Application No.:	A.21-04-001	
Exhibit No.:	SCE-01 A	
Witnesses:	C. Balgos	L. Gaillac
	J. Buerkle	D. Golden
	E. Castano	O. Heum
	T. Champ	R. Hite
	D. Coher	T. Maddox
	D. Cox	C. Winn
	S. DiBernardo	

SOUTHERN CALIFORNIA EDISON®

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(U 338-E)

Energy Resource Recovery Account (ERRA) Review of Operations, 2020 Chapters I-VII

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California

April 1, 2021

SCE-01: Testimony of Southern California Edison Company in Support of its Energy Resource Recovery Account (ERRA) Review of Operations, 2020 Chapters I-VII (Public Version)

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EXECUTIVE SUMMARY

In this testimony, SCE:

1. Demonstrates that the 2020 Energy Resource Recovery Account (ERRA) Record Period[1] Fuel and Purchased Power (F&PP) expenses were reasonably incurred;
2. Presents explanations of variances between 2020 forecast and recorded F&PP expenses;
3. Demonstrates that the dispatch of generation resources and related spot market transactions complied with SCE's 2014 Assembly Bill (AB) 57 Commission-approved Bundled Procurement Plan (BPP) and Standard of Conduct 4;
4. Shows that SCE's contract administration activities and management of Utility-Retained Generation (URG) outages were reasonable;
5. Presents the operation of various regulatory accounts (*i.e.*, balancing accounts (BA) and memorandum accounts (MA)). Most of these accounts, *e.g.*, ERRA BA, are audited by the Commission to ensure that recorded entries are accurate and consistent with Commission decisions;
6. Provides support for the recovery of the net under-collected balance of $47.805 ~~$60.772~~ million recorded in the Building Benchmarking Data Memorandum Account, COVID-19 Pandemic Protections Memorandum Account, Integrated Resource Planning Costs Memorandum Account, and Residential Rate Implementation Memorandum Account; and
7. Presents a review of other procurement-related activities and expenses and/or activities and expenses that the Commission has deemed within the scope of ERRA Review proceedings.

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[1] January 1, 2020 through December 31, 2020.

I.

INTRODUCTION

In compliance with Decision (D.) 02-10-062, D.03-07-029, and D.04-01-048, SCE submitted its 2020 ERRA Review Application on April 1, 2021, which sets forth SCE's operations for the Record Period. SCE's supporting testimony is included in Exhibits SCE-01 and SCE-02. SCE's testimony demonstrate, *inter alia*, that for the Record Period: (1) dispatch of generation resources and related spot market transactions complied with SCE's 2014 Commission-approved BPP and Standard of Conduct 4 (SOC 4); (2) procurement expenses eligible to be recovered through the Energy Resource Recovery Account (ERRA) Balancing Account (BA) and Portfolio Allocation Balancing Account (PABA) were accurately recorded; and (3) SCE's contract administration activities and URG outage-management operations were reasonable.

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

Pursuant to D.02-10-062, SCE is required to set forth the entries recorded in the ERRA BA for review. These entries, along with entries recorded in the Base Revenue Requirement Balancing Account, the Nuclear Decommissioning Adjustment Mechanism, the Public Purpose Programs Adjustment Mechanism, the California Alternate Rates for Energy Balancing Account, and the New System Generation Balancing Account, are discussed in Section B of Chapter XI.[2] Sections C through E of Chapter XI discuss the 2020 operations of 30 accounts.[3] Chapter XII supports the 2020 operations of

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

[3] *See* Table XI-12, lines 7-34 for a list of these accounts. SCE's preliminary statements require that these accounts be reviewed in SCE's annual April ERRA Review proceeding.

the Pole Loading and Deteriorated Pole Programs Balancing Account. As summarized in Table XI-11 of SCE-2, SCE seeks to recover from customers the net under-collected balance of $47.805 ~~$60.772~~ million recorded in the Building Benchmarking Data Memorandum Account, Residential Rate Implementation Memorandum Account, COVID-19 Pandemic Protections Memorandum Account, and the Integrated Resource Planning Costs Memorandum Account.

Therefore, SCE requests a net revenue requirement increase of $47.805 ~~$60.772~~ million (including Franchise Fees & Uncollectibles) in 2022 rate levels upon a Commission finding in this proceeding that the balances in the four accounts, shown in Table XI-11, are reasonable and appropriately recorded in compliance with applicable Commission decisions and resolutions.

A. **Organization of Testimony**

Exhibits SCE-1 through SCE-4 are organized as follows:

SCE-01

Chapter I – Introduction

Chapter II – Least-Cost Dispatch

Chapter III – Hydroelectric Generation

Chapter IV – Natural Gas Generation

Chapter V – Other Generation

Chapter VI – Nuclear Generation and Fuel

Chapter VII – Contract Administration and Costs

SCE-02

Chapter VIII – Natural Gas Procurement

Chapter IX – Inventory and GHG Carrying Cost Rates, Collateral Costs, Security and Performance Assurance

Chapter X – California Independent System Operator (CAISO) - Related Costs

Chapter XI – Operation of Ratemaking Accounts

Chapter XII – Pole Loading and Deteriorated Pole Programs Balancing Account

Chapter XIII – 2020 ERRA Review – ERRA-Related Audit Testimony

Chapter XIV – Greenhouse Gas Compliance Instrument Procurement

Chapter XV – Tehachapi Storage Project

SCE-03

Witness Qualifications and Confidentiality Declarations

SCE-04

Acronyms

Appendices for SCE-01 and SCE-02.

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

In SCE's Record Year 2013 ERRA Review, SCE provided a table that documented the difference between its 2013 forecast ERRA-related costs and SCE's actual recorded 2013 ERRA-related costs.[4] SCE continues to provide this information and this reconciliation has become standard in ERRA Review proceedings. This data is provided for informational purposes only, and is not relevant to any compliance or reasonableness review of SCE's actual recorded costs. The corresponding table for 2020 is provided in Table I-1 below. SCE provides an explanation for variances exceeding plus or minus 10% and greater than $5 million.

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

Table I-1
2020 Forecast & Recorded Fuel and Purchased Power Revenue Requirement
($000)

Line No.	Component	A.19-06-002 November Update 2020 Forecast	2020 Recorded	Variance	Variance %	Variance Explanation Greater than $5M (+ or -) & + or - 10%
1.	Fuel					
2.	Palo Verde - Nuclear	[redacted]	[redacted]	(13,409)	-30.41%	Palo Verde recorded generation lower than forecast due to outages.
3.	Diesel	6,711	4,669	(2,042)	-30.43%	N/A
4.	Propane	1,184	294	(890)	-75.17%	
5.	Mountainview	[redacted]	[redacted]	49,254	174.27%	Mountainview dispatched more than forecasted. CAISO did out of the money exceptional dispatch during 2020. Mountainview dispatch higher during heat wave.
6.	Fuel Inventory Carrying Costs	[redacted]	[redacted]	(614)	-29.06%	N/A
7.	**Subtotal Fuel**	**82,368**	**114,666**			
8.	Purchased Power					
9.	CHP and Renewables	[redacted]	[redacted]	(42,868)	-1.85%	Recorded energy production lower than forecast, resulted in lower expenses.
10.	Common 1/	[redacted]	[redacted]	(3,426)	-37.33%	N/A
11.	Direct GHG Costs	[redacted]	[redacted]	7,593	10.30%	Recorded costs higher due to increase in tolling GHG mainly due to higher dispatch during summer.
12.	Distribution - BRRBA (DRAM/PRP)	-	4,622	4,622	0.00%	N/A
13.	Gas Hedging	[redacted]	[redacted]	(1,863)	-7.61%	N/A
14.	Generic & Bilateral RA	[redacted]	[redacted]	18,395	25.98%	High cost is a result of incremental procurement to meet Month Ahead RA requirements. SCE also executed swap transactions to optimize the value from RA portfolio.
15.	Green Rate Program	2,009	12,957	10,948	544.95%	Forecasted GTSR based on an estimate of GTSR subscription and the weighted average price for the program. Actual cost based on actual subscription and actual cost for serving the GTSR pool.
16.	GTSR Contracts	[redacted]	[redacted]	(6,084)	-100.00%	Forecasted GTSR based on an estimate of GTSR subscription and the weighted average price for the program. Actual cost based on actual subscription and portfolio costs.
17.	Interutility	[redacted]	[redacted]	(554)	-8.13%	
18.	ISO & Short Term Market Activity Costs	[redacted]	[redacted]	213,013	9.61%	Higher costs mainly due to load procurement cost in CAISO market during heat waves.
19.	LCR Contracts	[redacted]	[redacted]	(20,800)	-50.92%	Primary reason for variance was due to COVID-19. COVID-19 impacted most of the contracts. Some parties submitted Covid related Force Majeure notices. There were basically two types of impacts: 1) the “Stay At Home” orders reduced customer loads and therefore ability to perform and 2) MWs scheduled to come online were delayed due to impacts to sales, permitting, construction, installation, interconnection, etc. Hybrid West LA 2 and Swell contracts were delayed due to COVID-19.
20.	PABA Energy Revenue	[redacted]	[redacted]	174,475	-16.99%	Recorded revenue based on energy prices at the location of the resources and forecast uses SP15 prices to come up with revenue. Locational Marginal Prices are very different from the aggregated SP15 prices.
21.	Western Renewable Energy Generation Information System	[redacted]	[redacted]	141	0.00%	N/A
22.	Miscellaneous	[redacted]	[redacted]	24,376	0.00%	N/A
23.	**Subtotal Purchased Power**	**3,735,565**	**4,113,531**			
24.	**Total - Generation Service (Fuel & PP)**	**3,817,933**	**4,228,198**			
25.	Delivery Service					
26.	New Gen RFO Capacity	[redacted]	[redacted]	(63,359)	-18.38%	Summer ran more than forecasted, but lower for the rest of the year.
27.	Combined Heat and Power	[redacted]	[redacted]	(13,129)	-13.95%	Net cost of Combined Heat and Power lower due to higher revenues during heat wave period.
28.	UOG	[redacted]	[redacted]	(15,632)	-6209.57%	Higher revenue from Peakers mainly due to higher prices during summer heat wave days.
29.	LCR	[redacted]	[redacted]	10,825	8.46%	N/A
30.	Bilateral CAM Contracts	[redacted]	[redacted]	(6,910)	-24.29%	Lower recorded payments due to resource availability.
31.	**Sub-Total CAM-Related Revenue Requirement**	**595,371**	**507,167**			
32.	Spent Nuclear Fuel (NDAM)	[redacted]	[redacted]	(4,333)	-100.00%	N/A
33.	**Total - Delivery Service**	**599,704**	**507,167**			
34.	**TOTAL F&PP**	**4,417,636**	**4,735,364**			

1/ Includes Gas Transportation and Storage Costs, Collateral Carrying Costs and GHG Carrying Costs.

C. Disallowance Cap

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

Pursuant to D.02-12-074, the maximum risk of potential disallowance is set at twice the annual expenditures on administrative expenses for all procurement activities as established in a General Rate Case (GRC). The 2020 administrative expenses for procurement activities that the Commission approved in SCE's 2018 GRC (D.19-05-020) is $28.840 million. Therefore, the maximum potential disallowance for SOC-4 related violation(s) is twice $28.840 million, for a total of $57.679 million, in the 2020 Record Period.[5]

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

		2018 GRC Authorized 2020$ As Approved in D.19-05-020
No.	**Administration Expenses for all Procurement Functions**	**Total**
1	DWR Contract Admin	–
2	URG	3,581
3	Renewables	6,220
4	QFs (including CHP)	1,508
5	Demand-side Resources	2,073
6	Other Admin Exp 1 (includes Tolls, RA Financial, Transmission, CAISO/AFA Activities	14,137
7	Other Admin Exp 2	1,319
8	Expenses Not Requested in 2018 GRC (e.g. Balancing / Memorandum Accounts)	–
9	All Procurement Activities	**28,840**
		x 2
10	**Standard of Conduct 4 Disallowance Cap**	**57,679**

D. Safety

D.16-01-017 approved an amendment to Rule 2.1(c) of the Commission's Rules of Practice and Procedure (Title 20, Division 1, of the California Code of Regulations) to require all applications to identify all relevant safety considerations implicated by the application. One of SCE's core values is to

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

ensure public and employee safety. As such, SCE's dispatch of generation inherently assumes that all power providers are fully compliant with laws, rules, regulations and internally-managed controls to assure that the generating facilities, (*i.e.* whether SCE-owned, Power Purchase Agreements (PPA) generation, Resource Purchase Agreements (RPA), or purchased through the California Independent System Operator (CAISO) or other power exchanges), are operated and maintained in a safe working condition. Likewise, SCE's purchasing decisions regarding fuel, and SCE's management of air emissions costs (*e.g.*, Greenhouse Gas Cap and Trade costs and other similar costs), and transmission capacity procurement activities, also assume the counter-parties to these transactions are fully compliant with laws, rules, regulations and internally-managed controls to assure that their facilities are operated and maintained in a safe working condition.

The safety performance of the contracted counter-parties is of concern to SCE but not directly related to SCE's activities at issue in this proceeding, which include sales and purchases of power, fuel, transmission capacity, and air emissions credits and allowances. Nevertheless, these activities do support public and employee safety, as these transactions are an inherent part of assuring a reliable supply of electricity to SCE customers. Costs incurred by SCE to operate and maintain the SCE office and public spaces, shops, warehouses, transmission, distribution, and power plants in a safe condition are reviewed in SCE's GRC Application. In addition, per D.14-12-025, SCE filed a Safety Model Assessment Proceeding Application "to provide Commission staff and other parties with the opportunity to analyze and understand the various models and methodologies that the energy utilities will be using to prioritize safety in their GRC proceedings. This prioritization of safety is to be achieved through the use of models and methodologies to assess the energy utility's risk, and the mitigation measures the energy utility plans to take to reduce and minimize such risks."[6]

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

II.

LEAST-COST DISPATCH

A. Introduction and Commission Standard Review

In this chapter, SCE discusses its compliance with least-cost dispatch (LCD) principles and requirements as specified by applicable Commission orders. The fundamental design of the CAISO Market Redesign and Technology Upgrade (MRTU) environment impacts how SCE "achieves" LCD. In D.11-10-002 (on SCE's 2009 Record Period ERRA compliance proceeding), the Commission acknowledged this, stating "[o]n April 1, 2009, the CAISO began implementation of [MRTU], which substantially changed the least-cost dispatch processes of SCE and other utilities."[7] More recent Commission guidance defines how SCE must demonstrate that it adhered to LCD principles, and the Commission formalized that guidance in D.15-05-007.

1. Information in SCE's Testimony and Workpapers

SCE's testimony and workpapers provide detailed documentation for the Record Period, as required by D.15-05-007. The testimony includes information on:

- Overview/narrative of LCD in the CAISO markets;
- Description of SCE's bidding and scheduling processes;
- Summary reports/tables documenting dispatchable thermal resource aggregated annual exception rates for:
    - Incremental cost bid calculations;
    - Self-commitment decisions; and
    - Master File data changes; and
- Narratives reviewing significant strategy changes, internal software and/or process changes, and the CAISO market design changes during the Record Period, including documentation of SCE's review of market changes.
- Background summary tables including:

[7] D.11-10-002, Finding of Fact (FOF) 1.

- Total capacity of the dispatchable portfolio;
    - Total dispatchable capacity lost due to planned or forced outages;
    - Total capacity of the non-dispatchable portfolio;
    - Total non-dispatchable capacity lost due to planned or forced outages; and
    - Total energy awards (dispatchable and non-dispatchable) by resource type (*e.g.*, hydro, pumped storage, thermal), broken down by self-scheduled versus market awards; and
- Spot market electric and natural gas transactions made by SCE.

SCE's workpapers provide other information required by the relevant decisions and fully document all key LCD-related activities as well as spot market transactions SCE made during the Record Period.[8] A close examination of SCE's LCD practices, or of any particular decision or energy transaction made during the Record Period, will confirm that SCE's procurement practices were consistent with SOC 4 and its LCD protocols (keeping in mind that any *ex post* analysis must appropriately consider the contemporaneous information SCE had when making *ex ante* LCD decisions).

2. The Commission's LCD Standard

In D.02-12-074, which was issued pre-MRTU, the Commission placed the following explanation of SOC 4 in the utilities' approved procurement plans:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. . . . The utility bears the burden of proving compliance with the standard set forth in its plan.[9]

[8] Dispatchable resource commitment and dispatch decisions are largely made by the CAISO, not SCE, although these decisions are based on the bids SCE submits to the CAISO.

[9] D.02-12-074, Ordering Paragraph (OP) 24b. The ellipsis indicates language deleted by D.03-06-076, p. 27 and OP 16.

In D.05-01-054, also issued pre-MRTU, the Commission affirmed that in conducting the daily economic dispatch of energy, utilities must comply with SOC 4, which states:

> The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and least-cost dispatch are the same as our existing standard.[10]

According to the Commission, once this definition of SOC 4 was placed in the utilities' procurement plans, it became the "upfront standard" under AB 57 regarding prudent contract administration and the daily dispatch of energy. As a result, the question to be addressed in the ERRA proceeding regarding LCD is whether the utility has complied with this standard – that is: (1) whether the utility has dispatched[11] the dispatchable contracts and Utility-Owned Generation (UOG) under its control "when it is most economical to do so;" (2) whether it has "disposed of economic long power and purchased economic short power in a manner that minimizes customer costs;" and (3) whether it has used "the most cost-effective mix of its total resources, thereby minimizing the cost of delivering electrical services."

Based on past Commission guidance and the application of basic economic principles, SCE bases its compliance with the LCD standard set forth in SOC 4 on the following operating objectives: (1) a dispatchable resource should run only when its variable costs can be expected to be recovered from the market; (2) SCE bids its dispatchable resources at their marginal cost (or, when applicable, opportunity cost), then CAISO commits and dispatches the resources through its market co-optimization mechanism;[12] (3) SCE purchases power bilaterally when it anticipates doing so will reduce price risk and result in a lower cost than purchasing from the CAISO market; and (4) SCE sells surplus

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[10] D.02-10-062, Conclusion of Law (COL) 11.

[11] In this context, "SCE's dispatch" of dispatchable resources is interpreted as submitting cost-based bids to the CAISO market, with the CAISO making resource commitment and dispatch decisions based on the bids <u>all</u> market participants submit for their respective resources. SCE complies with SOC 4 by appropriately executing processes <u>under its control</u> (*e.g.*, bidding its resources correctly), thus enabling the CAISO to commit the resources in a least-cost manner.

[12] The CAISO's market co-optimization process considers reliability standards and requirements, and includes a full network model reflecting transmission constraints, producing locational prices (including loss and congestion cost components) at thousands of points across the system.

power in a manner that reduces customer costs.[13] For the first objective, it should be understood that the CAISO will frequently force-commit certain resources out of economic order, solely for grid reliability reasons (*e.g.*, to provide voltage support, to ameliorate transmission congestion, etc.). For the second objective, Resource Adequacy (RA) resources must be presented to the market in order for SCE to comply with the Commission's and CAISO's reliability requirements. For *discretionary* resource bidding, SCE employed a strategy (discussed below) to address the cost-minimization objective set forth in SOC 4. This strategy was implemented through the actions of personnel in SCE's Energy Procurement and Management organization, specifically the Trading & Market Operations (TMO) department. In the sections below, SCE explains how its procurement processes and activities aligned with these LCD principles.

B. <u>Overview of LCD in the CAISO Wholesale Market</u>

The CAISO operates a market environment in which it determines the resource mix that will be utilized to serve each day's demand, based on supply and demand bids that all market participants (including SCE) submit. Below is a summary of SCE's LCD-related activities in the 2020 CAISO market:

1. <u>Supply and Demand Bidding/Scheduling</u>

During the Record Period, SCE, as a CAISO Scheduling Coordinator (SC), submitted bids and schedules for its available generator capacity and interchange schedules to the CAISO for commitment and dispatch evaluation in the day-ahead integrated forward market (IFM) and real-time market (RTM). SCE also submitted ancillary services (AS) bids to the CAISO markets, in which the CAISO's market optimization mechanism determines how to utilize resources for energy, for AS, a combination of both, or neither, if the resources are not economic relative to other resources. This process is referred to as "co-optimization," and results in more efficient commitment and dispatch of generating resources across the CAISO-controlled grid. SCE also submitted bids for its forecasted bundled service customer demand to the CAISO to acquire energy in the IFM.

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[13] Power purchases and/or sales can be through the bilateral or CAISO markets.

2. Spot Market Electrical and Natural Gas Transactions

SCE used market[14] energy transactions, when appropriate, to manage its forecast residual net short (RNS) and residual net long (RNL) CAISO[15] energy positions prior to the CAISO IFM. SCE also managed, when appropriate, its post-IFM residual net position (RNP) that developed because of changing supply availability or load forecast changes through the hour-ahead power market and/or the CAISO RTM. SCE also made physical natural gas transactions based on its forecast of the CAISO IFM results and exceptional dispatch (ED) activity.

C. LCD Principles during the Record Period

During the Record Period, SCE complied with SOC 4 by concurrently managing all of its resources, including contracts under its control, and engaging in spot market transactions in a manner designed to reduce price risk and minimize costs to bundled service customers. In making decisions regarding supply and demand bidding, scheduling, power trading, and natural gas trading, SCE sought to balance the following goals:

- Minimize the cost of energy to SCE's customers;
- Maximize reliability for each operating day by adhering to the Commission's RA requirements;
- Reduce SCE's hourly RNP prior to real-time, when appropriate;
- Submit economic bids/offers and schedules to the CAISO and other control areas in accordance with the applicable area timelines and reliability protocols; and
- Mitigate financial credit risk by ensuring that counterparties meet certain credit criteria.

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14 In this context, "market" refers to electrical energy transactions executed outside of the CAISO's IFM and includes transactions executed directly (bilaterally) with counterparties, through voice or electronic brokers (*e.g.*, ICE Brokerage) and through exchanges (*e.g.*, ICE Clear). Trading generally takes place between 5 a.m. and 7 a.m. PPT, Monday through Friday, excluding holidays.

15 SCE managed the electrical energy positions outside of the CAISO from SCE's ownership share of the Palo Verde Nuclear Generating Station and through other renewable and non-renewable contracts. These energy positions are managed to minimize SCE customer costs and may include scheduling and selling the energy outside of the CAISO system and markets.

D. Implementing the LCD Standard

In implementing the LCD standard, SCE evaluates the economics of its dispatchable resource portfolio before submitting bids and schedules to the CAISO. These resources include UOG and utility-contracted resources, as well as spot market transactions in the day-ahead, hour-ahead, and real-time markets.[16]

1. SCE's Bidding Strategy

In the CAISO environment, market participants (including SCE) submit bids to offer energy and AS from resources available to the grid (supply bids), and to acquire energy from the grid to serve customer load (demand bids). SCE employed a bidding strategy with the goal of serving SCE customers at the lowest possible cost, consistent with the Commission's intent set forth in SOC 4. SCE's strategy guided its supply and demand bidding activities during the Record Period and is described in more detail below.

a) Supply Bidding Strategy

SCE's supply bidding strategy is designed to make all dispatchable resources available to the CAISO at [redacted].[17]

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[16] As the Commission explained: "It is true that the existing scope of SOC 4 does not encompass all procurement activities. Specifically, ERRA filings review the reasonableness of contract administration and least-cost dispatch. On the other hand, forward purchase and sale transactions done months prior to the time of dispatch are considered procurement activities and as such, should be reviewed in the quarterly compliance Advice Letter filings." D.05-01-054 at p. 9.

[17] Uplift charges are based in part on the portion of a market participant's demand that is served by energy supplied through the CAISO market (*i.e.*, not served by self-scheduled supply).

Prior to the month (in its month-ahead RA showing), SCE designates enough RA resources to meet Commission and CAISO requirements for load-serving entities (System RA capacity at least equal to 115% of SCE's forecast monthly peak demand).

For dispatchable resources, SCE's bid prices are based on [redacted]

During the Record Period, [redacted]

(1) <u>Opportunity Cost Bidding</u>

[redacted]

[redacted]

(2) Dispatch Efficiency Bidding

[redacted]

(3) Import Bidding

Import bids are grouped into the categories discussed below.

(a) Must-Take Imports

[redacted]

(b) Bilaterally Transacted Energy Imports

[redacted]

2. Renewable Curtailment Bidding

[redacted]

[redacted]

3. Demand Bidding Strategy

In the CAISO market, SCE must submit hourly IFM bids (price and quantity) to obtain the power needed to serve SCE's forecast bundled customer demand. SCE's strategy [redacted]

4. Demand Response Bidding Strategy

[redacted]

5. Eastwood and Hoover Hydro Bidding Strategy

[redacted]

E. Daily LCD Process

SCE implements the guiding principles described above in its daily operations. LCD-related processes are primarily based on load and resource forecasts, as well as forecast and actual power and gas prices. These forecasts are documented in the daily resource plans and are in part based on continuous monitoring of market conditions. The daily forecasting and resource planning process for each operating day requires close coordination within the TMO department.

For each day of the Record Period, SCE prepared and utilized the daily resource plans to, among other things, identify the mix of available resources in the SCE portfolio, document SCE's forecast of CAISO IFM results, and estimate SCE's hourly RNP. The following discussion summarizes the processes and actions by SCE personnel during the Record Period to prepare robust daily resource plans.

TMO's forecasting team developed hourly short-term demand forecasts for each operating day for use in creating the daily resource plan. Such demand forecasts incorporated short-term weather forecasts prepared by SCE's meteorologists, in addition to weather forecasts and data obtained from other meteorological data providers. The demand forecasts also included expectations of customer migrations from SCE to Community Choice Aggregators and estimated impacts due to other external drivers (e.g., for 2020, changes to demand due to COVID-19 stay-at-home orders).

TMO's forecasting team also developed short-term wholesale power price projections using data gathered from internal and external sources. The hourly price forecasts were key elements in SCE's daily resource plans because they guided TMO personnel in formulating projected resource output based on expected CAISO IFM results. Together with the short-term demand forecasts, the short-term price forecasts were used to develop SCE's RNP forecasts, which were used in power and gas hedging activities.

TMO personnel integrated the short-term demand forecast, short-term price forecast, and then projected resource availability in the planning models to prepare daily resource plans. Each plan contained the following key elements:

- Projected hourly availability of SCE's non-dispatchable resources;
- Projected hourly availability of SCE's dispatchable resources;
- Forecasted hourly electricity prices in southern California;[18]
- Forecasted natural gas prices delivered to key California locations;
- Projected economic dispatch of SCE's dispatchable resources;
- Exceptions to marginal cost bidding for SCE's dispatchable resources;
- Energy transactions executed prior to daily trading;
- Forecasted hourly demand;
- Projected hourly RNP; and
- Projected gas requirements at each generating facility for which SCE had procurement responsibility.

1. SCE Managed Its Resources in Compliance with SOC 4

As evidenced by the documentation provided herein and in SCE's workpapers, SCE's market processes and actions throughout the Record Period enabled the CAISO to commit and dispatch SCE's resource portfolio in an economic manner, as described in SOC 4 and relevant Commission decisions interpreting SOC 4.

F. Summary Reports – Annual Exception Rates

As required by D.15-05-007, this section describes SCE's annual exception rates for dispatchable thermal resource incremental bid cost calculations, self-commitment decisions, and CAISO Master File (Resource Data Template, or RDT) changes.

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[18] At the SP-15 EZ Gen Hub, SCE's Load Aggregation Point (LAP) and at the Locational Marginal Pricing (LMP) nodes with dispatchable generation from SCE's portfolio.

1. **Incremental Bid Cost Calculations**

All energy bids submitted to the CAISO IFM during the Record Period are documented in SCE's confidential workpapers for Chapter II. As identified in the workpapers, SCE had 45 hours where dispatchable thermal resources were not bid into the CAISO market; 24 hours resulted from CAISO system issues and 21 hours resulted from user removal of bids. The 24 hours that resulted from CAISO system issues occurred when the CAISO system inadvertently removed the bids for the first configuration of a MSG unit when SCE resubmitted bids for the second configuration of the MSG unit. The remaining 21 hours of bids were [redacted]

Of the 45 hours not bid into the market, none of the hours had a cost impact. SCE's confidential workpapers include detailed information on the variances and evaluation methodology.[19] Table II-3 below shows the estimated cost impact.

The actual incremental bid utilized by the CAISO in the IFM - the clean bid[20] - is compared to the calculated incremental cost, using incremental heat rates, variable operating and maintenance cost (VOM) adders, greenhouse gas (GHG) costs, CAISO grid management charges, natural gas prices, and any applicable natural gas adders. During the Record Period, SCE submitted 336,596 bids[21] for its dispatchable thermal resources to the CAISO, with 0 bids found to have a variance[22] due to user error. A total of 49 bid variances (0.01% of the total bids) were due to system issues; 1 from SCE systems and 48 from CAISO systems. The SCE system issue occurred as the bid inputs were not current when it ran. CAISO system issues are defined as instances where SIBR returns a clean bid that is different from what SCE submitted. In these instances, all SCE internal systems show the calculated bid, but the CAISO SIBR shows a different value.

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[19] See "Chapter II_Section E_Inc Bid Cost Variance_CONFIDENTIAL" and "Chapter II_Section E_Inc Bid Cost Variance BLYTHE_CONFIDENTIAL".

[20] The clean bid is a proxy for SCE's submitted bid. A clean bid is defined as, "a valid Bid submitted by a Scheduling Coordinator that requires no modification, a Default Modified Bid, or a Generated Bid deemed to be acceptable for submission to the CAISO Market applications" (CAISO Tariff, Appendix A.)

[21] "Bid" is defined as an IFM energy bid for one resource, for one hour.

[22] Greater than $0.10 difference between calculated and actual submitted bids. *See* D.15-05-007, Appendix A.

Of the 49 total variances, none of the variances were impactful. SCE's confidential workpapers include detailed information on the variances and evaluation methodology.[23] Table II-3 below shows the estimated cost impact.

Table II-3
Summary of 2020 Thermal Resource Incremental Bid Cost Exceptions

Description	Variances >$0.10 (Hours)	% of Bid Hours	Resources Not Bid (Hours)	Est. Cost Impact
CAISO System Issue	48	0.01%	24	$ -
SCE System Issue	1	0.00%	0	$ -
User Issue	0	0.00%	21	$ -
Totals	**49**	**0.01%**	**45**	**$ -**

2. <u>Self-Commitment Exceptions</u>

During the Record Period, [redacted]

3. <u>Master File (RDT) Change Exceptions</u>

During the Record Period, SCE made 0 Master File (RDT) submissions to declare startup (SU) and minimum load (ML) costs for its dispatchable use-limited thermal resources.

The CAISO tariff provides two methodologies – "Proxy" or "Registered" – to declare resource SU/ML costs:

- Proxy cost option: The SU and/or ML costs are automatically calculated each day based on pre-defined fuel quantities for each, multiplied by an indexed gas price plus a variable operations and maintenance (VOM) adder.[24] The costs thus reflect any daily natural gas

[23] See "Chapter II_Section E_Inc Bid Cost Variance_CONFIDENTIAL" and "Chapter II_Section E_Inc Bid Cost Variance BLYTHE_CONFIDENTIAL".

[24] Electing the Proxy cost option also allows Market Participants to submit daily SU and/or ML cost *bids,* to the extent they are lower than the resulting CAISO-calculated costs.

price variations, and certain additional non fuel-based (*i.e.*, "fixed")[25] SU cost components that were approved by the CAISO; however, this option does not account for opportunity costs.

- Registered cost option: The SU and/or ML costs are pre-defined as static dollar amounts for the election period.[26] This option does not reflect the daily natural gas price changes, but allows other non-fuel based (*e.g.*, contractual) costs to be included (within certain limits). The CAISO tariff only allows this option for new use-limited resources for the first 14 months, then the resource is required to change to a proxy cost option.

During the Record Period, [redacted] This benefitted customers by more effectively enabling the CAISO to dispatch the resources in a least-cost manner.

G. Market and Business Process Changes

During 2020, the CAISO implemented several market changes that have impacted how market participants interact with the CAISO market, including how bids are submitted, and how bidding requirements are monitored and incentivized. Major changes are highlighted below:

1. Capacity Procurement Mechanism Soft Offer Cap

On February 25, 2020, the CAISO filed an amendment to its Tariff to implement its Capacity Procurement Mechanism (CPM) Soft Offer Cap stakeholder initiative. The CAISO proposed changes to replace the existing formula for determining compensation above the CPM soft offer cap with a new formula. Under the new formula, the CPM resource is allowed a 20% adder on top of their going forward fixed costs. This will allow resources the opportunity for sufficient recovery of fixed costs plus a return on capital to facilitate incremental upgrades and improvements by the resources.

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25 "Fixed" SU cost is a static component that does not vary with fuel price changes, but applies only when (and every time) the resource is started. As such, it is truly a variable operating cost, as it would not be incurred but for running the resource.

26 The CAISO tariff allows SU and ML cost updates every 30 days. Elections and defined values carry forward until changed.

FERC approved the CAISO's proposal on May 29, 2020 and the CAISO implemented the changes on June 1, 2020.[27]

2. Commitment Cost Enhancements Tariff Clarifications

On April 17, 2020, the CAISO filed an amendment to its Tariff to implement its Commitment Cost Enhancements Tariff Clarifications. The amendments to the Tariff clarify that Resource Adequacy (RA) resources that are subject to the expected energy must-offer obligation will be subject to RA Availability Incentive Mechanism (RAAIM) for the RA capacity they show in the RA process as if they had the standard 24x7 RA must-offer obligation. As such, the CAISO proposed changes to the (1) availability requirements and exemption status under the RAAIM for resources with operational limitations that are not eligible use limits, (2) exemption status under RAAIM for run-of-river hydroelectric generators, (3) exemption status under RAAIM for storage-backed hydroelectric generators, and (4) methodology and process for determining how much flexible RA capacity a resource is eligible to provide. These changes align with its original policy intent that conditionally available resources enjoy the expected energy must-offer obligation but not special RAAIM treatment. FERC approved the CAISO's proposal on June 30, 2020 and the CAISO implemented the changes on July 1, 2020.[28]

3. Energy Storage and Distributed Energy Resource Phase 3B

On July 16, 2020, the CAISO filed an amendment to its Tariff to implement its Energy Storage and Distributed Energy Resource Phase 3B stakeholder initiative to enhance DR participation in the CAISO markets. The CAISO proposed: (1) the addition of a Load Shift Product where DR resources with behind the meter storage devices can participate in both load consumption and load curtailment, and (2) sub-metered electric vehicles supply equipment to participate in load curtailment.

[27] *See* http://www.caiso.com/Documents/May29-2020-LetterOrderAcceptingTariffRevisionstoCapacityProcurementMechanism-SoftOfferCap-ER20-1075.pdf

[28] *See* http://www.caiso.com/Documents/Jun30-2020-OrderAcceptingResourceAdequacyAvailabilityIncentiveMechanism-CommitmentCostEnhancements3-ER20-1592.pdf

FERC approved the CAISO's proposal on September 30, 2020 and the CAISO implemented the changes on October 1, 2020.[29]

4. Hybrid Resources Phase 1

On September 16, 2020, the CAISO filed an amendment to its Tariff to implement its Hybrid Resources Phase 1 initiative. The purpose of the amendment is to integrate co-located resources, (two or more resources sharing the same point-of interconnection to the grid), into the CAISO market. The CAISO proposed to: (1) develop more robust rules and models to integrate and optimize these resources' performance, (2) establish market rules for using an aggregate capability constraint, (3) establish data requirements for hybrid resources with a wind or solar generation component, (4) develop a CAISO forecast for hybrid resources and allow scheduling coordinators to elect to use this forecast for a fee, and (5) make clarifying changes to its Tariff regarding Eligible Intermittent Resources providing outage data to the CAISO. FERC approved the CAISO's proposal November 19, 2020, the CAISO implemented the changes December 1, 2020.[30]

5. Internal Software Changes

Other than previously described topics, SCE did not implement any significant software changes.

6. LCD-Related Process Changes

Other than the previously described topics, SCE did not implement any significant LCD process changes.

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[29] *See* http://www.caiso.com/Documents/Sep30-2020-LetterOrderAccepting-EnergyStorageandDistributedEnergyResourceStakeholderESDERPhase3-ER20-2443.pdf

[30] *See* http://www.caiso.com/Documents/Nov19-2020-OrderAcceptingHybridResources-ER20-2890.pdf

H. Background Summary Tables

Table II-4 below provides annual summary data for SCE's resource portfolio broken down by dispatchable and non-dispatchable resources; including capacity,[31] unavailable capacity,[32] day-ahead self-schedule (SS) awards and day-ahead market awards. The CAISO reports market awards for day-ahead exceptional dispatches and the charging of energy storage resources as self-schedules.

Table II-4
Background Summary of 2020 Resource Capacity and Awards

Dispatchable	Capacity (MWh)	Unavailable Capacity (MWh)	DA SS Awards (MWh)	DA Market Awards (MWh)
Thermal	34,187,805	[redacted]		
Hydro	9,924,602			
Pump Storage	1,756,800			
Energy Storage	175,680			
Totals	**46,044,888**			

Non-Dispatchable	Capacity (MWh)	Unavailable Capacity (MWh)	DA SS Awards (MWh)	DA Market Awards (MWh)
Other	9,835,366	[redacted]		
Renewable	69,874,243			
Nuclear	5,577,840			
Hydro	1,324,848			
Totals	**86,612,296**			

I. Demand Response Resources

During the Record Period, all of SCE's economically triggered Demand Response (DR) resources were available for CAISO market dispatch. This represents up to an approximate 894 MW of integrated PDRs and RDRRs[33] capacity in September 2020.[34] SCE's confidential workpapers include

[31] "Capacity" is calculated as the aggregate of the applicable resources' maximum capacity ratings multiplied by the number of hours during the Record Period each resource was under SCE control.

[32] "Unavailable capacity" is defined as zero availability (*i.e.*, excludes partial de-rates) for the applicable resources.

[33] PDR includes customers in the Capacity Bidding Program (CBP), and Local Capacity Requirements (LCR) DR contracts. RDRR includes customers in the Base Interruptible Program (BIP), Agricultural Pumping Interruptible (API), Summer Discount Plan (SDP) and Smart Energy Program (SEP).

[34] Integrated MW vary by month, due to program availability and contracts coming on or off line.

detailed information on program parameters, dispatch,[35] opportunity cost methodology (when applicable), dispatch exceptions and estimated cost impacts.

J. **SCE's Market Purchases and Sales**

The CAISO determines which resources will be dispatched and ensures that physical supply and demand is matched (cleared) through its market operations. SCE's trading activities focus on managing the physical and financial risks associated with SCE's RNP. Transactions can be for physical or financial products, as both serve to hedge against the unknown IFM price at the time of the trade.

The clearing process that takes place in the IFM, where the difference between a market participant's awarded supply and demand (*i.e.*, the RNP) is cleared at the IFM price, effectively meets SCE's IFM RNP.

During the Record Period, SCE participated in the non-CAISO market (trading physical and financial electricity products) in order to diversify its exposure. For example, [redacted] Furthermore, SCE is still required to manage open positions outside the CAISO system with physical electricity transactions.

As the IFM will usually clear all of SCE's RNP, SCE's Energy Trading team does not have the objective of reducing the CAISO-delivered RNP to (or near) zero; rather, the objective is price-risk mitigation. For example, [redacted]

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[35] RDRR includes provisions for SCE's Grid Control Center to issue reliability-based dispatches, which are considered outside the scope of LCD and thus not included in this discussion.

1. **Day-Ahead Transaction Summary**

The majority (99%) of the day-ahead transactions (i.e., number of trades) were standard on-peak and off-peak products. However, as discussed above, in its price-risk minimization efforts, SCE also relied on the IFM to transact energy in order to manage the RNP. SCE's Record Period Day-Ahead purchases and sales are shown in Table II-5 below.

Table II-5
Summary of 2020 Day-Ahead Spot Electric Transactions
(Physical and Financial)

	Annual	
Deal Type	**Energy (GWh)**	**Number of Deals**
Broker/Exchange Purchases		
Standard On-Peak	6,397.54	719
Standard Off-Peak	129.84	175
Other Non-Standard Products	1.60	1
Subtotal Broker/Exchange	**6,528.98**	**895**
Bilateral Purchases		
Standard On-Peak	0.80	1
Standard Off-Peak	1.20	6
Other Non-Standard Products	0.00	0
Subtotal Bilateral	**2.00**	**7**
Total Purchased	**6,530.98**	**902**
Broker/Exchange Sales		
Standard On-Peak	0.00	0
Standard Off-Peak	0.00	0
Other Non-Standard Products	0.00	0
Subtotal Broker/Exchange	**0.00**	**0**
Bilateral Sales		
Standard On-Peak	30.00	2
Standard Off-Peak	0.00	0
Other Non-Standard Products	0.08	1
Subtotal Bilateral	**30.08**	**3**
Total Sold	**30.08**	**3**
Total Broker/Exchange	6,528.98	895
Total Bilateral	32.08	10
Total Transacted	**6,561.06**	**905**

2. <u>SCE's Day-Ahead Transactions Were Competitive and in Compliance with SOC 4</u>

As discussed above, SCE's day-ahead purchase and sale transactions during the Record Period were conducted via brokers/exchanges and bilateral processes in accordance with its LCD transaction protocols and SCE's Commission-approved BPP. Details of these transactions are included in SCE's confidential workpapers.

3. <u>Criteria Utilized in Selecting the Volume to Buy and Sell in the Hour-Ahead Market</u>

Moderating SCE's potential exposure to the CAISO's RTM was a consideration in SCE's determination of the energy quantities to potentially be transacted in the hour-ahead market. In addition, the criteria previously discussed regarding day-ahead transactions also applied to SCE's transaction decisions in the hour-ahead market.

Unlike the day-ahead spot market, which usually has many potential creditworthy counterparties who trade standard and non-standard on-peak and off-peak products, the hour-ahead spot market is usually far less liquid, with a low number of potential creditworthy counterparties.

The IFM clears most open positions in the day-ahead timeframe down to the hourly level, significantly reducing the amount of potential energy to transact in the hour-ahead markets. In general, low liquidity associated with hour-ahead trading is due to the following reasons:

- The IFM clearing most open positions for most market participants, prior to real-time;
- Many non-load-serving market participants (*e.g.*, banks and hedge funds, etc.) close out their positions prior to the hour-ahead market;
- The products transacted are for non-standard deliveries, typically for only up to a few hours on a given day; and
- Given SCE's estimated hour-ahead RNP is usually determined just a few hours before, it is often difficult to find creditworthy counterparties whose energy positions can offset SCE's energy positions.

SCE followed SOC 4 in its hour-ahead transacting during the Record Period by appropriately reducing its RNP, when feasible, through competitively-priced sales or purchases. This compliance can be confirmed by understanding the market conditions that existed at the time of a given transaction and reviewing SCE's daily resource plans.[36]

4. Hour-Ahead Transaction Summary

Table II-6 below is a summary of SCE's hour-ahead purchases and sales during the Record Period. The total volume of SCE's hour-ahead spot transactions (5.26 GWh) was less than 1% of the total volume of SCE's day-ahead spot transactions (6561.06 GWh). This is to be expected because the day-ahead market is generally more liquid than the real-time market.

[36] SCE provides this information to the Commission through the Quarterly Compliance Report (QCR) process.

Table II-6
Summary of 2020 Hour-Ahead Spot Electric Transactions
(Physical and Financial)

	Annual	
Deal Type	**Energy (GWh)**	**Number of Deals**
Broker/Exchange Purchases	0.00	0
Bilateral Purchases	0.00	0
Total Purchased	**0.00**	**0**
Broker/Exchange Sales	0.00	0
Bilateral Sales	5.26	121
Total Sold	**5.26**	**121**
Total Broker/Exchange	0.00	0
Total Bilateral	5.26	**121**
Total Transacted	**5.26**	**121**

5. <u>SCE's Hour-Ahead Transactions Were Competitive and in Compliance with SOC 4</u>

SCE's hour-ahead transactions during the Record Period were conducted in accordance with its LCD transaction protocols. In the absence of reliable price indices for the hour-ahead market (which, if available, would undoubtedly show a range of reported prices for each hour), SCE's price surveys are the best indicators available for hour-ahead market prices for the various products, locations, and market conditions.

6. <u>Gas Procurement Supporting LCD</u>

During the Record Period, SCE transacted, transported, stored, and hedged natural gas supplies in conjunction with SCE gas agreements. Only the short-term (i.e., daily spot and intra-day) gas transactions that were executed in support of dispatchable resources are reviewed in this ERRA Review proceeding; SCE's long-term transactions are reviewed in its Quarterly Compliance Report (QCR) submissions.

SCE's overall objective in providing gas supplies under the agreements[37] for which it was responsible during the Record Period was to minimize costs, while ensuring operational reliability and flexibility to respond to continuously-changing generation requirements of SCE's resource portfolio, as dictated by LCD requirements. During October through December of the Record Year, SCE utilized Backbone Transportation Service (BTS) to diversify supply receipt points and hedge gas price volatility.

To cost-effectively manage SCE's overall physical gas position, SCE's gas trading team reviewed the daily resource plan, market fundamentals, pipeline conditions, and gas imbalance account to determine the quantity of day-ahead gas needed to meet SCE's gas requirements. The traders purchased the required physical gas volumes utilizing a combination of daily index and fixed priced transactions, daily index call options, and baseload supply arrangements. Daily index and fixed price transactions are entered into bilaterally or via brokers and electronic exchanges (e.g. ICE). Daily index call options are set up as term deals (monthly) with the right to purchase gas up to the maximum volume on a daily basis, at a daily index price. Daily index call options allow SCE to secure reliable supply on a day ahead basis; while baseload supply arrangements provide SCE with consistent gas supply volumes across the month. Because the forecasted day-ahead gas requirements must be purchased before the CAISO's daily IFM results are published, SCE utilizes the intra-day and secondary imbalance gas markets to transact gas volumes due to unexpected IFM results or intra-day generation schedule changes.

7. Gas Transaction Summary

Table II-7 below is a summary of the daily spot and intra-day gas transactions during the Record Period. A portion of SCE's gas purchases were daily index call options which were set up as term deals; as such, their volumes are not included here. Please refer to Chapter VIII for additional information regarding gas transactions.

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[37] Relevant information regarding gas agreements is discussed in Chapter VIII.

Table II-7
Summary of 2020 Spot Gas Transactions

	Annual	
Deal Type	**Volume (Billion BTU)**	**Number of Deals**
Broker/Exchange Purchases	224,496	4,661
Bilateral Purchases	8,523	377
Total Purchased	**233,019**	**5038**
Broker/Exchange Sales	6,942	605
Bilateral Sales	1,663	104
Total Sold	**8,606**	**709**
Total Broker/Exchange	231,438	5,266
Total Bilateral	10,186	481
Total Transacted	**241,624**	**5,747**

8. <u>SCE's Spot Gas Transactions Were Competitive and in Compliance with SOC 4</u>

During the Record Period, all of SCE's spot gas transactions were at prices competitive with spot gas index prices published in recognized surveys. Accordingly, these transactions complied with SOC 4.

K. SCE's Spot Electric and Gas Transactions Met LCD Compliance Requirements

As evidenced by the foregoing discussion and the documentation provided in SCE's workpapers, SCE's electric and gas transactions, and processes, minimized costs to its customers throughout the Record Period.

L. Conclusion

During the Record Period, SCE consistently followed prudent procurement and bidding processes and practices to satisfy SOC 4. As evidenced by this testimony and the supporting workpapers, SCE also provided qualitative and quantitative documentation that its actions met the Commission's LCD Compliance Standard, and this showing complies with the requirements established in D.15-05-007. Accordingly, the Commission should find that SCE's LCD-related activities performed during the Record Period were reasonable and in compliance with the applicable Commission standards.

III.

HYDROELECTRIC GENERATION

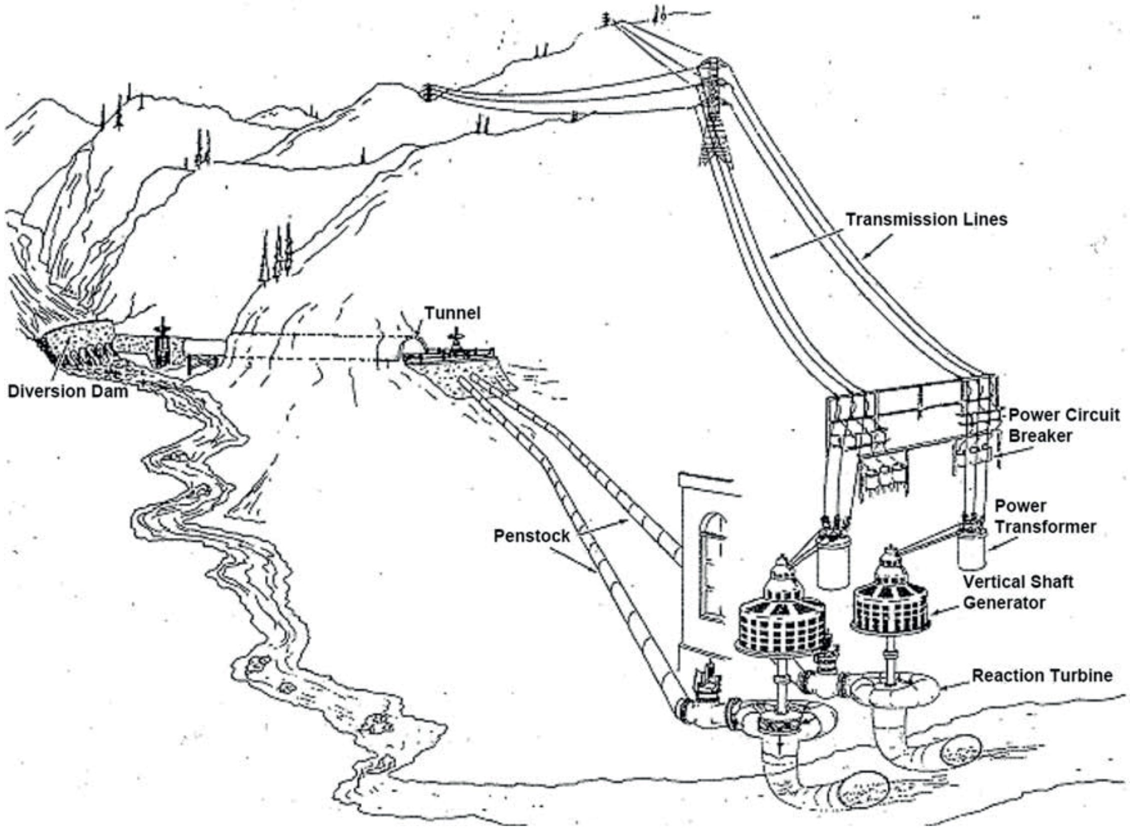
During the Record Period, SCE operated and maintained 32 hydroelectric generating plants including 33 dams, 43 stream diversions, and approximately 143 miles of tunnels, conduits, flumes, and flow lines.[38] These resources have an aggregate 1,164 MW of nameplate generating capacity. This chapter demonstrates that SCE's hydro facilities were operated in a reasonable and prudent manner during the Record Period.

A. Characteristics of SCE's Hydro Generation Resources

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

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

Figure III-1
Typical Hydroelectric Generating Station



SCE has three types of hydroelectric plants: (1) stream flow or "run-of the-river;"[39] (2) reservoir storage; and (3) pumped storage (plants where the water can be pumped back to a storage facility for reuse during peak hours).

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

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

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

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

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

For discussion purposes, SCE's Hydro assets can be divided into two groups: the Big Creek project and SCE's small hydro projects. The Big Creek project assets are the larger group, encompassing all SCE hydro facilities in the upper San Joaquin River watershed in the western Sierra Nevada Mountains.[40] Big Creek is a composite of six major reservoirs, 16 tunnels driven through solid granite, and nine powerhouses, most of which are reservoir storage plants. Most of the Big Creek powerhouses are directly connected to the 220kV bulk power transmission system. In aggregate, the Big Creek generating capacity is approximately 1,015 MW, or about 86% of SCE's total hydro generation capacity. Most of the Big Creek plants have been in service since the early- to mid-twentieth century.

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

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[40] The Big Creek system is located approximately 50 miles north and east of Fresno, California, in the Sierra Nevada mountain range.

Table III-8 below provides the rated MW rated capacity to the nearest one tenth of a MW for SCE's Hydro Powerhouses containing units that either by themselves, or in combination, equal or exceed 25 MW. These "large" powerhouses account for approximately 1,071 MW, or 92%, of SCE's total Hydro generating capacity.[41]

[41] Throughout this chapter, SCE defines "large" hydro powerhouses as those having capacities exceeding 25 MW, consistent with the ERRA review phase proceeding UOG outage reporting requirements established in D.15-03-023. However, note that in most forums "large" powerhouses are defined as those with capacities exceeding 30 MW (*e.g.,* powerhouses with capacities of 30 MW or less qualify as renewable resources while those exceeding 30 MW do not). As shown in Table III-9, SCE has one powerhouse that has a capacity between 25 MW and 30 MW (*i.e.,* Kern River 1).

Table III-8
SCE Large Hydro Powerhouses

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

1. <u>Big Creek</u>

Big Creek utilizes six major reservoirs for water storage, as well as smaller reservoirs that supply some of the powerhouses. The maximum storage for the six major reservoirs is approximately 560,000 acre-feet. Due to operational planning and contractual constraints, the reservoirs are typically lowered during the winter months to minimum levels and filled to maximum levels during spring runoff from melting snowpack. The average annual runoff (with significant yearly variations) from the Big

Creek watershed is approximately 1,830,000 acre-feet, with the majority of the runoff occurring during the months of April through August.[42] This creates a challenge for Big Creek to utilize as much of the runoff as possible for generation, while minimizing spill.[43] Once a reservoir reaches a full level, inflows that exceed the hydraulic capacity of the downstream powerhouse will bypass the powerhouse as controlled spill. If an outage occurs at the powerhouse during this time, it will cause an increase of water bypassing the powerhouse as controlled spill. SCE defines the energy in MWh lost due to water bypassing a powerhouse due to an outage as "outage bypassed energy." It is additional generation production that would have been possible had the hydro unit not been out of service.

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

a) Powerhouse Arrangement

Big Creek consists of nine hydro generating plants arranged in essentially three parallel chains in the upper elevations, which then join together in the lower elevations. Water stored in Lake Edison and Florence Lake is channeled to Huntington Lake through the Portal Powerhouse, where it is then divided between the Huntington Chain[44] of powerhouses and the Shaver Chain[45] of powerhouses, which includes Eastwood. Water passing through the Shaver Chain collects in Shaver Lake and is then fed to Dam 5 where it rejoins water passing through the Huntington Chain. Below Dam 5, the water joins flows from the Mammoth Pool Chain at Dam 6, and continues down the

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

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

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

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

mountain through Powerhouse 3 to Redinger Lake.[46] The Big Creek system ends at Powerhouse 4, which is fed from Redinger Lake and is at the edge of PG&E's Kerckhoff Reservoir.

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

Operation of Big Creek is subject to environmental and regulatory constraints. The overriding objective for using all the SCE Hydro powerhouses and water storage facilities is the prudent use of the water resource, and safety. Water management on the project is governed by FERC licenses, U.S. Forest Service agreements, water rights, and contractual commitments, which include provisions for water releases and storage levels.[47] Each reservoir has required storage levels at particular times of the year. The summer season typically requires nearly full levels to satisfy recreational interests. Additionally, there are limits on seasonal carry-over storage that apply to the whole Big Creek project that relate to downstream water users (largely for agricultural irrigation).

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

The runoff during the 2020 water year was approximately 49% of a normal (*i.e.*, average) year.[48] Given the fleet's high reliability and the effective management of fuel (water)

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46 The Mammoth Pool Chain utilizes the Mammoth Pool Powerhouse, BC 3 and BC 4 plants.

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

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

available, generation levels during the Record Period were approximately 65% of the 20-year historical average (2000-2019) despite the fact that a majority of the Big Creek Assets were off-line the entire fourth quarter of 2020 due to the Creek Fire.

c) <u>System Operation to Fulfill Requirements/Constraints</u>

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

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

(continued from previous page)
on a "water year" basis, which runs from October through September (*e.g.,* October 1, 2019 through September 30, 2020, for the 2020 water year).

d) Factors Affecting Operations

The amount of generation available in a given year depends upon the precipitation received plus carryover reservoir storage from the previous year, less the required storage commitments. During the 2020 water year flow in the San Joaquin River was approximately 886,200 acre-feet, or approximately 49% of an average year, following 2019, which had a runoff of approximately 150% of an average year. Long-term planning is used to generate a forecast of power available for scheduling each month during the year and includes consideration of:

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

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

2. Other SCE Hydro Assets

As mentioned above, in addition to Big Creek, SCE hydro assets include another 23 hydro generating plants with a total capacity of approximately 149 MW. The 23 plants range in capacity from less than one MW at several plants, up to approximately 40 MW at the Kern River 3 plant. These assets are in the Bishop and Mono Basin areas, the Kern, Kaweah, and Tule River areas, and the

Ontario, San Bernardino, and Banning areas in the San Gabriel and San Bernardino Mountains. Some of these powerhouses utilize flow from diversion dams on rivers, whereas others utilize flow from relatively small (*i.e.*, as compared to Big Creek) storage reservoirs.

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

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

a) <u>Environmental/Regulatory Requirements and Constraints</u>

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

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

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

c) Factors Affecting Operations

Like Big Creek, the amount of generation available each year from these 23 powerhouses depends upon precipitation during that year. However, for the diversion pools and reservoirs associated with these powerhouses, there is no carryover or target for storage to consider. Therefore, hydrology planning activities are considerably less than needed at Big Creek, but incorporate the following similar parameters:

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

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

d) Storm Debris

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

e) Eastwood Pumped Storage

Eastwood is SCE's largest hydroelectric generating unit and the only one with pump back capability. It consists of an underground powerhouse at Shaver Lake with a single pump/turbine rated at 200 MW. The powerhouse is fed water from a small reservoir known as the

Balsam Meadow forebay. This forebay is located geographically and in elevation between Huntington Lake and Shaver Lake. Balsam Meadow forebay has a maximum storage capacity of approximately 1,547 acre-feet of water. The forebay is fed primarily by a water conveyance tunnel bringing water from Huntington Lake. In addition, some water is diverted from Pitman Creek into the Balsam Meadow forebay. Water exiting the forebay to Eastwood enters another tunnel which later transitions into a penstock that feeds the Eastwood turbine. When generating, water from the Balsam Meadow forebay flows through Eastwood and is discharged into Shaver Lake. This is the customary way for water to flow from Huntington Lake to Shaver Lake.

Over its history, much of Eastwood's operation has been in the conventional manner, generating electricity during peak periods by capturing the potential energy of the water resource as it flows from higher to lower elevations, as described above. Eastwood also provides pumped storage capacity, whereby the generator can also be operated as a motor.[49] This turns the turbine in the reverse direction, which allows the turbine to operate as a pump. When used in this manner for pumped storage, Eastwood consumes electric power during low or negative-priced hours to pump water uphill to the Balsam Meadow forebay, so it can generate power during higher-priced hours. Under typical operations, Eastwood Pump schedules are determined by SCE's Short-Term Market Planning group to maximize the value of Eastwood's Pumped Storage capabilities. For pump operations to add value to Eastwood, the on-peak/off-peak differential must be large enough so the cost to pump is less than the value of generation.[50] In recent years, peak and off-peak prices have evolved with the increased penetration of renewable resources leading to lower market prices for electricity during peak periods as well as higher price uncertainty. Lower gas prices have also led to lower absolute differences between peak and off-peak prices, thereby reducing the margin prices between pump and generation.

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

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

SCE continues to monitor changing market conditions and will continue to utilize Eastwood, so it maximizes value for SCE customers.

C. Recorded Hydro Production

Table III-9 below summarizes SCE's Hydro generation for the 2020 Record Period, as well as the average annual generation recorded during 2001 through 2020 on a calendar-year basis.[51]

Table III-9
SCE Hydro – 2020 Recorded Hydro Production

Line No.	Region	2001-2020 Average Net Generation (MWh)	2020 Net Generation (MWh)
1	Big Creek	2,913,207	1,680,704
2	Other Assets	479,296	526,114
3	TOTAL	3,392,503	2,206,818

As shown, the combined 2020 generation of Big Creek and the Other Assets was 2,206,818 MWh, approximately 65% of the previous 20-year period average. This mainly reflects the fact that a majority of the Big Creek Assets were off-line for a large portion for the fourth quarter of 2020 due to the Creek Fire.

D. Large Hydro Performance During the Record Period

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

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

these metrics, along with summary information for the outages that affect these metrics, for SCE's large powerhouses.[52]

1. Equivalent Availability Factor Results

EAF is expressed as the percentage of time that a generating unit was available for service (regardless of whether it was actually in service) during the time period in question. EAF is reduced by scheduled outages, forced outages, and derates (*i.e.*, partial outages). EAF is not reduced by outages or derates resulting from issues that were external to the SCE-managed powerhouse, reservoir, dam site and flowline equipment including: (a) transmission system constraints or outages that impact the powerhouse, and (b) insufficient water flows to operate the turbines, or time periods when the water contains excessive levels of storm debris (whereby using the water would damage the turbine). EAF is calculated on a monthly basis for each powerhouse, which is then combined into a total aggregate EAF. Generally, the higher the EAF the better, SCE also considers the costs (non-labor and labor, including overtime) and benefits (including the value of electricity) when deciding how quickly to repair a given asset and return it to service. Ideally, the EAF level is as high a percentage as possible.[53] As shown in Table III-10 below, the recorded EAF for 2020 was approximately 89.08%, which is slightly lower than SCE's five-year average of 91.82% (2015-2019).[54]

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52 See Table III-9 for a list of SCE's large powerhouses (*i.e.,* those with capacities exceeding 25 MW). D.15-03-023, p. 3, requires that SCE provide certain information in its annual ERRA Review Phase filings for outages exceeding 24 hours, where the outage affected a generating unit with a rated capacity exceeding 25 MW, or affected multiple generating units at a given power plant having a combined capacity exceeding 25 MW.

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

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

Table III-10
SCE Large Hydro – Equivalent Availability Factor (EAF)

Line No.	Year	SCE	Industry
1	2015	95.49	80.80
2	2016	96.42	80.53
3	2017	93.88	81.99
4	2018	88.38	79.57
5	2019	84.95	81.73
6	Avg.	91.82	80.92
7	2020	89.08	Unavailable

2. <u>Forced Outage Factor Results</u>

FOF 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 FOF level is a low percentage. FOF is calculated for each powerhouse and combined (*i.e.*, pro-rated by each powerhouse's rated MW output) into an overall combined total for the SCE Hydro fleet. As with EAF, FOF does not include outages due to issues that are external to the SCE-managed hydro assets and equipment.

As shown in Table III-11 below, the recorded FOF for the 2020 Record Period was approximately 6.40%.[55] This value is significantly higher than SCE's prior five-year average (2015-2019) and discussed in greater detail in Section 3.

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

Table III-11
SCE Large Hydro – Forced Outage Factor (FOF)

Line No.	Year	SCE	Industry
1	2015	0.17	6.17
2	2016	1.06	6.08
3	2017	1.02	3.55
4	2018	1.65	6.15
5	2019	2.69	4.01
6	Avg.	1.32	5.19
7	2020	6.40	Unavailable

3. Outages and Outage Bypass Energy Loss

Since 1982, SCE has utilized the North American Electric Reliability Corporation (NERC) GADS (Generating Availability Data System) to classify and track outage events (*i.e.,* scheduled and unscheduled outages) at its hydro facilities.[56] GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, the following objectives for the GADS program were established: compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment.

Periodic production outages are required to perform maintenance on SCE's dams, flowlines and powerhouses. Planned maintenance outages are generally scheduled in the fall or winter when the lowest amount of water is available for generation. This practice minimizes outage bypass energy loss. However, relatively long outages are occasionally needed to complete major planned work

[56] NERC GADS (the North American Electric Reliability Corporation's Generation Availability Data System) is a group of databases used to collect, record, and retrieve operating information from power plants in North America. The data is used to improve performance of electric generating equipment, and to support equipment reliability and availability analysis by GADS data users. For information on outage report code definitions, please refer to Appendix III-A and the NERC-GADS Data Reporting Instructions, *available at* http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Entire%20GADS%20Data%20Reporting%20Instructions%20Effective%20January%201,%202015.pdf.

(*e.g.,* dam improvements). Therefore, it is not uncommon to incur some amount of outage by-pass energy loss during one or more of the planned outages undertaken in a typical year.

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

During the 2020 record period SCE achieved a high level of reliability and there were no outage bypass energy events at SCE's large powerhouses

a) Scheduled Outages

Scheduled outages include planned maintenance outages as well as planned maintenance outage extensions. Planned outages are typically scheduled at the start of each year. For example, it is common for planned outages to occur in the spring to prepare for the summer peak season, and in the fall to address issues observed during the summer peak season. During the year, maintenance outages are scheduled when needed to perform non-emergency repairs, typically during a time better suited for the bulk power grid (*e.g.,* on weekends). As summarized in Table III-12, there were 49 scheduled outages (with zero outage extensions) at SCE's large powerhouses during the Record Period.

Table III-12
SCE Large Hydro – 2020 Scheduled Outages

Line No.	Outage Classification	Quantity
1	Planned (PO)	42
2	Planned Extension (PE)	0
3	Maintenance Outage (MO)	7
4	Maintenance Outage Extension (ME)	0
5	TOTAL	49

Twenty-two of these scheduled outages exceeded 24 hours in duration. None of these 49 scheduled outages continued into 2021, and none of these 49 were extended by more than one week past the scheduled end date that was in place at the start of the outage. Additional details regarding Hydro scheduled outages are provided in SCE's response to the Master Data Request for this proceeding.[57]

b) Unscheduled Outages

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

During the Record Period, there were a total of 26 unscheduled (*i.e.*, forced) outages on SCE Hydro generating units. 18 of these outages affected a total generation capacity of less than 25 MW and/or had a duration of less than 24 hours. The other eight outages lasted longer than 24 hours, and either occurred on a generating unit larger than 25 MW or affected a generation capacity of greater than 25 MW.[58] These eight outages are summarized in Table III-13 and are discussed in more detail below. As shown, none of these eight outages incurred outage bypassed energy, thus no

[57] See SCE response to MDR A.20-04-XXX Q.1.1.12.b.

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

replacement power costs were incurred, as there was available storage at Big Creek at the time of these outages.[59]

Table III-13
SCE Large Hydro – 2019 Unscheduled Outages
(Lasting Longer than 24 Hours on Units Greater Than 25MW)

Line No.	Plant and Unit	NERC Event Type	MW Affected	Beginning Date/Time	Ending Time/Date	Outage Length (hrs:mins)	Bypassed Energy (MWh)
1	Big Creek # 2A Unit 1	U1	55.0	1/26/2020 16:56	2/1/2020 12:28	139:31	0
2	Big Creek # 2A Unit 1	U1	55.0	2/14/2020 13:00	2/22/2020 16:25	195:25	0
3	Big Creek # 2A Unit 2	U1	55.0	3/20/2020 11:26	3/23/2020 11:20	71:54	0
4	Big Creek # 3 Unit 2	U1	34.0	7/22/2020 9:56	7/24/2020 14:11	52:15	0
5	Big Creek # 3 Unit 5	U1	36.5	2/29/2020 13:45	3/18/2020 11:08	428:22	0
6	Big Creek # 4 Unit 2	U1	50.0	2/11/2020 20:23	2/14/2020 14:53	66:30	0
7	Mammoth Pool Unit 2	SF	95.0	6/6/2020 17:34	6/8/2020 13:59	44:25	0
8	All	U1	1015.0	Varies	Varies	Varies	0

(1) Big Creek 2A Unit 1 Low Field to Ground Resistance (IR 205)

On January 26, 2020, Big Creek 2A Unit 1 was taken offline because the magnetic field circuit to ground resistance reading was low (*i.e.,* the field ground detector indicated a decreased winding resistance relative to ground). SCE removed the unit from service as a precaution to prevent the ground from worsening, or a second ground from occurring, which could have potentially damaged the unit.

SCE's investigation revealed carbon dust buildup on the field windings and bus bars, likely caused from the brushes and oil mist of nearby operating equipment. Cleaning of the slip rings and associated bus work is labor intensive and time consuming due to the amount of equipment disassembly and reassembly required.

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

On February 1, 2020, the cleaning activities performed by SCE had improved the ground resistance reading to an acceptable level and the unit was restored to service. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(2) Big Creek 2A Unit 1 Faulty O-Ring (IR 215)

On February 14, 2020, during a routine inspection the plant operator noticed that the Left Hand (LH) gate position was swinging in the opening and closing directions more erratically than usual and the Right Hand (RH) gate was not moving at all.[60] During normal operating conditions, both gates should move in unison to maintain an equal amount of applied force to each side of the generator shaft. If too much of an imbalance occurs, (*i.e.,* one gate being more open than the other), the shaft bearings could be damaged. The control operator manually shut the unit down to prevent bearing damage from occurring. The ensuing investigation determined that the relay valve on the RH governor was binding due to a faulty O-ring. It was determined that the O-ring was an "add-on" part and not required for proper governor operation. Maintenance personnel removed the O-ring and reassembled the valve. Following reassembly the unit was tested to ensure proper working order of the RH and LH gates and the unit was released for service on February 22, 2020. An IR was created for this outage and has been provided in testimony workpapers.

(3) Big Creek 2A Unit 2 TSO Valve (IR 232)

On March 20, 2020, while Big Creek Powerhouse 2A, Unit 2 was online and generating, the LH (Left Hand) TSO (Turbine Shutoff) valve hydraulic actuator drain valve developed a pinhole leak in the body of the valve. Due to the high-water pressure within this piping system, a pinhole leak can grow and worsen in a short amount of time and operators immediately took the generator offline in order to prevent further damage. Replacement of the valve was completed on March 23 and took three days to complete due to the lack of an available spare valve in SCE's warehouse. In addition to the replacement valve, SCE also purchased an additional spare that will be

[60] The "gate" controls the flow of water to the turbine buckets (water wheel buckets). In normal operating conditions, both gates move in unison to maintain an equal amount of applied force to each side of the generator shaft.

available should any future failures occur. An IR was created for this outage and has been provided in testimony workpapers.

(4) Big Creek 3 Unit 2 Penstock Leak (IR 274)

On July 22, 2020, Big Creek 3 Unit 2 was in-service when SCE maintenance personnel observed excessive water spray emanating from the lower section of penstock number two. The leak was identified as a failure of the joint packing, which is used to seal the joint between two pipe sections. The on-duty Control Operator was notified, the unit was shut down, and the affected penstock was isolated and drained to expedite repairs. Once the joint packing was replaced the penstock was filled and the unit was returned to service.

It should be noted that penstock seal leaks can occur when: (a) water remains stagnate within a penstock (such as when hydro units are used for Peaking duty rather than around-the-clock operation) and thereby can undergo freeze/thaw conditions associated with expansion and contraction inside the penstock, causing joint leakage, or (b) there is insufficient water (such as during drought conditions) to maintain the penstock in a completely full condition, which can cause gaskets to dry out at the penstock joint connections. As the leak was at a lower section of the penstock, the resultant high-water pressure, aged packing, and the scenarios mentioned above were the probable causes of this joint leak.

A root cause analysis was not documented for this outage as the likely causes of joint leaks are well known, and current maintenance practices are generally effective in preventing the problem to the extent practical. An IR was created for this outage and has been provided in testimony workpapers.

(5) Big Creek 3 Unit 5 Broken Wicket Gate Shear Pin (IR 221)

On February 29, 2020, Big Creek 3 Unit 5 was online when the on-duty control operator observed excessive vibration emanating from the turbine room during a routine inspection. The ensuing investigation revealed a broken shear pin on the number 1 wicket gate, which are a series of adjustable vanes regulating the flow of water to the turbine. The operator notified the Big Creek Control Center of the issue, which resulted in shutting down the unit until repairs could be made.

Because this outage occurred during the annual Big Creek winter outage time period (October – April), maintenance personnel and their tooling, equipment and vehicles were being utilized for the annual inspection outage at Big Creek 4 Unit 2. Because demand for hydro generation is typically at its lowest during the winter months SCE management made the decision to address the repairs of Big Creek 3 Unit 5 following the conclusion of the Big Creek 4 Unit 2 planned outage which did not occur until mid-March. The shear pin was replaced, and the unit was returned to service on March 18, 2020. An IR was created for this outage and has been provided in testimony workpapers.

(6) <u>Big Creek 4 Unit 2 High Water Level in Plant (IR 212)</u>

On February 11, 2020, during a planned annual inspection outage for Big Creek 4 Unit 1, the Big Creek Operations Control Center began receiving battery ground and battery charger alarms. In response, an operator was dispatched to investigate the cause of alarms. Upon arrival to the powerhouse the operator discovered that approximately 5.5 feet of water had flooded the Big Creek 4 basement resulting in DC and AC grounds to the pump motors. Unit 2 was removed from service to prevent the bearing oil pumps from operating while under water.

The ensuing investigation revealed that the station sump float mechanism had become stuck in the low sump level position, thus not recognizing the high-water levels. Once the operator exercised the sump float mechanism, both sump pumps began to operate and remove the excess water from the basement. Once the basement water was pumped out, and SCE maintenance personnel were able to gain access, they begin the two-day process of drying out the waterlogged equipment (*e.g.,* pumps, motors, and electrical boxes). Also included in this work was draining oil from sumps which had incurred excessive water intrusion and replace with clean oil. In all, this process took approximately two days and required the installation of heaters to dry out motors and pump windings. Once things were completely dried, SCE electricians performed equipment testing prior to returning the unit to service on February 14, 2020. An IR was created for this outage and has been provided in testimony workpapers.

(7) Mammoth Pool Unit 2 Lower Guide Bearing Temperature Probe (IR 256)

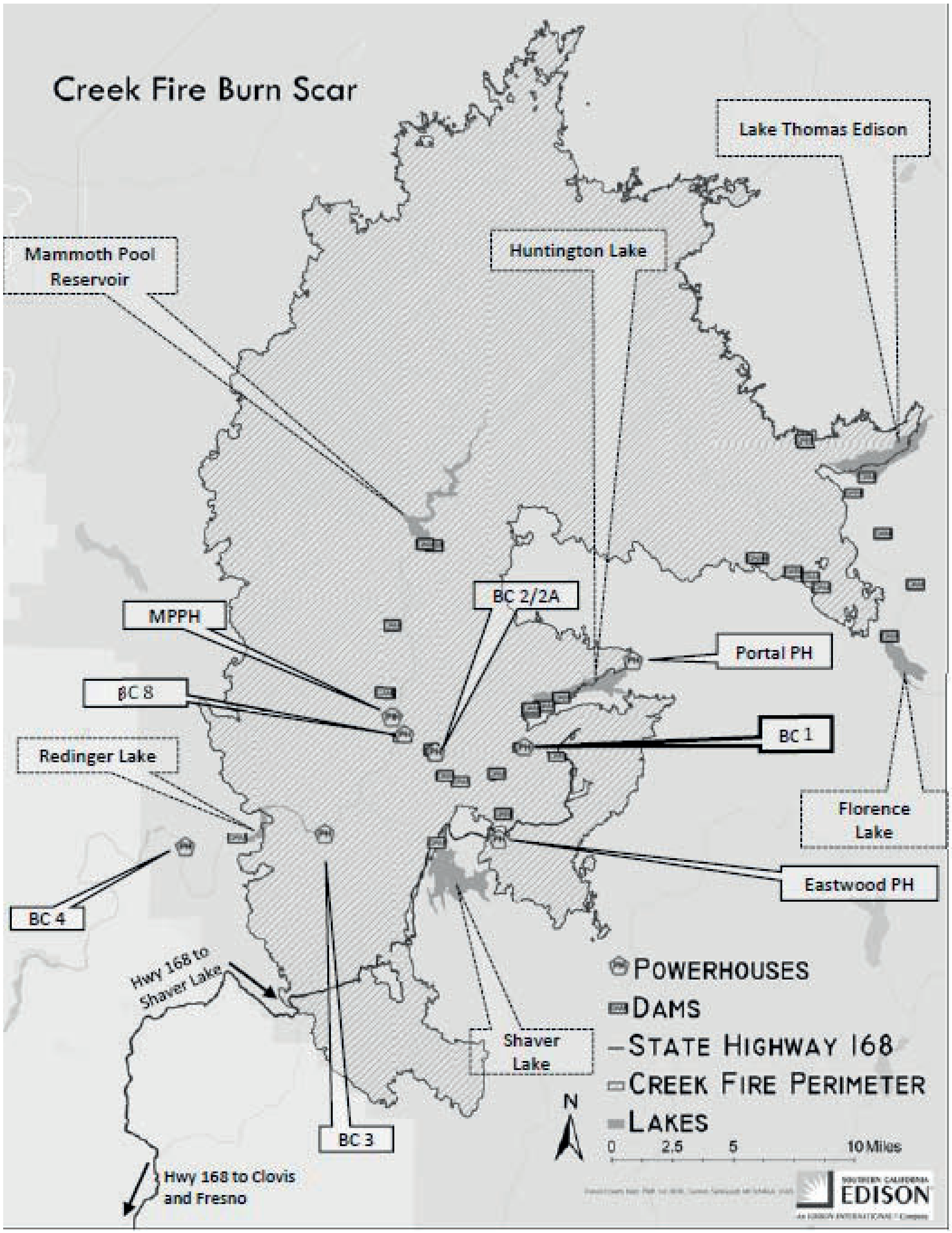
On June 6, 2020, Mammoth Pool Unit 2 was forced off-line due to the observance of high temperature readings in the lower guide bearing. The ensuing investigation by SCE personnel revealed no damage to the Unit, and high temperature readings were traced to a failed lower guide bearing temperature probe. As the unit has redundant temperature probes, the failed probe was temporarily bypassed on June 8, 2020, to permit continued operation of the unit. Replacement of the failed temperature probe has not yet occurred as the vendor, has been on restricted travel status due to COVID-19 restrictions. SCE personnel will continue to monitor the situation and will replace the failed temperature probe at the next available opportunity. An IR was created for this outage and has been provided in testimony workpapers.

(8) Creek Fire

On Friday September 4, at 6:33 PM, the Creek Fire was reported near Camp Sierra Road and Redding Road, approximately four miles North/East of Shaver Lake.[61] Shortly after midnight on September 5, source power to the Big Creek 1 powerhouse was lost as the 220 kV transmission lines were removed from service due to the close proximity of the fire. By daylight, on Saturday September 5, the SCE transmission operator and the Big Creek Operations Center had lost communications with nine Big Creek Powerhouses (1, 2, 2A, 3, 4, 8, Eastwood, Portal and Mammoth Pool). As fire conditions worsened, Cal Fire issued evacuation orders to the town of Big Creek (where SCE's Big Creek administrative offices are located, including company housing, maintenance and warehouse facilities, and the Big Creek 1 Powerhouse) and all other occupied Big Creek powerhouses. At some Big Creek powerhouses, the danger of fire overtaking the facility was so imminent that operators had little or no time to properly shut down the facilities prior to evacuating. SCE personnel were not permitted to return to the area(s) until evacuation orders were lifted by Cal Fire, on September 10, 2020.

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

Figure III-2
2020 Creek Fire Burn Scar



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

On September 13, 2020, SCE began restoration efforts of the Big Creek Powerhouses, support structures and appurtenant facilities. This effort is ongoing with the goal of ultimately restoring Big Creek's full 1,015 MW of hydroelectric generating capacity and reinstating SCE's ability to perform regulatory mandated water management activities within the upper San Joaquin River watershed.

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

1. Return electrical services to each facility in order to facilitate fire related hazard inspections and facility condition assessments.

2. Return key utilities to service, such as water treatment and wastewater treatment services.

3. Identify areas of high erosion risk near roadways leading to and from SCE generation, transmission, distribution, telecommunications and administration infrastructure to ensure the safety of people traveling on those roadways. A secondary priority was to ensure the safety of SCE infrastructure (penstocks, forebays, buildings, etc.)

4. Inspect, test and return powerhouses to service in order to provide needed power to undamaged portions of the grid. As a result of the fire, communication links were

destroyed along with the Transmission and Distribution infrastructure. Powerhouses 3 and 4 were operated at limited load levels while the IT telecommunications infrastructure was being restored (accomplished by staffing these plants around the clock) the seven additional Powerhouse required telecommunication infrastructure to be restored as well as Transmission & Distribution before they were placed back in service.

Table III-14
Creek Fire: Big Creek Outage Restoration Dates

		Fire		Transmission/Communication		Other	
Plant	Unit	Start Time	End Time	Start Time	End Time	Start Time	End Time
Big Creek # 1	Unit 1	9/5/2020 15:49	10/29/2020 14:35	10/29/2020 14:35	11/6/2020 9:05		
Big Creek # 1	Unit 2	9/5/2020 15:49	10/29/2020 14:35	10/29/2020 14:35	11/6/2020 9:05		
Big Creek # 1	Unit 3	9/5/2020 15:49	10/29/2020 14:35	10/29/2020 14:35	11/6/2020 9:05		
Big Creek # 1	Unit 4	9/5/2020 15:49	10/29/2020 14:35	10/29/2020 14:35	11/6/2020 9:05		
Big Creek # 2	Unit 3	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 2	Unit 4	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 2	Unit 5	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 2	Unit 6	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 2A	Unit 1	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 2A	Unit 2	9/5/2020 15:49	10/12/2020 7:00	10/12/2020 7:00	Extends into 2021		
Big Creek # 3	Unit 1	9/5/2020 15:49	10/1/2020 8:00	10/1/2020 8:00	11/23/2020 14:00		
Big Creek # 3	Unit 2	9/5/2020 15:49	10/1/2020 8:00	10/1/2020 8:00	11/23/2020 14:00		
Big Creek # 3	Unit 3	9/5/2020 15:49	10/1/2020 8:00	10/1/2020 8:00	11/23/2020 14:00		
Big Creek # 3	Unit 4	9/5/2020 15:49	10/1/2020 8:00	10/1/2020 8:00	11/23/2020 14:00		
Big Creek # 3	Unit 5	9/5/2020 15:49	10/1/2020 8:00	10/1/2020 8:00	11/23/2020 14:00		
Big Creek # 4	Unit 1	9/5/2020 15:49	9/27/2020 12:09				
Big Creek # 4	Unit 2	9/5/2020 15:49	9/27/2020 12:03				
Big Creek # 8	Unit 1	9/5/2020 15:49	10/14/2020 11:00	10/14/2020 11:00	12/3/2020 0:00	12/3/2020 0:00	Extends into 2021
Big Creek # 8	Unit 2	9/5/2020 15:49	10/14/2020 11:04	10/14/2020 11:04	12/3/2020 0:00	12/3/2020 0:00	Extends into 2021
Eastwood	Unit 1	9/5/2020 15:49	10/24/2020 18:20	10/24/2020 18:20	Extends into 2021		
Mammoth Pool	Unit 1	9/5/2020 15:49	9/29/2020 13:40	9/29/2020 13:40	11/30/2020 6:00	11/30/2020 6:00	Extends into 2021
Mammoth Pool	Unit 2	9/5/2020 15:49	9/29/2020 13:46	9/29/2020 13:46	11/30/2020 6:00	11/30/2020 6:00	Extends into 2021
Portal	Unit 1	9/5/2020 15:49	10/20/2020 16:21	10/20/2020 16:21	Extends into 2021		

As the outage and restoration efforts are likely to continue through the next ERRA cycle, and possibly the next two ERRA cycles, SCE will provide updates in future ERRA filings following a powerhouse(s) return to service.[62] As the cause of this incident was a natural disaster, an IR was not created for this outage.

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

4. **Summary**

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

IV.

NATURAL GAS GENERATION

A. SCE Peaker Introduction

SCE owns and operates five natural gas fired hybrid and peaking generating plants (known as the SCE Peakers). The five Peakers are: (1) Barre Peaker at SCE's Barre Substation in Stanton, CA; (2) Center Hybrid Peaker at SCE's Center Substation in Norwalk, CA; (3) Grapeland Hybrid Peaker at SCE's Etiwanda Substation in Rancho Cucamonga, CA; (4) Mira Loma Peaker at SCE's Mira Loma Substation in Ontario, CA; and (5) McGrath Peaker next to the GenOn Mandalay Generating Station in Oxnard, CA. Each Peaker plant consists of a single simple cycle combustion turbine generator of approximately 49 MW rated net capacity, for an aggregate 245 MW of generating net capacity for the five plants. The first four Peakers became operational in August 2007 and the fifth Peaker (McGrath) became operational in November 2012.[63] During 2016, two of the Peakers (Center and Grapeland) were converted into Hybrid units involving integration of battery energy storage technology into the combustion turbine operating regime.

The SCE Peaker units contribute to bulk power grid reliability with quick starting and rapid ramping capabilities and can run several times per day if necessary. Their relatively low startup costs and ability to start up and shut down quickly means the Peakers can be run only when necessary, helping to reduce overall customer costs.[64] SCE offers the Peakers to the CAISO energy and AS markets where the units can be run to meet unexpected customer demand, respond to unplanned system contingencies, or simply provide required system operating reserves by remaining off-line but immediately available. Because the onsite power needs of each of the Peakers can be supplied by small internal combustion engine driven generators (fueled by natural gas) that are installed at each site, the Peakers are designed

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

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

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

B. SCE Peakers Performance During the Record Period

The five SCE Peakers provided 124,443 MWh of energy and were started an aggregate 1,242 times during the Record Period as shown in Table IV-15. This yields an average capacity factor of 5.7%, an average of approximately 4.8 starts per Peaker per week, and an average of approximately 2.0 hours of run-time per Peaker start.

Table IV-15
SCE Peakers - 2020 Generation and Starts

Line No.	Peaker Site	Generation (MWh)	Starts
1	Barre	44,364	332
2	Center	20,077	321
3	Grapeland	17,531	158
4	Mira Loma	22,220	274
5	McGrath	20,251	157
6	TOTAL	124,443	1,242

1. Fuel Usage Cost

The SCE Peakers consumed 1,319,926 MMBtu of natural gas at a cost of approximately $5.3 million during the Record Period. Table IV-16 shows the monthly sums of fuel usage and cost for all five Peakers.[65]

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

Table IV-16
SCE Peakers - 2020 Fuel Usage & Cost

Line No.	Month	Usage (mmBtu)	Cost ($)
1	January	24,663	83,598
2	February	50,285	171,932
3	March	105,803	325,497
4	April	119,632	323,221
5	May	129,782	383,528
6	June	145,091	463,556
7	July	94,306	277,478
8	August	165,361	918,877
9	September	173,404	874,981
10	October	157,132	748,383
11	November	65,308	304,822
12	December	89,159	440,926
13	TOTAL	1,319,926	5,316,798

2. Results of Operation

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

a) Equivalent Availability Factor Results

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

The combined average EAF for the five Peakers for the 2020 Record Period was 92.97% as shown in Table IV-17 below. This is approximately 1.2% lower than the SCE Peaker average annual EAF for the prior five years. Nevertheless, Peaker 2020 EAF performance remained significantly higher than the five-year industry average of approximately 87.51% (2015-2019)[66], reflecting the continued excellent reliability of the SCE Peakers.[67] As discussed in more detail below, Record Period EAF was impacted by several factors, including the planned spring outages at the five Peakers.

b) Forced Outage Factor Results

FOF is a measure of plant reliability that reflects the extent of unscheduled (*i.e.*, forced) unit outages during the Record Period. Specifically, FOF is the percent of time a Peaker was not available for service due to an unscheduled outage. The ideal FOF level is a low percentage.[68] As shown in Table IV-17 below, the combined average FOF for the five Peakers during the 2020 Record Period was 3.78%. In contrast with EAF performance, 2020 FOF was higher (*i.e.,* worse) than that recorded by the SCE Peakers during the prior five years and the industry average.

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

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

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

Table IV-17
SCE Peakers - 2020 Reliability

Line No.	Year	EAF		FOF	
		SCE	Industry	SCE	Industry
1	2015	97.67	90.00	0.82	3.18
2	2016	96.42	89.29	0.68	2.69
3	2017	91.48	86.10	3.73	2.51
4	2018	93.95	86.03	2.89	2.63
5	2019	91.11	86.12	6.47	4.03
6	Avg.	94.13	87.51	2.92	3.01
7	2020	92.97	Unavailable	3.78	Unavailable

3. Outage Events

Since 2007 (the first year of operation for four of the five Peaker plants), SCE has utilized NERC GADS to track outage events (scheduled and unscheduled outages) at its Peaker facilities.[69] GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, specific objectives for the GADS program were established – compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment. The following sections discuss outage events that occurred during the Record Period.

a) Scheduled Outages

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

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

As shown in Table IV-18 below, there were six annual maintenance inspection outages performed on the five Peakers during the Record Period, which accounted for approximately 759 outage hours or approximately 57% of the 1,338 total scheduled outage hours.[70] Additional scheduled outages included approximately 119 hours to perform the IOS Upgrades, 64 hours for CEMS Relative Accuracy Test Audit (RATA) and Linearity Testing, 322 hours for the Center Peaker engine swap out, and 72 hours for misc. annual testing.[71]

Table IV-18
SCE Peakers - 2020 Scheduled Outage Results

Line No.	Outage Purpose	Number	Hours:Mins
1	Annual Maintenance Inspections	6	759:13
2	IOS Upgrades	5	119:37
3	CEMS RATA and Linearity Testing	9	64:56
4	Center Peaker Engine Swapout	1	322:04
5	Other - Misc. Annual Testing	10	72:09
6	TOTAL	31	1337:59

b) Unscheduled Outages

An unscheduled outage occurs when either equipment suddenly fails or must be removed from service relatively quickly because of control problems or to prevent damage. The unit either immediately trips or a shutdown is initiated, at which time the required repair proceeds. There were 63 unscheduled outages during the Record Period, which totaled approximately 2,057 hours. Many of the unexpected equipment problems that arose were diagnosed and quickly corrected. Seven of

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

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

the 63 unscheduled outages exceeded a duration of 24 hours.[72] These 7 outages are summarized in Table IV-19 and discussed in further detail thereafter.

Table IV-19
SCE Peakers - 2020 Unscheduled Outages Exceeding 24hrs

Line No.	Plant	NERC Event Type	MW's Affected	Beginning Date/Time	Ending Time/Date	Outage Length (hrs:mins)	Incident Report
1	Barre Peaker	U1	49.0	12/4/2019 15:00	1/20/2020 19:25	1132:25	Yes
2	Barre Peaker	U1	49.0	2/23/2020 13:25	2/25/2020 11:59	46:34	Yes
3	Barre Peaker	U1	49.0	6/10/2020 14:17	6/11/2020 16:31	26:14	Yes
4	Barre Peaker	U1	49.0	7/12/2020 17:55	7/14/2020 13:51	43:56	Yes
5	Center Peaker	D1	15.0	8/27/2020 17:58	8/29/2020 12:50	42:52	Yes
6	McGrath Peaker	U1	49.0	3/11/2020 12:02	3/15/2020 6:00	89:58	Yes
7	McGrath Peaker	U1	49.0	7/9/2020 16:59	7/22/2020 17:15	312:16	Yes

(1) <u>Barre Peaker Broken HPT Nozzle (199)</u>

On December 4, 2019, during the annual borescope inspection conducted by General Electric (GE), the original equipment manufacturer of the Barre Peaker gas turbine, damage to several areas of the high-pressure turbine (HPT) 2nd stage nozzle as well as evidence of impact damage were discovered. GE determined that the HPT 2nd stage nozzle had experienced increased oxidation, leading to the liberation (the failure or fracturing of a component, breaking free from its intended location) of material, and causing damage. GE also confirmed that the initial design of the nozzle did not provide for sufficient cooling and implemented Service Bulletin 238 for corrective action. The HPT 2nd stage nozzle was damaged beyond repair. SCE then moved forward with using the spare gas turbine engine it has in inventory. However, the South Coast Air Quality Management District did not approve of this use under SCE's operating permit categorizing the swap as a "major modification". As such the unit was placed in an extended outage to make the necessary arrangements to ship the damaged engine to the GE repair facility in Bakersfield. On January 10, the combustion turbine arrived at the GE repair facility. Repairs were completed on January 16, and the engine was shipped back to the

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

Barre Peaker site on January 17. On January 20, the unit re-assembly was completed, unit tested and returned to service at 19:25PM. An Apparent Cause Evaluation (ACE) report and an IR were created for this outage and have been provided in testimony workpapers.

(2) Barre Peaker Emissions Reduction Unit (ERU) Media Converter

On February 23, 2020, the Barre Peaker unit's Supervisor Control System (SCS) lost communication with the Emissions Reduction Unit (ERU), causing the unit to become unavailable. The unit experienced four forced outages during the month February, as well as intermittent failures since April 2019, all with similar causes. A common cause evaluation was conducted by SCE and a recommendation to mitigate the most common failure (the CAISO Router/Switch Module failure) included adding a Remote Intelligent Gateway (RIG) and Revenue meter copper interface switch. Additionally, to mitigate the CEMS System equipment failures, a recommendation was made to replace potentially obsolete equipment in the CEMS system. SCE reset the SCS and the ERU. Communications between the SCS and ERU resumed, and on February 25 the unit was tested and returned to service at 11:59AM. A Common Cause Evaluation (CCE) report and an IR were created for this outage and have been provided in testimony workpapers.

(3) Barre Peaker Gas Detector (257)

On June 10, 2020, the Barre Peaker unit automatically tripped offline. Upon investigation, SCE discovered that a high level of natural gas was detected inside the turbine enclosure forcing the unit to trip. Further investigation by SCE revealed a natural gas leak in the enclosure. For personnel safety, the natural gas was purged from the gas lines using pressurized nitrogen, and all joints and fittings were coated with a liquid soap solution to help detect the leak, which was found at the main gas line manual vent fitting. The original pipe thread sealant installed during construction of unit in 2007 had dried over time, allowing for a small leak to develop. The fitting was removed, repaired by adding new thread sealant and was re-installed. The system was tested to ensure no additional leaks existed, and unit was returned to service on June 11 at 4:31PM. An IR was created for this outage and has been provided in testimony workpapers.

(4) <u>Barre Peaker Failed Pressure Switch (268)</u>

On July 12, 2020, the Barre Peaker unit was brought offline after it was no longer needed by CAISO. Within the hour, CAISO called for the unit to operate. During startup, the unit tripped on “Gas Turbine Low Lubricating Oil Pressure”. The unit was placed in a forced outage. SCE begun investigations but found no leaks or damage to the lubricating oil system. On July 13, SCE continued investigations, replacing the turbine oil supply filters and scavenge filters. The scavenge system consists of an oil pump, flow lines and filter, and is a GE term for the return oil line from the turbine bearings to the oil reservoir. This did not solve the problem. Concurrently SCE also reviewed plant parameter trends and discovered that one pressure switch (PSLL-6016) had been erratic during the recent unit dispatches. On July 14, a replacement switch was installed in the Barre Peaker, unit was tested and returned to service at 2:51PM. An Incident Report (IR) was created for this outage and has been provided in testimony workpapers.

(5) <u>Center Hybrid Peaker Control Valve Actuator (307)</u>

On October 20, 2020, the Center Hybrid Peaker dilution air heater outlet temperature degraded below the designed minimum temperature of 240^{o} F, tripping the Ammonia (NH3) system and subsequently requiring the unit to be shut down. Selective Catalytic Reduction (SCR) systems use aqueous ammonia (NH3) to control nitrous oxide (NOx) emissions. Ammonia injection is carried out with dilution air into the flue gas exhaust duct. In some cases, large quantities of cool ambient air can affect the designed operation of the SCR system. Therefore, dilution air is heated to operate the system within design parameters. In this situation the dilution air heater outlet temperature controls were slow to react to changing air temperature. Upon initial investigation of the event, SCE determined that the heater, which was original to the plant construction, had deteriorated due to age. In the interim, SCE re-tuned the heater control parameters to speed up the heating and offset the performance degradation until investigation was completed. The unit was tested and returned to service on October 21 at 8:07PM. SCE and Integrated Flow Solutions (the original equipment supplier) continued to troubleshoot the dilution air heater system, completing several weeks of evaluating test results and made recommendations to replace the diluter air heater. A new air heater was ordered and is expected to be replaced in March 2021 upon receipt.

(6) McGrath Peaker Exciter Wiring Ground (Insulation Damage) (224)

On March 11, 2020, the McGrath Peaker tripped offline and was placed in a forced outage. Later that day, SCE begun troubleshooting the event and discovered a recorded error code of "Loss of Excitation" on the Beckwith Integrated Generator Protection System (IGPS) Relay as the cause of the unit trip. Over the next several days additional electrical testing was performed but did not reveal any issue at the generator. All connections were re-installed for energized testing on March 13. SCE continued investigation and found an exciter field wire running from the exciter through the open metal conduit located inside the generator housing to the Junction Box No. 8 to be damaged. New wires for both the Exciter Field and Permanent Magnet Generator (PMG) were pulled. Additional calibrations were made to the Automatic Voltage Regulator and the unit was started for testing on March 19th. The unit was returned to service later that day. An IR was created for this outage and has been provided in testimony workpapers.

(7) McGrath Peaker Contaminated Emissions Sample Bags (266)

On July 7, 2020, the McGrath Peaker unit failed the Reactive Organics Compounds (ROCs) portion of the annual Ventura County Air Pollution Control District (VCAQMD) compliance tests, performed by Montrose Air Quality Services (Montrose) and conducted as part of the RATA. Flue gas samples were collected at the stack during the tests and later analyzed in the laboratory. A 2.17 ppm ROC was reported against a permit limit 2.0 ppm. The VCAQMD was notified per regulation, and SCE was advised to cease operation of the unit until the test was repeated and passed. Subsequent retests conducted by Montrose revealed that the Tedlar bags which are polyvinyl chloride (PVC) sampling bags manufactured to collect gas samples, that had been used for the previous tests, were contaminated, resulting in the test failures. Source of contamination was unknown. A final test was conducted on July 20, using stainless steel canisters to collect and hold the samples instead of the previously used Tedlar bags. The results of this test indicated that all emissions parameters passed including the ROC portion. The unit was returned to service on July 22 at 5:15PM. An IR was created for this outage and has been provided in testimony workpapers.

C. SCE Mountainview Generating Station Introduction

Mountainview is a two-unit (Units 3 and 4) combined cycle gas-fired power plant in Redlands, California. Units 3 and 4 have a combined total nominal capacity of 1,110 MW.[73] Each unit has a nominal rating of 555 MW and consists of two combustion turbines and one steam turbine.

Mountainview was originally owned by Mountainview, LLC (MVL), a wholly owned subsidiary of SCE. In D.09-03-025, the Commission ordered SCE to transfer ownership of Mountainview from MVL to SCE, and ordered that the Reliability and Heat Rate (*i.e.*, Fuel Use Efficiency) Incentives be retained with slight modification.[74] These incentives were part of the Commission and FERC-approved SCE-MVL Power Purchase Agreement (PPA). Ownership was transferred in 2009 and, as a result, the MVL PPA was terminated. Since this transfer of ownership, all of Mountainview's capital and O&M costs recorded are recovered through SCE's base rates, and the fuel costs and incentive mechanism payments through the annual ERRA review proceedings.

In this chapter, SCE discusses Mountainview's operations and recorded fuel costs for the Record Period. Mountainview's availability and heat rate incentives are based on actual plant performance compared to target performance. Mountainview's performance relative to these incentives is also discussed in this chapter.

1. Mountainview Performance During the Record Period

As shown in Table IV-20, Mountainview Units 3 and 4 provided 2,812,499 MWh of energy during the Record Period (*i.e.*, a capacity factor of approximately 31%). While outages

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[73] 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 1,110 MW. The plant's actual maximum MW output varies above and below this value, as a function of ambient weather, and is also constrained by the plant's transmission limit of 1,110 MW.

[74] D.09-03-025 pp. 31-32.

occurring within the Record Period were contributors to the low-by-historical-standards capacity factor, the main driver was the change in CAISO dispatch.[75]

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

Table IV-20
SCE Mountainview - 2020 Generation

Line No.	Unit	Generation (MWh)
1	3	1,462,688
2	4	1,349,811
3	TOTAL	2,812,499

2. <u>Fuel Usage and Cost</u>

During the Record Period, the Mountainview units consumed 21,242,741 MMBtu of natural gas at a cost of approximately $77.517 million. Table IV-21 below provides the monthly fuel usage and fuel cost for the Record Period.[76]

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

Table IV-21
SCE Mountainview – 2020 Fuel Usage & Cost

Line No.	Month	Usage (mmBtu)	Cost ($000)
1	January	1,341,358	5,266
2	February	2,038,854	6,036
3	March	1,904,278	4,740
4	April	718,206	1,437
5	May	390,064	914
6	June	1,174,583	2,961
7	July	2,461,530	5,803
8	August	2,995,898	14,469
9	September	2,144,322	9,645
10	October	3,093,488	12,794
11	November	1,617,864	7,268
12	December	1,362,297	6,185
13	TOTAL	21,242,741	77,517

Fuel is commonly the major operating cost component of gas turbine-based power plants (like Mountainview) that burn natural gas and operate for significant time periods during the year. To encourage fuel efficiency, the Mountainview PPA included a fuel efficiency (*i.e.,* heat rate) incentive program.[77] The incentive was retained by the Commission in SCE's 2009 GRC, D.09-03-025.[78] The incentive requires that Mountainview conduct a test of its heat rate twice a year.[79] The test results are adjusted for variables beyond the control of SCE's Mountainview personnel, such as weather and expected normal equipment degradation. The adjusted "as tested" heat rate is then compared to the adjusted "as new" heat rate established when the plant first entered service in January 2006. The incentive provides for a bonus or penalty of 50% of the incremental fuel costs when the tested heat rate

[77] Heat rate is a measure (in Btu per kWh) of the average amount of natural gas fuel consumed for each kWh of electricity produced, over a given period.

[78] In December 2020, SCE submitted a PFM to the California Public Utilities Commission requesting that the Mountainview Heat Rate Incentive be eliminated.

[79] During this testing, both units must be operating at full rated output, and the test takes several hours to conduct. The tests are to be conducted each April and October, to determine the fuel efficiency performance (relative to the incentive) for each immediately preceding six-month period. When outages prevent the test from being performed during April and October, the testing is instead performed as soon as practical upon completion of the outage (*i.e.*, typically within 30 days).

is more than a 3% bandwidth above, or a 3% bandwidth below, the "as new" heat rate. SCE earns a bonus if the tested heat rate is less than 97% of the "as new" heat rate, and a penalty if the tested heat rate exceeds 103% of the "as new" heat rate.[80]

Consistent with prior years, the heat rate tests conducted for the Record Period showed that Mountainview continued to operate within the 6% bandwidth. Therefore, Mountainview neither earned a heat rate incentive bonus nor incurred penalties. This demonstrates excellent fuel efficiency performance, as it is not realistically possible to achieve a 3% or more fuel efficiency improvement compared to the heat rate target that was established when the plant was new.

3. Mountainview Reliability During the Record Period

To encourage plant reliability (measured as plant "availability"), Mountainview is subject to a reliability incentive program.[81] This incentive program was retained by the Commission in D.09-03-025 and upheld in SCE's 2010 Record Period ERRA review proceeding (D.13-11-005). Mountainview availability is computed for each summer and winter season and is compared to a target value.[82] The computation of Mountainview availability is similar to the computation of EAF, as discussed for the SCE Peakers. Like EAF, the Mountainview availability computation is based on the hours of forced outages, scheduled outages, and derates during a calendar year.[83]

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[80] For example, if the April test demonstrated a heat rate that was 95% of the "as new" heat rate, then SCE would receive 50% of 2% (97% minus 95%) of its natural gas fuel cost as a bonus for superior heat rate performance. This 1% bonus would then be applied to the total cost of fuel for the proceeding "winter" (*i.e.*, for the just-ended six-month time frame of November through April). So, if that fuel cost was $200 million, then SCE would be awarded a bonus of $2.0 million. Likewise, results of the October test are applied to the just-ended "summer" time frame of May through October.

[81] In December 2020, SCE submitted a PFM to the California Public Utilities Commission requesting that the Mountainview Reliability Incentive be eliminated.

[82] For the availability incentive, summer is defined as June through September, and winter is defined as October through May. The availability incentive is administered on a calendar year basis.

[83] Under the PPA, the availability computation also included Mountainview's adherence to the hourly scheduled output requested of it each day. In D.09-03-025, the Commission also approved a revision to the hourly scheduled output component of the availability calculation formula given that Mountainview is not being used as an hourly block-loaded resource. Rather, Mountainview plant output is routinely ramped up and down within and across each clock hour, in conjunction with LCD practices and in conformance with the current CAISO real-time market structure. In 2018, winter and summer availability were determined in accordance

Mountainview's summer availability target is 97%, which is higher than the winter target because the value of capacity is generally higher during summer. With such a high target, routine maintenance outages are generally not scheduled for the summer.

The winter availability target varies between 92% and 79% as shown in Table IV-22. The winter target incorporates expected planned outages for routine annual maintenance, including Hot Gas Path Inspection overhauls and Major Inspection overhauls that are periodically conducted on the gas turbines. During 2020, the winter availability incentive target was 92% because there was only Base level (no major maintenance) maintenance work planned.

Table IV-22
SCE Mountainview - Availability Targets

Line No.	Planned Maintenance	Summer Maximum	Summer Target	Summer Minimum	Winter Maximum	Winter Target	Winter Minimum
1	Base (No Major Maint)	100%	97%	94%	100%	92%	84%
2	HGPI (1 Unit)	100%	97%	94%	96%	88%	80%
3	HGPI (2 Unit)	100%	97%	94%	93%	85%	77%
4	MI (1 Unit)	100%	97%	94%	93%	85%	77%
5	MI (2 Units)	100%	97%	94%	87%	79%	71%

The summer availability annual incentive provides an award/charge of $360,000 for each percentage point of availability performance above/below the 97% target.[84] The maximum annual summer availability award/charge is $1,080,000. To receive the maximum award SCE must attain perfect summer performance (*i.e.*, 100% availability), which is 3% higher than the 97% summer target. The 3% is then multiplied by the bonus factor of $360,000 per percentage point, which yields a bonus potential of $1,080,000. Conversely, to incur the maximum charge of $1,080,000, SCE's performance would need to be at least 3% below the 97% summer target (*i.e.*, 94% or lower).

(continued from previous page)
with the revision approved in D.09-03-025. This practice was discussed in detail in SCE's 2010 Record Period ERRA review proceeding.

[84] Unless otherwise indicated, all heat rate and reliability incentive amounts discussed in this section are in 2003 dollars. The incentive mechanism includes annual adjustment of these 2003 dollar amounts to account for inflation.

Likewise, the annual winter availability incentive provides an award/charge of $60,000 per percentage point of performance above/below the target. In theory, Mountainview could achieve a winter availability of 100% in years where no overhauls were performed and assuming no other planned outages were taken that winter for routine annual maintenance. Achieving a winter availability of 100% would be 8% higher than the 92% winter target implicit in such a scenario, which equates to a maximum winter bonus of $480,000 (*i.e.*, 8% multiplied by the $60,000 bonus per percentage point).[85] The availability incentive mechanism was therefore designed so the maximum charge is also $480,000 per winter season (*i.e.*, if actual winter availability performance is more than 8% lower than the winter target, then the bonus calculation uses a default value set at 8% below the target).

As shown in Table IV-23 below, Mountainview achieved a summer availability of 88.0% (*i.e.,* below the 97% target) and recorded a winter availability of 91.4% (*i.e.,* below the 92% target). Thus, in aggregate, Mountainview achieved a net availability incentive charge of $1,684,330 for the Record Period, including the inflation adjustment. A summary of the 2020 Mountainview availability incentive calculations are provided in Appendix IV-A. The reason that the recorded winter availability was less than the incentive target is explained in greater detail below.

Table IV-23
SCE Mountainview - 2020 Availability

Line No.		Summer	Winter
1	Target	97.00	92.00
2	Achieved	87.97	91.41
3	Variance	(9.03)	(0.59)

[85] In a best-case scenario, it would take several days of outage time to conduct either a Hot Gas Path Inspection or Major Inspection overhaul. Thus, it is not possible to achieve 100% winter availability if that work is conducted during the winter season. Also, because the summer availability incentive bonus rate is higher than the winter bonus rate, and because capacity prices are generally higher during the summer, it is not economic to conduct routine maintenance, including HGP inspections or major overhauls, in summer rather than winter.

As shown in Table IV-24 below, Mountainview's overall (summer and winter combined) recorded EAF was 88.08% and FOF was 7.09% during the Record Period.[86]

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

Table IV-24
SCE Mountainview – 2020 Reliability

Line No.	Year	EAF		FOF	
		SCE	Industry	SCE	Industry
1	2015	96.07	84.80	0.66	2.20
2	2016	83.18	85.24	0.38	2.24
3	2017	83.46	84.17	10.31	2.35
4	2018	81.50	85.13	12.71	2.19
5	2019	89.36	85.08	7.11	2.21
6	Avg.	86.71	84.88	6.23	2.24
7	2020	88.08	Unavailable	7.09	Unavailable

The Plant's recorded EAF during the Record Period was higher (*i.e.,* better), and the FOF during the Record Period was higher than (*i.e.*, not as good) Mountainview's previous five-year average and the industry average. This was because Mountainview incurred a variety of unplanned outages on Unit 3 and Unit 4 as discussed in further detail in the next section of this testimony.

4. <u>Outage Events</u>

Since 2005 (the year Mountainview began operation), SCE has utilized the NERC GADS to track outage events (scheduled and unscheduled outages) at Mountainview. GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, specific objectives for the GADS program were established: compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment. The following sections discuss outage events that occurred during the Record Period.

a) <u>Scheduled Outages</u>

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

During the Record Period and across units 3 and 4, Mountainview scheduled seven outages, zero planned outage extensions, zero maintenance outages, and no maintenance outage extensions. Two of the seven planned outages were initiated to perform annual maintenance activities, and the other five were initiated perform necessary plant maintenance activities. Combined, the seven outages totaled approximately 648 outage hours.

b) Unscheduled Outage Events

The two generating units at Mountainview experienced a combined total of thirty-three unscheduled (*i.e.*, forced) outages, totaling approximately 1,360 hours during the Record Period. Seven of these outages exceeded a duration of 24 hours as summarized in Table IV-25 and explained in further detail thereafter.[87]

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

Table IV-25
Mountainview – 2020 Unscheduled Outages
(Lasting Longer than 24 Hours)

Line No.	Unit	NERC Event Type	MW Affected	Beginning Date/Time	Ending Time/Date	Outage Length (hrs:mins)	Incident Report
1	3	D1	182.0	1/23/2020 7:21	1/24/2020 17:16	33:55	Yes
2	3	U1	555.0	5/25/2020 10:30	5/27/2020 23:59	61:29	Yes
3	4	D1	182.0	1/13/2020 6:45	1/16/2020 16:20	81:35	Yes
4	4	D1	182.0	3/12/2020 1:20	3/13/2020 21:15	43:55	Yes
5	4	D1	182.0	3/31/2020 16:55	4/6/2020 0:28	127:33	Yes
6	4	D1	182.0	4/12/2020 5:30	4/14/2020 20:09	62:39	Yes
7	4	U1	555.0	9/6/2020 12:51	10/5/2020 7:21	690:30	Yes

(1) Unit 3A Gas Fuel Control Valve

At 07:21 on January 23, 2020, Mountainview Unit 3A was tripped offline due to a malfunctioning solenoid that controls the hydraulic actuators of the gas fuel control valve. Investigation by SCE maintenance personnel determined that the gas fuel control valve had reached the end of its service life and required replacement.[88] SCE ordered a replacement, with next day delivery, from an east coast supplier. Following its receipt, SCE maintenance personnel installed the new valve and placed the Unit back into service. As a result of this outage, and age of other similar valves, SCE plans to preemptively replace these valves and place them on a 12-15-year replacement schedule. Additionally, SCE has ordered and will stock spares of these valves within its plant warehouse. An IR was created for this outage and has been provided in testimony workpapers.

(2) Unit 3 Condenser Water Box Expansion Joint Replacement

On May 25, 2020, during a routine plant inspection of Mountainview Unit 3, SCE operations personnel observed a condenser water box expansion joint that appeared to be on the verge of imminent failure. To prevent an in-service failure, the Unit was immediately removed from service. Once offline, repairs necessitated that SCE maintenance personnel isolate the cooling water

[88] This and other solenoid valves within Mountainview are vintage 2005 original plant equipment.

system and drain the condenser. Expansion joint failures are not uncommon and typically result from standard plant wear and tear. SCE's current inspection and maintenance practices prevent in-service failures to every extent possible. Following replacement of the failed expansion joint the Unit was returned to service. An IR was created for this outage and has been provided in testimony workpapers.

(3) Unit 4A Fuel Gas Heater Head Leak

On January 13, 2020, while performing a routine plant inspection an SCE operator mechanic observed a natural gas leak emanating from one of the head covers on the Mountainview Unit 4A Performance Gas Heater skid. The Unit was immediately removed from service and SCE maintenance personnel began troubleshooting. SCE maintenance personnel traced the cause of the natural gas leak to a failed head cover (Tube Flange) internal seal, but during the investigation discovered a new problem, water leakage from a galled tube flange. The following day, January 14, 2020, SCE maintenance personnel installed a new shell side sealing ring (gas ring kit) and tube flange gasket which prevented further gas leakage. Repairs to the galled tube flange required that SCE maintenance personnel remove and send the damaged tube flange to an off-site machine shop for repair. On January 16, 2020, the repaired tube flange arrived back at Mountainview for installation. Following installation, the Unit was returned to service. Once the Unit was placed in-service SCE operations personnel observed slight water leakage emanating from the tube flange. As a temporary fix, SCE maintenance personnel further torqued the flange bolts which provided a temporarily seal. SCE maintenance and engineering personnel are developing a plan to perform a more permanent repair during a future planned outage. An IR was created for this outage and has been provided in testimony workpapers.

(4) Unit 4A Fuel Gas Heater Head Leak

This issue is a continuation of the January 13, 2020 incident discussed in the preceding section. On March 12, 2020, while performing a routine plant inspection an SCE operator mechanic observed a natural gas leak emanating from one of the head covers on the Mountainview Unit 4A Performance Gas Heater skid. The Unit was immediately removed from service and SCE maintenance personnel began troubleshooting. SCE maintenance personnel traced the cause of the natural gas leak to a misaligned gas seal ring that could not be remedied by increasing the torque on the sealing bolts. Disassembly and cleaning of the head covers, and internal sealing surfaces was performed by an SCE approved contractor, Turbine Repair Services (TRS). During disassembly it was discovered that the water sealing surfaces contained minor scratches and dents, which the gasket under normal operating conditions is designed to properly seal and prevent water leakage. Following reassembly of the gas heater skid a successful leak pressure test was performed and the Unit was returned to service. An IR was created for this outage and has been provided in testimony workpapers.

(5) Unit 4B Heat Recovery Steam Generator (HRSG) Tube Leak

On March 31, 2020, shortly after receiving dispatch orders from CAISO, the Mountainview Unit 4B Combustion Turbine (CT) was initiating the start-up sequence when the heat recovery steam generator (HRSG) Low Pressure Drum and Hotwell levels rapidly dropped. The observance of such a rapid drop is indicative of HRSG tube leaks and the Unit was immediately shut down so SCE personnel could investigate. The ensuing inspection by SCE maintenance personnel revealed tube failures, likely the result of excessive rubbing against the baffle plate. The purpose of the baffle plate is to direct the flow of hot exhaust gas from the combustion turbine. As the unit cycles on and off, the HRSG tubes and baffles expand and contract from heating and cooling and rub against one another. Over time the rubbing causes the tubes to become thin and brittle, ultimately resulting in a tube leak. Access to tubes within the HRSG is limited and many areas can only be accessed by first removing tube sections that are in proper working condition. Following repairs of the leaking tubes the unit was returned to service. SCE engineers are evaluating the HRSG design to develop a maintenance strategy to minimize similar failures in the future. An IR was created for this outage and has been provided in testimony workpapers.

(6) Unit 4A Fuel Gas Heater Head Leak

This issue is a continuation of the January 13, 2020, and March 12, 2020, incidents discussed in the preceding sections. During the April 12, 2020, Annual Spring Maintenance outage the fuel gas heater head assembly was completely overhauled. Scope of work included the performance of visual inspections, cleaning of internal surfaces, replacement of gaskets, and installation of Belleville washers to maintain torque. SCE believes that the installation of new closure bolts with the addition of Belleville washers will ensure the closure bolts clamping force is maintained during pressure and temperature fluctuations as the generating unit cycles on and off, minimizing future leaks. As this work was not contained within the original Annual Inspection scope of work, SCE in accordance with GADS protocols classified this portion of the outage as unplanned. Following repairs, the unit was returned to service. An IR was created for this outage and has been provided in testimony workpapers.

(7) Unit 4 Steam Turbine Hydraulic System Failure

On September 6, 2020, Mountainview Unit 4 was in operation when the south Main Stop Control Valve actuator filter housing failed, spraying high-pressure, atomized hydraulic fluid onto the surrounding area. When the atomized hydraulic fluid contacted nearby high temperature steam piping, it ignited, causing a fire. The resulting fire caused significant damage to the right-side control valve actuator requiring full replacement and damage to the right-side stop valve actuator and left-side control valve actuators requiring them to be removed and shipped to the original equipment manufacturer for refurbishment. Additionally, all wiring, pipe thermal insulation, pipe supports, fire system piping, and structural steel bolting impacted by the fire were replaced. SCE contracted an independent third-party consultant to perform a Root Cause Evaluation (RCE) for this event. The root cause of this incident was the failure of the Servo Supply Filter Housing due to material used in the manufacture of the component. As a corrective action, SCE's Engineering team is conducting a design review of all possible housing failure scenarios including a fire and will accordingly develop a revised maintenance plan. Additionally, the SCE Engineering team is updating the steam turbine hydraulic control system to facilitate a more expedient shutdown of the hydraulic pumps in the event of an emergency. An IR and Root Cause Evaluation Report were created for this outage and have been provided in testimony workpapers.

V.

OTHER GENERATION

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

During the Record Period, SCE purchased 47,015 barrels of ultra-low sulfur #2 red-dyed diesel fuel and burned approximately 47,468 barrels of diesel fuel for electric generation on Santa Catalina Island. The average cost of diesel fuel per barrel was $85.80, for an annual cost of approximately $4.034 million. The average transportation cost for the truck and barge delivery was $19.43 per barrel, for an annual cost of $913,816. When the total transportation cost is applied to the total fuel cost, the total annual cost for diesel fuel is $4.974 million.

SCE has 23 LPG-fired combustion turbines for electric generation on the Island which, for the Record Period, SCE purchased 705,652 gallons of LPG. The average total cost per gallon was $1.18, for an annual cost of approximately $832,669. The average transportation cost for the truck and barge delivery was $0.27 per gallon, for an annual cost of $189,841. When the total transportation cost is applied to the total fuel cost, the total annual cost for LPG fuel is $1.041 million.

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

In 2018, SCE conducted a competitive RFP and awarded a four-year contract to AAA Oil, Inc., DBA California Fuels and Lubricants, to provide diesel, LPG, and associated delivery services (subcontracted to Avalon Freight Services) to the Pebbly Beach Generating Station for diesel, LPG, and urea based on their lowest price qualified bid, which were negotiated to remain unchanged from their pre-RFP contract rates.

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

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

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

SCE's costs for diesel and LPG fuel for the Record Period are summarized below in Table V-26 and Table V-27. SCE's diesel fuel, LPG gas, and transportation costs conform to industry pricing information and regulatory-approved rates, and therefore should be found reasonable.

Table V-26
Catalina Operations Diesel Fuel
2020 Recorded Delivered Diesel Costs

Date	Gallons Purchased	Barrels Purchased	Gallons Burned	Barrels Burned	Cost per Barrel	Invoice Total	Shipping Fee	Delivery Fee	Total Transport. Cost	Transport. Cost per Barrel	Total Diesel Cost
Jan-20	179,756	4,280	176064	4192	$113.88	$487,386.03	$63,905.04	$19,080.00	$82,985.04	$19.39	$570,371.07
Feb-20	149,810	3,567	149646	3563	$105.88	$377,677.75	$53,366.40	$15,900.00	$69,266.40	$19.42	$446,944.15
Mar-20	164,532	3,917	155316	3698	$93.10	$364,708.37	$58,406.22	$17,490.00	$75,896.22	$19.37	$440,604.59
Apr-20	134,582	3,204	140490	3345	$70.35	$225,413.15	$47,858.40	$14,310.00	$62,168.40	$19.40	$287,581.55
May-20	134,087	3,193	135786	3233	$64.03	$204,431.57	$47,722.74	$14,310.00	$62,032.74	$19.43	$266,464.31
Jun-20	134,167	3,194	136710	3255	$79.83	$255,013.72	$47,703.36	$14,310.00	$62,013.36	$19.41	$317,027.08
Jul-20	178,483	4,250	197526	4703	$81.80	$347,617.80	$63,314.46	$19,080.00	$82,394.46	$19.39	$430,012.26
Aug-20	170,404	4,057	162792	3876	$84.02	$340,888.59	$60,997.02	$18,285.00	$79,282.02	$19.54	$420,170.61
Sep-20	163,590	3,895	179256	4268	$79.86	$311,069.18	$58,239.96	$17,490.00	$75,729.96	$19.44	$386,799.14
Oct-20	177,794	4,233	163086	3883	$79.84	$337,986.69	$63,615.36	$19,080.00	$82,695.36	$19.53	$420,682.05
Nov-20	230,434	5,487	244482	5821	$83.69	$459,182.41	$82,167.12	$24,645.00	$106,812.12	$19.47	$565,994.53
Dec-20	156,995	3,738	152502	3631	$93.27	$348,651.49	$55,845.00	$16,695.00	$72,540.00	$19.41	$421,191.49
Totals	1,974,634	47,015	1,993,656	47,468		$4,060,026.75	$703,141.08	$210,675.00	$913,816.08		$4,973,842.83
Averages					$85.80	$338,335.56				$19.43	

Table V-27
Catalina Operation Propane Fuel
2020 Recorded Delivered Propane Costs

Date	Gallons Purchased	Gallons Used	Cost per Gallon	Invoice Total	Shipping Fee	Delivery Fee	Total Transport. Cost	Transport. Cost per Gallon	Total Propane Cost
Jan-20	107,947	66,172	$1.42	$153,029.52	$23,427.36	$5,700.00	$29,127.36	$0.27	$182,156.88
Feb-20	81,111	37,888	$1.39	$112,515.87	$17,455.26	$4,275.00	$21,730.26	$0.27	$134,246.13
Mar-20	63,462	55,436	$1.22	$77,286.88	$13,604.76	$3,325.00	$16,929.76	$0.27	$94,216.64
Apr-20	44,857	34,947	$1.07	$47,902.96	$9,499.26	$2,375.00	$11,874.26	$0.26	$59,777.22
May-20	44,074	28,698	$1.14	$50,223.74	$9,534.96	$2,375.00	$11,909.96	$0.27	$62,133.70
Jun-20	53,661	21,478	$1.06	$57,092.25	$11,518.86	$2,850.00	$14,368.86	$0.27	$71,461.11
Jul-20	43,753	43,809	$1.08	$47,398.62	$9,562.50	$2,375.00	$11,937.50	$0.27	$59,336.12
Aug-20	62,061	52,604	$1.06	$66,013.44	$13,480.32	$3,325.00	$16,805.32	$0.27	$82,818.76
Sep-20	53,443	36,488	$1.05	$55,948.15	$11,460.21	$2,850.00	$14,310.21	$0.27	$70,258.36
Oct-20	53,201	50,600	$1.04	$55,523.63	$11,553.54	$2,850.00	$14,403.54	$0.27	$69,927.17
Nov-20	53,282	76,456	$1.21	$64,700.85	$11,508.66	$2,850.00	$14,358.66	$0.27	$79,059.51
Dec-20	44,800	23,670	$1.43	$63,857.24	$9,709.89	$2,375.00	$12,084.89	$0.27	$75,942.13
Totals	705,652	528,246		$851,493.15	$152,315.58	$37,525.00	$189,840.58		$1,041,333.73
Averages			1.18	$70,957.76				0.27	

B. SCE's Solar Photovoltaic (SPV) Program

1. Introduction

SCE owns and operates 24 SPV facilities in its service area.[89] The 24 sites include one ground-mounted and 23 rooftop solar facilities, ranging in size from 0.5 MW to 6 MW alternating current (AC). The total size of SCE's solar fleet is 59.5 MW AC (or 81.3 MW direct current (DC)). Facility locations and rated capacity for each solar facility is summarized in Table V-28, below.

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

Table V-28
SCE-Owned Solar PV Plants

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

As approved by the Commission on June 18, 2009, the goal of SCE's Solar Photovoltaic Program (SPVP) was to drive installation costs down, improve technology and pricing of certain components, increase installation efficiency, and improve installation methods for solar photovoltaic technology.[90] In approving the SPVP, the Commission articulated that this program was "about driving the costs of deploying an existing technology down by creating a new market opportunity."[91]

SPVP has contributed to these objectives, and SCE demonstrated in its 2015 GRC Application[92] that SPVP construction costs were below \$3.85/watt, approximately half of typical industrial SPV installed cost when SPVP commenced.[93] However, gathering operational experience continues for both SCE and the industry. Currently, there is only limited industry data upon which to compare SCE's solar plant performance.[94] There is relatively little published data on solar power plant outage causes, such as on the equipment failures that can cause outages and associated repair times. While external performance comparisons remain limited in terms of comparable peer groups, SCE believes that the performance of the SCE-owned solar plants during the Record Period was reasonable as discussed in further detail below.

2. Solar Performance Tracking

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

Although solar plants are not capable of night-time operation, the capacity factor computations discussed include night-time hours in the denominator (*i.e.,* achieving a capacity factor of

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90 D.09-06-049.

91 *Id.* at 53.

92 2015 GRC A.13-11-003, SCE-02, Vol. 10. SCE's capital expenditures for the construction of the 25 sites were reviewed by the Commission in that proceeding.

93 *See generally*, SCE Solar Photovoltaic Program Testimony, A.08-03-015.

94 Power plant reliability and production statistics are reported by most US power plant operators using NERC GADS. GADS utilizes very precise definitions for the various statistics being reported. While it may in the future, at the current time GADS does not include reporting for SPV power plants. Therefore, a single uniform industry wide SPV plant reliability and production statistical data reporting process and data base does not yet exist for SPV plants in the same manner as it exists via GADS for other power plant types.

even 50% would be impossible, even if all other parameters that limit capacity factor could be economically solved). Also, SCE computes capacity factor using AC measurements (*i.e.*, on the distribution grid side of the inverter), whereas others might use DC measurements (*i.e.,* on the panel side of the inverter) which would yield a higher computed capacity factor because it would exclude the inherent efficiency losses caused by the plant's inverters. There are numerous other factors that limit the economically achievable capacity factor of solar plants. These include:

- <u>Time of year and available daylight hours</u>: The time of year and associated daylight hours affect the cumulative output of SPV projects. There are more daylight hours during summer months than in the winter months, offering increased opportunity for the panels to generate electricity.
- <u>Weather and cloud cover</u>: Weather and varying degrees of cloud cover can also affect the output of the SPV projects. SPV modules generate the most electricity on cool, sunny days, and become less efficient as they heat up on hot days. Partially cloudy skies can also cause rapid swings in solar facility output.
- <u>Changes in temperature</u>: Changes in temperature can affect the generating efficiency of solar panels. Most SPV panels have a rating between 20 and 25 degrees Celsius (*i.e.*, between 68- and 77-degrees Fahrenheit). Panel's generating efficiency decreases when the air temperature surrounding the panel (known as ambient temperature) is warmer than the panel's rating.
- <u>Panel soiling</u>: During extended periods without rain, the SPV panels become soiled with dust, emissions, and other particulates in the air. This panel soiling can cause decreased panel efficiency.
- <u>Panel age</u>: The efficiency of SPV panels degrades with age. Newly installed panels will generate electricity more efficiently than panels operating for several years.
- <u>Aerosol scattering</u>: Aerosol scattering occurs when direct light from the sun passes through small aerosol particles in the air. Aerosol particles can include dust, saltwater droplets, smog, or smoke. Sunlight hits the particles and reflects off in many directions,

becoming scattered light. SPV panels produce electricity most efficiently with direct light. In inland areas where air pollution is more prevalent (and where all of SCE's SPV plants are located), aerosol scattering has a degrading effect on the ability of panels to generate electricity. The Porterville area where the ground-mounted facility (SPVP #042) is located experienced 90-120 days of severe filtration of the sun due to smoke from local fires.

- <u>Outages for Maintenance Activities</u>: While solar plants require relatively lower maintenance compared to other types of generating plants, some maintenance is required, including repairs to equipment components that fail. Such maintenance often requires the plant to be disconnected from the grid (*i.e.,* to incur an outage). Outages are also occasionally needed to perform plant modifications made in response to events that occur as operating experience is gained with this relatively new technology.[95]

3. SPV Generating Facilities Performance During the Record Period

When the SPVP was initiated, based on conversations with panel suppliers and other research, SCE forecasted that, once constructed, the SCE-owned SPV would operate with a 20% system capacity factor.[96] The SCE-owned SPV plants have operated slightly below this forecast, having recorded an overall capacity factor of 17.1% from the inception of the program through 2020. During the Record Period, the SCE-owned SPV plant fleet capacity factor was 12.5% (*i.e.*, the fleet recorded 65,253 MWh AC of generation).

The Record Period capacity factor performance was approximately 4.2% lower than the historic average because: (a) ongoing normal panel efficiency degradation over time, and (b) an

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95 While SPV panels have been manufactured for three or more decades, panel technology has continued to evolve. Also, the use of such panels in medium-scale rooftop solar arrays, such as found in SCE's SPV plants, is still relatively new. Relatively few medium-scale SPV plants (*i.e.*, plants 1-2 MW in size) existed prior to the start of SCE's SPV Program.

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

increased level of outages and derates resulting from the normal operation of the ground fault protective devices. (c) Equipment Failure

a) Panel Efficiency Degradation

An analysis of studies that examined the long-term degradation rates of various PV panels was performed by the National Renewable Energy Laboratory.[97] The results showed that for monocrystalline silicon, the most used panel for commercial and residential SPV panels, the degradation rate per year is less than 0.5% for panels made before 2000, and less than 0.4% for panels made after 2000. While this is a relatively low annual rate, it does result in some level of degradation over the expected life of solar installations. The SCE SPVP initial installation commenced in 2009 and many of the units are now approaching and or exceeding a decade of operation. The majority of SCE's SPV units are in the Inland Empire area of Southern California, where extreme high temperatures routinely occur in the summer months, worsening the rate of potential degradation of the units.

b) Ground Fault Protective Device Operation, and Other Outages

During the Record Period, there were times when site generation MW output was interrupted or reduced because of inverter trips triggered by transient ground faults detected by the site protective equipment. This equipment is designed to disconnect the inverter and the panels connected to it from the grid[98] to minimize the risk of a significant ground fault causing damage (or a fire) to the plant, or to the rooftop site's host building. This instrumentation is highly sensitive and could initiate a trip even if the ground fault detected is relatively minor or brief. SCE believes this is an appropriate trade-off, given the relatively small MW size of each SPV site (*i.e.*, compared to other generating plants). Other repair outage and derate causes during the Record Period included faulty Digital Processing Control Boards. SCE personnel are required to travel to the facility, perform an inspection, locate, and repair any failed equipment, and/or re-set the inverters.

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

[98] Each site is equipped with one inverter for each 0.5 MW of capacity. The inverter converts the DC electrical output of the solar panels into AC electrical power, so that it can be fed into the grid. When an inverter fails or trips offline, all the panels connected to it are disconnected from the grid.

c) Equipment Failure

On May 18, 2020, SPVP 042, SCE's ground-mounted facility in Porterville lost one of its ten transformers. The transformer lost was a sealed unit that could not be repaired. The transformer outage resulted in a loss of approximately 10% of the total facility output during the period between May and December. In late 2020 a new transformer was secured, installation scheduled, and the replacement unit was installed on January 15, 2021.

4. Summary

During the Record Period, SCE's SPV fleet performed at a reasonable capacity factor considering unit age and the operating characteristics of the ground fault protection systems installed to increase site safety. SCE continues to gain experience through operation and maintenance of its SPV fleet. This information is available to other parties, to help advance SPV technology and deployment. SCE continues to manage its SPV generating units in a manner that achieves an appropriate balance between fleet performance and O&M costs.

C. SCE Fuel Cell Demonstration Program

1. Introduction

SCE's Fuel Cell Demonstration Program is a partnership between SCE and the University of California Santa Barbara (UC Santa Barbara) and California State University San Bernardino (CSU San Bernardino) for educational and demonstration purposes.[99] The program consists of the installation and operation of two utility-owned fuel cell generating facilities with a combined capacity of 1.6 megawatts (MW) at UC Santa Barbara and CSU San Bernardino.

a) UC Santa Barbara

UC Santa Barbara's fuel cell facility is a 200-kW facility. This fuel cell uses a solid oxide fuel cell technology manufactured by Bloom Energy and is an electric-only fuel cell.[100] The

[99] *See* D.10-04-028, p. 27.

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

Bloom Energy fuel cell converts natural gas to electricity, providing electricity to SCE's local distribution electrical grid. The unit has been operational since September 6, 2012.

b) CSU San Bernardino

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

D. Fuel Cell Operations During the Record Period

The two SCE Fuel Cell projects provided 650.203 MWh of energy during the Record Period as shown in Table V-29.

Table V-29
SCE Fuel Cells – 2020 Performance

Line No.	Annual Values	USC Santa Barbara Electric Only	CSU San Bernadino Combined Heat and Power	Total
1	Electrical Output (kWh)	1,356,253	8,434,687	9,790,940
2	Fuel Consumption (mmBtu)	10,641	84,019	94,660
3	Fuel Costs	60,849	468,546	529,394
4	Capacity Factor (Electrical)	77%	69%	

1. Fuel Usage and Cost

During the Record Period, SCE Fuel Cells consumed 94,660 MMBtu of natural gas at a cost of $0.53 million. Table V-30 below shows the monthly sums of fuel usage and cost for both fuel cell projects.[101]

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

Table V-30
SCE Fuel Cell – 2020 Fuel Cell Usage and Cost

Line No.	Month	Usage (mmBtu)	Cost ($)
1	January	8,894	58,576
2	February	7,380	43,916
3	March	8,972	43,083
4	April	8,480	37,328
5	May	8,315	38,150
6	June	8,886	41,827
7	July	9,015	41,087
8	August	8,073	49,094
9	September	6,616	45,803
10	October	6,825	28,599
11	November	6,548	55,885
12	December	6,657	46,045
13	TOTAL	94,660	529,394

2. Record Period Performance Summary

The Record Period capacity factors (*i.e.*, for electrical generation only, relative to the rated kW electrical output of the fuel cell) for the UC Santa Barbara and CSU San Bernardino generating facilities were 77% and 69%, respectively.

Although no full site outages of 24 hours or greater were experienced at the UC Santa Barbara facility in 2020, there was an 8% drop in capacity factor when compared to 2019, resulting from degradation within the individual fuel cell modules. As part of its service agreement with SCE, Bloom Energy remotely monitors the site, and makes repairs and/or replaces equipment as needed, including the periodic replacement of modules to restore production capability. The most recent module replacement (two of six) occurred in September 2020.[102] Module life is approximately two years.

[102] Bloom fuel cell is modular in design. These modules can be removed from service, which decreases energy output although the system remains in service. There is a total of six modules.

The CSU San Bernardino Fuel Cell capacity factor for 2020 was 69%, a 5% drop when compared to 2019. The fuel cell experienced several short-term outages in 2020 contributing to the lower capacity factor.

The facility experienced a total of 420 hours of downtime over the record period. Five outages caused by grid connection interruptions due to emergent or Public Safety Power Shut-off events totaling over 96 hours, resulted in 346 hours of outages. The additional outage hours were a result of the loss of remote monitoring communications system during and after the grid interruptions, failed components, and long start-up time required to warm up the fuel cell modules after cooling down due to non-operation. The remaining outages (74 hours in total) consisted of miscellaneous repairs and maintenance activities. SCE will continue to compare its fuel cells with other similar fuel cell sites and work with the manufacturers and the host sites to study the use of fuel cells in a distributed generation utility grid environment.

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

VI.

NUCLEAR GENERATION AND FUEL

A. Introduction

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

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

B. SCE Oversight Responsibilities for Palo Verde

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

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

and approval. SCE's Nuclear Generation Senior Project Manager represents SCE on the E&O Committee. SCE's Project Manager actively participates in E&O Committee meetings discussing and approving significant cost, schedule, and resource issues, and confirms that the development, approval, monitoring, and control of the O&M budget is acceptable to SCE. The Palo Verde E&O Committee typically meets eight times per year.

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

C. Types of Nuclear Outage Activities

1. Refueling and Maintenance Outages

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

Planning the duration of each RFO is a complex task. Every RFO has work activities similar in scope and outage time requirements including: (1) shutdown and cooldown of the reactor; (2) disassembly of the reactor; (3) fuel replacement; and (4) reassembly of the reactor, followed by heatup and startup of the plant. During these periods, scheduled maintenance is conducted, surveillance tests[103] are performed, and plant modifications are completed. Because the three Palo Verde units do not shut down routinely for non-refueling outages (as do fossil fueled units when maintenance is required), a great deal of maintenance work is planned for these RFOs.

2. <u>Forced Outage Activities</u>

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

D. <u>Palo Verde Record Period Performance</u>

1. <u>Palo Verde Generation</u>

The capacity factor and net generation for the Record Period for Palo Verde Units 1, 2, and 3 are shown in Table VI-31.

Table VI-31
2020 Record Period Generation

Line No.	Palo Verde Unit	Capacity Factor	Generation MWh (Net)
1	1	85.26%	9,818,478
2	2	90.68%	10,466,373
3	3	97.77%	11,267,585
4	Total		31,552,436
5	Site Avg	91.24%	10,517,479
		SCE's 15.8% Share	4,985,285

[103] These tests are required by Nuclear Regulatory Commission (NRC)-approved technical specifications.

The EAFs and FOFs for five years of plant generation for Palo Verde are shown in Table VI-32. As previously stated in Chapter III Hydroelectric Generation, the EAF considers scheduled outages and forced outages. The ideal percentage is as high a level as possible. The FOF is calculated using the hours that the generating unit was forced off-line. The ideal percentage is as low as possible. As shown below, Palo Verde's Record Period and five-year averages for both factors were better than the industry averages.[104]

Table VI-32
2015-2020 EAF and FOF Palo Verde Generation

		EAF		FOF	
Line No.	Year	Palo Verde	Industry	Palo Verde	Industry
1	2015	92.41%	89.95%	0.00%	1.08%
2	2016	91.43%	90.33%	1.42%	2.51%
3	2017	91.95%	90.00%	0.51%	1.43%
4	2018	88.57%	91.58%	1.12%	0.58%
5	2019	90.82%	90.01%	0.34%	1.57%
6	Avg.	91.04%	90.37%	0.68%	1.43%
7	2020	89.48%	Not Available	1.15%	Not Available

Table VI-33 shows that for the Record Period, Palo Verde Unit 3 generated 737,359 MWh more than the five-year average, and Palo Verde Units 1 and 2 generated 1,209,658 MWh less than the five-year average.[105]

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

[105] 958,246 MWh (Palo Verde Unit 1) + 251,412 MWh (Palo Verde Unit 2) = 1,209,658 MWh (Palo Verde Units 1 and 2).

Table VI-33
2020 Palo Verde Generation (Net MWh, 100% Share)

Line No.	Period	Palo Verde 1	Palo Verde 2	Palo Verde 3
1	2015	11,600,880	10,410,837	10,502,984
2	2016	10,068,740	11,696,951	10,477,426
3	2017	10,477,953	10,588,603	11,273,582
4	2018	11,220,878	9,458,026	10,427,448
5	2019	10,515,168	11,434,510	9,969,691
6	5 Year Average	10,776,724	10,717,785	10,530,226
7	2020	9,818,478	10,466,373	11,267,585
8	2020 Delta from Average	(958,246)	(251,412)	737,359

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

a) Palo Verde Outages

(1) Palo Verde Unit 1

The capacity factor for Palo Verde Unit 1 was 85.26% during the Record Period. As shown in Table VI-34 below, the unit was shut down for 54 days in 2020.[106]

Table VI-34
2020 Palo Verde Unit 1 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	10/10/2020	S	Unit 1 Cycle 22 RFO	54

[106] Palo Verde Unit 1 ranked first in the United States for electrical generation (MWh) from January 1, 2020 through September 30, 2020. *See* the U.S. Department of Energy, Energy Information Administration (EIA) U.S. Nuclear Generation and Generating Capacity, Capacity and Generation by State and Reactor Report "2020 P," *available at* https://www.eia.gov/nuclear/generation/ [accessed on February 17, 2021].

(a) Unit 1 Cycle 22 Scheduled RFO[107]

Palo Verde Unit 1 was manually shut down for a scheduled 44-day RFO on October 10, 2020. In addition to routine RFO activities such as offloading and loading fuel, the work included replacement of the containment polar crane and scheduled preventative maintenance tasks on the primary, secondary, and electrical systems. The outage also included, but was not limited to: (1) reactor coolant pump "1A" motor and primary seal replacement; (2) reactor coolant pump "2A" and "2B" seal oil replacements; (3) reactor coolant pump "2A" seal cooler replacements; (4) high pressure safety injection pump "A" seal replacement; (5) safety injection "SI-1682" pressure locking modification; (6) main generator stator rewind, (7) main turbine valve and actuator replacements; (8) low pressure feedwater heater "1C" replacement; (9) condenser divider plate repairs; (10) condensate pump "A" replacement; and (11) other equipment repairs and replacements. APS completed the Palo Verde Unit 1 Cycle 22 RFO in 54 days on December 3, 2020, ten days longer than its 44-day business goal.

The 1R22 refueling outage was scheduled for a longer duration of 44 days (including turbine over-speed testing) to allow for completion of a stator rewind on the main generator and for replacement of the containment polar crane. These activities were part of the long-range plan for Palo Verde, allowing for continued strong performance with a reliable generator for online generation and a reliable containment polar crane for timely future outage completion. The Palo Verde outage was extended by ten days. The ten-day extension occurred primarily due to issues with the old polar crane and the polar crane replacement project. The emergent requirement to repair a bonnet leak on a block valve for an atmospheric dump valve also contributed to the outage extension.

(b) Palo Verde Unit 2

The capacity factor for Palo Verde Unit 2 was 90.68% during the Record Period. As shown in Table VI-35 below, the unit was shut down for 35 days in 2020.

[107] The NERC Cause Code for the Unit 1 Cycle 21 RFO is 2070.

Table VI-35
2020 Palo Verde Unit 2 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	3/3/2020	U	Unit 2 Reactor Trip	4
2	5/4/2020	S	Unit 2 Cycle 22 RFO	31

(c) Unit 2 Unscheduled Reactor Trip[108]

On March 3, 2020, Palo Verde Unit 2 was operating at full power when both main feedwater pumps (MFWP) tripped simultaneously during restoration of power to the MFWP lube oil control panel. This resulted in a reactor power cutback signal, followed by an automatic reactor trip. All equipment functioned as expected following the MFWP trips and the plant stabilized in hot standby. The unit was returned to service on March 7, 2020 after having been off-line for 4.1 days. The U.S. Nuclear Regulatory Commission (NRC) reviewed the outage but did not identify any violations.[109]

(d) Unit 2 Cycle 22 Scheduled RFO[110]

Palo Verde Unit 2 was manually shut down for a scheduled 30-day RFO on April 4, 2020. In addition to routine RFO activities such as offloading and loading fuel, the work included scheduled preventative maintenance tasks on the primary, secondary, and electrical systems. The outage also included, but was not limited to: (1) reactor vessel bare metal inspection; (2) steam generator eddy current testing; (3) steam generator foreign object search and retrieval inspection; (4) low pressure safety injection pump seal replacement; (5) reactor coolant pump "2B"

[108] The NERC Cause Code for the Unit 2 Unscheduled Reactor Trip outage is 3974.

[109] *See* Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Integrated Inspection Report, May 12, 2020, p. 8.

[110] The NERC Cause Code for the Unit 2 Cycle 22 RFO is 2070.

stuck seal replacement; (6) reactor coolant pump "1B" motor replacement; (7) main turbine valve actuator rebuilds; (8) stator cooling pump "A" rebuild; (9) low pressure feedwater heater eddy current inspections; (10) main turbine thrust bearing rebuild; (11) and other equipment repairs and replacements. The unit was returned to service on May 5, 2020 after having been off-line for 31 days.

(2) Palo Verde Unit 3

The capacity factor for Palo Verde Unit 3 was 97.77% during the Record Period. As shown in Table VI-36 below, the unit was shut down for eight days in 2020.[111]

Table VI-36
2020 Palo Verde Unit 3 Scheduled/Unscheduled Shutdowns

Line No.	Start Date	Scheduled (S) / Unscheduled (U)	Cause	Duration (Days)
1	2/9/2020	U	Unit 3 Reactor Trip	8

(a) Unit 3 Unscheduled Reactor Trip[112]

On February 9, 2020, Palo Verde Unit 3 was operating at full power when the reactor was manually tripped due to reactor coolant system leakage from degradation of a seal on reactor coolant pump "1B". After repairs were completed, the unit was returned to service on February 17, 2020 after having been off-line for 8.2 days. The U.S. Nuclear Regulatory Commission (NRC) reviewed the outage and issued one Green finding regarding Palo Verde's self-reported incorrect installation of a reactor coolant pump seal assembly, but did not identify any violations associated with this finding.[113]

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[111] Palo Verde Unit 3 ranked fifth in the United States for electrical generation (MWh) from January 1, 2020 through September 30, 2020. *See* the U.S. Department of Energy, Energy Information Administration (EIA) U.S. Nuclear Generation and Generating Capacity, Capacity and Generation by State and Reactor Report "2020 P," *available at* https://www.eia.gov/nuclear/generation/ [accessed on February 17, 2020].

[112] The NERC Cause Code for the Unit 2 Unscheduled Reactor Trip outage is 2200.

[113] *See* Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Integrated Inspection Report, July 31, 2020, pp. 9-11; and Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Integrated Inspection Report, January 28, 2021, p. 8.

E. Nuclear Fuel Expense

1. Overview

Nuclear fuel expenses incurred during the Record Period are dictated by unit operations and previous purchases of nuclear fuel materials and services. The nuclear fuel materials and services purchased during the Record Period are described in Section F of this chapter. The generation and fuel expense data related to Palo Verde are summarized in and discussed in Section E.2 of this chapter. SCE's share of nuclear fuel utilized at Palo Verde produced a net electrical generation of 4,984 gigawatt-hours (GWh) at an overall fuel expense of $35.46 million, equivalent to $7.11/MWh.

Table VI-37
Nuclear Fuel Energy Production and Expense[114]

Line No.	Station	GWh	$Millions	$/MWh
1	Palo Verde	4,984	35.46	7.11

2. Generation Related Nuclear Fuel Expense

a) Palo Verde Generation Related Expenses

Palo Verde Units 1, 2, and 3 nuclear fuel expenses for the Record Period were related to both generation and non-generation expenses. Palo Verde Unit 1 and Unit 2 experienced refueling outages during the Record Period. Palo Verde Unit 3 was in Cycle 22 through the entire Record Period.

Palo Verde Unit 1 was in Cycle 22 until October 10, 2020, when it began its 22nd refueling, returning to service on November 22, 2020 and operating thereafter in Cycle 23 through the end of the Record Period. Palo Verde Unit 2 was in Cycle 22 until April 10, 2020 when it began its 22nd refueling, returning to service on May 9, 2020 and operating thereafter in Cycle 23 through the end of the Record Period.

The generation-related fuel expense related to SCE's 15.8% ownership interest in Palo Verde was $35.46 million.

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114 Does not include monthly non-generation-related expenses.

3. Non-Generation-Related Expenses

During a reactor refueling, depleted fuel assemblies are removed from a reactor core and replaced with new fuel assemblies. Because the depleted assemblies are highly radioactive, they must be stored isolated from the environment. The United States Department of Energy (DOE) retains the ultimate responsibility for the permanent disposal of high-level radioactive waste and used nuclear fuel under the authority of the 1982 Act. Until DOE implements a program for the disposal of used fuel, utilities must provide interim used fuel storage. After the DOE licenses and constructs facilities for the storage and permanent disposal of used fuel, the used fuel being stored on an interim basis will be transferred to the DOE for disposition. Interim storage is being provided for Palo Verde Units 1, 2, and 3 in their respective used fuel pools and at the Palo Verde ISFSI[115] located on-site.

SCE's share of non-generation-related expenses during the Record Period for Palo Verde is a charge of $2.2 million for a dry cask storage system to store used fuel assemblies at the Palo Verde ISFSI located on-site. This included a credit from funds from the DOE spent fuel litigation damages award.

F. Nuclear Fuel Purchases

Nuclear fuel management consists of a sequence of activities involving the procurement and scheduling of materials and services required to manufacture nuclear fuel assemblies suitable for a nuclear power plant and the disposal of used fuel assemblies after their discharge from the reactor. These activities described below encompass: (a) mining and milling of natural uranium concentrates (U_3O_8), (b) conversion to uranium hexafluoride (UF_6), (c) enrichment, (d) design and fabrication of fuel assemblies, and (e) interim storage and permanent disposal of used nuclear fuel discussed in Section E.3 of this chapter. Scheduling materials and services required to manufacture finished fuel assemblies when needed is a critical aspect of managing SCE's nuclear fuel supply. Table VI-38 presents typical scheduling lead times established by contract terms and SCE's practices for reload batches.[116] The

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

[116] Nuclear fuel assemblies loaded together into the core of a nuclear generating unit at the beginning of an operating cycle and later removed together at the end of their operating life are referred to as a batch. At the

range in lead times covers simple material transfers via "book transfer" to and from existing on-site inventory accounts at the various suppliers, to physical material deliveries which may require many months of lead time to prepare and ship.

Table VI-38
Typical Reload Nuclear Fuel Procurement Schedule – Months

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

[1] In the case of a long-term supply contract, uranium procurement may have occurred several years in advance of uranium delivery.
[2] Shipment date of the last fuel assembly to the plant.

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

1. Natural Uranium Concentrates U_3O_8

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

(continued from previous page)
conclusion of each operating cycle, one or more batches of fuel are discharged and the fuel assemblies in the remaining batches are relocated within the reactor core. A batch typically remains in the reactor for at least two operating cycles. An operating cycle, also known as a fuel cycle, begins with a unit's return to operation following a refueling and maintenance outage.

may have taken place many years prior to the scheduling of deliveries under the contract. Requirements planning and procurement activity, including contract negotiation, must precede delivery.

2. Conversion

The conversion process converts impure U_3O_8 into high purity uranium hexafluoride (UF_6) suitable for the uranium enrichment process. U_3O_8 can be delivered to the converter two days to two months prior to UF_6 delivery, depending on contract provisions.[117] Conversion of U_3O_8 to UF_6 is available in the United States only from the ConverDyn plant near Metropolis, Illinois. Outside the United States, conversion service is available from two suppliers: Cameco in Canada, and Comurhex (Orano) in France. Material may be purchased as UF_6 (purchasing both the U_3O_8 and conversion services as one) from many sources, such as conversion suppliers, brokers, and others.

3. Enrichment

Uranium as found in nature consists principally of two isotopes, U-235 and U-238. The fission of the U-235 isotope is the primary heat source in the nuclear reactor. Natural uranium contains only 0.711% of U-235 by weight, however, most nuclear power plants are designed to use nuclear fuel containing uranium having approximately 3%-5% U-235. The enrichment process is therefore necessary to increase the concentration of the U-235 isotope to 3%-5% as required by the fuel design. Natural uranium feed UF_6 is typically delivered to the enrichment facility two days to four months prior to enriched UF_6 delivery to the fabrication facility. Services to enrich UF6 from the natural state to the required design enrichment is available in the United States from Louisiana Energy Services (LES), in Europe from Urenco and Areva (Orano), and in China from CNEI. The enrichment process is measured in separative work units (SWU). Enrichment services may be purchased with the UF_6 as enriched uranium product (EUP).

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

4. Design and Fabrication

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

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

G. Palo Verde Nuclear Fuel Purchases

1. Uranium Purchases

During the Record Period, SCE purchased 121,976 pounds of U_3O_8 for SCE's share of Palo Verde requirements under contracts with TRAXYS; MacQuarie Physical Commodities UK Limited; Itochu; Energy USA, Inc.; MTM Trading, LLC; and Energy USA. These contracts were awarded using strict competitive commercial processes.

2. Conversion to and/or Purchase of UF_6

During the Record Period, SCE purchased 41,870 KgU of conversion services for SCE's share of Palo Verde requirements under a contract with ConverDyn and Orano. SCE also purchased 47,556 KgU as UF_6 (U_3O_8 and conversion services together) for SCE's share of Palo Verde requirements under a contract with Cameco, Orano, and LES. These contracts were awarded using strict competitive processes.

3. **Enrichment**

During the Record Period, SCE purchased 85,418 SWU for SCE's share of Palo Verde under an enrichment uranium supply contract with Urenco, LES, and CNEIC. These contracts were awarded using strict competitive commercial processes.

4. **Enrichment Uranium Product - EUP**

During the Record Period, SCE purchased 8,000 KgU of EUP from LES. This contract was awarded using strict competitive commercial processes.

VII.

CONTRACT ADMINISTRATION AND COSTS

A. Introduction

The Commission has provided guidance on what it expects from the utility when reviewing energy contract administration and on the scope and nature of such reviews. As used in this chapter, the term "contract administration" means activities implementing the exercise of contract rights and performing contract obligations after contract execution by SCE. The administration and management of these contracts is explained throughout this chapter based upon the following resource categories: (1) Behind the Meter (BTM) contracts; (2) Conventional and Natural Gas products and contracts (including Demand Response Auction Mechanism (DRAM) and Energy Storage); (3) Public Utility Regulatory Policy Act (PURPA) and Combined Heat and Power (CHP) contracts; and, (4) Renewables Portfolio Standard (RPS) contracts.

1. Behind-The-Meter Contracts

SCE executes and administers BTM contracts which are contracts for resources on the customer side of the meter, with the objective of reducing load. BTM contracts are entered into under the procurement authority granted to SCE through its Commission-approved procurement plans including the 2012 LTPP proceeding (Tracks 1 and 4) and other RFOs. BTM activities are behind-the-meter projects managed by SCE's Customer Program & Services (CP&S) group and are discussed separately from the Conventional, PURPA/CHP, or RPS sections of this chapter.

2. Conventional and Natural Gas Products

"Conventional energy contracts" are contracts with, or related to, non-CHP fossil-fired, thermal resources including tolling agreements or Power Purchase Agreements (PPAs), physical or financial structured commodity transactions (*e.g.*, commodity transactions other than trades), contracts for fuel or electricity transportation, energy storage (ES) contracts, resource adequacy (RA) contracts, or demand response resource purchase agreements (RPAs), and contracts that do not fit exclusively within PURPA, CHP, RPS or BTM. SCE executed conventional contracts either prior to the passage of AB

57,[118] after the passage of AB 57[119] under the procurement authority granted to SCE through its then-applicable Commission-approved procurement plan, through various SCE RFOs, through Commission-approved DRAM solicitations,[120] through Commission-approved ES solicitations (*i.e.*, Bi-annual Energy Storage RFO, Integrated Distributed Energy Resources, and Aliso Canyon Energy Storage),[121] or through bilateral transactions outside of the Commission-approved procurement plan for which SCE sought separate upfront approval from the Commission. In addition, SCE has Master Enabling Agreements under which power, natural gas, resource adequacy capacity, transmission, emissions, and financial hedging transactions (most short-term),[122] are executed under SCE's Commission-approved procurement plan.

3. PURPA and CHP

SCE also administers PPAs entered under the Commission's implementation of PURPA.[123] The generating facilities subject to these PPAs are referred to as Qualifying Facilities or QFs within the meaning of PURPA and consist of either small power producers fueled by renewable resources, or cogeneration facilities as defined in PURPA. Most PPAs are "standard offer" contracts approved by the Commission, including: Standard Offer 1 (SO1); Standard Offer 2 (SO2); Standard Offer 3 (SO3); and, Interim Standard Offer 4 (ISO4 or SO4) contracts. In addition, SCE has signed "nonstandard" or negotiated (NEG) contracts with QFs, usually based on a standard offer, which have been approved by the Commission.

Since November 2011, SCE administers PPAs entered into under the CHP Settlement adopted by the Commission in D.10-12-035. The CHP Settlement developed a State CHP Program with

[118] Inter-utility contracts that SCE entered into with other utilities prior to re-entering the procurement role on behalf of bundled service customers on January 1, 2003 are often referred to as legacy agreements.

[119] New transactions are generally reviewed in SCE's quarterly compliance report (QCR) Advice Letter filings or through a separate advice letter or application to the Commission for pre-approval.

[120] In accordance with CPUC Decisions D.14-12-024 and D.16-06-029.

[121] In accordance with CPUC Decisions/ Resolutions D.13-10-040, D.16-12-036, and E-4791.

[122] SCE considers short-term transactions to be those with delivery terms up to and including one quarter in duration and up to one quarter forward.

[123] Public Law No. 95-617 (Nov. 9, 1978), 92 Stat. 3117, *available at* https://www.gpo.gov/fdsys/pkg/STATUTE-92/pdf/STATUTE-92-Pg3117.pdf.

the intent of transitioning from the prior PURPA program to a market-based, state-administered program for CHP projects above 20 MW. This program is governed by a set of provisions called the CHP Settlement Term Sheet. One condition precedent to implementing the CHP Settlement was that the FERC terminate the IOUs' PURPA must-take obligation pursuant to §210(m), as modified by the Energy Policy Act of 2005,[124] for QFs above 20 MW. On June 16, 2011, the FERC granted the California IOUs §210(m) application to terminate the PURPA must-take obligation for QFs above 20 MW.[125]

The CHP Settlement provided a path for CHP resources above 20 MW to obtain PPAs in the absence of the IOUs' PURPA must-take obligation and established a PURPA QF Standard Offer Contract (QF SOC) for QFs 20 MW or less. The CHP Settlement created market-based agreements for CHP projects. One agreement is a Standard PPA signed under the CHP Settlement's RFO PPA. Bilateral negotiations are another, less common procurement process for CHP. These PPAs are known as CHP Bilateral PPAs. These CHP RFO and CHP Bilateral PPA contracts are not PURPA contracts but rather a result of a collaborative effort between the IOUs and the CHP parties through the CHP Settlement. Additionally, qualifying CHP projects of 20 MW or less are eligible to execute a tariff contract, at any time, pursuant to AB 1613.[126] Similar to the QF SOC, the AB 1613 program and its associated contracts are administered per the requirements of PURPA, which remains in effect in California for QFs of 20 MW or less.[127]

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[124] Public Law No. 109-58 (Aug. 8, 2005), 119 Stat. 594, *available at* https://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.

[125] 135 FERC ¶ 61,234.

[126] Assembly Bill 1613 (Blakeslee 2007) and amended by Assembly Bill 2791 (Blakeslee 2008) directed the California Energy Commission, the CPUC, and the ARB to implement the Waste Heat and Carbon Emissions Reduction Act. The Act is designed to encourage the development of new CHP systems in California with a generating capacity of not more than 20 MW. See also D. 09-12-042 (as modified by D.10-04-055, D.10-12-055 and D.11-04-033) and Resolution E-4424 for approved contract form and program specifics.

[127] Adopted in D.09-12-042.

4. RPS

SCE executes and administers PPAs to implement California's RPS, which became effective January 1, 2003.[128] Initial RPS legislation (SB 1078 and SB 107) required certain LSEs, including the IOUs, to increase procurement from eligible renewable resources (ERRs), as defined in the legislation, by at least 1% of annual sales per year, so that 20% of retail sales are served from ERRs by 2010.[129] In 2011, SB X1-2 expanded the RPS to 33% by 2020.[130] In September 2015, SB 350 further expanded the RPS requirement to 50% by 2030. In September 2018, SB 100 expanded the RPS requirement to 50% by 2026, 60% by 2030 and established a state policy that 100% of retail sales of electricity to California end-use customers come from eligible renewable resources and zero-carbon resources by 2045.[131]

SCE has an excess inventory of renewable energy credits (RECs). As such, SCE has entered into REC sales agreements under the Edison Electric Institute Master Enabling Agreement executed under SCE's Commission-approved RPS procurement plan to provide value to its customers.

B. Safety

1. BTM Contract Developing Project Monitoring and Safety

SCE is strongly committed to safety in all aspects of its business. Consistent with SCE's focus on safety, SCE includes a requirement in its BTM contracts that Sellers must safely construct and operate their projects and comply with applicable safety regulations and standards. The contracts require that the Seller provide SCE a report from an independent engineer certifying that the Seller has a written plan for the safe construction and operation of the project prior to commencement of any construction activities on the project site.

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[128] *See* Pub. Util. Code §399.11, et. seq.

[129] *See* Pub. Util. Code § 399.15, et. seq.

[130] Senate BillX1-2, *available at* http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412 chaptered.pdf. Additionally, this bill eliminated the 1% per year requirement in the previous RPS legislation.

[131] Senate Bill SB100, *available at* *https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.*

For the BTM projects that are required to interconnect to SCE's grid, safety is addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnection generation. Sellers may commence deliveries under the contract only after certain criteria have been met, including confirmation of completing safety testing and issuance of a Permission to Operate letter from SCE's interconnection department. Additionally, local, state, and federal agencies with review and approval authority over the projects are charged with enforcing safety, environmental, and other regulations.

2. Non-BTM Contract Administration Safety Practices

Consistent with SCE's strong commitment to safety in all aspects of its business, SCE holds its contract counterparties ("sellers") responsible for the safe construction and operation of their generating facilities and compliance with all safety regulations. SCE has taken several steps to address those issues over which it has the most visibility and control – the delivery of electricity products to SCE in a reliable, safe, and operationally sound manner.

Consistent with this focus, SCE includes a provision in many of its contracts providing that prior to commencement of any construction activities on the project site, the seller must provide to SCE a report from an independent engineer certifying that the seller has a written plan for the safe construction and operation of the generating facility, in accordance with Prudent Electrical Practices.

All of SCE's PPAs provide that the seller must operate the generating facility in accordance with Prudent Electrical Practices. Further, these provisions specifically require that all sellers take reasonable steps to ensure that:

a) Equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the generating facility's needs;

b) Sufficient operating personnel are available at all times and are adequately experienced, trained, and licensed as necessary to operate the generating facility properly and efficiently, and are capable of responding to reasonably foreseeable emergency conditions at the generating facility and emergencies whether caused by events on or off the project site;

c) Preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long term and safe operation of the generating facility, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

d) Appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

e) Equipment is not operated in a reckless manner, in violation of manufacturer's guidelines or in a manner unsafe to workers, the general public, the Transmission Provider's electric system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as flood conditions, safety inspection requirements, operating voltage, current, VAR loading, frequency, rotational speed, polarity, synchronization, and control system limits; and,

f) Equipment and components are designed and manufactured to meet or exceed the standard of durability generally used for electric generating facilities operating in the Western United States and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the project site under both normal and emergency conditions.

SCE energy contract managers and members from SCE's Contract Compliance and Technical Services group monitor the development of counterparty energy projects, from contract execution through the term of the PPA. Typically, a contract requires the counterparty to provide written progress reports on their project's development status to SCE on a monthly or quarterly basis until Commercial Operation is achieved. As part of these progress reports, generators must provide the status of construction activities, including Occupational Health and Safety Administration (OSHA) recordable and work stoppage information. The assigned contract managers and compliance team members review the written progress reports, conduct conference calls with counterparty personnel, and conduct site visits to ensure that SCE is consistently up-to-date regarding the status of each project, along with any associated issues that impact the project. Prior to a project achieving Commercial

Operation, SCE consistently reviews and tracks development activities, including site control, permitting, financing, construction, and safety.

During the onboarding process of bringing a project to commercial operation, Engineers from SCE's Contract Compliance and Technical Services group conduct site visits to verify that the facility has been built to the specifications referenced in the contract. Prior to the site visit, an SCE Engineer contacts the counterparty to discuss any safety hazards unique to the facility such as dangerous wildlife, abnormal noise issues, dangerous access roads, etc., and assess the minimum personal protective equipment (PPE) required for the site visit. The SCE Engineer then reviews a technology-specific hazard assessment developed by the Engineers and safety professionals from within SCE. This review prepares the Engineer for the potential hazards associated with each of the generation technologies and the required PPE[132] before the site visit.

Upon arriving at the site, the SCE Engineer and any other SCE personnel meet with the site representative(s) and conduct a Safety Tailboard. During this tailboard, participants discuss the planned activities and all safety considerations by using a checklist developed by SCE. The checklist includes, *inter alia*, personal protective equipment, communication protocols, emergency response, location of safety/first aid equipment, and location of nearest emergency room. The site contact will also perform various safety trainings or reminders depending on whether the site is still under construction or if control of the project has transferred to an O&M provider. In all cases, conducting the Safety Tailboard prior to the inspection ensures SCE and facility personnel keep safety top of mind during all site visits.

For procurement contracts with third-party generators, local, state, and federal agencies with review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the project, including decommissioning. Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. SCE declares that a facility has commenced deliveries

[132] The SCE Engineer maintains an inventory of personal protective equipment (PPE) covering all types of generating facilities. The inventory is used to outfit, as needed, for site visits and also to replenish "site visit kits" containing a standard set of PPE provided to employees that may engage in site visits.

under the contract only after certain criteria has been met, including that the interconnecting utility and the CAISO have concluded such testing and given permission to commence Commercial Operation.

C. **Authorization for Recovery of Contract Expenses**

The California Public Utilities Code, Commission decisions, and approved advice letters provide for recovery of the costs associated with SCE's procurement contracts during the term of those agreements. Pursuant to D.02-10-062, SCE submitted Advice 1665-E to implement the ERRA BA and allow SCE to debit and recover its net purchased power expenses,[133] including applicable energy contract costs, to the ERRA BA for cost recovery. In addition, D.02-12-074 authorized cost recovery for the reasonable costs associated with administering and managing SCE's energy contracts.[134]

In D.06-07-029, as modified by D.11-05-005, the Commission adopted a cost allocation methodology (CAM) to allocate the benefits and costs of new generation to all benefiting customers in an IOU's service territory. Specifically, the Commission allowed the IOUs to recover "net capacity costs" for certain contracts from all bundled, Direct Access (DA), and Community Choice Aggregation (CCA) customers through the CAM.

In D.07-09-044, the Commission authorized each IOU to establish a balancing account to record costs and benefits associated with new generation resources. SCE established the New System Generation Balancing Account (NSGBA)[135] to track and recover the net costs of the new generation resources from all benefiting customers (including bundled service, DA, and CCA customers), while continuing to record all other costs associated with the energy contracts in the ERRA BA. Since only the net capacity costs of these resources are recovered through the CAM (*i.e.*, NSGBA) sometimes a contract has a portion of its costs recovered through the CAM and a portion of its costs recovered through the ERRA BA or the PABA.

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[133] Purchased power expenses include costs associated with renewable contracts, inter-utility contracts, bilateral contracts, ancillary services, uplift charges, and residual net short and net long procurement activities.

[134] *See* D.02-12-074 and Pub. Util. Code Section 454.5(d)(2).

[135] The NSGBA is discussed in Chapter XI of this ERRA Application. This Chapter VII discusses cost recovery for procurement activities through ERRA.

Pursuant to D.18-10-019, SCE filed Advice 3914-E to establish the Portfolio Allocation Balancing Account,[136] with subaccounts for each vintaged portfolio, to record the costs, market revenues, actual retained RA and RPS values, and billed customer revenues associated with its Competition Transition Charge (CTC) and Power Charge Indifference Adjustment (PCIA) eligible resources. The establishment of the PABA moved recovery of certain procurement contracts out of the ERRA BA and into the PABA.

During the Record Period, the following conventional projects listed below in Table VII-39, have costs recovered through CAM/NSGBA, the ERRA BA, and/or the PABA.

[136] Advice 3914-E was approved by the Commission's Energy Division with an effective date of January 1, 2019.

Table VII-39
Conventional Projects Costs Recovered Through CAM/NSGBA, ERRA BA, and PABA
January 1, 2020 Through December 31, 2020

	Project	CAM Authorization	Contract Type
1	Barre Peaker	A. 07-12-029/D.09-03-031	UOG[1]
2	Center Peaker	A. 07-12-029/D.09-03-031	UOG
3	Grapeland Peaker	A. 07-12-029/D.09-03-031	UOG
4	Mira Loma Peaker	A. 07-12-029/D.09-03-031	UOG
5	McGrath Peaker	A. 12-12-028/D.14-06-043	UOG
6	EGT Grapeland	A. 17-03-020/D.18-06-009	UOG[2]
7	EGT Center	A. 17-03-020/D.18-06-009	UOG[2]
8	Mira Loma A	A. 17-03-020/D.18-06-009	Energy Storage
9	Mira Loma B	A. 17-03-020/D.18-06-009	Energy Storage
10	Blythe Energy, LLC	A. 07-02-026/D.08-05-028	Toll/RA [3]
11	Delano Energy Center, LLC	A. 08-04-011/D.08-09-041	Toll/RA
12	Walnut Creek Energy, LLC	A. 08-04-011/D.08-09-041	Toll/RA
13	CPV Sentinel, LLC	A. 08-04-011/D.08-04-011/D.08-09-041	Toll/RA
14	El Segundo Energy Center, LLC	A. 08-04-011/D.08-09-041	Toll/RA
15	CSU Channel Islands Site Authority	AL 3769/Res. E-4957	RA
16	Vesi Pomona Energy Storage, Inc.	AL 3455/Res. E-4804	RA
17	PPA Grand Johanna LLC	AL 3455/Res. E-4804	Energy Storage
18	Sycamore Cogeneration Company	AL 2784/ Res. E-4555	Toll/RA
19	Calpine Energy Services LP- Los Medanos	AL 2771/ Res. E-4569	RA
20	O.L.S. Energy - Chino	AL 3485/ Res. E-4860	Toll/RA
21	GenOn Energy Management, LLC (Ellwood)	AL 3884/D.18-06-030	RA
22	GenOn Energy Management, LLC (Ormond Beach Unit 2)	AL 3885/Res. E-4986	RA
23	AES Huntington Beach Energy, LLC	D.15-11-041	RA
24	AES Alamitos Energy, LLC	D.15-11-041	RA
25	Stanton Energy Reliability Center, LLC	D.15-11-041	RA

[1] Utility owned generation (UOG) has no power purchase contract, but all bundled customers benefit through offered products and services provided to the CAISO marketplace.

[2] Battery storage projects integrated with Grapeland and Center Peakers resulting in Hybrid Electric Gas Turbine (EGT) Grapeland and EGT Center.

[3] The previous Power Purchase Tolling Agreement with Blythe Energy, LLC ("Blythe Toll") expired on July 31, 2020. In accordance with Advice Letter 4056-E, a new Blythe Toll became effective August 1, 2020, with cost recovery through PABA.

1. The Standard of Review for Cost Recovery

In a series of decisions, the Commission explained the standards it would apply to review the utilities' administration of contracts in the utility supply portfolio.[137] In this ERRA Review proceeding, SCE provides evidence that its contracts were administered in accordance with the terms of the contracts and that any contract disputes that arose were, or are in the process of being, reasonably

[137] *See* D.02-10-062, D.02-12-069, D.02-12-074, D.03-06-067, D.03-06-074, D.03-06-076, D.03-12-003, and D.05-01-054.

resolved.[138] In this chapter, SCE demonstrates that during the Record Period it administered all contracts for which it has responsibility in a manner consistent with these standards and that its contract administration activities should therefore be found prudent and reasonable. The Commission's review of purchase and sale transactions, including the type of product purchased or sold, together with the bidding or other transaction procedure followed, and the contracts' terms and prices, is conducted in SCE's QCR Advice Letter filings[139] or through separate Advice Letters or Applications.

D. **Summary of Contract Administration and Management Processes**

SCE's goal is to administer its contracts through a balanced and fair process to maximize benefits to customers at the lowest achievable cost. Certain contract transactions provide not only commodity and price benefits, but also non-price benefits such as dispatchability or favorable terms and conditions.

The contract administration process consists of several activities including: (1) exercising contract options in a prudent and economic manner; (2) verifying that the counterparty is complying with the contract terms, including credit support and collateral requirements; (3) verifying that billing and payments are accurate and consistent with the terms of the contract; (4) reviewing interruptions of service and *force majeure* events; (5) renegotiating contract provisions as necessary due to changed circumstances or conditions; (6) resolving disputes; (7) purchasing natural gas fuel at certain times and under certain types of contracts; and, (8) assigning, amending, renewing, or terminating contracts.

After execution, contracts are assigned to a SCE contract manager who carries out the management and administration of that contract and all activities related to it. While the contract manager ensures comprehensive oversight and takes the lead in communicating with the counterparty, he or she will seek assistance from other SCE groups with specialized functions. These groups include, *inter alia*, Portfolio Planning and Analysis, Trading and Market Operations, Settlements, Regulatory Affairs, Law, Credit Risk, Risk Operations & Collateral Management, and Contract Compliance and Technical Services, as needed.

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[138] Pub. Util. Code Section 454.5(d)(2).

[139] D.05-01-054, pp. 7-10.

When SCE determines that a counterparty does not comply with the terms or conditions of an agreement, or that differences exist between SCE and a counterparty over interpretation of the contract terms or conditions, SCE initiates discussions to resolve the non-compliance or the difference in interpretation and seeks to recover the lost value, if any. When differences with a counterparty cannot be resolved by an amendment or otherwise, SCE or the counterparty initiates the appropriate dispute resolution process as described in the applicable agreement (typically mediation and then arbitration).

The administration and management of these contracts is explained below and is separated by the following contract types: (1) BTM Contracts; (2) conventional and natural gas products; (3) PURPA and CHP; and, (4) RPS.

1. <u>Behind-The-Meter</u>

The BTM contracts addressed in this section are for resources procured to meet Local Reliability Requirements pursuant to the 2012 LTPP proceeding Tracks 1 and 4, to support the Preferred Resources Pilot, system reliability needs resulting from the 2021-2023 Integrated Resource Planning proceeding and to meet reliability needs resulting from the limited operations of the Aliso Canyon gas storage field.

a) <u>Contract Administration</u>

This section provides information on all activities related to the management of BTM contracts, including contract development, amendments, assignments, contract capacity demonstrations, measurement of energy deliveries, terminations, and other contract administration activities.

b) <u>Summary of Contract Activity</u>

During the Record Period, SCE managed twenty-seven (27) Energy Efficiency, eleven (11) Demand Response, eleven (11) Renewable Distributed Generation (DG), and eight (8) Permanent Load Shifting contracts for a total of fifty-seven (57) BTM contracts. Below, SCE sets forth its recorded contract-related expenses, describes its BTM contract development and administration activities during the Record Period, and demonstrates that such activities were reasonable.

c) Contract Development

During the Record Period, there were two (2) new Demand Response Energy Storage Agreements procured through the 2019 System Reliability RFO. SCE is awaiting final Commission approval on the 2019 System Reliability Standard Track Advice Letter. See Table VII-40 below:

Table VII-40
BTM Contracts Newly Executed
January 1, 2020 Through December 31, 2020

Contract ID	Seller	Capacity (MW)	Contract Type	Date Executed	CPUC Resolution or Decision/SCE Advice Letter/Application
SR-2019-DRES-01	SunRun Inc.	4.5	Demand Response	11/4/2020	AL 4373-E
SR-2019-DRES-02	SunRun Inc.	0.5	Demand Response (DAC)	11/4/2020	AL 4373-E

d) Contract Amendment Administration

After contract execution, BTM contract terms and conditions may be changed by amendments. SCE executed forty-eight (48) BTM contract amendments during the Record Period as shown and summarized in Table VII-41 below. BTM amendments are comprised of one (1) Renewable Distributed Generation, forty-four (44) Energy Efficiency, and three (3) Demand Response.

Table VII-41
SCE BTM Contract Amendments
January 1, 2020 through December 31, 2020

	Contract Counterparty	Contract ID	Amendment No. and Description	Date Executed
Renewable Distributed Generation (Solar)				
1	Amended & Restated Solar Star California XXXVIII, LLC	490006	[redacted]	1/31/2020
Energy Efficiency				
2	Amended & Restated Willdan Energy Solutions, Inc.	408002	[redacted]	6/18/2020
3	Amended & Restated Willdan Energy Solutions, Inc.	408002	[redacted]	12/21/2020
4	Amended & Restated Willdan Energy Solutions, Inc.	408005	[redacted]	6/18/2020
5	Amended & Restated Willdan Energy Solutions, Inc.	408008	[redacted]	6/18/2020
6	Amended & Restated Willdan Energy Solutions, Inc.	408008	[redacted]	12/21/2020
7	Amended & Restated Willdan Energy Solutions, Inc.	408011	[redacted]	4/8/2020
8	Amended & Restated Willdan Energy Solutions, Inc.	408011	[redacted]	7/1/2020
9	Amended & Restated Willdan Energy Solutions, Inc.	408014	[redacted]	2/6/2020
10	Amended & Restated Willdan Energy Solutions, Inc.	408017	[redacted]	6/19/2020
11	Amended & Restated Willdan Energy Solutions, Inc.	408001	[redacted]	12/21/2020
12	Amended & Restated Willdan Energy Solutions, Inc.	408002	[redacted]	12/21/2020
13	Amended & Restated Willdan Energy Solutions, Inc.	408003	[redacted]	12/21/2020
14	Amended & Restated Willdan Energy Solutions, Inc.	408004	[redacted]	12/21/2020
15	Amended & Restated Willdan Energy Solutions, Inc.	408005	[redacted]	12/21/2020
16	Amended & Restated Willdan Energy Solutions, Inc.	408006	[redacted]	12/21/2020

17	Amended & Restated Willdan Energy Solutions, Inc.	408007	[redacted]	12/21/2020
18	Amended & Restated Willdan Energy Solutions, Inc.	408008		12/21/2020
19	Amended & Restated Willdan Energy Solutions, Inc.	408009		12/21/2020
20	Amended & Restated Willdan Energy Solutions, Inc.	408010		12/21/2020
21	Amended & Restated Willdan Energy Solutions, Inc.	408011		12/21/2020
22	Amended & Restated Willdan Energy Solutions, Inc.	408012		12/21/2020
23	Amended & Restated Willdan Energy Solutions, Inc.	408013		12/21/2020
24	Amended & Restated Willdan Energy Solutions, Inc.	408014		12/21/2020
25	Amended & Restated Willdan Energy Solutions, Inc.	408015		12/21/2020
26	Amended & Restated Willdan Energy Solutions, Inc.	408016		12/21/2020
27	Amended & Restated Willdan Energy Solutions, Inc.	408017		12/21/2020
28	FSG Energy Efficiency, LLC	447101		3/10/2020
29	FSG Energy Efficiency, LLC	447102		3/10/2020
30	FSG Energy Efficiency, LLC	447103		3/10/2020
31	FSG Energy Efficiency, LLC	447101		7/27/2020

32	FSG Energy Efficiency, LLC	447102	[redacted]	7/27/2020
33	FSG Energy Efficiency, LLC	447103		7/27/2020
34	FSG Energy Efficiency, LLC	447101		7/30/2020
35	FSG Energy Efficiency, LLC	447102		7/30/2020
36	FSG Energy Efficiency, LLC	447103		7/30/2020
37	FSG Energy Efficiency, LLC	447102		10/23/2020
38	Sterling Analytics, LLC	429002		11/11/2020
39	Sterling Analytics, LLC	429005		11/11/2020
40	Sterling Analytics, LLC	429006		11/11/2020

41	Sterling Analytics, LLC	429007	[redacted]	11/11/2020
42	Sterling Analytics, LLC	429002	[redacted]	11/17/2020
43	Sterling Analytics, LLC	429005	[redacted]	11/17/2020
44	Sterling Analytics, LLC	429006	[redacted]	11/17/2020
45	Sterling Analytics, LLC	429007	[redacted]	11/17/2020
			Permanent Load Shifting	
			Demand Response	
46	Swell Energy Fund 2016 LLC	PRP-2016-DRES-006	[redacted]	12/18/2020
47	Stem Energy Southern California, LLC	402040	[redacted]	12/9/2020
48	Hybrid-Electric Building Technologies West LA 2	467025	[redacted]	12/9/2020

(1) Amended & Restated Solar Star California XXXVIII, LLC (Offer 490006)

Amended & Restated Solar Star California XXXVIII, LLC LCR Energy Savings Agreement is a 10.335 MW solar PV project located in the West LA Basin substation area. Solar Star California XXXVIII, LLC was originally signed as part of SCE's Local Capacity Requirements (LCR) solicitation executed on November 3, 2014, Amended & Restated Solar Star California XXXVIII, LLC LCR Energy Savings agreement was executed on December 27, 2017. SCE and Solar Star California XXXVIII, LLC executed a Second Amended & Restated Solar Star California XXXVIII, LLC executed on January 31, 2020. Seller executed their rights to amend and restate the Agreement [redacted] i) the Original Agreement, offer 490006 new Expected Capacity Savings is 3.982 MW (ii) Solar Star LCR LA 1, LLC is a separate Energy Savings Agreement, with Expected Capacity Savings of 1.142 MW (Offer No. 490011); (iii) Solar Star LCR LA 2, LLC is a separate Energy Savings Agreement, with an Expected Capacity Savings of 2.038 MW (Offer No. 490012); (iv) Solar Star LCR Split 1, LLC is a separate Energy Savings Agreement, with an Expected Capacity Savings of 1.974 MW (Offer No. 490013); and (v) Solar Star LCR Irvine, LLC is a separate Energy Savings Agreement with an Expected Capacity Savings of 1.199 MW (Offer No. 490014). SCE customers benefitted by receiving the needed MW deliveries which otherwise may not have been realized if [redacted]

(2) Willdan Energy Solutions, Incorporated (Offer 408002)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment ten (10) on June 18, 2020. The following areas were part of the amendment: [redacted]

[redacted] This is an administrative change that is a benefit to the customer as it provides a more streamlined method for reviewing these reports which saves time and labor costs.

(3) Willdan Energy Solutions, Incorporated (Offer 408002)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment eleven (11) on December 21,2020. The following areas were part of the amendment: [redacted] These changes are a benefit to the customer as they allowed the Seller, through COVID-19 conditions, the ability to bring capacity savings online by the deadline.

(4) Willdan Energy Solutions, Incorporated (Offer 408005)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment eleven (11) on December 21,2020. The following areas were part of the amendment: [redacted]

[redacted] These changes are a benefit to the customer as they allowed the Seller, through COVID-19 conditions, the ability to bring capacity savings online by the deadline.

(5) Willdan Energy Solutions, Incorporated (Offer 408008)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment ten (10) on June 18, 2020. The following areas were part of the amendment: [redacted] This is an administrative change that is a benefit to the customer as it provides a more streamlined method for reviewing these reports which saves time and labor costs.

(6) Willdan Energy Solutions, Incorporated (Offer 408008)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment eleven (11) on December 21, 2020. The following areas were part of the amendment: [redacted] These changes are a benefit to the customer as they allowed the Seller, through COVID-19 conditions, the ability to bring capacity savings online by the deadline.

(7) Willdan Energy Solutions, Incorporated (Offer 408011)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment ten (10) on April 8, 2020. The following areas were part of the amendment: [redacted] This is an administrative change that is a benefit to the customer as it provides a more streamlined method for reviewing these reports which saves time and labor costs.

(8) Willdan Energy Solutions, Incorporated (Offer 408011)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment eleven (11) on July 1, 2020. The following areas were part of the amendment: [redacted] To the customer's benefit, granting the extension of the Project Completion Deadline during a pandemic, allowed the Seller to bring needed capacity savings online.

(9) Willdan Energy Solutions, Incorporated (Offer 408014)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of

SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed amendment nine (9) on February 2, 2020. The following areas were part of the amendment: [redacted]. These changes were a benefit to the customers which allowed the Seller, during COVID-19 conditions, the ability to bring capacity savings online by the deadline date and provide ratepayer commensurate benefit.

(10) Willdan Energy Solutions, Incorporated (Offer 408017)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions Corporation executed amendment ten (10) on June 19, 2020. The following areas were part of the amendment: [redacted] This is an administrative change that is a benefit to the customer as it provides a more streamlined method for reviewing these reports which saves time and labor costs.

(11) Willdan Energy Solutions, Incorporated (Offers 408001)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(12) Willdan Energy Solutions, Incorporated (Offer 408002)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(13) Willdan Energy Solutions, Incorporated (Offer 408003)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(14) Willdan Energy Solutions, Incorporated (Offer 408004)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]. There is a benefit to the customer through ongoing capacity savings.

(15) Willdan Energy Solutions, Incorporated (Offer 408005)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(16) Willdan Energy Solutions, Incorporated (Offer 408006)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(17) Willdan Energy Solutions, Incorporated (Offer 408007)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted] There is a benefit to the customer through ongoing capacity savings..

(18) Willdan Energy Solutions, Incorporated (Offer 408008)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(19) Willdan Energy Solutions, Incorporated (Offer 408009)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted]. There is a benefit to the customer through ongoing capacity savings.

(20) Willdan Energy Solutions, Incorporated (Offer 408010)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Johanna/Santiago area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(21) Willdan Energy Solutions, Incorporated (Offer 408011)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted] There is a benefit to the customer through ongoing capacity savings.

(22) <u>Willdan Energy Solutions, Incorporated (Offer 408012)</u>

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Johanna/Santiago area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(23) <u>Willdan Energy Solutions, Incorporated (Offer 408013)</u>

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Johanna/Santiago area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted] There is a benefit to the customer through ongoing capacity savings.

(24) Willdan Energy Solutions, Incorporated (Offer 408014)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Goleta area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted] There is a benefit to the customer through ongoing capacity savings.

(25) Willdan Energy Solutions, Incorporated (Offer 408015)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted] There is a benefit to the customer through ongoing capacity savings.

(26) Willdan Energy Solutions, Incorporated (Offer 408016)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the West LA Basin area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]. There is a benefit to the customer through ongoing capacity savings.

(27) Willdan Energy Solutions, Incorporated (Offer 408017)

Amended and Restated Willdan Energy Solutions, Incorporated (formerly Onsite Energy, Corporation) Energy Efficiency Agreement is 1 MW of Energy Efficiency projects located in the Moorpark area. Willdan Energy Solutions, Incorporated was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and Willdan Energy Solutions, Corporation executed this Omnibus amendment on December 21, 2020. The following areas were part of the amendment: [redacted]

[redacted] There is a benefit to the customer through ongoing capacity savings.

(28) FSG Energy Efficiency, LLC (Offer 447101)

FSG Energy Efficiency, LLC is a 7.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Letter Agreement on March 10, 2020, and [redacted] SCE's customers are impartial to this change as it is administrative in nature.

(29) FSG Energy Efficiency, LLC (Offer 447102)

FSG Energy Efficiency, LLC is a 12.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Letter Agreement on March 10, 2020, and [redacted] SCE's customers are impartial to this change as it is administrative in nature.

(30) FSG Energy Efficiency, LLC (Offer 447103)

FSG Energy Efficiency, LLC is a 4.99 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Letter Agreement on March 10, 2020, and [redacted] SCE's customers are impartial to this change as it is administrative in nature.

(31) FSG Energy Efficiency, LLC (Offer 447101)

FSG Energy Efficiency, LLC is a 7.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Settlement and Mutual Release Agreement on July 27, 2020, and [redacted] SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(32) FSG Energy Efficiency, LLC (Offer 447102)

FSG Energy Efficiency, LLC is a 12.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Settlement and Mutual Release Agreement on July 27, 2020, and [redacted] SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(33) FSG Energy Efficiency, LLC (Offer 447103)

FSG Energy Efficiency, LLC is a 4.99 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed a Settlement and Mutual Release Agreement on July 27, 2020, and [redacted]

[redacted] SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(34) FSG Energy Efficiency, LLC (Offer 447101)

FSG Energy Efficiency, LLC is a 7.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed amendment ten (10) on July 30, 2020. The following areas were part of the amendment: [redacted] SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(35) FSG Energy Efficiency, LLC (Offer 447102)

FSG Energy Efficiency, LLC is a 12.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed amendment nine (9) on July 30, 2020. The following areas were part of the amendment: [redacted]

[redacted]

SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(36) FSG Energy Efficiency, LLC (Offer 447103)

FSG Energy Efficiency, LLC is a 4.99 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed amendment nine (9) on July 30, 2020. The following areas were part of the amendment: [redacted]

SCE's customers benefit from this Settlement Agreement because it settled the dispute between the Parties and reduced future payments to Seller by approximately [redacted]

(37) FSG Energy Efficiency, LLC (Offer 447102)

FSG Energy Efficiency, LLC is a 12.49 MW Energy Efficiency Agreement located in the West LA Basin substation area. FSG Energy Efficiency, LLC was originally signed as part of SCE's LCR Solicitation executed on November 3, 2014. SCE and FSG Energy Efficiency, LLC executed amendment ten (10) on October 23, 2020. [redacted]

[redacted] SCE's customers benefit from this amendment because it allowed the project to complete and deliver capacity savings by the deadline despite COVID-19 Force Majeure impacts.

(38) Sterling Analytics, LLC (Offer 429002)

Sterling Analytics, LLC is a 2.36 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed a Settlement and Mutual Release Agreement on November 11, 2020, and [redacted] SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(39) Sterling Analytics, LLC (Offer 429005)

Sterling Analytics, LLC is a 3.05 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed a Settlement and Mutual Release Agreement on November 11, 2020, and [redacted]

[redacted]

SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(40) Sterling Analytics, LLC (Offer 429006)

Sterling Analytics, LLC is a 3.05 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed a Settlement and Mutual Release Agreement on November 11, 2020, and [redacted]

SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(41) Sterling Analytics, LLC (Offer 429007)

Sterling Analytics, LLC is a 2.73 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed a Settlement and Mutual Release Agreement on November 11, 2020, and [redacted]

[redacted]

SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(42) Sterling Analytics, LLC (Offer 429002)

Sterling Analytics, LLC is a 2.36 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed amendment eight (8) on November 17, 2020. The following areas were part of the agreement: [redacted] SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(43) Sterling Analytics, LLC (Offer 429005)

Sterling Analytics, LLC is a 3.05 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed amendment eight (8) on November 17, 2020. The following areas were part of the agreement: [redacted] SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(44) Sterling Analytics, LLC (Offer 429006)

Sterling Analytics, LLC is a 3.05 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed amendment eight (8) on November 17, 2020. The following areas were part of the agreement: [redacted]

[redacted] SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(45) Sterling Analytics, LLC (Offer 429007)

Sterling Analytics, LLC is a 2.73 MW Energy Efficiency Agreement located in the West LA Basin substation area. Sterling Analytics, LLC was originally signed as part of SCE's LCR solicitation executed on November 3, 2014. SCE and Sterling Analytics, LLC executed amendment eight (8) on November 17, 2020. The following areas were part of the agreement: [redacted] SCE's customers benefit because it settled the dispute and avoided arbitration and litigation costs.

(46) Swell Energy Fund 2016 LLC (PRP-2016-DRES-006)

The Swell PRP 5MW agreement was originally executed on September 8, 2016 as part of SCE's Second Preferred Resources Pilot RFO. In April 2020, Swell notified SCE about COVID-19 impacts to their PRP and ACES (Aliso Canyon Energy Storage) Demand Response Energy Storage agreements. Swell identified COVID-19 impacts and offered proposals to address the impacts.

[redacted]

[redacted] SCE's customers benefit from this amendment as it provides a cost reduction of [redacted]

(47) Stem Energy Southern California (Offer 402040)

The Stem agreement is Demand Response Energy Storage (DRES) in the West LA Basin area which was originally executed on November 4, 2014 as part of SCE's Local Capacity Requirements solicitation. Stem submitted COVID-19 Force Majeure notices to SCE in April and May 2020. The agreement includes Force Majeure provisions which either the buyer or seller may invoke. These Force Majeure notices did not identify specific impacts nor request specific remedies since they were unknown at the time. Even though SCE did not consider these actual Force Majeure notices, SCE communicated our willingness to work with vendors and suppliers to consider specific requests for relief since COVID-19 presented unprecedented challenges and impacts.

[redacted]

[redacted] These adjustments were documented in a Temporary Reduction of Contract Capacity Letter Agreement dated December 9, 2020. SCE's customers are indifferent to this change as it is administrative in nature.

(48) Hybrid Electric Building Technologies West LA 2 (467025)

The Hybrid-Electric Building Technologies West LA 2 agreement is Demand Response Energy Storage (DRES) originally executed on November 4, 2014 as part of SCE's Local Capacity Requirements solicitation.

Hybrid submitted COVID-19 Force Majeure notices to SCE in April and March 2020. The agreements include Force Majeure provisions which either the buyer or seller may invoke. These Force Majeure notices did not identify specific impacts nor request specific remedies since they were unknown at the time. Even though SCE did not consider these actual Force Majeure notices, SCE communicated our willingness to work with vendors and suppliers to consider specific requests for relief since COVID-19 presented unprecedented challenges and impacts.

[redacted]

[redacted]

[redacted] SCE's customers are indifferent to this change as it is administrative in nature.

e) Contract Assignment Administration

BTM contracts may only be assigned with the written consent of the parties, which may not be unreasonably withheld. There are many reasons why BTM contract counterparties seek to assign their contracts. For example, the counterparty might want to sell or transfer the project to a new entity, assign the contract to a lender as security for a loan, or a change of control of the project. Table VII-42 below lists the three (3) contract assignments to which SCE consented during the Record Period. SCE and Sellers have executed three (3) Renewable Distributed Generation Consents to Assignment of Membership Interest for existing contracts.

Table VII-42
SCE BTM Contract Consents
January 1, 2020 through December 31, 2020

Contract ID	**Project**	**Type of Assignment or Consents**	**Date Signed**
490011	Solar Star LCR LA 1, LLC	Consent to Assignment of Membership Interest	3/23/2020
490012	Solar Star LCR LA 2, LLC	Consent to Assignment of Membership Interest	3/23/2020
490013	Solar Star LCR Split 1, LLC	Consent to Assignment of Membership Interest	3/23/2020

f) Contract Capacity Verifications

SCE's capacity verification activities for BTM projects are designed to ensure that SCE's customers can reasonably expect to receive appropriate quantities of energy and capacity savings in full compliance with the associated contracts. During the Record Period, there were five (5) Renewable Distributed Generation, eight (8) Energy Efficiency, and two (2) Permanent Load Shift projects that underwent capacity verification activities. Table VII-43 lists the BTM unit(s) inspected and the capacity sizing result(s) as of the end of the Record Period

Table VII-43
Contract Capacity Verifications
January 1, 2020 through December 31, 2020

Contract ID	Project	Contract Type	Date of Inspection Report	Capacity (MW)
490006	Solar Star California XXXVIII, LLC	Renewable Distributed Generation	1/21/2020	1.154
490011	Solar Star LCR LA 1, LLC	Renewable Distributed Generation	7/27/2020	1.232
490012	Solar Star LCR LA 2, LLC	Renewable Distributed Generation	7/28/2020	2.239
490013	Solar Star LCR Split 1, LLC	Renewable Distributed Generation	7/17/2020	2.081
490014	Solar Star LCR Irvine, LLC	Renewable Distributed Generation	1/22/2020	1.411
408002	Willdan Energy Solutions	Energy Efficiency	12/31/2020	0.87 (i)
408004	Willdan Energy Solutions	Energy Efficiency	12/28/2020	1 (i)
408008	Willdan Energy Solutions	Energy Efficiency	12/31/2020	0.92 (i)
408009	Willdan Energy Solutions	Energy Efficiency	4/28/2020	0.98
408011	Willdan Energy Solutions	Energy Efficiency	9/24/2020	0.97
408014	Willdan Energy Solutions	Energy Efficiency	3/17/2020	0.71
408017	Willdan Energy Solutions	Energy Efficiency	12/28/2020	1 (i)
447102	FSG Energy Efficiency, LLC	Energy Efficiency	12/15/2020	6.38 (i)
431151	Ice Bear SPV #1, LLC	Permanent Load Shifting	12/18/2020	1.28
431154	Ice Bear SPV #1, LLC	Permanent Load Shifting	11/23/2020	1.28

(i) Submitted Primary Post-Installation Report is in the SCE final review and approval of savings stage.

(i) On 12/30/2020, Seller submitted Primary Post-Installation Report for SCE review and approval of savings. SCE review and approval of savings pending.

a. <u>Renewable Distributed Generation:</u>

Renewable DG capacity verifications are generally a one-time event performed prior to the contract becoming operational. The activity consists of a site visit by an independent third-party evaluator who is to document the equipment that was installed, collect measurements as outlined in contract to determine the minimal acceptable system performance and ensure that the outputs will be higher than that minimal acceptable system performance, determine if it is interconnected as a non-export system, identify the meter unique identification number(s), and to verify that the meter is collecting data from the project installation only. The verification is intended to determine: (i) whether the generating facility has been completed and installed in accordance with the contract and is operating as planned and designed; and (ii) the amount of capacity installed at the site as a result of the generating facility. During the Record Period, there were five (5) Renewable Distributed Generation BTM solar generation facilities that underwent capacity verifications. The projects passed the verification process with a site inspection for determination of the installed equipment's capacity savings.

b. Energy Efficiency:

Energy Efficiency capacity verifications are generally performed prior to the contract becoming operational. The activity consists of a site visit by an independent third-party evaluator who is to document the existing equipment in order to establish the pre-Project conditions necessary and as outlined in the contract for determining the energy and capacity savings expected from installing the EE measures at one or more customer sites. The verification is intended to determine: (i) if the project has been completed and the measures have been installed in accordance with the Project description and the Measuring and Verification Plan; (ii) the measures are operating as planned and designed; (iii) the measures will reduce the capacity at the site(s) in an amount equal to or exceeding the expected capacity savings, and (iii) the measures will reduce the energy use at the site(s) in an amount equal to or exceeding the Minimum Summer On-Peak Energy Savings, Minimum Summer Off-Peak Energy Savings, and Minimum Winter On-Peak Energy Savings.

During the Record Period, there were eight (8) Energy Efficiency projects that underwent capacity verifications. The projects passed the verification process with a site inspection for determination of the installed equipment's capacity savings.

c. Permanent Load Shift (PLS):

PLS energy and capacity reduction verifications are generally performed prior to the contract becoming operational. The activity consists of a site visit by an independent third-party evaluator who is to document the existing equipment in order to establish the pre-project conditions necessary and as outlined in the contract for determining the energy and capacity savings expected from installing the PLS measures at one or more customer sites. The independent third-party evaluator shall use the Pre-Installation Description for purposes of establishing the Measurement Baseline and each

Individual Measurement Baseline and corresponding Rated Capacity and energy savings of each Thermal Energy Resource (TES). Twenty percent (20%) of the sites are subject to the Pre-Installation Equipment Inspection and the sites shall be selected by SCE, or if not enough Sites are selected by SCE, then by the independent third party evaluator.

The verification is intended to determine: (i) the project has been completed and installed in accordance with this Exhibit B; (ii) all Measures in the project are operating as planned and designed; (iii) the project reduced the capacity use at the Sites in an amount not less than the Expected Capacity Savings as determined in accordance with the agreement; and (iv) the project will result in a reduction in the energy use at the site in an amount not less than the expected summer on-peak energy savings, expected summer off-peak energy savings, and expected winter on-peak energy savings as determined in accordance with the agreement. For Sites that were not subject to a Primary Post-Installation Inspection or Post-Installation Inspection, the independent third-party evaluator shall deem that the forgoing criteria were met.

During the Record Period, there were two (2) PLS projects that underwent capacity verifications. The projects passed the verification process with a site inspection for determination of the installed equipment's corresponding Rated Capacity and energy savings of each Thermal Energy Resource (TES).

g) Measurement of Energy Deliveries

(1) Energy Efficiency:

SCE uses energy and capacity reductions to calculate payments owed to BTM Energy Efficiency projects. In order to determine the payment for energy savings delivered by the party and overall energy savings delivery performance, the project must have (i) been completed and the measures have been installed in accordance with the project description and the M&V protocol; (ii) the measures are operating as planned and designed; (iii) the measures will reduce the capacity at the site(s) in the amount equal to or exceeding the minimum capacity savings; and (iv) the measures will reduce the capacity at the sites in an amount equal to or exceeding the minimum summer on-peak energy savings, minimum summer off-peak energy savings and minimum winter on-peak energy savings.

(2) Renewable Distributed Generation:

SCE uses meter data to calculate payments owed to BTM Renewable Distributed Generation projects. SCE requires the installation of revenue grade interval meters that have been tested according to all applicable ANSI C-12 testing protocols and certified by an independent testing body, along with being listed on the Go Solar California website as an approved meter. The meter data is read, retrieved, validated, and sent to SCE by an independent third-party Performance Data Provider (PDP) on a monthly basis and is used to determine the payment for energy savings delivered by the party and overall energy savings delivery performance.

(3) Permanent Load Shift:

SCE uses grid reliable energy and capacity reduction savings to calculate payments owed to BTM PLS projects. In order to determine the payment for energy savings delivered by the party and overall energy savings delivery performance, the project must have (i) the project has been completed and installed in accordance with the terms of the agreement; (ii) all measures in the project are operating as planned and designed; (iii) the project reduced the capacity use at the Site in an amount not less than the Expected Capacity Savings as determined in accordance with Exhibit B of the agreement; and (iv) the project will result in a reduction in the energy use at the Site in an amount not less than the expected summer on-peak energy savings, expected summer off-peak energy savings, and expected winter on peak energy savings all as determined in accordance with Exhibit B of the agreement.

(4) Demand Response:

SCE uses meter data from SCE meters to determine demand response performance and to calculate payments to BTM demand response aggregators. After SCE has read, retrieved, and validated meter data, it is uploaded into the APX system and demand response aggregators are able to retrieve the data to determine performance and prepared invoices which are submitted to SCE for payment. For the four Hybrid Electric Building Technologies agreements which utilize the CAISO alternative baseline, SCE also uses Hybrid sub-meter data in the settlement process.

h) Dispute Resolution and Litigation

Details on BTM Project dispute resolutions and litigation activities during the Record Period are provided below:

(1) Sterling Analytics, LLC (ID 429001, 429002, 429003, 429004, 429005, 429006, 429007)

The Sterling Analytics, LLC contracts are for 16.7 MW of non-residential Energy Efficiency lighting projects, located in the West LA/Santiago-Johanna regions, originally executed as part of CPUC`s LCR decision D-13-02-015 in 2013. [redacted]

(2) FSG Energy Efficiency, LLC (ID 447100, 447101, 447102, 447103)

The FSG Energy Efficiency, LLC (Seller) contracts are for 30 MW of non-residential Energy Efficiency projects, located in the West LA/Santiago-Johanna, originally executed as part of CPUC`s LCR decision D-13-02-015 in 2013. [redacted]

[redacted]

(3) Willdan Energy Solutions, Inc (ID 408001, 408002, 408003, 408004, 408005, 408006, 408007, 408008, 408009, 408010, 408011, 408012, 408013, 408014, 408015, 408016, 408017)

The Willdan Energy Solutions, Inc. contracts are for 17 MW of non-residential Energy Efficiency projects, located in the West LA/Santiago-Johanna regions. Originally executed as part of the CPUC's LCR decision D-13-02-015 in 2013. [redacted]

i) Contract Terminations

During the Record Period, a total of 16.856 MW of BTM contracts were terminated due to not meeting the project completion date by the project completion deadline. This included one (1) Renewable Distributed Generation, and one (1) Energy Efficiency contract from SCE's 2013 LCR solicitation. These agreements and their associated capacity losses are shown below in Table VII-44.

Table VII-44
BTM Contracts that Terminated
January 1, 2020 Through December 31, 2020

Contract ID	Project Name	Capacity (MW)	Contract Type	Termination Date	Note
490003	Solar Star California XXXVI, LLC	11.866	Renewable Distributed Generation	2/4/2020	[redacted]
447103	FSG Energy Efficiency, LLC	4.99	Energy Efficiency	10/29/2020	

j) Contracts that Achieved Commercial Operation

During the Record Period, five (5) renewable distributed generation, one (1) demand response, one (1) permanent load shift, and eight (8) energy efficiency contracts achieved commercial operation. These agreements are shown in Table VII-45 below.

Table VII-45
BTM Contracts that Achieved Commercial Operation
January 1, 2020 Through December 31, 2020

Contract ID	Project Name	Capacity (MW)	Contract Type	Commercial Online Date
490006	Solar Star California XXXVIII, LLC	1.15405	Renewable Distributed Generation	2/2/2020
490011	Solar Star LCR LA 1, LLC	1.142	Renewable Distributed Generation	9/4/2020
490012	Solar Star LCR LA 2, LLC	2.038	Renewable Distributed Generation	8/6/2020
490013	Solar Star LCR Split 1, LLC	1.974	Renewable Distributed Generation	7/27/2020
490014	Solar Star LCR Irvine, LLC	1.199	Renewable Distributed Generation	1/31/2020
408002	Willdan Energy Solutions, Inc.	0.86	Energy Efficiency	12/31/2020
408004	Willdan Energy Solutions, Inc.	1	Energy Efficiency	12/28/2020
408008	Willdan Energy Solutions, Inc.	0.92	Energy Efficiency	12/31/2020
408009	Willdan Energy Solutions, Inc.	0.98	Energy Efficiency	4/28/2020
408011	Willdan Energy Solutions, Inc.	0.98	Energy Efficiency	9/24/2020
408014	Willdan Energy Solutions, Inc.	0.71	Energy Efficiency	3/17/2020
408017	Willdan Energy Solutions, Inc.	1	Energy Efficiency	12/18/2020
447102	FSG Energy Efficiency, LLC	6.38 (i)	Energy Efficiency	12/30/2020
431151	Ice Bear SPV #1, LLC	1.28	Permanent Load Shifting	3/20/2020
467025	Hybrid Electric Building Technologies West LA 2, LLC	15	Demand Response	3/1/2020

(i) Seller submitted Primary Post-Installation Report for SCE review and approval of savings. SCE review and approval of savings pending.

k) <u>Other Contract Activities</u>

During the record period two (2) Renewable Distributed Generation offers 490004 and 490010, received their 1st Notice(s) of Event of Deficient Energy Savings Delivery and Seller had paid the applicable Product Replacement Damage Amounts of [redacted] and [redacted] respectively, and three (3) Renewable Distributed Generation contracts (490011, 490012, and 490013) had paid Daily Delayed Liquidated Damages of [redacted] and [redacted] respectively to extend their project completion deadlines. The agreements mentioned may be found in Table VII-46.

Table VII-46
Other Activities
January 1, 2020 through December 31, 2020

Project	Contract ID	Description	MW
Amended & Restated Solar Star California XXXVII, LLC	490004	Issued 1st Notice(s) of Event of Deficient Energy Savings Delivery; for being below the "Seller's Energy Savings Delivery Obligation". Seller paid the Product Replacement Damage Amount as outlined in the agreement	2.98
LA Basin Solar III, LLC	490010	Issued 1st Notice(s) of Event of Deficient Energy Savings Delivery; for being below the "Seller's Energy Savings Delivery Obligation". Seller paid the Product Replacement Damage Amount as outlined in the agreement	1.134
Solar Star LCR LA 1, LLC	490011	Paid Daily Delayed Liquidated Damages to extend their project completion deadline from 2/2/2020 to 9/4/2020	1.142
Solar Star LCR LA 2, LLC	490012	Paid Daily Delayed Liquidated Damages to extend their project completion deadline from 2/2/2020 to 8/6/2020	2.038
Solar Star LCR Split 1, LLC	490013	Paid Daily Delayed Liquidated Damages to extend their project completion deadline from 2/2/2020 to 7/27/2020	1.974

l) BTM Contract Payment Process

The sections below discuss the administrative procedures, guidelines and processes regarding the monitoring, validation, and calculations of the various BTM contract settlement provisions. Appendix VII-O lists the summary of payments during the Record Period.

(1) Energy Efficiency:

SCE receives the capacity savings and pays the Energy Efficiency projects based upon a Payment Adjustment Factor – a percentage used to calculate the Adjusted Contract Price, calculated from the energy and capacity reductions as stated in the most recent Primary Post-Installation Inspection Report or Post-Installation Inspection Report as described in the agreement.

BTM Energy Efficiency contracts are (i) paid annually for the capacity savings delivered based on the most recent Primary Post-Installation Inspection Report or Post-Installation Inspection Report, and (ii) determined independent of any previous or future Adjusted Contract Price calculation.

(2) Renewable Distributed Generation (DG):

SCE receives the quantity of energy savings and pays the Renewable DG projects based upon metered amounts per the contract settlement provisions. BTM Renewable DG contracts are paid every three months for the energy savings delivered by the generator based on time of delivery and the contracted energy savings price. During the Record Period, SCE managed active Renewable DG contracts which were paid using Time of Delivery Allocation Factors (TOD Factors) in the energy savings payment calculations. The TOD Factors for the delivery period are multiplied by the product of metered energy for that delivery period and the energy price.

Other payment impacts to the SCE's Renewable DG contracts include: (i) payment caps on 15 minute and annual kWh deliveries and (ii) provisions that require a seller to meet certain energy savings delivery obligations. SCE and the seller set expected annual energy savings targets for the specific projects. These annual saving targets function as the basis for determining whether, for a 24-month period immediately preceding the end of each term year, the projects meet their energy savings delivery obligations. If a project does not meet its energy savings delivery requirements after supplementing their production kWh with confirmed Lost Output, the project may be subject to liquidated damages known as a Product Replacement Damage Amount. During the record period there were two (2) offers (490004 & 490010) that incurred such penalties.

(3) Permanent Load Shift:

SCE receives the capacity reduction savings and pays the Permanent Load Shift projects based upon the Project Completion Date until the end of the Term. SCE shall make quarterly Capacity Payments to Seller in arrears and in accordance with the provisions of the contract so long as (i) no Event of Default with respect to the Seller has occurred and is continuing and (ii) no Early Termination Date has occurred or been designated as a result of an Event of Default with respect to the Seller.

The quarterly "Capacity Payment" shall equal the sum of the Expected Capacity Savings for each given month of the Quarter multiplied by the Contract Price less any adjustments for Capacity Shortfall for each given month.

For any month in which a TES Compressor failed to shut off in accordance with the TES Resource Schedule, the "Capacity Shortfall" shall equal the sum of the following for each such TES Compressor; (i) the Individual Measurement Baseline for that TES

Compressor multiplied by (ii) the ratio of the period of time that month that the TES Compressor failed to shut off divided by the period of time the TES Compressor was available to be shut off.

(4) Demand Response:

On a monthly basis, the Demand Response sellers and SCE use meter data to determine demand response performance and to calculate payments, zero payments or penalties to BTM demand response aggregators. After SCE has read, retrieved, and validated meter data, it is uploaded into the APX cloud-based system where demand response aggregators are able to retrieve the data to determine performance and prepared invoices which are submitted to SCE. For the four Hybrid Electric Building Technologies agreements which utilize the CAISO alternative baseline, SCE also uses Hybrid sub-meter data in the settlement process.

m) BTM Contract Collateral

The administration and tracking of BTM contract collateral is between two groups at SCE. Officially, administration of collateral activity is assigned to SCE's Credit Risk group and Risk Operations & Collateral Management group. SCE's Risk Operations & Collateral Management group directly handles the routine collateral posting transactions with the counterparty and informs the contract managers of any Delivery Date Security amount posted and due. In order to provide continuity for counterparties external to the company, contract managers within Customer Programs & Services (CP&S) serve as the primary contact for collateral issues. Delivery Date security and Performance Assurance is typically posted in the form of cash or letter of credit. Appendix VII-N lists the significant activities that took place during the Record Period related to CP&S project development security.

2. Conventional and Natural Gas

Conventional contracts are typically executed through RFOs or through a bilateral negotiation procurement process. Some of these contracts are executed under industry-standard master agreements with modifications agreed upon through negotiations. These form agreements include the Western Systems Power Pool (WSPP), the Edison Electric Institute (EEI), the North American Energy Standards Board (NAESB), the International Swaps and Derivatives Association (ISDA), the Transmission Resale Enabling Agreement (TREA), and FERC-approved transmission tariff agreements.

Some agreements offer an “annex to the agreement” effectuating the right to contract for or trade another product or function under the same agreement. ISDA agreements offer a gas or power annex that enables the trading of both physical and financial transactions under a single agreement. Similarly, EEI offers a gas annex to allow for gas and power trades under the same master EEI agreement. A description of these are included below:

- The WSPP, EEI, and power annex to the ISDA agreements are used for physical electricity transactions including tolling agreements;
- The NAESB, gas annex to the EEI, and gas annex to the ISDA agreements are used for physical natural gas transactions;
- The ISDA agreements are used for financial electricity and natural gas transactions; and,
- The TREA is used for transmission transactions.

SCE’s Energy Contracts Management group manages the administration of all enabling agreements required for the purchase and sale of electric and natural gas related products, including physical and financial gas transactions. Transactions for physical gas take place under a NAESB agreement, a gas annex to the ISDA agreement, or a gas annex to the EEI agreement. SCE’s financial transactions during the Record Period were executed via a broker and then cleared through an exchange with one of the counterparties under an active enabling agreement with SCE. During the Record Period, SCE was enabled to transact with many counterparties to facilitate the purchase and sale of electricity, capacity, physical natural gas, and transmission; and with brokers, clearing firms and trading platforms, for financial gas transactions. A list of these agreements is included in Appendix VII-B.

Each agreement specifies terms and conditions related to performance, events of default, payments, confidentiality requirements, dispute resolution, and other general contractual provisions. SCE may use the agreements in their standard form or agree to special provisions or amended forms of the agreements.

These agreements and any transactions done under them, including PPAs and RPAs, are submitted for Commission review in SCE’s QCR, via Advice Letter filing, or in separate Advice Letters or Applications. Once the agreements are in place and other required measures are taken by the parties (*i.e.*, providing collateral, development security, etc.), SCE's Credit Risk group adds the counterparty to SCE's "OK-to-trade" list, as applicable. SCE's traders may then execute transactions in compliance with the requirements of SCE's Financial Risk Management Committee and SCE's Commission-approved AB 57 BPP or LTPP. Individual transactions underlying each enabling agreement and any amendments are reported in SCE's QCR.[140]

a) Contract Administration

During the Record Period, SCE administered bilateral transactions, contracts, and enabling agreements related to electric and natural gas purchases and sales, demand response, transmission and emissions offsets. SCE administered these contracts prudently, and according to their terms and conditions.[141]

b) Summary of Contract Activity

The conventional contracts administered by SCE during the Record Period include: tolling confirmations, RA confirmations, transmission contracts, gas transportation contracts, gas storage contracts, energy storage contracts, demand response resource purchase agreements, and power purchase agreements. The list of transactions active and/or in SCE's energy contracts portfolio during the Record Period are sorted by types and listed in Appendix VII-A. All transactions in Appendix VII-A were either approved through the QCR in conformance with the guidelines in SCE's AB 57 BPP or through separate Advice Letter or Application filings with the CPUC.

c) Conventional Contract Delivery

Table VII-47 shows the conventional projects that came on-line or started delivering to SCE under a new contract during the Record Period.

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[140] Advice letter filings for Q1, Q2, Q3, and Q4 of 2020 were submitted as Advice Letters 4203-E, 4263-E, 4323-E, and 4405-E, respectively.

[141] Confidential Appendix VII-H includes a summary of bilateral power payments during the Record Period, which includes transmission, RA, and toll activity payments.

Table VII-47
Conventional Projects that Began Operations
January 1, 2020 Through December 31, 2020

	ID	Project	Date	Capacity (MW)
1	10002	AES Huntington Beach Energy, LLC	5/1/2020	649.0
2	10001	AES Alamitos Energy, LLC	6/1/2020	650.0
3	10051	Stanton Energy Reliability Center, LLC	7/1/2020	98.0
4	10109	Blythe Energy Inc.	8/1/2020	490.0
5	12008	Stanton Energy Reliability Center, LLC	11/1/2020	1.3

d) Contract Development

All new contracts executed during the Record Period were filed through either the QCR in conformance with the guidelines in SCE's AB 57 BPP or through the Advice Letter or Application processes, as noted. These are included here in Table VII-48 and in Appendix VII-A as information only related to contract activity during the Record Period.

Table VII-48
New Conventional and Natural Gas Contracts
January 1, 2020 Through December 31, 2020

	ID	Contract Counterparty	Capacity (MW)	Type of Agreement	Date Executed	CPUC Resolution or Decision/SCE Advice Letter/Application
1	11034-1032	Calpine Energy Services LP	182.0 - 290.0	EEI - RA Sale	1/15/2020	4203-E
2	11034-1033	Calpine Energy Services LP	24.0 - 73.0	EEI - RA Sale	1/15/2020	4203-E
3	11034-1031	Calpine Energy Services LP	100.0 - 250.0	EEI - RA Sale	1/15/2020	4203-E
4	11088-1019	Exelon Generation Company, LLC	50.0 - 75.0	EEI - RA Sale	1/16/2020	4203-E
5	11181-1012	Shell Energy North America (US), L.P.	30.0 - 36.0	EEI - RA Sale	2/14/2020	4203-E
6	11139-1001	NextEra Energy Power Marketing, LLC	6.2 - 25.4	EEI - RA Purchase	2/28/2020	4184-E/ Draft Resolution E-5126
7	11034-1034	Calpine Energy Services LP	57.1 - 250.0	EEI - RA Sale	2/28/2020	4203-E
8	11262-1004	The Energy Authority, Inc.	36.0	EEI - Import Allocation Rights Sale	3/12/2020	4203-E
9	11258-1006	Direct Energy Business Marketing, LLC	5.0 - 10.0	EEI - RA Sale	3/13/2020	4203-E
10	11034-1035	Calpine Energy Services LP	105.0	EEI - RA Sale	3/16/2020	4203-E
11	11272-1001	AES Alamitos, L.L.C.	1165.8	EEI - RA Purchase	3/23/2020	E-5098
12	10119	OhmConnect California, LLC	4.8 - 8.0	DRAM Resource Purchase Agreement	3/27/2020	4191-E
13	10120	OhmConnect California, LLC	3.3 - 5.5	DRAM Resource Purchase Agreement	3/27/2020	4191-E
14	10121	Voltus, Inc.	1.0 - 2.0	DRAM Resource Purchase Agreement	3/27/2020	4191-E
15	10117	Enerwise Global Technologies, LLC	3.4 - 4.0	DRAM Resource Purchase Agreement	3/27/2020	4191-E
16	10118	Leapfrog Power, Inc.	20.0	DRAM Resource Purchase Agreement	3/27/2020	4191-E
17	11034-1036	Calpine Energy Services LP	1420.0 - 1770.0	EEI - RA Purchase	3/30/2020	4203-E
18	11073-1016	Dynegy Moss Landing LLC	460.0 - 970.0	EEI - RA Purchase	3/31/2020	E-5097
19	12040	Blythe Energy Storage III, LLC	115.0	RA Purchase Agreement	4/9/2020	E-5101
20	12039	Blythe Energy Storage II, LLC	115.0	RA Purchase Agreement	4/9/2020	E-5101
21	12038	McCoy Energy Storage, LLC	230.0	RA Purchase Agreement	4/9/2020	E-5101
22	11153-1023	Pacific Gas & Electric Company	144.0	EEI - RA Sale	4/15/2020	4263-E
23	11094-1031	GenOn Energy Management, LLC	1491.0	EEI - RA Purchase	4/17/2020	E-5099
24	12037	Gateway Energy Storage, LLC	100.0	RA Purchase Agreement	4/22/2020	E-5101
25	12035	SP Garland Solar Storage, LLC	88.0	RA Purchase Agreement	4/22/2020	E-5101
26	12034	SP Tranquillity Solar Storage, LLC	72.0	RA Purchase Agreement	4/22/2020	E-5101
27	12036	Edwards Sanborn Storage I, LLC	50.0	RA Purchase Agreement	4/23/2020	E-5101
28	11258-1007	Direct Energy Business Marketing, LLC	40.0	EEI - RA Sale	4/24/2020	4263-E
29	11253-1011	Monterey Bay Community Power Authority	20.0 - 55.0	EEI - RA Sale	5/12/2020	4263-E
30	11253-1012	Monterey Bay Community Power Authority	54.0	EEI - Import Allocation Rights Sale	6/5/2020	4263-E
31	11034-1037	Calpine Energy Services LP	21.0 - 41.0	EEI - RA Sale	6/10/2020	4263-E
32	11181-1013	Shell Energy North America (US), L.P.	50.0	EEI - Import Allocation Rights Sale	6/12/2020	4263-E

33	11181-1014	Shell Energy North America (US), L.P.	50.0	EEI - Import Allocation Rights Sale	6/12/2020	4263-E
34	11257-1012	City of San Jose, a California municipality	74.0	EEI - Import Allocation Rights Sale	6/15/2020	4263-E
35	11265-1003	San Diego Gas & Electric Company	5.0	EEI - RA Sale	6/17/2020	4263-E
36	11265-1004	San Diego Gas & Electric Company	5.0	EEI - RA Purchase	6/17/2020	4263-E
37	11256-1008	East Bay Community Energy Authority	71.0	EEI - RA Sale	6/24/2020	4263-E
38	11259-1006	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	13.0	EEI - RA Purchase	7/1/2020	4323-E
39	11259-1005	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	13.0	EEI - RA Sale	7/1/2020	4323-E
40	11258-1008	Direct Energy Business Marketing, LLC	30.0	EEI - RA Sale	7/2/2020	4323-E
41	11181-1015	Shell Energy North America (US), L.P.	290.0	WSPP - Firm Sale	7/7/2020	4323-E
42	11181-1016	Shell Energy North America (US), L.P.	290.0	WSPP - Firm Sale	7/7/2020	4323-E
43	13077-1004	Shell Energy North America (US), L.P.	248.0	Transmission - Resale	7/7/2020	4323-E
44	13077-1003	Shell Energy North America (US), L.P.	248.0	Transmission - Resale	7/7/2020	4323-E
45	10122	Enerwise Global Technologies, LLC	6.4 - 8.0	DRAM Resource Purchase Agreement	7/14/2020	4262-E
46	10123	Leapfrog Power, Inc.	38.0 - 45.0	DRAM Resource Purchase Agreement	7/14/2020	4262-E
47	10124	OhmConnect, Inc.	0.5 - 3.0	DRAM Resource Purchase Agreement	7/14/2020	4262-E
48	10125	OhmConnect, Inc.	0.9 - 6.0	DRAM Resource Purchase Agreement	7/14/2020	4262-E
49	10126	Voltus, Inc.	22.3 - 38.0	DRAM Resource Purchase Agreement	7/14/2020	4262-E
50	11134-1005	Morgan Stanley Capital Group Inc.	265.0	WSPP - Firm Sale	7/14/2020	4323-E
51	13076-1009	Morgan Stanley Capital Group Inc.	2.0	Transmission - Resale	7/14/2020	4323-E
52	13076-1008	Morgan Stanley Capital Group Inc.	226.0	Transmission - Resale	7/14/2020	4323-E
53	11153-1024	Pacific Gas & Electric Company	25.0	EEI - Import Allocation Rights Sale	7/17/2020	4323-E
54	11228-1019	Sonoma Clean Power Authority	1.0 - 19.5	EEI - RA Sale	8/2/2020	4323-E
55	11228-1018	Sonoma Clean Power Authority	1.0 - 19.5	EEI - RA Purchase	8/2/2020	4323-E
56	11180-1016	Sempra Gas & Power Marketing, LLC	605.0	EEI - RA Sale	8/6/2020	4323-E
57	11273-1001	NextEra Energy Power Marketing, LLC	60.0	EEI - RA Sale	8/7/2020	4323-E
58	11246-1016	Clean Power Alliance of Southern California	40.0	EEI - RA Sale	8/7/2020	4323-E
59	11257-1014	City of San Jose, a California municipality	0.5 - 4.2	EEI - RA Purchase	8/10/2020	4323-E
60	11257-1013	City of San Jose, a California municipality	0.5 - 4.2	EEI - RA Sale	8/10/2020	4323-E
61	11270-1002	Tenaska Power Services Co.	146.0	EEI - RA Sale	8/12/2020	4323-E
62	12041	Homestead Energy Storage, LLC	2.8 - 14.0	RA Purchase Agreement	8/21/2020	4316-E
63	11270-1003	Tenaska Power Services Co.	146.0	EEI - RA Sale	8/31/2020	4323-E
64	14026-1040	SoCalGas	-	Gas Transportation	9/8/2020	4323-E
65	14026-1039	SoCalGas	-	Gas Transportation	9/8/2020	4323-E

66	13092	Puget Sound Energy, Inc.	-	Transmission - Firm	9/9/2020	4323-E
67	13093	Puget Sound Energy, Inc.	-	Transmission - Non Firm	9/9/2020	4323-E
68	13094	Puget Sound Energy, Inc.	-	Transmission - Resale	9/9/2020	4323-E
69	11034-1039	Calpine Energy Services LP	170.0	EEI - RA Sale	9/16/2020	4323-E
70	11541-1010	Bonneville Power Administration	-	WSPP - Transmission Loss Purchase	9/22/2020	4323-E
71	11252-1014	Peninsula Clean Energy Authority	28.0 - 53.0	EEI - RA Sale	10/1/2020	4405-E
72	11034-1038	Calpine Energy Services LP	25.0	EEI - RA Sale	10/6/2020	4405-E
73	11146-1016	NRG Power Marketing LLC	306.0 - 586.0	EEI - RA Sale	10/12/2020	4405-E
74	12044	Desert Peak Energy Storage I, LLC	325.0	Power Purchase Tolling Agreement	10/14/2020	4373-E
75	11257-1017	City of San Jose	10.0 - 100.0	EEI - RA Purchase	10/16/2020	4405-E
76	11257-1015	City of San Jose	120.0	EEI - RA Sale	10/16/2020	4405-E
77	11257-1016	City of San Jose	10.0 - 100.0	EEI - RA Sale	10/16/2020	4405-E
78	11259-1007	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	18.0 - 53.0	EEI - RA Sale	10/19/2020	4405-E
79	11274	Ellwood Power, LLC	-	EEI Master Agreement	10/19/2020	4405-E
80	11088-1020	Exelon Generation Company, LLC	25.0 - 100.0	EEI - RA Sale	10/20/2020	4405-E
81	11256-1009	East Bay Community Energy Authority	155.0 - 181.0	EEI - RA Sale	10/27/2020	4405-E
82	11229-1006	Silicon Valley Clean Energy Authority	11.7	EEI - RA Sale	10/28/2020	4405-E
83	11258-1011	Direct Energy Business Marketing, LLC	1.0	EEI - RA Sale	10/28/2020	4405-E
84	11275	Western Community Energy	-	EEI Master Agreement	10/28/2020	4405-E
85	11252-1016	Peninsula Clean Energy Authority	1.0 - 31.0	EEI - RA Sale	10/28/2020	4405-E
86	11229-1005	Silicon Valley Clean Energy Authority	16.4	EEI - RA Sale	10/28/2020	4405-E
87	11258-1010	Direct Energy Business Marketing, LLC	1.0	EEI - RA Purchase	10/28/2020	4405-E
88	11258-1009	Direct Energy Business Marketing, LLC	1.0	EEI - RA Sale	10/28/2020	4405-E
89	12042	Sonoran West Solar Holdings, LLC	200.0	RA Purchase Agreement	10/28/2020	4373-E
90	11233-1003	Lancaster Choice Energy	20.0	EEI - RA Sale	10/29/2020	4405-E
91	11259-1014	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	4.0	EEI - RA Sale	10/29/2020	4405-E
92	11259-1012	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	46.0 - 47.0	EEI - RA Sale	10/29/2020	4405-E
93	11253-1015	Central Coast Community Energy	108.0 - 124.0	EEI - RA Purchase	10/29/2020	4405-E
94	11253-1016	Central Coast Community Energy	108.0 - 124.0	EEI - RA Sale	10/29/2020	4405-E
95	11234-1012	Marin Clean Energy	20.0 - 29.0	EEI - RA Sale	10/29/2020	4405-E
96	11234-1013	Marin Clean Energy	29.0	EEI - RA Sale	10/29/2020	4405-E
97	11234-1014	Marin Clean Energy	87.0	EEI - RA Purchase	10/29/2020	4405-E
98	11234-1016	Marin Clean Energy	5.0 - 20.7	EEI - RA Purchase	10/29/2020	4405-E
99	11233-1004	Lancaster Choice Energy	60.0	EEI - RA Purchase	10/29/2020	4405-E

100	11266-1003	Pioneer Community Energy	7.0	EEI - RA Sale	10/29/2020	4405-E
101	11266-1002	Pioneer Community Energy	21.0	EEI - Import Allocation Rights Purchase	10/29/2020	4405-E
102	11259-1011	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	46.0 - 47.0	EEI - RA Purchase	10/29/2020	4405-E
103	11234-1015	Marin Clean Energy	5.0 - 20.7	EEI - RA Sale	10/29/2020	4405-E
104	11259-1009	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	2.0 - 4.0	EEI - RA Sale	10/29/2020	4405-E
105	11153-1025	Pacific Gas & Electric Company	513.0 - 540.0	EEI - RA Sale	10/29/2020	4405-E
106	11153-1026	Pacific Gas & Electric Company	3.0 - 65.0	EEI - RA Sale	10/29/2020	4405-E
107	11153-1027	Pacific Gas & Electric Company	1.0 - 592.0	EEI - RA Sale	10/29/2020	4405-E
108	11257-1018	City of San Jose	6.0 - 119.0	EEI - RA Sale	10/29/2020	4405-E
109	11257-1019	City of San Jose	121.0	EEI - RA Purchase	10/29/2020	4405-E
110	11257-1020	City of San Jose	121.0	EEI - RA Sale	10/29/2020	4405-E
111	11259-1008	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	43.0 - 66.0	EEI - RA Sale	10/29/2020	4405-E
112	11253-1014	Central Coast Community Energy	3.0 - 37.0	EEI - RA Sale	10/29/2020	4405-E
113	11259-1010	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	119.0 - 150.0	EEI - RA Sale	10/29/2020	4405-E
114	11259-1013	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	4.0	EEI - RA Purchase	10/29/2020	4405-E
115	11153-1030	Pacific Gas & Electric Company	50.0 - 67.0	EEI - RA Purchase	10/29/2020	4405-E
116	11153-1029	Pacific Gas & Electric Company	50.0 - 67.0	EEI - RA Sale	10/29/2020	4405-E
117	11153-1028	Pacific Gas & Electric Company	1.0 - 574.3	EEI - RA Purchase	10/29/2020	4405-E
118	11275-1003	Western Community Energy	65.0 - 265.0	EEI - RA Sale	10/29/2020	4405-E
119	11275-1002	Western Community Energy	37.0	EEI - RA Sale	10/29/2020	4405-E
120	11275-1001	Western Community Energy	39.0	EEI - RA Sale	10/29/2020	4405-E
121	11253-1013	Central Coast Community Energy	12.0 - 124.0	EEI - RA Sale	10/29/2020	4405-E
122	11088-1022	Exelon Generation Company, LLC	2.0 - 39.0	EEI - RA Sale	10/29/2020	4405-E
123	11088-1023	Exelon Generation Company, LLC	48.0	EEI - RA Purchase	10/29/2020	4405-E
124	11088-1024	Exelon Generation Company, LLC	48.0	EEI - RA Sale	10/29/2020	4405-E
125	11088-1025	Exelon Generation Company, LLC	17.0 - 25.0	EEI - RA Purchase	10/29/2020	4405-E
126	11088-1026	Exelon Generation Company, LLC	17.0 - 25.0	EEI - RA Sale	10/29/2020	4405-E
127	11088-1028	Exelon Generation Company, LLC	9.0	EEI - RA Sale	10/29/2020	4405-E
128	11034-1040	Calpine Energy Services LP	4.0	EEI - RA Sale	10/29/2020	4405-E
129	11088-1027	Exelon Generation Company, LLC	9.0	EEI - RA Purchase	10/29/2020	4405-E
130	11034-1041	Calpine Energy Services LP	4.0	EEI - RA Sale	10/29/2020	4405-E
131	11088-1021	Exelon Generation Company, LLC	48.0	EEI - RA Sale	10/29/2020	4405-E
132	11034-1042	Calpine Energy Services LP	4.0	EEI - RA Purchase	10/29/2020	4405-E
133	11256-1011	East Bay Community Energy Authority	135.0	EEI - RA Sale	10/30/2020	4405-E
134	11256-1010	East Bay Community Energy Authority	100.0 - 200.0	EEI - RA Sale	10/30/2020	4405-E
135	11280	G4 Energy, LLC	-	NAESB Master Agreement	11/3/2020	4405-E
136	15054	Source Commodities LLC	-	Broker	11/17/2020	4405-E
137	12043	Silver Peak Solar, LLC	60.0	Power Purchase Tolling Agreement	12/4/2020	4373-E

e) Contract Amendment Administration

The following contract amendments to Conventional and Natural Gas Contracts were executed during the Record Period and submitted for approval as identified in Table VII-49.

Table VII-49
Conventional and Gas Amendments and Letter Agreements
January 1, 2020 Through December 31, 2020

	ID	Contract Counterparty	Amendment No and Description	Date Executed
1	12021	Quarantina Energy Storage, LLC	Amendment No. 3 to update the state in which the project is incorporated.	1/29/2020
2	12028	Ventura Energy Storage, LLC	[redacted]	3/18/2020
3	12026	Silverstrand Grid LLC	[redacted]	4/8/2020
4	10117	Enerwise Global Technologies, LLC	Amendment No. 1 to modify the Delivery Period section of the DRAM Purchase Agreement pursuant to the CPUC's issued Disposition Letter.	4/16/2020
5	10118	Leapfrog Power, Inc.	Amendment No. 1 to modify the Delivery Period section of the DRAM Purchase Agreement pursuant to the CPUC's issued Disposition Letter.	4/16/2020
6	10119	OhmConnect California, LLC	Amendment No. 1 to modify the Delivery Period section of the DRAM Purchase Agreement pursuant to the CPUC's issued Disposition Letter.	4/16/2020
7	10120	OhmConnect California, LLC	Amendment No. 1 to modify the Delivery Period section of the DRAM Purchase Agreement pursuant to the CPUC's issued Disposition Letter.	4/16/2020
8	10121	Voltus, Inc.	Amendment No. 1 to modify the Delivery Period section of the DRAM Purchase Agreement pursuant to the CPUC's issued Disposition Letter.	4/16/2020
9	11262-1001 11262-1002	The Energy Authority, Inc.	[redacted]	5/6/2020
10	11266-1001	Pioneer Community Energy, a California joint powers authority	[redacted]	5/12/2020
11	11258-1004	Direct Energy Business Marketing, LLC	[redacted]	5/13/2020
12	11234-1010 11234-1011	Marin Clean Energy	[redacted]	5/13/2020
13	11088-1010 11088-1011	Exelon Generation Company, LLC	[redacted]	5/18/2020

14	11252-1007 11252-1008 11252-1009	Peninsula Clean Energy Authority	[redacted]	5/19/2020
15	12038	McCoy Energy Storage, LLC	[redacted]	5/22/2020
16	12039	Blythe Energy Storage II, LLC	[redacted]	5/22/2020
17	12040	Blythe Energy Storage III, LLC	[redacted]	5/22/2020
18	11256-1004 11256-1005 11256-1006	East Bay Community Energy Authority	[redacted]	5/29/2020
19	12028	Ventura Energy Storage, LLC	Amendment No. 2 to update the definition of Ultimate Parent in connection to Consent to Collateral Assignment prior to project financing.	7/7/2020
20	13077	Shell Energy North America (US), L.P.	Amendment No. 1 to update credit provisions to be in alignment with other SENA agreements.	7/7/2020
21	11259-1002 11259-1003	The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF	[redacted]	7/9/2020
22	12010	AltaGas Pomona Energy Storage, Inc.	Amendment No. 1 to add shared facility provisions to alllow AltaGas Pomona Energy Storage, Inc. to share existing interconnection facilities and to update the project description and single-line drawing accordingly.	7/13/2020
	12038	McCoy Energy Storage, LLC	[redacted]	7/14/2020
23	12039	Blythe Energy Storage II, LLC	[redacted]	7/14/2020
	12040	Blythe Energy Storage III, LLC	[redacted]	7/14/2020
24	13076	Morgan Stanley Capital Group Inc.	Amendment No. 1 to update credit provisions to be in alignment with other MSCG agreements.	7/14/2020
25	11228-1015 11228-1016 11228-1017	Sonoma Clean Power Authority	[redacted]	7/20/2020
26	12002	Johanna Energy Center, LLC	Amendment No. 6 to allow JEC to develop, own and operate a separate and distinct battery storage project with a unique Resource ID and metering that may share JEC's interconnection facility.	7/23/2020

27	11257-1008	City of San Jose, a California municipality	[redacted]	8/10/2020
28	12032	Painter Energy Storage, LLC	[redacted]	8/20/2020
29	11153-1013	Pacific Gas & Electric Company	Amendment No. 1 to change the “Flexible Capacity” designation from applicable to not applicable, and remove the flex delivery obligations throughout the entire Delivery Period.	8/24/2020
30	12037	Gateway Energy Storage, LLC	Amendment No. 1 to modify the provisions and defined terms regarding Portfolio Financing of the Project.	9/18/2020
31	11094-1031	GenOn Energy Management, LLC	Amendment No. 1 to address potential State Water Resources Control Board (SWRCB) Approval delays.	9/28/2020
32	12034	SP Tranquillity Solar Storage, LLC	[redacted]	9/30/2020
33	12033	Goleta Energy Storage, LLC	[redacted]	10/6/2020
34	11272-1001	AES Alamitos, L.L.C.	[redacted]	10/16/2020
35	10109	Blythe Energy Inc.	Amendment No. 1 to correct typographical error in certain heat rate values.	10/19/2020
36	11094	GenOn Energy Management, LLC	EEI amended and restated to reflect a change in the name of the counterparty from GenOn Energy Management, LLC to Ormond Beach Power, LLC.	10/19/2020
37	11094-1028	GenOn Energy Management, LLC	Amendment No. 1 to assign the new contract ID and name of 11274 Ellwood Power, LLC, and replace all GenOn Energy Managmeent, LLC references in the Confirmation with Ellwood Power, LLC.	10/19/2020
38	11073-1016	Dynegy Moss Landing LLC	[redacted]	10/28/2020
39	12008	Stanton Energy Reliability Center, LLC	[redacted]	10/30/2020
40	10051	Stanton Energy Reliability Center, LLC	[redacted]	10/30/2020
41	12034	SP Tranquillity Solar Storage, LLC	[redacted]	11/5/2020 11/10/2020 11/19/2020

42	12042	Sonoran West Solar Holdings, LLC	[redacted]	11/20/2020
43	12029	Enel Bella Energy Storage, LLC	[redacted]	11/25/2020
44	10001	AES Alamitos Energy, LLC	[redacted]	12/31/2020
45	10002	AES Huntington Beach Energy, LLC	[redacted]	12/31/2020

(1) Quarantina Energy Storage LLC (ID 12021)

Quarantina Energy Storage, LLC (f/k/a Powin SBI, LLC) is a 10 MW energy storage project, located in Santa Barbara, California, originally executed as part of SCE's 2016 Energy Storage and Distribution Deferral solicitation. The Resource Adequacy Purchase Agreement (RAPA) was executed on September 1, 2017. SCE and Quarantina Energy Storage, LLC executed Amendment No. 3 on January 29, 2020 to update the state in which the project is incorporated. SCE's customers benefit from this amendment by having accurate project information available for contract administration.

(2) Ventura Energy Storage LLC (ID 12028)

Ventura Energy Storage, LLC (f/k/a Strata Saticoy) is a 100 MW energy storage project located in Ventura County, California, originally executed as part of SCE's LCR RFO. The Resource Adequacy Purchase and Sale Agreement (RAPSA) was executed on April 1, 2019. SCE and Ventura Energy Storage LLC executed Amendment No. 1 on March 18, 2020 to (i) update the delivery period and certain delivery date provisions to address interconnection delays and commercial operation date readiness, and [redacted]. SCE's customers benefit from this amendment by ensuring that a highly flexible resource comes online to provide important reliability to the grid. The total benefit to SCE's customers from this amendment is [redacted]

(3) Silverstrand Grid LLC (ID 12026)

Silverstrand Grid LLC (Silverstrand) is an 11 MW energy storage project located in Ventura County, California, originally executed as part of SCE's ACES 2 RFO. The Resource Adequacy Purchase and Sale Agreement (RAPSA) was executed on April 1, 2019. SCE and

Silverstrand executed Amendment No. 1 on April 8, 2020 to (i) update the delivery period and certain delivery date provisions, (ii) update the Critical Path Development Milestone table, and [redacted] SCE's customers benefit from this amendment by ensuring that a highly flexible resource comes online to provide important reliability to the grid. The total benefit to SCE's customers from this amendment is [redacted]

(4) Enerwise Global Technologies, LLC (ID 10117)

Enerwise Global Technologies is a 3.4 MW Non-Residential DRAM project originally executed as part of SCE's DRAM 5 solicitation. The Demand Response Resource Purchase Agreement was executed on March 27, 2020. SCE and Enerwise Global Technologies, LLC. executed Amendment No. 1 on April 16, 2020 to modify the Delivery Period of the Agreement pursuant to the Disposition Letter issued by the CPUC on April 16, 2020 to permit June and July 2020 deliveries. SCE's customers benefit from this amendment by having clear and accurate information available for contract administration.

(5) Leapfrog Power, Inc. (ID 10118)

Leapfrog Power Inc. is a 20 MW Non-Residential DRAM project originally executed as part of SCE's DRAM 5 solicitation. The Demand Response Resource Purchase Agreement was executed on March 27, 2020. SCE and Leapfrog Power Inc. executed Amendment No. 1 on April 16, 2020 to modify the Delivery Period of the Agreement pursuant to the Disposition Letter issued by the CPUC on April 16, 2020 to permit June and July 2020 deliveries. SCE's customers benefit from this amendment by having clear and accurate information available for contract administration.

(6) OhmConnect California LLC (ID 10119)

OhmConnect California is a 4.8 MW Residential DRAM project originally executed as part of SCE's DRAM 5 solicitation. The Demand Response Resource Purchase Agreement was executed on March 27, 2020. SCE and OhmConnect California, LLC executed Amendment No. 1

on April 16, 2020 to modify the Delivery Period of the Agreement pursuant to the Disposition Letter issued by the CPUC on April 16, 2020 to permit June and July 2020 deliveries. SCE's customers benefit from this amendment by having clear and accurate information available for contract administration.

(7) OhmConnect California LLC (ID 10120)

OhmConnect California is a 3.3 MW Non-Residential DRAM project originally executed as part of SCE's DRAM 5 solicitation. The Demand Response Resource Purchase Agreement was executed on March 27, 2020. SCE and OhmConnect California, LLC executed Amendment No. 1 on April 16, 2020 to modify the Delivery Period of the Agreement pursuant to the Disposition Letter issued by the CPUC on April 16, 2020 to permit June and July 2020 deliveries. SCE's customers benefit from this amendment by having clear and accurate information available for contract administration.

(8) Voltus Inc. (ID 10121)

Voltus Inc. is a 2 MW Non-Residential DRAM project originally executed as part of SCE's DRAM-5 solicitation. The Demand Response Resource Purchase Agreement was executed on March 27, 2020. SCE and Voltus Inc. executed Amendment No. 1 on April 16, 2020 to modify the Delivery Period of the Agreement pursuant to the Disposition Letter issued by the CPUC on April 16, 2020 to permit June and July 2020 deliveries. SCE's customers benefit from this amendment by having clear and accurate information available for contract administration.

(9) The Energy Authority Inc. (ID 11262-1001 & 1002)

The Energy Authority Inc. and SCE executed an EEI Master Power Purchase and Sale Agreement on October 25, 2019, and Confirmation Letters were executed October 29, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). SCE and The Energy Authority Inc. executed Amendment No. 1 to each RA Confirm on May 6, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted]

SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(10) Pioneer Community Energy (ID 11266-1001)

Pioneer Community Energy and SCE executed an EEI Master Power Purchase and Sale Agreement on October 24, 2019, and a Confirmation Letter was executed October 24, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). SCE and The Pioneer Community Energy executed Amendment No. 1 to the RA Confirm on May 12, 2020 to modify the RA Confirm to change the "Flexible Capacity" designation from applicable to not applicable and [redacted] SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(11) Direct Energy Business Marketing, LLC (ID 11258-1004)

Direct Energy Business Marketing LLC and SCE executed an EEI Master Power Purchase and Sale Agreement on July 16, 2019, and a Confirmation Letter was executed October 29, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). SCE and Direct Energy Business Marketing LLC executed Amendment No. 1 to the RA Confirm on May 13, 2020 to modify the RA Confirm to change the "Flexible Capacity" designation from applicable to not applicable and [redacted] SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(12) Marin Clean Energy (ID 11234-1010 & 1011)

Marin Clean Energy (MCE) and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on February 7, 2018, and Confirmation Letters were executed October 24, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). MCE and SCE executed Amendment No. 1 to each RA Confirm on May 13, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted] SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(13) Exelon Generation Company, LLC (ID 11088-1010 & 1011)

Exelon Generation Company LLC (Exelon) and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on June 22, 2004, and Confirmation Letters were executed October 30, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). Exelon and SCE executed Amendment No. 1 to each RA Confirmation on May 18, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted] SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(14) Peninsula Clean Energy Authority (ID 11252-1007, 1008 & 1009)

Peninsula Clean Energy Authority and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on May 9, 2019, and Confirmation Letters were executed October 24, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). Peninsula Clean Energy Authority and SCE executed Amendment No. 1 to each RA

Confirm on May 19, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted] SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(15) McCoy Energy Storage, LLC (ID 12038)

McCoy Energy Storage LLC is a 230 MW energy storage project located in Riverside County, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track. The PPA was executed on April 10, 2020. SCE and McCoy Energy Storage LLC executed Amendment No. 1 on May 22, 2020 to (i) [redacted], (ii) add a definition for income tax component of contributions (ITCC) Recapture Period to clarify the parameters by which ITCC funds may be recaptured, (iii) [redacted] SCE's customers benefit from this amendment by clarifying definitions and [redacted] and by allowing a critically important resource to be constructed and provide reliability to the grid early.

(16) Blythe Energy Storage II, LLC (ID 12039)

Blythe Energy Storage II, LLC is a 115 MW energy storage project located in Riverside County, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track. The PPA was executed on April 10, 2020. SCE and Blythe Energy Storage II LLC executed Amendment No. 1 on May 22, 2020 to (i) [redacted] (ii) add a definition for income tax component of contributions (ITCC) Recapture Period to clarify the parameters by which ITCC funds may be recaptured, (iii) [redacted]

[redacted]. SCE's customers benefit from this amendment by clarifying definitions and [redacted] and by allowing a critically important resource to be constructed and provide reliability to the grid early.

(17) Blythe Energy Storage III, LLC (ID 12040)

Blythe Energy Storage III, LLC is a 115 MW energy storage project located in Riverside County, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track. The PPA was executed on April 10, 2020. SCE and Blythe Energy Storage III, LLC executed Amendment No. 1 on May 22, 2020 to (i) [redacted], (ii) add a definition for income tax component of contributions (ITCC) Recapture Period to clarify the parameters by which ITCC funds may be recaptured, (iii) [redacted] and (iv) [redacted] SCE's customers benefit from this amendment by clarifying definitions and [redacted] and by allowing a critically important resource to be constructed and provide reliability to the grid early.

(18) East Bay Community Energy Authority (ID 11256-1004, 1005 & 1006)

East Bay Community Energy Authority and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on June 14, 2019, and Confirmation Letters were executed October 23, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). East Bay Community Energy Authority and SCE executed Amendment No. 1 to each RA Confirm on May 29, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted]

[redacted]. SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(19) Ventura Energy Storage, LLC (ID 12028)

Ventura Energy Storage, LLC (f/k/a Strata Saticoy) is a 100 MW energy storage project located in Ventura County, California, originally executed as part of SCE's LCR solicitation. The Resource Adequacy Purchase and Sale Agreement (RAPA) was executed on April 1, 2019. SCE and Ventura Energy Storage LLC executed Amendment No. 2 on July 7, 2020 to update the definition of Ultimate Parent in connection with a Consent to Collateral Assignment prior to project financing. SCE's customers benefit from the execution of this amendment by having accurate project counterparty information available for contract administration and by ensuring a critically important resource is constructed for grid reliability.

(20) Shell Energy North America (U.S) L.P. (ID 13077)

Shell Energy North America (U.S.) L.P. (SENA) and SCE entered into a Transmission Resale Enabling Agreement (Enabling Agreement) on March 19, 2012. SENA and SCE executed Amendment No. 1 to the Enabling Agreement on July 7, 2020 to update credit provisions to be in alignment with other SENA agreements. SCE's customers benefit from this amendment by having accurate credit worthiness information available for future transactions.

(21) CleanPowerSF (ID 11259-1002 & 1003)

The City and County of San Francisco, acting by and through its Public Utilities Commission, CleanPowerSF and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on August 6, 2019, and Confirmation Letters were executed October 25, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). CleanPowerSF and SCE executed Amendment No. 1 to each RA Confirm on July 9, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted]. SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(22) AltaGas Pomona Energy Storage, Inc. (ID 12010)

AltaGas Pomona Energy Storage, Inc. is a 20 MW battery storage project located in Pomona, California, originally executed as part of SCE's 2016 ACES RFO. The Resource Adequacy Purchase Agreement (RAPA) was executed on August 5, 2016. SCE and AltaGas Pomona Energy Storage, Inc. executed Amendment No. 1 on July 13, 2020 to add shared facility provisions to allow AltaGas Pomona Energy Storage, Inc. to share existing interconnection facilities and to update the project description and single-line drawing to identify the changes associated with the shared facility. SCE's customers benefit from this amendment by allowing efficient use of interconnection facilities while having accurate project information available for contract administration.

(23) McCoy Energy Storage, LLC (ID 12038), Blythe Energy Storage II, LLC (ID 12039), and Blythe Energy Storage III, LLC (ID 12040)

McCoy Energy Storage LLC is a 230 MW energy storage project, Blythe Energy Storage II, LLC is a 115 MW energy storage project, and Blythe Energy Storage III, LLC is a 115 MW energy storage project (collectively Sellers), all of which are located in Riverside County, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track. The PPAs were executed on April 10, 2020. SCE and McCoy Energy Storage LLC, Blythe Energy Storage II, LLC and Blythe Energy Storage III, LLC each executed Amendment No. 2 on July 14, 2020 to [redacted] SCE's customers benefit from these amendments since SCE will now control the energy dispatch rights for the entire term of each of the contracts for a cumulative customer savings of [redacted]. These amendments were submitted to the CPUC for approval via a Supplement to Advice Letter 4218-E-A, dated July 16, 2020.

(24) Morgan Stanley Capital Group, Inc. (ID 13076)

Morgan Stanley Capital Group, Inc. (MSCG) and SCE entered into a Transmission Resale Enabling Agreement (Agreement) on March 16, 2012. MSCG and SCE executed Amendment No. 1 to the Agreement on July 14, 2020 to update credit provisions to be in alignment with other MSCG agreements. SCE's customers benefit from this amendment by having accurate credit worthiness information available for future transactions.

(25) Sonoma Clean Power Authority (ID 11228-1015, 1016 & 1017)

Sonoma Clean Power Authority and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on October 5, 2017, and Confirmation Letters were executed October 29, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (collectively the "RA Confirms"). Sonoma Clean Power Authority and SCE executed Amendment No. 1 to each RA Confirm on July 20, 2020 to modify the RA Confirms to change the "Flexible Capacity" designation from applicable to not applicable and [redacted]. SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(26) Johanna Energy Center, LLC (ID 12002)

Johanna Energy Center, LLC (JEC) (f/k/a Orange County Energy Storage 1, LLC) is a 20 MW Energy Storage project located in Santa Ana, California, originally executed as part of SCE's Preferred Resource Pilot 2 solicitation. The Energy Storage Resource Adequacy and Purchase Agreement (RAPA) was executed on September 8, 2016. SCE and the JEC executed Amendment No. 6 on July 23, 2020 to allow JEC to develop, own and operate a separate and distinct battery storage project with a unique Resource ID and metering that may share JEC's interconnection facilities. SCE's customers benefit from this amendment by allowing efficient use of interconnection facilities while having accurate project information available for contract administration.

(27) <u>City of San Jose (ID 11257-1008)</u>

City of San Jose and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on July 9, 2019, and a Confirmation Letter was executed October 29, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). City of San Jose and SCE executed Amendment No. 1 to the RA Confirm on August 10, 2020 to modify the RA Confirm to (i) change the "Flexible Capacity" designation from applicable to not applicable, (ii) [redacted], and (iii) remove the flex delivery obligations, effective July 1, 2020 through the end of the Delivery Period. SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(28) <u>Painter Energy Storage, LLC (ID 12032)</u>

Painter Energy Storage, LLC is a 10 MW energy storage project located in Ventura County, California, originally executed as part of SCE's Aliso Canyon Energy Storage 2 solicitation. The Energy Storage Resource Adequacy and Purchase Agreement was executed on April 1, 2019. Painter Energy Storage, LLC acknowledged that it would have difficulty meeting the current contractual timelines. SCE and Painter Energy Storage, LLC executed Amendment No. 1 on August 20, 2020 to (i) [redacted] (ii) adjust the Expected Initial Delivery Date by one month from March 1, 2021 to April 1, 2021, and (iii) modify a Critical Path Development Milestone deadline of the Agreement to accommodate commercial operation date readiness. SCE's customers benefit from this amendment because of the associated savings in the amount of [redacted].

(29) <u>Pacific Gas and Electric (ID 11153-1013)</u>

Pacific Gas and Electric (PG&E) and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement) on April 15, 2014, and a Confirmation Letter was executed October 31, 2019 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). PG&E and SCE executed Amendment No. 1 to the RA Confirm on August 24, 2020 to modify the RA Confirm to change the "Flexible Capacity" designation from applicable to not applicable, and remove the flex delivery obligations throughout the entire Delivery Period. SCE's customers benefit from this amendment because it allows SCE to fulfill its responsibility to accurately reflect unit capabilities to the market and avoid procuring additional RA and Flex RA from the market to replace the loss of Flexible Capacity.

(30) Gateway Energy Storage, LLC (ID 12037)

Gateway Energy Storage, LLC is a 100 MW energy storage project located in Otay Mesa, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track. The PPA was executed on April 22, 2020. SCE and Gateway Energy Storage, LLC executed Amendment No. 1 on September 18, 2020 to modify the provisions and defined terms regarding Portfolio Financing of the Project. SCE's customers benefit from this amendment by supporting broader financing options to ensure critically important resources that provide reliability to the grid are constructed.

(31) GenOn Energy Management LLC (ID 11094-1031)

GenOn Energy Management LLC (GenOn) and SCE executed an EEI Master Power Purchase and Sale Agreement on June 22, 2004, and a Confirmation Letter was executed April 17, 2020 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). SCE and GenOn executed Amendment No. 1 to the RA Confirm on September 28, 2020 to (i) remove the automatic termination provision that triggers if a final and non-appealable decision is not received from the State Water Resources Control Board (SWRCB) on or before October 30, 2020, (ii) modify Sellers delivery obligations in event that SWRCB Approval is delayed, (iii) indemnify SCE from any penalties, fines or costs related to receipt of product prior to Office of Administrative Law approval, and (iv) remove the right to appeal provision from the definition of "SWRCB Approval." SCE's customers benefit from this amendment by preventing a potential automatic termination of the RA Confirm and thus allowing a highly flexible resource be utilized to provide important reliability to the grid.

(32) SP Tranquility Solar Storage, LLC (ID 12034)

SP Tranquility Solar Storage, LLC (Tranquility) is a 72 MW energy storage project located in Cantua Creek, California, originally executed as part of SCE's 2019 System Reliability RFO Fast Track solicitation. The PPA was executed on April 22, 2020. SCE and Tranquility executed a Letter Agreement on September 30, 2020 to [redacted] SCE's customers benefit from this Letter Agreement by [redacted]

(33) Goleta Energy Storage, LLC (ID 12033)

Goleta Energy Storage, LLC (formerly AltaGas Power Holdings U.S. Inc.) is a 40 MW energy storage project located in Goleta, California, originally executed as part of SCE's Aliso Canyon Energy Storage 2 RFO. The RA Only Purchase and Sale Agreement was executed on April 1, 2019. Goleta acknowledged that it would have difficulty meeting the current contractual timelines. SCE and Goleta Energy Storage, LLC executed Amendment No. 1 on October 6, 2020 to (i) [redacted] (ii) modify the Initial Delivery Deadline and the Expected Initial Delivery Date, (iii) modify Critical Path Development Milestone deadlines, and (iv) update the Milestone Schedule to accommodate commercial operation date readiness. SCE's customers benefit from this amendment because of the associated savings in the amount of [redacted]

(34) AES Alamitos, LLC (ID 11272-1001)

AES Alamitos LLC and SCE executed an EEI Master Power Purchase and Sale Agreement on March 23, 2020, and a Confirmation Letter was executed on March 23, 2020 (RA Confirm) as part of SCE's 2019 Resource Adequacy (RA) solicitation. SCE and AES Alamitos executed Amendment No. 1 to the RA Confirm on October 16, 2020 to [redacted]

[redacted] SCE's customers benefit from this amendment by allowing a highly flexible resource be utilized to provide important reliability to the grid.

(35) Blythe Energy, Inc. (ID 10109)

Blythe Energy Inc. is a 490 MW combined cycle gas turbine project located in Riverside County, California, originally executed as a bilateral negotiation in 2019. The PPA was executed on June 28, 2019. SCE and Blythe executed Amendment No. 1 to the PPA on October 19, 2020 to correct a typographical error in certain heat rate values. SCE's customers benefit from this amendment by having accurate project information available for contract administration.

(36) GenOn Energy Management, LLC (ID 11094)

GenOn Energy Management, LLC and SCE entered into an EEI Master Power Purchase and Sale Agreement (EEI Agreement), including the Cover Sheet, the Collateral Annex and Paragraph 10 to the Collateral Annex on June 22, 2004. SCE and GenOn Energy Management executed an Amended and Restated EEI Agreement and Amended and Restated Paragraph 10 to the Collateral Annex on October 19, 2020 to change the entity on the EEI Agreement to Ormond Beach Power, LLC to allow for a collateral assignment and internal restructuring at GenOn Energy Management, LLC. SCE customers benefit from this amendment by having updated documents and accurate counterparty information available for contract administration.

(37) GenOn Energy Management, LLC (ID 11094-1028)

GenOn Energy Management LLC (GenOn) and SCE executed an EEI Master Power Purchase and Sale Agreement on June 22, 2004, and a Confirmation Letter was executed on October 18, 2018 as part of SCE's 2018 Resource Adequacy (RA) solicitation (the "RA Confirm"). SCE and GenOn executed Amendment No. 1 to the RA Confirm on October 19, 2020 to (i) replace GenOn Energy Management, LLC with Ellwood Power, LLC, (ii) delete all references to GenOn

Energy Management, LLC in the Confirm and replace all such references with Ellwood Power, LLC, and (iii) to delete all references to the Original EEI Master Power Purchase Agreement and replace all such references with the Ellwood Power EEI Agreement. SCE's customers benefit from this amendment by having accurate counterparty information available for contract administration.

(38) Dynegy Moss Landing, LLC (ID 11073-1016)

Dynegy Moss Landing LLC and SCE executed an EEI Master Power Purchase and Sale Agreement on March 13, 2013, and a Confirmation Letter was executed March 31, 2020 as part of SCE's 2019 Resource Adequacy (RA) solicitation (the "RA Confirm"). SCE and Dynegy Moss Landing LLC executed Amendment No. 1 to the RA Confirm on October 28, 2020 to [redacted] SCE's customers benefit from this amendment by [redacted] and thus allowing a highly flexible resource be utilized to provide important reliability to the grid.

(39) Stanton Energy Reliability Center, LLC (ID 12008)

Stanton Energy Reliability Center, LLC is a 1.3 MW hybrid energy storage project located in Stanton, California, originally executed as part of Southern California Edison's (SCE) 2014 Energy Storage RFO. The Resource Adequacy Purchase Agreement (RAPA) was executed on September 21, 2015. SCE and Stanton Energy Reliability Center, LLC executed Amendment No. 1 on October 30, 2020 to [redacted] SCE's customers benefit from this amendment by ensuring that a [redacted] resource comes online and includes contractual provisions to ensure transparency and compliance with the RAPA.

(40) Stanton Energy Reliability Center, LLC (ID 10051)

Stanton Energy Reliability Center, LLC is a 98 MW gas fired facility located in Stanton, California, originally executed as part of SCE's 2013 LCR RFO. The Resource

Adequacy Purchase Agreement was executed on November 3, 2014. SCE and Stanton Energy Reliability Center, LLC executed a Letter Agreement on October 30, 2020 to [redacted] SCE's customers benefit from this letter agreement by including contractual provisions to ensure transparency and compliance, and by having accurate project information available for contract administration.

(41) <u>SP Tranquility Solar Storage, LLC (ID 12034)</u>

SP Tranquility Solar Storage, LLC (Tranquility) is a 72 MW storage facility located in Cantua Creek, California, originally executed as part of Southern California Edison's (SCE) 2019 System Reliability RFO Fast Track solicitation. The Energy Storage Resource Purchase and Sale Agreement (RPSA) was executed on April 22, 2020. SCE and Tranquility executed the first amendment to the Letter Agreement on November 5, 2020, an Amended and Restated Letter Agreement on November 10, 2020, and Amendment No. 1 on November 19, 2020, to [redacted] SCE and Tranquility executed Amendment No. 1 on November 10, 2020 to [redacted] SCE's customers benefit from this amendment and Amended and Restated Letter Agreement by [redacted]

[redacted]

(42) Sonoran West Holdings, LLC (ID 12042)

Sonoran West Holdings, LLC is a 200 MW storage facility located in Riverside County, California, originally executed as part SCE's 2019 System Reliability RFO Standard Track solicitation. The Energy Storage Resource Purchase and Sale Agreement (RPSA) was executed on October 28, 2020. SCE and Sonoran West Holdings executed Amendment No. 1 on November 20, 2020 to [redacted] SCE's customers benefit from this amendment by [redacted]

(43) Enel Bella Storage, LLC (ID 12042)

Enel Bella Energy Storage, LLC is a 10 MW energy storage project located in Goleta, California, originally executed as part of SCE's Aliso Canyon Energy Storage (ACES) 2 solicitation. The PPA was executed on April 1, 2019. Enel Bella Energy Storage, LLC acknowledged that it would have difficulty meeting the current contractual timelines. SCE and Enel Bella Energy Storage, LLC executed Amendment No. 2 on November 25, 2020, to [redacted] ii) modify the Initial Delivery Deadline and the Expected Initial Delivery Date, (iii) modify Critical Path Development Milestone deadlines, and (iv) update the Milestone Schedule to accommodate commercial operation date readiness. SCE's customers benefit from this amendment by [redacted]

(44) AES Alamitos Energy, LLC (ID 10001)

AES Alamitos Energy, LLC is a 650 MW combined cycle gas-fired project located in Long Beach, California, originally executed as part of SCE's 2013 Local Capacity Requirements (LCR) solicitation. The PPA was executed on November 3, 2014. [redacted]

[redacted]

(45) AES Huntington Beach Energy, LLC (ID 10002)

AES Huntington Beach Energy, LLC is a 649 MW combined cycle gas-fired project located in Huntington Beach, California, originally executed as part of SCE's 2013 Local Capacity Requirements (LCR) solicitation. The PPA was executed on November 3, 2014. [redacted]

f) Contract Assignment Administration

Conventional contracts may only be assigned with the written consent of the parties, which may not be unreasonably withheld. There are many reasons contract counterparties seek to assign their contracts. For example, the counterparty may want to sell or transfer the project to a new entity, sell or assign part of the ownership in the project to tax equity, assign the contract to a lender as security for a loan, or effectuate a change of control of the project. Table VII-50 lists the Conventional and Gas contract consents and assignments to which SCE consented during the Record Period.

Table VII-50
Conventional and Gas Contract Consents and Consents to Assignments
January 1, 2020 Through December 31, 2020

	ID	Contract Counterparty	Consents and Description	Date Executed
1	12022	Acorn I Energy Storage LLC	Consent to Assignment of Membership Interest	1/29/2020
2	12025	Wildcat I Energy Storage LLC	Consent to Assignment of Membership Interest	1/29/2020
3	12021	Quarantina Energy Storage, LLC	Consent to Collateral Assignment	1/29/2020
4	12022	Acorn I Energy Storage LLC	Consent to Collateral Assignment	1/29/2020
5	12025	Wildcat I Energy Storage LLC	Consent to Collateral Assignment	1/29/2020
6	12021	Quarantina Energy Storage, LLC	Consent to Assignment of Membership Interest	1/29/2020
7	12026	Silverstrand Grid LLC	Consent to Assignment of Membership Interest	4/16/2020
8	12028	Ventura Energy Storage, LLC	Consent to Assignment of Membership Interest	5/4/2020
9	12028	Ventura Energy Storage, LLC	Consent to Collateral Assignment	7/7/2020
10	12037	Gateway Energy Storage, LLC	Consent to Collateral Assignment	9/17/2020
11	11094	GenOn Energy Management, LLC	Consent to Collateral Assignment	10/19/2020
12	11279	Ormond Beach Power, LLC	Consent to Collateral Assignment	11/18/2020
13	11274	Ellwood Power, LLC	Consent to Collateral Assignment	11/18/2020
14	12034	SP Tranquillity Solar Storage, LLC	Consent to Assignment of Membership Interest	11/23/2020
15	12035	SP Garland Solar Storage, LLC	Consent to Assignment of Membership Interest	11/23/2020
16	12029	Enel Bella Energy Storage, LLC	Consent to Assignment of Membership Interest	11/25/2020

g) Affiliate Transactions and Contract Information

There were no affiliate conventional contracts during the Record Period.

h) Dispute Resolution and Litigation

Details on conventional project dispute resolution and litigation activities during the Record Period are provided below.

(1) Carson Cogeneration Company, LLC (ID 11038 f/k/a 2087)

Carson Cogeneration Company, LLC (Carson Cogen) was a 48 MW combined cycle gas-fired project located in Carson, California, executed as a part of SCE's PURPA QF procurement requirement as a CHP resource with a steam host. The SO2 PPA was executed on June 10,1985, and subsequently amended and restated pursuant to the CHP Settlement Agreement on January 31, 2013, including a Master Power Purchase and Sale Agreement and an Amended and Restated Power Purchase and Sale Agreement Confirmation Letter for resource adequacy (RA).

SCE discovered that Carson Cogen had not been delivering the full amount of RA during the months of March, October, November, and December 2015 and 2016 due to a Net Qualifying Capacity (NQC) amount that was less than the Contract Quantity. SCE invoiced Carson Cogen an amount of [redacted] and subsequently netted that amount from their payment on February 3,

2017. Carson disputed SCE's netting from their payment and requested mediation. On April 27, 2017, SCE and Carson Cogen held a management meeting to seek resolution on the issue, but the parties were not able to resolve the dispute. On June 7, 2017, SCE and Carson Cogen executed a Termination & Shut-Down Agreement, associated Closing Agreement and Assignment (*see* SCE ERRA Filing A.18-03-016, SCE-01C, Chapter VII, Section E.2) to allow the plant to cease operation, while preserving Carson Cogen's right to continue to pursue the dispute. On October 9, 2018, Carson Cogen requested dispute resolution under the terms of the agreement, then limiting its claim to [redacted] On June 25, 2019, Carson Cogen and SCE attended mediation [redacted] The parties were unable to settle the matter at the mediation. Carson Cogen subsequently filed a lawsuit against SCE in state court, despite the mandatory arbitration provision in the PPA, and subsequently stipulated to stay that litigation while participating in an arbitration, which is in line with the PPA's dispute resolution provisions. The parties engaged in arbitration, culminating in a hearing in late December 2020. SCE expects a final decision in that arbitration in the first quarter of 2021.

(2) CPV Sentinel, LLC (ID 11059)

CPV Sentinel, LLC (Sentinel) is an 802 MW simple cycle gas-fired project consisting of eight generating units located in Desert Hot Springs, California, originally executed as part of SCE's 2006 New Gen solicitation. One PPA was executed on February 15, 2007 for five generating units and a second PPA was executed on March 5, 2008 for an additional three generating units. The PPAs were subsequently amended and restated into one PPA on November 30, 2010 (the Amended and Restated Power Purchase Tolling Agreement or PPTA).

In September 2018, Sentinel voluntarily conducted a CAISO capacity test for each of its eight generating units. The tests resulted in higher Maximum Normal Capacity (new PMax) for the generating units, which new ratings are above the contract capacity in the PPTA (Contract Capacity). As required by CAISO Tariff, the new PMax values were included in each of the Generating Units' Master Resource Data Template (MRDT) files. SCE contractually claimed all additional output, including RA, as reported in the CAISO's NQC list. As such, Sentinel was dispatched by the CAISO based on the new PMax values and the MRDT, while SCE continued to pay based on the lower Contract Capacity. On December 6, 2018, Sentinel submitted a notice of dispute and request for informal dispute resolution regarding dispatches above the Contract Capacity. Sentinel disputes SCE's payment based on the Contract Capacity and sought reimbursement for the products in excess of the Contract Capacity. The parties were unable to resolve the matter in informal discussions or during mediation on July 25, 2019. An arbitrator was selected for binding arbitration, which subsequently commenced, however, Sentinel and SCE reached a Settlement Agreement which was executed on September 23, 2020.

The key aspects in the Settlement Agreement and Release (Settlement) include: [redacted] The Parties terminated the binding arbitration process on September 30, 2020. [redacted]

[redacted]

i) <u>Contract Termination</u>

Table VII-51 below identifies the conventional contract terminations that occurred during the Record Period.

Table VII-51
Conventional Contract Terminations
January 1, 2020 Through December 31, 2020

	ID	Project	Contract Type	Termination Date	Notes
1	11034-1031	Calpine Energy Services LP	EEI - RA Sale	2/28/2020	[redacted]
2	11255-1001	Blythe Energy Inc.	EEI - RA Purchase	3/9/2020	Early Termination Agreement executed on 3/9/2020 to terminate RA Purchase Agreement upon CPUC Approval of Tolling Agreement with Blythe. Associated collateral was returned to Seller in accordance with the terms of the RA Purchase Agreement.
5	11108	Inland Empire Energy Center, LLC	EEI Master Agreement	3/10/2020	EEI Agreement terminated persuant to termination notice dated 3/3/2020. No collateral was posted in accordance with the terms of the Agreement.
6	11232-1002	CSU Channel Islands Site Authority	EEI - RA Purchase	3/31/2020	[redacted]
7	11232	CSU Channel Islands Site Authority	EEI Master Agreement	3/31/2020	EEI Agreement expired and no collateral was posted in accordance with the terms of the Agreement.
8	11232-1001	CSU Channel Islands Site Authority	EEI - Toll Purchase	3/31/2020	[redacted]
9	11140	NJR Energy Services Company	NAESB Master Agreement	4/30/2020	NAESB Agreement was terminated through notice provided by NJR Energy Services Company.
10	11515	ConocoPhillips Company	WSPP Master Agreement	5/18/2020	Seller notified SCE that WSPP agreement is no longer active. No collateral was posted in accordance with the terms of the Agreement.
11	15014	Edge Energy, LLC	Brokerage Enabling Agreement	6/19/2020	Contract terminated pursuant to SCE's termination notice dated 5/20/2020. No collateral was posted in accordance with the terms of the Agreement.
12	15007	CGS Brokerage, LLC	Brokerage Enabling Agreement	6/30/2020	Contract terminated pursuant to SCE's termination notice dated 5/28/2020. No collateral was posted in accordance with the terms of the Agreement.
13	15028	Longevous Capital, LLC	Brokerage Enabling Agreement	6/30/2020	Contract terminated pursuant to SCE's termination notice dated 5/26/2020. No collateral was posted in accordance with the terms of the Agreement.
14	15033	Spectron Energy Inc	Brokerage Enabling Agreement	7/24/2020	Contract terminated pursuant to SCE's termination notice dated 6/23/2020. No collateral was posted in accordance with the terms of the Agreement.
15	11020	Blythe Energy Inc.	Power Purchase Tolling Agreement	7/31/2020	Contract expired in accordance with the terms of the Agreement.

16	11270-1002	Tenaska Power Services Co.	EEI - RA Sale	8/28/2020	[redacted]
17	15004	Black Barrell Energy, L.P.	Brokerage Enabling Agreement	9/15/2020	Contract terminated pursuant to termination notice dated 8/4/2020. No collateral was posted in accordance with the terms of the Agreement.
18	15023	INFA Energy Brokers, LLC	Brokerage Enabling Agreement	9/15/2020	Contract terminated pursuant to termination notice dated 8/4/2020. No collateral was posted in accordance with the terms of the Agreement.
19	13014	Puget Sound Energy, Inc.	Transmission - Firm	9/30/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
20	13063	Puget Sound Energy, Inc.	Transmission - Non Firm	9/30/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
21	10117	Enerwise Global Technologies, LLC	DRAM Resource Purchase Agreement	10/31/2020	[redacted]
22	10110	Enel X North America, Inc.	DRAM Resource Purchase Agreement	10/31/2020	[redacted]
23	10111	Enerwise Global Technologies, LLC	DRAM Resource Purchase Agreement	10/31/2020	[redacted]
24	10112	Leapfrog Power, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
25	10120	OhmConnect California, LLC	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
26	10113	Stem, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
27	10114	Stem, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
28	10115	Tesla, Inc	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
29	10116	Voltus, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
30	10119	OhmConnect California, LLC	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
31	10121	Voltus, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
32	10118	Leapfrog Power, Inc.	DRAM Resource Purchase Agreement	12/31/2020	[redacted]
33	11192-1001	Chevron Power Holdings, Inc. (Sycamore Units, 2, 3, and 4)	EEI - RA Purchase	12/31/2020	Contract expired and collateral was returned to Seller in accordance with the terms of the Agreement.
34	11192-1002	Chevron Power Holdings, Inc. (Sycamore Units, 2, 3, and 4)	EEI - Toll Purchase	12/31/2020	Contract expired and collateral was returned to Seller in accordance with the terms of the Agreement.
35	11223-1001	AES Alamitos, L.L.C.	EEI - RA Purchase	12/31/2020	[redacted]
36	11224-1001	AES Huntington Beach, L.L.C.	EEI - RA Purchase	12/31/2020	[redacted]

j) Inter-utility Contracts

SCE was a party to two[142] major inter-utility contracts during the Record Period under which it was expected to purchase and/or exchange capacity and associated energy, as shown in Table VII-52. The Pasadena inter-utility contract was executed prior to industry restructuring and contains complex terms and conditions that were designed to satisfy the unique needs of SCE and each of the counterparties at the time of execution.

Table VII-52
Non-Coincident Contract Capacity Quantities and Expiration Dates for SCE's Major Inter-utility for 2020 Contracts

	ID	Counterparty	Type of Contract	Inbound Capacity (MW)	Outbound Capacity (MW)	Expiration Date
1	10045	WAPA/Bureau of Reclamation	Purchase	280.245	0	9/30/2067
2	11048	Pasadena	Exchange	3	15	Evergreen

(1) WAPA / Bureau of Reclamation (ID 10045)

The current contract with Western Area Power Administration (WAPA) and the Bureau of Reclamation, concerning the Boulder Canyon Project or Hoover Dam, was approved by the Commission in D.16-08-017. The delivery term under the contract began October 1, 2017 and will expire on September 30, 2067. There were no contractual changes or modifications associated with this contract during the Record Period.

(2) City of Pasadena Corporation Grant Deed (ID 11048)

On June 20, 1933, SCE and the City of Pasadena (Pasadena) entered into the Corporation Grant Deed that transferred ownership of a hydroelectric powerhouse and accompanying parcels of land in Azusa Canyon to Pasadena. In accordance with the exchange provisions of the Corporation Grant Deed, Pasadena delivers to SCE the entire electrical output of the Azusa Powerhouse (nameplate rated at 3 MW). Pasadena then has 12 months from the time of delivery

[142] Excluded from this total are SCE's so-called "Fringe Service" agreements, which provide for small amounts of energy exchanges among neighboring utilities. These include two contracts with the Department of Defense for the Air Force that SCE presented to the Commission in Advice Letters 2686-E and 1777-E and contracts associated with retail tariffs.

to SCE to request that SCE return a like amount of energy. SCE charges Pasadena for transmission service on the returned energy. If Pasadena does not request the like amount of energy, or any portion thereof, to be returned within this twelve-month period, Pasadena forfeits any subsequent right to the non-returned energy, and the energy is purchased by SCE at a rate of $2.50/MWh. There were no contractual changes or modifications associated with this contract during the Record Period.

3. PURPA AND CHP

This section provides information on PURPA and CHP contract management, including contract development, amendments, assignments, uncontrollable force claim administration, forced outage claim administration, dispute resolution, and contract terminations. SCE pursues these activities and programs in accordance with its contract administration principles and practices, and Commission guidelines. The following four fundamental principles have evolved to guide SCE's administration of its PURPA and CHP contracts:

- SCE's actions must be consistent with Commission directives;
- PURPA and CHP contract provisions that benefit or protect SCE's customers must be enforced pursuant to a reasonable interpretation of contract language;
- Contracts with affiliate and non-affiliate PURPA or CHP counterparties are to be administered in a consistent manner; and,
- Where appropriate, SCE's administration of PURPA and CHP contracts should be consistent with utility and/or industry practice.

a) Contract Administration

This section discusses SCE's administration of SO1, SO2, SO3, ISO4, NEG (negotiated), QF SOC, and AB 1613 Agreements; these PPAs are referred to in this section as "PURPA contracts," and the projects that generate power for sale to SCE under such contracts are referred to as "PURPA projects." This section also discusses the administration of CHP RFO and CHP Bilateral PPAs; these PPAs are "CHP contracts," and as explained earlier are no longer PURPA contracts, and the projects that generate power for sale to SCE under such contracts are referred to as "CHP projects." As explained below, the Commission has authorized SCE to recover the costs associated with PURPA and CHP contracts, subject to its review of SCE's administration of the contracts.[143]

In D.97-11-074, the Commission held that "costs associated with QF and inter-utility contracts should undergo reasonableness reviews" and that "[a]nnual reviews will include a review of contract administration and litigation costs."[144] In addressing the reasonableness of PURPA contract administration, the Commission found that utilities must administer their contracts in a prudent manner, ensure compliance with the terms and conditions of the contracts, and purchase and sell power in a manner that minimizes customer costs. Utilities are to exercise good utility practice in administering contracts. Utilities are expected to engage in those practices, methods, and acts that, in exercising reasonable judgment in light of the facts known when the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. The prudence standard is intended to include a range of acceptable practices, methods, or acts.[145]

In D.02-10-062, the Commission established the ERRA BA to track utility-retained generation, procurement activities, and purchased power expenses. In the Term Sheet of the QF Settlement adopted by D.10-12-035, the IOUs are directed to "recover the cost of all payments made pursuant to PPAs and PPA Amendments executed under [the] CHP Program in their respective Energy Resources Recovery Accounts".[146] Per D.10-12-035, the Commission adopted terms to allocate "relevant costs, as appropriate," for purposes of cost recovery through the CAM.[147] Similar to conventional, Table VII-53 includes PURPA and CHP projects with contract costs recovered through both CAM and the ERRA BA during the Record Period.

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[143] PURPA: Pub. Util. Code §367(2); D.95-12-063 at p. 130. CHP: D.10-12-035, approving Section 13.2 of Term Sheet.

[144] D.97-11-074, pp. 125, 127-128.

[145] *See, e.g.*, D.90-09-088, pp. 14-16.

[146] CHP Program Settlement Agreement Term Sheet, October 8, 2010, Section 13.2.1 at p. 56, *available at* https://www.pge.com/includes/docs/pdfs/b2b/energysupply/qualifyingfacilities/settlement/final_term_sheet.pdf.

[147] *Id.* at pp. 55-56, Sections 13.1.1 & 13.1.2.2.

Table VII-53
PURPA and CHP Contract Costs Recovered Through CAM and ERRA BA

	ID	Project	CAM Authorization	Contract Type
1	2155	Chevron USA (Train D)	D.14-07-019	SO1
2	2814	Berry Petroleum Company	E-4553	CHP RFO
3	2815	Sycamore Cogeneration Company (Baseload)	E-4555	CHP RFO
4	2818	GFP Ethanol, LLC (Pixley Cogen Partners, LLC)	D.09-12-042	AB1613
5	2819	Berry Petroleum Company	E-4681	CHP RFO
6	2824	Elk Hills	E-4682	CHP RFO
7	2826	U.S. Borax Inc.	E-4681	CHP RFO
8	2829	Watson Cogeneration Company	E-4714	CHP Bilateral
9	2834	Techni-Cast Corporation	D.09-12-042	AB1613
10	2835	CEFF II Tehachapi Property, LLC	N/A	AB1613
11	2845	New-Indy Ontario	E-4681	CHP RFO
12	2847	Houweling Nurseries Oxnard, Inc.	D.09-12-042	AB1613
13	2855	New-Indy Oxnard	E-4681	CHP RFO
14	2872	The Procter & Gamble Paper Products Company	3882-E	CHP RFO
15	2913	The Procter & Gamble Paper Products Company	D.07-09-040	QF SOC
16	2915	Tesoro Refining & Marketing Company, LLC	E-4800	CHP RFO

In this Section, SCE sets forth its recorded PURPA and CHP contract-related expenses and describes its PURPA and CHP contract administration activities, demonstrating that SCE reasonably administered these contracts during the Record Period.[148]

b) Summary of Contract Activity

During the Record Period, SCE purchased 0.74 billion kWh[149] from 45 PURPA contracts and recorded PURPA contract-related costs of $44.59 million. There was one PURPA project on-line that sold no power to SCE during the Record Period. Also, during the Record Period, SCE

[148] Two summary documents accompany this chapter as appendices. Appendix VII-I lists each active PURPA and CHP project and the Commission decision that found the applicable PURPA or CHP contract reasonable and eligible for rate recovery, subject to the contract administration review described above. Appendix VII-J sets forth payment and production figures for each active PURPA or CHP project from which SCE purchased power during the Record Period.

[149] Purchases in billion kWh from PURPA projects by month were as follows:

Billions of kwh	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
PURPA	0.09	0.05	0.06	0.06	0.06	0.07	0.08	0.07	0.06	0.05	0.05	0.04	0.74

purchased 0.063 billion kWh[150] from 10 active CHP contracts, and recorded CHP contract-related costs of $3.32 million.

There was 1,543 MW of net on-line capacity available for sale to SCE from PURPA and CHP projects during the Record Period (*i.e.,* generating capacity net of station use and other committed on-site loads). This net on-line capacity includes six technologies: (1) biomass; (2) cogeneration or combined heat and power; (3) geothermal; (4) small hydro; (5) solar; and, (6) wind.[151] Approximately 27% of SCE's net on-line capacity from PURPA, CHP RFO or CHP Bilateral PPAs is from renewable technologies[152] (423 net MW), while the remaining 73% is from cogeneration or other QFs ineligible to be classified as renewable projects (1,120 net MW).[153] No PURPA projects achieved commercial operation during the record period. While most CHP and PURPA projects are within SCE's 50,000 square mile service area, SCE also has PURPA and CHP contracts with projects in the service areas of PG&E, and the Imperial Irrigation District (IID).

The PURPA and CHP contracts administered by SCE during the Record Period include: 4 AB 1613 contracts; 10 SO1 contracts; 2 SO2 contracts; 8 SO3 contracts; 9 ISO4 contracts; 8 NEG contracts; 10 CHP RFO contracts; and 4 QF SOC contracts.

c) PURPA and CHP Projects That Achieved Commercial Operation or Started Delivering to SCE under a New Contract

Table VII-54 shows the CHP and PURPA projects that came on-line or started delivering to SCE under a new contract during the Record Period.

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[150] Purchases in billion kWh from CHP projects by month were as follows:

Billions of kwh	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
CHP	0.005	0.006	0.006	0.004	0.005	0.005	0.005	0.005	0.004	0.005	0.006	0.008	0.063

[151] SCE uses a numbering convention to identify contracts by technology. The 1000 series refers to biomass, the 2000 series refers to cogeneration, the 3000 series refers to geothermal, the 4000 series refers to small hydro, the 5000 series refers to solar, and the 6000 series refers to wind. In previous years, these may have been identified as "RAP ID".

[152] Renewable technologies include: small hydro projects less than 30 MW, biomass, geothermal, wind, and solar. Though classified as QFs, output from these RPS-eligible projects contribute to RPS goals.

[153] Note that much of this capacity is due to projects that are currently delivering under Legacy PURPA contracts; however, many of these projects have signed and will begin deliveries under CHP RFO PPAs in upcoming record periods.

Table VII-54
PURPA and CHP Contracts that Achieved Commercial Operation
January 1, 2020 Through December 31, 2020

	ID	Project	PPA Type	Commercial On-line Date	Capacity (MW)
1	2872	The Procter and Gamble Paper Products	CHP-RFO	1/1/2020	20.5
2	2913	The Procter and Gamble Paper Products	QF-SOC	8/1/2020	19.6

d) Contract Development

During the Record Period, SCE entered into the PURPA and CHP contracts identified in Table VII-55.

Table VII-55
PURPA and CHP New Contracts Executed
January 1, 2020 Through December 31, 2020

	ID	Project	Contract Type	Capacity (MW)	Date Executed	CPUC Resolution or Decision/SCE Advice Letter/Application
1	2913	The Procter and Gamble Paper Products	QF-SOC	19.6	5/13/2020	D.10-12-035

e) Contract Amendment Administration

Table VII-56 summarizes the PURPA and CHP amendments SCE entered into during the Record Period for which it is seeking approval through this ERRA filing.

Table VII-56
PURPA and CHP Contract Amendments and Letter Agreements
January 1, 2020 Through December 31, 2020

	ID	Project	Amendment or Agreement and Description	Date Executed
1	2872	The Procter and Gamble Paper Products	[redacted]	1/13/2020
2	6065 6066 6067	Sky River Partnership (Wilderness I) Sky River Partnership (Wilderness II) Sky River Partnership (Wilderness III)	Letter Agreement to extend the the time provided to negotiate and execute a Resource Adequacy (RA) purchase agreement.	1/31/2020
3	2872	The Procter and Gamble Paper Products	Amendment No. 2 to provide additional output of 19.7 MW from Cogen 2 until May 31, 2020, until Cogen 1 completed its metering equipment installation under a separate PURPA PPA.	3/2/2020
4	2872	The Procter and Gamble Paper Products	Amendment No. 3 to modify the term to extend the additional output of 19.7 MW form Cogen 2 until July 31, 2020.	5/21/2020
5	5050	Luz Solar Partners Ltd. VIII	Amendment No. 6 to terminate the IIFA with respect to SEGS VIII upon the expiration of SEG VIII's SO2 contract on May 29, 2020.	5/28/2020
6	2913	The Procter and Gamble Paper Products	[redacted]	8/10/2020
7	2826	U.S. Borax Inc.	Amendment No. 2 to modify the definition of Required GHG Quantity.	9/15/2020
8	3027	Mammoth-Pacific, L.P.	Letter Agreement to modify provisions to extend, by one additional day to allow for continuous operation and scheduling coordinator services through December 7, 2020.	12/3/2020

(1) Procter and Gamble Paper Products, LLC (ID 2872)

The Procter and Gamble Paper Products (P&G) Cogen 2 is a 49.9 MW combined cycle gas turbine project located in Oxnard, California, originally executed as part of SCE's CHP 6 solicitation. The PPA was executed on August 27, 2018. SCE and P&G executed a Letter Agreement on January 13, 2020 to [redacted] SCE's customers benefit from this letter agreement because [redacted]

(2) Sky River Partnership (Wilderness I, Wilderness II and Wilderness III) (ID 6065, 6066 and 6067)

Sky River Partnership-Wilderness I is a 36.775 MW wind project, Sky River Partnership-Wilderness II is a 19.8 MW wind project, and Sky River Partnership-Wilderness III is a 20.925 MW wind project (collectively "Sky River"), all of which are located in Kern County, California, originally executed as Interim Standard Offer 4 contracts on January 30, 1985. SCE and Sky River executed Termination Agreements on December 18, 2018 (see SCE ERRA Filing A.19-04-001, SCE-01C, Chapter VII, Section 4.E.5, 6 and 7) to terminate the PPAs on December 31, 2019 and decommission the facilities immediately thereafter. SCE and Sky River executed a Letter Agreement on December 31, 2019 to suspend the decommissioning of the facilities and to allow Sky River to continue operating as a merchant facility after the termination of the PPAs on January 1, 2020. SCE and Sky River executed an amendment to the Letter Agreement on January 31, 2020 to extend the time provided to negotiate and execute an agreement where SCE will purchase all of the Resource Adequacy from each of the facilities in 2020 and 2021. SCE's customers benefit from this Letter Agreement because it allows the projects to continue operating and providing much needed resource adequacy to the grid.

(3) <u>Procter and Gamble Paper Products, LLC (ID 2872)</u>

The Procter and Gamble Paper Products (P&G) Cogen 2 is a 49.9 MW combined cycle gas turbine project located in Oxnard, California, originally executed as part of SCE's CHP 6 solicitation. The PPA was executed on August 27, 2018. The PPA was originally awarded for 20.5 MW of contract capacity, the balance of the plant was to be used for on-site and host load. P&G is also seeking a PURPA PPA (QF SOC) for its Cogen 1 plant which is rated at 19.7 MW. The Cogen 1 plant has experienced delays in installation of metering equipment which is causing a delay of the start of its QF SOC. Prior to Cogen 1 operating under the QF SOC, Cogen 1 will provide on-site and host load. After the start of the QF SOC, Cogen 2 will provide on-site and host load. SCE and P&G executed Amendment No. 2 on March 2, 2020 to modify the contract capacity to allow additional output in the amount of 19.7 MW from Cogen 2 until May 31, 2020, until Cogen 1 completed its metering equipment installation under its separate QF SOC. SCE's customers benefit from this amendment because of [redacted] and because it provides increased capacity and important reliability to the grid.

(4) Procter and Gamble Paper Products, LLC (ID 2872)

The Procter and Gamble Paper Products (P&G) Cogen 2 is a 49.9 MW combined cycle gas turbine project located in Oxnard, California, originally executed as part of SCE's CHP 6 solicitation. The PPA was executed on August 27, 2018. The PPA was originally awarded for 20.5 MW of contract capacity, the balance of the plant was to be used for on-site and host load. SCE and P&G executed Amendment No. 3 on May 21, 2020 to modify the term to extend the additional output in the amount of 19.7 MW from Cogen 2 until July 31, 2020 due to continued delays associated with Cogen 1 under a separate PURPA PPA. SCE's customers benefit from this amendment because of [redacted] and because it provides increased capacity and important reliability to the grid.

(5) Luz Solar Partners Ltd. VIII (ID 5050)

Luz Solar Partners Ltd. VIII (SEGS VIII) is an 80 MW solar thermal project located in Hinkley, California originally executed as a Standard Offer 2 (SO2) contract. The PPA was executed on June 14, 1988. The SEGS VIII project shares an Interconnection and Integration Facilities Agreement (IIFA) with the SEGS IX project. The IIFA was executed on November 30, 1988. SCE and SEGS VIII executed Amendment No. 6 to the IIFA on May 28, 2020 to terminate the IIFA with respect to SEGS VIII upon the expiration of SEG VIII's SO2 contract on May 29, 2020, thus allowing SEGS VIII to operate under a new Large Generator Interconnection Agreement after contract expiry and allows SEGS IX to continue operating under the existing IIFA. SCE's customers benefit from the amendment by having the project transition to its own and a current interconnection agreement.

(6) Procter and Gamble Paper Products Company (ID 2913)

The Procter and Gamble Paper Products Company (P&G) is a 19.57 MW gas combustion turbine project located in Oxnard, California, originally executed as a QF Standard Offer contract. The PPA was executed on May 13, 2020. SCE and P&G executed a Letter Agreement on August 10, 2020 to [redacted] SCE's customers benefit from this letter agreement because [redacted]

(7) U.S. Borax, Inc. (ID 2826)

U.S. Borax Inc. is a 28 MW cogeneration project located in Boron, California, originally executed as part of SCE's CHP 2 RFO. The PPA was executed on April 23, 2014. SCE and U.S. Borax Inc. executed Amendment No. 2 on September 15, 2020 to modify the definition of "Required GHG Quantity" to allow for clarity and accuracy of the contractual term as it relates to the calculation of the GHG quantity. SCE's customers benefit from this amendment by having accurate information available for contract administration.

(8) Mammoth-Pacific, LP (ID 3027)

Mammoth-Pacific, L.P. is a 10.5 MW geothermal facility located in Mammoth Lakes, California, originally executed as an Interim Standard Offer 4 contract. The PPA was executed on April 15, 1985 and the original term expired on December 6, 2020. On March 15, 2013, SCE and Mammoth-Pacific, L.P executed an Amended and Restated Power Purchase Contract to extend the contact term by 73 months beginning December 8, 2020. SCE and Mammoth-Pacific, L.P executed a Letter Agreement on December 3, 2020 to modify the provisions of the PPA to extend by one additional day to allow for continuous operation and scheduling coordinator services through December 7, 2020 and bridge the gap between the original term expiration date of December 6, 2020 and the start of the Amended and Restated Power Purchase Contract on December 8, 2020. SCE's customers benefit from this letter agreement because of the associated one-time payment of [redacted] SCE retains all CAISO revenues and SCE is not responsible for a capacity payment for that day, and CAISO debts, costs, penalties, interests or sanctions assigned by CAISO are for Mammoth-Pacific, L.P.'s account.

f) Contract Assignment Administration

PURPA and CHP contracts typically may be assigned to other parties based upon the written consent of the parties, which may not be unreasonably withheld. Counterparties may request SCE's consent to assignment of their contracts for many reasons, including, among others, the project's sale or transfer to a new entity, sell or assign part of the ownership in the project to tax equity, assign the contract to a lender as security for a loan, or effectuate a change of control of the project. Certain assignments may require SCE to consent to the appointment of a project manager. Table VII-57 lists the CHP and PURPA contract consents and assignments to which SCE consented during the Record Period.

Table VII-57
CHP and PURPA Contract Consents and Consents to Assignments
January 1, 2020 Through December 31, 2020

	ID	Project	Types of Assignment or Consents	Date Signed
1	2835	SunSelect Produce (California), Inc.	Consent to Assignment	1/30/2020
2	2836	Victorville Energy Center, LLC	Consent to Assignment of Membership Interest	3/30/2020

g) Affiliate Transactions and Contract Information

SCE had no affiliate PURPA or CHP contracts during the Record Period.

h) Dispute Resolution and Litigation

SCE did not have any PURPA and CHP Projects that had dispute resolutions and litigation activities during the Record Period.

i) Uncontrollable Force Administration

SCE's SO2, ISO4 contracts, many of its NEG contracts, and CHP contracts include provisions that may excuse a PURPA or CHP project from performing certain contractual obligations to the extent the project can demonstrate that the occurrence of an uncontrollable force prevented the project from performing such obligations. An uncontrollable force is any circumstance beyond a project's reasonable control as defined in the agreements and is often known as a *force majeure*.

Whenever a PURPA or CHP contract holder claims that an uncontrollable force caused it to fail to meet its contractual obligations, SCE undertakes the following activities:

- Determines whether the claim was submitted within the contractually-required period, which is typically two weeks;
- Requires that the counterparty submit sufficient evidence to substantiate the claim that an uncontrollable force event occurred. This may include meteorological or weather reports to support a claim of weather damage, construction and equipment specifications, manufacturer

maintenance manuals and bulletins, the project's operations and maintenance/repair logs, copies of insurance claims, damage assessments, failure reports, or other relevant materials; and

- Evaluates whether the suspension of performance was of no greater scope and of no longer duration than was required by the uncontrollable force, and that the contract holder used its best efforts to remedy its inability to perform.

If SCE grants the claim, and if the contract does not provide otherwise, the firm capacity PURPA or CHP contract counterparty will continue to receive firm capacity payments for up to 90 days from the occurrence, despite its inability to deliver power to SCE. Such payments are typically based upon the project's historical performance during the affected time period. In addition, during the period of an approved uncontrollable force event, delivery requirements under the contract are excused.

There were no uncontrollable force claims tendered to SCE or pending during the Record Year.

j) <u>Forced Outage Claim Administration</u>

A forced outage claim is approved when a project operating pursuant to a PURPA or CHP contract is otherwise capable of generating electricity but is forced to shut down either because SCE is unable to receive the generation due to abnormal system conditions or because of a failure in the project's operations. An approved forced outage claim generally has the same effect upon the project as an approved uncontrollable force claim (otherwise known as a f*orce majeure*); namely, the project's performance requirements are excused during the period of the forced outage. The forced outage may also be contractually obligated and defined in the contract. There is no deadline specified in the PURPA or CHP contracts by which the counterparty must notify SCE that a forced outage has occurred. However, SCE considers the promptness with which the claim is submitted, among other factors, in determining whether to grant the claim. In assessing the claim, SCE verifies that an outage occurred, whether the outage resulted from an event that constitutes a forced outage under the contract, and the magnitude and duration of the outage. If appropriate, SCE analyzes meter data, substation logs, and system operations reports in reviewing the claim. SCE did not have any PURPA or CHP Projects that had uncontrollable forced outage claim activities during the Record Period.

k) Contract Terminations

Table VII-58 identifies the terminations that occurred during the Record Period.

Table VII-58
PURPA and CHP Contract Terminations
January 1, 2020 Through December 31, 2020

	ID	Project	Capacity (MW)	Contract Type	Termination Date	Notes
1	6103	Victory Garden Phase IV Partner - 6103	7.0	ISO4	1/1/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
2	6102	Victory Garden Phase IV Partner - 6102	7.0	ISO4	1/31/2020	[redacted]
3	6104	Victory Garden Phase IV Partner - 6104	7.0	ISO4	1/31/2020	
4	6113	Desert Winds II Pwr Purch Trst	75.0	ISO4	2/29/2020	
5	4039	Kaweah River Power Authority	17.0	ISO4	3/15/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
6	3028	Salton Sea Power Generation Co #2	20.0	ISO4	4/4/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
7	6095	Dutch Wind, LLC	8.0	ISO4	4/12/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
8	2205	E. F. Oxnard Incorporated	48.5	NEG	5/24/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
9	5050	Luz Solar Partners Ltd. VIII	80.0	SO2	5/29/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
10	4145	Mesa Consolidated Water District	0.1	SO3	6/5/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
11	2010	Loma Linda University	13.4	SO1	6/30/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
12	1009	L.A. Co. Sanitation Dist CSD 2610	3.9	NEG	7/23/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
13	5010	Curtis, Edwin	0.0	SO3	9/10/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
14	4034	Central Hydroelectric Corp.	12.0	ISO4	12/7/2020	Contract expired and no collateral was posted in accordance with the terms of the Agreement.
15	2815	Sycamore Cogeneration Company (Baseload)	85.0 - 170.0	CHP-RFO	12/31/2020	Contract expired and collateral was returned to Seller in accordance with the terms of the Agreement.
16	2824	Elk Hills Power, LLC	200.0	CHP-RFO	12/31/2020	Contract expired and collateral was returned to Seller in accordance with the terms of the Agreement.

4. RPS

Commission Resolutions approving RPS contracts typically provide for the recovery of all payments made pursuant to those contracts, subject to the Commission's review of the reasonableness of SCE's contract administration. In D.02-10-062, the Commission established the ERRA to track utility retained generation, procurement activities, and purchased power expenses. These expenses include power purchased pursuant to the RPS contracts discussed in this chapter.

a) Contract Administration

This section provides information on all activities related to the management of RPS contracts, including contract development, amendments, assignments, contract capacity verifications, measurement of energy deliveries, terminations, active monitoring of contracts to ensure the project output qualifies under requirements of the RPS, and activities related to management of projects in the Western Renewable Energy Generation Information System (WREGIS).[154]

b) Summary of Contract Activity

During the Record Period, SCE purchased 24.71 billion kWh [155] from 265 RPS contracts, and recorded RPS payments of $2.321 billion.

Below, SCE sets forth its recorded RPS contract-related expenses, describes its RPS contract development and administration activities during the Record Period, and demonstrates that such activities were reasonable.[156] SCE executes power purchase agreements (referred to as RPS contracts or PPAs) with renewable generators through competitive solicitations, bilateral negotiations, standard contracts, and feed-in tariffs.

Pursuant to AB 1969 and SB 380, SCE administers a feed-in tariff for eligible renewable projects that are 3 MW and less. In July 2013, the Renewable Market Adjusting Tariff (ReMAT) replaced the California Renewable Energy Small Tariff (CREST) and the Water Agency

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[154] Throughout this section, any undefined capitalized terms have the meaning set forth in the relevant RPS project contract.

[155] Purchases in billion kWh from RPS contracts by month were as follows:

Billions of kwh	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
ERR	1.650	1.750	1.900	2.220	2.520	2.570	2.690	2.450	1.910	1.760	1.700	1.580	24.71

[156] Two summary documents accompany this chapter as Appendices VII-K and VII-L. Appendix VII-K lists each RPS project active or terminated during the Record Period and the corresponding Commission application for approval or resolution that found the RPS contract reasonable as to formation Appendix VII-L sets forth payment and production figures for each RPS project from which SCE purchased power during the Record Period.

Tariff for Eligible Renewables (WATER) for eligible renewable projects that are 1.5 MW and less. On December 6, 2017, an order was issued by the U.S. District Court for the Northern District of California granting summary judgment in favor of plaintiff Winding Creek Solar LLC in case No. 13-cv-04934-JD. In a letter dated December 15, 2017, the CPUC instructed each of the three IOUs to not execute any new ReMAT contracts, to not hold any new ReMAT program periods, and to not accept any new ReMAT applications effective as of that date, pending further CPUC action or another court order. Therefore, no such ReMAT activity occurred in the Record Period, however, SCE's Contract Management group continued to administer ReMAT contracts executed in prior years. On January 22, 2021, the CPUC approved (1) Advice Letters ("AL") 4331-E and AL 4331-E-A filed by SCE that presented modifications to ReMAT and to the power purchase agreement pursuant to D. 20-10-005, which authorized the re-launch of the ReMAT program, and (2) other pending advice letters (AL 3660-E and AL 3660-E-A) filed by SCE for the ReMAT program. At the CPUC's direction, SCE re-launched the program on February 11, 2021.

Pursuant to Executive Order S-06-06,[157] SCE voluntarily developed a standard biomass program for eligible projects of 20 MW and less. This program was then expanded to all renewable generators through Renewable Standard Contracts (RSC) for generators 5 MW and less (RSC5) and 20 MW and less (RSC20). During the 2010 Record Period, in response to the market, SCE changed the structure of the RSC program and modeled it after SCE's all-source RFOs with reverse auction pricing instead of a fixed price at the Market Price Referent (MPR). In D.10-12-048, issued on December 17, 2010, the Commission adopted the then new procurement process called Renewable Auction Mechanism (RAM) to procure renewable energy from projects 20 MW or less that are RPS-eligible, replacing SCE's RSC program. D.10-12-048 ordered SCE, PG&E, and SDG&E to implement the RAM and procure 1,000 MW allocated across the utilities over a two-year period through

[157] Signed April 25, 2006, the executive order established a 20% biomass target within the 20% state RPS target.

competitive auctions using standard non-negotiable contracts.[158] As a result of these programs, SCE administers many RSC and RAM program contracts.

SCE administers the Community Renewables-Renewables Auction Mechanism contracts implementing SB 43's goal to encourage the use of renewable energy, for those who might not have access to products such as solar rooftop. Minimum customer subscription requirement ramps from 45% in year one to 95% in year four and beyond. D.15-01-051,[159] D.16-05-006, and Resolution E-4734 established the Green Tariff Shared Renewables (GTSR) program to implement SB 43. The Commission ordered the IOUs to use the RAM or ReMAT programs for this advance procurement and to have advance procurement under contract within one year following the issuance of the GTSR Decision. The GTSR Decision further authorized the IOUs to seek approval of a GTSR standard contract through changes to the RAM standard contract using a Tier 2 Advice Letter.[160]

Following the sixth RAM auction (RAM 6), SCE incorporated the RAM procurement tool into its annual RPS solicitation as the "Standard Contract Option." The Commission approved this approach in D.14-11-042 and D.15-12-025.[161] Additionally, in accordance with its tariff and prior Commission decisions, SCE launched its first solicitation for Enhanced Community Renewables (ECR) projects between 0.5 MW and 3 MW using the ECR-Market Adjusting Tariff. D.16-05-006, which was the culmination of Phase IV of the proceeding concerning Applications 12-01-008, 12-04-020, and 14-01-007, refined the GTSR Program rules adopted in D.15-01-051. Among other things, D.16-05-006 allowed ECR projects between 500 kW and 20 MW and ECR-Environmental Justice projects, located in SCE's top 20% most impacted communities, between 500 kW and 1 MW to participate in newly required solicitations using the RAM tool.[162] D.16-05-006 also indicated that use of

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158 The Commission further clarified details of the RAM program in Resolution E-4414, issued August 22, 2011, Resolution E-4489, issued April 19, 2012 and Resolution E-4546, issued November 8, 2012.

159 D.15-01-051, at p. 27, OP 8, at p. 181.

160 See GTSR Decision, OP 5, at p. 180.

161 D.14-11-042 at OP 30 and D.15-12-025 at OP 1.

162 D.16-05-006 at p. 12.

the ReMAT tool to procure ECR projects is no longer required, but each IOU may use the ReMAT tool at its discretion.

SCE administers the BioRAM contracts implemented in response to the Emergency Proclamation issued on October 30, 2015, by Governor Brown to protect public safety and property from falling dead trees and wildfire. On March 18, 2016, the Commission issued Resolution E-4770 requiring each IOU to hold a RAM auction targeted at facilities that utilize fuel from high hazard zones (HHZ) in order to procure at least 50 MW (20 MW, PG&E; 20 MW, SCE; and 10 MW, SDG&E). On August 31, 2016, the California legislature passed SB 859 and it was signed into law on September 14, 2016. As a result, the Commission issued Resolution E-4805 on October 21, 2016, to include a new requirement for IOUs to procure their respective shares of capacity from existing biomass facilities using dead and dying trees located in HHZs as feedstock. On December 13, 2018, the Commission issued D.18-12-003 establishing a methodology for calculating a non-bypassable charge to collect revenue to pay for BioRAM procurement by the IOUs through each utility's public purpose program charge.

SCE administers the Solar Photovoltaic Program (SPVP). Under SPVP RFOs, SCE conducted solicitations for an overall target of 125 MW of non-utility-owned solar photovoltaic installations over a five-year period, made up of primarily rooftop projects in the 1 to 2 MW range; however, larger systems and ground-mount systems were also eligible to participate.[163] SCE satisfied its procurement target, therefore, the program is now closed.

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[163] On February 11, 2011, SCE filed a Petition for Modification (PFM) of the SPVP, requesting that the Commission increase the competitive solicitation portion of the SPVP from 250 MW to 375 MW, with 125 MW administered under the original SPVP-RFO parameters set forth in D.09-06-049 and Resolution E-4299 and 250 MW administered under revised parameters. The SPVP goals are rated in MW DC. On January 16, 2012, the Commission issued a Decision partially granting SCE's PFM. The Decision modifies the SPVP to no more than 125 MW each of IPP procurement and utility development, with the amount of ground-mounted facilities increased to 20% (25 MW). The 250 MW cut from the original capacity cap were moved to the RAM program (as 200 MW AC). On July 27, 2012, SCE filed a second PFM of the SPVP, requesting that the Commission reduce the 125 MW target for the utility development portion of the SPVP to no more than 91 MW and move the remaining 34 MW to SCE's RAM allocation (as 31 MW AC). On June 3, 2013, the Commission granted SCE's second PFM.

SCE administers the Preferred Resources Pilot (PRP) program, which is a multi-year study designed to determine whether clean energy resources, including Energy Efficiency, Demand Response, Renewable Distributed Generation, and Energy Storage, can be acquired and deployed to offset the increasing customer demand for electricity in portions of central and south Orange County. The growing gap between supply and demand for electricity in the PRP area is due in part to the closure of the San Onofre Nuclear Generating Station and the impending retirement of nearby ocean-cooled power plants, known as Once-Through-Cooling (OTC), which may affect grid reliability. Based on the pilot's results, the need for new gas-powered power plants in the region may be deferred or eliminated.

SCE also administers Disadvantaged Communities (DAC) Green Tariff (GT or DAC-GT) and Community Solar Green Tariff (CSGT, or DAC-CSGT). Assembly Bill (AB) 327 (Perea), Stats. 2013, ch. 611, directed the Commission to develop a successor to the then existing Net Energy Metering tariff that included, "promoting the installation of renewable generation among residential customers in disadvantaged communities." On June 22, 2018, the alternate Decision (D.) 18-06-027 adopted alternatives to promote solar distributed generation in DAC, with further corrections and clarifications issued on October 18, 2018. On May 30, 2019, Commission approved via Resolution E-4999, with modifications, tariffs to implement DAC-GT and DAC-CSGT programs. Final approval of Advice Letters 4049-E and 4049-E-A providing the procurement plan, RFO and RFI, and non-negotiable contract, was received on December 30, 2019. DAC-GT program provides low-income customers in DACs the option to receive 100% of their energy from renewable resources located within a DAC that is anywhere in SCE's service territory. DAC-CSGT program provides DAC customers the option to receive 100% of their energy from a local solar renewable resource located within five miles of a DAC census tract within SCE's service territory, or within 40 miles of San Joaquin Valley pilot program community identified in Decision 17-05-014. SCE gives DAC-GT and DAC-CSGT customers a 20% discount on their electric bill. SCE is required to launch two DAC-GT and DAC-CSGT RFOs a year, until program caps of DAC-GT 56.50 MW and DAC-CSGT 14.63 MW are met.

Projects that are in development or generate power for purchase by SCE under RPS contracts or REC sales from SCE to counterparties under an EEI Confirm, are discussed in this chapter and are referred to as "RPS projects."[164] There are many renewable projects selling electric power to SCE which have maintained status as QFs and are delivering renewable energy to SCE under a PURPA contract. They are covered in the earlier testimony section for PURPA and CHP.

c) RPS Contracts that Achieved Commercial Operation

Table VII-59 shows the RPS projects that came on-line or started delivering to SCE under a new contract during the Record Period.

Table VII-59
RPS Contracts that Achieved Commercial Operation
January 1, 2020 Through December 31, 2020

	ID	Project	Commercial On-line Date	Capacity (MW)
1	5804	Copper Mountain Solar 4, LLC	1/1/2020	93.6
2	5882	Sun Streams, LLC	1/1/2020	160.0
3	5884	Sunshine Valley Solar, LLC	1/1/2020	104.0
4	6380	Voyager Wind I, LLC	1/1/2020	132.0
5	5889	Blythe Solar III, LLC	5/20/2020	136.8
6	5805	Imperial Valley Solar 2, LLC (f/k/a 88FT 8me LLC)	6/1/2020	153.5
7	5810	41MB 8me LLC	6/1/2020	51.3
8	5263	American Kings Solar, LLC	12/12/2020	128.0
9	5264	Maverick Solar, LLC	12/16/2020	125.0

d) Contract Development

Table VII-60 below shows the RPS contracts executed during the Record Year. This is for information only as these contracts were either pre-approved or submitted for approval through an advice letter or application as indicated in the table.

[164] SCE uses a contract numbering convention to identify contracts by technology, where the 1000 series refers to biomass, the 3000 series refers to geothermal, the 4000 series refers to small hydro, the 5000 series to solar, the 6000 series to wind, and a five digit number followed by a dash, and then by a four digit number (e.g. 11234-8015) refers to REC sales.

Table VII-60
New RPS Contracts Executed
January 1, 2020 Through December 31, 2020

	ID	Project	Initial Nameplate Contract Capacity and Expansion Option (MW)	Contract Type	Executed Date	Advice Letter or CPUC Resolution and Date
1	1346	Santa Barbara County	2.3	BioMAT	1/7/2020	N/A - Pre-Approved
2	1347	Organic Energy Solutions, LLC	2.6	BioMAT	1/13/2020	N/A - Pre-Approved
3	11181-8039	Shell Energy North America (US), L.P.	13.3 - 17.1	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
4	11234-8038	Marin Clean Energy	21.6 - 39.9	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
5	11246-8034	Clean Power Alliance of Southern California	0.1 - 1.1	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
6	11246-8035	Clean Power Alliance of Southern California	79.9	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
7	11256-8037	East Bay Community Energy Authority	57.1	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
8	11260-8036	Commercial Energy of Montana, Inc.	2.0 - 3.5	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
9	11262-8040	The Energy Authority, Inc.	3.4 - 32.5	EEI - Energy + REC Sale	7/10/2020	4251-E, 4251-E-A
10	5126	Visalia CSG LLC	3.0	CSGT	9/18/2020	4297-E
11	11181-8044	Shell Energy North America (US), L.P.	11.4	EEI - Energy + REC Sale	12/7/2020	4392-E
12	11228-8045	Sonoma Clean Power Authority	31.3 - 32.5	EEI - Energy + REC Sale	12/7/2020	4392-E
13	11246-8041	Clean Power Alliance of Southern California	148.4	EEI - Energy + REC Sale	12/7/2020	4392-E
14	11256-8043	East Bay Community Energy Authority	2.9	EEI - Energy + REC Sale	12/7/2020	4392-E
15	11258-8042	Direct Energy Business Marketing, LLC	9.1	EEI - Energy + REC Sale	12/7/2020	4392-E
16	11260-8047	Commercial Energy of Montana, Inc.	74.1	EEI - Energy + REC Sale	12/18/2020	4378-E

e) Contract Amendment Administration

After execution, RPS contract terms and conditions may be changed by amendment. Table VII-61 below lists the RPS contract amendments SCE entered into during the Record Period and for which it seeks Commission approval through this filing.

Table VII-61
RPS Contract Amendments and Letter Agreements
January 1, 2020 Through December 31, 2020

	ID	Project	Amendment Number and Description	Date Executed
1	1245	MM Tulare Energy, LLC	[redacted]	1/14/2020
2	5628	Vega Solar, LLC	Amendment No. 3 to reduce the collateral held by SCE for a one-time payment to SCE.	3/3/2020
3	5810	41MB 8me LLC	[redacted]	5/15/2020
4	5811	RE Tranquillity LLC	[redacted]	5/20/2020
5	5888	RE Garland, LLC	[redacted]	5/20/2020
6	5774	Solar Oasis LLC	Amendment No. 3 to reduce the collateral held by SCE for a one-time payment to SCE.	6/1/2020
7	5814	North Rosamond Solar, LLC	[redacted]	6/17/2020
8	3118	Geysers Power Company, LLC	Amendment No. 1 to clarify the PPA definitions for Term Year and Term, and to delete a PPA term no longer defined and used, however unintentionally left in the PPA.	7/22/2020
9	5810	41MB 8me LLC	[redacted]	7/22/2020
10	5774	Solar Oasis LLC	Amendment No. 4 to resolve a potential dispute arising from a change in methodology to calculate Net Qualifying Capacity from the exceedance methodology to the effective load carrying capacity methodology effective January 1, 2018. The amendment also updates certain curtailment provisions in the PPA.	8/5/2020
11	5805	Imperial Valley Solar 2, LLC	[redacted]	8/6/2020
12	5774	Solar Oasis LLC	Amendment No. 5 to modify the assignment provisions by adding Permitted Transferee language to allow Solar Oasis to assign the PPA without SCE consent under specific conditions and requirements.	9/17/2020

13	5626	Orion Solar II, LLC	Amendment No. 4 to reduce the collateral held by SCE for a one-time payment to SCE.	11/25/2020
14	5885	Blythe Solar II, LLC	Letter Agreement No. 2 to allow more time for Seller to participate in a Pilot Program providing ancillary services (AS) to the grid. This extension will allow SCE to collect more data on the effectiveness of solar PV failities providing AS to the grid.	12/2/2020
15	5886	Valentine Solar, LLC	[redacted]	12/15/2020
16	11260-8047	Commercial Energy of Montana, Inc.	[redacted]	12/23/2020
17	5284	Silver State Solar Power South, LLC	Amendment No. 3 to reduce the collateral held by SCE for a one-time payment to SCE.	12/28/2020
18	5494	McCoy Solar, LLC	Amendment No. 2 to reduce the collateral held by SCE for a one-time payment to SCE.	12/28/2020
19	5758	Adelanto Solar, LLC	Amendment No. 5 to reduce the collateral held by SCE for a one-time payment to SCE.	12/28/2020
20	4213	TKO Power, LLC (South Bear Creek)	Amendment No. 2 to reduce the Product Price in exchange for waiving SCE's termination right in connection with an Event of Default for failing to meet 20% of Expected Net Annual Energy Production over a twelve (12) month period.	12/30/2020

(1) <u>MM Tulare Energy, LLC (ID 1245)</u>

MM Tulare Energy, LLC is a 1.5 MW biomethane landfill gas project located in Visalia, California, originally executed as part of SCE's ReMAT solicitation. The PPA was executed on March 14, 2017. SCE and MM Tulare Energy executed a Letter Agreement on January 14, 2020 to [redacted] SCE's customers benefit from this Letter Agreement because [redacted]

(2) <u>Vega Solar, LLC (ID 5628)</u>

Vega Solar, LLC is a 20 MW solar project located in Los Banos, California, originally executed as part of SCE's RAM 2 solicitation. The PPA was executed on August

30, 2012. SCE and Vega Solar executed Amendment No. 3 on March 3, 2020 to modify Vega Solar's Performance Assurance collateral posting obligation to [redacted] in exchange for a one-time payment to SCE. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted]

(3) 41MB 8me, LLC (ID 5810)

41MB 8me, LLC (Borden Solar Farm) is a 51.30 MW solar PV project located in Madera County, California, originally executed as part of SCE's 2013 RPS solicitation. The PPA was executed on July 31, 2014. SCE and Borden Solar Farm executed Amendment No. 3 on May 15, 2020 to [redacted] and (iii) to update Borden Solar Farm's Notice information. SCE's customers benefit from this amendment by having correct and current information available for contract administration and [redacted].

(4) RE Tranquillity, LLC (ID 5811)

RE Tranquillity LLC is a 205.296 MW solar PV project located in Tranquillity, California, originally executed as part of SCE's 2013 RPS solicitation. The PPA was executed on July 31, 2014. SCE and RE Tranquillity executed Amendment No. 4 on May 20, 2020 to [redacted] SCE's customers benefit from this amendment because it allows the funding, construction, and the efficient operation of the new energy storage project and by having correct and accurate information available for contract administration.

(5) RE Garland LLC (ID 5888)

RE Garland LLC is a 185.133 MW solar PV project located in Rosamond, California, originally executed as part of SCE's 2014 RPS solicitation. The PPA was executed on July 16, 2015. SCE and RE Garland executed Amendment No. 2 on May 20, 2020 to [redacted] SCE's customers benefit from this amendment because it allows the funding, construction, and the efficient operation of the new energy storage project and by having correct and accurate information available for contract administration.

(6) Solar Oasis LLC (ID 5774)

Solar Oasis, LLC is a 20 MW solar PV project located in Palmdale, California, originally executed as part of SCE's RAM4 solicitation. The PPA was executed on September 30, 2013. SCE and Solar Oasis executed Amendment No. 3 on June 1, 2020 to reduce the performance assurance collateral amount in exchange for a one-time payment to SCE. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted].

(7) North Rosamond Solar, LLC (ID 5814)

North Rosamond Solar, LLC is a 151.05 MW solar photovoltaic project located in Rosamond, California, originally executed as part of SCE's 2014 RPS solicitation. The PPA was executed on October 9, 2015. SCE and North Rosamond Solar executed Amendment No. 3 on June 17, 2020 to adjust [redacted] (iii) the description of the generating facility to include the as-built equipment description. SCE's customers benefit from this amendment by having accurate equipment descriptions for the generating facility's design available for contract administration.

(8) Geysers Power Company, LLC (ID 3118)

Geysers Power Company, LLC which is a 50 MW PPA of a 725 MW geothermal project portfolio located in Sonoma and Lake Counties, California, originally executed as part of SCE's 2014 RPS solicitation. The PPA was executed on July 28, 2015. SCE and Geysers Power Company, LLC executed Amendment No. 1 on July 22, 2020 to correct clerical errors by clarifying the PPA definitions for Term Year and Term, and to delete a PPA term no longer defined and used, however unintentionally left in the PPA. SCE's customers benefit from this amendment by having clear information available for contract administration.

(9) 41MB 8me, LLC (ID 5810)

41MB 8me, LLC (Borden Solar Farm) is a 51.30 MW solar photovoltaic project located in unincorporated Madera County, California, originally executed as part of SCE's 2013 RPS solicitation. The PPA was executed on July 31, 2014. SCE and Borden Solar Farm executed a Letter Agreement on July 22, 2020 to [redacted]. SCE's customers benefit from this Letter Agreement by [redacted] and by having accurate information available for contract administration.

(10) Solar Oasis LLC (ID 5774)

Solar Oasis, LLC is a 20 MW solar PV project located in Palmdale, California, originally executed as part of SCE's RAM4 solicitation. The PPA was executed on September 30, 2013. SCE and Solar Oasis executed Amendment No. 4 on August 5, 2020 to resolve a potential dispute arising from a change in the CAISO Tariff that resulted in replacing the Exceedance method of calculating Net Qualifying Capacity (NQC) with the CPUC's Effective Load Carrying Capacity (ELCC) methodology when determining the project's Resource Adequacy. The Parties agreed that the change in CAISO Tariff equated to a change in law and agreed to implement the Compliance Expenditure Cap provision for RA Deficit payments, thus capping Solar Oasis' RA Deficit payment obligations to [redacted] starting January 1, 2018. The Amendment also updates the curtailment provisions in the PPA by updating the Day Ahead-MCP language to "Take-or-Pay". SCE's customers benefit by (i) being entitled to up to [redacted] of RA Deficit payments under the PPA and avoid any costs and potential negative rulings in a formal dispute proceeding, and (ii) administrative ease from the new Take-or-Pay curtailment provisions.

(11) Imperial Valley Solar 2, LLC (ID 5805)

Imperial Valley Solar 2, LLC (IVS2) is a 153.52 MW solar photovoltaic project located in Calexico, California, originally executed as part of SCE's 2013 RPS solicitation. The PPA was executed on July 31, 2014. SCE and IVS2 executed a Letter Agreement on August 6, 2020 to [redacted] SCE's customers benefit from this Letter Agreement by [redacted] and by having accurate information available for contract administration.

(12) Solar Oasis, LLC (ID 5774)

Solar Oasis, LLC is a 20 MW solar PV project located in Palmdale, California, originally executed as part of SCE's RAM4 solicitation. The PPA was executed on September 30, 2013. SCE and Solar Oasis executed Amendment No. 5 on September 17, 2020 to modify the assignment provisions by adding Permitted Transferee language to allow Solar Oasis to assign the PPA without SCE consent under specific conditions and requirements. SCE customers benefit from this amendment by ensuring any future Permitted Transferees meet the appropriate creditworthiness standards and by having accurate information available for contract administration.

(13) Orion Solar II, LLC (ID 5626)

Orion Solar II, LLC is an 8 MW solar project located in Arvin, California. The PPA was executed on August 30, 2012 as part of the RAM 2 solicitation. SCE and Orion Solar II executed Amendment No. 4 on November 25, 2020 to allow Orion Solar II to reduce its Performance Assurance collateral posting obligation to [redacted] in exchange for an upfront payment to SCE. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted]

(14) Blythe Solar II, LLC (ID 5885)

Blythe Solar II, LLC is a 125 MW solar PV project located in Riverside County, California. The PPA was executed on July 15, 2015 as part of SCE's 2014 RPS Solicitation. SCE and Blythe Solar II executed a Letter Agreement on April 29, 2019 which sets forth the terms and conditions under which SCE and Blythe Solar will participate in a Pilot Program to determine the effectiveness of a large utility-scale solar PV facility as a potential provider of essential ancillary services (AS) to the grid. To continue the Pilot Program, SCE and Blythe Solar II executed a second Letter Agreement on December 2, 2020 to allow more time for the project to participate in the AS market. SCE's customers benefit from this Letter Agreement because SCE will collect critical information and data to further study and understand the effectiveness of solar PV facilities in providing AS to support grid reliability.

(15) Valentine Solar, LLC (ID 5886)

Valentine Solar, LLC is a 111.2 MW solar project located in Rosamond, California. The PPA was executed on October 16, 2015 as part of SCE's 2014 RPS solicitation. SCE and Valentine Solar executed Amendment No. 4 on December 15, 2020 to [redacted] SCE's customers benefit from this amendment by having accurate counterparty information available for contract administration.

(16) Commercial Energy of Montana, Inc. (ID 11260-8047)

Commercial Energy of Montana, Inc. and SCE executed an EEI Master Agreement on August 6, 2019, and REC Sales Confirmation Letter was executed on December 18, 2020, as a bilateral transaction. SCE and Commercial Energy of Montana, Inc. executed a Letter Agreement on December 23, 2020 to [redacted] SCE's customers benefit from this Letter Agreement as it [redacted]

(17) Silver State Solar Power South, LLC (ID 5284)

Silver State Solar Power South, LLC is a 250 MW solar project located in Clark County, Nevada. The PPA was executed on February 7, 2011. SCE and Silver State Solar Power South executed Amendment No. 3 on December 28, 2020 to allow for a reduction in its Performance Assurance collateral posting obligation to [redacted] in exchange for a one-time payment. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted]

(18) McCoy Solar, LLC (ID 5494)

McCoy Solar, LLC is a 250 MW solar project located in Riverside County, California. The PPA was executed on September 29, 2011. SCE and McCoy Solar executed Amendment No. 2 on December 28, 2020 to allow for a reduction in the Performance Assurance collateral amount by [redacted] in exchange for a one-time payment. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted]

(19) Adelanto Solar, LLC (ID 5758)

Adelanto Solar is a 20 MW solar project located in Adelanto, California. The PPA was executed on March 22, 2013 as part of the RAM 3 solicitation. SCE and Adelanto Solar executed Amendment No. 5 on December 28, 2020 to allow for a reduction in the Performance Assurance collateral amount by [redacted] in exchange for a one-time payment. SCE's customers benefit from this amendment because of the customer savings associated with the upfront payment in the amount of [redacted]

(20) TKO Power, LLC (South Bear Creek) (ID 4213)

TKO Power, LLC (South Bear Creek) is a 2.834 MW small hydro project located in Shingletown, California. The PPA was executed on July 15, 2015 as part of SCE's 2014 RPS solicitation. SCE and TKO Power executed Amendment No. 2 on December 30, 2020 to reduce the Product Price and waive SCE's termination right in connection with an Event of Default for failing to meet 20% of Expected Net Annual Energy Production over a twelve (12) month period. SCE's customers benefit from this amendment by reducing the product price for a net present value benefit of approximately [redacted]

f) Contract Assignment Administration

RPS contracts may only be assigned with the written consent of the parties, which may not be unreasonably withheld. There are many reasons RPS contract counterparties seek to assign their contracts. The counterparty might want to sell or transfer the project to a new entity, sell or assign a portion of the project to tax equity, assign the contract to a lender as security for a loan, or a change of control of the project. Table VII-62 lists the contract assignments to which SCE consented during the Record Period.

Table VII-62
RPS Contract Consents and Consents to Assignments
January 1, 2020 Through December 31, 2020

	ID	Project	Types of Assignment or Consents	Consent Signed
1	1347	Organic Energy Solutions, LLC	Consent and Agreement	1/22/2020
2	1252	Central CA Fuel Cell 2 LLC	Consent and Agreement	1/23/2020
3	6320	Pinyon Pines Wind I, LLC	Consent to Collateral Assignment	1/29/2020
4	6322	Pinyon Pines Wind II, LLC	Consent to Collateral Assignment	1/29/2020
5	5261	Windhub Solar A, LLC	Consent to Collateral Assignment of Membership Interest	5/6/2020
6	5882	Sun Streams, LLC	Consent to Collateral Assignment of Membership Interest	5/6/2020
7	5884	Sunshine Valley Solar, LLC	Consent to Collateral Assignment of Membership Interest	5/6/2020
8	5263	American Kings Solar, LLC	Consent to Assignment of Membership Interest	6/22/2020
9	5627	Coronal Lost Hills, LLC	Consent to Assignment of Membership Interest	6/30/2020
10	5627	Coronal Lost Hills, LLC	Consent to Collateral Assignment Agreement	6/30/2020
11	5485	Nicolis, LLC	Consent to Assignment of Membership Interest	6/30/2020
12	5490	Tropico, LLC	Consent to Assignment of Membership Interest	6/30/2020
13	5485	Nicolis, LLC	Consent to Assignment and Change of Control	7/2/2020
14	5490	Tropico, LLC	Consent to Assignment and Change of Control	7/2/2020
15	3117	Geysers Power Company, LLC	Consent to Collateral Assignment	8/25/2020
16	3118	Geysers Power Company, LLC	Consent to Collateral Assignment	8/25/2020
17	5264	Maverick Solar, LLC	Consent to Assignment of Membership Interest	9/17/2020
18	5520	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
19	5521	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
20	5522	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
21	5523	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
22	5524	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
23	5525	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
24	5536	TerraForm Phoenix I CD Holdings , LLC	Consent to Assignment	9/21/2020
25	5539	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
26	5541	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
27	5549	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
28	5550	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
29	5551	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
30	5559	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
31	5560	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
32	5561	TerraForm Phoenix I CD Holdings, LLC	Consent to Assignment	9/21/2020
33	5263	American Kings Solar, LLC	Consent to Assignment of Membership Interest	10/30/2020
34	5700	Coronus Adelanto West 1 LLC	Consent and Agreement	10/30/2020
35	5701	Coronus Adelanto West 2 LLC	Consent and Agreement	10/30/2020
36	5264	Maverick Solar, LLC	Consent to Assignment Interest	12/10/2020
37	5886	Valentine Solar, LLC	Consent to Assignment of Membership Interest	12/15/2020
38	5626	Orion Solar II, LLC	Consent to Collateral Assignment	12/16/2020
39	5628	Vega Solar, LLC	Consent to Collateral Assignment	12/16/2020

g) Affiliate Transactions and Contract Information

There were no affiliate RPS contracts during the Record Period.

h) Uncontrollable Force Administration

SCE's RPS contracts include provisions that may excuse an RPS project from performing certain contractual obligations to the extent the project can demonstrate that the occurrence of an uncontrollable force, or a circumstance beyond its reasonable control as defined in the agreements (often known as a *Force Majeure*), prevented the project from performing such obligations.

Whenever an RPS contract holder claims that an uncontrollable force caused it to fail to meet its contractual obligations, SCE undertakes the following activities:

- Determines whether the claim was submitted within the contractually-required period, which is typically two weeks;
- Requires that the counterparty submit sufficient evidence to substantiate the claim that an uncontrollable force event occurred. This may include meteorological or weather reports to support a claim of weather damage, construction and equipment specifications, manufacturer maintenance manuals and bulletins, the project's operations and maintenance/repair logs, copies of insurance claims, damage assessments, failure reports, and other relevant materials; and
- Evaluates whether the suspension of performance was of no greater scope and of no longer duration than was required by the uncontrollable force, and that the RPS contract holder used its best efforts to remedy its inability to perform.

If SCE grants the claim, and if the contract does not provide otherwise, the RPS contract counterparty receives lost output credit (kWh) for the period of the event, up to 365 days, despite a failure to deliver power to SCE. Lost output credit is applied to the annual production amounts found in the contract to offset any replacement energy damages to compensate SCE customers for nonperformance of the contract.

Table VII-63
RPS Uncontrollable Force Claims Tendered and/or Pending
January 1, 2020 Through December 31, 2020

	ID	Project	Date and Event	Status
1	5208	Solar Partners 1, LLC	07/29/2018 - Force Majeure claim due to damage caused by hailstorm.	On January 20, 2020, at SCE's request, Seller provided a timeline of activities to mitigate the Force Majeure which outlined the repair plan from initial damage assessment and insurance planning. On September 10, 2020, SCE revised its partial acceptance of Ivanpah's Force Majeure and based on this revised partial acceptance of Force Majeure, SCE rescinded its prior Notice of Deficient Deliveries. SCE considers this claim closed.
			09/19/2020 - Force Majeure claim due to area wildfires.	SCE is awaiting additional information from Seller. Claim is pending.
2	3117 & 3118	Geysers Power Comapny, LLC	10/23/2019 and 10/24/2019 - Force Majeure claim due to forecasted severe wind condition, PG&E Public Safety Power Shutoff (PSPS) and Kincaid Fire.	On October 9, 2020, SCE accepted the Force Majeure claim. SCE considers this claim closed.
			11/20/2019 - Force Majeure claim due to forecasted severe wind conditions and PG&E PSPS order.	
			10/24/2020 - Force Majeure claim due to forecasted severe wind conditions and PG&E PSPS order.	On January 25, 2021, SCE accepted the Force Majeure claim. SCE considers this claim closed.
3	4213	TKO Power, LLC	12/19/2019 - Force Majeure claim due to local heavy rainfall.	On July 1, 2020, SCE rejected the Force Majeure claim. SCE considers this claim closed.

(1) <u>Solar Partners I, LLC (ID 5208)</u>

Solar Partners I, LLC (Ivanpah) is a 117 MW solar thermal project located in San Bernardino County, California, originally executed as a part of SCE's 2008 RPS solicitation. The PPA was executed on February 6, 2009. Following are *Force Majeure* claims that were active during the Record Period.

On August 2, 2018 Ivanpah provided SCE with notification of a *Force Majeure* event after the project experienced damage to about 4,000 mirrors following a hailstorm on July 29, 2018. The claim was submitted in accordance with the PPA. The facility has since commenced partial operation but is operating at a reduced capacity as a result of the damage. Ivanpah has represented that new equipment has been ordered, and replacement of the damaged mirrors was expected to begin in mid-2020. SCE requested additional information surrounding the timing of the outage, Ivanpah's actions taken following the outage, and the impact on the generation output of resource. Ivanpah provided additional information on October 11, 2018, January 21, 2019, and March 29, 2019, as requested by SCE. On April 30, 2019 SCE partially accepted Ivanpah's

Force Majeure claim regarding the damage to the mirrors for a period of 30 days, as SCE did not receive sufficient information to justify the delay to restore the site. The remainder of Seller's *Force Majeure* claim was rejected.

Due to the *Force Majeure* claims, Ivanpah failed to meet its Minimum Performance Delivery obligation in the most recent 24-month period and was subsequently penalized [redacted] on May 1, 2019. On May 29, 2019, Ivanpah disputed the charges and the partial rejection of the claimed *Force Majeure* event on July 29, 2018. On July 11, 2019, Ivanpah informed SCE that its original mirror supplier is unable to provide the necessary replacement equipment, so Ivanpah was seeking an alternate supplier. On August 28, 2019, Ivanpah informed SCE that they had found a qualified supplier and was working to procure approximately 7,000 replacement mirrors. On December 12, 2019, Ivanpah informed SCE that the replacement of the mirrors is tentatively scheduled for completion around February 2021.

On January 20, 2020, at SCE's request, Seller provided a timeline of activities to mitigate the Force Majeure which outlined the repair plan from initial damage assessment and insurance planning to project approval of the plan. Upon assessing the new data, on September 10, 2020, SCE revised its partial acceptance of Ivanpah's Force Majeure regarding the damage to the mirrors for a period of twelve (12) months from July 19, 2018 through July 29, 2019. Based on this revised partial acceptance of the Force Majeure, SCE rescinded its Notice of Deficient Deliveries dated May 1, 2019 and considers this claim closed.

On September 19, 2020 Ivanpah provided SCE with Notification of a *Force Majeure* event after the project experienced lost generation attributed to wildfires in the area. On September 24, 2020 SCE acknowledged receipt of Ivanpah's Notice and requested further supporting documentation of the event. On December 2, 2020 SCE received a report on the wildfire event to further support its Force Majeure. On December 18, 2020, SCE provided feedback on Ivanpah's report and requested further clarification on their data and Lost Output methodology. Ivanpah is continuing to review SCE's request.

(2) Geysers Power Company, LLC (ID 3117 & 3118)

Geysers Power Company, LLC (Geysers) is a portfolio of geothermal projects with a total capacity of 725 MW located in Sonoma and Lake Counties, California, originally executed as part of SCE's 2013 and 2014 RPS solicitations, respectively. SCE has 275 MW under PPAs (225 MW under contract ID 3117 and 50 MW under contract ID 3118). The PPAs were executed on July 29, 2014 and July 28, 2015, respectively. Geysers provided the following timely notices to SCE of potential *Force Majeure* events during the Record Period:

On October 23, 2019, Geysers submitted a claim for potential *Force Majeure* event due to forecasted severe wind conditions and PG&E Public Safety Power Shutoff (PG&E PSPS) order. On October 24, 2019 Geysers submitted another notice of potential *Force Majeure* event related to the "Kincade Fire," which damaged equipment at the Geysers facility. Further, on November 20, 2019, Geysers submitted a third claim for potential *Force Majeure* event due to forecasted severe wind conditions and PG&E PSPS order. The PG&E PSPS events ended on October 30, 2019 and November 20, 2019, respectively. The notices were delivered in accordance with the PPA following the occurrences of the PG&E PSPS events and the Kincade Fire. The Kincade Fire caused damage and forced transmission outages on both Lakeville 230 kV and Fulton 230 kV PG&E transmission lines, and damage to the 21kv distribution system, fiber optics systems and to the communication systems at the Geysers' Facility. The Kincade Fire affected Geysers' communication infrastructure, initially preventing CAISO from successfully polling the meters, which Geysers worked with AT&T to restore these communications and update the meter data accordingly. The Kincade Fire Force Majeure ended on March 9, 2020. Geysers submitted information and data to establish that the event constituted Force Majeure in accordance with the PPAs. Geysers' claim was for Lost Output under the PPAs in the total amount of 249,711 MWh. SCE completed its review and analysis and on October 9, 2020 SCE accepted the Force Majeure claim.

On October 24, 2020, Geysers submitted claim for potential *Force Majeure* event due to forecasted severe wind conditions and PG&E PSPS order. Geysers submitted supporting documentation regarding the event covering the period of October 25 through October 28, 2020 for a total lost output claim in the amount of 10,713 MWh. SCE completed its review and analysis of the data provided by Geysers in accordance with the PPAs and on January 25, 2021 SCE accepted the Force Majeure claim.

(3) TKO Power, LLC (ID 4213)

TKO Power, LLC (South Bear Creek) is a 2.83 MW small run-of-river hydro project located in Shingletown, California, originally executed as part of SCE's 2014 RPS solicitation. The PPA was executed on July 15, 2015. On December 19, 2019 South Bear Creek submitted a timely Notice of *Force Majeure* event claiming local heavy rainfalls eroded the penstock saddle foundation material causing the saddle to overturn. South Bear Creek repaired the saddle and penstock and provided supporting documentation on the root cause of the failure. SCE reviewed the *Force Majeure* claim and supporting documentation and determined that the problem was preventable with due diligence and routine maintenance. On July 1, 2020 SCE rejected the claim and considers this claim closed.

i) Energy Delivery Performance Administration

Some of SCE's RPS contracts include provisions that require a seller to meet certain energy delivery obligations. During the negotiations of the RPS contracts, SCE and the seller set expected annual net energy production targets for the specific projects. These annual production targets function as the basis for determining whether, in a term year, the projects meet their energy delivery obligations. The energy delivery obligation calculation may be performed on either an annual or multi-year basis depending on contract terms. Regardless of the timing of the calculation, the result is either a comparison of the actual annual energy deliveries or the average annual energy delivery over multiple years to determine if the energy delivery obligation has been met.

SCE examines the production of each project and determines if the project has met the energy delivery requirement. Depending on the contract, the seller may request credit for lost production if the loss is attributed to lost output (output the facility otherwise would have produced if not curtailed) as defined in the PPA. If a project does not meet its energy delivery requirements after supplementing their production kWh with confirmed lost output, the project may be subject to liquidated damages known as an Energy Replacement Damage Amount.

During the Record Period, calculations regarding annual production were performed on 119 contracts. Of those, 115 contracts were found to have met their annual net energy production target. Four contracts did not meet their required target and one contract that did not meet its required target in 2019 was fully settled in 2020. Those failures for the contracts that did not meet their required targets and the one contract from 2019 are described below:

(1) Republic Services of Sonoma County Energy Producers (ID 1238)

Republic Service of Sonoma County Energy Producers (Sonoma), a 5 MW biogas facility, had a 12-month (2019 through 2020) Performance Measurement Period production target of 31.54 GWh and delivered 26.12 GWh, with no qualified lost output claimed by Sonoma to reduce the obligation, leaving a shortfall of 5,419.75 MWh. The Energy Replacement Damage Amount was calculated to be [redacted] which was netted from SCE's payment to Sonoma and fully settled in January 2021.

(2) MM Tulare Energy, LLC (ID 1245)

MM Tulare Energy, LLC (MM Tulare), a 1.90 MW biogas facility, [redacted]. The Energy Replacement Damage Amount was netted from SCE's payment to MM Tulare consistent with the terms of the January 14, 2020 Letter Agreement. The energy replacement damage amount was fully settled in September 2020.

(3) ORNI 18 (ID 3108)

ORNI 18 (Orni), a 33 MW geothermal facility, had a 12-montn (2019 through 2020) Performance Measurement Period production target of 84.33 GWh and delivered 65.39 GWh, with no qualified lost output claimed by Orni to reduce the obligation, leaving a shortfall of

18,931 MWh. The Energy Replacement Damage Amount was calculated to be [redacted] which was netted from SCE's payment to Orni and fully settled in October 2020.

(4) Calleguas Municipal Water District (ID 4252)

Calleguas Municipal Water District (Calleguas), a 1.0 MW hydro facility, had a 24-month (2018 through 2020) Performance Measurement Period production target of 2.25 GWh and delivered 2.15 GWh, with no qualified lost output claimed by Calleguas to reduce the obligation, leaving a shortfall of 102 MWh. The Energy Replacement Damage Amount was calculated to be [redacted], which was netted from SCE's payment to Calleguas and fully settled in August 2020.

(5) Garnet Solar Power Generation Station 1, LLC (ID 5488)

Garnet Solar Power Generation Station 1, LLC (Garnet), a 4.0 MW solar photovoltaic facility, had a 24-month (2018 through 2020) Calculation Period production target of 15.71 GWh and delivered 13.78 GWh, including 1.02 GWh submitted by Garnet and confirmed by SCE to qualify as lost output, reducing Garnet's obligation and leaving a shortfall of 1,926 MWh. The Energy Replacement Damage Amount was calculated to be [redacted] which was netted from SCE's payment to Garnet and fully settled in June 2020.

j) Dispute Resolution and Litigation

Details on RPS Project dispute resolutions and litigation activities during the Record Period are provided below.

(1) Sand Canyon of Tehachapi LLC (ID 6341)

The Sand Canyon of Tehachapi LLC PPA was terminated by SCE on November 11, 2011 due to network upgrade costs substantially exceeding the cap specified in the PPA. After the termination, GLJ LLC (a lender and previous owner) for the Sand Canyon PPA, asserted its rights, based on a Consent to Collateral Assignment Agreement signed by SCE, Sand Canyon, GLJ, and Sand Canyon's controlling entity, Helo Energy, to take control of the then-terminated PPA. Pursuant to the terms of the Consent to Collateral Assignment Agreement and the PPA, SCE returned the development security of [redacted] associated with the PPA to GLJ.

On March 28, 2012, Helo Energy and Saugatuck Energy, another claimant to the development security, disregarded the alternative dispute resolution (ADR) provisions of the PPA and filed suit against SCE and several other parties in California Superior Court. The lawsuit claimed that SCE wrongfully terminated the PPA and incorrectly returned the development security to GLJ. The lawsuit also made numerous unrelated allegations against defendants other than SCE, related to the prior sale of the Sand Canyon PPA and assets. SCE moved to compel the ADR of plaintiffs' contract claims under the PPA. The trial court denied the motion and SCE appealed the decision. The Court of Appeal reversed the trial court, ruling that the plaintiffs' claims against SCE must be arbitrated. On remand, the trial court stayed plaintiffs' claims against SCE until the plaintiffs resolve their unrelated claims against the other defendants. That trial was held in California District Court on April 12, 2016. SCE monitored the case. The lawsuit to determine the ownership of the project, which SCE was not a party to, was settled by the litigants in 2019, with Helo prevailing as the owner of the project.

Subsequently, Helo is pursuing a claim against SCE for, allegedly, improper termination of the PPA. A mediation between Helo and SCE in October 2020 was unsuccessful in reaching an agreement. On December 18, 2020, Helo issued an arbitration demand to SCE. Helo and SCE are currently engaged in the arbitration of this matter, with resolution expected by fourth quarter of 2021.

(2) Mountain View Power Partners IV, LLC (ID 6304)

Mountain View Power Partners IV, LLC (MVPP) is a 49 MW wind project located in North Palm Springs, California originally executed as a part of the 2003 RPS solicitation. The PPA was executed on March 8, 2005. [redacted]

[redacted]

(3) Caithness Shephards Flat, LLC (ID 6330, 6331, and 6332)

North Hurlburt (265 MW), South Hurlburt (290MW), and Horseshoe Bend Wind (290 MW) are three wind facilities owned by Caithness Shephards Flat, LLC ("CSF"), located in Arlington, Oregon and within Bonneville Power Administration's Balancing Authority. Originally executed as part of SCE's 2007 RPS solicitation, the PPAs were executed on August 14, 2008 (the "Wind Projects").

[redacted]

k) Contract Terminations

Table VII-64 shows the RPS contracts that terminated during the Record Period.

Table VII-64
RPS Contract Terminations
January 1, 2020 Through December 31, 2020

	ID	Project	Contract Capacity (MW)	Contract Type	Termination Date	Note
1	1247	Organic Energy Solutions, LLC	1.6	BioMAT	1/13/2020	[redacted]
2	1210	MM Tajiguas Energy LLC	2.8	ERR	10/21/2020	[redacted]
3	11062-8024	EDF Trading North America, LLC	8.0	EEI - Energy + REC Sale	12/31/2020	[redacted]
4	11181-8016	Shell Energy North America (US), L.P.	22.8	EEI - Energy + REC Sale	12/31/2020	[redacted]
5	11234-8015	Marin Clean Energy	22.7 - 75.7	EEI - Energy + REC Sale	12/31/2020	[redacted]
6	11234-8026	Marin Clean Energy	34.1 - 143.6	EEI - Energy + REC Sale	12/31/2020	[redacted]
7	11246-8017	Clean Power Alliance of Southern California	79.7	EEI - Energy + REC Sale	12/31/2020	[redacted]
8	11256-8019	East Bay Community Energy Authority	22.8	EEI - Energy + REC Sale	12/31/2020	[redacted]
9	11256-8025	East Bay Community Energy Authority	22.7 - 646.5	EEI - Energy + REC Sale	12/31/2020	[redacted]
10	11258-8020	Direct Energy Business Marketing, LLC	7.5 - 9.1	EEI - Energy + REC Sale	12/31/2020	[redacted]
11	11258-8030	Direct Energy Business Marketing, LLC	14.0	EEI - Energy + REC Sale	12/31/2020	[redacted]
12	11260-8022	Commercial Energy of Montana, Inc.	2.0	EEI - Energy + REC Sale	12/31/2020	[redacted]
13	11260-8023	Commercial Energy of Montana, Inc.	2.0	EEI - Energy + REC Sale	12/31/2020	[redacted]
14	11260-8047	Commercial Energy of Montana, Inc.	74.1	EEI - Energy + REC Sale	12/31/2020	[redacted]
15	11271-8032	SRECTrade, Inc.	1.4	EEI - Energy + REC Sale	12/31/2020	[redacted]

E. **Other Contract Administration Activities**

Below are other contract administration activities:

1. COVID-19 Force Majeure Claims

Since the start of the COVID-19 pandemic, eleven PPA counterparties have submitted Force Majeure claims to SCE related to the COVID-19 pandemic potentially adversely affecting their ability to timely perform their obligations under the contracts. Eight of the projects are currently in development while three reached their on-line operation date in accordance with the PPA, despite the impacts of the COVID-19 pandemic. The Force Majeure claims fall within one or all of the following three categories: (1) supply chain delays; (2) interconnection delays; or (3) permitting delays. In all instances, the counterparties are seeking relief of certain development milestones or delivery requirements.

SCE's review of the COVID-19 pandemic related claims include a determination in accordance with the PPA of whether the claim was submitted within the contractually required time period, whether the counterparty submitted sufficient evidence to substantiate the claim, and whether the counterparty used its best efforts to mitigate the delay or remedy its inability to perform.

Table VII-65 shows the COVID-19 pandemic related claims delivered to SCE during the Record Year.

Table VII-65
COVID-19 Force Majeure Claims

ID	Project (Project Status)	Date and Event	Claim Status
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]

2. CAISO System Emergency

For the first time since 2001, CAISO ordered the IOUs to shed load, declaring Stage 2 and Stage 3 Emergencies during heat waves occurring in the months of August and September 2020. A Stage 2 Emergency is declared when CAISO is no longer able to meet energy requirements, absent intervention in the market. In parallel with the CAISO's actions, Governor Newsom also signed two related Emergency Proclamations[165] on August 14, 2020, with a corresponding Governor Executive Order No. N-74-20[166] issued on August 16, 2020, and September 2, 2020, to support freeing up additional capacity amid the heat waves. Further, the Department of Energy also issued an order on September 6, 2020 declaring an energy emergency under Section 202c[167] of the Federal Power Act, authorizing additional dispatch by the units at El Segundo Generating Station and Walnut Creek Energy, in order to meet the CAISO System Emergency, to serve the public interest, and to establish reporting requirements.

Throughout this period, the Contract Management group cast a wide net across its portfolio of generator owners with existing contracts, to secure approximately 200 MW of incremental capacity and associated energy deliveries. The Contract Management outreach included 1) identifying those generators that could provide additional energy deliveries, 2) waiving PPA obligations to allow for generation above the contract capacity or for energy generation in excess of the settlement interval cap, where appropriate, 3) entering into narrowly tailored, short-term agreements with certain generators to allow for fuel compensation where not otherwise addressed, 4) working with the SCE Transmission & Distribution group and CAISO to identify projects that could safely deliver additional energy to the grid in excess of contractual limits in the respective Interconnection Agreements, and 5) identifying generators that could generate beyond emissions and other permit limitations with approval from the

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[165] August 14, 2020 Governor Emergency Proclamation: 8.16.20-Extreme-Heat-Event-proclamation.pdf (ca.gov) and September 2, 2020 Governor Emergency Proclamation: CAP14-20200903171225

[166] Governor Executive Order No. N-74-20: CAP14-20200817142014

[167] Department of Energy Order No. 202-20-2 https://www.energy.gov/sites/prod/files/2020/09/f78/CAISO%20202c%20Order_1.pdf

appropriate governmental entity or entities, pursuant to a Governor's Proclamation, Governor's Executive Order, or Department of Energy Order.

Table VII-66 lists the contracts that ultimately delivered incremental capacity and associated energy and had additional cost impact above the existing PPA terms during the CAISO System Emergency, in the Record Period.

Table VII-66
CAISO System Emergency

	Contract ID	Counterparty	Settlement Impact
1	[redacted]		
2			
3			
4			
5			
6			
7			
			[redacted]

3. Community Choice Aggregator Implementation and Resource Adequacy (RA) Compliance Agreements

In 2019, SCE began working with certain Community Choice Aggregators ("CCAs") whose program start dates were impacted by SCE's Customer Service Re-Platform ("CRSP") project. SCE entered into bilateral agreements regarding CCA implementation and Resource Adequacy (RA) compliance ("CCA RA Agreements") with three impacted CCAs in 2019 and two in 2020, as shown in Table VII-66 below. The CCA RA Agreements addressed uncertainties CSRP may cause in the timing of the CCA implementation start dates and the financial impacts of delayed CCA program launches, including the risk of CCAs procuring unneeded RA resources. All CCA RA Agreements were submitted for CPUC approval under Tier 3 Advice Letters as specified in Table VII-66.

During the Record Period, SCE began the implementation and development of system modifications and procedures to capture these unique CCA RA Agreements for proper contract administration and settlement. SCE activities associated with the CCA RA Agreements include appropriate amendments, managing the CCA's Year-Ahead and Month-Ahead RA compliance showings, and coordination with the CPUC and the CEC regarding Load Serving Entity allocations.

Table VII-67 lists the CCA RA Agreements & Amendments administered by SCE during the Record Period.

Table VII-67
CCA RA Agreements & Amendments
January 1, 2020 Through December 31, 2020

	Community Choice Aggregator (ID)	RA Compliance Year	Executed Date	Advice Letter	CPUC Resolution & Disposition	Amendments
1	Desert Community Energy (10128)	2020	8/12/2019	4059-E-B	Approved in Resolution E-5051, issued February 27, 2020	[redacted]
2	Western Community Energy (10127)	2020	8/15/2019	4058-E-B	Approved in Resolution E-5051, issued February 27, 2020	
3	Clean Power Alliance[1] (10129)	2020	8/16/2019	4060-E-A	Approved in Resolution E-5051, issued February 27, 2020	N/A
4	City of Santa Barbara (10130)	2022	9/15/2020	4303-E	Pending CPUC's final disposition	N/A
5	Central Coast Community Energy[2] (10131)	2021	10/8/2020	4314-E-A	Pending CPUC's final disposition	[redacted]

[1] Includes Phase V - City of Westlake Village only

[2] Includes Goleta, Carpinteria, and parts of unincorporated Santa Barbara County only

4. Supplier Diversity

Contract Management supports SCE's compliance and participation with GO 156, which requires utilities to submit annual detailed and verifiable plans for increasing women, minority, disabled veteran, lesbian, gay, bisexual and transgender owned business enterprises' (WMDVLGBTBE) procurement in all categories. SCE's Contract Management group actively reaches out to contract counterparties to encourage and foster new procurement opportunities for those groups. Many of our PPAs require that counterparties report to SCE their procurement activities with businesses certified as

WMDVLGBTBEs. Twice per year, SCE sends a survey to its energy contract counterparts requesting this information and, in many cases, spends time discussing the survey and data collected with the counterparty. This information is analyzed and compiled for publication in SCE's Supplier Diversity Annual Report. Contract Management also participates in annual meetings with Commission staff and the other IOUs, when requested, and supports various supplier diversity outreach activities and events throughout the year.

5. Enterprise Contract Management System and Training

During 2020, contract managers participated in training related to several topics, including market operations, interconnection process, procurement programs, and continued training on SCE's recently implemented and system of record for managing principal provisions and payments Endur. SCE's Energy Contracts Management group continued updating the Endur training handbook during the Record Period. These projects/initiatives are on-going and will continue to achieve improvements and overall savings.

6. **Portfolio Optimization**

In an effort to improve operational excellence, several initiatives were undertaken that focused on process improvements and obtaining value for customers. To optimize value in SCE's portfolio of contracts, contract managers proactively reached out to counterparties to consider amendments or termination agreements that would result in savings for both parties. Potential topics included performance assurance reductions (to more closely reflect current market value of renewables), buy-out opportunities of high-cost contracts, and other topics. Counterparties provided a benefit to SCE customers in the form of a price reduction, upfront payment or elimination of future payments. Total customer savings related to these efforts in 2020 were in the tens of millions of dollars. Those amendments and terminations are reflected in the respective Contract Amendment and Contract Termination sections. Negotiated contract amendments and terminations are provided in sections above and Appendix VII-L.

F. Contract Collateral

1. Conventional

a) Development Security and Performance Assurance

Conventional contracts have obligations for collateral to be provided to SCE. These obligations include different types of performance assurances. Some include mark-to-market calculations and others are simply a fixed amount. Appendix VII-N lists the collateral held in cash, letter(s) of credit, or parental guarantees, from a creditworthy entity acceptable to SCE, for these contracts on December 31, 2020.

2. PURPA and CHP

SCE has a variety of cash and non-cash deposits that are collected from non-investment grade energy suppliers in the procurement process to assure performance. There are three types of obligations for which collateral is held by SCE for PURPA and CHP contracts: Development Security; Performance Assurance; and income tax component of contributions (ITCC) (sometimes referred to as CIAC, explained in Section 4 below). SCE has assigned its Risk Operations & Collateral Management group to handle the administration and tracking of the collateral posted for Development Security and Performance Assurance and its Energy Contracts Management group to handle the administration of the ITCC collateral. The contract managers within SCE's Energy Contracts Management group still serve as the primary contact for collateral replacement, changes or questions; however, Credit Risk group and Risk Operations & Collateral Management group handles SCE's routine transactions with the counterparties. Appendix VII-N lists the collateral held for these contracts on December 31, 2020.

3. RPS

There are two types of obligations that collateral was posted for in the Record Period from RPS contracts: Development Security and Performance Assurance. Each obligation is discussed, in detail, below.

a) Development Security

SCE contract managers work closely with RPS project developers to assist them in meeting project milestones so they can achieve commercial operation and contribute to the State's renewable energy goals. As SCE has reported in other contexts, these projects can face several challenges, including permitting delays and difficulty securing financing. As part of its contract administration activities, SCE diligently monitors the progress of RPS projects and provides on-going support to move these projects forward for the benefit of its customers. However, in order to mitigate the risk of a project's failure to reach commercial operation, SCE requires counterparties to post development security to maintain the incentive for the counterparty to complete the project and to defray some of the costs of replacing failed projects.

The administration and tracking of this collateral are assigned to SCE's Risk Operations & Collateral Management group. One significant milestone to be met by RPS projects is the posting of a required development security to ensure that the contracted project will be developed. Development security is typically posted in the form of cash or letter(s) of credit.

b) <u>Performance Assurance</u>

On or before a project's Commercial Operation Date (COD), RPS contracts require posting of "performance assurance," which is collateral for performance during the term of the PPA. This is distinct from "development security" described in the previous section, which provides collateral for development of the project prior to commercial operation. The collateral amount may be posted in the form of cash, letter(s) of credit, or a guaranty from a creditworthy entity acceptable to SCE. Counterparties may provide performance assurance in multiple forms as acceptable to SCE.

Appendix VII-N lists the collateral held in cash or letter(s) of credit and guarantees from a creditworthy entity acceptable to SCE for these contracts on December 31, 2020, related to RPS project development security and performance assurance. Appendix VII-L lists the collateral retained and transferred by SCE to ERRA in this current Record Period, including RFO cash bid deposits from prior RPS solicitations.

4. <u>Contribution in Aid of Construction (CIAC) Tax</u>

Legacy QF agreements managed by SCE's Energy Contracts Management group require that the counterparty either (1) construct and transfer ownership of the interconnection facilities to the utility or (2) pay the utility for building the project's intertie. In 1986, the Internal Revenue Code was amended by the Tax Reform Act of 1986 to provide that these transfers of property and/or payments of money may be determined by the Internal Revenue Service (IRS) to be taxable income to SCE as CIAC. In 1988, the IRS clarified that such transfers only become taxable under the circumstances described in the IRS' regulations.

Counterparties to Legacy QF Agreements are ultimately responsible for CIAC tax, also referred to as the income tax component of contributions (ITCC) imposed on the utility as a result of the project's interconnection arrangements. Pursuant to D.87-09-026, SCE collected the ITCC during the development of each project, which may be in the form of cash deposits to securitize the obligation. The tax liability of this potential taxable event has diminished such that SCE enacted the return of the ITCC. Cash deposits plus accrued interest are subject to execution of an indemnity agreement in accordance with D.94-06-038. During the Record Period, SCE executed 24 Indemnity Agreements and returned ITCC security totaling $2,153,711. The contracts that SCE returned ITCC cash security to are summarized in Table VII-68 below.

Table VII-68
PURPA and CHP Indemnity Agreements
January 1, 2020 through December 31, 2020

	ID	Project	Description	Date
1	3008	Coso Finance Partners	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/13/2020
2	3029	Coso Power Developers	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/13/2020
3	3030	Coso Geothermal Power Holdings	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/13/2020
4	3011	Terra-Gen Dixie Valley, LLC	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
5	6102	Victory Garden Phase IV Partners - 6102	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
6	6103	Victory Garden Phase IV Partners - 6103	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
7	6104	Victory Garden Phase IV Partners - 6104	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
8	6105	Terra-Gen 251 Wind, LLC (Monolith X)	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
9	6106	Terra-Gen 251 Wind, LLC (Monolith XI)	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
10	6107	Terra-Gen 251 Wind, LLC (Monolith XII)	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020

11	6108	Terra-Gen 251 Wind, LLC (Monolith XIII)	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/15/2020
12	3006	Vulcan/Bn Geothermal Power Co	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/28/2020
13	4028	Lower Tule River Irrigation District	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	5/28/2020
14	1040	City of Corona	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	6/15/2020
15	2210	Crimson Resource Management	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	7/1/2020
16	2058	Sycamore Cogeneration Company	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	9/23/2020
17	6213	The BNY Mellon Trust Company, N.A.	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	10/13/2020
18	1023	Covanta Delano, Inc.	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	10/14/2020
19	2064	Wheelabrator Norwalk Energy Co, Inc	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	10/29/2020
20	3001	Heber Geothermal Company LLC	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	11/18/2020

21	3010	Ormesa LLC	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	11/18/2020
22	3018	Mammoth-Pacific, L.P.	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	11/18/2020
23	2413	St. John's Hospital and Health Center	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	12/9/2020
24	2077	Rio Bravo Jasmin	Indemnity Agreement executed to allow SCE to return posted Income Tax Component of Contribution (ITCC) to Seller.	12/14/2020

G. Contract Compliance

1. Conventional

a) Insurance Verification

Specific conventional projects are required to obtain and maintain comprehensive general liability insurance during the terms of their power purchase contracts. SCE uses a third-party insurance management solutions company, Insurance Tracking Services, Inc. (ITS) to monitor counterparty compliance with these requirements. During the Record Period, 19 conventional projects, inclusive of 13 energy storage projects, were actively monitored by ITS. ITS, in conjunction with SCE, ensures that these projects have:

- Obtained required insurance upon execution;
- Maintained insurance policies and insurance carriers that meet the contract's requirements; and
- Maintained adequate insurance coverage throughout the terms of their contracts.

2. PURPA and CHP

Compliance programs have been developed to ensure that PURPA and CHP projects adhere to the terms of their contracts, and to integrate those projects effectively with the electric system grid. This section discusses the following contract compliance programs: (a) capacity performance; (b) metering energy deliveries; (c) prescribed dispatch; (d) protection equipment testing; (e) efficiency monitoring; (f) scheduled maintenance; (g) wind operations; (h) insurance verification; and, (i) forecasting and scheduling accuracy.

a) Capacity Performance Programs and Verification

SCE's capacity performance monitoring programs and activities assist in ensuring that SCE's customers receive the firm capacity for which SCE has contracted. There are two major programs: the annual contract capacity demonstration (CapDemo) program, and the summer capacity performance (CapPerformance) program.

(1) CapDemo Program

The CapDemo program applies to those PURPA and CHP contracts that provide payment for firm capacity and contain a capacity testing clause. These facilities are required to achieve and reliably sustain 100% of their firm contract capacity for each metering interval (typically 15 minutes) during a specified period of testing (typically six hours during an on-peak period), or as otherwise specified either in the contract or other agreements between SCE and the counterparty. This performance test simulates the condition described in most contracts requiring the project to make best efforts to provide full contract output when a system emergency is declared. Most firm capacity contracts contain a firm capacity reduction clause that provides a remedy if the generator is unable to provide the required capacity during the test. Typically, the remedy is a reduction of firm capacity to the level demonstrated during the test.[168]

The steps involved in implementing the CapDemo program include scheduling mutually agreeable test dates, visits by SCE personnel to the facility to ensure that the test protocols are properly followed, or setting up the tests remotely, when feasible, analysis of the regular revenue meter data for pass or fail status, communicating the results to the project, and administering the appropriate remedy for those projects that fail. During the record period all tests were done remotely. Demonstrations are generally performed during the summer season on-peak hours for the months of

[168] SCE has historically experienced disputes with projects operating pursuant to PURPA contracts regarding the appropriate capacity reduction in the event of a CapDemo test failure.

June through September. Longer test periods specified in a few of the contracts also include hours from the mid-peak and off-peak periods.

During the Record Period, SCE witnessed four initial demonstrations, one retest, and sent notices of pass/fail status to all the facilities. Of the four projects that demonstrated capacity, two passed their initial demonstrations, one failed its initial demonstration and was retested, and one facility failed its demonstration. The circumstances regarding the single failure and single retest are as follows:

(a) Desert Power Company (ID 4008)

Desert Power Company is a small 0.60 MW run-of-the-river hydroelectric generator located near Bishop, California originally executed as a Negotiated contract. The PPA was executed on August 13, 1982. As in past years, Desert Power failed to demonstrate firm contract capacity in 2020. The capacity of the unit was restricted by continuing drought conditions that reduced the available water flow to the facility. Desert Power's nonstandard contract contains no explicit provisions for capacity reduction.

(b) LUZ Solar Partners IX (ID 5051)

Luz Solar Partners Ltd. IX (SEGS 9) is an 80 MW solar thermal project located in Hinkley, California originally executed as a Standard Offer 2 (SO2) contract. The PPA was executed on June 14, 1988. SEGS 9 failed its initial capacity demonstration due to abnormal weather conditions and was granted a retest. SEGS 9 passed the retest one week later.

(2) CapPerformance Program

Most PURPA and CHP contracts with firm capacity provisions require that the project achieve a minimum performance factor (as more specifically defined in the applicable contract) of 80% of its firm contract capacity for the on-peak periods during the peak months of June, July, August, and September.[169] If the project fails to meet this minimum requirement for any month, it is placed on probation beginning the month following the failure. Probation generally continues through

[169] Many firm capacity PURPA and CHP contracts also contain provisions enabling projects to earn bonus payments for exceeding minimum contract performance requirements during both the summer and winter months. *See* "Performance Bonus" discussion in H.2.c of this chapter.

September of the following year. Therefore, depending on which summer month the project first fails, the probation period can last between 12 and 15 months, subject to SCE's discretion to shorten the period based on obtaining the best customer outcome for each case. If a project fails to meet the minimum performance factor requirement during any month of its probationary period, its contract capacity may be reduced and/or it can lose its eligibility for winter bonus payments pursuant to the terms of the contract. A project can return to normal status at the end of probation if it satisfies the peak performance requirement during all months of the probationary period.

During the Record Period, three PURPA contracts were subject to the summer capacity performance provisions for the months of June through September. Of those contracts, none of the projects failed their performance obligation in at least one summer month during the on-peak delivery period.

b) <u>Metering Energy Deliveries</u>

SCE uses meter and schedule data to calculate payments owed to PURPA and CHP projects that existed prior to the CAISO. Since these legacy contracts had no provision for CAISO metering, they were permitted to use their existing metering in place of CAISO metering for CAISO settlements until their contracts expire or are replaced. SCE uses its own metering along with a variety of quality control measures to create Settlement Quality Meter Data that is transmitted to the CAISO on a daily basis for settlements purposes. Once the legacy contract is replaced, the seller is required to comply with all CAISO tariffs including the installation and use of CAISO approved metering. SCE generally maintains its own backup meter in addition to the CAISO metering. The SCE meter also provides the data for retail billing when the project is not generating and instead is consuming energy from the grid.

(1) <u>PURPA and CHP Projects within SCE's Territory</u>

SCE uses three types of "interval" metering for PURPA projects located within its service area: (1) real time energy metering (RTEM); (2) Basic interval; and (3) CAISO. Each of these meter types are described below in this section. The meter data provides three major functions: (1) billing for energy used; (2) payment for energy delivered; and (3) providing data to the CAISO for settlements purposes. There remains one extremely small project, Tehachapi Cummings Water District, which uses a non-interval meter that provides only monthly totals which are manually read from the display on the meter face by a meter reader. This project is inactive, and the generating equipment has been removed. Voluntary termination has been offered to this project; however, no response has been received.

For the purpose of CAISO settlements, SCE provides settlement ready meter data to the CAISO for those legacy PURPA and CHP generators within its service territory that are not required to have CAISO meters. Readings from all these RTEM and interval meters are accumulated into hourly totals and aggregated according to the CAISO delivery point. Each delivery point, whether it has a single dedicated generator, or an aggregation of multiple generators is reported to the CAISO under a single global resource ID. Applicable loss factors are applied and the resulting data are compiled into a comma separated value (.csv) format file by SCE's MV-90 meter reading system and subsequently reported to the CAISO for settlement by uploading the data into the Market Results Interface Settlements system, previously known as OMAR. Generators that have CAISO meters installed have their meter data captured by the CAISO directly through a dedicated network referred to as the Energy Communication Network (ECN), or as in the case of two projects, through a traditional Internet Service Providers (ISP) for settlements. SCE uses either these same meters read by its MV-90 meter reading system or its own revenue meters read through the retail billing system, known as Customer Data Acquisition System (CDAS), to obtain the data needed to process payments. The meter data is transferred from the meter data systems mentioned above to Endur which is used to generate payment statements for these projects.

(a) <u>The RTEM Process</u>

SCE uses the RTEM process to measure most production pursuant to PURPA and CHP contracts. Some installations have multiple meters. These RTEM meters generally measure energy sold to SCE, energy supplied to the facility by SCE, and reactive power (VARs) supplied by SCE. The RTEM meters store data internally, and the data are transmitted to a central computer every 15 minutes.[170] Depending on the best pathway available at the site, the data transmission occurs through the SCE-owned radio packet network called NETCOM, through a cell phone system, or through the domestic telephone system. If the communication system fails, the meters retain the data internally until the communication pathway is restored. The meters can also be read manually using a handheld device or laptop computer. The data are transferred from the field to the central computer and then to Endur, which is used to generate payment statements for these projects and to the MV-90 system for CAISO settlements.

(b) Interval Meters

Basic manually read interval meters are used on very small projects in areas still accessible by manual meter reading. These simple meters are all-electronic interval meters that contain an internal recorder. Each month, an SCE meter reader visits the facility to collect the meter data, using a laptop computer with an optical link that connects to the meter. The data is then transferred to a central computer via SCE's internal network where it is used for contract payments, CAISO settlement shadowing, and billing purposes for the business customer.

Some of the manually read interval meters are now being replaced with SCEs smart meters which have the same recording capability but have the added feature of being read remotely, thus eliminating the need for a meter reader to visit the site each month. The data from the smart meters are automatically uploaded into the central metering database from which it is used for payments, billing, and CAISO settlements.

(c) CAISO Meters

CAISO meters are required on all projects created after the formation of the CAISO; however, a few exceptions are allowed for very small units. CAISO meters are installed and maintained by the facility owner. Maintenance is performed only by those parties certified by the CAISO. These parties are known as Meter Service Agents (MSA). Some installations have multiple CAISO meters. The use of multiple meters is for measuring each component of a facility's total generation or as a primary and secondary (backup) metering scheme.

[170] The central computer also supports SCE's billing, generation grid operations, and energy accounting systems.

CAISO meters are four-quadrant interval meters that measure forward and reverse watts as well as forward and reverse VARs. CAISO meters are programmed with applicable loss factors. The meters are capable of communicating with a remote system for data collection. This communication generally occurs through a secure internet-like network known as the ECN. In a few cases, a traditional Internet Service Providers (ISP) is used where the ECN is not readily accessible. Two projects leverage a traditional ISP. The CAISO remotely reads these meters for settlements. SCE also remotely reads these meters using its MV-90 meter reading system. As provided in a specific contract, the meter data are used for various purposes, including CAISO settlements.

(2) Out-of-Service Territory PURPA Projects

SCE meters PURPA projects outside of its service territory (OST). Most of the OST projects are located within the area operated by the Imperial Irrigation District (IID) in south eastern California. Energy is delivered by the local utility on behalf of the generators to SCE over that utility's interties with SCE.[171] SCE receives the quantity of energy represented by and pays these PURPA projects based upon hour-by-hour energy delivery schedules from the delivering utility. The energy deliveries are compensated for line losses by the transmitting utility according to agreements with the generators. The schedules are established one day ahead and are adjusted in real time between SCE, the delivering utility, and the CAISO. The final schedule for each hour is retained in SCE's IAM Web Harness System, which was previously known as the Gen Manager System.

The projects located in IID's service territory are covered by a single aggregated schedule in IAM Web Harness. Because each project must be paid separately, IID creates a spreadsheet of hourly meter data and e-mails the spreadsheet on a weekly basis to SCE's Energy Contract Management Settlements group. The metered values are collected by revenue meters owned by IID. The hourly meter data is uploaded to Endur on a monthly basis. For more discussion on SCE's payment administration of its OST PURPA contracts, see Section VII.H.2.d) of this chapter.

[171] The special administration procedures discussed in this section are not applicable to the Sycamore (ID 2815/2816), and Terra-Gen Dixie Valley (ID 3106) projects, which are located outside of SCE's normal service territory, but do not utilize an interconnecting utility because they are directly connected to SCE's system and therefore are directly metered by SCE. These projects are not discussed in this section.

c) Prescribed Dispatch

During the Record Period, there was one PURPA project that contained provisions permitting SCE to exercise a prescribed curtailment option. These provisions allow SCE to prescribe periods when the project must either limit energy deliveries or receive a lower price for energy not curtailed, to render SCE's customers economically indifferent. By exercising this right when SCE expects to experience low market prices or transmission curtailment, higher cost PURPA contract energy is curtailed, allowing for lower cost market purchases and therefore reduced costs to SCE's customers. The one project, E.F. Oxnard (ID 2205), did not select the contractual option to participate in the program for this Record Period.

d) Protection Equipment Testing Program

The protection equipment testing program (Protection Program) provides for the uniform implementation of the standards and requirements contained in SCE's Rule 21 tariff, as applicable to PURPA projects interconnected within SCE's service territory. The Protection Program is intended to assure that any protection equipment owned by a party operating a facility pursuant to a PURPA contract that directly interfaces with SCE's transmission or distribution system is regularly tested in accordance with contractual requirements. Most PURPA contracts require that protection equipment be tested at regular intervals of one, two, or four years depending on connection voltage.

Non-compliance with applicable protection equipment standards may subject SCE and its customers to greater risk that generation equipment will not disconnect as required if it malfunctions. This could cause damage to the project's equipment and introduce unwanted and possibly harmful voltage fluctuations into SCE's system or could cause a portion of the SCE system to shut down, thereby interrupting service to customers. There are also some conditions that could cause harmonics and other power quality problems.

Compliance with this program is established by the project's submission to SCE of a report that indicates a licensed electrician inspected the protective relays. SCE may deny a forced outage claim for a project that does not provide the required reports because SCE will not have had proof that equipment was properly maintained as required by the Rule 21 tariff.

e) QF Efficiency Monitoring Program

In D.91-05-007, the Commission authorized the utilities to monitor the operations of cogenerators, as well as small power producers that use supplemental fossil fuel, to ensure that they follow FERC operating and efficiency standards. The program implementing this decision is known as the QF Efficiency Monitoring (QFEM) program.

Originally, state regulations permitted suspension of contract payments and disconnection of PURPA projects from parallel operation for failure to comply with FERC standards. Subsequent litigation and Commission decisions have modified the QFEM program, based on a determination that federal law preempted the state's regulations. Currently, only FERC can determine if a project is compliant and prescribe corrective actions in the event of noncompliance. However, PURPA projects are still required to submit operating data to utilities annually to demonstrate compliance with FERC standards. When it is cost effective, SCE will take measures necessary to file complaints at FERC with respect to projects operating pursuant to a PURPA contract that fail to come into compliance after notice. PURPA projects found to be out of compliance by FERC may lose their QF status and be ordered to refund overpayments to the utility.

During the Record Period, SCE determined that all PURPA projects that submitted complete operating, efficiency, and fuel use data for calendar year 2019 met FERC standards for that year.[172] SCE continues to follow-up with 10 PURPA cogeneration projects that have not submitted data for various reasons as described in the table. These projects are identified below.

[172] Data is requested on an annual basis, so SCE receives 2019 data in 2020

Table VII-69
Projects That Failed to Submit Operation and Efficiency Data for Calendar Year 2020

	ID	Project Name	Size (kW)	Notes
1	2060	BP Amocco	8,000	Project not currently operating.
2	2155	Chevron USA	170,700	Data promised by end of year but delayed due to resource contraints from COVID-19.
3	2205	E.F. Oxnard Inc.	48,500	Project terminated contract in record period.
4	2215	Mobil Oil Corporation #1	41,900	Data promised by end of year but delayed due to resource contraints from COVID-19.
5	2413	St. John's Hospital and Health Center	1,080	No reply received during record period.
6	2462	B. Braun Medical Inc.	6,100	No reply received during record period. Noted prior contact retired.
7	2818	GFP Ethanol, LLC (d.b.a Calgren Renewable Fuels)	5,000	No reply received during record period.
8	2845	New-Indy Ontario, LLC.	33,860	No reply received during record period.
9	2855	New-Indy Oxnard, LLC.	14,000	No reply received during record period.
10	2915	Tesoro Refining & Marketing Company LLC	31,000	No reply received during record period.

* Note: QF data is requested in 2020 for prior operating year 2019

f) Scheduled Maintenance

The scheduled maintenance program provides for uniform implementation and verification of the scheduled maintenance procedures in each firm capacity PURPA or CHP contract. Under all SOCs, and some nonstandard contracts, PURPA and CHP projects are responsible for providing advance notice to SCE of reductions in capacity availability due to scheduled maintenance. PURPA and CHP projects that give proper notice of their scheduled maintenance outages receive an “allowable maintenance hours” credit to be used in calculating their monthly firm capacity payment. Projects that reduce or cease generation without proper notice do not receive scheduled outage credit and, as a result, may be unable to earn their full capacity payment. PURPA and CHP projects are required to make all reasonable efforts to schedule maintenance during SCE’s off-peak winter months (October – May).

During the Record Period, six PURPA projects made a total of 140 requests to schedule maintenance, and four CHP projects submitted 44 such requests. SCE approved 125 of those requests for PURPA projects and 29 for CHP projects after first verifying the hours taken were in conformance with the schedule, contractual provisions, and maintenance procedures. The aggregate maintenance credit totaled 5,260 hours.

g) Wind Operating Programs

Wind generation from SCE's PURPA projects is primarily concentrated in two geographical areas: the Tehachapi Wind Resource Area near Mojave and the San Gorgonio Wind Resource Area near Palm Springs. Wind generation from SCE's RPS projects are either in the same two Wind Resource Areas or out-of-state. During the Record Period, SCE administered PURPA contracts with 6 unique wind generation projects with a total on-line capacity of approximately 123 MW. SCE purchased wind energy from 30 projects procured through solicitations required by the RPS program totaling approximately 3,889 MW of capacity during the Record Period.

Wind generation presents unique challenges due to its unpredictability, power factor demands, distributed location, time of delivery, and rapid ramp rates, among others. SCE had been performing a number of special administrative activities unique to wind generation to assure contract performance including turbine inventory, VAR monitoring / enforcement, wind generation forecasting, real time wind monitoring, and wind generation curtailments. The latter two of these activities have been transitioned to the Transmission Operations Organization. The annual turbine inventories have been eliminated due to the ability to monitor production using meter data and the time intensive nature of the inventory activity. The completion of the Tehachapi Renewable Transmission Project (TRTP) and the Interim West of Devers project have eliminated the recent need to curtail wind generation due to voltage instability and line overloads. With the elimination of these transmission-constrained real time curtailments, the need to notify, track and pay for these curtailments has been eliminated. All the above-mentioned activities apply to wind generation whether it was procured under the PURPA or RPS programs.

h) Insurance Verification

PURPA and CHP projects are required to obtain and maintain comprehensive general liability insurance during the terms of their power purchase contracts. SCE uses a third-party insurance management solutions company, Insurance Tracking Services, Inc. (ITS) to monitor these requirements. During the Record Period, 35 PURPA projects and 10 CHP projects were actively monitored by ITS. ITS, in conjunction with SCE, ensures that these projects have:

- Obtained required insurance upon execution;
- Maintained insurance policies and insurance carriers that meet the contract's requirements; and
- Maintained adequate insurance coverage throughout the terms of their contracts.

i) <u>Forecasting and Scheduling Accuracy</u>

Certain CHP contracts have provisions for evaluating the accuracy of project's energy and/or capacity forecast and assessing financial penalties associated with excessive forecast errors. Two compliance programs related to forecasting and scheduling accuracy were in effect during the Record Period: Mean Absolute Error (MAE) and Scheduling and Delivery Deviation (SDD) Adjustments.

In the MAE program, a monthly mean absolute error between a project's day-ahead forecast and actual production is quantified and compared to a threshold. Exceeding the error threshold can result in a forecasting penalty, and multiple non-compliances can trigger a temporary de-rating of the project's firm contract capacity. SCE has six CHP projects subject to the MAE program. During the Record Period, two of the projects failed the MAE requirements and penalties in the amount of $12,500 were assessed.

The purpose of SDD Energy Adjustments is to mitigate, for SCE and the project, any financial impacts due to excessive deviation of metered energy deliveries from the project's schedule. SDD Adjustments are based on differences between real-time energy prices and contract energy prices. Additionally, an administrative charge, based on CAISO's grid management charge for uninstructed deviations, is assessed and charged to the project for any scheduling deviation outside of the performance tolerance band. During the Record Period, 12 PURPA and CHP projects incurred administrative charges totaling $34,880.40 for generating outside of the SDD performance tolerance band.

3. RPS

Compliance programs have been developed to ensure that RPS projects adhere to the terms of their contracts, and to integrate these projects effectively with the electric system grid. This section will discuss the RPS compliance. In addition, this section includes a summary of REC retirement activities.

a) Renewable Capacity Verification

SCE's capacity verification activities for renewable projects are designed to ensure that SCE's customers can reasonably expect to receive appropriate quantities of energy in full compliance with the associated contracts. Renewable capacity verifications are generally a one-time event performed either prior to the contract becoming commercial or around the contractual Firm Operation Date.[173] The activity generally consists of a site visit to verify the equipment listed in the contract has been installed, to collect and verify the meter unique identification number(s), and, in some cases, to collect meter data for a chosen interval. The verification is intended to determine the maximum capacity capability of the project. From the demonstrated capacity, the energy delivery performance requirements are derived.

During the Record Period, there were 10 renewable projects that underwent capacity verifications. All these projects passed the verification process with a combination of a demonstration for one hour utilizing meter readings and site inspection for determination of the installed equipment. The breakdown of these projects by their respective solicitations is: BioMAT (0), ReMAT (1), ERR (97) and RAM (1). Table VII-70 lists the units tested and the results as of the end of the Record Period.

[173] *See* ***Table VII-59***, "RPS Contracts that Achieved Commercial Operation" for a list of contracts that may have been eligible for a verification test. Note that due to different testing schedules established in each PPA, not all contracts in this table were tested during the Record Period.

Table VII-70
Renewable Capacity Verifications
January 1, 2020 Through December 31, 2020

	ID	Project	Date of Capacity Test	Capacity (MW)	
1	5261	Windhub Solar "A", LLC	1/8/2020	20.0	(b)
2	5263	American Kings Solar, LLC	12/12/2020	128.0	(c)
3	5264	Maverick Solar, LLC	12/16/2020	125.0	(b), (c)
4	5804	Copper Mountain Solar 4, LLC	1/15/2020	93.6	(b)
5	5805	Imperial Valley Solar 2, LLC (f.k.a. 88F 8me (Mount Signal Solar 2))	6/1/2020	153.5	(b), (c)
6	5810	41MB 8me, LLC (Lotus Solar)	3/18/2020	51.3	(c)
7	5882	Sun Streams, LLC	1/22/2020	154.3	(b)
8	5884	Sunshine Valley Solar, LLC	1/16/2020	103.5	(b)
9	5889	Blythe Solar III, LLC	4/3/2020	136.8	(c)
10	6380	Voyager Wind I, LLC	1/29/2020	131.1	(b)

(a) The Solar PV and SPVP-IPP project capacity are reported in kW DC to the nearest Watt.
(b) Multiple site visits required to verify corrective actions.
(c) Final verification pending site visit relief from COVID19 travel restrictions.

b) Metering Energy Deliveries

SCE uses a combination of meter and schedule data to calculate payments for RPS projects that delivered energy during the Record Period. Generally, RPS generators are required to obtain CAISO-approved metering for their facilities. SCE will also install a settlement quality meter at all of the projects within its service territory to serve as a billing meter for energy used by the project and to serve as a backup and validation for the CAISO meter. The SCE meter is also used to account for renewable energy credits where applicable because it measures the actual generated energy without applying loss/credit factors which do not apply to renewable credits administered by the WREGIS organization.

CAISO meters are four-quadrant interval meters that measure forward and reverse watts and VARs. CAISO meters can communicate with a remote system through ECN, a dedicated secure network for data collection. The CAISO reads these meters remotely through the ECN. Two projects leverage a traditional Internet Service Provider (ISP) for settlements. SCE also reads these meters remotely, to check the data and to use the data in other ways as provided in the contracts.

SCE maintains its own meters at most of the RPS projects. These meters are used for retail billing, verification, backup, RPS reporting through WREGIS, and in some cases, monthly payments. The SCE meters are either real time energy meters (RTEMs) or standard interval meters.

For a more detailed description of the process surrounding the meters and data collection see the Metering Energy Deliveries section for the PURPA and CHP generators.

c) Active Monitoring

D.10-06-004 requires SCE to (a) devise a method to actively monitor each seller's compliance with Standard Term and Condition 6[174] (STC 6) and related contract terms, (b) administer the active monitoring, and (c) make an affirmative showing in each ERRA proceeding of its method for active monitoring and the results of that monitoring. This will demonstrate SCE's reasonable contract administration of all contract terms, inclusive of obligations prior to and after the project's commercial operation, as appropriate.[175]

SCE's method to actively monitor each seller's compliance with STC 6 consists of: (1) requesting the seller to provide a copy of the project's CEC pre-certification prior to initial project delivery or within 365 days after the effective date of the contract, whichever is applicable according to the contract, and requiring the project to attain full certification from the CEC shortly after the project begins commercial delivery; (2) monitoring changes in law or regulations that may affect RPS eligibility; (3) monthly monitoring of the CEC website to verify that facilities are RPS-certified via each facility's unique RPS ID (cross-checked to the CEC certification); and (4) verifying the RPS ID during WREGIS registration and routine maintenance. Additionally, SCE performs site visits, capacity

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[174] STC 6 requires that the seller warrant throughout the term of the PPA that (i) the project qualifies and is certified as an ERR and (ii) the output qualifies under requirements of the California RPS. The only exception is upon a change in law, wherein seller is contractually obligated to use commercially reasonable efforts to comply with the change in law (paraphrased for simplicity, for actual STC 6 verbiage, *see* D.08-04-009, Appendix A, p. 6).

[175] D.10-06-004, p. 21, OP 2.

demonstrations, and capacity verifications during the construction and commercial operation of each of the phases of the project to ensure that the project follows the contract.

RPS projects with contracts executed during the Record Period are in varying stages of providing a copy of the individual project's CEC pre-certification.

Currently, SCE's entire portfolio of RPS-eligible contracts consists of proven applications of landfill gas, biomass, digester gas, geothermal, small hydro, conduit hydro, solar thermal, solar PV, and wind technologies as generating facilities.

SCE's contract compliance includes regular monitoring of the CEC website to verify that facilities are RPS-certified. This review is embedded in the process for WREGIS registration and maintenance. There was one (1) project found during the Record Period to have issues with their CEC Certifications.

(1) <u>Terra-Gen Dixie Valley, LLC (ID 3011/3106)</u>

When this project transitioned from a PURPA contract to an RPS contract, SCE discovered the capacity in the CEC Certification was outdated and the update was not submitted with the CEC in a timely manner. Per the RPS Guidebook rules, SCE expects the project to be ineligible for RPS counting for a period before the capacity update. However, the CEC processed the capacity update without changing the RPS eligibility in the CEC Certification. For the purpose of total transparency and to ensure correct determination of RPS eligibility, SCE sent a notification letter in late 2018 to the CEC explaining the issue and to also confirm the RPS eligibility. SCE has followed up with the CEC numerous times, however, as of the close of this Reporting Period SCE still awaits a final response from the CEC.

Capacity verifications are discussed in detail in a prior section of this chapter. Also, visits were conducted at project sites during various phases of those projects' construction. See Table VII-71 below. As a result of those visits, no inquiries from observations at those sites were necessary, and all visits revealed that the projects were complying with the contract terms including STC 6.

Table VII-71 below is a summary of SCE's Active Monitoring activities during the Record Period.

Table VII-71
RPS Active Monitoring
January 1, 2020 Through December 31, 2020

	ID	Project	Site Visit During Record Period	Capacity Verification (a)
1	5261	Windhub Solar "A"	X	X
2	5264	Maverick Solar	X	X
3	5804	Copper Mountain Solar 4	X	X
4	5805	Imperial Valley Solar 2, LLC (f.k.a. 88F 8me (Mount Signal Solar 2))	*	(b)
5	5810	41MB 8me (Lotus Solar)	*	(b)
6	5882	Sun Streams	X	X
7	5884	Sunshine Valley Solar	X	X
8	5889	Blythe Solar III	*	(b)
9	6380	Voyager Wind I	X	X

(a) Not all projects require capacity verifications because they are either not yet constructed or operating, or they have already been verified in a prior Record Period.
(b) Capacity verification was conducted based on the as-built Exhibit B drawings. Final determination is pending Site Visit.

* Physical Site Visit Pending

d) Western Renewable Energy Generation Information System (WREGIS)

Pursuant to SB 1078 and Public Utilities Code §399.25, an electronic accounting and tracking system was developed to verify retail sellers' compliance with the RPS. This system, WREGIS, became operational in June 2007. SCE participates in WREGIS pursuant to Public Utilities Code §399.25 and is subject to the compliance requirements of the CEC and the Commission.

During the Record Period, SCE was account holder for 341 facilities registered in the WREGIS system. Those facilities were comprised of 401 individually-registered generating units representing all eligible renewable PURPA and utility-owned projects, and most RPS contracts. All other RPS projects register their facilities as their own account holder and then transfer their RPS credits to SCE for compliance purposes.

SCE's costs associated with registering and tracking renewable energy deliveries in WREGIS includes account fees, volumetric fees, and service fees for renewable power. SCE paid $129,886.29 in WREGIS fees during the Record Period.

e) RPS Insurance Verification

RPS projects are required to obtain and maintain comprehensive general liability insurance during the terms of their power purchase contracts. SCE uses a third-party insurance management solutions company, ITS, to monitor these requirements. During the Record Period, 267 RPS projects were actively monitored by ITS. ITS, in conjunction with SCE, ensures that these projects have:

- Obtained the required insurance upon contract execution;
- Maintained insurance policies and insurance carriers that meet the contract's requirements; and
- Maintained adequate insurance coverage throughout the terms of their contracts.

f) Wind Operating Programs

Please refer to the Wind Operating Programs section under Contract Compliance for PURPA/CHP for details regarding both RPS and PURPA wind operating programs.

g) Renewable Energy Credit (REC) Retirement

During the Record Period, SCE retired 6.2 million RECs corresponding to generation from vintage years 2018 and 2019.

RECs tracked in WREGIS must be retired before they can be counted toward meeting RPS targets. The RPS Eligibility Guidebook requires that WREGIS certificates, or RECs, be retired within 36 months from the initial month and year (vintage month and year) of generation of the associated electricity to be eligible for the RPS program. RECs may be retired across compliance periods if the retirement is within 36 months of the vintage month and year.

To ensure that the proper number of RECs are retired, SCE must compare, for every month and by project, the number of WREGIS certificates that are eligible for retirement with the amount of RPS eligible generation that was procured. Any discrepancy must be investigated, explained, and reconciled. Discrepancies usually arise from initial meter data errors that have resulted in prior period adjustments in WREGIS. These are adjustments in which 1) additional WREGIS certificates are created in a subsequent month (but labeled with the original vintage month) to account for a deficiency in the original vintage month when the additional certificates should have been created, or 2) creation of certificates is withheld in a subsequent vintage month to account for a surplus of certificates created in a prior vintage month. When a discrepancy is found, SCE must submit a prior period adjustment to the WREGIS website and verify in the subsequent month that the proper number of certificates were created or withheld, as applicable, in WREGIS. For withheld certificates, SCE must manually track outside WREGIS the correct vintage month and year of the adjustment to ensure the adjusted RECs are retired within the 36-month window, since the vintage information of the adjusted RECs recorded in WREGIS does not reflect the true vintage month and year. When retiring WREGIS certificates, SCE must also identify RECs whose RPS eligibility has not been established and work with the generating project to resolve outstanding issues before retirement. If resolution is not possible before the reporting deadline, SCE excludes the RECs in question from retirement for the compliance period.

The actual retirement of RECs takes place on the WREGIS website. Several factors related to the WREGIS website make REC retirement a cumbersome, manual process. RECs are retired in batches, which are groups of RECs consisting of all the generation from a generating unit during a given month. In a typical record period, SCE's portfolio includes more than 400 registered generating units, which equates to more than 4800 batches of RECs to be retired. Since REC retirement is final, every batch selected must be double checked to ensure correct association with the generator and vintage month. In addition, each selected batch is checked for the correct number of total RECs. This is especially difficult for batches with prior period adjustments, as multiple batches may need to be added to form one complete month, or a batch may need to be split to different months. After the REC batches are selected, the correct retirement subaccount, retirement type, state, RPS Compliance

Period, and retirement reason must be specified to complete the process. The WREGIS website allows a maximum of 300 batches to be selected per retirement action, but typically only around 100 batches are selected per retirement action. This is done to reduce the chance of batch selection error and to allow adequate time to double check selection quantity before the website times out. Therefore, the process must be repeated about 50 times if all REC batches from a typical record period were to be retired.

In summary, the REC retirement process is highly complex and involves a substantial amount of manual effort and rigorous processes to avoid errors and ensure accuracy. It is SCE's former practice to hold all RECs from a compliance period in the active subaccount and retire those RECs in late spring/early summer following the end of the compliance period. In the Record Period, SCE started a new practice of retiring all RECs on an annual basis from the previous year. This practice was implemented for the purpose of workload balance between each year of the compliance period and reducing risk of RECs expiring prior to retirement. An exception to this new practice is that RECs with outstanding quantity or eligibility issues will be held off from retirement and retired as issues are resolved.

During the Record Period, there was 1 partial batch of RECs that expired (went beyond the 36-month window), which totaled to 6 RECs. These RECs were intentionally allowed to expire because they were over-created, or they were not owned by SCE, but the owners declined the REC transfer.

h) Curtailment of Renewable Resources

Many of SCE's RPS contracts contain a variety of curtailment provisions. Curtailment of resources may be a result of CAISO grid reliability events, outages by the transmission providers, or for economic reasons. Curtailments may include directing the resource to reduce output to any level less than its current schedule and may be of any duration greater than one-meter interval. Generally, if the curtailment is a result of CAISO grid reliability or an outage called by the transmission provider, whether planned or unplanned, the resource is obligated to comply accordingly, and the curtailed energy is not paid under SCE's contracts. Economic curtailments, however, are contemplated in most of the contracts and generally allow some form of reimbursement to the project. RPS contract provisions vary and may include simple "take or pay" methodologies, provisions including a portion of "no cost" curtailments in MWh prior to a "take or pay" method or more complex provisions such as Day Ahead Market Clearing Price (DA-MCP).

During the Record Period, SCE implemented a systematic approach to monitoring and identifying the types of curtailments and calculating payment of curtailed amounts to support contract settlements in Endur. Approximately 654,000 curtailed intervals were analyzed and appropriately settled.

H. **Contract Payment Process**

SCE applies a set of four policies to ensure that all PURPA, CHP, RPS, tolling, RA, Energy Storage, DRAM, transmission and gas contracts are paid accurately and on time. All payment documentation is placed in the identified network drives and updates to contract terms are placed into their respective settlement system, (*i.e.*, Endur[176], and/or the appropriate trading/transactional databases). These policies are: (1) pay projects according to the terms and conditions of their contracts, as interpreted by relevant Commission decisions, orders, pertinent industry practices, and internal SCE controls, including those controls necessary to comply with the Sarbanes-Oxley legislation; (2) make payments in a timely manner according to the terms and conditions of the contracts; (3) subject to timely notification of errors in conformity with contractual terms, correct calculation errors for a time period up to that permitted under the contract and applicable statute of limitations; (4) promptly investigate the facts relating to payment variances and coordinate with Energy Procurement and Management's Energy Contracts Management group as applicable. If adjustments are warranted, carry them out in a timely manner.

Depending upon the type of PPA/product (EEI, WSPP, ISDA, NAESB, ERR), there are numerous contracts that require the parties to exchange invoices each month. In the instances where counterparty invoicing is required and SCE disputes the correctness of the invoice or a portion thereof, SCE will pay only the undisputed portion of the invoice and communicate, in writing (via e-mail), the

[176] This includes User Defined Applications (UDA's), and systems developed for Emissions trading.

basis for the variance. Payment of the disputed portion of the invoice shall not be required until the parties resolve the invoice variance.

The sections below discuss the procedures, guidelines, and processes regarding the monitoring, validation, and calculation of Conventional, PURPA, CHP, RPS, Energy Storage and DRAM contract settlements.

1. <u>Conventional</u>

The sections below discuss the administrative procedures, guidelines, and processes regarding the monitoring, validation, and calculation of Resource Adequacy (RA), Energy Storage, DRAM, gas, transmission, tolling and power contract settlement provisions.

a) <u>RA</u>

SCE compensates contracted generators using the unit availability quantity (in MW) filed in the CAISO/CPUC Supply-Plan Template, which occurs at T-45 days prior to the showing month. These RA availability quantities are used for calculation of a monthly RA capacity payment. Each payment is based on contractual parameters as specified in the contract terms and conditions. Adjustments or reductions to payments are made based on events of unavailability. Any non-availability charges or availability credits are captured in the CAISO Resource Adequacy Availability Incentive Mechanism (RAAIM)[177] process and are passed-through on the monthly invoice to the applicable counterparty.

b) <u>Energy Storage</u>

SCE compensates the seller on a monthly basis. The monthly capacity payment is calculated based on the contractual price per unit of the capacity received from the seller. SCE pays the monthly capacity payment to seller for each showing month of the Energy Storage/RA Delivery Period as the product of the delivered capacity and the contract price.

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[177] While the RAAIM market mechanism implementation was initially delayed in April 2017, in early 2018, the CAISO successfully implemented the program with retroactive payments covering the entire Record Period.

c) DRAM

SCE compensates either the Aggregator or Demand Response Provider (seller) for various products, including, system capacity, local capacity and flexible capacity. The product monthly quantity and contract price for the type of products are indicated in a seller-provided table for the applicable showing month. SCE makes a monthly payment to seller after the applicable showing month. The delivered capacity payment is equal to the product of the contract price and the demonstrated capacity for the applicable showing month.

d) Gas Transactions

SCE purchases physical and financial gas from market suppliers to deliver gas to generating facilities either under contract with or owned by SCE. These transactions are completed using various agreements including the NAESB, gas annex to the EEI, or gas annex to the ISDA. Payment provisions are covered under the NAESB and/or gas annex to a master agreement. Payment is based on a volume (MMBtu) and price (either fixed or identified by reference to a published index) per each individual transaction. Payments are typically made on the twenty-fifth day (25th) of the month following the month of delivery.

e) Transmission

SCE purchases transmission from market suppliers. These transactions are covered under the TREA or tariff and are paid based on the contractual obligations under the contract. Payment is based on volume (MW) multiplied by price (either fixed or identified by reference to a published index). Payments are typically made within twenty (20) days of receipt of invoice.

f) Power Purchase Tolling Agreements

Generators that have a tolling agreement with SCE are compensated using a combination of energy and capacity payment types varying from monthly capacity, reduced monthly capacity, variable O&M, and start-up charges. Each payment is based on contractual parameters. The generator is also paid a heat-rate adjustment payment, which calculates the difference between actual gas usage and contractual heat rates, as defined in the respective agreement. Adjustments or reductions to payments are made based on events of unavailability. SCE settles after-the-fact on a calendar-month basis, with payments for the prior month being settled on either the twentieth (20th) day of each month or ten (10) days after receipt of invoice, whichever is greater.

g) Power Transactions

In addition to power purchase tolling agreements, SCE purchases power from market suppliers. SCE power transactions under the EEI, WSPP, or power annex to the ISDA are paid based on the contractual obligations under the contract. Payment is based on volume (MWh) multiplied by the identified index and is typically made on the twentieth day (20th) of each month following the month of delivery.

2. PURPA and CHP

The sections below discuss the administrative procedures, guidelines, and processes regarding the monitoring, validation, and calculation for PURPA and CHP contract settlement provisions.

a) Energy Rates for PURPA and CHP Contracts

Monthly energy rates are calculated based on the following components: contract specific Time of Delivery (TOD) heat rates, gas index, gas transportation rate, contract specific annual Variable O&M Charges (VOM), and Hourly Location Adjustment Factors (LA), as described below.

On August 1, 2009, the Commission implemented Resolution E-4246, which finalized a new market index formula (MIF) that changed how SRAC energy pricing is calculated and established new as-available capacity rates. Resolution E-4246 affects all PURPA contracts, both renewable and cogeneration that are paid SRAC pricing for energy and as-available capacity.

The new SRAC, effective January 1, 2012, includes an adder called the Hourly Location Adjustment Factor (LA).[178] The LA was implemented to replace the Generation Meter Multiplier (GMM); after CAISO's MRTU "go-live" in April 2009, CAISO discontinued publishing the GMMs because it had converted to a nodal market. The market utilizes locational marginal pricing (LMP) at various pricing nodes (PNodes) throughout the CAISO. The LA is equal to LMP(QF) minus LMP (Trading Hub), where LMP(QF) equals the hourly day-ahead LMP at the point of interconnection

[178] D.10-12-035; CHP Program Settlement Agreement Term Sheet, Section 10, pp. 45-48.

with the CAISO grid associated with the QF generating facility, and LMP (Trading Hub) is the hourly LMP of the trading hub where the generating facility is located (*e.g.*, SP15). The LA calculation applies to various PURPA and CHP agreements as follows:

- Legacy Amendments
  - Option A: Subject to LA
  - Option B: Non-renewable projects are subject to LA, renewable projects are not
- CHP RFO PPA: Subject to LA
- QF SOC: Subject to LA
- AB 1613 Agreements: Not subject to LA

As addressed in SCE's 2013 (for the 2012 Record Period) ERRA filing, Chapter IX, pages 7-13, SCE executed numerous Legacy Amendments per the QF Settlement. These Pro Forma Legacy amendments were offered to all QFs that had existing contracts (Legacy PPAs or Legacy Agreements) with SCE as of the Settlement Effective Date; these projects are often referred to as Legacy QFs. The Legacy Amendments provided five options, called A, B, C1, C2, and C3 (as of 12/31/2015, the QF Legacy Amendments Energy Pricing Options for C1, C2 and C3 expired). The details of these options are explained further in Table VII-72 below.

Table VII-72
QF Legacy Amendment Energy Pricing Options

<table>
<tr><th>Legacy Amendment Option</th><th>A</th><th>B</th></tr>
<tr><td>Eligible Contracts</td><td>Legacy</td><td>Legacy</td></tr>
<tr><td rowspan="5">Incremental Energy Heat Rate (IER)</td><td>2012 = 8,225</td><td>2012 = 8,600 IER</td></tr>
<tr><td>2013 = 8,125</td><td>2013 = 8,500 IER</td></tr>
<tr><td>2014 = 8,125</td><td>2014 = 8,500 IER</td></tr>
<tr><td>2015 = 2011 & 2012 Actual Heat Rate</td><td rowspan="2">2015+ = Market</td></tr>
<tr><td>2016+ = Market</td></tr>
<tr><td>GHG Risk</td><td>Buyer 100%
2013 - 2015
2016+ GHG cost embedded in the gas price, and therefore paid to Seller through the calculated SRAC energy pricing</td><td>Seller</td></tr>
<tr><td>Location Adjustment Factor</td><td>YES</td><td>No, if renewable QF</td></tr>
</table>

b) Capacity for PURPA and CHP Contracts

PURPA and CHP contracts receive a capacity payment based on production. There are three types of capacity payments eligible to PURPA and CHP projects. Those include Firm, As-Available, and Excess As-Available. The pricing for these products is generally based on forecasts at the time of execution or SRAC.

c) Performance Bonus – Capacity

Many firm capacity PURPA contracts contain provisions that enable the projects to earn capacity bonus payments to encourage on-peak production during summer months. Projects are eligible to receive winter bonus payments if they meet specified summer on-peak contract performance requirements. SCE ensures that only the firm capacity PURPA contracts that have met monthly and seasonal contractual requirements receive a bonus payment.

d) Out of Service Territory Projects

A number of SCE's PURPA and CHP projects are located outside of SCE's service territory (*e.g.*, the IID and PG&E service territories), where energy is typically delivered by the local utility to SCE over that utility's interties. SCE receives the quantity of energy represented by and pays the PURPA projects based upon hour-by-hour energy delivery schedules from the delivering utility.[179]

e) Line Loss Factor

During the Record Period, PURPA and CHP projects that received Commission-approved short run avoided cost (SRAC) prices for their energy deliveries (and did not execute a Legacy Amendment providing for a line loss factor of 1.00) continued to have the line loss factor methodology specified in D.01-01-007 applied to their energy payment calculations. The line loss factors for a particular PURPA or CHP contract include the project's distribution loss factor (DLF) and transmission loss factor (TLF), and, in some cases, a transformer loss factor (unrelated to D.01-01-007). Since the April 1, 2009 "go live" of MRTU, the CAISO discontinued posting generation meter multipliers (GMM)/tie meter multipliers (TMM) that are a component of the TLF calculation. Starting in May 2009, SCE replicated the April through December 2008 GMM/TMM data to use in the calculations for the same monthly settlement periods in 2009 and going forward.

f) Time of Delivery (TOD) Periods

During the Record Period SCE managed active PURPA/CHP contracts which were paid using Time of Delivery Allocation Factors (TOD Factors) in the payment calculations. The TOD Factors for the delivery period are multiplied by the product of metered energy for that delivery period and the energy price.

3. RPS

The sections below discuss the administrative procedures, guidelines, and processes regarding the monitoring, validation, and calculation for RPS contract settlement provisions.

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[179] Other projects that are out-of-state are either dynamically scheduled to the CAISO or are directly connected to SCE's transmission/distribution system via generator intertie. Those projects, from a payment standpoint, are considered within SCE's territory.

a) Out of Service Territory Projects

Some of SCE's RPS projects are located outside of SCE's service territory (*e.g.*, the IID, PG&E, and out of state territories), where energy is typically delivered by the local utility to SCE over that utility's interties. SCE receives the quantity of energy represented by, and pays the RPS projects based upon, hour-by-hour energy delivery schedules from the delivering utility, or metered amounts per the contract settlement provisions.

b) Renewable Energy Credit (REC) Sales

SCE REC Sales are transacted under the EEI and Confirmation. SCE receives payment from the counterparty based on price multiplied by quantity.

c) Energy Payment Calculations

Many RPS contracts are paid for the energy delivered by the generator based on time of delivery and the contracted energy price.

(1) Time of Delivery (TOD) Periods

During the Record Period, SCE managed active RPS contracts which were paid using Time of Delivery Allocation Factors (TOD Factors) in the energy payment calculations. The TOD Factors for the delivery period are multiplied by the product of metered energy for that delivery period and the energy price.

4. Other Impacts to Payments

a) CAISO Charges

Certain contracts provide for CAISO charges, and in some cases CAISO revenues, to be the seller's responsibility. Some of those contracts include specific payment provisions during the start-up period through commercial operation, regarding schedule deviations, and in cases of a seller-initiated test. As the Schedule Coordinator for most of SCE's contract portfolio, CAISO charges and revenues are allocated and available to SCE. Upon receipt of the charges and/or revenues, SCE credits or debits the next payment to the generator depending on the activities that took place during the delivery month.

b) Scheduled Delivery Deviation Adjustments (SDD)

Certain contracts provide for SCE to calculate SDD adjustments in cases where SCE is the Scheduling Coordinator. For PURPA/CHP, the hourly SDD Adjustments are based on the difference between real-time LMP prices and contract energy prices. Certain tolling contracts use SDD as an uninstructed energy deviation charge. Additionally, a charge based on CAISO's grid management for uninstructed deviations is assessed and charged to the project for any scheduling deviation outside of the performance tolerance band identified within each contract. For Record Period charge results, see Section G.2.i above.

c) Scheduling Coordinator Fees

The QF SOC, CHP RFO, and the AB1613 contracts provide for SCE to apply a monthly Scheduling Coordinator (SC) Fee for SCE's SC services if the generator elects to use SCE as their SC. The monthly fee is based on the generator's net contract capacity and the respective fee amount provided in the contract. The fee is a constant value that appears on each of the generator's monthly payment statements.

d) Mean Absolute Error (MAE)

The firm capacity QF SOC and CHP RFO contracts contain provisions for SCE to calculate the MAE based on a comparison of the generator's metered output and their day-ahead forecast, quantified and compared to a threshold. If the MAE is greater than 15%, or if the average forecast error for all hours of the month is greater than three MW or 3% of the Seller's Day-Ahead Forecast (depending on the contract), then an "MAE Failure" will be deemed to have occurred. In the event of a MAE Failure, the generator will be assessed a penalty. If the failure continues for several months, the generator may be either temporarily or permanently derated. For Record Period charge results, see Section G.2.i above.

e) Energy Delivery Performance Administration

Certain RPS contracts include provisions that require the sellers to meet certain minimum energy delivery obligations. The energy delivery obligation calculation may be performed on either an annual or multi-year basis depending on contract terms. A comparison of the actual annual energy deliveries or the average annual energy delivery over multiple years, to the contracted minimum amount determines if the energy delivery obligation has been met. Performance requirements for the delivery obligation differ by resource type. If in any term year a failure to meet the minimum delivery obligation occurs, then the seller is subject to a penalty using the amount of shortfall multiplied by a contractual rate. For Record Period charge results, see Section D.4.i above.

f) Economic Curtailments

Economic curtailments are contemplated in most of SCE's RPS contracts and generally allow some form of reimbursement to the project. Contract provisions vary and may include simple "take or pay" methodologies, provisions including a portion of "no cost" curtailments in MWh prior to a "take or pay" method, or more complex provisions such as Day Ahead Market Clearing Price (DA-MCP). Based on case-by-case contract language, SCE processes payments to compensate the Seller the month following an economic curtailment.

g) CAISO System Emergency

Certain short-term agreements were entered into in response to the CAISO System Emergency that resulted from the heat waves occurring in the months of August and September 2020. Per the agreements, compensation to the sellers allowed for supplemental payment for fuel where not otherwise addressed in the PPA, for generation in excess of a settlement interval cap, for generation above contract capacity, or for certain CAISO revenue to be passed through to the generator, during the defined heat wave period. For additional information regarding the CAISO System Emergency and the Record Period payments, see Section E.2 above.