Application No.:	A.19-08-
Exhibit No.:	SCE-05, Vol. 1
Witnesses:	J. Buerkle
	T. Condit
	T. Champ

SOUTHERN CALIFORNIA
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(U 338-E)

2021 General Rate Case

GENERATION

Before the

Public Utilities Commission of the State of California

Rosemead, California
August 30, 2019

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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 thirty-three hydroelectric plants (Hydro);[1] five gas-fired peaking units (Peakers), of which two are Hybrid Enhanced Gas Turbine (EGT); two Battery Energy Storage Systems (BESS); one combined-cycle gas plant with two generating units (Mountainview); a largely diesel-driven electric generating plant (Catalina Pebbly Beach); twenty-four rooftop solar photovoltaic (SPV) plants; and one ground-based SPV plant.[2] 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 of 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 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, Regulatory Support Services, and Business Planning 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 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 this GRC are consistent with recorded costs. SCE's forecast includes funding to continue operating these assets at historic levels of reliability for the duration of their FERC licenses, many of which are in the process of being renewed.

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[1] SCE currently has 35 hydroelectric power houses of which two, San Gorgonio 1 and San Gorgonio 2, are no longer in operation as the units at these two facilities have been disconnected from the grid. SCE is in negotiations with FERC to relinquish the licenses of these facilities.

[2] The building owner of the Perris Solar (SPVP044) site has notified SCE of the emergent need to re-roof the building requiring the removal of all solar panels and ancillary equipment from the building's rooftop. Further detailed discussion of this request and SCE's planned response can be found in Chapter IV of this testimony volume.

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 2021 through 2023) to perform two separate Major Inspection overhauls (one on each of the two units) forecast to occur in the fall of 2021 and spring of 2022. Overhauls are conducted on Mountainview units approximately every four years. SCE averages the cost of overhaul expenses over the three-year rate case cycle of 2021 through 2023 consistent with how similar Mountainview overhaul costs were averaged in SCE's previous GRC requests.[3]

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; waste water disposal; repair parts; and other related items. Our Peaker O&M Expense forecast also includes transitioning costs associated with the two existing EGT systems from the Aliso Canyon Energy Storage Balancing Account (ACESBA) to base rates.[4]

Since 1962, SCE has maintained six diesel engine generators that provide electric service to Catalina Island, which includes the cities of Avalon and Two Harbors as well as rural areas located in Catalina's rugged interior.[5] The O&M and capital forecast for Catalina Island will continue electric service for approximately 4,000 permanent residents and over one million annual visitors.[6]

In 2012, SCE completed the construction of the UCSB Fuel Cell, and construction of the CSUSB Fuel Cell was completed in 2013. The O&M and capital forecast will continue funding necessary for the planned operation 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. Our GRC forecast is consistent with these prior Commission decisions.

SCE also is responsible for the operations and maintenance of 91 MW direct current (DC) from its Solar Photovoltaic Program (SPVP) power plants.[7] Our funding request includes the estimated O&M

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[3] D.09-03-025, pp. 31-33.

[4] Transfer of EGT system costs from the ACESBA to base rates was authorized by D.18-06-009, Order, p. 44.

[5] SCE provides water and gas services to Catalina, although those costs are recovered through separate GRCs.

[6] United States Census Bureau, 2017 Population Estimates.

[7] D.13-05-033.

expense to operate these plants, including roof lease payments, consistent with the Commission's decision governing our SPVP program. It also includes the 2019-2023 capital expenditures to fund equipment replacement needs that arise during that time (*e.g.*, for replacing failed inverters).

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.

B. Summary of O&M Request

The 2021 Test Year O&M expense forecast for the Generation Business Planning Group totals $167.692 million, as summarized in Table I-1 below.[8] The table also summarizes the recorded expenses incurred during 2014 through 2018.

Table I-1
Generation Business Planning Group - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)

Generation	**Recorded**					**Forecast**		
BPE/Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Hydro	43,501	45,160	43,158	43,512	44,347	38,641	40,881	42,028
Fossil Fuel	41,491	36,445	41,198	45,432	38,367	36,234	39,354	43,005
Solar	4,563	4,381	4,379	3,974	3,968	3,795	3,635	3,755
Nuclear	79,044	84,798	86,136	83,054	77,619	78,916	78,904	78,904
TOTAL	**168,599**	**170,784**	**174,872**	**175,972**	**164,302**	**157,586**	**162,775**	**167,692**

SCE's 2021 Test Year O&M expense forecasts for the continued operation and maintenance of our Generation Hydro, Fossil Fuel (Mountainview, Peakers, Catalina, and Fuel Cells), Solar, and Nuclear BPEs are consistent with recent past recorded costs, with appropriate adjustments for recent and future events. Approval of our Test Year forecast will fund the continued safe and reliable operation of

[8] Refer to WP SCE-05, Vol. 1, Book A, p. 2.

these power generating assets, in compliance with environmental objectives and other regulatory requirements.

C. Summary of Capital Request

As summarized in Table I-2 below, the 2019 through 2023 forecast capital expenditures for our Hydro, Fossil Fuel, Solar, and Nuclear BPEs total $538.389 million.[9] This is $50.534 million less (approximately 9 percent) than the $588.923 million of capital expenditures recorded during 2014 through 2018. The main reason for this reduction is the completion of the large one-time Mountainview Advanced Gas Path and Dry Low NOx (AGP/DLN) Combustion Turbine (CT) Upgrade project in 2015-2016.[10] The reduction is partially offset by a forecast increase in Hydro expenditures, which are necessary for a variety of reasons including dam improvements. The dam 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.

Table I-2
Generation Business Planning Group
2014-2018 Recorded and 2019-2023 Forecast
(Nominal $000)

Generation BPE/Year	2014-18 Recorded	2019-23 Forecast	Difference
Hydro	187,377	243,247	55,870
Fossil Fuel	217,693	111,678	(106,015)
Solar	1,620	500	(1,120)
Nuclear	182,233	182,964	731
TOTAL	588,923	538,389	(50,534)

SCE's Hydro capital expenditure forecast funds a wide variety of necessary work. This includes the ongoing FERC relicensing of several Hydro facilities that will allow us to continue to operate these facilities 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

[9] Refer to WP SCE-05, Vol. 1, Book A, p. 3.

[10] This project was presented in SCE’s 2018 GRC testimony SCE-05, Vol. 4.

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.

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 $54.0 million for the purchase of new combustion turbine rotors and $6.0 million for the installation of a new control system. The forecast for Catalina includes $34.3 million for the Catalina Repower project, which when complete will serve to address the SCAQMD requirement to achieve Pebbly Beach Generating Station emission reductions by replacing the existing units with newer and cleaner generating technology.

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 the Testimony Sections II - 0. Further information and discussion of our 2014 through 2018 recorded capital expenditures, and their comparison to GRC-adopted capital forecasts, can be found in Section D below.

D. <u>2018 Decision</u>

In accordance with D.15-11-021 Ordering Paragraph 3, this Chapter compares Commission-authorized 2018 O&M expense and capital expenditures to SCE's recorded 2018 O&M and capital expenditures for SCE's Generation BPG; excluding Palo Verde which is addressed separately in Chapter V of this testimony volume.

1. <u>Comparison of 2018 Authorized to Recorded O&M</u>

As shown in Table I-3, the Commission's adopted 2018 GRC Test Year forecast for the Generation BPG O&M expense was $83.239 million, equal to SCE's request of $83.239.[11] SCE's recorded 2018 expense was $86.683 million, approximately $3.444 million higher than adopted.[12]

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[11] D.19-05-020. Note that the figures given herein are in $2018 constant dollars, while the O&M expense dollar figures discussed in SCE's 2018 GRC testimonies and the Decision are in $2015 constant dollars.

[12] Refer to WP SCE-07, Vol. 1 – Authorized to recorded.

Table I-3
2018 Generation Business Planning Group
O&M Expenses – Adopted versus Recorded
(Constant 2018 $000)

Generation BPE	2018 - O&M			
	Requested	**Adopted**	**Recorded**	**Authorized vs. Recorded over/(under)**
Hydro	41,888	41,888	44,347	2,459
Fossil Fuel	37,346	37,346	38,367	1,021
Solar	4,005	4,005	3,968	(37)
TOTAL	**83,239**	**83,239**	**86,683**	**3,444**

In mid-2016, the Generation Department initiated several process changes to increase productivity and reduce labor expenses. These changes included consolidating the Generation Department from three field organizations (*i.e.,* Gas and Solar, Northern Hydro and Eastern Hydro) down to two field organizations (*i.e.,* Western Operations and Eastern Operations). While our cross-support approach has been successful in lowering overall costs, a by-product is that we have begun to observe larger than historic year-to-year variations within the three Generation Department managed BPE's (*i.e.,* Hydro, Fossil Fuel and Solar). These variances can largely be attributed to reprioritization of work based on the most immediate need.

The main factor contributing to the higher-than-adopted recorded Hydro expense was the significant increase in the generation output of SCE's Hydro fleet in 2017 (approximately 158% of normal), following many years of record lows (2014 was approximately 39% of normal and 2015 was approximately 25% of normal) experienced during the 2011-2016 California drought.[13] Higher generation output led to increased FERC administration fees and higher operating expenses for consumables and overtime labor costs for operating personnel.[14]

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[13] The 2014-2016 calendar years were some of California's driest years, based on records dating back to the 1800's.

[14] Refer to testimony section II.B.3.a) for further detailed information regarding Hydro FERC administration fees.

Higher-than-adopted Fossil Fuel operating expenses can largely be attributed to unplanned repair expenses incurred during the Mountainview Steam Turbine outage (October 2017 to January 2018) and the Mountainview transformer replacement outage (fall-2018).

2. Comparison of 2018 Authorized to Recorded Capital Expenditures

As shown in Table I-4 below, SCE requested $66.601 million in 2018 for Generation BPG capital expenditures; excluding Palo Verde which is addressed separately in Chapter V of this testimony volume. The Commission authorized $64.727 million, which reflected a $1.874 million reduction due to the Commission's disallowance of the Catalina Automation Project and adoption of ORA's recommendation of utilizing a five-year average of recorded costs.[15]/[16] The Catalina Automation Project was already complete, and SCE does not intend to challenge the Commission's disallowance in the 2021 GRC.[17]

As reflected in Table I-4 below, SCE's total recorded 2018 capital expenditures were $63.551 million ($2018), approximately $1.175 million ($2018), or two percent, lower than authorized.

[15] Refer to WP SCE-07, Vol. 1 – Authorized to recorded.

[16] SCE's original request for Catalina, as reflected in Table I-4 within the Fossil Fuel BPE, was modified in rebuttal testimony as indicated in D.19-05-020 pp. 167-168 and 416, Conclusion of Law - 96.

[17] This amount excludes the approximate total $17.7 million write-off of the Catalina Pebbly Beach generation station automation project, which was disallowed in the 2018 GRC.

Table I-4
Generation Business Planning Group
2018 Capital Expenditure – Requested, Authorized and Recorded
(Nominal $000)

Generation BPE	2018 TY - Capital			
	Requested	Authorized	Recorded	Authorized vs. Recorded over/(under)
Hydro	60,930	60,930	39,169	(21,760)
Fossil Fuel	5,470	3,596	24,382	20,786
Solar	202	202	-	(202)
TOTAL	66,601	64,727	63,551	(1,175)

The $21.760 million underrun in 2018 Hydro capital expenditures largely occurred because several Hydro capital projects originally forecast to occur in 2018 were deferred to 2019 and 2020, as summarized in Table I-5. SCE utilized the deferral of these projects to perform emergent work at the Mountainview Generating Station and Peaker power plants to preserve equipment reliability and safety.

Table I-5
Generation Business Planning Group
2018 GRC – Itemized Under-Spend
(Nominal $000)

Project	Authorized	Recorded	Variance
Hydro:			
Big Creek 8 Unit 1 Generator Rewind	9,060	-	(9,060)
Big Creek 2 Unit 6 Generator Rewind	5,290	-	(5,290)
Hydro Relicensing	11,707	4,452	(7,255)
Other Hydro Projects	34,873	34,717	(156)
Subtotal Hydro	**60,930**	**39,169**	**(21,760)**
Fossil Fuel:			
Mountainview Superheat Attemperation System Repairs	-	7,357	7,357
Mountainview Storage Building	-	1,424	1,424
Mountainview Unit 3 Main Transformer Replacement	-	1,399	1,399
Mountainview Generator Excitation Upgrades	-	779	779
Barre Peaker SCR Upgrade	-	3,778	3,778
Pebbly Beach Subtation - Replace 2.4kV Switchgear	-	3,064	3,064
Pebbly Beach Unit 15 Diesel Engine Overhaul	-	1,159	1,159
Pebbly Beach Vibration Monitoring System Installation	-	988	988
Other Fossil Fuel Projects	3,596	4,434	838
Subtotal Fossil Fuel	**3,596**	**24,382**	**20,786**
Solar	201	-	(201)
Total Over/(Under) Spend	**64,727**	**63,551**	**(1,175)**

a) Deferred Hydro Projects Discussion

(1) Big Creek 8 Unit 1 Generator Rewind

While SCE had originally forecast this project to commence in 2018, 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.[18]

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[18] Following two failures of the penstock in the early 1920's, the flow within the penstock serving Big Creek 8 Unit 1 was restricted which lowered the maximum capacity output of the unit from 30MW to 19MW. This

(*Continued*)

(2) **Big Creek 2 Unit 6 Generator Rewind**

While SCE had originally forecasted this project to commence in 2018, lower than anticipated total run (*i.e.,* operating) hours resulting from five years of drought and favorable condition assessments allowed this project to be deferred to 2020.

(3) **Hydro Relicensing**

Delays experienced in issuing the new FERC license for many of the Big Creek assets caused 2018 expenditures for Hydro relicensing to be substantially lower than forecast. At the time of the 2018 GRC, SCE had forecast that the licenses would be issued in 2017. As explained in more detail in Section II.C.3 of this testimony, SCE expects the Big Creek licenses to be issued in mid to late 2020.

b) **Emergent Fossil Fuel Projects Discussion**

As shown in Table I-5 above, three of the emergent Fossil Fuel projects (Mountainview Superheat Attemperation System Repairs, Barre Peaker SCR Upgrade, and the Pebbly Beach Substation – Replace 2.4kV Switchgear) exceeded the $3 million threshold SCE utilizes when discussing forecasted capital projects within GRC testimony. Therefore, to provide visibility to the two already completed and in-service projects, SCE discusses them below. The third project, Pebbly Beach Substation – Replace 2.4kV Switchgear, is still under construction and is being presented in Section III.D.4.c) of this volume.

(1) **Mountainview Superheat Attemperation System Repairs**

(a) **Background**

During the scheduled 2017 Mountainview fall outage inspection, SCE personnel discovered excessive wear to the steam turbine blades as compared to what had been expected from the approximate four-year service run since the last respective major overhaul. Additional inspections indicated potential premature failure of the High Pressure Superheat Attemperator System, leaking spray water control valves, cracks in the inner liner, and weld failures. As this equipment is located in an area frequently traversed by plant personnel, the severity of the equipment damage

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study will determine if it is cost effective to replace the existing penstock to enable the generator to operate at full capacity.

required immediate repairs and replacements to ensure equipment reliability and safety. Due to the long lead time of replacement components (36 to 40 weeks lead time), SCE made temporary repairs that allowed the units to remain operational and safe until the replacement components could be procured. SCE took additional precautionary safety measures by limiting access to this area of the plant while the units were operating.

(b) Project Scope

The superheat attemperation system repairs included replacement of the single stage valves with an optimum spray water control valve, a re-designed liner in the discharge steam piping system, installation of a temperature monitoring system, piping system modifications including the severing, welding, heat treat and inspection, and changes to the Ovation DCS (Distributed Control System).

(c) Project Justification and Benefit

SCE determined that the damage created an unacceptable level of risk of a catastrophic in-service failure should the repairs and replacements be deferred until the next scheduled unit overhauls (2021/2022). Therefore, SCE completed the project in the fall of 2018 to allow for the continued safe and reliable operation of the plant. This project also addressed other known industry issues.

(2) Barre Peaker – Selective Catalytic Reduction (SCR) Upgrade

(a) Background

In early 2017, the Barre Peaker unit experienced turbine blade coating damage caused by excessive water injection to meet NOx level limits. Additionally, the unit experienced high levels of ammonia consumption (including ammonia slip) to compensate for deteriorated NOx catalyst modules within the exhaust duct. In addition, the catalyst frame was found to be in poor condition. Temporary repair measures were implemented, but further repairs were necessary to fully resolve the issues. Early in 2018, SCE made a determination that the SCR was reaching the end of its useful life and needed to be replaced during the scheduled fall outage, to mitigate any potential permit violations associated with NOx limits. Due to the deteriorated SCR, SCE reported 21 hours (1,010 equivalent MWh) of forced outage resulting from the NOx catalyst inability to maintain NOx emissions below acceptable limits.

(b) **Project Scope**

The upgrade of the SCR at Barre Peaker unit included installing a new catalyst bed, including new sensors down-stream of the catalyst. The project installed an optimized emissions control system that reduces water consumption in the combustor. Typically in a gas turbine, the NOx emissions are controlled by water injection in the combustor and ammonia injection at the exhaust duct in front of the SCR. The aqueous ammonia concentration was increased from 19 percent to 29 percent to provide for delivery of the additional volume of ammonia without requiring more expensive changes to the existing ammonia-handling system.

(c) **Project Justification and Benefit**

Potential consequences of not upgrading the SCR include failure to meet the NOx level requirements (non-compliance), which would also impact availability of the unit. The enhanced version of the SCR provides more surface area for reaction between NOx and ammonia molecules, increasing the NOx reduction capability in the exhaust duct. As a result, the system can meet its emissions limit of 2.5 ppm even if the water injection rate is reduced and the concentration of NOx emissions coming out of the combustor is higher. The significant reduction in the water injection rate enabled by the optimized emissions control system lowers the risk of damage to system components and increases their longevity. Based on the operating forecast for the next decade, the lower water injection rate will reduce overall water consumption at each Peaker plant by approximately 45 percent and save two million gallons of water annually, resulting in a reduction in operating and maintenance costs and increasing value for SCE's customers.

Furthermore, this upgrade will be compatible with an EGT conversion, should/when the decision to convert the units occurs, whereas a replacement in-kind is not.

E. Generation Department Overview

As mentioned in Section I.A., SCE's Generation Department is responsible for operating and maintaining thirty-three hydroelectric plants (Hydro),[19] five gas-fired peaking units (Peakers) which include two Hybrid Enhanced 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 (Catalina Pebbly Beach), twenty-four rooftop solar photovoltaic (SPV) plants and one

[19] SCE currently has 35 hydroelectric power houses of which two, San Gorgonio 1 and San Gorgonio 2, are no longer in operation as the units at these two facilities have been disconnected from the grid. SCE is in negotiations with FERC to relinquish the licenses of these facilities.

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 labor expenses. These changes, implemented across the entire Generation Department, included organizational changes with an emphasis on enhanced asset management. SCE’s enhanced asset management has allowed the Generation Department to better focus its resources on the O&M activities and capital projects that provide the highest value for SCE's customers. Additionally, the asset management program improved operating practices to better align with the economic incentives and disincentives of California's wholesale power market.

These changes included separating engineering work related to capital project management from engineering support of O&M activities, and increased the outsourcing of capital project design and construction work. The changes allow SCE to provide more focused technical support for daily O&M activities, without affecting capital project schedules.

Additional efficiency improvements resulted from the Generation Department consolidating from three field organizations (*i.e.,* Gas and Solar, Northern Hydro, and Eastern Hydro) down to two field organizations (*i.e.,* Western Operations and Eastern Operations). This consolidation built upon the consolidation made in late 2013, where 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 the gas-fired assets, with those who formerly worked primarily on the Hydro assets.

As shown in Table I-6 below, total recorded costs for the Generation Department BPEs have generally remained flat over the most-recent five years, indicating that both the consolidation and cross-support efficiency improvements have been successful at controlling overall costs.

Table I-6
Generation Department
2014-2018 Recorded O&M
(Constant 2018 $000)

Generation BPE/Year	Recorded				
	2014	**2015**	**2016**	**2017**	**2018**
Hydro	43,501	45,160	43,158	43,512	44,347
Fossil Fuel	41,491	36,445	41,198	45,432	38,367
Solar	4,563	4,381	4,379	3,974	3,968
TOTAL	**89,555**	**85,985**	**88,735**	**92,918**	**86,683**

While our 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 the three Generation Department managed BPE's (*i.e.,* Hydro, Fossil Fuel and Solar). These variances, illustrated in Table I-6 above, can largely be attributed to reprioritization of 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 2017).[20] While overall costs have remained relatively flat (*i.e.,* less than 6% year-to-year variance), SCE has continued to maintain high reliability at its generation facilities even though its annual spend by BPE has experienced above-average variance.

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 or not it is dispatched to operate.[21] EFOF is the percentage of time that a generating asset is not available to operate, because it is undergoing a forced outage.[22]

A 100 percent EAF and zero percent EFOF is not practical, as generating assets must be periodically removed from service to conduct routine maintenance, and because of the diminishing

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

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

[22] 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 are 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).

returns of the cost to design and maintain a power plant to the level required to fully mitigate all of the possible problems that can cause forced outages.

To maintain high reliability with real world constraints of time, costs and resources, power plant engineers and technicians must manage and complete extensive maintenance and capital project work within aggressively planned outage durations. 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 getting timely delivery of parts and materials.

As shown in Table I-7, SCE's average EAF and EFOF performance over the past 10 years generally exceeds industry averages; Mountainview is the exception.[23] Capital projects performed during this time period have been effective in improving the performance of SCE's Generation fleet.

Table I-7
SCE Generation – 2009-2018 EAF and EFOF Performance

Generation BPE	SCE		Industry	
	EAF	EFOF	EAF	EFOF
Hydro	88.88	2.02	82.58	4.88
Fossil Fuel				
Mountainview	89.89	3.55	84.96	2.62
Peakers	93.93	1.66	87.04	4.40
Nuclear	91.34	0.59	89.44	2.39

During the 2021-2023 three-year rate cycle, our planned outage work includes the 2021/2022 Mountainview Major Inspection (MI) overhauls. 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.

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[23] 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.

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 details 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.[24] As discussed in ERRA, our Hydro, Mountainview, and Peaker reliability performance has been and continues to be very 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.

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

1. Energy Storage and EGTs

To help alleviate electric-generation reliability concerns arising out of the moratorium on gas injections into the Aliso Canyon Storage Facility, the California Public Utilities Commission ("Commission" or "CPUC") issued Resolution E-4791 ("the Resolution") on May 31, 2016. Pursuant to Governor Brown's State of Emergency Proclamation to "take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Storage Facility,"[25] the Resolution, among other things, deemed it reasonable for SCE to pursue Resource Adequacy (RA) eligible, utility-owned, turnkey, in-front-of-the-meter (IFOM) energy storage projects at SCE's substations or on utility-owned or utility-operated sites south of Path 26. The Commission determined that developing such turnkey "build and transfer" projects "would increase the likelihood of resources being timely developed" to mitigate the Aliso Canyon gas-injection moratorium.[26]

Consistent with the Resolution, the two BESS for which SCE seeks continued cost recovery (SCE-02 Vol. 04 Part 1, Grid Modernization, Grid Technology, Energy Storage testimony[27]) (Mira Loma Battery Energy Storage System A & B) were sited adjacent to SCE's Mira Loma substation

[24] A.19-04-001.

[25] CPUC Resolution E-4791, p. 3.

[26] CPUC Resolution E-4791, p. 12.

[27] See SCE-02 Vol. 4 Part 1, Grid Modernization, Grid Technology, Energy Storage, Chapter IV (Energy Storage), (A), (2).

in Ontario, California. Two GE energy storage systems were also integrated into SCE's existing GE LM 6000 Gas Turbine Peaker Generating Stations in Norwalk, California ("Center Peaker") and Rancho Cucamonga, California ("Grapeland Peaker"), successfully upgrading the units into Hybrid Enhanced Gas Turbines (EGTs). The Tesla and GE Projects all became operational on December 30, 2016.

In D.18-06-009, the Commission granted SCE's application to recover the recorded and forecast costs of the Tesla Projects and General Electric Projects. The Commission further authorized SCE to establish the Aliso Canyon Energy Storage Balancing Account (ACESBA) to record the Tesla and General Electric Projects' actual revenue requirements. The ACESBA was to be used until the remaining cost recovery was transitioned to SCE's General Rate Case base rates in SCE's 2021 General Rate Case.[28]/[29]

2. Catalina

The fossil-fueled generation units (6 diesel locomotive engines and 23 propane-fueled micro-turbines) at SCE's Pebbly Beach Generating Station (PBGS) are subject to Nitrogen Oxides (NOx) and other criteria pollutants and toxic air contaminants emissions limitations set forth by the South Coast Air Quality Management District (SCAQMD). SCE must operate within various emissions permit limits for the overall generation site, and separately for the diesel units. Compliance is maintained through the emissions credits balance through the SCAQMD administered NOx Cap-and-Trade program called RECLAIM (Regional Clean Air Incentives Market). Beginning on January 5, 2018, SCAQMD began the transition of the RECLAIM program to a command and control regulatory structure, which requires Best Available Retrofit Control Technology (BARCT). Additionally, California State Assembly Bill (AB) 617 which was signed into law requires an expedited schedule for implementing BARCT no later than December 31, 2023.[30]

As a result of the RECLAIM transition and AB 617, PBGS is subject to Rule 1135 (Emissions of Oxides of Nitrogen from Electricity Generating Facilities), which was finalized on November 2, 2018. To comply with Rule 1135, PBGS must reduce NOx emissions on five of its six[31]

[28] D.18-06-009, p. 42 – Conclusion of Law 2.

[29] See SCE-07 Vol. 1 Pt. 1(Results of Operations) Chapter IV (F) (2b) - Elimination of the Aliso Canyon Energy Storage UOG Balancing Account.

[30] SCAQMD Governing Board monthly meeting, January 5, 2018.

[31] SCAQMD Rule 1135(g) (3), pp. 1135-13.

engines to a level that is more stringent than the readily commercially available USEPA certified Tier 4 engines or reduce total facility-wide NOx emissions by over 80%.[32] The facility must also meet a very aggressive compliance timeline as prescribed by the rule and BARCT requirements per AB 617. To achieve these new stringent regulatory requirements, SCE is currently studying options for new and cleaner generation capacity to support Catalina Island.

3. Solar

In D.09-06-049, which approved SCE's SPVP, the Commission stated that the objective of the program was ". . . driving the costs of deploying an existing technology down by creating a new market opportunity."[33] The decision authorized SCE to install, operate, and maintain utility-owned SPV generating facilities primarily on commercial and industrial rooftop space,[34] with no more than 10% of the program to consist of ground-mounted SPV.[35] The Commission found that other California solar programs had ". . . left a gap in the one to two MW solar energy market"[36] and found SCE's SPVP Program as"... one possible solution to help address the existing gap ..."[37] The five-year program envisioned installing up to 250 MW Direct Current (DC) of solar generating facilities by SCE. The program was modified in Decision D.12-02-035, reducing the program installation to 125 MW, with no less than 115 MW of solar generation facilities absent additional authorization,[38] and increasing the allowable ground mount installations from 10 percent to 20 percent of total capacity. The program was further modified again in D.13-05-033, which reduced the program installation to no less than 91 MW DC (67.5 MW AC). SCE achieved this capacity level in 2013 with a total solar generating plant fleet of 91.4 MW DC.

In D.09-06-049, the Commission authorized the SPVP Balancing Account (SPVPBA) to record capital and O&M costs that SCE would incur to construct and operate SCE-owned solar generating plants. The Commission further directed that the SPVPBA amounts would be reviewed for

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[32] SCAQMD Rule 1135(d) (2), p. 1135-5.

[33] D.09-06-049, p. 53.

[34] D.09-06-049, Ordering Paragraph 1.

[35] D.09-06-049, p. 40, fn. 48.

[36] D.09-06-049, Findings of Fact, Paragraph 3, p. 54.

[37] D.09-06-049, Findings of Fact, Paragraph 5, p. 54.

[38] D.12-02-035, Ordering Paragraph 1.

reasonableness in SCE's General Rate Case. SCE completed construction of SPVP in 2013, and therefore presented total recorded capital expenditures for plant construction for review in SCE's 2015 GRC. Capital expenditures were below the Commission's reasonableness review threshold of $3.85/MW (DC) specified in D.09-06-049 and were not disputed.

In SCE's 2015 GRC, the Commission also approved closure of the SPVPBA and transitioned recovery of future SPVP plant costs to SCE base rates beginning January 1, 2015. Correspondingly, the Commission also reviewed and adopted SCE's 2014 and 2015 SPV plant forecast capital expenditures for maintaining the newly constructed plants (*e.g.*, to fund the purchase of replacement inverters as SCE had forecast that a few inverters would fail and require replacement in each future year).

4. <u>Fuel Cells</u>

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."[39] The Commission further stated that the fuel cell projects "… can supplement the Commission's SGIP efforts to advance fuel cell technologies in California."[40] Consistent with program approval, SCE constructed and now owns and operates two fuel cells. SCE's Fuel Cell Demonstration Program is 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."[41] 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 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.

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

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

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

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) 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.[42] 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 fault 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-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 in advance.[43]

Aside from the safety considerations and possible 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, as required by the unique issues associated with each of the different powerhouse (*i.e.,* 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

[42] A small percentage of SCE's Hydro assets are not regulated by FERC; see Chapter II.A.1.

[43] 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.

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.

H. Connection with RAMP

1. Overview

SCE's RAMP report identified the top nine safety risks associated with the operations of SCE's assets. This included Hydro Asset Safety. As shown in Table I-8 below, SCE identified ten compliance/control activities for the Hydro BPE.

Table I-8
GRC Controls & Mitigations Included in SCE's 2018 RAMP Filing

Generation BPE	Compliance/Control Activities	RAMP ID	Risk
Hydro	Hydro Operations	CM1	Hydro Asset Safety
	Hydro Maintenance	CM2	
	Dam Safety Program	CM3	
	External Inspections	CM4	
	Seismic Retrofit	C1	
	Dam Surface Protection	C2	
	Spillway Remediation and Improvement	C3	
	Low Level Outlet Improvements	C4	
	Seepage Mitigation	C5	
	Instrumentation/Communication Enhancements	C6	

CM = Compliance Activity; C = Control

a) Hydro Asset Safety

SCE operates a portfolio of thirty-three Hydro dams that support thirty-three hydroelectric plants that provide a combined 1,153 MW of generating capacity.[44] 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.

[44] SCE also operates two dams on Catalina Island that support its potable water supply.

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. 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) and/or the Federal Energy Regulatory Commission (FERC).[45] 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 three drivers that could potentially lead to URRW: seismic events, flooding, and failure under normal operations. 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-eight high-hazard dams was estimated as one failure every 175 years.

Table I-9 summarizes the compliance activities (CM1-CM4) 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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[45] 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-9
Hydro Asset Safety
RAMP - Compliance 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	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.
CM4	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.
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-CM4) are required to adhere to laws and regulations governing dam safety. 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. In addition to the compliance 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 2019-2023 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 and II.C of this testimony volume.

2. SED/Intervenor Comments

The Commission's SED authored "A Regulatory Review of the Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case" (SED RAMP Report) and stated that: (1) "Given such uncertainties in terms of future Hydro assets and operations, it is difficult for the Commission to come to any conclusion on the proposed mitigation plan",[46] and (2) "SCE's C6 mitigation, instrumentation/communication enhancements, should be considered for expansion to better enable accurate risk assessments and performance metrics."[47]

Regarding SED's first statement, SCE disagrees that potential uncertainty over whether some of SCE's smaller Hydro plants may be decommissioned at an uncertain point in the future implies that the controls and mitigations in the chapter cannot be evaluated regarding their potential risk reduction and forecasted cost. Foregoing identified dam *safety* repairs and improvements due to uncertainty regarding the dam's future operational life would unnecessarily and irresponsibly increase risk to the public. Federal and state regulators will not (and should not) allow a dam owner to forego investment in Dam Safety due to financial considerations, as demonstrated by the revocation of Boyce Hydropower's FERC license for Edenville dam referenced above.

Regarding SED's second statement about expanding C6, the recommendation incorrectly links unrelated issues and does not have a basis in fact. C6 includes a combination of surveillance cameras and instrumentation associated with day-to-day operation and monitoring of Hydro resources (*e.g.,* monitoring reservoir levels and water flow rates). While such instrumentation is foundational to managing Hydro assets on a daily basis and identifying potential issues, it should not be misunderstood as something that will "better enable accurate risk assessments and performance metrics." Rather, risk assessments are based on factors such as risk-driver frequency (*e.g.* earthquakes or excessive rain), asset

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[46] SED Investigation 18-11-006, p. 54.

[47] SED Investigation 18-11-006, p. 55.

conditions, and other external factors such as the presence of people downstream. The controls used to operate a Hydro asset do not provide insight into these risk factors.

Additionally, while the instrumentation in C6 provides factually neutral operational metrics (*e.g.,* measured water pressure within a given line), these metrics should not be conflated with the concept of "performance metrics", which would typically be understood as measuring human performance relative to a stated goal.

Further, the instrumentation in C6 should not be considered an appropriate means to "better enable" tracking of "collateral benefits" related to wildfire, physical security, or emergency response risk management. The surveillance cameras in C6 are intended to provide advance warning of potential water inundation (flooding), which would allow people potentially at risk to move to a safer location. However, beyond the benefit of providing advance notice in potential flooding scenarios, C6 does not having anything to do with "wildfire, physical security, and emergency response risk management."

Based on the above analyses and additional factual errors in the SEC RAMP Report's analysis of SCE's Hydro safety activities, SCE does not recommend changes from its proposed course of action.[48]

3. Reconciliation Between RAMP and GRC

As discussed in Section 1 above, compliance activities (CM1-CM4) 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).[49] 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.

Hydro Capital Maintenance Refurbishment and/or Replacement activities (C1-C6) are controls consisting of capital investments necessary for maintaining dam infrastructure and equipment.

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[48] SCE Response to CPUC SED comments on RAMP Hydro.

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

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-10 below, there are no material differences between the RAMP forecast for Hydro Asset Safety Controls, as estimated in SCE's 2018 RAMP report, and the forecast requested in this GRC.

Table I-10
Hydro Asset Safety Controls
Capital Forecast
(Nominal $000)

RAMP ID	Control / Mitigation Name	Filing	2019	2020	2021	2022	2023
C1	Seismic Retrofit	RAMP	$ 500	$ -	$ -	$ -	$ 2,000
C2	Dam Surface Protection		$ -	$ -	$ -	$ -	$ 500
C3	Spillway Remediation and Improvement		$ 4,000	$ 3,000	$ 2,500	$ 2,000	$ -
C4	Low Level Outlet Maintenance and Improvement		$ 5,550	$ 1,500	$ -	$ -	$ 5,000
C5	Seepage Mitigation		$ 2,000	$ 2,000	$ 3,900	$ 2,600	$ -
C6	Instrumentation / Communication Enhancements		$ 1,495	$ 2,853	$ 250	$ -	$ -
	Total		**$ 13,545**	**$ 9,353**	**$ 6,650**	**$ 4,600**	**$ 7,500**
C1	Seismic Retrofit	GRC	$ 500	$ -	$ -	$ -	$ 2,000
C2	Dam Surface Protection		$ -	$ -	$ -	$ -	$ 500
C3	Spillway Remediation and Improvement		$ 4,000	$ 3,000	$ 2,500	$ 2,000	$ -
C4	Low Level Outlet Maintenance and Improvement		$ 5,550	$ 1,500	$ -	$ -	$ 5,000
C5	Seepage Mitigation		$ 2,000	$ 2,000	$ 3,900	$ 2,600	$ -
C6	Instrumentation / Communication Enhancements		$ 1,495	$ 3,516	$ 250	$ -	$ -
	Total		**$ 13,545**	**$ 10,016**	**$ 6,650**	**$ 4,600**	**$ 7,500**
C1	Seismic Retrofit	Variance	$ -	$ -	$ -	$ -	$ -
C2	Dam Surface Protection		$ -	$ -	$ -	$ -	$ -
C3	Spillway Remediation and Improvement		$ -	$ -	$ -	$ -	$ -
C4	Low Level Outlet Maintenance and Improvement		$ -	$ -	$ -	$ -	$ -
C5	Seepage Mitigation		$ -	$ -	$ -	$ -	$ -
C6	Instrumentation / Communication Enhancements		$ 0	$ 663	$ -	$ -	$ -
	Total		**$ 0**	**$ 663**	**$ -**	**$ -**	**$ -**

The sole variance, shown in C6, is due to a forecast increase made to the IT-funded portion of the "Hydro Dam Safety – Security Camera" project; further details can be found in Section II.C.7.g) of this testimony volume and SCE-06 Vol. 01 Part 2. Further information regarding the projects comprising Controls C1-C6 and their forecasted costs can be found in Section C of this volume of testimony.

II.

HYDRO

SCE operates and maintains thirty-three hydroelectric (Hydro) generating facilities, including thirty-three dams, forty-three stream diversions, and approximately 143 miles of tunnels, conduits, flumes, and flow lines.[50]/[51] SCE's Hydro generating facilities have an aggregate 1,176 MW of nameplate capacity. This Chapter presents SCE's 2021 Test Year (TY) forecast of $42.028 million (constant 2018 dollars) in operational and maintenance (O&M) expense, and forecast of $243.247 million (nominal dollars) in 2019-2023 capital expenditures for Hydro generating facilities. 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

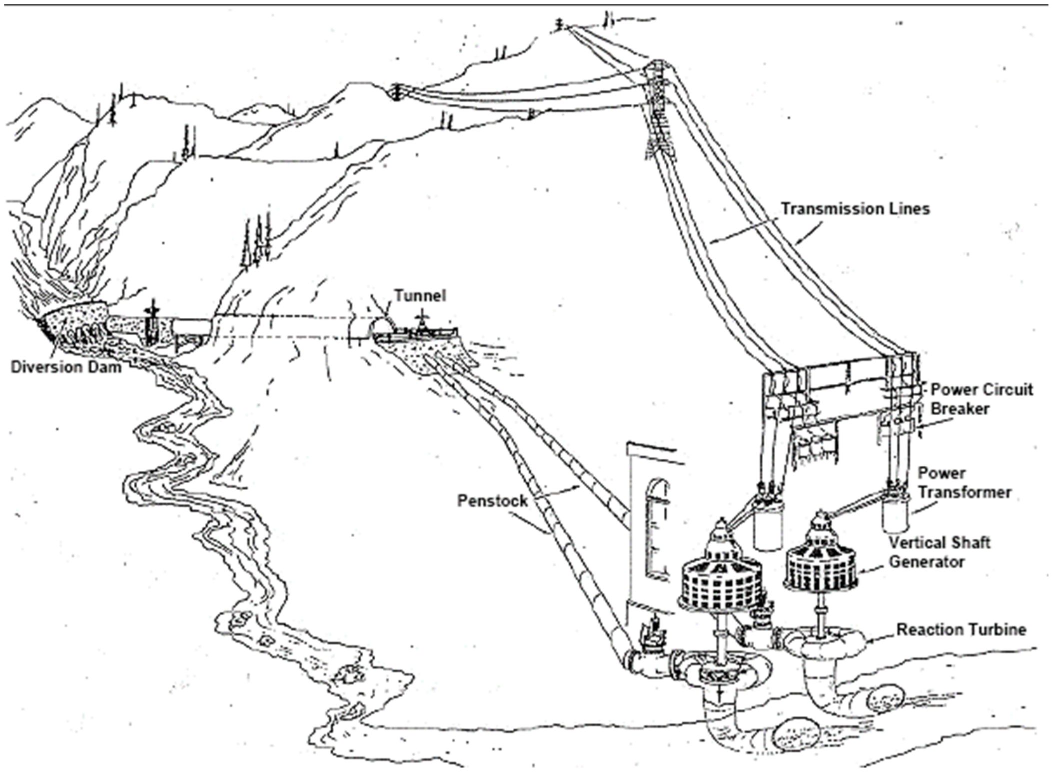
1. Hydro Assets

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 storage and conveyance facilities are used to capture, 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-1 below, illustrates a typical hydroelectric generating plant.

[50] SCE currently has thirty-five hydroelectric power houses of which two, San Gorgonio 1 and San Gorgonio 2, are no longer in operation as the units at these two facilities have been disconnected from the grid. SCE is in negotiations with FERC to relinquish the licenses of these facilities.

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

Figure II-1
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.

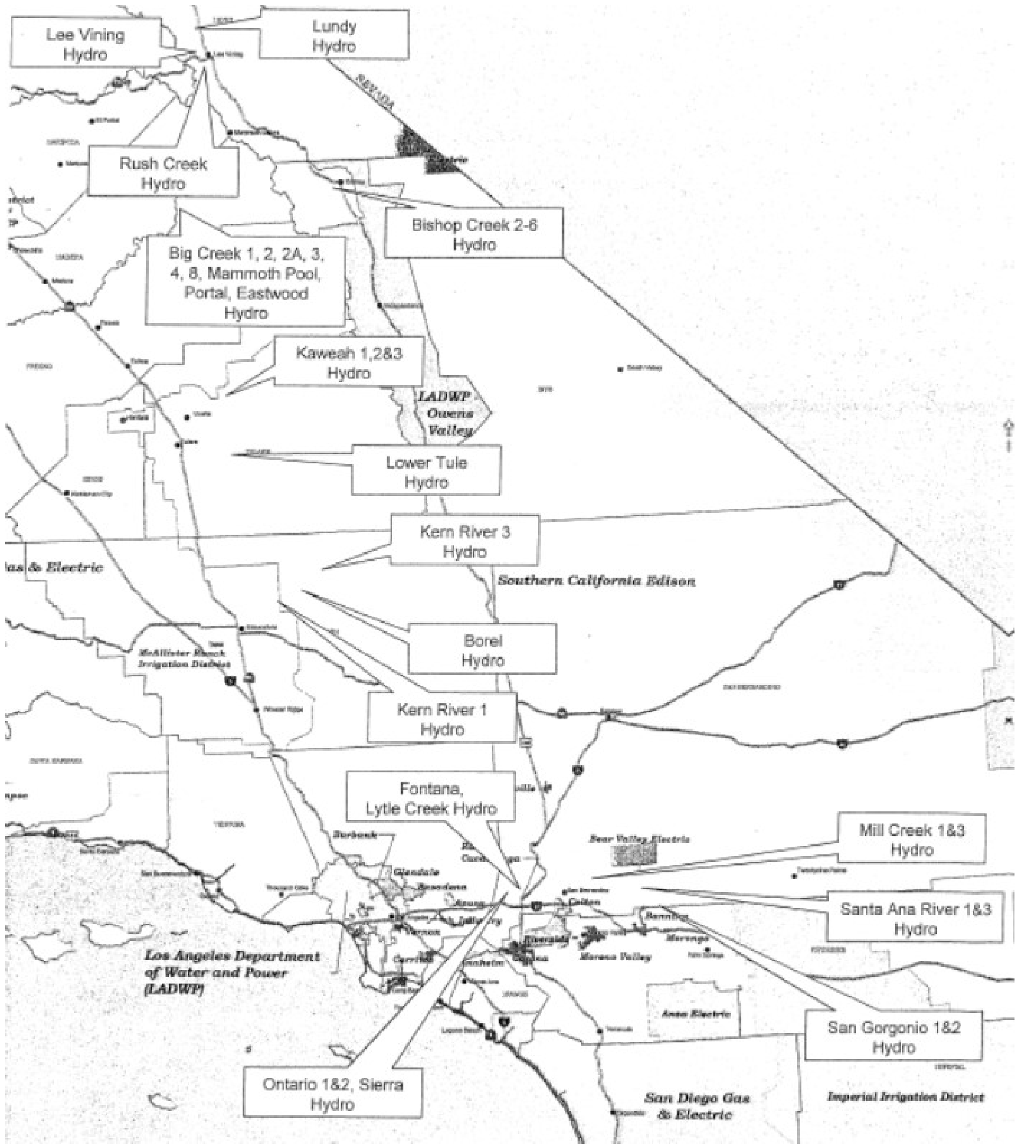
Hydro facilities with reservoir storage have the added benefit of storing water during the spring and early summer to allow increased utilization of the water during the hottest months and peak demand periods in late summer and early fall. Storing water in reservoirs extends the window of opportunity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

SCE has one pumped storage facility (John S. Eastwood Power Station) that operates as a reservoir storage facility with the benefit of pumpback operations. SCE uses the pumpback capabilities when market conditions warrant doing so. When the unit runs in the pumpback 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 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 located in the western Sierra Nevada Mountains, across an area that is centered approximately 50 miles northeast of Fresno. Big Creek is a composite of six major reservoirs, sixteen tunnels through solid granite, and nine powerhouses, most of which are reservoir storage facilities. Most Big Creek facilities directly connect to the bulk, 220kV power transmission system. In aggregate, the system represents approximately 1,015 MW, or about 86 percent of our 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 located 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 resource 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 twenty-four 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 161 MW, or about 14 percent, of our Hydro generation. Figure II-2 below, is a map showing the location of Hydro facilities.

Figure II-2
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 cyber security;

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-11 summarizes the MW capacity, year of initial operation, and type of Hydro powerhouses.

Table II-11
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		Borel	12.0	Run-of-the-river	1904
24		Kaweah/Tule:			
25		Kaweah 1	2.3	Run-of-the-river	1929
26		Kaweah 2	1.8	Run-of-the-river	1929
27		Kaweah 3	4.8	Run-of-the-river	1913
28		Tule	2.5	Run-of-the-river	1909
29		East End:			
30		Lytle Creek	0.5	Run-of-the-river	1904
31		Ontario 1	0.6	Run-of-the-river	1902
32		Ontario 2	0.3	Run-of-the-river	1963
33		Fontana	3.0	Run-of-the-river	1917
34		Santa Ana 1	3.2	Run-of-the-river	1899
35		Santa Ana 3	3.1	Run-of-the-river	1999
36		Sierra	0.5	Run-of-the-river	1922
37		Mill Creek 1	0.8	Run-of-the-river	1893
38		Mill Creek 2&3	3.0	Run-of-the-river	1903
39		TOTAL Eastern	161.5		
40	**TOTAL SCE HYDRO**		**1176.4**		

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 particular times of the year. The summer season typically requires nearly-full levels to satisfy recreational interests. Additionally, there are limits on seasonal carry-over storage that apply to the Big Creek project and downstream water users (largely for agricultural irrigation).

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

The runoff during the 2018 water year was approximately 74 percent of a normal (*i.e.,* average) year.[52] Nevertheless, given the fleet's high reliability and the effective management of fuel (water), generation levels during 2018 were approximately 95 percent of the 20-year historical average (1998-2017).

Table II-12 summarizes SCE's Hydro generation for 2018, as well as the average annual generation recorded during 1998 through 2017 on a calendar-year basis.

[52] 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, 2017 through September 30, 2018, for the 2018 water year).

Table II-12
SCE Hydro – 2018 Recorded Hydro Production

Line No.	Region	1998-2017 Average Net Generation (MWh)	2018 Net Generation (MWh)
1	Big Creek	3,117,793	3,011,791
2	Other Assets	560,079	492,128
3	TOTAL	3,677,872	3,503,919

As shown, the combined 2018 generation of Big Creek and the Other Assets was 3,503,919 MWh, approximately 95% of the previous 20-year period. This mainly reflects the fact that water run-off during 2018 was below the 20-year historic average.

Although Hydro's average annual generation has been lower than typical in recent years, Hydro still continues to provide a net benefit to SCE customers. Much of SCE's Hydro capacity has quick starting and ramping capabilities. Low startup costs and 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 unexpected customer demand, respond to unplanned system contingencies, or simply provide required system operating reserves by remaining off-line but immediately available. Because certain Hydro 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 "black-out."

The efficient use and availability (*i.e.,* reliability) of SCE Hydro generation resources are fostered through attentive management of the facilities. Reliability can be measured through the use of two metrics: (1) Equivalent Availability Factor (EAF), and (2) Equivalent Forced Outage Factor (EFOF).

3. <u>Hydro Reliability Performance</u>

EAF (equivalent availability factor) is expressed as the percentage of time that a generating unit was available for service (regardless of whether it was actually in service) during the time period in question. EAF takes into account scheduled outages as well as forced outages, and includes both outages and derates (*i.e.,* partial outages). EAF does not include outages or derates resulting from issues external to the SCE-managed powerhouse, reservoir, dam site and flowline equipment including: (a) transmission system constraints or outages that impact the powerhouse, and (b) insufficient water flows to operate the turbines, or time periods when the water contains excessive levels of storm debris (whereby using the water would damage the turbine). EAF is calculated on a monthly and annual basis for each powerhouse, which is then combined into a total aggregate EAF for the SCE Hydro fleet (*i.e.,* pro-rated by each powerhouse's rated MW output). Ideally, the EAF level is as high a percentage as possible.

EFOF is calculated by dividing the hours that the generating unit was forced off-line, due to equipment problems or other issues, by the total hours in the year. Therefore, the ideal EFOF level is a low percentage. EFOF is calculated monthly and annually for each powerhouse and then combined into a fleet total. As with EAF, EFOF does not include outages due to issues that are external to the SCE-managed Hydro assets and equipment.

As shown in Table II-13 below, SCE's EAF and EFOF performance has generally shown continued improvements over the last ten years. Capital projects performed during this time period have been effective in improving the performance of SCE's Hydro fleet.

Table II-13
SCE Hydro – 2009-2018 EAF and EFOF Performance

Line No.	Year	EAF %	FOF %
1	2009	78.80	8.80
2	2010	85.70	3.70
3	2011	86.50	1.20
4	2012	89.68	1.27
5	2013	87.36	0.22
6	2014	86.05	0.71
7	2015	95.49	0.17
8	2016	96.42	1.06
9	2017	93.88	1.02
10	2018	88.38	1.65
11	**09-18' Avg**	**88.88**	**2.02**

SCE's Hydro assets have served its customers for over one-hundred years by providing reliable and cost effective (and essentially greenhouse gas emissions free) power. SCE expects the majority of the Hydro assets (*i.e.,* as measured by rated MW output) to continue to be cost effective for many decades into the future.

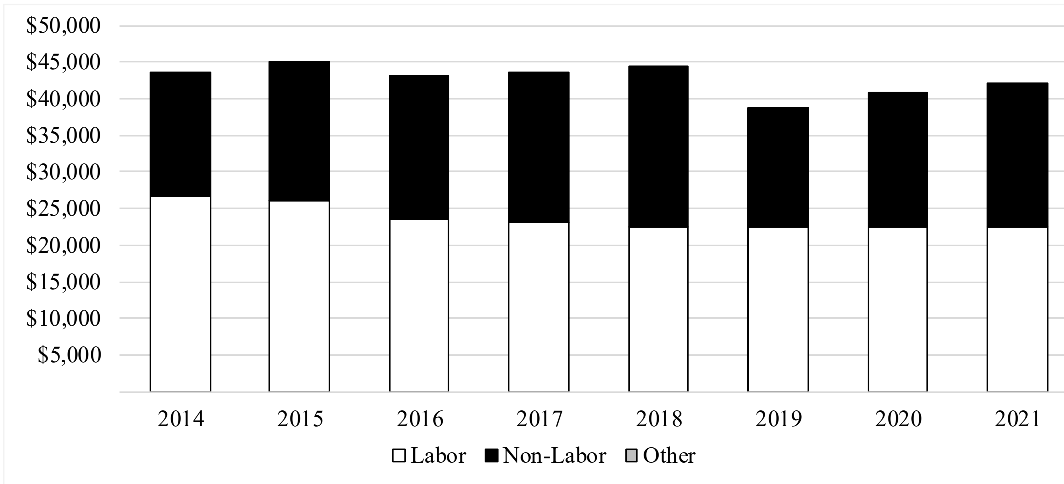
B. Hydro O&M Expense Forecast

1. Introduction

This section presents our 2021 Test Year O&M expense forecast, including the analysis of recorded costs and business reasons underlying the forecast. The expenses include costs for operating and maintaining SCE's Hydro generating units and associated reservoirs, dams, waterways, and miscellaneous Hydro facilities. Work activities are presented in 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 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 (2014–2018) and our forecast for years 2019–2021. Based on our analysis of labor and non-labor, the 2021 Test Year O&M expense forecast is $42.028 million, as shown in Figure II-3 below.

Figure II-3
Hydro - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	$26,662	$26,169	$23,576	$23,072	$22,486	$22,485	$22,485	$22,486
Non-Labor	$16,839	$18,991	$19,582	$20,440	$21,862	$16,155	$18,396	$19,543
Other	-							
Total Expenses	**$43,501**	**$45,160**	**$43,158**	**$43,512**	**$44,347**	**$38,641**	**$40,881**	**$42,028**
Ratio of Labor to Total	61%	58%	55%	53%	51%	58%	55%	54%

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

Our 2021 Test Year forecast for the Hydro BPE is $42.028 million, including $22.486 million labor expense and $19.543 million non-labor expense.[53]

a) <u>Labor - Analysis of Recorded and Forecast Expenses</u>

In 2016, the Generation Department initiated several process improvements to increase productivity and reduce labor expenses.[54] These efficiency improvements resulted in an approximate $2.6 million dollar reduction in Hydro labor costs between 2015 and 2016. Since 2016 Hydro labor expenses have remained relatively stable (*i.e.,* less than 5 percent variance). Assuming

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[53] Refer to WP SCE-05, Vol. 1, Book A, p. 6.

[54] These process efficiency improvements were presented in greater detail in SCE's 2018 GRC Application – SCE-05 Volume 3.

current workload remains constant, SCE expects Hydro labor expenses for the 2021 Test Year to be similar to those recorded in 2018. Therefore, SCE used the last recorded year as our basis for estimating 2021 Test Year labor expenses, yielding a labor Test Year forecast of $22.486 million.[55]

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

In 2014 and 2015, California received historically low precipitation (approximately 30% of normal), lowering the water available for generation.[56] Recorded non-labor costs during this time were commensurately low as less total generation resulted in less maintenance and lower FERC fees compared to high precipitation years experienced in 2012 and 2018. The increase in non-labor costs observed since 2014 is attributable to an increased level of required annual maintenance and breakdown repairs performed at powerhouses and other ancillary Hydro infrastructure such as flumes, flowlines, penstocks, camps, trails, and other support facilities.

While non-labor expenses from 2014 through 2018 indicate a steady upward trend, the 2018 base year could potentially be more than required to support non-labor activities during the 2021 Test Year. Therefore, a five-year average (*i.e.,* the average annual expense of 2014 through 2018) best reflects historical and future non-labor expenses, yielding a non-labor Test Year 2021 forecast of $19.543 million.[57]

3. Hydro O&M 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 the U.S. Army Corps of Engineers that are transferred to FERC. The fees are paid for the benefit of having a reservoir upstream of our facilities maintained by the U.S. Army Corps of Engineers, resulting in additional Hydro generation.[58] SCE pays HBF for the Kern River 1 and Borel powerhouses.[59]

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[55] Refer to WP SCE-05, Vol. 1, Book A, p. 8.

[56] The 2015 calendar year was California's driest year on record, surpassing the previous record set in 2014 (based on records dating to the 1800's).

[57] Refer to WP SCE-05, Vol. 1, Book A, p. 8.

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

Additionally, SCE collects HBF from Pacific Gas & Electric Company (PG&E) for water used at the Kerckhoff Power plant which is supplied from dams maintained by SCE. 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.[60]

(2) Cloud Seeding Expenses

Cloud seeding adds artificial condensation particles (such as dry ice and silver iodide) to clouds to create more precipitation than would occur under normal circumstances. The increased rain and snowfall yield increased generation at Big Creek. SCE pays a fee to a contractor to administer this program. The third-party contract labor expenses (*i.e.,* those paid to vendors performing work to administer the program) for cloud seeding are recorded as non-labor expenses.

(3) FERC Administrative Fees

SCE pays FERC administrative fees (Hydropower Annual Charges) as a reimbursement to the United States government for the cost of administering Part 1 of the Federal Power Act.[61] FERC calculates fees using an equation that includes our prior year Hydro generation output (*i.e.,* 2018 fees are based on 2017 recorded generation), Hydro capacity, the national Hydroelectric generation output, and FERC expenses. These fees vary annually depending upon the level of FERC expenses and the amount of Hydro generation output nationally and at our facilities. FERC administration fees represent approximately 65 percent of the Hydro Water for Power Plant expense. Annual precipitation is the primary factor in the amount of Hydro generation in a given year and also causes Hydro FERC fees to vary from year-to-year, because the Hydro FERC fees are based upon on the generation output.

Continued from the previous page

[59] Borel Powerhouse utilizes water received from Isabella Reservoir to generate power. The Isabella Reservoir is subject to storage level restrictions currently in place for dam structure seismic risk mitigation. These restrictions, combined with the 2012-2016 drought and other factors, resulted in Lake Isabella storage levels being insufficient to provide water flow to the 12 MW Borel Powerhouse primary intake structure, resulting in zero generation from June 2013 through May 2016. In May 2016, although still significantly restricted due to seismic concerns, Isabella Reservoir water levels became sufficient to return the Borel powerhouse water conveyance to service (*i.e.,* this conveyance routes water from Isabella reservoir to the powerhouse). However, because the Army Corps of Engineers (ACE) are upgrading the Lake Isabella Dam to address seismic issues, the Borel powerhouse continues to remain out of service and pending on-going negotiations with the ACE will likely be decommissioned.

[60] Refer to SCE-02, Vol. 7 - Other Costs and OOR.

[61] *See* 18 C.F.R. § 11.1.

(4) California State Water Resources Control Board (SWRCB) Fees

SCE pays three categories of fees to the SWRCB: (1) Water Rights License fees, (2) Water Rights Permit fees, and (3) Water Quality Certification fees.[62] Under the federal Clean Water Act (CWA) and California's Porter-Cologne Water Quality Control Act, the State 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. These fees are utilized by the SWRCB to ensure abundant clean water for human uses and environmental protection to sustain California's future.

(5) 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.

(6) U.S. Geological Survey (USGS) Fees

The USGS requires that SCE pay yearly 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.

(7) Hydro Rent Expenses

SCE pays FERC for SCE's use of federal lands upon which the majority of our Hydro facilities are located. The fee calculations are based on a per acre appraisal.

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[62] Fees are calculated per the SWRCB Fee schedule which can be found at: www.waterboards.ca.gov/waterrights/water_issues/programs/fees.

(8) **Kaweah 3 Special Use Permit**

SCE pays a Special Use Permit (SUP) to the National Park Service (NPS) for SCE's operation of a diversion dam and flowline for Kaweah 3 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 and (2) Big Creek 3, overseeing the Lower Canyon facilities. The following locations each have a manager of O&M activities: (1) Kern River 3, overseeing the Kern River facilities; (2) Kaweah 1, overseeing the Kaweah and Tule facilities; and (3) Bishop Creek 4, overseeing the Bishop Creek and Mono Basin facilities and the distribution and transmission substation facilities associated with the Bishop/Mono Basin Region. The following locations each have a chief operator: (1) Kern River 3, and (2) Bishop/Mono Basin. A production supervisor at the Bishop Control substation also assists in overseeing operations activities, and dispatching.[63]

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

(2) **Dispatching**

Dispatching work includes directing all O&M 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 substation contains all primary supervisory control equipment for the Bishop Creek, Mono Basin, and Kern River facilities. The Los Angeles Basin (East End) Hydro and Kaweah facilities have alarms that notify the Bishop Control substation of unusual events through a dial-up system when not manned. This 24-hour surveillance of the operating equipment from a central point helps maintain system integrity and operational effectiveness. The Bishop Control

[63] 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.

substation also directs all activities involving circuit switching of distribution and transmission for these powerhouses. Remote monitoring of the Los Angeles Basin units is also performed from the Eastern Operations Generation Control Center in Redlands, California (on the site of Mountainview Generating Station).

(3) <u>Operations Engineering</u>

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 reservoir facilities. The report is completed by independent consultants, supervised by SCE in-house engineering, and is reviewed by DSOD.[64] 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.

(4) <u>Home Office Operations Supervision and Engineering</u>

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) <u>Operation of Reservoirs, Dams, and Waterways</u>

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) <u>Hydrography</u>

Hydrography expenses include: (1) maintaining water rights; (2) complying with water rights and water-related FERC license requirements; (3) managing and staffing of

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[64] *See* 18 C.F.R. §§ 12.30-12.39 (2013).

stream and reservoir gauging stations; (4) managing and staffing meteorological stations; (5) collecting and analyzing snow survey data; (6) forecasting water supply from snow survey data; and (7) administrating SCE's cloud seeding program. 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 personnel and the administrative support staff at field offices.

(9) License/Environmental Support

This activity includes expenditures to support FERC licenses, other regulatory licenses, and environmental activities. Due to cutbacks and reduced staffing at various regulatory agencies, SCE has found it necessary to provide funds for the agencies' review of plans, projects, or proposals to facilitate timely review. An example of this is SCE providing funds to State Historic Preservation Office (SHPO) for that office to hire an additional person to review our plans. The alternative is to wait an undetermined period of time for review and risk violating timeline requirements set by FERC for project completion dates.

(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 includes payroll, automotive, and other 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 systems, supplies and maintenance, some of the expense for 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,[65] and costs for condition analysis, engineering recommendations, and mandated reports.[66] 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

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[65] 23 CA ADC T. 23, and 18 C.F.R. Part 12.

[66] *Id.*

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.

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 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 shut off 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 and work equipment, and production roads, trails, and bridges. 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, costs to maintain and clear all production roads, bridges, trails, aerial tramways, inclines, and penstock tramways, including costs for snow removal, costs for repairing property and equipment damaged by flood or storms. 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 2019-2023 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 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 renew the FERC licenses for many of our facilities. Infrastructure work includes projects such as dam improvements needed to address areas of concern (*e.g.,* safety and performance), flowline refurbishment, and substation refurbishment. Equipment replacement work includes projects such as transformers, automation, switchgear, turbine overhauls, and generator rewinds.

The Investment Decision Process (IDP) 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.[67] 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 be performed. 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 million have been provided in workpapers, which are referenced in the following sections of testimony.

[67] Generation Department Order Gen A-05 - Generation Project Approval Process.

2. Hydro Capital Project Categories

As shown in Table II-14, each Hydro capital project is placed (based on the work being performed) into one of six categories: (1) Relicensing, (2) Dams and Waterways, (3) Prime Movers, (4) Structures and Grounds, (5) Electrical Equipment, and (6) Decommissioning.

Table II-14
SCE Hydro Capital Project Categories for 2019-2023
(Nominal $000)

Line No.	Project Description	2019	2020	2021	2022	2023	TOTAL
1	Hydro - Relicensing	6,230	15,695	14,951	18,580	24,179	79,635
2	Hydro - Dams & Waterways	12,156	10,575	12,292	14,100	13,150	62,273
3	Hydro - Prime Movers	10,470	7,460	9,770	9,550	12,700	49,950
4	Hydro - Structures & Grounds	8,666	2,850	3,128	5,710	5,700	26,054
5	Hydro - Electrical Equipment	6,470	1,850	3,450	6,000	1,000	18,770
6	Hydro - Decommissioning	650	2,250	2,250	1,145	270	6,565
7	**Grand Total**	**44,642**	**40,680**	**45,841**	**55,085**	**56,999**	**243,247**

The first category of capital expenditures is Hydro Relicensing. This category will require $79.635 million in 2019-2023 and will include implementing:

- License order terms and conditions
- Resource management plans and license articles
- Dam spillway or instream water release improvements
- Campground infrastructure refurbishment and replacements

The second category of capital expenditures is for Dams & Waterway projects. This category will require $62.273 million in 2019-2023 and will include:

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

The third category of capital expenditure is Prime Movers. This category will require $49.950 million in 2019-2023 and will include:

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

The fourth category of capital expenditure is Structures and Grounds projects. This category will require $26.054 million in 2019-2023 and will include:

- High pressure piping replacements

- Road improvements and repairs

The fifth category of capital expenditure is Electrical Equipment. This category will require $18.770 million in 2019-2023 and will include:

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

The sixth category of capital expenditure is the Decommissioning of the San Gorgonio and Pedley powerhouses, which accounts for the remaining $6.565 million balance of the Capital forecast.

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 2019 and 2023.

3. Hydro Relicensing

This section describes the requirements of FERC relicensing and new license implementation projects, including Minimum Instream Flow Upgrades and Campground Infrastructure Refurbishments/Replacements. In connection with these relicensing efforts, SCE will also be required to implement resource management plans to protect sensitive environmental and cultural resources.

SCE completes a five-year capital forecast for FERC relicensing and updates this forecast annually. Our total Hydro Relicensing expenditure forecast is $79.635 million for 2019-2023.[68] Table II-15 lists the programs and projects within the FERC relicensing category.

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[68] Refer to WP SCE-05, Vol. 1, Book A, pp. 16-30.

Table II-15
SCE Hydro FERC Relicensing Programs and Projects
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
1	Relicensing: Big Creek ALP	-	4,650	2,176	835	599	8,260
2	Relicensing: Big Creek 1	75	30	335	60	10	510
3	Relicensing: Big Creek 2	75	30	335	60	10	510
4	Relicensing: Big Creek 2A	70	25	75	100	10	280
5	Relicensing: Big Creek 3	75	30	175	15	20	315
6	Relicensing: Big Creek 4	350	-	-	-	-	350
7	Relicensing: Big Creek 8	70	25	75	100	10	280
8	Relicensing: Bishop Creek	750	1,800	1,000	750	250	4,550
9	Relicensing: Eastwood	70	25	75	100	10	280
10	Relicensing: Kaweah	1,800	500	500	150	250	3,200
11	Relicensing: Kern River 1	-	-	50	550	1,000	1,600
12	Relicensing: Kern River 3	250	750	1,000	1,000	1,000	4,000
13	Relicensing: Lee Vining	50	500	500	1,000	1,000	3,050
14	Relicensing: Lundy	-	-	-	50	550	600
15	Relicensing: Mammoth Pool	75	30	285	70	30	490
16	Relicensing: Portal	70	25	145	25	100	365
17	Relicensing: Rush Creek	500	1,000	1,500	2,000	2,000	7,000
18	Relicensing: Vermilion	70	25	170	10	-	275
19-28	Campground Infrastructure Refurb./Replace	1,830	3,750	1,795	5,220	9,650	22,245
29-42	Infrastructure Refurb./Modifications	50	2,500	4,760	6,485	7,680	21,475
	TOTAL	**6,230**	**15,695**	**14,951**	**18,580**	**24,179**	**79,635**

a) Hydro Relicensing Expenditure Forecast

SCE's expenditure forecast for implementing new FERC license orders is modeled on experience gained from the Big Creek 4 Project in 2003. The Big Creek 4 license is the most recent licensed project in the Big Creek System and many of the activities completed to support implementing the license have been carried forward into the Big Creek Alternative Licensing Process (ALP), Vermilion Valley, and Portal projects (collectively referred to as the "Big Creek projects"). The new FERC license orders for the Big Creek projects requires developing resource agency approved management and protection plans; implementing adaptive management environmental resource studies over the term of the license; and preparing license compliance tools and data management databases.

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.

Thirty of SCE Hydro's thirty-five powerhouses are subject to federal regulations requiring FERC licenses to operate. Twenty FERC licenses govern operation of the thirty powerhouses. The thirty powerhouses account for approximately 1,171 MW of our total Hydro nameplate capacity of 1,176 MW. The FERC licenses include requirements (terms and conditions) that SCE must meet when operating these projects. These requirements typically include providing minimum stream flows and maintaining reservoir levels, conducting periodic assessments of our operations impact on environmental and cultural resources, implementing management plans to protect environmental and cultural resources potentially affected by operation of the projects, constructing and maintaining nearby recreational facilities, and submitting periodic reports. In addition, the 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 hydropower Projects. The licenses also include requirements for dam safety by conducting dam safety investigations on a reoccurring five year cycle in accordance with Part 12 requirements.

FERC grants each license for a defined period and SCE must renew the license upon expiration to continue project operation. SCE's original licenses were for a 50-year term, and the default license term is 40-years for new licenses issued by FERC. The FERC relicensing process typically takes between five and five and one-half years to complete. However, relicensing the Big Creek Projects has taken an additional ten years while SCE and FERC awaited the issuance of a water quality certification from the State of California Water Resources Control Board.

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 and that includes terms and conditions that will protect these resource from continued project operations during the term of the License order. The new licenses, when issued, typically include license conditions imposing mitigation costs and restrictions on our operations that are greater than those required by the previous license. The mitigation costs may include a reduction in our electrical generation output because of requirements to increase instream flow release 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 period. 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 eight FERC licenses it holds. Six are for Big Creek projects that account for approximately 915 MW of nameplate capacity, or approximately 77.8 percent of SCE's total Hydro capacity of 1,176 MW, the remaining two projects are the Kaweah Project (8.9 MW nameplate capacity), and the Bishop Creek Project (29.3 MW nameplate capacity). SCE has also received six renewed FERC licenses since 2000. Five require continued capital expenditures for studies or mitigation costs as a license condition. Combined, the eight licenses in process of relicensing, and the six previously renewed licenses, will require capital expenditures of $79.635 million during 2019-2023.

Table II-16 summarizes the relicensing status for each of our generating facilities. A discussion of the FERC relicensing process and SCE's relicensing cost estimate follows Table II-16. We then address each FERC relicensing action requiring capital expenditures during 2019-2023.

Table II-16
SCE Hydro FERC Licenses

Line	FERC PROJECT		License		Nameplate
No.	Name	Number	Expiration	Notes	Capacity (MW)
1	**Northern Hydro Region**				
2	Big Creek No. 1 & 2	2175	2/28/2009	(c)(d)(e)	154.9
3	Big Creek No. 2A, 8 & John				
4	S. Eastwood	67	2/28/2009	(c)(d)(e)	384.8
5	Big Creek No. 3	120	2/28/2009	(c)(d)(e)	174.5
6	Big Creek No. 4	2017	11/30/2039		100.0
7	Portal	2174	3/31/2005	(c)(e)	10.8
8	Mammoth Pool	2085	11/30/2007	(c)(d)(e)	190.0
9	Vermilion Valley	2086	8/31/2003	(b)(c)(e)	-
10			Sub-Total Northern Region		1014.9
11	**Eastern Hydro Region**				
12	Kern River No. 1	1930	5/31/2028		26.3
13	Kern River No. 3	2290	11/30/2026		40.2
14	Borel	382	5/17/2046	(f)	12.0
15	Lytle Creek	1932	5/31/2033		0.5
16	Santa Ana River No. 1 & 3	1933	6/30/2033		6.3
17	Mill Creek No. 3	1934	6/30/2033		3.0
18	San Gorgonio No. 1 & 2	344	4/26/2003	(a)	-
19	Bishop Creek 2, 3, 4, 5 & 6	1394	6/30/2024	(h)	29.3
20	Lee Vining Creek (Poole)	1388	1/31/2027		11.3
21	Rush Creek	1389	1/31/2027		13.0
22	Mill Creek (Lundy)	1390	2/28/2029		3.0
23	Kaweah No's. 1, 2 & 3	298	12/31/2021	(g)	8.9
24	Lower Tule River	372	7/31/2033		2.5
25			Sub-Total Eastern Region		156.2
26	Total FERC Licensed Plants				1171.0
27	Capacity of Hydro Plants without FERC Licenses				5.2
28	Total Hydro Capacity				1176.4

Notes:

a) Inoperable, planned for decommissioning and will not be relicensed

b) Storage only

c) Application for new license filed with the FERC

d) Will be relicensed under the Alternative Licensing Process

e) Operating under an annually renewable license pending issuance of new term license

f) U.S. Army Corps has initiated condemnation of a portion of the water conveyance canal, which has made the project inoperable (FERC requires surrender/removal of

g) Application for new license will be filed with the FERC in 2019

h) Pre-application document for relicensing will be filed with the FERC in May 2019

(1) <u>FERC Relicensing Process</u>

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 when the licensee applies 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. The Kaweah and Bishop Creek projects are in the pre-application licensing phase.

Once FERC has determined that the application meets filing requirements, the studies have been completed, any deficiencies have been resolved, and no additional information is required (*i.e.,* concludes the pre-application process), FERC 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 National Environmental Protection Act (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. FERC has completed the relicensing process steps for all six Big Creek projects, except for issuing a new license 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. All six Big Creek projects still undergoing the relicensing process are operating under annual license renewals.

FERC regulations governing the relicensing of an existing hydroelectric project allow the licensee to use the ALP, traditional licensing process (TLP), or the integrated licensing process (ILP) to prepare, file, and process a new license application.[69] In the Big Creek System, SCE is using both the TLP and the ALP to relicense six FERC licensed projects. The two projects being relicensed using the TLP are the Vermilion Valley Hydroelectric Project (FERC No. 2086) and the Portal Hydroelectric Project (FERC No. 2174). The four FERC projects being relicensed using the ALP are the Mammoth Pool Project (FERC No. 2085); Big Creek 1 and 2 Project (FERC No. 2175); Big Creek 2A, 8 and Eastwood Project (FERC No. 67); and Big Creek 3 Project (FERC No. 120). The Kaweah and Bishop Creek projects are being relicensed using the FERC ILP.

(a) Alternative Licensing Process (ALP)

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.

(b) Traditional Licensing Process (TLP)

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 the 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. The FERC conducts an independent environmental review of the project, and resource agencies, Native American tribes, the public, and the applicant can provide comments. The FERC will issue a new license order with terms and conditions based on the

[69] In July 2003, FERC added a third relicensing process called the Integrated Licensing Process; however, this was not available in time for any of the Big Creek relicensing projects discussed herein. The ILP is the default licensing that is used by FERC. An applicant must request permission from FERC to use either the TLP or ALP.

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.

(c) Integrated Licensing Process (ILP)

The ILP is the default relicensing process used by FERC and was approved through FERC 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. At that time a licensee simultaneously files with FERC a NOI to relicense the project and a Pre-Application Document (PAD). The NOI is a formal announcement to FERC of an applicant's intent to apply for a new license and the PAD is a detailed collection of information about the project. A timeline is initiated once the NOI and PAD are filed. 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 study plan review process includes a dispute resolution process that allows FERC to form an independent panel to review the notice of study dispute and deliver its recommendations to FERC 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. Subsequent to filing the license application, FERC will complete NEPA by conducting their independent analysis, preparing a final Environmental Impact Statement (EIS), and ultimately issue a new license.

(2) Big Creek ALP Relicensing Projects

(a) Background

Six of Big Creek's seven FERC project licenses are undergoing relicensing activity as mentioned above. The Big Creek 4 Project (FERC No. 2017) has already completed its relicensing process and received a new FERC license in December 2003. 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 within a single process. The Vermilion Valley and Portal projects were not incorporated into the ALP because earlier FERC License expiration dates required that their licensing process begin sooner than the initiation of the ALP.

The Big Creek ALP began in May 2000 after receiving FERC approval to use the process. On October 30, 2002, SCE filed its NOIs to apply for the Mammoth Pool Project and on February 27, 2004, SCE filed its NOI to file applications for the three remaining Big Creek ALP projects. FERC is processing all four projects simultaneously in a single ALP. By combining these four relicensing projects into a single ALP, SCE expects the development of more comprehensive license conditions that are focused on a watershed protection approach with reduced costs for the implementation of license conditions.

During implementation of the ALP, SCE: (1) developed, implemented and evaluated the results of technical resource studies designed to access the effects of project operations on environmental and cultural resources; (2) prepared the license applications and a preliminary draft environmental assessment (PDEA); and (3) negotiated a comprehensive settlement agreement with stakeholders that included the proposed terms and conditions for the projects over the terms of the new license orders filed with the applications for new license. The Settlement Agreement was signed by twenty-one signatories including the California Department of Fish and Game (CDFG), the U.S. Department of Agriculture-Forest Service (USDA-FS), the Fish and Wildlife Service (FWS), and the Friant Water Authority and included the support of the California State Water Resources Control Board (State Water Board). SCE anticipates that FERC will model the new license requirements on the Settlement Agreement without significant additional requirements.

Since filing the license application for the ALP projects, FERC has completed the NEPA process, issuing a final environmental impact statement (FEIS) on March 13, 2009. FERC also has completed the relicensing process and is waiting for the State Water Board to issue a Water Quality Certification (WQC) for the projects under the Clean Water Act before it can issue a new license order. The existing licenses for the Big Creek ALP Projects have expired and FERC has issued Notice of Authorization(s) for Continued Project Operation, which allows the projects to operate on annual renewals until new license orders are issued.

(b) **Delay of License Issuance**

While the FERC completed their process to comply with the NEPA requirements for issuing the six Big Creek project licenses, the new license orders have been delayed because the State Water Board failed to issue a timely Water Quality Certificate (WQC).[70]

The State Water Board's intent was to issue a single WQC for all six projects. However, before the State Water Board can issue a WQC it is required to evaluate the projects under the California Environmental Quality Act (CEQA) which required preparation of a supplemental document to FERC's EIS addressing additional environmental analysis as required by CEQA.

At the request of the State Water Board, SCE prepared a draft supplemental document on November 9, 2011, addressing the additional CEQA environmental analysis. The State Water Board issued its draft WQC and the CEQA Supplemental Document on August 13, 2018, that contained additional terms and conditions inconsistent with the original negotiated 2007 relicensing Settlement Agreement. On November 16, 2018 the State Water Board issued notification to SCE that the request for WQC had been denied without prejudice and that SCE would need to submit a new WQC request before the State Water Board can issue certification for the Big Creek Projects. To date SCE has not submitted a follow up request to the State Water Board for a WQC. However, on May 31, 2019, the State Water Board moved forward with issuing a WQC for the Big Creek Projects, prior to consulting with SCE and FERC. SCE is currently awaiting a decision from FERC regarding the validity of the State Water Board WQC notification and if the SWB, due to the untimely issuance of the WQC, has waived its authority to issue a WQC.

(c) **Implementation of New License Order Terms and Conditions**

The total 2019-2023 capital expenditure forecast for the Big Creek ALP is $10.925 million (Ref. 1-5, 7, 9, and 15).[71] The Big Creek ALP activities can be divided into three main categories: (1) preparing for license issuance; (2) permitting and planning activities associated with implementing new license terms; and (3) implementation of the new license requirements.

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[70] FERC must comply with the Federal Water Quality Act, which requires the issuance of a WQC. The State Water Board is the lead agency responsible for issuance of the WQC.

[71] "Ref" for projects listed in this testimony refers to corresponding references on related Tables.

Issuing the new licenses for the six Big Creek Projects is expected to occur in mid to late 2020. Prior to license issuance, a WQC must be issued by the State Water Board. To prepare for the new license, several tools are being developed to track and comply with the new license order(s). These tools include license implementation tracking tools and an environmental compliance database (ECD). The license implementation tracking tools include developing management tools, which comprise resource management plan summaries, reporting and consultation requirements, decision records, flow charts to track and monitor activities, and a project timeline and calendar. The ECD is a GIS based tool that identifies biological and cultural resources and associated PM&E measures associated with the operation and maintenance of the Big Creek ALP Projects.

The major relicensing costs for the six Big Creek Projects relate to implementing the new license order terms and conditions which include the resource management plans and license articles outlined in the Settlement Agreement. 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 in order to mitigate project impacts identified in studies and enhance habitat conditions for aquatic life. The following describes the activities SCE will be required to complete, including some of the associated monitoring or 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.[72] 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

[72] 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.

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.

Four back-country hydropower diversions and two domestic water diversions are to be decommissioned and the natural flows returned to the channel. All six diversions are proposed for removal within five years following license issuance. To complete the decommissioning at each location, applicable permits will be obtained and supporting documentation will be prepared in consultation with resource agencies.

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 temperature targets are met. Installation and ongoing maintenance or calibration of the stream temperature recorders will occur throughout the monitoring period.

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.

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 of sediment. 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 draft permit applications for the CDFG 1600 Streambed Alteration Agreement and an Army Corp of Engineers (ACOE) Section 404 permit will be obtained prior to implementation of the sediment management prescriptions.

Baseline studies to establish fine sediment in pools will also be conducted prior to implementing sediment management prescriptions. During the implementation, SCE will monitor water quality and fine sediment conditions associated with the sediment pass through prescription.

Instream flow release improvements include installation, modification, and maintenance of flow monitoring equipment and/or release structures at twenty-one stream gaging stations. At locations where infrastructure changes are proposed to comply with the new instream flow release requirements, preliminary engineering designs, permitting, and construction will occur.

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.

(ii) <u>Terrestrial Resources Measures</u>

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, Valley Elderberry Longhorn Beetle Plan, and Vegetation and Integrated Pest Management Plan. The following activities will be conducted as required by the plans: (1) wintering and nesting surveys to monitor the status of bald eagles near the Big Creek projects; (2) monitoring of the Valley Elderberry Longhorn Beetle (VELB) mitigation site; (3) monitoring of special status plant species and Native American plant populations; (4) treating and monitoring of noxious weed populations; and (5) training employees on various resource conservation topics.

(iii) <u>Land Management</u>

SCE will implement resource management plans for visual and transportation resources. The visual resource plan will be implemented to address visual effects of project facilities on the surrounding landscapes and view shed (*i.e.,* the geographical area visible from a location) in the USDA-FS. Several project facilities affecting visual resources will be repainted during their normal painting schedule with natural colors that blend in with the surrounding environments and are approved by the USDA-FS.

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. SCE will coordinate with the USDA-FS to conduct initial road condition surveys of SCE maintained 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 also will establish a transportation signage fund in coordination with the USDA-FS. This fund will allow the USDA-FS to purchase, repair, and maintain road and recreation use signs throughout the Big Creek project area.

(iv) <u>Cultural Resources</u>

- 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; (7) nominating the Big Creek Hydroelectric System Historic District to the National Register; and (8) 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.
- Fulfilling financial obligations as outlined in the Non-FERC Settlement Agreement, including: (1) designating 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; and (5) providing training to SCE employees regarding environmental and cultural awareness.

(v) <u>Recreational Resources</u>

SCE will be required to maintain and enhance recreational resources by operating and maintaining recreation facilities and through the rehabilitation, replacement, and improvement of recreation facilities near the ALP Projects.

From 2019-2023, 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. Under the terms of the Settlement Agreement, SCE initiated the recreation facility major rehabilitation program upon the signing of the ALP Settlement Agreement. To date, SCE has completed the rehabilitation of two large campgrounds, two small campgrounds, three day-use areas, and an accessible fishing platform.

When the license is issued, three new recreation facility capital improvements (day use area, accessible boat landing facility, and as accessible fishing platform) will be planned, designed and constructed with the major rehabilitation activities described above. Several interpretative display exhibits (kiosks) will also be included with the major rehabilitation activities. SCE will support fish stocking in project reservoirs and bypass stream reaches below project diversions to enhance recreational fishing opportunities. Whitewater flow releases will be provided downstream of various diversions and dams in Wet and Above Normal Water Years to enhance other recreational opportunities. SCE will enhance recreation opportunities in the vicinity of the projects by funding the USDA-FS to: (1) repair and maintain recreational facilities around the project area; (2) rehabilitate recreational facilities; and (3) support interpretive programs.

SCE will also fulfill financial obligations as outlined in the Non-FERC Settlement Agreement to other non-governmental groups.[73] Examples include the Huntington Lake Association, Huntington Lake Big Creek Historical Conservancy, and the Shaver Crossing Railroad Station Group.

(3) Bishop Creek Relicensing

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 pre-application document (PAD). In May 2019 SCE filed the NOI and PAD which initiated the formal FERC ILP for the Bishop Creek Project. The PAD identified fifteen technical resource studies that will be implemented to evaluate the environmental and cultural resources that could be potential affected by the continued operation of the Project. These studies will be conducted over two field seasons during 2020 and 2021 and may extend into a third field season in 2023 if needed.

The information obtained from the technical resource studies will be evaluated to determine if project operations may have a potential effect on sensitive resources. New license terms and conditions will be developed and included in the license application as proposed measures to address potential resource issues that are identified. SCE will prepare the DLA for submittal to FERC in early 2022. Resource agencies and stakeholders will review and provide comments to the DLA, which will be addressed by SCE in the Final License Application that will be filed with FERC in mid- 2020 (no later than two years prior to license expiration on June 30, 2024). The capital forecast for Bishop Creek relicensing efforts is $4.550 million for 2019-2023. (Ref. 8)

(4) Kaweah Relicensing

SCE initiated relicensing of the 8.9 MW Kaweah Project in February 2017 with filing its NOI for a new license. SCE will be filing the DLA in August 2019 and filing the final license application (FLA) in December 2019. After the filing of the FLA the project will enter the post application filing phase of the relicensing. During this phase FERC will determine if the application meets filing requirements and may issue an additional information request that would require SCE to

[73] An agreement to perform defined requirements entered into with non-governmental agencies.

prepare and provide supplemental information to the license application. During this phase SCE will complete the fish entrainment study (field work, data analysis, reporting and impact evaluation) which could not be completed during the pre-application phase, and begin preparing for license issuance by conducting training on new license requirements and developing compliance tools that will schedule and document the completion of license requirements. The capital forecast for Kaweah relicensing efforts is $3.2 million for 2019-2023. (Ref. 10)

(5) Kern River 3 Relicensing

SCE will initiate relicensing of the 40.2 MW Kern River 3 Project in late 2019 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 2021. SCE anticipates obtaining a study plan determination from FERC in early to mid-2022 and to be implementing the approved technical resource studies over two field seasons in 2022 and 2023. The capital forecast for Kern River 3 Project relicensing efforts is $4.0 million for 2019-2023. (Ref. 12)

(6) Lee Vining Creek Relicensing

SCE will initiate relicensing of the 11.3 MW Lee Vining Creek Project in late 2019 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 2021. SCE anticipates obtaining a study plan determination from FERC in early to mid-2022 and to be implementing the approved technical resource studies over two field seasons in 2022 and 2023. The capital forecast for Lee Vining Creek Project relicensing efforts is $3.05 million for 2019-2023. (Ref. 13)

(7) Rush Creek Relicensing

SCE will initiate relicensing of the 13.0 MW Rush Creek Project in late 2019 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 has 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. 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.*, upper portion 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.

SCE will begin the formal FERC relicensing process by filing the NOI and PAD in late 2021. SCE anticipates obtaining a study plan determination from FERC in mid-2022 and to be implementing the approved technical resource studies over two field seasons in 2022 and 2023, and into a third field season in 2024 if needed. The capital forecast for Rush Creek Project relicensing efforts is $7.0 million for 2019-2023. (Ref. 17)

(8) Campground Infrastructure Refurbishment and Replacement

Under the new FERC license order and per the Big Creek ALP Settlement Agreement, SCE will be required to refurbish and rehabilitate twenty-nine U.S. Forest Service developed recreation facilities (campground, day-use areas, and boat ramps) that are associated (indirectly) to SCE's Big Creek hydroelectric project based on their location near or adjacent to project reservoirs. During 2019-2023, SCE plans to refurbish and reconstruct the following recreation facilities: (1) Jackass Meadows Campground and Fish Platform; (2) Mammoth Pool Campground and Boat Launch; (3) Eastwood Day-use Visitors Center at Huntington Lake; (4) Portal Campground at Portal Forebay; and (5) Vermilion Campground at Lake Thomas A. Edison.

(a) Background

Refurbishing and reconstructing U.S. Forest Service campgrounds and any supporting roads and ancillary structures is part of the recreation management plan included in the Big Creek Settlement Agreement. Although SCE has not yet received the ALP license, SCE agreed to rehabilitate the recreation facilities upon signing the 2007 relicensing Settlement Agreement. The FERC Relicensing - Campground Infrastructure Refurbishment and Replacement capital expenditure forecast is $22.245 million for 2019-2023.[74] Table II-17 below, lists the projects within the FERC Relicensing - Campground Infrastructure Refurbishment and Replacement program category.

Table II-17
Hydro Relicensing – Campground Infrastructure Refurbishment and Replacement Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
19	Jackass Meadow - Campground & Fish Platform	500	3,500	1,000	-	-	5,000
20	Windy Point - Recreation Complex Refurb	100	100	100	2,320	1,650	4,270
21	Mammoth Pool - Boat Launch & Campground	-	-	-	2,000	2,000	4,000
22	Big Creek 1 & 2 - Dam 3 Day Use Area	-	50	45	200	3,000	3,295
23	Huntington Lake - Boat Loading Station Refurb	-	100	500	500	1,000	2,100
24	Vermilion - Campground Refurbishment	-	-	-	100	1,000	1,100
25	Portal - Campground & Campsites Refurb	-	-	-	100	1,000	1,100
26	Eastwood - Visitors Center and Parking Area Refurb	1,080	-	-	-	-	1,080
27	Big Creek 3 - Parking Area & Stairway/Angler Access	150	-	-	-	-	150
28	Kern River 3 - Fish Hatchery Valve Replacement	-	-	150	-	-	150
	TOTAL	**1,830**	**3,750**	**1,795**	**5,220**	**9,650**	**22,245**

(b) <u>Project Scope</u>

The projects within this category are similar in that SCE will perform all required refurbishing and reconstruction activities, including engaging personnel, providing equipment and materials, and providing project management. SCE will renovate recreation features existing at the recreation facilities. The recreation facility refurbishment projects will be designed and constructed under U.S. Forest Service specifications and standards, including their outdoor recreation accessibility guidelines and the forest service trails accessibility guidelines. The renovated recreational facilities will strive to meet ADA requirements regarding accessibility at campgrounds, depending upon topography, vegetation, cultural and archaeological resources, feasibility and practicality, preserving the primitive character of campgrounds, and applicable design and construction standards. (Ref. 19-28)

[74] Refer to WP SCE-05, Vol. 1, Book A, pp. 19-24.

(c) Project Justification and Benefit

SCE is required under the current license and Big Creek Settlement Agreement to maintain and/or rehabilitate recreation facilities. Performance of these projects (and others that have already completed) prior to finalizing the license renewal process allows SCE to avoid additional and increased maintenance costs otherwise incurred pending the delayed issuance of the new FERC license orders.

(9) Big Creek Hydro Relicensing – Infrastructure Modifications

(a) Background

New instream flow requirements under the new FERC license orders, when issued, will require SCE to make infrastructure modifications at fourteen impoundments (two large dam, four moderate dams, and eight small diversions). The proposed infrastructure changes are necessary to monitor and measure the higher instream flows. The infrastructure modifications include installing new outlet valves and structures and stream gages that can monitor and measure these higher release flows. During 2019-2023, SCE will complete infrastructure modification at six facilities (Camp 62, Dam 1, Dam 4, Portal, Mono Diversion, Dam 5, Warm Creek Diversion and Dam 6). The largest (by costs) include the Camp 62, Dam 1, Dam 4 and Portal projects. The Hydro Relicensing – Infrastructure Modifications capital expenditure forecast for these projects is $21.475 million for 2019-2023.[75] Table II-18 below, lists the projects within the Hydro Relicensing - Infrastructure Modifications program category.

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[75] Refer to WP SCE-05, Vol. 1, Book A, pp. 25-30.

Table II-18
Hydro Relicensing – Infrastructure Modifications
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
29	Big Creek - Camp 62 Creek Diversion Flow Release	-	750	750	750	750	3,000
30	Big Creek - Dam 1 LLOV Refurbishment	-	1,500	1,500	-	-	3,000
31	Big Creek - Road & OHV Refurbishment Projects	-	200	1,500	800	250	2,750
32	Big Creek 1 - Dam 4 LLOV Refurbishment	-	-	-	2,500	-	2,500
33	Portal - Dam Release Structure	-	-	-	55	2,000	2,055
34	Big Creek - Mono Diversion Instream Flow Release	-	-	-	775	775	1,550
35	Big Creek 2A, 8 & Eastwood - Small Diversion Decommissioning	-	-	165	400	700	1,265
36	Big Creek - Dam 5 Forebay Instream Flow Release	-	-	270	375	550	1,195
37	Vermilion - Warm Creek Diversion Dam and Release Structure	-	-	-	80	1,100	1,180
38	Big Creek 1 & 2 - Dam 4 Forebay - Instream Flow Release	-	-	270	190	550	1,010
39	Huntington Lake - Dam Instream Flow Release	-	-	-	400	405	805
40	Big Creek 3 - Dam 6 Forebay Instream Flow Release	-	-	55	110	550	715
41	Big Creek - Replace Flow Meters and AVM's	50	50	50	50	50	250
42	Big Creek 1 & 2 - Eastwood Lane Road Rehab	-	-	200	-	-	200
	TOTAL	**50**	**2,500**	**4,760**	**6,485**	**7,680**	**21,475**

(b) <u>Project Scope</u>

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, and access needs, will be assessed first. Based on this preliminary work, necessary permits from resource agencies other than FERC to construct the infrastructure changes will be identified. SCE will consult with the relevant agencies regarding permits for construction-related activities. Permit applications will be prepared and any necessary site-specific studies will be carried out, while engineering design proceeds. In some cases, access will need to be provided for construction equipment. Site access below Dam 4 and Dam 6 is difficult and access is likely to require additional construction, or, depending upon site-specific conditions, alternative design strategies.

When needed, procurement of equipment and support services to implement the infrastructure modifications will take place after design work is complete. The timing of these activities will vary with location due to potential differences in license issuances, site-specific design issues, permitting, and procurement. SCE plans to stagger construction work to allow for efficient use of personnel and resources (Ref. 29-42).

(c) Projects Justification and Benefit

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.

4. Dams and Waterways

Hydro operates and maintains thirty-three dams, forty-three 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 of 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 $62.273 million for 2019-2023.[76] Table II-19 below, lists the programs for the Dams and Waterways category.

[76] Refer to WP SCE-05, Vol. 1, Book A, pp. 67-85.

Table II-19
Dams and Waterways Programs & Major Projects
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
62-65	Penstock, Flume and Flowline Replacements	3,855	-	-	1,000	1,250	6,105
66-71	Structure Improvements	7,615	7,700	9,250	8,150	7,900	40,615
72-82	Gates and Valve Replacements	300	2,125	3,042	4,700	3,500	13,667
83-88	Miscellaneous Dams and Waterways	386	750	-	250	500	1,886
	Grand Total	**12,156**	**10,575**	**12,292**	**14,100**	**13,150**	**62,273**

a) Penstock, Flume and Flowline Replacements

SCE Hydro maintains 143 miles of flowlines. Flowline-replacement projects include various types of designs and materials: steel flumes on wood structures, concrete pipe, steel pipe, concrete canals, and concrete v-ditches. The capital forecast for these projects is $6.105 million for 2019-2023. Table II-20 below, lists the flowline replacement projects and the cost for each.

Table II-20
Penstock, Flume and Flowline Replacements
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
62	Bishop - South Fork Diversion Flowline Replacement	-	-	-	1,000	1,250	2,250
63	Lundy - Return Conveyance System Refurbishment	2,060	-	-	-	-	2,060
64	Kaweah 1 - Flume Refurbishment	1,100	-	-	-	-	1,100
65	Kaweah 3 - Box Flume Replacement	695	-	-	-	-	695
	Grand Total	**3,855**	**-**	**-**	**1,000**	**1,250**	**6,105**

(1) Background

Flowlines utilizing flumes require routine replacement due to exposure to weather conditions. Concrete canals must be recoated with gunite on a periodic basis to maintain integrity of the structure. Some installations with steel or concrete pipe are over 80 years old and now leaking, and must be replaced. Flumes and flowlines are visually inspected regularly to identify and monitor conditions. When a problem is identified, a more in-depth inspection is performed. If the in-depth inspection shows that replacement is required, the project is initiated.

(2) Project Scope

The project scope includes: (1) engineering and drawings for the project; (2) obtaining permits; (3) evaluating the impact of the flowline outage with downstream water users; (4) purchasing the materials for the flowline; and (5) installing the flowline and associated equipment. (Ref. 62-65)

(3) Project Justification and Benefit

Many of SCE's flowlines pass through areas that would affect the public with flooding if a failure occurred. Failure of either a flume or flowline can have several consequences including potential endangerment of the public, negative impact on the environment in severe soil erosion and/or slides, and interruption of some portion of the flow through the tunnel. Project benefits include maintaining reliability for operation of the affected Hydro facilities, maintaining safety for operation personnel and the public, and maintaining the environment.

b) Lundy Return Conveyance System Refurbishment

(1) Background

The Lundy Return Conveyance System or "Return Ditch" currently consists of a gate diversion system and an earthen ditch that lies between Wilson Creek and Mill Creek. The Return Ditch conveys water diverted from Wilson Creek to Mill Creek. The term "return" was coined because the water discharging from the Lundy Powerhouse tailrace was diverted from Mill Creek at Lundy Dam via a pipeline to Lundy Powerhouse. The Return Ditch provides a method of returning a portion of the total flow diverted from Mill Creek at Lundy Dam back to Mill Creek at a location downstream of the dam. This ditch was built to satisfy water rights established in the early 1900s.

As part of the settlement reached to finalize the FERC license renewal, No. 1390, SCE agreed to improve the Return ditch to carry a larger capacity of water. At the time of the settlement, the name of the Return Ditch was changed to Return Conveyance System since it was not known if the system would be a pipe or an open channel or ditch.

In 2017 SCE renewed consultation with the Settlement Parties to determine if the return could be used to distribute water between Mill Creek and Wilson Creek in accordance with pre-1914 water rights requirements. In 2017 and 2018 SCE conducted tests of the return ditch and implemented repairs to reinforce the sidewalls of the ditch (canal) where water seepage was observed. Based on the results of the testing it was determined that the ditch can be returned to service and SCE is working with the Settling Parties to amend the Settlement Agreement. Further, SCE will be implementing infrastructure upgrades to the flow distribution valves and flow measuring devices associated with the return ditch and at Lundy Dam. These upgrades will improve measurement and regulation of flows distribution required to fulfill and deliver water per the water rights and associated delivery priorities. The capital cost for this project is $2.060 million for 2019.[77]

(2) Project Scope

The new Return Conveyance System will consist of a “concrete head works” and “return pipeline” which is made of high density polyethylene (HDPE) pipe and buried almost entirely within the existing alignment of the existing Return Ditch. The new concrete head works will be constructed at the tailrace of Lundy Powerhouse. The return pipeline will exit the lower portion of the head works directly under the existing Wilson Creek channel concrete liner for a short distance and then diverge to one side of the channel until it reaches the upstream end of the existing Return Ditch diversion at which point it will be buried within the existing alignment of the Return Ditch to Mill Creek. Energy absorbers, thrust blocks, air/vacuum valves, gates and other appurtenances will be employed as required for functionality, safety and durability.

The new system will operate as follows: All water flowing through Lundy Powerhouse will enter the new head works via the powerhouse tailrace. The head works is divided into an upstream and downstream compartment. A gate located within the downstream compartment at the entrance to HDPE pipe is incorporated to isolate the HDPE pipe for maintenance or to facilitate emergency shut off. The water level within the upstream compartment is maintained via another gate located between the upstream and downstream compartments. A small gate located within the upstream compartment may be employed to meter water into the Upper Conway Ditch. A knife gate installed at the downstream end of the return pipe line will be employed to meter flow through the pipeline. Water entering the head works that is not metered to either the return pipeline or to the Upper Conway Ditch overflows a weir located at top of the downstream end of the downstream compartment into the existing Wilson Creek channel.[78] The entire head works is designed such that in the event of a gate control or gate failure, miss-operation, flow blockage or other unexpected condition all of the water will over flow

[77] Refer to WP SCE-05, Vol. 1, Book A, p. 70.

[78] A weir or low head dam is a barrier across the width of a river that alters the flow characteristics of water and usually results in a change in the height of the river level.

from compartment to compartment and finally into the Wilson Creek channel without damage to the structure or surrounding area.

Flow measurement is accomplished as follows: An acoustic velocity meter (AVM) will be installed in the Lundy Powerhouse Penstock up-stream of the powerhouse. This AVM will measure total flow through the powerhouse. Another AVM will be located at the downstream end of the return pipeline at Mill Creek. This AVM will measure total flow through the return pipeline. An Ultra Mag Flow Meter will be placed in the discharge piping to the Upper Conway Ditch. This will measure total flow in the Upper Conway Ditch. By subtracting the measured flow into the Upper Conway Ditch and return pipeline from the total flow through the powerhouse, the flow into Wilson Creek may be accurately calculated. All of the measured and calculated flows will be recorded and published per USGS standards. (Ref. 63)

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

SCE entered into a binding agreement with other parties including water rights holders to assure that SCE is not violating those rights. The Lundy plant has had the ability to discharge water into either creek (including simultaneously) for decades. However, over time, the return conveyance to Mill Creek suffered various issues (*e.g.*, wash outs) and (dating back many years ago) lost capacity, and therefore saw less usage. This project corrects this degradation, and improves the Mill Creek return canal to a flow capacity that is commensurate with the water rights at issue.

The primary justification for this project is that SCE agreed to construct the system as part of a settlement agreement to obtain the FERC license for this project. By constructing this system, SCE can reliably comply with water rights as requested by downstream water users.

c) <u>Gates and Valve Replacements</u>

Hydro 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.

The capital forecast for these projects is $13.667 million for 2019-2023. Table II-21 below, provides a list of the Gates and Valves projects and the cost for each.

Table II-21
Gates and Valve Replacements
Forecast 2019 - 2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
66	Big Creek 1 & 2 - Penstock Valve Replacements	-	60	477	1,750	3,500	5,787
67	Gem - Arch 8 Mid-Level Outlet Reinforcement	300	1,000	1,000	1,000	-	3,300
68	Florence Lake Low Level Outlet Valve (LLOV) - Phase 2	-	1,065	1,565	-	-	2,630
69	Balsam Forebay - LLOV-Repair/Replace	-	-	-	800	-	800
70	Big Creek 2A - Adit 8 Diversion Gate Replacement	-	-	-	750	-	750
71	Big Creek - Dam 6 Gate Actuator Replacements	-	-	-	400	-	400
	Grand Total	**300**	**2,125**	**3,042**	**4,700**	**3,500**	**13,667**

(1) <u>Background</u>

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 valves requiring replacement are in critical locations such as the Big Creek 1 and 2 Penstock Valves, Gen – Arch 8 Mid-level Outlet and the Florence Lake Low Level Outlet Valves. Failure of these valves could cause consequences that include:

- Failure to comply with FERC required instream 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
- Failure in an open position, possibly causing flooding of facilities

(2) <u>Project Scope</u>

The project scope includes engineering replacement components (often the nearby piping must be modified to fit new style gates or valves), removing existing equipment, and installing new equipment. (Ref. 66-71)

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

The benefit of replacing the gates and valves varies among the individual projects. Virtually all have a benefit of increased reliability and safety. Most of the larger projects are required for changing flows due to impending FERC license requirements. The present reporting method does not provide adequate flow measurement, while flumes and AVMs provide improved reporting of instream release flow data to comply with the FERC license.

d) <u>Big Creek 1 & 2 - Penstock Valve Replacements</u>

(1) <u>Background</u>

The penstock valves within the Big Creek 1 and 2 powerhouses are original 1920's equipment, and a majority are nonstandard sizes which will require custom valves in order to fit into the existing spaces. Each valve has varying degrees of internal leakage, and when closed do not allow for complete isolation of the water source required to perform routine maintenance of the penstock or equipment downstream of the valve. This necessitates draining of upstream conveyance systems to minimize flows for performance of required maintenance. The capital cost for this project is $5.787 million for 2019-2023.[79]

(2) <u>Project Scope</u>

The scope of the penstock valve replacement project includes engineering of the replacement components (often the nearby piping must be modified to fit new style gates or valves), consideration of outage timing, removal of existing equipment, and installation of the new equipment. (Ref. 66)

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

The benefit of replacing individual valves varies but virtually all have a benefit of increased reliability and safety. Penstock valves work in conjunction with Turbine Shut Off (TSO) valves to quickly shut off water flow to all turbines during an emergency. Failure of one of these valves could potentially allow the release of water at a pressure of 850 psi with a delivery rate over 200 CFS. This flow rate and pressure is capable of washing out the Big Creek road, the powerhouse, and possibly some of Big Creek town and Camp Sierra. Replacement of these valves is required for the continued safety of plant workers and the public.

e) <u>Gem – Arch 8 Mid-Level Outlet Reinforcement</u>

(1) <u>Background</u>

Gem Lake Dam is a 75 foot high concrete multiple arch dam that is part of the Rush Creek project. It was constructed in 1917 and is classified as High Hazard by FERC and DSOD. In 2012 the reservoir was restricted to 30 feet below the crest of the dam due to seismic

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[79] Refer to WP SCE-05, Vol. 1, Book A, p. 72.

concerns. FERC and DSOD have ordered SCE to maintain the reservoir restriction until seismic retrofits of the dam are completed. The Arch 8 outlet is one of the means by which Gem can discharge water to avoid exceeding reservoir restrictions. Although the outlet pipe diameter is 36 inch, discharge is restricted by a 30 inch orifice plate, which decreases flows by approximately 30%. Operation of the outlet with the orifice plate removed causes the outlet works to vibrate excessively. Analysis by consultants indicate that this is because the gate valve controlling the outlet is prone to cavitation. Additionally, the gate valve has poor hydraulic characteristics when operated in a partially open (or "throttled") position, limiting the ability of SCE to control outflow. If SCE is unable to maintain reservoir restrictions in a high runoff year such as 2017, there could be significant compliance penalties from FERC and/or DSOD. Downstream residents may be required to evacuate the inundation area while the restriction is exceeded. If an earthquake were to occur while the reservoir restriction was exceeded, analyses indicate that this could result in a failure of the upper portion of Gem Lake dam, leading to flooding and jeopardizing downstream people and property. The capital cost for this project is $3.300 million for 2019-2023.[80]

(2) Project Scope

Work for this project involves: (1) installing fall protection and heavy duty scaffolding in the work area, (2) constructing an 8 foot long, 8 foot wide, 6 foot tall concrete foundation for the new valve, (3) removing two feet of the existing 36 inch pipe, (4) adding a slip on flange, (5) installing a 36 to 42 inch expansion ring, (6) installing a 42 inch fixed-cone valve, (7) installing a hydraulic powered system to operate the valve, and (8) installing steel valve housing over the valve assembly. The work will require extensive helicopter support and a full-time rigger at the staging area and assumes that construction personnel will be transported by helicopter from June Mountain ski resort parking lot to Gem Lake Landing Zone (Hat Ridge) on a daily basis. (Ref. 67)

(3) Project Justification and Benefit

This new fixed-cone valve will allow for greater control over outflow without inducing vibration and should serve as a stable discharge point with a higher capacity to respond to high runoff seasons. Without modification, the combined discharge capacity of all outlets for Gem Lake Dam can likely pass a 100-yer runoff event without significant exceedance of restrictions; with the proposed modification Gem Lake Dam would likely be able to pass a 200-year runoff event without

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[80] Refer to WP SCE-05, Vol. 1, Book A, p. 73.

exceedances. Although SCE has identified this dam as having a 50% chance of being decommissioned (see Table II-38) in 2027 when the current operating license expires, SCE believes the project cannot be delayed due to the potential failure risk that could lead to flooding and jeopardizing downstream people and property.

f) <u>Florence Lake - LLOV Refurbishment (Phase 2)</u>

(1) <u>Background</u>

FERC and California Division of Dam Safety (DSOD) standards mandate that each reservoir is equipped with an acceptable low-level outlet system. The Low Level Outlet Valve (LLOV) 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 have reached their end of their useful life, and Phase 1 of this project was executed in 2017-2018. Phase 1 included installing the 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 are planned to be removed from the face of the dam in 2019. The capital cost for this project is $2.630 million for 2019 -2023.[81]

(2) <u>Project Scope</u>

Phase 2 of the Low Level Outlet System upgrade 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 water releases that lead to generation loss and potential turbidity concerns.[82] Valve cycling is required annually per DSOD, with full operation performed in their presence every three years. Also included in this project are infrastructure modifications necessary to meet the minimum instream flow releases per the pending FERC license renewal. The major scope of

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[81] Refer to WP SCE-05, Vol. 1, Book A, p. 74.

[82] Turbidity is the cloudiness or haziness of a fluid caused by large numbers of individual particles that are generally invisible to the naked eye, similar to smoke in air. The measurement of turbidity is a key test of water quality.

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

- Provide engineered design drawings, Quality Control Inspection Procedure, 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.
- Install new 36 inch piping to extend the release location outside of Arch 53 to prevent access concerns to the release valves during releases from the 36 inch pipes and/or install raised walkways to provide safe ingress/egress to the release valves.
- Install secondary release valves with bypasses/drains on both 36 inch outlets to allow for "Double Block and Bleed" operation of the outlets.
- Install additional MIF piping from the east outlet to allow continuous MIF releases during maintenance/operation of the west outlet.
- Install additional MIF piping to increase the flow capabilities of the MIF system to meet the new FERC license requirements, including sufficient piping to release approximately 400 feet downstream of the arch to avoid interference with the existing access road. (Ref. 68)

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

Upon completion of the project the new LLOV system will be able to be maintained and operated on a minimum annual basis without releasing unnecessary generation water and without creating environmental concerns during valve operations. The MIF upgrades will provide the necessary release requirements per the Settlement Agreement of the pending FERC license.

g) <u>Structure Improvements</u>

This category covers a variety of projects that are essential to reliably and safely operate several Hydro waterways and comply with applicable regulations. The capital forecast for the Structure Improvement projects is $40.615 million for 2019-2023. Table II-22 provides a list of the Structure Improvement projects and the cost for each.

Table II-22
Structure Improvements
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
72	Vermillion - Spillway Rehabilitation	600	1,900	1,400	1,400	1,400	6,700
73	Kern River 1 - Tunnel Refurbishment (Phase 5)	300	1,000	3,850	1,500	-	6,650
74	Kern River 3 - Tunnel Refurbishment (Phase 2)	-	-	2,000	2,000	1,500	5,500
75	Huntington Lake - Dam 1 Spillway Refurbishment	-	-	-	250	5,000	5,250
76	Kern River 3 - Sandbox Refurbishment	3,400	1,300	-	-	-	4,700
77	Vermillion - Red Ditch Seepage Mitigation Installation	565	1,000	1,000	1,000	-	3,565
78	Huntington Lake - Leakage Mitigation	-	1,000	1,000	1,000	-	3,000
79	Shaver Lake - Dike Flood Mitigation Installation	300	1,500	-	-	-	1,800
80	Shakeflat Creek Crossing Canal Replacement	1,250	-	-	-	-	1,250
81	Florence Lake - Dam Arch 52-53 Coating	1,200	-	-	-	-	1,200
82	Rhinedollar - Overtopping Protection Installation	-	-	-	1,000	-	1,000
	Grand Total	**7,615**	**7,700**	**9,250**	**8,150**	**7,900**	**40,615**

(1) <u>Background</u>

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 wide variety of projects to improve dams and waterways essential for reliable and safe operation, and compliance with applicable regulations.

(2) <u>Project Scope</u>

The Dams and Waterways miscellaneous projects include projects in both the Eastern and Western Hydro divisions.

The dams and waterways in Western Hydro are greater than 50 years old and have been well-maintained over the period. However, facility improvements due to new regulations and operating experience will be required. Improvements will be made to dam and waterway infrastructure including spillways, sandbox, diversion dam replacement, tailrace and forebays. The scope of work is similar for these projects and includes: (1) completing engineering and drawings for the project; (2) obtaining regulatory and environmental approvals to perform the work appropriate for the location; (3) directing a purchase order for the construction and purchase of materials; and (4) completing the work specific to each project. (Ref. 72-82)

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

The benefit of replacing the Dams and Waterways infrastructure vary among the projects. Virtually all are vital infrastructure components and must be refurbished or replaced to maintain a reliable and safe Hydro system. Some of the work fulfills regulatory requirements for FERC license requirements or DSOD regulations.

h) Vermilion – Spillway Rehabilitation

(1) 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 as bedrock is hundreds of feet below the ground surface. The service spillway has flowed relatively often during the project history, 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 spillway chute edge, water then flowed under the chute resulting in the lower portion of the chute being floated off its subgrade causing extensive cracking. This damage was repaired by cutting the damaged concrete out, tying new rebar mat to rebar tails from adjacent undamaged slabs, and pouring new slabs. The 1983 repairs have since degraded and are now in need of replacement.

The 2017 Oroville Spillway incident has raised awareness and concern within the overall dam safety industry, and within the regulatory community, over the condition and anticipated performance of spillways. Both FERC and DSOD have initiated significant spillway evaluation programs, and both include the spillways at Vermilion. In response, SCE Dam and Public Safety has performed a comprehensive re-evaluation of the Vermilion spillways. This evaluation included review of design documents and as-built drawings, review of historical performance, review of maintenance and repair records, review of 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 leading outside consultant 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 Dam and Public Safety and O&M personnel, FERC engineers, and SCE's Part 12 Independent Consultants. The four risk reduction measures recommended during that workshop have been incorporated into this project request. The capital cost for this project is $6.700 million for 2019-2023.[83]

[83] Refer to WP SCE-05, Vol. 1, Book A, p. 75.

(2) **Project Scope**

The overall project scope includes complete rehabilitation of the concrete service spillway chute and mitigation of excess uplift pressures which includes installation of piezometers adjacent to the spillway in order to quantify uplift forces and the resulting safety margins. If inadequate margins are detected, additional engineering will be required to design a mitigation strategy, likely to include installation of a new sub drain 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 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, back cutting 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.[84] The installation of rip-rap along the upper portion of this berm will minimize the chance of such a breach between the spillway and the groin of the dam. (Ref. 72)

(3) **Project Justification and Benefit**

The service spillway foundation at Vermilion is erodible and therefore any failure of the spillway chute risks failure of the dam through back cutting 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 been tested, and is considered only to be "marginally stable" during a severe flood event.

Neither FERC nor DSOD 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

[84] Rip-rap is man-placed rock or other material used to armor shorelines, streambeds, bridge abutments, pilings and other shoreline structures against scour from water or ice erosion.

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 their annual inspection findings last fall. Completion of this project will mitigate the following four risks identified during a PFMA workshop for the spillway.

Risk 1 - High hydrostatic uplift forces cause loss of spillway slab, erosion of the subgrade, and eventually lead to dam failure. Project Risk Mitigation: The project will evaluate the magnitude of the uplift forces and the resulting safety factors and recommend appropriate mitigation options to minimize this risk.

Risk 2 - Defect(s) in the spillway chute lead to loss of chute slabs during spill event, erosion of subgrade, eventually leading to dam failure. Project Risk Mitigation: The project will identify and repair such defects, thus minimizing this risk.

Risk 3 - Logs accumulate on the log boom during a storm or other high runoff event, log boom fails or collapses into spillway entrance, reservoir rises because of the reduced Service Spillway capacity and flows over the Emergency Spillway causing erosion and environmental damage, possibly washing out the road to the Resort, campground and Pack Stations. Because the Emergency Spillway has never been used, we cannot be certain how it will perform. Poor performance could result in dam failure by back cutting erosion. Project Risk Mitigation: The project will reduce this risk by reducing the chance that the Emergency Spillway will be required (by reducing the chance that logs will clog the spillway entrance).

Risk 4 - Use of Emergency Spillway results in erosion and loss of berm between Emergency Spillway and the right groin of the dam, flows exit spillway channel into the right groin, back cutting erosion moves up the right groin to the dam crest, resulting in dam failure. Project Risk Mitigation: this risk will be mitigated by increasing the erosion resistance of the berm between the Emergency Spillway and the right groin of the dam, keeping flows within the spillway.

i) Kern River 1 - Tunnel Refurbishment (Phase 5)

(1) Background

The Kern River 1 tunnel is a delivery system for the water needed by the plant to produce power. The tunnel was placed in-service in 1907 and has been repaired many times over its 100 plus years of service, but has reached the end of its useful life. Following a tunnel failure in July 2002, SCE initiated a multiyear phased project to rebuild the tunnel. This is the fifth and final phase of the rebuild, which will enable the safe operation of the tunnel for the life of the project's thirty-year

FERC license and beyond. The capital expenditure forecast for this project is $6.650 million for 2019-2023.[85]

(2) Project Scope

Phase 5 of the Kern River tunnel refurbishment project will complete the Kern River 1 tunnel repair work from the intake to Stark Creek. The refurbishment work involves repairing and/or replacing multiple concrete sections of floors and walls with new sections. Areas of floor damage will require removing large sections of damaged concrete and replacing it with new concrete sections. Wall areas that support cap sections must be repaired to return those sections to sufficient structural integrity for useful and uninterrupted flow through the tunnel. (Ref. 73)

(3) Project Justification and Benefit

The project will provide continued reliability and address public safety issues. A tunnel failure can endanger the public, harm the environment due to severe soil erosion and/or slides, and interrupt the flow through the tunnel. Project benefits include maintaining reliability for operation of the affected Hydro facilities, maintaining safety for operation personnel and the public, and restoring the 412+ cfs maximum flow capacity of the Kern River 1 tunnel.

j) Kern River 3 – Tunnel Refurbishment (Phase 2)

(1) Background

This project will be implemented to repair deterioration and corrosion damage that has developed in the Kern 3 tunnel system since its construction. In addition, certain geologic conditions increase the impact of the aging of the structures. The tunnel is constructed of mainly unreinforced concrete with only limited section of closed conduit and adit access locations having steel reinforcement.[86] A number of the closed conduit areas are supported above ground, and failure at these locations would release water which would erode the hillsides and possibly flood the public road. The tunnel system is approximately 12 miles long with limited access points. At some locations the only construction access is six miles away. The project would consist of repair/replacement of invert sections, some wall locations, and reinforced concrete sections where corrosion of reinforcing

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[85] Refer to WP SCE-05, Vol. 1, Book A, p. 76.

[86] An adit is a horizontal or nearly horizontal passage leading into an underground mine for the purposes of access or drainage.

steel has severely reduced the structural integrity of the flowline. The capital cost for this project is $5.500 million for 2019-2023.[87]

(2) Project Scope

The rehabilitation consists of repairing and/or replacing structural concrete sections of floors, walls and cap (roof). Areas of floor damage will require removing large sections of damaged concrete and replacement with new sections. Some of these areas may require special ground water protections for water pressure and inflow. Wall areas that support cap sections will need to be repaired to return them to sufficient structural integrity to insure useful and uninterrupted flow through the tunnel. Repairs to closed conduit sections will consist of repair and/or replacement on sections of the concrete conduit to correct damage due to corrosion that has led to leakage and lack of structural support for cap sections. (Ref. 74)

(3) Project Justification and Benefit

The failure at any of the damaged locations can have consequences including potential endangerment of the public, negative impact on the environment in form of severe soil erosion and/or slides, and interruption of some portion of the flow through the tunnel. A full engineering assessment of the degree of damage and risk is part of this project and the specific remediation work will be more defined after this assessment is completed.

k) Huntington Lake – Dam 1 Spillway Refurbishment

(1) Background

The Huntington Lake Dam 1 Service Spillway consists of fifteen manually operated steel gates and ungated concrete ogees located at both ends of the Service Spillway.[88] The steel gates are supported by concrete piers resting on the spillway crest. The gate's seals have been prone to leaks and need to be replaced. A recent DSOD inspection noted observable cracks and spalls on the piers, spillway crest and the ogees and indicated that there was evidence of leakage thru the ogees and at isolated locations of the crest. The spillway gates are susceptible to corrosion and in need of recoating. The capital cost for this project is $5.250 million for 2019-2023.[89]

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[87] Refer to WP SCE-05, Vol. 1, Book A, p. 77.

[88] An ogee is a curve shaped somewhat like the letter S, consisting of two arcs that curve in opposite senses, so that the ends are parallel, or roughly so.

[89] Refer to WP SCE-05, Vol. 1, Book A, p. 78.

(2) Project Scope

The needed refurbishments include: (1) removing and replacing cracked/spalling/hollow-sounding spillway crest and ogee concrete (appx. 400 cubic yards), (2) removing and replacing damaged concrete areas of the piers (approximately 2500 square feet), (3) replacing leaking seals, and (4) coating and painting of the spillway gate seals. (Ref. 75)

(3) Project Justification and Benefit

Following the 2017 Oroville Spillway failure, DSOD required a thorough evaluation of a number of spillways, including the Huntington Lake Dam 1 Spillway. Refurbishing the service spillway will enhance its condition and bring it closer to modern design standards, and will satisfy a regulatory commitment to DSOD and FERC regarding this spillway. The reliability of the spillway, in the case of large discharges due to sizeable floods, will be enhanced and thus reduce the risk of failure and downstream damage due to the uncontrolled rapid release of water.

l) Kern River 3 - Sandbox

(1) Background

The Kern River 3 Sandbox is a large concrete settling basin, which allows sediment from upstream to settle from the water. This provides cleaner water to be diverted into the flowline that supplies the Kern River 3 powerhouse. An engineering inspection report in 2006 recommended that major rehabilitation work be done to the sandbox caused by erosion. These replacements, when completed, will increase reliability and employee safety. The capital cost for this project is $4.700 million for 2019-2023.[90]

(2) Project Scope

New FERC license requirements stipulate that the Kern River 3 Sandbox be flushed once a week, which also adds to the erosion of the sandbox floors and support structures. An engineering inspection and report conducted in 2006 by the Generation engineering group recommended that major work be performed on the structure to maintain continued reliability.

The Kern River 3 Sandbox work scope includes: (1) developing an engineering package to identify work scope, cost and schedule to rebuild the sandbox structure; (2) removing deteriorated concrete liner, injecting cracks to seal them, and installing a new reinforced

[90] Refer to WP SCE-05, Vol. 1, Book A, p. 79.

concrete liner; (3) inspecting support beams and refurbish as required; and (4) inspecting and refurbishing exterior walls. (Ref. 76)

(3) Project Justification and Benefit

The Kern River 3 Sandbox is a vital component of the powerhouse flowline system. The concrete structure deteriorates over time due to water and weather erosion. Exposed rebar must not be allowed to rust or it can lead to further deterioration of the concrete, resulting in possible structural failure. A failure would cause lost electric generation from the plant. Depending on the extent of damage, an unforeseen outage due to structural failure could last 6 to 12 months. A failure could cause large amounts of captured solids to enter the Kern River, causing environmental damage.

m) Vermilion – Red Ditch Seepage Mitigation Installation

(1) 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 moraine ridges from past glaciation periods. 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 sand bag chimneys, fine sand accumulated in the chimneys.[91] With the

[91] Sand boils or sand volcanoes occur when water under pressure wells up through a bed of sand. The water looks like it is "boiling" up from the bed of sand.

chimneys not present, that sand would simply wash away in the Red Ditch flow, and would not be detected. It is 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 previous 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. Ultimately, this may cause instability of the embankment, and potentially 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. The capital cost for this project is $3.565 million for 2019-2023.[92]

(2) Project Scope

As a result of these observations and seepage study findings, SCE will perform a significant remediation effort, including installing a perforated collection drain pipe and an unperforated bypass pipe in the Red Ditch, both surrounded by an engineered gravel filter. (Ref. 77)

(3) 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. Mitigation will likely 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 regarding the specific nature and extent of this mitigation will be developed during the conceptual engineering phase, and will be evaluated with respect to cost- and risk-reduction potential.

n) Huntington Lake – Leakage Mitigation

(1) Background

Huntington Lake Dam 1 is a concrete dam that includes a sheet steel liner on the upstream face. The intent of the liner is to isolate the dam face from reservoir head pressure, thus minimizing the potential for leakage through cracks and construction joints in the dam. Between this liner and the original concrete face is a set of drains which carry any water that leaks past the liner out

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92 Refer to WP SCE-05, Vol. 1, Book A, p. 80.

through one of the sluice pipes where it is measured at a weir (a specific location within the structure). Leakage measured at this weir has exhibited an increasing trend over the past 10 years, and in early October of 2017, a significant increase in leakage was observed, with peak leakage measured at 2,182 gallons per minute (about 5 cubic feet per second). This prompted an inspection using a submersible Remotely Operable Vehicle (ROV), but this inspection was not able to identify a specific source of the leakage.

The grout seal at the base of the steel liner facing has deteriorated several times in the past and has required repairs to reduce leakage. It appears likely that the increasing leakage trend over the past 10 years, and the sudden increase in leakage observed in 2017, indicate that the grout seal has been compromised. If the issue is not addressed, it is likely that the leakage will continue to increase as the grout seal continues to degrade and water flows through the damaged area erode and enlarge the seepage entrance. This seepage could eventually overwhelm the capacity of the drain system, resulting in water rising to the reservoir elevation behind the steel liner face. This could likely drive seepage through cracks and constructions joints in the concrete dam, and into the downstream earthen embankment. Saturation of the downstream embankment could result in slope instability, especially during an earthquake. The capital cost for this project is $3.000 million for 2019-2023.[93]

(2) Project Scope

Current plans call for a systematic inspection using a submersible camera mounted on a custom wheeled "sled." The findings of this inspection will drive further inspection/repair efforts. The intent of the project is to mitigate the excessive leakage using the most cost effective means possible. The nature of this mitigation will be determined based on additional inspections, and could range from a localized repair using divers, to a comprehensive mitigation such as installing a Carpi geotextile liner over the existing steel liner. (Ref. 78)

(3) Project Justification and Benefit

The project will mitigate risks associated with increasing leakage past the dam liner. These risks include increased leakage flows through the downstream embankment, which increases the risk of dam failure resulting from internal erosion or saturation and possible slope failure of the downstream embankment. These risks will be mitigated by identifying the specific upstream source(s) of the increased leakage and recommending appropriate repair strategies.

[93] Refer to WP SCE-05, Vol. 1, Book A, p. 81.

o) **Miscellaneous Dams and Waterways**

SCE will also complete various miscellaneous projects. The capital cost for these projects is $1.886 million for 2019-2023. Table II-23 lists Dams and Waterways Miscellaneous projects and the cost for each.

Table II-23
Miscellaneous Dams and Waterways
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
83	Huntington Lake - Sluice Pipe Refurbishment	-	500	-	-	-	500
84	Big Creek - Dam 7 Water Stop/Liner Installation	-	-	-	-	500	500
85	Kaweah 3 - Gunite Tailrace Refurbishment	316	-	-	-	-	316
86	Big Creek - Dam 4 Shotcrete Repairs	-	-	-	250	-	250
87	Big Creek - Dam 7 Piezometer Telemetry Installation	-	250	-	-	-	250
88	Shaver Lake - Dam Rip Rap Installation	70	-	-	-	-	70
	Grand Total	**386**	**750**	**-**	**250**	**500**	**1,886**

(1) Background

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.

(2) Project Scope

The miscellaneous projects largely include several low-cost projects in the Big Creek area. These projects include a sluice pipe refurbishment and a water stop/liner installation at Dam 7. (Ref. 83-88)

(3) Projects Justification and Benefit

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.

5. **Prime Movers**

SCE Hydro operates seventy-six generating units at thirty-five 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 $49.950 million for 2019-2023.[94] Table II-24 lists the programs for the Prime Movers category.

Table II-24
Prime Movers
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
43-50	Generator Coils and Rewinds	3,715	3,100	2,200	4,300	10,200	23,515
51	Big Creek 3 - Unit 3 Field Pole Refurbishment	-	-	4,000	250	-	4,250
52-54	Turbine Wicket Gates, Runner and Repowers	1,860	2,930	1,070	500	2,500	8,860
55	Big Creek 3 - Unit 5 Headcover/Wicket Gate Replacements	-	-	910	4,500	-	5,410
56-61	Miscellaneaous Prime Movers	4,895	1,430	1,590	-	-	7,915
	Grand Total	**10,470**	**7,460**	**9,770**	**9,550**	**12,700**	**49,950**

a) <u>Generator Coils and Rewinds</u>

Hydro generators consist of the stator with windings (half-coils) and the rotating field with coils or poles.[95] 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 $23.515 million for 2019-2023. Table II-25 summarizes the cost of each Generator Coil and Rewind project. (Ref. 43-50)

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94 Refer to WP SCE-05, Vol. 1, Book A, pp. 31-65.

95 The “stator” is the stationary portion of a generator, within which the rotor (rotating field) revolves.

Table II-25
Generator Coils and Rewinds
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
43	Big Creek 2A - Unit 1 Generator Rewind	-	-	-	2,200	6,100	8,300
44	Big Creek 1 - Unit 2 Generator Rewind	-	-	-	1,000	3,000	4,000
45	Big Creek 2 - Unit 6 Generator Rewind	-	1,800	2,200	-	-	4,000
46	Big Creek 8 - Unit 1 Generator Rewind	1,900	1,300	-	-	-	3,200
47	Bishop 6 - Unit 1 Generator Rewind	1,300	-	-	-	-	1,300
48	Kern River 1 - Unit 3 Generator Rewind	-	-	-	-	1,100	1,100
49	Kern River 1 - Unit 2 Generator Rewind	-	-	-	1,100	-	1,100
50	Bishop 3 - Unit 1 Generator Rewind	515	-	-	-	-	515
	Grand Total	**3,715**	**3,100**	**2,200**	**4,300**	**10,200**	**23,515**

(1) <u>Background</u>

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 forecast to need repair prior to 2023 based on age or recent inspection. SCE's experience shows that additional generator repairs could be needed during 2019-2023, 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 seven generator rewind projects that exceed $1 million each (*i.e.,* from among the eight total repairs forecast) is provided in Table II-26 below.

Table II-26
Winding Age of Generator Stator Rewind Projects Exceeding $1 Million

Line #	Ref #	Plant	Unit	Winding Installation (Year)	Winding Age (Years)	Nameplate Capacity (MW)
1	43	Big Creek 2A	Unit 1	1987	32	55.0
2	44	Big Creek 1	Unit 2	1989	30	15.8
3	45	Big Creek 2	Unit 6	1985	34	17.5
4	46	Big Creek 8	Unit 1	1985	34	30.0
5	47	Bishop 6	Unit 1	1979	40	1.6
6	48	Kern River 1	Unit 3	1996	23	6.6
7	49	Kern River 1	Unit 2	1995	24	6.6

As shown, the first five projects all have windings at or exceeding thirty years of age. While the two units at Kern River 1 have not exceeded thirty years in operation, SCE has determined it is prudent to include these two projects in its forecast due to a recent failure of the Kern River Unit 1 stator which was rewound during the same time period (1995-1996) as Units 2 and 3. These seven projects account for approximately 98% of the total Generator Coils and Rewinds forecast.

(2) <u>Project Scope</u>

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. (Ref. 43-51)

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

The project 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 workpapers for those generator rewind and stator replacement projects exceeding $1.0 million) have been performed demonstrating the economic benefits of those projects.

b) <u>Big Creek 3 – Unit 3 Field Pole Refurbishment</u>

(1) <u>Background</u>

Hydro generators are inspected on a periodic basis to assess the condition of their rotor windings. Over time, the stresses from producing electrical power and the rotational forces will cause deterioration of the insulation that separates the individual coil components. Deteriorated insulation causes shorting of the coils reducing the efficiency of the generators. Further deterioration and shorts result in generator failure. Big Creek 3 Unit 3's initial date of operation was in 1923 and the current rotor winding was refurbished in 1945. An inspection performed during the 2015 stator rewind revealed that the Big Creek Unit 3 rotor had at some time in its past experienced an out of step synchronization resulting in a twisted rotor body. Generator rotor windings typically require a three to five month outage for removal, refurbishment and installation, so planning is essential for refurbishment outages. Performance of necessary repairs were deemed too extensive to perform during the 2015 stator rewind and were postponed to a later date. The capital expenditure forecast for the Big Creek 3 – Unit 3 Field Pole refurbishment project is $4.250 million for 2019-2023.[96]

(2) <u>Project Scope</u>

This scope of this project includes: disassembling the generator, removing the field poles from the rotor, shipping to factory for refurbishment, re-installing the field poles onto the

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[96] Refer to WP SCE-05, Vol. 1, Book A, p. 48.

rotor, and reassembling the generator. The insulation system will also be removed and replaced. The coil winding copper will be cleaned and reused. The field poles will be tested reassembled along with installation of a new wedging and support system. (Ref. 51)

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

The Big Creek 3 Unit 3 rotor winding was installed in 1945 and will have an effective age of seventy-seven years in 2022.[97] The field poles on this unit exhibit signs of deterioration and need to be refurbished for operational reliability. An in-service failure could lead to an extended forced outage, during which time we would need to purchase replacement power. An economic analyses has been performed demonstrating the economic benefit of this project at a benefit-to-cost ratio of 1.3.[98]

c) <u>Turbine Wicket Gates, Runners and Repowers</u>

SCE Hydro powerhouses operate with two types of turbines:

- Francis (also known as reaction turbines), which utilize curved wicket gates to control and direct high pressure water to a runner that has vane type blades
- Pelton (also known as impulse turbines), which utilize one or more nozzles that control and direct high pressure water to buckets on a "waterwheel"

Refurbishment typically includes extensive repairs or replacement of some or all of the turbine blades, control elements and journal bearings, and other related work. A complete replacement of major turbine elements (*e.g.,* the entire turbine rotor) is called a repower and is done infrequently. The Turbine Wicket Gates, Runners, and Repowers (Refurbishment) project forecast for Hydro is $8.860 million for 2019-2023. Table II-27 lists the projects and the cost for each replacement.

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[97] Sixty years is normal life expectancy for rotor windings run under normal operating conditions.

[98] Refer to WP SCE-05, Vol. 1, Book A, p. 49.

Table II-27
Turbine Wicket Gates, Runner and Repowers
Forecast 2019 - 2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
52	Big Creek 4 - Unit 1 Runner Replacement	-	-	-	500	2,500	3,000
53	Big Creek 2 - Unit 5 Turbine Replacement	1,860	1,070	-	-	-	2,930
54	Big Creek 2 - Unit 6 Turbine Replacement	-	1,860	1,070	-	-	2,930
	Grand Total	**1,860**	**2,930**	**1,070**	**500**	**2,500**	**8,860**

(1) <u>Background</u>

Turbine runners and wheels become worn and develop cracks from the force of the water. Cavitation and erosion contribute to the wear. Water with high amounts of suspended solids accelerates the erosion process. When possible, repairs are often accomplished by grinding out the damaged areas, welding in a repair patch using stainless steel, and machining the repaired surface back to its proper dimensions and shape. However, over time, the wheels and runners can no longer be repaired because of the cumulative heat-related damage to the surrounding steel from successive weld repairs, and must be replaced. Carbon steel wheels erode much faster than stainless steel and require more repairs. Replacement of waterwheels is often done with stainless steel to reduce the effects of cavitation and erosion.

(2) <u>Project Scope</u>

A typical project includes procuring materials prior to the project due to lead times, removing the generator, removing the head cover and disassembling the turbine, replacing damaged equipment, reassembling, and testing the turbine. (Ref. 52-54)

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

The project will return the generating unit to a reliable and safe operating condition. An in-service turbine failure can damage numerous turbine components that could have been re-used if the turbine had been removed from service for routine overhaul prior to in-service failure. Ancillary damage from in-service failures can include damage to the turbine foundation, linkages, and numerous other items. Sometimes, an in-service failure can cause parts to break free of the turbine, which is revolving at a significant speed, compromising safety and adjacent equipment. In addition, there are also economic benefits to replacing equipment before in-service failure, such as lower replacement costs when damage caused by in-service failures is avoided.

d) Big Creek 3 Unit 5 – Headcover Replacement

(1) Background

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 packing life has continued to be less than normal due to significant wear to the headcover caused by cavitation. Replacement of the head cover is needed to finalize the repairs, and to prevent a more catastrophic failure of the head cover. The capital expenditure forecast for the Big Creek 3 Unit 5 – Headcover Replacement project is $5.409 million for 2019-2023.[99]

(2) 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. (Ref. 55)

(3) 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 analyses has been performed demonstrating the economic benefit of this project at a benefit-to-cost ratio of 1.4.[100]

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[99] Refer to WP SCE-05, Vol. 1, Book A, p. 57.

[100] Refer to WP SCE-05, Vol. 1, Book A, p. 58.

e) 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 Vibration System Upgrade, which is discussed separately below with various generator replacements, governor replacements, turbine shut-off (TSO) valve control replacements, and other small Prime Mover projects. The capital forecast for these six projects is $7.915 million for 2019-2023. Table II-28 below, lists the six Miscellaneous Prime Mover projects and the cost for each.

Table II-28
Miscellaneous Prime Movers
Forecast 2019-2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
56	Big Creek - Vibration Monitoring System Upgrade	890	980	770	-	-	2,640
57	Big Creek 4 - Low Voltage Switchgear Replacement	1,800	-	-	-	-	1,800
58	Eastwood - Governor Replacement	30	150	820	-	-	1,000
59	Kern River 1 - Excitation Upgrade	1,750	-	-	-	-	1,750
60	Kern River 3 - Solid State Exciters Installation	300	300	-	-	-	600
61	Santa Ana River 1 - TSO Valve(s) Replacement	125	-	-	-	-	125
	Grand Total	**4,895**	**1,430**	**1,590**	**-**	**-**	**7,915**

(1) Big Creek Vibration Monitoring System

(a) Background

The current vibration monitoring systems used in Big Creek are inadequate as they are outdated and lack the capability to provide diagnostic evaluation of real-time operating conditions. Installation of a robust vibration monitoring system will increase the likelihood of catching minor operational defects early and correcting them during scheduled outages. The capital expenditure forecast for the Big Creek Vibration Monitoring System project is $2.640 million for 2019-2023.[101]

(b) Project Scope

This project includes the procurement and installation of a Bently Nevada 3500 Continuous Monitoring system, including the system 1 software. The installation would

[101] Refer to WP SCE-05, Vol. 1, Book A, p. 59.

consist of equipment procurement, powerhouse vulnerability assessments, equipment installation, and IT connectivity development, followed by acceptance testing. Following installation, operations and maintenance personnel will receive training on the new systems. The installations are scheduled to occur in three phases over three years: 2019 - Big Creek 3 & 4, and Eastwood; 2020 - Big Creek 1, 2 and 2A; and 2021 – Big Creek 8, Mammoth Pool and Portal Powerhouses. (Ref. 56)

(c) Project Justification and Benefit

Continued operation of equipment without state-of-the-art vibration monitoring poses a risk of unidentified equipment conditions that could cause significant damage, including in-service failure of rotating equipment. These facilities are currently experiencing an average of two forced outages per year due to problems that are preventable with the proposed vibration monitoring system installed. Small and easily correctable defects go undetected and become larger, resulting in more expensive issues, forced outages and possible catastrophic failure for equipment. This project will enhance the reliable and safe operations for the Hydro Prime Mover equipment.

6. 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 complete replacement of excitation equipment, high voltage plant circuit breakers, transformers, or automation work. Excitation equipment provides the power to a generator’s field windings, which is necessary to produce output power. 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 $18.770 million for 2019-2023.[102] Table II-29 lists the programs within the Electrical Equipment category.

[102] Refer to WP SCE-05, Vol. 1, Book A, pp. 86-98.

Table II-29
Electrical Equipment Programs
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
89-91	Transformer Bank Replacements	2,500	-	950	5,000	-	8,450
92-95	Circuit Protection Equipment	3,610	100	1,500	-	-	5,210
96-98	Miscellaneous Electrical Equipment	360	1,750	1,000	1,000	1,000	5,110
	Grand Total	**6,470**	**1,850**	**3,450**	**6,000**	**1,000**	**18,770**

a) <u>Transformer Bank Replacements</u>

SCE utilizes voltage transformers in a variety of applications and locations. Step-up transformers are used to increase voltage, usually from generation units or powerhouses to the higher voltage used in transmission lines. Step-down transformers are used to decrease voltage, usually from generator, powerhouse, or distribution system voltages for station light and power or other purposes. Many of the transformers are used in switchyard locations that support the transmission and distribution grid. The capital estimate for the transformer bank replacement projects is $8.450 million for 2019-2023. Table II-30 lists these projects and the cost for each replacement. (Ref. 89-91)

Table II-30
Transformer Bank Replacements
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
89	Big Creek 2A - No. 1 Bank Transformer Replacement	-	-	500	5,000	-	5,500
90	Mammoth Pool - Unit 2 Transformer Bank 1 & 2 Replacement	2,500	-	-	-	-	2,500
91	Kern River 3 - Local Service Banks Replacement	-	-	450	-	-	450
	Grand Total	**2,500**	**-**	**950**	**5,000**	**-**	**8,450**

(1) <u>Background</u>

Many of the transformers requiring replacement have been in continuous service for longer than fifty years, have reached the ends of their useful lives, and must be replaced for reliability and safety. Dissolved gas (in oil) analysis (DGA) is an industry benchmark used to assess transformer winding condition. Significant increases in gassing levels and dielectric degradation, which, inherent with the transformer's age, indicate a high risk of failure. A fault in the electrical system could trigger catastrophic failure of a degraded transformer, resulting in fire, damage to neighboring equipment, release of hazardous materials, or injury to personnel. Replacement of transformers is part of

Generation's program to monitor old-age equipment and prioritize replacement. The transformers that have DGA levels indicating deterioration and degradation beyond repair will be replaced.

(2) Project Scope

The Big Creek 2A transformer bank upgrade project includes replacing switchgear and the main power transformer, which have reached and/or exceeded their anticipated service life. The potential and current transformers, and additional breakers will also be replaced. The oil containment structure will be redesigned in order meet SPCC requirements of the containment of all oil on the transformer deck.[103] (Ref. 89)

The Mammoth Pool Powerhouse was constructed in 1960 and has operated continuously since that time. Its generator step up (GSU) Transformers have operated since 1981 and have exceeded their useful lives. Work includes electrical and civil/structural engineering, design, procurement, installation, and startup/test activities related to the replacement and upgrade of the main transformer, unit breaker, neutral ground potential transformer, generator bus and transformer bus. The structural work scope includes evaluating and retrofitting (if required) the existing floor slab and support structures supporting the transformer; analyzing the existing take-off structure for new loads; designing bus runs; and determining the need to design a new GSU neutral ground potential transformer support structure.[104] (Ref. 90)

(3) Project Justification and Benefit

Safety, environmental considerations, and operational reliability are the prime factors considered in replacing transformers that have reached or exceeded their useful life. A catastrophic failure of a degraded transformer could cause fire, damage neighboring equipment, release hazardous materials, and/or injure personnel.

In addition, there are also economic benefits to replacing transformers before they fail in-service. An unexpected failure in-service will have a greater cost than a planned replacement due to loss of generation during the procurement and planning phases of work. These transformers typically have lead times greater than six months and sometimes up to two years. Economic analyses have been performed demonstrating the economic benefit of these three projects;

[103] Refer to WP SCE-05, Vol. 1, Book A, p. 89.

[104] Refer to WP SCE-05, Vol. 1, Book A, p. 91.

cost/benefit ratio of Big Creek 2A is 1.4,[105] Mammoth Pool U1 and U2 transformer replacements is 2.4.[106]

b) Circuit Protection Equipment

(1) Background

Many of the existing circuit breakers at these powerhouse are the original powerhouse equipment and are approximately seventy-five years old. They are almost worn out 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. The capital estimate for the Circuit Protection Replacement projects is $5.210 million for 2019-2023. Table II-31 below, provides the list of these projects and the cost for each replacement.

Table II-31
Circuit Protection Equipment Replacements
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
92	Casa Diablo - Protective Relay Replacements	2,990	-	-	-	-	2,990
93	Kaweah 2 - Switchyard 66KV Breaker Replacement	-	-	1,500	-	-	1,500
94	Kern River 3 - 2.4 KV Circuit Breaker Replacement	525	100	-	-	-	625
95	Fontana - Unit 1 and 2 Circuit Breaker Replacement	95	-	-	-	-	95
	Grand Total	**3,610**	**100**	**1,500**	**-**	**-**	**5,210**

(2) Project Scope

The circuit breaker replacement project involve 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. (Ref. 92-95)

[105] Refer to WP SCE-05, Vol. 1, Book A, p. 90.

[106] Refer to WP SCE-05, Vol. 1, Book A, p. 92.

(3) **Project Justification and Benefit**

These breakers must perform reliably to maintain station power for generation and transmission operations. They are outdated, and their reliability is below utility system standards. This new equipment will return the station reliability to utility system standards.

c) **Casa Diablo Substation – Protective Relay Replacements**

(1) **Background**

Most of SCE's transmission substations are maintained by SCE's Transmission and Distribution organization. However, the substations in the Inyo and Mono County areas and those in the Big Creek area are maintained by SCE Generation due to their remote locations and proximity to Hydro powerhouses. These substations operate utilizing 12kV, 33kV, 55kV, and 115kV circuit breakers and associated equipment.

The Casa Diablo Substation was constructed and expanded from 1964 through 1974 with most of its current equipment having been installed during that time period. In addition, some pieces of equipment in-service within the Casa Diablo Substation was salvaged from other SCE substations dating back to the early 1950s.

Replacement of infrastructure at the Casa Diablo Substation is necessary as many of the circuit breakers, switches, and transformers at this substation have been in continuous use for between thirty and sixty-five years, have reached the ends of their useful lives, and must be replaced for reliability and safety. The replacement circuit breakers are expected to have a thirty-year reliable service life. The capital cost for this project is $2.990 million for 2019-2023.[107]

(2) **Project Scope**

The scope of this project involves installing new transformers, circuit breakers, disconnect switches, relays, and associated control and protective equipment. This will include inspecting and repairing foundations, cable trenches, and covers. Engineering and procurement activities, as required, are included in these costs. (Ref. 92)

(3) **Project Justification and Benefit**

The existing equipment at Casa Diablo Substation is old, making it difficult to find parts for repairs, as the aging equipment requires increasing levels of maintenance. Where replacement parts are not available, they must be specially fabricated, which can in some cases

[107] Refer to WP SCE-05, Vol. 1, Book A, p. 93.

increase the cost and the length of outages. The newly installed equipment will provide a higher reliability as the digital relays and micro-processors are less prone to failure than the existing electro-mechanical devices. Not performing this work increases the risk of a lengthy outage in the event of a failure. Also these relays are safety equipment, if they do not trip when needed there could be damage to the lines and other distribution equipment.

d) <u>Miscellaneous Electrical Equipment</u>

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 $5.110 million for 2019-2023. Table II-32 lists the projects and the cost for each replacement.

Table II-32
Miscellaneous Electrical Equipment
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
96	Mammoth Pool - Replace LV Switchgear	300	1,000	1,000	1,000	1,000	4,300
97	Kern River 3 - Station Light and Power	-	750	-	-	-	750
98	Inyo - Potential Transformer (PT) Replacements	60	-	-	-	-	60
	Grand Total	**360**	**1,750**	**1,000**	**1,000**	**1,000**	**5,110**

(1) <u>Background</u>

The 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.

(2) <u>Project Scope</u>

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. (Ref. 96-98)

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

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.

e) **Mammoth Pool Low Voltage Switchgear**

(1) **Background**

The Mammoth Pool Low Voltage Switchgear supplies balance of plant (BOP) electrical power to the auxiliary equipment and lighting in the powerhouse. All of the switchgear system is old and obsolete, and has outlived its useful life. Replacement parts are difficult to obtain and the equipment lacks modern safety-protection features and the physical space for expansion to meet upgrades to, or the addition of, BOP equipment and instrumentation. The capital cost for this project is $4.300 million for 2019-2023.[108]

(2) **Project Scope**

The scope of work includes engineering, design, procurement, installation, and startup activities related to the replacement and/or upgrade of the aged and overloaded Low Voltage Switchgear system and associated equipment and cables with new ten compartment Low Voltage (240V Rated) Switchgear that includes Arc Flash Protection System. The scope of the project will include the removing existing equipment, modifying foundations and support structures, installing new equipment, removing/reinstalling control wiring and power cables, and testing/commissioning of new equipment. (Ref. 96)

(3) **Project Justification and Benefit**

Station service power is essential for proper functioning of the power plant. Replacing and upgrading the current electrical equipment and components will help to ensure plant reliability. Planned repair and /or replacement require significant shorter outage periods as compared to a forced outage due to an in-service failure which lengthens the outage due to the long lead times for replacement part procurement. An economic analyses has been performed demonstrating the economic benefit of this project at a benefit-to-cost ratio of 2.4.[109]

7. **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,

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[108] Refer to WP SCE-05, Vol. 1, Book A, p. 96.

[109] Refer to WP SCE-05, Vol. 1, Book A, pp. 97-98.

and installing dam safety video surveillance equipment. The Structures and Grounds capital forecast for Hydro projects is $26.054 million for 2019-2023.[110] Table II-33 lists the programs and major projects for the Structures and Grounds category.

Table II-33
Structures and Grounds Programs
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
99-101	High Pressure Piping Replacment	310	1,000	2,570	4,210	4,700	12,790
102-105	Hydro Road Improvement and Paving	2,150	600	558	1,500	1,000	5,808
106-111	Miscellaneous - Structures and Gounds	6,206	1,250	-	-	-	7,456
	Grand Total	**8,666**	**2,850**	**3,128**	**5,710**	**5,700**	**26,054**

a) High Pressure Piping Replacement/Refurbishment Projects

(1) Background

Big Creek powerhouses utilize high pressure water from penstocks to cool bearings and for other purposes. The piping in powerhouses at Big Creek 3, Big Creek 4, and Big Creek 8 are virtually all original installations 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 3, Big Creek 4, and Big Creek 8 powerhouses as well. The thinning of the piping walls creates a significant safety hazard and a reliability risk of unplanned outages. As shown in Table II-34, the capital cost for these projects is $12.790 million for 2019-2023.[111]

Table II-34
High Pressure Piping Projects
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
99	Big Creek 4 - High Pressure Piping Replacement	310	1,000	1,500	1,500	1,500	5,810
100	Big Creek 8 - High Pressure Piping Refurbishment	-	-	500	2,000	2,000	4,500
101	Big Creek 3 - High Pressure Piping Refurbishment	-	-	570	710	1,200	2,480
	Grand Total	**310**	**1,000**	**2,570**	**4,210**	**4,700**	**12,790**

[110] Refer to WP SCE-05, Vol. 1, Book A, pp. 99-108.

[111] Refer to WP SCE-05, Vol. 1, Book A, pp. 102-104.

(2) **Project Scope**

The project scope for the Big Creek 3, 4, and 8 High Pressure Piping projects are similar and include 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. (Ref. 99-101)

(3) **Project Justification and Benefit**

The High Pressure Piping projects are 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.

b) **Road Improvements and Repaving**

Hydro maintains approximately 120 miles of private roads located throughout our hydroelectric system to access our remote sites. We are anticipating approval of the Big Creek ALP FERC license conditions, which will require us to assume maintenance responsibility for an additional 70 miles of mountain roads. Capital projects include major repairs to existing roads and other road improvements to address traffic safety and help ensure safe transportation of large equipment to and from job sites. Most roads are in areas with severe weather, and experience significant snow plow damage, high rain and snow-melt erosion along the shoulder or across the lanes, and several “freeze and thaw” cycles each year. Also, these roads are generally located in steep terrain and in areas where only a limited amount of road base preparatory work is practical. Hence, subsurface settlement and movement also stresses the roads, creating fractures and potholes that quickly grow when subjected to the elements.

SCE provides road maintenance as needed. However, complete restoration of the asphalt surface is still necessary every ten to fifteen years. Almost all roads are in relatively remote areas. Road repair projects incur added material transportation costs and premiums paid for labor. The capital cost for these projects is $5.808 million for 2019-2023. Table II-35 below, provides a list of the four forecasted Road Improvement and Paving projects and the cost for each.

Table II-35
Hydro Road Improvement and Paving
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
102	Big Creek - Canyon Road Asphalt Paving Refurbishment	2,000	600	-	-	-	2,600
103	Huntington Lake - Dam Bridge Load Capacity Increase	-	-	-	1,500	1,000	2,500
104	Bishop 2 - Asphalt Pavement Replacement	-	-	558	-	-	558
105	Big Creek 4 - Access Road Refurbishment	150	-	-	-	-	150
	Grand Total	**2,150**	**600**	**558**	**1,500**	**1,000**	**5,808**

c) <u>Big Creek - Canyon Road Asphalt Paving Refurbishment</u>

(1) <u>Background</u>

The Canyon Road, used to access Big Creek Powerhouses 2/2A, 3, 8, Mammoth Pool Powerhouse and the Mid-Canyon Machine Shop, is degrading and in need of re-pavement to increase longevity of the access roads and to improve safety for driving conditions. The 2017 heavy winter conditions, and a Cal/OSHA visit, highlighted deficient areas of the access roads with cross slope issues, undersized or missing culverts, missing over the side drainages, and extended releases from Shaver caused damages to the road at Stevenson Creek Bridge. The capital cost for this project is $2.600 million for 2019-2023.[112]

(2) <u>Project Scope</u>

The scope of this project includes performing road re-pavement of selected locations along the Million Dollar Mile and Canyon Road areas with a rating of 3.5 or less. Paving will involve a 2 inch grind and overlay, except at Million Dollar Mile section where grinding and overlay will vary from 2 inch to 4 inch to create adequate cross slope for drainage. As part of this effort, large-scale survey work will be required to document and address slope issues. In addition, USFS permitting and coordination will be required on culvert upgrade scope. (Ref. 102)

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

The road improvement projects will improve traffic safety and allow for prompt response of our employees and safety personnel to the sites. Mitigation of cross slope issues and

[112] Refer to WP SCE-05, Vol. 1, Book A, p. 105.

other safety concerns which currently increase the risk to travel this road during the winter months. SCE will also repave known degraded areas to increase the longevity of the access roads and mitigate access restrictions due to road closures and/or other unplanned repairs.

d) <u>Huntington Lake Dam – Bridge Load Capacity Upgrade</u>

(1) <u>Background</u>

Access to Huntington Dam 1 is through a controlled-access road across USFS and SCE property. There are two bridges on this road, one across the reservoir spillway and one at the west end of Dam 1, that are SCE structures. An engineering assessment was performed to determine if the bridges were adequate to support typical heavy equipment that SCE uses in this area. The engineering report determined modifications are necessary to provide an adequate load rating. Currently the bridge is rated at 20T (tons), with some minor exceptions. This project will modify the existing structure to increase the load rating to 25T. The capital cost for this project is $2.500 million for 2019-2023.[113]

(2) <u>Project Scope</u>

The project includes engineering services, design drawings, and construction activities to increase the load rating from 20T to 25T for two bridges at Huntington Lake Dam 1. (Ref. 103)

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

The upgraded load rating is necessary to cover all proposed heavy equipment that needs to use the bridges. The project will reduce the risk of structural member failure, and increased accessibility for equipment for typical O&M tasks and future projects, decreasing the costs of those future projects because they will be easier to complete.

e) <u>Structures and Grounds Miscellaneous</u>

This category of work contains various projects, such as fiber communications installation, dam safety video surveillance and retaining wall refurbishments.

The capital forecast for these projects is $7.456 million for 2019-2023. Table II-36 lists the Miscellaneous Structures and Grounds projects and the cost for each.

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[113] Refer to WP SCE-05, Vol. 1, Book A, p. 106.

Table II-36
Miscellaneous Structures and Grounds Projects
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
106	Big Creek - Dam 1 Fiber Communications Installation	3,700	-	-	-	-	3,700
107	Hydro Dam Safety Video Surveillance Installation (Gen portion only)	1,200	1,200	-	-	-	2,400
108	Lee Vining - Substation Retaining Wall Refurbishment (Phase 6)	736	-	-	-	-	736
109	Vermilion - Staff Gauge Replacement	390	-	-	-	-	390
110	Decommissioning: Pedley Powerhouse	130	-	-	-	-	130
111	Kaweah 2 - Barrier Wall Extension	50	50	-	-	-	100
	Grand Total	**6,206**	**1,250**	**-**	**-**	**-**	**7,456**

f) <u>Big Creek – Dam 1 Fiber Communications Installation</u>

(1) <u>Background</u>

Reliable communications at Dam 1 has existed for many years. However, major elements of the East Incline 7kV Line burned down in a fire in 1994. In 2008, a project to rebuild the line and install fiber on a brand new line from Big Creek to Dam 1 was estimated to cost between $7 and $17 million dollars and SCE declined to pursue that large scale project. In 2013, the alarm contacts stopped functioning at the Dam 1 Intake Structure. A 2017 FERC special security inspection of Huntington Lake Dams identified a need to install reliable communication at Dam 1 and repair the door alarms at the Dam 1 intake structure. The capital cost for this project is $3.700 million for 2019-2023.[114]

(2) <u>Project Scope</u>

The project will install fiber optic cable on existing Big Creek/Portal 33kv line to Dam 1 via existing Grouse 7kV line (creating a connection through Camp 10 substation). Once fiber is installed, the existing communication line will be removed. The installation of interface panels at the Big Creek 1 penstocks valve houses, panels at the Dam 2 valve houses, and at Gate 1A/1B and intake structure at Dam 1 will be performed. In additional, environmental and USFS approvals will be necessary. Assessments, environmental approvals, and replacement of deteriorated poles began in 2018 with installation of fiber and upgraded controls scheduled to take place in the summer of 2019. (Ref. 106)

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

This project is necessary to comply with FERC's requirements that SCE install reliable communication to Dam 1 and repair the alarms at the intake structure. By installing fiber

[114] Refer to WP SCE-05, Vol. 1, Book A, p. 107.

from Big Creek 1 to Dam 1, the fiber will also allow operations to upgrade its controls to increase reliability and enable the remote operation of gates and valves.

g) <u>Hydro Dam Safety – Security Cameras</u>

Hydro operates and maintains twenty-two dams that are considered by FERC to be either large and/or high-hazard dams, and many of these facilities are located in mountainous terrain at elevations over 7,000 feet above sea level. These locations are often remote and difficult places to work and/or maintain a continuous workforce presence. SCE's dams are under FERC jurisdiction and FERC has an ongoing effort to increase the safety of dams across the U.S. by improving the monitoring of dams and their ability to withstand natural disasters, including seismic events (earthquakes) and severe storms.

(1) <u>Background</u>

Certain dams, including those in the Eastern Operations region, are considered both high-hazard and time-sensitive. Time-sensitive means that emergency services need to be promptly notified in case of a dam failure for potential evacuation of downstream towns. Currently, SCE monitors its dams through remote sensors that measure water levels and water flows. When a sensor returns an unexpected or abnormal reading (which frequently occurs), an operator must travel to the dam to perform a visual inspection. In many cases, the travel time required can exceed two hours, which in an emergency condition is not adequate. The total capital forecast for this project is $5.180 million and the Hydro portion of this project is $2.400 million for 2019-2023.[115] Please refer to SCE-06 Vol. 1 Part 2, for the IT portion of this project.

(2) <u>Project Scope</u>

In general, the project scope at each dam will be similar and includes the engineering, permitting, and construction work necessary to install cameras and communication equipment (satellite and/or microwave links), which will allow personnel to remotely monitor dam sites. (Ref. 107)

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

As noted above, FERC has an ongoing effort to increase dam safety across the U.S. The primary benefit of this project is improved response time to a pending or developing dam

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[115] Refer to WP SCE-05, Vol. 1, Book A, p. 108.

failure by adding visual surveillance capabilities to high-risk dams, and removing the need to send operations personnel to perform visual inspections when abnormal sensor readings are received.

8. Decommissioning: San Gorgonio

a) San Gorgonio Hydro Project

The San Gorgonio project is being decommissioned. Due to contractual obligations and proposed U.S. Forest Service requirements, SCE anticipates it will be required to do significant construction work on the San Gorgonio facilities before turning the project over to the local water agencies.

(1) Background

San Gorgonio 1 (SG1) and San Gorgonio 2 (SG2) were constructed in 1923 with respective capacities of 1.5 MW and 0.94 MW. To enhance the flow in the San Gorgonio River, additional flow was diverted from the Whitewater River, which would normally flow to the Morongo Valley. This diverted water in the San Gorgonio River flows to Banning, not the Morongo Valley, which caused the Morongo Band of Mission Indians to lose water that would otherwise go to their reservation. The Morongo Band of Mission Indians contested the diversion, but were overruled, during the last FERC relicensing in 1983. FERC relicensing, which was due in April 2003, would have likely supported reinstating water flows to the Morongo Valley, likely resulting in a 50 percent loss of water for generation.

SG1 is located upstream from SG2, and flow from SG1 will feed SG2 from a flowline. This flowline travels 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. The operating capacity from 1975 to 1998 averaged 15 percent, compared to approximately 47 percent for SCE Hydro total. In fall of 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.

SCE decided not to pursue the FERC relicensing of the SG1 and SG2 facilities in 2001 when the FERC Notice of Intent was due for the 2003 expiration of the San Gorgonio FERC license. This was due to the high costs of maintaining and relicensing a low capacity factor, small generation facility, which needed major work and would likely lose a significant portion of its generation in the process of relicensing. The capital cost for this decommissioning project is $6.565 million for 2019-2023.[116]

(2) Project Scope

SCE is contractually bound to deliver water through its facilities to the downstream water user, Banning Heights Mutual. Therefore, SCE must convey the facilities in a condition that will pass water before Banning Heights Mutual will assume ownership. The following work must be done prior to conveyance to satisfy them and the US Forest Service:

- Reline canal sections from the East and South Forks of the San Gorgonio to Raywood Flats
- Refurbish the flowline from Burnt Canyon to below SG1
- Remove flowline trestles in Raywood Flats
- Remove all generation equipment, SG2 water tank, and some sections of flow line as directed by the US Forest Service (Ref. 112)

(3) Project Justification and Benefit

The San Gorgonio Decommissioning project will eliminate future costs for flowline upkeep, which was agreed to in historical water contracts. Future generation benefits from the two small powerhouses did not exceed the costs of returning the facility to service plus FERC relicensing cost.

D. Small Hydro Decommissioning Estimates

Until recently, decommissioning of SCE's small Hydro assets seemed unlikely because of their renewable benefits.[117] 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 accrue for their decommissioning beginning in Test Year 2021.

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[116] Refer to WP SCE-05, Vol. 1, Book A, pp. 109-112.

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

The following 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.

1. Continued Cost Effectiveness of SCE Small Hydro is Uncertain

The Big Creek system (1,015 MW) is a reservoir storage system with appreciable storage and significant economic benefits. SCE expects that the nine Big Creek powerhouses will continue to be economic and remain in service without the need for decommissioning for the foreseeable future. The Kern River 1 and Kern River 3 powerhouses account for approximately 66 MW of the 161 MW of assets outside of Big Creek. While Kern River 1 and 3 have no reservoir storage, their capacity factors have historically averaged 51%, and their size provides reasonable economies of scale.[118] Therefore, it is expected that these two powerhouses will also remain in-service for the foreseeable future.

Outside of Big Creek (1,015 MW)[119] and Kern River 1 & 3 (66 MW), the remaining 95 MW in SCE's Hydro portfolio can be classified as "small hydro."[120] The average output of SCE's small powerhouses us 4.3 MW, with the largest powerhouse rated at less than 13 MW.

While a small portion of these twenty-two 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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[118] Capacity Factor is a measure of the total electricity output of a generating plant (or collection of plants) expressed as the percentage of actual generation compared to the theoretical generation that would be achieved had the plant (or collection of plants) operated at full rated MW output for the entire defined time period (*i.e.*, typically defined as a calendar year). SCE's total combined Hydro assets have a historic average capacity factor of 40%.

[119] 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.

[120] While the Kern River 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.[121] Almost all of these small Hydro assets entered service between 1899 and 1929;[122] 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. An analysis of small and medium-sized hydro dams operated by Investor Owned Utilities across the U.S. found that, from the period of 2005 through 2014, 30% of the hydroelectric units were retired (417 out of 1,396), including 60% of units that were 2MW or smaller and exceeded an age of 90 years old.

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 ten 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-37 below.[123]

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[121] 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 inter-mingled 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.

[122] The Santa Ana River 3 powerhouse (3.1 MW) began operation in 1999, replacing the earlier Santa Ana River 2 and Santa Ana River 3 powerhouses (constructed in the late 1800s and early 1900s). The Santa Ana River 2 and 3 powerhouses were removed to build the Seven Oaks Dam.

[123] US Bureau of Reclamation, Risk Management Best Practices and Risk Methodology, Chapter A-6, Table A-6-1.

Table II-37
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 (18 CFR 6.1). The total decommissioning forecast of $905.2 million (in 2018 dollars), the probability-adjusted value of $325.7 million, and the plant-level probability estimates are summarized in Table II-38.

Table II-38
Small Hydro Decommissioning Estimate
(2018 $Millions)

Plant	Nameplate Capacity (MW)	License Expiration	Decom. Estimate ($2018 Millions)	Decom. Prob. (1%, 10%, 50%, 90%, 99%)	Approx. Year Decom. Would Begin	Probability-Adjusted Decom. Estimate	Decom. Estimate Source
Borel	12.0	2046	$ 117.1	99%	2025	$ 116.0	A
Rush Creek (Agnew, Rush M.)	-	2027	$ 46.3	90%	2027	$ 41.7	B
Rush Creek (Gem)	13.0	2027	$ 167.1	50%	2027	$ 83.6	B
Lower Tule River	2.5	2033	$ 21.9	50%	2033	$ 11.0	C
Kaweah 1-2	4.1	2021	$ 88.8	10%	2021	$ 8.9	D
Kaweah 3	4.8	2021	$ 45.8	50%	2026	$ 22.9	D
Lundy (Mill Creek)	3.0	2029	$ 17.7	10%	2029	$ 1.8	E
Bishop Creek 2-6	29.3	2024	$ 214.2	10%	2024	$ 21.4	F
Poole (Lee Vining Creek)	11.3	2027	$ 82.4	10%	2027	$ 8.2	F
Fontana	3.0	N/A	$ 11.3	10%	2033	$ 1.1	F
Lytle Creek	0.5	2033	$ 15.8	10%	2033	$ 1.6	F
Mill Creek No. 1	0.8	N/A	$ 7.1	10%	2033	$ 0.7	F
Mill Creek No. 3	3.0	2033	$ 24.2	10%	2033	$ 2.4	F
Ontario No. 1	0.6	N/A	$ 10.9	10%	2033	$ 1.1	F
Ontario No. 2	0.3	N/A	$ 5.3	10%	2033	$ 0.5	F
Santa Ana 1 & 3	6.3	2033	$ 24.2	10%	2033	$ 2.4	F
Sierra	0.5	N/A	$ 5.1	10%	2033	$ 0.5	F
TOTALS:	**95.0**		**$ 905.2**			**$ 325.7**	

Source Notes	
A -	2017 Cardno - Decommission of Borel Hydroelectric Project
B -	2019 SR Diversified - Rush Creek Hydro System Conceptual Decommissioning
C -	2017 SR Diversified - Lower Tule System Project Class 4 Estimate Narrative
D -	2015 Cardno - Kaweah Hydroelectric Project Decommissioning Conceptual-Level Economic Analysis
E -	2017 Stantec - Lundy Lake Hydroelectric System: Decommissioning and Alternatives Study
F -	2012 GRC Small Plant Study

a) Decommissioning Estimate Scope of Work

The conceptual-level decommissioning estimates referenced in Table II-38 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. The cost estimates and respective assumptions are provided in workpapers accompanying this testimony.[124]

[124] Refer to WP SCE-05, Vol. 1, Book A, pp. 113-194 and SCE-05 Vol. 1 Book B pp. 3-162.

3. Rationale Behind Probability Selections

SCE expects 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 5 to 10 years.

a) Borel Powerhouse (99% or "Virtually Certain" Probability)

The Borel Powerhouse water conveyance system is supplied via an intake structure (essentially a tunnel) traveling through the Lake Isabella dam, which is owned and operated by the U.S. Army Corp of Engineers (ACOE). A seismic study performed in 2006 revealed a seismic fault running through the Lake Isabella Dam structure. Subsequent ACOE engineering studies have determined that major modifications to the existing dam are required to meet seismic standards.

In the fall of 2018, the ACOE began construction activities and condemned the SCE tunnel easement, rendering SCE's Borel project inoperable.[125] In March of 2019, at the request of FERC, SCE began the process of license surrender, and is targeting 2021 for submission of the license surrender application to FERC.

SCE estimates a 99% probability that the Borel project will initiate decommissioning work within the next 5 years.[126] The cost estimate of decommissioning the Borel Powerhouse and upper and lower canals is $117.1 million ($2018).[127] SCE is in discussions with the ACOE regarding the potential to share the decommissioning costs facing the Borel project; should that result in a contribution from the ACOE, SCE would pass those savings along to ratepayers.

b) Agnew Lake and Rush Meadows Dams (90% or "Very Likely" Probability)

The Rush Creek system has dams at three lakes: Rush Meadows, Gem, and Agnew. The system's generating facilities are fed via Gem Lake; the ability to generate power does not depend on water from the Rush Meadows and Agnew Lake dams and associated infrastructure.

In 2007, a seismic study performed by the California DSOD identified the Silver Lake seismic fault as a potential concern for the three Rush Creek Dams. Detailed investigation of the seismic fault led to SCE's voluntary restriction of water levels in 2012 and 2013 within the three

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[125] The tunnel was the only source of water feeding the Borel powerhouse.

[126] SCE utilizes the US Bureau of Reclamation Risk Management Best Practices and Risk Methodology, Chapter A-6, Table A-6-1 to determine a suggested probability of Decommissioning occurrence.

[127] Refer to WP SCE-05, Vol. 1, Book A, pp. 114-123.

reservoirs to reduce hydrostatic pressure/forces on the dams, and to reduce the water level below the area most vulnerable to a seismic event (i.e., upper portion of the dams). In 2017, in anticipation of record precipitation, SCE added notches (i.e., cut large holes) to the Agnew Lake Dam to facilitate the safe and controlled passage of water during high runoff years. SCE notched the Rush Meadows Dam in 2018.

Seismic retrofitting cost estimates range between $135.0 and $243.0 million, which exceeds decommissioning estimates.128 As neither of these two dams are required for generation, and current year-round lower reservoir levels do not meet FERC license conditions—which require higher water levels for recreation and aesthetics many months throughout the year—SCE estimates the probability at 90% that it will initiate decommissioning of the Rush Meadows and Agnew Lake dams within the next 5 to 10 years. The current cost estimate of decommissioning these two dams is $46.3 million ($2018).[129]

c) <u>Gem Lake, Kaweah 3, and Tule (50% or "Equally Likely" Probability)</u>

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 Rush Creek 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 3 powerhouse is located within Sequoia National Park, and requires a Special Use Permit (SUP) from the National Park Service. Operation of Kaweah 3 beyond 2026 requires a new SUP, which would require negotiations with the National Park Service, agreement on fees, agreement on 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 as a result of damage from a 2017 fire. The cost to repair and continue operation depends on methods of construction (*e.g.*, metal vs.

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[128] Refer to WP SCE-05, Vol. 1, Book A, pp. 124-151.

[129] Refer to WP SCE-05, Vol. 1, Book A, pp. 124-151.

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%.

d) Remaining Portfolio (10% or "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 farther 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 1-2 and Bishop Creek 2-6, 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.

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 1,104 MW (nominal);[130] five combustion turbine Peaker power plants (Peakers) with an aggregate capacity of 245 MW; six diesel engine generators at SCE's Pebbly Beach Generating Station (PBGS) with a capacity of 9.4 MW, twenty-three 65 kilowatt (kW) propane-fueled micro turbines, and one 1.0 MW energy storage battery;[131] and two Fuel Cell generating plants with a combined total capacity of 1.5 MW. This section of testimony presents SCE's 2021 Test Year O&M expense forecast of $29.409 million (constant 2018 dollars) for Mountainview, $7.624 million for the Peakers, $5.481 million for Catalina, and $0.491 million for Fuel Cell. SCE also presents its 2019-2023 capital expenditure forecast of $66.618 million (nominal dollars) for Mountainview, $4.900 million for the Peakers and $40.160 million for Catalina.

B. Mountainview Generating Station

1. Summary of Request – Mountainview

The 2021 O&M expense forecast for Mountainview is $29.409 million.[132] Forecasted costs includes the costs of major maintenance planned for 2021/2022. 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 2021 Test Year O&M expense forecast is based on 2018 recorded expense for labor, a four-year average of the 2015 through 2018 recorded expense for non-labor, and one-third (*i.e.,* the 2021 through 2023 annual average) of the forecasted cost of the Mountainview Major Inspection Overhaul planned for 2021/2022.

Approximately every four years, each of the two generating units at Mountainview undergoes major maintenance. This major maintenance consists of either a Hot Gas Path Inspection (HGPI) overhaul or Major Inspection (MI) overhaul. HGPI overhauls were performed on both units in

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[130] In mid-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 1,104 MW. The plant's actual maximum MW output varies above and below this value, as a function of ambient weather.

[131] This Energy Storage Battery is part of the Catalin generation, and not related to the Energy Storage activity discussed in SCE-02 Vol. 4 Part 1, Grid Modernization, Grid Technology, Energy Storage.

[132] Refer to WP SCE-05, Vol. 1, Book B, p. 168.

2016; MI overhauls are scheduled to occur on Unit 3 in the fall of 2021 and on Unit 4 in the spring of 2022. Accordingly, consistent with prior GRCs, the Mountainview annual forecast includes one-third of the forecast costs for the planned 2021/2022 MI overhauls

The capital forecast for Mountainview is $66.618 million for 2019-2023.[133] This forecast largely includes projects required to sustain station reliability. Additional information regarding Mountainview capital projects is contained in Section 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 contains two combined-cycle gas turbine 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 1,104 MW (nominal) of power, with low air emissions and high fuel economy. Each of the Units 3 & 4 has two General Electric (GE) "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-4 provides an overhead photograph of Mountainview, which includes the following additional major equipment components:

- Water treatment system to treat cooling tower blowdown, thereby minimizing plant waste water 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;

[133] Refer to WP SCE-05, Vol. 1, Book B, p. 183.

- 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-4
Mountainview Generating Station

Mountainview typically is operated as "intermediate duty" capacity where the units are dispatched in a manner that follows customer load demand. The Mountainview units are relatively quick starting and are highly fuel efficient. Over the past five-years (*i.e.,* 2014-2018) Mountainview Units 3 & 4 have generated on average 4,572,039 net megawatt-hours (MWh), with an overall average capacity factor of 50.0%.

b) <u>Plant Operational Performance Objectives</u>

(1) <u>Safety</u>

Mountainview's highest priority is worker and public safety. The station maintains a robust safety program. 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.

(2) <u>Reliability</u>

Reliability also is an important performance objective for SCE's generation assets including Mountainview. Mountainview is subject to a reliability incentive (*i.e.,* an availability incentive) that provides SCE monetary bonuses or penalties if Mountainview's availability performance is above or below pre-established target levels. Mountainview's performance relative to this incentive is reviewed in SCE's annual Energy Resource Recovery Account (ERRA) Review of Operations proceedings. SCE's 2018 ERRA filing, A.19-04-001, contains details of this incentive.

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, including costs for the GE Contract Service Agreement (CSA). 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.

(3) <u>Heat Rate</u>

Heat rate is a measure of power plant fuel efficiency (*i.e.,* the amount of natural gas fuel consumed in BTUs for each kWh of electricity produced). Fuel is the major cost component of natural gas fueled power plants like Mountainview, which operate for significant periods of time each year. Heat rate performance is affected by normal equipment degradation occurring over time and between overhauls. It is also impacted by the added fuel requirement attributable to the number of start-ups per year, changing load, operating at reduced power output, or operating in off-design conditions where equipment operates less efficiently. An example of this is operating during a hot and humid day when the evaporative coolers have limited effect on cooling the gas turbine inlet air, which reduces efficiency. A baseload plant, which operates primarily at or near rated MW output and with relatively fewer start-ups and shutdowns in a year, will typically have a better annual average heat rate than a highly dispatched plant that is started and shut down more frequently.

Mountainview's heat rate performance is tracked by conducting tests twice each year following the spring and fall planned maintenance outages. The test results are compared to previous annual tests, and to the baseline test conducted in January 2006 when the plant was first placed in service. The test results show slight heat rate degradation since full operation commenced in 2006, due to normal equipment wear and tear. Such degradation can be partially recovered (but normally not fully recovered) during the plant's periodic overhauls.

Like the reliability incentive discussed above, Mountainview's annual heat rate performance is also subject to an incentive. The heat rate incentive specifies that Mountainview shall test its heat rate at the end of every summer season, and at the end of every winter season (*i.e.,* two tests per year). The test results are adjusted for variables beyond SCE's operational control, such as weather and normal expected (*i.e.,* non-recoverable) degradation. The incentive target heat rate performance band is to maintain the tested full load heat rate to within ± 3.0 percent of the recorded heat rate when the plant was new. Tested heat rate has been maintained within this target rate since commercial operations began, and no penalty or bonus has been incurred to date. This incentive is reviewed in SCE's annual ERRA proceedings. Further discussion of the heat rate incentive and Mountainview's heat rate performance can be found in SCE's 2018 ERRA filing, A.19-04-001.

(4) <u>Environmental and Regulatory Compliance</u>

Mountainview's air quality emissions are regulated by several permits, licenses, and other requirements, including a RECLAIM/Title V permit from South Coast Air Quality Management District (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 imposes 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 (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 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 aesthetics 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 waste water 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.

c) <u>Mountainview Maintenance Practices</u>

Much of the plant's 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).

(1) <u>Spring and Fall Planned Maintenance Outages</u>

Major maintenance includes periodic hot gas path inspection (HGPI) overhauls and major inspection (MI) overhauls. Initially, these overhauls occurred approximately every three years. Given that the turbine upgrade project completed in 2016 extended the overhaul maintenance interval, and based on expected operating profiles, we forecast that these overhauls will now (going forward) only be required approximately every four years.

In years for which no major maintenance is planned, the station 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.

The station also typically conducts a similar routine maintenance outage each fall to address concerns noted during the summer peak season. Hence, two planned outages are usually conducted on each unit each year. Going forward, approximately every four years, one of those outages will be an HGPI or MI overhaul that is conducted pursuant to the GE CSA.

(2) <u>Contract Services Agreement with General Electric</u>

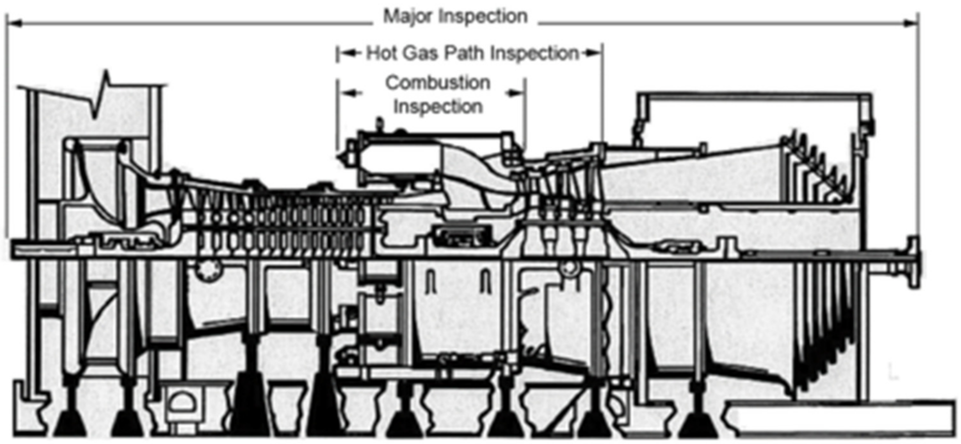
Mountainview uses GE-supplied major power island equipment including the combustion turbine generators, steam turbine generators, and controls. SCE purchased the plant from InterGen (a Shell-Bechtel subsidiary) while it was under construction in March 2003. This purchase included a GE Contractual Services Agreement (CSA). The CSA provides continuous condition monitoring and warranty repair coverage of GE furnished equipment. The CSA also provides major maintenance (*i.e.,* HGPI and MI overhauls), including parts and services. The original CSA had an estimated contract term of approximately seventeen years from the commencement of plant operations, subject to certain contractual conditions regarding operating-based and/or start-up based milestones. As will be discussed in further detail below, a new CSA was executed in 2015.

(3) <u>Scope of Major Maintenance Outages Including Overhauls</u>

In conformance with GE's maintenance recommendations and CSA contractual requirements, 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 generators: (1) combustion inspections (CI) including replacement of combustor parts; (2) HGPI overhauls including replacement of additional hot section components of the gas turbine; and (3) MI overhauls including additional component replacements of the combustion turbine compressor section, combustor, and turbine sections as well as overhaul of the steam turbine.

HGPI overhauls include all of the work performed during a CI plus a significant amount of additional work. Likewise, MI overhauls include all of the work performed during an HGPI overhaul plus significant additional work. Figure III-5 below, shows the areas of the combustion turbine targeted during each of these outages.

Figure III-5
Areas of Turbine Targeted During Inspections



(a) <u>Combustion Inspection</u>

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).[134] 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.

[134] For purposes of scheduling major maintenance and for determining CSA invoice amounts payable to GE, turbine operating hours are adjusted upward to compute "factored fired hours" using GE formulas that account for the added wear and tear associated with certain events. These events include cold start-ups (*i.e.*, as compared to hot start-ups) and sudden turbine trips.

(b) Hot Gas Path Inspection Overhaul

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 and with the CSA, prior to the 2016 turbine upgrade project, HGPI overhauls were planned approximately every 24,000 operating hours, or 900 startups, whichever occurred first. The exact schedule is determined by the on-site GE representative assigned to Mountainview and considers previous inspections and operating conditions during the previous operating cycle. 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, and as incorporated into the new 2015 CSA, 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.

(c) Major Inspection 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 included. Consistent with GE maintenance recommendations and the CSA, MI overhauls were conducted approximately every 48,000 operating hours or 2,400 startups, whichever occurred first. As with HGPI overhauls, the exact schedule is determined by the on-site GE representative. 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 we forecast will next occur in fall 2021 and spring 2022.

(d) Balance of Plant Maintenance during Major Inspection Outages

Both the new and old CSAs cover certain scheduled maintenance and break-down repair work on the plants' four combustion turbines and two steam turbines. The old

CSA had restrictions whereby significant turbine work was outside the CSA and therefore needed to be separately paid for by SCE (*i.e.,* besides the CSA payment). The new CSA has expanded the scope of the turbine work that is covered.[135] The new CSA scope also includes future generator overhauls that SCE expects to incur in 2021 and 2032 that were not covered under the old CSA.

Major overhauls also include maintenance work on many other equipment items that are not covered by either the old or new CSAs, which can be collectively referred to as balance-of-plant (BOP) equipment. To minimize total planned outage time over the plant's life, major planned maintenance needed on BOP equipment is typically performed during the relative long turbine overhaul outages, rather than during the shorter routine spring and fall planned outages. BOP equipment includes the plant's four heat recovery steam generators, numerous valves, fuel gas compressors, cooling towers, condensers, water treatment plant, generator step-up (GSU) transformers, 4.16 kV and 480V transformers, motors and pumps, collection sumps, and water retention basins, along with many other equipment items. Maintenance performed on this BOP equipment substantially contributes to the total costs of the scheduled plant overhauls, and is appropriately incorporated into SCE's Test Year O&M expense forecast, as further discussed in Section 4 below.

3. New GE Contractual Services Agreement and Turbine Upgrades

a) Execution of New CSA and Turbine Upgrades

In April 2014, SCE began exploring what actions SCE might take when Mountainview's combustion turbines reached 60,000 factored fired hours (the point at which, contractually, SCE could either exit the CSA by paying a $4.5 million termination fee or renegotiate with GE). During 2014, the 60,000 hours milestone was reached for each of the four units; unit 3A in the second quarter, units 4A and 4B in the third quarter, and unit 3B in the fourth quarter. SCE concluded the best strategy was to initiate negotiations for a new CSA agreement with GE, to determine if a new agreement could be achieved that would deliver significant positive net value to SCE customers.

The negotiations were successful. The new CSA agreement was finalized in June 2015, and among numerous other changes, included AGP/DLN upgrades of the plant's for combustion

[135] Refer to WP SCE-05, Vol. 1, Book B, pp. 174-175.

turbines.[136] The new CSA utilizes a simplified and less costly fee structure compared to the original CSA. Table III-39 below compares the two CSA agreements.

Table III-39
CSA Fee Comparison

Expense	Original CSA	New CSA
Quarterly Fees		
Fixed Fee	Significant cost item	Same
Variable Fee	Significant cost item	Reduced
Performance Fee	Significant cost item	None
Major Outage Fees		
HGPI Adder Fee	Significant cost item	None
Use Tax Reimbursement	Taxes owed on turbine parts provided as part of O&M fee structure	Reduced, but Sales Tax paid for Capital turbine part purchases
Cash Adjustment Fee	Based on true-up of Variable Fee	None
Total Escalation Factor	Custom escalation calculation	Escalation Factor: Fixed rate at a lower value than Custom rate
Capital	No capital work included	Includes capital upgrades

SCE installed the turbine upgrade components on the four existing combustion turbines as part of the regularly scheduled 2016 HGPI overhauls. These components are functionally identical to the previous equipment except that they are made from advanced materials that can withstand higher operating temperatures and more rapid heating and cooling. These improvements allow the plant to achieve high MWh outputs during warm weather, and improve plant heat rate, ramp rate, and turndown. The upgrade increases the approximate duration between overhauls from three years to four years, thereby reducing overhaul expenses and plant downtime.[137]

[136] The new CSA also includes additional future capital expenditures to replace the three remaining CT rotors (*i.e.*, the 3B replacement rotor was already procured in 2015) forecast to occur in 2022 at a cost of $54.0 million, and one Generator Field Rotor forecast to occur in February 2032 at a cost of $8.0 million. The CSA costs and savings discussed herein do not include these future capital projects.

[137] Further information regarding the new CSA and associated turbine upgrades, and cost benefits can be found in A.16-09-001 SCE-05, Vol. 4, pp. 19-23.

b) **Increased Scope Major Maintenance**

As noted above, the original CSA contained limitations on the scope of the turbine work covered. Covered work is expanded in the new CSA, as summarized in Table III-40. The increased CSA scope is expected to reduce SCE's future costs and other risks associated with planned and unplanned repairs to covered components. For example, based on analysis of the costs recorded during the 2013 MI overhaul, we expect an approximately $12.2 million (nominal) cost reduction to be realized during the upcoming 2021/2022 MI overhaul due to the CSA's increased scope.

Table III-40
CSA Scope Maintenance/Replacements Comparison

Original CSA Scope	New CSA Scope
Combustion Turbine: Limited to Combustion & HGP sections only	Combustion Turbine: Greater end-to-end coverage plus new AGP/DLN 2.6+ upgrade
CT Compressor section: Not covered	CT Compressor section: Covered
Steam Turbine & Associated Valves: Inspection only	Steam Turbine & Associated Valves: Covered
Electrical Generator: Inspection only	Electrical Generator: Covered
No heavy lift equipment and transportation	Heavy lift equipment/scaffolding/ transportation: Included

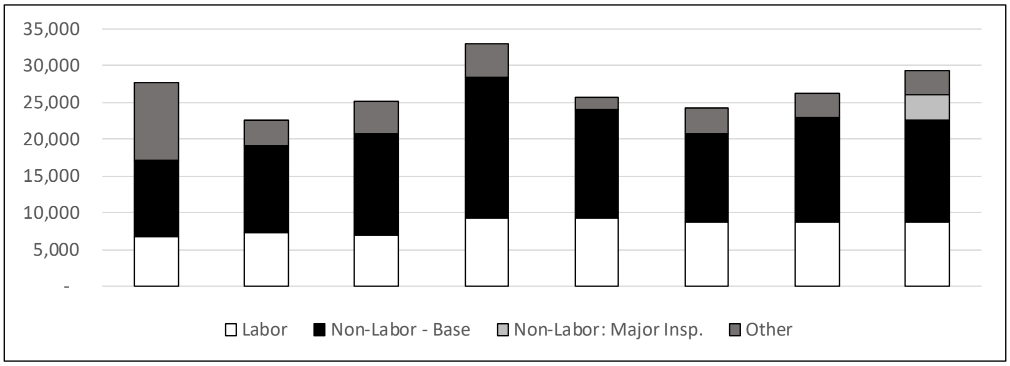
4. **Mountainview O&M Expense Forecast**

a) **Introduction**

SCE's total Mountainview Test Year O&M expense forecast of $29.409 million is summarized in Figure III-6. The figure shows the recorded expenses for 2014-2018 and the forecast expenses for 2019-2021. 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 and the GE CSA expenses.[138]

[138] 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 $2018 constant dollar basis unless otherwise noted.

Figure III-6
Mountainview - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	6,798	7,290	6,907	9,226	9,363	8,763	8,763	8,763
Non-Labor - Base	10,252	11,773	13,934	19,273	14,756	12,026	14,107	13,875
Non-Labor: Major Insp.	-	-	-	-	-	-	-	3,333
Other	10,563	3,535	4,346	4,393	1,477	3,438	3,438	3,438
Total Expenses	27,613	22,598	25,187	32,893	25,596	24,227	26,308	29,409
Ratio of Labor to Total	33%	48%	38%	39%	58%	57%	50%	42%

b) <u>Development of Test Year Forecast</u>

The 2021 Test Year forecast of $29.409 million includes four cost components. These are briefly summarized below, and are also 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 cost of incremental work performed during overhauls not covered by the below CSA fees. This balance of plant (BOP) overhaul work 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 includes the interconnection fees SCE must pay to be connected to the grid and the quarterly fees and payments for the CSA contract. The CSA fees include both milestone payments, including fixed fees and variable (*i.e.,* production based) fees, which are calculated by multiplying the factored fired hours (FFH) by a fixed rate for each of the four combustion turbines.

(1) <u>Labor – Analysis of Recorded and Forecast Expenses</u>

While labor expenses remained relatively stable from 2014-2016, the increase in 2017 expenses can largely be attributed to increased maintenance activities undertaken during an unplanned outage that began in late-2017 and continued into early-2018; and the completion of the consolidated Mountainview/Peaker/Solar Control Center project in late 2016 which combined the former Westminster Peaker Control Room and the old Mountainview Control room into a new Eastern Operations Generation Control Center (EOGCC) located on the site of Mountainview Generating Station, in Redlands (*i.e.,* Operators who had formally recorded their labor costs to the Peakers Operations and/or Solar Operations accounts began to instead record to the Mountainview Operations Accounts). Labor expenses remained relatively consistent between 2017 and 2018.

Because the scope of work performed in 2018 most closely matches the planned scope of work in 2021, the last recorded year (2018) is our basis to forecast future labor expense for Test Year 2021.[139] To this base forecast of $8.763 million, we apply the downward adjustment discussed below.

In mid-2016, the Generation Department initiated a number of process changes that increased productivity and reduced overall labor expenses. As mentioned previously, part of these process changes involved the centralization of station Operators from various locations into the new Eastern Operations Generation Control Center at Mountainview which occurred in late-2016. Additionally, some of these Operators had reached retirement age and chose to voluntarily leave the company following the 2016 reorganization. This combination of events left a deficiency within the Operations staffing levels requiring the remaining Operators to increase levels of overtime shift work. To address the shortfall in Operator staffing levels, SCE initiated the hiring of Apprentice Operators. In many cases, Apprentices must complete a training regimen that can take between 12 and 18 months

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[139] Refer to WP SCE-05, Vol. 1, Book B, pp. 170-171.

before becoming fully qualified trained Operators (*i.e.,* ability to work alone without a fully trained and qualified Operator present to oversee their work). The first group of Apprentice Operators, hired in early 2017, have completed their formal training and their assumption of normal duties has started to lower overtime requirements. As a result, we have made a downward adjustment of $0.600 million (*i.e.,* a 6.0% reduction) to the 2018 recorded labor expense of $9.363 million, yielding a Test Year forecast of $8.763 million for Mountainview Labor.

(2) <u>Base Non-labor – Analysis of Recorded and Forecast Expenses</u>

As previously explained, in 2014 the Mountainview facility was operating under the old CSA structure. In anticipation of increased maintenance coverage under the new CSA, during the 2015 contract negotiations SCE chose to defer less critical maintenance work into 2016 to coincide with work planned during the 2016 AGP/DLN Upgrade. The higher costs recorded in 2017 are attributable to an unplanned outage that occurred in late 2017.[140]

Due to the inherent year-to-year variations of non-labor, a historical average is most representative of non-labor expenses that can be expected in Test Year 2021. We selected a 4-year average (*i.e.,* 2015-2018; excluding 2014 when costs were incurred under the old CSA) as the basis to forecast a non-labor expense of $13.875 million for Test Year 2021.

(3) <u>Incremental Non-Labor Overhaul Costs for the 2021/2022 Major Inspection</u>

Major maintenance continues to be the major driver of Mountainview O&M expenses from year to year. Although the structure of the new CSA has lessened year-to-year variability, costs incurred during overhaul years will continue to be higher than other years.

The cost variability of periodic overhauls is not unique to Mountainview. 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.[141] The Commission reasoned that it did not want

[140] 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.

[141] D.04-07-022, pp. 71-72.

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.[142]

Consistent with prior GRC decisions, the Mountainview 2021 Test Year O&M expense forecast includes the annual average cost forecast to be incurred during 2021 through 2023 for the planned 2021/2022 MI overhaul. Continued use of this approach will facilitate 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 forecasted incremental non-labor cost for the 2021/2022 overhaul is $10.000 million.[143] Specifically, we add one-third (*i.e.,* $3.333 million) of this $10.000 million overhaul cost (*i.e.,* the average annual overhaul cost during 2021 through 2023) to the 2021 Test Year base forecast.

(4) <u>Other - Analysis of Recorded and Forecast Expenses</u>

The Mountainview other expense category consists of CSA expenses and 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 an "other" expense). CSA expenses are deemed to be “other” because the CSA utilizes a specific escalation factor. Expenses were high in 2014 because Mountainview was still operating under the “old” CSA payment terms and conditions, which were more expensive.

Annual other expenses vary between 2015-2018 due to variances in run-time hours that are largely affected by CAISO dispatch and length of outages.[144] Due to the inherent variations of non-labor in this account, a historical average is most representative of non-labor expenses that can be expected in this account in Test Year 2021. We selected a four-year average (*i.e.,* 2015-2018;

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[142] Ibid.

[143] Refer to WP SCE-05, Vol. 1, Book B, pp. 176-180.

[144] Mountainview’s capacity factor averaged 65% from 2007 through 2015. It was 53% in 2016, 44% in 2017 and 21% in 2018. Although outages played a part in lowering the capacity factors in 2016-2018 it appears that the significant increases in renewable energy coming on-line is increasing energy supply during certain periods, lowering market clearing prices and causing Mountainview to be economic to run fewer hours during the year. This trend will likely continue as more renewables are brought on-line to meet increasing Renewable portfolio Standards.

excluding 2014 when costs were incurred under the old CSA) as the basis to forecast non-labor expense for Test Year 2021, which is $3.438 million.

c) Mountainview O&M Work Activities

The Mountainview Operations Work Activity comprises all labor and non-labor expenses that record as operations-related expenses. As further discussed in the sections below, these activities include operation supervision and engineering, general expenses, miscellaneous other power generation expenses, and rentals.

(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 waste water 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, waste water discharge lines or transmission corridors.

d) Mountainview Maintenance Account O&M Expense Analysis

The Mountainview Maintenance work activity includes all labor, non-labor, and other (*e.g.*, the GE CSA 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. The labor and non-labor portions of this work capture the costs of maintenance activities on the plant's core power generating equipment that are outside of the scope of the CSA contract. The other category within this activity specifically records costs for the GE CSA. This is the only Mountainview account that captures other expenses, which consist solely of the various fees payable under the CSA governing technical support 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, waste water 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. Our forecast of Mountainview capital expenditures total $66.618 million for 2019-2023, as summarized in Table III-41 below.

Table III-41
2019-2023 Mountainview Capital Expenditure Forecast
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
113	Rotor Replacements	-	18,000	36,000	-	-	54,000
114	GE (Mark VIe) Control Upgrade	-	-	6,000	-	-	6,000
115	Spare Transformer Rewind	-	3,000	-	-	-	3,000
116	Relay Replacements	640	900	-	-	-	1,540
117	Startup/Shutdown Standardization & Automation	250	750	440	-	-	1,440
118	Storage Building	338	-	-	-	-	338
119	Cooling Tower Deluge system replacements	-	300	-	-	-	300
	Grand Total	**1,228**	**22,950**	**42,440**	**-**	**-**	**66,618**

The following sections of testimony provide further discussion of Mountainview capital projects exceeding $1.500 million.

a) Rotor Replacements

(1) Background

In June 2015, SCE successfully negotiated a new Contractual Services Agreement (CSA) with GE. The new CSA included numerous changes, including the Advance Gas Path and Dry Low NOx upgrades which were completed in 2016, and the capital expenditure for four new combustion turbine rotors. One of which was procured in 2015. SCE is required by the CSA to take delivery of the three remaining combustion turbine rotors no later than December 15, 2021.[145]

[145] Refer to WP SCE-05, Vol. 1, Book A, CONFIDENIAL p. 47.

(2) **Project Scope**

SCE will order and accept delivery of three new rotors and store them until such time as any installed rotor requires replacement.

(3) **Project Justification and Benefit**

In addition to being contractually obligated to take delivery of the replacement combustion turbine rotors, the renegotiated CSA provided a $237.1 million ($2016 present worth) benefit to SCE customers.[146] The purchase and ultimate installation of the replacement rotors will allow the Mountainview facility to maintain a high level of safe and reliable operation.

b) **GE (Mark Vle) Control Upgrade**

(1) **Background**

The GE controls manage the plant's core turbine-generator equipment, which began commercial service in January 2006. The current control system at Mountainview is a hybrid of the old GE Mark V control system and a newer version called Mark VI. The hybrid is a result of major upgrades that were installed in the plant in 2016. Many of the Mark V components, such as control cards, are obsolete and are no longer supported by the manufacturer. The hybridized nature of the system has caused premature failure of control cards and Mountainview currently has a limited supply of control cards and replacements will not be available once this supply is exhausted. The capital cost for this project is $6.000 million for 2021.[147]

(2) **Project Scope**

The Mountainview Distributed Control System (DCS) manages all of the systems that are operator controlled and not controlled by the GE control system. This includes the BOP equipment such as the gas supply system, cooling system, water treatment system, and other plant equipment. Complete conversion to the Mark VI control system will involve both hardware and software upgrades and will enable Mountainview to maintain GE product support for an additional ten to fifteen years.

(3) **Project Justification and Benefit**

Digital control components have a typical life cycle of ten to fifteen years, consistent with digital component life expectancy due to the continuing high rate of technological

[146] A.16-09-001: SCE-05, Vol. 4, p. 19.

[147] Refer to WP SCE-05, Vol. 1, Book B, p. 185.

advancement, and the lack of legacy system support, including, difficulty in procuring spare parts. When the controls are replaced in 2021, they will be approximately fifteen years old. This upgrade will enable Mountainview to upgrade to current level of technology and maintain GE product support for an additional ten to fifteen years.

c) <u>Combustion Turbine Generator – Spare Transformer Rewind</u>

(1) <u>Background</u>

Mountainview Generating Station was placed in full commercial operation in January 2006. Mountainview's two combined cycle units each consist of two combustion turbine generators (CTGs) and one steam turbine generator (STG). Both CTGs are electrically connected to a single transformer and the STG is electrically connected to a separate and different transformer. These transformers are not interchangeable and each of uncommon design. Because of the uncommon design features, no transformers are available for immediate rent or purchase if one should fail. Because the lead time to order and fabricate a replacement could approach 18 months, SCE purchased two spare transformers (one common spare for the four CTGs, and one for the two STGs).

In 2018, during a regularly scheduled maintenance outage, the Unit 3 CTG transformer underwent a routine inspection and was determined to be unsuitable for return to service, and therefore replaced by the spare CTG transformer. The station is now left without a spare CTG transformer, and if another should fail it would result in a lengthy forced outage. The capital cost for this project is $3.000 million for 2020.[148]

(2) <u>Project Scope</u>

The project scope is to ship the removed CTG transformer to an authorized vendor so that it can be refurbished and rewound. Upon completion, the spare transformer will be stored onsite at Mountainview for rapid installation should an in-service transformer failure occur. (Ref. 115)

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

The lead time to order and fabricate a replacement transformer is approximately 18 months. A failure of one gas turbine transformer or of the steam turbine transformer, on either Unit 3 or Unit 4, would require a lengthy shutdown of that unit. This would restrict station capacity by half (*i.e.,* 552 MW). Transformer failures occasionally occur and replacement transformers

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[148] Refer to WP SCE-05, Vol. 1, Book B, p. 186.

take many months to fabricate; therefore, most utility power plants maintain spare transformers. Although the probability of a transformer failure at Mountainview is small, a long outage could have a significant financial impact on our customers including replacement power costs. Having appropriate spare transformers will mitigate the length of an unplanned outage. The economic evaluation yielded a benefit to cost (B/C) ratio of 5.2 for this project.[149]

d) Relay Replacements

(1) Background

The existing relays at the Mountainview Generation Station are Original Equipment Manufacturer (OEM) and have reached the end of their useful life. Mountainview has been informed by the OEM that it no longer supports these relays and recommended replacement. SCE commissioned a 2017 study of the existing relays by Power Engineers who also recommended replacement. The capital cost for this project is $1.540 million for 2019-2020.[150]

(2) Project Scope

This project will replace the six existing primary generator relays and four transformer primary relays. They will be replaced with new Schweitzer 300G relays for the generators and new 487E relays for the transformers. The existing racks will be utilized for the new equipment. (Ref. 116)

(3) Project Justification and Benefit

If the relays were to suffer an in-service failure, the plant will enter a forced outage and there would be risk of damage to major pieces of generation equipment and extended outages due to necessary lead time to procure replacement parts. An economic analyses has been performed demonstrating the economic benefit of this project at a benefit-to-cost ratio of 3.0.[151]

C. Peaker Power Plants

1. Summary of Request – Peaker Generation

SCE forecasts Test Year 2021 O&M expenses of $7.624 million ($2018) to operate and maintain its five Peaker plants. The forecast is based on last recorded year (*i.e.,* 2018 recorded) expense for labor and a five-year average of the 2014-2018 recorded expense for non-labor.

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[149] Refer to WP SCE-05, Vol. 1, Book B, pp. 187-188.

[150] Refer to WP SCE-05, Vol. 1, Book B, p. 189.

[151] Refer to WP SCE-05, Vol. 1, Book B, pp. 190-191.

The capital forecast for the Peaker plants is $4.900 million (nominal dollars) for 2019-2023. 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 section III.C.4 below.

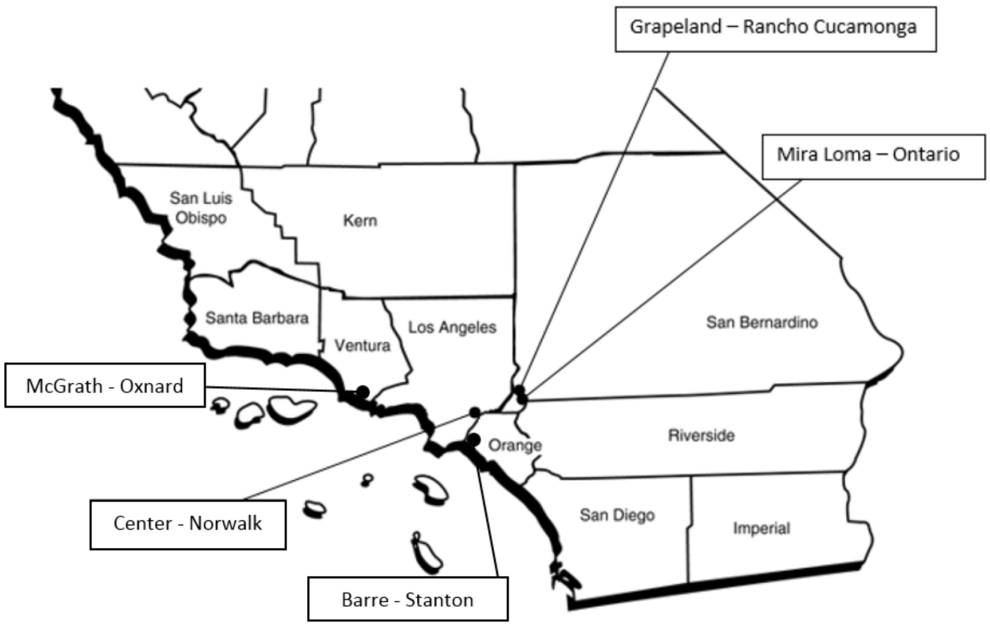
2. <u>Overview of Peaker Power Plants</u>

SCE owns and operates five GE LM6000 gas-fired Peaker power plants, of which two are Hybrid/Peakers, providing an aggregate of 245 MW. Peakers serve the electrical grid by starting and ramping to full load rapidly, including the capability of starting and stopping multiple times each day. Each Peaker can reach full load within ten minutes after start-up and has relatively low start-up costs. In addition, these Peakers can provide "black-start" capability if a system wide black-out occurs.

Each of the five Peaker plants has a nominal capacity of 49 MW. Figure III-7 Primary Peaker Locations 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 support facilities and the employees who operate, maintain, and manage these facilities are also located. The first four units – Barre Peaker (next to the SCE Barre substation), Center Hybrid (next to the SCE Center substation), Grapeland Hybrid (next to the Etiwanda Substation), and Mira Loma Peaker (next to the SCE Mira Loma substation) – began commercial operation in August 2007. Due to permitting delays, the fifth Peaker – McGrath (next to the Mandalay Generating Station) – did not begin commercial operation until November 2012.[152]

[152] The Etiwanda and Mandalay Generating Stations are owned by GenOn Holdings.

Figure III-7
Primary Peaker Locations



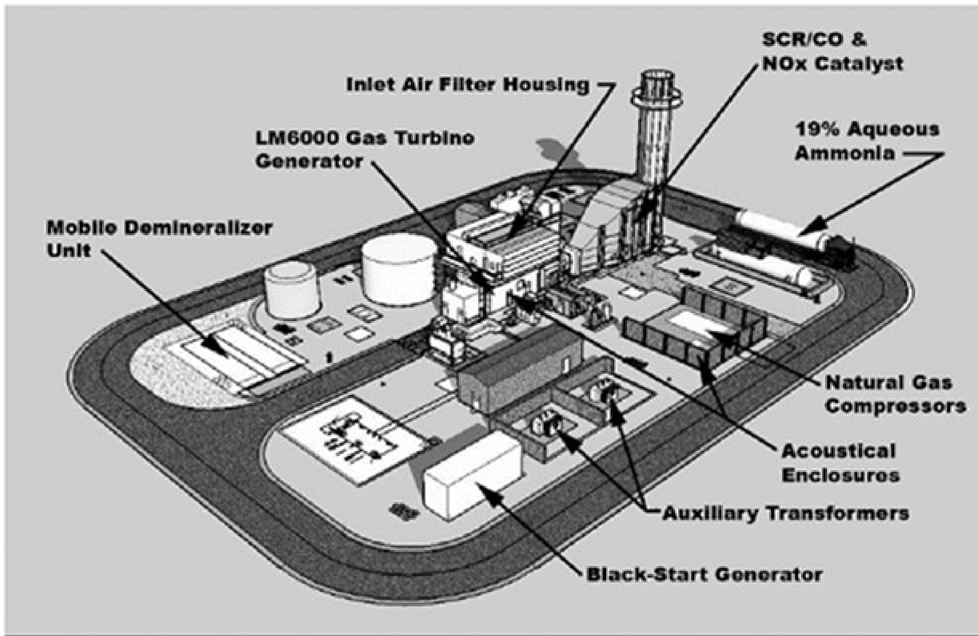
Each Peaker power plant uses a simple-cycle combustion turbine generator set, operated with selective catalytic reduction (SCR) for nitrogen oxide (NOx) air pollution reduction.[153] Each Peaker includes one General Electric (GE) LM6000 SPRINT™ (SPRay INTercooling)[154] natural gas turbine generator set and associated auxiliary equipment.

Figure III-8 illustrates the power plant package, including many accessories required to provide efficient, safe, and reliable operation.

[153] NOx are Nitrogen Oxide air pollutants.

[154] 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.

Figure III-8
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 an 800-HP electric motor-driven gas compressor to raise the natural gas pressure from the gas pipeline pressure to the required pressure for injection into the combustion turbine. A portable demineralizer, consisting of water softening followed by ion exchange, treats water to a high purity state. Nitrogen oxides (NOx) emission controls require treated water to be injected into the turbine. The combustion turbine inlet air conditioning uses treated water and increases the 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 tall 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 electrical grid by starting and ramping to full load rapidly as needed for load. Utilization is based on each Peaker start-up and operating costs as compared to other resource options, existing market prices, and system needs. Because of their fast-start capability, the Peaker plants can also fulfill off-line operating reserve requirements, standing ready to meet additional generation needs caused by sudden unanticipated loss of generating capacity elsewhere in the system, unexpected demand, or the power output variability of renewable resources such as solar and wind. SCE anticipated that the future usage of the Peaker plants (especially the Hybrid units) will continue at a high level.

The first four Peaker plants are in Los Angeles, Orange, and San Bernardino counties and operate under air permits granted by the South Coast Air Quality Management District (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, the two GE 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 Enhanced Gas Turbines (EGTs). The GE Projects became operational on December 30, 2016, and cost recovery was ordered to be transitioned to SCE's base rates in SCE's 2021 GRC.

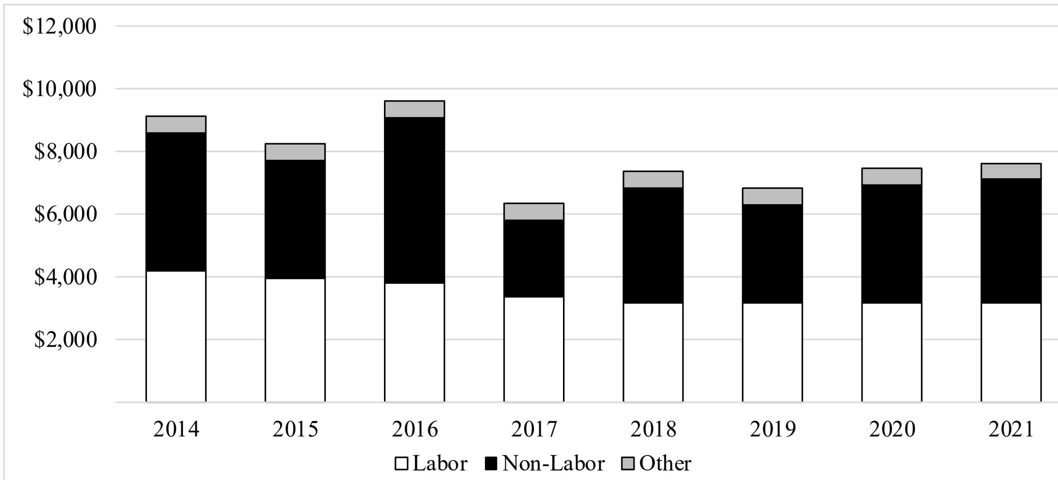
3. <u>Peaker O&M Expense Forecast</u>

a) <u>Introduction</u>

This section presents our 2021 Test Year O&M expense forecast to operate and maintain SCE's Peaker units.

Figure III-9 summarizes Peaker labor, non-labor and other O&M recorded expenses from 2014 through 2018, with the Test Year 2021 forecast of $7.624 million. The table also shows the forecasts for 2019 and 2020. The 2021 labor forecast of $3.188 million, includes costs for operations and maintenance activities discussed in analysis below. This labor forecast includes costs for the SCE employees who are routinely assigned work at the Peaker locations, and support provided to the plant by employees who work at other locations. Non-labor forecast of $3.910 million includes costs to repair parts, chemicals, supplies, contracts, and numerous other items needed to operate and maintain the plants. Other forecast of $0.526 million includes costs for interconnection fee's SCE pays to be connected to the bulk power grid. Below we examine past recorded costs and explain our Test Year forecast.

Figure III-9
Peaker - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	$4,170	$3,954	$3,788	$3,371	$3,188	$3,187	$3,187	$3,188
Non-Labor	$4,418	$3,771	$5,287	$2,432	$3,643	$3,118	$3,739	$3,910
Other	$534	$534	$520	$520	$520	$526	$526	$526
Total Expenses	**$9,122**	**$8,259**	**$9,595**	**$6,323**	**$7,351**	**$6,831**	**$7,452**	**$7,624**
Ratio of Labor to Total	46%	48%	39%	53%	43%	47%	43%	42%

b) Development of Test Year Forecast

Our 2021 Test Year forecast for the Peaker Generation activity is $7.624 million, including $3.188 million labor expense, $3.910 million non-labor expense and $0.526 million for other.[155]

(1) Labor – Analysis of Recorded and Forecast Expenses

Recorded labor expenses remained flat from 2014-2016 following the companywide re-organization that occurred in late 2013, when staffing was reduced. In mid-2016, the Generation Department initiated a number of process changes expected to increase productivity and further reduce labor expenses, which is evidenced in the further decrease of 2016 recorded labor costs.

[155] Refer to WP SCE-05, Vol. 1, Book B, p. 195.

Upon completion of the Mountainview/Peaker/Solar Control Center project in late-2016, which combined the former Westminster Peaker Control Room and the old Mountainview Control Room into a new Eastern Operations Generation Control Center, Operators who had formally recorded their labor costs to the Peakers Operations accounts began to record to the Mountainview Operations Accounts. This accounts for the decrease in the 2017 recorded labor costs.

Because staffing levels have stabilized and the scope of work performed in 2018 most closely matches the planned scope of work in 2021, the last recorded year (2018) is our basis to forecast future labor expense for 2021 and beyond, at $3.188 million.[156]

(2) Non-Labor – Analysis of Recorded and Forecast Expenses

Non-labor costs remained flat for 2014-2015 period. In the 2016-2017 timeframe, there were variations attributable to certain contract costs for the installation of the Grapeland Hybrid EGT project inadvertently recording to O&M in 2016, but were later moved appropriately into capital in 2017. Due to the potential of variations of non-labor in this account, as reflected by this recorded cost history, a historical average is most representative of non-labor expenses that can be expected in this account in Test Year 2021. We therefore selected a five-year average (*i.e.,* 2014-2018) as the basis to forecast Test Year 2021 non-labor expense, at $3.910 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).

Annual other expenses remained relatively stable between 2014-2018 and are largely affected by CAISO dispatch and length of outages. Due to the potential of variations of non-labor in this account, however, a historical average is most representative of non-labor expenses that can be expected in this account in Test Year 2021. We therefore selected a five-year average (*i.e.,* 2014-2018) as the basis to forecast other expense for Test Year 2021, which is $0.526 million.

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

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[156] Refer to WP SCE-05, Vol. 1, Book B, pp. 197-198.

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.

(1) Peaker Operations Activities

Peaker Operations work activities include labor and non-labor expenses incurred in operating prime movers, generators and electric equipment at power generating stations, up to the point where electricity is delivered to the distribution system. Labor expenses include the Production Manager and Production Supervisors, who supervise the control operators and operator mechanics and daily plant operation. Also included are the labor costs of the control operators and operator mechanics who directly operate and control station equipment, and Chemical Technicians who work throughout Generation, monitoring and resolving water chemistry problems.

Operational costs from support staff in the Business Planning, Asset Management and Major Projects and Engineering groups, based in the corporate office or other locations are partially allocated to the Peaker plants. The support staff provide financial budgeting, accounting, administrative activities, environmental health & safety compliance, regulatory compliance, long-range planning, and other activities. Also included in this account are costs for preliminary engineering studies, water quality and waste water laboratory analyses, and other general engineering support. Lastly, labor costs not readily assignable to other operating accounts, for example the Eastern Operations and Western Operations management, are partially allocated to the Peaker fleet.

Non-labor expenses include contract costs, materials, employee reimbursement expenses, SCE corporate support for various air, water, hazardous waste, and similar regulatory activities and miscellaneous fees. Other expenses include the costs of chemicals, water used for turbine injection and turbine inlet air cooling, costs of air emissions control, environmental monitoring and reporting, permits and fees, communications and computing equipment expenses, office supplies, labor relations expenses, safety and training costs, and janitorial services.

Included in Other are Added Facility Charges expenses, which are fixed payments that Peaker plants pay to SCE T&D for interconnecting the units to the grid (*i.e.,* the assessed interconnection fee includes no periodic inflation adjustment and is therefore categorized as an "other" expense).

(2) Peaker Maintenance Activities

Peaker Maintenance work activities include labor and non-labor expenses incurred in the general supervision, direction, and engineering needed to support Peaker maintenance activities. Non-labor costs recorded to this account include maintenance of certain Peaker auxiliary equipment, including security monitoring equipment required for NERC grid reliability and cyber security compliance. The account also includes the management and control of hazardous materials, such as the ammonia used for emissions control.

This account also includes the cost of labor, material, contractor services, and other expenses to maintain and repair facilities used in power generation, including the combustion turbine, generator and accessory electric equipment, the compressed air system, fire suppression equipment, other plant systems, and station maintenance equipment such as lathes, drill presses, and other shop equipment. The majority of the labor costs of the maintenance journeymen employed to work on the Peaker plants, the maintenance training expenses, vehicle expenses (*i.e.,* work trucks and small cranes) and consumable supplies are also included in this account.

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 $4.900 million (nominal, work order level) for 2019-2023 as summarized in Table III-42.

Table III-42
2019-2023 Peaker Capital Expenditure Forecast
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	Total
121	Turbine Refurbishment	-	-	-	-	2,600	2,600
122	Fire Tank and Booster Pump Installation	1,300	-	-	-	-	1,300
123	CEMS Replacements	-	800	-	200	-	1,000
	Total	**1,300**	**800**	-	**200**	**2,600**	**4,900**

The following section of testimony provides further discussion of Peaker capital projects exceeding $1.000 million.

a) **Turbine Refurbishment**

(1) **Background**

Four of the five Peaker turbines have been in service since 2007 and are nearing replacement dates. Due to the current run profile, SCE estimates that the turbine replacements, scheduled one unit per outage, will begin in 2023. SCE currently owns a spare turbine in stock for use during the initial change out of the first turbine. This project is necessary in order to refurbish the removed turbine, creating a spare available during the subsequent turbine change outs. The capital cost for this project is $2.600 million for 2023.[157]

(2) **Project Scope**

The project involves replacing one of the five Peaker turbines and refurbishing the existing 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 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 turbine ready for installation reduces the likelihood of an extended outage lasting the duration of the lead time. An economic analyses has been performed demonstrating the economic benefit of this project at a cost/benefit ratio of 1.0.[158]

b) **Center Hybrid - Fire Tank and Booster Pump Installation**

(1) **Background**

The Center Hybrid Enhanced Gas Turbine (EGT) project completed in December 2016 included the installation of a battery energy storage system (BESS). Permit conditions for the project require the installation of new fire suppression system capable of meeting water flow requirements.

(2) **Project Scope**

Installation of a fire water tank and booster pump.

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[157] Refer to WP SCE-05, Vol. 1, Book B, p. 204.

[158] Refer to WP SCE-05, Vol. 1, Book B, pp. 205-206.

(3) **Project Justification and Benefit**

This project is necessary to fulfill the permit requirements for operations of the Center Hybrid.

c) **Continuous Emissions Monitoring System (CEMS) Replacements**

(1) **Background**

Title V Air Permit requirement stipulates the continuous monitoring of gaseous emissions for NOx, NOx-NH3, CO, and O2, at the Peaker power plants. The existing OEM Continuous Monitoring Emissions Systems (CEMS) is obsolete, and recent failures have resulted in numerous forced outages across the Peaker fleet. Installation of a new CEMS system will maintain compliance with existing permit conditions and restore plant reliability.

(2) **Project Scope**

The project scope includes: (1) purchasing and installing new CEMS analyzers, (2) permitting, testing and certifying modified CEMS, (3) updating and revising the CEMS quality assurance plan document, and (4) training employees on the operations and maintenance of the new equipment.

(3) **Project Justification and Benefit**

The existing CEMS equipment has reached the end of its useful service life, and replacement minimizes the risk associated with environmental noncompliance due to unplanned breakdowns or malfunctions.

D. Catalina Generation (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.[159] To maintain reliable service to this isolated system, SCE is requesting $5.481 million in O&M expenses for Test Year 2021 and $40.160 million in capital expenditures for years 2019-2023.

2. Overview of Catalina Diesel Generation

Santa Catalina Island, usually referred to as "Catalina," is located approximately twenty-two miles south-southwest of Los Angeles. Since 1962, SCE has provided electric service to the entire

[159] Santa-Catalina-Island-Demographics from 2018-2019 Suburban Stats.

island, which includes the cities of Avalon and Two Harbors as well as the rural areas located in Catalina's interior.

Catalina is a closed electrical system; electricity generated and distributed on Catalina is isolated and self-contained. 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. Diesel fuel for the generators is delivered from refineries on the mainland to Catalina in tanker trucks, which are 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 fluctuates throughout the day to ensure the generators meet customer demand.

Generated electricity flows to a substation and is then 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 capacity in Catalina totals approximately 11.9 megawatts (MW), which includes six diesel generators (9.4 MW), twenty-three 65 kilowatt (KW) propane-fueled micro turbines (1.5 MW), and one energy storage battery (1.0 MW). Generation exhaust emissions are regulated by the South Coast Air Quality Management District (SCAQMD), and extensive air emissions monitoring and control equipment has been installed to meet operating permit requirements.

3. Catalina O&M Expense Forecast

a) Introduction

SCE's total Catalina Test Year O&M expense is forecast to be $5.481 million including $2.880 million labor expense and $2.601 million non-labor expense.[160] Figure III-10 presents the recorded expenses from 2014-2018 and the forecasts for 2019-2021. Labor costs reflect the costs for the SCE employees who work at the PBGS as well as additional 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.

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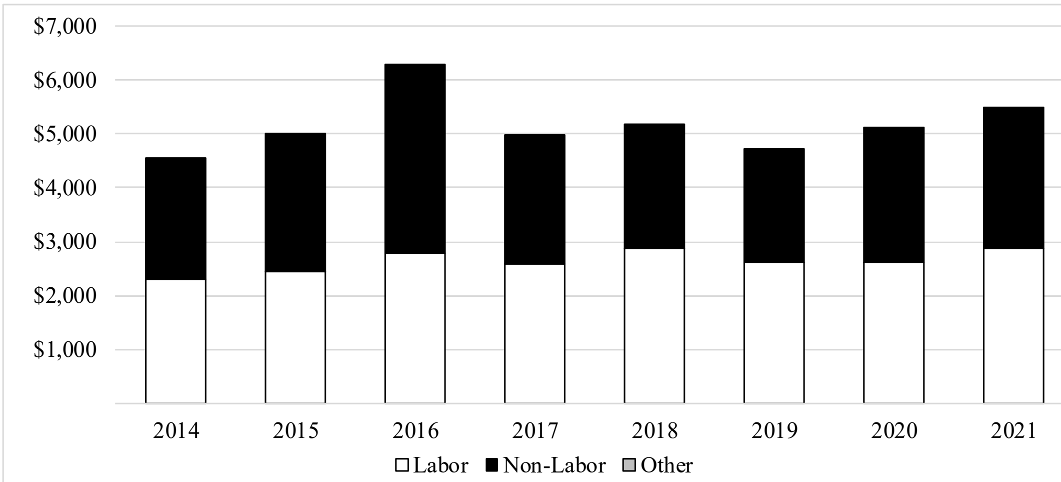
[160] Refer to WP SCE-05, Vol. 1, Book B, p. 211.

Figure III-10
Catalina - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)



	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Labor	$2,317	$2,449	$2,782	$2,577	$2,880	$2,610	$2,610	$2,880
Non-Labor	$2,239	$2,570	$3,510	$2,398	$2,286	$2,103	$2,522	$2,601
Other								
Total Expenses	**$4,557**	**$5,019**	**$6,292**	**$4,975**	**$5,166**	**$4,712**	**$5,131**	**$5,481**
Ratio of Labor to Total	51%	49%	44%	52%	56%	55%	51%	53%

b) <u>Development of Test Year Forecast</u>

(1) <u>Labor – Analysis of Recorded and Forecast Expenses</u>

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 distribution). Labor expenses also include those from administrative support staff at Catalina PBGS.

Because the scope of work performed in 2018 most closely matches the planned scope of work in 2021, the last recorded year (2018) is our basis to forecast future labor expense for Catalina Production activity Test Year 2021 at $2.880 million.[161]

[161] Refer to WP SCE-05, Vol. 1, Book B, p. 212.

(2) **Non-Labor – Analysis of Recorded and Forecast Expenses**

Historical O&M expenses for this activity varied slightly between 2014 and 2015, largely driven by fluctuations in maintenance activity. Scheduled maintenance on the generator units varies with contractual requirements, inspection cycles and results, and machine performance. Unscheduled, or emergent maintenance fluctuates from year to year. In 2016, Pebbly Beach Unit 14 experienced a failed generator shaft that resulted in damage to the winding and the bearing. The generator needed to be rewound and the bearings replaced, hence the increased costs in 2016. Since recorded costs do not follow a predictable pattern, SCE used a historical five-year average (2014-2018) for its non-labor 2021 Test Year forecast of $2.601 million. This is the same methodology adopted for Catalina Generation expenses in D.15-11-021, and is consistent with Commission guidance on forecast methodologies.

c) **Catalina O&M Work Activities**

Catalina Generation's 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 $40.160 million in capital expenditures for 2019-2023. The Catalina Repower project, with an overall project forecast of $34.300 million, is comprised of $17.300 million in forecast expenditures in 2019-2021 and $17.000 million in 2022-23. The remaining $5.860 million includes expenditures for the Pebbly Beach Generating Station resurface paving and a 2.4 kV Switchyard Upgrade projects. The capital forecast is shown in Table III-43 below.

Table III-43
2019-2023 Catalina Generation Capital Expenditure Forecast
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	TOTAL
124	Catalina Repower	500	5,300	11,500	11,000	6,000	34,300
125	PBGS - Resurface paving	-	1,500	2,000	-	-	3,500
126	PBGS - 2.4 KV Switchyard Upgrade	2,360	-	-	-	-	2,360
	Grand Total	**2,860**	**6,800**	**13,500**	**11,000**	**6,000**	**40,160**

The following section of testimony provides further discussion of Catalina capital projects exceeding $1.000 million.

a) **Catalina Repower**

(1) **Background**

The diesel electric generator sets serving Catalina Island date back to the 1920s, and although have been retrofitted with emission control systems to meet emissions regulations while meeting the extreme variable loads of the island's largely tourism-based economy, cannot feasibly be upgraded to meet the new SCAQMD emissions regulations.[162] As discussed in Section I.F.1 above, SCAQMD has required that the Pebbly Beach Generating Station implement BARCT on an expedited schedule for no later than December 31, 2023.

(a) **Project Overview**

The Catalina repower project proposes replacement of the existing 9.4 MW six unit configuration with equivalent SCAQMD compliant engine generator sets.[163]/[164] Table III-44 below reflects the Island's existing generation unit numbers, their associated capacity, voltage output, and the SCAQMD compliant equivalent capacity offered in today's market.

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162 SCAQMD Rule 1135(d) (2) [Page 1135-5].

163 Tier 4 refers to the latest emission milestone established by the U.S. Environmental Protection Agency and the California Air Resources Board applicable to new engines found in off-road equipment including construction, mining and agricultural equipment, marine vessels and workboats, locomotives and stationary engines found in industrial and power generation applications. Reference: https://www.dieselforum.org/policy/tier-4-standards

164 SCE continues to evaluate augmentation to the diesel replacement through high penetrating renewables like solar or wind installations, and will be presented to the CPUC for review and approval upon completion of feasibility studies.

Table III-44
Catalina Repower Project Details

Installation Phase	Unit	Operating Year	Age /Average Age	Nameplate Capacity kW	Replacement Capacity kW	Forecasted In-Service Date
1	14	1986	33	1,400	2,127	April 2021
	7	1958	61	1,000	1,233	
2	15	1995	24	2,800	2,127	April 2022
	8	1963	56	1,500	1,633	
3	12	1976	43	1,575	1,633	April 2023
	10	1966	53	1,125	1,233	
Total			**45**	**9,400**	**9,986**	

(2) <u>Project Scope</u>

To maintain reliability and service load, replacement will occur in three phases. Each of the three anticipated phases will replace two of the existing generators with two new SCAQMD compliant generators. Each phase has an expected duration of about 18 months, which includes permitting, engineering, procurement, demolition, construction/installation, and start-up/commissioning.

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

This project will ensure that Catalina Generation can meet the new SCAQMD emissions requirements while providing reliable power supply to the island grid.

b) <u>Resurface Paving</u>

(1) <u>Background</u>

The PBGS facility paving is showing significant damage and deterioration and in need of resurfacing. Numerous areas present uneven surface and/or breaks which allow moisture to percolate below the surface, undermining the integrity of the pavement, compromising the layers of gravel and earth below the pavement. These conditions create potential tripping and/or slipping hazards as well as unsafe work conditions, particularly to heavy moving equipment.

(2) <u>Project Scope</u>

This project includes topographic survey of the site, underground utility clearance survey, civil evaluation, design, and construction specification including required SPCC (spill prevention control and counter measures). Final construction may be asphalt, concrete, or a combination of both.

(3) **Project Justification and Benefit**

This project will provide a solution to mitigate current sub-standard pavement conditions around Catalina, which have the potential to create trip-and-fall incidents, or damage to moving equipment as well as safety of the workers operating the equipment on the premises.

c) **2.4 kV Switchyard Upgrade**

(1) **Background**

The 2.4 kV bus at PBGS is the station's primary generator bus feeding all of the plant's auxiliary systems, and is critical to the operation of the entire electric system on Catalina Island. This infrastructure at the Catalina, Pebbly Beach facility has reached the end of its useful service life, with potential arc flash hazard due to the worn condition of the metal clad switchgear. Parts needed to repair the switchgear are obsolete and need to be custom made, which impacts cost to maintain as well as reliability of the equipment. This project will replace the existing cubicle switchrack structure (and open-air structure) and associated substation equipment with new 2.4 kV cubicle switchgear equipment.

(2) **Project Scope**

This project includes designing and rebuilding existing switchgear/open air switchrack with new switchgear. The new switchgear is expected to be installed within the existing footprint of the 2.4kV rack and switchgear. Replaced equipment will be removed from the site and existing relays will be reused. Secondary circuits from metal clad switchgear will be reconnected to the existing control room.

(3) **Project Justification and Benefit**

Existing equipment is at the end of its useful service life, experiencing regular equipment outages. Replacement parts to repair are no longer in existence. This project will serve to mitigate the issues identified in (1) above.

E. Fuel Cells

1. Summary of Request – Fuel Cells

SCE owns and operates two fuel cell generating plants with a combined total capacity of 1.6 MW. This chapter presents SCE's 2021 Test Year Operations and Maintenance expense forecast of $0.491 million (constant $2018 dollars) for the SCE Fuel Cells.

2. Overview of Fuel Cell Generation

A fuel cell converts a source fuel, such as natural gas, into electrical current through an electro-chemical reaction. Fuel cell technology generates electricity more efficiently than other similarly sized combustion technologies, resulting in lower emissions of greenhouse gases. Because fuel cells do not burn the natural gas supplied to them, they produce minimal emissions of nitrogen oxide, sulfur dioxide, and particulate matter. Fuel cells have been designated as "Ultra-Clean" by the California Air Resources Board (CARB) and exceed all 2007 CARB standards.

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.[165]

3. Fuel Cell O&M Expense Forecast

a) Introduction

This section presents our 2021 Test Year O&M expense forecast of $0.491 for operating and maintaining SCE's Fuel Cell units, including the business reasons underlying the forecast. Figure III-11, shows Fuel Cell recorded O&M expense for 2014-2018 and forecast for 2019-2021.[166]

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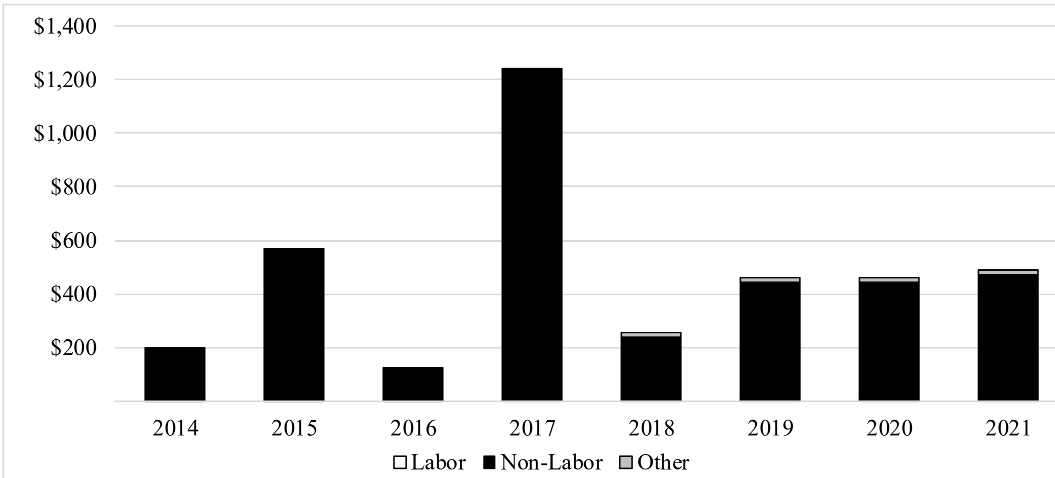
[165] *See* A.09-04-018, Exhibit SCE-01, pp. 9-15.

[166] Refer to WP SCE-05, Vol. 1, Book B, p. 228.

Figure III-11
Fuel Cell - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecast
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	$2	$2	$2	$5	$3	$3	$3	$3
Non-Labor	$198	$567	$122	$1,236	$235	$444	$444	$472
Other					$16	$16	$16	$16
Total Expenses	**$200**	**$569**	**$123**	**$1,241**	**$254**	**$463**	**$463**	**$491**
Ratio of Labor to Total	1%	0%	1%	0%	1%	1%	1%	1%

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 facilities charges, water treatment system service agreement, site maintenance service agreements, and air quality permit certification and renewal.

The ten-year contracts with the hosts for both UCSB and CSUSB Fuel Cell programs are set to expire in 2022 and 2023 respectively. SCE will continue to operate the two programs within the contractual agreements, unless either site host indicates a desire to renew or extend the pilots. If the universities decline to exercise their contractual right to retain the assets beyond the lease term(s) and take over the related O&M obligations, SCE is obligated under the terms of the contracts to remove the assets at the site owners' request. SCE's decommissioning proposal is discussed further in SCE-07, Vol. 3.

b) Development of Test Year Forecast

(1) Labor – Analysis of Recorded and Forecast Expenses

Because the scope of work performed in 2018 most closely matches the planned scope of work in 2021, the last recorded year (2018) is our basis to forecast future labor expense for the Fuel Cells activity Test Year 2021 at $ $0.003 million.

(2) Non-Labor – Analysis of Recorded and Forecast Expenses

As discussed above, the UCSB and CSUSB Fuel Cell demonstration generating plants became operational in 2012 and 2013 respectively. Fuel Cell O&M costs were somewhat unstable during their first three years of operation (*i.e.,* 2012-2015) during the transition from initial start-up testing to a period of more routine operation.

The LTSAs are the primary driver of SCE's 2014-2018 recorded non-labor expense for the fuel cells and forecast non-labor costs. Most of the O&M work performed under each LTSA is invoiced on a fixed-price basis. The LTSA contract includes an incentive/penalty cost credit computed based on the overall plant generating performance achieved during the year. Cost variances recorded during 2015-2018 were largely the result of varying billing cycle processing times, and differing levels of recorded plant performance in each year (*i.e.,* lower performance results in a lower overall O&M contract payment to the fuel cell supplier). Our 2021 Test Year non-labor forecast of 0.472 million assumes an average level of performance going forward, and is based on a five-year average (*i.e.,* is based on the average annual expense recorded during 2014-2018).

(3) Other – Added Facility Charges

The Other - Added Facility Charges expenses are fixed payments the Fuel Cell sites pay SCE T&D for interconnecting to the grid. The assessed interconnection fee includes no periodic inflation adjustment and is therefore categorized as an "other" expense. SCE's 2021 Test Year forecast for Added Facility Charges is $0.016 million, as recorded in 2018 (last recorded year).[167]

4. Fuel Cell Capital Expenditure Forecast

There are no forecasted capital expenditures for the Fuel Cells.

[167] Refer to WP SCE-05, Vol. 1, Book B, p. 231

IV.

SOLAR

A. Summary of Request – Solar Photovoltaic Program (SPVP)

SCE owns and operates twenty-five solar generating plants constructed as part of the SCE Solar Photovoltaic Program (SPVP)[168] with a combined total capacity of 67.5 MW (AC).[169] This section presents SCE's 2021 Test Year Operations and Maintenance expense forecast of $3.755 million (constant $2018 dollars) and SCE's $0.500 million (nominal dollars) 2019-2023 capital expenditure forecast.

B. Overview of SPVP

Solar photovoltaic panels convert sunlight directly into electricity using a semiconductor material. Photovoltaic (PV) panels generate DC electricity, and electrical devices called inverters convert the output to alternating current (AC) electricity for export to SCE's electrical distribution system. Each 1.35 MW of DC yields approximately 1 MW of AC. The Commission found this technology "can help advance California's broad goal of developing renewable energy and specifically help make progress toward the state's emphasis on developing distributed rooftop solar PV projects."[170]

The SCE SPVP commercial/industrial rooftop projects range primarily in size from 1 to 2 MW.[171] The goals of the program include gaining and sharing operational experience to assist California in meeting its renewable energy and Greenhouse Gas emissions reduction objectives.[172]

Between 2008 and 2013, SCE constructed twenty-five sites, all of which were delivering energy to the grid by the end of August 2013. Table IV-45 summarizes the SPVP sites.[173]

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[168] The Commission authorized SCE's SPVP Program and Fuel Cell Demonstration Program Applications in D.09-06-049 and D.10-04-028, respectively.

[169] 24 rooftop solar photovoltaic (SPV) plants, and one ground-based SPV plant.

[170] D.09-06-049, (*mimeo*), p. 11.

[171] SCE's Application in A.08-03-015 states that "SCE envisions the individual Solar PV Program installations to be in the 1 to 2 MW range. As the program proceeds, however, some installations may be larger or smaller than this range due to roof size or circuit loading considerations."

[172] D.09-06-049, (*mimeo*), p. 11.

[173] The former SPVP001 Site was incorporated into the SPVP015 site at the time the SPVP015 site was constructed.

Table IV-45
SPVP Sites

SPVP Site Name	MW AC	MW DC	Location
SPVP002 - Chino	1.0	1.2	Rooftop
SPVP003 - Rialto	1.0	1.2	Rooftop
SPVP005 - Redlands	2.5	3.4	Rooftop
SPVP006 - Ontario	2.0	2.6	Rooftop
SPVP007 - Redlands	2.5	3.2	Rooftop
SPVP008 - Ontario	2.0	2.9	Rooftop
SPVP009 - Ontario	1.0	1.4	Rooftop
SPVP010 - Fontana	1.5	2.3	Rooftop
SPVP011 - Redlands	3.5	5.0	Rooftop
SPVP012 - Ontario	0.5	0.8	Rooftop
SPVP013 - Redlands	3.5	4.9	Rooftop
SPVP015 - Fontana	3.5	4.7	Rooftop
SPVP016 - Redlands	1.5	1.8	Rooftop
SPVP017 - Fontana	3.5	4.5	Rooftop
SPVP018 - Fontana	1.5	1.9	Rooftop
SPVP022 - Redlands	2.0	3.1	Rooftop
SPVP023 - Fontana	2.5	3.9	Rooftop
SPVP026 - Rialto	6.0	8.6	Rooftop
SPVP027 - Rialto	2.0	2.6	Rooftop
SPVP028 - San Bernardino	3.5	4.9	Rooftop
SPVP032 - Ontario	1.5	1.7	Rooftop
SPVP033 - Ontario	1.0	1.3	Rooftop
SPVP042 - Porterville	5.0	6.8	Ground
SPVP044 - Perris	8.0	10.2	Rooftop
SPVP048 - Redlands	5.0	6.8	Rooftop
25 SPVP Sites	**67.5**	**91.4**	

The Porterville Site (SPVP 042) with 6.8 MW DC capacity is a ground mounted installation; the rest are on the rooftops of large commercial and industrial buildings. SCE leases the rooftop space from the building owners. Funding of SCE's O&M and capital forecasts for the SPVP fleet will allow the continued safe, reliable and compliant operation of these important renewable energy generating assets for SCE customers.

In May of 2019, SCE received notice from the building owner of the Perris Site (SPVP044) regarding its desire to re-roof the building seven years into initial 20-year lease term. Prior to entering into the lease, SCE hired an independent roofing consultant to assess the condition of the roof and its suitability to host the proposed solar system. The consultant found the roof suitable for the proposed use subject to the completion of several repairs. SCE negotiated a lease with the ownership requiring that the ownership perform these repairs prior to installation and agree to certain ongoing maintenance. These repairs were performed, and SCE entered into a lease agreement with the building owner and installed the solar system. In early 2019, SCE was notified by the building owner of its intent to replace the entire roof due to leaks that threaten the contents in the building. Pursuant to a contractual obligation in the lease to clear the roof for re-roofing at the owner's request, SCE has initiated removal of the solar system located on the roof. The forecast cost of removal is $6.500 million (2019$).[174] Due to the high cost of re-installation relative to the forecast of market revenue, SCE determined that it does not make economic sense to re-install the panels, and SCE expects to proceed with decommissioning.[175] Further information regarding the recovery methods for decommissioning costs can be found in testimony SCE-07, Vol. 3.

C. SPVP O&M Expense Forecast

1. Introduction

The SPVP Test Year O&M expense of $3.755 million is summarized in Figure IV-12, which shows the recorded expenses for 2014 through 2019 and the forecast expenses for 2019 through 2021. Labor costs reflect the costs for the SCE employees that work at the solar facilities and support provided to the plants by employees that work at the other locations. Non-labor costs include repair parts, supplies, contracts and other items needed to operate and maintain the SPVP sites. Other costs consist of the interconnection fees. The SCE SPVP generating plant cost forecasts demonstrate an overall decrease as compared to past recorded O&M expenses.

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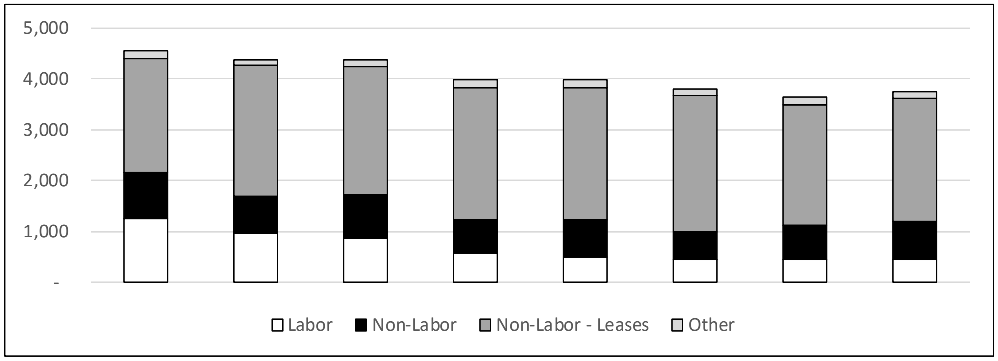
[174] Refer to WP SCE-05, Vol. 1, Book B, pp. 242-243 – SPVP044-Dexus Lease Agreement.

[175] Refer to WP SCE-05, Vol. 1, Book B, p. 244 – Dexus Roof Removal - Economic Analysis

Figure IV-12
SPVP - Operations and Maintenance Expenses
2014-2018 Recorded and 2019-2021 Forecasted
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	1,254	975	858	585	506	438	438	437
Non-Labor	898	704	853	644	715	564	676	763
Non-Labor - Leases	2,258	2,594	2,526	2,588	2,602	2,656	2,384	2,414
Other	153	107	142	157	145	138	138	141
Total Expenses	4,563	4,381	4,379	3,974	3,968	3,795	3,635	3,755
Ratio of Labor to Total	40%	30%	25%	18%	15%	14%	14%	14%

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

The 2021 Test Year forecast of $3.755 million includes four cost components. These are briefly summarized below, and discussed in more detail within the following sections of testimony.

- The first O&M cost component is the base labor O&M expenses to perform annual work activities.
- The second O&M cost component is the non-labor O&M expenses to perform annual work activities.
- The third O&M expense component is the cost of the leases.
- The fourth O&M expense component includes the interconnection fees SCE must pay to be connected grid.

a) <u>Labor – Analysis of Recorded and Forecast Expenses</u>

Labor expenses include control operators who remotely monitor the SPVP sites and production supervisors who supervise the control operators and oversee daily operations from control centers at locations other than the solar plant sites. Labor expenses also include a portion of the salary of support employees who work at other locations, 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. As shown in Figure IV-12, labor expenses have experienced a steady downward trend since 2013 when the SPVP program became fully operational. Coupled with the operational efficiencies and productivity gains realized through process changes implemented in 2016, the SPVP realized its lowest recorded labor costs in 2018. SCE expects SPVP maintenance labor expenses for the 2021 Test Year to be similar to those recorded in 2018. As such, SCE utilizes the last year recorded as the basis for the 2021 Test Year labor expense of $0.438 million.

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

Non-labor expenses include: (1) reimbursement expenses (*e.g.,* travel expenses as required); (2) corporate support for various air, hazardous waste and similar regulatory activities; and (3) engineering support provided by contract vendors such as those that perform modifications to the electrical fault protection systems.

Historical costs vary slightly from year to year, largely driven by fluctuations in maintenance activities. Since these costs have not followed any predictable pattern, SCE utilizes a historical five-year average, 2014-2018, for the non-labor 2021 Test Year request of $0.766 million.

c) Non-Labor Lease Expense – Analysis of Recorded and Forecast Expenses

A portion of our 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 an itemized forecast more accurately represents future obligations for leases than a multi-year average or last recorded year. SCE's itemized forecast for site leases is $2.414 million ($2018), and was calculated based on the 2018 scheduled lease payment obligation for the 25 sites.[176]

d) Other - Analysis of Recorded and Forecast Expenses

The SPVP Other expense category consists of interconnection fees, which are fixed payments that SPVP pays to SCE T&D for interconnecting the SPVP sites to the grid (*i.e.,* the

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[176] Refer to WP SCE-05, Vol. 1, Book B, pp. 249-250.

assessed interconnection fee includes no periodic inflation adjustment and is therefore categorized as an "other" expense).

Annual other expenses vary between 2014-2018 due to variances in run-time hours that are largely effected by weather and length of outages. Due to the inherent variations of non-labor in this account, a historical average is most representative of non-labor expenses that can be expected in this account in Test Year 2021. We selected a five-year average (*i.e.,* 2014-2018) as the basis to forecast non-labor expense for Test Year 2021, which is $0.138 million.

D. Solar Photovoltaic Capital Expenditure Forecast

The total SPVP plant capital expenditure forecast is $0.500 million for 2019-2023, and is shown by year in Table IV-46 below.

Table IV-46
SPVP Capital Expenditure Forecast 2019– 2023
(Nominal $000)

Ref. #	Project Description	2019	2020	2021	2022	2023	Total
127	Spare Parts (Inverters/Transformers)	100	100	100	100	100	500
	Total	**100**	**100**	**100**	**100**	**100**	**500**

The SPVP capital expenditures include purchase of spare parts such as inverters, transformers, and other capital designated replacement components that fail in service; principal tools such as test and technical equipment, portable tools such as test and technical equipment, and to address furniture and office equipment needs.[177] These expenditures will allow SCE to continue to maintain the SPVP assets in a safe, compliant and reliable condition. SCE does not expect to construct additional solar PV sites.

[177] Refer to WP SCE-05, Vol. 1, Book B, p. 255.

V.

PALO VERDE

A. Overview

SCE owns 15.8 percent of Palo Verde Nuclear Generating Station (Palo Verde) Units 1, 2, and 3; the nation's largest nuclear installation. Palo Verde is located approximately 50 miles west of Phoenix. Arizona. Arizona Public Service Company (APS) 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-1980's.

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 2021 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 2021 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

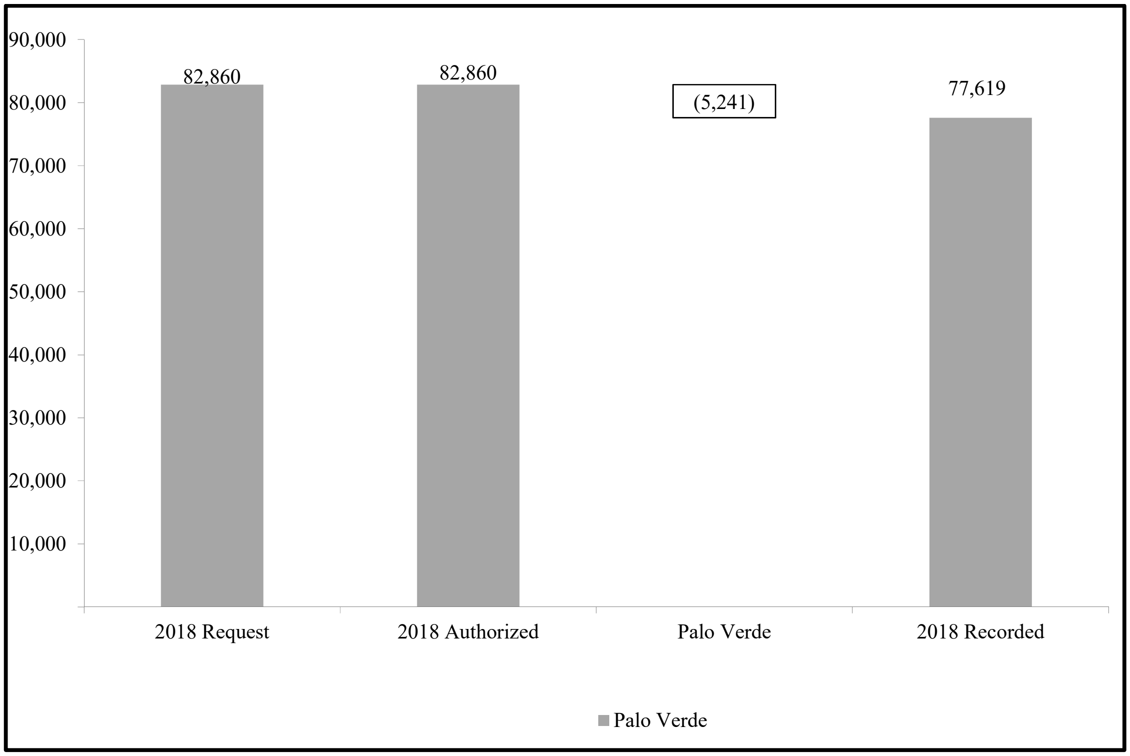
Pursuant to D.19-05-020 Ordering Paragraph 3, this Chapter compares Commission-authorized 2018 O&M expense and capital expenditures to SCE's recorded 2018 O&M and capital expenditures for SCE's Palo Verde facility, as shown in Figure V-15and Figure V-13 below. In Section V.D. of this testimony, SCE also 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).

B. Comparison of Authorized 2018 to Recorded – O&M Expenses[178]

As shown in Figure V-13 below, SCE requested $82.860 million for Palo Verde's 2018 Test Year forecast in the 2018 GRC and the Commission adopted $82.860 million. In 2018, SCE recorded approximately $77.619 million, $5.241 million under SCE's 2018 authorized O&M expenses. This variance occurred primarily because performance-based compensation to Palo Verde employees was reduced due to the Palo Verde Unit 2 Cycle 21 refueling outage during the fall of 2018 lasting 16.4 days longer than its planned 44.5 day duration.

[178] Refer to WP SCE-07, Vol. 1 – Authorized to recorded.

Figure V-13
Palo Verde
O&M Expenses for 2018 – Authorized versus Recorded
(Constant 2018 $000, SCE's Share)



C. <u>Comparison of Authorized 2018 to Recorded - Capital</u>[179]

As shown in Figure V-14 below, SCE requested $39.805 million for Palo Verde's 2018 Test Year forecast in the 2018 GRC and the Commission adopted $39.805 million. In 2018, SCE recorded approximately $37.824 million, $1.980 million under SCE's 2018 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.

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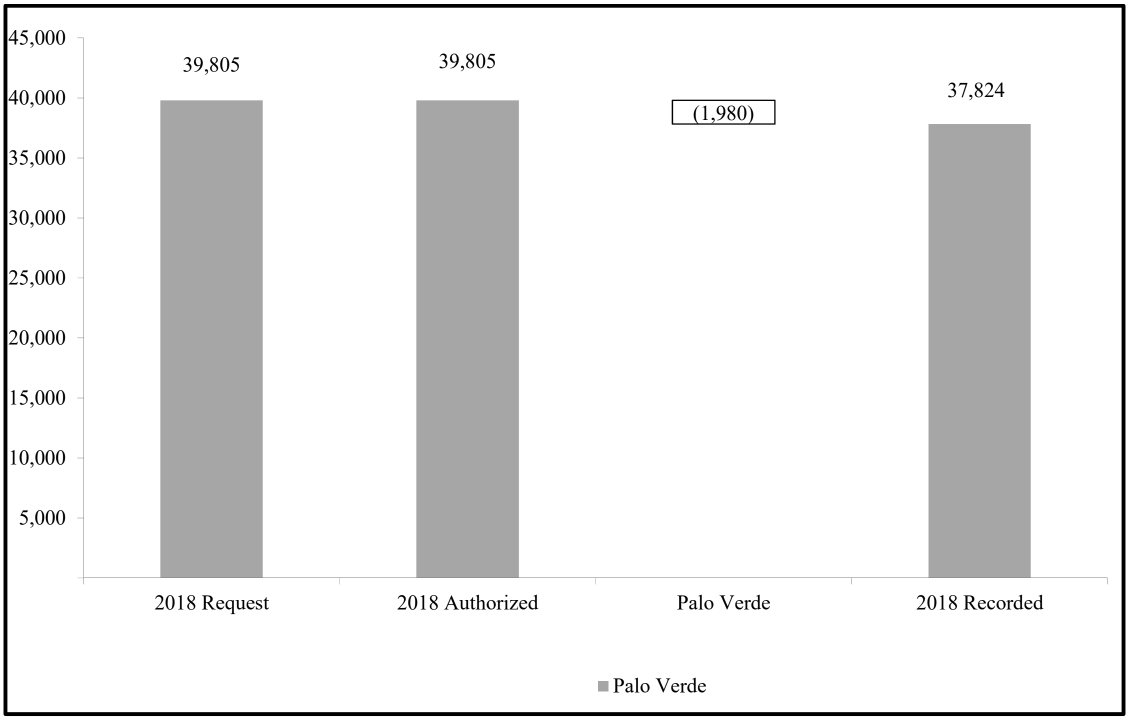
179 Refer to WP SCE-07, Vol. 1 – Authorized to recorded.

Figure V-14
Palo Verde
Capital Expenses for 2018 – Authorized versus Recorded
(Constant 2018 $000, SCE's Share)



D. O&M Forecast

1. O&M Budget Process

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.

a) <u>O&M Cost Control Process</u>

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.

b) <u>Palo Verde</u>

(1) <u>Activity Description</u>

SCE's 15.8 percent share of Palo Verde's labor and non-labor expenses are recorded based on billing information provided by APS. SCE's 2021 Test Year forecast of $78.904 million is shown below in Figure V-15 and includes plant operating expense and RFO expenses as further described below.

(a) <u>Plant Operating Expense</u>

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, 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-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 3 (spring) and Unit 2 (fall) are forecast during the 2021 Test Year.

(c) 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.

(d) Development of an RFO Plan

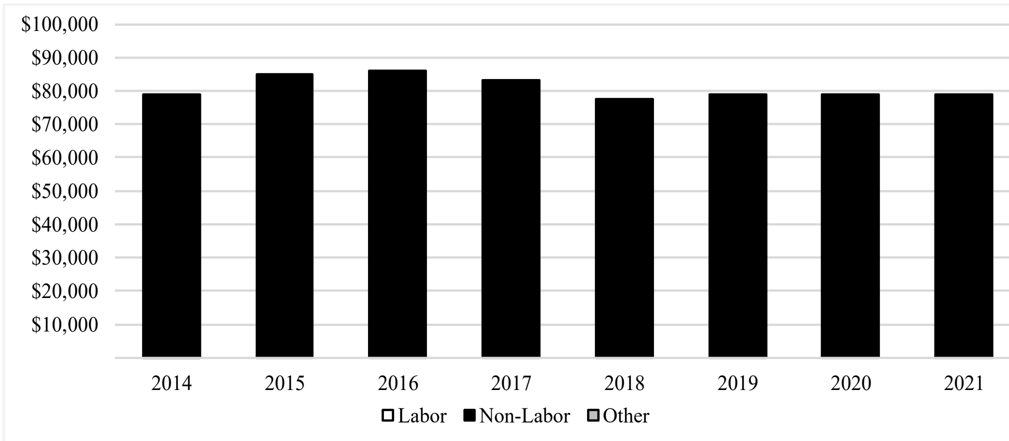
APS plans each RFO with three major parameters in mind: scope, duration, and cost. APS bases its initial RFO planning on the prevailing work processes and procedures in effect at Palo Verde, the demonstrated organizational capabilities, and the required work scope. The foundation of an RFO is the work 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) Palo Verde O&M Forecast

Figure V-15
Palo Verde O&M Expense
2014-2018 Recorded and 2019-2021 Forecast[180]
(Constant 2018 $000, SCE Share)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	$108	$143	$137	$120	$149	$235	$235	$235
Non-Labor	$78,937	$84,655	$86,000	$82,934	$77,470	$78,681	$78,669	$78,669
Other	-							
Total Expenses	**$79,044**	**$84,798**	**$86,136**	**$83,054**	**$77,619**	**$78,916**	**$78,904**	**$78,904**
Ratio of Labor to Total	0%	0%	0%	0%	0%	0%	0%	0%

d) Historical Variance Analysis

(1) Labor

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-15 above, Palo Verde labor expense fluctuated between $0.108 million in 2014 and $0.149 million in 2018. Palo Verde labor expense was exceptionally low in 2014 because some SCE employees who provided support to both Palo Verde and SONGS were severed due to the permanent closure of SONGS 2&3. In 2015, some of the remaining personnel at SONGS were reassigned to spend a portion of their time performing Palo Verde oversight functions, resulting in a slight increase in labor expense compared to 2014. In 2016-2017, as personnel became more proficient in performing their Palo Verde

[180] Refer to WP SCE-05, Vol. 1, Book B, pp. 257-262.

oversight functions, they charged fewer labor hours to Palo Verde, resulting in modest decreases. In 2018, Palo Verde Fuel Services functions were transferred from the SCE Supply Chain Division to the SCE Nuclear Finance Division, resulting in a slight increase.

(a) Non-Labor

Palo Verde O&M expense, invoiced to SCE by APS, are recorded by SCE as non-labor expenses. Palo Verde non-labor expenses trended upward from 2014 through 2016 due to reduced plant chemical usage in 2014, and increases in materials and supplies for preventive and corrective maintenance activities performed during 2016. The trend downward in 2017-2018 is attributed primarily to employee attrition in 2017 and 2018, as well as a reduction in the employee performance payout due to the 2R21 Refueling Outage scheduled extension in 2018.

(2) Forecast

(a) Labor

SCE forecasts $0.235 million (Constant 2018$, SCE share) in 2021 for Palo Verde O&M labor costs, as shown in Figure V-15 above. SCE's forecast is based on the last-recorded-year forecast method plus a Test Year adjustment of $86,000. SCE's 2021 labor expense forecast reflects a modest increase above 2018 levels because the Palo Verde Fuel Services functions that were transferred from the SCE Supply Chain Division to the SCE Nuclear Finance Division in late 2018 will be reflected in labor expenses as a full year ongoing expense for 2019 through 2021. In addition, SCE has determined that personnel who perform regulatory work related to Palo Verde will charge the time spent on those activities to Palo Verde oversight instead of the general Corporate Regulatory account.

(b) Non-Labor

In D.89-12-057, the CPUC stated that if recorded expenses in an account have fluctuated over three or more years, an averaging forecast methodology is appropriate for determining a base estimate. Because non-labor costs have fluctuated over the last five years as explained above, it would be appropriate for SCE to use the five-year average forecast method as the basis for its Test Year 2021 forecast. The five-year average for Palo Verde non-labor costs is $81.999 million. However, APS, the Palo Verde operating agent, has forecasted that Palo Verde non-labor costs for Test Year 2021 will be $78.669 million (Constant 2018$, SCE share), which is $3.330 million less than the five-year average. Although SCE's forecast is $1.199 million more than 2018 recorded expenses of $77.470 million, as shown in Figure V-15 above, SCE believes it is appropriate because it was provided by APS, and because 2018 recorded costs were substantially lower than the non-labor costs recorded in the three preceding years.

E. Capital Expenditures

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 2019-2020.

1. Palo Verde Capital Budget Process

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 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 Work Authorizations (WAs) to oversee the capital expenditures at Palo Verde and to verify that APS is effectively administering budget and cost control processes.

2. APS Capital Project Approval Process

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 Plant Health Committee Sub-Committee (PHCSC) for review and ranking. The PHCSC reviews each plant modification project and assigns an implementation priority and schedule based on the following criteria:

* A ranking between two and seven is established based on the project's importance to safety (nuclear and personnel), reliability improvements or production.
* A multiplier applies to the ranking:

5 - 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.

3 - Items that improve/maintain equipment reliability, plant operation or worker condition economically justified but not urgent to resolve.

2 - Plant improvement/betterment item that provides short term benefit. May include intangible benefits such as improvement in employee morale and plant appearance.

1 - Item might add value, but shows little short-term benefit.

Following PHCSC's initial ranking and approval, the proposed project proceeds to the Plant Health Committee (PHC) for implementation approval and then to the Management Review Committee (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 Long Range Plan (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 2021 Palo Verde Capital Forecast

Table V-47
Palo Verde Units 1, 2, and 3
2019-2020 Capital Expenditures Detail[181]
(Nominal $ in Millions, SCE Share Without SCE Corporate Overheads)

Category	Prior Costs	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2019-2023 Forecast	Project Total
Plant Modifications	8.642	7.568	6.549	7.334	9.156	9.000	39.606	48.247
Equipment & Replacements	16.611	13.644	13.843	11.581	11.781	8.947	59.796	76.407
Water Reclamation Facility	5.452	5.286	5.198	4.765	3.692	3.974	22.915	28.367
Buildings	1.515	2.314	1.895	2.937	2.236	1.657	11.039	12.555
General Plant	2.477	2.361	2.162	1.520	1.106	1.700	8.850	11.326
Computers	2.349	1.723	1.983	2.341	2.425	2.133	10.605	12.954
Emergent Work Fund	-	1.816	1.866	2.370	2.310	4.426	12.789	12.789
Overheads & Distributables	0.627	3.207	3.318	3.492	3.634	3.713	17.364	17.991
Grand Total	**37.673**	**37.920**	**36.814**	**36.340**	**36.340**	**35.550**	**182.964**	**220.637**

Table V-47 above shows projects by budget category for Palo Verde capital expenditures for 2019-2023. As shown in this table, SCE forecasts $111.1 million for Palo Verde capital expenditures from 2019-2021 (Nominal $, SCE share), and $71.9 million during 2022-2023. Table V-48 below provides a listing by budget category of Palo Verde capital expenditures forecast for 2019-2023. It also delineates projects for which SCE's 15.8 percent share of the cost exceeds $3.0 million throughout the period 2019-2023. There are six projects where SCE's share exceeds $3.0 million over the 2019-2023 period. These projects are described in Section V.E.8 below.

181 Refer to WP SCE-05, Vol. 1, Book B, pp. 263-264.

Table V-48
Palo Verde Units 1, 2, and 3
2019-2023 Capital Expenditures Forecast Detail
(Nominal $ in Millions, SCE Share Without Corporate Overheads)

	Prior Costs	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2019-2023 Forecast	Project Total
t Modifications								
Digital SMP Phase II U1	0.000	0.000	0.000	0.000	0.000	4.543	4.543	4.543
Digital SMP Phase II U3	0.000	0.000	0.403	2.809	4.069	0.000	7.280	7.280
Other	8.642	7.568	6.146	4.525	5.088	4.457	27.783	36.425
Plant Modifications Subtotal	**8.642**	**7.568**	**6.549**	**7.334**	**9.156**	**9.000**	**39.606**	**48.247**
ipment & Replacements								
Main Generator Stator Rewind U1	0.013	0.000	3.272	0.000	0.000	0.000	3.272	3.284
Main Generator Stator Rewind U3	0.070	3.271	0.000	0.000	0.000	0.000	3.271	3.341
Other	16.528	10.374	10.572	11.581	11.781	8.947	53.254	69.782
Equipment & Replacements Subtotal	**16.611**	**13.644**	**13.843**	**11.581**	**11.781**	**8.947**	**59.796**	**76.407**
er Reclamation Facility								
Clarifiers Life Extension T2	2.785	0.360	0.000	0.000	0.000	0.000	0.360	3.145
Other	2.667	4.925	5.198	4.765	3.692	3.974	22.555	25.222
Water Reclamation Facility Subtotal	**5.452**	**5.286**	**5.198**	**4.765**	**3.692**	**3.974**	**22.915**	**28.367**
dings								
Other	1.515	2.314	1.895	2.937	2.236	1.657	11.039	12.555
Buildings Subtotal	**1.515**	**2.314**	**1.895**	**2.937**	**2.236**	**1.657**	**11.039**	**12.555**
eral Plant								
Other	2.477	2.361	2.162	1.520	1.106	1.700	8.850	11.326
General Plant Subtotal	**2.477**	**2.361**	**2.162**	**1.520**	**1.106**	**1.700**	**8.850**	**11.326**
puters								
Other	2.349	1.723	1.983	2.341	2.425	2.133	10.605	12.954
Computers Subtotal	**2.349**	**1.723**	**1.983**	**2.341**	**2.425**	**2.133**	**10.605**	**12.954**
rgent Work Fund								
Other	0.000	1.816	1.866	2.370	2.310	4.426	12.789	12.789
Emergent Work Fund Subtotal	**0.000**	**1.816**	**1.866**	**2.370**	**2.310**	**4.426**	**12.789**	**12.789**
rheads & Distributables								
Other	0.627	3.207	3.318	3.492	3.634	3.713	17.364	17.991
Overheads & Distributables Subtotal	**0.627**	**3.207**	**3.318**	**3.492**	**3.634**	**3.713**	**17.364**	**17.991**
Grand Total	**37.673**	**37.920**	**36.814**	**36.340**	**36.340**	**35.550**	**182.964**	**220.637**

a) Plant Modifications

Plant modifications projects are implemented for plant system-related upgrades and replacements. They include changes in plant design, including simulator computers, motors, pumps, valves, heat exchangers, breakers, etc. Plant modifications projects help to keep plant operations reliable (at a high capacity factor), safe, and compliant with NRC requirements. Sub-categories of plant modifications projects are listed below:

- 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 2019-2023 period is $39.606 million (Nominal $, SCE share). This includes the Digital Strategic Modernization Programs for Units 1 and 3, each having a cost greater than $3 million.

(1) Digital Strategic Modernization Program (SMP) for Units 1 and 3

Several analog and digital plant instrumentation and control (I&C) systems are reaching the end of reliable operation. In order 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 modern technology replacement.

As a result of this analysis, Palo Verde will implement a Strategic Modernization Program 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 will be executed in five phases throughout a twelve year period, will address obsolescence, remove single point vulnerabilities where practical, improve human-to-machine interfaces, and minimize spare parts inventories.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers.[182] SCE's share of the capital forecast for this project during the 2019-2023 period is $11.823 million (Nominal $, SCE share).

b) Equipment and Replacements

The Equipment and Replacements category covers the items listed below:

[182] Refer to WP SCE-05, Vol. 1, Book B, pp. 265-281.

(1) Tools & Equipment

This subcategory includes capitalized tools and equipment used to perform routine and repetitive maintenance, construction, and training activities. It is important to maintain complete sets of working, undamaged tools and equipment so that work can be completed efficiently and worker safety maintained.

(2) Replacements

This includes replacement of retirement units in-kind, excluding items controlled by the Water Reclamation Facility (WRF) Department.

(3) Other Equipment & Replacements

The forecast cost of the capital expenditures for Other Equipment & Replacements projects during the 2019-2023 period is $59.796 million (Nominal $, SCE share). This includes the Main Generator Stator Rewind Projects for Units 1 and 3, each having a cost greater than $3 million.

(a) Main Generator Stator Rewind Projects -- Units 1 and 3

Each Palo Verde unit has a main generator. A main generator converts mechanical energy from the high and low pressure turbines to electrical energy. This is done by creating an electromagnetic field that forces electrons through stator windings,[183] generating electricity that can be transmitted to the power grid.

The life expectancy for the stator windings is approximately 30 years, and is limited by the life of the winding insulation. Stator cooling water leaks may also adversely impact the useful lives of stator windings. Such leaks may result in equipment damage, forced unit outages, and increased maintenance costs.

The main generator stator windings for each of the Palo Verde units has either already reached or will soon reach 30 years of service, indicating they are approaching the end of their useful lives. Palo Verde, therefore, plans to perform rewinds for the Unit 3 and Unit 1 main generator stators during the fall RFOs of 2019 and 2020, respectively. APS successfully performed the main generator stator rewind project for Palo Verde Unit 2 in 2018.

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[183] The stator winding is the stationary winding in an electric generator.

These projects will extend the design lives of the main generator stator windings and associated equipment, and mitigate stator water cooling leaks. It will also reduce the ongoing maintenance costs associated with these aging electrical components.

Due to the duration of these work scopes, it will be necessary to increase the planned durations of the corresponding RFOs from approximately 30 days to 38-45 days. SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers.[184] SCE's share of the capital forecast for these two projects is $6.543 million (Nominal $, SCE share) during the 2019-2023 period.

c) Water Reclamation Facility

The Palo Verde Water Reclamation Facility (WRF) category covers WRF plant modifications, equipment, and replacements, and WRF process computers,[185] but excludes items covered by the Buildings, General Plant, and Computers budget categories. Water is essential for safe and reliable plant operations. The WRF provides the reclaimed water that serves as the ultimate heat sink for the plant to maintain cooling. The capital work planned by APS for this project keeps the water source for this purpose secure.

The forecast cost of the capital expenditures for WRF projects during the 2019-2023 period is $22.915 million (Nominal $, SCE share). This includes the Clarifiers Life Extension – Train 2 Project, which has a cost greater than $3 million.

(1) Clarifier Life Extension – Train 2

The WRF Solids Contact Clarifier System Structures have exceeded their design life expectancy. Several independent studies corroborate this fact and indicate that refurbishment is necessary to extend the life of the clarifiers. The WRF Clarifier Extension Repair for all six of the original clarifier trains commenced in 2016 with Repair #1 on Train 5. These projects are projected to run through 2021.

SCE includes further detail provided by APS regarding the project need, scope, and cost estimate in the workpapers.[186] SCE's share of the capital forecast for this project is $0.360 million (Nominal $, SCE share) during the 2019-2023 period.

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[184] Refer to WP SCE-05, Vol. 1, Book B, pp. 282-290.

[185] Computers directly related to WRF operation.

[186] Refer to WP SCE-05, Vol. 1, Book B, pp. 291-295.

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 2019-2023 period is $11.039 million (Nominal $, SCE share). No single Buildings project has a cost greater than $3 million.

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 2019-2023 period is $8.850 million (Nominal $, SCE share). No single General Plant project has a cost greater than $3 million.

f) **Computers**

The Computer 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 computer 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 Computer projects during the 2019-2023 period is $10.605 million (Nominal $, SCE share). No single Computer project has a cost greater than $3 million.

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 this project during the 2019-2023 period is $12.789 million (Nominal $, SCE share).

h) **Overheads & 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 Distributable projects during the 2019-2023 period is $17.364 million (Nominal $, SCE share).