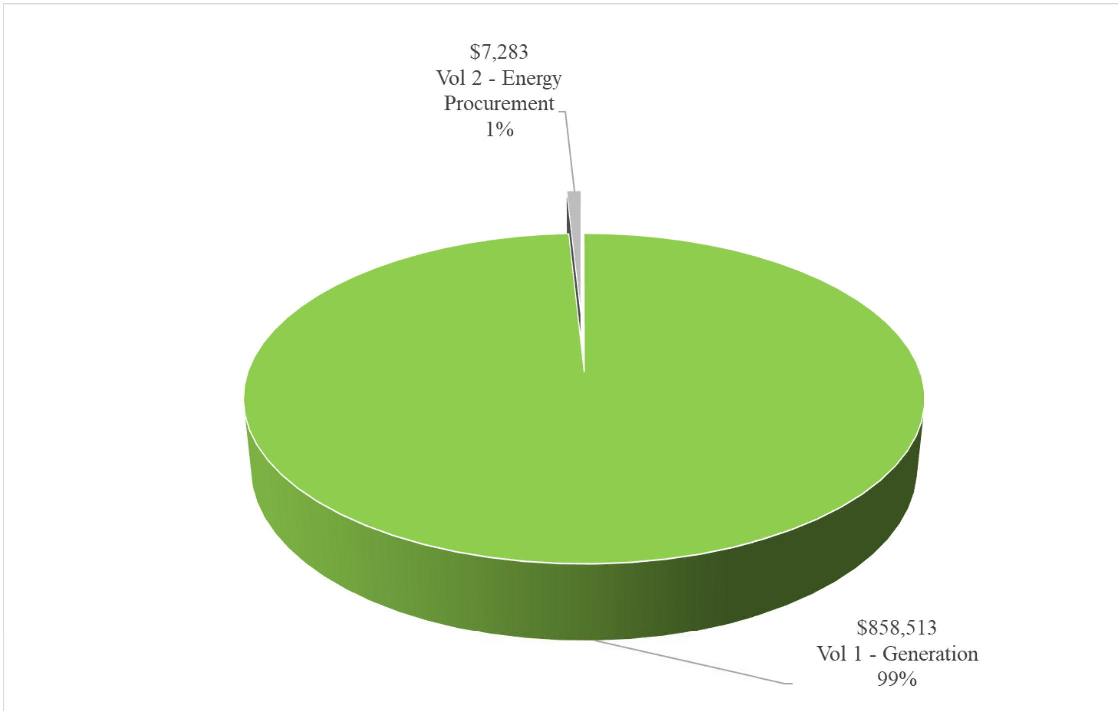
Table I-2
Generation Business Planning Group – Capital Expenditures
2018-2022 Recorded and 2023-2028 Forecast
(Nominal $000)

Line No.	BPE/Year	2018-22 Recorded	2023-28 Forecast	Difference
1	Hydro	202,815	471,520	268,705
2	Fossil Fuel	67,083	103,941	36,858
3	Solar	4,595	77,972	73,377
4	Nuclear	182,033	205,084	23,051
5	**TOTAL**	**456,526**	**858,517**	**401,991**

[10] The forecast reflects certain changes made to SCE's employee compensation program. Please refer to Exhibit SCE-06, Vol. 04.

[11] An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

Figure I-2
2023-2028 Generation & Energy Procurement Capital Expenditures
(Nominal $000)



SCE's Hydro capital expenditure forecast funds a wide variety of necessary work. This includes the ongoing FERC relicensing of several facilities that will allow us to continue to operate them for many years into the future for the benefit of SCE's customers. We also must continue to refurbish Hydro equipment and infrastructure, to assure these plants continue to operate with high safety and reliability as they have in the past. This includes overhauls of the turbines and generators, as well as needed refurbishment to tunnels, dam spillways, and other water conveyance systems so that they continue to operate safely and reliably. These improvements include: (1) required modifications to meet increased minimum stream release flow rates contained in the new FERC licenses expected to be issued during this GRC rate cycle; and (2) projects resulting from a heightened awareness and concern within the overall dam safety industry and regulatory community regarding the condition and performance of spillways following the 2017 Oroville Spillway incident.[12]

Additional increases in Hydro expenditures are necessary due to the expected decommissioning of two small Hydro facilities (San Gorgonio and Borel) and two dams at Rush Creek (Agnew and Rush Creek Meadows).

Our forecast for Fossil Fuel includes projects at the Mountainview Generating Station, Peaker facilities, and the Catalina Pebbly Beach Generating station. The forecast for Mountainview includes $28.3 million for the Turbine/Generator Improvement Program, $20.7 million for upgrades to the heat recovery steam generators, $14.1 million to upgrade the turbine control systems, and $20.8 million for various plant upgrades to ensure future operational flexibility at Mountainview necessary to meet increased demands from CAISO to provide faster response times when backfilling lost load demand from renewable power sources. The $10.6 million forecast for Peakers will fund the necessary replacement of relays, an overhaul to the Barre Peaker and upgrade to the Mira Loma Carbon Monoxide (CO) Catalyst and Emissions Reduction Unit (ERU). These projects will ensure that the Peakers continue to provide reliable service, maintain compliance with applicable laws and regulations, and perform safe operations for employees and the public. The forecast for Catalina includes $6.1 million for various improvements necessary to maintain reliability. SCE also provides testimony in this GRC Application to update the Commission on the Catalina Repower Project and is requesting the use of a Tier 3 Advice Letter process for reasonableness review of this project, rather than delay review and cost recovery to the 2029 GRC. The Catalina Repower project will address the South Coast Air Quality Management District (SCAQMD) requirement to reduce emissions by replacing the existing units with newer and cleaner generating technology.

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[12] In 2017, heavy rainfall damaged the main and emergency spillways of the Oroville Dam, an important part of the California State Water Project in northern California. High water levels caused water to flow over the emergency spillway even after the main spillway was reopened, damaging the main spillway and causing erosion.

Finally, SCE has determined that continued operation of the SPVP facilities is no longer in the best interests of SCE customers and is forecasting $77.972 million to decommission the remaining SPVP sites.

Adoption of the capital expenditure forecast will provide funding for the continued safe and reliable operation of these power generating assets, in compliance with environmental objectives and other regulatory requirements. Further details regarding our Generation capital expenditure forecasts are provided in Testimony Sections II-IV. Further information and discussion of our 2018 through 2022 recorded capital expenditures, and their comparison to GRC-adopted capital forecasts, can be found in Section D below.

In addition to the capital expenditure forecast presented in this testimony volume, 2023-2028 Generation related Energy Storage projects are presented in SCE-02 Vol. 6 and capitalized software projects in support of the Generation BPG are presented in SCE-06 Vol. 2. The capital software projects will allow SCE to mature and improve functions and capabilities to better execute on power dispatch and monitoring, predictive maintenance, and regulatory compliance. Following their completion, the energy storage projects will be transferred to the Generation BPG to perform future O&M activities.

D. 2021 Decision

In accordance with D.15-11-021 Ordering Paragraph 3, this Chapter compares Commission-authorized 2021 O&M expense and capital expenditures to SCE's recorded 2021 O&M and capital expenditures for SCE's Generation BPG; excluding Palo Verde, which is addressed separately in section V of this testimony volume.

1. Comparison of Authorized 2021 to Recorded O&M

As shown in Table I-3 below, the Commission's adopted 2021 GRC Test Year forecast for the Generation BPG O&M expense was $179.157 million, $1.849 million less than SCE's original request of $181.006 million.[13] SCE's recorded 2021 expense was $161.961 million, approximately $17.196 million lower than adopted.

[13] D.19-05-020. Note that the figures given herein are in $2022 constant dollars, while the O&M expense dollar figures discussed in SCE's 2021 GRC testimony, and the Decision are in $2018 constant dollars.

Table I-3
2021 Generation Business Planning Group
O&M Expenses – Authorized versus Recorded
(Constant 2022 $000)

Line No.	Generation BPE	2021 O&M Expenses			
		Requested	**Authorized**	**Recorded**	**Authorized vs. Recorded over/(under)**
1	Hydro	47,193	47,193	36,663	(10,530)
2	Fossil Fuel	47,217	47,217	39,002	(8,215)
3	Solar	4,248	4,248	4,513	265
4	Nuclear	82,348	80,500	81,783	1,283
5	**TOTAL**	**181,006**	**179,157**	**161,961**	**(17,196)**

Lower-than-adopted recorded Hydro expenses is primarily the result of two catastrophic events occurring in 2020 – the 2020 Creek Fire, discussed in section I.F.1.b)(1), and the 2020 Apple fire, discussed in section II.C.4.b). In 2021, SCE focused on protracted restoration efforts related to these fire events and deferred Hydro O&M work. Specifically, SCE recorded $3.5 million of restoration costs for the Creek Fire and $7.7 million of restoration costs for the Apple Fire ($11.2 million total) to subaccounts of the Catastrophic Event Memorandum Account (CEMA).[14]

Lower-recorded than adopted Fossil Fuel operating expenses can be attributed to an $8.9 million underrun by Mountainview in the following three areas: (1) $4.5 million - cancelling the General Electric (GE) contractual service agreement, (2) $3.0 million - lower than previously forecasted run hours, resulting in deferral of the Major Inspection originally planned for 2021/2022, and (3) $1.4 million - deferral of maintenance work resulting from budget reallocation based on risk prioritization. Further information on Mountainview recorded costs can be found in section III.B.2.c) of testimony.

Higher-recorded than adopted SPVP operating expenses can be attributed to $0.265 million in unexpected costs required for wiring remediation following an unplanned outage event.

[14] Apple Fire-related costs above GRC-authorized storm-related costs were requested in SCE's 2022 CEMA filing, A.22-03-018. Generation-related Creek Fire costs have not yet been requested in a CEMA filing but are being tracked in a CEMA subaccount.

Higher-recorded than adopted Nuclear operating expenses are discussed in section V of this testimony volume.

2. Comparison of Authorized 2021 to Recorded Capital Expenditures

As shown in Table I-4 below, SCE requested $92.897 million in 2021 for Generation BPG capital expenditures. The Commission authorized $91.011 million, which reflected a $1.886 million reduction following the Commission's interim disallowance of the San Gorgonio Decommissioning project.

Table I-4
Generation Business Planning Group
2021 Capital Expenditure – Requested, Authorized and Recorded
(Nominal $000)

Line No.	Generation BPE	2021TY - Capital			
		Requested	Authorized	Recorded	Authorized vs. Recorded over/(under)
1	Hydro	46,940	45,054	33,838	(11,216)
2	Fossil Fuel	8,643	8,643	16,671	8,028
3	Solar	102	102	16	(87)
4	Nuclear	37,212	37,212	35,851	(1,361)
5	**TOTAL**	**92,897**	**91,011**	**86,375**	**(4,636)**

Lower-than-recorded Hydro expenditures are primarily the result of the need to defer Hydro capital projects in order to focus on CEMA restoration activities related to the 2020 Creek Fire. 2021 CEMA expenditures, in the amount of $8.543 million, were recorded to the Creek Fire CEMA. Further discussion of the Creek Fire is provided in testimony section I.F.1.b)(1).

The remaining $2.673 million underrun in 2021 Hydro capital expenditures largely occurred because portions of several Hydro capital projects originally forecasted to occur in 2021 were deferred to future years. The Big Creek 3 Unit 3 field pole refurbishment project was deferred due to station crane damage that occurred during removal of the rotor assembly, and the Big Creek 8 Unit 1 (BC8U1) generator rewind project was deferred due to the inability to run Big Creek 8 Unit 2 (BC8U2) because of damage incurred during the Creek Fire. SCE had originally forecasted the BC8U1 generator rewind project to commence in 2018, however it was deferred to 2019 so SCE could complete a condition assessment of the penstock serving the unit. The results of the study will provide SCE with a better understanding of the condition of the penstock and ultimately whether the currently limited flow within the penstock can be increased back to the original rating. The work was postponed again when BC8U2 was damaged during the Creek fire. Big Creek 8 is a bottleneck for water movement on the Big Creek system. Consequently, BC8U1 is being kept in-service until the Creek Fire repair work on BC8U2 can be completed. Further explanation of these outages is discussed in testimony section I.F.1.b)(1).

SCE utilized the deferral of these two Hydro projects to perform three emergent projects at the Peaker power plants to preserve equipment reliability and safety: (1) the Grapeland Hybrid Peaker turbine refurbishment project, (2) Carbon Monoxide (CO) catalyst replacement projects at the Center and Grapeland hybrid units, and (3) the selective catalytic reduction upgrade project at the Mira Loma Peaker. The performance of these emergent projects accounts for the majority of the $8.028 million overrun experienced in Fossil Fuel recorded capital expenditures.

The $0.087 million underrun in Solar was due to fewer capital spare parts being purchased than originally forecasted.

The $1.361 million underrun in Nuclear is discussed in section V of this testimony volume.

E. Generation Department Overview

As mentioned in Section I.A., SCE's Generation Department is responsible for operating and maintaining 32 hydroelectric plants (Hydro),[15] five gas-fired peaking units (Peakers) which include two Hybrid Electric Gas Turbine (EGT), two adjacent Battery Energy Storage Systems, one combined-cycle gas plant with two generating units (Mountainview), a largely diesel-driven electric generating plant

[15] SCE currently has 35 hydroelectric power houses of which three, San Gorgonio 1 and San Gorgonio 2, and Borel are no longer in operation as the units at these three facilities have been disconnected from the grid. SCE has initiated proceedings that will result in the surrender of these project licenses.

(Pebbly Beach), 23 rooftop solar photovoltaic (SPV) plants and one ground-based SPV plant, and oversight of the demonstration Fuel Cell power plants located on the campuses of CSUSB and UCSB.

In mid-2016, the Generation Department initiated several process changes to increase productivity and reduce expenses. These changes, implemented across the entire Generation Department, included organizational changes with an emphasis on an asset management program approach. SCE Generation's asset management program has allowed the Generation Department to focus resources on O&M activities and capital projects that provide the highest value for SCE's customers. Additionally, the asset management program has improved operating practices to align with a risk-informed decision-making approach and factoring economic incentives and disincentives of California's wholesale power market.

Additional efficiency improvements resulted from the Generation Department consolidating from three field organizations (*i.e.,* Gas and Solar, Northern Hydro, and Eastern Hydro) to two (*i.e.,* Western Operations and Eastern Operations). This built upon the consolidation made in 2013, when the Peaker-Solar and Mountainview organizations were combined into the Gas and Solar organization. This consolidation allowed for further increases in cross-support between personnel who formerly worked primarily on gas-fired assets, with those who formerly worked primarily on Hydro assets.

In recent years, the Generation department has continued to build upon past efficiency improvement successes by continuing to evaluate and identify opportunities for improvement. Opportunities identified impacting SCE's 2025 GRC request include the decommissioning of uneconomic solar rooftop sites and consolidation of the Catalina control room. Further information regarding these improvements is discussed in SCE's testimony and associated cost benefits have been incorporated into the base forecast of each respective area.

While Generation's cross-support approach has been successful in controlling overall costs, a by-product is that we have begun to observe larger than historic year-to-year variations within two of the three Generation Department-managed BPEs (*i.e.,* Hydro and Fossil Fuel). These variances, illustrated in Table I-5 below, can largely be attributed to the asset management approach of reprioritizing work based on the most immediate need (*e.g.,* deferring less critical preventive maintenance at Hydro facilities in order to fund unplanned repairs encountered at Mountainview in 2018).[16]

Also shown in Table I-5 below, total recorded costs for the Generation Department BPEs have experienced a decrease over the past five years. This decrease, discussed in greater detail later in this testimony volume, is largely the result of challenges experienced during the COVID-19 pandemic. During this time, SCE's Hydro locations have incurred a higher-than-historical rate of turnover, losing approximately 20% of their total workforce. This loss is unsustainable, and SCE is proposing to recover the loss of 30 key craft positions over the next three years (*i.e.,* hiring 10 additional employees per year).

Table I-5
Generation Business Planning Group
2018-2022 Recorded O&M
(Constant 2022 $000)

Line No.	Generation BPE/Year	Recorded				
		2018	**2019**	**2020**	**2021**	**2022**
1	Hydro	51,979	47,352	50,528	36,663	39,800
2	Fossil Fuel	44,606	32,905	40,803	39,002	43,869
3	Solar	4,588	4,417	3,797	4,513	4,515
4	Nuclear	94,495	91,222	87,944	81,783	75,076
5	**TOTAL**	**195,668**	**175,896**	**183,072**	**161,961**	**163,260**

While overall costs have decreased SCE continues to maintain high reliability at its generation facilities. The Generation Department tracks power plant reliability utilizing Equivalent Availability Factor (EAF) and Equivalent Forced Outage Factor (EFOF). EAF is the percentage of time that a generating asset is available for operation, whether it is dispatched to operate, or remains available in

[16] Year-to-year variance explanations are discussed in greater detail within the respective sections of testimony that follow.

reserve shutdown status as determined through CAISO market awards.[17] EFOF is the percentage of time that a generating asset is not available to operate because it is undergoing a forced outage.[18]

Neither a 100 percent EAF nor a zero percent EFOF is practical because (1) generating assets must be periodically removed from service to conduct routine maintenance; and (2) there are diminishing returns on the cost to design and maintain a power plant to the level required to fully mitigate all the possible problems that can cause forced outages.

SCE Generation also tracks its commercial availability, energy price-adjusted unit availability to make sure the generating resource is available when most beneficial to SCE customers. Power plant engineers and technicians must (1) identify the best schedules for planned maintenance outages; and (2) manage and complete extensive maintenance and capital project work within strategically planned outages. Some of the challenges include handling unforeseen equipment problems and other emergent repairs, obtaining sufficient contractor resources (particularly during our busy power plant outage seasons of spring and fall), and securing the timely delivery of parts and materials.

As shown in Table I-6, with the exception of Mountainview, SCE's average EAF and EFOF performance over the past 10 years exceeds industry averages.[19] Capital projects performed during this period have been effective in improving the performance of SCE's Generation fleet.

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[17] EAF is computed by dividing the number of hours in which the asset is available for operation, by the total hours in the record period (*i.e.*, 8,760 hours when measured annually, or 365 days x 24 hours per day).

[18] EFOF is computed by dividing the number of hours the asset is unavailable because of forced outages by the total hours in the record period (*i.e.*, 8,760 hours when measured annually). Both EAF and EFOF include derates (*i.e.*, partial outages), whereby the duration of such outages is measured on an "equivalent" or pro-rata basis (*e.g.*, a two-hour derate outage of half of the plant's MW capacity is equivalent to a one-hour outage involving the plant's total capacity).

[19] Historical industry EAF and EFOF performance data was obtained from http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx. Further detailed information can be found in SCE's annual ERRA filings.

Table I-6
Generation BPE – 2013-2022 EAF and EFOF Performance

Line No.	Generation BPE	SCE		Industry	
		EAF	EFOF	EAF	EFOF
1	Hydro	86.62	5.16	80.83	5.11
2	Fossil Fuel				
3	Mountainview	87.34	4.61	84.54	2.63
4	Peakers	94.73	2.14	86.88	3.44
5	Nuclear	91.34	0.59	89.44	2.39

During the 2025-2028 four-year rate cycle, our planned outage work includes the 2023 through 2027 Mountainview Major Inspection (MI) outages. Our planned outage work also includes significant refurbishment work at several of our Hydro dams and infrastructure. Maintaining high reliability, commensurate with previous years, will require that we respond quickly to forced outages to minimize their duration as much as practical. While most of SCE's power is purchased, SCE-owned power plants are important to SCE customers as they help maintain overall reliability of electrical service, support California's clean energy future, and provide a hedge against significant market price increases.

The length of time needed to accomplish planned and emergent work during scheduled outages can be influenced by a variety of circumstances. Likewise, forced outages are an inherent part of cost-effective power plant operations and maintenance strategies.

Further detail regarding our Generation power plant outages and reliability performance is provided to the Commission in our Energy Resource Recovery Account (ERRA) Annual Review Phase proceedings.[20] As discussed in ERRA, our Hydro, Mountainview, and Peaker reliability performance has been and continues to be exceptionally good compared to the industry average for these types of generating plants. Approval of our forecast O&M expense and capital expenditure forecasts in this GRC will provide funding to sustain acceptable levels of power plant reliability performance in the future, maximizing the value of these resources for SCE's customers.

[20] A.23-04-001.

F. Regulatory, Compliance and Background/Policies Driving SCE's Request

1. Hydro

a) Small Hydro Divestiture

The following section of testimony describes SCE's current Hydro portfolio and outlines the rationale supporting a decision to initiate a divestment process for some of SCE's small Hydro projects. SCE operates 25 Hydro projects that include powerhouses and generating units, dams, stream diversions, and water conveyance systems consisting of tunnels, conduits, flumes, and flow lines. Cumulatively, SCE's Hydro facilities have 1,164 MW of nameplate generating capacity. The Big Creek system accounts for 1,015 MW of the SCE generating capacity and includes six large reservoirs with appreciable storage that provides significant economic benefits. The Big Creek system continues to be economic and will remain in service without any consideration of divestment for the foreseeable future. Additionally, the Kern River No. 1 and Kern River No. 3 projects account for approximately 66 MW of the 161 MW of generating assets outside of Big Creek. While the two Kern Projects do not have reservoir storage, their capacity factors have historically averaged 51%, and their size provides reasonable economies of scale, so they are not under consideration for divestment. SCE's small Hydro assets (16 Hydro projects) make up the remaining 95 MW in SCE's Hydro portfolio. The average capacity of SCE's small Hydro projects is 4.3 MW, with the largest rated at less than 13 MW.

Until recently, divestment of SCE's small Hydro assets seemed unlikely because of their renewable energy benefits. However, due to the age of the existing infrastructure (much of it exceeding 100 years), changes in the California energy market resulting in lower wholesale energy revenues, and increasing costs to license and operate the facilities, some of SCE's small Hydro projects may be retired or divested in the coming years. Some of the small Hydro projects do have limited reservoir storage, but most are run-of-the-river systems, meaning that power is only generating when water if flowing. The limited reservoir storage and run-of-the-river nature of the small Hydro projects decrease their ability to be optimized for market revenue, resulting in a reduced benefit to customers. The increased penetration and decreasing cost of solar generation in the market has placed downward pressure on wholesale energy prices and renewable energy credits, further challenging the economic value of small Hydro. Additionally, the FERC relicensing process has the potential to further challenge small Hydro economics by requiring increased capital expenditures for relicensing and continued operation. Almost all of these small Hydro assets entered service between 1899 and 1929; while appreciable capital refurbishment and improvement has been made over their lives, much of this infrastructure is original equipment, and significant additional refurbishment will be needed if operations are to safely and reliably continue for several more decades. SCE expects that the general trend of continued degradation of small Hydro economics may lead to the outcome that, in some cases, divestment or decommissioning will be the least-cost option for customers over the long term.

The decision to retire (divest or decommission) a small Hydro project is difficult to make since multiple variables can influence the economic viability of a project such as the need to refurbish aging assets, renew FERC operating licenses through relicensing, implement new license requirements, rehabilitate existing recreation facilities or provide new recreation facilities, complete environmental permitting and mitigation requirements, comply with contractual water rights requirements, provide flood control, and address concerns with numerous stakeholders and/or public advocacy groups. SCE expects that the decision to divest a small Hydro project (or to continue operations into the future) will be made on a case-by-case basis and will typically be linked to the FERC license renewal process (FERC license expiration dates for SCE's small Hydro plants span from 2021 through 2033). Once a decision is made to retire an asset, the next decision is to determine if divestiture or decommissioning will provide a better cost benefit to customers. Costs to decommission projects are extremely high since the Hydro facilities (powerhouses, dams, stream diversion, and water conveyance systems) must be removed and the project lands may need to be restored to pre-project conditions. Even if only a small number of SCE's small Hydro projects are decommissioned, costs will likely reach into the hundreds of millions of dollars. As such, SCE determined that divestment of a Hydro project (provided the project can be sold) generally yields a greater benefit to customers over the high cost of decommissioning.

Therefore, in 2019 SCE began exploring the possibility of divesting many of its smaller and less-economic Hydro facilities and in 2022 initiated a divestment process with potential bidders to sell 10 small Hydro projects, presented in Table I-7. The divestment process is anticipated to be completed in late 2024 following the negotiation of purchase and sale agreement(s) with the successful bidder(s) and upon approval by the CPUC and FERC. SCE will file 851 application(s) with the CPUC that will demonstrate how divestment is in the overall public interest relative to alternatives (decommissioning, continued operations of the project) and the reasonableness of the purchase and sale agreement(s) to SCE customers. SCE and the successful bidder(s) will also file joint Application(s) for Transfer of License with FERC that must demonstrate that the new owner(s) have the qualifications to hold the license and operate the project, and that the transfer is in the public interest.

Table I-7
Small Hydro Projects Included in Divestment Process
2018-2022 Recorded O&M
(Constant 2022 $)

Line No.	Location		Recorded 2018	2019	2020	2021	2022
1		Labor	105,983	127,840	118,308	140,100	64,209
2	Ontario 1 -2	Non-Labor	28,342	38,323	1,644	21,799	20,555
3		Total	134,325	166,163	119,952	161,899	84,764
4		Labor	125,983	90,708	65,045	45,078	14,272
5	Sierra	Non-Labor	15,654	17,522	566	679	752
6		Total	141,636	108,230	65,611	45,757	15,024
7		Labor	60,645	83,815	222,803	112,295	6,118
8	Lytle Creek	Non-Labor	33,458	32,999	46,096	57,472	63,708
9		Total	94,103	116,814	268,900	169,767	69,826
10		Labor	47,786	43,331	109,939	46,032	38,942
11	Fontana	Non-Labor	4,248	12,551	13,778	10,699	19,825
12		Total	52,034	55,883	123,717	56,732	58,767
13		Labor	43,180	122,744	177,945	72,697	99,812
14	Mill Creek 1-3	Non-Labor	55,957	158,065	73,539	821	20,519
15		Total	99,137	280,809	251,484	73,518	120,331
16		Labor	511,715	464,157	467,889	422,541	475,052
17	Kaweah 1-3	Non-Labor	215,438	180,421	261,048	68,666	208,458
18		Total	727,154	644,578	728,937	491,207	683,510
19		Labor	79,274	22,899	34,281	33,684	61,540
20	Tule	Non-Labor	93,198	23,181	2,866	6,858	6,488
21		Total	172,472	46,080	37,147	40,542	68,028
22	TOTAL	Labor	**974,566**	**955,495**	**1,196,210**	**872,427**	**759,945**
23	Small Hydro	Non-Labor	**446,295**	**463,062**	**399,538**	**166,994**	**340,305**
24	Divestiture	Total	**1,420,861**	**1,418,556**	**1,595,749**	**1,039,421**	**1,100,250**

Should SCE be successful with divesting the Hydro assts presented in Table I-7, prior to a final decision being reached in this GRC proceeding, SCE would propose that $0.760 million labor and $0.340 million non-labor, $1.100 million total, of Hydro expenses be removed from the Hydro 2025 TY O&M forecast presented in testimony section II.B.2.

Additionally, SCE currently anticipates that it will be required to perform an estimated $20 million of interconnection-related upgrades to the electric transmission and distribution equipment in order to conform these existing facilities to applicable standards as a condition of the sale agreement(s). SCE plans to include these costs as part of the sales transaction for purposes of the gain/loss calculation in the required Public Utilities Code Section 851 filings and has not included these costs in its GRC forecast. To the extent these costs are actually incurred, SCE may seek alternate cost recovery, including potential recovery in GRC rates, depending on the outcome of the divestment process.

b) 455.5(b) Letters

California Public Utilities Code Section 455.5(b) requires utilities to notify the Commission when a major generation facility has been out of service for nine consecutive months. A major generation facility includes any generation plant or facility with a nameplate capacity of 50 megawatts ("MW") or more, or that represents at least one percent (1%) of an electric utility's retained generation system capacity whichever is smaller.[21]

During the preceding 5 years (*i.e.,* 2018 – 2022) SCE submitted two 455.5(b) notices to the Commission regarding extended outages at Big Creek 8 Unit 2 and Big Creek 3 Unit 3.[22] SCE has been in discussions with Commission staff regarding the status of the units.

(1) Big Creek 8 Unit 2 - Creek Fire

The Creek fire started on September 4, 2020, near Shaver Lake, California.[23] The fire was sparked by a lightning strike and burned 379,895 acres before being fully contained on December 24, 2020, making it the largest single fire in SCE's service area. On September

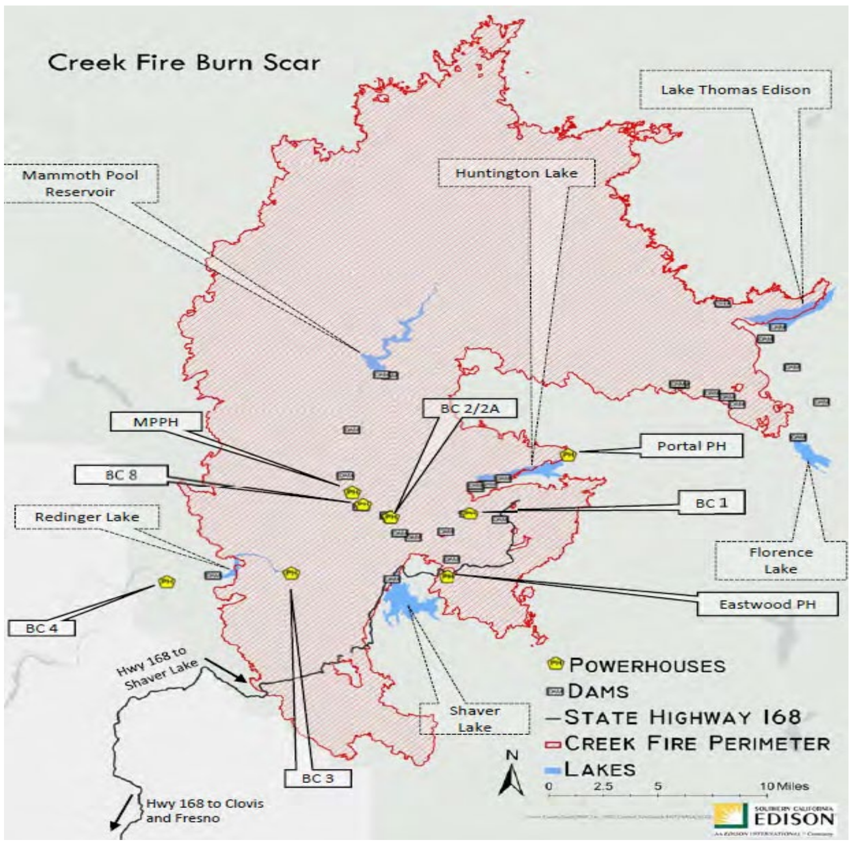
[21] D.07-09-021, Ordering Paragraph 1.

[22] WP SCE-05 Vol. 1, pp. 2-5. 455.5(b) Notice-Big Creek 8 Unit 2 and 455.4.(b) Notice-Big Creek 3 Unit 3.

[23] 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.

6, 2020, Governor Newsom issued an Emergency Proclamation for Fresno and Madera Counties because of the Creek Fire.[24] Figure I-3 below shows the burn area of the Creek fire.

Figure I-3
2020 Creek Fire Burn Scar



The fire significantly impacted SCE's distribution, transmission, telecommunication, and Hydro facilities in the area, including the critical Big Creek generation facilities.

SCE subsequently filed CEMA Application A.22-03-018 to recover incremental restoration and repair costs incurred because of the Creek Fire.[25] As noted on page 45, footnote 27, the CEMA application did not include costs related to the damage to SCE's Big Creek

[24] *See* FEMA website / California Creek Fire, *available at* https://www.fema.gov/disaster/5348.

[25] SCE continues to record Creek Fire costs to the CEMA, and all recorded/forecasted costs have been removed from SCE's GRC application.

Hydro facilities. This is because at the time of the application the repairs to the hydroelectric generation facilities were not completed and some of the costs for the repairs will be covered by applicable insurance. SCE indicated that it may seek cost recovery in a future CEMA application for damages to the hydroelectric generation facilities that were not covered by insurance.

The Big Creek Powerhouse 8 Unit 2, which has a capacity of 45MW, suffered severe damage as a result of the Creek Fire while three other powerhouses (Powerhouse 2, Powerhouse 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, efforts to fully restore BC8U2 will extend into 2025.

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

The Big Creek 3 Unit 3 ("BC3U3") unplanned outage resulted from the failure of field poles on the generator 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 entire rotor assembly. During this removal process, the station crane failed. Repairs to the crane were completed in late September 2022 and the crane was used to remove the rotor assembly. Thereafter, the field poles were cut out and shipped to a vendor for repair/refurbishment. SCE expects to receive the repaired components from the vendor in mid-late May 2023 and is forecasting BC3U3 to return to operation in the third quarter of 2023.

2. Mountainview

During the preceding five years, SCE has successfully complied with General Order 167 reporting requirements. These requirements implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy.

3. Catalina

The generation resources (currently six diesel-fueled generators, 23 propane-fueled micro-turbines and a sodium-sulfur (NaS) battery) at SCE's Pebbly Beach Generating Station (PBGS) are subject to emission limitations for nitrogen oxides (NOx), other criteria pollutants, and toxic air contaminants set by the SCAQMD. SCE must operate within various emissions limits for the overall generation site, and separately for the diesel units. Compliance was historically maintained through the SCAQMD-administered NOx emissions trading program called RECLAIM (REgional CLean Air Incentives Market). In 2018, SCAQMD began a transition from the RECLAIM program to a command-and-control regulatory structure that requires the use of Best Available Retrofit Control Technology (BARCT) at covered facilities. The SCAQMD determines which technology meets the BARCT standard. Assembly Bill (AB) 617 imposed a December 31, 2023, deadline for implementing BARCT.[26]

As a result of the RECLAIM transition and AB 617, PBGS is subject to SCAQMD Rule 1135 (Emissions of Oxides of Nitrogen from Electricity Generating Facilities), which was amended on January 7, 2022. To comply with Rule 1135 on and after January 1, 2026, PBGS must reduce NOx emissions to 13 tons per year,[27] which will require the replacement of several of SCE's six diesel engines with new U.S. EPA Tier 4 Final-certified diesel engines as well as implement additional zero- and near-zero emission generation resources.

In SCE's 2021 GRC application, SCE sought to replace the six existing diesel generators with six new U.S. EPA Tier 4 Final-certified diesel generators (Catalina Repower Project).[28] However, in D. 21-08-036, the Commission directed SCE to submit a standalone application with an updated version of the Catalina Repower Project and authorized SCE to create a Catalina Repower Memorandum Account to track costs related to the Project for recovery following a reasonableness review in the next

[26] AB 617 is codified at Health & Safety Code Sections 40920.6 and 40920.8. The December 31, 2023, deadline appears in Section 40920.6 (c)(1).

[27] SCAQMD Rule 1135(d)(2)(D), pp. 1135-5.

[28] D.21-08-036, pp. 359-363.

GRC.[29] As indicated in SCE's Catalina Repower Application (A.21-10-005), SCE, TURN, and Cal Advocates reached a Settlement Agreement in April 2022, which was approved by the Commission in Decision No. 22-11-007, whereby SCE committed to take all reasonable actions under a Clean Energy All-Source RFO to maximize the use of zero-emissions resources to meet Catalina customer demand and thus reducing the number of diesel generators on the Island. As indicated in Decision No. 22-11-007, the Catalina Repower Project evolved from six new diesel generators to: (1) Phase IA: the installation of two new diesel units to replace the existing Units 8 and 10, along with a Tier 2 Advice Letter process by which SCE would seek CPUC approval of these units following SCAQMD's issuance of a Permit to Construct,[30] (2) Phase IB: the replacement, retrofitting, or retirement of Unit 15, along with a Tier 2 Advice Letter process by which SCE would seek CPUC approval of the selected option following the SCAQMD's issuance of the Permit to Construct, and (3) Phase 2: a Clean Energy, All-Source RFO, which SCE anticipates will lead to the execution of power purchase agreements with third parties for zero- and near-zero emissions generation resources and demand-side resources, along with the Tier 3 Advice Letter process by which SCE would seek approval of the resulting power purchase agreements.[31]

While there is agreement over the replacement of Units 8 and 10, there is still uncertainty over the replacement of Unit 15 as well as the balance of the generation that SCE expects to secure as a result of the Clean Energy All Source RFO since those resources are not expected to be online until after the 2025 Test Year. As directed by the Commission in D.22-11-007, SCE will seek cost recovery approval through submission of a Tier 2 advice letter for replacement of Unit 15 (if necessary) following

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29 D.21-08-036, pp. 362-363.

30 Pursuant to Section 6.1 of the Settlement Agreement, TURN and Cal Advocates agreed not to protest the need for the replacement of Units 8 and 10 with U.S. EPA Tier 4 Final-certified generators.

31 The RFO was launched on December 21, 2022, with an initial offer submittal deadline of May 1, 2023 (later extended to September 1, 2023) and a final offer submittal deadline of May 1, 2024 (later extended to September 1, 2024). Any execution of contracts with third parties is not expected until approximately October 30, 2024. Pursuant to the Settlement Agreement, if any non-zero-emissions generation is needed for Catalina beyond Phase 1 and the All-Source RFO, SCE will use the Application process to seek approval for any specific commitments, including utility-owned resources. Prospective dates are subject to change.

issuance of a permit to construct, a Tier 3 advice letter for contracts executed via the Catalina Clean Energy All-Source RFO for renewable, zero-emission, and near-zero-emission generation resources, and an application process if additional non-zero emission resources are needed beyond up to three new U.S. EPA-certified Tier 4 final diesels and successful RFO projects.

Table I-8 below summarizes the approval phases and cost recovery mechanisms for the different phases of the Catalina Repower Project.

Table I-8
Catalina Repower Project – Approval Phases and Cost Recovery Mechanism

Catalina Repower Project	Approval Process	Forum for Cost Recovery
Phase IA: Units 8 and 10 replacement with two new U.S. EPA Tier-4 Final Certified	Tier 2 Advice Letter	SCE proposes cost recovery of Catalina Repower Memorandum Account costs via Tier 3 Advice Letter.
Phase IB: Unit 15 replacement, retirement, or retrofitting	Tier 2 Advice Letter	Catalina Repower Memorandum Account in future cost recovery proceeding.
Phase 2: Clean Energy, All-Source RFO	Power purchase agreements with third parties secured through the Clean Energy All Source RFO will be approved via SCE's Energy Resource Recovery Account (ERRA) Review Application. If SCE needs any non-zero emissions generation (including utility owned generation), SCE must seek approval via an application.	Cost recovery for power purchase agreements with third parties secured through the Clean Energy All Source RFO will be secured via ERRA. Cost recovery for any non-zero emissions generation (including utility owned generation) will be secured via an application.

At this time, SCE is not eligible for a reasonableness review of the costs that have been recorded in the Catalina Repower Memorandum Account, as contemplated by the Commission in D.21-08-026 when the Commission directed SCE to track costs related to the Catalina Repower Project in the memorandum account for future recovery following a reasonableness review in "the next GRC."[32] This is because SCE cannot seek recovery of Units 8 and 10's costs in the memorandum account in this 2025 GRC application because these units are not yet in service,[33] and thus SCE cannot provide testimony for a reasonableness review at the time of the filing of SCE's 2025 GRC application. SCE is thus providing

[32] "We also authorize SCE to create a Catalina Repower Memorandum Account to track costs related to the project for possible future recovery following a reasonableness review in the next GRC." D.21-08-036, p. 363.

[33] SCE anticipates that Units 8 and 10 will be in service at the end of 2024 or at the beginning of 2025.

testimony in this GRC Application for information purposes and to update the Commission on the Catalina Repower Project, including the status of these two units. SCE requests that it be authorized to use a Tier 3 Advice Letter process for reasonableness review of Units 8 and 10, rather than delay review and cost recovery to the 2029 GRC.

a) Catalina Repower Memorandum Account Reasonableness Review

On October 15, 2021, SCE filed Application 21-10-005, requesting authority to proceed with its proposal to install six new diesel generation units to replace the existing six units. In its application, SCE forecasted $11.9 million (nominal) in capital expenditures for years 2018-2022, with actual costs to be recorded to the Catalina Repower Memorandum Account as authorized in D.21-08-036. On April 29, 2022, SCE filed its Amended Application and submitted amended testimony requesting approval of the Catalina Repower Project consistent with the Settlement Agreement between SCE, TURN, and Cal Advocates and submitted to the Commission for approval on April 29, 2022. As of the filing date of this testimony, none of the three diesel generation units (Units 8, 10, and 15) planned for replacement are in-service and providing benefit to customers. SCE anticipates that Units 8 and 10 will be in service at the end of 2024 or at the beginning of 2025. Because a capital project must be in-service and providing benefit to customers prior to seeking cost recovery, SCE is unable to provide testimony at the time of the filing of its 2021 GRC Application and seek a reasonableness review and recovery of the capital expenditures in this GRC application, as contemplated by the Commission in D. 21-08-026.[34] Because these projects are expected to be placed in service at the end of 2024 or at the beginning of 2025, SCE proposes the Commission in this GRC proceeding specify review and future recovery of recorded costs occur via submission of a Tier 3 Advice Letter as opposed to carrying these costs until the 2029 GRC. SCE has provided further information regarding this proposal in its 2022 ERRA Review Application (A.23-04-003).

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[34] "We also authorize SCE to create a Catalina Repower Memorandum Account to track costs related to the project for possible future recovery following a reasonableness review in the next GRC." D.21-08-036, p. 363.

b) Repower - Catalina Rule 1135 Diesel Replacements

(1) Background

In SCE's 2021 GRC application, SCE sought to replace the six existing diesel generators on Catalina with six new U.S. EPA Tier-4 Final Certified diesel generators (Catalina Repower Project or Project).[35] However, in D. 21-08-036, the Commission directed SCE to submit a standalone application with an updated version of the Catalina Repower Project and authorized SCE to create a Catalina Repower Memorandum Account to track costs related to the Project for recovery following a reasonableness review in the next GRC.[36] The Commission's authorization of a Memorandum Account,[37] along with the Commission's approval of the Settlement Agreement in SCE's standalone application,[38] impacts the process by which SCE will seek approval of any new generation resources and the forum where SCE will seek recovery of project costs.

(2) Project Scope

The Catalina Repower Project Settlement Agreement approved in Decision No. 22-11-007 provided the following direction for the project scope, which has been divided into two phases:

In 2023, SCE will perform Phase IA of the project, which includes the installation of two new diesel units to replace the existing Units 8 and 10, along with a Tier 2 Advice Letter process by which SCE would seek CPUC approval of these units following SCAQMD's issuance of a Permit to Construct. SCE submitted a Permit to Construct application on April 30, 2021, and expects to receive the SCAQMD's Permit to Construct in 2023. Consistent with the Settlement Agreement approved in Decision No. 22-11-007, SCE will be requesting approval of these units via a Tier 2 Advice Letter.[39]

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[35] D. 21-08-036, pp. 359-363.

[36] D. 21-08-036, pp. 362-363.

[37] D. 21-08-036, p. 363.

[38] D. 22-11-077.

[39] Pursuant to Section 6.1 of the Settlement Agreement, TURN and Cal Advocates agree not to protest the need for the replacement of Units 8 and 10 with the U.S. EPA Tier 4 Final-certified generators.

In years 2024 and 2025, SCE will perform Phase IB of the project, which includes the replacement of Unit 15, along with a Tier 2 Advice Letter process by which SCE would seek CPUC approval of the selected option following the SCAQMD's issuance of the Permit to Construct. In 2022, SCE tested new catalyst blocks to reduce particulate matter emissions below the Rule 1470 threshold. The new catalyst blocks were not successful in reducing emissions, so SCE informed the SCAQMD on November 23, 2022, that it would seek to replace Unit 15 with a new U.S. EPA Tier 4 Final-certified engine.[40] SCE is working with SCAQMD staff to evaluate whether a propane-fueled unit is feasible. Consistent with the Settlement Agreement approved in Decision No. 22-11-007, SCE will be requesting approval of Unit 15's replacement via a Tier 2 Advice Letter.

4. Fuel Cells

In D.10-04-028, issued on April 14, 2010, the Commission approved the SCE Fuel Cell Demonstration Program, citing that the "Commission should support the advancement of fuel cell technologies through the Fuel Cell Projects because investment in fuel cells through the Self-Generation Incentive Program (SGIP) has lagged."[41] The Commission further stated that the fuel cell projects "… can supplement the Commission's SGIP efforts to advance fuel cell technologies in California."[42] Consistent with program approval, SCE constructed and operated two fuel cells. SCE's Fuel Cell Demonstration Program was a unique partnership between SCE and two California universities that "… will enhance the universities' educational curriculum, particularly sustainable instructional programs in business, engineering, and environmental studies."[43] In April, SCE submits to the Commission an annual report summarizing Fuel Cell operations for the prior calendar year, so operational data and lessons learned from the program can be shared with other interested parties.

Decision 10-04-028 also directed SCE to record Fuel Cell Program capital and O&M costs in the Fuel Cell Program Memorandum Account ("FCPMA") and to present the annual recorded

[40] WP SCE-05 Vol. 1, p. 6. SCE's 11/23/2022 letter to SCAQMD.

[41] D.10-04-028, p. 37.

[42] D.10-04-028, p. 37.

[43] D.10-04-028, p. 3.

costs for reasonableness review in SCE's annual ERRA Review Phase proceedings. In SCE's 2015 GRC, the Commission approved SCE's request to eliminate the FCPMA, and transition fuel cell cost recovery to base rates effective January 1, 2015.

SCE has successfully operated the two fuel cell facilities and met the objectives of the 10-year demonstration program. Both facilities will have reached their 10-year anniversary before the end of 2023 and SCE is targeting to decommission both facilities in 2023, as discussed further in testimony section III E.

G. Risk Factors, Safety, Reliability

SCE's forecasts for Generation BPG O&M expenses and capital expenditures are necessary to operate SCE's generation resources safely, reliably, and in compliance with applicable regulations. Because of the potential impact on safety and the environment, SCE's management of these facilities is subject to numerous regulatory requirements, including those of the California Division of Safety of Dams ("DSOD"), South Coast Air Quality Management District ("SCAQMD") and the Federal Energy Regulatory Commission ("FERC"). SCE must comply with the conditions of the numerous FERC licenses governing Hydro assets, along with numerous other state and federal requirements.[44] Hydro dams and flowlines undergo regulatory-prescribed and other inspections and analysis. SCE's capital forecast includes funds for repairs and upgrades that were identified through these inspections and analysis.

Routine maintenance and replacement of Hydro equipment, including prime mover overhauls, is necessary to maintain plant reliability as the equipment reaches the end of its service life, and minimize (to the extent practical) in-service failures. Such in-service failures can cause electrical faults or mechanical damage to other interconnected equipment, resulting in long outages of the affected generating unit(s). There are also economic benefits to performing capital projects that replace end-of-

[44] A small percentage of SCE's Hydro assets are not regulated by FERC; see Chapter II.C.3.

life equipment prior to in-service failure(s), as an in-service failure will typically be more costly and require a longer repair outage than had the repair been planned.[45]

Aside from the safety considerations and damage to adjacent equipment, there are other reasons that make it impractical to operate major equipment items to failure. Most major equipment items are unique to the unit in which they are installed. Only a small percentage of the major equipment items (*e.g.*, large transformers, generator windings, turbine rotors, etc.) can be used in more than one (or a few) of the generating units. These generating units have varying MW sizes (*i.e.,* rated capacity) and other design differences based on the unique requirements associated with each of the different powerhouse (*e.g.,* the water "pressure head" and flow rates varies among the powerhouses). Other replacement-part differences result from these generating units being designed and built over several decades. Therefore, it is not practical to maintain a complete inventory of spare replacement parts. Also, some items, such as generator windings, have a limited shelf life. Generator windings must be installed within a few months of delivery, or the winding insulation becomes too brittle to withstand the bending and other stresses involved in their installation.

Funding for Generation O&M and capital work will facilitate the continued safe, compliant, and reliable operation of the Generation fleet. Further details of O&M and Capital work are explained in the following sections of testimony below.

1. Catalina

Catalina is physically isolated from other California energy sources, but service requirements are high due to the large influx of annual visitors. This results in a larger inventory of critical spare equipment, parts, and consumables located on the island. Consequently, Catalina is a very challenging and costly place to conduct a utility business. Evolving regulations and climate change pose additional challenges to maintaining service reliability and affordability. Like other parts of California, the island faces a variety of climate risks, including sea level rise, wildfire, drought, extreme heat, and

[45] Results of benefit-to-cost calculations are referenced in the Capital project section of this testimony and further details are provided in the accompanying workpapers.

heavy precipitation. However, the island's remote location and rural setting increase its vulnerability and pose unique challenges that require adaptation planning to respond to climate risks.

A 2021 evaluation process and vulnerability assessment analyzed potential climate impacts on SCE's electric assets, operations, and services on Catalina Island. Key threats identified during this process include:

- Coastal flooding and erosion exposing power systems
- Pending additional modeling data, Atmospheric River 1,000-year storm (ARkSTorm) and debris flow exposing power systems

H. Connection with RAMP

1. Overview

SCE's 2022 RAMP report identified the top 10 safety risks associated with the operations of SCE's assets, including Hydro Dam Failure. As shown in Table I-9 below, SCE identified three compliance activities, one foundational activity, and six controls, for the Hydro Dam Failure RAMP risk.[46, 47]

[46] SCE defines a control as an activity that was undertaken prior to 2021 to address the RAMP Risk, and which may continue through the RAMP period. Compliance activities are those activities that are required by law or regulation. Foundational activities are defined as "initiatives that support or enable two or more mitigation programs or two or more risks, but do not directly reduce the consequences or reduce the likelihood of safety risk events." Per D.21-11-009, Ordering Paragraph 1e, p. 11, RSE calculations for foundational activities are not required. However, the estimated budget, subject to certain thresholds, should be incorporated into the mitigation programs that the foundational activities enable.

[47] WP SCE-05 Vol. 1, pp. 7-14. Hydro Dam Failure - Tranches, Controls and Mitigations.

Table I-9
GRC Controls & Mitigations Included in SCE's 2022 RAMP Filing

RAMP Risk	GRC Activity	2022 RAMP ID	Control/Mitigation Name
Hydro Dam Failure	Hydro	CM1	Hydro Operations
Hydro Dam Failure	Hydro	CM2	Hydro Maintanence
Hydro Dam Failure	Hydro	CM3	External Inspections
Hydro Dam Failure	Hydro	F1	Dam Safety Program
Hydro Dam Failure	Hydro Dams and Waterways	C1	Seismic Retrofit
Hydro Dam Failure	Hydro Dams and Waterways	C2	Dam Safety Protection
Hydro Dam Failure	Hydro Dams and Waterways	C3	Spillway Remediation and Improvement
Hydro Dam Failure	Hydro Dams and Waterways	C4	Low Level Outlet (LLO) Improvements
Hydro Dam Failure	Hydro Dams and Waterways	C5	Seepage Mitigation
Hydro Dam Failure	Hydro Dams and Waterways	C6	Instrument and Communication Improvements

CM = Compliance Activity; F= Foundational, C = Control

a) Hydro Asset Safety

SCE operates a portfolio of thirty-three Hydro dams that support thirty-two hydroelectric plants that provide a combined 1,164 MW of generating capacity.[48] The dams are typically in remote mountainous areas and situated to capture the energy from high elevation rain and snowmelt as it flows downward. Most dams were constructed in the early 20th century, with the oldest dating to 1893 and the most recent dating to 1986.

SCE approached its analysis of Hydro dam risk by building on its existing Dam Safety Risk Assessment Program, which SCE initiated in 2008 and modeled after Hydro dam risk management best practices established by the U.S. Bureau of Reclamation.[49] The analysis approach is based on identifying the potential ways a specific dam could fail, known as Potential Failure Modes (PFMs), and then evaluating the likelihood of occurrence and the consequence of each PFM.

SCE defined the risk event as the Uncontrolled Rapid Release of Water ("URRW"). The scope is defined by dams with a hazard classification of "high-hazard" or greater as designated by the California Department of Water Resources Division of Safety of Dams ("DSOD")

48 SCE also operates two dams on Catalina Island that support its potable water supply.

49 In cases where SCE has relied on SME judgment, SCE provides additional detail, where applicable, as to why such judgement is prudent and should be used to inform RAMP analyses. WP SCE-05 Vol. 1, p. 15. Hydro Dam Failure - Subject Matter Expert Qualifications.

and/or FERC.[50] SCE believes that this was an appropriate scope for the analysis, as the facilities have been identified by the relevant federal and/or state regulators as having the greatest potential to cause the loss of human life in the event a hazard materializes.

SCE identified five drivers that could potentially lead to URRW: seismic events, flooding, failure under normal operations, physical attack, and cyber-attack. Risk outcomes were described in terms of three categories: (1) the facility is inoperable and there is no significant inundation; (2) there is inundation of an unpopulated area; and (3) there is inundation of populated and unpopulated areas. The overall likelihood of a catastrophic failure of one of SCE's twenty-seven high-hazard dams was estimated as one failure every 238 years.

Table I-10 summarizes the compliance activities (CM1-CM3), foundational activity (F1) and controls (C1-C6) that SCE utilizes to cost-effectively mitigate the risk of an URRW event occurring at its high-hazard dams.

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50 Hazard classification is based on potential downstream impacts to life and property should the dam fail when operating with a full reservoir, as defined in the Federal Guidelines for Inundation Mapping of Flood Risk Associated with Dam Incidents and Failures (FEMA P946, July 2013). A classification of "High" is given for a dam where one or more fatalities would be expected. DSOD created an "Extremely High" category in 2017 to identify dams that are expected to cause considerable loss of human life or result in an inundation area with a population of 1,000 persons or more). Five of SCE's 28 high hazard dams are classified as Extremely High Hazard.

Table I-10
Hydro Asset Safety
RAMP – Compliance, Foundational and Control Activities

RAMP ID	Compliance/Control Activities	Description
CM1	Hydro Operations	Monitoring and controlling reservoir levels and flows, routine observation and data collection by trained personnel, and regular testing of critical systems.
CM2	Hydro Maintenance	Repairing minor/localized deterioration and maintaining operability of critical systems.
CM3	External Inspections	Regular regulatory inspections are performed by the FERC and DSOD. Additionally, independent Consultant Safety Inspections are performed at five-year intervals for each dam in accordance with Chapter 18 of the Code of Federal Regulations (18 CFR) Part 12D.
F1	Dam Safety Program	This program utilizes qualified engineers, supported by internal and external Subject Matter Experts, to help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.
C1	Seismic Retrofit	Reinforcing dams to withstand seismic loading and/or making improvements to maintain seismic restrictions on reservoir levels.
C2	Dam Surface Protection	Protecting upstream dam surfaces with geomembrane liner systems.
C3	Spillway Remediation and Improvement	Repairing and improving structures used to safely pass water flows from flooding events.
C4	Low Level Outlet Improvements	Repairing and improving systems used to draw down dam reservoir levels in a controlled manner.
C5	Seepage Mitigation	Repairing or enhancing the structure and/or drainage systems of earthen dams to inhibit the initiation and progression of internal erosion.
C6	Instrumentation/ Communication Enhancements	Improving instrumentation and communication systems used to detect conditions that may indicate dam failure.

Compliance activities (CM1-CM3) are required to adhere to laws and regulations governing dam safety.[51] Electing not to perform this work for a dam would likely result in an order from the FERC to cease generation, and possibly revocation of the associated FERC license (as was recently issued in 2018 to Boyce Hydro in Michigan). Similarly, DSOD has the authority to impose reservoir restrictions and to revoke the certificate of approval required to operate a dam in California, if it determines that there is a danger to life and property.

[51] 18 CFR Part 12 – Safety of Water Power Projects and Project Works, Parts 1 and 2 of Division 3, Dams and Reservoirs, California Water Code, and Chapter 1 of Division 2, Title 23 Waters, California Code of Regulations.

Foundational activities (F1) include the Dam Safety Program. This program utilizes qualified engineers, supported by internal and external Subject Matter Experts, to help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.

In addition to the compliance and foundational activities, SCE further mitigates risk of an URRW event through the performance of Hydro Capital Maintenance Refurbishment and/or Replacement – control activities (C1-C6). These controls consist of capital investments necessary for maintaining dam infrastructure and equipment. Infrastructure work includes projects such as dam improvements needed to address identified areas of concern.

SCE's existing programs and processes serve to reduce the likelihood of the risk materializing, or the impact level of a risk event should it occur. SCE considered all work forecast to occur in 2023-2028 for the twenty-eight high-hazard dams and evaluated the work's impact on mitigating the RAMP drivers, outcomes, and consequences. Further information regarding these compliance and control activities can be found in sections II.B.3.a), II.B.3.b) and II.C.4.c)(3) of this testimony volume.

2. Safety Policy Division (SPD) Comments

SPD Staff noted that it was unclear why C2 – Dam Surface Protection and C5 – Seepage Mitigation were separated as they did not appear to have different homogenous risk profiles and suggested that SCE consider consolidating C2 and C5.[52]

SPD also noted that SCE should provide risk spend efficiency calculations for all controls, regardless of whether they are compliance based.[53]

3. SCE's Response to SPD Comments

SCE notes that SPD seems to be confusing tranching with mitigations. As noted in the Settlement Agreement (SA) establishing the RAMP process, tranches are supposed to have homogenous

[52] Safety Policy Division Staff Evaluation Report on the Southern California Edison Company's 2022 Risk Assessment and Mitigation Phase (RAMP) Application (A.)22-05-013, p.56.

[53] Safety Policy Division Staff Evaluation Report on the Southern California Edison Company's 2022 Risk Assessment and Mitigation Phase (RAMP) Application (A.)22-05-013, pp. 16 – 17.

risk profiles,[54] while mitigations are not. However, C2 is generally only applicable to concrete dams while C5 is applicable to embankment dams. While the controls could be technically combined, SCE feels it is important to separate these out based on the tranches.

SCE disagrees with SPD and other parties' interpretation of D.21-11-009 and the need and rationale for scoring compliance-based work.[55] Despite this, SCE has provided additional RSEs for the compliance activities presented in RAMP. SCE calculated an RSE for CM-2 Hydro Maintenance work activity,[56] and has included CM3 – External Inspections as a foundational cost as the inspections performed help inform the necessary scope for the mitigation efforts. SCE did not calculate an RSE for CM-1 Hydro Operations, as SCE's SMEs were unable to develop a reasonable estimation of the risk associated with not operating SCE dams. This is because neither SCE, nor any other prudent dam owner, would ever consider the option of consciously choosing to ignore the laws and regulations governing dam safety and endanger its employees and public to an URRW event.

4. **Reconciliation Between RAMP and GRC**

As discussed in Section 1 above, compliance activities (CM1-CM3) are required to adhere to laws and regulations governing dam safety. Electing not to perform this work for a dam is not an option and would likely result in an order from FERC to cease generation and possibly revocation of the associated FERC license (as recently issued to Boyce Hydro in 2018).[57] Similarly, DSOD has the authority to impose reservoir restrictions and to revoke the certificate of approval required to operate a dam in California if it determines that there is a danger to life and property. Consequently, SCE did not consider a "baseline" risk that lacked compliance activities and accordingly did not risk-score compliance activities nor forecast associated compliance O&M costs in the RAMP filing. However as noted above SCE has provided RSE's for some of the Hydro compliance activities.

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[54] D.18-12-014, Attachment A, Row 14, p. A-11.

[55] For additional discussion on compliance RSE's please refer to Exhibit SCE-01, Vol 02.

[56] WP SCE-05 Vol. 1, pp. 16-18. RSE for CM-2 Hydro Maintenance Work Activity.

[57] "Boyce Hydro Power, LLC; Order Proposing Revocation of License." Federal Energy Regulatory Commission, Document 83 FR 8253. February 26, 2018.

Foundational activities (F1) help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.

Hydro Capital Maintenance Refurbishment and/or Replacement activities (C1-C6) are controls consisting of capital investments necessary for maintaining dam infrastructure and equipment. SCE has included in its GRC request all Control activities identified in its RAMP filing. These controls consist of capital investments necessary for maintaining dam infrastructure and equipment. Infrastructure work includes projects such as dam improvements needed to address identified areas of concern.

As shown in Table I-11 below, there were a few differences between the RAMP forecast for Hydro Asset Safety Controls, as estimated in SCE's 2022 RAMP report, and the forecast requested in this GRC.[58] These differences were the result of project delays (C3, C4 and C5) and the addition of new projects (C6).[59] While RSE's are one factor in determining implementation of Hydro Asset Safety Controls a further justification regarding these Capital projects is provided in testimony Section C.

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[58] WP SCE-05 Vol. 1, pp. 19-20. Hydro Dam Failure - RAMP to GRC Variance and RSE.

[59] Foundational control costs, F1 and F2, were allocated by proportioning the annual capital spend by control.

Table I-11
Hydro Asset Safety Controls - Risk Spend Efficiencies
Capital Forecast
(Nominal $000)

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	2025 - 2028 Total Spend	2025 - 2028 RSE
Hydro Dam Failure	C1	Seismic Retrofit	RAMP	200	1,800	-	-	-	-	-	-	N/A
			GRC	109	1,500	-	-	-	-	-	-	N/A
			Variance	(91)	(300)	-	-	-	-	-	-	N/A
Hydro Dam Failure	C2	Dam Surface Protection	RAMP	6,507	-	-	-	-	-	-	-	N/A
			GRC	347	6,406	-	-	-	-	-	-	N/A
			Variance	(6,160)	6,406	-	-	-	-	-	-	N/A
Hydro Dam Failure	C3	Spillway Remediation and Improvement	RAMP	11,263	1,400	6,750	5,200	5,000	-	-	10,200	67.0
			GRC	1,758	7,930	6,750	850	5,000	4,987	-	10,837	61.0
			Variance	(9,505)	6,530	-	(4,350)	-	4,987	-	637	(6.0)
Hydro Dam Failure	C4	Low Level Outlet Improvements	RAMP	1,123	1,957	2,057	4,039	6,759	22	-	10,820	0.2
			GRC	1,342	20,088	14,463	3,472	943	4,206	2,793	11,413	0.3
			Variance	219	18,131	12,406	(567)	(5,816)	4,184	2,793	593	0.1
Hydro Dam Failure	C5	Seepage Mitigation	RAMP	250	150	150	3,100	900	-	-	4,000	121.0
			GRC	0	-	-	498	3,100	900	-	4,498	24.0
			Variance	(250)	(150)	(150)	(2,602)	2,200	900	-	498	(97.0)
Hydro Dam Failure	C6	Instrumentation / Communication Enhancements	RAMP	1,000	-	-	150	-	-	-	150	11.3
			GRC	421	2,351	60	330	1,295	-	-	1,625	7.3
			Variance	(579)	2,351	60	180	1,295	-	-	1,475	(4.3)
Hydro Dam Failure	F1	Dam Safety Program	RAMP	1,000	1,230	1,230	1,230	1,230	1,230	1,230	4,920	N/A
			GRC	N/A	1,230	1,230	1,230	1,230	1,230	1,230	4,920	N/A
			Variance	-	-	-	-	-	-	-	-	N/A
Hydro Dam Failure	F2/CM3	External Inspections	RAMP	1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
			GRC	N/A	1,275	1,275	1,275	1,275	1,275	1,275	5,100	N/A
			Variance	-	1,275	1,275	1,275	1,275	1,275	1,275	5,100	N/A
Hydro Dam Failure	C7/CM2	Hydro Maintenance	RAMP	1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
			GRC	N/A	1,464	1,464	1,464	1,464	1,464	1,464	5,856	3.1
			Variance	-	1,464	1,464	1,464	1,464	1,464	1,464	5,856	N/A

II.

HYDRO

SCE operates and maintains 32 hydroelectric (Hydro) generating facilities, including 33 dams, 43 stream diversions, and approximately 143 miles of tunnels, conduits, flumes, and flow lines.[60], [61] SCE's Hydro generating facilities have an aggregate 1,164 MW of nameplate capacity. This Chapter presents SCE's 2025 Test Year ("TY") forecast of $53.475 million (constant 2022 dollars) in operations and maintenance expense and forecast of $471.520 million (nominal dollars) in 2023-2028 capital expenditures for Hydro generating facilities.[62] These expenditures are necessary for SCE to maintain safe Hydro operations for employees and the public, provide reliable service at low cost, and comply with applicable laws and regulations.

A. Overview of Hydro Generation

1. Hydro Assets

SCE's Hydro generation facilities can be separated into two major systems: (1) water storage and conveyance facilities; and (2) powerhouses and associated auxiliary equipment. Hydro water diversion, storage and conveyance facilities are used to divert, store, and direct water to powerhouse facilities through 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-4 below illustrates a typical hydroelectric generating plant.

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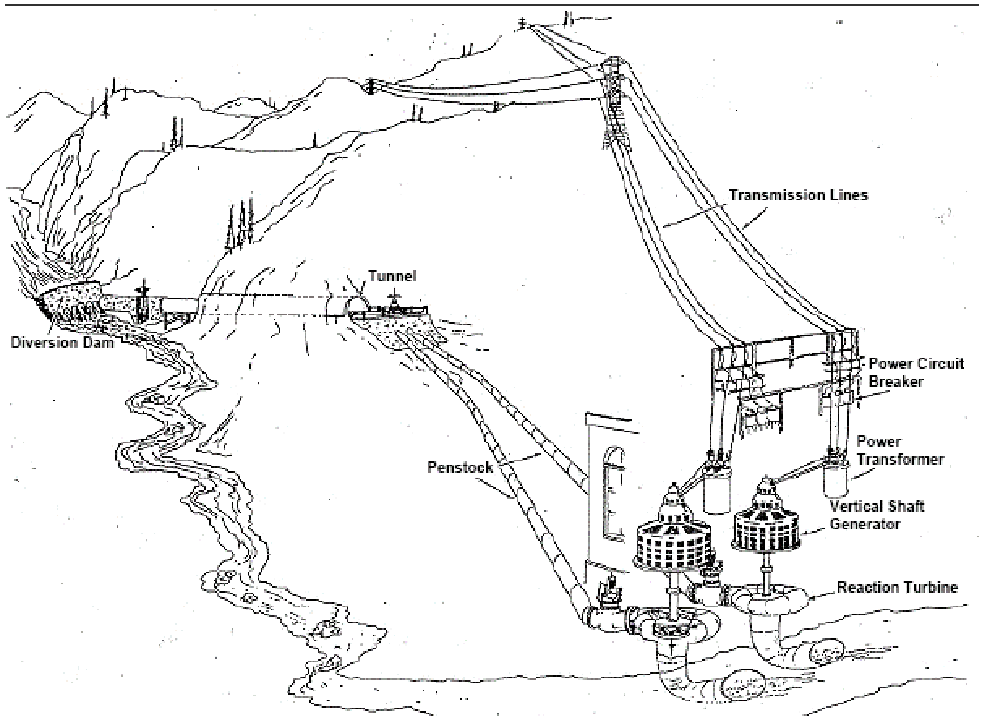
60 SCE currently has 35 hydroelectric power houses, of which three (San Gorgonio 1, San Gorgonio 2, and Borel) are no longer in operation as the units at these three facilities have been disconnected from the grid. SCE has initiated proceedings at FERC to surrender the licenses of these facilities.

61 All but five of the Hydro generating facilities operate under FERC licenses. The units date from as early as 1893.

62 The forecast reflects certain changes made to SCE's employee compensation program. Please refer to Exhibit SCE-06, Vol. 04.

Figure II-4
Typical Hydroelectric Generating Station



SCE has three types of Hydro generating resources: (1) stream flow or "run-of the-river;" (2) reservoir storage; and (3) pumped storage, 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 open flumes and canals, flow lines, 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 turbine is located.

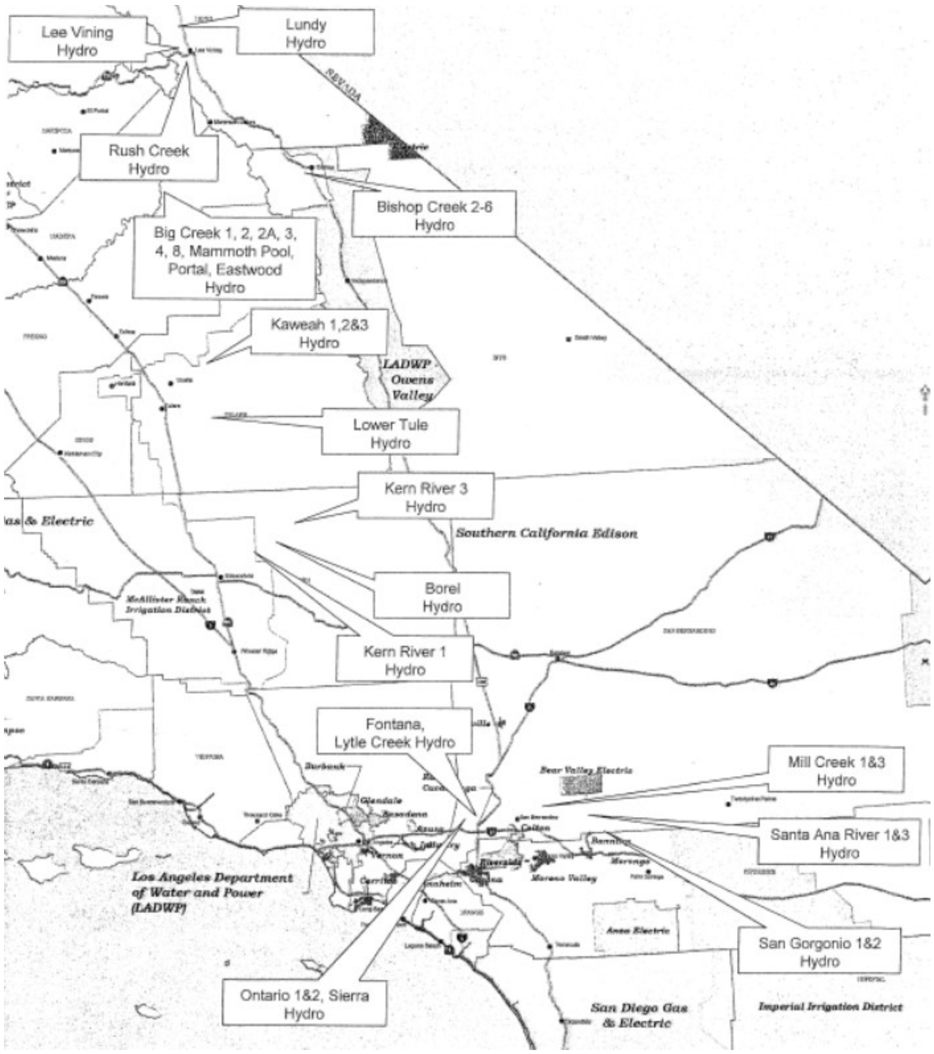
Hydro facilities with reservoir storage have the added benefit of storing water during the spring and early summer to allow increased utilization of the water during the hottest months and peak demand periods in late summer and early fall. Storing water in reservoirs extends the window of opportunity for generation beyond the runoff period and allows greater control and utilization of the water.

SCE has one pump storage facility (John S. Eastwood Power Station) that operates as a reservoir storage facility with the benefit of pump-back operations. SCE uses the pump-back capabilities when market conditions warrant. When the unit runs in pump-back mode, the generator is used as a motor and the turbine is used to pump water back to the unit's storage facility. This mode of operation allows limited water resources to be reused during peak summer operating hours, when demand is high, and other times during the year.

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 in the western Sierra Nevada Mountains, across an area that is centered approximately 50 miles northeast of Fresno. The Big Creek hydroelectric system includes six major reservoirs, 16 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 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 Bernardino and San Gabriel Mountains. As the water resources in these areas are generally not as plentiful as found in Big Creek, these other assets are smaller than most of the Big Creek assets. There are 23 powerhouses in this grouping, and most are run-of-the-river facilities. Most have been in service since the late nineteenth and early twentieth centuries, with some equipment older than 125 years. These assets connect to the sub-transmission or distribution systems and make up approximately 150 MW, or about 13 percent, of SCE's Hydro generation. Figure II-5 below is a map showing the location of Hydro facilities.

Figure II-5
SCE Hydro Locations



Employees who work in the Generation Department home office, headquartered in the city of Rosemead, California (in Los Angeles County), provide support to the Hydro divisions for FERC relicensing; environmental compliance; hydrological and biological studies; training and water chemistry support; dam safety analysis and other engineering services; and business analysis. Employees in other departments also support operating and maintaining the Hydro assets, such as assisting in complying with CPUC and FERC requirements governing reliability and cybersecurity; assisting with obtaining regulatory permits and ensuring permit compliance; assisting with maintenance of Hydro powerhouse and related control systems; maintaining the vehicles used by Hydro; and other similar activities that typically affect multiple SCE organizations.

Table II-12 summarizes the MW capacity, year of initial operation, and type of Hydro powerhouse.

Table II-12
SCE Hydro Generation Facilities

Line No.	Region	Powerhouse	Generator Nameplate Capacity (MW)	Type	Initial Date of Operation
1	BIG CREEK	Big Creek 1	88.4	Storage	1913
2		Big Creek 2	66.5	Storage	1913
3		Big Creek 2A	110.0	Storage	1928
4		Big Creek 3	174.5	Storage	1923
5		Big Creek 4	100.0	Storage	1951
6		Big Creek 8	75.0	Storage	1921
7		Mammoth Pool	190.0	Storage	1960
8		Portal	10.8	Storage	1956
9		Eastwood	199.8	Pump Storage	1987
10		TOTAL Northern	1014.9		
11	OTHER	Bishop/Mono Basin:			
12		Bishop Creek 2	7.3	Storage	1908
13		Bishop Creek 3	7.9	Storage	1913
14		Bishop Creek 4	8.0	Storage	1905
15		Bishop Creek 5	4.5	Storage	1919
16		Bishop Creek 6	1.6	Storage	1913
17		Lundy	3.0	Storage	1911
18		Poole	11.3	Storage	1924
19		Rush Creek	13.0	Storage	1916
20		Kern River:			
21		Kern River 1	26.3	Run-of-the-river	1907
22		Kern River 3	40.2	Run-of-the-river	1921
23		Kaweah/Tule:			
24		Kaweah 1	2.3	Run-of-the-river	1929
25		Kaweah 2	1.8	Run-of-the-river	1929
26		Kaweah 3	4.8	Run-of-the-river	1913
27		Tule	2.5	Run-of-the-river	1909
28		East End:			
29		Lytle Creek	0.5	Run-of-the-river	1904
30		Ontario 1	0.6	Run-of-the-river	1902
31		Ontario 2	0.3	Run-of-the-river	1963
32		Fontana	3.0	Run-of-the-river	1917
33		Santa Ana 1	3.2	Run-of-the-river	1899
34		Santa Ana 3	3.1	Run-of-the-river	1999
35		Sierra	0.5	Run-of-the-river	1922
36		Mill Creek 1	0.8	Run-of-the-river	1893
37		Mill Creek 2&3	3.0	Run-of-the-river	1903
38		TOTAL Eastern	149.5		
39	**TOTAL SCE HYDRO**		**1164.4**		

2. Hydro Capabilities and Generation Output

The overriding objective for SCE Hydro powerhouses and water storage facilities is safety and the prudent use of the water resource. Water management is governed by FERC licenses, U.S. Forest Service agreements, water rights, and contractual commitments, which include provisions for water releases and storage levels. Each reservoir has required storage levels for 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 Big Creek project and downstream water users (largely for agricultural irrigation).

Water management requires balancing the following factors: 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. Most 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 down through the watershed within a specific period to either meet water rights delivery obligations to downstream users or reduce the potential of causing spill at various reservoirs that would reduce total generation. During instances when reservoirs are full and energy market prices are negative, it can be more economical to spill than to generate.

The runoff during the 2022 water year was approximately 58 percent of a normal (*i.e.,* median historical inflow) year.[63] Nevertheless, given the fleet's high reliability and the effective management of fuel (water), generation levels during 2022 water year were approximately 76 percent of the 20-year historical average (2002-2021).

Table II-13 summarizes SCE's Hydro generation for 2022, as well as the average annual generation recorded during 2002 through 2021.

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63 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 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).

Table II-13
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 average annual generation over the previous 20-year period. This reflects the fact that there was less-than-average water available for generation resulting from the persisting drought conditions that occurred during the year.

Although Hydro's average annual generation has been lower than typical in recent years, it continues to provide a net benefit to SCE customers. Much of SCE's Hydro generation units have quick-starting and ramping capabilities. Low startup costs and the ability to start up and shut down quickly means the Hydro units can help to reduce overall customer costs. SCE's Hydro facilities can be run to meet electrical grid demand, respond to system contingencies, or simply provide required system operating reserves when necessary. Because certain units can be started without an external source of electrical power (*i.e.,* a "black start"), they can be used to help restore power if the grid experiences a total shutdown or blackout. SCE's Hydro assets have served SCE customers for over 100 years by providing reliable and cost-effective (and greenhouse gas emissions-free) power. SCE expects its larger Hydro assets (*i.e.,* as measured by rated MW output) to continue to be cost effective for many decades into the future.

B. Hydro O&M Expense Forecast

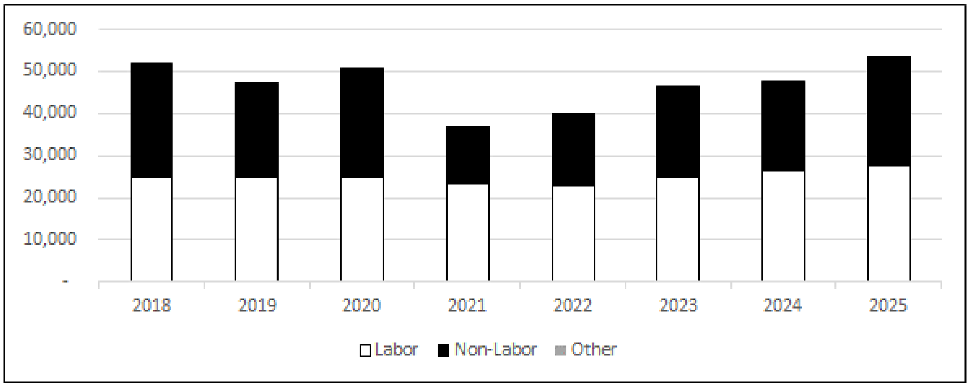
1. Introduction

This section presents our Hydro 2025 Test Year O&M expense forecast, including the analysis of recorded costs and business reasons underlying the forecast. The expenses include operation and maintenance of SCE Hydro generating units and associated reservoirs, dams, waterways, and miscellaneous Hydro facilities. Work activities are categorized into three main categories: (1) Water for Power and Rents, (2) Hydro Operations, and (3) Hydro Maintenance. These expenditures are necessary for SCE's Hydro generation to provide reliable service at a low cost, maintain safe operations for employees and the public, and comply with applicable laws and regulations.

Our testimony on Hydro O&M expenses includes an analysis of the five years of recorded data (2018–2022) and our forecast for years 2023–2025.[64] Based on our analysis of labor and non-labor, the 2025 Test Year O&M expense forecast is $53.475 million, as shown in Figure II-6 below.

[64] WP SCE-05 Vol. 1, pp. 21-26. Hydro Operations and Maintenance Recorded/Forecast Summary.

Figure II-6
Hydro - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	24,928	24,670	24,674	23,181	22,973	24,990	26,223	27,504
Non-Labor	27,051	22,682	25,854	13,482	16,827	21,292	21,588	25,971
Other	-	-	-	-	-	-	-	-
Total Expenses	51,979	47,352	50,528	36,663	39,800	46,282	47,812	53,475
Ratio of Labor to Total	48%	52%	49%	63%	58%	54%	55%	51%

2. <u>Development of Test Year Forecast</u>

We began the process of forecasting Test Year Hydro O&M costs by examining recorded data from 2018 through 2022. We then adjusted the recorded data to add or remove one-time charges, or to correct accounting errors.[65] These adjustments made the historical data more representative of ongoing activities. After making appropriate adjustments to recorded data, we escalated the data to 2022 constant dollars. The results are the 2018-2022 "base year" data. We then tested a variety of forecast methods, including:

- Trend analysis for three, four, and five years
- Average analysis for two, three, four, and five years

[65] The workpapers accompanying this testimony document all historical adjustments.

- Last Recorded Year

We then separately decided on a forecasting method for labor expense and a forecasting method for non-labor expense. The chosen forecasting methods yielded a “base year forecast” for labor expense and a “base year forecast” for nonlabor expenses. Finally, we increased the base year forecasts by future adjustments (discussed in greater detail below) to arrive at a 2025 Test Year forecast for the Hydro BPE of $53.475 million, including $27.504 million labor expense and $25.971 million non-labor expense.[66]

a) Labor – Analysis of Recorded and Forecast Expenses

Recorded labor expenses were relatively flat from 2018-2020, decreased in 2021, and then further decreased in 2022. While recorded 2018-2020 labor costs were relatively flat, a closer look reveals that in 2020 recorded premium labor time costs significantly increased ($2.7 million) as compared to 2019,[67] thus negating an expected decrease in recorded labor costs. SCE’s expectation of a decrease in 2020 recorded labor costs is based on a higher level of attrition in Hydro that was experienced in 2019, resulting in the loss of 23 employees by 2019 year-end.[68] This significant decline in headcount, 15% year-over-year,[69] did not - as would be expected - affect overall recorded labor costs in 2020 because higher amounts of premium time were worked by the remaining employees ($2.7 million higher in 2020 vs. 2019 recorded).[70] The observed increase in recorded premium time in 2020 was also in part due to the COVID-19 pandemic. This is because to mitigate the risks of COVID-19, in 2020 and 2021, SCE was required to sequester key employees performing critical operations work by physically isolating these employees from their families and other employees for many months. During isolation the sequestered employees were paid a premium and although incremental to authorized

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[66] WP SCE-05 Vol. 1, pp. 21-26. Hydro Operations and Maintenance Recorded/Forecast Summary.

[67] WP SCE-05 Vol. 1, p. 27. 2018-2022 Recorded Hydro Premium Time Expenses.

[68] 2018-2022 end-of-year staffing levels by job category of active, full-time, and part-time employees of SCE's Generation Department is provided in response to Cal Advocates MDR Question 4.

[69] Historical Generation vacancy rates range between 3% and 6%.

[70] WP SCE-05 Vol. 1, p. 27 2018-2022 Recorded Hydro Premium Time Expenses.

sequestration costs were removed from the recorded cost reflected in this testimony, some sequestration costs (*i.e.,* those not incremental to authorized) remained and are reflected in the 2020 recorded costs.

In total, between year-end 2018 and year-end 2022, SCE's Hydro department had a higher-than-historic rate of turnover[71] (*i.e.,* counts of employees voluntarily leaving SCE or transfers from Generation to other SCE departments), losing approximately 20% (30 employees) of its total workforce.[72] A 2022 internal analysis performed by SCE's Human Resources department indicates this retirement trend will continue and by 2026, 25% of Generation employees will reach likely retirement age (union 62.7 years, non-union 61.3).[73] As will be discussed in greater detail below, because of the unexpected level of attrition and overall headcount decline and to ensure continued safe and reliable operation of SCE's Hydro assets, SCE is proposing to recover the loss of 30 key craft positions over the next three years (*i.e.,* hiring 10 additional employees per year).

Because of the aforementioned variability in the number of employees and premium time expenses observed in the preceding 5 years, SCE utilizes 2022 recorded, $22.973 million, minus a $0.068 reduction to exclude labor costs related to storm activities that are being forecasted in the new Generation Storm Response GRC activity presented in SCE-04 Vol 2, plus a $0.079 million increase for the additional labor required to achieve $0.970 million of efficiency improvements in non-labor, to arrive at a base year labor forecast amount of $22.984 million.[74] To this base amount SCE requests an increase of $4.520 million to the 2025 Test Year, yielding a 2025 Test Year labor forecast of $27.504 million.[75]

The requested adjustment of $4.520 million is comprised of two subparts. The first is a $3.528 increase for 30 additional employees to replace those lost during the past 3 years, and

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[71] Generation vacancy rates historically range between 3% and 6%.

[72] 2018-2022 end-of-year staffing levels by job category of active, full-time, and part-time employees of SCE's Generation Department are provided in response to Cal Advocates MDR Question 4.

[73] WP SCE-05 Vol. 1, pp. 28-35. Generation Analysis - Craft Positions Eastern/Western July 2022.

[74] Operational efficiencies include streamlining, centralizing, and standardizing work management, as well as efficiencies related to the scoping and management of outages.

[75] WP SCE-05 Vol. 1, pp. 21-26. Hydro O&M Recorded/Forecast Summary.

the second is a $0.992 adjustment to reflect certain changes made to SCE's employee compensation program; please refer to SCE-06, Vol. 04. Further information regarding the proposed labor adjustment is provided in the following section of testimony.

(1) Future Labor Adjustment

SCE's Hydro Division strives to sustain high reliability and electricity production levels of the low-cost, highly efficient Hydro assets, while complying with increasingly stringent regulatory and watershed management requirements. As previously described, in 2019, SCE's Generation department began to experience higher-than-expected employee attrition, largely the result of retirements of represented employees and resignations of non-represented employees exceeding new hires.[76] Following the exit of 23 Hydro employees in 2019, additional staffing shortfalls continued to occur throughout the first two years of the COVID-19 pandemic (*i.e.,* 2020 and 2021). At the beginning of 2019, the Hydro Division employed 156 full time employees, which by 2022 year-end had fallen to 126.[77]

As SCE will explain in the Hydro non-labor testimony below, Hydro operations between 2020 and 2022 were severely affected by multiple natural disasters (extreme drought and the Creek and Apple fires) and the COVID-19 pandemic. It is largely because these events limited SCE's ability to operate its Hydro facilities (*i.e.,* they operated below historic levels) that SCE was able to maintain operations with approximately 20% less staff during this time.

During this asset restoration period (*i.e.,* 2021-2022) labor costs dropped due to SCE staff recording higher-than-historic levels of their time to Capital restoration projects.[78] In addition, due to reduced Hydro staffing levels, contract labor and SCE staff from other locations were utilized and their time largely recorded to the Capital restoration projects. As explained in testimony, section I.E, beginning in 2016 SCE's Generation department has utilized an asset management approach

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[76] WP SCE-05 Vol. 1, pp. 28-35 Generation Analysis - Craft Positions Eastern/Western July 2022.

[77] 2018-2022 end-of-year staffing levels by job category of active, full-time, and part-time employees of SCE's Generation Department are provided in response to Cal Advocates MDR Question 4.

[78] SCE's recorded costs appropriately reflect past and present activity-based accounting practices.

of reprioritizing work and employee assignments based on the most immediate need. In this case the resource sharing activity was used as a stopgap to address reduced staffing numbers and these measures will not be sustainable for extended periods.

To meet increasing work demands (*i.e.,* expected return of operations to historic levels), stay ahead of the current wave of baby-boomer generation retirements exacerbated by the COVID-19 pandemic, and perform necessary work required from the pending issuance of the Big Creek FERC licenses expected in 2023, SCE forecasts the need to regain the recent loss of 30 Hydro staff members. SCE's plan is to hire and train at a minimum 10 new employees per year between 2023 and 2025. While SCE is forecasting the need for 30 additional Hydro staff over the next three years (*i.e.,* 2023-2025), further in-depth analysis indicates that by 2026, 25% of represented Generation employees will reach likely retirement age (union 62.7 years, non-union 61.3).[79] Because of this SCE expects the recent trend of continuously backfilling retired employees with newly trained employees will continue for the foreseeable future – *i.e.*, through the 2025 GRC cycle. Table II-14 below lists the 30 most-needed positions, the activities they will perform, and total forecasted cost.

[79] WP SCE-05 Vol. 1, pp. 28-35 Generation Analysis – Craft Positions Eastern/Western July 2022.

Table II-14
SCE Hydro – Future Labor Needs

Line No.	Position	FTE	Activities	FTE Market Reference Point	Total Cost
1	Technician, Instrument Control & Electrical	10	Instrument Control and Electrical Technicians are responsible for maintenance, calibration, and testing of critical instrumentation to ensure that equipment meets NERC requirements. The technicians test, repair, and replace computerized logic control systems, recording instruments, indicating instruments, and automatic control instruments. Components consist of electrical, electronic, mechanical, and pneumatic devices located at powerhouses, switchyards, dams, and remote locations that utilize controls or instrumentation.	$120,749	$1,207,488
2	Test Technician	3	Test Technicians are responsible for maintenance, calibration, and testing of critical electrical components such as relays, timers and switchgear to ensure that equipment meets NERC requirements. The technicians test, repair, and replace electrical control, switching, metering, or monitoring devices. Components consist of electrical, electronic, or electromechanical devices located at powerhouses, switchyards, dams, and remote locations that utilize electrical equipment.	$127,699	$383,098
3	Mechanical Maintenance Technician	10	Mechanical Maintenance Technicians are responsible for maintenance, design and fabrication of critical generation equipment to ensure that equipment meets optimal performance requirements. They test, repair and replace mechanical generation equipment, such as turbines, governors, pumps and water convenance components.	$106,272	$1,062,720
4	Operator	7	Operate generation facilities, performing regular inspections and periodic maintenance of generation equipment, ensuring the facility is operating appropriately and in accordance with regulatory requirements.	$124,954	$874,675
5	**Total**	**30**			**$3,527,981**

In addition, as will be explained further in the following section of testimony, the 30 positions listed in Table II-14 also require an increase to Hydro non-labor expenses. This is because these positions will require additional training to perform necessary job functions.

b) Non-Labor – Analysis of Recorded and Forecast Expenses

From 2018 to 2019, non-labor expenses decreased due to lower-than-expected 2019 FERC administration fees because of lower Hydro generation in 2018,[80] and the deferment of planned Hydro maintenance activities at Huntington Lake and Rush Creek. This work was deferred as SCE continued its efforts to effectively respond to the climate crisis by providing and managing the electric infrastructure programs needed to help defend against the impacts of climate change and to prioritize emergent public safety risks pertaining to wildfire-related events (*e.g.,* protecting communities and customers against the threat of wildfires associated with utility equipment). In prioritizing climate change-related risks and impacts, SCE made the prudent decision to reduce or defer certain non-

[80] FERC administration fees are largely based on generation that occurred during the previous calendar year (*i.e.,* a one-year lag), which was lower due to 2018 drought conditions.

wildfire-related activities (*e.g.,* less critical repairs at Hydro facilities) and programs during the 2019 calendar year to address the emergent public safety risks.

More recent Hydro non-labor O&M expenses (*i.e.,* 2020-2022) have considerably varied due to three CEMA events, do not follow a predictable pattern, and are not representative of future needs.

In 2020, recorded non-labor expenses increased significantly due to the first (Creek Fire) of three CEMA events that affected Hydro non-labor recorded costs between 2020 and 2022.[81] As discussed in footnote 27 on page 45 of SCE's 2022 CEMA filing, A.22-03-018, the 2022 application did not include costs related to the damage to SCE's Big Creek Hydroelectric facilities. This is because repairs to the hydroelectric generation facilities have not yet been completed (the current forecast estimates the completion of this work in 2023), and some repair costs should be covered by insurance.[82] While considerably lower, Creek Fire-related costs have continued to be incurred in subsequent years and continue to record to the Creek Fire CEMA. Recorded Creek Fire CEMA costs were $3.609 million in 2020, $3.780 million in 2021, and $1.750 million in 2022.

In 2021, recorded non-labor costs were low compared to authorized levels due to the 2020 Apple Fire. SCE recorded non-labor restoration costs in the amount of $8.630 to the Apple Fire CEMA.[83] Recovery of these costs above GRC-authorized "storm" activity amounts were requested in SCE's 2022 CEMA filing, A.22-03-018., pp. 26-31. Additionally, 2021 costs were lower as SCE, in prioritizing climate change-related risks and impacts, made the prudent decision to reduce or defer certain non-wildfire-related activities (*e.g.,* less-critical repairs at Hydro facilities) and programs during the 2021 calendar year to address the emergent public safety risks.

While 2022 recorded non-labor costs moderately increased from 2021 levels, they were again affected by SCE's deferral of less-critical repairs at Hydro facilities and a third CEMA event,

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[81] Further discussion of the Creek Fire is provided in testimony section I.F.1.b)(1).

[82] SCE continues to record Creek Fire costs to the CEMA, and all recorded/forecasted CEMA costs have been removed from SCE's GRC application.

[83] Further discussion of the Apple Fire is provided in testimony section II.C.4.b).

the August 2022 monsoon, that affected Inyo and Fresno counties. Total recorded 2022 costs for the August 2022 monsoon event were $1.064 million.[84]

As a result of the three CEMA storm events – the 2020 Creek Fire, the 2020 Apple Fire, and the August 2022 Monsoon – SCE has removed 2018-2022 recorded costs associated with past Hydro storm events from this testimony volume. Given the increased frequency of storm events at SCE's hydro facilities, SCE is proposing the creation of a new Hydro Storm GRC activity. Further information on this proposal can be found in SCE-04 Vol 2.

Due to the high variability of recorded non-labor expenses experienced during the most recent two years (*i.e.,* 2021-2022), and because the non-CEMA storm recorded costs within that period were significantly lower due to the deferral of less-critical repairs, a historical 5-year average containing 2021 and 2022 would not be representative of non-labor expenses that can be expected to occur in Test Year 2025. We therefore selected a 3-year average (*i.e.,* 2018-2020) because a multi-year average of these three years (*i.e.*, the average annual expense of 2018 through 2020) provides an adequate base year non-labor forecast for the 2025 Test Year, while excluding the increase in non-labor costs attributable to CEMA storm restoration and recovery costs as well as recent deferrals of less critical repairs.[85] Further, SCE makes the two reductions, a $0.148 million reduction to exclude costs related to storm activities and a $0.970 million reduction to account for operational efficiencies related to streamlining, centralizing, and standardizing work management, as well as efficiencies related to the scoping and management of outages, to arrive at a base forecast amount of $24.077 million. To the base amount forecast of $24.077 million, SCE requests three future adjustments totaling $1.895 million, further described in the following sections of testimony. When added to the $24.077 million base year amount, these adjustments yield a non-labor Test Year forecast of $25.971 million.

[84] SCE has not yet sought recovery of these costs.

[85] WP SCE-05 Vol. 1, pp. 21-36. Hydro Operations and Maintenance Recorded/Forecast Summary.

(1) First Non-Labor Adjustment – Dam and Public Safety

The first non-labor adjustment is for an expected annual increase of $0.446 million to address Dam and Public Safety revised regulations issued by FERC in April 2022.[86] These new regulatory driven changes/requirements include new Part 12D Comprehensive Assessment Reports.[87]

(2) Second Non-Labor Adjustment – Relicensing

The second non-labor adjustment is for an expected annual increase of $1.331 million to fund expected increases in existing FERC license compliance activities, and for new FERC license requirements forecasted to commence in early 2023 following the issuance of the Big Creek and Kaweah licenses.[88] This increase will provide necessary funding to perform various recurring studies as required by existing FERC licenses, and for the implementation of other new compliance programs as new license orders are issued. The primary new non-labor costs associated with the new Big Creek FERC licenses are the annual USFS fees, annual costs for fish stocking at specified reservoirs, recurring environmental studies, and compliance tracking and programmatic support necessary to comply with new license requirements.[89] Compliance with both new and existing license orders, and their articles and conditions, is non-discretionary and SCE must fulfill these obligations to continue operating these projects over the life of their license terms. Portions of the costs for implementing these requirements, per general accounting practices, will be capitalized while some remain an O&M expense. Further information regarding the status of relicensing for various FERC projects is presented in testimony section II.C.3

[86] WP SCE-05 Vol. 1, p. 36. Hydro Non-Labor Operation and Maintenance Forecast Increases.

[87] Code of Federal Regulations Chapter 18 Part 12 - Safety of Water Power Projects and Project Works (revised April 11, 2022).

[88] WP SCE-05 Vol. 1, p. 36 Hydro Non-Labor Operation and Maintenance Forecast Increases.

[89] WP SCE-05 Vol. 1, p. 36 Hydro Non-Labor Operation and Maintenance Forecast Increases.

(3) Third Non-Labor Adjustment – Training

The third non-labor adjustment is for an expected annual increase of $0.117 million to fund required training activities for the 30 additional staff identified in testimony above.[90] As explained, Hydro forecasts the need for 30 additional staff over the next three years (*i.e.,* 10 per year between 2023 and 2025), in order to meet increasing work demands, stay ahead of the current wave of baby-boomer generation retirements exacerbated by the 2020 COVID pandemic, and perform necessary work required from the pending issuance of the Big Creek FERC licenses in 2023. Based on previous experience, SCE estimates that it takes on average approximately two-and one-half years of training for a newly hired craft employee to complete proper training to achieve respective job competencies.[91] Thus, an employee hired in early 2023 would not likely become fully trained/competent until, at the earliest, mid-2025. As mentioned previously, further in-depth analysis indicates that by 2026, 25% of represented Generation employees will reach likely retirement age (union 62.7 years, non-union 61.3).[92] Thus, the recent trends of continuously backfilling retired employees with newly trained employees will likely continue for the foreseeable future - through the 2025 GRC cycle. SCE is therefore forecasting the need of increased training activities for new employee hires to continue through the 2025 GRC cycle.

3. Hydro Operation and Maintenance Work Activities

a) Water for Power and Rents

The Hydro Water for Power and Rent Expense Activities comprises non-labor expenses including annual fees and rent expenses charged by various governmental agencies.

(1) Headwater Benefit Fees

Headwater Benefits Fees ("HBF") are indirect fees collected by FERC and transferred to upstream reservoir operators that provide additional generation benefit to downstream Hydro projects. SCE pays HWB fees for the Kern River No. 1 Project, which has the opportunity for

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[90] WP SCE-05 Vol. 1, p. 36 Hydro Non-Labor Operation and Maintenance Forecast Increases.

[91] WP SCE-05 Vol. 1, pp. 28-35 Generation Analysis – Craft Positions Eastern/Western July 2022.

[92] WP SCE-05 Vol. 1, pp. 28-35 Generation Analysis – Craft Positions Eastern/Western July 2022.

increased generation because of the presence upstream of the U.S. Army Corps of Engineers-administered Lake Isabella reservoir.[93] Additionally, SCE collects HBF from Pacific Gas & Electric Company ("PG&E") for water used at the Kerckhoff Power plant which is supplied from dams and reservoirs maintained by SCE in the Big Creek hydroelectric system. The HBF revenues collected from PG&E are recorded as Other Operating Revenues ("OOR"). SCE's method for billing PG&E uses a multi-year average to project future invoices.[94]

(2) FERC Administrative Fees

SCE pays FERC administrative fees (Hydropower Annual Charges) as a reimbursement to the U.S. government for the cost of administering Part 1 of the Federal Power Act.[95] FERC calculates fees using an equation that includes our prior year Hydro generation output (*i.e.,* 2022 fees are based on 2021 recorded generation), Hydro capacity, national Hydroelectric generation output, and FERC's expenses. These fees vary annually depending upon the level of FERC expenses and the amount of Hydro generation output nationally and at our facilities. In 2022, FERC's administration fees represented approximately 52% percent of the Hydro Water for Power Plant expense. Annual precipitation is the primary factor in the amount of Hydro generation each year and also causes Hydro FERC fees to vary from year to year, because the Hydro FERC fees are based upon on annual generation output.

(3) California State Water Resources Control Board ("State Water Board") Fees

SCE pays three categories of fees to the State Water Board: (1) water rights license fees, (2) water rights permit fees, and (3) Water Quality Certification fees.[96] Under the federal Clean Water Act ("CWA") and California's Porter-Cologne Water Quality Control Act, the State

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[93] SCE transfers the funds to FERC, which remits them to the Army Corps of Engineers.

[94] Exhibit SCE-02, Vol. 07 - Other Costs and OOR.

[95] 18 C.F.R. § 11.1.

[96] Fees are calculated per the State Water Board fee schedule, *available at* www.waterboards.ca.gov/waterrights/water_issues/programs/fees.

and Regional Water Boards have regulatory responsibility for protecting the water quality of nearly 1.6 million acres of lakes, 1.3 million acres of bays and estuaries, 211,000 miles of rivers and streams, and about 1,100 miles of exquisite California coastline. The State Water Board uses these fees to ensure abundant clean water for human uses and environmental protection to sustain California's future.

(4) California Department of Water Resources ("CDWR") Fees for Division of Safety Dams ("DSOD")

The CDWR collects fees for the DSOD. These fees support a wide variety of activities, including the DSOD's monitoring and inspecting of dams, and completing engineering studies which include hydrologic, structural, and seismic stability re-evaluations. Additionally, the fees cover DSOD's review for new or repair work, alterations, and review or consultation regarding Part 12 Reports, which involves a FERC-mandated independent safety study performed every five years to help ensure the integrity of SCE's Hydro reservoir facilities. Annual CDWR fees are computed via a flat fee per dam plus an additional fee per foot height of that dam.

(5) U.S. Geological Survey ("USGS") Fees

The USGS requires that SCE pay annual fees assessed per gauging station based upon a predetermined fee for the station in operation. The USGS utilizes these fees to: (1) review and publish stream flow and reservoir records, and (2) perform annual inspections to verify the accuracy of recorded data.

(6) Hydro Rent Expenses

SCE pays FERC for SCE's use of federal lands (upon which most of our Hydro facilities are located). The fee calculations are based on a cost-per-acre appraisal for the total number of acres that are encumbered within the FERC boundary as described in the license for each individual Hydro project.

(7) Kaweah 3 Special Use Permit

SCE pays an annual Special Use Permit ("SUP") fee to the National Park Service ("NPS") to allow SCE's operation and maintenance of the Kaweah No. 3 Project (a diversion dam and flowline) and the Mineral King dams' portion of the Kaweah No. 1 Project within Sequoia National Park based on a previously agreed-upon formula.

b) Hydro Operations

The Hydro Operations O&M work activity comprises all labor and non-labor for operational-related expenses.

(1) Operations Supervision

The following locations each have a supervisor of O&M activities: (1) Big Creek 1, overseeing the Upper Canyon facilities; (2) Big Creek 8, overseeing Mid Canyon facilities; (3) Big Creek 3 overseeing Lower Canyon facilities; (4) Big Creek Operations Supervisor, overseeing all operation activity; and (5) Bishop/Mono Basin, overseeing production (O&M) activities for facilities in Inyo and Mono counties. The following locations each have a manager of O&M activities: (1) Kern River No. 3, overseeing the Kern, Kaweah, and Tule river facilities; (2) Bishop Creek Plant 4, overseeing the Bishop Creek and Mono Basin facilities and associated distribution and transmission substation facilities; (3) Big Creek, where two Managers for Operations and Maintenance oversee the Big Creek project., and (4) The Los Angeles Basin Hydroelectric facilities ("East End Hydro"), managed from the Eastern Operations Generation Control Center ("EOGCC") in Redlands. The following locations also each have chief operators: (1) Kern River No. 3, and (2) Big Creek (three total). A production supervisor at the Bishop Control Station also assists in overseeing operations activities, including local (manual) switching.[97]

The non-labor services and activities associated with these expenses include automotive services, computer services, miscellaneous material requirements, and travel for supervisors, managers, and chief operators.

[97] Certain Chief Operator and Production Supervisor positions are necessary where the geography of the assigned area precludes a Production Supervisor or Production Manager from being able to effectively oversee the entire operation.

(2) Dispatching

Dispatching work includes directing all Operations activities associated with the powerhouses in the Big Creek and Bishop Creek/Mono Basin areas, and the associated transmission and distribution facilities. The Big Creek Control Center contains all the supervisory control equipment for the Big Creek facilities while the Bishop Control Station contains supervisory control equipment for the Bishop Creek, Mono Basin, and Kern River facilities. The Los Angeles Basin (East End) Hydro facilities have alarms that notify the Eastern Operations Generation Control Center ("EOGCC") of unusual events through a dial-up system when not staffed. This 24-hour surveillance of the operating equipment from a central point helps maintain system integrity and operational effectiveness. The Bishop Control Station also supports activities involving local manual circuit switching of distribution and transmission for distribution, power generation, and transmission systems located in Inyo and Mono counties. Remote monitoring of the Los Angeles Basin units is performed from the Eastern Operations Generation Control Center in Redlands, California (on the site of Mountainview Generating Station).

(3) Operations Engineering

Operations Engineering provides engineering services to support Hydro facilities. While both regions in Hydro have small engineering groups (one to two employees), both regions also rely on other engineers within the Generation Department in Rosemead. Dam inspections and evaluations are the primary expense as FERC regulations require an independent safety study (referred to as a Part 12 Report) every five years to help ensure the integrity of SCE's Hydro dams and reservoir facilities. The report is completed by independent consultants, supervised by SCE in-house dam safety and engineering personnel, and reviewed by FERC.[98] Other activities in this account include support for civil, mechanical, electrical, power systems, dam inspection and evaluation, testing or design of unit/station relays, and geology issues.

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[98] 18 C.F.R. §§ 12.30-12.39 (2013).

(4) Home Office Operations Supervision and Engineering

This activity includes general management and home office expenses to accomplish administrative tasks to support the generation operations, including regulatory proceedings, regulatory and safety compliance activities, and union activities. This activity is also proportionately applicable to other generation accounts within the Generation Department.

(5) Operation of Reservoirs, Dams and Waterways

Operations personnel regulate water flows to help ensure efficient use of water and maximum generation from resources. This activity includes labor costs for completing inspections of the reservoir facilities and making gate changes to regulate water releases. It also includes labor costs to clean the grids at flowline entrances, and remove debris from in and around flowlines, flumes, penstocks, and other typical Hydro waterways. Non-labor costs are for equipment and vehicles used for this activity.

(6) Hydrography

Hydrography expenses include: (1) maintaining water rights; (2) complying with water rights and water-related FERC license requirements; (3) managing and staffing of stream and reservoir gauging stations; (4) managing and staffing meteorological stations; (5) collecting and analyzing snow survey data; and (6) forecasting water supply from snow survey data. Non-labor costs include equipment and vehicles used to perform this activity.

(7) Electric Expenses

Electric expenses include operation of prime movers, generators, and their auxiliary apparatus, switchgear, and other electric equipment; general supervision and direction of our Hydro facilities' operation; and management of water resources for SCE's Hydro facilities.

(8) Field Division Management

Field Division Management costs include salaries and other expenses of all staff, management, and administrative support staff at field offices.

(9) License/Environmental Support

This activity includes expenditures to support compliance with FERC licenses, other regulatory certifications and conditions, and environmental requirements. FERC licenses include several long-term compliance requirements such as recurring environmental studies (e.g., riparian habitat studies, botanical studies, fish population studies, cultural resources surveys, recreation use surveys), updates to management plans or other guidance documents on a specified frequency, and annual consultation meetings with agencies such as the U.S. Department of Agriculture – United States Forest Service ("USFS"), California Department of Fish and Wildlife ("CDFW"), National Park Service ("NPS"), and the Bureau of Land Management ("BLM"). Some Hydro projects also have long-term programmatic permitting that require annual reporting or renewals when they expire. O&M activities that require project-specific water permitting may also have added costs for environmental compliance including field monitoring or pre-activity biological or cultural surveys.

For the 2023-2025 years, SCE anticipates a large increase in the O&M spend for new requirements tied to the new Big Creek license orders and their implementation. These new costs include USDA-FS recuring annual fees that will be in place for the duration of the new license terms, and certain recurring costs for environmental studies or consultation as described above.

In addition, due to cutbacks and reduced staffing at various regulatory agencies, SCE has found it necessary to provide funds for certain agencies' review of plans, projects, or proposals to facilitate timely review. For example, SCE has a funding agreement with CDFW at a corporate level and O&M projects or activities that require permitting through CDFW would have to pay a portion of the time spent working on the project.

(10) Safety

This activity includes labor and other costs of most employees attending safety meetings and costs of materials, supplies, and program development expenses.

(11) Training Expenses

Training expenses include costs associated with employees attending training sessions.

(12) Warehousing

This activity involves expenses associated with performing warehousing and storekeeping activities, such as costs for storing, receiving, shipping, transporting, tracking, and accounting for inventory, materials, and spare parts; maintenance and repair of material handling and storage equipment (if applicable); and janitorial services.

(13) Hydro Chargebacks

Hydro Chargebacks include the labor, material, contract, and other expenses from SCE service providers supporting Hydro. These charges cover such things as vehicles and fuel, computer & IT systems, supplies and maintenance, a portion of the expense of helicopter use in Hydro areas, communications equipment and service, material management charges, mailing service, expenses for hazardous waste disposal, and other miscellaneous services.

(14) Other Expenses

Other Expenses include miscellaneous employee expenses and non-labor costs not assigned to other Hydro accounts, including office supplies and equipment, utility and communications service, small tools, gaskets, packing material, hoses, indicating lamps, employee safety equipment and first-aid supplies, some automotive, transportation (vehicle and helicopter) charges, computer service charges, miscellaneous material used in plant operations, and meal expenses associated with labor-related overtime assignments publications, monthly reports, and some engineering charges not affecting individual facilities.

c) Hydro Maintenance

The Hydro Maintenance work activity comprises all labor and non-labor for maintenance-related expenses.

(1) Maintenance Supervision and Engineering

This activity includes inspecting reservoirs, dams, canals, flumes, and other appurtenant hydraulic structures to comply with state and federal regulatory requirements,[99] and

[99] 23 CA ADC T. 23, and 18 C.F.R. Part 12.

costs for condition analysis, engineering recommendations, and mandated reports.[100] The testing, inspection, and reporting function is necessary to assure that the physical condition of facilities and equipment is safe for continued operation through: (1) technical inspection; (2) electrical and mechanical engineering; (3) civil, structural, and geotechnical engineering; (4) construction management and cost engineering; and (5) performance engineering and testing.

This activity also includes all expenses for supervising repairs to Hydro production facilities, structures, and equipment, and expenses for tests, inspections, and preparation of reports by engineering support personnel. Routine general supervision labor includes: (1) planning and scheduling equipment maintenance activity; (2) compiling and analyzing unit condition reports; (3) maintaining a list of workforce availability; (4) correlating water movement requirements with unit condition and staff availability; and (5) coordinating availability of specialized maintenance equipment. General maintenance supervision coordinates availability of labor resources, fuel resources, and equipment to efficiently maintain equipment, as needed.

Labor also includes the engineering required to support the Hydro maintenance program. This engineering work supports the maintenance of structures, water conveyance devices, turbines and generators, controls, automation, and other equipment such as filters, blowers, transformers, and dams.

Non-labor includes transportation, travel and lodging expenses, miscellaneous equipment materials and supplies, and contracted engineering work.

(2) Maintenance of Structures

This activity includes maintenance costs for Hydro structures and lines. The structures include powerhouses, machine/electrical/carpenter shops, office structures, company housing and garages, and miscellaneous outbuildings. Building maintenance activities include structural repairs, painting interior/exterior finishes, plumbing repairs and minor system upgrades, electrical system repairs, and roof repairs.

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[100] 23 CA ADC T. 23, and 18 C.F.R. Part 12.

Labor expenses include staffing costs for SCE personnel performing these repairs. Non-labor includes the costs of contractors and supplies. Miscellaneous non-labor expenses include the costs for contract janitorial service, transportation, and refuse collection service, and the costs of maintaining distribution voltage electric lines that serve Hydro facility complexes exclusively.

(3) Maintenance of Reservoirs, Dams and Waterways

This activity includes maintaining reservoirs, dams, waterways, and other structures and appurtenant facilities used with Hydro generation. Labor includes: (1) applying concrete gunite to repair aged and weather-damaged surfaces of dams and intakes; (2) repacking joints and repairing leaks in steel penstock pipes and flumes; (3) maintaining water-diverting equipment such as valves and spillways; and (4) repairing wood-frame structures appurtenant to Hydro facilities, such as flowline trestles, snow shelter survival cabins, gatehouses, and hydraulic equipment shelters. These repairs include painting, carpentry, and plumbing.

(4) Maintenance of Electrical Plant

This activity includes all maintenance associated with the Hydro units' hydraulic, mechanical, and electrical plant, which includes the costs to repair and overhaul components and appurtenances identified with prime movers and generators from the lower penstock valve to the tailrace (the location where the water leaves the turbine and exits the powerhouse). This account includes costs to maintain hydraulic generators, turbines, waterwheels, governors, turbine shutoff valves, draft tubes, controls, and other accessory equipment.

Labor costs include: (1) hydraulic and electrical inspections and repairs; (2) overhaul of generators, turbines, valves, and governors; (3) condition testing of field coils and electrical windings; (4) repair and calibration of generation unit control and monitoring devices; and (5) generator cleaning. Non-labor costs include the following materials: valves, pipe, conduit, relays, circuit breakers, temperature monitors, valve packing material, steel, welding materials, and miscellaneous mechanical and electrical hardware.

CAISO requirements necessitate that we maintain the controls and valves in excellent condition. For example, if Hydro is operating with the automatic generation control ancillary service from the CAISO, the generation units must ramp automatically from CAISO command, using the automated valves and controls.

(5) Maintenance of Miscellaneous Hydraulic Plant

This activity includes all miscellaneous maintenance (labor and non-labor) expenses required to maintain Hydro tools, work equipment, and production roads, trails, and bridges; including vegetation management.[101] This account includes costs to repair machine shop tools and work equipment, compressed air systems, signal systems, powerhouse cranes and monorail hoists, and other miscellaneous equipment not included in other station equipment repair functions; and costs to maintain and clear all production roads, bridges, trails, aerial tramways, inclines, and penstock tramways, including costs for snow removal. Computer/telecommunications support and expenses related to these activities are also recorded in this account. Non-labor costs include equipment, materials, or contract expenses for the above work.

C. Hydro Capital Expenditures Forecast

1. Introduction

SCE's planned capital expenditures for its Hydro generating facilities are necessary to provide reliable service at a reasonable cost, comply with applicable laws and regulations, and maintain safe operations for employees and the public. This section describes the Hydro capital forecast for years 2023-2028 and the categories of expenditures, with a list of individual projects within each category. This section further explains the background, scope and need for each cost category as well as those projects exceeding $3.0 million.

SCE Hydro capital investments are necessary for infrastructure, equipment replacement, and our ongoing efforts to maintain compliance with existing FERC license requirements and to secure new FERC licenses. Infrastructure work includes projects such as dam improvements needed to address areas of concern (*e.g.,* safety and performance) and flowline refurbishments. Equipment replacement

[101] SCE's Modeling, Analysis and Forecasting O&M forecast presented in Exhibit SCE-06, Vol. 3, CH V, includes $0.236 million for site specific vegetation studies that will be used to inform the Generation Climate Adaptation Vulnerability Assessment (CAVA) Capital projects presented in testimony section II.C.9.

work includes projects such as transformers, automation, switchgear, turbine overhauls, and generator rewinds.

The Generation Project Approval Process (*i.e.,* Generation Department Order A-05) used to forecast capital expenditures begins with local Generation Department staff identifying equipment needing capital replacement or refurbishment, safety concerns or regulatory compliance issues requiring plant additions or modifications (which includes Hydro relicensing), and other site modifications or improvements needed to address operations or maintenance needs that have affected (or are forecast to affect) plant performance relative to historic levels, or in very limited cases, to capture cost-effective opportunities to improve plant performance relative to historic levels.

Once a project has been identified and approved through the IDP, the Generation Department follows American Association of Cost Engineers ("AACE") guidelines and project management practices of conceptual, preliminary, and final engineering design. The level of project detail and precision of the cost forecast increases as a project progresses through the three engineering design phases. Many Hydro capital projects are similar to previously performed projects and cost estimates can be developed utilizing recorded costs, while other projects are unique and require a more detailed cost analysis. Detailed project cost forecasts generally are developed utilizing current material costs and labor rates and/or engineering/contractor cost estimates. Cost estimates for those projects exceeding $1.0 million have been provided in workpapers, which are referenced in the following sections of testimony.

2. Hydro – Capital Project Categories

As shown in Table II-15, SCE's forecast of Hydro capital expenditures total $471.520 million (nominal, work order level) for 2023-2028.[102], [103] SCE is also forecasting future efficiency improvements because of changes being implemented to construction oversight representation and

[102] The forecast reflects certain changes made to SCE's employee compensation program. Please refer to Exhibit SCE-06, Vol. 04.

[103] WP SCE-05 Vol. 1, pp. 37-180. Hydro Capital Expenditures.

competitive bidding processes. These improvements are expected to result in $4.585 million of future cost savings which is being applied to the 2023-2028 Hydro Capital forecast.

Table II-15
Hydro Capital Project Categories
Forecast 2023-2028
(Nominal $000)

Line No.	Project Category	2023	2024	2025	2026	2027	2028	TOTAL
1	Hydro - Licensing and Implementation	23,961	28,181	22,947	11,807	21,942	29,789	138,627
2	Hydro - Decommissioning	24,356	15,509	2,212	20,276	27,778	21,078	111,208
3	Hydro - Dams and Waterways	34,227	14,442	7,606	16,773	8,599	362	82,010
4	Hydro - Prime Movers	13,382	10,619	20,379	13,862	8,559	7,017	73,817
5	Hydro - Electrical Equipment	4,882	10,500	10,329	7,826	8,500	8,000	50,037
6	Hydro - Structures and Grounds	4,526	1,154	3,651	3,879	1,454	1,208	15,873
7	Hydro - CAVA	-	-	1,013	1,521	1,269	731	4,533
8	Efficiency Improvements	(303)	(869)	(944)	(824)	(822)	(822)	(4,585)
9	**GRAND TOTAL**	**105,032**	**79,536**	**67,191**	**75,119**	**77,279**	**67,363**	**471,520**

Each Hydro capital project is placed (based on the work being performed) into one of seven categories: (1) Licensing and Implementation, (2) Decommissioning, (3) Dams and Waterways, (4) Prime Movers, (5) Electrical Equipment, (6) Structures and Grounds, and (7) Climate Adaptation Vulnerability Assessment ("CAVA").

The first category of capital expenditures is Hydro Licensing and Implementation.[104] This category will require $138.627 million in 2023-2028 and will include:

- FERC relicensing proceedings;
- New license order requirements (terms and conditions);
- Resource management plans and license articles (environmental studies and protection measures);
- Big Creek infrastructure modifications (to provide required instream water releases); and

[104] WP SCE-05 Vol. 1, pp. 39-58. Hydro Capital Expenditures – Licensing and Implementation.

- Big Creek recreation facility rehabilitation (campgrounds, day-use areas and boat ramps) and new campground infrastructure refurbishment and replacements,

The second category of capital expenditure is for FERC Project Decommissioning.[105] This category will require $111.208 million in 2023-2028 and will include the decommissioning of Borel, San Gorgonio, and Rush Creek (Agnew and Rush Meadows Dams).

The third category of capital expenditures is for Dams & Waterway projects.[106] This category will require $82.010 million in 2023-2028 and will include:

- Tunnel and flowline rehabilitations to restore flow and reliability; and
- Aging penstock and flowline replacements.

The fourth category of capital expenditure is Prime Movers.[107] This category will require $73.817 million in 2023-2028 and will include:

- Generator rewinds for stators or rotors; and
- Turbine wicket gates, runners, and repowers.

The fifth category of capital expenditure is Electrical Equipment.[108] This category will require $50.037 million in 2023-2028 and will include:

- Powerhouse transformer bank replacements; and
- Protective relay and circuit breaker replacements.

The sixth category of capital expenditure is Structures and Grounds projects.[109] This category will require $15.873 million in 2023-2028 and will include:

- High-pressure piping replacements; and
- Road improvements and repairs.

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105 WP SCE-05 Vol. 1, pp. 59-106. Hydro Capital Expenditures - Decommissioning.

106 WP SCE-05 Vol. 1, pp. 107-132. Hydro Capital Expenditures – Dams and Waterways.

107 WP SCE-05 Vol. 1, pp. 133-152. Hydro Capital Expenditures – Prime Movers.

108 WP SCE-05 Vol. 1, pp. 153-161. Hydro Capital Expenditures – Electrical Equipment.

109 WP SCE-05 Vol. 1, pp. 162-175. Hydro Capital Expenditures – Structures and Grounds.

The seventh and final category of capital expenditure is the Climate Adaptation Vulnerability Assessment (CAVA) projects.[110] This category will require $4.533 million in 2023-2028 and will include:

- Big Creek - Power and Communications Redundancy project; and
- Climate Change SEFM studies & installation of monitoring equipment.

Both testimony and workpapers include project descriptions and justifications for all capital projects with forecast costs exceeding three million dollars and forecast to be placed in-service between 2023 and 2028.

3. Hydro – Licensing and Implementation

This section describes the requirements of FERC relicensing and new license implementation projects, including: (a) continued implementation of the Big Creek recreation facility rehabilitation program; (b) completing Big Creek infrastructure modifications to provide instream flow releases; (c) conducting FERC relicensing proceedings; (d) implementing new FERC license order requirements (Big Creek, Kaweah and Bishop Creek projects); (e) decommissioning/removal of small Hydro assets required by the new Big Creek licenses; and (f) completing rehabilitation of Big Creek project roads and bridges.

SCE's total Hydro licensing and implementation expenditure forecast is $138.429 million (nominal, work order level) for 2023-2028.[111] Table II-16 lists the six programs within the FERC licensing category.

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[110] WP SCE-05 Vol. 1, pp. 176-180. Hydro Capital Expenditures – Climate Adaptation Vulnerability Assessment.

[111] WP SCE-05 Vol. 1, pp. 39-58. Hydro Capital Expenditures – Licensing and Implementation.

Table II-16
Hydro Licensing and Implementation Programs
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project Category	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek Recreation Rehabilitation and New Facility Construction	4,450	10,270	9,832	3,541	9,454	18,821	56,367
2	Infrastructure Modifications	7,665	8,440	4,059	1,780	8,415	3,793	34,151
3	Relicensing Proceedings	8,800	6,050	3,610	1,965	1,000	1,800	23,225
4	License Implementation	2,489	3,042	2,480	1,788	1,717	2,837	14,353
5	Decommissioning (Small Hydro Assets)	548	351	2,676	1,637	586	603	6,401
6	Road/Bridge Rehabilitation	-	14	240	1,054	730	1,894	3,931
7	**GRAND TOTAL**	**23,951**	**28,167**	**22,896**	**11,765**	**21,901**	**29,748**	**138,429**

a) Hydro Relicensing - Big Creek Recreation Rehabilitation and New Facility Construction

Under the Recreation Management Plan for the four Big Creek Alternative Licensing Process ("ALP") projects that was included in the ALP Settlement Agreement,[112] SCE agreed to construct several new recreation facilities and to rehabilitate 28 existing USFS-developed recreation facilities (campground, day-use areas, and boat ramps) that are associated (indirectly) with SCE's Big Creek hydroelectric project based on their location near or adjacent to project reservoirs. The Recreation Management Plan included a schedule to complete the new construction and rehabilitation of recreation facilities over a 27-year period. In addition to the ALP projects, the Vermilion and Portal Project FERC licenses (when issued) are expected to require that SCE rehabilitate recreation facilities (campgrounds, day-use areas, and boat ramps) at both projects. During 2023-2028, SCE plans to initiate rehabilitation activities at eight recreation facilities associated with the ALP, Vermilion, and Portal projects: (1) Vermilion boat launch and campground; (2) Mammoth Pool recreation complex; (3) Mono campground and day-use area; (4) Florence Lake recreation complex; (5) Huntington Lake - Dam 3 Day-use area (new facility); (6) Portal Forebay Campground; (7) Huntington Lake East Boat Ramp; and (8) Catavee Campground. Construction of new recreation facilities and rehabilitation of existing USFS recreation facilities (and any associated supporting roads and ancillary structures) are required by the ALP

[112] There are 22 Parties to the 2007 ALP Settlement Agreement, including SCE, CDFW, State Water Board, USFS, U.S. Fish & Wildlife Service, Fresno County Sherriff's Department, Friant Water Authority, and American Whitewater, among others.

Recreation Management Plan, which is part of the license applications that were filed for the ALP, Vermilion, and Portal projects. Although SCE has not yet received the new FERC license orders for the six Big Creek Projects, SCE agreed to begin the program to rehabilitate recreation facilities identified in the ALP Recreation Management Plan upon signing the 2007 relicensing Settlement Agreement. The rehabilitation of the recreation facilities associated with the Vermilion and Portal projects will be initiated upon issuance of the FERC licenses. The Hydro Relicensing – Big Creek Recreation Facility Rehabilitation Program and New Facility Construction capital expenditure forecast is $56.367 million for 2023-2028.[113] This cost includes the scope of work to continue the recreation facility rehabilitation program in the ALP Recreation Management Plan and assumes that FERC will issue new license orders in 2023 for the six Big Creek projects (the four ALP projects and the Vermilion and Portal projects). Table II-17 below, lists the projects within the Hydro Relicensing – Big Creek Recreation Rehabilitation Program and New Facility Construction program category.

Table II-17
Hydro Relicensing – Big Creek Recreation Rehabilitation and New Facility Construction
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Vermilion - Boat Launch & Campground Refurbishments	-	50	2,124	2,149	2,149	10,578	17,050
2	Mammoth Pool - Recreation Complex	500	5,596	6,341	-	-	-	12,437
3	Mono Campground and Day-Use Area	-	837	837	837	3,349	2,512	8,372
4	Florence Lake - Recreation Complex Rehabilitation	3,800	3,487	-	-	-	-	7,287
5	Huntington Lake - Dam 3 Day Use Area	150	275	300	300	3,000	2,275	6,300
6	Portal Forebay - Campground & Campsites Refurbishment	-	25	230	255	255	1,788	2,553
7	Huntington Lake - East Boat Ramp	-	-	-	-	701	701	1,402
8	Catavee Campground	-	-	-	-	-	967	967
9	**GRAND TOTAL**	**4,450**	**10,270**	**9,832**	**3,541**	**9,454**	**18,821**	**56,367**

The scope of work for the construction of new recreation facilities and the rehabilitation of existing recreation facilities for the Big Creek ALP projects is based on the process outlined in the Recreation Management Plan that was included in the negotiated settlement agreement between SCE and stakeholders. The rehabilitation of recreation facilities at the Portal and Vermilion

[113] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation - Capital Projects.

projects will follow the same process. Per the ALP Recreation Management Plan, the recreation facilities will be designed and constructed after review of applicable USFS specifications and standards at the time of construction including the Forest Manual direction concerning outdoor recreation accessibility guidelines and trails accessibility guidelines. The recreation facilities will strive to meet applicable ADA requirements regarding accessibility at campgrounds at the time of facility design and as feasible. However, the recreation facilities may differ from these requirements depending on topography, vegetation, cultural and archaeological resources, feasibility, practicality, preserving the primitive character of campgrounds, and the current design standards during the time of the Project design and construction.

The process for the new recreation facility construction and existing recreation facility rehabilitation is outlined in the ALP Recreation Management Plan. It describes a five-year planning and implementation timeframe to complete activities associated with recreation facility rehabilitation. The process activities include: in year one, the preparation of a design narrative, conceptual plan, and completing any necessary National Environmental Policy Act ("NEPA") compliance; in year two, preparing a site development plan and construction plan; in year three, completing contracting and procurement of contractors and materials; and in years four and five, conducting the new construction or rehabilitation activities.

Each of the eight recreation facilities in this 2023 and 2028 forecast will be constructed or rehabilitated as described above and are briefly described as follows.

(1) <u>Vermillion – Boat Launch and Campground Refurbishments</u>

(a) <u>Background and Project Scope</u>

The recreation facilities to be rehabilitated at the Vermilion Project (FERC No. 2086) include the 31-site developed campground, the boat launch ramp, and the overlook parking area that provides a scenic view of Lake Thomas A Edison. SCE agreed to rehabilitate these facilities during the relicensing of the Vermilion Project and the USFS included the rehabilitation requirement in their Section 4(e) mandatory conditions that were filed with FERC for inclusion in the new license orders. Upon issuance of the new license orders by FERC, SCE will be required to initiate consultation with the USFS and begin the rehabilitation process for this project. The total capital forecasted cost for the Vermillion – Boat Launch and Campground Refurbishments is $17.050 million for 2023-2028[114]

(2) Mammoth Pool - Recreation Complex

(a) Background and Project Scope

The five recreation facilities to be rehabilitated at the Mammoth Pool Recreation Complex include: (1) Mammoth Pool Campground (a 47-site developed campground); (2) Mammoth Pool Boat Launch and Parking Area; (3) Windy Point Day-Use Picnic Area; (4) Windy Point Boat Launch; and (5) China Bar Boat-in Campground (which includes six sites). SCE agreed to rehabilitate these facilities during the relicensing of the Mammoth Pool Project (FERC No. 2085) as part of the Recreation Management Plan included in the settlement agreement; and to begin the Recreation Facility Rehabilitation Program upon the signing of the settlement agreement (rather than upon the issuance of the new licenses by FERC). The five-year rehabilitation process was initiated in 2021 with completion of the design narrative, conceptual plan, and site development plan. Activities planned for 2023-2025 include completion of the construction plan, procurement of contractors, and rehabilitation construction activities. The capital forecast for Mammoth Pool – Recreation Complex project is $12.437 million for 2023-2028.[115]

(3) Mono Campground and Day-Use Area

(a) Background and Project Scope

The recreation facilities to be rehabilitated associated with the Mono Forebay include a 14-site developed campground and day-use picnic area. SCE agreed to rehabilitate these facilities during the relicensing of the Big Creek Nos. 2A, 8, and Eastwood Project (FERC No. 67) as part of the Recreation Management Plan included in the settlement agreement. SCE also agreed to begin the Recreation Facility Rehabilitation Program upon the signing of the settlement

[114] WP SCE-05 Vol. 1, p. 54. Big Creek New License Program Implementation- Capital Costs.

[115] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

agreement (rather than upon the issuance of the new licenses by FERC). According to the current schedule of rehabilitation projects, SCE will be required to begin the rehabilitation process for this project in 2024. The capital forecast for Mono Campground and Day-Use Area project is $8.372 million for 2023-2028.[116]

(4) Florence Lake Recreation Complex Rehabilitation

(a) Background and Project Scope

The three recreation facilities to be rehabilitated at the Florence Lake Recreation Complex include: (1) Jackass Meadow Campground (a 50-site developed campground); (2) Florence Lake Boat Launch; and (3) Florence Lake Day-Use Picnic Area. SCE agreed to rehabilitate these facilities during the relicensing of Big Creek Nos. 2A, 8, and Eastwood Project (FERC No. 67) as part of the Recreation Management Plan included in the settlement agreement. SCE also agreed to begin the Recreation Facility Rehabilitation Program upon the signing of the settlement agreement (rather than upon the issuance of the new licenses by FERC). The rehabilitation process for this project is nearly complete (after completion of the design narrative, conceptual plan, and site development plan) but construction was delayed due to the Creek Fire. Activities planned for 2023-2025 include procurement and rehabilitation construction activities over two seasons due to the scale and remoteness of the site. The capital forecast for Florence Lake Recreation Complex Rehabilitation project is $7.287 million for 2023-2028.[117]

(5) Huntington Lake - Dam 3 Day-Use Area

(a) Background and Project Scope

SCE agreed to construct a new recreation site on Huntington Lake at Dam 3 during the relicensing of Big Creek Nos. 2A, 8, and Eastwood Project (FERC No. 67) as part of the Recreation Management Plan included in the settlement agreement. The agreement specifies that new recreation sites will not begin development or construction until issuance of the new FERC

[116] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

[117] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

licenses. Therefore, upon issuance of the new license order by FERC, SCE will initiate consultation with the USFS and begin the process to develop the Dam 3 Day-Use Area. The capital forecast for Huntington Lake – Dam 3 Day-Use Area project is $6.300 million for 2023-2028.[118]

(6) Portal Forebay Campground

(a) Background and Project Scope

The Portal Forebay Campground is a 14-site primitive campground to be rehabilitated at the Portal Project (FERC Project No. 2174). SCE agreed to rehabilitate this facility during the relicensing of the Portal Project and USFS included the rehabilitation requirement in their Section 4(e) mandatory conditions that were filed with FERC for inclusion in the new license orders. Upon issuance of the new license orders by FERC, SCE will be required to initiate consultation with the USFS and begin the rehabilitation process in 2024. The capital forecast for Portal Forebay Campground project is $2.553 million for 2023-2028.[119]

(7) Huntington Lake – East Boat Ramp

(a) Background and Project Scope

SCE agreed to rehabilitate the Huntington Lake East Boat Ramp during the relicensing of Big Creek Nos. 1 and 2 (FERC Project No. 2175) as part of the Recreation Management Plan included in the settlement agreement, SCE also agreed to begin the Recreation Facility Rehabilitation Program upon the signing of the settlement agreement (rather than upon the issuance of the new licenses by FERC). According to the current schedule of rehabilitation projects, SCE will be required to initiate consultation with the USFS and begin the rehabilitation process in 2027. The capital forecast for Huntington Lake – East Boat Ramp project is $1.402 million for 2023-2028.[120]

[118] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

[119] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

[120] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

(8) Catavee Campground

(a) Background and Project Scope

The Catavee Campground is a 24-site developed campground on Huntington Lake. SCE agreed to rehabilitate Catavee Campground during the relicensing of Big Creek Nos. 1 and 2 (FERC Project No. 2175) as part of the Recreation Management Plan included in the settlement agreement. SCE also agreed to begin the Recreation Facility Rehabilitation Program upon the signing of the settlement agreement (rather than upon the issuance of the new licenses by FERC). According to the current schedule of rehabilitation projects, SCE will be required to initiate consultation with the USFS and begin the rehabilitation process in 2028. The capital forecast for Catavee Campground project is $0.967 million for 2023-2028.[121]

b) Hydro Relicensing – Big Creek Infrastructure Modifications

(1) Background

New instream flow requirements under the new Big Creek FERC license orders, expected to be issued in 2023, will require that SCE make infrastructure modifications at 14 impoundments (two large dams, four moderate dams, and eight small diversions). The proposed infrastructure changes are necessary to provide new higher instream flow releases to enhance aquatic habitat as well as monitor and measure the higher instream flows for compliance reporting. The new license orders and 2007 settlement agreement require new instantaneous flow requirements in addition to the 24-hour average flow requirement under which the Projects have been operating. This more stringent requirement may also necessitate automation at some remote sites to ensure flows remain in compliance. During 2023-2028, SCE will complete infrastructure modification at seven facilities (Dam 4, Portal, Mono Diversion, Dam 5, Dam 6, Warm Creek Diversion, Mammoth Pool Dam, and Rock Creek Diversion). The largest (by costs) include the Dam 6, Dam 4, and Mono Diversion projects. Most of the small diversions were originally slated for infrastructure modification but have now moved to a decommissioning (facility removal) approach instead and are further discussed below in Section II.C.4.

[121] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

The Hydro Relicensing – Infrastructure Refurbishments/Modifications capital expenditure forecast for these projects is $34.151 million for 2023-2028.[122] Table II-18 lists the projects within the Hydro Relicensing - Infrastructure Refurbishments/Modifications program category.

Table II-18
Hydro Relicensing – Infrastructure Modifications
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 3 - Dam 6 Forebay Instream Flow Release	1,202	6,809	-	-	-	-	8,011
2	Big Creek 2 - Dam 4 LLOV Replacement and MIF Infrastructure Install	6,113	-	-	-	-	-	6,113
3	Big Creek - Mono Diversion Instream Flow Release	-	587	587	587	4,109	-	5,870
4	Mammoth Pool - Minimum Instream Flow Release	-	544	544	544	3,807	-	5,438
5	Portal powerhouse - Forebay Instream Flow Release	-	-	399	399	399	2,793	3,990
6	Big Creek - Dam 5 Forebay Instream Flow Release	350	500	2,529	-	-	-	3,379
7	Big Creek - Rock Creek Diversion Instream Flow Release	-	-	-	250	100	1,000	1,350
8	**GRAND TOTAL**	**7,665**	**8,440**	**4,059**	**1,780**	**8,415**	**3,793**	**34,151**

(2) Project Scope

The infrastructure modifications include installing new outlet valves in a variety of configurations (depending on the location), supporting structures, stream gages, and/or automation equipment that can monitor and measure the newly required higher release flows. Some locations also include the ability to provide remote or local automation (partial or full) for the infrastructure to make adjustments due to changing conditions in order to remain in compliance with the new more stringent requirements.

The engineering, designing, constructing, and agency permitting process (other than FERC) for each infrastructure modification will vary. For each site at which infrastructure changes are proposed, preliminary engineering work, including design, likely construction approach (including considerations for dewatering or other means and methods of work), and access needs have been assessed in the last few years and a preferred alternative has been selected. These alternatives were used as the basis of the cost estimates provided.

[122] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation- Capital Projects.

The proposed improvements at Dam 4 have already completed final engineering and are scheduled to enter the construction phase in 2023. This work was accelerated ahead of license issuance due to additional drivers to complete repairs to the LLOV at this facility and because of the delayed license issuance. The next steps for the remaining projects will be to conduct final engineering design of the selected alternative, permitting, procurement of materials, and construction.

The projects are proposed in phases over the next several years with some projects being grouped together for engineering. Actual construction timing will vary with location due to potential differences in license issuances and site-specific design issues and will likely be determined by permitting and agency approval timelines, which may be longer than usual due to the complexity, potential for significant impacts, water quality study needs, and/or complex water management or system outage dependencies. SCE plans to stagger construction work over several years to allow for efficient use of personnel and resources and reduce impacts to normal generation operations.

(3) Project Justification and Benefit

Compliance with new license orders and the 2007 settlement agreement requirements is non-discretionary. SCE must fulfill compliance obligations to continue operating the Big Creek System. The project infrastructure modifications required by the new license orders will provide higher instream flow releases and channel riparian maintenance flows that will enhance aquatic habitat, control water temperature, and benefit aquatic species in the stream reach downstream of the dams and diversions. Automation of some of these systems will provide reliable and compliant flows and streamline new reporting obligations.

c) Hydro Relicensing – Relicensing Proceedings

The Hydro Relicensing – Relicensing Proceedings capital expenditure forecast is $23.225 million for 2023-2028.[123] Table II-19 below lists the projects within the Hydro Relicensing - License Activities/Implementation program category.

[123] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

Table II-19
Hydro Relicensing – Relicensing Proceedings
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Rush Creek - Application	3,600	2,250	760	440	250	150	7,450
2	Lundy	550	1,000	1,000	625	250	150	3,575
3	Kern River 1	1,000	1,000	750	250	250	250	3,500
4	Kern River 3	1,450	800	400	250	100	100	3,100
5	Lee Vining	1,400	500	200	50	50	50	2,250
6	Bishop Creek	500	250	250	100	-	-	1,100
7	Kaweah - National Park Service SUP Renewal	300	250	250	250	-	-	1,050
8	Mill Creek 2 and 3	-	-	-	-	50	550	600
9	Lytle Creek	-	-	-	-	50	550	600
10	**GRAND TOTAL**	**8,800**	**6,050**	**3,610**	**1,965**	**1,000**	**1,800**	**23,225**

Thirty of SCE Hydro’s 35 powerhouses are subject to federal regulations requiring FERC licenses to operate. Twenty FERC licenses govern operation of the 30 powerhouses, which account for approximately 1,164 MW of our total Hydro capacity. FERC grants each license for a defined period and SCE must renew the license prior to expiration to continue project operation. SCE’s original licenses were for 50-year terms; now, the default term for new licenses is 40 years. The FERC relicensing timeline requires licensees to begin the relicensing process between five and five and one-half years prior to expiration of the current license. The relicensing process is initiated with the filing of a Notice of Intent (“NOI”) and Pre-application Document (“PAD”). The PAD is a comprehensive document that includes: (1) a description of the hydroelectric project features and operations that will be relicensed; (2) a relicensing process plan; (3) a summary of all reasonable and readily available information on environmental and cultural resource potentially affected by the project; and (5) a list of proposed technical resource studies that will be implemented to collect additional resource information needed to evaluate the effect of the continued operation of the project. Licensees must typically begin the preparation of the PAD approximately two years prior to filing the NOI.

During the relicensing process, SCE will develop and implement technical resource studies to evaluate the effect of the continued operation of the hydroelectric projects. SCE must prepare a license application that describes the environmental and cultural resources associated with the projects, describes the effect of continued project operations of these resources, and includes terms and conditions (measures) that will protect resources from continued project operations during the term of the license order. The new licenses, when issued, typically include conditions imposing mitigation costs and operational restrictions that are greater than those required by the previous license. The mitigation costs may include a reduction in electrical generation output because of requirements to increase instream flow releases that reduce the availability of water for power generation. They may also include increased studies of the environmental impact of our operations and additional recreational studies and improvements.

Despite the various costs associated with FERC relicensing, these facilities are expected to provide substantial benefits to customers over the new license periods. To provide intergenerational equity, SCE capitalizes FERC relicensing costs rather than expensing these costs as they are incurred. This practice follows Generally Accepted Accounting Principles ("GAAP") and is accepted utility practice.

SCE is in the relicensing process for 13 FERC licenses. Six are for Big Creek projects that account for approximately 915 MW of nameplate capacity (approximately 78.6 percent of SCE's total Hydro capacity of 1,164 MW). The remaining projects include the Kaweah Project (8.9 MW), Bishop Creek Project (29.3 MW), Kern River No. 3 Project (40.2 MW), Lee Vining Project (11.3 MW), Kern River No. 1 Project (26.3 MW), Lundy Project (3.0 MW), and the Rush Creek Project (13MW). Two projects, Lytle Creek (0.5 MW) and Mill Creek 2/3 (3.0 MW), will begin relicensing in 2027. Combined, the 13 projects already in the relicensing process, and the two projects that will begin relicensing in 2027, will require capital expenditures of $23.225 million during 2023-2028.

When FERC relicensing begins for a Hydro facility, SCE opens a capital work order and records expenditures in the work order until the existing license expires, which also becomes the in-service date for the capital expenditures incurred up to that point in time. Expenditures recorded up to this date are then "in-service" and eligible to be included in rate base. Subsequent capital expenditures related to gaining the new license record to this existing work order, to be placed in-service as the additional relicensing related work proceeds. Capital projects relating to large FERC license-related mitigation projects receive separate work orders.

Table II-20 summarizes the relicensing status for each of our FERC licensed projects facilities. A discussion of the FERC relicensing process and SCE's relicensing cost estimate follows in section II.C.3.c)(1). We then address each FERC relicensing action requiring capital expenditures during 2023-2028.

Table II-20
SCE Hydro FERC Licenses

FERC PROJECT		License		Nameplate
Name	**Number**	**Expiration**	**Notes**	**Capacity (MW)**
Western Operations Region				
Big Creek Operations				
Big Creek Nos. 1 & 2	2175	2/28/2009	(a)(b)	154.9
Big Creek Nos. 2A, 8 & John S. Eastwood	67	2/28/2009	(a)(b)	384.8
Big Creek No. 3	120	2/28/2009	(a)(b)	174.5
Mammoth Pool	2085	11/30/2007	(c)(b)	190.0
Portal	2174	3/31/2005	(d)(b)	10.8
Vermilion Valley	2086	8/31/2003	(e)(b)	-
Big Creek No. 4	2017	11/30/2039		100.0
Southwest Operations				
Kern River No. 1	1930	5/31/2028		26.3
Kern River No. 3	2290	11/30/2026		40.2
Borel	382	5/17/2046	(f)	-
Kaweah	298	12/31/2021	(g)(b)	8.9
Lower Tule River	372	7/31/2033		2.5
		Sub-Total of Western Region		1092.7
Eastern Operations Region				
Mono Basin Operations				
Bishop Creek	1394	6/30/2024	(h)	29.3
Lee Vining	1388	1/31/2027		11.3
Rush Creek	1389	1/31/2027		13.0
Lundy	1390	2/28/2029		3.0
East End Operations				
Lytle Creek	1932	5/31/2033		0.5
Santa Ana River No. 1 & 3	1933	6/30/2033		6.3
Mill Creek No. 3	1934	6/30/2033		3.0
San Gorgonio	344	4/26/2003	(i)	-
		Sub-Total of Eastern Region		66.4
Total FERC Licensed Plants				1159.1
Capacity of Hydro Plants without FERC Licenses				5.2
TOTAL HYDROELECTRIC CAPACITY				1164.2

Notes:

a) Application for new license filed with the FERC on 2/21/2007
b) Operating under annually renewable license pending issuance of new license
c) Application for new license filed with the FERC on 11/21/2005
d) Application for new license filed with the FERC on 3/27/2003
e) Application for new license filed with the FERC on 8/29/2001
f) SCE filed the Draft License Surrender Application and Decommissioning Plan with FERC on 12/13/2022 after the U.S. Army Corps of Engineers condemned its easement and implemented a safety modification to its Lake Isabella Auxiliary Dam which sealed of the intake conduct for the project.
g) Application for new license filed with the FERC on 12/23/2019
h) Final License Application filed with FERC on 6/29/2022
i) Project is non-operable and SCE filed an application to surrender the license with the FERC on 9/27/2010

(1) FERC Relicensing Process

FERC divides the licensing process into two phases: (1) a pre-application consultation phase; and (2) a post-application analysis phase. During the pre-application consultation phase, the licensee files a Notice of Intent ("NOI") to seek an original, new, or subsequent license, and consults with resource agencies, stakeholders, and the public regarding the project. The post-application analysis phase begins after the licensee files its Final License Application ("FLA") with FERC to obtain a new license. The application must be filed no later than two years before the existing license expires. The application is a comprehensive, detailed document specifying the project's proposed operations, its anticipated impact on resources and other land uses, and proposed actions to mitigate adverse effects from the continued operation of the project. FERC reviews the application to help ensure that it meets all requirements and then asks federal and state land and resource agencies to formally comment.

Once FERC has determined that the application meets filing requirements, the studies have been completed, and no additional information is required (*i.e.,* concludes the pre-application process), it will issue the notice of acceptance and ready for environmental analysis ("REA") (*i.e.,* initiate the post-application analysis phase). The REA notice triggers a deadline for comments, recommendations, and mandatory conditions or prescriptions. When these filings are complete, FERC has the information needed to prepare the NEPA document. An environmental assessment ("EA") or environmental impact statement ("EIS") will typically be the NEPA document prepared for a license application. The licensing process concludes with issuing a licensing order.

The Federal Power Act ("FPA") provides for subsequent administrative and judicial reviews of a FERC license decision. If a license expires while a project is undergoing relicensing, FERC issues an annual license, allowing a project to continue to operate under the conditions found in the original license until the relicensing process is complete.

FERC regulations governing the relicensing of an existing hydroelectric project allow the licensee to use the alternative licensing ("ALP"), traditional licensing process ("TLP"), or the integrated licensing process ("ILP") to prepare, file, and process a new license application. SCE has used all three relicensing processes for the projects that are currently ongoing relicensing as identified in Table II-20 SCE Hydro FERC Licenses.

The ALP is a multi-year collaborative process that allows the consultation and environmental review phases of relicensing to be combined into a single process. Under this process, the applicant conducts a preliminary NEPA analysis during the pre-application phase rather than having FERC begin the NEPA analysis during the post-application phase. Also, the applicant prepares a preliminary draft environmental assessment ("PDEA") that is filed with the application for new license. The ALP seeks to improve communication and collaboration among the applicant and stakeholders during the process and often results in a settlement agreement at the end of the pre-application phase. This settlement agreement, signed by all the participants, includes the conditions to protect and enhance resources and, if reached, is filed with the application for new license.

The TLP comprises a three-stage consultation process for preparing and filing a new license application for an existing hydroelectric project. Under this process, the applicant prepares and submits a license application to FERC presenting information about the project and the resources in the project area. The application also provides information regarding the licensee's protection, mitigation and enhancement ("PM&E") proposals, including the measures proposed by other parties, but not adopted by the licensee. FERC conducts an independent environmental review of the project and solicits comments from resource agencies, Native American tribes, the public, and the applicant. FERC will issue a new license order with terms and conditions based on the PM&E measures proposed in the license application and on stakeholder comments received during the review period. The TLP was previously the only process available to a licensee.

The ILP is the default relicensing process used by FERC and was approved through regulations issued July 23, 2003 (18 CFR Part 5). Similar to the TLP and ALP, the ILP formally begins five to five and one-half years before license expiration with the filing of the NOI and PAD. In an ILP the licensee must prepare a detailed study plan document for review and comment by the regulatory agencies and other interested parties participating in the relicensing proceeding. The ILP includes a study plan dispute resolution process that, if needed, allows FERC to form an independent panel to review the notice of study dispute and deliver its recommendations to resolve the dispute. FERC will then issue a written determination pertaining to the licensee's study plan document. The licensee must then implement the FERC-approved detailed study plan. Near the end of the study period (and no later than 150 days prior to the deadline for filing its final license application), the licensee must file a Preliminary Licensing Proposal ("PLP") or a draft license application ("DLA"), which describes the existing and proposed project facilities, existing and proposed project operation and maintenance plan, protection measures, and mitigation and enhancement for resource areas affected by the proposal. The PLP or DLA also includes a draft environmental assessment by resource area including information obtained from completion of the study plan document. After the license application is filed, FERC will fulfill its NEPA responsibilities by conducting an independent analysis and preparing a final Environmental Impact Statement ("EIS") and will ultimately issue a new license.

(a) <u>Rush Creek Relicensing</u>

(i) <u>Background</u>

SCE initiated early licensing activities of the 13.0 MW Rush Creek Project in late 2019 by consulting with key stakeholders to identify resource management objectives and compile information on existing resources that would be described in the PAD. SCE identified sensitive environmental and cultural resources that could be affected by the continued operation of the Project and developed a list of proposed studies that are focused on obtaining additional resource information to further support an evaluation of project operations on these resources. These studies were included with the PAD that was filed.

Prior to the early relicensing activities in 2019, SCE had already initiated consultation with FERC, DSOD, and the USFS to address seismic safety for the three Rush Creek dams due to the nearby Silver Lake seismic fault that was discovered in 2012. Detailed investigation of the seismic fault led to SCE's voluntary restriction of water levels in 2012 and 2013 within the three reservoirs to reduce the water levels below the area most vulnerable to a seismic event (i.e., the upper portions of the dams). SCE has (through a consultation with FERC, DSOD and the USFS) obtained agreement to address the seismic concerns in the relicensing process for the Project.

On December 16, 2021, SCE filed its NOI and PAD, initiating the ILP. The Project description in the PAD that will be evaluated during relicensing is for the continued hydroelectric operation of Gem Dam and Rush Creek Powerhouse and to discontinue hydroelectric operations at Rush Meadows and Agnew Dams. The PAD described alternatives for the disposition of facilities at Rush Meadows Dam, Agnew Dam, and Gem Dam under consideration in the relicensing proceeding. One proposed alternative for Gem Dam involves retrofitting it with a new spillway and reduced dam height, which would make the current restricted level the new normal pool reservoir level. Under this alternative, hydroelectric operations at Gem Dam and Rush Creek Powerhouse would continue under FERC jurisdiction consistent with conditions identified in a new FERC license. Two alternatives were identified to bookend the analysis for disposition of Rush Meadows and Agnew Dams: (1) full dam removal and (2) partial dam removal. Under each alternative, hydroelectric operations at Rush Meadows and Agnew Dams would be discontinued, and these facilities would be removed from the FERC license once all license conditions and regulatory requirements are met. In both removal scenarios, no water would be impounded at any time at the previous dam location. The alternatives were developed at a conceptual engineering level of design with structural modeling completed for the Gem Dam retrofitting. During the relicensing proceeding, other alternatives could be identified and may warrant further analysis. The capital forecast for the Rush Creek Project relicensing effort is $7.450 million for 2023-2028.[124]

During the relicensing process, the USFS has questioned whether FERC has the jurisdiction to relicense the project because a portion of it is in a federally designated wilderness area. This issue must be resolved before a new license can be issued.

(ii) Project Scope

During relicensing, SCE will implement environmental resource studies to obtain information needed to evaluate the effect of continued hydroelectric operations at Gem Dam, and the effect of construction activities associated with the partial or full removal of Rush Meadows and Agnew Dams. The environmental and cultural resource studies will be conducted in 2023 and 2024 and study results will support the Project effects analysis and lead to the development of proposed license terms and conditions to protect sensitive environmental resources. The

[124] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

environmental study results, effects analysis, and proposed license terms and conditions will be used to prepare the Application for New License that will be filed with FERC in January 2025.

Following submittal of the License Application, FERC will complete its NEPA process and issue a new license to SCE (early 2027). Construction activities are anticipated to begin in 2029 and continue through 2038, following FERC's approval of the engineering package and obtaining resource agency permits/approvals.

(b) Lundy Relicensing

(i) Background

SCE will initiate relicensing of the 3.0 MW Lundy Project in 2023 by starting early licensing activities that will include consultation with key stakeholders to identify their resource management objectives and to garner information on existing resources that would be described as the existing environment in the PAD. During the early licensing activities, SCE will identify sensitive environmental and cultural resources that may be affected by the continued operation of the Project and will develop a list of proposed studies that are focused on obtaining resource information that will support an evaluation of project operations on these resources. SCE will begin the formal FERC relicensing process by filing the NOI and PAD in the fall of 2023.

SCE intends to utilize the ILP to relicense the Project. Prior to filing the PAD, SCE intends to conduct early outreach with resource agencies to obtain from them readily available and relevant information of key resource associated with the project. Based on the available information, SCE will identify sensitive environmental and cultural resources that could be affected by the continued operation of the Project and will develop a list of proposed studies that are focused on obtaining additional resource information to further support an evaluation of project operations on these resources. The list of proposed studies will be included with the PAD. The capital forecast for Lundy relicensing efforts is \$3.575 million for 2023-2028.[125]

[125] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

(ii) Project Scope

The scope of work under this relicensing includes: (1) pre-filing activities (focused consultation with resource agencies and other stakeholders); (2) preparation of the NOI/PAD; (3) development of technical resource study plans; (4) obtaining a study plan determination from FERC; (5) implementation of the FERC approved technical resource studies; (6) completing a project effects analysis to determine impacts to sensitive environmental and cultural resources from the continued operation of the project; (7) developing measures to protect sensitive resources potentially affected by the project (these will become the proposed terms and condition in the new FERC license order); and (8) preparation and filing to FERC the draft and final Applications for New License.

(c) Kern River No. 1 Relicensing

(i) Background

SCE will initiate relicensing of the 26.3 MW Kern River No. 1 Project in 2022 by starting early licensing activities that will include consultation with key stakeholders to identify their resource management objectives and to garner information on existing resources that would be described as the existing environment in the PAD. During the early licensing activities, SCE will identify sensitive environmental and cultural resources that may be affected by the continued operation of the Project and will develop a list of proposed studies that are focused on obtaining resource information that will support an evaluation of project operations on these resources. SCE will begin the formal FERC relicensing process by filing the NOI and PAD in the spring of 2023.

SCE intends to utilize the ILP to relicense the Project. Prior to filing the PAD, SCE intends to conduct early outreach with resource agencies to obtain from them readily available and relevant information of key resource associated with the project. Based on the available information, SCE will identify sensitive environmental and cultural resources that could be affected by the continued operation of the Project and will develop a list of proposed studies that are focused on obtaining additional resource information to further support an evaluation of project operations on these resources. The list of proposed studies will be included with the PAD. The capital forecast for Kern River No. 1 Project relicensing efforts is $3.500 million for 2023-2028.[126]

(ii) Project Scope

The scope of work under this relicensing includes: (1) pre-filing activities (focused consultation with resource agencies and other stakeholders); (2) preparation of the NOI/PAD; (3) development of technical resource study plans; (4) obtaining a study plan determination from FERC; (5) implementation of the FERC approved technical resource studies; (6) completing a project effects analysis to determine impacts to sensitive environmental and cultural resources from the continued operation of the project; (7) developing measure to protect sensitive resources potentially affected by the project (these will become the proposed terms and condition in the new FERC license order); and (8) preparation and filing to FERC the draft and final Applications for New License.

(d) Kern River No. 3 Relicensing

(i) Background

SCE initiated early licensing activities of the 40.2 MW Kern River No. 3 Project in late 2019 by consulting with key stakeholders to identify resource management objectives and compile information on existing resources that would be described in the PAD. SCE identified sensitive environmental and cultural resources that could be affected by the continued operation of the Project and developed a list of proposed environmental and cultural resource studies that are focused on obtaining additional resource information to further support an evaluation of project operations on these resources. SCE worked closely and collaboratively with key stakeholders by conducting early engagement meetings to obtain information regarding stakeholder resource interests and study requests. SCE reviewed and evaluated the study requests submitted by the Stakeholders and identified potential resource issues that would require further study during the relicensing process.

[126] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

On September 22, 2021, SCE filed its NOI and PAD, which initiated the ILP. The Project description in the PAD that will be evaluated during relicensing is for the continued hydroelectric operation of the project, which includes the following key facilities: Fairview Dam and its water conveyance system, and the Kern River No. 3 Powerhouse. Also included in the PAD are 10 proposed environmental and cultural resource studies related to water resources, aquatic resources, wildlife resources, botanical resources, recreation use, and cultural/tribal resources, for which further information gathering or studies will occur. Stakeholders filed numerous comments with FERC in response to SCE's PAD and FERC's scoping document, including requests for several additional resource studies. SCE addressed the comments received and the requests for additional studies in the Proposed Study Plan filed on March 4, 2022, which included 15 proposed studies. Additional comments and study requests were received from stakeholders addressed by SCE in the Revised Study Plan filed on July 5, 2022, which included 18 proposed studies. FERC reviewed all comments and proposed study requests and issued a Study Plan Determination on October 12, 2022 which required SCE to conduct 19 technical resource studies to inform FERC's assessment of environmental effects, as well as federal and state resource decisions in the relicensing effort.

SCE is implementing the approved technical resource studies over two field seasons in 2022 and 2023. The capital forecast for Kern River No. 3 Creek Project relicensing efforts is $3.100 million for 2023-2028.[127]

(ii) Project Scope

SCE began conducting select studies starting in spring 2022 and will complete study implementation in 2023. Study results will be used to support the Project effects analysis leading to the development of proposed license terms and conditions to protect sensitive environmental resources. The environmental study results, effects analysis, and proposed license terms and conditions will be used to prepare the Application for New License that will be filed with FERC in November 2024.

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127 WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

Following submittal of the License Application, FERC will complete its NEPA process and issue a new license to SCE (early 2027).

(e) Lee Vining Creek Relicensing

(i) Background

SCE initiated early licensing activities of the 11.3 MW Lee Vining Project in late 2019 by consulting with key stakeholders to identify resource management objectives and compile information on existing resources that would be described in the PAD. SCE identified sensitive environmental and cultural resources that could be affected by the continued operation of the Project and developed a list of proposed environmental and cultural resource studies that are focused on obtaining additional resource information to further support an evaluation of project operations on these resources. SCE worked closely and collaboratively with key stakeholders by conducting early engagement meetings to obtain information regarding stakeholder resource interests and study requests. SCE evaluated the stakeholders' study requests and identified potential resource issues that would require further study during the relicensing process.

On August 12, 2021 SCE filed its NOI and PAD, which initiated the Traditional Licensing Process ("TLP") for the Project. The Project description that will be evaluated during relicensing is for the continued hydroelectric operation of Saddlebag Dam and Lake, Tioga Dam and Lake, Rhinedollar Dam and Lake (also called Ellery Lake), and a flowline consisting of a pipeline and penstock that provide water for generation to Poole Powerhouse. Also included in the PAD are 15 draft study plan outlines related to water resources, aquatic resources, wildlife resources, botanical resources, recreation use, and cultural/tribal resources, for which further information gathering or studies will occur. SCE continued to refine these study plans in collaboration with stakeholders and filed final plans on April 25, 2022. The capital forecast for Lee Vining Creek Project relicensing efforts is $2.250 million for 2023-2028.[128]

[128] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

(ii) Project Scope

SCE began conducting select studies starting in spring 2022 and will complete study implementation in 2023. Study results will be used to support the Project effects analysis leading to the development of proposed license terms and conditions to protect sensitive environmental resources. The environmental study results, effects analysis, and proposed license terms and conditions will be used to prepare the Application for New License that will be filed with FERC in January 2025.

Following submittal of the License Application, FERC will complete its NEPA process and issue a new license to SCE (early 2027).

(f) Bishop Creek Relicensing

(i) Background

SCE initiated relicensing of the 29.3 MW Bishop Creek Project in late 2017 by conducting early licensing activities with key stakeholders to identify resource management objectives and garner information on existing resources that would be described as the existing environment within the PAD. In May 2019, SCE filed the NOI and PAD, which initiated the ILP. The PAD identified 15 technical resource studies that were to be implemented to evaluate the environmental and cultural resources that could be potential affected by the continued operation of the Project. These studies were be conducted over two field seasons during 2020 and 2021 and extended into a third field season in 2023. The information was used to support an effects analysis to determine how the continued operation of the project would affect sensitive resources. Based on that analysis, measures were developed to protect affected resources and were included as new license terms and conditions in the draft and final license applications filed with FERC. SCE filed the DLA on January 26, 2022. Resource agencies and stakeholders reviewed and provided comments on the DLA, which SCE addressed in the FLA that was filed with FERC on June 29, 2022.

The relicensing process is now in the post-filing stage, in which SCE will support FERC's NEPA process and apply for a water quality certification from the State Water Board, as required by the Federal Power Act. During the relicensing process, the USFS has questioned whether FERC has the jurisdiction to relicense the project because a portion of it is in a federally designated wilderness area. This issue must be resolved before a new license can be issued.

The capital forecast for Bishop Creek relicensing efforts is $1.100 million for 2023-2028.[129]

(ii) Project Scope

Since the filing of the FLA, SCE has continued to negotiate with resource agencies regarding proposed new license terms and conditions associated with instream flow releases, recreation enhancements, and cultural resources. These negotiations will be completed in early 2023 and SCE will file with FERC updated proposed new license terms and conditions and a supplemental document to the final FLA that will provide additional environmental analysis to support the NEPA process needed to issue a new license. SCE will continue to support FERC by responding to information requests as needed. Additionally, SCE will apply for a water quality certification from the State Water Board, as required by the Federal Power Act.

(g) Kaweah National Park Service SUP Renewal Process (Kaweah No. 3)

(i) Background

The Kaweah Project includes three developments named Kaweah No. 1, Kaweah No. 2, and Kaweah No. 3. Portions of Kaweah Nos. 1 and 3 are located in Sequoia National Park, which is under the jurisdiction of the National Park Service ("NPS"). The NPS authorizes the operation of these facilities through the issuance of a Special Use Permit ("SUP"). The current permit expires on September 8, 2026. Renewal of the SUP requires Congressional approval, which could take years. The capital forecast for the SUP Renewal Process (Kaweah No. 3) relicensing efforts is $1.050 million for 2023-2028.[130]

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[129] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

[130] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

(ii) Project Scope

The process to obtain congressional approval will require SCE to garner support for the SUP renewal. SCE will need to prepare rationale statements demonstrating the need and value for the continued operation and existence of the project and solicit the support of the congressional representative of the district where Sequoia National Park is located. SCE anticipates that the process will require about four years to complete. SCE will initiate congressional outreach in 2023 with the expectation of obtaining a new SUP before the 2026 expiration date.

(h) Lytle Creek and Mill Creek No. 2&3

(i) Background

SCE will initiate early relicensing activities for the Mill Creek Nos. 2&3 and the Lytle Creek projects in 2027. The license expiration for these projects is in May and June 2033 and therefore their relicensing proceedings will be implemented on concurrent timelines. The 2023-2028 capital forecast for the Mill Creek Nos. 2&3 and Lytle Creek relicensing effort is $1.200 million ($0.600 million each).[131]

(ii) Project Scope

SCE will conduct early licensing activities with key stakeholders to identify resource management objectives and gather information on environmental and cultural resources which must be described in the PAD. SCE will prepare the NOI and PAD in 2027 and 2028 and file both documents for each of the three projects in May 2028. The filing of the NOI and PAD will initiate the formal FERC relicensing process for these projects, which will continue through 2033 when the license expires.

d) Hydro Relicensing – License Implementation

The new FERC licenses will include requirements (terms and conditions) that SCE must meet or implement when operating these projects over the life of their new license terms. These requirements typically include providing minimum instream flows and maintaining reservoir

[131] WP SCE-05 Vol. 1, p. 57. Estimated Relicensing Spend Projects (2023-2028).

levels, conducting periodic assessments of ongoing operations' potential impact on environmental and cultural resources, implementing management plans or mitigation measures to protect environmental and cultural resources, enhancing (e.g., constructing, rehabilitating, maintaining) nearby recreational facilities or opportunities, and submitting periodic reports. The new minimum instream flow requirements, channel riparian maintenance flows, and geomorphic flow releases will also drive the need to make infrastructure modifications at our dams and diversion structures (e.g., requiring new or expanded capacity flow release valves, low level outlet valves, and flow measuring devices) to comply with the large volume flow release requirement.

New FERC license orders require developing resource agency-approved management and protection plans, preparing license compliance tools and data management databases, and implementing environmental resource studies on a recurring basis.

FERC licenses also require SCE to operate our projects in a safe manner to protect public safety and maintain and operate our dams safely. FERC performs annual public safety inspections at SCE's Hydro Projects. The licenses also require dam safety investigations on a recurring five-year cycle. The Hydro Relicensing – License Implementation capital expenditure forecast is $14.353 million for 2023-2028. Table II-21 below lists the projects within the Hydro Relicensing - License Implementation program category.

Table II-21
Hydro Licensing – License Implementation
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 1, 2, 2A, 3, 8, Eastwood, Mammoth Pool, Portal and Vermilion	2,489	2,042	1,032	548	717	337	7,165
2	Rush Creek - Implementation (Gem Lake Dam)	-	-	-	1,000	1,000	2,500	4,500
3	Bishop Creek - Implementation	-	-	1,218	240	-	-	1,458
4	Kaweah - Implementation	-	1,000	230	-	-	-	1,230
5	**GRAND TOTAL**	**2,489**	**3,042**	**2,480**	**1,788**	**1,717**	**2,837**	**14,353**

(1) Big Creek Implementation

(a) Background

Six of Big Creek's seven FERC project licenses are still pending issuance due to an ongoing proceeding that has spanned over two decades. The existing licenses for the Big Creek ALP Projects have expired and FERC issued Notices of Authorization for Continued Project Operation, which allows the projects to operate on annual renewals until new license orders are issued. Four Big Creek projects are being relicensed in a single ALP and two projects are being relicensed individually using the TLP. SCE elected to use the multi-year collaborative ALP for relicensing four of its Big Creek projects to address complex resource balancing issues with stakeholders within a single process. The Vermilion Valley and Portal projects used a TLP since their earlier FERC License expiration dates required starting their relicensing process sooner. The Big Creek ALP began in May 2000 after receiving FERC approval to use the process.

SCE negotiated a comprehensive settlement agreement with stakeholders that included the proposed terms and conditions for the projects over the new license terms. The 2007 agreement was signed by 21 parties including CDFW, the USFS, the USFWS, and the Friant Water Authority, and included support from the California State Water Resources Control Board (State Water Board).[132] SCE anticipates that FERC will model the new license requirements on the settlement agreement without significant additional requirements and has structured the implementation requirements below based on the commitments in the settlement agreement.

FERC's issuance of the new license orders for the six Big Creek Projects has been delayed by the State Water Board's water quality certification process under Clean Water Act Section 401[133] and by recent listings of endangered species which require additional consultation with the USFWS in accordance with Section 7 of the Endangered Species Act. These

[132] At the time of signing, the agency's name was California Department of Fish and Game (CDFG).

[133] FERC must comply with the Clean Water Act requirement that a state be afforded the opportunity to issue a certification. In California, the State Water Board is the lead agency responsible for issuance of the certification.

delays are described in the next section. It is anticipated that FERC will issue the new license orders in 2023 which will require that SCE begin implementation of the terms and conditions. The capital forecast for the Big Creek – License implementation efforts is $7.165 million for 2023-2028.[134]

(i) Delay of License Issuance

The State Water Board intended to issue a single water quality certification for all six projects; however, this required supplemental analysis under the California Environmental Quality Act ("CEQA") first. At the State Water Board's request, SCE prepared a draft supplemental document on November 9, 2011 to address the required analysis. Nearly seven years later, on August 13, 2018 the State Water Board issued its draft certification and the CEQA Supplemental Document with additional terms and conditions which were inconsistent with the negotiated 2007 settlement agreement. SCE began development of technical comments addressing these inconsistencies and requestion modification to the draft WQC conditions. On November 16, 2018, the State Water Board notified SCE that its certification request had been denied without prejudice and that SCE would need to reapply. SCE did not reapply. However, without an active application in process, on May 31, 2019, the State Water Board issued a final WQC for the Big Creek Projects, prior to consulting with SCE and FERC and without addressing the extensive technical comments submitted by SCE on the draft certification under the open public comment period. On June 17, 2019, SCE petitioned FERC for a declaratory order that the State Water Board waived authority under Section 401 of the Clean Water Act by failing to issue the certification within the statutorily prescribed one-year period. On February 20, 2020, FERC granted SCE's petition and found that the State Water Board's delay resulted in the waiver of its water quality certification authority with respect to the relicensing of the six Big Creek Projects.

Three months later, the USFWS listed a new species under the Endangered Species Act ("ESA"), requiring SCE to formally consult with the USFWS. SCE prepared a supplemental Biological Assessment and filed it with FERC on August 28, 2020. FERC requested concurrence of the USFWS on September 15, 2020, and then after that month's Creek Fire,

[134] WP SCE-05 Vol. 1, p. 54. Big Creek New License Program Implementation - Capital Costs.

the, USFWS requested additional information from SCE on September 28, 2020. SCE conducted the supplemental consultation with USFWS and provided the requested information on December 14, 2020. SCE and the USFWS negotiated appropriate conservation measures which were agreed to by both parties and on April 5, 2021, the USFWS filed a letter with FERC concurring with the finding that the Big Creek licenses were not likely to adversely affect the newly listed species. SCE began awaiting issuance of the final license orders for Big Creek as all regulatory requirements had been satisfied. In late July 2022, FERC requested that SCE file a summary of the supplemental consultation with FERC for the record and SCE completed the filing on September 1, 2022. SCE is currently waiting for license issuance and expecting the FERC to move forward in issuing the six new license orders in early 2023.

(b) Implementation of New License Order Terms and Conditions

The Big Creek ALP activities can be divided into three main categories: (1) immediate actions upon license issuance (i.e., including technical consistency review, completing license issuance-related FERC processes, and compliance requirements database updates); (2) permitting, agency coordination, and planning activities associated with implementing new environmental resource studies; and (3) implementation of the new license requirements and resource studies.

Several tools are being developed to track and comply with the new license orders. These tools include license implementation and compliance tracking tools, a document repository, and a GIS-based screening tool to evaluate projects and activities. Previous tools developed include resource management plan summaries, reporting and consultation requirements, decision records, flow charts to track and monitor activities, and a holistic project timeline and multiple calendars based on program/resource area. After the license orders are issued, SCE will conduct a thorough comparison of the new orders to the requirements of the settlement agreement to determine if there are any changes and if SCE will proceed with the license acceptance process (during the initial statutory period in which an appeal may be filed; approximately within 30 days of issuance). SCE will also the aforementioned tools as needed to address the new license orders.

The major implementation costs for the six Big Creek Projects relate to conducting the resource management plan studies and complying with the license articles. These management plans and license articles are grouped into five main resource areas (Aquatic Resources, Recreational Resources, Terrestrial Resources, Land Management, and Cultural Resources), and include measures to conduct environmental resource studies, perform enhancements, or implement mitigation measures to address potential impacts resulting from the continued operation of the hydroelectric projects. Each resource area is discussed below.

(i) Aquatic Resources

The Aquatic Resources area involves implementing various required enhancements and mitigation measures to mitigate project impacts identified in studies and to enhance habitat conditions for aquatic life. The following describes the activities SCE will be required to complete, including some of the associated monitoring and mitigation activities.

Channel riparian maintenance ("CRM") flows will be released along selected stream reaches to provide enhanced habitat that will sustain aquatic and riparian ecosystems with these seasonal pulse flows during wet water years.[135] Prior to the high flow releases on Mono Creek, baseline measurements of the current sediment and riparian conditions will be conducted within the first year following license issuance. Along the South Fork San Joaquin River below Florence Reservoir, a detailed topographic survey of the Jackass Meadow Complex will be performed prior to the CRM flow releases. Subsequent surveys will be conducted to determine the extent of inundation from the CRM flows. Studies of riparian conditions along the stream corridor will also be conducted within the first year following license issuance.

Stream and reservoir temperatures will be monitored during the first three to five years that instream flows are released under the new project licenses, to verify that water temperature targets are met. Installation and ongoing maintenance or calibration of the stream

[135] A reach is a length of a stream or river, usually suggesting a level, uninterrupted stretch. The beginning and ending points may be selected for geographic, historical, or other reasons and may be based on landmarks such as gauging stations, river miles, natural features, and topography.

temperature recorders will occur throughout the monitoring period. Some of those releases will not start until the completion of the infrastructure modification projects to provide the new minimum instream flows identified above in section II.C.3.d)(1)(b)(i).

An interim water temperature control program will be prepared in consultation with resource agencies. The interim program will contain measures that may be feasibly implemented by SCE to maintain water temperature targets in project stream reaches. Additional water temperature studies and modeling will be included as a component of the interim program and the results will be integrated into the long-term water temperature control program.

Fish populations will be monitored in selected stream reaches to assess the effects of the newly agreed upon stream flow releases on the fish community composition and abundance. Night snorkeling surveys will also be conducted at several established sampling sites prior to the implementation of the new minimum instream flows. Some of the monitoring locations will not be implemented until the completion of the infrastructure modification projects to provide the new minimum instream flows identified above in section II.C.3.d)(1)(b)(i).

Sediment that has accumulated behind project dams and diversions will be reduced through implementing sediment management prescriptions that include sediment pass-through or physical removal. Sediment management activities are required to maintain proper operation of the projects and protect facility reliability (low-level outlets and intake structures). Initial agency consultation and water permits may need to be obtained prior to implementation of the sediment management prescriptions. Baseline studies to identify accumulations of fine sediment in pools will also be conducted prior to implementing sediment management prescriptions. During implementation, SCE will monitor water quality and fine sediment conditions associated with the sediment passthrough prescription by conducting volumetric measurement of accumulation in deeper pools in the affected stream reaches.

A gravel augmentation program is proposed below Mammoth Pool Dam to improve trout recruitment by providing additional spawning gravel to the reach.

SCE will consult with various agencies on the feasibility of adding gravel to the channel and will prepare necessary permits and supporting documents to implement the plan.

A macroinvertebrate study is required to be conducted in the first three years following license issuance for the Vermilion Valley leakage channel downstream of the dam.

(ii) Terrestrial Resources Measures

SCE also will implement various measures to protect terrestrial resources potentially affected by project operations. Resource management plans were developed to address these areas and include the Bald Eagle Management Plan and Vegetation and Integrated Pest Management Plan. The Bald Eagle Management Plan requires conducting recurring wintering and nesting surveys to monitor the status of bald eagles near the Big Creek projects, annual consultation about new bald eagle nests, and reporting. The Vegetation and Integrated Pest Management Plan includes extensive requirements for: (1) treating and monitoring of noxious weed populations; (2) monitoring of special status plant species; (3) incorporating protection measures for Native American traditional plant populations; and (4) training employees on various resource conservation topics. To complete these activities, vegetation-specific program improvements such as GIS mapping tools and the ability to field input observed populations directly into the dataset will occur in the first year of license issuance. Other requirements include annual seasonal protections of species (e.g., for Mule Deer prior to and during their annual peak migration period).

(iii) Land Management

SCE will implement resource management plans for visual and transportation resources. The visual resource plan will address visual effects of project facilities on the surrounding landscapes and view shed (i.e., the geographical area visible from a location) in the Sierra National Forest. This includes potential planting trees or vegetation for visual screening. Several project facilities identified in the plan will be repainted during their normal painting schedule with USFS-approved natural colors that blend in with the surrounding environments.

The transportation system management plan describes measures that SCE will implement to repair, minimize, or eliminate impacts associated with the maintenance and operation of the projects on local roads in the Forest. SCE will coordinate with the USFS to conduct initial road condition surveys of SCE-maintained roads (referred to as "Project Roads") to identify and prioritize roads requiring rehabilitation. Any roads identified as requiring immediate rehabilitation will be documented in the annual plan of operations and scheduled for repair the following year.

SCE will be responsible to maintain non-project USFS roads historically under the USFS's maintenance responsibility per the settlement agreement. Road and Bridge Rehabilitation Projects are described in section II.C.3.f) below. SCE may also need to obtain road use permits for work on USFS roads or special projects.

SCE also will establish a transportation signage fund in coordination with the USFS. This fund will allow the USFS to purchase, repair, and maintain road and recreation use signs throughout the Big Creek project area.

(iv) Cultural Resources

SCE will implement the Historic Properties Management Plan (HPMP) prepared for the ALP projects. Activities associated with implementing the HPMP include:

- Establishing an advisory committee to periodically review and revise the HPMP that will meet twice a year during the first five years following license implementation.
- Completing historic preservation activities called for in the HPMP within two years following license issuance, including: (1) evaluating or determining National Register of Historic Places (NRHP) eligibility of some resources; (2) instituting a public education and

interpretation program; (3) designing, manufacturing, and installing advisory and educational/interpretive signage; (4) implementing an SCE employee education program; (5) planning to manage unanticipated discoveries; (6) developing a Native American Graves Protection and Repatriation Act (NAGPRA) plan of action for archaeological data recovery excavations; and (7) nominating the Big Creek Hydroelectric System Historic District to the National Register, which involves implementing a maintenance and repair plan for historic buildings and structures associated with the Big Creek Hydroelectric System Historic District.

- Coordinating and assisting in the facilitation of the Native American advisory group, which will consist of representatives from all local tribal communities and the Sierra Nevada Native American Coalition. A facilitator will be provided, and meetings may occur a maximum of once every three months.
- Fulfilling financial obligations as outlined in the settlement agreement, including: (1) designating a significant area near Shaver Lake on Edison-owned lands for Native American use; (2) establishing a Native American scholarship fund; (3) contributing to the Sierra Mono museum curation funding; (4) improving pedestrian access and protection of cultural resources at Mono Hot Springs; (5) providing appropriate training for Native Americans to participate

as monitors for archaeological field work referenced in the HPMP; (6) providing training to SCE employees regarding environmental and cultural awareness; (7) developing an extensive annotated bibliography of reports to submit to tribes and historical societies within six months of license issuance; and (8) allowing access to SCE lands and identifying a location for a plant gathering and tending garden.

(v) Recreational Resources

SCE will be required to maintain and enhance recreational resources through the rehabilitation, replacement, and improvement of recreation facilities near the Big Creek Projects. SCE is also required to periodically conduct recreational use and facility condition surveys at required sites. The surveys determine the current trends of use, parking demand (and whether capacity is exceeded), as well as whether damage is occurring. SCE will also be required to provide certain additional data such as annual water surface elevations during the recreation season.

From 2023-2028, SCE will complete major rehabilitation/reconstruction of two campgrounds located at two reservoirs, an accessible fishing platform, a boat ramp, and a day-use visitor's center. Major rehabilitation comprises conceptual planning, engineering design, permitting, and constructing these facilities. These improvements are discussed further in section II.C.3.a) above.

Approximately 13 interpretative display exhibits (kiosks) will also be designed and installed at various locations in the vicinity of the Big Creek Projects. SCE will consult with the USFS and the Big Creek Heritage Advisory Committee regarding design, content, and placement of kiosks generally at the locations described in the Recreation Management Plan. SCE will support annual fish stocking in project reservoirs and bypass stream reaches below project diversions to enhance recreational fishing opportunities, in partnership with CDFW. Whitewater flow releases will be provided downstream of various diversions and dams in water years designated "Wet" and "Above Normal" to enhance other recreational opportunities.

SCE will enhance recreation opportunities in the vicinity of the projects by providing annual funding to the USFS to: (1) repair and maintain recreational facilities around the project area due to concentrated use; (2) conduct minor rehabilitation at recreational facilities; and (3) support interpretive programs (which may include signage or development and publications of brochures to distribute in the vicinity of the Big Creek Projects).

SCE will also fulfill one-time financial obligations as outlined in the settlement agreement to other non-governmental groups. Examples include the Huntington Lake Association, Huntington Lake Big Creek Historical Conservancy, Shaver Crossing Railroad Station Group, Huntington Lake Volunteer Fire Department, and the Fresno County Sherriff Department.

(2) Rush Creek – Implementation (Gem Lake Dam)

(a) Background

SCE expects that any new license for the Rush Creek Project will require SCE to retrofit Gem Lake Dam to comply with seismic water level restrictions.[136] The seismic restrictions were imposed after the discovery of the nearby Silver Lake Fault identified a potential dam safety issue should a large earthquake occur when the reservoirs are full. Therefore, in the relicensing process for the Rush Creek project, discussed in section (a)II.C.3.c)(1)(a) aboveII.C.3.d)(1)(b)(i), SCE proposed to retrofit Gem Lake Dam with a new spillway and reduced dam height, which would make the current seismic restricted level the new normal pool reservoir level. Additionally, during relicensing, SCE also proposed to discontinue hydroelectric operations at Rush Meadows and Agnew Dams by partially or fully removing the dams and removing them from the FERC license. Under either the full or

[136] During the relicensing process, the USFS has questioned whether FERC has the jurisdiction to relicense the project because a portion of it is in a federally designated wilderness area. This issue must be resolved before a new license can be issued.

partial dam removal alternatives, no water would be impounded at any time at the previous dam location.

The approach to retrofit Gem Lake Dam and decommission Rush Meadows and Agnew dams was developed at a conceptual engineering level of design to support the development of the project description that would be evaluated during the relicensing of the project. However, during the relicensing proceeding, other alternatives for retrofitting or decommissioning could be identified and may require further analysis.

The conceptual engineering also included an implementation timeline that extended through 2039 to complete the retrofitting of Gem Lake Dam and decommissioning of Rush Meadows and Agnew dams. The implementation generally outlines the following activities: (1) relicensing, including the development of the license application, FERC completing its NEPA process and issuing a new license is completed by 2027; (2) permitting and review and approval of the final engineering package for the three dams is conducted between 2026 and 2029; (3) construction activities (retrofitting and partial or full removal) for the three dams would be staggered between 2029 and 2035; and (4) post-construction monitoring or environmental resources would continue through 2038.

The final project approach for retrofitting and decommissioning will be identified based on agency and stakeholder input during relicensing and will be deferred until submittal of the Final License Application in January 2025. Once the final approach has been developed, SCE can initiate final engineering design and regulatory permitting processes. Construction would not begin until 2029 pending issuance of the new license, approval of the final engineering plans by FERC and DSOD, and issuance of regulatory permits.

The capital forecast for Rush Creek – Implementation (Gem) relicensing efforts is \$4.500 million for 2023-2028,[137] and total forecasted costs to retrofit Gem Lake

[137] WP SCE-05 Vol. 1, p. 106. Rush Creek Project - Decommission and License Implementation Cost Estimate.

Dam ranges from $101.0 to $136.2 million depending on whether the retrofit work is completed in water (the reservoir is not drained) or not in water (the reservoir is drained).

(b) Project Scope

Project implementation begins in 2026 (in anticipation of a new license order) and includes completing final engineering design and regulatory permitting processes before construction can begin.

Final engineering design (of the approach filed with FERC in the license application) must be completed ensure that the dam retrofit will meet seismic restrictions, address hydrologic/hydraulic issues, and address future Project use and operation and maintenance issues, as well as describing the construction approach. The final engineering design for the Gem Dam retrofit will be completed between 2026 and 2028.

SCE will also need to obtain the required regulatory permits and approval between 2026 and 2029 before construction activities can begin in 2030. The following identifies anticipated permitting requirements and authorizations necessary for the retrofitting and decommissioning construction activities, and the post-construction restoration and monitoring activities at all three dams: (1) a USFS SUP will be required to use the June Mountain Ski Area Parking Lot as a staging area for material and helicopter use; (2) a USFS order may be required to close the recreation trail in the construction area; (3) various permits must be issued before construction can begin (a U.S. Army Corps of Engineers Clean Water Act Section 404 permit, a State Water Board Clean Water Act Section 401 water quality certification, and a CDFW Lake & Streambed Alteration Agreement. Additionally, since some project features are in the designated Ansel Adams Wilderness Area, a Wilderness Act Variance will be required to conduct construction activities within the wilderness boundary. To obtain the wilderness variance, SCE will need to conduct a minimum requirements analysis to obtain permission from the USFS for the use of motorized equipment within the wilderness boundary. SCE would initiate the minimum requirements analysis in 2028. (This assumes that the parties have resolved the USFS's concerns about FERC's authority to relicense a project in a wilderness area.)

(3) Bishop Creek Implementation

(a) Background

SCE anticipates that the new license order will be issued in 2025 and required activities will be completed in 2025 and 2026. These activities can be divided into three main categories: (1) preparing for license issuance and reviewing the new license order for consistency with proposed measures in the license application; (2) permitting and planning activities associated with implementing new license requirements; and (3) implementation of the new license requirements. The capital forecast for Bishop Creek – Implementation is $1.458 million for 2023-2028, and total forecasted costs are $14.707 million for the expected 40-year term of the FERC license.[138]

(b) Project Scope

The implementation scope of work in 2026 through 2028 includes: (1) review of the new license order terms and conditions for consistency with the final license application; (2) planning and managing the implementation of new license requirements, including the development of tools to track compliance; (3) implementation of the Recreation Resources Management Plan, which includes the planning and design of the rehabilitation of existing project recreation facilities and development of new facilities; and (4) implementing sediment management measures to either mobilize or remove sediment from project impoundments.

(4) Kaweah – Implementation

(a) Background

SCE anticipates that the new license order will be issued in 2023 and required activities will be completed in 2024 and 2025. Kaweah activities can be divided into three main categories: (1) preparing for license issuance and reviewing the new license for consistency with proposed measures in the license application; (2) permitting and planning activities associated with implementing new license requirements; and (3) implementation of the new license requirements. The capital forecast for Kaweah – Implementation relicensing efforts is $1.230 million for 2023-2028, and

[138] WP SCE-05 Vol. 1, p. 56. Bishop Creek New License Implementation.

total forecasted costs are approximately $10.710 million for the expected 40-year term of the FERC license.[139]

(b) Project Scope

The implementation scope of work includes: (1) review of the new license order terms and conditions for consistency with the final license application; (2) implementation of eight resource management plans to monitor environmental resources potentially affected by the project operations; (3) conducting maintenance activities at a project recreation sites; (4) conducting maintenance and periodic condition assessments along project trails and roads; and (5) installation of fencing along BLM lands. SCE anticipates that the new license order will be issued in 2023 and the license-required activities will be completed in 2024 and 2025.

e) Hydro Relicensing – Decommissioning (Small Hydro Assets)

(1) Big Creek Diversions

(a) Background

As described in section II.C.3.d) above, with issuance of the new Big Creek license orders, SCE will be required to comply with the requirements of the 2007 settlement agreement. It includes a small diversions decommissioning plan requiring the removal of four small backcountry diversions and two domestic diversions. Decommissioning activities include permanently reverting the sites to their pre-Project condition to the satisfaction of the jurisdictional land management agency and to the greatest extent practicable. All six diversions are proposed for removal within five years following license issuance, assuming all permits and approvals have been obtained.

SCE has also identified five other small diversions for decommissioning. These five diversions were identified in the Flow Monitoring and Reservoir Water Level Measurement Plan as needing infrastructure modifications to provide new instream flows under the new FERC license. At the time of the filing of the final license application, the cost of modifications to other small diversions was still considered reasonable. However, because market conditions have

[139] WP SCE-05 Vol. 1, p. 58. Estimated Cost of Compliance with New License Conditions for the Kaweah Project (FERC Project No. 298)

changed, SCE has determined that making the infrastructure modification to these does not provide sufficient benefit to customers and has therefore elected to remove them.

The Hydro Relicensing – Decommissioning (Small Hydro Assets) Expenditure Forecast capital expenditure forecast for these projects is $6.401 million for 2023-2028.[140] Table II-22 below, lists the projects within the Hydro Relicensing - Decommissioning program category.

Table II-22
Hydro Relicensing – Decommissioning (Small Hydro Assets)
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Tombstone Creek Diversion	291	291	1,163	1,163	-	-	2,908
2	Crater Creek Diversion	157	-	1,413	-	-	-	1,570
3	Ross Creek Small Diversion	-	-	15	15	151	351	532
4	North Slide Creek Diversions	50	-	-	419	-	-	469
5	Lower Balsam Creek Small Diversion	-	15	15	-	-	252	282
6	Pitman Creek Domestic Diversion	25	-	-	-	210	-	235
7	Snow Slide Creek Domestic Diversion	25	-	-	-	210	-	235
8	Ely Creek Small Diversion	-	15	15	15	15	-	60
9	Vermilion - Warm Creek Diversion	-	-	25	25	-	-	50
10	Bolsillo Creek Small Diversion	-	15	15	-	-	-	30
11	Camp 62 Creek Small Diversion	-	15	15	-	-	-	30
12	**GRAND TOTAL**	**548**	**351**	**2,676**	**1,637**	**586**	**603**	**6,401**

(b) Project Scope

(i) Small Diversions Decommissioning Plan

The four backcountry small diversions include: Tombstone Creek; Crater Creek; North Slide Creek; and South Slide Creek. The two domestic water diversions are: Pitman Creek and 2 Snow Slide Creek. To meet the requirements of the decommissioning plan, these facilities would be removed, and all flows returned to the natural channel. To complete the decommissioning at each location, SCE will need to consult with the USFS regarding the extent to which SCE must remove facilities and the dispositioning of the waste materials. For the purposes of these expenditures, SCE assumed that only the aboveground components require removal, and that buried pipeline can be capped and remain in place. For each facility, applicable permits will be obtained and supporting documentation will be prepared in consultation with resource agencies.

[140] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation - Capital Projects.

Decommissioning activities of these facilities include removing all existing diversion structures (typically concrete or mortar anchored into granite bedrock channel bottoms), ancillary structures, aboveground channels or conduits/piping, and any supporting equipment or buildings that house monitoring equipment. Removal will likely include the use of explosives and hand tools to break up the diversion structure while metal components will need to be cut up and either packed out or flown out. Because the Tombstone and Crater facilities are located in a designated wilderness area, the USFS, will require submittal of a minimum requirements analysis and the likely "primitive" means that SCE will be allowed to use (which will be extremely constrained and probably prohibit the use of motorized vehicles, equipment, and aircraft).

Project disposal costs assume that concrete, masonry, and rock can be scattered in the vicinity of each Project facility and do not need to be hauled or flown offsite.

(ii) Additional Small Diversions Removal

Five small diversions were determined to have marginal or negative outcomes indicating that removal and decommissioning was the least-cost alternative. These diversions include Ross Creek, Warm Creek, Ely Creek, Balsam Creek, Bolsillo Creek, and Camp 62 Creek.

The scope for the removal is very similar in nature to the Small Diversion Decommissioning described above, but these facilities are generally a bit larger. In addition to removing the dam structures as above, these locations may also include removal of electrical components, gaging stations, access stairways, or walkways, as well as installation of an underground tunnel plug (at Ross Creek, Bolsillo Creek, Camp 62 Creek, and Warm Creek) or blind flange installation (Balsam Creek) where they currently connect to more significant Hydro conveyance structures. As with the four small diversions and two domestic diversions, all appropriate permits and agency approvals would also be obtained in advance. In addition, SCE will file an application to remove the facilities from the FERC license.

(c) Project Justification and Benefit

Compliance with new license conditions and the settlement agreement is non-discretionary. During the original relicensing process, SCE determined that the four small diversions and domestic diversions were unprofitable and of very limited usefulness because their contributing flows for generation are very small and they are generally inoperable without significant capital improvements.

For the five other small diversions that are being decommissioned, SCE conducted an economic analysis comparing the costs of conducting infrastructure modifications (including long-term operations and maintenance costs) to the costs of full removal. The analysis indicated that implementing the infrastructure modifications to comply with new license requirements and operating them over the new license term would not benefit customers and therefore that decommissioning is the least-cost alternative.

f) Hydro Relicensing – Road/Bridge Rehabilitation Expenditure Forecast

(1) Background

Under the new FERC license orders and the settlement agreement, SCE is required to conduct certain road rehabilitation and bridge repair projects on USFS roads in the vicinity of the Big Creek System to offset the potential impact of SCE's use of these roads. Within the first year of the new license term, SCE must survey road and bridge conditions in coordination with the USFS to validate the current need for the projects identified in the settlement agreement.

The Hydro Relicensing – Road/Bridge Rehabilitation Expenditure Forecast capital expenditure forecast for these projects is $3.931 million for 2023-2028.[141] Table II-23 below lists the projects within the Hydro Relicensing - Road/Bridge Rehabilitation Expenditure Forecast category.

[141] WP SCE-05 Vol. 1, p. 55. Big Creek New License Program Implementation - Capital Projects.

Table II-23
Hydro Relicensing – Road/Bridge Rehabilitation
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek - Bridge Refurb - Mono Bridge	-	-	-	-	117	1,049	1,166
2	Big Creek - Road Rehab: Kaiser Pass Road	-	-	-	30	535	-	565
3	Big Creek - Road Rehab: Florence Lake Roads	-	-	-	-	46	411	457
4	Big Creek - Bridge Refurb - Florence Lake Spillway/Edison Pipeline/Bosillo	-	-	43	387	-	-	430
5	Big Creek - Road Rehab: Mammoth Roads	-	-	36	326	-	-	362
6	Big Creek - Road Rehab: Eastwood Lane Refurbishment	-	-	35	311	-	-	346
7	Big Creek - Road Rehab: SJ&E Railroad Grade Rd	-	-	-	-	33	294	327
8	Big Creek - Bridge Refurb - Crater/Chinquapin Bridges	-	14	126	-	-	-	140
9	Big Creek - Bridge Refurb - High Rock Bridge	-	-	-	-	-	119	119
10	Big Creek - Road Rehab: Hooper Div Roads	-	-	-	-	-	20	20
11	**GRAND TOTAL**	**-**	**14**	**240**	**1,054**	**730**	**1,894**	**3,931**

(2) Project Scope

Following the condition surveys in the first license year, the scope for these repairs will be validated and further refined. The roads and bridges identified in this section are slated for some form of rehabilitation work and the cost estimates presented assume the least-cost option as described further below.

Road rehabilitation work may include any of the following activities: placing gravel/rock on unpaved road surfaces where surface erosion is causing damage; repairing erosion damage to road surfaces; repairing or replacing failed road shoulders; replacement of corrugated metal pipe culverts that are impaired, nonfunctional, or significantly undersized; the potential addition a concrete wet crossing or other stream crossings; and the installation of guardrails or object markers as needed.

The bridge rehabilitation scope includes the following bridges identified during relicensing (and grouped based on geography and/or cost complexity): o Hot Springs Bridge, 2) Florence Lake Spillway, Edison Pipeline, and Bolsillo Bridges; Crater Creek and Chinquapin Creek Bridges, and High Rock Bridge. The scope for each of bridge location is summarized below:

- Crater Creek Bridge – replacement
- Chinquapin Creek Bridge – evaluation and potential replacement

- Mono Hot Springs Bridge – at a minimum, repainting; possible upgrade/replacement if reinforcement is needed
- Bolsillo Bridge – evaluation and potential reinforcement
- Florence Spillway Bridge – minor rehabilitation and maintenance based on outcome of conditions survey
- Edison Pipeline Bridge – minor rehabilitation and maintenance based on outcome of conditions survey
- High Rock Bridge - minor rehabilitation and maintenance based on outcome of conditions survey

(3) Project Justification and Benefit

Compliance with the new license and the settlement agreement requirements is non-discretionary. SCE will continue to seek the lowest-cost outcome for these projects to meet compliance obligations and USFS road standards. Because a road condition assessment had not been completed in over a decade since the settlement agreement, SCE performed an initial construction feasibility and alternatives assessment to support the cost estimates provided for these projects. SCE, the USFS, and members of the public who visit the Big Creek System will all benefit from the road and bridge improvements to provide safer access to project facilities and dispersed recreational opportunities.

4. Hydro – Decommissioning

Two SCE Hydro projects (Borel and San Gorgonio) are currently in active FERC license surrender proceedings that will lead to the decommissioning (removal) of the Hydro facilities. Separately, at Rush Creek, SCE expects to begin decommissioning the Agnew and Rush Meadows Dams in this GRC cycle. These projects are discussed in further detail below.

The Hydro – Decommissioning capital expenditure forecast during this GRC cycle, 2023-2028, for these projects is $111.100 million (nominal, work order level).[142] Table II-24 below lists the projects within the Hydro - Decommissioning program category.

Table II-24
Hydro Relicensing – Decommissioning
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project Category	2023	2024	2025	2026	2027	2028	TOTAL
1	Decommissioning - Borel Hydro Project	850	-	-	20,000	26,500	20,000	67,350
2	Decommissioning - San Gorgonio Hydro Project	23,500	15,500	2,200	-	-	-	41,200
3	Decommissioning - Rush Creek (Agnew and Rush Meadow Dams)	-	-	-	250	1,250	1,050	2,550
4	**GRAND TOTAL**	**24,350**	**15,500**	**2,200**	**20,250**	**27,750**	**21,050**	**111,100**

The following testimony outlines the Hydro decommissioning activities forecasted to occur during this GRC cycle.

a) Decommissioning - Borel Hydro Project

(1) Background

The 12MW Borel Hydroelectric Powerhouse, located downstream from the Lake Isabella Dam and Reservoir, was originally placed into service in 1904. In 1950, the U.S. Army Corps of Engineers ("Corps") built the Lake Isabella Dam and Reservoir for flood protection. The lake regularly inundates the Borel diversion and the uppermost 4.2 miles of the Borel Canal, rendering them inoperable. At that time, SCE altered the Borel canal to allow water to pass into the lower seven miles of the canal to the Borel Powerhouse.

In mid-2013, a Corps study revealed that a recently discovered seismic fault posed a potentially high-hazard risk to Lake Isabella Dam. SCE took the Borel Powerhouse offline because the water levels required to feed the canal dropped below the intake structure. Lower water levels remained until 2017, when the Corps implemented a safety modification project to its Lake Isabella Auxiliary Dam intended to address the seismic risk. This modification included the condemnation of the easement that had allow SCE to occupy 10.7 acres of private and public land

[142] WP SCE-05 Vol. 1, pp. 59-106. Hydro Capital Expenditures - Decommissioning.

associated with the project, after which the Corps sealed the existing section of conduit through the Auxiliary Dam by filling it with concrete.

The Borel Project's FERC license requires SCE to retain all rights needed to maintain and operate the Project. After the Corps condemned the easement allowing SCE to use the lands occupied by the Borel Canal, and because the project is no longer operational, FERC notified SCE on March 11, 2019 that it must file an application to surrender the project license. On December 16, 2020, SCE filed a plan and schedule to prepare and file (by January 31, 2023) a license surrender application ("LSA") to address the disposition (*i.e.,* removal, modification, or abandonment-in-place) of all licensed Project facilities. On August 25, 2022, SCE filed with FERC a request for an extension of time to file the LSA by May 1, 2023, which was approved by FERC on August 30, 2022.

On December 14, 2023, SCE distributed to stakeholders a draft LSA for a 50-day review and written comment period. The draft LSA included: (1) a proposed decommissioning plan; (2) an environmental assessment of SCE's proposed decommissioning activities and license surrender; and (3) documentation of SCE's consultation with agencies, landowners, and other stakeholders during preparation of the surrender application. The decommissioning plan described SCE's: proposed disposition (*i.e.,* removal, modification, or abandonment-in-place) of all Project facilities, the manner in which Project lands would be restored and their final configuration; proposed monitoring during decommissioning and post-decommissioning to assess the effectiveness of SCE's the restoration work; proposed measures to mitigate the identified decommissioning plan's impacts; and a plan for the final disposition of all Project lands, which will be implemented after the decommissioning is accomplished to the satisfaction of the Commission. The decommission plan included the proposed disposition of all land ownership, easements, and rights-of-way associated with Project roads and facilities, including the transfer of ownership, maintenance, and operation of any Project facilities that are to be left in place, and lands on which historically or culturally significant properties occur. SCE will prepare a final LSA that will include and address all comments received on the draft LSA.

Since the Borel project works are constructed on federal land, SCE is required to restore the lands to a condition satisfactory to the department having jurisdiction over such lands.

The capital forecast for Decommissioning - Borel Hydro Project effort is $67.350 million for 2023-2028.[143]

(2) Project Scope

SCE will file a LSA for the Borel Project License before May 1, 2023 in accordance with FERC regulations. As required by FERC, SCE reviewed Borel Project License articles that address environmental issues and consulted with the appropriate resource agencies to inform the preparation and filing of the LSA. SCE's consultation activities included conducting public meetings, a virtual town hall, and private meetings with stakeholders, including private landowners, Native American Tribes, and federal, state, and local agencies.

Because the Borel project works were constructed on federal land, SCE will restore the lands to a condition satisfactory to the Department having supervision over such lands; annual charges will continue until such restoration has been satisfactorily completed and the surrender becomes effective.

Once FERC determines that the Final LSA is complete and ready for environmental review, FERC will announce a minimum 30-day public comment period. FERC staff will address comments and will complete the environmental analysis required by the National Environmental Protection Act (NEPA). Upon completion of the NEPA process, FERC will issue a License Surrender Order that approves the decommissioning plan and provides authorization for SCE to start the decommissioning activities. SCE will then move forward and implement the decommission plan to remove project facilities and restore Project lands. The decommission activities will include the following key areas of focus: project management, agency coordination, environmental studies and permitting, additional studies and surveys, utility coordination, civil design, and construction services.

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143 WP SCE-05 Vol. 1, pp. 60-62. Borel Decommissioning.

The final Surrender of the FERC project License will not occur until SCE completes the decommissioning of project facilities and restoration of project lands to the satisfaction of the Commission and other federal land jurisdictional agencies.

(3) Project Justification and Benefit

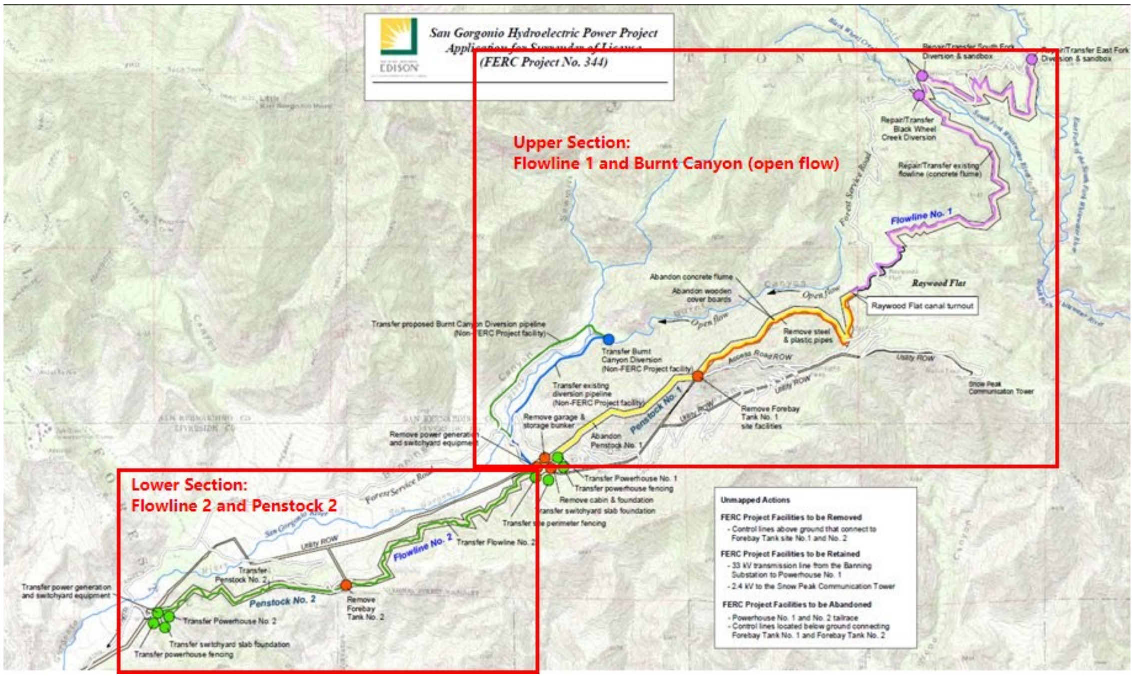
The Borel Project FERC license requires SCE to retain all rights needed to maintain and operate the Project. Because the Corps, through implementation of safety modification to its Lake Isabella Auxiliary Dam, has acquired the rights to lands occupied by the Borel Canal, and because the project is no longer operational, FERC directed SCE in 2019 to file a license surrender application. In accordance with 18 C.F.R. § 6.1, SCE's surrender application must address the disposition of all project facilities (i.e., removal, modification, or abandonment in place).

Since the project was rendered non-operational by the Corps' condemnation, there is no benefit to continue to maintain and operate Project works and decommissioning is the required regulatory path forward.

b) Decommissioning - San Gorgonio Hydro Project

The San Gorgonio No. 1 ("SG1") and San Gorgonio No. 2 ("SG2") powerhouses were constructed in 1923 with respective capacities of 1.5 MW and 0.94 MW. At that time, generation was added to an already existing water system which diverted water per existing pre-1914 consumptive water rights from the Whitewater River, which flows to the Morongo Valley. The diverted water is delivered into the adjacent San Gorgonio River watershed and used by the water rights holders. As shown in Figure II-7 below, the San Gorgonio water conveyance system can be described as having an upper and lower section.

Figure II-7
San Gorgonio Hydroelectric Power Project



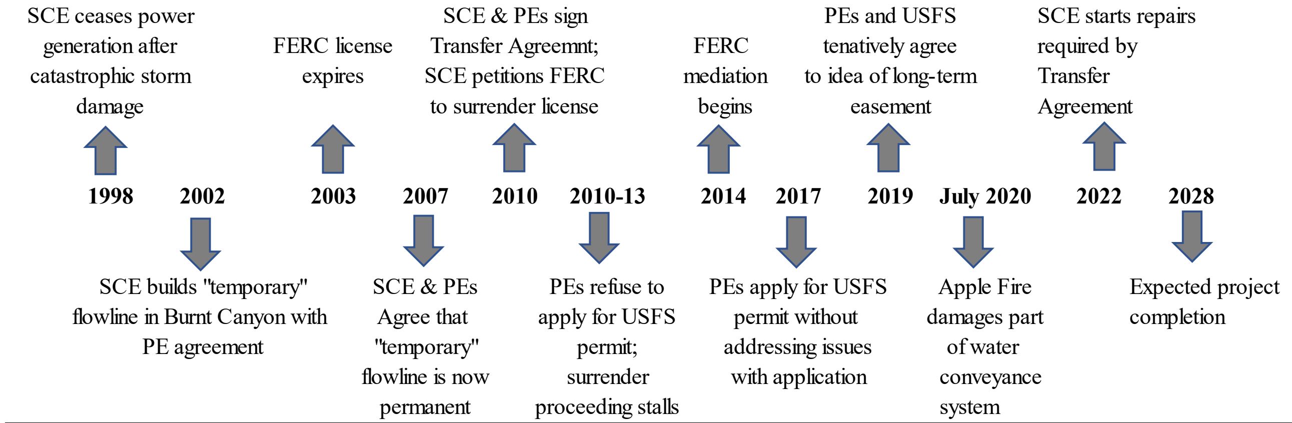
SG1 is located upstream from SG2, and flow from SG1 will feed SG2 from a flowline. The two associated flowlines (Nos. 1 & 2) travel through steep terrain, some of which is unstable. This area frequently required rebuilding. Due to the low flow available for generation, SG1 and SG2 were designed with water storage tanks, which would fill up with water diverted for power generation. When the tanks were full, the turbines would operate until the tanks were empty. In fall 1998, a level controller on the SG1 tank malfunctioned and overflowed the tank. The water running down the side washed out the base of the tank, causing it to collapse. Shortly after the tank failure, additional damage was incurred along an unstable portion of the flowline resulting in the inability to generate any electricity. Repairs were deemed too risky and the possibility for future failure was imminent.

In 2001, SCE decided not to pursue the relicensing of the San Gorgonio Project when the Notice of Intent was due for the 2003 expiration of the FERC license.[144] This was due to the high costs of maintaining and relicensing a low-capacity factor, small facility that needed major work and would likely lose a significant portion of its generation in the process of relicensing. For these reasons, in 2003, SCE announced plans to surrender its FERC license and initiated the FERC license surrender process to decommission the San Gorgonio project. The surrender process was complicated and contingent upon SCE repairing the existing water conveyance system and USFS authorization for the water system to be maintained following FERC license termination. At issue was the contractual requirement that SCE repair, maintain, and ultimately transfer the entire water conveyance system to three parties collectively known as the "Participating Entities" or "PEs" (Banning Heights Mutual Water Co., the City of Banning, and the San Gorgonio Pass Water Agency).

Shortly after announcing plans to surrender the FERC license, SCE repaired the water conveyance system and restored water flow to the PEs. As shown in Figure II-8 below, it was not until four years later, in 2007, that SCE and the PEs were able to agree that the repairs to the water conveyance system were adequate and could be considered permanent.

[144] SCE had been attempting to surrender its FERC license since 2003; however, a variety of legal, regulatory, and environmental issues impeded this effort.

Figure II-8
San Gorgonio FERC License Surrender and Transfer Process



Due to contractual obligations, FERC license responsibilities, and proposed USFS requirements, in 2010 SCE began the necessary preparation required to perform additional construction work and repairs on the San Gorgonio facilities as a condition of the regulatory process to transfer the remaining water conveyance system to the PEs following license surrender.

In addition to repairs to the water conveyance system, the regulatory process requires the removal of certain ancillary water storage and/or generation facilities, which is an extremely complex process involving the PEs' water rights and USFS environmental requirements). The facilities are located on USFS land, and many sections (such as diversion structures and flowlines) existed before the powerhouse was built.

SCE has longstanding contractual agreements with the Participating Entities to: 1) continue performance of repairs and maintenance of the water conveyance infrastructure until the USFS issues a special-use permit or easement to the Participating Entities allowing FERC to approve the license surrender; and 2) transfer the repaired infrastructure to the PEs following license surrender. As shown in Figure II-8, the FERC license surrender, and transfer process has been protracted and adversarial.

As noted in the timeline above, on June 30, 2010, SCE entered into a Transfer Agreement with the PEs, for the repair and transfer of the conveyance system.[145] The conditions of the transfer agreement were agreed upon by all parties for the disposition of the water conveyance system to be transferred as part of the overall FERC surrender/transfer process. The agreement includes a collaborative process known as the Joint Design & Review Team ("JDRT") with a single representative from each party, including SCE, participating in the design review for approval associated with repairs and decommissioning activities. Under the current FERC license, SCE personnel must maintain safe access to the water conveyance system and keep it in good working order. Once the parties entered into the Transfer Agreement, SCE became contractually obligated to perform a variety of additional repairs to the water conveyance system before transferring ownership to the Participating Entities after license surrender.

Shortly after signing the Transfer Agreement, the PEs' application for a USFS permit was deemed deficient, stalling the surrender proceedings for the next three years. Major issues included verification of existing right-of-way authority, the USFS's recommended environmental flow requirements, and the PEs' demands for increased water delivery to account for their calculated water loss due to surface diversion and seepage from the re-routing of the existing water conveyance system through Burnt Canyon. The Burnt Canyon Diversion and Flowline bypass (non-FERC facility) was built in 2002 to provide a new conveyance path for a failed flowline caused by major storm damage in 1998. A portion of the flowline was considered temporary and future permanent improvements are necessary for fulfillment of the license transfer and for the water conveyance system to be deemed complete.

Despite SCE's efforts, which were recognized by the Commission,[146] minimal progress was made until 2014, when FERC referred the matter to its Dispute Resolution Service ("DRS") to act as mediator, based on the lack of progress and slow pace of negotiations between USFS and the PEs. The mediation process continued for the next five years and in October 2019, U.S.

[145] WP SCE-05 Vol. 1, pp. 63-96. 2010 SCE and PEs Transfer Agreement.

[146] D.21-08-036, p. 610, Finding of Fact 434. "The failure to start full-scale decommissioning of San Gorgonio is due to events beyond SCE's control."

Representative Raul Ruiz attended the FERC DRS meeting while members of his staff toured the San Gorgonio site. Also, in 2019, SCE conducted environmental studies, which were used by the USFS to recommend a reduction of contested environmental flow requirements. Using this recommendation, in early 2021, the USFS and the PEs negotiated a long-term easement for the continued operation of the water conveyance system contingent upon SCE's completion of repairs to the facilities and license surrender[147]

On July 31, 2020, burning vehicle exhaust started a fire along the east side of Yucaipa in San Bernardino County.[148] The fire, which was named the Apple Fire, quickly spread to Riverside County and burned a total of 33,424 acres before reaching full containment on November 16, 2020. Figure II-9 shows the burn area.

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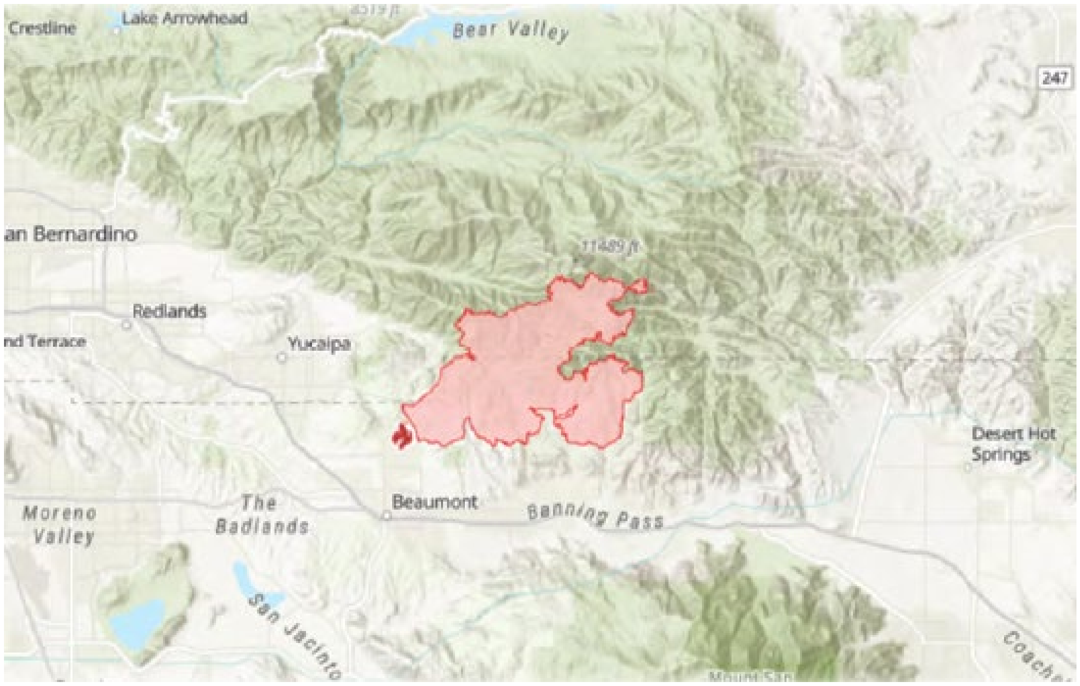
[147] WP SCE-05 Vol. 1, pp. 97-102. San Gorgonio – 2021 USFS and PEs Easement Agreement.

[148] Richard K. Deatley, *Apple Fire Caused by Diesel Vehicle's Exhaust System, Investigators Say*, (Aug. 3, 2020) (*available at* https://www.dailybulletin.com/2020/08/03/apple-fire-at-26450-acres-relief-crews-for-weary-firefighters-arriving/).

Figure II-9
2020 Apple Fire



On August 2, 2020, the Federal Emergency Management Agency ("FEMA") declared a disaster in Riverside and San Bernardino Counties because of the Apple Fire. Damage from the Apple Fire rendered the existing San Gorgonio water system inoperable and, as mentioned above, SCE has both a contractual obligation to restore water flow to the PEs and a regulatory obligation to restore the water system prior to receiving FERC approval for license surrender and site decommissioning. This meant that SCE was now obligated to repair sections of the water conveyance system damaged by the fire.

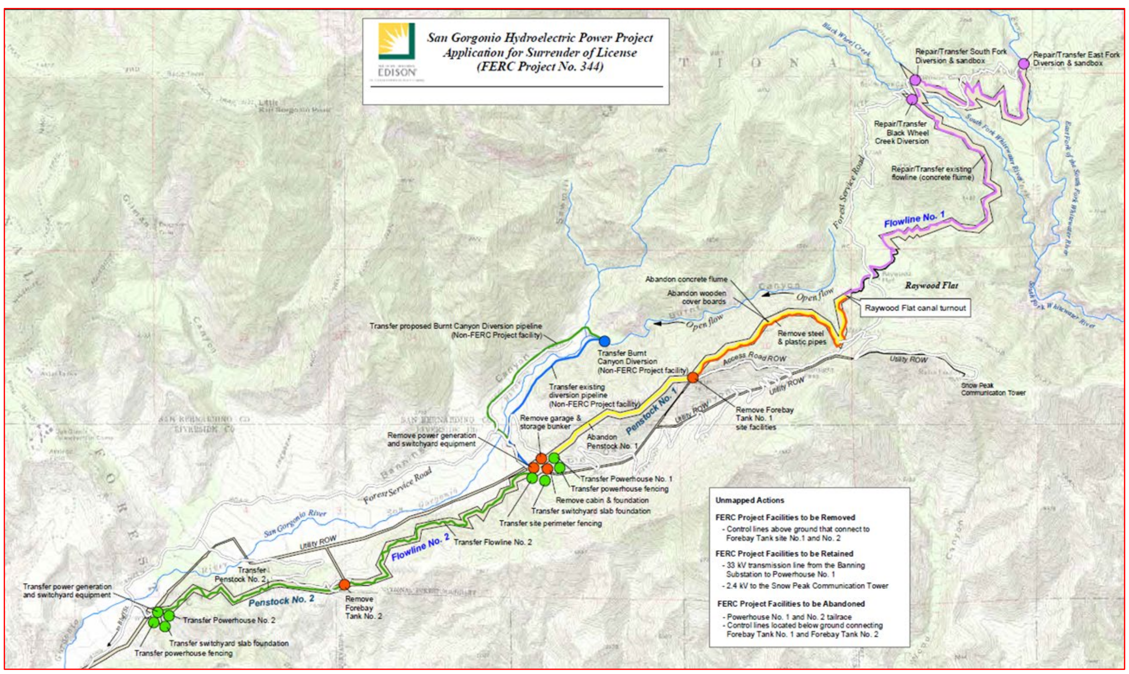
In April 2021, SCE engaged in discussions with the PEs regarding alternatives to SCE's contractual obligation of repairing the water conveyance system. The PEs expressed they were not interested in deviating from the contractual agreement between the parties. SCE explored the option of finding an alternative water source for the PEs but found this to be more expensive than repairing the existing conveyance with no guarantee of future water availability, leaving only one remaining solution:

repairing the existing water conveyance system, described below, which SCE has since been actively performing.

(1) Background

After the post-Apple Fire damage assessments were complete, SCE began construction on a portion of Flowline No. 1 (from the South Fork diversion to the Raywood Flat area) to restore water flow into the San Gorgonio watershed. This repair work was necessary to provide water to the downstream water users in the local communities. Figure II-10 below identifies the location of Flowline No. 1 and the repair work performed in 2022.

Figure II-10
San Gorgonio Hydroelectric Project
Flowline 1 (Phase 1) Reconstruction (South Fork to Raywood)



Repairs to Flowline No. 1, performed in 2022, consisted of the replacement of the South Fork Diversion sandbox, reconfiguration of the Black Wheel Creek Diversion and suspended pipe and the installation of two 18” HDPE pipes within the footprint of the existing concrete flume within the flowline’s lower section. The South Fork Sandbox was rebuilt due to damage caused by the 2020 Apple Fire. The new sandbox is 10 feet by 11 feet in size and connects to two 18-inch HDPE pipes that will carry water from to lower Flowline No. 1. The new sandbox has a 14-inch sluice pipe. The Black Wheel Creek Diversion is a FERC Project facility located on Black Wheel Creek, approximately 1,200 feet downstream of the South Fork Sandbox at an approximate elevation of 7,120 feet MSL. The diversion intake consists of a 26-inch-deep by 16-inch-wide concrete flowline topped by a 30-inch-high by 36-inch-wide concrete wall and discharges into Flowline No. 1 through a steel pipe that is suspended above Black Wheel Creek. SCE replaced that steel pipe because of damage from the Apple Fire. SCE rebuilt the Black Wheel Diversion (which is approximately the same size as the original and occupies the same location). Lower Flowline No. 1 is a FERC Project facility that extends from the combined junction box at the South Fork Diversion to the Forebay Tank No. 1 site. It is 21,902 feet long and consists primarily of a concrete flume covered with wood planks. It is 24 inches deep and varies in width between 18 and 30 inches. As stated above, the water conveyed by this flowline is vital to residents of an area known as the Banning Bench as well as the City of Banning.[149]

Repairing this section enabled water to again be conveyed from the South Fork of the Whitewater River into Burnt Canyon and subsequently into the City of Banning's recharge basins in the lower canyon within the San Gorgonio River watershed. The Banning Heights Mutual Water Company has an agreement with the City of Banning to purchase water from the city's system. This arrangement puts a strain on the city's limited water supply.

In 2022, SCE also repaired the usable portion of the lower Flowline No. 1 (phase 1) by installing two 18-inch HDPE pipes along the existing alignment. Prior to laying the HDPE pipe, the flowline alignment was leveled, and the existing flowline excavated and cleaned to accept one of the 18-inch HDPE pipes. An approximate 24-inch by 24-inch trench was excavated on either the upslope or downslope side of the existing flowline (depending on slope integrity and available space) for the installation of the second HDPE pipe. Repairs to some sections of lower Flowline No. 1 (phase 1) required stabilization of the adjacent hillside either upslope and/or downslope of the flowline depending

[149] The Banning Bench community receives water from the Banning Height Mutual Water Company.

on existing conditions. There are multiple locations where slope stabilization was necessary to protect the alignment of the two new pipes and this was achieved primarily by the installation of gabion-type retaining walls.

Additional repairs are needed to the upper portion of Flowline No. 1, referred to as Flowline No. 1 (Phase 2, and the entirety of Flowline No. 2, which would then deliver all the water into a large tank (owned by the PEs) just below the SG2 Powerhouse.

The capital cost for the Decommissioning – San Gorgonio Hydro Project effort is $41.200 million for 2023-2028, and total forecasted costs are $86.900 million.[150], [151] Figure II-11 below presents the spend timeline and future milestones necessary for project completion. As shown therein, SCE is currently projecting that construction of the two flowlines, decommissioning of the remaining generation assets, and implementation of a solution to prevent or address water losses will be finalized by the end of 2028.

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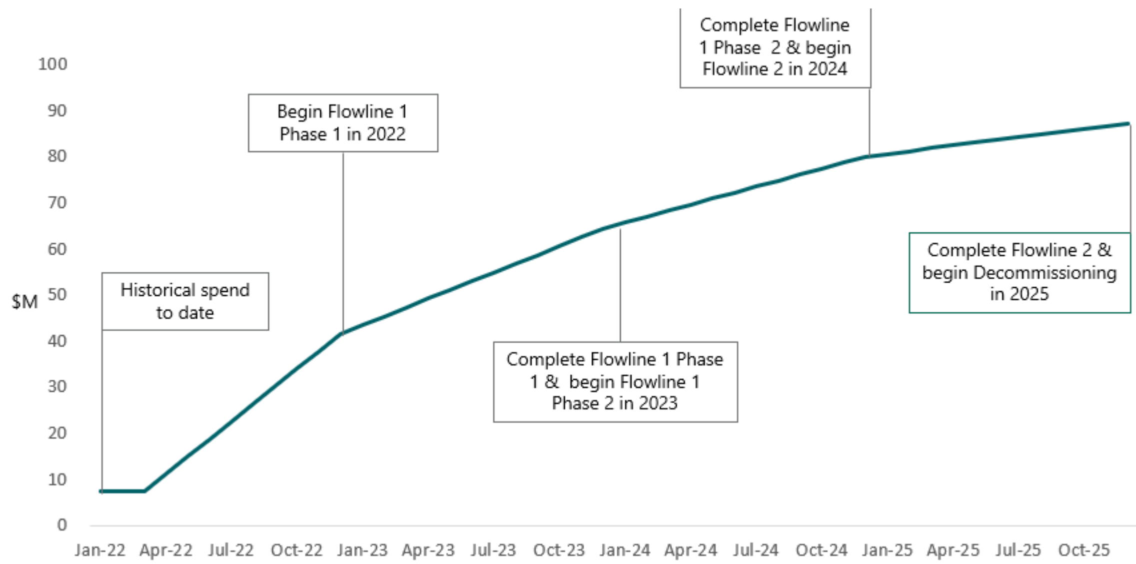
[150] The 2023-2028 project costs do not reflect a $5.0 million insurance reimbursement SCE expects to receive. SCE has accordingly adjusted its RO model in the 2025TY to incorporate the expected $5.0 million insurance reimbursement.

[151] WP SCE-05 Vol. 1, pp. 103-104. San Gorgonio Decommissioning.

Figure II-11
Decommissioning - San Gorgonio Hydro Project Milestones



Based on Project Milestone Phases (Option 1d Repair Flowline 1, Replace Flowline 2 with Pipe in Forest Service Road & Install Groundwater wells)
2022 = Reconstruct Flowline 1 Phase 1 to restore water supply
2023 = Finish Flowline 1 Phase 1 and begin reconstruction of Flowline 1 Phase 2
2024 = Finish Flowline 1 Phase 2 and begin reconstruction of Flowline 2
2025 = Finish flowline 2, Decommission Generation Assets, and Install Groundwater Wells

(2) Project Scope

Pursuant to regulatory requirements and contractual obligations, SCE must deliver water through its facilities to the downstream water users (Banning Heights Mutual Water Company and the City of Banning). Therefore, SCE must repair the facilities to an operable condition before the PEs will assume ownership. As explained above, some improvements to Flowline No. 1 (phase 1) already complete. Additional repairs to Flowline No. 1 (phase 2), Flowline No. 2, and removal of non-water conveyance facilities are necessary for SCE to meet its regulatory and contractional agreements. The following work must be done prior to the transfer of the facilities to the PEs:

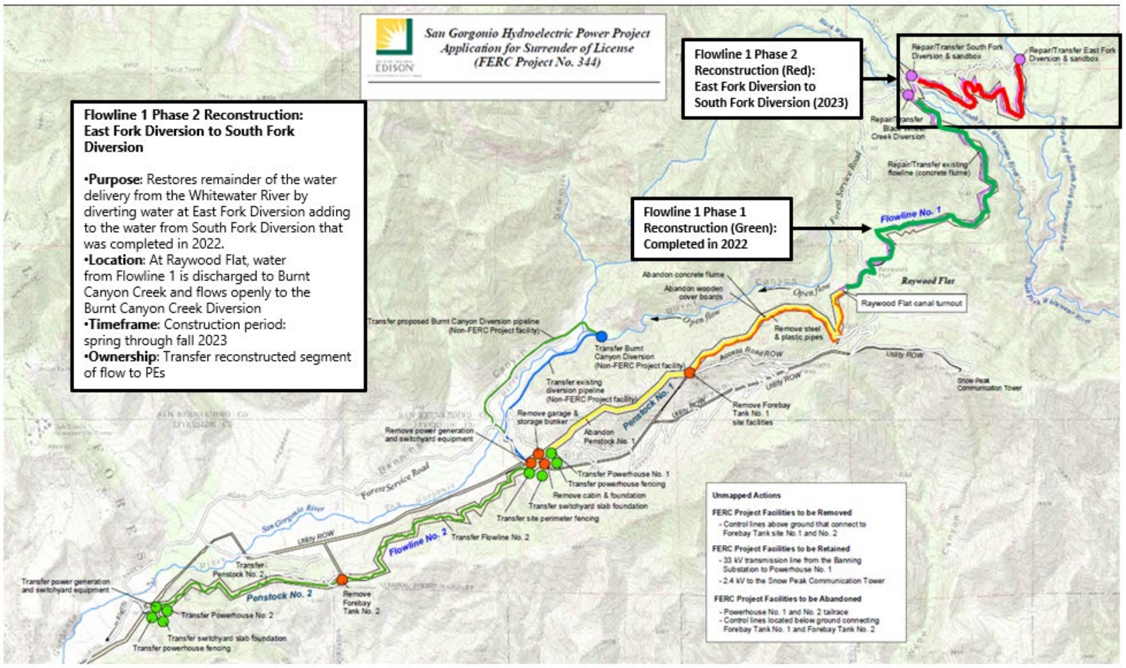
- Refurbish Flowline No. 1 (phase 2) from the East Fork Diversion to South Fork Diversion (2023);
- Refurbish the South Fork Diversion & East Fork Diversion (2023/24);
- Refurbish Flowline No. 2 (2024/25);

- Remove all generation equipment, Powerhouse Nos. 1 & 2, the No. 2 water tank, and some sections of flowline, as directed by the USFS (2025); and
- Remove flowline trestles in Raywood Flat (2025).

The planned 2023 refurbishment of Flowline No. 1 (phase 2) will be similar in scope to the work performed in 2022 to refurbish Flowline No. 1 (phase 1). SCE proposes to repair the 7,793-foot flowline with HDPE flexible pipe. The inside of the existing flowline would be cleared to make way for the placement of the new pipe. After placement, the pipe will be covered with native soil, which will then be compacted. The individual sections of the HDPE flexible pipe will be connected in the field. The method of connection, (*e.g.,* fusion weld or chemical weld) will be determined in the field and based on the location and conditions. The anticipated work area width required to complete this effort is approximately 10 feet along the extent of the flowline, for a disturbance area of approximately 77,930 square feet (1.8 acres).

Repairs to some sections of upper Flowline No. 1 (phase 2) would require stabilization of the adjacent hillside (upslope and/or downslope of the flowline in different locations depending on existing conditions). The methods to strengthen and bolster the adjacent hillside are under development. The location of Flowline 1 reconstruction, Phases 1 and 2, is shown in Figure II-12 below.

Figure II-12
San Gorgonio Hydroelectric Power Project
Flowline 1 (Phase 2) Reconstruction (East Fork to South Fork)



The planned 2023/24 refurbishment of the South Fork and East Fork two Diversions will require repairs to the concrete structures to ensure they meet engineering standards. The East Fork Diversion is a rock/masonry structure with a crest length of 47 feet and a height of 14 feet above the streambed, at approximately 7,180 feet MSL. The downstream face has a slope of 45 degrees. The East Fork Diversion outlet works consist of a 4-foot by 12-foot concrete intake structure (covered by metal grating located on the downstream face of the diversion structure near the crest) connected to a 24-inch-by-26-inch concrete pipe behind the upstream side of the diversion structure, a valve box into which the intake structure empties, a 24-inch-diameter manually-operated slide gate, a 4.5-foot-by-4-foot concrete flume covered with wooden boards, and a 30-foot-by-12-foot concrete sandbox. SCE proposes to repair and restore the East Fork Diversion structure and sandbox by repairing the undercut portion of its toe (currently exposed) and by repairing the concrete in the sandbox as needed. The South Fork Diversion is a rock/concrete structure with a crest length of 18 feet and a height of approximately 6 feet above the streambed. The diversion is equipped with a steel trash rack and manually operated gates to control the rate of diversion from the stream. The diversion outlet works include a 24-inch-diameter slide gate. The diversion extends to the concrete flume, which proceeds to a 10-foot-by-10-foot concrete sandbox where the water commingles with the water from the East Fork Diversion and continues back into Flowline No. 1. For water overflow control at the South Fork Diversion, SCE will install flap gates (or something similar) to allow excess water to empty into the stream bed without overtopping the diversion. SCE will also make necessary concrete repairs to the diversion on the downstream side to insure stability.

Flowline No. 2 begins at the Burnt Canyon Diversion; currently, water bypasses the tailrace of Powerhouse No. 2 and flows through Forebay Tank No. 2 through Penstock No. 2 to Powerhouse No. 2, and then from Powerhouse No. 2 into Banning Heights Mutual Water Company's tank. In 2025, SCE will install a flexible HDPE pipe from the Burnt Canyon Diversion to the top of Penstock No. 2. Alternative routes may be analyzed to determine if a more suitable alignment should be implemented.

In 2027, SCE estimates that all structures and equipment at Powerhouse Nos. 1 & 2 will be removed and the sites restored to a natural state. Powerhouse No. 1 is situated on approximately 4 acres of land and consists of a 32-foot-by-22-foot steel-reinforced concrete structure that houses a single generator and a single horizontal-shaft impulse turbine. SCE will remove the hydroelectric generators, equipment, and other pieces of hardware, including the switchyard equipment, from the Powerhouse No. 1 building site. The power generating equipment will be moved out of the building through the existing large doors. The transformer oil was previously removed by SCE. Once the equipment is removed, the following other structures/facilities will be demolished and removed: the Powerhouse, switchyard and associated concrete slab, cabin, garage, storage building, and fencing. Powerhouse No. 2 is situated on approximately 3.4 acres of land and consists of a 32-foot-by-22-foot steel-reinforced concrete structure that houses a single generator and a horizontal-shaft impulse turbine. The powerhouse is accompanied by an adjacent switchyard, which sits on a 25-foot-by-36-foot concrete slab and contains three step-up transformers. The switchyard also contains dead-end racks and an instrumentation transformer. The tailrace at Powerhouse No. 2 is approximately 180 feet long, with two 12-inch diameter metal pipes that lead to the San Gorgonio River. There is a second pipe that leads from the powerhouse tailrace to the Banning Heights Mutual Water Company water tank. This second pipe is not a FERC Project facility and will remain in place. SCE proposes to remove the hydroelectric generators and associated equipment (including the switchyard equipment) from the Powerhouse No. 2 site. The electrical power generating equipment and switchyard equipment would be removed using the same methods and equipment as described for Powerhouse No. 1. After that SCE would demolish and remove Powerhouse No. 2, the switchyard and associated concrete slab foundation, and fencing.

The SG2 water tank is located at an approximate elevation of 5,170 feet MSL. It has a 320,000-gallon capacity. Currently, the tank is unusable due to its degraded condition and will be removed. SCE proposes to dismantle and remove it tank and re-contour the tank site to match the adjacent natural land. SCE would access the site by the existing roadway. Forebay Tank No. 2 would be dismantled on site using hand crews, hand tools, a small bulldozer, a flat-bed truck, a small boom crane, and a helicopter. Additionally, there is debris in the bottom of Burnt Canyon from the previously failed flowline that will be removed. This includes a large trestle structure and several sections of large PVC pipe. This will require helicopter support for removal.

(3) Project Justification and Benefit

Decommissioning the San Gorgonio project will eliminate future costs to SCE's customers for flowline maintenance and repair, which was agreed to in the historical water contracts that allowed for the use of the water to generate electricity.

c) Decommissioning – Rush Creek (Agnew and Rush Meadows Dams)

(1) Background

SCE anticipates that the new license for the Rush Creek Project will require SCE to retrofit Gem Dam and to remove (decommission) Rush Meadows Dam and Agnew Dam partially or fully. This work would enable SCE to comply with seismic water level restrictions that were imposed on the three project dams after the discovery of the nearby Silver Lake Fault identified a potential dam safety issue when the reservoirs are full and there is a large seismic loading event (earthquake). Therefore, in the relicensing process, SCE proposed to retrofit Gem Dam with a new spillway and reduced dam height, which would render the current seismic restricted level the new normal pool reservoir level. Additionally, during relicensing SCE proposed to discontinue hydroelectric operations at Rush Meadows and Agnew Dams by partially or fully removing them (both physically and from the FERC license). Under either the full and partial dam removal alternatives for Rush Meadows and Agnew Dams, no water would be impounded at any time after the dam removal.

The plan to retrofit Gem Lake Dam and decommission Rush Meadows and Agnew Dams was developed at a conceptual engineering level of design to support the creation of the project description that would be evaluated during relicensing. However, during the proceeding, other alternatives for Project retrofitting or decommissioning could be identified and may require further analysis in the Application for New License.

The conceptual engineering also included an implementation timeline that extended through 2038 to complete the retrofitting of Gem Lake Dam and decommissioning of Rush Meadows and Agnew Dams. The implementation generally outlines the following activities and projected completion dates:

- Relicensing (including the development of the license application; FERC's completion of the NEPA process, and issuance of a new license by 2027
- Permitting, review, and approval of the final engineering package for the three dams between 2026 and 2029
- Construction activities (retrofitting and partial or full removal) for the three dams staggered between 2029 and 2035; and
- Post-construction monitoring of environmental resources continues through 2038.

The capital forecast for Rush Creek – Decommissioning (removal of Agnew and Rush Meadows Dams) is $2.550 million for 2023-2028, and total forecasted costs range between $48 million and $101 million depending on whether Rush Meadows and Agnew Dams are partially or fully removed.[152]

(2) Project Scope

The project implementation scope of work begins in 2026 (in anticipation of issuance of a new license order) and includes completing final engineering design and regulatory permitting processes before construction can begin.

Final engineering design of the approach filed with FERC in the Final License Application must be completed to ensure that the dam retrofits will meet seismic restrictions, address hydrologic/hydraulic issues, and address future Project use and operation and maintenance issues. SCE must also describe its construction approach. The final engineering design for Agnew Dam will be completed in 2026-2027, concurrent with the final design for the Gem Dam retrofit that will be completed in 2026-2028.

SCE will also need to obtain the required regulatory permits and approvals starting in 2026 so that construction activities can begin in 2029. SCE expects to apply for the following permits and authorizations for all three dams: (1) a USFS special use permit (SUP) will be required to use the June Mountain Ski Area Parking Lot as a staging area for material and helicopter use; (2) possibly, an order from the USFS closing the recreation trail in the construction area; (3) a Clean Water Act Section 404 permit from the Corps, a Clean Water Act Section 401 water quality certification from the State Water Board, and a Lake/Streambed Alteration Agreement from CDFW. Additionally, because Rush Meadows Dam and Gem Dam are located in the Ansel Adams Wilderness Area, SCE must secure a Wilderness Act variance from the USFS to conduct construction activities within the wilderness boundary. To obtain the variance, SCE would need to analyze the use of motorized equipment within the wilderness boundary. SCE would initiate the analysis in 2028.

[152] WP SCE-05 Vol. 1, pp. 105-106. Rush Creek Decommissioning.

(3) Project Justification and Benefit

The final approach for retrofitting and decommissioning will be identified based on agency and stakeholder input during relicensing and will be deferred until submittal of the Final License Application (expected in January 2025). Once the final approach has been developed, SCE can initiate final engineering design and regulatory permitting processes. Construction would not begin until 2029 pending issuance of the new license, approval of the final engineering plans by FERC and DSOD, and acquisition of regulatory permits.

d) Future Small Hydro Decommissioning

Until recently, decommissioning of SCE's small Hydro assets seemed unlikely because of their renewable energy benefits.[153] However, due to aging assets and infrastructure (many exceeding 100 years), changes in the California energy market resulting in lower wholesale energy revenues, and increasing costs to license and operate the facilities, some of SCE's small Hydro powerhouses may be retired in the coming years. As discussed in SCE-07, Vol. 3, to address the likelihood of small Hydro assets retiring in the future, SCE is proposing to continue accruing funds for (which began in 2021) their eventual decommissioning.

The following section of testimony outlines the rationale behind estimating a reasonable small Hydro decommissioning cost level for inclusion in depreciation expense; SCE-07, Vol. 3 describes the forecast methodology that would seek to recover decommissioning costs at a portfolio level.

[153] In California, powerhouses with capacities of 30 MW or less qualify as RPS-eligible renewable resources and are considered "small."

(1) Continued Cost-Effectiveness of SCE Small Hydro is Uncertain

Outside of Big Creek (1,015 MW)[154] and Kern River Nos. 1 & 3 (66 MW), the remaining 95 MW in SCE's Hydro portfolio can be classified as "small Hydro."[155] The average capacity of SCE's small powerhouses us 4.3 MW, with the largest powerhouse rated at less than 13 MW.

Until recently, decommissioning of SCE's small Hydro assets seemed unlikely because of their renewable benefits. However, due to aging assets and infrastructure (many exceeding 100 years), changes in the California energy market resulting in lower wholesale energy revenues, and increasing costs to license and operate the facilities, some of SCE's small Hydro powerhouses will be retired in the coming years. Beginning in Test Year 2021, SCE began accruing at a portfolio level for future small Hydro decommissioning activities. SCE-07, Vol. 3 describes the forecast methodology that would seek to recover decommissioning costs at a portfolio level. While SCE has begun to accrue for eventual decommissioning activities the immediate level required exceeds the amount currently being accrued through customer rates.

While a small portion of these 22 small Hydro powerhouses have reservoir storage, most are run-of-the-river systems, which decreases their ability to be optimized for market revenue that reduces customer costs. The increased penetration and decreasing cost of solar has placed downward pressure on wholesale energy prices and renewable energy credits, further challenging the economic value of small Hydro. Finally, the FERC relicensing process has the potential to further challenge small Hydro economics by requiring increased capital expenditures for relicensing and

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[154] The Portal Powerhouse (10.8 MW capacity) located in Big Creek is classified as small Hydro. The small Hydro forecasts presented herein exclude Portal Powerhouse because it is intermingled with, and its continued future is tied to, the Big Creek assets.

[155] Although the Kern River No. 1 Powerhouse (26 MW capacity) would be classified as small Hydro according to industry definitions (that define "small" as those plants with less than 30 MW capacity), SCE has excluded it from the scope of the decommissioning reserve portfolio because it is not subject to the same cost-effectiveness challenges as the other small Hydro plants within SCE's portfolio.

continued operation.[156] Almost all of these small Hydro assets entered service between 1899 and 1929;[157] while appreciable capital refurbishment and improvement has been made over their lives, much of this infrastructure is original equipment, and significant additional refurbishment will be needed if operations are to continue for several more decades. SCE expects that the general trend of continued degradation of small Hydro economics may lead to the outcome that, in some cases, decommissioning will be the least-cost option for customers over the long term.

(2) Small Hydro Decommissioning Costs Could be Significant

It is challenging to predict the timing and scope of small Hydro plant decommissioning for two reasons. First, the decision timeline process typically takes between five and 10 years due to the lengthy FERC relicensing process. Second, Hydro licensing and decommissioning decisions involve a range of connected variables such as environmental permitting and impact requirements, water rights, recreational use rights, flood control, and concerns with numerous stakeholders and/or public advocacy groups. SCE expects that the decision to retire a small Hydro asset (or to continue operations into the future) will be made on a case-by-case basis and will typically be linked to the FERC license renewal process (FERC license expiration dates for SCE's small Hydro plants span from 2021 through 2033). Using a combination of known facts and expert judgement, SCE has estimated a probability of decommissioning for each plant. SCE followed industry practice as established by the U.S. Bureau of Reclamation in selecting from the five probability choices, as shown in Table II-25 below.[158]

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[156] Five of the 22 small Hydro powerhouses, with a total combined capacity of 4.8 MW, do not have FERC licenses (i.e., are not regulated by FERC). However, these five powerhouses are geographically intermingled with other small powerhouses that do have FERC licenses, and their routine O&M activities are performed by the same staff. Therefore, these five powerhouses are included among the 22 small Hydro assets (i.e., 95 MW) that are the subject of the Decommissioning forecasts presented herein.

[157] The Santa Ana River No. 3 Powerhouse (3.1 MW) began operation in 1999, replacing the earlier Santa Ana River Nos. 2 and 3 Powerhouses (constructed in the late 1800s and early 1900s). The Santa Ana River Nos. 2 and 3 Powerhouses were removed to build the Seven Oaks Dam.

[158] U.S. Bureau of Reclamation, Risk Management Best Practices and Risk Methodology, Chapter A-6, Table A-6-1.

Table II-25
US Bureau of Reclamation, Risk Management Best Practices and Risk Methodology

Description	Probability
Virtually Impossible, due to known physical conditions or processes that can be described and specified with almost complete confidence	1%
Very Unlikely, although the possibility cannot be ruled out	10%
Equally Likely, with no reason to believe that one outcome is more or less likely than the other (when given two outcomes)	50%
Very Likely, but not completely certain	90%
Virtually Certain, due to known physical processes and conditions that can be described and specified with almost complete confidence	99%

Even if only a minority of SCE's small Hydro plants are decommissioned, costs will likely reach into the hundreds of millions of dollars. SCE has developed individual decommissioning cost estimates based on the assumption of removing major structures and performing moderate levels of site restoration, which is consistent with FERC regulations. The total decommissioning forecast of $1,195.0 million (in 2022 dollars), the probability-adjusted value of $460.2 million, and the plant-level probability estimates are summarized in Table II-26.

Table II-26
Small Hydro Decommissioning Estimate
(2022 $ Millions)

Plant	Nameplate Capacity (MW)	License Expiration	Decom. Estimate (2022$) (Millions)	Decom. Prob. (1%, 10%, 50%, 90%, 99%)	Approx. Year Decom. Would Begin	Probability-Adjusted Decom. Estimate	Decom. Estimate Source
San Gorgonio	-	2003	$ 78.0	100%	In Progress	$ 78.0	H
Borel	12.0	2046	$ 55.0	100%	2026	$ 55.0	A
Rush Creek (Agnew, Rush M.)	-	2027	$ 81.0	90%	2027	$ 72.9	B
Rush Creek (Gem)	13.0	2027	$ 249.7	50%	2030	$ 124.8	C
Lower Tule River	2.5	2033	$ 27.9	50%	2033	$ 14.0	D
Kaweah 3	4.8	2021	$ 113.0	50%	2026	$ 56.5	E
Kaweah 1-2	4.1	2021	$ 58.2	10%	2026	$ 5.8	E
Lundy (Mill Creek)	3.0	2029	$ 22.5	10%	2029	$ 2.3	F
Bishop Creek 2-6	29.3	2024	$ 272.5	10%	2024	$ 27.3	G
Poole (Lee Vining Creek)	11.3	2027	$ 104.8	10%	2027	$ 10.5	G
Fontana	1.9	N/A	$ 14.4	10%	2033	$ 1.4	G
Lytle Creek	0.5	2033	$ 20.1	10%	2033	$ 2.0	G
Mill Creek No. 1	0.8	N/A	$ 9.0	10%	2033	$ 0.9	G
Mill Creek No. 3	3.0	2033	$ 30.8	10%	2033	$ 3.1	G
Ontario No. 1	0.6	N/A	$ 13.9	10%	2033	$ 1.4	G
Ontario No. 2	0.3	N/A	$ 6.8	10%	2033	$ 0.7	G
Santa Ana 1 & 3	6.3	2033	$ 30.8	10%	2033	$ 3.1	G
Sierra	0.5	N/A	$ 6.5	10%	2033	$ 0.7	G
TOTALS:	**93.9**		**$ 1,195.0**			**$ 460.2**	

Source Notes:	
A -	30% Design from 2022 HDR Engineers - Borel Hydroelectric Project Decommissioning
B -	2019 SR Diversified - Rush Creek Hydro System Conceptual Decommissioning
C -	2021 SR Diversified - Rush Creek Hydro System Engineering Analysis Report
D -	2017 SR Diversified - Lower Tule System Project Class 4 Estimate Narrative
E -	2015 Cardno - Kaweah Hydroelectric Project Decommissioning Conceptual-Level Economic Analysis
F -	2017 Stantec - Lundy Lake Hydroelectric System: Decommissioning and Alternatives Study
G -	2012 GRC Small Plant Study
H -	2021 Blair, Church and Flynn - San Gorgonio Cost Estimate

(3) Decommissioning Estimate Scope of Work

The conceptual-level decommissioning estimates referenced in Table II-26 include costs for the planning, permitting, FERC license surrender, and performance of decommissioning of the respective hydroelectric projects. A significant majority (88%) of the probability-adjusted estimate of $325.7 is based on third-party studies by specialized engineering and construction services firms. Specific assumptions and estimation approaches (e.g., comparisons to past or related work, site walks, construction timing, river/stream flow constrains, equipment access/remoteness, environmental complexity, contractor overhead, and public involvement) have been explained in greater detail within each cost estimate.

(4) Rationale Behind Probability Selections

As previously discussed, SCE is forecasting that the Borel Powerhouse, Agnew Lake Dam, and Rush Meadows Dam will begin decommissioning activities within this GRC rate cycle and will require significant decommissioning costs within the next five to 10 years. SCE assigns a 99% or "Virtually Certain" probability that decommissioning activities will occur on these three facilities.

(a) Gem Lake, Kaweah 3, and Tule

As discussed above, the Gem Lake Dam is part of the Rush Creek system and is the only dam necessary for SCE to generate power from the overall system. Like the Rush Meadows and Agnew Lake dams, Gem Lake is operating at a restricted level to mitigate seismic risk. The financial and economic analysis of the cost to decommission Rush Creek versus the cost to continue operation does not point strongly in either direction. Therefore, SCE has estimated the decommissioning probability at 50%.

The Kaweah No. 3 Powerhouse is located within Sequoia National Park and requires a SUP from the National Park Service ("NPS"). Operation beyond 2026 requires a new SUP, which would require negotiations with the NPS on fees and additional concessions or actions (if any), and approval of the SUP by Congress. SCE does not see factors impacting its decision to continue operations versus decommissioning the facility as weighing strongly in either direction. Therefore, SCE has estimated the decommissioning probability at 50%.

The Tule Powerhouse is currently not operational because of damage from a 2017 fire. The cost to repair and continue operation depends on methods of construction (e.g., metal vs. wood), fire mitigation measures, and future fire frequency (i.e., expected life of equipment post-repair). SCE's economic analysis of decommissioning versus repairing and continuing operations does not point strongly in either direction. Therefore, SCE has estimated the decommissioning probability at 50%.

(b) Remaining Portfolio (10%) of "Very Unlikely" Probability

SCE has estimated the decommissioning probability of the remaining small Hydro plants at 10%. In the case of Kaweah 1-2 and Bishop Creek 2-6, SCE has initiated the FERC relicensing process with an expectation that, barring unforeseen circumstances, the plants can be relicensed without undue financial burdens. For the plants with relicensing dates further in the future (i.e., the plants with a 2033 license expiration date), SCE generally anticipates that relicensing will be economically preferable to decommissioning. However, as with the case of Kaweah Nos. 1&2 and Bishop Creek, SCE selected 10 percent as the decommissioning probability given that it is possible that unforeseen circumstances will emerge during the relicensing process that will make decommissioning a more cost-effective approach.

(5) Recovery of Decommissioning Costs at a Portfolio Level

In D.21-08-036, pp 640, the Commission concluded that it was reasonable for SCE to begin recovery for future decommissioning of the Borel Powerhouse, Agnew Lake Dam, and Rush Meadows Dam. This conclusion was reached given the high probability that decommissioning of these plants were forecasted to occur within the next 10 years and the significant costs of decommissioning. The Commission further concluded that SCE failed to provide adequate justification to begin recovery for Hydro plants assigned either a 50% or 10% probability of future decommissioning.

While there is a low probability that many of SCE's small Hydro assets will be decommissioned soon, it would be inaccurate to conclude they are "forever assets" that will never require decommissioning. It can and should be expected that all small Hydro assets listed in Table II-26, as well as the large Hydro assets listed in Table II-12, will at some point reach the end of their respective useful lives and require retirement.

Consistent with Commission guidance that current customers benefiting from these resources should pay a portion of future decommissioning expenses, SCE proposes to continue recovery of future decommissioning costs at a portfolio level per the amounts authorized in D.21-08-036. The methodology behind the requested costs is discussed further in SCE-07, Vol. 3.

5. Hydro – Dams and Waterways

Hydro operates and maintains 33 dams, 43 stream diversions, and approximately 143 miles of tunnels, conduits, flumes, flowlines, and pressurized penstocks. Maintaining this critical infrastructure represents our largest category of Hydro capital investment. Many facilities are in mountainous terrain at elevations over 7,000 feet above sea level. These locations are remote and difficult places to work. The work sites have limited access with little room for mobile cranes and other equipment. These sites are also subject to cold weather, ice, and deep snow in the winter months. Contractors must be familiar with this environment and trained to safely work in these areas. The need to pay for travel and lodging can increase labor costs. In addition, many contractors opt for simpler work and will not bid on these projects. All these factors increase the capital expenditures for these projects.

Dams and Waterways projects include the rebuilding of reservoirs, flowlines, or flumes, installing flow measurement equipment, replacing valves, and installing debris removal equipment or fish screens. The projects in this category will sufficiently restore affected facilities to reliable operation for several decades. The Dams and Waterways capital forecast for these projects is $81.971 million (nominal, work order level) for 2023-2028.[159] Table II-27 below lists the programs for the Dams and Waterways category.

Table II-27
Dams and Waterways Programs
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project Category	2023	2024	2025	2026	2027	2028	TOTAL
1	Structure Improvements	16,200	7,550	3,650	5,146	8,463	-	41,009
2	Gates and Valve Replacements	16,089	6,890	2,771	983	136	362	27,232
3	Misc	1,933	-	1,154	10,643	-	-	13,730
4	**GRAND TOTAL**	**34,222**	**14,440**	**7,575**	**16,773**	**8,599**	**362**	**81,971**

a) Structure Improvements

Dams and Waterways are an essential part of the Hydro system, providing transportation and control of the water used for hydroelectric power generation. This category covers a

[159] WP SCE-05 Vol. 1, pp. 107-132. Hydro Capital Expenditures – Dams and Waterways.

variety of projects that are essential to operate Hydro waterways reliably and safely and comply with applicable regulations. The capital forecast for the Dams and Waterways - Structure Improvement projects is $41.009 million (nominal, work order level) for 2023-2028. Table II-28 provides a list of the Dams and Waterways - Structure Improvement projects and the cost for each.

Table II-28
Structure Improvements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Vermilion - Service Spillway Improvement	500	6,400	-	-	-	-	6,900
2	Big Creek 2 - Dam 4 Resurface Downstream Face	6,406	-	-	-	-	-	6,406
3	Vermilion - Auxillary Spillway Improvement	-	150	150	5,000	-	-	5,300
4	Huntington Lake - Spillway Enhancement (Long Term)	-	-	-	-	4,987	-	4,987
5	Bishop - Intake 2 Spillway Repair/Modification	4,082	-	-	-	-	-	4,082
6	Huntington Lake - Spillway Refurbishment (FERC Findings)	2,654	-	-	-	-	-	2,654
7	Florence Lake - Multiple Arch Dam Concrete Repair	-	-	-	-	2,576	-	2,576
8	Kern River 1 - Tunnel Refurbishment	-	500	1,200	-	-	-	1,700
9	Big Creek - Dam 5, 6 & 7 Grid Rake Refurbishment	-	300	1,200	-	-	-	1,500
10	Sabrina Service Spillway Retrofit (Seismic/Flood loading)	1,500	-	-	-	-	-	1,500
11	Big Creek - Dam 7 Water Stop/Liner	-	-	-	100	900	-	1,000
12	Rhinedollar Overtopping Protection (RIDM)	-	200	700	-	-	-	900
13	Gem Lake - Arch 8 (Phase 2)	500	-	-	-	-	-	500
14	Shaver Lake Dam Dike Flood Mitigation	493	-	-	-	-	-	493
15	Kaweah 3 - Forebay Leak Repair	-	-	200	-	-	-	200
16	Kaweah 2 - Flume 13 Sheet Replacement	-	-	100	-	-	-	100
17	Kaweah 2 - Flume 7 & 8 Sheet Replacement	-	-	100	-	-	-	100
18	Lundy Return Conveyance	64	-	-	-	-	-	64
19	Mill Creek 3 - Retaining Wall	-	-	-	46	-	-	46
20	**GRAND TOTAL**	**16,200**	**7,550**	**3,650**	**5,146**	**8,463**	**-**	**41,009**

(1) Vermillion – Service Spillway Improvement

(a) Background

Vermilion Valley Dam has two spillways: a concrete-lined service spillway on the left (east) side, and an unlined emergency spillway on the right (west) side. Both spillways are founded on glacial soils because bedrock is hundreds of feet below the ground surface. The service spillway has flowed relatively often, generally without significant damage. However, in 1983, surface water runoff from the east flowed over the east spillway wall into the spillway. This flow caused soil erosion which eventually undermined the edge of the spillway chute. Water then flowed under the chute resulting in extensive cracking in its lower portion. This damage was repaired by cutting out the damaged concrete, tying a new rebar mat to rebar tails from adjacent undamaged slabs, and pouring new slabs.

The 2017 Oroville Spillway incident has raised awareness and concern within the overall Hydro industry, and within the regulatory community, over the condition and anticipated performance of spillways. Both FERC and DSOD have initiated significant spillway evaluation programs which include the spillways at Vermilion. In response, SCE performed a comprehensive re-evaluation of the Vermilion spillways. This evaluation included review of design documents and as-built drawings, historical performance, maintenance and repair records, previous inspections and technical studies of the spillways, and field inspections before, during, and after the significant 2017 spill event. SCE's evaluation has also included consultation with a consultant, Dr. Craig Findlay, who participated in the inspections mentioned previously and who has been involved with Vermilion Dam since the 1980s. The FERC spillway evaluation required a Potential Failure Mode Analysis (PFMA) workshop, specifically focused on the spillways. This workshop included input from SCE personnel, FERC engineers, and SCE’s Part 12 Independent Consultants. SCE has incorporated the risk-reduction measures recommended during that workshop into this project request.

The capital forecast for Vermilion – Service Spillway Improvement project is $6.900 million for 2023-2028.[160]

(b) Project Scope

The service spillway foundation at Vermilion is erodible and therefore any failure of the spillway chute risks failure of the dam through backcutting erosion. This is a known condition but is critical to understanding the risk posed by a possible failure of the Vermilion service spillway. If spillway flows exit the chute anywhere but into the rip-rap at the bottom of the chute, rapid erosion will occur, and would likely cut quickly back towards the dam crest, potentially leading to dam failure within a matter of hours. Once the chute fails, the only opportunity for intervention would be to close the gate and force the use of the Emergency Spillway, which has never

[160] WP SCE-05 Vol. 1, p. 109. Vermilion - Service Spillway Improvement.

been tested, and is considered only to be "marginally stable" during a severe flood event. All the issues with the Vermilion service spillway discussed below should be considered with this potentially high consequence of failure in mind.

Excess hydrostatic uplift pressures resulting from high groundwater conditions in the upper portion of the spillway are not being adequately relieved by the existing sub-drainage system. This condition has been observed since early in the project, as evidenced by water flowing into the spillway chute through joints and cracks when the reservoir level is high. Some attempts at mitigation have been made by installing relief drains, but these drains have not been successful in lowering the water table below the bottom of the chute. High hydrostatic pressures beneath the slabs could contribute to a failure similar to Oroville (high pressure beneath the slabs resulting in uplift and loss of slabs, followed by rapid erosion of the subgrade). The 1983 damage is proof that buoyant uplift can result in significant damage to the chute slabs. The proposed scope of work includes installation of piezometers adjacent to the spillway in order to quantify these uplift forces and the resulting safety margins. If inadequate margins are indicated, then additional engineering will be required to design a mitigation strategy, likely to include installation of a new subdrain adjacent to the spillway chute or other significant effort to increase drainage capacity. The piezometers would also be used for ongoing monitoring of uplift pressures and would be integrated into our FERC-mandated Dam Safety Surveillance and Monitoring Plan.

The service spillway concrete chute is fundamentally sound, but there are numerous cracks and spalls and several distressed construction joints that are in need of repair. Aside from the 1983 repair discussed above, the concrete chute is the original early 1950s construction. The design is robust and the spillway is in generally good condition considering its age. However, abundant minor cracks, spalling, and erosion are present, and several construction joints exhibit more significant distress consistent with excessive compressional forces. Previous maintenance and repair records for the spillway are essentially nonexistent. The primary intent of this project is to identify and address all issues with a formal engineering evaluation and documented repair program in order to provide high confidence in the spillway's future safe performance. In other words, we want to return the spillway chute to a known good condition.

The 1983 repair to the lower portion of the spillway, discussed above, performed inadequately in the 2017 spill event and therefore may need to be replaced. This concrete eroded rapidly during the 2017 spill event. A longer or more extreme spill could have resulted in the complete loss of spillway chute slabs and extensive erosion, risking dam failure. The engineering evaluation will recommend whether complete replacement of this concrete is necessary, or whether some rehabilitation short of complete replacement may be acceptable.

The service spillway entrance is narrow, and therefore vulnerable to clogging with debris. The service spillway entrance channel is only about 25 feet wide, and the gate structure is only 15 feet wide. This is narrower than modern design standards, which call for additional size to minimize the potential for clogging during spill. As a result, the spillway is potentially vulnerable to clogging with logs when spilling. A simple approximately 225-foot-long log boom is currently the only barrier preventing floating logs from entering the spillway, and a significant accumulation of debris likely would cause it to collapse into the spillway entrance. Clogging of the spillway could force the use of the untested Emergency Spillway, with resulting risk of erosion and environmental damage. To mitigate this possibility, during the 2017 spill event, we stationed a crane at the spillway entrance, and stationed personnel there 24/7 for more than a week to remove logs from the boom, and to proactively remove logs and stumps from the nearby shorelines as they were floated by the rising reservoir. A longer (allowing it to be positioned farther away from the spillway entrance) and more robust debris barrier would allow a much less labor-intensive effort, likely only requiring occasional debris removal based on inspection findings during the spill. The more robust barrier would also reduce the risk of clogging during an unanticipated storm, when debris removal equipment would not already be on site. In addition, the longer and more robust boom would increase the safety of crew members who may need to work in boats to remove debris from the barrier.

The berm between the Emergency Spillway and the right groin of the dam is vulnerable to erosion. If flows through the emergency spillway erode this berm, flows could go down the right groin, rather than through the downstream end of emergency spillway. In this case, backcutting erosion could cut up the right groin, bypassing the rip-rap-filled trench and concrete control structure, which are intended to prevent erosion working its way back to the dam crest. The project would install rip-rap along the upper portion of this berm to minimize the chance of such a breach between the spillway and the groin of the dam.

(c) Project Justification and Benefit

Neither regulator has formally responded to SCE's spillway evaluation submittals. However, increased regulatory scrutiny by both FERC and DSOD following the Oroville event make it unlikely that a continued "patch and monitor" approach will be considered satisfactory in the future. Independent of the spillway evaluation programs, repair of concrete defects within the spillway chute has already been requested by DSOD based on annual inspection findings in the fall of 2021. Performance of this project would maintain compliance with applicable FERC and DSOD regulations.

(2) Big Creek 2 - Dam 4 Resurface Downstream Face

(a) Background

Big Creek Dam 4 is a 75-foot high constant-radius concrete arch dam with a crest length of 287 feet at elevation 4,805 feet. The dam is an overpour structure with 27 ungated spillway bays separated by piers. Five-foot high flashboards can be lowered into each spillway bay to raise the reservoir to 4,810 feet. The dam consists of cyclopean unreinforced concrete and was originally built in 1913. A reinforced concrete (gunite) layer ranging from two inches to six feet thick was installed in 1940 to protect of the dam's downstream face, including an underdrain system to manage dam leakage and freeze/thaw damages. In the 1980s additional gunite repair/resurfacing efforts were completed on the spillway piers and adjacent areas.

Deterioration and damage to the downstream 1940s-reinforced concrete protection layer of the dam has occurred and needs repair. Cracking is observed across the face with voids, exposed wire mesh reinforcing, and areas of complete reinforced layer missing. In 2016 a small O&M project was executed to repair spalling damage observed at the base of the dam to the reinforced concrete layer. This area can only be accessed via rope access or with very extensive scaffolding, as there is no safe access to the downstream side of the dam or creek at this location. The repairs planned and executed for this effort were anticipated to be approximately 15 square feet, however during the rope access work, crews found wide areas damaged and/or “hollow”-sounding concrete across the majority of the base of the dam, indicating a much larger area needs to be repaired. In 2017 during a high runoff year, several areas of the protection layer concrete were damaged and removed from the dam.

The capital forecast for the Big Creek 2 – Dam 4 Resurface Downstream Face project is $6.406 million for 2023-2028.[161]

(b) Project Scope

The major scope of work items for the Big Creek Dam 4 Downstream Face project includes, but is not limited to the following:

- Provide engineered design drawings, QCIP, TCEAP, Project Description and other related project documents.
- Obtain agency permits/approvals (USFS, FERC, DSOD, USFW, State/Regional Water Board and potentially U.S. Army Corps of Engineers)
- Install water quality BMPs, including containments, temporary pumps/piping, water treatment skid for pH and turbidity removal, etc.
- Provide onsite turbidity monitor during construction for environmental monitoring/compliance.
- LIDAR/Survey of existing surfaces, which includes minor engineering investigation, assuming the full project scope pursued (larger engineering investigation detailed in Alternates

[161] WP SCE-05 Vol. 1, p. 110. Big Creek 2 – Dam 4 Resurface Downstream Face.

if smaller scope is pursued and FERC/DSOD approval (which is difficult to obtain) is required).

- Perform temporary bridge-shoring on the local Pittman Bridge. The bridge rating is below the level required to support proposed construction equipment transport vehicles.
- Demolition of the existing reinforced concrete/gunite surface, including existing drainage system, to sound competent material. Assumes 6 inches of material removal.
- Barge-mounted crane included on upstream forebay pond to provide material/equipment handling. Nearby overhead 220KV powerlines limit helicopter access for material handling and there is no feasible nearby location for a ground-mounted crane support.
- Hydro blast demolition tools assumed in constructability assessment
- The area of work is assumed from the downstream edge of the flashboard steel track, to all surfaces downstream which are impacted by spillway bay water flows (Estimate ~13,000SF). Includes minor areas of the lower piers as needed to maintain a smooth transition from the existing pier surfaces to the new shotcrete surface.
- Installation of new 6-inch reinforced shotcrete layer.
- Includes new drain system for management of dam leakage to prevent freeze/thaw damage to the surface.
- Currently does not include waterproofing injections or other preventative means to stop any dam leakage, because the new

drain system will serve that purpose, but may be considered/required as project design/approval progresses.

- Project includes scaffolding with stair tower, rope access suspended work, suspended platforms/equipment, etc. as needed to provide safe access to work areas.
- Assumes no temporary minimum instream flow ("MIF") release piping during construction, as this location currently does not require a MIF release. If the project is executed after completion of MIF infrastructure and initiation of MIF releases per the imminently expected new FERC license, a temporary MIF extension will likely be required to separate the MIF releases from the construction area.

A construction estimate for this project was completed by SCE personnel. Due to the unique nature of the project, the associated access constraints for performing the work on the downstream face of the dam, and the lack of previous similar projects for reference, the cost estimate had several large assumptions included which led to uncertainty of the overall cost. A constructability study was initiated with an engineering/construction firm to determine a feasible approach with options for construction per their previous experience performing similar type of work. The construction estimate for the proposed project is based on addressing the entire downstream dam face as a single capital project effort, in lieu of performing smaller scale O&M repairs over several years which would increase overall project costs due to increased mobilization/demobilization costs.

(c) <u>Project Justification and Benefit</u>

This project is being proposed to remove and replace the entire protection layer surface on the downstream face of the dam to restore the dam's spill surface and ability to manage leakage and spill events without damage to the main concrete structure. FERC and DSOD standards require SCE to maintain dams in serviceable condition. Performance of this project would maintain compliance with applicable FERC and DSOD regulations.

(3) Vermilion – Auxiliary Spillway Improvement

(a) Background

Vermilion Valley Dam has two spillways: a concrete-lined service spillway on the left (east) side, and an unlined emergency spillway on the right (west) side. Both spillways are founded on glacial soils because bedrock is hundreds of feet below the ground surface. The service spillway has flowed relatively often, generally without significant damage. However, in 1983, surface water runoff from the east flowed over the east spillway wall into the spillway. This flow caused soil erosion which eventually undermined the edge of the spillway chute. Water then flowed under the chute resulting in extensive cracking in its lower portion. This damage was repaired by cutting out the damaged concrete, tying a new rebar mat to rebar tails from adjacent undamaged slabs, and pouring new slabs.

The 2017 Oroville Spillway incident has raised awareness and concern within the overall Hydro industry, and within the regulatory community, over the condition and anticipated performance of spillways. Both FERC and DSOD have initiated significant spillway evaluation programs which include the spillways at Vermilion. In response, SCE performed a comprehensive re-evaluation of the Vermilion spillways. This evaluation included review of design documents and as-built drawings, historical performance, maintenance and repair records, previous inspections and technical studies of the spillways, and field inspections before, during, and after the significant 2017 spill event. SCE's evaluation has also included consultation with a consultant, Dr. Craig Findlay, who participated in the inspections mentioned previously and who has been involved with Vermilion Dam since the 1980s. The FERC spillway evaluation required a Potential Failure Mode Analysis (PFMA) workshop, specifically focused on the spillways. This workshop included input from SCE personnel, FERC engineers, and SCE’s Part 12 Independent Consultants. SCE has incorporated the risk-reduction measures recommended during that workshop into this project request.

The capital forecast for Vermillion – Auxiliary Spillway Improvement project is $5.300 million for 2023-2028.[162]

(b) Project Scope

The Emergency Spillway at Vermilion is unlined and is underlain by glacial till and fluvioglacial soil materials. Previous studies have suggested that it is potentially vulnerable to back cutting erosion if it is needed to pass flows that exceed the capacity of the Service Spillway, or if it is needed to be used as a result of problems at the Service Spillway. Such erosion could potentially lead to failure of the dam if that backcutting erosion were to extend back to the crest of the spillway. In addition, the berm between the Emergency Spillway and the right groin of the dam is potentially vulnerable to erosion. If flows through the emergency spillway erode this berm, flows could go down the right groin, rather than through the downstream end of emergency spillway. In this case, backcutting erosion could cut up the right groin, bypassing the riprap-filled trench and concrete control structure which are intended to prevent erosion working its way back to the dam crest. The project would install riprap along the upper portion of this berm to minimize the chance of such a breach between the spillway and the groin of the dam.

To date, the project has performed the following:

- Completion of a comprehensive focused spillway evaluation of the Vermilion Spillways in 2019, with submittal to both FERC and DSOD. Work included detailed inspections and non-destructive geophysical testing to document the spillway designs, construction, past performance, and existing conditions.
- Detailed hydrologic modeling of potential flows through the Emergency Spillway, to inform erosion mitigation concept development.

[162] WP SCE-05 Vol. 1, p. 111. Vermillion – Auxiliary Spillway Improvement.

- A conceptual engineering workshop was conducted with SCE's Dam and Public Safety Staff and their engineering consultants to evaluate develop preliminary alternatives for mitigation of the erosion potential.

Based on the findings from that workshop, and from the Phase 2 Risk Evaluation for Vermilion Valley Dam performed in 2021, SCE believes that improvements to the Emergency Spillway are expected to include construction of one or more additional control structures within the downstream areas of the Emergency Spillway, to form a series of "step-pools." These would limit the flow depths and velocities, preventing the initiation of backcutting erosion within the spillway channel. It is also expected that some riprap erosion protection will be provided along the berm between the Emergency Spillway and the right groin of the dam.

(c) <u>Project Justification and Benefit</u>

Neither regulator has formally responded to SCE's spillway evaluation submittals. However, SCE has identified unacceptable public safety, environmental and economic risks associated with significant flows through the Emergency Spillway. In addition, increased regulatory scrutiny by both FERC and DSOD following the Oroville event makes it likely that they will require improvements to be made to the Emergency Spillway to increase confidence that it will perform adequately in the event that it is needed. Performance of this project would maintain compliance with applicable FERC and DSOD regulations.

(4) <u>Huntington Lake - Spillway Enhancement</u>

(a) <u>Background</u>

Huntington Lake is impounded by Big Creek Dam Nos. 1, 2, 3 and 3a, originally constructed between 1913 and 1917 as concrete structures with an overflow spillway at Dam 1 and a siphon spillway at the right (west) end of the dam. From the 1930s through the 1950s, earth-fill embankments were added to provide additional stability. With the addition of the embankments, the overflow spillway at Dam No. 1 was replaced, at which point the siphon spillway was supplemented with an additional gated spillway approximately 100 feet west of the end of the siphon spillway. FERC and DSOD have indicated that the current spillway system is inadequate to pass the Probable Maximum Flood (PMF) standard. While SCE has calculated that the probability of the PMF is extremely low, enhancement of the capacity of the spillway system may be necessary to meet regulatory requirements.

The capital forecast for the Huntington Lake Spillway Enhancement project is $4.987 million for 2023-2028.[163]

(b) Project Scope

The preliminary design for the modification is the conversion of a portion of the smallest dam, Big Creek No. 3a, into a spillway. It would potentially be controlled with a fuse plug or fuse gate to prevent spilling except in extreme flooding events.

As stated above, the annual probability of the PMF is estimated to be extremely low. SCE using the Risk Informed Decision Making (RIDM) guidelines issued by FERC to evaluate the how much additional spillway capacity is needed to reduce risk associated with flooding As Low As Reasonably Practicable (ALARP), as defined in the FERC guidelines. The scope of the project may be increased if regulators require retrofit for an extreme event beyond what is required for ALARP.

(c) Project Justification and Benefit

The proposed modification is needed to meet FERC and DSOD requirements for spillway capacity of High Hazard Dams.

(5) Bishop - Intake 2 Spillway Repair/Modification

(a) Background

Bishop Creek Intake 2 Dam has two spillways: (1) a service spillway consisting of an ungated concrete gravity section constructed with the dam in 1908, and (2) an auxiliary spillway consisting of an ungated roller-compacted concrete structure constructed in 1989. FERC and DSOD inspections have identified deterioration on and around the spillways and required

[163] WP SCE-05 Vol. 1, p. 112. Huntington Lake - Spillway Enhancement (Long Term).

SCE to perform repairs. The capital forecast for Bishop - Intake 2 Spillway Repair/Modification project is $4.082 million for 2023-2028.[164]

(b) Project Scope

SCE intended to start project activities in June 2023 with a completion date of November 2023 to ensure the maximum allowable time to slowly dewater the reservoir and mitigate the turbidity issues. However, continued challenges with environmental and other approvals may lead to some portions of the work being performed in later years. Anticipated repairs are:

1. Repair numerous cracks and spalls in the concrete of the Service Spillway structure. This will involve the removal of deteriorated material and replacement with reinforced concrete. The work may be phased to prioritize repair of the crest and upper portion of the downstream facing, as these are the most heavily impacted areas.
2. Replacement of eroded soil in the upper portion of the upstream embankment on either side of the entrance to the service spillway
3. The crest and downstream slope of the auxiliary spillway will be cleared of vegetation, and
4. Remove vegetation and sediment of the spillway channel.

(c) Project Justification and Benefit

Execution of this project is a DSOD and FERC requirement. Performance of this project would maintain compliance with applicable FERC and DSOD regulations. Failure to perform could result in the decommissioning of Bishop Creek Plant 2.

[164] WP SCE-05 Vol. 1, p. 126. Bishop - Intake 2 Spillway Repair/Modification.

b) Gate(s) and Valve(s) Replacements

Water conveyance systems utilize gates and valves to control the transfer of water from one location to another. Some gates and valves are used to regulate the volume of flow and others are used only in an “open” or “closed” mode. These gates and valves are essential for the reliable and safe operation of the Hydro facilities.

Gates and valves generally have a long life, and many have been in operation for decades. Gates and valves that have exceeded their useful lives are usually so old that no replacement parts are available. Therefore, only minor servicing can be done to these units until they are replaced with new equipment. Some of the low-level outlet valves requiring replacement are in critical locations such as the ones at Huntington and Florence Lake. Failure of these valves could cause consequences that include:

- Failure to comply with FERC-required minimum instream flow releases
- Failure to allow water into designated flowlines to powerhouses, resulting in energy loss due to water spilling from reservoirs
- Failure to allow water to drain from reservoirs, interfering with maintenance; and
- Failure in an open position, possibly causing flooding of facilities

The capital forecast for these projects is $27.232 million (nominal, work order level) for 2023-2028. Table II-29 below, provides a list of the Gates and Valves projects and the cost for each.

Table II-29
Gate(s) and Valve(s) Replacements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Huntington Lake - Dam 1 Low Level Outlet Valve Replacement	8,668	6,610	-	-	-	-	15,278
2	Florence Lake - Minimum Instream Flow Infrastructure and Low Level Outlet Valves (Phase 2)	3,756	-	-	-	-	-	3,756
3	Florence Lake - Spillway Gate Recoating Replacement Project	2,406	-	-	-	-	-	2,406
4	Big Creek 8 - Unit 1 & 2 PSV	-	-	1,500	-	-	-	1,500
5	Big Creek 2A - Shaver Low Level Outlet Valve Physical Protection & Remote Automation	-	60	130	645	-	-	835
6	Big Creek 2A - Shaver Low Level Outlet Valve Barrier Installations	558	-	-	-	-	-	558
7	Big Creek 2A - 102" Penstock Valve	552	-	-	-	-	-	552
8	Big Creek - Dam 7 Intake Gate 1 & 2 Controls Replacement	-	-	400	-	-	-	400
9	Big Creek 2 - Penstock Valve Replacements	-	-	-	202	136	-	338
10	Big Creek 1 - Unit 2 Pressure Relief Valves	-	220	41	-	-	-	261
11	Big Creek 2 - Unit 6 Pressure Relief Valves	-	-	-	-	-	244	244
12	Big Creek 1 - Penstock Valve Replacements	-	-	-	136	-	68	204
13	Big Creek 3 - Unut 1 Dam 6 DS Low Level Outlet Valves	-	-	200	-	-	-	200
14	Big Creek 8 - Unit 1 Dam 5 East/West Low Level Outlet Valves	-	-	200	-	-	-	200
15	Florence Lake - Intake Gates (2)	-	-	200	-	-	-	200
16	Big Creek 1 - Pressure Relief Valves	150	-	-	-	-	-	150
17	Big Creek 3 - Cooling Water Penstock Supply Valve Replace	-	-	100	-	-	-	100
18	Kern River 3 - Fish Hatchery Valve Replacement	-	-	-	-	-	50	50
19	**GRAND TOTAL**	**16,089**	**6,890**	**2,771**	**983**	**136**	**362**	**27,232**

(1) Huntington Lake - Dam 1 Low-Level Outlet Valve (LLOV) Replacement

(a) Background

The low-level outlet system at Huntington Dam 1 is comprised of three 42-inch outlet pipes that pass through the dam. The outlet pipes are controlled by manually operated vertical slide gates on the upstream side of the dam and manually operated gate valves on the downstream side of the dam. Current MIF releases are provided by a 6-inch bypass valve and leakage behind the dam's steel liner that discharges into a vault on the upstream side of the dam, which is then routed through a cored hole within the concrete dam and down into the eastmost lower level outlet pipe.

The last recorded successful operation of the LLOVs at Huntington Dam 1 occurred in 1993. The capital forecast for Huntington Lake – Dam 1 LLOV Replacement project is $15.278 million for 2023-2028.[165]

(b) Project Scope

The major scope of work items for the Huntington Dam 1 LLOV Replacement includes, but is not limited to the following:

[165] WP SCE-05 Vol. 1, p. 121. Huntington Lake – Dam 1 Low Level Outlet Valve Replacement.

- Providing engineered design drawings, QCIP, TCEAP, Project Description and other related project documents;
- Obtaining agency permits/approvals (USFS, FERC, DSOD, USFWS, State/Regional Water Board, and potentially U.S. Army Corps of Engineers);
- Performing dive investigation during design to validate assumptions made during the constructability analysis;
- Performing dive investigation and repairs along the upstream dam face to minimize leakage into the steel liner drain system;
- Installing temporary piping or bypasses as necessary to maintain stream releases throughout the project;
- Installing temporary turbidity curtain around upstream LLOVs work area to contain sediment disturbed during the project;
- Installing temporary pumps, piping, and plugs to redirect the steel liner drain system dam leakage from the MIF vault back inside the turbidity curtain, to avoid releasing turbid water;
- Providing sediment and debris removal from the upstream face of the dam to allow access to the LLOVs and trash grid: grizzly;
- Using a barge mounted crane with dump trucks on the dam to off-haul material to USFS-approved disposal location(s);
- Removing and replacing upstream vertical slide gate LLOVs, Operating Shafts, and Operators;
- Removing and replacing grizzly components (or entirely based on condition) as needed for access to the LLOVs;
- Installing bubbler devices or other engineered features to prevent ice buildup on LLOV operating shafts;

- Removing and replacing downstream gate valves and any access platform components needed for the new valves;
- Replacing MIF components as needed to confirm full functionality of system and to meet the new FERC license requirements;
- Installing new gaging features as needed to record MIF releases (includes dam liner leakage at this location);
- Lining the existing conduits/riveted steel pipe;
- Based on EOR evaluation, increasing the required dredging material during dive investigation.

(c) Project Justification and Benefit

FERC and DSOD standards mandate that each reservoir is equipped with an acceptable low-level outlet system. DSOD regulations mandate that SCE shall operate all LLOVs annually and shall be operated in the presence of DSOD every three years.[166] Upon completion of the project, the low-level outlet system will be able to be maintained and operated on a minimum annual basis without releasing unnecessary generation water and without creating environmental or public safety concerns during valve operations.

(2) Florence Lake - Minimum Instream Flow ("MIF") Infrastructure and Low-Level Outlet Valves ("LLOV") (Phase 2)

(a) Background

The low-level outlet system at Florence Dam is comprised of two pipes that pass through the dam. The original pipes were each controlled by a rectangular slide gate on the upstream side of the dam. On the downstream side of the dam, the West outlet pipe was fitted with a 36-inch valve and minimum release piping while the East outlet pipe was left open with no control on the downstream side. The upstream slide gates reached their end of their useful life and a project (Phase

[166] Water Code Section 6102.5 (c).

1) was executed in 2017-2018 installing new 36-inch gate valves on the downstream side of the dam on both outlet pipes. The upstream gates were abandoned in place, with the slide gates blocked opened and the operating shafts were removed from the face of the dam in 2020.

This project is Phase 2 of the Low-Level Outlet System upgrade, which will install secondary outlet valves and provide necessary extensions and access improvements to allow operating the valves in a safe manner year-round. The addition of secondary valves will provide independent isolation of the system, which allows for maintenance activities and valve cycling to occur without impacting minimum instream flow releases or unnecessary large water releases that lead to generation loss, potential turbidity concerns, and public safety concerns. Valve cycling is required per DSOD annually, with full operation performed in their presence every three years. Also included in this project are infrastructure modifications necessary to meet the MIF releases per the pending FERC license renewal settlement agreement. The capital forecast for Florence Lake - Minimum Instream Flow ("MIF") Infrastructure and Low Level Outlet Valves ("LLOV") (Phase 2) project is $3.756 million for 2023-2028.[167]

(b) Project Scope

The major scope of work items for the Florence Dam LLOV Installation Phase 2 include, but are not limited to the following:

- Provide engineered design drawings, QCIP, Project Description and other related project documents.
- Obtain agency permits/approvals (USFS, FERC, DSOD, USFW, Water Board and potentially US Army Corps of Engineers)
- Install temporary Minimum Instream Flow (MIF) release piping or bypasses as necessary to maintain stream releases throughout the project. Project assumes temporary siphon

[167] WP SCE-05 Vol. 1, p. 122. Florence Lake - Minimum Instream Flow (MIF) Infrastructure and Low Level Outlet Valves (LLOV) (Phase 2).

system installed over spillway to redirect MIF releases of 40cfs (new license minimum requirement during construction window).

- Demolish existing MIF release piping not adequately sized for new license release requirements.
- Install new 36" piping, redundant LLO valves, MIF bifurcations, and MIF piping (reference SRD Florence Low Level Outlet Phase 2 - Rev 2 cost narrative for conceptual proposal), including:
- Install secondary/redundant LLO valves/piping with bypasses/drains on both east and west 36" outlets to allow for "Double Block and Bleed" operation of the outlets.
- Install additional MIF piping from the east outlet and replace MIF piping from the west outlet (size as needed for new license release requirements, 24" piping assumed in estimate) to allow continuous MIF releases during maintenance/operation of the LLO valves.
- Install raised walkways from Arch 52 to all LLOV/MIF valves within Arch 53 to provide safe ingress/egress to the valves during operations (reference conceptual arrangement sketches provided to SRD).
- Replace MIF piping with piping sized to meet the new FERC license requirements, including sufficient piping to release approximately 400' downstream of the arch to avoid interference with the existing access road.

- Install motor operated MIF throttling valve, measuring devices (AVM) and controls in protected building at similar location to current MIF release point.
- Install solar panels, batteries, and SCADA control equipment for remote operation of the MIF system.
- Install air/vent valves to the existing upstream air supply piping, to restore the original design for air entrainment at the upstream inlet of the LLO system.
- Install drain piping from air/vent valves and all LLOV bonnet valves to drain to common header pipe (~12"), routed out of the arch for winter freeze protection operation. Drain header assumed to be routed to same discharge location of MIF piping and include an AVM to account for those releases as part of the MIF supply, when in use.
- Perform condition assessment of existing LLO piping to satisfy current outstanding FERC commitment.
- Install new coatings on all existing piping or components not adequately protected from corrosion.
- Cut, cap, and provide freeze protection (concrete encasement or other) for the existing abandoned 8" MIF piping, as close to the arch concrete as possible. Piping exits arch near east LLOV and is sleeved thru Phase 1 LLOV thrust block.
- Update the applicable FERC Exhibit Drawings, Division Station Orders and LLOV Operating Procedures for the new configuration and MIF release requirements.

(c) Project Justification and Benefit

FERC and DSOD standards mandate that each reservoir is equipped with an acceptable low-level outlet system. Upon completion of the project the Low Level Outlet System will be able to be maintained and operated on a minimum annual basis without releasing unnecessary generation water and without creating environmental or public safety concerns during valve operations. The MIF upgrades will provide the necessary release requirements per the Settlement Agreement of the pending FERC license.

c) Miscellaneous Dams and Waterways

This category covers a wide variety of miscellaneous projects that, although small, are essential for the continued reliable and safe operation of the Hydro facilities, and compliance with applicable regulations. These projects must be accomplished to maintain a reliable and safe Hydro system. Some of the work in this section is required for compliance with FERC or DSOD regulations. The cumulative capital cost for these projects is $13.730 million (nominal, work order level) for 2023-2028. Table II-30 lists Dams and Waterways Miscellaneous projects and the cost for each.

Table II-30
Miscellaneous Dams and Waterways
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 8 - Unit 1 Piping System	-	-	-	6,016	-	-	6,016
2	Vermilion - Red Ditch Seepage Mitigation	-	-	498	3,000	-	-	3,498
3	Big Creek 1 - Flowline Communication Upgrade	1,933	-	-	-	-	-	1,933
4	Big Creek 4 - Dam 7 Supervisory Controls Upgrade	-	-	206	577	-	-	783
5	Florence Lake - Ward Tunnel Power and Control Upgrade	-	-	200	500	-	-	700
6	Eastwood - Draft Tube Gate HPU, Inducation, & Locking Mechanism	-	-	-	400	-	-	400
7	Big Creek - Dam 7, Shaver & Vermilion Piezometer Telemetry	-	-	-	150	-	-	150
8	Big Creek 8 - Surge Chamber Internal Recoat	-	-	150	-	-	-	150
9	Mono Flowline Flowmeter Installation	-	-	100	-	-	-	100
10	**GRAND TOTAL**	**1,933**	**-**	**1,154**	**10,643**	**-**	**-**	**13,730**

(1) Big Creek 8 – Unit 1 Piping System

(a) Background

Big Creek powerhouses utilize high pressure water from penstocks to cool bearings and for other purposes. The piping in the Big Creek 8 powerhouse is virtually all original installation dating back as far as 1913. Recent observed leakage and repairs at Big Creek 1 and Big Creek 2 has caused SCE to inspect other Big Creek powerhouses. These inspections revealed that general erosion and corrosion compromises Big Creek 8 powerhouses as well. The thinning of the piping walls creates a significant safety hazard and a reliability risk of unplanned outages. The capital cost for the Big Creek 8 – Unit 1 Piping System project is $6.016 million for 2023-2028.[168]

(b) Project Scope

The project scope for the Big Creek 8 High Pressure Piping includes engineering, design, procurement, and installation and startup/test activities for the installation of a new primary water supply system. Additionally, removal and replacement of the bearing cooling water piping from the source at the penstocks, strainers, control valves, heat exchangers and return piping.

(c) Project Justification and Benefit

The High Pressure Piping project is necessary for both safety and reliability. To date, leaks have been limited to the piping on the low-pressure portion of the system, which is downstream of the pressure regulation equipment. However, if further piping degradation occurs, a leak could occur on a large high-pressure line and flood the powerhouse before the penstock flow could be shut off. The existing water systems do not meet current piping codes per industry standards, because the system was installed prior to industry adoption of standards. A new piping system covering over 10,000 feet will be designed to meet all current applicable code requirements. A failure of the high pressure piping system could lead to a powerhouse outage because there is currently no standby cooling system.

(2) Vermilion - Red Ditch Seepage Mitigation

(a) Background

Vermilion Valley Dam was constructed in a glacially carved valley containing glacial till and moraine deposits of Pleistocene age. The abutments of the dam are lateral

[168] WP SCE-05 Vol. 1, p. 117. Big Creek 8 – Unit 1 Piping System.

moraine ridges from past glaciation. The foundation of Vermilion Dam consists of highly complex layers and lenses of fluvial and glacial-fluvial silts, sands, gravels, and boulders. Since these materials are permeable, to varying degrees, it has been understood since the project's design stage, that the control and monitoring of seepage through the dam embankment and foundation would be critical to safe operation of the dam.

The "Red Ditch" is located along the original Mono Creek stream bed. As a part of the dam's original construction, a new low-level outlet channel was excavated to the west, which receives flow from the low-level outlet valve. The Red Ditch is now used to receive the outlet flows from the various drain systems for the dam and carry them south where they merge with the releases from the low-level outlet, forming Mono Creek.

Seepage through the permeable foundation exits the ground between the upper end of the Red Ditch and the toe of the dam and along the lower portion of the slope immediately to the north and east, resulting in saturated ground conditions. During prolonged high-reservoir conditions observed in 2011 and 2012, sand boils were observed in the Red Ditch. When these sand boils were surrounded by sandbag chimneys, fine sand accumulated in the chimneys. With the chimneys not present, it is possible that the sand would simply wash away in the red ditch flow and would not be detected. It is therefore possible that loss of sand from the foundation in this manner has been occurring since first filling of the reservoir.

The presence of significant seepage at the ground surface around the upper end of the Red Ditch, and the observation of sand boils within the ditch, are concerning because they may indicate the initiation of an internal erosion process, which ultimately could lead to dam failure. Failure would occur as the erosion removes sediment and this erosion progresses backwards towards the dam. This could cause instability of the embankment, and ultimately a breach of the crest, either by downstream slope failure, or loss of freeboard as the crest settles or collapses into a void resulting from the internal erosion. Short of actual dam failure, a seepage breakout could occur, requiring emergency responses.

Apart from the internal erosion risk, the Red Ditch has become a maintenance issue with potentially significant future costs resulting from environmental considerations. Riparian vegetation (reeds and grasses) naturally grows in and along the ditch. The ditch also gradually accumulates silt as a result of runoff into the ditch during storms. In the past, this vegetation and sediment was routinely cleared from the ditch in order to maintain unobstructed flow between the drain outlets and the river. However, the turbidity that this operation would produce is no longer considered acceptable, and therefore, the ditch hasn't been cleared in a number of years. If this work is put off indefinitely, the vegetation and siltation will eventually result in a backwater condition for the weirs, making monitoring of the leakage at the dam impossible, which would not be acceptable to Dam and Public Safety or to our regulators. Clearing of the ditch in a way that doesn't introduce turbidity into Mono Creek will be an expensive proposition, if even technically feasible. One mitigation alternative that will be evaluated involves filling of the ditch, which would eliminate future maintenance and environmental costs related to keeping the ditch open and flowing freely. The capital forecast for Vermillion – Red Ditch Seepage Mitigation project is $3.498 million for 2023-2028.[169]

(b) Project Scope

As a result of these observations and seepage study findings, SCE's Board of Consultants, has recommended a significant remediation effort, including installing a perforated collection drainpipe and an unperforated bypass pipe in the Red Ditch, both surrounded by an engineered gravel filter. This work would likely involve significant permitting efforts.

(c) Project Justification and Benefit

Studies and observations have indicated that the seepage issues present in the Red Ditch area result in both public safety and regulatory risks. This project will seek to reduce these risks by mitigation of the adverse seepage exit conditions. Such mitigation is likely to involve filtering the seepage exit (providing an engineered design that will allow the seepage flows to exit, while preventing the transportation of soil particles out of the dam's foundation). Alternatives

[169] WP SCE-05 Vol. 1, p. 118. Vermilion - Red Ditch Seepage Mitigation.

regarding the specific nature, and aerial extent of this mitigation will be developed during the conceptual engineering phase and will be evaluated with respect to cost and risk reduction potential. It should be noted that the Phase 2 Risk Evaluation for Vermilion Valley Dam in 2021 Mitigation indicated that mitigation of risks associated with the spillways should be a higher priority than mitigation of the Red Ditch seepage issues. As such, SCE has indicated to regulators its preference for performing the spillway work before the seepage mitigation. SCE has not formally received an indication from those regulators that this approach is acceptable.

6. Hydro – Prime Movers

SCE Hydro operates seventy-six generating units at thirty-two powerhouses. Water turbines convert the flow of high-pressure water into rotary motion or mechanical energy, which the generators convert into electrical power. The high-pressure water and rotary motion cause wear and tear on the turbine units. The heat created by a generator when producing electrical power also causes wear and tear on the generator bearings and windings. If timely repairs are not performed when warranted, unit failure is inevitable. Therefore, turbines and generators receive annual maintenance and inspections. They generally will operate for several decades without major refurbishment. However, when they require refurbishment, the size and specialized nature of the equipment generally results in projects exceeding $100,000 for the Hydro units under 5MW, and often exceeding $1 million for the units larger than 5 MW. Additional Prime Mover projects include replacement or refurbishment of turbine shut-off valves, runners, seals, wicket gates, and governors. The Prime Movers capital forecast for Hydro is $73.560 million (nominal, work order level) for 2023-2028.[170] Table II-31 lists the programs for the Prime Movers category.

[170] WP SCE-05 Vol. 1, pp. 133-152. Hydro Capital Expenditures – Prime Movers.

Table II-31
Prime Movers
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Generator Coils and Rewinds	7,253	4,882	12,290	13,000	8,500	6,500	52,425
2	Misc	3,292	3,320	5,129	300	-	-	12,041
3	Excitation, Govenor and Control Systems	2,805	2,370	2,869	500	-	551	9,094
4	**GRAND TOTAL**	**13,350**	**10,572**	**20,288**	**13,800**	**8,500**	**7,051**	**73,560**

a) Generator Coils and Rewinds

Hydro generators consist of the stator with windings (half-coils) and the rotating field with coils or poles.[171] Due to the high-power flows, stators require more maintenance and refurbishment than the rotating field. Rewinds indicate a total replacement of the stator half-coils, which will return the generator to an efficient and reliable condition. Some projects also require replacement of field poles. The capital forecast funds Generator Coil and Rewind projects for eight generating units, and totals $52.425 million (nominal, work order level) for 2023-2028. Table II-32 summarizes the cost of each Generator Coil and Rewind project.

[171] The "stator" is the stationary portion of a generator, within which the rotor (rotating field) revolves.

Table II-32
Generator Coils and Rewinds
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 2A - Unit 1 Generator Winding	-	-	6,500	-	-	-	6,500
2	Big Creek 1 - Unit 1 Generator Winding	-	-	-	-	-	6,500	6,500
3	Big Creek 3 - Unit 4 Generator - Rotor Electrical	-	-	-	6,500	-	-	6,500
4	Big Creek 1 - Unit 2 Generator Winding	-	1,500	5,000	-	-	-	6,500
5	Big Creek 2 - Unit 3 Generator Winding	-	-	-	-	6,500	-	6,500
6	Big Creek 2 - Unit 4 Generator Winding	-	-	-	6,500	-	-	6,500
7	Big Creek 8 - Unit 2 Generator Winding	5,700	-	-	-	-	-	5,700
8	Mammoth Pool - Unit 2 Stator Cooling Upgrade	1,517	940	-	-	-	-	2,457
9	Portal Powerhouse - Generator Winding	-	-	-	-	2,000	-	2,000
10	Big Creek 8 - Unit 1 Generator Winding	36	1,792	-	-	-	-	1,828
11	Portal Powerhouse - Cooling Coil Replacement	-	420	-	-	-	-	420
12	Big Creek 8 - Cooling Coil Replacement	-	-	230	-	-	-	230
13	Mammoth Pool - Cooling Coil Replacement	-	-	230	-	-	-	230
14	Eastwood - Cooling Coil Replacement	-	230	-	-	-	-	230
15	Big Creek 3 - Cooling Coil Replacement	-	-	115	-	-	-	115
16	Big Creek 4 - Cooling Coil Replacement	-	-	115	-	-	-	115
17	Big Creek 4 - Unit 2 Lower Guide Bearing Cooling Coils	-	-	100	-	-	-	100
18	**GRAND TOTAL**	**7,253**	**4,882**	**12,290**	**13,000**	**8,500**	**6,500**	**52,425**

(1) Background

Generators are periodically inspected to assess the condition of their windings. The stresses from producing electrical power will deteriorate insulation that separates the individual coil components. Deteriorated insulation causes shorting of the coils, which reduces the efficiency of the generator. Further deterioration and shorts result in generator failure. Temperature monitoring and testing can usually provide advance warning of a condition that could cause generator failure. An unexpected generator failure can cause a sudden large electrical short circuit of the generator while in service. Such an event could cause extensive damage to other parts of the generator and possibly to other electrical equipment connected to the generator.

SCE’s forecast is based on the specific generators that are currently undergoing repairs or are in the final planning stages of repair, along with generators forecasted to need repair prior to 2028 based on age or recent inspection. SCE’s experience shows that additional generator repairs could be needed during 2023-2028, due to unexpected in-service failures or because future inspections reveal that one or more generators are deteriorating faster than currently expected.

Conversely, SCE might learn through future inspections that one or more of the generators in the forecast (particularly those listed in the later years of the forecast) can be delayed a few additional years, should such inspection show that continued deterioration is not progressing as rapidly as forecast. The list of generators requiring repair over the next five years can change as new information becomes available.

The time a generator has been in-service is one of the best predictors used by SCE to forecast future generator repairs. Industry experience is that a stator winding life cycle of thirty years is typical, although winding life of less than or greater than thirty years is not uncommon. Other predictors considered by SCE in its generator forecast include operating conditions, and inspection and testing results. For reference, the winding ages for the eight generator rewind projects is provided in Table II-33 below.

Table II-33
Winding Age of Generator Stator Rewind Projects Exceeding $1.0 Million

Line No.	Plant	Unit	Winding Installation (Year)	Winding Age (Years)	Nameplate Capacity (MW)
1	Big Creek 2A	Unit 1	1987	38	55.0
2	Big Creek 1	Unit 1	1992	36	19.8
3	Big Creek 1	Unit 2	1989	35	15.8
4	Big Creek 2	Unit 3	1991	36	15.8
5	Big Creek 2	Unit 4	1989	37	15.8
6	Big Creek 8	Unit 2	1993	30	45.0
7	Portal Powerhouse	Unit 1	1995	32	10.8
8	Big Creek 8	Unit 1	1986	38	30.0

As shown, all eight projects have windings at or exceeding thirty years of age. These eight projects account for approximately 80% of the total Generator Coils and Rewinds forecast.[172]

[172] WP SCE-05 Vol. 1, pp. 134-144. Various – Generator Rewind Projects.

(2) Project Scope

A typical generator rewind project includes expenditures to:

- Disassemble the generator
- Remove the stator windings
- Unstack and restack the core iron if testing indicates problems
- Rewind the stator and/or rotor
- Replace field poles
- Reassemble the generator

Generator windings normally have a six month minimum lead time, so planning is essential for rewind outages.

(3) Project Justification and Benefit

The projects will return the generating unit to a reliable and safe operating condition. An unexpected generator failure can cause a sudden, large electrical short circuit of the generator while in-service. Such an event would likely cause extensive damage to other parts of the generator and possibly to other electrical equipment connected to the generator. An unexpected failure that occurs without the benefit of planning for replacement materials can result in much greater outage duration. Economic analyses (provided in confidential workpapers for those generator rewind and stator replacement projects exceeding $1.0 million) have been performed demonstrating the economic benefits of those projects.[173]

b) Miscellaneous Prime Movers

The Miscellaneous Prime Movers capital category includes turbine, generator, governor, turbine shutoff valve, and other system projects not accounted for in the other three Prime Mover categories discussed above. Miscellaneous projects in the Prime Movers category include the Big Creek 3 – Unit 5 Headcover Replacement project, which is discussed separately below with various generator replacements, governor replacements, turbine shut-off (TSO) valve control replacements, and

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173 WP SCE-05 Vol. 1, CONFIDENTIAL, pp. 1, 20-27. Various Generator – Winding B/C.

other small Prime Mover projects. The capital forecast for these six projects is $12.041 million (nominal, work order level) for 2023-2028. Table II-34 below, lists the 13 Miscellaneous Prime Mover projects and the cost for each.

Table II-34
Miscellaneous Prime Movers
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 3 - Unit 5 Headcover Replacement	-	2,700	2,700	-	-	-	5,400
2	Big Creek 3 - Unit 3 Field Pole Refurbishment and Stator Inspection	1,408	-	-	-	-	-	1,408
3	Big Creek 3 - Unit 1/2/3 Bestobel Shaft Seals Replace	-	-	1,000	-	-	-	1,000
4	Big Creek 2A - Unit 1 Turbine Shut-Off Valves	-	-	679	-	-	-	679
5	Big Creek - Vibration Monitoring Upgrade	628	-	-	-	-	-	628
6	Big Creek 2 - External Cooling System Install	575	-	-	-	-	-	575
7	Big Creek 8 - Turbine Shutoff Valve Repairs	-	520	-	-	-	-	520
8	Eastwood - Actuator Refurbishment	-	-	150	300	-	-	450
9	Big Creek 1 - External Cooling System Install	420	-	-	-	-	-	420
10	Big Creek 3 - Unit 5 Turbine Shutoff Valve Refurbishment	50	-	250	-	-	-	300
11	Big Creek 8 - Unit 1 Turbine Shutoff Valve Repairs	-	-	250	-	-	-	250
12	Big Creek 2A - External Cooling System Install	210	-	-	-	-	-	210
13	Big Creek - 102 & 103 Power Needle Refurbishment	-	100	100	-	-	-	200
14	**GRAND TOTAL**	**3,292**	**3,320**	**5,129**	**300**	**-**	**-**	**12,041**

(1) <u>Big Creek 3 – Unit 5 Headcover Replacement</u>

(a) <u>Background</u>

Big Creek 3 Unit 5 is a Francis-type vertical shaft hydraulic reaction turbine installed in 1980. No major turbine refurbishment has been performed during its operation, although the generator was rewound by General Electric in 2010. Over the past five years, the unit has experienced excessive leakage from the upper wicket gate packing areas. The packing has been replaced several times, but the packing life has continued to deteriorate due to significant wear to the headcover caused by cavitation. While the temporary modifications made to the wicket gate packing areas have provided an interim solution to the leakage concerns, and allowed SCE to defer this project and utilize the funding provided in the 2021 GRC for other higher priority work, the temporary solution has begun to wear through and replacement of the head cover is required to finalize the repairs, and to prevent a more catastrophic failure. The capital expenditure forecast for the Big Creek 3 – Unit 5 Headcover Replacement project is $5.400 million for 2023-2028.[174]

(b) Project Scope

The work includes replacing the headcover and headcover bolt; re-machining (line bore) the wicket gate bushing bores; inspecting the wicket gate inspection; repairing wicket gate foils (minor welding); replacing the wicket gate journal sleeve, bushing, and link pin; and performing minor weld repairs on the liner plates as needed. This work also includes modifying the design of the upper wicket gate bore to accept standard 5/8 inch packing; modifying the upper wicket gate packing follower to a three bolt design and a possible split design; and removing the turbine runner and for nondestructive examination. If needed, weld repairs on the turbine runner will also be performed, along with replacing the runner seals and journal bearings. The plant's 30-inch Howell Bunger pressure reducing valve will also be rebuilt as part of the project.

(c) Project Justification and Benefit

An in-service failure of the headcover could cause additional damage to ancillary equipment and poses a significant safety risk to powerhouse personnel. Replacing the headcover during a planned outage will minimize the likelihood of an extended outage that could result in lost generation for an additional twelve months or more depending on manufacturer lead time for replacement parts. An economic analysis has been performed demonstrating the economic benefit of this project at a benefit-to-cost ratio of 2.4.[175]

c) Excitation, Governor and Control System Upgrades

Excitation equipment provides the power to a generator's field windings, which is necessary to produce output power. The capital forecast for the Excitation, Governor and Control System Upgrade projects totals $9.094 million (nominal, work order level) for 2023-2028. Table II-35 summarizes the cost of each of the nine Excitation, Governor and Control System Upgrade projects.

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174 WP SCE-05 Vol. 1, p. 146. Big Creek 3 - Unit 5 Headcover Replacement.

175 WP SCE-05 Vol. 1, CONFIDENTIAL p. 19. Big Creek 3 - Unit 5 Headcover Replacement B/C.

Table II-35
Excitation, Governor and Control System Upgrades
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek - Excitation System Replacements	-	500	1,500	500	-	250	2,750
2	Big Creek - Governor Stepper Motor Upgrades	-	1,250	1,250	-	-	-	2,500
3	Eastwood - Governor Replacement	1,593	-	-	-	-	-	1,593
4	Eastwood - Excitation Replacement	1,213	-	-	-	-	-	1,213
5	Big Creek 2A - Unit 1 Governor Control System	-	445	-	-	-	-	445
6	Bishop 3 - Unit 3 Excitation System	-	-	-	-	-	233	233
7	Big Creek 2A - Unit 2 Governor Control System	-	175	-	-	-	-	175
8	Big Creek 3 - Unit 2 Governor - Control System	-	-	119	-	-	-	119
9	Fontana - Unit 2 Governor Control System	-	-	-	-	-	67	67
10	**GRAND TOTAL**	**2,805**	**2,370**	**2,869**	**500**	**-**	**551**	**9,094**

(1) Big Creek – Excitation System Replacements

(a) Background

Excitation equipment is vital to producing and controlling electrical power from a generation unit. The excitation system energizes and controls the generator's magnetic field. The generator rotor is a large electro-magnet that rotates inside the stationary windings. The magnet's rotation causes the windings to generate electrical power, which is proportional to the magnet strength. The rotating turbine drives this magnet.

The excitation systems are approaching the end of their reliable life. Excitation systems are intrinsically important to the operation of our generating units. While excitation transformers and power conversion bridges can last up to 40 years, the solid state and digital components only have a 15 year reliable operating life. The current excitation systems at Big Creek have been in service since 1986 (PPH), 2006 (BC2A, BC4), 2007 (BC8), 2009 (MPPH), 2010 (BC3, BC2 U5/6), 2011 BC1 U3/4, BC2 U3/4), and 2012 (BC1 U1/2). SCE purchased a set of spare parts (an entire replacement excitation system and several circuit boards) but has depleted the stock of spares over the last few years to keep the excitation systems operable. The existing model of the excitation systems is no longer manufactured. A loss of an excitation system would result in loss of a generating unit. It is estimated that the likelihood of failure (LOF) for the present systems ranges from 50% to 10% oldest to newest units, but that all units will attain a 63% LOF at 15 years except PPH which would occur 40 years.

The capital expenditure forecast for the Big Creek – Excitation System Replacement project is $2.750 million for 2023-2028.[176]

(b) Project Scope

Excitation system replacement scope includes removing existing excitation switchgear including the power bridges, firing circuits, automatic voltage regulator, power system stabilizer, and controls, and the power transformer. A new, digital excitation system, including a new power transformer, will be installed similar to what SCE has done on other Northern Hydro generators. The governor system will be upgraded with new electronic controls and new control valves. The liquid rheostat, pony motor, and control system will be replaced by a new solid-state drive system.

Programmatic approach to the replacement of the excitation systems at Big Creek. Portal Powerhouse will require a complete excitation system (it is an older model than the others) including a new excitation transformer, power rectifier bridge, and new electronics and control relays. The remaining excitation systems will require a front-end upgrade including replacement of the electronics and control relays only. Demolition and installation work to be performed by contract labor, with testing and commissioning performed by SCE personnel. Work can be performed during annual maintenance outages and should take approximately 3 weeks per unit.

(c) Project Justification and Benefit

Replacement of the obsolete excitation equipment with new digital static excitation systems is necessary to improve reactive power performance that will assist in mitigating grid-instability problems. Additional benefits of replacing the exciters before in-service failure include preventing extended outages and improving reliability. Individual economic analyses

[176] WP SCE-05 Vol. 1, p. 150. Big Creek – Excitation System Replacements.

have been performed for each project in the Big Creek – Excitation System Replacement program, demonstrating the economic benefit of these projects at a cost/benefit ratio ranging from 9.5 to 30.3.[177]

(2) Big Creek – Governor Stepper Motor Upgrades

(a) Background

Current remote control of turbine governors is by way of an open control loop conducted by sending DC electrical pulses and durations to a Speeder Motor that mechanically drives governor hydraulic positioning to control waterflow into the turbine that produces and controls electrical energy output from the coupled generator.

The current control circuit developed a reliability issue with the DC circuit interruption relay. In previous years experimentation with Speeder Motor RPM changes were implemented to attempt to minimize the number and duration of electrical pulses initiated by the Ovation control system through an "Ice Cube" relay that actually interrupts the DC circuit to the Speeder Motor. Inconsistent Speeder Motor application resulted with no significant improvement to relay reliability.

The capital expenditure forecast for the Big Creek – Governor Stepper Motor Upgrades is $2.500 million for 2023-2028.[178]

(b) Project Scope

The project replaces the Speeder Motor with a Stepper Motor coordinated by a programmable logic controller (PLC) that provides a constant smooth electrical drive with a closed control loop. The PLC provides for correlation between the turbine mechanical gate position and the generator electrical output. The PLC automatically captures and updates the associated process conditions (head pressure, temperature, density) that marks the current control signal setpoint dispatch to be referenced in the next future dispatch for that same control signal setpoint.

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177 WP SCE-05 Vol. 1, CONFIDENTIAL pp. 6-17. Various Big Creek – Excitation System Replacements B/C.

178 WP SCE-05 Vol. 1, p. 151. Big Creek – Governor Stepper Motor Upgrades.

(c) Project Justification and Benefit

The Speeder Motor replacement project is identified as a single initiative within the larger scope of the “Big Creek CAISO Control Signal Accuracy Project” that will deliver an incremental improvement in the projects control signal accuracy as required by the CAISO of resources certifying for Energy Regulation Market participation. Currently CAISO requires Generation Resources to meet and maintain > 25% Control Signal Accuracy. This current accuracy requirement is predicted to increase in time with Energy Storage deployments. CAISO has already issued SCE performance warning notices for potential de-certification, as SCE is not meeting the >25% requirement.

The proposed modification provides predetermined mechanical setpoints that improves process control by expediting hardware response time to control signal dispatch.

7. Hydro – Electrical Equipment

This section describes the electrical equipment at the Hydro facilities that must be refurbished or replaced. Control systems, circuit protection, and transformers wear out over time and require replacement. Larger projects in this category typically involve high voltage plant circuit breakers, transformers, or automation work. Plant circuit breakers are large devices that protect and disconnect Hydro facilities from the transmission network. Step-up transformers convert the Hydro plant voltage to that of the transmission network or grid. Automation equipment is used to remotely or efficiently control processes at powerhouses and ancillary facilities.

The Electrical Equipment capital expenditure forecast for these projects is $50.005 million (nominal, work order level) for 2023-2028.[179] Table II-36 lists the programs within the Electrical Equipment category.

[179] WP SCE-05 Vol. 1, pp. 153-161. Hydro Capital Expenditures – Electrical Equipment.

Table II-36
Electrical Equipment Programs
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Relays and Control Cables Replacement	4,000	5,500	9,475	7,000	8,500	7,500	41,975
2	Misc	876	5,000	828	825	-	500	8,030
3	**GRAND TOTAL**	**4,876**	**10,500**	**10,303**	**7,825**	**8,500**	**8,000**	**50,005**

a) Relays and Control Cables Replacement

(1) Background

Protective relays are a critical electrical component designed to trip a circuit breaker when an electrical fault is encountered or identified. Its main function is to protect power system elements, which are critical to reliable and safe operation of generation units. A failure of the protection system can result in equipment damage, personnel hazards, wide area disturbances, unplanned outages, or potential equipment fires.

Many of the existing relays at SCE's smaller powerhouses are the original powerhouse equipment engineered and manufactured at the turn of the 20th century. They are well beyond their expected lifespan and SCE has been utilizing replacement parts cannibalized from out-of-service exciter circuit breakers (of the same vintage) which are almost exhausted; spare parts from outside vendors are no longer available. Relays at SCE's large Hydro facilities in Big Creek were replaced during the 1970s and 1990s, and many have, or will very shortly, exceed their expected useful life of 30 years. In the past 5 to 10 years SCE has on average experienced one relay failure per year at Big Creek and expects this trend to increase. In-service relay failures are undesirable as they can lead to ancillary equipment damage that would necessitate an extended outage requiring extensive repairs. Currently SCE has only 11 spare relays remaining, most of which are overload relays. Due to the shortage of available replacement parts a non-overload relay failure or depletion of the overload relay inventory could potentially lead to an extended outage lasting up to 1- year, which could result in local grid reliability issues.

SCE estimates the need to replace approximately 267 relays over the course of the next 10 years. Execution will be performed in multiple phases to allow water movement and other powerhouses to stay online while work is being performed. SCE has prioritized the planned replacements of its larger assets and will utilize lessons learned from first replacements to improve execution and reduce risk in latter replacements. The capital estimate for the Relay and Control Cable Replacement projects is $41.975 million (nominal, work order level) for 2023-2028.[180] Table II-37 below provides the list of these projects and the cost for each replacement.

Table II-37
Relay and Control Cable Replacements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek - Relay and Control Cables Replacement Program	4,000	5,500	7,000	7,000	7,000	7,500	38,000
2	Bishop 2 & 3 - Relay Replacement	-	-	2,475	-	-	-	2,475
3	Kern River 3 - Relay Replacement	-	-	-	-	1,500	-	1,500
4	**GRAND TOTAL**	**4,000**	**5,500**	**9,475**	**7,000**	**8,500**	**7,500**	**41,975**

(2) Project Scope

The Big Creek - Relays and Control Cables replacement program involves engineering, procuring and installing new 2.4kV and 66kV circuit breakers. In each case the condition of the mounting pads will be investigated for their ability to serve safely over the life of the new breakers, and they will be re-engineered if there is any doubt of their ability to provide stability as required. All of the new breakers to be procured are anticipated to be gas-filled breakers to reduce the exposure to the environment of having oil-filled breakers in the plant.

(3) Project Justification and Benefit

These breakers must perform reliably to maintain station power for generation and transmission operations. Current equipment is outdated, and their reliability is below utility system standards. This new equipment will return the station reliability to utility system standards.

[180] WP SCE-05 Vol. 1, pp. 155-157, 159. Various - Relay and Control Cable Replacement projects.

b) Miscellaneous Electrical Equipment

The projects in this category include a wide variety of work and provide for replacing aging electrical equipment in the system. The capital forecast for these projects is $8.030 million (nominal, work order level) for 2023-2028.[181] Table II-38 lists the projects and the cost for each replacement.

Table II-38
Miscellaneous Electrical Equipment
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Eastwood - Circuit Breaker Replacement	-	5,000	-	-	-	-	5,000
2	Big Creek 1 - Bank 3 & 4 Circuit Breaker Replacements	-	-	200	400	-	-	600
3	Big Creek 8 - Back-up Power Assessment	-	-	528	-	-	-	528
4	Big Creek 2A - #1 Bank Transformer Replacement	-	-	-	-	-	500	500
5	Huntington Lake - Dam 1 Fiber Communications/BC-Dam 1 Flowline Comms Upgrade	418	-	-	-	-	-	418
6	Big Creek Squelch	283	-	-	-	-	-	283
7	Big Creek 1 - Uninterruptible Power Supply	175	-	-	-	-	-	175
8	Portal Powerhouse - Uninterruptible Power Supply	-	-	-	175	-	-	175
9	Big Creek 8 - Generator Bus Insulation	-	-	-	150	-	-	150
10	Big Creek 4 - Unit 2 Rochester/Temp instr/Equip	-	-	100	-	-	-	100
11	Bishop 2 - Unit 1 Circuit Breaker (Oil)	-	-	-	100	-	-	100
12	**GRAND TOTAL**	**876**	**5,000**	**828**	**825**	**-**	**500**	**8,030**

(1) Eastwood – Circuit Breaker Replacement

(a) Background

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.[182] This failure caused the breaker to fail, 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.

(b) Project Scope

The proposed scope of this project is to replace the unit circuit breaker with a like in kind or similar model. The project would also include demolition and rebuilding of the concrete room that houses the breaker. The paint on the outside of the concrete wall contains lead which requires remediation.

[181] WP SCE-05 Vol. 1, p. 157. Eastwood Circuit Breaker Replacement.

[182] The circuit breaker was installed in the early 2000s.

(c) Project Justification and Background

Eastwood will be in forced outage until this piece of equipment is replaced. Lead time for the breaker is estimated at 16 months. An economic analysis has been performed demonstrating the economic benefit of this project at a cost/benefit ratio of 6.0.[183]

(2) Miscellaneous Electrical Equipment – Other Projects

(a) Background

The various other projects in this category involve replacing aging equipment in the system. Most of the equipment is over fifty years old and has surpassed their original expected life and hence is a continuing source of outages that affect system reliability.

(b) Project Scope

The projects include a variety of small replacement projects for service banks, generator relays, bus work, station light and power, low voltage switchgear, and other miscellaneous projects.

(c) Project Justification and Benefit

The projects are needed to provide reliable and safe operations for the Hydro equipment. All of the projects in this category involve replacing old equipment that compromise the reliability of various parts of the Hydro electrical system. In addition, the proposed projects will bring the equipment up to utility-system standards. The new equipment will decrease the likelihood of outages within the system, which could extend for unacceptable lengths of time.

8. Hydro – Structures and Grounds

This category involves needed work related to various structures including the powerhouses, roofs, cranes, heating ventilation and air conditioning, and to infrastructure including roads, bridges, paving, fencing and gates, fire and water systems, and wastewater projects. The major projects in this category are replacing high-pressure piping, completing road and bridge improvements, and installing dam safety video surveillance equipment. The Structures and Grounds capital forecast for

[183] WP SCE-05 Vol. 1, CONFIDENTIAL, p. 29. Eastwood Main Circuit Breaker Replacement B/C

Hydro projects is $14.732 million (nominal, work order level) for 2023-2028.[184] Table II-39 lists the programs and major projects for the Structures and Grounds category.

Table II-39
Hydro - Structures and Grounds Projects
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Misc	2,968	639	1,089	428	339	339	5,800
2	Safety Improvements	774	386	1,030	966	816	55	4,026
3	Roadway Improvements	700	-	300	2,206	-	150	3,356
4	Powerhouse and Building Refurbishments/Improvements	-	-	1,050	-	-	500	1,550
5	**GRAND TOTAL**	**4,443**	**1,024**	**3,468**	**3,600**	**1,154**	**1,043**	**14,732**

a) Miscellaneous - Structures and Grounds

This category of work contains various projects, such as the Big Creek 4 – Dam 7 Generator Room Piping Replacement, Capital Spare Parts & Tools and the Eastern Operations Generation Control Center improvement projects.

The capital forecast for these projects is $5.800 million (nominal, work order level) for 2023-2028. Table II-40 lists the Miscellaneous - Structures and Grounds projects and the cost for each.

Table II-40
Miscellaneous Structures and Grounds Projects
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 4 - Dam 7 Generator Room Piping Replacement	2,219	-	-	-	-	-	2,219
2	Big Creek - Spare Parts & Portable Tools	339	339	339	339	339	339	2,031
3	Eastern Operations Generation Control Center (EOGCC) Improvements - Bishop/Mono Basin	-	300	750	-	-	-	1,050
4	Big Creek 4 - High Pressure Piping Replacement	410	-	-	-	-	-	410
5	Kern River 3 - Domestic Water System Piping Replacement	-	-	-	75	-	-	75
6	Florence Lake - Gate House Solar System Replacement	-	-	-	14	-	-	14
7	**GRAND TOTAL**	**2,968**	**639**	**1,089**	**428**	**339**	**339**	**5,800**

[184] WP SCE-05 Vol. 1, pp. 162-175. Hydro Capital Expenditures – Structures and Grounds.

(1) Big Creek 4 - Dam 7 Generator Room Piping Replacement

(a) Background

The Big Creek 4 – Dam 7 generator room piping is significantly degraded and in need of repair. Failed valves could result in excessive water release and a loss of generation. The capital estimate for Big Creek 4 - Dam 7 Generator Room Piping Replacement project is $2.219 million for 2023-2028.[185]

(b) Project Scope

The scope of the project is to repair/replace the Big Creek 4 - Dam 7 Generator room piping and valves and installation of a duplex pump system to add redundancy to the pumping system. The Generator room is difficult to access and requires climbing down steps and ladders to the lowest point within the dam structure and there are no mechanical means to haul equipment or material to this location. There are instead a series of rebar hooks above each ladder/stairs that are utilized to raise and lower material. As such, there will be a higher than normal labor costs associated with performing this work.

(c) Project Justification and Benefit

Repairing/replacing the current generator room piping and valves will ensure they are capable of maintaining the required minimum instream flow releases as required by FERC. An in-service failure of either the piping and/or pumping system(s) would be undesirable as the area would fill with water and the process would then require an underwater repair/replacement which would increase the project complexity and cost.

(2) Big Creek - Spare Parts & Portable Tools

(a) Background

SCE Hydro stocks spare parts for generators and turbines to ensure plant reliability. While replacement of portable tools and equipment reflects our need to replace aging

[185] WP SCE-05 Vol. 1, p. 163. Big Creek 4 - Dam 7 Generator Room Piping Replacement

and worn tools in years 2023 through 2028. The capital estimate for Big Creek - Spare Parts & Portable Tools is $2.031 million for 2023-2028.[186]

(b) Project Scope

SCE's forecast reflects increased spending compared to prior years, due to increases in portable as well as principal tools and equipment due to increased staffing. This equipment will include eligible replacements such as small pumps, compressors, or portable tools such as Megger machines that need to be replaced as they fail during the years.

(c) Project Justification and Benefit

These spare parts and tools are integral to keeping the larger powerhouses operating in a safe condition. Replacement of worn parts and aging equipment ensures reliability of Hydro facilities and reflects our need to replace aging and worn tools in years 2023 through 2028.

b) Structures and Grounds – Safety Improvements

This category of work contains various projects, such as the Big Creek – Overhead Crane Load Indication Initiative, Eastwood - Fire Protection System Replacement and the Mammoth Pool – Fire Suppression System

The capital forecast for these projects is $4.026 million (nominal, work order level) for 2023-2028. Table II-41 lists the Safety Improvements projects and the cost for each.

[186] WP SCE-05 Vol. 1, p. 169. Big Creek - Spare Parts & Portable Tools.

Table II-41
Structures and Grounds – Safety Improvements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek - Overhead Crane Load Indication Initiative	-	-	150	761	761	-	1,672
2	Eastwood - Fire Protection System Replacement	500	-	400	-	-	-	900
3	Mammoth Pool - Fire Supression System	-	50	400	150	-	-	600
4	Big Creek - OSHA Guard Program	220	281	-	-	-	-	500
5	Eastern Blanket: Portable Tools	55	55	55	55	55	55	328
6	Florence Lake - Intake Safety Barrier Installation	-	-	25	-	-	-	25
7	**GRAND TOTAL**	**774**	**386**	**1,030**	**966**	**816**	**55**	**4,026**

(1) Big Creek – Overhead Crane Load Initiative

(a) Background

The proposed project will include an engineering investigation into all Big Creek Powerhouses to review the condition of the existing overhead cranes and their limitations to load indication and load limits. Reports of the conditions of the cranes along with a comparison of the crane capacity and crane expected load lifts will be presented to the initiative team and reviewed. As needed if a crane does not have load indication, load indication sill be scoped, designed and installed. If a crane electrical and breaking system will allow for a load limit system it too will be designed and installed. The capital estimate for Big Creek – Overhead Crane Load Initiative project is $1.672 million for 2023-2028.[187]

(b) Project Scope

A complete crane overhaul/upgrade was an alternative considered in conjunction with this project. This would likely result in multiple lines of defense against a future crane overload. This would also include a crane capacity upgrade. The cost and required outage time for this alternative did not appear to provide the received value from the alternative when compared to the less invasive and lower cost options of providing the load indication.

[187] WP SCE-05 Vol. 1, p. 165. Big Creek – Overhead Crane Load Initiative.

Additionally, a do-nothing alternative was considered and deemed not preferable given the understanding of a recent failure as a result of the lack of load indication on the crane. With load indication included on the crane control systems the crane operator will be able to monitor each lift and make decision to suspend operation of a lift if the indicated load is encroaching on the rated crane capacity. With this additional operational information, the crane will have another tool to prevent a potential overload condition in the future.

(c) Project Justification and Benefit

The scope of this project is not believed to provide impact to environmental, biological and cultural conditions. No significant change to existing infrastructure appearance is anticipated to take place a part of the proposed project scope. Any localized structural improvements will be done so as to not adversely impact the visual appearance of the existing in place structure. Any visual impacts will be reviewed with SCE Environmental, biological, and cultural teams.

c) Structures and Grounds – Roadway Improvements

This category of work contains various projects, such as the Eastwood – Access Road Repave, the Big Creek – Mid-Canyon Road Culvert Replacement and Huntington Lake-Bridge replacement projects.

The capital forecast for these projects is $3.356 million (nominal, work order level) for 2023-2028. Table II-42 lists the Roadway Improvement projects and the cost for each.

Table II-42
Structures and Grounds – Roadway Improvements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Eastwood - Access Road Repave	-	-	-	2,000	-	-	2,000
2	Big Creek - Mid-Canyon Road Culvert Replacement	700	-	-	-	-	-	700
3	Huntington Lake - Bridges	-	-	-	206	-	-	206
4	Big Creek 1 - Culvert Replacement	-	-	150	-	-	-	150
5	Kern River 3 - Adit 9 & 10 Access Road Replacement	-	-	-	-	-	150	150
6	Kern River 1 - Intake & Stark Road Refurbishment	-	-	150	-	-	-	150
7	**GRAND TOTAL**	**700**	**-**	**300**	**2,206**	**-**	**150**	**3,356**

(1) Eastwood – Access Road Repave

(a) Background

The Eastwood access road is the only road that provides vehicle access to Eastwood Powerhouse. This road begins at Hwy 168 and runs parallel to Shaver Lake. Due to the fact this road is at high evaluation in the Sierra mountains, the road is subject to extreme weather conditions. The road encounters high snow drifts and icing conditions that requires large snow removal equipment. Depending on the severity of the storm, snow and ice removal may be required daily to ensure access to the Powerhouse is maintained. Because of the extreme conditions at Eastwood and the heavy equipment that is required to maintain access, this road deteriorates rapidly and needs replacement or access will not be ensured to the Plant. The capital forecast for Eastwood - Access Road Repave project is $2.000 million for 2023-2028.[188]

(b) Project Scope

Remove existing deteriorated asphalt and replace with new paving.

(c) Project Justification and Benefit

No alternative or contingence plan exists, as road must be repaired to maintain access to 200 megawatt Plant.

d) Structures and Grounds – Powerhouse and Building Refurbishments/Improvements

This category of work contains various projects, such as the Big Creek, Sierra and Huntington Lake Roof replacement projects.

The capital forecast for these projects is $1.550 million (nominal, work order level) for 2023-2028. Table II-43 lists the Powerhouse and Building Refurbishments/Improvements projects and the cost for each.

[188] WP SCE-05 Vol. 1, p. 166. Eastwood - Access Road Repave.

Table II-43
Structures and Grounds – Powerhouse and Building Refurbishments/Improvements
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Big Creek 1 & 2 - Roof Replacements	-	-	500	-	-	500	1,000
2	Sierra Powerhouse - Repair/Replace Roof	-	-	350	-	-	-	350
3	Huntington Lake - Gate 1B Roof	-	-	100	-	-	-	100
4	Big Creek 8 - OSHA Fall Protection Upgrades	-	-	100	-	-	-	100
5	**GRAND TOTAL**	**-**	**-**	**1,050**	**-**	**-**	**500**	**1,550**

(1) Roof Replacements

(a) Background

The aging membrane roofs on the powerhouses are starting to fail. Rain is getting under the membrane and no longer flowing to the drain spouts. This is causing increased damage to the membrane system as well as leading to rot of the substructure of the roof. During heavy rain events, water is finding its way into the powerhouse through leaks and dripping onto machinery or running down the walls. This will lead to damage of shop equipment and potential failure of generating units or associated electrical equipment. The capital forecast for Big Creek 1 & 2 Roof Replacements project is $1.000 million for 2023-2028.[189]

(b) Project Scope

Replace entire membrane system and any damaged substructure that has signs of rot. Install new roof that allows water to flow into roof drains and off of powerhouse footprint.

(c) Project Justification and Benefit

Prevention of further damage to shop equipment and failure of generating units or associated electrical equipment.

[189] WP SCE-05 Vol. 1, p. 167. Big Creek 1 & 2 Roof Replacements.

9. **Hydro – Climate Adaptation Vulnerability Assessment (CAVA)**

This category of work contains various projects, such as the Big Creek – Power and Communications Redundancy, Climate Change SEFM Studies & Installation of Monitoring Equipment and Florence, Huntington Lakes-Installation of debris booms projects.

The capital forecast for these projects is $4.500 million (nominal, work order level) for 2023-2028.[190] Table II-44 lists the Hydro - CAVA projects and the cost for each.

Table II-44
Hydro - CAVA
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	CAVA - Big Creek - Power and Communications Redundancy	-	-	625	1,125	1,125	625	3,500
2	CAVA - Climate Change SEFM Studies & Installation of Monitoring Equipment	-	-	125	125	125	125	500
3	CAVA - Florence, Huntington Lakes-Installation of debris booms	-	-	250	250	-	-	500
4	**GRAND TOTAL**	**-**	**-**	**1,000**	**1,500**	**1,250**	**750**	**4,500**

a) CAVA – Big Creek Power and Communications Redundancy

(1) Background

Many of SCE’s high hazard dams rely on power and communications through local distribution and fiber networks. These systems are reliable but could burn during a wildfire. During the 2020 Creek Fire, SCE lost road access to most of its powerhouses and many remote hydro support systems went offline including SCADA due to burned power and communication lines. This reduced SCE's situational awareness of the high hazard dam portfolio and prevented access to perform water management duties. There could be a scenario where this loss of access during an event could cause a dam safety concern and lead to cascading consequences. Though the likelihood of this is low since a fire and storm would be happening in close proximity in time and space. The most likely scenario is a loss that is not repaired promptly and allows the events to cascade. A Dam safety concern would have substantial life safety, economic environmental and compliance consequence. This

[190] WP SCE-05 Vol. 1, pp. 176-180. Hydro Capital Expenditures – Climate Adaptation Vulnerability Assessment.

alternative was developed through the CPUC CAVA program. The capital forecast for the CAVA – Big Creek Power and Communications Redundancy is $3.500 million for 2023-2028.[191]

(2) Project Scope

This project will evaluate Big Creek systems to identify locations where power and communications redundancy would be helpful to maintain situational awareness and water control during events such as wildfire. The project will also identify water control systems where remote operability is warranted. There could be impacts to generation if the valves are inoperable during construction.

(3) Justification and Benefit

By providing redundant power and communication pathways, wildfire impacts such as burned down lines will not completely hinder SCE's ability to monitor and control water within the Big Creek Hydro system. Local power and communications through solar, batteries and satellite dishes would allow support systems to continue to function through wildfire and other events. The project may also allow for additional benefits with normal operations as well.

b) CAVA - Climate Change SEFM Studies and Installation of Monitoring Equipment

(1) Background

The changing climate has impacts on the behavior of watersheds within the mountainous regions in which SCE’s hydroelectric generation assets reside. The changed magnitude, frequency, and variability of water that flows into the reservoirs has effects on hydrogeneration capacity and dam safety. Key climate variables that impact these inflows include temperature and precipitation. On their own, neither variable can convey meaningful information on the behavior of the reservoirs as they are correlated within the hydrologic models and reality. An example of the correlation is temperature’s effect on the type of precipitation that falls. Additionally, it is difficult for simple models to capture events such as rain-on-snow that are crucial to dam safety.

[191] WP SCE-05 Vol. 1, p. 178. CAVA - Big Creek Power and Communications Redundancy.

While climate change will have global impacts, it is not clear what effect climate change will have on the local watersheds relevant to SCE's assets. With this project SCE will perform site-specific hydrologic studies that will model the effects of climate change. These studies will provide the necessary design information relevant to planned and future capital work. The goal is to capture the range of possible futures sufficiently such that capital improvements are robust and adaptable to changing climate for operational and dam safety needs.

Since data is critical for both the large floods and operational inflow forecasting, the hydrologic analysis will inform SCE on the construction of new data gathering stations to monitor relevant variables. These variables will be fed back through the models to recalibrate with site-specific information such that SCE can better manage water through the high hazard dams. This is especially critical for operational forecasting as current methods rely on historical data which will become increasingly inaccurate as climate changes. The capital forecast for the CAVA - Climate Change SEFM Studies and Installation of Monitoring Equipment project is $0.500 million for 2023-2028.

(2) Project Scope

Current tools are not sufficiently detailed to provide the necessary hydrologic information for decision-making for hydroelectric generation and dam safety. As noted, the climate variables are correlated and so SCE is proposing to develop these detailed models, simulate climate projections within the models, and determine the effect climate change has on flood risk at the dams.

There is continued uncertainty about which of the many climate projections will occur so SCE will perform the analyses with two bounding cases: Warm-Wet and Hot-Dry. These bounding cases are meant to capture a reasonable range of climate projections such that capital improvement projects are likely to be robust in the future.

The two bounding cases are based on an ensemble of 10 global climate models. The ensemble of projections is then broken down statistically to obtain the 10th and 90th percentile values for temperature and precipitation. Warm-Wet represents 10% of temperature and 90% of precipitation and Hot-Dry is the 90% of temperature and 10% of precipitation.

The analyses will be performed on SCE's high hazard dams. High hazard dams are defined as having the potential for life loss should a failure occur. It is noted that the likelihood and therefore risk of failure occurring is not accounted for in this definition. The prioritization schema for the analyses will be determined by SCE' Dam and Public Safety team. The prioritization schema can be based on future, relevant capital improvements, risk, and/or importance in water management.

(3) <u>Justification and Benefit</u>

A pilot study has been performed as part of the Commission's mandated Climate Adaptation Vulnerability Assessment ("CAVA"). The methodology discussed was successfully completed at two high hazard dams on both the western and eastern side of the Sierra Nevada Mountain range where SCE's hydroelectric assets reside. The results indicate that there are significant changes to the flood-frequency relationship due to climate change on both sides of the Sierras. These changes have important implications for decision making for the two dams.

These results suggest that similar changes are possible at other SCE's high hazard dams and that further analyses would be prudent where necessary.

It should be noted that the type of analyses described here are at the forefront of hydrologic analyses. While it is the future and other dam owners are starting to pursue similar types of work, there is a current lack of widespread expertise, consultants, and regulatory acceptance to perform and review the analyses. These challenges are mitigated as SCE has experience and an existing relationship with a consultant that is qualified to perform this work.

III.

FOSSIL FUEL GENERATION

A. Overview of Fossil Fuel Generation

SCE owns and operates the gas-fired Mountainview Generating Station ("Mountainview") combined-cycle power plant with a capacity of 1,110 MW (nominal);[192] five combustion turbine Peaker power plants ("Peakers") with an aggregate capacity of 245 MW; six diesel engine generators with a capacity of 9.4 MW; twenty-three 65 kilowatt (kW) propane-fueled micro turbines, and one 1.0 MW energy storage battery at SCE's Pebbly Beach Generating Station ("PBGS");[193] and two fuel cell generating plants with a combined total capacity of 1.5 MW. This section of testimony presents SCE's 2025 Test Year O&M expense forecast of $29.703 million (constant 2022 dollars) for Mountainview, $8.626 million for the Peakers, and $5.808 million for Catalina.[194] SCE also presents its 2023-2028 capital expenditure forecast of $84.765 million (nominal dollars, work order level) for Mountainview, $11.480 million for the Peakers, $6.185 million for Catalina, and $1.510 million for Fuel Cell.[195]

B. Mountainview Generating Station

1. Summary of Request – Mountainview

The 2025 O&M expense forecast for Mountainview is $29.703 million.[196] Forecasted costs includes the costs of major maintenance planned for 2023 through 2027. As in past years, Mountainview O&M expense is expected to continue to vary year-to-year because of the normal fluctuations in annual major maintenance expense. The 2025 Test Year O&M expense forecast is based

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[192] In 2016 the Mountainview combustion turbines were upgraded, during a routine overhaul, which raised the plant's California Energy Commission specified 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 weather.

[193] This Energy Storage Battery is part of the Catalina generation, and not related to the Energy Storage activity discussed in Exhibit SCE-02 Vol. 4 Part 1, Grid Modernization, Grid Technology, Energy Storage.

[194] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[195] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[196] WP SCE-05 Vol. 1, pp. 181-186. Mountainview Operations and Maintenance Recorded/Forecast Summary.

on 2022 recorded expense for labor, a five-year average of the 2018 through 2022 recorded expense for non-labor and other, and one-fourth (*i.e.,* the 2025 through 2027 annual average) of the forecasted cost of the Mountainview Major Inspection ("MI") Overhaul planned for 2023 through 2027.

Each of the combustion turbines at Mountainview undergoes major maintenance every 32,000 Factor Fired Hours ("FFH"), per Original Equipment Manufacturer (OEM) guidelines. This major maintenance consists of either a Hot Gas Path Inspection ("HGPI") overhaul or Major Inspection overhaul. HGPI overhauls were performed on all four combustion turbines (two per unit) in 2016; with the next MI overhaul scheduled to occur each Spring over the course of four years (2024 through 2027). All four combustion turbines-generators and two steam turbine-generators will receive major maintenance during this period.

The capital forecast for Mountainview is $84.765 million for 2023-2028.[197] [198] This forecast largely includes projects required to sustain station reliability. Additional information regarding Mountainview capital projects is contained in Section III.B.5 of this chapter.

2. Overview of Mountainview Generating Station

SCE owns and operates Mountainview, located 90 miles east of Los Angeles in Redlands, California. Mountainview consists of two combined cycle generating units, Units 3 & 4. Mountainview went into commercial service in December 2005 (and achieved full commercial operation in early-2006) with costs recovered under an approved power purchase agreement ("PPA") between SCE and Mountainview Power Company, LLC ("MVL"), a wholly owned subsidiary of SCE. In 2009, Mountainview transitioned from PPA cost recovery to base rate cost recovery, as approved by the Commission in SCE's 2009 GRC (D.09-03-025).

a) Mountainview Plant Description and Operating Profile

Mountainview uses combined cycle technology to generate 1,110 MW (nominal) of power, with low air pollutant emissions and high fuel economy. Each of the Units 3 & 4 has two

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[197] WP SCE-05 Vol. 1, pp. 191-209. Mountainview Capital Expenditures.

[198] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

General Electric “F-class” combustion turbines and one GE “D11” steam turbine. Each combustion turbine discharges its hot exhaust gas into a heat recovery steam generator (“HRSG”). On each unit, steam from that unit’s two HRSGs combines to power that unit’s single steam turbine.

Figure III-13 provides an overhead photograph of Mountainview, which includes the following additional major equipment components:

- Water treatment system to treat cooling tower water, thereby minimizing plant wastewater discharge
- Rotary screw natural gas compressors to boost pressure for fuel injection into the gas turbines
- Inlet primary and secondary air filters with evaporative air coolers providing improved performance with greater output for each combustion turbine
- Selective catalytic reduction (“SCR”) to control plant NOx air pollution emissions
- Carbon monoxide (“CO”) catalyst to control plant CO air pollution emissions
- Cooling towers with associated circulating water systems for condensing turbine exhaust steam and for cooling other plant equipment
- A 1,500 kilowatt diesel generator to provide auxiliary power to portions of the plant in case of a power failure

Figure III-13
Mountainview Generating Station

Mountainview is typically operated as “intermediate duty” capacity where the units are dispatched in a manner that follows customer load demand. Mountainview normally generates during peak load periods through the summer months, specifically on weekdays and into the evening. The Mountainview units are relatively quick starting and are highly fuel efficient. Over the past five-years (*i.e.,* 2018-2022) Mountainview Units 3 & 4 have generated on average 2,699,573 net megawatt-hours (MWh), with an overall average capacity factor of 29.3%. SCE's TY 2025 forecast assumes that Mountainview will continue to operate at this level.

b) Mountainview Operational Objectives

(1) Safety

Mountainview’s highest priority is worker and public safety. The station maintains a robust safety program. SCE Corporate Safety supports the station with safety specialists, as well as subject matter experts and various safety programs and resources. All required safety plans and programs are documented and reviewed periodically for updates. Employees are trained on a variety of required and optional safety topics, and contractors working onsite must receive a site safety orientation prior to working.

Lockout-tagout and work-authorization programs are utilized to provide a solid framework for thorough communications between the control center and any employee working onsite. The station's safety practices include daily tailboards between production supervisors and employees where hazard mitigation measures specific to that day's work are discussed. The Los Angeles Basin safety team is led by and composed of non-management employees from each job classification working at facilities within the Los Angeles Basin, which includes Mountainview. The safety team is empowered to make substantial changes to station conditions to correct unsafe conditions or make safety improvements. All employees are also involved in periodic safety meetings on a variety of topics. Safety concerns are gathered through a Safety Observation program and tracked to closure using the Work Management system.

(2) Environmental and Regulatory Compliance

SCE Corporate Environmental and Compliance groups provide significant support to Mountainview. Mountainview's air quality emissions are regulated by several permits, licenses, and other requirements, including a RECLAIM/Title V permit from SCAQMD, which contains both state-level SCAQMD requirements and federal U.S. EPA requirements. This permit requires that the plant meet stringent emissions standards. In particular, the control of nitrogen oxides (*i.e.,* NOx) air emissions impose costs, including costs for ammonia used in the plant's selective catalytic reduction ("SCR") NOx emissions abatement system. The permit specifies the types of pollution measurements to be performed, as well as the pollution control equipment and continuous emissions monitoring system ("CEMS") equipment required for the plant and how it is to be maintained and tested. The permit also specifies reporting that must be done at various frequencies. Periodic air emissions testing, independently performed by a third party, is also required. The plant's instrument, controls, and electrical technicians expend significant effort in managing the CEMS equipment to facilitate compliance with air quality requirements.

Mountainview manages its hazardous waste and materials with oversight primarily from the San Bernardino County Fire Department. The California Energy Commission ("CEC") license for Mountainview also addresses numerous compliance areas such as air quality, safety, noise-abatement, and aesthetic standards. The CEC license requires compliance above and beyond some of the individual permit requirements, plus periodic reports on air and water quality.

One requirement imposed by Mountainview's CEC license is that the plant use only non-potable sources of water in its cooling towers. The cooling tower makeup water is composed of at least 50 percent reclaimed water purchased from Redlands, and the remainder is drawn from onsite mid-aquifer wells. Using wet cooling towers, the plant's waste heat is removed by air using the counter-current effect of air in contact with cooling water. Air drawn through the cooling tower evaporates a portion of the cooling water, which concentrates minerals and contaminants in the cooling water that falls back into the cooling tower basin. Excessive mineral content in the cooling tower water can cause operational problems (corrosion and scaling) and air permit limit exceedances. The concentrated minerals and contaminants are therefore controlled by blowing down the cooling tower (*i.e.,* discharging a portion of the water from the system, and adding well water or recycled water in its place).

Blowdown from the tower is routed to the plant's water treatment system. Mountainview's water treatment system cleans and reuses water that would otherwise be discharged as wastewater. The processes require chemicals, including soda ash, magnesium sulfate, ferric sulfate, sodium hydroxide, sodium hypochlorite, sulfuric acid, and several other chemicals designed specifically to perform necessary functions in the treatment process. The volume of wastewater is greatly reduced through these processes and is concentrated into a waste brine solution.

The waste brine solution (which is being produced at a rate of up to 300 gallons per minute) is discharged to a local industrial wastewater line called the Santa Ana Regional Interceptor (SARI) by permission from San Bernardino Valley Municipal Water District. The district imposes a direct user discharge permit and associated discharge fees. This permit requires continuous monitoring, periodic testing, and reporting on the water discharged.

Another by-product of the water treatment process is a filter cake generated from the clarification process. The cake is disposed at Redland's California Street landfill into a

double-lined cell designed to eliminate the leaching of any contaminants into the surrounding soil.

(3) Reliability

Reliability also is an important performance objective for SCE's generation assets including Mountainview. To sustain Mountainview's reliability performance consistent with the incentive targets and with SCE's reliability objectives, the plant's O&M and capital budgets must be sufficient to fully fund work to operate and maintain the plant. Mountainview's O&M forecast includes labor and non-labor needed to fund O&M activities. In addition, these O&M costs include upgrades and refurbishment projects to Mountainview if they do not meet capital project accounting criteria. Mountainview has an excellent reliability performance record, and approval of the plant's O&M and capital forecast will help sustain this reliability performance.

(4) Efficiency and Flexibility

Mountainview is dispatched by the CAISO to meet varying grid demands. The penetration of intermittent renewable technology, such as solar, into the CAISO market has significantly changed the value proposition for Mountainview in recent years. Market products that focus on flexibility are rewarded more than traditional baseload generating capabilities and therefore provide more value to the SCE customer. To meet this need, Mountainview was upgraded in 2016 with Advanced Gas Path ("AGP") and Dry Low NOx ("DLN") technology from General Electric. The AGP/DLN2.6+ upgrade involved replacing original combustion turbine materials with upgraded materials capable of withstanding higher and more variable temperatures. This improvement allows the plant to achieve higher MW outputs during warm weather, improved plant efficiency, increased speed at which the plant can change loads to meet demand, and it allows the plant to produce at lower outputs.

Mountainview historically operated with availability and heat rate incentives applied by the CPUC. In 2021, SCE filed a petition to remove the incentives, arguing that the incentives, which dated back to 2005, had been outdated by recent CPUC and California ISO policies and are contrary to the best interest of SCE's customers. On June 3, 2021, in CPUC Meeting #3487, the CPUC agreed to remove the incentive mechanisms for Mountainview and instead rely solely on current market mechanisms and the Energy Resource Recovery Accounts filing process to incentivize the efficient and reliable operation of Mountainview. This change allowed SCE to end the practice of performing biannual heat rate tests associated with high fuel costs. The change also allows for SCE to take advantage of lower demand periods in high demand seasons (e.g., weekends in the summertime) to perform preventative maintenance work that precludes the risk of unplanned forced outages during higher demand periods (e.g., weekdays during the summertime) thus improving the reliability of the plant when it matters most to the customer.

c) Mountainview Maintenance Practices

Much of the plant maintenance work can be performed while the Mountainview generating units are on-line and producing electricity. However, certain maintenance, including most major maintenance tasks, requires one or both generating units to be off-line (*i.e.*, this work requires a generating unit maintenance outage). The following sections of testimony describe the maintenance practices employed at Mountainview.

(1) Major Maintenance Philosophy

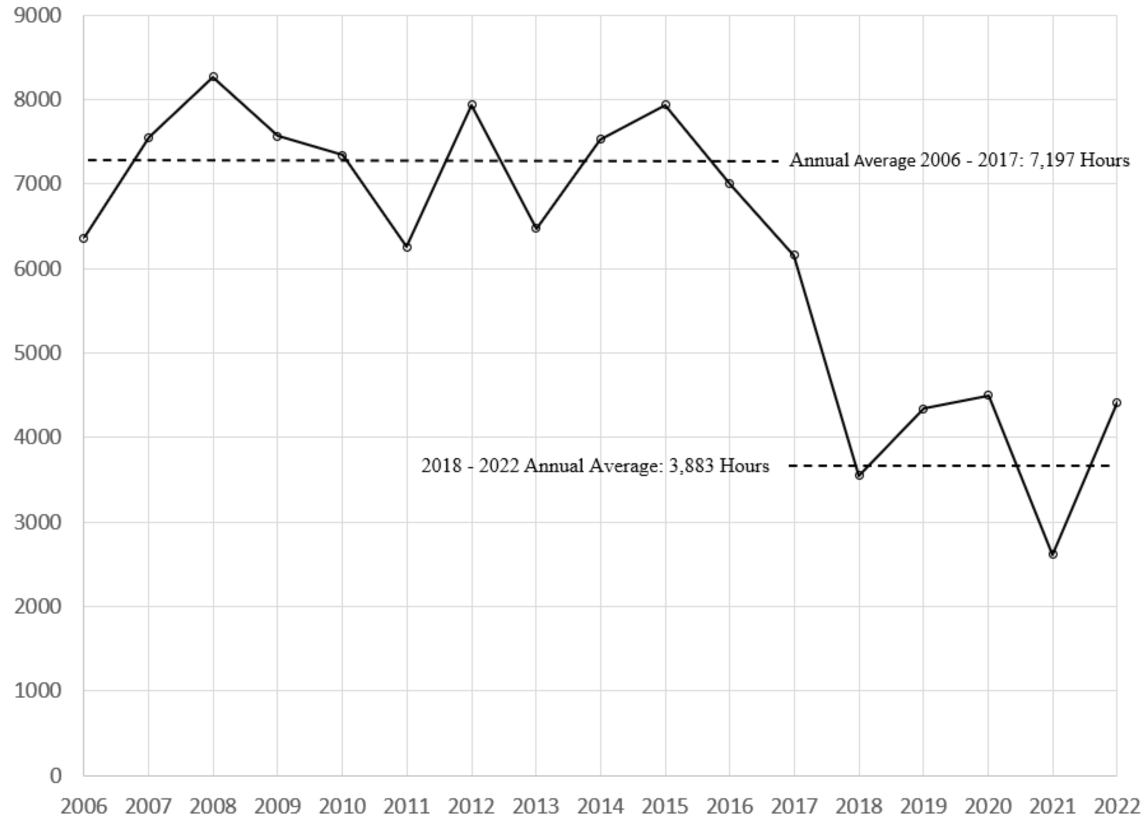
A Long-Term Service Agreement ("LTSA") with the Original Equipment Manufacturer ("OEM") General Electric ("GE") was transferred to SCE when it acquired Mountainview in 2003.[199] Since the initial startup of Mountainview, a strict regimen of maintenance has been followed based on the published service guidelines of the OEM. At the time Mountainview was put into service, the OEM was the only source of component spare parts, component repairs, and generating unit disassembly and reassembly services. The frequency of maintenance was high as the generating units were operating between 7,000 and 8,000 hours per year necessitating major maintenance approximately every three years (24,000 operating hours per OEM recommendations). In late 2014, SCE began engagement with the OEM to renegotiate the LTSA to lower the overall cost of the agreement to align with the new needs of the equipment. The renegotiations, finalized on June 5, 2015, also provided an opportunity to upgrade the units to improve efficiency and prolong service intervals (from 24,000 hours

[199] Also referred to as a Contractual Services Agreement ("CSA").

to 32,000 hours), driving down lifetime maintenance costs of the plant. Additionally, the renegotiated contract provided SCE with some major components anticipated to need replacement in the early 2020s. The renegotiation and LTSA structure were based on the forecasted operation of the units remaining above 5,000 hours per year for the life of the plant.

As shown in Figure III-14 below, prior to 2018, operating hours at Mountainview had never dropped below 6,000 annual operating hours; averaging 7,197 hours for the first 12 years of the plant's life (*i.e.,* 2006-2017). However, in 2018, the annual operating hours at Mountainview dropped significantly to 3,548 hours and since that time have averaged only 3,883 hours per year. This significant drop, 46%, in average annual operating hours, observed during the last five years versus the first twelve years increased the required interval time between major maintenance overhauls and significantly impacted the overall value brought about by the LTSA renegotiated in 2015.

Figure III-14
Mountainview Operating Hours
2006-2022 Recorded



In 2016, a year following SCE's LTSA renegotiation with GE, unexpected changes began to occur in: 1) lower dispatch of the Mountainview generating units, which as previously mentioned is controlled by CAISO, and 2) the service market for the models of combustion turbines used at the plant.[200] In fact, by 2018 these changes had become so significant that the economics of the 2015 LTSA were called into question by SCE.

Based on the future unit operation hours forecasted in 2015, the LTSA would have required that SCE purchase three combustion turbine rotors from the OEM at a purchase price of $18.0 million each ($54.0 million total). However, in late 2018 SCE observed that vendors had

[200] In 2015, combustion turbine rotor refurbishment was not fully recommended by the industry. Based on, at that time, forecasted annual plant run hours the purchase of new rotors was the preferred option.

begun advertising the ability to disassemble a GE combustion turbine rotor and refurbish it—replacing only the components showing distress. This rotor refurbishment, as shown in Table III-45, was available for approximately $5.770 million per rotor versus purchasing a new rotor from the OEM for $18.000 million, an approximate savings of $12.230 million per rotor. Thus, rotor refurbishment was on the order of 68% less than purchasing new rotors, as specified in the renegotiated LTSA.

In late 2019 several non-OEM service and repair vendors also began advertising their ability to refurbish the critical hot section components of the turbine and SCE began investigating non-OEM capability and pricing for major overhaul work on the combustion turbines at Mountainview. SCE's analysis presented in Table III-45 showed that the non-OEM sources of service and repair were approximately 57% less than the same services and repair done by the OEM.[201], [202]

[201] WP SCE-05 Vol. 1, p. 187. Mountainview Component Repair Pricing Comparison Summary.

[202] WP SCE-05 Vol. 1, p. 188. 2015 GE LTSA Schedule 13.

Table III-45
Mountainview Component Pricing Comparison
($2019)

Line No.	Component	OEM Pricing	Non-OEM Pricing	Delta
1	Stage 1 Bucket	$ 593,560	$ 180,000	$ 413,560.00
2	Stage 2 Bucket	$ 330,105	$ 108,750	$ 221,355.00
3	Stage 3 Bucket	$ 112,000	$ 55,000	$ 57,000.00
4	Stage 1 Nozzle	$ 482,702	$ 150,000	$ 332,702.00
5	Stage 2 Nozzle	$ 234,845	$ 153,000	$ 81,845.00
6	Stage 3 Nozzle	$ 57,100	$ 66,922	$ (9,822.00)
7	Stage 1 Shroud	$ 180,000	$ 53,450	$ 126,550.00
8	Stage 2 Shroud	$ 51,790	$ 27,000	$ 24,790.00
9	Stage 3 Shroud	$ 67,974	$ 24,000	$ 43,974.00
10	Fuel Nozzles	$ 71,135	$ 90,000	$ (18,865.00)
11	Cap	$ 63,000	$ 40,720	$ 22,280.00
12	Liner	$ 81,725	$ 32,000	$ 49,725.00
13	Transition Piece	$ 129,704	$ 83,044	$ 46,660.00
14	**Total**	**$ 2,455,640**	**$ 1,063,886**	**$ 1,391,754**
15			**Percent Savings - Non-OEM vs. OEM**	**57%**
		New Rotor	**Refurbished Rotor**	**Delta**
16	Rotor	$ 18,000,000	$ 5,770,000	$ 12,230,000
17			**Percent Savings - Refurbished vs. New Rotor**	**68%**

As a result of the dispatch and repair market changes mentioned above, SCE approached the OEM for a second LTSA renegotiation in late 2019 which continued into 2020. The focus of the renegotiation was to significantly reduce the pricing built into the LTSA to cover the assumed major maintenance and to eliminate the need to purchase three new combustion turbine rotors (one new rotor was purchased in 2016 to be used as a spare) that would no longer be needed due to the reduction in future planned operating hours.

The OEM was initially agreeable to renegotiating the LTSA and acknowledged both the changed operating profile of the units and changes to the service market. However, as negotiations continued it became apparent that the OEM was unwilling to reduce their pricing in a meaningful manner. In fact, SCE's analysis of the revised OEM pricing, despite removing

$54.0 million for three new rotors and the far less intensive maintenance forecast, showed that the OEM was repricing other parts of the agreement which had the effect of preserving close to the original price and maintained the original margin dollars. Additionally, the OEM proposed to remove important overhaul scope items, to introduce lower limits of coverage, and to limit their liability for quality of work performed. The removal of these important contractual clauses was perceived by SCE as detrimental as they would have produced a higher longer term overall cost. As a result, SCE and the OEM were unable to reach acceptable scope and pricing terms and agreed to mutually terminate the LTSA effective in 2021.[203] Following termination of the LTSA, SCE decided to manage the work with a mix of internal and contracted resources and believes that termination of the OEM LTSA will result in a long-term savings of approximately $32.2 million (PVRR).[204]

(2) Spring Planned Maintenance Outages

In years for which no major maintenance is planned, Mountainview conducts short maintenance outages each spring to prepare for the summer peak season. Work typically accomplished during these short outages includes valve repair, instrument calibration, filter change out, water treatment system cleaning and overhaul, pump-motor repair and alignment, and inspections of equipment, including the heat recovery steam generators (or HRSGs), the condensers, and the fire suppression systems. Work performed includes all inspections required by permitting and insurance carriers.

(3) Major Maintenance Activities

In conformance with OEM maintenance recommendations, the combustion turbines, steam turbines, and generators undergo periodic major maintenance. Major maintenance initially consisted of three types of scheduled outages for the Mountainview turbine

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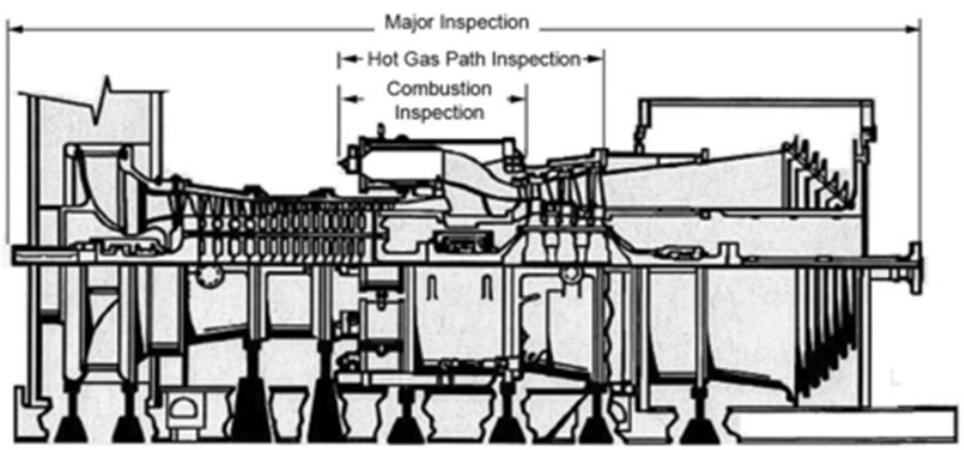
[203] Termination fees in the amount of $4.0 million were specified in section 11.2 of the GE LTSA and would have been incurred if the agreement was unilaterally terminated or if a default of obligation occurred by SCE. However, this was not the case as SCE requested, and GE mutually agreed to renegotiate the LTSA under Section 11.3, “Renegotiation or Termination for Non-Competitiveness”. Section 11.3 provided for no termination fees in the event the agreement is restructured or if the parties cannot reach agreement and the contract is terminated.

[204] WP SCE-05 Vol. 1, p. 189. GE LTSA Negotiation Analysis.

generators: (1) combustion inspections (CI) including replacement of combustor parts; (2) Hot Gas Path Inspection (HGPI) overhauls including replacement of additional hot section components of the gas turbine; and (3) Major Inspection(MI) overhauls including additional component replacements of the combustion turbine compressor section, combustor, and turbine sections as well as overhaul of the steam turbine and associated generators.

HGPI overhauls include all work performed during a CI plus a significant amount of additional work. Likewise, MI overhauls include all work performed during an HGPI overhaul plus significant additional work. Figure III-15 below, shows the areas of the combustion turbine targeted during each of these outages.

Figure III-15
Areas of Turbine Targeted During Inspections



(a) Combustion Inspection ("CI")

The CI is a relatively short (*i.e.,* typically seven days) outage where work includes partial disassembly of the combustion turbine, and replacement of fuel nozzles, liners, flow sleeves, and transition pieces, along with consumables such as seals, nuts, bolts, and gaskets. A visual inspection of the inlet of the compressor section, first stage turbine nozzles, and turbine exhaust area is also conducted with a visual inspection of the compressor section using a borescope. Any damage found during CI can influence planning of subsequent overhauls.

When the plant was new, CIs were to be conducted approximately every 12,000 operating hours (*i.e.,* Factored Fired Hours – FFH). However, as upgraded combustion parts were installed during the first CI in 2007, this interval was extended to every 24,000 operating hours, or 900 startups, whichever occurred first. Due to the extension, Mountainview's CI outages coincide with HGPI overhaul outages, thereby eliminating the need to conduct separate CI outages.

(b) Hot Gas Path Inspection ("HGPI")

The HGPI overhaul examines and repairs those components exposed to high temperatures from the hot gases discharged during the combustion process. To perform the inspection, SCE removes the top of the turbine shell to provide access to the turbine rotor. The HGPI overhaul includes the full scope of the CI plus the replacement of first stage nozzles, buckets (*i.e.,* turbine blades), and shrouds, and the inspection of the second stage nozzles, buckets, and shrouds. The second stage turbine components are also replaced.

Consistent with GE maintenance recommendations HGPI overhauls were planned approximately every 24,000 operating hours, or 900 startups, whichever occurred first. The first HGPI overhauls were completed on Unit 3 and 4 during the fall and spring of 2009, respectively, followed by the plant's first major inspection overhaul in 2013. The second HGPI overhauls were then completed in 2016. The upgraded turbine parts discussed above were installed as part of the 2016 HGPI overhaul outage. Because of these upgrades, HGPI overhauls, going forward, will now be conducted approximately every 32,000 operating hours, and MI overhauls will now be conducted every 64,000 operating hours.

During an HGPI the steam turbine inlet valves, valve actuators, and selected bearings are inspected and repaired as necessary. Additionally, the associated generators have an external inspection and if necessary, a robotic internal inspection done without disassembly of the generator.

(c) Major Inspection ("MI") Overhauls

The MI overhaul examines all the internal rotating and stationary components of the combustion turbine, from the inlet of the machine through to the exhaust. A steam turbine overhaul is also conducted coincident with the combustion turbine MI. Consistent with GE maintenance recommendations and the LTSA (*i.e.,* GE Contract Service Agreement), MI overhauls were conducted approximately every 48,000 operating hours or 2,400 startups, whichever occurred first. The first MI overhauls for Units 3 and 4 were completed during 2013. As noted above, the upgraded turbine parts will now allow the MI overhaul interval to be extended to approximately every 64,000 operating hours, which SCE is forecasting to occur from 2024 through 2027. During a combustion turbine MI, the steam turbine is also disassembled, inspected, and repaired as necessary to restore performance and reliability. Also, during an MI, the associated generators are disassembled, the rotors removed, and a complete external and internal inspection performed, and repairs are made to insure reliability.

Additional specifics of Mountainview major maintenance are as follows:

- The need for major maintenance can result from in-service equipment operating issues or failures that need to be addressed during a plant shutdown.
- Equipment operating hours accrue as the units are in service. Unit dispatch (i.e., operating hours) is determined by and directed by the California Independent System Operator.
- The combustion turbines determine the intervals of planned major maintenance as they have strict operating limits and shortest intervals between necessary major maintenance.
- Since its inception, Mountainview was covered by an OEM LTSA with GE as the only means to maintain the turbines and generators. Since the gas turbines were the OEM's latest and most efficient technology there were no alternative service and repair contractors capable of providing replacement components, parts repairs, or maintenance overhaul services for state-of-the-art turbine components.

- Since initial operation of the turbine and generator equipment, several contractors have developed the ability to provide maintenance overhaul services, parts repairs, and even provide alternative new components. This alternative network of service and parts providers has had the effect of lowering market level prices for maintenance services as compared to OEM pricing.

(i) Major Inspection Intervals

Based on the revised operating forecast at Mountainview it is now anticipated that major inspections of the generating units will be performed from 2024 through 2027, with a less intensive inspection in 2023 to correct an emerging combustion turbine issue and replace an obsolete control system. A leading non-OEM service and repair contractor has been prequalified for the 2023 work. Work is ongoing to familiarize the company with specific aspects of the Mountainview outage scope of work.

3. Mountainview O&M Expense Forecast

a) Introduction

SCE's total Mountainview Test Year O&M expense forecast of $29.703 million is summarized in Figure III-16.[205] The figure shows the recorded expenses for 2018-2022 and the forecast expenses for 2023-2025. Labor costs reflect the costs both for SCE employees who work primarily at Mountainview and employees who work at other locations but support the plant. Non-labor costs include repair parts, chemicals, supplies, contracts, and numerous other items needed to operate and maintain the plant. Other costs consist of grid interconnection fees.[206]

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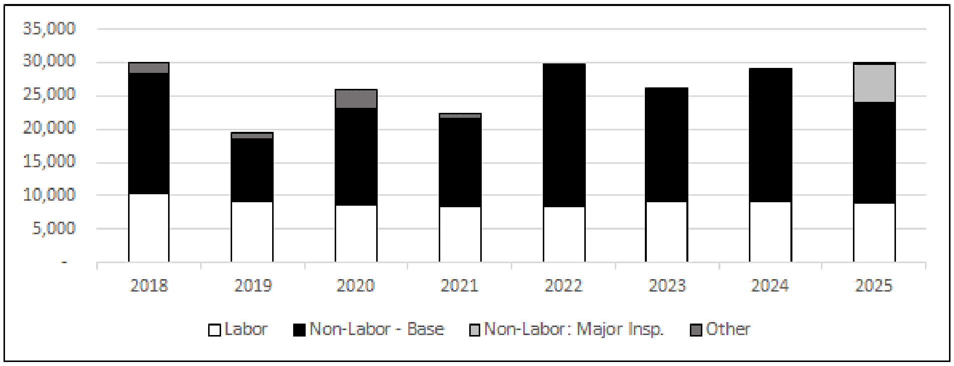
[205] WP SCE-05 Vol. 1, pp. 181-186. Mountainview Operations and Maintenance Recorded/Forecast Summary.

[206] The "Other" cost category are costs that have pre-established escalation rates (such as those set by contract) and, therefore, are provided on a nominal year dollar basis consistent with past GRC proceedings. Labor and non-labor cost categories are given on a $2022 constant dollar basis unless otherwise noted.

Figure III-16
Mountainview - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	10,380	9,206	8,665	8,409	8,509	9,135	9,232	8,872
Non-Labor - Base	18,012	9,346	14,265	13,156	20,915	16,810	19,453	15,139
Non-Labor: Major Insp.	-	-	-	-	-	-	-	5,629
Other	1,477	894	3,039	784	54	63	63	63
Total Expenses	29,869	19,445	25,969	22,348	29,478	26,007	28,749	29,703
Ratio of Labor to Total	53%	90%	50%	60%	41%	54%	47%	43%

b) <u>Development of Test Year Forecast</u>

The 2025 Test Year forecast of $29.703 million includes four cost components. These are briefly summarized below and discussed in more detail in the following sections of this testimony.

- The first O&M cost component is the base labor O&M expenses incurred by the station to perform annual work activities.
- The second O&M cost component is the base non-labor O&M expenses incurred by the station to perform annual work activities, but not including the costs for overhauls.
- The third O&M expense component is the non-labor O&M expenses incurred by the station for work performed during Major Inspection (MI) overhauls. This work also includes balance of plant (BOP) overhaul work which records

- primarily as non-labor, although overhaul work can cause increased labor costs due to overtime costs incurred during the overhauls.
- The fourth O&M expense component, Other, includes the interconnection fees which SCE must pay to be connected to the electrical grid.

(1) Labor – Analysis of Recorded and Forecast Expenses

As previously explained in testimony section I.E, in mid-2016, the Generation Department initiated several process changes to increase productivity and reduce labor expenses. While Generation's cross-support approach has been successful in controlling overall costs, a by-product is that we have begun to observe larger than historical year-to-year variations within two of the three Generation Department managed BPEs (*i.e.,* Hydro and Fossil Fuel). These variances can largely be attributed to reprioritization of work based on the most immediate need (*e.g.,* deferring less critical preventive maintenance at Hydro facilities to fund unplanned repairs encountered at Mountainview in 2018).

The higher labor costs recorded in 2018 are attributable to an unplanned outage that began in in late 2017 which extended into 2018.[207] This resulted in lower 2019 recorded labor costs as SCE paid employees at Mountainview more premium time hours while performing repairs during the 2017/1018 unplanned outage.

Labor costs between 2019 and 2020 slightly decreased and then remained relatively constant through 2022. Because staffing levels have stabilized and the scope of work performed in 2022 most closely matches the planned scope of work in 2025, we use the last recorded year (2022) amount of $8.509 million as the basis to forecast future labor expenses for 2025 and beyond, with an adjustment of $0.363 to reflect certain changes made to SCE's employee compensation program, yielding a 2025 Test Year labor forecast of $8.872 million. Please refer to SCE-06 Vol. 04.

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[207] This outage is discussed in greater detail in A.19-04-001 – Energy Resource Recovery Account Review of Operations, 2018 Chapters I-VII, pp. 68-78.

(2) <u>Non-labor – Base: Analysis of Recorded and Forecast Expenses</u>

Over the past five years non-labor costs at Mountainview have exhibited extreme year-to-year variances, ranging from a low of 8% to a high of 61%. Such high variability can be expected to continue as Mountainview approaches the midpoint of its expected lifecycle. This is because as steam plants age components that may have remained relatively trouble free in the early years of a plant's existence begin to require higher levels of maintenance, and in some cases may experience in-service failures.

The higher costs recorded in 2018 are attributable to an unplanned outage that began in in late 2017 which extended into 2018.[208] This resulted in higher 2018, and lower 2019, recorded non-labor costs as a large amount of work planned for 2019 was accelerated into 2018 to take advantage of the opportunity to perform maintenance planned for 2019 during the 2017/2018 unplanned outage. SCE will oftentimes accelerate future planned maintenance activities during an unplanned outage to shorten the length of future planned outages which has the desired effect of increasing plant availability and maximizing value to customers. Additional contributors to the lower 2019 recorded non-labor expenses include the cancelling the GE contractual service agreement and lower than previously forecasted run hours; lower run-hours reduces plant variable non-labor costs (*e.g.,* chemicals used for emissions control and chemicals used to treat cooling tower water).

In 2020 and 2021, recorded costs moderately increased from 2019 levels and remained relatively stable. Recorded costs again significantly increased in 2022 as Mountainview experienced a higher level of emergent maintenance activities discovered during the annual spring planned outage. Additionally, in 2022 Mountainview began purchasing materials in preparation to perform the 2023 phase of the next Major Inspection Overhaul. Forecasted costs for the next Mountainview MI Overhaul is discussed in greater detail in the following section of testimony.

Due to the inherent year-to-year variations of non-labor expenses, a historical average is most representative of non-labor – base expenses that can be expected in Test Year

[208] This outage is discussed in greater detail in A.19-04-001 – Energy Resource Recovery Account Review of Operations, 2018 Chapters I-VII, pp. 68-78.

2025. We selected a 5-year average (*i.e.,* 2018-2022); as the basis to forecast a non-labor - base expense of $15.139 million for Test Year 2025.

To this base year amount, SCE requests a future adjustment totaling $5.629 million, further described in the following section of testimony. This increase when added to the $15.139 base year amount yields a non-labor Test Year forecast of $20.767 million.

(3) Non-Labor – Major Inspection

Major maintenance continues to be a major driver of Mountainview O&M expenses. The cost variability of periodic overhauls is not unique to Mountainview as major overhaul maintenance at power plants is a common cause of substantial variations in year-to-year costs. Major maintenance cost variations can affect SCE's ability to recover its costs, particularly when the scheduled major maintenance outage does not coincide with the Test Year. In the 2003 GRC, the Commission agreed that SCE should include an average annual cost of overhauls in its GRC forecasts even if an overhaul was planned outside the Test Year.[209] The Commission reasoned that it did not want to create the incentive for utilities to schedule major projects for the Test Year because this would unnecessarily over-fund the utilities in the subsequent attrition years.[210]

Consistent with these prior GRC decisions, the Mountainview 2025 Test Year O&M expense forecast includes the annual average cost forecast to be incurred during the 2025 GRC cycle (*i.e.,* 2025-2028) for the planned 2023-2027 Major Inspection (MI) overhaul. Continued use of this approach will help ensure that customers do not overfund overhauls scheduled in GRC TYs, while also appropriately funding needed overhauls scheduled for years other than the GRC TY.

The 2025-2027 forecasted incremental non-labor cost for the 2023-2027 MI overhaul is $22.514 million.[211] Specifically, we utilize one-fourth (*i.e.,* $5.629 million) of the forecasted $22.514 million O&M MI overhaul cost (*i.e.,* the average annual overhaul cost during 2025 through 2027) as the basis for the 2025 Test Year non-labor - MI forecast.

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[209] D.04-07-022, pp. 71-72.

[210] D.04-07-022, pp. 71-72.

[211] WP SCE-05 Vol. 1, p. 190. Mountainview MI Overhaul O&M Expense Forecast.

(4) Other - Analysis of Recorded and Forecast Expenses

The Mountainview Other expense category consists of interconnection fees, which are fixed payments that Mountainview pays to SCE T&D for interconnecting the Mountainview units to the grid (*i.e.,* the assessed interconnection fee includes no periodic inflation adjustment and is therefore categorized as "other" expenses). These payments flow back to SCE customers through T&D Other Operating Revenue (OOR). Further information regarding interconnection fees and OOR can be found in SCE-02 Volume 11.

Recorded costs in the "Other" account include payments SCE made to GE as part of the LTSA. As previously mentioned in testimony, SCE and GE mutually agreed to terminate the LTSA effective in 2021. Therefore, SCE has excluded any recorded LTSA costs and utilized the remaining expenses, consisting solely of interconnection fees, to calculate a 5-year average (*i.e.,* 2018-2022); as the basis to forecast non-labor - Other expense of $0.063 million for Test Year 2025.

4. Mountainview Operations and Maintenance Work Activities

Much of the plant maintenance work can be performed while the Mountainview generating units are on-line and producing electricity. However, certain maintenance, including most major maintenance tasks, requires one or both generating units to be off-line (i.e., this work requires a generating unit maintenance outage).

Mountainview operations activities occur year-round with operations personnel providing 24/7 coverage. Activities include operating the units, performing equipment rounds and inspections, clearing equipment for work, and other operational tasks. Routine maintenance activities, such as preventative maintenance and simple equipment repair are also conducted year-round. Preventative maintenance activities such as oil sampling, vibration monitoring, battery testing, etc., are performed in accordance with the Mountainview Work Management program and informed by SCE Engineering to maximize the reliability and availability of Mountainview.

a) Operations Activities

Mountainview Operations work activities include labor and non-labor expenses incurred in operating prime movers, generators, and electric equipment at Mountainview, up to the point where electricity is delivered to the distribution system. The operations and maintenance (production) staff that supports Mountainview also supports other generating stations in the region and their labor costs are allocated according to their level of support for each plant. Personnel include Control Operators who primarily control plant equipment from the Eastern Operations Generation Control Center (EOGCC), Operator Mechanics who primarily control plant components in the field, Chemistry Technicians who primarily perform duties to maintain plant water chemistry, and a Supervisor who supervises Control Operators, Operator Mechanics, and Chemistry Technicians. A Production Manager manages Operations and Maintenance (O&M) for power plants in the LA Basin area, a Principal Manager manages O&M for power plants in the Eastern Operations region (consisting of utility operations on Santa Catalina Island, and the mainland areas of Bishop/Mono and Los Angeles basins), and a Managing Director responsible for all aspects of SCE's power generation portfolio. Various support staff also provide Operational services to the Peaker plants. Support staff include members of the Asset Management and Generation Strategy group as well as the Major Projects and Engineering group within Generation. The support staff provide financial budgeting, accounting, administrative services, regulatory compliance support, project management, long-range planning, and other support activities.

Non-labor operational expenses include contract costs, materials, employee reimbursement expenses, SCE corporate support for various air, water, hazardous waste, and similar regulatory activities, chemicals and water used for the steam system as well as cooling systems across the plant, environmental monitoring and reporting, water discharge fees, permits and fees, communications and computing equipment expenses, office supplies, labor relations expenses, safety and training costs, and janitorial services. Also, fixed payments are made to SCE T&D for interconnecting Mountainview to the grid.

(1) Operations Supervision and Engineering

Operations Supervision and Engineering includes labor and non-labor expenses for control operators who operate the plant and the shift supervisors who supervise the control operators and oversee the daily plant operation. Labor expenses also include a portion of the salary of support employees who work at locations other than Mountainview, such as the corporate office. The support staff employees provide labor for budgeting, accounting, administrative activities, business planning and development, general management, environmental health and safety, regulatory, long-range planning, and other activities. Non-labor expenses include: (1) reimbursement expenses (*e.g.*, travel expenses as required); (2) corporate support for various air, water, hazardous waste, and similar regulatory activities; and (3) fees. This includes expenses for preliminary engineering studies, analytical laboratory analyses, and other general engineering support.

(2) Generation Expenses

Generation expenses includes all labor and non-labor expenses for the water treatment plant, and other chemical-related aspects of operating the plant. It also includes the expense of chemicals used for water treatment and emission control, and the cost for environmental fees, permits, and monitoring and reporting for air pollution emissions.

(3) Miscellaneous Other Power Generation Expenses

This category of work includes all labor and non-labor expenses used in operations not specifically provided for or are not readily assignable to other operating accounts. This includes general management and administration, clerical support, labor relations expenses, safety and training, facility security and janitorial services, and environmental compliance activities for wastewater and solid wastes.

(4) Rents

Rents are primarily non-labor and capture the cost of rental property used with power generation. SCE owns the property Mountainview is on and does not make lease payments for easements for water supply lines, wastewater discharge lines or transmission corridors.

b) Mountainview Maintenance Account O&M Expense Analysis

The Mountainview Maintenance work activity includes all labor, non-labor, and other (*e.g.*, interconnection costs) expenses associated with the maintenance and repair of the power island and all general plant maintenance related expenses.

(1) Maintenance Supervision & Engineering

Maintenance Supervision & Engineering includes labor and non-labor expenses for the general supervision, direction, and engineering in support of maintenance activities. The labor portion of this account primarily captures the costs of the plant engineer, maintenance planner, and drafting technician.

(2) Maintenance of Structures

Maintenance of Structures includes labor and non-labor expenses required to maintain and repair structures such as offices, control rooms, shops, garages, and improvements to grounds. This account also captures maintenance costs for the plants electrical and controls systems.

(3) Maintenance of Generating & Electrical Plant

Maintenance of Generating & Electrical Plant includes labor, non-labor, and other expenses to maintain and repair generating equipment and maintenance services for the combustion turbines, steam turbines, generators, and related systems commonly referred to as the power island.

(4) Maintenance of Miscellaneous Other Power Generation Plant

Maintenance of Miscellaneous Other Power Generation Plant includes labor and non-labor expenses to maintain and repair power plant auxiliary equipment. This equipment is described as balance-of-plant (BOP) equipment. BOP equipment is not part of the power island but is critical to plant operation. This equipment includes cooling towers, water treatment systems, wastewater treatment and disposal, water storage tanks, instrument and plant air systems, and electrical equipment including transformers and breakers. Also included are cranes and hoists, fire suppression equipment, weather stations, and station maintenance equipment such as lathes, drill presses, and other shop equipment.

5. Mountainview Capital Expenditure Forecast

SCE's planned capital expenditures for Mountainview support reliable service, compliance with applicable laws and regulations, and safe operations for employees and the public.

SCE's forecast of Mountainview capital expenditures total $84.765 million (nominal, work order level) for 2023-2028, as summarized in Table III-46 below.[212], [213]

Table III-46
Mountainview Capital Expenditure
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Turbine(s)/Generator Improvement Program	3,924	4,048	9,534	10,790	-	-	28,296
2	Turbine Control and BCS Project	-	-	-		3,600	4,272	7,872
3	Heat Recovery Steam Generator (HRSG) Purge Credit	-	-	-	1,100	6,258	-	7,358
4	Heat Recovery Steam Generator (HRSG) Drains Upgrades	-	550	3,606	2,806	-	-	6,962
5	Heat Recovery Steam Generator (HRSG) Inlet Flow Distribution Grids	-	400	3,401	2,601	-	-	6,401
6	GE Variable Load Path	-	-	-	800	5,519	-	6,319
7	Turbine Distributed Control System Upgrade	5,913	-	-	-	-	-	5,913
8	Capital Spares and Tools - 89SS and 89ND Switches, CT Gas and Bleed Valves, Steam Attemperators	154	1,004	654	154	154	154	2,275
9	Unit 3 CO Catalyst Bed Replacements	-	-	-	-	-	1,900	1,900
10	Unit 3A and 3B Combustion Turbine Battery Replacement	-	-	-	-	900	900	1,800
11	Cooling Tower Film Fill and Drift Eliminators	-	-	-	600	600	600	1,800
12	Unit 3 & 4 Heat Recovery Steam Generator (HRSG) Exhaust Duct Liners	-	800	800	-	-	-	1,600
13	Capital Spares - 7FH2 GT Generator Rotor	1,250	-	-	-	-	-	1,250
14	3A and 3B MS-318 Replacement	934	-	-	-	-	-	934
15	Cooling Tower Fan Hub Corrosion	900	-	-	-	-	-	900
16	HRSG Performance and Reliability Monitoring Solution	-	200	200	200	-	-	600
17	Water Treatment Roof Replacement	-	-	-	-	500	-	500
18	Unit 3 & 4 Vacuum Pump Replacements	491	-	-	-	-	-	491
19	HRSG Upper Crawl Space 1 / Upper Crawl Space 2 access door and staircase	-	400	-	-	-	-	400
20	SH5 Tube Tie Clamps	-	242	-	-	-	-	242
21	Unit 3 & 4 Power Block HVAC Replacements	-	-	-	-	130	-	130
22	Interconnection Relay	110	-	-	-	-	-	110
23	CAVA - MVGS HVAC Assessment and Upgrades	-	-	100	100	150	150	500
24	**GRAND TOTAL**	**13,676**	**7,644**	**18,295**	**19,151**	**17,811**	**7,976**	**84,553**

The following sections of testimony provide further discussion of Mountainview capital projects exceeding $1.000 million.

a) Turbine/Generator Improvement Program

(1) Background

Heavy-duty gas turbines, steam turbines, and generators are constructed to have high availability, assuming manufacturer recommended maintenance and inspection intervals are followed. The OEM, GE, recommends a Major Inspection on 7FA.04 gas turbines and D11 steam turbines every 64,000 FFH. Given Mountainview's midrange operating profile, GE recommends MI interval reduction of roughly 25%, making Mountainview's target MI interval 48,000 FFH.

[212] The forecast amount reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[213] WP SCE-05 Vol. 1, p. 191-209. Mountainview Capital Expenditures.

Mountainview averages 3,000 FFH per year. As of 1Q22, Unit 3 has run 41,000 FFH and Unit 4 has run 48,000 FFH since their last MIs. It is SCE engineering's recommendation to execute the MIs as soon as practical, but no later than 2026 to assure the continued reliability of the asset. Additionally, significant findings in 4B combustion turbine require hot section work in the Spring of 2023, ahead of the next major outage. The capital forecast for the MVGS Turbine(s)/Generator Improvement Program is $28.296 million for 2023-2028, and total forecasted costs are $67.100 million.[214]

(2) Project Scope

Complete major inspection and refurbishment (Major Inspection, or MI) of Mountainview's four gas turbines, two steam turbines, and their associated generators per OEM-recommended maintenance schedule. Utilize a competitively bid contract with Mechanical Dynamics and Analysis (MD&A) for hot section work in 2023 and competitively bid expanded Major Outage work for 2024 and 2025.

(3) Project Justification and Benefit

This program is based on GE's field experience and accumulated knowledge. It supports the continued safe and reliable operation of Mountainview for the next 48,000 operating hours. The Major Inspection scope of work ensures all critical components of the prime movers and generators are in good working condition. The 3A gas turbine has a unique design compared to the other three gas turbines that increases its risk of failure. Cooling slots in the number one and two turbine wheels have stress-rising geometry that will be corrected as part of this program, increasing reliability of the unit.

b) Turbine Control and Baseline Security Center (“BSC”) Project

(1) Background

Mountainview has a Turbine Control System (“TCS”) supplied by GE. This system entails a combination of hardware and control system applications which are used to manage the operational performance of the GE turbines and auxiliary equipment. The BSC is a set of

[214] WP SCE-05 Vol. 1, p. 194. Turbine/Generator Improvement Program.

hardware and applications that are integrated into the Turbine Control System and perform various cybersecurity functionalities to bring in enhanced security measures. The TCS and BSC systems are largely on a five-year life cycle and will require replacement by 2028 to adhere to the lifecycle plan and avoid forced outages. Additionally, by replacing the system on time, we will ensure that we continue to receive critical cybersecurity patches and retain vendor support. The capital forecast for the Turbine Control and BCS Project is $7.872 million for 2023-2028.[215]

(2) Project Scope

The Human-Machine Interface ("HMI") upgrade consists of replacing the existing 13 HMIs and 1 Historian with the new equipment at the same locations with similar functionality. This refresh also includes replacing the redundant network switches to retain the reliability of the network which adds needed redundancy and improved reliability. Additionally, this system includes servers and workstations associated with the BSC which will also need to be replaced.

The TCS (GE Mark Vie) upgrade consists of installation and commissioning of new Mark VIe TMR turbine controllers, input/output ("I/O") Packs, Power Supplies/Power Distribution, Internal Cabinet wiring and miscellaneous Hardware – i.e., Ethernet cables, mounting hardware, labels, etc., Seismic Zone 4 Certified Control Cabinets for the gas and steam turbines at Mountainview.

(3) Project Justification and Benefit

The servers, workstations and network components have a five-year life expectancy and will need to be replaced in 2028. Additionally, when the system is replaced, the applications will be upgraded to the latest version offered by the vendor, and this will ensure that we are using the latest technology to efficiently manage the performance and safety of the powerplant. As MVGS ages and the power market changes, it is important to retain the latest control system technology which will maximize life expectancy of the turbines and meet the changing needs of the power industry. If the control system is not replaced on time, we also risk losing vendor cybersecurity patches.

[215] WP SCE-05 Vol. 1, p. 195. Turbine Control and Baseline Security Center.

Obsolesce, increased forced outages, increased forced outage duration, and difficulty troubleshooting are risks associated with not completing this project.

c) Heat Recovery Steam Generator ("HRSG") Purge Credit

(1) Background

Each time the gas turbine is started, the exhaust duct and Heat Recovery Steam Generator ("HRSG") must be purged of any potential flammable gases that may have accumulated. This purge sequence is accomplished by spinning the gas turbine at approximately 800rpm for 15 minutes with all gas valves closed. This forces fresh air through the HRSG and purges any combustible gases prior to establishing flame in the gas turbine. Failure to purge the HRSG could result in a large explosion if any combustible gases were allowed to accumulate.

This purge cycle is added to the time it takes to start the gas turbine and also force cools the HRSG by blowing relatively cool air across hot tubes.

Issues created during this purge cycle include:

- Cracking in HRSG - Stresses induced by cold air flowing over warm/hot HRSG surfaces during the normal startup purge cycle can lead to low cycle fatigue cracking of tubes, headers, and casings in the HRSGs. Repairs that are made necessary by such fatigue cracks can represent an ongoing expense to our annual maintenance budgets.

- Condensate Drainage - The purge during startup forces relatively cool air through the HRSG. If the HRSG is hot/warm, this causes condensate to form that may accumulate in the lower headers. The water accumulation will rapidly cool the header and induce stress in the headers and tube to header welds.

The capital forecast for HRSG Purge Credit is $7.358 million for 2023-2028.[216]

[216] WP SCE-05 Vol. 1, p. 196. Heat Recovery Steam Generator Purge Credit.

(2) Project Scope

Engineering, parts procurement, installation of required equipment, controls updates, training, and testing/verification as needed to eliminate the pre-start purge sequence during startups.

Elimination of the startup purge cycle is accomplished by adding valves and instrumentation that gives positive indication that no natural gas or ammonia can enter and accumulate in the HRSG when the unit is shut down. Once plant confirms that no gas or ammonia can enter the HRSG, the purge cycle will be completed during normal shutdown as the gas turbine coasts to a stop.

(3) Project Justification and Benefit

Updating the plant to perform HRSG Purge during shutdown will reduce start up times since the start up purge cycle will no longer be needed, thus eliminating the following potential issues for units in cyclic operation with frequent hot/warm restarts:

- Cracking in HRSG - Stresses induced by cold air flowing over warm/hot HRSG surfaces during the normal startup purge cycle can lead to fatigue cracking. Repairs that are made necessary by such fatigue cracks can represent an ongoing expense within the customer's annual maintenance budgets. Shutdown purge eliminates this effect.

- Condensate Drainage - The purge during startup forces relatively cool air through the HRSG. If the HRSG is hot/warm, this causes condensate to form that may accumulate in the lower header. The water accumulation can rapidly cool the header and induce stress. Shutdown purge eliminates this effect.

d) Heat Recovery Steam Generator (HRSG) Drains Upgrades

(1) Background

HRSGs and the Steam Piping Drains at Mountainview were not designed to accommodate cyclic operation and are reducing the life of HRSG and High Energy Piping components. 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. ASME (American Society of Mechanical Engineers) develops codes and standards that provide rules for the design, fabrication, and inspection of boilers and pressure vessels. The latest version of ASME code and industry experience show that HRSG drain design like that at Mountainview are not adequate at removing condensate during startups. Additionally, automation of drains will ensure complete condensate removal and free up operators to focus on other critical steps during startups. Condensate is liquid water that forms when steam either encounters a cooler surface than saturation temperature at the current operating pressure or when pressure decreases below saturation pressure at current operating temperature. Condensate in steam piping can rapidly cool hot steam piping creating high stresses that can lead to cracking and condensate in steam piping will flash into steam resulting in a large increase in volume and forces on the piping and pipe support system (often referred to as hammering the piping or water hammer). These forces can damage pipe hangers and cause cracking in piping.

An engineering assessment of the HRSG drains at Mountainview was performed after multiple tube to header cracks were identified and repaired during annual planned outage HRSG inspections in 2019. This assessment's recommendations are the basis for this project. Industry experience of this type of cracking is related to inadequate condensate draining during startups. In addition to rapid cooling and hammering of piping, condensate that is not properly drained from headers can also cause the header to distort. This distortion can lead to high tensile stresses on tube to header welds that lead to these cracks. See photos and drawings tab with a drawing that shows this distortion caused from condensate in a HRSG Header. The capital forecast for Heat Recovery Steam Generator (HRSG) Drains Upgrade project is $6.962 million for 2023-2028.[217]

(2) Project Scope

Scope of work will be completed on all 4 HRSGs at Mountainview. Long duration outages being planned for Gas and Steam Turbines are the ideal time to complete this work.

[217] WP SCE-05 Vol. 1, p. 197. Heat Recovery Steam Generator Drains Upgrades.

These outages are scheduled for Spring 2023 and Spring 2024. Engineering and parts procurement for this project will be in 2023.

- Modify Drains with new drain system using condensate detection and automatic drains.
- Replace globe valves with metal seated ball valves for better sealing and longer life.
- Route SH and RH Drains to blowdown tank separate from Evaporator and Economizer drains.
- Add new drain at Reheater 1 Inlet Header, Reheater 3 Outlet Header, High Pressure Supper Heater 5 Inlet Header, and Low-Pressure Admission Steam Outlet Piping.
- Add control logic aligned with Industry best practice for automation of Drains during starts.

Reheater, High Pressure Super Heater, and Low-Pressure Steam are different sections of the HRSGs that provide steam to different sections of the Steam Turbine.

(3) <u>Project Justification and Benefit</u>

Upgrading the drains system at Mountainview will help to maintain needed long-term reliability to meet CAISO needs for cyclic operation supporting renewable power generation.

It is anticipated that this project will mitigate 1 forced derate per year at Mountainview starting in 2025 increasing linearly to avoiding 4 forced derates per year in 2035. Additionally, this project will defer large capital expenditure replacement of the High Pressure and Reheater sections of the HRSGs by approximately 6 years.

e) <u>Heat Recovery Steam Generator (HRSG) Inlet Flow Distribution Grids</u>

(1) <u>Background</u>

Mountainview is a combined cycle power plant. Major equipment at combined cycle power plants are gas turbines, HRSGs and Steam Turbines. The gas turbines are used to convert chemical energy in natural gas to electricity. Hot gases exhausting from the gas turbines are used by HRSGs to create high temperature and high-pressure steam that is used by steam turbines to generate electricity more electricity. The HRSGs were designed with an Inlet Flow Distribution Grid that ensures consistent mass flow and temperature distribution of hot gas turbine exhaust side to side and top to bottom.

The Inlet Flow Distribution Grids at MVGS were removed at some point in the early life of the plant due to ongoing maintenance issues. This was the right decision at the time with the plant operating mainly at base load. However, current cyclic operation and hours spent at low load results in inconsistent heating of HRSG components. Mountainview was originally 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 and will continue to be required to cycle off and on regularly. Inconsistent heating results in stresses at tube to header welds and potential for overheat and life reduction of tubes receiving more heat. The capital forecast for HRSG Inlet Flow Distribution Grids project is $6.401 million for 2023-2028.[218]

(2) Project Scope

Install new Flow Distribution Grids in all 4 HRSGs at Mountainview. Long duration outages are required to complete this scope and the upcoming Turbine/Generator Refurbishments are the ideal time to perform this work. Project will require engineering and parts procurement in 2023 with installation in 2024 and 2025 to align with Turbine Generator Major Refurbishment Planned Outages.

(3) Project Justification and Benefit

Installation of flow distribution grids will provide even heat distribution in the HRSGs minimizing stresses and long term overheat creep damage to steam tubes.

[218] WP SCE-05 Vol. 1, p. 198. Heat Recovery Steam Generator Inlet Flow Distribution Grids.

Installation of new Flow Distribution Grids will minimize tube to header weld cracks and delay large capital expenditures to replace High Pressure and Hot Reheat Steam sections in the HRSGs.

f) GE Variable Load Path

(1) Background

There is a need for additional operational flexibility at Mountainview in the future. This need is being driven by increasing power generation from non-dispatchable renewable power resources, such as wind and solar. This requires other generation sources, especially gas turbines, to be able to quickly respond to backfill lost renewable power when wind or sun quickly disappears. This need is particularly acute for existing, older combined cycle power plants, like Mountainview, where newer generation power plants with higher efficiency are coming online, forcing the older plants into very cyclic, unpredictable operating modes. These older plants need to be able to respond quickly and reliably to the needs of the electrical grid.

The capital forecast for GE Variable Load Path project is $6.319 million for 2023-2028.[219]

(2) Project Scope

The GE Variable Load Path project is a control system upgrade with minimal physical change to the plant and will begin with an engineering assessment of the proposed projects' impact to plant operation and equipment life.

Following a successful analysis, the project will include installation and implementation of Variable Load Path, Autotune MX, Variable Inlet Bleed Heat, and Fast Ramp control system upgrades. The Variable Load Path upgrade will provide the station with the ability to reduce gas turbine exhaust temperature while the Autotune MX, a combustion controls upgrade, will help the station maintain flame stability, emissions compliance, and gas turbine load. The Variable Inlet Bleed Heat will improve plant efficiency at lower outputs (*i.e.,* MW produced) and the Fast Ramp Control will

[219] WP SCE-05 Vol. 1, p. 199. GE Variable Load Path.

improve station control of gas turbine emissions as the plant changes from baseload to more cyclic operation.

(3) Project Justification and Benefit

The California Independent System Operator needs Mountainview and similar combined cycle power plants to be flexible for the state to meet its renewable energy and emissions reductions goals. Cyclic operation is unavoidable and Mountainview needs to ensure it can continue to operate reliably. This project helps Mountainview remain competitive with newer combined cycle power plants while minimizing the negative impacts to maintenance cost and reliability that are associated with cyclic operation.

This project will optimize Mountainview's gas turbines to be able to respond as needed by the electrical grid while minimizing the negative impacts associated with cyclic operation. Cyclic operation is when plants start and stop and raise and lower load frequently. Cyclic operation results have been shown to increase maintenance costs and downtime.

Increased flexibility is achieved by optimizing start up times and reducing stresses in Heat Recovery Steam Generators (HRSG) by reducing Gas Turbine Exhaust Temperatures. HRSGs use hot waste heat from the gas turbine to produce steam for the steam turbines to generate additional electricity. HRSG failures related to high temperatures and rapid temperature changes will be reduced by optimizing gas turbine exhaust temperature.

g) Turbine Distributed Control System Upgrade

(1) Background

The Mountainview Gas and Steam Turbines control system Human Machine Interface (HMI) currently operates on a Windows 7 platform and consists of 13 HMIs (2 per turbine) and one engineering station. As of January 2020, the existing Windows 7 operating systems are considered obsolete and the OEM no longer provides support for this operating system, resulting in increased cyber security vulnerability.

In addition to the HMIs, the current control system is difficult to troubleshoot due to the hybrid system of MarkV and MarkVI equipment that monitors and controls the steam and gas turbines at Mountainview. Firmware updates and software patches from the OEM don't always work with the existing hybrid system. Additionally, some of the control system hardware is obsolete, at end of life, and in some instances has caused forced outages. The capital forecast for Turbine Distributed Control System Upgrade project is $5.913 million for 2023-2028.[220]

(2) Project Scope

The HMI upgrade consists of replacing the existing 13 HMIs and 1 Historian with a new platform running Windows 10 that will be fully supported by the OEM. Additionally, the new equipment hardware will be installed in the same locations with similar functionality. This refresh also includes adding redundant network switches to increase the reliability of the network adding needed redundancy and improved reliability.

Mark VIe upgrade consists of installation and commissioning of new Mark VIe TMR turbine controllers, I/O Packs, Power Supplies/Power Distribution, Internal Cabinet wiring and Misc. Hardware – i.e., Ethernet cables, mounting hardware, labels, etc., Seismic Zone 4 Certified Control Cabinets for all gas and steam turbines at Mountainview.

(3) Project Justification and Benefit

Windows 7 is obsolete; security and update patching are no longer being released by the OEM. The only option will be to configure one of the HMIs used on PEECCs to replace any critical HMI (Engineering Workstations & Control Room HMIs) that may fail. Also, failure to upgrade the HMIs will result in increased cyber security risk. Since Windows 10 will be the system used for all HMIs, the control system will be fully supported by the vendor, mitigating system vulnerability. Furthermore, the addition of redundancy on the network will increase the reliability providing full visibility of units even if one of the network switches were to fail.

Obsolesce, increased forced outages, increased forced outage duration, and difficulty troubleshooting are risks associated with not completing this project.

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[220] WP SCE-05 Vol. 1, p. 206. Turbine Distributed Control System Upgrade.

h) Capital Spares and Tools – Replacement Generator 89SS and 89ND Switches, CT Gas and Bleed Valves, Steam Attemperators

(1) Background

Mountainview was originally 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 between high and low load and start and stop more frequently than originally designed, and this cyclic operation is expected to continue throughout the remaining life of Mountainview. Cyclic operation and more frequent starts/stops result in increased thermal and cyclic stresses on the generator rotor coils and insulation system resulting in increased wear and tear and reduced reliability as compared to original base load operation.

Based on General Electric's (GE) experience with the vintage and model of generator rotors (GE 7FH2 Generator) used at Mountainview, they are at an increased risk of forced outage which, if were to occur, would require major repair and is likely take the plant offline for an extended time while a replacement was procured.[221] To mitigate this risk SCE is planning to purchase a spare generator rotor in 2023, which will coincide with the next planned Major Inspection (MI) overhaul at Mountainview.

The capital forecast for Capital Spares and Tools – Replacement Generator 89SS and 89ND Switches, CT Gas and Bleed Valves, Steam Attemperators is \$2.275 million for 2023-2028.[222]

(2) Project Scope

Scope includes the purchase of a Spare Generator Rotor with GE's "Flexpack" upgrades to minimize forced outage and planned outage time required for generator rotor

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[221] Per GE, generator rewinds for the 7FH2 Generator Fleet originally saw that 50% of the fleet would achieve 20 years of service prior to failure or major repairs. As cyclic duty demands have increased, this timeframe has been decreased from 20 to between 15 and 18 years.

[222] WP SCE-05 Vol. 1, p. 208. Capital Spares and Tools – Replacement Generator 89SS and 89ND Switches, CT Gas and Bleed Valves, Steam Attemperators.

associated outages. A sealed storage container will also be purchased for this generator rotor. GE's Flexpack upgrades are design improvements that improve reliability for plants that are expected to see cyclic operation.

(3) Project Justification and Benefit

If there is a forced outage due to a generator failure, having a spare rotor on site would remove any shop inspection and repair time from the outage duration. This would reduce generator rotor inspection/repair timeframe by approximately 4-6 weeks. Additionally, if needed, this spare rotor could also be used in the steam turbines generators following some excitation adjustments.

i) Unit 3 CO Catalyst Bed Replacements

(1) Background

Carbon Monoxide (CO) Catalysts are installed in the exhaust of each gas turbine at Mountainview and are used as a catalyst for changing CO to CO2 to meet emissions limits. Over time, the CO catalysts lose effectiveness due to contaminants like iron oxide and sulfur. Iron oxide and sulfur are normal, expected, and unavoidable contaminants in the exhaust duct of the gas turbine. The iron comes from corrosion of the heat recovery steam generator tubes and casing and there is a small amount of sulfur in the natural gas that is combusted in the gas turbines. Mountainview is currently meeting emissions requirements. Routine testing and monitoring of emissions are done to optimize the life of the CO Catalysts while ensuring compliance with emissions limits. The CO catalysts for Units 4A and 4B are also being monitored and budgeted for replacement in 2029. The capital forecast for the Unit 3 – Co Catalyst Bed Replacements project is $1.900 million for 2023-2028.[223]

(2) Project Scope

Purchase new CO Catalysts, remove, and recycle existing CO Catalysts, and install new CO Catalysts.

[223] WP SCE-05 Vol. 1, p. 200. Unit 3 CO Catalyst Bed Replacements.

(3) Project Justification and Benefit

Replacement of the CO Catalysts ensures Mountainview can meet its emissions limits as needed for continued operation and support of our electrical system while minimizing impact to the environment and surrounding community.

Alternatives: 1. Do nothing: Not an acceptable alternative. Mountainview is required to meet emissions requirements and generation at Mountainview is needed to support the bulk electrical system as we decarbonize our energy supply to meet Pathway 2045 goals.

2. Replace Catalyst with new. This is the preferred option that ensures Mountainview can continue to meet emissions requirements while supporting the bulk electric system as it transitions to 100% renewable power.

j) Unit 3A and 3B Combustion Turbine Battery Replacement

(1) Background

Mountainview Generation Station (MVGS) Units 3 and 4 Combustion Turbines (CT) are equipped with battery banks that supply power to various components. Annual internal maintenance inspections in 2022 discovered that the batteries are nearing their end of life. This project would replace the four Unit 3 and 4 CT batteries.

Gas turbine generators that are equipped with diesel engine starting devices are optionally capable of starting in a "black-start" condition (*i.e.,* without outside electrical power). Lubricating oil for starting is supplied by the DC emergency pump powered from the unit battery. This battery also provides power to the DC fuel forwarding pump for black starts on distillate. The turbine and generator control panels on all units are powered from the battery. Without these batteries in a good working condition the units would not be able to start up from a blackout condition. The capital forecast for Unit 3A and 3B Combustion Turbine Battery Replacement project is $1.800 million for 2023-2028.[224]

[224] WP SCE-05 Vol. 1, p. 201. Unit 3A and 3B Combustion Turbine Battery Replacement.

(2) Project Scope

Materials would include new batteries and cables for connecting batteries together and with the turbine circuit. Work would be completed by both SCE maintenance personnel and outside contractors. The project will be scheduled during the unit's annual spring outage. There should not be any effect on generation since the work will be performed during a planned outage.

(3) Project Justification and Benefit

Reddish brown patches, flaking plates and severe corrosion on battery terminals were outlined as findings during 2022's annual inspection. Damaged batteries are also at increased risk of fire. Replacing the batteries would mitigate current findings on the annual inspections and ensure Mountainview is "black-start" capable.

k) Cooling Tower Film Fill and Drift Eliminators

(1) Background

Cooling tower fill film and drift eliminators are constructed of ABS sheets that become brittle over time. With age, sections of fill can break apart and become insufficiently supported in the cooling tower. This can result in sections of film falling out of position and causing flow and structural concerns with the cooling tower. Broken film will also cause reduced cooling tower efficiencies that can put limits on power production during warmer weather. The capital forecast for Cooling Tower Film Fill and Drift Eliminators project is $1.800 million for 2023-2028.[225]

(2) Project Scope

Replace sections of film cell by cell. Correct any structural issues that are exposed while fill is removed.

(3) Project Justification and Benefit

Project would ensure Unit reliability and the ability to make full load during hot weather. Reduce the potential for structural concerns with falling and loose fill.

[225] WP SCE-05 Vol. 1, p. 202. Cooling Tower Film Fill and Drift Eliminators.

l) Unit 3 & 4 Heat Recovery Steam Generator (HRSG) Exhaust Duct Liners

(1) Background

Standard maintenance practice at Mountainview has been to repair exhaust duct liner damage during planned annual outages. Over the course of the past five years liner cracks have increased in both frequency and magnitude which results in a higher number of unplanned outages. This project will restore the exhaust duct liners to a more acceptable level of required maintenance. The capital forecast for Units 3 and 4 Heat Recovery Steam Generator (HRSG) Exhaust Duct Liners project is $1.600 million for 2023-2028.[226]

(2) Project Scope

Replace existing exhaust duct liner with an upgraded liner.

(3) Project Justification and Benefit

Project would restore the exhaust duct liners to a more acceptable level of required maintenance necessary to ensure continued Unit reliability.

m) Capital 7FH2 GT Generator Rotor

(1) Background

Mountainview was originally 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 between high and low load and start and stop regularly. This cyclic operation is expected to continue throughout the remaining life of Mountainview. This cyclic operation and starts stops results in increased thermal and cyclic stresses on the generator rotor coils and insulation system resulting in increased wear and tear and reduced reliability as compared to base load operation.

General Electric's (GE) experience with the vintage and model of generator rotors (GE 7FH2 Generator) at Mountainview indicates an increased risk of forced outage or major repairs being needed at the next major overhaul. GE states that, historically, field rewinds for the

[226] WP SCE-05 Vol. 1, p. 203. Unit 3 & 4 Heat Recovery Steam Generator Exhaust Duct Liners.

7FH2 Generator Fleet originally saw that 50% of the fleet achieved 20 years of service prior to failure or requiring major repairs. As cyclic duty demands have increased, this period has accelerated to between 15 and 18 years. Emergent field rewinds have increased significantly in the last 2 years. GE has observed accelerated/elevated risks within the Hitachi manufactured "sub fleet"; same as the Gas Turbine Generators at MVGS. The capital forecast for purchasing the Spare Generator Rotor is $1.250 million for 2023-2028.[227]

(2) Project Scope

Purchase a Spare Generator Rotor with GE's Flexpack upgrades to minimize forced outage and planned outage time required for generator rotor associated outages. A sealed storage container will also be purchased for this generator rotor. GE's Flexpack upgrades are design improvements that improve reliability for plants that are expected to see cyclic operation.

(3) Project Justification and Benefit

Outage Reduction - if there is a forced outage due to a generator failure, having a spare rotor on site would remove any shop inspection and repair time from the outage duration. This would reduce generator rotor inspection/repair timeframe by 4-6 weeks.

If needed, this spare rotor could also be used in the steam turbines generators with some excitation adjustments. An economic analysis was performed demonstrating the economic benefit of this project at a cost/benefit ratio of 6.0.[228]

n) CAVA- MVGS HVAC Assessment and Upgrades

(1) Background

Mountainview Generation Site (MVGS) has over 60 Heating and Ventilation Air Conditioning (HVAC) units. These HVAC Units climate control critical rooms which house employees and critical electrical equipment. This project would replace existing units that have been determined to be at risk because they have reached their end of service life. Additionally, the

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[227] WP SCE-05 Vol. 1, p. 204. Capital Spares - 7FH2 GT Generator Rotor.

[228] WP SCE-05, CONFIDENTIAL p. 39. Capital Spares – Spare 7FH2 GT Generator Rotor B/C.

project will install increased capacity HVAC units on rooms housing critical electrical equipment. Lastly, the California Public Utilities Commission (CPUC) mandated Climate Adaptation Vulnerability Assessment (CAVA) detailed high risk potential of forced outages from high temperature weather. This project serves as a mitigation to potential outages detailed in the CAVA. The original design of MVGS was to operate under 115 degrees Fahrenheit. However, the CAVA detailed that the number of days exceeding 115 degrees Fahrenheit is expected to rise threefold by 2050 and that HVAC Units with higher cooling potential will need to be installed to prevent critical equipment from overheating.

The capital forecast for CAVA – MVGS HVAC Assessment and Upgrades project is $0.500 million for 2023-2028.

(2) Project Scope

The project will: 1) perform an assessment of critical rooms containing approximately 20 HVAC Units that have reached end-of-life and 2) replacement of those HVAC units, in 2025, that have been determined to be critical and at end of life. SCE's estimates that between 8 and 12 HVAC units will need to be replaced in 2025. Installation of additional HVAC units on rooms which have been identified as housing personnel or critical plant electrical equipment to be performed in 2027 and 2028. Work will involve SCE maintenance team members as well as support from outside contractors.

(3) Project Justification and Benefit

Outage risk will be lowered by improving the reliability of HVAC systems where critical plant electrical equipment is housed. Units that were installed during the plant's inception will be replaced with new units, while rooms at risk during higher temperature days will be replaced with higher capacity systems.

C. Peaker Power Plants

1. Summary of Request – Peaker Generation

SCE forecasts Test Year 2025 O&M expenses of $8.626 million ($2022) to operate and maintain its five Peaker plants.[229] The forecast is based on last recorded year (*i.e.,* 2022 recorded) expense for labor and a five-year average of the 2018-2022 recorded expense for non-labor.

The capital forecast for the Peaker plants is $11.480 million (nominal, work order level) for 2023-2028.[230], [231]This forecast includes projects to facilitate continued compliance with safety and environmental objectives, and projects to sustain station reliability. Additional information regarding Peaker capital projects is discussed in testimony section III.C.4 below.

2. Overview of Peaker Power Plants

SCE owns and operates five General Electric Land/Marine ("LM") 6000 aeroderivative gas-fired Peaker power plants, of which two are battery/combustion turbine Hybrid Peakers, providing an aggregate of 245 MW. Peakers serve the electrical grid by starting quickly and ramping to meet the demand of the California Independent System Operator (California ISO) market. They have relatively low startup costs and can start and stop multiple times each day to support the grid, as needed. Each Peaker can reach full load within ten minutes after a start-up signal is received from the CAISO. Hybrid Peakers can respond instantaneously to a startup signal from the CAISO by using batteries to meet demand while the combustion turbine ramps up. In addition, all five SCE Peakers can start without external power from the grid. SCE would rely on this "black-start" capability to restart the grid in the event of a wide-scale system blackout.

Each of the five Peaker plants has a nominal capacity of 49 MW. Figure III-17 shows the location of the Peaker plants. The Peaker units are controlled and operated out of the Eastern Operations Generation Control Center (in Redlands, on the site of Mountainview Generating Station), where the

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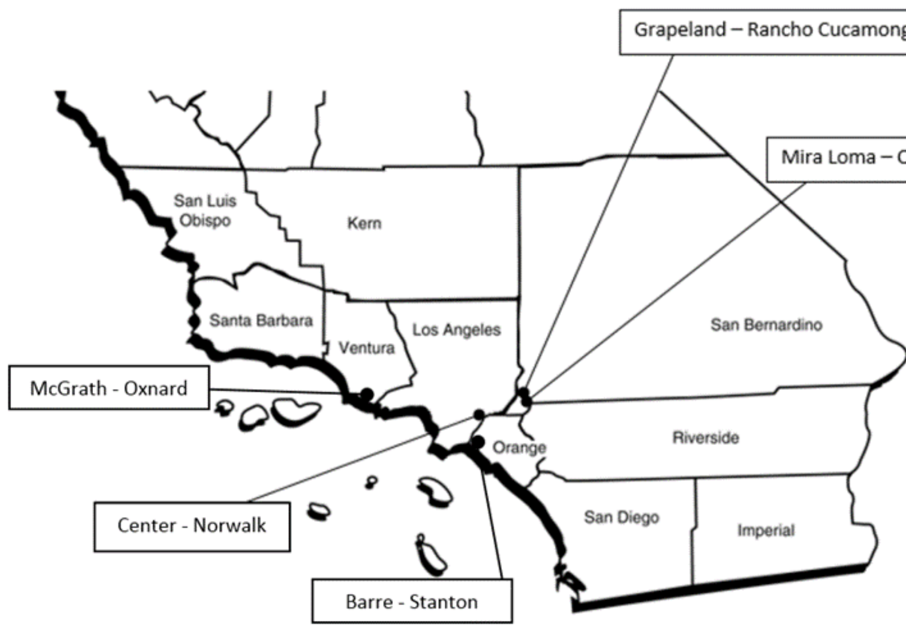
[229] WP SCE-05 Vol. 1, pp. 210-215. Peaker Operations and Maintenance Recorded/Forecast Summary.

[230] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[231] WP SCE-05 Vol. 1, pp. 216-221. Peaker Capital Expenditures.

support facilities and the employees who operate, maintain, and manage these facilities are also located. The first four Peaker units – Barre, Center, Grapeland, and Mira Loma – began commercial operation in August 2007. Due to permitting delays, the fifth Peaker unit – McGrath – did not begin commercial operation until November 2012. In 2016, utility-scale battery energy storage systems were added to Center and Grapeland, making them "Hybrid" units.

Figure III-17
Primary Peaker Locations



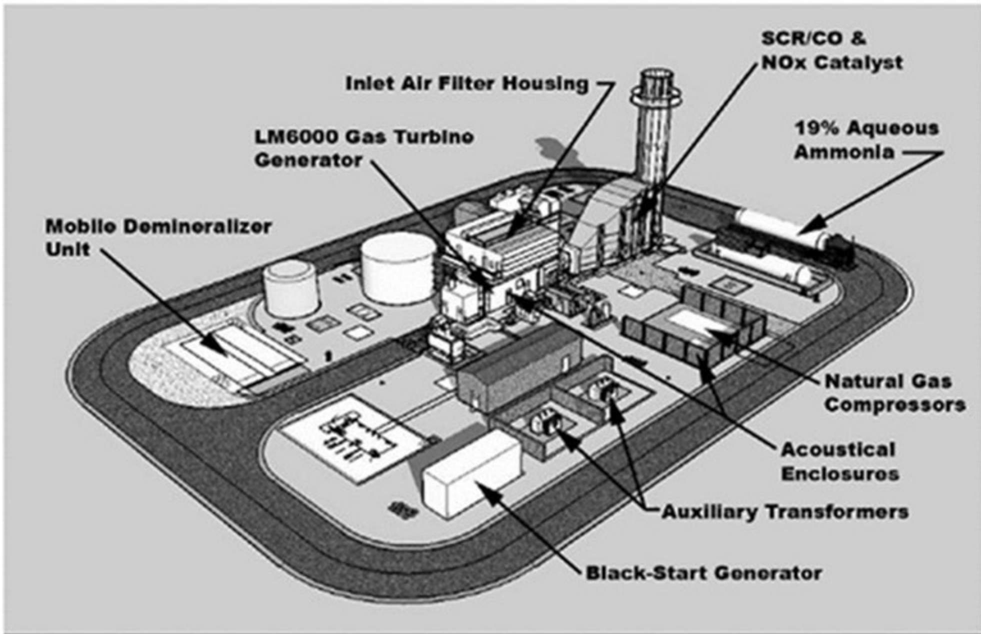
Each Peaker power plant uses a simple-cycle General Electric LM6000 SPRINT™ (SPRay INTercooling)[232] combustion turbine generator set, operated with a selective catalytic reduction (SCR) catalyst for nitrogen oxide (NOx) air pollution reduction and a Carbon Monoxide (“CO”) catalyst for CO air pollution reduction.[233]

Figure III-18 illustrates the power plant package, including many accessories required to provide efficient, safe, compliant, and reliable operation.

[232] General Electric's SPRINT option includes equipment which allows water to be injected directly into the combustion turbine HP or LP compressor sections, which increases the turbine’s power output.

[233] NOx are Nitrogen Oxide air pollutants.

Figure III-18
Typical Peaker Design



The gas-fired combustion turbine drives an electrical generator, producing electricity. The turbine consumes natural gas, air, and water, each of which needs to be conditioned prior to use. The local gas pipeline provides natural gas used to run the units. Each Peaker has two large electric motor-driven gas compressors to raise the natural gas pressure from the gas pipeline pressure to the required pressure for injection into the combustion turbine. A Closed-Circuit Reverse Osmosis system consisting of reverse osmosis filtration, water softening and conditioning treats water to a high purity state while minimizing brine production. The treated water is injected in two places within the gas turbine to control Nitrogen oxides ("NOx") emission and increase power output of the turbine. To minimize the damage foreign matter can cause to the turbine blades, a self-cleaning filter removes suspended matter from the inlet air prior to use.

Exhaust gases from the combustion turbine are routed to an 80-foot exhaust stack. Water injection into the turbine, a selective catalytic reduction ("SCR") system, and an additional layer of catalyst in the exhaust gas ducting for the control of organic compounds, control the air emissions. The

SCR system reduces NOx emissions from 25 parts per million (ppm) to 2.5 ppm by injecting ammonia which is stored in a 10,000-gallon storage tank, into the exhaust gas. A continuous emissions monitoring system ("CEMS") measures and reports the effectiveness of the air pollution control equipment to SCE and regulatory agencies.

Each Peaker plant has a 645 kW auxiliary electric generator driven by a natural gas-fired reciprocating engine. These auxiliary generators provide each Peaker plant with black-start capability by generating the initial power to operate turbine start-up related equipment and other auxiliary equipment required for black-starting.

Peaker plants serve the electric grid by starting and ramping quickly to meet system load demands. Each Peaker is bid into the CAISO market and offers energy, spinning reserve, and resource adequacy products. The CAISO dispatches the Peakers to meet system load and ancillary service needs when it is economic to do so (i.e., the cost to meet the need with the Peaker is less than the cost to meet the need with other available resources). SCE anticipates the future usage of the Peaker plants (especially the Hybrid units) will continue at a high level as the addition of intermittent energy sources such as wind and solar to the grid continue to increase the need for flexible, on-demand generation.

The first four Peaker plants are in Los Angeles, Orange, and San Bernardino counties and operate under air permits granted by the SCAQMD. The conditions in these permits limit the annual fuel usage, which is determined on a sliding scale based on the number of turbine start-ups, up to a maximum of 350 per year. Inherent in the Peakers' design, air emissions produced during the start-up of a Peaker will account for an appreciable percentage of overall emissions. SCE worked with SCAQMD to create sliding scales where fuel usage is limited based on the number of start-ups over a 12-month rolling period. As the number of start-ups increase, the allowable fuel usage decreases, which ensures that the Peaker plants maintain compliance with their respective emission limits. The fuel usage limit varies between 430 – 660 MMscf (million standard cubic feet) per year of natural gas, depending on the site and the number of starts.

The McGrath Peaker in Ventura County operates under an air permit granted by the Ventura County Air Pollution Control District ("VCAPCD"). Like the permits granted by SCAQMD, the VCAPCD granted a permit to operate under emission limits. This air emission permit allows for unlimited start-ups and run hours but limits the fuel usage to 1,667 MMscf per year of natural gas.

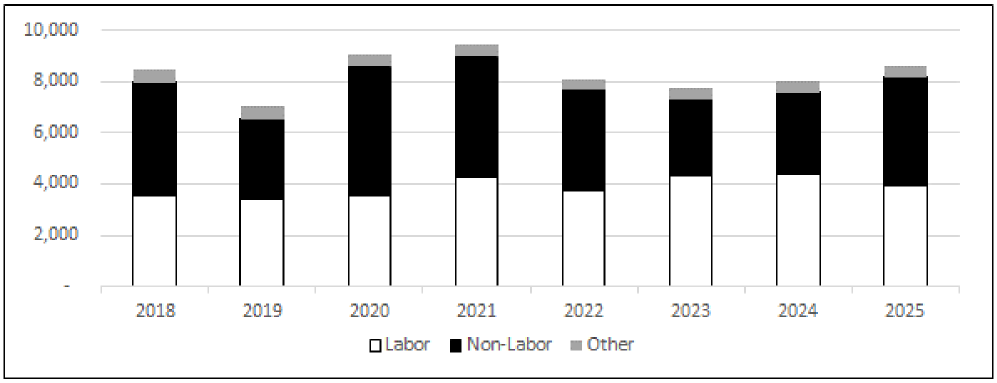
Consistent with the Resolution E-4791, two General Electric battery energy storage systems were integrated into SCE's existing GE LM6000 Gas Turbine Peaker Generating Stations in Norwalk, California ("Center Peaker") and Rancho Cucamonga, California ("Grapeland Peaker"), successfully upgrading the units into Hybrid Electric Gas Turbines ("EGTs"). The Hybrids became operational on December 30, 2016, and cost recovery was ordered to be transitioned to SCE's base rates in SCE's 2021 GRC.

3. Peaker O&M Forecast

a) Introduction

SCE's total Peaker Test Year O&M expense forecast of $8.626 million is summarized in Figure III-19. The figure also shows the recorded expenses for 2018-2022 and the forecast expenses for 2023-2025. Labor costs reflect the costs both for SCE employees who work primarily at Peakers and employees who work at other locations but support the plant. Non-labor costs include repair parts, chemicals, supplies, contracts, and numerous other items needed to operate and maintain the plant. Other costs consist of grid interconnection fees.

Figure III-19
Peaker - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)



	Recorded					Forecast		
	2018	2019	2020	2021	2022	2023	2024	2025
Labor	3,535	3,416	3,519	4,253	3,747	4,311	4,354	3,903
Non-Labor	4,415	3,122	5,062	4,716	3,935	2,992	3,198	4,250
Other	520	498	466	455	422	472	472	472
Total Expenses	8,470	7,036	9,047	9,424	8,104	7,776	8,023	8,626
Ratio of Labor to Total	42%	49%	39%	45%	46%	55%	54%	45%

b) Development of Test Year Forecast

Our 2025 Test Year forecast for the Peaker Generation activity is $8.626 million, including $3.903 million labor expense, $4.250 million non-labor expense and $0.472 million for other.[234]

(1) Labor – Analysis of Recorded and Forecast Expenses

Recorded labor expenses remained flat from 2018-2019, and then increased in 2020 due to the COVID-19 pandemic. To mitigate the risks of COVID-19, during 2020 and through 2021, SCE was required to sequester key employees performing critical operations work by physically isolating these employees from their families and other employees for many months. During isolation the sequestered employees were paid a premium and although incremental to authorized,

[234] WP SCE-05 Vol. 1, pp. 210-215. Peaker Operations and Maintenance Recorded/Forecast Summary.

sequestration costs were largely removed from the recorded cost reflected in this testimony, some sequestration costs (*i.e.,* those not incremental to authorized) remained and are reflected in the 2020 recorded costs. The 2022 recorded costs returned to more expected levels.

Because staffing levels have stabilized and the scope of work performed in 2022 most closely matches the planned scope of work in 2025, we use the last recorded year (2022) as the basis to forecast future labor expense for 2025 and beyond, $3.747 million. To this base amount, we make an adjustment of $0.157 to reflect certain changes made to SCE's employee compensation program, yielding a 2025 Test Year labor forecast of $3.903 million. For further information regarding this adjustment please refer to SCE-06 Vol. 04.

(2) Non-Labor – Analysis of Recorded and Forecast Expenses

During the past 5 years non-labor spend has experienced high variability due to unexpected maintenance activities at the Peaker facilities. This is because four of the five Peaker facilities have now been in commercial operation for 15 years and as they continue to age require additional maintenance. While the fifth Peaker (McGrath) has been operational for only a decade, it is uniquely located in a coastal environment creating accelerated weathering of exterior components that are exposed to inclement marine weather. Additionally, due to the nature of a Peaker run profile which includes on average over 200 annual starts with an average run-time of just under 2 hours, SCE expects this cost variability to continue for the foreseeable future.

Due to the potential of variations of non-labor in this account, as reflected by the recorded cost history, a historical average is most representative of non-labor expenses that can be expected in Test Year 2025. We therefore selected a five-year average (*i.e.,* 2018-2022) as the basis to forecast Test Year 2025 non-labor expense, at $4.250 million.

(3) Other - Analysis of Recorded and Forecast Expenses

The Peaker Other expense category consists of interconnection fees, which are fixed payments that Peakers pays to SCE T&D for interconnecting the Peaker units to the grid (*i.e.,* the assessed interconnection fee includes no periodic inflation adjustment and is therefore categorized as an "other" expense). These payments flow back to SCE customers through T&D Other Operating

Revenue (OOR). Further information regarding interconnection fees and OOR can be found in SCE-02 Volume 11.

SCE utilizes a 5-year average (*i.e.,* 2018-2022); as the basis to forecast non-labor Other expense of $0.472 million for Test Year 2025.

c) Peaker O&M Work Activities

Peaker O&M work activities are presented in two primary categories: (1) Operations and (2) Maintenance. These expenditures are necessary for SCE's Peaker generation to continue to provide reliable, fast-start, fast-ramp, and other auxiliary services to support the grid at low cost, maintain safe operations for employees and the public, and comply with applicable laws and regulations. Operations and maintenance personnel who support the Peaker facilities also support other generating assets in Eastern Operations (primarily Los Angeles Basin) area. Therefore, their labor costs are partially allocated to Peakers, according to the extent to which they support Peaker O&M activities.

(1) Peaker Operation Activities

Peaker Operations work activities include labor and non-labor expenses incurred in operating prime movers, generators, and electric equipment at the Peaker plants, up to the point where electricity is delivered to the distribution system. The operations and maintenance (production) staff that supports the Peakers also supports other generating stations in the region and their labor costs are allocated according to their level of support for each plant. Personnel include Control Operators who primarily control plant equipment from the Eastern Operations Generation Control Center ("EOGCC"), Operator Mechanics who primarily control plant components in the field, Chemistry Technicians who primarily perform duties to maintain plant water chemistry, and a Supervisor who supervises Control Operators, Operator Mechanics, and Chemistry Technicians. A Production Manager manages Operations and Maintenance (O&M) for power plants in the LA Basin area, a Principal Manager manages O&M for power plants in the Eastern Operations region (consisting of utility operations on Santa Catalina Island, and the mainland areas of Bishop/Mono and Los Angeles basins), and a Managing Director responsible for all aspects of SCE's power generation portfolio. Various support staff also provide Operational services to the Peaker plants. Support staff include members of the Asset Management and Generation Strategy group as well as the Major Projects and Engineering group within Generation. The support staff provide financial budgeting, accounting, administrative services, regulatory compliance support, project management, long-range planning, and other support activities.

Non-labor operational expenses include contract costs, materials, employee reimbursement expenses, SCE corporate support for various air, water, hazardous waste, and similar regulatory activities, chemicals and water used for turbine power augmentation and air emissions control, environmental monitoring and reporting, water discharge fees, permits and fees, communications and computing equipment expenses, office supplies, labor relations expenses, safety and training costs, and janitorial services. Also, fixed payments are made to SCE T&D for interconnecting the Peaker plants to the grid.

(2) Peaker Maintenance Activities

Peaker Maintenance work activities include labor and non-labor expenses incurred in the general planning, engineering, supervision, and execution of work activities that keep Peaker plant equipment in good working condition. Peaker maintenance is performed by SCE technicians and contract personnel. Maintenance Foremen and Supervisors ensure technicians work safely and direct the work of front-line technicians and contractors. The same Production Manager, Principal Manager, and Director discussed in (1) Peaker Operations Activities also support Peaker Maintenance Activities. Non-labor costs associated with Peaker maintenance include hardware, replacement equipment components, inspection equipment, vehicle expenses, contractor services, tools, and other miscellaneous items needed to support maintenance activities. Peaker maintenance activities also includes the management and control of hazardous materials, such as the ammonia used for emissions control.

4. Peaker Capital Expenditure Forecast

SCE's planned capital expenditures for the Peaker plants will support reliable service, compliance with applicable laws and regulations, and safe operations for employees and the public.

The total Peaker capital expenditure forecast is $11.480 million (nominal, work order level) for 2023-2028 as summarized in Table III-47.[235], [236]

Table III-47
Peaker Capital Expenditure
Capital Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Peaker - Relay Replacements	-	-	1,000	1,000	1,000	1,000	4,000
2	Peaker - Barre Turbine Overhaul	-	-	-	-	-	3,050	3,050
3	Peaker - Mira Loma CO Catalyst, Emissions Reduction Unit (ERU), Ammonia Upgrade	-	-	-	-	2,400	-	2,400
4	Peaker - System 1 Vibration Monitoring Package	-	-	800	-	-	-	800
5	Peaker - Spare Parts & Portable Tools	52	52	52	52	52	52	315
6	Peaker - Barre Excitation System	84	150	-	-	-	-	234
7	Peaker - Center Excitation System	84	150	-	-	-	-	234
8	Peaker - Grapeland Excitation System	84	150	-	-	-	-	234
9	Peaker - HVAC Replacements	-	-	-	-	120	-	120
10	Peaker - Mira Loma Excitation System	16	-	-	-	-	-	16
11	**GRAND TOTAL**	**320**	**502**	**1,852**	**1,052**	**3,572**	**4,102**	**11,402**

The following section of testimony provides further discussion of Peaker capital projects exceeding $1.000 million.

a) Peaker - Relay Replacements

(1) Background

The existing relays at the five Peakers were installed between 2007-2008 and by 2025 will have been in-service for 18 years. The current installed relays at SCE's five Peaker sites are modern micro-processor relays with a designed service life of 20 years. Other facilities may have electro-mechanical relays that have been in service for over 40-50 years. When comparing acceptable service life, it's important to compare with the same type of mechanism. The obsolete electro-mechanical models, which were the past generation of protective device, operated on magnetic and mechanical principles, while newer micro-processor relays are multi-functional digital devices that require updated firmware and software to operate reliably.

[235] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[236] WP SCE-05 Vol. 1, pp. 216-221. Peaker – Capital Expenditures.

To meet compliance requirements, micro-processor relays must be tested every 6 years. North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) cybersecurity requires that all devices connected to the bulk power system relays need to be an approved Transient Cyber Asset ("TCA"). This requirement includes the test tech's laptops which are used for testing the micro-processor relays. Software that was in use 18 years ago is no longer compatible with new operating systems. For example, relays installed in the early 2000s cannot communicate with the test tech's current laptop operating system (Windows 10). This causing issues for troubleshooting, routine maintenance tasks and meeting compliance requirements.

One major difference between electro-mechanical and micro-processor relays is that all protection elements (up to 20 or more) can be performed by one single micro-processor relay instead of having 20-30 individual electro-mechanical relays. When a microprocessor relay fails, it cannot be repaired by replacing a mechanical component, it needs to be sent back for repair or replaced with a new unit to return to service.

Micro-processor relays offer monitoring, self-diagnostics, event recording, and alarms as standard functions, these functions are not available in electro-mechanical relays.

New Micro-processor relays will be compatible with current computer operating systems. This will provide test techs the ability to test relays using their company laptops. As a result, SCE will be in compliance with NERC-CIP since test techs' company laptops are TCA approved assets. The capital expenditure forecast for the Peaker - Relay Replacements project is $4.000 million for 2023-2028, overall project cost forecast is $5.000 million.[237]

(2) Project Scope

This project will upgrade the microprocessor-based relays with modern units that are compatible with current computer operating systems. The installations for the five Peaker sites will take place from 2025 through 2031.

[237] WP SCE-05 Vol. 1, p. 217. Peaker - Relay Replacements.

(3) Project Justification and Benefit

In-service relay failure will have high consequence cost, aligning relay replacement with scheduled plant outages will minimize risk and unplanned outage cost. Additionally, the Peakers serve as a Black Start resource and without operable Black Start resources or alternatives, there is the potential for NERC Severe Violation Severity Level ("Severe VSL") EOP-005-2 R7. An economic analysis was performed demonstrating the economic benefit of this program at an average cost/benefit ratio of 3.6.[238]

b) Barre Turbine Overhaul

(1) Background

Four of the five Peaker turbines have been in-service since 2007 and based on General Electric's LM6000 Major Turbine Overhaul schedule are nearing their recommended replacement dates. Due to the current operating profile, it is estimated that the turbine change out at Barre Peaker will occur in 2028. SCE currently owns a spare turbine that will be used to replace the Barre turbine currently in-service, returning that generating unit to a reliable and safe operating condition in the shortest time possible. This project will refurbish the removed turbine so that it becomes available for use during subsequent turbine change outs. The capital expenditure forecast for the Peaker – Bare Turbine Overhaul project is $3.050 million for 2023-2028.[239]

(2) Project Scope

The project involves replacing and refurbishing the Barre Peaker turbine to utilize as a back-up should a planned replacement be necessary, or to replace a failed turbine.

(3) Project Justification and Benefit

The lead time to procure and receive a replacement turbine in the event of in-service failure can take 6 to 12 months. Refurbishment of the existing turbine provides an emergency backup turbine should one of the remaining 4 turbine generators fail while in-service. Having a spare

[238] WP SCE-05, CONFIDENTIAL p. 35-38. Various Peaker - Relay Replacements B/C.

[239] WP SCE-05 Vol. 1, p. 220. Bare Turbine Overhaul.

turbine ready for installation reduces the likelihood of an extended outage lasting the duration of the lead time. Additionally, the Peakers serve as a Black Start resource and without operable Black Start resources or alternatives, there is the potential for NERC Severe VSL EOP-005-2 R7. An economic analysis was performed demonstrating the economic benefit of this project at a cost/benefit ratio of 1.7.[240]

c) Mira Loma CO Catalyst, Emissions Reduction Unit (ERU), Ammonia Upgrade

(1) Background

Mira Loma Peaker is one of five Peaker stations operated by SCE. These machines use a gas turbine to generate electrical power with an output of approximately 49 megawatts. As part of the fuel combustion process, emissions are generated in the form of Nitrogen oxides and Carbon monoxide. These emission gases are reduced in a chemical reaction which includes the use of catalytic converting materials. As time goes on these catalytic materials become less efficient and require replacement to keep exhaust gases within environmental requirements. As we approach the replacement period for these at Mira Loma SCE is requesting to enhance these by upgrading the catalytic material and increasing the concentration of the ammonia utilized as part of the chemical conversion from 19% to 29%. This conversion will allow the plant to exhaust cleaner emissions at lower output power, which will give the plant the ability to provide a range of output power as demanded. The capital expenditure forecast for the Peaker – Mira Loma CO Catalyst, Emissions Reduction Unit (ERU), Ammonia Upgrade project is $2.400 million for 2023-2028.[241]

(2) Project Scope

Upgrading the emission reduction system will consist of:

1) A new Carbon monoxide (CO) Oxidation Catalyst made of platinum to reduce effects from natural gas odorizing chemical, for longer life. This catalyst will utilize existing main exhaust compartment structure with enhanced sealing ability between modules.

[240] WP SCE-05, CONFIDENTIAL p. 34. Bare Turbine Overhaul B/C.

[241] WP SCE-05 Vol. 1, p. 221. Mira Loma CO Catalyst, ERU, Ammonia Upgrade.

2) Upgrade of the Selective Catalyst Reactor ("SCR") system responsible for the reduction of the Nitrogen Oxides (NOx) by utilizing ammonia (NH3) as a reducing agent in concert with the catalyst. To better support the Peaker's ability to move between power ranges an increase in ammonia concentration will serve to better control the NOx and maintain the unit within emissions limits. This change will require submitting and approval of permitting from the air resource board. This change will also require upgrade of several control assets and controls updates requiring IT support.

3) Emission monitoring equipment will be added to provide real time out of engine exhaust emission concentrations for more effective control.

(3) Project Justification and Benefit

The primary function of the ERU is to maintain plant emissions compliance within permit requirements. Upgrading the ERU will result in an advantage of allowing the unit to operate and maintain compliance within a wider power range, between 49MW down to 5MW, to help support CAISO demands. Enhancement of the CO catalyst will result in longer life as it is not affected by the odorizing chemical added to the natural gas. An economic analysis was performed demonstrating the economic benefit of this project at a cost/benefit ratio of 3.6.[242]

d) System 1 Vibration Monitoring Package

(1) Background

Vibration monitoring equipment protects the engines and generators from vibration-caused damage. SCE's Peaker fleet is currently equipped with a Bently Nevada 3500 vibration monitoring system. This system allows the collection of basic trend data (i.e., once per second) that provides only limited monitoring without any diagnostic functionality. The addition of a System 1 Vibration monitoring system and required hardware will allow SCE to collect high frequency (i.e., millisecond) data that will allow diagnostics and predictive monitoring of the equipment. The capital

[242] WP SCE-05, CONFIDENTIAL p. 33. Mira Loma CO Catalyst B/C.

expenditure forecast for the Peaker – System 1 Vibration Monitoring Package project is $0.800 million for 2023-2028.

(2) Project Scope

This project will add a TDI card to the Bentley Nevada (BN) 3500 racks that will collect high density / high frequency vibration data that is required for vibration monitoring and diagnostics of various rotating machinery. This data will be stored in a centrally located server that will allow engineering access to the data. This project will also add a Bently Nevada maintenance and diagnostic capabilities which is in line with the support provided by BN at MVGS.

(3) Project Justification and Benefit

Peaker fleet combustion turbines are currently not included in the vibration monitoring program due to a lack of equipment and technical expertise within SCE. As the Peaker units age, they become more susceptible to vibration events and this project will add the required equipment and technical expertise to ensure the long-term reliability of the units.

D. Catalina (Pebbly Beach Generating Station)

1. Summary of Request – Catalina Generation

This section discusses the O&M and capital expenditures for Catalina Generation. SCE provides electric service to approximately 4,000 permanent residents and over one million annual visitors on Santa Catalina Island.[243] To maintain reliable service to this isolated system, SCE is requesting $5.781 million ($2022) in O&M expenses for Test Year 2025[244] and $6.185 million (nominal, work order level) in capital expenditures for years 2023-2028.[245], [246] For the reasons set forth in Chapter I.F.3(a) of this testimony, SCE's capital request does not include the costs recorded in the

[243] Santa-Catalina-Island-Demographics from 2018-2019 Suburban Stats.

[244] WP SCE-05 Vol. 1, pp. 221-226. Catalina (PBGS) Operations and Maintenance Recorded/Forecast Summary.

[245] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[246] WP SCE-05 Vol. 1, pp. 227-234. Catalina (PBGS) Capital Expenditures.

Catalina Repower Memorandum Account, which SCE seeks to have reviewed and recovered via a Tier 3 advice letter. Rather, SCE's capital request is for the six capital projects listed in Table III-48.

2. Overview of Catalina

Santa Catalina Island, usually referred to as "Catalina," is located offshore, approximately twenty-two miles south-southwest of Long Beach. Since 1962, SCE has provided electric service to the entire island, which includes the cities of Avalon and Two Harbors as well as the rural areas located in Catalina's interior and coastline.

The sizing and layout of the electric system spanning the geographically isolated, sparsely populated, topographically rugged, and semi-arid island poses unique operational challenges. SCE maintains a generation fleet to meet the demands of the island, and the heat wave experienced in September 2022 set an all-time peak demand for Catalina at 5.866MW, which was approximately 9.3% higher than the previous peak demand of 5.366MW experienced in 2018. SCE continues to monitor changes like this heatwave-induced peak demand and improve understanding related to the impacts of climate change on the utility services.[247] Roughly 98.7% of the island is characterized by the CPUC as a Tier 3 High Fire Threat District. Prior to SCE taking over as utility provider in 1962, Catalina experienced increasing infrastructure and reliability concerns that prompted several utility transfers.[248] SCE is encouraged by the recent 60-year utility service anniversary for Catalina Island and committed to the critical work ahead.

Catalina is a closed electrical system; electricity generated and distributed on Catalina is isolated and self-contained, thus reliability, safety, and resiliency are paramount concerns in SCE's resource planning for Catalina. Electricity is not obtained from the mainland. Six diesel engine generators at SCE's Pebbly Beach Generating Station ("PBGS") in the city of Avalon provide the primary power generation to Catalina residents and visitors, but because of a Clean Energy All Source RFO, SCE anticipates that the number of diesel generators needed to operate daily and provide reliable

[247] SCE provides water and gas services to Catalina, although those costs are recovered through separate GRCs.

[248] 1956 Decision 52861, 1919 Decision 6665, 1916 Decision 3422.

back-up generation will be reduced via zero- and near-zero-carbon-emissions resources that SCE secures through the RFO, although renewable resources are not expected to be completed for another four years or longer. For the diesel generators on the Island, fuel is delivered from refineries on the mainland to Long Beach in tanker trucks, which are then transported to Catalina by barge. The fuel is then transferred to storage tanks that feed the diesel engine generators. The control operators and plant equipment operators at PBGS monitor electrical load as it continually fluctuates throughout the day to ensure the generators meet customer demand.

Generated electricity flows to Pebbly Beach Substation and is distributed through three circuits (Hi Line, Interior, and Wrigley) at 12 kilovolts (kV). Through numerous distribution transformers located closer to customers, the 12 kV electricity is stepped down to service voltages for general use.

SCE's generation maximum nameplate capacity in Catalina totals approximately 11.8 megawatts (MW), which includes twenty-three 65-kilowatt (KW) propane-fueled microturbines (1.5 MW) and one energy storage battery (1.0 MW). The bulk of SCE's electric generation capacity has been provided via six diesel generators (9.3 MW), however, as indicated in section I.F.3 of testimony, SCE is committed to taking all reasonable actions to maximize the use of zero-carbon resources via a Clean Energy All-Source RFO and thus reduce diesel-based generation to meet demand on the Island. Moreover, because the SCAQMD regulates and enforces the federal and state regulations on equipment and facilities with the potential to emit air emissions, the SCAQMD plays a key role in determining the generation resources available on the Island.

3. Catalina O&M Recorded and Forecast Expense

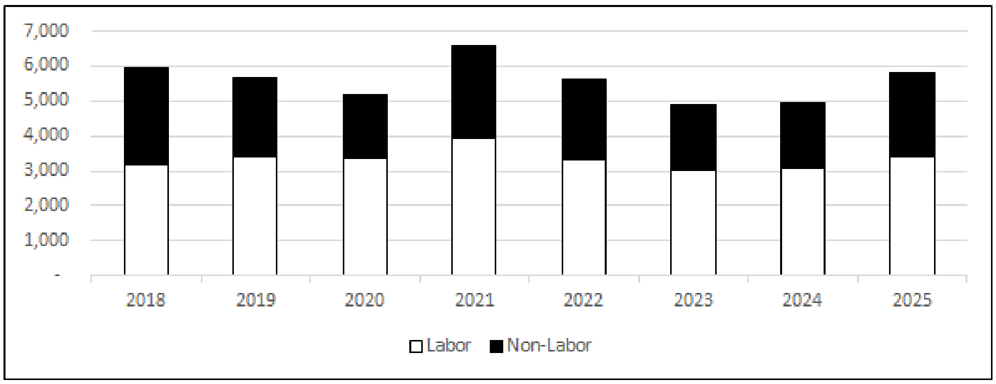
a) Introduction

SCE's total Catalina Test Year O&M expense is forecast to be $5.781 million, including $3.413 million labor expense and $2.368 million non-labor expense.[249] Figure III-20 presents the recorded expenses from 2018-2022 and the forecasts for 2023-2025. Labor costs reflect the costs for

[249] WP SCE-05 Vol. 1, pp. 221-226. Catalina (PBGS) Operations and Maintenance Recorded/Forecast Summary.

the SCE employees who work full-time at PBGS as well as additional, part-time support provided to the plant by employees that work at other locations. Non-labor costs include repair parts, chemicals, supplies, contracts and various miscellaneous expenses needed to operate and maintain Catalina's generation units.

Figure III-20
Catalina - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	3,193	3,390	3,357	3,920	3,313	3,024	3,057	3,413
Non-Labor	2,770	2,289	1,803	2,665	2,312	1,862	1,905	2,368
Total Expenses	5,963	5,679	5,161	6,585	5,625	4,886	4,961	5,781
Ratio of Labor to Total	54%	60%	65%	60%	59%	62%	62%	59%

(1) Development of Test Year Forecast

(a) Labor – Analysis of Recorded and Forecast Expenses

SCE's Catalina generation facilities are currently operated by one control operator and one plant equipment operator for each shift. The plant operators work 12 hour rotating shifts with 24/7 coverage to ensure the reliable operation and maintenance of Catalina's utility systems (electrical energy, gas and water). Labor expenses also include those from administrative support staff at PBGS. Recorded labor expenses were relatively flat from 2018 to 2020 but increased significantly in 2021, with a significant portion of the labor expenses related to sequestration. Due to the COVID-19 pandemic, in 2020 and 2021, SCE sequestered key employees that performed unique, critical operations work so that SCE could mitigate the risks of COVID-19 on its operations by physically isolating these employees from their families and other employees for months. Sequestered employees were paid a premium during isolation. Although sequestration costs have been predominantly removed from the recorded cost reflected in this testimony and are recorded in a memorandum account, some sequestration costs deemed not to be incremental remained and are reflected in the O&M recorded cost.

Because the scope of work performed in 2022 most closely matches the planned scope of work in 2025 and because SCE does not anticipate any changes to staffing, we use the last recorded year (*i.e.,* 2022) as the basis to forecast future labor expense for Test Year 2025, $3.313 million. To this base amount, we make an adjustment of $0.100 to reflect certain changes made to SCE's employee compensation program, yielding a 2025 Test Year labor forecast of $3.413 million. For further information regarding this adjustment please refer to SCE-06, Vol. 04.

(b) <u>Non-Labor – Analysis of Recorded and Forecast Expenses</u>

Historical non-labor O&M expenses for this activity varied during the recorded years and do not follow a predictable pattern. From 2018-2019, nonlabor expenses decreased from $2.770 million to $2.289 million due to reduced maintenance costs because of the completion of a zero-time overhaul of Unit 15 completed in early 2018. That major overhaul resets the run-hour clock to zero and is undertaken only after an engine runs for approximately 150,000 hours. Because Unit 15 has been the cleanest and most efficient unit on Catalina and is required to operate to meet PBGS's site-wide emissions permit, it has been run significantly more than any other engine. Therefore, Unit 15 has had the most maintenance requirements and the largest impacts on the Catalina O&M budget. The maintenance schedule following a zero-time overhaul is very minimal until the unit starts to reach a new set of maintenance milestones. In 2020 recorded nonlabor costs dropped further as SCE had to defer maintenance as a result of the COVID-19 pandemic's impact on the availability of parts and materials. In 2021, recorded nonlabor increased as the supply chain started to normalize allowing SCE to catch up on the deferred maintenance. Following 2021, recorded non-labor expenses returned to 2018 recorded levels.

Since recorded costs do not follow a predictable pattern, SCE used a historical five-year average (*i.e.,* 2018-2022) for its non-labor 2025 Test Year forecast of $2.368 million. This is consistent with Commission guidance on forecast methodologies and the same methodology adopted for Catalina Generation non-labor expenses in previous GRC submissions.

(2) Catalina O&M Work Activities

Catalina Generation O&M expenses are for the ongoing operations and maintenance activities necessary to carry out safe and reliable operation of the generators and connected electrical systems. These activities include miscellaneous expenses such as minor spare parts, general and administrative support staff, automotive repair, tools, and compliance reporting.

4. Catalina Capital Expenditure Forecast

SCE is requesting $6.185 million (nominal, work order level) in capital expenditures for 2023-2028.[250], [251] The forecast is comprised of two Catalina Rule 1470-related projects, with an overall project forecast of $3.077 million, while the remaining $3.000 million includes expenditures for the Diesel offloading improvements, Sodium Sulphur (NaS) Battery Replacement Upgrade, PBGS Repavement, and Repurpose Microturbine Space. The capital forecast is shown in Table III-48 below.

Table III-48
Catalina Capital Expenditure
Forecast 2023-2028
(Nominal $000)

Line No.	Project	2023	2024	2025	2026	2027	2028	TOTAL
1	Rule 1470 Unit 15 Order for Abatement: Solar Carports	1,279	1,079	-	-	-	-	2,358
2	Rule 1470 Unit 15 Order for Abatement: R95 Fuel Test	720	-	-	-	-	-	720
3	Diesel offloading improvements	-	-	1,000	-	-	-	1,000
4	NaS Battery Replacement/Upgrade	-	-	-	1,000	-	-	1,000
5	Pebbly Beach Generating Station Repavements	-	-	-	-	-	500	500
6	Repurpose Microturbine Space	-	-	-	-	500	-	500
7	**GRAND TOTAL**	**1,998**	**1,079**	**1,000**	**1,000**	**500**	**500**	**6,077**

[250] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[251] WP SCE-05 Vol. 1, pp. 227-234. Catalina (PBGS) – Capital Expenditures.

The following section of testimony provides further discussion of the Catalina capital projects listed above.

a) Rule 1470 Unit 15 Order for Abatement: Solar Carports

(1) Background

In 2021, during the five-year renewal of PBGS's Title V permit, the SCAQMD determined that because the 2017/2018 overhaul of Unit 15 exceeded 50% of the cost of a new unit, Unit 15 was subject to Rule 1470 limits for particulate matter (PM) emissions that it could not meet. SCE applied for a variance to continue running Unit 15 but was denied. SCE subsequently applied and was granted an Order for Abatement ("Abatement Order") in January 2022 with several conditions. Condition 6d of the Abatement Order states: "Respondent shall, by January 18, 2022 begin investigating the feasibility of the following: Installing a 100kW-400kW PV solar system at the Pebbly Beach facility and provide South Coast AQMD with the preliminary results of that investigation." SCE engaged a consultant to perform a feasibility analysis of the conditions outlined in the Abatement Order and found that a system comprised of two solar carports, covering the east and west parking lots, was feasible and practical and could provide a power output in the range of 104 kW-AC. A subsequent Abatement Order issued by the SCAQMD Hearing Board on September 10, 2022 requires SCE to install the carports by January 31, 2026. The capital expenditure forecast for the Rule 1470 Unit 15 Order for Abatement: Solar Carports project is \$2.358 million for 2023-2028.[252]

(2) Project Scope

The project includes costs for engineering and construction of two solar carports covering the east and west parking lots, including electric vehicle charging stations. Solar carports will be mounted on raised structures so that vehicles can park beneath. The power generated will be used to charge electric vehicles and offset the load of the PBGS main building. Minor or ministerial permits are expected to be required. Engineering and construction will be competitively bid.

[252] WP SCE-05 Vol. 1, p. 231. Rule 1470 Unit 15 Order for Abatement: Solar Carports.

Engineering and construction are both expected to take six months each to complete. Major material acquisition is expected to take 12 months after orders are placed.

(3) Project Justification and Benefit

Installation of the solar carports is necessary for SCE to comply with the Abatement Order.

b) Rule 1470 Unit 15 Order for Abatement: R95 Fuel Test

(1) Background

Condition 6a of the January 2022 Abatement Order states: "Respondent shall, by January 18, 2022, begin investigating the feasibility of the following: Using biodiesel or renewable diesel fuel for Unit 15 by contacting at least one biodiesel or renewable diesel supplier and provide South Coast AQMD with all correspondence from the biodiesel or renewable diesel supplier concerning that inquiry." SCE engaged a consultant to perform a feasibility analysis of the conditions outlined in the Abatement Order and found that the use of renewable diesel was feasible. However, based on CARB testing on an EMD 645 engine nearly identical to five of the six generators at PBGS, the results, provided by Metrolink, suggested that renewable diesel by itself would not bring Unit 15 into compliance with the Rule 1470 limit for Particulate Matter. However, SCE is investigating the conversion of the entire mobile diesel fleet to renewable diesel within two to three years. To that end, SCE plans to test renewable diesel on one Unit in the existing fleet to identify any potential negative impacts prior to a wholesale switch to this fuel in the very near future. The capital expenditure forecast for the Rule 1470 Unit 15 Order for Abatement project is $0.720 million for 2023-2028.

(2) Project Scope

The project will follow the manufacturer's recommendation to replace one or more power packs on the test engine and one or more power packs on the control engine. The power packs shall be monitored with visual inspections to identify any indications of unusual wear. SCE would test for up to 2,000 hours per the manufacturer's recommendation, if practical, because measurable cylinder liner wear may be difficult to quantify in a shorter test. Upon conclusion of R99 testing, powerpacks from the control and test engine will be sent to the manufacturer for final analysis. SCE will add R95/R99 fuel tests to the current fuel testing program and collect approximately three months' worth of emission monitoring data for the test engine.

(3) Project Justification and Benefit

SCE analyzed the feasibility of using renewable fuel in the PBGS generators. In the July 2022 Action Plan required by the Order for Abatement, SCE stated it intended to test renewable fuel in one existing unit in 2023.

c) Diesel Offloading Improvements

(1) Background

The diesel offloading system at the PBGS is a term used to describe the equipment, a series of pumps, motors, valves, hard piping, flexible piping, connectors, and meters, that transfers fuel from the mobile tankers into the PBGS fuel storage tanks. It is considered to be critical equipment because if it fails, SCE would be unable to offload diesel fuel form the mobile tankers, and would not have necessary fuel to power the PBGS. SCE Operations identified the existing diesel offloading system as a vulnerability and at high risk of failure with no redundancy currently in place for the system to recover. Improvements are needed to ensure the continued safe and reliable operation of the diesel offloading system). SCE will perform a baseline condition assessment of the diesel offloading system and its components to identify its current system health and provide recommendations for maintenance mitigations and improvements until the single point vulnerability has been eliminated with the necessary design change project. The capital expenditure forecast for the Repower - Diesel Offloading Improvements project is $1.000 million for 2023-2028.[253]

(2) Project Scope

Project scope includes the engineering and design and installation of a more reliable system, which includes items such repair/refurbishment of the currently installed diesel offloading system components (*i.e.,* painting of pipes, changing of in-line filters, and mitigation of the single point vulnerability).

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[253] WP SCE-05 Vol. 1, p. 233. Catalina Diesel Offloading Improvements.

(3) Project Justification and Benefit

The repair/refurbishment of the diesel offloading system along with the baseline condition assessment of the system by SCE will result in the design needs to eliminate the single point vulnerability of the current system configuration. The refurbishments and upgrades made to the system as result of this project will reduce the existing high risk of failure of the system due to the single point vulnerability and ensure the continued safe and reliable operation of the system and ultimately Pebbly Beach Generating Station.

d) Sodium Sulfide (NaS) Battery Control System Replacement/Upgrade

(1) Background

The PBGS battery system is comprised of a Sodium Sulfide (NaS) battery and an inverter control system. The existing NaS battery was installed in 2011 and its switchgear and electronics have, for some time, been experiencing performance issues/unplanned outages. Recent analysis performed by SCE indicates that the battery has approximately five years of useful life remaining while the inverter control system has reached end of life and requires replacement.

The capital expenditure forecast for the Sodium Sulfide (NaS) Battery Control System Replacement/Upgrade project is $1.000 million for 2023-2028.[254]

(2) Project Scope

The project scope involves purchasing and installing a new inverter control system with more reliable and efficient switchgear/electronics.

(3) Project Justification and Benefit

The PBGS battery system's operability and availability, a condition of the existing AQMD permit, is being used to shave peak demand which assists the diesel engines in meeting their AQMD emissions requirements. Replacing the battery's switchgear and electronics to a more reliable system will assist SCE in continuing to meet AQMD permit requirements.

[254] WP SCE-05 Vol. 1, p. 234. Catalina NaS Battery Replacement/Upgrade.

e) Pebbly Beach Generating Station Pavement

(1) Background

The PBGS facility needs to be repaved. It has numerous areas with uneven and broken surfaces that are tripping hazards, as well as numerous areas where the surface needs to be repaired for the storm water containment system to function properly, which may be problematic during a hazardous waste spill event. At present, water tends to pool during heavy rain events resulting in a potential slip/trip hazard. Repaving would mitigate these issues. The capital expenditure forecast for the Pebbly Beach Generating Station Repavement project is $0.500 million for 2023-2028.

(2) Project Scope

The project scope involves (1) performing a topographic survey of the site and a geophysical underground utility clearance survey, (2) completing a civil engineering evaluation, design, and construction specification including required SPCC (spill prevention control and countermeasures) assessment, and (3) competitively bid construction via a competitive solicitation. The final construction may be asphalt, concrete, or a combination of both.

(3) Project Justification and Benefit

The value of this project is a safer work environment for employees and greater demonstration of responsibility and ownership of the station's ecological impact on the community.

f) Repurpose Microturbine Space

(1) Background

As part of the ongoing Rule 1135 BARCT analysis, SCE continues to work with SCAQMD to evaluate the opportunity to install zero- and near-zero- emissions generation resources at PBGS. In 2021, during the five-year renewal of PBGS's Title V permit, the South Coast Air Quality Management District (SCAQMD; air district, or district) discovered that Unit 15, because of the overhaul (occurring in 2017-2018) cost exceeding 50% of the cost of a new engine, was in violation of Rule 1470 for Particulate Matter. SCE applied for a variance to continue running Unit 15 but was denied. SCE subsequently applied and was granted an Order for Abatement; however, the order came with several conditions. Condition 5 of the Abatement Order stated "Beginning January 10, 2022, Respondent shall: (a) assess the feasibility and the environmental, service, and operational impacts of increasing the use of the microturbines that are both permitted and currently operational at the Pebbly Beach facility; and (b) shall report the results of that assessment to the South Coast AQMD by March 18, 2022. The assessment shall include a conclusion regarding whether at least 1,270,000 kWh of power can be generated by the microturbines each calendar year until Unit 15 is brought into compliance, and if not, the maximum kWh/year of electric power production that can be reasonably and reliably achieved using those microturbines."

SCE engaged Power Engineers to perform a feasibility analysis of the conditions outlined in the Abatement Order and reached the following conclusion: “Because the microturbines are at the end of their useful life and have both limited availability, and output constraints, SCE cannot reasonably expect them to generate 1,270,000 kWh/year. The maximum amount of power that could be reasonably and reliably achieved with the microturbines is 635,000 kWh, the amount required by the facility permit, and that would require significant repairs to achieve.” SCE proposed to SCAQMD that SCE would be willing to refurbish and return 15 microturbines to good operating condition to achieve meeting the 635 kWh amount required by the facility permit. However, in subsequent discussions, SCAQMD stated that they would prefer to repurpose the microturbine pad for zero- and near-zero- emissions generation resources. The capital expenditure forecast for the Repurpose Microturbine Space project is $0.500 million for 2023-2028.

(2) Project Scope

The project scope involves performing an engineering assessment to determine the civil/structural, electrical, and mechanical properties of the microturbine pad, which would take into consideration constraints such as seismic and code requirements, soil liquefaction potential, electrical and arc flash required working clearances, operational working clearances for ingress and egress, proximity to hazardous materials and existing site structures, and the mechanical load that the pad could support. A geophysical survey would be completed to identify underground utilities. Preliminary Coastal Development Permit (CDP) and CEQA analysis would be completed, including the identification of other environmental concerns. And SCE would determine the least cost/best fit zero- and near-zero- emissions generation resources to replace the microturbines within the existing footprint. Resources under consideration may include, but not limited to, fuel cells, free piston linear generators, and propane-powered reciprocating generators.

(3) Project Justification and Benefit

Repurposing the micro turbine pad to accommodate zero- and near-zero- emissions generation resources would demonstrate SCEs compliance with the conditions in the Abatement Order. Additionally, to comply with Rule 1135 on and after January 1, 2026, PBGS must reduce facility NOx emissions to 13 tons per year, which is equivalent to a level that would require the facility to replace several of its six diesel engines with new U.S. EPA Tier 4 Final-certified diesel engines and implement additional zero- and near-zero emission technologies. Repurposing of the microturbine pad to accommodate zero- and near-zero- emissions generation resources would help SCE achieve compliance with Rule 1135 on and after January 1, 2026.

B. Fuel Cells

SCE owns and operates two fuel cell generating plants with a combined total capacity of 1.6 MW. The 0.2 MW fuel cell project at University of California Santa Barbara ("UCSB") has been operational since September 6, 2012 and utilizes an electric-only fuel cell technology. The 1.4 MW fuel cell at California State University San Bernardino ("CSUSB") has been operational since October 3, 2013 and utilizes a combined heat and power fuel cell technology. The fuel cell system at CSUSB utilizes the fuel cell's exhaust heat to generate hot water for CSUSB's building heating system. A description of the selection of the fuel cell sites can be found in SCE's Fuel Cell Program direct testimony in A.09-04-018.[255]

The operations and maintenance of the Fuel Cell facilities is performed by the Fuel Cell suppliers under their respective Long Term Service Agreements ("LTSA") which records as non-labor. Also included in the non-labor forecast are telecommunications and data services, interconnection

[255] A.09-04-018, Exhibit SCE-01, p. 2.

facilities charges, water treatment system service agreement, site maintenance service agreements, and air quality permit certification and renewal.

1. **Fuel Cell Decommissioning**

a) Background

In 2010, the Commission approved SCE's request to install, own and operate fuel cell units located at CSU San Bernardino and UC Santa Barbara.[256] The purpose of the ten-year demonstration project(s) was to advance fuel cell technologies by contributing to a better understanding of fuel cell operations and processes, and by sharing the benefits of fuel cell technology through community outreach and education. At the time it was believed that fuel cell installations lagged other forms of clean technologies due, in part, to a lack of understanding by the public of this advanced technology.

The larger 1,400 kW system at CSU San Bernardino would be used to demonstrate combined heat and power ("CHP," or cogeneration) while the smaller, 200 kW system at UC Santa Barbara would demonstrate an electricity-only high efficiency fuel cell where the waste heat is used in the generation process.

SCE has successfully demonstrated operation of these facilities in its annual ERRA Review filing. Therein, SCE has reported annual operational results with no intervenor recommended disallowances during the Fuel Cells' ten-year operational life.

The ten-year contracts with the hosts for both UCSB and CSUSB Fuel Cell programs expire in 2022 and 2023 respectively. SCE will conclude the ten-year demonstration program and discontinue operation of the two facilities at the expiration of the contracts, as the universities have declined to exercise their contractual rights to retain the assets beyond the lease terms. SCE is therefore obligated under the terms of the contracts to remove the assets. SCE's decommissioning proposal is

[256] Three Fuel Cell Units were approved in D.10-02-048, but that decision was modified in D. 12-04-011 to a reduction of two Units when SCE found it could not negotiate a reasonable ground lease with CSU Long Beach.

discussed further in SCE-07, Vol. 3. The capital expenditure forecast for the Fuel Cell Decommissioning project is $1.511 million for 2023-2028.[257], [258]

b) Project Scope

SCE developed a 2,436 square foot, 1,400 kW dual-use Fuel Cell project on the campus of CSUSB. The fuel cell project generates power that is sold by SCE to the CAISO grid, as well as providing waste heat water to CSUSB for their use.

SCE has a ten- year Lease Agreement with CSUSB that will cease in September 2023. Per that lease agreement, CSUSB has the right to obtain ownership and operate the facility at their request. CSUSB has communicated to SCE that it does not want to obtain the project, and SCE's service agreement with Fuel Cell Energy Inc. ended at the end of 2022. SCE is preparing to perform a complete demobilization of the project and return the property to CSUSB in its original condition. SCE has assigned a project manager who will be working with CSUSB, Fuel Cell Energy Inc. and a future contracted construction firm to de-construct and remove the site and return it to as found condition by the end of 2023.

Of note, the original estimate provided in the last General Rate Case had the demobilization/removal cost for the CSUSB fuel cell project was estimated at $1.5 million dollars.

SCE entered a ten-year lease with UCSB to operate a 200-kW demonstration fuel cell plant located on the UCSB campus in August 2011. The fuel cell manufacturer, Bloom Energy, held the proprietary rights to the fuel cell equipment. Per the lease agreement, either party could cancel the lease at the end of the ten-year lease period, and UCSB so informed SCE of their intention to cancel said lease due to plans to build student housing at that location.

Upon cancellation notice, the lease expired on September 5th, 2022, and SCE requested to utilize the six-month decommission/demolition period allowed for in the lease agreement to fully disassemble and remove the equipment and site utilities to an as-found condition.

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[257] The forecast reflects certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

[258] WP SCE-05 Vol. 1, p. 243. CSU at San Bernardino Fuel Cell Transfer (Decommissioning).

SCE assigned a project manager who is currently working with UCSB, Bloom Energy and a contracted construction firm to de-construct and remove the site and return it to as found condition by the end of 2023.

c) Project Justification and Benefit

The costs to operate the facilities far exceed the value to SCE customers in both instances. Given the end of the contracts with the hosts and the OEMs, it is in the best interest of SCE customers to decommission the facilities.

IV.

SOLAR

Pursuant to California state directives including the California Solar Initiative ("CSI") and Renewable Portfolio Standard ("RPS") programs, SCE currently owns and operates twenty-four solar generating plants[259] constructed as part of the SCE Solar Photovoltaic Program ("SPVP")[260] with a combined total capacity of 67.5 MW (AC).[261] The first of SCE's solar plants entered service in 2008 with the final plant in 2013.

In D.09-06-049, which approved the SPVP in SCE's service area, the Commission directed that the program was "... about driving the costs of deploying an existing technology down by creating a new market opportunity." The decision authorized SCE to install, operate, and maintain utility-owned solar photovoltaic ("SPV") generating facilities primarily on commercial and industrial rooftop space, with no more than 10% of the program to consist of ground mounted SPV. The Commission found that other California solar programs had "... left a gap in the one to two MW solar energy market" and found SCE's SPVP Program as "... one possible solution to help address the existing gap ..." The five-year program envisioned installation of up to 250 MW Direct Current ("DC") of solar generating facilities by SCE. The program was modified in D.12 02-035, reducing the program installation to 125 MW, with no less than 115 MW of solar generation facilities absent additional authorization. This decision also increased the allowable ground mount installations from 10 percent of total capacity to 20 percent. The program was further reduced to no less than 91 MW DC (67.5 MW AC) in D.13-05-033. The program's goals were accomplished in 2013 with the installation of the final solar rooftop project, whereby SCE achieved a total solar generating plant fleet of 91.4 MW DC.

Except for the Porterville SPVP Site (SPVP 042), which is a 6.8 MW DC Capacity ground-mounted installation, all the SCE solar plants are located on the rooftops of large commercial and industrial buildings. SCE leases the rooftop spaces from the building owners, with the lease agreements

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

[260] The Commission authorized SCE's SPVP Program in D.09-06-049.

[261] 24 rooftop solar photovoltaic (SPV) plants, and one ground based SPV plant (at Porterville).

reviewed and approved by the Commission in D.15-11-021. In compliance with the lease terms and conditions, SCE must operate and maintain these plants in a manner that mitigates fire hazards and other risks these plants might otherwise pose to the building owners' staff and operations.

In D.09-06-049 the Commission required SCE to submit recorded capital expenditures, annual O&M, and lease costs for reasonableness reviews in SCE's subsequent GRCs. The Commission subsequently has reviewed and approved all SPVP capital expenditure costs as reasonable, with zero disallowances. The Commission also reviewed and approved all SPVP O&M expenses and lease costs as reasonable, with the sole exception of costs SCE incurred to terminate a solar-panel supply contract.

A. <u>Solar Photovoltaic Program (SPVP) Decommissioning</u>

SCE Generation has been operating and maintaining the SPVP facilities utilizing prudent industry practices and targeting to maintain a 20% capacity factor. SCE maintenance practices are designed to optimize the O&M expense and keep it aligned with 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 reduced the net value of these facilities.

In addition, 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 at the time, 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 on an installation site. The incident evaluation attributed the damage to a design deficiency in the panel string connector.[262] 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, fires, and asset failures.

Challenges associated with rooftop solar installation are not unique to SCE's facilities, which at the time of installation in 2009 were among the first of its kind in the world.[263] For example, Walmart experienced seven fires between 2012 and 2019, and in 2020 and 2021 the rooftop solar panels atop six Amazon fulfillment centers caught fire or experienced electrical explosions.[264] A 2021 study performed by Clean Energy Associates (CEA) showed that, while many rooftop solar systems may operate for years without incident, more than 90% of inspected rooftops had significant safety and fire risks.[265]

SCE has been operating the portfolio for over 10 years and has successfully demonstrated solar photovoltaic technology as a new market opportunity. As solar 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 our customers because an increase in maintenance expenses and safety risks, coupled with declining value, has turned the operating economics unfavorable to SCE customers.

As shown in Table IV-49, in 2022 SCE's Present Value of Revenue Requirement (PVRR) analysis of repairing and/or decommissioning the twenty-four remaining SPVP sites suggests decommissioning in 2025 and 2026 is the least-cost alternative to SCE customers.[266]

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[262] WP SCE-05 Vol. 1, pp. 245-296. Standard Cause Evaluation - 2022 Solar Site 012 Fire.

[263] D.09-06-049.

[264] *Available at* https://www.cnbc.com/2022/09/01/amazon-took-solar-rooftops-offline-last-year-after-fires-explosions.html.

[265] *Available at* https://www.pv-magazine.com/2021/11/17/fire-risks-for-rooftop-solar/.

[266] In theory, the remaining sites could be refurbished and then decommissioned during "reroofing years," but financial analysis of this approach would be purely speculative due to uncertainty and lack of transparency regarding building owners' plans for reroofing (which could occur any time between now and 2032). If reroofing occurred in later years, continued operation will be costly and may expose sites to additional liability. As such, SCE recommends decommissioning in 2025 and 2026.

Table IV-49
2022 Present Value of Revenue Requirement (PVRR) Analysis of SPVP Repair and Decommissioning Options
(Constant 2022 $ Millions)

Line No.	Total	Option 1 - Refurbish/Reinstall; Decom at the original end of asset life	Option 2 - Deenergize by 2023; Decom in 2025-2026
1	Ongoing Capital	$ 4	$ -
2	Ongoing O&M	$ 164	$ 12
3	Ongoing Lease	$ 30	$ 30
4	Energy, Capacity & REC Benefits	$ (19)	$ -
5	Decommission & NBV/Rate Base Impact	$ 18	$ 57
6	Sunk Plant	$ 196	$ 196
7	**Total Cost (PVRR)**	**$ 393**	**$ 295**

While this analysis demonstrates that decommissioning in 2025 and 2026 is the least-cost alternative to SCE customers, SCE will continue to incur O&M expenses following site decommissioning. These expenses and associated forecasts are discussed in greater detail in testimony section IV.B.2.

1. Background

SCE's SPVP Portfolio currently consists of 23 total rooftop solar power sites and one ground mounted site totaling 80.6MW direct current (DC) output power.[267] While SCE has reasonably operated and maintained its SPVP assets, as demonstrated in the Commission's annual ERRA review of operations, the assets have undergone significant wear and tear since the first solar plant entered service in 2008 and recent wiring and component failures have caused hotspots and localized roof fires on occupied buildings.[268] Continued safe operation therefore requires significant equipment repairs which SCE estimates would total approximately $14.3 million.[269]

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

[268] WP SCE-05 Vol. 1, pp. 245-296. Standard Cause Evaluation - 2022 Solar Site 012 Fire.

[269] SCE calculated this number using recorded costs of approximately $578K for repair of Site 6, plus an estimated $1.0 million for contract management. (i.e., $578K x 23 sites = $13.3 million; + $1.0 million = $14.3 million total).

In addition, the assets operate within the CAISO market which requires, per the 2018 CAISO tariff 4.2.1,[270] the installation of automatic remote dispatch capability. While SCE has been deferring this work due to the estimated high cost of approximately $1.8 million for adding dispatch capability to its twenty four remote SPVP sites,[271] in 2020 CAISO informed SCE that in its view, all of SCE's SPVP resources were expected to respond to dispatch and operating instructions, except in case of an emergency.[272] Additionally, in order to resolve intermittent communication issues due to outdated weather instrumentation, SCE would also need to upgrade or replace site telemetry at an estimated cost of $2.3 million.[273]

Future revenue from energy, capacity, and Renewable Energy Credit ("REC") is also estimated to be insufficient to cover ongoing capital and O&M costs, primarily due to a significant drop of forecasted energy and REC prices and high O&M costs.[274]

Based on the aforementioned factors SCE has determined that decommissioning the SPVP sites is the least cost option. The capital forecast for decommissioning the SPVP sites is $77.972 million for 2023-2028.

2. Project Scope

Decommissioning of the SPVP sites will require de-energization and disconnection from the grid, removal of sites as CAISO assets, removal of solar arrays, support assemblies, electrical/telemetry/controls hardware, repair of any roof damage experienced during activity, removal

[270] With respect to this Section 4.2, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating Transmission Owners, Participating Generators, Participating Loads, Demand Response Providers, Distributed Energy Resource Providers, Balancing Authorities (to the extent the agreement between the Balancing Authority and the CAISO so provides), and MSS Operators within the CAISO Balancing Authority Area and all System Resources shall comply fully and promptly with the Dispatch Instructions1 and Operating Instructions2, unless such compliance (1) would impair public health or safety; (2) is otherwise exempted pursuant to Section 34.13.1; or (3) it is physically impossible for the Market Participant to perform in compliance with the Dispatch Instruction or Operating Instruction.

[271] WP SCE-05 Vol. 1, pp. 297-314. SPVP - Solar Initiative Automatic Dispatch and Operations, p. 300.

[272] WP SCE-05 Vol. 1, pp. 297-314. SPVP - Solar Initiative Automatic Dispatch and Operations, p. 306.

[273] SCE Internal Cost Estimate of approximately $100K per site. (i.e., $100K x 23 sites = $2.3 million).

[274] WP SCE-05, CONFIDENTIAL, p. 40. SCE Forecasted REC Prices.

of conduit pop outs, enclosure removal and repaving, and disposition of removed equipment (disposal or possible sale).

Most of the activities will be performed by a contractor. Engineering contractor support will be required to provide disconnect strategy, demolition review, and revisions to as-built drawings. SCE will provide oversight (in-house or contractor) as well as project management support.

3. Justification and Benefit

De-energization of the solar systems, followed by removal of the infrastructure, will remove the identified risks associated with the current conditions and is the least-cost option for customers. While SCE plans to move forward with decommissioning, SCE is also pursuing a potential sale of a portion of the SPVP installations. Should this alternative prove successful, SCE will file an 851 application for approval of the transactions and propose appropriate ratemaking treatment therein to ensure that customers are made whole for any revenues authorized by the Commission in this GRC.

B. SPVP O&M Forecast

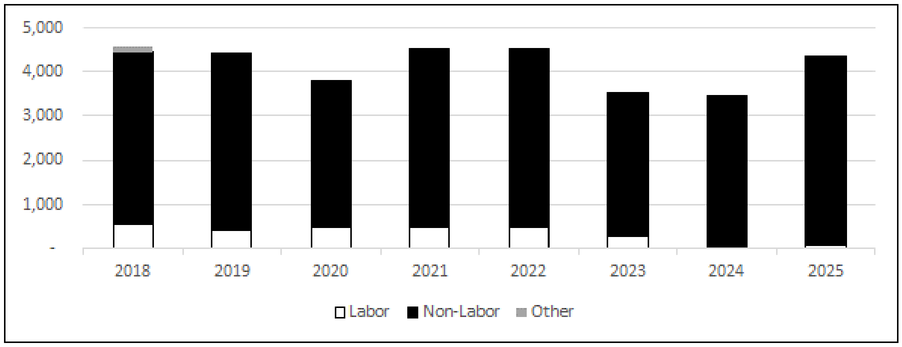
1. Introduction

As previously discussed, while SCE is recommending that site decommissioning in 2025 and 2026 is the least-cost alternative to SCE customers, SCE will continue to incur O&M expenses, as remaining lease payments total $40.490 million ($2022) under current contract terms.[275]

SCE's total SPVP 2025 Test Year O&M expense forecast of $4.347 million is summarized in Figure IV-21. The figure also shows the recorded expenses for 2018-2022 and the forecast expenses for 2023-2025. Labor costs reflect the costs for SCE employees who will perform work at the remaining solar facilities and employees who maintain the lease agreements. Non-labor costs include the forecasted contract costs (*i.e.,* lease payments to the building owners).

[275] WP SCE-05, CONFIDENTIAL, p. 41. Solar Rooftop Leases Itemized Forecast.

Figure IV-21
SPVP - Operations and Maintenance Expenses
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	561	425	494	502	483	280	-	72
Non-Labor	3,882	3,993	3,303	4,011	4,033	3,237	3,476	4,275
Other	145	-	-	-	-	-	-	-
Total Expenses	4,588	4,417	3,797	4,513	4,515	3,517	3,476	4,347
Ratio of Labor to Total	12%	10%	13%	11%	11%	8%	0%	2%

2. <u>Development of Test Year Forecast</u>

Our 2025 total Test Year forecast for the SPVP activity is $4.347 million, including $0.072 million labor expense and $4.275 million non-labor expense.[276]

a) <u>Labor – Analysis of Recorded and Forecast Expenses</u>

Recorded labor expenses remained relatively flat from 2018-2022. As SCE expects decommissioning activities to commence in 2025, SCE utilizes an itemized forecast of $0.072 million as the basis to forecast future labor expense for 2025 and beyond. These costs are necessary to maintain the lease agreements which, unless SCE can negotiate a buyout with the building owners, will continue to be incurred throughout the remaining life of the contracts, which in some cases is 2032.

[276] WP SCE-05 Vol. 1, pp. 321-326. Solar Rooftop Leases Operations and Maintenance Recorded/Forecast Summary.

b) Non-Labor – Analysis of Recorded and Forecast Expenses

The non-labor forecast includes expenses for site leases that escalate on their yearly anniversary based on the general Consumer Price Index escalation rates. Besides these annual inflation adjustments, lease costs can vary from one year to the next because of billing cycle processing time (*i.e.,* recorded costs in one year might include 13 monthly lease payments for a site, while recorded expense for that site in a different year might include only 11 monthly payments). SCE has determined that a normalized itemized forecast more accurately represents future obligations for leases than a multi-year average or last recorded year. SCE's normalized itemized forecast for site leases is $4.275 million ($2022) and was calculated based on the 2023-2028 scheduled lease payment obligation for the 24 sites.[277]

[277] WP SCE-05, CONFIDENTIAL, p. 41. Solar Rooftop Leases Itemized Forecast.

V.

PALO VERDE

A. Summary of Request

The 2025 O&M expense forecast for Palo Verde is $76.453 million ($2022, SCE Share).[278] Forecasted costs includes $0.324 million for labor and $76.129 million for non-labor.

The capital forecast for Palo Verde is $205.084 million for 2023-2028.[279] This forecast largely includes projects required to sustain station reliability. Additional information regarding Palo Verde capital projects is contained in Section F of this chapter.

SCE's 2025 Test Year O&M non-labor and Capital forecasts provided in this testimony were based on the Palo Verde O&M and Capital budgets published in December 2022. Late in the GRC testimony development timeline, Arizona Public Service Company ("APS"), the operating agent for Palo Verde, issued updated O&M and Capital budgets that reflect material cost increases. These updates occurred too late to enable their effective inclusion in this testimony, and the Palo Verde participants will not approve the updated budget until November 2023.

In D.21-08-036, the Commission noted that SCE relied on the budget prepared by APS in July 2018 for its 2021 non-labor forecast, whereas TURN recommended that the Commission approve an updated budget approved by APS in November 2019, which resulted in a 7.59% reduction to SCE's Test Year 2021 non-labor forecast for Palo Verde. The Commission agreed with TURN and found it reasonable to use the most up-to-date budget information available in that record.[280]

Accordingly, consistent with the Commission's ruling in the 2021 GRC, SCE proposes to revise its 2025 Test Year Palo Verde forecasts for both O&M non-labor and Capital as the updated Palo Verde budgets become available. SCE proposes to submit Supplemental Testimony reflecting the latest available Palo Verde O&M and Capital budgets by no later than December 22, 2023, which would allow parties to address SCE's Supplemental Testimony in their Concurrent Rebuttal Testimony due on

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[278] WP SCE-05 Vol. 1, pp. 329-334. Palo Verde Operations and Maintenance Recorded/Forecast Summary.

[279] WP SCE-05 Vol. 1, pp. 340-346. Palo Verde Capital Expenditures.

[280] D.21-08-036, pp. 364-65.

January 30, 2024, under SCE's proposed schedule in Section VII.C of this Application. SCE requests that the Commission adopt the updated Test Year 2025 O&M non-labor and Capital forecasts that SCE will provide, so as to use the most up-to-date budget information available for all such externally-driven Palo Verde costs in this proceeding, consistent with the Commission's approach in SCE's 2021 GRC.

B. Overview of Palo Verde

SCE owns 15.8 percent of Palo Verde Nuclear Generating Station ("Palo Verde") Units 1, 2, and 3; the nation's largest nuclear installation at the time this testimony was prepared. Palo Verde is located approximately 50 miles west of Phoenix. Arizona. Arizona Public Service Company is the operating agent for Palo Verde. The rated electrical generating capacities of Palo Verde Units 1, 2, and 3 are approximately 1,346 net MWe per unit. SCE's share of Palo Verde has provided SCE customers with a safe, clean, reliable, and economic source of baseload generation since the mid-1980s.

1. Risk Factors, Safety, and Reliability

a) Palo Verde Safety Program

APS is committed to maintaining a strong safety culture throughout company operations, including Palo Verde operations. APS does this by creating and sustaining a work environment that values:

- Having every employee leave the workplace unhurt;
- Using work behaviors and practices that uncompromisingly protect the safety of everyone;
- Caring for the safety of each other; and
- Stopping work anytime unsafe conditions or behaviors are observed until the job can be completed safely.

APS strives to achieve the continuous commitment and dedication by all workers to follow these values to assure that the safest workplace is established and that the safest work behaviors are always used to prevent hazardous conditions and injuries. APS trains all workers on using a variety of human performance and safety awareness tools. Among other areas of the company, these tools are deployed at Palo Verde and include: (1) completing meticulous pre-job planning, pre-job briefs, and safety observations during work; and (2) requiring appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. APS insists upon their use, and monitors adherence through a variety of human-performance / safety metrics. Every worker is also authorized to stop work and obtain clarification any time a question arises regarding the safe performance of any job.

APS has instituted several oversight mechanisms to help ensure that work proceeds safely at Palo Verde, and to monitor and report on safety performance. APS uses a focused, risk-based observation program through which qualified safety inspectors personally observe the performance of plant maintenance and refueling activities and provide real-time safety recommendations as needed. The Palo Verde Safety group continually monitors safety performance, including near-misses and other lessons learned, and provides frequent safety reports to the Palo Verde Chief Nuclear Officer and senior leadership team. Palo Verde safety performance is also reviewed by the Offsite Safety Review Committee, an independent team of nuclear industry executives that provide objective input to Palo Verde leaders regarding all aspects of nuclear facility operations including safety. Palo Verde also employs a corrective action program that performs in-depth evaluations of all plant events.

b) SCE's Risk Mitigation

SCE's GRC request supports SCE's portion of oversight functions and ability to mitigate environmental, safety, financial, and compliance risks. As a minority owner, SCE is contractually responsible for compensating APS for our 15.8 percent share. Failure to meet our contract terms could lead to litigation between and among APS and the other participant owners. Further, Palo Verde is regulated by the U.S. Nuclear Regulatory Commission ("NRC") and must meet requirements set by other federal and state agencies. If the plant is found uncompliant with any of these agencies' requirements, SCE could be subject to financial penalties and/or an increased level of regulatory scrutiny. Therefore, evaluating SCE's O&M and capital forecast should consider not only the support levels required for Palo Verde's operations, but must also consider safety, environmental, financial, and compliance issues.

2. SCE'S Oversight Responsibilities for Palo Verde

SCE oversees and reviews Palo Verde operations and expenditures through participation in two committees comprised of representatives of each of the seven Palo Verde participants. The Palo Verde Administrative Committee is chaired by an APS officer/Chief Nuclear Officer. The Administrative Committee also has other members as appointed by the participant owners. SCE has a representative member on the Palo Verde Administrative Committee. The Palo Verde Administrative Committee meets quarterly to focus on the strategy and planning for the station.

The Palo Verde Engineering and Operations ("E&O") Committee is responsible for reviewing and approving the annual O&M budget as prepared by APS, reviewing O&M budget status and variance reports, and reviewing and approving recommended corrective actions to budget variances. The E&O Committee is also responsible for reviewing and approving refueling and maintenance outage ("RFO") schedules and plans. Similarly, the E&O Committee is responsible for reviewing and approving Palo Verde capital projects.

SCE's Palo Verde project manager represents SCE on the E&O Committee. The project manager participates in E&O Committee meetings discussing and approving significant cost, schedule, and resource issues. The project manager provides oversight by confirming that Palo Verde's development, approval, monitoring, and control of the O&M and capital budgets are acceptable to SCE and comport with prudent utility practices. The Palo Verde E&O Committee typically meets about eight times per year.

Palo Verde has a comprehensive budget development, approval, and cost-control process. SCE and the other owners' participation in the E&O and Administrative Committees provides assurance that APS properly plans and controls Palo Verde O&M and capital expenditures in a way consistent with prudent utility practices, and meets the objectives of excellent safety performance, regulatory compliance, and cost-effective maximization of generation.

In addition to oversight of Palo Verde O&M and capital expenditures, these two committees also provide for oversight of engineering, plant operations, nuclear fuels, audits, and switchyard issues. The committees receive reports from Palo Verde and review plant information at committee meetings, usually at Palo Verde or APS headquarters. The 2025 Test Year O&M funding request includes costs for SCE's Palo Verde oversight functions described above.

3. Regulatory Background/Policies Driving SCE's Request

The ongoing operations of Palo Verde requires compliance with NRC and other regulatory requirements. For the 2025 Test Year period, there are no known changes in regulations at this time that are expected to result in material cost increases or decreases.

4. Compliance Requirements

Pursuant to D.19-05-020 Ordering Paragraph 3, this Chapter compares Commission-authorized 2021 O&M expense and capital expenditures to SCE's recorded 2021 O&M and capital expenditures for SCE's Palo Verde facility, as shown in Figure V-22 and Figure V-23 below. In Section V.D. of this testimony, SCE also describes activities and ratepayer benefits related to SCE's participation with the Nuclear Energy Institute ("NEI"), consistent with D.06-05-016 (2006 GRC Decision).

C. Comparison of Authorized 2021 to Recorded – O&M Expenses[281]

As shown in Figure V-22 below, SCE requested $82.348 million for Palo Verde's 2021 Test Year forecast in the 2021 GRC and the Commission adopted $80.500 million. In 2021, SCE recorded approximately $81.783 million, $1.283 million over SCE's 2021 authorized O&M expenses. This variance occurred primarily because a $0.53 million true-up for 2020 Palo Verde A&G expense was recorded in 2021, and because a $0.60 million milestone payment for steam generator chemical cleaning and other outage support activities for the Palo Verde Unit 1 Cycle 23 refueling and maintenance outage scheduled in the spring of 2022 was recorded in 2021. In addition, $0.139 million of this variance occurred because SCE's 2021 authorized O&M expense was reduced from $80.639 million to $80.500 million to reflect the Commission's order to authorize customer funding of only 50% of Palo Verde's NEI dues.[282]

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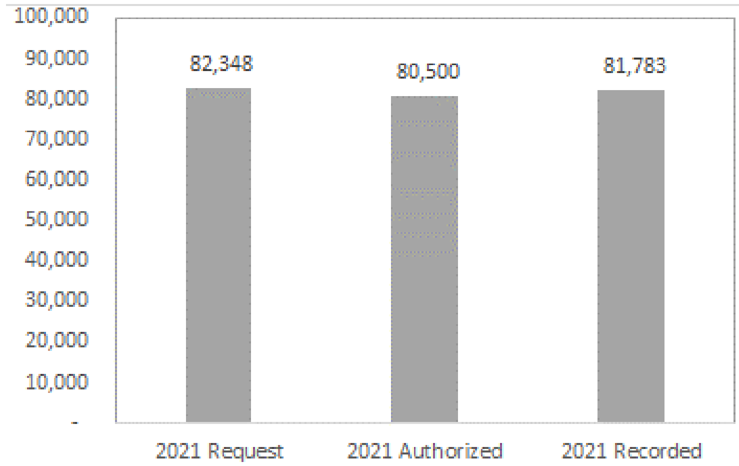
[281] WP SCE-07. Authorized vs. Recorded.

[282] D.21-08-036 at pp. 365-67 and 611.

Figure V-22
Palo Verde
2021 O&M Expenses – Authorized versus Recorded
(Constant 2021 $000, SCE Share)

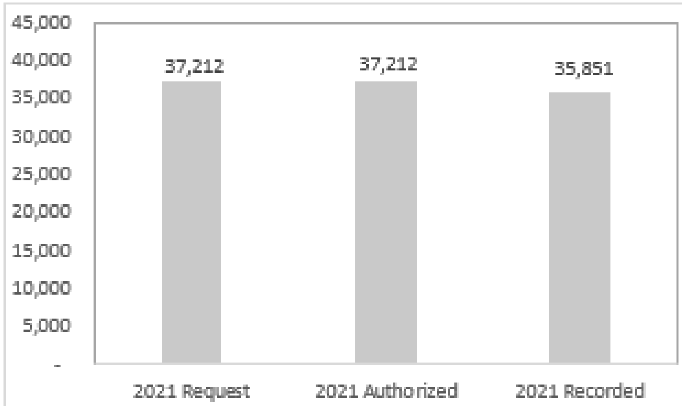


2021 Request	2021 Authorized	2021 Recorded
82,348	80,500	81,783

D. Comparison of Authorized 2021 to Recorded – Capital

As shown in Figure V-23 below, SCE requested, and the Commission adopted $37.212 million for Palo Verde's 2021 Test Year forecast in the 2021 GRC. In 2021, SCE recorded approximately $35.851 million, $1.361 million under SCE's 2021 authorized Capital expenses. This variance occurred primarily due to changes in Capital project implementation schedules as determined by APS, the plant operating agent, throughout the most recent three-year period.

Figure V-23
Palo Verde
2021 Capital Expenditures – Authorized versus Recorded
(Constant 2021 $000, SCE Share)



2021 Request	2021 Authorized	2021 Recorded
37,212	37,212	35,851

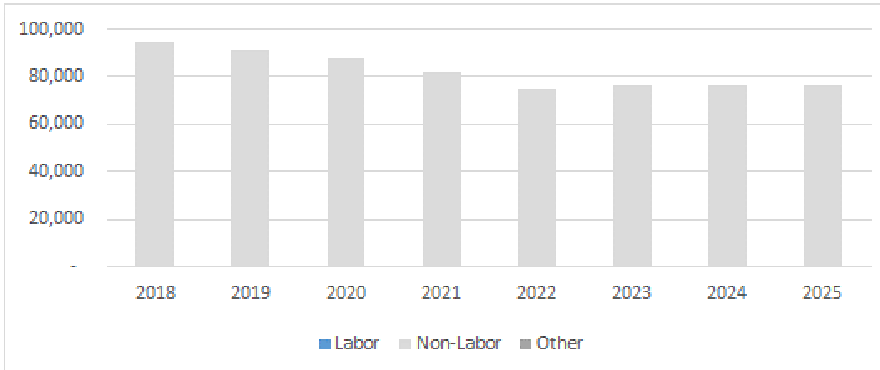
E. Palo Verde O&M Expense Forecast

1. Introduction

SCE's total Palo Verde Test Year O&M expense forecast of $76.453 million ($2022, SCE Share) is summarized in Figure V-24 below.[283] The figure shows the recorded expenses for 2018-2022 and the forecast expenses for 2023-2025. Palo Verde labor expenses include the costs for SCE employees who perform oversight and accounting functions related to SCE's Palo Verde ownership share. Palo Verde O&M expense, invoiced to SCE by APS, are recorded by SCE as non-labor expenses.

[283] WP SCE-05 Vol. 1, pp. 329-334. Palo Verde Operations and Maintenance Recorded/Forecast Summary.

Figure V-24
Palo Verde O&M Expense
2018-2022 Recorded and 2023-2025 Forecast
(Constant 2022 $000, SCE Share)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	165	179	252	264	376	302	299	324
Non-Labor	94,330	91,044	87,692	81,519	74,700	76,129	76,129	76,129
Other	-	-	-	-	-	-	-	-
Total Expenses	**94,495**	**91,222**	**87,944**	**81,783**	**75,076**	**76,431**	**76,428**	**76,453**
Ratio of Labor to Total	0%	0%	0%	0%	1%	0%	0%	0%

a) <u>O&M Budget Process</u>

APS develops, monitors, and administers budgets at Palo Verde using a methodology and process consistent with prudent industry practices. The budgeting process considers Palo Verde operational needs and cost experiences, and other industry experience. The process also considers the level of funding necessary for safe operation and to achieve high levels of electricity production, consistent with compliant and reliable long-term operation. The cost professionals who support the budgeting process are part of a centralized cost organization that provide effective budget and cost control services for the entire Palo Verde organization.

APS develops annual O&M work and staffing requirements based on input of line management. This approach allows APS to define a scope of work and budget that maintains safe, reliable, and efficient plant operations while generating electricity in a cost-effective manner. The line managers identify specific needs of their organization for the upcoming year. They also evaluate the impact of the next year's anticipated work activities to identify needs for resources other than manpower. They consider such things as: (1) RFO schedules, (2) operating and support requirements, (3) future staffing development needs, (4) efficiency improvements in their particular work areas, and (5) information technologies to further improve work processes.

The APS cost professional staff considers all inputs available from the line managers and determines the resource needs. From this information, they forecast costs for each group at Palo Verde. They organize these costs into an overall budget for the plant that reflects the total resource requirements and costs for the upcoming budget year. All organizations systematically review budget performance throughout the year to identify budget adjustments (*i.e.*, increases or decreases) that may be achieved without compromising the safety and reliability of operations.

b) O&M Cost Control Process

To monitor O&M costs, Palo Verde produces monthly reports that identify the variance between budgeted and recorded costs. Palo Verde management holds meetings with the E&O Committee (which includes representatives from each co-owner) to formally review this information, and to discuss any unbudgeted or emergent work. Line managers address potential budget changes that may affect costs. A key function of these meetings is for the E&O Committee to agree on budget plans and set priorities, so that all work performed is not only necessary, but justified in relation to other emergent work requirements.

2. Development of Test Year Forecast

a) Labor – Analysis of Recorded and Forecast Expenses

Palo Verde labor expenses include the costs for SCE employees who perform oversight and accounting functions related to SCE's Palo Verde ownership share. As shown in Figure V-24 above, Palo Verde labor expense increased from $0.165 million in 2018 to $0.376 million in 2022. This increase occurred as a full-time role for Palo Verde oversight was developed and combined with a nuclear fuels role. In 2018 and 2019, Palo Verde labor expense included the salary of SCE's project manager for Palo Verde, with a few additional labor hours charged by other SCE personnel who performed Palo Verde oversight functions. In 2020 through 2022, Palo Verde labor expense increased as the Palo Verde Fuel Services functions that were transferred from the SCE Supply Chain Division to the SCE Nuclear Finance Division were reflected in Palo Verde labor expense. In addition, SCE personnel who perform regulatory work related to Palo Verde began charging all of their time spent on those activities to Palo Verde oversight instead of to the general Corporate Regulatory account. SCE's forecast for 2023 includes the salary of SCE's project manager for Palo Verde, the estimated expense for a part-time nuclear fuels consultant, and the estimated expense for other SCE personnel who will perform regulatory work related to Palo Verde.

Because staffing levels have stabilized and the scope of work performed in 2022 most closely matches the planned scope of work in 2025, we use the last recorded year (2022) as the basis to forecast future labor expense for 2025 and beyond, $0.302 million. To this base amount, we make an adjustment of $0.022 to reflect certain changes made to SCE's employee compensation program, yielding a 2025 Test Year labor forecast of $0.324 million. For further information regarding this adjustment please refer to SCE-06 Vol. 04.

b) Non-Labor – Analysis of Recorded and Forecast Expenses

Palo Verde O&M expenses, invoiced to SCE by APS, are recorded by SCE as non-labor expenses. Palo Verde non-labor expenses trended downward from 2018 through 2022 as Palo Verde strived to reduce O&M costs (including incentives) primarily through employee attrition. After routine attrition resulted in a moderate O&M reduction in 2019, Palo Verde experienced unexpectedly increased attrition during 2020 and 2021 due to the COVID-19 pandemic and the ensuing "Great Resignation."[284] Many of the departing personnel were licensed plant equipment operators, control room operators, and shift technical advisors, who work rotating 12-hour day and night shifts. Because the NRC license requires minimum staffing levels on each shift for each of these positions, and due to the relatively long training periods required to qualify for these positions, the remaining personnel in these positions were required to work extra shifts. The resulting adverse impacts on their quality of life resulted in additional personnel resignations, and further unexpected staffing cost reductions, during

[284] *Available at* https://en.wikipedia.org/wiki/Great_Resignation (accessed February 17, 2023).

2022. Palo Verde anticipates that as additional personnel become qualified to fill these positions during 2023 through 2025, Palo Verde's O&M costs will gradually rebound toward 2021 levels by 2025.

Because the scope of work performed in 2022 most closely matches the planned scope of work in 2025, SCE forecasts $74.700 million (Constant $2022, SCE share) in 2025 for Palo Verde O&M base non-labor costs. To this base amount, SCE makes a modest 1.9 percent adjustment of $1.429 million to compensate for the anticipated increase of 99 employees[285] from 2023 through 2025 to arrive at a 2025 Test Year non-labor forecast of $76.129 million, as shown in Figure V-24 above.

3. Palo Verde O&M Work Activities

a) Plant Operating Expense

The operation of a three-unit nuclear facility such as Palo Verde requires highly-skilled personnel. Examples of the major staffing categories include but are not limited to Operations, Engineering, Maintenance, and Support. Palo Verde staff performs activities that range from highly technical and specialized functions that are specific to operation of a nuclear plant (e.g., radiation protection, nuclear plant system engineering, instrument and technology technicians) to corporate support functions (e.g., information technology, training, finance, regulatory, legal, safety, and security). The personnel costs for these ongoing onsite and corporate support functions is the largest cost driver of Palo Verde O&M expenses. Other expenses such as material, contract, NRC fees, Nuclear Energy Institute (NEI) membership fees, and vendors are also included in Palo Verde O&M expenses.

b) Refueling and Maintenance Outage Expense

In addition, each Palo Verde unit undergoes a planned RFO once every 18 months. These outages are required to replenish the inventory of fuel used in each unit's nuclear reactor, and to perform other necessary maintenance activities that can only be performed when the unit is offline. RFOs are part of the total O&M funding request consistent with the plan for two RFOs each year. A primary goal at Palo Verde is to avoid summer outages because all participants are southwestern U.S. utilities that typically experience their peak load periods during the summer months (June-

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[285] SCE's share of the 99 additional employees is 15.8 employees.

September). For this reason, Palo Verde plans its fuel cycles so one unit refuels in the spring each year and another refuels in the fall. These RFOs rotate among the three units in an approximately 18-month period for each unit, resulting in two RFOs per year. Palo Verde has used this rotation for many years. Therefore, SCE reasonably expects that the plant will experience two RFOs per year. RFOs for Palo Verde Unit 1 (spring) and Unit 3 (fall) are forecast during the 2025 Test Year.

(1) RFO Plans

Each RFO plan identifies the work and schedule for the corresponding refueling outage. Palo Verde establishes a cost forecast using historical RFO costs as a basis. Palo Verde removes the costs for cycle-specific activities from the historical costs for past years and averages the historical costs. Palo Verde then adds costs for the planned cycle-specific activities for the planned RFO to the average historical costs to determine the total RFO cost.

(a) Development of an RFO Plan

APS plans each RFO with three major parameters in mind: scope, duration, and cost. APS bases its initial RFO planning on the prevailing work processes and procedures in effect at Palo Verde, the demonstrated organizational capabilities, and the required work scope. The foundation of an RFO is the work scope or activities to be performed. Besides refueling activities, a typical Palo Verde RFO work scope includes over 3,000 maintenance orders and over 10,000 individually identified activities.

Planning the duration of an RFO is complex. Every RFO includes refueling activities similar in scope and outage time requirements, such as: (1) shut down and cool down of the reactor, (2) remove the reactor vessel head and fuel replacement, (3) reassemble the reactor vessel, and (4) heat-up and start-up the reactor. Other activities in an RFO are one-time projects or follow a periodic cycle. Each RFO has a work scope consisting of generic work activities and cycle-specific activities (*i.e.*, plant modifications, surveillances, and corrective maintenance). Before detailed planning of an RFO can begin, Palo Verde determines cycle-specific activities to be performed with the generic activities; therefore, each RFO scope is unique.

Within the framework of the generic work activities, Palo Verde creates an RFO plan, based upon the particular work scope. This plan begins with the generic refueling activities and standard work windows, which allow access to specific plant systems. Palo Verde adds cycle-specific activities to this plan, including surveillance tests, preventive maintenance, plant modifications, corrective maintenance, and fuel cycle-specific activities. Palo Verde then establishes the planned duration for each RFO based on the scope of work necessary for safe, compliant, and reliable operations. Prior to each outage, the planned scope, duration, and costs are reviewed with the participants.

c) Nuclear Energy Institute ("NEI") Dues

Palo Verde is a member of the Nuclear Energy Institute, which is the policy organization of the nuclear technologies industry. SCE includes its share of Palo Verde's NEI membership dues as a non-labor expense. In D.21-08-035, the Commission's final decision for SCE's Test Year 2021 GRC, the Commission found it reasonable to adopt a 50/50 split of NEI dues between shareholders and customers. Citing its decision in the 2006 GRC, the Commission explained that the allocation of 50% of Palo Verde's NEI dues to shareholders was "due to the lack of information regarding the 'specific activities and related benefits that accrue to the company and/or ratepayers'.[286] The Commission, however, directed that if SCE requests a different allocation of NEI dues in the future, "SCE should provide more detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits".[287] In this section of testimony, SCE provides detailed descriptions of NEI's activities that pertain to Palo Verde and the related benefits that accrue to Palo Verde customers (including SCE's customers), with the expectation that the Commission will more fully appreciate the customer benefits of Palo Verde's NEI membership and appropriately allocate 100% of Palo Verde's NEI costs to customers in this and future GRC proceedings.[288]

[286] D.21-08-035, p. 366.

[287] D.21-08-035, p. 366.

[288] WP SCE-05 Vol. 1, pp. 335-336. NEI Member Value Overview: Operating Plants.

As the policy organization of the nuclear technologies industry, NEI performs a wide range of functions for a broad range of members. NEI members include not only companies that own or operate nuclear power plants, but also reactor designers and advanced technology companies, architect and engineering firms, fuel suppliers and service companies, consulting services and manufacturing companies, companies involved in nuclear medicine and nuclear industrial applications, radionuclide and radiopharmaceutical companies, universities and research laboratories, law firms, labor unions, and international electric utilities.[289]

Due to the diverse types and sizes of member entities, NEI established a tiered schedule of membership dues based on the various types and sizes of member organizations and the services and benefits that each type of member receives from their respective NEI memberships. Through this tiered structure, each type of NEI member pays only for the types of services it receives through its NEI membership.

Whereas many NEI members benefit from its lobbying and public advocacy functions, the benefits of NEI membership to operating nuclear plants including Palo Verde are centered in supporting and facilitating the safe, efficient, and cost-effective operation of these facilities. NEI functions that support nuclear plant operations include:

- NEI coordination of industry voluntary actions in lieu of regulation.
- NEI development of key policy and regulatory positions for the industry and negotiating with the NRC on those positions.
- NEI providing a unified industry voice and a buffer for member utilities when interfacing with regulatory bodies.
- NEI providing industry emergency response and crisis communications support.
- NEI providing a forum for industrywide collegial coordination among industry peers, especially at the executive level.

[289] *Available at* https://www.nei.org/about-nei (accessed on December 5, 2022).

- In addition, examples of NEI activities whose benefits have flowed to nuclear facility customers include:
    - NEI's "Delivering the Nuclear Promise" initiative has resulted in more than seventy efficiencies with a total enabled savings in excess of $1.6 billion industrywide.
    - NEI's efforts resulted in the enactment of federal legislation that imposed caps on annual NRC fees for operating reactors, which reduced NRC fees industrywide by more than $150 million since 2014.
    - NEI's joint lawsuit with the National Association of Regulatory Utility Commissioners ("NARUC") resulted in the suspension of Nuclear Waste Fee collections from operating nuclear plants, resulting in average annual savings of $7-8 million per reactor.

Palo Verde is not merely a passive beneficiary of NEI initiatives and efforts. Palo Verde actively participates in and benefits from past and ongoing NEI activities. Moreover, NEI membership affords Palo Verde "a seat at the table" to participate on NEI committees, working groups, and issue task forces, and thus, the ability to help shape the outcomes of these efforts instead of merely accepting the outcomes developed by others. Several Palo Verde executives and other senior personnel currently participate actively on NEI committees, attend NEI-sponsored conferences regarding various topics, and communicate frequently with other NEI members regarding issues of shared interest.

As a member of NEI, Palo Verde also has access to the Personnel Access Data System ("PADS"). The PADS database contains information that is shared among PADS participants to enhance the in-processing of nuclear industry personnel. PADS information is used to support decisions to grant, deny, or revoke unescorted access to the protected areas of operating nuclear power plants, nuclear decommissioning facilities, and ISFSI-only sites. The PADS database meets the regulatory requirement (10 C.F.R. § 73.56) for facilities to share their data.

The PADS database includes the following components:

- Access Authorization – nuclear facility access dates, background investigations fingerprints, psychological reviews, drug testing results, reinvestigations, potentially disqualifying information, denials of unescorted access. Participating nuclear facilities use this information to make informed decisions regarding the suitability of a candidate nuclear worker. Favorable data helps to expedite the access authorization process. Unfavorable data expedites the denial of access.
- Visitor Access – identifies non-worker personnel who have been denied visitor access to nuclear facilities and the reasons for such denials
- Training – includes industry-wide NANTEL training records, and has greater importance for ISFSI-only sites that no longer rely on NANTEL
- Radiation Protection – includes radiation worker dose records, which facilitates and expedites records sharing between nuclear facilities

Every spring and fall, hundreds of experienced nuclear personnel travel from all over the country to Palo Verde for short-term work on the refueling and maintenance outages. The PADS database, which is accessible only by participating NEI members, reduces the need for costly background checks and by facilitating compliance with federal access authorization requirements for temporary outage workers and other prospective plant workers at Palo Verde. Without access to PADS, Palo Verde would be required to incur the costs of performing all investigations and data gathering required by federal access authorization requirements on a standalone basis.

As a result of these and many other NEI initiatives and efforts, Palo Verde customers (including SCE's customers) have benefitted, and continue to benefit, from Palo Verde's NEI membership.[290] The value arising from the totality of NEI's efforts related to operating plants continue to result in improved safety, efficiency, and cost performance at Palo Verde. These benefits flow to customers in the form of improved Palo Verde performance, reduced operating costs, and reduced

[290] WP SCE-05 Vol. 1, pp. 337-339. NEI Activities & Resources.

nuclear fuel costs. Whereas it would be impossible to precisely quantify the cost savings each of these NEI initiatives provides to Palo Verde, it would be reasonable to assume that Palo Verde's joint communications and collaborations with its peers at other operating nuclear facilities that are facilitated by Palo Verde's membership in NEI is at least equal to the cost of Palo Verde's annual NEI dues.[291] For all of these reasons, the Commission should allocate 100% of the cost of Palo Verde's NEI dues to customers, consistent with long-standing cost-of-service ratemaking principles.

F. <u>Palo Verde Capital Expenditure Forecast</u>

As the operating agent for Palo Verde, APS identifies and implements capital projects to support safe operation of the plant to meet regulatory requirements, optimize overall cost-effective plant operation, and provide reliable plant operation. APS has developed and utilized a budgeting and cost-control program to implement an optimum level of capital expenditures. This section describes the capital budgeting and approval process, identifies the categorization of capital investments, and provides the capital expenditure forecast for years 2023-2028.

1. <u>Palo Verde Capital Budget Process</u>

APS plans capital expenditures to address regulatory requirements, emergent work, and plant reliability or operability issues. The capital budgeting process considers the results of benchmarking and feasibility studies, conceptual or preliminary engineering, industry developments, replacement energy costs (used in cost-benefits analyses), and other evolving factors. APS does not rigidly "fix" the scope of capital work to be implemented in future years. Prudent management of capital expenditures includes flexibility in deferring or substituting projects as needed to respond to emergent work, changing priorities, and other factors. SCE and the other participants approve necessary individual capital improvement projects and necessary revisions to the capital budget to respond to changing conditions.

APS categorizes capital work by project type, and the participants approve the work under E&O Committee procedures. The E&O Committee is responsible for reviewing and approving the

[291] SCE's share of fees paid by Palo Verde to NEI in 2022 was $0.307 million, including $0.293 million for NEI membership dues and $0.014 million for NEI's PADS assessment.

annual capital and O&M budgets prepared by APS, and periodic review of the status of those budgets and any variances with actual costs.

APS documents justification for proposed capital work and, where appropriate, develops engineering cost evaluations of alternatives. The Palo Verde capital program contains the following elements for project and expenditure prioritization: (1) System Engineering, Plant Health Committee Sub-Committee ("PHCSC"), Plant Health Committee ("PHC"), Management Review Committee ("MRC"), and Long Range Plan ("LRP"); (2) the Work Authorization ("WA") process; and (3) the Annual Capital Budget.

SCE reviews monthly variance reports, reviews and approves the annual capital budget, and reviews and approves individual projects known as WAs to oversee the capital expenditures at Palo Verde and to verify that APS is effectively administering budget and cost control processes.

2. <u>APS Capital Project Approval Process</u>

Each proposed Palo Verde capital project undergoes a thorough multi-step review process before it is submitted to the E&O Committee. The Palo Verde System Engineering Team identifies each proposed project and submits a package/presentation to the PHCSC for review and ranking. The PHCSC reviews each plant modification project and assigns an implementation priority and schedule based on the following criteria:

1. A ranking between two and seven is established based on the project's importance to safety (nuclear and personnel), reliability improvements or production.
2. A multiplier applies to the ranking:
3. Short-term implication or limited option needed to correct existing or imminent condition. Failing to implement may affect the health or safety of public/plant personnel; result in plant shutdowns, or delay start-up or plant return to service.
4. Aggressive completion is necessary to prevent future significant or adverse conditions, or hinders response to design basis or critical plant transients.
5. Items that improve/maintain equipment reliability, plant operation or worker condition economically justified but not urgent to resolve.

6. Plant improvement/betterment item that provides short term benefit. May include intangible benefits such as improvement in employee morale and plant appearance.
7. Item might add value, but shows little short-term benefit.

Following PHCSC's initial ranking and approval, the proposed project proceeds to the PHC for implementation approval and then to the MRC for funding approval. After the MRC approves funding for a project, Palo Verde assigns WA numbers to the capital project and processes the project for approval via the WA process.

The Palo Verde LRP schedules and tracks current and future capital projects and requirements, including PHCSC / PHC approved projects. The LRP incorporates a cost estimate for capital work and is periodically updated as necessary. The LRP documents deferral of scheduled projects and identifies and/or substitutes new projects in response to regulatory requirements and other evolving factors. The LRP database cross-references projects to the NRC and other regulatory agency requirements and commitments.

3. Work Authorization Process

Palo Verde develops a WA package for each new or revised capital project and routes it internally for review and approval. Each WA package includes the description, justification, and cost estimate for the project. Palo Verde-approved WA packages are then submitted to the E&O Committee for review and approval. WA packages include descriptive documents and justification for review and approval. A capital project is justified if it is: (1) required for personnel, public or plant health and safety, (2) necessary to meet regulatory requirements, (3) necessary for continuing reliable plant operation, or (4) a cost-effective plant betterment. The E&O Committee reviews WA packages on an ongoing basis and approves them on a monthly basis. If the cost of a project exceeds its approved budget by at least $500,000 (100% share), Administrative Committee approval is required.

4. Annual Capital Budget

Palo Verde prepares an annual capital budget for each year and processes it for APS and E&O Committee approval. The annual capital budget is based on the LRP and contains APS-approved projects planned for the upcoming year and conceptual projects expected to be approved during the year. Some projects may require several years to complete. APS also presents a forecast for the year following the upcoming budget year. E&O Committee approval of the budget provides acceptance of the total dollar value for the annual budget but does not constitute final approval of the line items within the budget. This is because the WA process controls individual project approval. Typically, during the budget year, APS may change the timing of some individual projects to allow other emergent, higher priority work to be performed. APS only implements projects approved through the WA process.

Throughout the year, APS manages its expenditures within the budget approved by the E&O Committee, using the WA process to obtain approval for any timing or funding changes that become necessary. SCE and the other participants provide continuous oversight of this process

5. Capital Budget Categorization

APS groups its Palo Verde capital projects by reason or type of expenditure. There are nine categories, which are described in Section V.E.8 below. The capital budget includes known projects, identified by category, for the upcoming budget year. The budget also includes costs for nuclear support organizations that perform administrative support activities directly related to the capital projects. Palo Verde classifies this support as "Overheads and Distributables" and identifies the costs for these support activities in its own category.

6. SCE Capital Cost Classifications

SCE reviews the Palo Verde annual capital budget through its participation in the E&O Committee's review and approval of the Palo Verde budget, including WA packages already approved by APS management and conceptual projects forecast for approval. SCE tracks each Palo Verde project individually by creating an SCE internal order to mirror each capital project. SCE develops its work orders and forecast expenditures within SCE's budgeting system consistent with: (1) approved budget information provided by APS, and (2) SCE's forecast of Palo Verde budget changes.

7. Summary of 2025 Palo Verde Capital Forecast

The total Palo Verde capital expenditure forecast is $205.084 million (nominal, SCE Share, work order level) for 2023-2028 as summarized in Table V-50.[292]

Table V-50
2023-2028 Palo Verde Units 1, 2, and 3
Capital Expenditures Forecast
(Nominal $000, SCE Share Without SCE Corporate Overheads)

Category	Prior Costs	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2023-2028 Forecast	Project Total
Plant Modifications	9,958	12,494	11,246	10,684	8,961	9,422	6,889	59,696	69,654
Plant Equipment & Replacements	10,586	9,816	12,542	10,820	10,592	8,956	9,736	62,462	73,048
Water Reclamation Facility	5,358	4,479	2,556	3,658	4,599	5,599	7,716	28,607	33,966
Buildings	48	773	397	954	1,168	1,277	1,311	5,880	5,929
General Plant	3,483	1,797	517	1,035	719	719	514	5,300	8,783
Computers	5,133	2,789	2,702	2,777	2,715	2,715	2,432	16,131	21,263
Emergent Work Fund	85	674	571	585	1,770	1,762	1,778	7,139	7,225
Overheads & Distributables	-	3,202	3,282	3,297	3,289	3,362	3,437	19,868	19,868
Grand Total	34,652	36,024	33,812	33,812	33,812	33,812	33,812	205,084	239,736

Table V-50 above shows projects by budget category for Palo Verde capital expenditures for 2023-2028. As shown in this table, SCE forecasts $103.648 million for Palo Verde capital expenditure from 2023-2025 (Nominal$, SCE share), and $101.436 million during 2026-2028.[293] Table V-51 below provides a listing by budget category of Palo Verde capital expenditures forecast for 2023-2028. It also delineates projects for which SCE's 15.8 percent share of the cost exceeds $3.0 million throughout the period 2023-2028. There are nine projects where SCE’s share exceeds $3.0 million over the 2023-2028 period. These projects are described in V.F.8 below.

[292] WP SCE-05 Vol. 1, pp. 340-527. Palo Verde Capital Expenditures.

[293] WP SCE-05 Vol. 1, pp. 340-527. Palo Verde Capital Expenditures.

Table V-51
2023-2028 Palo Verde Units 1, 2, and 3
Capital Expenditures Forecast Detail
(Nominal $ in Millions, SCE Share Without Corporate Overheads)

Category	Prior Costs	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2023-2028 Forecast	Project Total
Plant Modifications									
Cooling Tower Life Extension	24	3,290	3,404	3,048	3,511	3,053	3,334	19,640	19,663
Digital Strategic Modernization Program	7,242	4,745	5,920	3,542	2,648	3,991	2,369	23,217	30,459
Normal Chiller Replacement	323	729	164	2,276	2,308	1,992	-	7,469	7,792
Other	2,369	3,729	1,758	1,818	494	386	1,186	9,370	11,739
Plant Modifications Subtotal	9,958	12,494	11,246	10,684	8,961	9,422	6,889	59,696	69,654
Plant Equipment & Replacements									
Low Pressure Feedwater Heaters Replacement	1,039	1,878	3,764	2,139	1,871	1,814	2,098	13,564	14,603
Plant Cooling Water Pipeline Replacement	674	254	904	1,367	1,407	1,446	1,486	6,865	7,538
Essential Spray Pond Piping Replacement	318	650	543	622	581	739	649	3,783	4,101
Valve Reworks and Replacements	-	799	805	792	632	632	632	4,292	4,292
Other	8,555	6,235	6,526	5,900	6,102	4,325	4,871	33,958	42,513
Plant Equipment & Replacements Subtotal	10,586	9,816	12,542	10,820	10,592	8,956	9,736	62,462	73,048
Water Reclamation Facility									
Clarifiers Life Extension	4,955	3,414	1,258	-	-	-	-	4,671	9,627
Other	403	1,066	1,298	3,658	4,599	5,599	7,716	23,936	24,339
Water Reclamation Facility Subtotal	5,358	4,479	2,556	3,658	4,599	5,599	7,716	28,607	33,966
Buildings									
Other	48	773	397	954	1,168	1,277	1,311	5,880	5,929
Buildings Subtotal	48	773	397	954	1,168	1,277	1,311	5,880	5,929
General Plant									
Other	3,483	1,797	517	1,035	719	719	514	5,300	8,783
General Plant Subtotal	3,483	1,797	517	1,035	719	719	514	5,300	8,783
Computers									
TESC Replacement Projects	-	-	356	1,747	2,178	2,139	1,926	8,346	8,346
Other	5,133	2,789	2,346	1,030	537	577	506	7,785	12,918
Computers Subtotal	5,133	2,789	2,702	2,777	2,715	2,715	2,432	16,131	21,263
Emergent Work Fund									
Other	85	674	571	585	1,770	1,762	1,778	7,139	7,225
Emergent Work Fund Subtotal	85	674	571	585	1,770	1,762	1,778	7,139	7,225
Overheads and Distributables									
Other	-	3,202	3,282	3,297	3,289	3,362	3,437	19,868	19,868
Overheads and Distributables Subtotal	-	3,202	3,282	3,297	3,289	3,362	3,437	19,868	19,868
Grand Total	34,652	36,024	33,812	33,812	33,812	33,812	33,812	205,084	239,736

8. Descriptions of Capital Project Categories and Projects Over $3 Million (SCE share)

The following section of testimony provides further discussion of Palo Verde capital projects for which SCE's forecasted share of the cost is $3.0 million or greater.[294]

[294] WP SCE-05 Vol. 01, pp. 340-527. Palo Verde Capital Expenditures

a) Plant Modifications

The Plant Modifications budget category includes funding for modifications and upgrades required for the continued operation of the Palo Verde nuclear steam supply systems and their auxiliary systems, including plant process computers and the control room simulator, and excluding the Water Reclamation Facility. They include changes in plant design, including simulator computers, motors, pumps, valves, heat exchangers, breakers, etc. Plant Modifications projects help to keep plant operations safe, reliable (at a high capacity factor), and compliant with NRC requirements. Plant Modifications projects are authorized and prioritized according to the following sub-categories:

- NRC Regulatory Requirements: Plant modifications required by a rule, regulation, or regulatory guides.
- Other Regulatory Requirements: Plant modifications mandated by any federal, state, or local governmental agency other than the NRC.
- Non-Regulatory Safety: Plant modifications required to improve the plant industrial and personnel safety, other than items required by the Occupational Safety & Health Administration or other governmental regulatory bodies included in the "Other Regulatory Requirements" sub-category above.
- Availability Improvements: Plant modifications, other than those listed above, that are justified based predominantly on improving the availability or capacity factor of the generating units.
- Economic Improvements: Plant modifications for improvements other than those included in the "Availability Improvements" sub-category above.

SCE’s share of the capital forecast for Plant Modifications during the 2023-2028 period is $59.696 million (Nominal$, SCE share). This includes the Cooling Tower Life Extension Program, the Digital Strategic Modernization Programs and the Normal Chiller Replacement Project, each having a cost greater than $3 million (Nominal$, SCE share).

(1) Cooling Towers Life Extension Program

The nine Palo Verde cooling towers (three per unit) have been in service since the mid-1980s. They have been continuously exposed to harsh desert weather conditions, and to residues from strong chemicals that were used to reclaim the partially treated sewage effluent piped in from the Phoenix metropolitan area sufficiently for use as cooling water for the plant. Consequently, the concrete structures, reinforcing steel, and mechanical and electrical components of the cooling towers have experienced degradation. Although Palo Verde has been replacing degraded cooling tower components since the mid-1990s, the Cooling Tower Life Extension Program has been updated in the Palo Verde Long Range Plan to replace degraded pre-cast concrete sections, concrete components, support beams, fan assemblies, water flumes, access doors, and many other components. In addition, Palo Verde will retain a third-party expert to perform an independent engineering evaluation of the cooling tower structural member to determine their current condition and life expectancy.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $19.640 million (Nominal$, SCE share).[295]

(2) Digital Strategic Modernization Program

Several analog and digital plant instrumentation and control ("I&C") systems are reaching the end of reliable operation. To proactively address this issue, Palo Verde performed an analysis using both APS and third-party industry experts to prioritize I&C systems for replacement. Each system was scored based on: (1) degree of hardware obsolescence, (2) impact of system failure, and (3) potential for system improvements with modem technology replacement.

As a result of this analysis, Palo Verde is implementing a Digital Strategic Modernization Program ("DSMP") that will replace several plant control systems with newly designed and upgraded equipment. The replacement strategy will utilize a common digital platform insofar as possible. Palo Verde anticipates that this program, which is being executed in five phases throughout a

[295] WP SCE-05 Vol. 01, pp. 347-365. Cooling Towers Life Extension Program

twelve-year period, will address obsolescence, remove single point vulnerabilities where practical, improve human-to-machine interfaces, and minimize spare parts inventories.

During 2023-2028, scheduled DSMP activities include: (1) replacing the roughly 40-year-old Control Element Drive Mechanism System ("CEDMS") technology in Units 1, 2, and 3 with a state-of-the-art digital Rod Control Upgrade technology that will be an add-on to the Windows-based Distributed Control System ("DCS") that was previously installed at Palo Verde; (2) replacing of the Rod Drive Motor Generator Sets and Controls that were used with the CEDMS technology with redundant Motor Generator Sets and Control Cabinets in each unit; and (3) upgrading Control Room Simulators A and B to reflect the replacement of the antiquated CEDMS technology with the state-of-the-art digital Rod Control Upgrade technology.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $23.217 million (Nominal$, SCE share).[296]

(3) Normal Chillers Replacement Program

The Normal Chilled Water ("NCW") system provides chilled water to the cooling coils of "normal" air handling units within the Containment Building, Control Building, Auxiliary Building, Radwaste Building, Turbine Building, and Generator Collector Housing for each Palo Verde unit. The NCW system has four normal water chillers per unit, including three 800-ton Large Normal Chillers and one 213-ton Small Normal Chiller. The existing chillers were purchased and installed during the mid-1980s. Due to their installed locations on the roof of each unit's Auxiliary Building, the Normal chillers have been exposed to extreme environmental conditions, which over time have adversely impacted their reliability.

Palo Verde's 40-year service agreement with the supplier, Carrier, will expire in 2024. Carrier has phased out support of the existing chillers and is expected to discontinue supporting the availability of replacement parts after the service agreement expires. Palo Verde also

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[296] WP SCE-05 Vol. 01, pp. 366-387. Digital Strategic Modernization Program

determined that replacing these chillers with ground-mounted, fully enclosed modular chiller plants located in a climate-controlled environment outside the Radiologically Controlled Area ("RCA") would support improved future performance and reliability, and facilitate routine maintenance. This project includes the purchase and installation of replacement chillers, as well as the design and installation of the requisite electrical connections and piping tie-ins.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $7.469 million (Nominal$, SCE share).[297]

b) Plant Equipment & Replacements

The Plant Equipment & Replacements budget category includes capitalized tools and equipment used to perform routine and repetitive maintenance, construction, and training activities. It is essential to maintain complete sets of working, undamaged tools and equipment at the Palo Verde site so that needed repairs can be completed promptly and efficiently, while maintaining worker safety. In addition, this category includes the in-kind replacement of retirement units,[298] excluding items controlled by the Water Reclamation Facility ("WRF") Department. Plant Equipment and Replacements projects are authorized under the following sub-categories:

- Tools & Equipment
- Replacements

The forecast cost of the capital expenditures for Plant Equipment & Replacements projects during the 2023-2028 period is $62.462 million (Nominal$, SCE share). This

[297] WP SCE-05 Vol. 01, pp. 388-434. Normal Chillers Replacement Program

[298] In 18 C.F.R. § 101.34, "retirement units" are defined as those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which included. Under 10 C.F.R. § 1710.2, "ordinary replacement" means replacing one or more units of plant, called "retirement units," with similar units when made necessary by normal wear and tear, damage beyond repair, or obsolescence of the facilities.

includes the Low Pressure Feedwater Heater Replacement Project, the Piping Plant Water Pipeline Project, the Spray Pond Piping Replacement Project, and the Valve Replacement Project, each having a cost greater than $3 million (Nominal$, SCE share).

(1) Low Pressure Feedwater Heaters Replacement

Low pressure feedwater heaters ("LPFWH") are heat exchangers installed inside the condensers to pre-heat feed water for delivery to the steam generators. Pre-heating the feed water improves the thermodynamic efficiency of the steam cycle. Each unit has three condensers, each of which has four LPFWHs. Within each condenser, the four LPFWHs are designated Stage 1, 2, 3, and 4.[299] Due to the system design, the Stage 1 and 2 LPFWHs incur more wear than the Stage 3 and 4 heaters. The LPFWHs in all three Palo Verde units (primarily in Stages 1 and 2) have experienced tube failures, resulting in non-radiological leaks that have required planned repairs during refueling outages and emergency repairs during forced power reductions. A study by an outside consultant assessed the LPFWH tube damage and recommended a phased replacement of 12 of the 18 Stage 1 and 2 LPFWH and other repairs. Palo Verde is scheduled to perform the last three planned LPFWH replacements during 2023, and will perform other related repairs, such as low pressure and high-pressure piping and expansion joint replacements and "dogbone seal" replacements during 2023-2028.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $13.564 million (Nominal$, SCE share).[300]

(2) Plant Cooling Water System Pipeline Replacement

The Plant Cooling Water ("PCW") system transfers heat from the Turbine Cooling Water ("TCW") system, the Nuclear Cooling Water ("NCW") system, and the Condenser Vacuum Pump Seal Cooler system into the Circulating Water System, where it is rejected into the ultimate heat sink, the atmosphere. The original bar-wrapped concrete cylinder piping is now

[299] Each of the Palo Verde units has twelve LPFWHs, including three designated Stage 1, three designated Stage 2, three designated Stage 3, and three designated Stage 4, constituting a total of 36 LPFWHs.

[300] WP SCE-05 Vol. 01, pp. 435-451. Low Pressure Feedwater Heaters Replacement

approximately 40 years old, is degrading and requires replacement. After evaluating the available alternatives, Palo Verde determined that the PCW system piping should be replaced or re-lined with high density polyethylene ("HDPE") piping, which will be less prone to future degradation. This project also includes the replacement of valves, expansion joints, and tie-ins to the TCW and NCW heat exchangers.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $6.865 million (Nominal$, SCE share).[301]

(3) Essential Spray Pond Piping Replacement

The Essential Spray Pond ("ESP") piping is located from the essential spray pond vaults to the Auxiliary and Emergency Diesel Generator Buildings. This safety-related piping transfers heat loads from the essential cooling water system and diesel generator coolers to the spray ponds. The essential spray pond underground piping has experienced internal corrosion, challenging its structural integrity. Essential spray pond piping located in the underground vaults has experienced severe external pitting which limits wall thickness margin for internal corrosion. Structural integrity is required for ASME Code compliance and for reliable spray pond system operations.

After evaluating the available alternatives, Palo Verde determined that the ESP piping should be replaced with Duplex 2205 stainless steel piping, which will provide greater resistance to corrosion and pitting, and which is essentially immune to chloride stress corrosion cracking. This project includes the development of a complete Design Package, consisting of the solutions for the above hydrology/instrumentations study and the material study completed under the PWA, and the completion of all required project planning and prerequisites. The ESP piping replacement will be completed in a phased approach as follows: Phase 1: pipe/instruments spanning vaults; Phase 2: buried pipe between vaults and tunnels/building; and Phase 3: Piping in Essential Pipe Tunnel and Diesel/Auxiliary building up to the isolation valves.

[301] WP SCE-05 Vol. 01, pp. 452-483. Plant Cooling Water System Pipeline Replacement

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $3.783 million (Nominal$, SCE share).[302]

(4) Valve Reworks and Replacements

Periodically, valves and valve internals throughout Palo Verde 1, 2, and 3 require replacement due to degradation and failure. If a valve or valve internal assembly is not replaced at appropriate intervals, the degrading conditions will worsen, resulting in the need for increased surveillance testing, and possible leakage or valve failure. Under the Palo Verde Valve Predictive Maintenance and Monitoring Program Periodic, valve replacements and reworks are identified, prioritized, and scheduled both to address known problems in a timely manner and to prevent emergent valve failures. Valve reworks and replacements are performed on-line if possible, and also during scheduled refueling and maintenance outages.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project during the 2023-2028 period is $4.292 million (Nominal$, SCE share).[303]

c) Water Reclamation Facility

The Palo Verde Water Reclamation Facility ("WRF") category covers WRF plant modifications, equipment, and replacements, and WRF process computers, but excludes items covered by the Buildings, General Plant, and Computer's budget categories. Water is essential for safe and reliable plant operations. The WRF provides the reclaimed water that transfers heat generated by plant operations to the ultimate heat sink. The capital work planned by APS for this project keeps the water source for this purpose secure.

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[302] WP SCE-05 Vol. 01, pp. 484-494. Essential Spray Pond Piping Replacement

[303] WP SCE-05 Vol. 01, pp. 495-507. Valve Reworks and Replacements

The forecast cost of the capital expenditures for WRF projects during the 2023-2028 period is $28.607 million (Nominal$, SCE share). This includes the Clarifiers Life Extension Project, which has a cost greater than $3.0 million (Nominal$, SCE share).

(1) Clarifier Life Extension

Wastewater clarifiers are setting tanks that allow suspended particles to settle out of wastewater as it flows through the tanks. The Palo Verde WRF Solids Contact Clarifier System Structures (i.e., settling tanks) are approximately 40 years old and have exceeded their design life expectancies. Several independent studies indicate that refurbishment is necessary to extend the life of the clarifiers. The WRF Clarifier Extension Repair project for Clarifier Train 4 is scheduled to be performed during 2023-2024. This project will include the repair and replacement of components that are worn out or outdated.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers. SCE's share of the capital forecast for this project is $4.671 million (Nominal$, SCE share) during the 2023-2028 period.[304]

d) Buildings

The Palo Verde facility includes many buildings located inside the security-protected areas that are integral components of the three nuclear units. In addition, the facility includes many other buildings located inside or outside the security owner-controlled area that directly support the operation of the nuclear units and the Independent Spent Fuel Storage Installation ("ISFSI"). From time to time, these buildings require repairs or modifications so that plant workers have suitable space to plan and perform their work to meet the business needs of the plant.

SCE's share of the capital forecast for Building-related projects during the 2023-2028 period is $5.880 million (Nominal$, SCE share). No single Buildings project has a cost greater than $3.0 million (Nominal$, SCE share).

[304] WP SCE-05 Vol. 01, pp. 508-527. Clarifiers Life Extension

e) General Plant

The General Plant category covers furniture, office equipment, communications-related equipment, and transportation (e.g., radio system replacements and modifications, railroad concrete insert replacements, temporary power for outages, concrete and paving, wireless infrastructure, and hardened security posts). It also covers periodic replacement of vanpool and plant vehicles due to age and/or increasing maintenance costs. Periodically, these various items require replacement so that plant workers are able to complete their work at the plant.

SCE's share of capital forecast for General Plant projects during the 2023-2028 period is $5.300 million (Nominal$, SCE share). No single General Plant project has a cost greater than $3.0 million (Nominal$, SCE share).

f) Computers

The Computers category covers non-process computer hardware and software including central processing units, personal computers, and peripherals. This also includes applications and infrastructure required to maintain plant computers and systems in workable status. The Computers work order is used for computer-related upgrades and replacements. Computers are a basic tool used by plant workers for planning and conducting essential plant activities, including operations, maintenance, engineering, security, quality assurance, regulatory affairs, and other functions. It is sound business practice to implement a capital program for computer upgrades and replacements.

SCE’s share of the capital forecast for Computers projects during the 2019-2023 period is $16.131 million (Nominal$, SCE share). No single Computers project has a cost greater than $3.0 million (Nominal$, SCE share) although the aggregate cost for projects authorized by the Technology Executive Steering Committee could exceed $3.0 million, SCE share.

g) Emergent Work Fund

The Emergent Work Fund is a blanket work authorization for unforeseen capital investments at the plant to address: (1) issues raised by the NRC and other regulatory agencies, or (2) issues discovered during future operation and/or refueling outages. The foregoing issues typically arise at nuclear facilities, including Palo Verde. The Emergent Work Fund appears as a line item in the five-year capital forecast for 2019-2023. Any capital work item funded from the Emergent Work Fund requires a detailed, work authorization approved by the E&O Committee. The Emergent Work Fund allows APS to keep Palo Verde operations safe, reliable, and compliant with NRC and other regulatory requirements. SCE's share of the capital forecast for the Emergent Work Fund during the 2023-2028 period is $7.139 million (Nominal$, SCE share).

h) Overheads and Distributables

Significant costs are incurred in the overall support of the capital program at Palo Verde. Because it is not practical to assign these costs to individual projects, the "Overheads" project accounts for them. Various groups, such as Business Operations, Warehouse, Long Range Planning, and Supply Chain, are included in this cost category. Similarly, the Maintenance and Project Engineering Departments incur significant costs to specifically support the categories "Plant Modifications" and "Replacements," but it is not practical to assign these costs to individual projects. The "Distributables" project accounts for them.

SCE's share of the capital forecast for Overheads and Distributables projects during the 2023-2028 period is $19.868 million (Nominal$, SCE share).