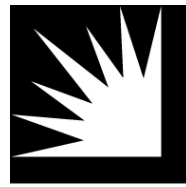


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SOUTHERN CALIFORNIA
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***TESTIMONY OF SOUTHERN CALIFORNIA
EDISON COMPANY ON THE RESULTS OF ITS
2013 LOCAL CAPACITY REQUIREMENTS
REQUEST FOR OFFERS (LCR RFO) FOR THE
WESTERN LOS ANGELES BASIN***

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 21, 2014

SCE-1: Testimony of Southern California Edison Company on the Results of its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Western Los Angeles Basin

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I.

INTRODUCTION

In 2013 and 2014, in two separate tracks of the 2012 Long Term Procurement Plan (“LTPP”) proceeding (Tracks 1 and 4), the California Public Utilities Commission (“Commission” or “CPUC”) authorized Southern California Edison (“SCE”) to procure 1,900 to 2,500 Megawatts (“MW”) of electrical capacity in the Western Los Angeles sub-area of the Los Angeles basin (“Western LA Basin”) local reliability area to meet long-term local capacity requirements by 2021.¹ To meet this need, SCE issued a request for offers (“RFO”) seeking new Local Capacity Requirement (“LCR”) resources, including Preferred Resources² (*i.e.*, Energy Efficiency (“EE”), Demand Response (“DR”), renewable resources, Combined Heat and Power (“CHP”) resources, and Distributed Generation (“DG”)), Energy Storage (“ES”) resources, and Gas-Fired Generation (“GFG”).

SCE has extensive experience running solicitations for the procurement of various power-related products. The LCR RFO, however, presented a number of unique and new challenges, including: (1) determining EE and DR incrementality; (2) in front of the meter (“IFOM”) ES interconnection; (3) ES charging/discharging tariff rules; (4) ES performance measurement for behind the meter (“BTM”) resources; (5) Preferred Resource performance characteristics; (6) locational effectiveness factors

¹ Decision (“D.”) 13-02-015 (“Track 1 decision”) at 130-131 (Ordering Paragraph (“OP”) 1); D.14-03-004 (“Track 4 decision”) at 141-143 (OP 1). D.13-02-015 also authorized SCE to procure between 215 and 290 MW of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area. D.13-02-015 at 131 (OP 2). The Commission required SCE to file a separate Application for approval of contracts for the Moorpark sub-area. *Id.* at 135 (OP 11). See A.14-11-XXX for the Moorpark Application and testimony.

² Preferred Resources are defined in the State’s Energy Action Plan II, at page 2, as follows: “The loading order identifies energy efficiency and demand response as the State’s preferred means of meeting growing energy needs. After cost-effective [energy] efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent [energy] efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.”

1 (“LEFs”); and (7) debt equivalents issues.³ Notwithstanding these challenges, SCE was able to
2 successfully execute approximately 500 MW of Preferred Resource and ES contracts through its LCR
3 RFO. SCE will continue to seek to acquire Preferred Resources and ES in the Western LA Basin to
4 meet the minimum 600 MW procurement authorization the Commission provided for Preferred
5 Resources and ES in the LTPP Track 1 and 4 decisions, as well as address the Commission’s assumption
6 that SCE will develop more than 1,000 MW of uncommitted Preferred Resources in the Western LA
7 Basin by 2020.⁴

8 The LTPP Track 1 and 4 decisions ordered SCE to file an application for approval of all
9 contracts entered into as a result of SCE’s LCR RFO for new capacity in the Western LA Basin.⁵ In this
10 application (“Application”), SCE explains how it procured the required new LCR resources authorized
11 by the LTPP Track 1 and Track 4 decisions for the Western LA Basin. Chapter II of the Application
12 provides background on the LCR RFO. Chapter III describes the Western LA Basin local reliability
13 area. Chapter IV summarizes the solicitation process, with details on (1) the schedule and structure of
14 the solicitation, (2) bidder requirements, (3) outreach efforts, (4) procurement challenges, (5) SCE’s
15 attempts to procure EE and DR incremental to existing programs, (6) SCE’s consultation with the
16 California Independent System Operator (“CAISO”), (7) the role of the Independent Evaluator (“IE”)
17 and consultation with the Cost Allocation Mechanism (“CAM”) group,⁶ and (8) the impact of debt
18 equivalence on the LCR RFO. Chapter V provides an overview of bidder participation in the
19 solicitation. Chapter VI explains the valuation and selection process. Chapter VII includes a summary
20 of the solicitation results. Chapter VIII provides SCE’s proposal for the allocation of benefits and costs.

³ See Section IV.E for further discussion of these issues.

⁴ D.13-02-015 at 67, 123-124 (Findings of Fact “FOF” (FOF 31)).

⁵ D.13-02-015 at 135 (OP 11). Appendix F explains how this Application meets the requirements of each OP in the Track 1 and Track 4 decisions.

⁶ As required by the Commission, SCE conducts procurement reviews with one of two groups, its Procurement Review Group or its CAM group, when appropriate. D.04-12-048 at 241 (OP 15); D.07-12-052 at 127-130, 301 (OP 8). The Procurement Review Group is consulted for procurement on behalf of bundled load while the CAM Group is consulted for procurement on behalf of all benefitting customers.

Chapter IX explains SCE’s proposal for recovering the costs of the LCR resources, ratemaking treatment and revenue allocation. Finally, Chapter X addresses additional procurement of Preferred Resources and ES in the Western LA Basin.

This Application seeks approval of 63 contracts selected through the LCR RFO process. A summary of the selected offers is provided in Table I-1 below.

Table I-1
Summary of Selected Offers

Product Category	Counterparty	Total Contracts	Max Quantity (LCR MW)
Preferred Resources and ES			
EE	<ul style="list-style-type: none"> • Onsite Energy Corporation • Sterling Analytics LLC • NRG Energy Efficiency-L LLC • NRG Energy Efficiency-P LLC 	26	124.04
DR	<ul style="list-style-type: none"> • NRG Distributed Generation PR LLC • NRG Curtailment Solutions LLC 	7	75.00
Renewable DG	<ul style="list-style-type: none"> • Solar Star California XXXV, LLC • Solar Star California XXXVI, LLC • Solar Star California XXXVII, LLC • Solar Star California XXXVIII, LLC 	4	37.92
ES	<ul style="list-style-type: none"> • AES ES Alamos, LLC • Ice Bear SPV #1, LLC • Hybrid-Electric Building Technologies Irvine 1, LLC • Hybrid-Electric Building Technologies Irvine 2, LLC • Hybrid-Electric Building Technologies West Los Angeles 1, LLC • Hybrid-Electric Building Technologies West Los Angeles 2, LLC • Stem Energy Southern California, LLC 	23	263.64
Total Preferred Resources and ES		60	500.60
GFG			
GFG	<ul style="list-style-type: none"> • AES Alamos Energy, LLC • AES Huntington Beach Energy, LLC • Stanton Energy Reliability Center, LLC 	3	1,382.00
Total Preferred Resources, ES, and GFG		63	1,882.60

In conjunction with the remaining LCR procurement authorization from the LTPP Track 1 and 4 decisions and the Commission’s assumptions on the development of uncommitted Preferred Resources

1 by 2020, it is anticipated that more than half of the Western LA Basin local area reliability needs will be
2 met by Preferred Resources and ES. Table I-2 below summarizes SCE's proposed LCR procurement
3 from this Application and planned LCR resources.

Table I-2
LCR Portfolio Breakdown

Resource Bucket	LCR RFO Procurement Recommendation (MW)	Minimum Authorization Remaining (MW)	Uncommitted Resource Assumptions (MW)⁽¹⁾	Total (MW)
Preferred Resources and Energy Storage	501	99	1339	1939
Gas-Fired Generation	1382	0	0	1382
Total	1883	99	1339⁽²⁾	3321

(1) Track 1 LTTP Decision assumed 800 MW of uncommitted EE and CHP, 200 MW of uncommitted DR, and 339 MW of uncommitted DG in West LA Basin

(2) This total volume does not include additional MWs of Preferred Resources and ES that may be implemented through other procurement activities or programs such as Energy Storage OIR, RPS Solicitations, Preferred Resource Pilot Program, etc.

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II.

LCR RFO BACKGROUND

On February 13, 2013, the Commission issued D.13-02-015, the LTPP Track 1 decision. The Track 1 decision ordered SCE to procure between 1,400 and 1,800 MW of electrical capacity in the Western LA Basin to meet long-term local capacity requirements by 2021, largely due to the expected retirement of once-through-cooling (“OTC”) generation facilities.⁷

The Track 1 decision also ordered SCE to file an LCR procurement plan (“LCR Procurement Plan”) explaining how it would conduct its LCR RFO.⁸ SCE filed its LCR Procurement Plan on July 15, 2013. In accordance with the Track 1 decision, Energy Division reviewed SCE’s LCR Procurement Plan and requested that SCE submit a modified LCR Procurement Plan with additional information. SCE filed its final modified LCR Procurement Plan on August 30, 2013. Energy Division approved SCE’s modified LCR Procurement Plan on September 4, 2013. SCE launched its LCR RFO on September 12, 2013.

On March 13, 2014, the Commission issued D.14-03-004, the LTPP Track 4 decision, authorizing SCE to procure an additional 500 to 700 MW by 2021 to meet local capacity needs stemming from the retirement of the San Onofre Nuclear Generating Station (“SONGS”).⁹ Combined, the LTPP Track 1 and 4 decisions authorize SCE to procure between 1,900 to 2,500 MW in the Western LA Basin.

The LTPP Track 1 and Track 4 decisions require SCE to procure minimum amounts of Preferred Resources, ES¹⁰ and GFG in the Western LA Basin local reliability area as shown in Figure II-1 below.¹¹ Specifically, SCE’s minimum procurement authorization is 550 MW of Preferred Resources,

⁷ D.13-02-015 at 130-131 (OP 1).

⁸ *Id.* at 133-134 (OP 5-7).

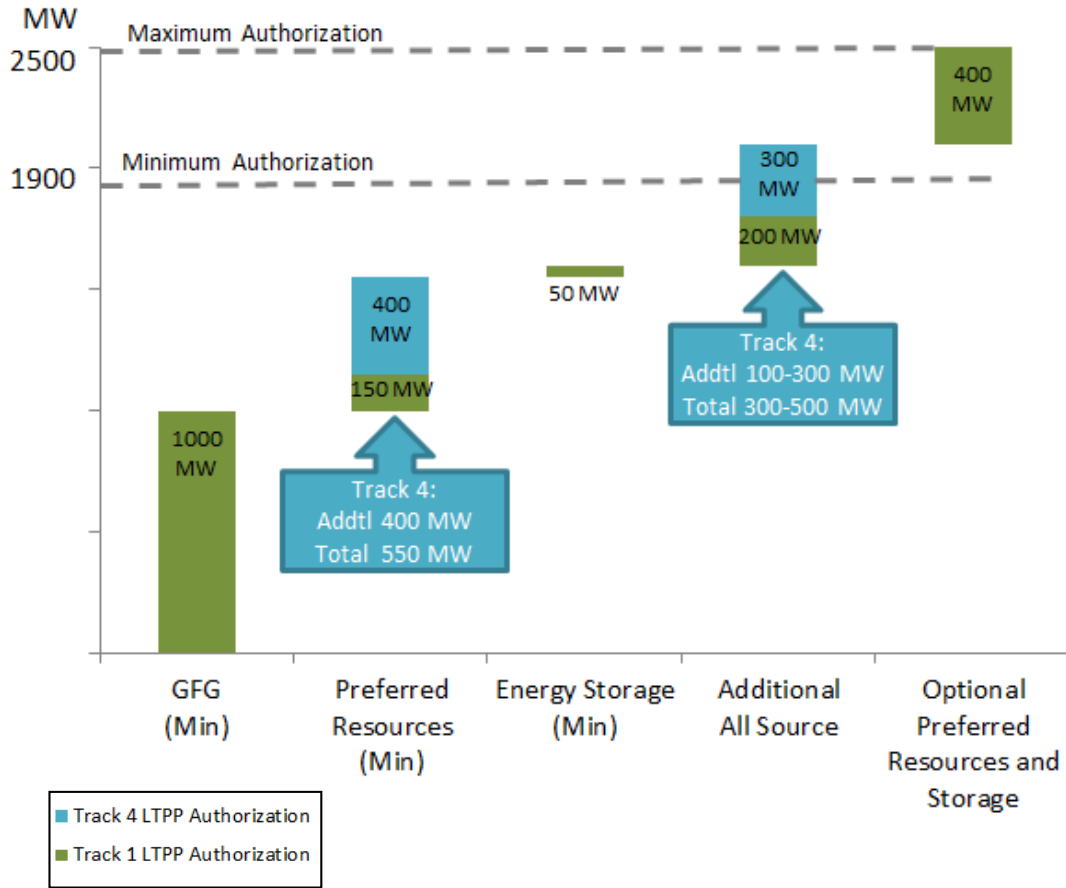
⁹ D.14-03-004 at 141-143 (OP 1).

¹⁰ SCE “may also procure energy storage as part of [its] preferred resources requirement[] or all source authorization[]” D.14-03-004 at 100.

¹¹ D.13-02-015 at 130-131 (OP 1); D.14-03-004 at 141-143 (OP 1).

1 50 MW of ES, 1,000 MW of GFG, and an additional 300 MW from any resource type.¹² SCE's
 2 maximum procurement authorization includes an additional 400 MW of Preferred Resources and ES,
 3 plus an additional 200 MW from any resource type.

Figure II-1
Types of Resources
Western LA Basin Procurement Authorization



¹² D.14-03-004 at 141-143 (OP 1).

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III.

DESCRIPTION OF THE WESTERN LA BASIN LOCAL RELIABILITY AREA

In its LCR RFO, SCE sought new resources in the Western LA Basin local reliability area, and only accepted offers from resources connected to substation systems in this area. The Western LA Basin is divided into three sub-areas that include 28 A-bank substations¹³: (1) the Northwest LA Basin sub-area, which includes the Eagle Rock, Gould, Goodrich, El Segundo, Chevmain, El Nido, La Cienega, La Fresa, Redondo, Hinson, Long Beach, Lighthipe and Laguna Bell substations; (2) the Western Central LA Basin sub-area, which includes the Center, Del Amo, Mesa, Rio Hondo, Walnut and Olinda substations; and (3) the Southwest LA Basin sub-area, which includes the Alamitos, Barre, Lewis, Villa Park, Ellis, Huntington Beach, Johanna, Santiago and Viejo substations.¹⁴ See Figure III-2 below for a map of the Western LA Basin sub-areas and the A-Bank substations in each sub-area. As stated above, the need for additional capacity in the Western LA Basin is largely due to the expected retirement of approximately 5,900 MW¹⁵ from current OTC generators in the LA Basin due to compliance with State Water Resources Control Board (“SWRCB”) policy,¹⁶ and the permanent closure of SONGS.¹⁷

¹³ An A-Bank substation is a substation which connects the transmission system to the sub-transmission system. These stations typically step voltage down to 66 kV or 115 kV.

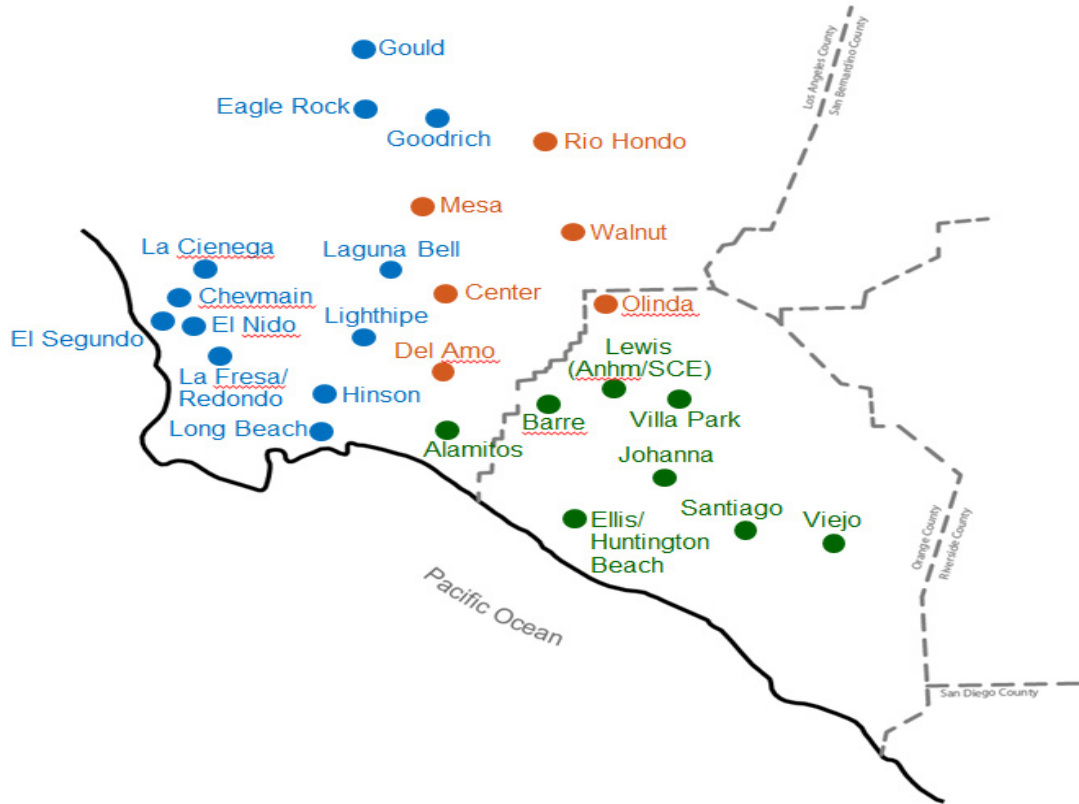
¹⁴ CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 2. Arcogen and Harborgen were omitted from the list of substations in the Northwest LA Basin sub-area because they are not load serving substations.

¹⁵ D. 14-03-004 at 6.

¹⁶ See SWRCB Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (October 1, 2010).

¹⁷ D.13-02-015 at 2.

Figure III-2
Western LA Basin A-Bank Substations



- Northwest Sub-area
- Western Central Sub-area
- Southwest Sub-area

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IV.

LCR RFO SOLICITATION PROCESS OVERVIEW

This Chapter describes the following aspects of the solicitation process: (1) the schedule and structure of the solicitation, (2) bidder requirements, (3) outreach efforts, (4) procurement challenges, (5) SCE’s attempts to procure EE and DR incremental to existing programs, (6) SCE’s consultation with the CAISO, (7) the role of the IE and SCE’s consultation with the CAM group and Energy Division, and (8) the impact of debt equivalence.

A. Solicitation Schedule

In its LCR Procurement Plan, SCE proposed the RFO schedule shown below in Table IV-3.

*Table IV-3
SCE’s Proposed LCR RFO Schedule*

No of Days	LCR RFO Step
T	Energy Division approves LCR Procurement Plan
T+14	Launch LCR RFO
T+103	Indicative offers submitted
T+148	Shortlisting, contract negotiations commence
T+260	Negotiation deadline
T+267	Final offers submitted
T+295	SCE notifies successful bidders and contract execution
T+355	SCE files application for approval

10 On May 2, 2014, Energy Division approved SCE’s request to extend the LCR RFO to: (1) resolve
11 issues related to ES; (2) address how to determine whether an EE resource is incremental; (3) conduct
12 additional analysis as a result of CAISO’s LEF changes published on April 9, 2014; and (4) follow-up
13 with counterparties with Preferred Resources on outstanding issues in order to complete negotiations.
14 The additional time resulted in enhanced participation and competition amongst Preferred Resource
15 offers. Table IV-4 shows the approved, modified LCR RFO schedule.

Table IV-4
Revised LCR RFO Schedule

No of Days	Milestone
T	Energy Division approves LCR Procurement Plan
T+14	Launch LCR RFO
T+103	Indicative offers submitted
T+148	Shortlisting, contract negotiations commence
T+293	Negotiation deadline
T+300	Final offers submitted
T+328	SCE notifies successful bidders and contract execution
T+359	SCE files application for approval

On July 21, 2014, SCE requested a second and final extension to file its Western LA Basin LCR RFO Application on November 21, 2014. The proposed change to the filing date enabled SCE to internally resolve debt equivalency issues that arose with respect to certain products through the incorporation of additional language in the contracts at issue. Those contract changes were then communicated to the impacted bidders. The details of the debt equivalency issues impacting certain contracts is described in Section IV.I. Table IV-5 below shows the final Western LA Basin LCR RFO schedule, which was approved by the Energy Division on July 28, 2014.

Table IV-5
Final Revised LCR RFO Schedule

No of Days	Milestone
T	Energy Division approves LCR Procurement Plan
T+14	Launch LCR RFO
T+103	Indicative offers Submitted
T+148	Shortlisting, contract negotiations commence
T+359	Negotiation deadline
T+365	Final offers submitted
T+415	SCE notifies successful bidders and contract execution
T+443	SCE files LA Basin Application for approval

B. Solicitation Structure

The format of the RFO structure, detailed in SCE’s LCR Procurement Plan, was approved by the Energy Division and included an initial solicitation of indicative offers, negotiations on contract terms with “shortlisted” offers, a final price refresh of “shortlisted” offers, and an evaluation and selection process.

Below is a list of steps, in chronological order, that were used in the LCR RFO process:

1 **1. Internal Preparation**

2 Prior to launch, SCE finalized all documents that were a part of the LCR RFO (*e.g.*, pro forma
3 contracts, participants’ instructions and submittal templates) and reviewed the LCR RFO details with
4 internal and external stakeholders. External stakeholders included the IE, the CAM Group, and
5 Commission staff.¹⁸ The roles of each of the external stakeholders are described in Section IV.H.

6 **2. RFO Launch**

7 SCE created an LCR RFO website (hosted on <http://www.sce.com>) which included all of the
8 information that bidders needed to participate in the process. SCE notified market participants directly,
9 via an extensive email list maintained by SCE, and through various service lists, including those for
10 dockets involving EE, DR and DG matters. SCE also issued a press release which was run in industry
11 publications and sent a notice to various industry organizations. For additional information on outreach
12 efforts see Section IV.D.

13 After the launch, SCE hosted a bidder’s conference to walk through the various aspects of the
14 solicitation, discuss its valuation approach, and respond to questions and concerns. Due to the
15 complexity of the LCR RFO process and the variety of resources solicited, SCE provided a very
16 thorough and detailed overview of the solicitation process, the documents involved, and the valuation
17 process during the bidder’s conference. At the request of market participants, SCE also hosted separate
18 EE and ES webinars to provide further details on the contracts, bidding templates, and valuation
19 methodology specific to these resources. All materials from the bidders’ conference and webinars were
20 made available on the LCR RFO website. SCE also maintained a list of frequently asked questions
21 (“FAQs”) on its LCR RFO website. SCE’s LCR RFO materials are included as Appendix E.

¹⁸ Throughout the LCR RFO process, SCE employed the use of an IE to ensure that all bidders received comparable and non-discriminatory treatment, and periodically consulted with the CAM Group and the Commission’s Energy Division.

1 **3. Notice of Intent Submission**

2 After reviewing the LCR RFO materials, bidders submitted an official nonbinding notification of
3 which resources they intended to bid. Obtaining this information early in the LCR RFO process helped
4 SCE fine-tune a plan to manage the forecasted workload and address issues related to offer templates
5 associated with new products that were not initially contemplated.

6 **4. Indicative Offers Submitted by Bidders**

7 Using the offer templates from the LCR RFO website, bidders submitted non-binding indicative
8 offers. The indicative offers provided pricing that SCE used for shortlist notification. An ancillary
9 benefit of this process is that bidders could input their information directly into submittal templates
10 which allowed SCE to identify anomalies that required additional information. Although it is common
11 for SCE to work with bidders to cure deficiencies on indicative offers, SCE expended significantly more
12 effort working with bidders in the LCR RFO to get a completed and conforming set of offers to value
13 for its shortlist process. Indeed, SCE ultimately ended up working with bidders to cure over eighty
14 percent of the indicative offers received. This was due in large part to ES being a new product, SCE
15 proposing to contract for certain demand-side management (“DSM”) products in a new manner, and
16 many of the bidders not having participated in an SCE RFO.

17 **5. Shortlist Notification**

18 Based on shortlist criteria and valuation results from indicative offers, SCE notified bidders of
19 whether they had been shortlisted.

20 **6. Contract Negotiation**

21 Once the shortlist was determined, SCE and bidders began negotiating the terms and conditions
22 of contract forms based on SCE’s published pro forma contracts.

23 **7. Commercial Lockdown**

24 At commercial lockdown, all “commercial” terms were finalized (*e.g.*, contract quantity, term,
25 location, operational attributes and restrictions), except for price. These commercial terms describe a
26 potential offer, and need to be finalized sufficiently early to provide adequate time for proper valuation.

1 **8. Negotiation Deadline**

2 This deadline was the date by which all terms and conditions of contract forms had to be
3 finalized and ready for execution. Agreement on a negotiated contract form was required for bidders to
4 submit final pricing.

5 **9. Final Binding Offers Submission**

6 Bidders submitted final binding prices based on previously negotiated contract forms. These
7 documents represented each bidder’s final offer.

8 **10. SCE Accepts or Rejects**

9 SCE chose to either outright accept or reject offers. After offer acceptance, SCE and the bidder
10 prepared the final executable form of the contract. As a result of debt equivalency concerns discussed in
11 Section IV.I., the contracts for ES and combined-cycle GFG offers were structured to include an
12 “Embedded Put Option” which included providing the seller with annual energy put option prices to be
13 incorporated into the contract for each year of the contract. In addition, the GFG contracts for CT’s
14 were restructured as fixed-price RA contracts and the BTM ES contracts were structured to include a
15 provision that allows the seller to add, remove or replace the assets associated with the contracts as
16 needed.

17 **C. Requirements and Considerations**

18 For a project to be considered in the LCR RFO, it was required to meet the following general
19 qualifications: minimum capacity quantities for each type of technology; all bidders had to either reduce
20 load or otherwise interconnect in the Western LA Basin at the A-Bank substations (or lower voltage
21 substations connected to the Western LA Basin A-Bank substations) in Figure III-2 above;¹⁹ generation
22 projects had to apply, or have applied, for interconnection to the CAISO grid selecting Full Capacity

¹⁹ After the CAISO provided its *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, SCE concluded that it was in customers’ economic interest to focus GFG procurement in only the most effective locations, and thus removed GFG offers from the shortlist if the projects were not in the Southwest sub-area of the Western LA Basin. See Section IV.G.2 for discussion of LEFs.

1 Deliverability Status, qualifying the project to be counted for RA; the project must be incremental (*i.e.*,
2 new capacity); and the delivery had to include the entire calendar year 2021.

3 SCE considered offers for contract terms of any length as required by the Track 1 decision.
4 However, SCE requested a contract term of up to 20 years as part of its “preferred” contract terms at the
5 launch of the LCR RFO. SCE allowed for flexibility with online dates to accommodate staggered
6 delivery period commencements. Online dates could be as early as 2016 for those projects
7 interconnected to the Johanna and Santiago substations,²⁰ and 2018 for all other substations. All
8 projects had to be online by January 2021.

9 Given the desire to facilitate competition within the relatively short solicitation timeline, SCE did
10 not have a minimum transmission study requirement for offers in the LCR RFO. Instead, SCE proposed
11 a cap on transmission network upgrades in its Pro Forma documents with the dollar amount for each
12 contract to be determined through the negotiations.

13 **D. Outreach Efforts**

14 Historically, SCE has been very successful in its outreach efforts and ensuring potential sellers
15 are aware of a solicitation for renewable, CHP, and conventional resources. However, many of the
16 resources being procured in SCE’s LCR RFO process, specifically EE, DR, DG and ES, are not
17 typically procured through SCE’s standard power procurement efforts. For that reason, SCE sent emails
18 announcing the launch of the solicitation to CPUC distribution lists for proceedings that involve EE, DR
19 and DG matters. SCE also sent notices regarding the LCR RFO to the following organizations:
20 National Association of Energy Service Companies; California Energy Efficiency Industry Council;
21 Association of Energy Services Professionals; Peak Load Management Alliance; Solar Energy
22 Industries Association; California Solar Energy Industries Association; Solar Electric Power
23 Association; California Energy Storage Association; American Wind Energy Association; and the Fuel
24 Cell & Hydrogen Energy Association. Finally, SCE posted an announcement of the launch of the LCR

²⁰ SCE allowed for 2016 project start dates for resources connected to Johanna and Santiago substations to offset immediate needs at those locations and to support SCE’s Preferred Resources Pilot.

1 RFO on the Proposal Evaluation & Proposal Management Application website, which has historically
2 been used to notify the market of California’s Investor-Owned Utilities’ (“IOU”) EE solicitations.
3 SCE’s additional outreach efforts raised awareness of the LCR RFO, and as a result, the number of
4 potential sellers of Preferred Resources and ES increased. As described below, SCE also emphasized
5 the procurement of Preferred Resources and ES in its bidder’s conference.

6 CPUC General Order 156 (“GO 156”) contains “rules governing the development of programs to
7 increase participation of women, minority and disabled veteran business enterprises (“WMDVBES”) in
8 procurement of contracts from utilities as required by Public Utilities Code Sections 8281-8286.”²¹ In
9 recognition of GO 156, SCE continues to look for opportunities to build an increased pool of diverse
10 suppliers, including WMDVBE participants in power procurement activities. SCE encouraged
11 WMDVBES to participate in the LCR RFO by including information specific to WMDVBES in its LCR
12 RFO bidder’s instructions and in the LCR RFO bidder’s conference presentation. In addition, SCE
13 provided direct one-on-one support to help answer RFO process questions and educate potential
14 WMDVBE bidders on the LCR RFO solicitation documents and process, SCE’s supplier diversity
15 development program,²² and the interconnection study process.

16 **E. Addressing Procurement Challenges**

17 The LCR RFO presented unique and new challenges to SCE’s procurement process. This was
18 the first time SCE administered a solicitation that explicitly sought a range of resource technologies,
19 from demand-side management resources to natural gas-fired generation facilities. Additionally, within
20 the solicitation, it was the first time SCE ever procured ES resources through a competitive solicitation.
21 Overlaying the focus of meeting local reliability needs, these new circumstances led to the following
22 procurement challenges:

²¹ CPUC GO 156 at 1.

²² Information on SCE’s supplier diversity development program can be found on the SCE website at www.sce.com/SD.

1 **1. Energy Efficiency & Demand Response Incrementality**

- 2 • See Section IV.F for a discussion of this issue.

3 **2. In Front of the Meter Energy Storage Interconnection**

- 4 • Issue: Current tariffs do not clearly address how ES resources will be interconnected.
5 This uncertainty created confusion around: (1) the appropriate rules for studying the
6 charging of ES, (2) costs associated with necessary upgrades for the charging of ES, and
7 (3) metering requirements for ES.
- 8 • Status: SCE is exploring options for establishing interconnection policy for ES consistent
9 with the language in SCE’s Rule 21 Tariff, SCE’s Wholesale Distribution Access Tariff,
10 SCE’s Transmission Owner Tariff, and the CAISO Tariff.

11 **3. In Front of the Meter Energy Storage Charging/Discharging Tariff**

- 12 • Issue: The current tariffs do not contemplate many of the unique characteristics of ES;
13 thus, there is little guidance as to how grid-connected ES devices should pay for the
14 energy they use to charge. In particular, the tariffs are not clear on whether grid-
15 connected storage will pay transmission and distribution access charges. Such
16 uncertainty on relatively large potential charges makes valuation and contracting
17 difficult.
- 18 • Status: For IFOM ES devices (*i.e.*, for those devices not located behind a retail
19 customer’s meter), SCE plans to separately meter and bill the interconnecting ES
20 customer for its station and auxiliary load (*e.g.*, air conditioning load, heating load,
21 pumping load, and other energy consumed at the project not taken directly into the actual
22 ES device). As a result, the ES station and auxiliary load will be charged at SCE’s retail
23 rates. The energy stored by the ES device (which excludes the station and auxiliary load)
24 will be charged the CAISO Locational Marginal Price (*i.e.*, wholesale rates). The
25 CAISO’s Tariff is unclear on whether the energy used directly by ES resources will be
26 assessed a Transmission Access Charge (“TAC”) in addition to the Locational Marginal
27 Price, as currently occurs with wholesale load customers and pumped hydro storage. If

1 the CAISO assesses a TAC, it may prompt SCE to create a FERC-jurisdictional
2 distribution access charge for the use of utilities' distribution systems in order to maintain
3 consistent treatment of ES connecting to the transmission and distribution systems. SCE
4 has asked the CAISO to provide an interpretation of its tariff to reduce the outstanding
5 uncertainty on whether access charges apply to grid-connected storage charging.

6 **4. Energy Storage Performance Measurement for Behind the Meter Resources**

- 7 • Background: SCE originally assumed BTM storage performance would be measured by
8 existing demand response performance measurement protocols, which are based on load
9 dropped.
- 10 • Issue: Certain bidders [REDACTED] wanted their performance to be based on metered output of the
11 energy storage device.
- 12 • Solution: [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]²⁴

18 **5. Preferred Resource Performance Characteristics**

- 19 • Background: The LTPP Track 1 and 4 decisions require that resources provide the
20 required LCR performance characteristics to be eligible to count as local RA capacity.
- 21 • Issue: Performance characteristics were not defined in the LTPP Track 1 and 4 decisions.
- 22 • Solution: SCE worked with the CAISO to identify minimum performance characteristics
23 of Preferred Resources in meeting the identified LCR need. As part of this collaboration,

23 [REDACTED]

24 The 10/10 baseline refers to the current utility demand response programs where performance is measured based on the metered load drop relative to the average consumption over the last 10 similar days.

1 SCE provided CAISO with a range of portfolios of Preferred Resources with various
2 operational characteristics for LCR effectiveness testing. This allowed the CAISO to
3 conduct analysis to identify the minimum operational characteristics of Preferred
4 Resources in meeting the identified LCR need. As a result, SCE set the maximum
5 response time for DR resources to twenty minutes. In addition, the CAISO's study
6 showed that a maximum of 150 MW of two-hour dispatch/discharge duration for DR and
7 ES resources in the Western LA Basin could be used to meet or reduce LCR need. The
8 CAISO, however, did not study the effectiveness of two-hour resources in meeting
9 system RA requirements beyond the local area and was not prepared to support system
10 RA value for such resources. As a result, SCE decided not to include two-hour resources
11 in its LCR procurement.

12 **6. Locational Effectiveness Factors**

- 13 • **Background:** The Track 1 decision ordered that LCR “resources must meet the identified
14 reliability constraint identified by the [CAISO],” the “consideration of costs and benefits
15 must be adjusted by their relative effectiveness factor at meeting the [CAISO] identified
16 constraint,” and SCE has to use “the most up-to-date effectiveness ratings.”²⁵
- 17 • **Issue:** SCE launched the RFO using the CAISO studies that were available at the time,
18 with the understanding that new studies were likely to be performed during the RFO
19 process. CAISO's updated studies identified different system constraints as a result of
20 the permanent closure of SONGS and CAISO's new approved transmission projects.²⁶
21 This resulted in the Western LA Basin being divided into three sub-areas: Northwest,
22 Western Central, and Southwest. CAISO studied three different scenarios that resulted in
23 three different sets of LEFs for each of the sub-areas.²⁷

²⁵ D.13-02-015 at 131-132 (OP 4.a, c, and 1).

²⁶ See CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, 1-5.

²⁷ *Id.*

- **Solution:** All of the LEF scenarios and CAISO’s original study showed that resources in the Southwest sub-area of the Western LA Basin (*i.e.*, the Orange County area) are significantly more effective at meeting the LCR need compared to resources located in other sub-areas of the Western LA Basin. Further, SCE concluded that it was likely any large procurement of resources outside of the Southwest sub-area of the Western LA Basin would significantly increase the likelihood that additional LCR procurement would be required beyond the existing Track 1 and 4 authorizations. Therefore, SCE only entertained offers from, and negotiated contracts with, natural gas-fired resources located in the identified preferred location (*i.e.*, the Southwest sub-area of the Western LA Basin). For Preferred Resources, except for IFOM ES, SCE assumed the highest effectiveness of such resources for the entire Western LA Basin. This followed the CAISO’s modeling assumption, which included Preferred Resources throughout the entire LA Basin. For IFOM ES, which operates similar to controllable generating units in meeting LCR needs, SCE relied on the LEFs from CAISO’s recent studies.²⁸

7. **Debt Equivalent**

- See Section IV.I for a discussion of this issue.

F. **Energy Efficiency and Demand Response Incremental To Existing Programs**

1. **SCE’s LCR RFO Attempts to Procure Preferred Resources Incremental to the Assumptions Used in CAISO’s Studies**

The Track 1 decision ordered that any RFOs issued by SCE must be for resources that are “demonstrably incremental” to the assumptions used in the studies²⁹ presented by the CAISO in Track 1 of the LTPP, “to ensure that a given resource is not double counted.”³⁰ The analysis in the CAISO

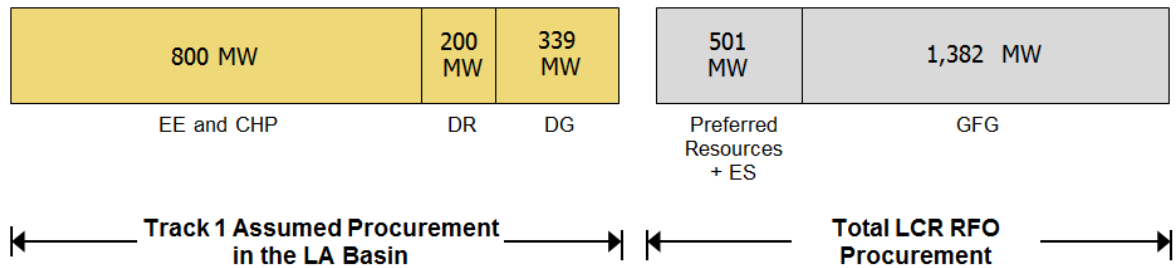
²⁸ *See id.*

²⁹ As described in D.13-02-015 at 21, CAISO performed a sensitivity analysis at the request of the CPUC, CEC, and California Air Resources Board to study a variation on the Environmentally Constrained Portfolio.

³⁰ D.13-02-015 at 131-132 (OP 4.b).

1 studies and Track 1 decision assumed that 1,339 MW of Preferred Resources would be in place in 2022,
2 as shown in Figure IV-3 below:³¹

Figure IV-3
Committed and Uncommitted Preferred Resources in Western LA Basin



3 Although the Track 1 decision assumed that this level of Preferred Resources would be in place,
4 it did not identify the specific Preferred Resources that would be developed. Consequently, there is no
5 way to definitively assess if a resource in SCE’s LCR RFO is truly incremental “to the assumptions used
6 in the CAISO studies.”³² To ensure “that a given resource is not double counted,” but that all needed
7 resources are ultimately procured, SCE’s total Preferred Resource procurement to meet LCR needs must
8 equal the sum of: (1) the Preferred Resource assumptions adopted in the Track 1 decision, and (2) the
9 minimum procurement authorization for Preferred Resources in the LTPP Track 1 and Track 4
10 decisions. Thus, the totality of SCE’s procurement of Preferred Resources to meet LCR needs is the
11 critical procurement objective, and not individual assumptions. Nonetheless, SCE did screen out certain
12 LCR RFO offers as not being incremental through its Tranche analysis identified above and described
13 further below.

³¹ The Track 1 decision adjusted the identified LCR need by assuming 800 MW of uncommitted EE and CHP in the Western LA Basin. D.13-02-015 at 65. An assumed nominal level of 200 MW of DR and 339 MW of distributed generation are also identified in the Track 1 decision. *Id.* at 56, 58.

³² D.13-02-015 at 131-132 (OP 4.b).

1 **2. SCE Assessed Incrementality of Preferred Resources Based on the Characteristics**
2 **of Individual Offers**

3 Because it would not be practical to delay the procurement of Preferred Resources through
4 SCE's LCR RFO until after the results of SCE's utility-run DSM programs concluded for 2020
5 deliveries and Track 1 decision assumptions on uncommitted DG and CHP targets were met, SCE
6 commenced with the procurement of Preferred Resources in its LCR RFO recognizing that its total
7 procurement of Preferred Resources through utility programs and its LCR RFO must meet the sum of
8 the assumptions and procurement authorization for Preferred Resources adopted in the LTPP Track 1
9 and 4 decisions to ensure local area reliability. Additionally, delaying the procurement of Preferred
10 Resources would not have allowed for head-to-head competition of all resource types due to the need to
11 immediately proceed with the LCR solicitation to contract for necessary GFG given its long
12 development cycle.

13 To move forward with the procurement of Preferred Resources, SCE developed a methodology
14 to categorize Preferred Resource offers based on their likelihood of being incremental to the types of
15 Preferred Resources assumed in the CAISO's studies presented in Track 1 of the LTPP proceeding.
16 This methodology examined the characteristics of each offer, and placed them into one of four
17 "tranches" based on their dissimilarity to SCE's existing DSM programs, and therefore their likely
18 incrementality to the Preferred Resources in CAISO's analysis. EE and DR offers were both assessed
19 using similar, but not identical (due to differences in technology, market characteristics, savings load
20 profiles, etc.), tranche definitions, as shown for EE in Figure IV-4 and for DR Figure IV-5 below:

Figure IV-4
Energy Efficiency Tranche Framework

	<u>Category</u>	<u>Description</u>	<u>Incremental</u>	<u>Procure?</u>
Tranche 1	New Product (Technical Innovation)	<ul style="list-style-type: none"> New measures, programs, strategies, or transactions. Measures outside SCE's DSM portfolio. 	Yes	Yes
Tranche 2	New Use of Existing Products (Market Innovation)	<ul style="list-style-type: none"> Existing measures, but with new customer type, markets, incentive levels, or delivery channel Hybrid/combination offers (EE, DR, DG, ES) 	Yes	Yes
Tranche 3	Value	<ul style="list-style-type: none"> Existing measures or programs that are <i>less expensive than current EE program offerings</i>. 	Yes	Yes
Tranche 4	Do Not Procure: Low Value and/or ineligible savings	<ul style="list-style-type: none"> Existing measures/programs that do not offer the value of Tranche 3 or start in 2015 Savings that are likely ineligible (below code, naturally occurring, ISP, etc) 	No	No

Figure IV-5
Demand Response Tranche Framework

	<u>Category</u>	<u>Description</u>	<u>Incremental</u>	<u>Procure?</u>
Tranche 1	Technical Innovation	<ul style="list-style-type: none"> New measures/technologies that expand the market by enabling new DR solutions or solutions that allow customers to participate who otherwise would not (i.e. dispatchable storage) 	Yes	Yes
Tranche 2	Product / Market Innovation	<ul style="list-style-type: none"> New programs, measures, strategies or transactions (i.e. flexible dispatch) New resource capabilities (i.e. faster dispatch time) 	Yes	Yes
Tranche 3	Value	<ul style="list-style-type: none"> Existing DR programs but <i>cheaper than existing DR Programs</i> 	Yes	Yes
Tranche 4	Do Not Procure: Low Value	<ul style="list-style-type: none"> Existing proposals that do not offer the value of Tranche 3 	No	No

1 SCE identifies that the Track 4 decision requires SCE to procure Preferred Resources “in
2 addition to Preferred Resources already required by the Commission to be procured or obtained through
3 decisions in other relevant proceedings,”³³ as well as the additional Preferred Resources ordered in the
4 Track 1 decision. For both EE and DR, Tranches 1 through 3 represent innovation or savings

³³ D.14-30-004 at 141-142 (OP 1.e).

1 incremental to SCE’s existing DSM programs, and SCE recommends that they be considered
2 incremental for purposes of complying with the LTPP Track 1 and 4 decisions.³⁴

3 **G. Consultation With CAISO**

4 **1. Overview**

5 As mentioned above, in the Track 1 decision the Commission ordered that any resource procured
6 should, among other things, “meet the identified reliability constraint identified by the CAISO” and that
7 SCE “use [] the most up-to-date effectiveness ratings.”³⁵ Information about the studied reliability
8 constraint and resulting effectiveness ratings is contained in the CAISO document, “Clarification to the
9 ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the
10 LA Basin Area.” It states:

11 The ISO is providing in this document additional information about locational effectiveness
12 factors for the LA Basin area, to assist the resource procurement process of Southern
13 California Edison currently underway. This information is being provided to assist SCE with
14 the direction received from the CPUC in D.13-02-015 to take into account the locational
15 effectiveness of resources as determined by the ISO.³⁶

16 The CAISO analysis in this document is the basis for SCE’s use of LEFs in its valuation of offers.
17 Following the CAISO’s initial LEF determination in Track 1, the retirement of SONGS and the
18 transmission projects approved in the CAISO’s 2013-14 Transmission Plan prompted a need to provide
19 updated LEFs as further described below.

20 **2. Locational Effectiveness Factors**

21 Locational effectiveness factors are a measurement of the effectiveness of a resource, located in
22 a particular place/substation, in relieving specific reliability constraint. LEFs are affected by the
23 configuration of the transmission system and the distribution of loads and generating facilities within the
24 area. Higher LEFs point to a resource location being more effective at relieving the subject constraint.

³⁴ As discussed in detail in Sections VI.C.3 and VII.B.1, SCE selected one contract that was in Tranche 4.

³⁵ D.13-02-015 at 131-132 (OP 4.a., 1).

³⁶ CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 1.

1 For purposes of this RFO, the CAISO identifies the reliability constraint as a post-transient voltage
2 instability concern based on the most critical contingency that affects the LA Basin and San Diego local
3 capacity areas: the overlapping contingency of the loss of the East County – Miguel 500 kV line,
4 system readjusted, followed by the loss of the Ocotillo – Suncrest 500 kV line.³⁷ This contingency,
5 which represents a situation in which two 500 kV transmission lines that feed San Diego Gas &
6 Electric’s (“SDG&E”) territory are lost, is known in shorthand as an “N-1-1” contingency. This
7 contingency will reroute power to the remaining lines that feed SDG&E. The rerouted power flows
8 through lines in the Western LA Basin and produces thermal overloads and voltage deviation violations.
9 Adding generation at key substations will mitigate these violations by reducing power flows pre-
10 contingency and providing voltage support on specific portions of the transmission system to prepare for
11 the contingency.³⁸ The CAISO determined LEFs based on this N-1-1 contingency.

12 The CAISO provided LEFs for the three sub-areas that it apportioned in the Western LA Basin:
13 Northwest, Western Central, and Southwest. LEFs for these three sub-areas of the Western LA Basin
14 are provided in three scenarios labeled by the CAISO as A, B and C. The CAISO assumed different
15 levels of transmission and generation development to provide a range of scenarios. Scenario C assumes
16 the successful and timely completion of three transmission projects (*i.e.*, Imperial Valley Flow
17 Controller, Mesa Loop-in and San Luis Rey synchronous condensers), as well as the timely completion
18 of 800 MW of resource additions in San Diego per the LTPP Track 1 and 4 decisions. Scenario A does
19 not assume completion of the transmission projects, and models only 500-550 MW of resource additions
20 coming online in San Diego from the Track 4 LTPP authorization, rather than the full 800 MW³⁹.
21 Scenario B is similar to Scenario C, except for the absence of the Imperial Valley Flow Controller
22 project. Table IV-6 below provides the LEFs for the LA Basin sub-areas of each scenario.⁴⁰

³⁷ *Id.* at 2-3.

³⁸ SCE Opening Testimony, 2012 LTPP Track IV, p.24, lines 11-17.

³⁹ D.14-03-004 at 143 (OP 2).

⁴⁰ CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 2.

Table IV-6
Updated Locational Effectiveness Factors

Los Angeles Basin Area	Scenario		
	A	B	C
Northwest	0%	< 13.6%	56.9%
Western Central	not studied	34.4%	66.6%
Southwest	50%	71.7%	100%

1 The LEF values provide a basis for comparing the effectiveness of resources sited in these areas.
2 When comparing the LEFs for Scenario C, the Western Central area has an effectiveness two-thirds that
3 of the Southwest sub-area. This means that for every MW of resources placed in the Southwest sub-
4 area, to achieve the same effect, approximately 1.5 MW must be placed in the Western Central sub-area.
5 The scenarios are shown in sequence in the table starting with the conservative case, Scenario A,
6 followed by Scenario B, the moderate case, and Scenario C, the optimistic case where all transmission
7 and generation projects are modeled. All three scenarios showed the highest locational effectiveness for
8 resources in the Southwest sub-area, indicating that for a range of possible outcomes of generation and
9 transmission projects, resources in the Southwest sub-area are significantly more effective at relieving
10 the identified constraint.

11 SCE focused on the moderate case, Scenario B, to determine if its 2012 LTPP authorization to
12 meet the CAISO-identified reliability constraint is sufficient. The CAISO’s Scenario B reflects that
13 14,200 MW in the Northwest sub-area and 200 MW and 158 megavars (“MVar”)⁴¹ in the Southwest
14 sub-area are required to resolve the critical N-1-1 contingency for Scenario B.⁴² This is well beyond the
15 maximum 2012 LTPP authorization of 2,500 MW for SCE.

16 The CAISO did not provide the minimum MW required to resolve the critical N-1-1 contingency
17 if all resources were in either the Western Central or Southwest sub-areas, but this minimum value can

⁴¹ Megavars are the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.

⁴² CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 4.

1 be approximated using Scenario B LEFs. Ignoring the resources added to the Southwest sub-area for
 2 Scenario B, the Southwest sub-area minimum can be approximated by multiplying the ratio of the LEFs
 3 of the Northwest and Southwest sub-areas with the total resources required in the Northwest sub-area to
 4 resolve the critical N-1-1 contingency $[(13.6 / 71.7) \times 14,200 \text{ MW} = 2,693 \text{ MW}]$. The minimum
 5 resources required in the Western Central sub-area can be calculated in a similar manner. Table IV-7
 6 below provides the estimated minimum MW required if all resources were in the Northwest, Western
 7 Central or Southwest sub-areas.

Table IV-7
Minimum Resources Required to Mitigate Reliability Constraint

Scenario B		
Los Angeles Basin Area	LEF	Minimum MW Required
Northwest	13.6	14,200
Western Central	34.4	5,614
Southwest	71.7	2,693

8 Thus, based on the calculations using Scenario B LEFs, the most effective area to site resources
 9 is the Southwest sub-area of the Western LA Basin (requiring 2,693 MW); substantially less than the
 10 amount required in the Northwest or Western Central sub-areas. Even for the most effective area, the
 11 resources required exceed the total 2012 LTPP maximum procurement authorization of 2,500 MW for
 12 SCE. Due to the lower effectiveness of resources in other areas, each MW procured outside of the
 13 Southwest sub-area will increase the likelihood of a residual need for future resources and transmission,
 14 thus significantly increasing costs to customers and adding resources that would not have otherwise been
 15 needed if more effective locations were originally considered in SCE’s LCR RFO. Because sufficient
 16 GFG offers in the Southwest sub-area were available to meet the procurement authorizations in the
 17 Track 1 and 4 decisions, SCE elected not to consider GFG offers for its Northwest and Western Central
 18 sub-areas within the Western LA Basin. This approach provided a large block of resources located in
 19 the most effective area under a variety of scenarios to relieve the critical N-1-1 reliability constraint.

20 In order to procure the most effective IFOM ES, SCE utilized Scenario B LEFs in the evaluation
 21 of this resource type which showed non-zero LEFs for all three areas. This provides a 72 percent LEF

1 for the Southwest sub-area, exemplifying the importance of this area, but this also allows IFOM ES
2 located in other areas to participate and increase the total amount of ES procured.

3 Other Preferred Resource offers (*e.g.*, DSM) can be distributed across areas within the Western
4 LA Basin and due to their small size and geographic diversity, are not amenable to the application of
5 LEFs. As such, SCE elected to consider all Preferred Resources, excluding IFOM ES, as equally
6 effective throughout the Western LA Basin. This assumption was also consistent with the CAISO's
7 modeling assumptions.

8 a) Preferred Resource Characteristics

9 Preferred Resources will play an important role in meeting the LCR need; however, they do
10 present certain challenges. One of the challenges in the LCR RFO was to identify the minimum
11 operational characteristics of each Preferred Resource type (*e.g.*, response time, dispatch/discharge
12 duration, resource availability, etc.) to meet the LCR need. In order to identify the minimum operational
13 characteristics, SCE initiated a study measuring the LCR effectiveness of Preferred Resources in
14 collaboration with the CAISO. In September 2013, SCE developed, and submitted to the CAISO,
15 several hypothetical portfolios of various Preferred Resource scenarios. The CAISO studied a subset of
16 the submitted portfolios.⁴³ Results of these studies provided some high-level guidelines and direction on
17 the minimum operational characteristics that were necessary for each Preferred Resource type to meet
18 the LCR need, and SCE refined the required minimum resource attributes accordingly. For example,
19 SCE reduced the maximum response time requirement of DR resources to twenty minutes because of
20 the CAISO's studies and direction. The CAISO studies also indicated there should be a MW quantity
21 cap for two-hour ES and DR resources to meet or reduce the LCR need.

22 In March 2014, SCE developed and submitted additional hypothetical LCR portfolios to the
23 CAISO. These additional portfolios were more refined because they were based on resource
24 characteristics of the indicative offers submitted to SCE in the LCR RFO. The CAISO study results

⁴³ See CAISO's *2013-2014 Transmission Plan* (March 25, 2014) for details on the studies and analysis discussed in Section IV.G.2.a.

1 indicated that some Preferred Resources are effective in meeting the LCR need in conjunction with GFG
2 and transmission solutions. The results of these studies also suggested that up to 150 MW of two-hour
3 dispatch/discharge resources will be effective in meeting or reducing the identified LCR need in the LA
4 Basin. The CAISO, however, did not study the effectiveness of two-hour resources in meeting the
5 system RA requirements beyond the local area, and was not prepared to support any system RA value
6 for such resources. As a result, SCE ultimately excluded the consideration of two-hour resources from
7 its recommended LCR procurement.

8 **H. Role of IE and CAM Group**

9 Pursuant to applicable Commission decisions, SCE engaged an IE and consulted with its CAM
10 Group throughout the LCR RFO process.

11 **1. Engagement of IE**

12 D.08-11-008 requires an IE for all competitive solicitations that involve affiliate
13 transactions, utility-owned or utility-turnkey offers, and for all solicitations that seek products two years
14 or greater in duration, regardless of who participates.⁴⁴ In addition, D.06-07-029 states that an IE is
15 required if an IOU runs a solicitation that seeks to allocate new generation costs in accordance with the
16 CAM outlined in the same decision.⁴⁵

17 In compliance with these requirements, SCE recommended Sedway Consulting, Inc. (“Sedway”)
18 as the IE for SCE’s LCR RFO. Sedway is currently in SCE’s pre-qualified IE pool and has prior
19 experience developing and running solicitations in other parts of the country for EE, DR, and DG, as
20 well as renewable and conventional resources. Sedway also has some prior experience overseeing the
21 negotiation and evaluation of ES. SCE provided Sedway with a whitepaper and presentation on ES
22 technologies and requested that Sedway review appropriate staff and consultant reports developed
23 pursuant to R.10-12-007, the Energy Storage Rulemaking, to ensure Sedway had the latest information
24 on ES. SCE sought and obtained Energy Division approval to use Sedway as the IE for the LCR RFO.

⁴⁴ D.08-11-008 at 39-40 (OP 2).

⁴⁵ D.06-07-029 at 28.

1 Sedway was engaged to ensure that the solicitation process was fair to all qualified bidders and
2 that no SCE affiliate had an undue advantage over non-affiliates in the solicitation.⁴⁶ Sedway was
3 required to make a determination as to whether SCE's final selection was fair and free from anti-
4 competitive behavior. Sedway also reported its findings throughout the RFO process to the Energy
5 Division and SCE's CAM Group by participating in meetings that SCE scheduled with both groups.
6 Sedway also communicated with the Energy Division directly regarding the EE/DR incrementality
7 issue. Finally, Sedway completed the CPUC's IE Report Template, with updates pending based on
8 completion of the solicitation. The IE Report has been provided to the Energy Division and a copy is
9 included as Appendix D.

10 **2. Consultations with CAM Group and Energy Division**

11 D.06-07-029 adopted a CAM that allows the benefits and costs of new generation that meets
12 specific needs to be distributed among all benefitting customers. In Section VIII.B, SCE describes the
13 cost allocation treatment for each category of resource procured to meet the LCR need. Consistent with
14 Public Utilities Code §365.1(c)(2)(A)-(B), prior Commission decisions,⁴⁷ and the LTPP Track 1 and
15 Track 4 decisions⁴⁸ which authorized the LCR procurement to benefit all customers in the SCE service
16 territory, SCE requests that its LCR procurement cost be allocated to all customers within the SCE
17 service territory consistent with CAM principles. See Chapter VIII for further discussion on the
18 recommended allocation of costs and benefits. As has been SCE's practice, SCE consulted with its
19 CAM Group on a regular basis prior to, during, and after the close of the LCR RFO. Table IV-8 lists
20 SCE's consultations with the CAM Group and the topic of each consultation.

21 SCE also briefed various members of Energy Division throughout the process on different
22 aspects of the LCR RFO, including the shortlist and final selection, issues related to ES, debt

⁴⁶ No SCE affiliate participated in SCE's LCR RFO.

⁴⁷ See D.06-07-029, D.07-09-044, D.08-09-012, D.11-05-005 and D.13-02-015.

⁴⁸ D.13-02-015 and D.14-03-004.

1 equivalency considerations, and EE/DR incrementality. In addition, SCE previewed information that
 2 was going to be presented at the CAM Group meetings with Energy Division personnel.

Table IV-8
CAM Group Meetings

Date	Topic	Description of Information Provided to CAM
2-Jul-13	SCE's Local Capacity Requirements (LCR) Procurement Plan	LCR Procurement Plan
9-Sep-13	Launch of the LCR RFO	Presentation on the launch of the LCR RFO
9-Dec-13	LCR RFO Shortlist Process	Presentation on the process SCE is using to shortlist bidders
23-Jan-14	LCR RFO Shortlist	LCR RFO preliminary shortlist provided
29-Jan-14	LCR RFO Shortlist	Review of the final shortlist
12-Mar-14	Update on LCR RFO	Impacts of the CAISO's recent transmission studies on the LCR RFO
3-Apr-14	Update on LCR RFO	Updates to the shortlist based on CAISO changes in effectiveness factors
17-Apr-14	Update on LCR RFO	Demand Response – LCR incremental framework
1-May-14	Update on LCR RFO	Schedule update
23-May-14	Update on LCR RFO	Analysis of incremental energy efficiency
19-Jun-14	Update on LCR RFO	Final offer valuation and selection process
25-Jul-14	Update on LCR RFO	Debt equivalence issues and solutions
3-Sep-14	Update on LCR RFO	Update of offers and review of issues
23-Sep-14	LCR Final EE and DR Tranche Analysis	Energy efficiency and demand response incremental resources
1-Oct-14	Cost Allocation Plan for LCR RFO	Review of SCE proposal to allocate costs to all benefitting customers
2-Oct-14	LCR RFO Selection Process and Preliminary result IE Presentation on his Independent Assessment Capital Lease and Debt Equivalence	Presentations on the selection process and preliminary results, IE assessment, and capital lease/debt equivalence
8-Oct-14	Continuation of Selection Process and Preliminary Results	Continued discussion of capital lease and debt equivalence
21-Oct-14	LCR RFO Final Selection Results	Final selection methodology and results
5-Nov-14	LCR RFO Final Selection Results Update	Update to final selection methodology and results

1 **I. Impact of Debt Equivalence on LCR RFO Contract Structure**

2 **1. Significance of Debt Equivalence**

3 Debt equivalence arises from long-term contracts and other long-term financial commitments
4 that are not included as debt on the balance sheet, but are viewed as debt by credit rating agencies. The
5 fixed capacity payments of contracts or the adjusted all-in energy payments are considered to be debt
6 equivalents by rating agencies because the buyer's (*i.e.*, SCE) payment obligations under the contract
7 are fixed obligations and cannot be avoided without defaulting on the contract. These fixed obligations
8 have a priority claim on a utility's cash flow. Such fixed obligations are one of the most important
9 considerations in a credit rating analysis. The credit rating agencies pay careful attention to SCE's
10 contracts, as they have a significant effect on the utility's credit rating and ultimately, SCE's cost of
11 borrowing.

12 Although all three rating agencies consider debt equivalence in their credit rating determinations,
13 Standard & Poor's ("S&P") places the greatest emphasis on debt equivalence and has published the
14 most detailed explanation of its calculations, which involve calculating the net present value of future
15 capacity payments or adjusted all-in energy payments and then multiplying that net present value by a
16 risk factor that reflects the risk of recovery of those payments through the utility's rates. For SCE,
17 S&P's current risk factor is 25 percent.⁴⁹ Even at a 25 percent risk factor, debt equivalents from the
18 LCR RFO contracts⁵⁰ could be in the range of \$1 billion.

19 Once debt equivalents are calculated, the rating agencies modify their calculations of the utility's
20 capital structure and related credit statistics by adding the debt equivalents to the debt that is already on
21 the utility's balance sheet. In addition, S&P imputes interest expense on the debt equivalence in cash
22 flow calculations, offset by additional cash flow from imputed depreciation expense,⁵¹ to measure the

⁴⁹ S&P assigns each utility a risk factor based on items such as the utility's regulatory structure and likelihood of recovering long-term contract costs in rates.

⁵⁰ For the purposes of this sentence, the LCR RFO contracts include the contracts for both the Western LA Basin and Moorpark sub-area.

⁵¹ The interest expense reduces cash flow. The depreciation expense, calculated as the risk factor times the capacity payment, minus the imputed interest expense for the year, increases cash flow because it is a non-

(Continued)

1 impact of the debt equivalents on the utility's financial structure. S&P also adds other long-term
2 obligations to the utility's balance sheets.

3 The overall effect of debt equivalence is to make SCE's balance sheet more leveraged and to
4 reduce the quality of SCE's cash flow in credit rating calculations. If SCE's debt equivalents increase
5 by a significant amount, it could result in a downgrade of SCE's credit rating at some future date. A
6 credit rating downgrade would be harmful to SCE, its suppliers, and its customers, and would likely
7 increase SCE's cost of issuing debt and preferred equity and SCE's collateral requirements and
8 collateral costs. Customers would ultimately bear these higher costs. Further, SCE would have less
9 favorable access to capital.⁵² Generally, less favorable access to capital means higher financing costs.
10 However, in times of financial crisis, SCE may be denied access to short-term financing, which could
11 result in SCE being unable to meet its financial obligations in a timely manner. In addition, SCE's
12 suppliers could be harmed because SCE would be a less creditworthy counterparty, making it more
13 difficult for SCE's suppliers to obtain credit on favorable terms and conditions.

14 **2. Seeking a Potential Solution to Minimize the Debt Equivalency Issue**

15 Once a long-term contract has been negotiated, SCE performs a preliminary accounting
16 assessment of that contract using generally accepted accounting principles. The primary considerations
17 of this assessment include the negotiated contract language and SCE's valuation. The contract may fall
18 into one of the following categories: (1) accrual accounting; (2) lease; (3) derivative; or (4)
19 consolidation. Each of these categories results in different accounting treatment which may influence
20 how a rating agency determines the debt equivalents associated with each contract as discussed above in

Continued from the previous page

cash expense. Imputed debt, imputed interest expense and imputed depreciation all impact key financial ratios reviewed by credit agencies in determining creditworthiness.

⁵² For example, if a credit rating downgrade led to some or all of SCE's debt and preferred equity securities being downgraded below investment grade, many investment funds, such as pension funds, would no longer be able to purchase those securities and would have to divest the ones that they owned at the time of the downgrade.

1 Section IV.I.1. When performing its preliminary assessment of the contracts, SCE determined that its
2 then-current form of GFG, IFOM ES, and BTM ES contracts would result in capital lease accounting
3 treatment, which has an unacceptable level of debt equivalents.

4 In order to minimize the debt equivalency issue, SCE made the following changes to the
5 structure of the contracts: (1) added an “Embedded Put Option” to GFG contracts for combined-cycle
6 gas turbines (“CCGT”) power plants and IFOM ES contracts; (2) converted GFG contracts for
7 combustion turbines (“CTs”) to fixed-price per unit RA-only contracts; and (3) modified the terms of the
8 BTM ES contracts.

9 The contracts with the Embedded Put Option now contain a “put option” where the seller
10 can transfer annual control of the energy rights to SCE at a “put” price that SCE can modify up until
11 CPUC approval (as defined in the contract).⁵³ The inclusion of an “Embedded Put Option” results in
12 lower debt equivalents than the original assessed capital lease accounting treatment.

13 The preliminary accounting assessment for the GFG contracts for CTs also resulted in capital
14 lease accounting treatment with an unacceptable level of debt equivalents. The “Embedded Put Option”
15 approach did not work for these contracts because they are peaker units that are not forecasted to run
16 frequently and, therefore, are not expected to generate much energy output. The low output resulted in a
17 low energy valuation which caused the contract to still be subject to capital lease accounting treatment,
18 even with the “Embedded Put Option.” Instead, SCE was able to restructure the GFG CT contracts to
19 fixed-price per unit RA-only contracts. The accounting assessment for the restructured contract resulted
20 in accrual accounting treatment and thus reduced the debt equivalence impact.

21 For BTM ES contracts, the preliminary accounting assessment also resulted in capital lease
22 accounting treatment. SCE restructured the contracts to include a provision that allows the seller to add,
23 remove or replace the assets associated with contracts as needed. Since the contract performance is not

⁵³ In the contracts, CPUC approval is thirty days after a Commission decision approving the agreement.

1 dependent on specified assets throughout the term of the contract, the contract accounting assessment
2 indicates accrual accounting treatment is appropriate, which reduces the debt equivalence impact.⁵⁴

⁵⁴ The contract solutions discussed in Section IV.I are based on current facts, circumstances and accounting literature. Any change to these variables prior to lease inception may drive changes to the debt equivalency treatment of the contracts and will need to be assessed accordingly.

V.

LCR RFO PARTICIPATION

A. Summary of Solicitation Participation

This Chapter provides an overview of the following steps in the LCR RFO: (1) indicative offers submitted by bidders; (2) shortlist notification; (3) contract negotiations; and (4) final binding offers submitted.

1. Indicative Offer Submittal

SCE received a very robust set of indicative offers. In total, SCE received 1,136 offers from bidders, spanning all of the technology types SCE solicited.⁵⁵ A summary of the indicative offers received is provided in Table V-9 below.⁵⁶

*Table V-9
Summary of Indicative Offers*

Product Type		Number of Offers
EE		181
DR		113
Renewable		11
CHP		14
DG		40
ES		579
GFG		198
Total		1,136

Many of the counterparties who bid into the LCF RFO were new to SCE's structured procurement programs and required a significant amount of assistance with filling out the bid templates and providing all required information. This was further complicated by SCE soliciting products such as ES and EE aggregation for the first time. Thus, after receiving indicative offers, SCE went through a

⁵⁵ The 1,136 indicative offers includes offers for both the Western LA Basin and Moorpark sub-area.

⁵⁶ The number of counterparties in the table is greater than because some counterparties submitted offers for multiple product types.

1 very intensive process of “curing” offers. Nearly every counterparty was contacted, and close to 80
2 percent of the offers were revised in some manner.

3 **2. Shortlist Notification**

4 SCE removed some projects from shortlist consideration because they did not meet the RFO
5 requirements (*e.g.*, the most common non-conforming issue was proposed projects that were outside of
6 the LCR region). In the LCR RFO, consistent with other procurement programs, SCE did not shortlist
7 specific offers, but instead shortlisted entire counterparty/product combinations by comparing the best
8 valued offer by counterparty/product. The rationale behind this practice is: (1) offers were likely going
9 to change throughout the negotiation process; and (2) the main measure of workload for the SCE team is
10 the counterparty/product combination, as each combination requires a separate document negotiation.
11 Notwithstanding SCE’s screening process, SCE shortlisted many counterparties/product types for the
12 Western LA Basin.⁵⁷ Counterparties were only required to commit to certain offers and offer structures
13 during the Indicative Offer and Final Offer phase. In between these two phases, counterparties were
14 continuously refining offers, and even switched between in-front-of-the-meter and behind-the-meter
15 resources. These changes occurred because counterparties continued to refine their projects as they
16 became more knowledgeable about the feasibility and risk associated with them, and as a result of
17 receiving feedback from SCE. As described in Section IV.H, SCE met with the CAM Group multiple
18 times during the shortlist process.

19 **3. Contract Negotiations**

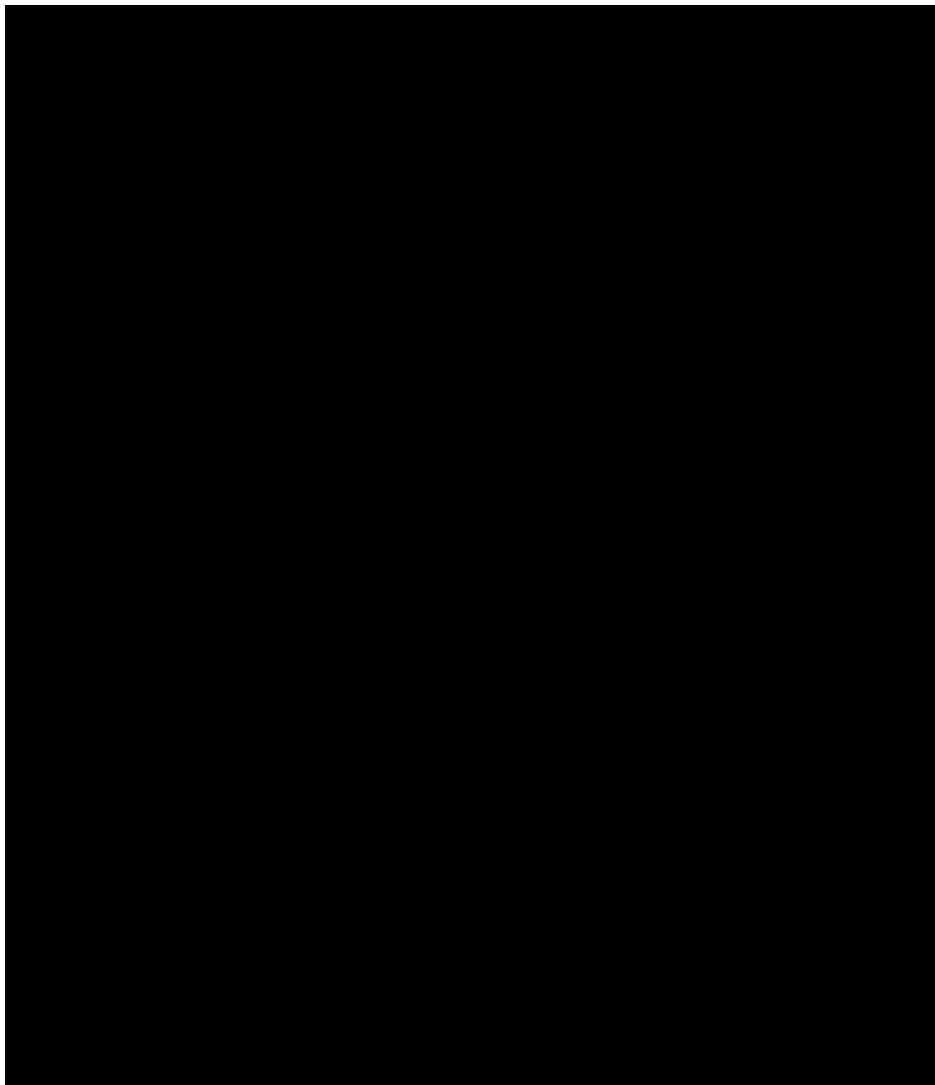
20 Shortlist notification was made on January 30, 2014, and form of contract negotiations
21 commenced soon after. Per the revised LCR RFO schedule, the negotiation phase was originally

⁵⁷ Counterparties that were shortlisted for a product in one of the LCR areas, Western LA Basin or Moorpark, were usually shortlisted for the other area. This is because historically, a factor in how many projects to shortlist has been the amount of workload that the SCE team could handle. A large part of this workload is negotiations to reach agreement on a form of contract, and the assumption at shortlisting was that regardless of the geographic location of the project, a common form of the agreement could be used for Western LA Basin and Moorpark.

1 scheduled to end on August 29, 2014. However, as described in Section IV.E, a number of the
2 complexities and challenges specific to the LCR RFO surfaced, which caused schedule delays.

3 During the negotiation phase, various counterparties withdrew or were removed from the
4 solicitation. Table V-10 below lists those counterparties and the reason(s) why they could not continue
5 to participate in the LCR RFO.

Table V-10
Counterparties That Withdrew/Removed From Solicitation During Negotiations



6 During this phase, SCE added two counterparty-product types not originally on the shortlist

7  in order to increase competition. 

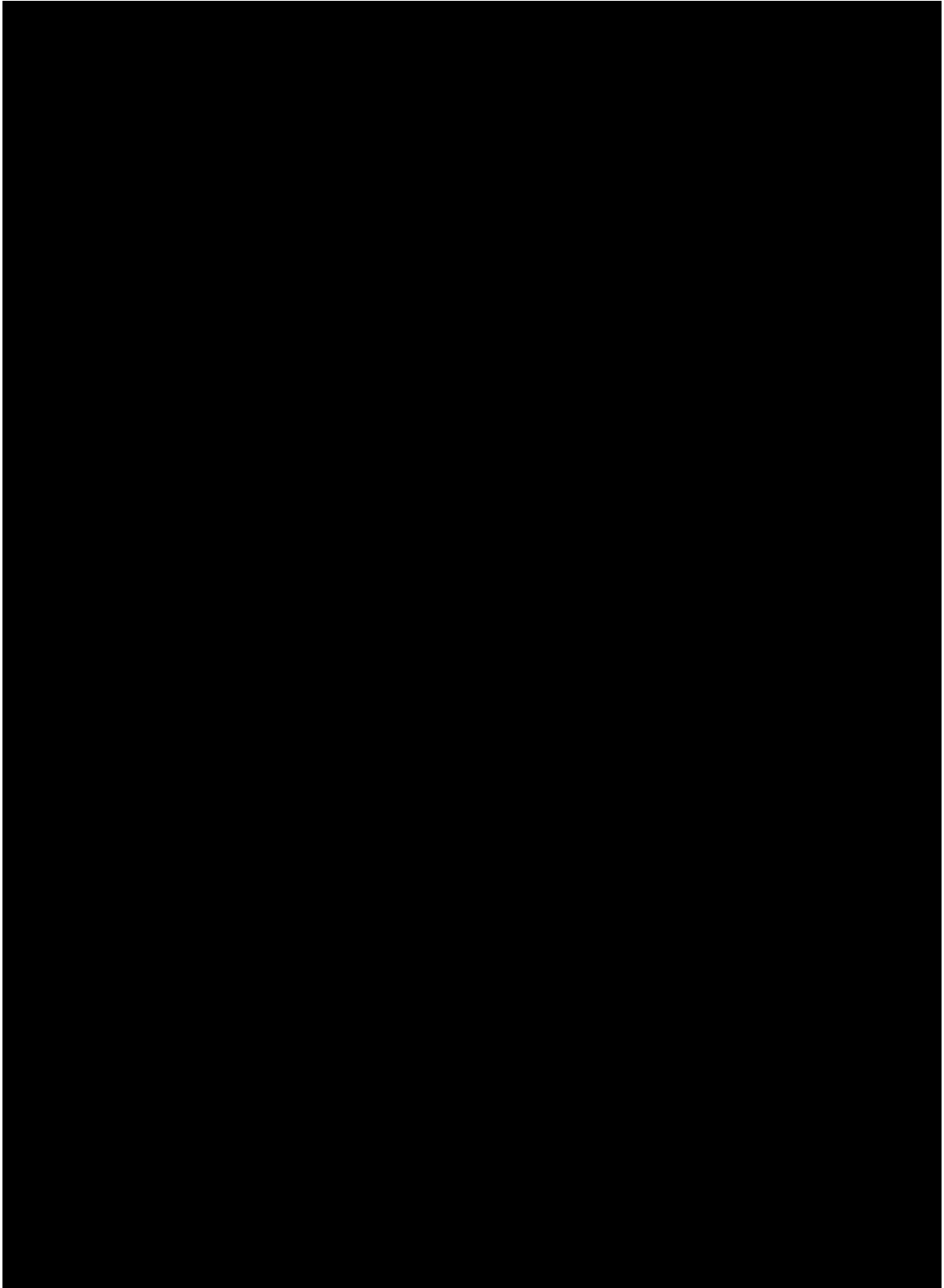
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4. Final Binding Offer Submission

SCE received final offers on September 4, 2014. Table V-11 below summarizes the Western LA Basin offers.

Table V-11
Summary of Western LA Basin Final Offers



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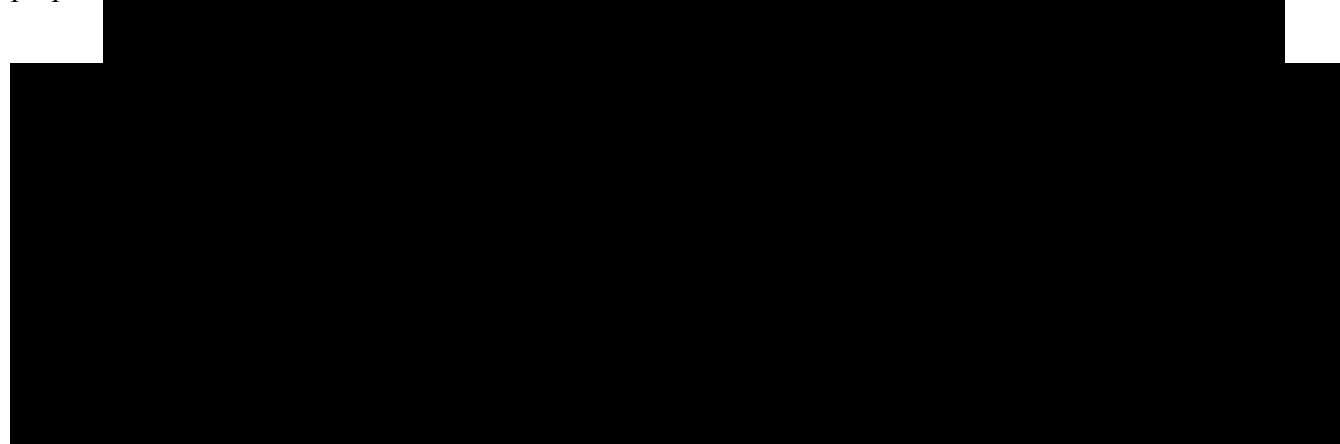
VI.

VALUATION PROCESS

SCE utilized a number of criteria during its evaluation and selection of offers. In accordance with D.04-12-048, SCE used a Least-Cost, Best Fit⁵⁸ methodology to value and award contracts in the LCR RFO. This Chapter is comprised of two main sections: (A) a description of SCE’s market outlook methodology and (B) a description of SCE’s valuation and selection methodology, including a discussion on the selected set of contracts that best met the constraints and preferences associated with SCE’s LCR needs.

A. Market Outlook Methodology

SCE prepared forecasts for RA capacity, electrical energy, ancillary services (“AS”), natural gas, and greenhouse gas (“GHG”) compliance market prices. These price forecasts were used to model and prepare valuations of each offer received in the LCR RFO.



Specifically, SCE used market quotes as of [redacted] to set the market period and consultant forecasts for natural gas and GHG compliance prices which were key inputs used in the fundamental model to develop forecast electrical energy prices.

AS prices were developed using an econometric model which captures energy prices, upward and downward movement in energy prices and electricity demand, and hydroelectric production. AS

⁵⁸ Methodology for taking into account both the cost of offers received from bidders and the extent to which the offers provide energy or other attributes needed by the buyer.

1 prices evolve over time in shape and magnitude to capture the increased ramping need due to increased
2 intermittent renewable penetration.

3 SCE used the RA value adopted in D.11-12-018⁵⁹ for the Market Price Benchmark (“MPB”)
4 methodology used for calculating the Customer Responsibility Surcharge (“CRS”) for departing
5 customers as a reasonable proxy for the RA compliance value of LCR offers. D.11-12-018 adopted an
6 RA value based on the most current calculation by the CEC of the going-forward cost of a combustion
7 turbine,⁶⁰ currently set to \$50.17/kW-year⁶¹ (\$4.18/kW-month).
8 [REDACTED]
9 [REDACTED]

10 **B. Valuation Methodology & Selection Methodology**

11 **1. Overview**

12 SCE’s offer evaluation process follows Least-Cost, Best-Fit principles. SCE employs a net
13 present value (“NPV”) analysis when it evaluates offers submitted through an RFO. This methodology
14 is consistent with evaluations performed by SCE in other solicitations, such as SCE’s CHP RFOs,
15 Renewables Portfolio Standard (“RPS”) solicitations, and All-Source RFOs for energy and RA. The
16 quantitative component of the evaluation entails forecasting (1) the value of the contract benefits, (2) the
17 value of the contract costs, and (3) the net value between (1) and (2).

18 SCE calculated each offer’s forecasted quantity of RA capacity, electrical energy, and AS using
19 a combination of models specific to each resource type. SCE then multiplied these quantities by the
20 respective market price forecasts.⁶² These calculations represent (1) the value of the contract benefits
21 based on the forecasted market value for each resource. SCE then calculated (2) the contract costs

⁵⁹ D.11-12-018 at 108 (Conclusions of Law (“COL”) 5)).

⁶⁰ *Id.*

⁶¹ The CEC value is based on a 2009 study published in a January 2010 report. Going-forward cost components include insurance, ad valorem, and fixed operations & maintenance. The report can be found at:
<http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF>.

⁶² SCE did not apply any locational adjustments for congestion or losses for the LCR RFO valuation as all bids were in the same local area.

1 required to realize this market value, including estimates of capacity payments, variable operations and
2 maintenance (“VOM”) costs, start-up payments, and fuel costs to generate electrical energy. These
3 elements were used to determine the cost-effectiveness of each resource.

4 The benchmark for determining cost-effectiveness (*i.e.*, the resource’s market value forecast
5 minus the costs required to receive these benefits, plus any other value that can be attributed to the
6 resource, discounted at 10 percent) is the calculated NPV of the offer. This NPV was the cost metric
7 that SCE used in the selection process and its elements are described below.

8 **2. Contract Benefits**

9 a) Energy and Ancillary Service Benefits

10 (1) Energy Efficiency

11 Energy efficiency bidders provide SCE with the each offer’s expected useful life and a typical
12 meteorological year (“TMY”) hourly energy savings profile (versus codes and standards). The offer’s
13 energy benefits are calculated by multiplying each month’s total time-of-use (“TOU”)-period TMY
14 energy savings by its respective TOU-period average energy price forecast. Since EE benefits are
15 derived from load reductions, the energy benefits are grossed up by SCE’s Transmission & Distribution
16 line loss factor of [REDACTED] percent to reflect avoided line losses.

17 (2) Demand Response and Behind the Meter Energy Storage

18 For dispatchable demand response resources and BTM ES, energy benefits are calculated
19 through a dispatch simulation that projects the economically beneficial periods when SCE would pay for
20 a reduction in load. This is done by calculating each offer’s theoretical maximum annual net revenues
21 given the specified daily dispatch costs and limits (*i.e.*, minimum and maximum duration, maximum
22 events per day, available hours, and energy rate), monthly availability and dispatch maximums, and
23 annual dispatch maximums. This simulation is performed on multiple power price scenarios, and results
24 in an expected monthly energy benefit forecast associated with utilizing the demand response resource.
25 Since demand response and BTM ES benefits are derived from load reductions, the energy benefits are

1 grossed up by SCE's Transmission & Distribution line loss factor of [REDACTED] percent to reflect avoided
2 line losses.⁶³

3 (3) In Front of the Meter Energy Storage

4 To maintain consistency of valuations across different technologies, SCE adapted its approach to
5 valuing dispatchable thermal resources for use in the valuation of IFOM ES assets. Specifically, SCE
6 developed a proprietary economic dispatch model to determine optimal charge and dispatch of IFOM
7 energy storage devices. Inputs into this model include forecasted price streams for energy and ancillary
8 services and the contractual terms, such as VOM charges and operational parameters, of the storage
9 device. Typical operational parameters for the storage device include maximum power output,
10 maximum power input, maximum and minimum storage quantities, and device efficiency. The output
11 of the model is the optimal operation and revenue earned by using the device to arbitrage prices through
12 time based on SCE's forecasts of market conditions (*i.e.*, load the device when prices are low and
13 dispatch the device when prices are high). The model is coupled with a Monte Carlo price simulator
14 that generates hourly pricing scenarios across the time horizon being valued. A forecast of energy
15 revenue is obtained for each scenario, yielding multiple revenue outcomes. SCE averages and discounts
16 the outcomes to obtain a single energy value and AS value.

17 (4) Gas-Fired Generation

18 For dispatchable thermal resources, SCE utilized a fundamental production-cost model (ProSym)
19 combined with a stochastic price process via a Monte Carlo simulation, to value the energy and AS
20 benefits of the generating units. Inputs to the fundamental model include unit characteristics such as
21 capacity, heat rate curve, ramp rate, start fuel and start cost, minimum and maximum run-time, VOM
22 cost, GHG cost, fuel cost, and emission constraints, among others. SCE uses the economic dispatch
23 principle, wherein a unit is simulated to dispatch if its forecasted benefits exceed its costs (*i.e.*, if it is "in

⁶³ DR resources are supplied at the customer meter level, and therefore, eliminate the need to account for T&D line losses. The "Transmission & Distribution line loss factor" captures this benefit and is calculated based on the methodology described in D.10-06-036 at 40.

1 the money”). ProSym compares the forecasted cost of running a unit against energy and AS price
2 forecasts to determine whether a unit is in the money.

3 SCE creates an expansive “lookup” library of dispatch results to avoid the need to perform
4 multiple runs for each analysis.

5
6 SCE then deploys a stochastic Monte Carlo simulation process to generate
7 many gas price and implied market heat rate pairs, using blended power and gas price curves derived
8 from market and fundamental models as the expected case, and by applying a volatility process on top of
9 the blended price forecasts to create a distribution of price outcomes. The volatility process estimates
10 correlation, volatility, mean reversion, stochastic volatility and seasonal parameters. The simulated
11 price pairs are used to “look up” the forecasted gross energy benefits and costs from the dispatch library
12 identified above. SCE defines the expected energy and AS benefits as the average of the simulated
13 cases. This process allows SCE to value both the intrinsic and extrinsic (optionality) value of the
14 resource.

15 (5) Other Resources

16 Finally, for must-take and baseload resources, SCE calculated the energy benefits of an offer
17 based on the estimated market value of energy using the offer’s expected generation or delivery profile.
18 Since SCE does not have dispatch rights to these types of resources, production cost modeling and
19 Monte Carlo simulation is unnecessary. In addition, these resources receive no AS value because they
20 cannot participate in the CAISO’s AS markets.

21 b) Resource Adequacy (“RA”) Capacity Benefits

22 RA compliance capacity benefits are derived by first developing a forecast of expected forward
23 RA compliance prices and then applying these forecasted prices to the total RA capacity provided by the
24 offer. In its Procurement Plan, SCE explained that it would apply LEFs to the RA value. Additionally,
25 the Track 1 decision required SCE to use the most up to date LEFs in its valuation. Because Southwest
26 sub-area resources were considered most effective, only Western Central and Northwest sub-areas
27 IFOM ES offers received an RA value adjustment based on their LEF. The adjustment factor was equal

to one minus the difference between the project’s LEF and the 0.717 LEF of the Southwest sub-area. SCE received IFOM ES offers that were located only in the Southwest and Northwest sub-areas of the Western LA Basin. Consequently, only offers located in the Northwest sub-area (which has an LEF of 0.136) received an LEF RA adjustment factor. This resulted in Northwest IFOM ES offers receiving 41.9 percent (1 - (0.717 - 0.136)) of full RA value in SCE’s calculation of RA benefits.

To determine the RA capacity provided by each of the offers, SCE used current RA counting rules where applicable, and applied similar rules where RA counting rules have not been established. The Table VI-12 below summarizes how the RA capacity was determined for each offer type:

Table VI-12
RA Capacity Determination by Product

Offer Type	RA Capacity – Determination				
Gas-Fired Generation	RA capacity equals monthly contract capacity				
Energy Storage Energy Efficiency	<p>RA capacity equals monthly contract capacity</p> <p>RA quantities are calculated separately for summer and non-summer months. Non-summer month RA quantities are calculated by averaging the TMY hourly energy savings from 2 to 5 PM coincident with SCE’s highest three forecasted peak demand days (nine hours total for each month). Summer month RA quantities are set equal to the guaranteed “capacity” savings as specified in the offer.</p> <p>Since EE benefits are derived from load reductions, RA benefits are grossed up by the T&D loss factor in addition to the 15 percent reserve margin requirement.</p>				
Solar Rooftop	<p>RA quantities were calculated using the exceedance approach. Since the technology was solar, SCE used a 70% exceedance level and the following hours (from the offer’s TMY delivery profile) for observations:</p> <table border="1" style="margin-left: auto; margin-right: auto;"> <tr> <td style="padding: 2px;">Jan–Mar, Nov and Dec:</td> <td style="padding: 2px;">HE17 - HE21¹ (4:00 p.m. - 9:00 p.m.)</td> </tr> <tr> <td style="padding: 2px;">Apr–Oct:</td> <td style="padding: 2px;">HE14 - HE18 (1:00 p.m. - 6:00 p.m.)</td> </tr> </table> <p>Since Rooftop solar offers are all behind-the-meter, and therefore load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</p>	Jan–Mar, Nov and Dec:	HE17 - HE21 ¹ (4:00 p.m. - 9:00 p.m.)	Apr–Oct:	HE14 - HE18 (1:00 p.m. - 6:00 p.m.)
Jan–Mar, Nov and Dec:	HE17 - HE21 ¹ (4:00 p.m. - 9:00 p.m.)				
Apr–Oct:	HE14 - HE18 (1:00 p.m. - 6:00 p.m.)				
CHP	<p>RA quantities for the first two years of the contract term were set equal to the offer’s firm capacity multiplied by the 2014 monthly technology factors for Cogeneration resources. The remaining term was equal to the minimum of the firm contract capacity and the specified average peak-period energy deliveries.</p> <p>Since CHP offers are all behind-the-meter, and therefore load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</p>				
Demand Response	<p>RA quantities are equal to the monthly contract quantity, or load reduction amount, provided in each offer.</p> <p>Since these benefits are derived from load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</p>				
<p>¹ HE indicates “hour ending”</p>					

1 **3. Contract Costs**

2 a) Dispatch and Energy Costs

3 (1) Demand Response and Behind the Meter Energy Storage

4 For dispatchable DR and BTM ES resources, the “dispatch” or variable costs (\$/MWh) are
5 calculated by projecting the economically beneficial periods when SCE would pay for a reduction in
6 load using the dispatch process described above in Section VI.B.2.a)(4) when calculating energy value.

7 (2) In Front of the Meter Energy Storage

8 For dispatchable IFOM ES resources, charging and VOM costs are accounted for in the dispatch
9 optimization model.

10 (3) Gas-Fired Generation

11 For dispatchable thermal resources, dispatch costs include unit start costs, VOM costs, GHG
12 compliance cost, and fuel costs. Start costs include the fixed cost of starting a unit, and are differentiated
13 by hot and cold starts, depending on how long the unit has been simulated to be offline. VOM costs are
14 costs which are directly proportional to the output of the unit, measured in \$/MWh. GHG compliance
15 cost is the California Cap & Trade compliance cost of obtaining the allowances for a unit emitting GHG.
16 Fuel costs include the variable cost of generating power and the fixed cost of the required fuel amount
17 used to start up a unit. These cost components are accounted for in the ProSym production cost
18 modeling and are used to make the simulated economic dispatch decisions.

19 (4) Other Resources

20 For must-take and baseload resources, energy costs can include fuel costs (as indicated by a heat
21 rate), VOM, and GHG compliance costs, or an all-in energy price in dollars per Megawatt-hour
22 (“MWh”) as is typically used for RPS resources.

23 b) Capacity Payments

24 Capacity payments represent the total fixed contract payments SCE is expected to make under
25 the contract for delivery of the energy and capacity benefits.

1 c) Debt Equivalents

2 Debt equivalents is the term used by credit rating agencies to describe the fixed financial
3 obligation resulting from long-term contracts (see Section IV.I for more detail). Pursuant to D.04-12-
4 048 and D.08-11-008, the Commission permits the utilities to recognize in their valuation processes the
5 cost associated with the effect debt equivalence has on the utilities' credit quality and cost of
6 borrowing.⁶⁴ Consistent with these decisions, SCE considers debt equivalence in its valuation process
7 using the 20 percent risk factor authorized by the Commission.

8 d) Transmission Cost

9 For IFOM projects that either (1) do not have an existing interconnection to the electric system,
10 or (2) have an existing interconnection, but do not have an approved expansion to an existing facility,
11 system transmission network upgrade costs are based on the most recent interconnection study from the
12 CAISO. For projects with no interconnection study, but with an offer providing SCE the right to
13 terminate if system transmission network upgrade costs exceed a specified amount, transmission costs
14 are based on the specified transmission network upgrade amount.

15 e) Greenhouse Gas Cost

16 For any offer that requires customers to absorb GHG compliance costs, SCE will assess a GHG
17 cost to the offer based on SCE's forecast of GHG prices and the offer's forecasted amount of GHG
18 emissions.

19 f) Put Option Cost for IFOM ES and GFG

20 For the specific GFG resources and IFOM ES which would have a dispatch put option embedded
21 in their contract, SCE calculated a put option cost for use in the valuation analysis. As described above,
22 SCE uses a distribution analysis to derive the energy and AS value associated with dispatchable units,
23 such as GFG and IFOM ES. SCE used these results to determine the value of the Embedded Put Option
24 to the seller, and hence the cost to the customer. In order to derive the put option value, SCE first

⁶⁴ D.04-12-048 at 243 (OP 22) and D.08-11-008 at 38 (OP 1.a).

1 calculated the strike price for each year of the delivery period by setting the strike price equal [REDACTED]
2 [REDACTED] of the value distribution for the respective resource. SCE then calculated the conditional
3 expected returns above the [REDACTED] by averaging the distribution results from the [REDACTED]
4 [REDACTED]. The put option cost to the customer was set as the difference between these two values
5 (conditional expected returns minus strike price) multiplied by [REDACTED] to reflect
6 the probability of the value being realized).

7 g) Other Quantitative Considerations⁶⁵

8 One counterparty had additional incremental cost impacts to SCE due to the offers that they had
9 submitted. [REDACTED] had proposed DR programs targeting residential customers that would require
10 system upgrades and ongoing administrative and operational costs. SCE included these costs in its
11 valuation of [REDACTED] offers.

12 **4. Quantitative Benefits Summary**

13 As explained above, SCE calculated the quantitative benefits of offers by subtracting the present
14 value of expected costs from the present value of expected benefits to determine the expected NPV of
15 the offer.

16 **5. Qualitative Assessment**

17 In addition to the benefits and costs quantified during the evaluation, SCE assessed non-
18 quantifiable characteristics of each offer by conducting an analysis of each project's qualitative
19 attributes. SCE considered qualitative characteristics in determining the final selection. These
20 characteristics included:

- 21 • Locational Effectiveness, as determined through CAISO LEFs
- 22 • Permitting and interconnection

65 [REDACTED]

- 1 ○ Environmental and permitting status
- 2 ○ Electrical interconnection status
- 3 ○ Fuel interconnection and source
- 4 ● Pre-development milestones
 - 5 ○ Project financing status
 - 6 ○ Project development experience
 - 7 ○ Emissions performance standards
- 8 ● Development milestones
 - 9 ○ Site control
 - 10 ○ Reasonableness of commercial operation date
- 11 ● Risks associated with the resource type
- 12 ● Portfolio fit of energy, capacity, and term

13 **6. Selection Constraints**

14 SCE performed a least-cost, best-fit optimization selection by imposing constraints over a series
 15 of iterative optimizations. Then, SCE selected the set of contracts that satisfied the constraints while
 16 providing the most cost-effective valuation. To do this, SCE developed an optimization model that
 17 selects the highest NPV contracts subject to the constraints that are further described below. Inputs into
 18 the optimization model include the NPV of all contracts offered into the RFO, relevant contract
 19 information, and constraint information. There are three sources of constraints: (1) regulatory limits,
 20 (2) SCE operations, and (3) counterparty/project specific requirements.

21 Regulatory limits included minimum and maximum allowable purchase quantities for different
 22 asset categories (*e.g.*, fossil fuel, ES, Preferred Resources). SCE specific constraints included
 23 information derived from its offer template which allowed for inclusivity and exclusivity among offers.
 24 SCE also set additional constraints to consider viability, seller concentration and/or to limit exposure to
 25 certain technologies. For example, SCE set limits on the amount of DR offers that could be selected in a
 26 particular area based on the expected potential for DR in that area to avoid selecting offers that would be

1 in excess of the potential load reductions from the same customer population. Counterparty limits are
2 set by each counterparty's offer structure.

3 Once the minimum constraints were defined, the optimization model output a set of contracts
4 with the greatest value that satisfied the constraint set. SCE reviewed the results and modified its
5 constraint set to reflect qualitative determinations (e.g., technology concentration) and generated another
6 output set. SCE continued to iterate the generation of output sets by adjusting constraints based on
7 qualitative assessments until a final selection set was selected.

8 **C. Valuation and Selection Optimization Results**

9 **1. Overview**

10 SCE considered approximately [REDACTED] for final
11 selection. Contract durations ranged from 4 to 30 years, with the earliest start date being January 2016
12 and the latest end date being June 2048. [REDACTED]

13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED] Using these price outlooks, SCE calculated NPVs for each offer using
17 the applicable methodology as described in Section VI.B.

18 Due to the complexities and time constraints associated with modeling and running GFG, DR,
19 BTM ES, and IFOM ES offers through the valuation process, [REDACTED]

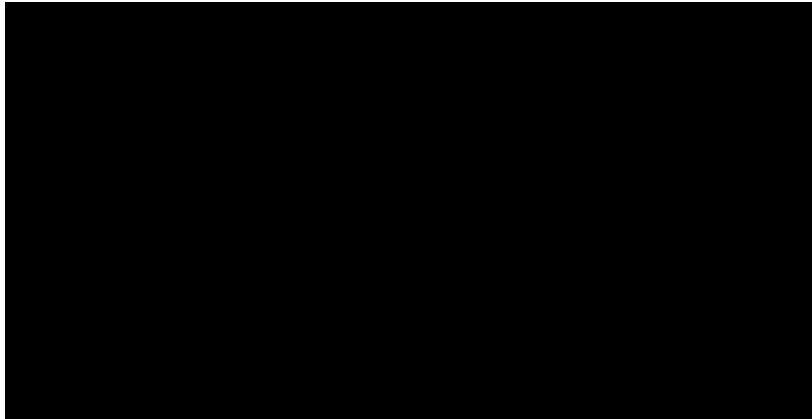
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]
24 [REDACTED]
[REDACTED]



A summary of the

number of offers evaluated by technology is provided in Table VI-13 below.

***Table VI-13
Offers Evaluated by Category***



2. Valuation Results⁶⁷

In addition to the NPV that was calculated for each offer and used in the selection optimization process, SCE developed three normalization metrics to be applied to each offer to support decision making for the LCR RFO selection process:

- 1) Average Contract kW-month - defined as the average contract quantity (kW-month) over the delivery term.
- 2) RA kW-month - defined as the average RA quantity (kW-month⁶⁸) over the delivery term.
- 3) LCR kW – defined as the August 2021 RA quantity (kW). SCE used this value in measuring whether SCE met its LCR RFO procurement requirements.

Next, SCE converted the NPV results for each offer into three premiums by multiplying each by minus one and then dividing by the respective normalization values. This resulted in the following normalized metrics:

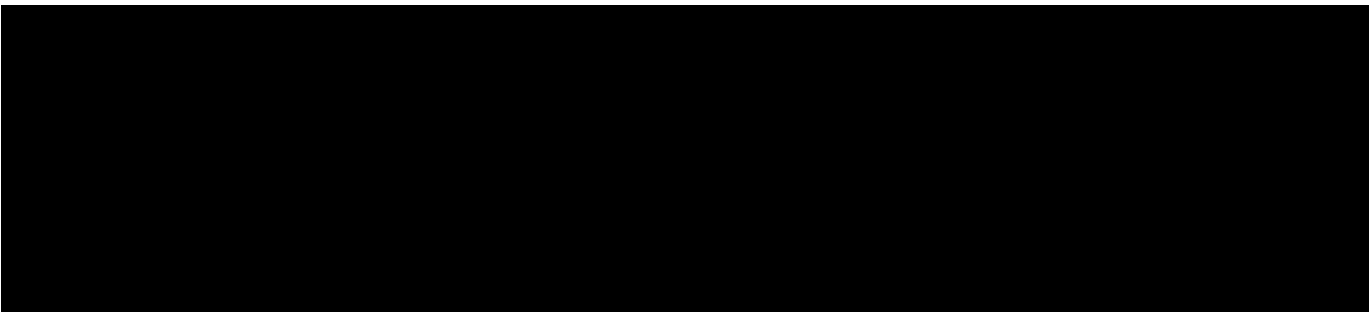
⁶⁷ The results of the valuation analysis for all offers can be found in SCE’s workpapers.

⁶⁸ This value could be higher or lower than the contracted kW due to the RA capacity counting rules described in Section VI.B.2.b).

- 1) Discounted Premium per contract kW-month.
- 2) Discounted Premium per RA kW-month.
- 3) Discounted Premium per LCR kW.

A summary of the valuation results showing the minimum, average and maximum metric for each resource type bidding into the LA Basin is provided in Table VI-14 below.⁶⁹

Table VI-14
Valuation Metrics by Category



As can be seen in Table VI-14 above, offer valuations ranged from negative premiums to positive premiums.⁷⁰

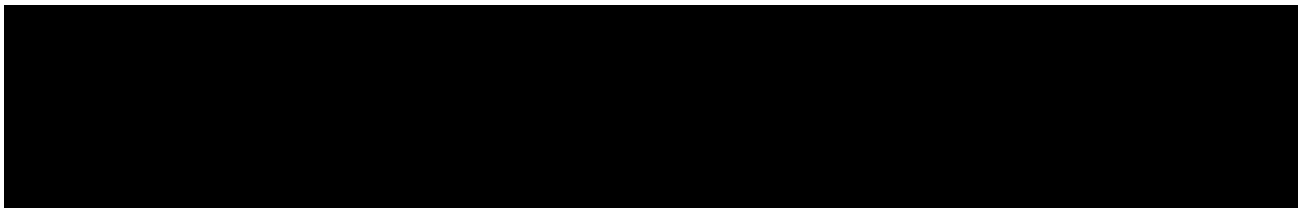


In addition, many of the offers were offered on a mutually inclusive basis (*i.e.*, if SCE selects one of these offers, it must take the other inclusive offer(s)). This constraint is the primary reason that a simple rank ordering selection process by category is not feasible. In some cases, offers were linked

⁶⁹ The full valuation results and metrics for each offer can be found in SCE's workpapers.

⁷⁰ A negative premium equates to a positive NPV, meaning, based on the price forecast used, the forecasted benefits of the contract outweigh the costs. A positive premium equates to a negative NPV, meaning, based on the price forecast used, the forecasted costs of the contract outweigh the forecasted benefit.

⁷¹



1 across resource types. In order to develop an optimal portfolio selection, given the regulatory and
2 counterparty constraints, SCE developed and executed a selection optimization process that maximized
3 the portfolio NPV while controlling for specific constraints using qualitative criteria.

4 **3. Summary of Portfolio Selections**

5 Prior to execution of the selection process, SCE completed a review of the valuation results and
6 confirmed that: (1) the results were internally consistent, (2) the valuation process had been executed
7 consistently, and (3) the process was executed as planned and communicated to SCE management and
8 the CAM Group. SCE then executed its selection process using a mathematical optimization process.
9 SCE iterated through several selection sets considering both the quantitative and qualitative aspects of
10 the selections before finalizing its recommendations. Each new selection set adjusted both the
11 optimization constraints, and in some cases, the offers and packages included in the process. Key
12 qualitative considerations included:

- 13 • Amount of IFOM ES MW Selected: As discussed in Section IV.E, SCE has some concerns
14 related to IFOM ES and thus elected to limit the amount of procurement of IFOM ES in the
15 optimization. In addition, SCE's valuation of IFOM ES offers assumed unconstrained
16 operations in CAISO markets leading to significant assessed AS revenues from participating
17 in AS markets during all hours. Current uncertainty around the interconnection of IFOM ES,
18 which may result in restrictions on charging ability during peak hours, and uncertainty on
19 how IFOM ES will actually participate in CAISO markets, warranted SCE to assume that its
20 IFOM ES valuation results may be higher than what will be achieved. Uncertainty around
21 the valuation results also created additional risk for potential capital lease accounting and
22 higher amounts of debt equivalence, as the valuation analysis is being used to set the strike
23 prices for the Embedded Put Option.
- 24 • Site Concentration for GFG: SCE was concerned that having most of the GFG at one site
25 would not be optimal. SCE also recognized that the valuation results of some of the GFG
26 resources were very close and within the error bounds of the model, which supported
27 imposing qualitative factors into the selection of the optimization constraints.

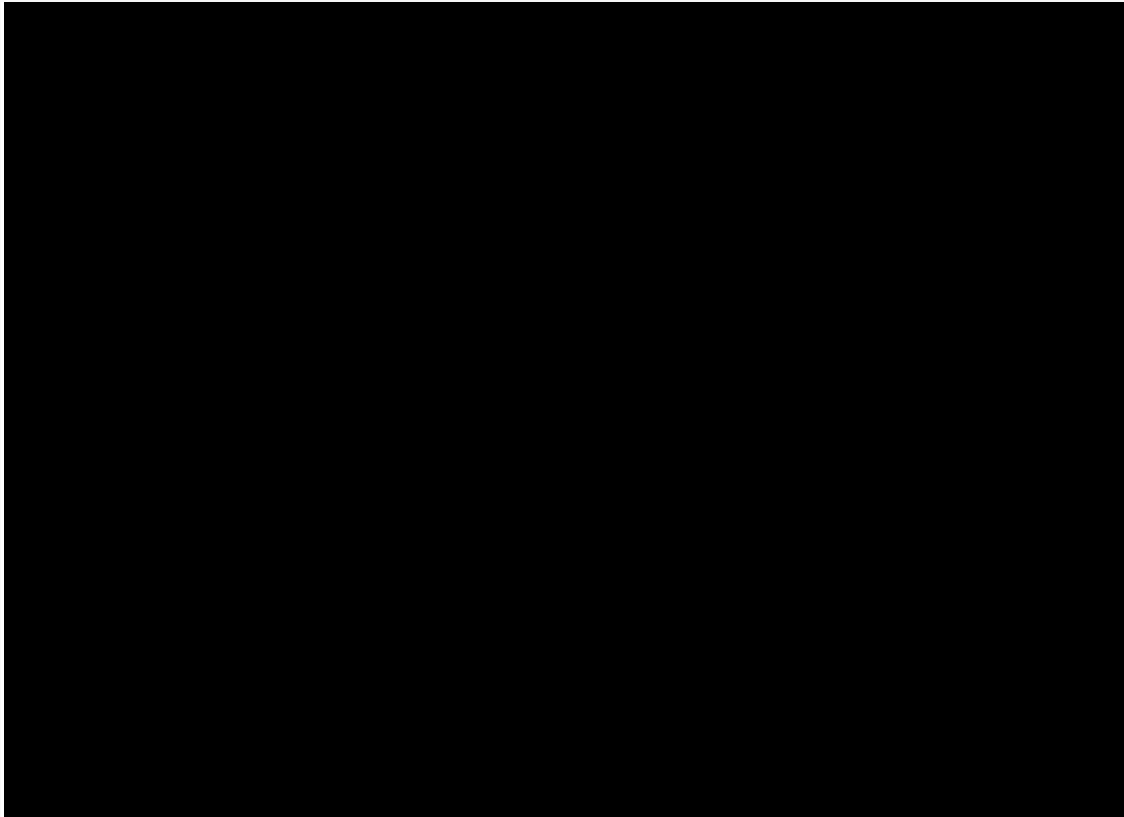
- 1 • Amount of Preferred Resources Pilot (“PRP”)⁷² MW Selected: SCE had specified in its RFO
2 instructions that it had a preference for resources in the Johanna or Santiago sub-areas to
3 support its PRP.
- 4 • Two-Hour vs. Four-Hour Resources: SCE worked with the CAISO to develop a quantity
5 limit of resources that only provide two hours of energy discharge capability to meet the
6 LCR need.⁷³ As discussed below, SCE ultimately decided not to procure two-hour resources
7 because CAISO had not studied their application as System RA resources.
- 8 • Cost of Meeting the Minimum Targets: With counterparty exclusivity constraints, less than
9 700 MW of Preferred Resources could be selected.⁷⁴ This amount was a little larger than the
10 minimum target for Preferred Resources and, as more Preferred Resources were selected, the
11 incremental costs of these resources increased greatly. See chart below. As such, SCE chose
12 not to meet the Track 1 and 4 decisions’ minimum Preferred Resource amount in this
13 solicitation.

⁷² SCE’s PRP is a significant-scale, multiyear pilot to investigate and demonstrate how the integrated use of Preferred Resources may simultaneously meet demands for electricity in the PRP target region. See Section VII.B.1 for additional information on the PRP.

⁷³ Current CAISO and RA rules provide that in order to qualify as an RA resource, the resource must be able to provide energy over a continuous four-hour period.

⁷⁴ Excluding IFOM ES and two-hour products.

*Figure VI-6
Preferred Resource Supply Curve (Excluding IFOM ES)*



1 Table VI-15 below shows the key constraints that were used or adjusted during the development
2 of the selection sets in SCE's iterative optimization process.

Table VI-15
Selection Optimization Constraints

Constraint	Description
Minimum GFG	Minimum GFG MW value that must be included in the selection set.
Maximum GFG	Maximum GFG MW value that could be included in the selection set.
Minimum Preferred Resources/ES	Minimum Preferred Resources/Storage MW value that must be included in the selection set.
Minimum Total Procurement	Minimum Total MW value that must be included in the selection set.
Maximum Total Procurement	Maximum Total MW value that could be included in the selection set.
Maximum 2-hour product	Maximum 2-hour product MW value that could be included in the selection set.
Minimum Storage	Minimum Storage MW value that must be included in the selection set. Included both IFOM and BTM ES products.
Maximum IFOM ES	Maximum IFOM ES MW value that could be included in the selection set.
Minimum PRP	Minimum amount of PRP eligible MW to be included in the selection set.

1 SCE’s selection optimization tool allowed for the generation of a single selection set or multiple
2 selection sets called “draws” based on increments of LCR MW⁷⁵ selected between the minimum and
3 maximum total procurement levels. SCE set different LCR MW target levels and used its optimization
4 tool to generate selection sets and a decision document that summarized the selection sets. The
5 summary included a list of the selected offers for each draw in the selection set, MW selected in each
6 category, the normalized metrics discussed above, cash flow items, marginal costs, summary statistics,
7 MW build-out by year, and other information. After reviewing the summary, SCE configured the
8 optimization program in order to provide better cost and portfolio fit outcomes. SCE went through
9 several iterations of this process yielding different optimization configurations that are summarized
10 below.

⁷⁵ LCR MW is defined as the forecasted August 2021 net qualifying capacity (“NQC”).

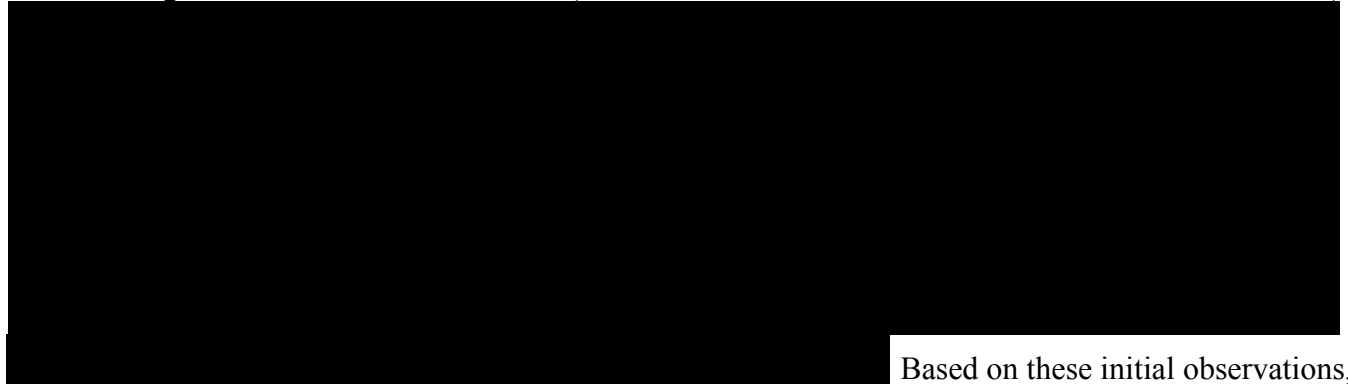
1 a) Selection Sets

2 Using the optimization tool, SCE set its initial constraints based on the minimum and maximum
3 levels of procurement authorized in the LTPP Track 1 and 4 decisions. Those constraints are listed in
4 Table VI-16 below:

Table VI-16
Initial Selection Constraints

Min GFG	Max GFG	Min Pref. Res./ES	Min Total	Max Total	Max 2-hour	Min ES	Max IFOM ES	Min PRP
1000	1500	600	1900	2500	150	50	N/A	N/A

5 The optimization tool created a selection set consisting of 25 draws in 25 MW increments
6 between 1,900 and 2,500 MW.⁷⁶ While all draws were consistent with the specified targets, the
7 resources selected in each of the draws caused some concerns from a best-fit perspective. All draws
8 contained significant amounts of IFOM ES (Draw 1 had over 400 MW and Draw 25 had over 900 MW).



14 Based on these initial observations,

15 SCE performed several iterations of constraints, making adjustments to the procurement levels to arrive
16 at its final selection set. SCE sets forth these final constraints and the rationale for each below.

17 First, SCE limited the amount of IFOM ES that could be selected to 100 MW. The rationale for
18 limiting IFOM ES is discussed in Sections IV.E.2 and IV.E.3, and earlier in this section. This constraint
19 resulted in the selection of the maximum amount of IFOM ES (*i.e.*, 100 MW). SCE ran sensitivities on
20 the amount of IFOM ES selected ranging from 0 MW to 100 MW. Procuring lower amounts of IFOM

⁷⁶ SCE's decision document for this selection set can be found in SCE's workpapers.

1 ES resulted in the additional selection of Preferred Resources/ES MW at a significant cost, as these
2 alternatives required the procurement of increasingly higher-cost Preferred Resources (see Figure VI-6
3 above). In addition, the 100 MW selection of IFOM ES resulted in a single resource at the existing
4 Alamos site that was connected to the transmission⁷⁷ system at 220kV, in an area where there was less
5 likelihood of charging restrictions and congestion. SCE decided that the maximum 100 MW IFOM ES
6 constraint provided an appropriate balance between financial impacts and technology concentrations.

7 Second, with respect to GFG, SCE removed the initial selected packaged GFG offers for the
8 Alamos site to allow other combinations of offers to be selected. Initially, in conjunction with the
9 IFOM ES constraint, the optimization selected a higher amount of GFG. This was largely due to the
10 limitation on IFOM ES and GFG being the next economic resource in terms of NPV. After SCE
11 removed the selected packaged offers for the Alamos site, SCE observed that the diversity of GFG
12 selections was greatly improved versus the initial selection set. While there was still GFG selected at
13 the AES Alamos site, it had been reduced from 1280 to 640 MW in all draws. However, other GFG
14 sites and counterparties were also selected in a number of the optimization runs. SCE eventually
15 selected an optimization set with 644 MW of GFG at the AES Huntington Beach site with 6,600 run
16 hours per year, 640 MW of GFG at the AES Alamos site with 4,600 run hours per year, and 98 MW of
17 GFG peakers at a greenfield site location connected to Barre sub-station through a WMDVBE supplier.
18 The impact of selecting the Alamos and Huntington Beach site over the just the Alamos site was a
19 modest increase in the premium [REDACTED]
20 [REDACTED] combined-cycle resources, and is reasonable given the diversity and optionality
21 created by having two brownfield sites developed versus one, and the Huntington Beach site has the
22 most run-hours possible.

⁷⁷ SCE's concerns around IFOM ES were exacerbated by distribution level connections.

1 Third, SCE focused on maximizing the amount of PRP eligible⁷⁸ MW selected to support the
2 PRP with new Preferred Resources that could be measured and assessed with respect to providing
3 reliability in the Johanna/Santiago sub-areas. The initial selection set included 58 MW of PRP eligible
4 MW relative to a total potential of 91 MW. Based on sensitivity analysis, SCE determined that 66 MW
5 of PRP eligible MW was optimal and cost competitive. The premium increase per LCR kW between
6 moving from 58 MW to 66 MW of PRP eligible MW was [REDACTED]
7 [REDACTED].

8 Fourth, SCE incrementally added back into its selection set a negative premium Tranche 4 EE
9 offer located in the Johanna/Santiago sub-area that was eligible for the PRP. The IE identified that the
10 EE tranche analysis, as described above in Section IV.F., had excluded some offers that were eligible for
11 the PRP and were very close to the Tranche 3 cut-off point. [REDACTED]
12 [REDACTED]⁷⁹ and there was a PRP eligible offer for [REDACTED]

13 SCE decided to pull this offer back into the selection set for two reasons: (1) it was located in the PRP
14 area and started deliveries prior to October 2017; and (2) [REDACTED]
15 [REDACTED]
16 [REDACTED]

17 Including this 5.55 MW offer increased the
18 amount of PRP eligible MW and improved the overall premium for the selection set from [REDACTED]
19 [REDACTED]. While there were other PRP eligible MW excluded due to the tranche analysis, none
20 had a negative premium.

21 Fifth, SCE eventually excluded two-hour products from the final selection set because the
22 CAISO had not conducted analysis to determine the effectiveness of two-hour products in meeting a
23 System RA need. The RA counting rules require that dispatchable resources be able to provide energy
onto the grid for a continuous four-hour period in order to qualify as an RA resource. SCE required

⁷⁸ For the purposes of the LCR selection process, PRP eligible MW were defined as LCR MW of Preferred Resources located at either the Johanna or Santiago substation service area with a COD prior to October 2017.

⁷⁹ The cut-off represented an estimate of the cost in 2015 \$/kW for a portfolio of EE programs with similar characteristics to the submitted offers.

1 these resources to bid four-hour products, but also allowed them to bid two-hour products to determine
 2 whether a large enough cost savings existed to pursue a change in the RA rules. SCE conducted a
 3 sensitivity excluding two-hour products from the selection set. The new optimization resulted in a
 4 selection in which four-hour products replaced two-hour products at a slightly higher cost. [REDACTED]

5 [REDACTED]
 6 [REDACTED]
 7 [REDACTED]
 8 [REDACTED]
 9 [REDACTED]
 10 Finally, SCE also excluded three-hour Permanent Load Shift (“PLS”) products from its final
 11 selection set. SCE initially included the three-hour PLS products, but then questioned whether there was
 12 value in moving to the more flexible four-hour PLS resources. SCE conducted a sensitivity analysis
 13 excluding the three-hour resources from the optimization selection set, thus allowing the optimization to
 14 select the next best resource(s). The optimization selected 28.6 MW of four-hour PLS product. [REDACTED]

15 [REDACTED] This is well
 16 within the error bands of the valuation process and thus the two selections were essentially equivalent.

17 The final set of constraints was set as follows:

Table VI-17
Final Selection Constraints

Min GFG	Max GFG	Min Pref Res./ES	Min Total	Max Total	Max 2-hour	Min ES	Max IFOM ES	Min PRP
1000	1500	600	1975	2000	0	50	100	66

18 The optimization tool was used to create a single draw selection set consistent with SCE’s final
 19 optimization constraints. SCE’s decision document for this selection set can be found in SCE’s
 20 workpapers. The optimized selection set met all of the targets specified in the constraints and selected a
 21 total of 1,989 MW, consisting of 343 MW of non-storage Preferred Resources, 100 MW of IFOM ES,

1 and 164 MW of BTM ES, for a total of 607 MW of Preferred Resources/ES and 1,382 MW of GFG
2 (composed of 1,284 MW of CCGT and 98 MW of peakers/CTs). The selection set also included 75
3 MW of PRP resources beginning delivery in 2017, with a build-out schedule increasing to 94 MW by
4 2021. The total NPV for the selection set was [REDACTED] with a total nominal cost of [REDACTED]
5 [REDACTED]. The final premium per LCR kW was [REDACTED].

6 During the development of this recommended selection set it was identified that the selected
7 GFG peakers would trigger debt equivalence issues, regardless of the inclusion of the Embedded Put
8 Option. The energy and AS value⁸⁰ associated with these low utilization peakers was too low and did
9 not represent more than a minor⁸¹ amount of the output. To minimize the impact of these contracts on
10 its balance sheet, SCE structured the contract as a fixed price RA contract. Such contract form is not a
11 lease commitment and therefore minimizes the impact on SCE's credit rating. In consultation with the
12 IE, SCE approached the impacted counterparty to request updated offers for RA only contracts for the
13 GFG peaker offers. [REDACTED]

14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 As SCE prepared to notify counterparties of their contract awards, [REDACTED]
18 [REDACTED]

19 [REDACTED] creating a deficit in meeting the 600 MW regulatory minimum for the Preferred
20 Resource/ES category. Given that there were no cost competitive options remaining to meet the 600
21 MW minimum for Preferred Resources and ES, SCE removed two other packaged offers totaling 50
22 MW because it was determined that more cost effective options could be secured later, given that SCE
23 would have to conduct additional LCR procurement to meet its 600 MW minimum requirement for

⁸⁰ The energy and AS value represented approximately [REDACTED] of the total output in dollars.

⁸¹ A minor amount was defined a 10% of total contract payments for the purposes of the accounting assessment.

1 Preferred Resources and ES. [REDACTED]

2 [REDACTED]

3 As a result of the loss of the [REDACTED] offers and SCE's removal of an additional 50 MW of

4 Preferred Resources, SCE's final awarded selection set included a total of 1,883 MW with 237 MW of

5 non-storage Preferred Resources, 100 MW of IFOM ES, 164 MW of BTM ES, and 1,382 MW of GFG.

6 The final selection included a slightly lower level of PRP resources than what SCE targeted because of

7 the withdrawn offers; 70 MW beginning delivery in 2017 and building up to 89 MW by 2021. The total

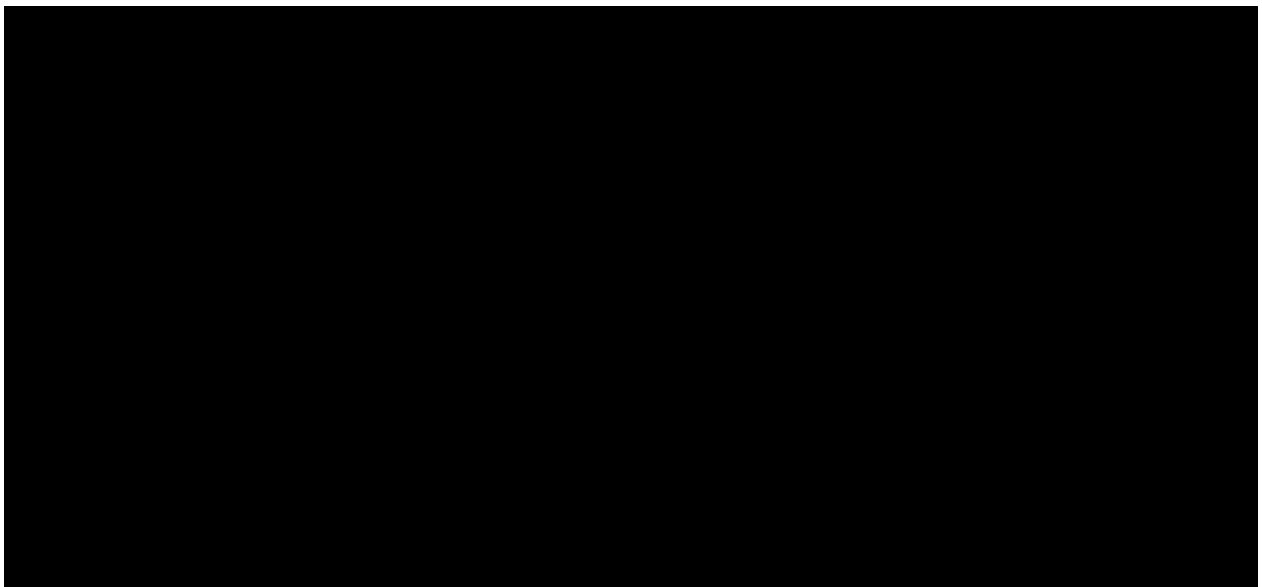
8 NPV for the selection set was [REDACTED] with a total nominal cost of [REDACTED]. The final

9 premium per LCR kW was [REDACTED]. The selected offers are described in more detail in Chapter

10 VII. A summary of the selection sets discussed above is provided in Table VI-18 below showing the

11 progression of SCE's selection process and final award.

Table VI-18
Selection Progression – Key Metrics



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VII.

SOLICITATION RESULTS

A. Summary of Selected Offers

SCE selected 60 Preferred Resource contracts and three GFG contracts. Within the Preferred Resources category, SCE selected 23 contracts for ES, one of which was for IFOM ES. Table VII-19 summarizes the LCR MW⁸² procured by product category. Additional detail for each category is provided below.

*Table VII-19
Summary of Selected Offers*

Product Category	Total Contracts	Max Quantity (LCR MW)
Preferred Resources and ES		
EE	26	124.04
DR	7	75.00
Renewable DG	4	37.92
ES	23	263.64
Total Preferred Resources and ES	60	500.60
GFG Resources		
GFG	3	1,382.00
Total Preferred Resources, ES, and GFG	63	1,882.60

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B. Description of Selected Offers

1. Preferred Resources

In this competitive solicitation, SCE adhered to and selected resources consistent with the Loading Order of the State’s Energy Action Plan II. This resulted in 60 contracts for EE, DR, Renewable DG, BTM ES, and IFOM ES for a total of 500.60 LCR MW. The breakdown of the resources can be seen in Table VII-20.

⁸² To clarify, the LCR MW are a resource’s contribution to the LCR need in August 2021. This may differ from the MW quantity specified in the contract.

Table VII-20
Summary of Preferred Resource Selected Offers

Product Category	Counterparty	Total Contracts	Max Quantity (LCR MW)
EE	<ul style="list-style-type: none"> • Onsite Energy Corporation • Sterling Analytics LLC • NRG Energy Efficiency-L LLC • NRG Energy Efficiency-P LLC 	26	124.04
DR	<ul style="list-style-type: none"> • NRG Distributed Generation PR LLC • NRG Curtailment Solutions LLC 	7	75.00
Renewable DG	<ul style="list-style-type: none"> • Solar Star California XXXV, LLC • Solar Star California XXXVI, LLC • Solar Star California XXXVII, LLC • Solar Star California XXXVIII, LLC 	4	37.92
ES	<ul style="list-style-type: none"> • AES ES Alamitos, LLC • Ice Bear SPV #1, LLC • Hybrid-Electric Building Technologies Irvine 1, LLC • Hybrid-Electric Building Technologies Irvine 2, LLC • Hybrid-Electric Building Technologies West Los Angeles 1, LLC • Hybrid-Electric Building Technologies West Los Angeles 2, LLC • Stem Energy Southern California, LLC 	23	263.64
Total Preferred Resources (including ES)		60	500.60

1 As stated in Section VI.C.3, a qualitative consideration in the selection process was the amount
2 of PRP MW selected. SCE specified in its RFO instructions that it had a preference for Preferred
3 Resources in the Johanna or Santiago areas to support its PRP. SCE chose the Johanna and Santiago
4 sub-areas in the Southwest sub-area of the Western LA Basin because the Southwest sub-area is the area
5 most impacted by the permanent closure of SONGS. To assess the capabilities of Preferred Resources,
6 SCE, as part of the PRP, will design, acquire, and measure a diverse portfolio of Preferred Resources
7 that will meet the area’s power needs, while informing the development of the grid of the future and
8 contributing toward California’s progressive environmental and renewable energy goals. Through the
9 PRP, SCE seeks to provide customers, regulators, electric system operators, transmission planners,
10 procurement entities, and stakeholders, greater understanding about the ability and availability of
11 Preferred Resources to perform where and when needed to meet local reliability, while ensuring grid

1 stability and resiliency. As identified below, several of the Preferred Resource offers selected are
2 located in the Johanna/Santiago area.

3 a) Energy Efficiency

4 SCE selected 26 EE offers from three different counterparties representing a total of 124.04 MW
5 of savings.

6 SCE created a new EE contract for the LCR RFO where the seller commits to achieve a specified
7 quantity of energy (kWh) and capacity (kW) savings through installation of specified energy efficiency
8 measures at customers' sites. In the contract, the sellers generally identified the types of measures they
9 intend to deploy as well as the customer class they intend to target. However, for the most part, specific
10 customers had not yet been identified at the time of contract execution.

11 Per the agreement, the seller is obligated to achieve energy savings during three distinct periods:
12 Summer-On-Peak, Summer Off-Peak, and Winter On-Peak. In addition, the seller is obligated to meet
13 certain capacity savings. Failure to meet these savings reduces payment under the contract.

14 The parties rely on an independent evaluator to measure savings. The independent evaluator is
15 hired by the seller, although SCE has discretion to determine the acceptability of the seller's choice.
16 The independent evaluator will create a measurement and verification ("M&V") plan, subject to SCE's
17 review, in accordance with the M&V protocol included in the contract. The independent evaluator will
18 perform the M&V consistent with the M&V Plan, and will ultimately create a report setting forth energy
19 and capacity savings for purposes of determining payment under the contract. If SCE does not
20 reasonably agree with the M&V report, SCE has the right to hire its own independent evaluator whose
21 report will be used to assess performance under the contract. This process is performed upon
22 installation of all of the measures, and allows for SCE to require additional M&V measurements over
23 the term of the agreement.

24 The EE contracts also contain a delivery date security requirement of \$22.50/kW and include
25 provisions where the total payment is made over a four- to six-year period to ensure some payment is
26 made under the contract in 2021 when the resources are first needed. As described in Section IV.F, SCE

1 selected contracts that were incremental per the EE tranche analysis performed by SCE. [REDACTED]
2 [REDACTED] which is discussed in further detail below.

Table VII-21
Summary of Energy Efficiency Selected Offers

EE Contracts							
Line #	Offer Number	Counterparty	Description of Technology	LCR MW	Location	COD	Contract Term (Years)
1	408001	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2018	4
2	408003	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2019	4
3	408004	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2020	4
4	408006	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2018	4
5	408007	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2019	4
6	408009	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2020	4
7	408010	Onsite Energy Corporation	EE	1	Johanna/ Santiago Substations	7/1/2016	6
8	408012	Onsite Energy Corporation	EE	1	Johanna/ Santiago Substations	1/1/2017	5
9	408013	Onsite Energy Corporation	EE	1	Johanna/ Santiago Substations	7/1/2017	5
10	408015	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2018	4
11	408016	Onsite Energy Corporation	EE	1	Western LA Basin Substations	7/1/2018	4
12	429001	Sterling Analytics LLC	EE	2 34	Johanna/ Santiago Substations	5/1/2016	6
13	429002	Sterling Analytics LLC	EE	2 36	Johanna/ Santiago Substations	10/1/2016	6
14	429003	Sterling Analytics LLC	EE	2 33	Johanna/ Santiago Substations	7/1/2016	6
15	429004	Sterling Analytics LLC	EE	0 84	Johanna/ Santiago Substations	2/1/2017	5
16	429005	Sterling Analytics LLC	EE	3 04	Western LA Basin Substations	1/1/2018	4
17	429006	Sterling Analytics LLC	EE	3 04	Western LA Basin Substations	4/1/2018	4
18	429007	Sterling Analytics LLC	EE	2 73	Western LA Basin Substations	7/1/2018	4
19	447100	NRG Energy Efficiency-L LLC	EE	5 55	Johanna/ Santiago Substations ¹	1/1/2017	5
20	447101	NRG Energy Efficiency-L LLC	EE	8 32	Western LA Basin Substations	1/1/2018	4
21	447102	NRG Energy Efficiency-L LLC	EE	13 86	Western LA Basin Substations	6/1/2019	4
22	447103	NRG Energy Efficiency-L LLC	EE	5 55	Western LA Basin Substations	6/1/2020	4
23	447150	NRG Energy Efficiency-P LLC	EE	2 31	Johanna/ Santiago Substations	5/1/2016	6
24	447151	NRG Energy Efficiency-P LLC	EE	4 63	Johanna/ Santiago Substations	5/1/2017	5
25	447152	NRG Energy Efficiency-P LLC	EE	4 32	Western LA Basin Substations	1/1/2018	4
26	447153 447154 447155	NRG Energy Efficiency-P LLC	EE	51 82	Western LA Basin Substations	5/1/2018	4
Total EE:				124.04 MW			

¹ The Johanna and Santiago substations are in the Southwest sub-area of the Western LA Basin

1 The following are brief descriptions of the selected EE offers:

1 (1) Onsite Energy Corporation (Offers: 408001, 408003, 408004, 408006,
2 408007, 408009, 408010, 408012, 408013, 408015, 408016)

3 The Onsite Energy Corporation's ("Onsite Energy") offers consist of the following measures:

4 [REDACTED]
5 [REDACTED]
6 [REDACTED]

7 [REDACTED] Customer types for the various measures have been identified, but specific sites
8 have not.

9 (2) Sterling Analytics LLC (Offers: 429001-429007)

10 The Sterling Analytics LLC's ("Sterling Analytics") offers consist of [REDACTED]

11 [REDACTED] Customer types have been identified, but specific sites have not.

12 (3) NRG Energy Efficiency-L LLC (Offers: 447100-447103)

13 The NRG Energy Efficiency-L LLC's ("NRG Energy Efficiency-L") offers consist of the
14 following measure categories that NRG Energy Efficiency-L may use: [REDACTED]

15 [REDACTED]
16 [REDACTED] although they have yet to be

17 identified.

18 The NRG Energy Efficiency-L offer for 5.55 MW of EE (offer 447100) is an EE [REDACTED]
19 [REDACTED] SCE included this offer in its final selection because it is a viable Preferred Resource with
20 relatively attractive pricing that provided for energy savings in the Johanna and Santiago sub-area. The
21 offer supports the PRP and adds value to customers as the forecasted benefits exceed the costs of the
22 resource (*i.e.*, the resource has a positive NPV). [REDACTED]

23 [REDACTED] Finally, for many
24 of the same reasons stated above, the IE supported the inclusion of this offer.

25 (4) NRG Energy Efficiency-P LLC (Offers: 447150-447155)

26 The NRG Energy Efficiency-P LLC's ("NRG Energy Efficiency-P") offers consist of measures
27 utilizing [REDACTED]. NRG Energy

Efficiency-P proposes relying on industrial and commercial sites, although they have yet to be identified.

b) Demand Response

SCE selected seven DR contracts from one counterparty that provide a total of 75 LCR MW of savings. SCE created a DR contract for the LCR RFO that was based largely on SCE’s current Aggregator Managed Portfolio (“AMP”) contracts, although the LCR contracts have a 20-minute response time and credit and collateral requirements. The seller must provide delivery date security in the amount of \$45/kW prior to the start of the contract, and performance assurance during the delivery period in the amount of either (1) 10 percent of the remaining capacity payments, or (2) five percent of remaining capacity payments if the contract term is greater than 10 years.

**Table VII-22
Summary of Demand Response Selected Offers**

DR Contracts							
Line #	Offer Number	Counterparty	Description of Technology	LCR MW	Location	COD	Contract Term (Years)
1	447200	NRG Distributed Generation PR LLC	DR	5	Johanna/ Santiago Substations	1/1/2017	10
2	447201	NRG Distributed Generation PR LLC	DR	5	Johanna/ Santiago Substations	1/1/2017	10
3	447202	NRG Distributed Generation PR LLC	DR	15	Western LA Basin Substations	1/1/2018	10
4	447203	NRG Distributed Generation PR LLC	DR	15	Western LA Basin Substations	1/1/2018	10
5	447204	NRG Distributed Generation PR LLC	DR	15	Western LA Basin Substations	8/1/2018	10
6	447205	NRG Distributed Generation PR LLC	DR	15	Western LA Basin Substations	8/1/2018	10
7	447250	NRG Curtailment Solutions LLC	DR	5	Western LA Basin Substations	1/1/2018	4
Total DR				75.00 MW			

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(1) NRG Distributed Generation PR LLC (Offers: 447200-447205)

The NRG Distributed Generation PR LLC's ("NRG Distributed Generation") offers provide [REDACTED]
[REDACTED]
[REDACTED] NRG Distributed Generation proposes relying on industrial and commercial sites, although they have yet to be identified.

(2) NRG Curtailment Solutions LLC (Offers: 447250)

The NRG Curtailment Solutions LLC's ("NRG Curtailment Solutions") offer [REDACTED]
[REDACTED] NRG Curtailment Solutions proposes relying on industrial and commercial sites, although they have yet to be identified.

c) Renewable Distributed Generation

SCE selected four contracts from a single counterparty for BTM distributed renewable generation. SCE created a custom contract for this agreement that incorporates many of the EE contract provisions, but also borrows heavily from renewables contracts. [REDACTED]
[REDACTED]

Table VII-23
Summary of Renewable Distributed Generation Selected Offers

Renewable DG Contracts							
Line #	Offer Number	Counterparty	Description of Technology	LCR MW	Location	COD	Contract Term (Years)
1	490002	Solar Star California XXXV, LLC	Renewable DG BTM	10.32	Johanna/Santiago Substations	10/1/2016	15
2	490003	Solar Star California XXXVI, LLC	Renewable DG BTM	11.22	Western LA Basin Substations	1/1/2018	15
3	490004	Solar Star California XXXVII, LLC	Renewable DG BTM	4.17	Western LA Basin Substations	1/1/2018	15
4	490006	Solar Star California XXXVIII, LLC	Renewable DG BTM	12.21	Western LA Basin Substations	1/1/2018	15
Total Renewable DG				37.92 MW			

(1) Solar Star California XXXV, LLC, Solar Star California XXXVI, LLC, Solar Star California XXXVII, LLC, and Solar Star California XXXVIII, LLC (Offers: 490002-490004 and 4290006)

Solar Star California XXXV, LLC, Solar Star California XXXVI, LLC, Solar Star California XXXVII, LLC, and Solar Star California XXXVIII, LLC (collectively “Solar Star California”) are wholly-owned subsidiaries of SunPower Corporation. Solar Star California’s offers require the seller to install PV (typical installation [REDACTED]) at various Commercial/Industrial sites that have yet to be identified, in order to achieve energy savings. The installations will serve part of the customer’s energy needs. From SCE’s perspective, the power to the customer provided by the solar installation will result in customer load drop. [REDACTED]

d) Energy Storage

SCE selected 23 offers of ES from four counterparties for a total of 263.64 MW. A total of 100 MW was from IFOM ES.

1 SCE developed a separate contract form for IFOM ES and BTM ES for the LCR RFO. The
2 IFOM ES contract takes concepts from a typical tolling contract.⁸³ SCE controls the charge and
3 discharge of the ES device and payment is largely based on the availability of the unit to charge,
4 discharge, and store electric energy. The IFOM ES contract, however, was heavily modified to capture
5 the nuances of ES. For example, SCE incorporated guaranteed energy efficiencies on the charge and
6 discharge cycles (*i.e.*, for every MW put into the storage device, specifying how much energy can be
7 taken out), operating characteristics associated with ES (*e.g.*, number of cycles per month or year,
8 number of deep discharges per day/month/year, number of MWh of discharge per year) and clarified
9 responsibilities for charging energy versus auxiliary load for onsite energy needs. SCE also
10 incorporated the Embedded Put Option into the IFOM ES contract to mitigate potential adverse financial
11 impacts from 100 percent debt equivalents assessments. The IFOM ES contract includes a delivery
12 security of \$45/kW prior to the start of deliveries, and performance assurance of 10 percent of the sum
13 of the capacity payments for 36 months during the delivery period.

14 For BTM ES, SCE modified the DR contract to include specific provisions associated with the
15 construction and testing of the ES device. Fundamentally, however, the pro forma contract is largely the
16 same as the DR contract. The seller must provide delivery date security in the amount of is \$45/kW
17 prior to the start of the contract, and performance assurance during the delivery period, in the amount of
18 either (1) 10 percent of the remaining capacity payments, or (2) five percent of remaining capacity
19 payments if the contract term is greater than 10 years.

20 A BTM ES (PLS) resource shifts energy consumption from the peak hours to the off-peak hours
21 through the use of a storage device. The resource is non-dispatchable and is expected to run every day.
22 Because of these characteristics and given the energy savings profile of these resources is consistent
23 with and similar to the energy savings of EE resources, SCE modified the EE contract as the form of the
24 agreement for BTM ES (PLS). [REDACTED]

⁸³ Fundamentally, the GFG tolling contract and IFOM ES agreement are very similar except that electric energy serves as the “fuel” instead of natural gas.

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[Redacted]

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[Redacted]

Table VII-24
Summary of Energy Storage Selected Offers

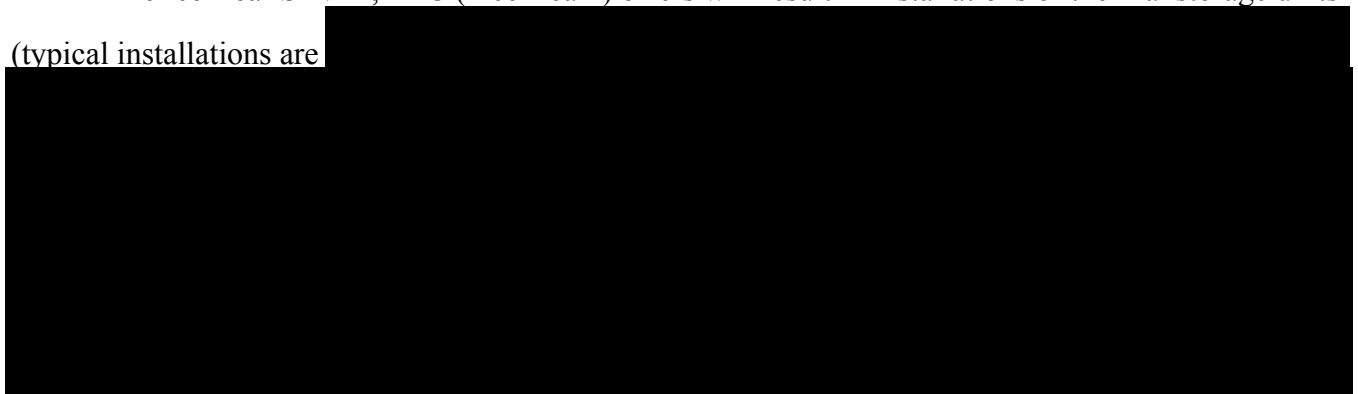
ES Contracts							
Line #	Offer Number	Counterparty	Description of Technology	LCR MW	Location	COD	Contract Term (Years)
1	475127	AES ES Alamitos, LLC	ES IFOM	100 00	690 North Studebaker Road, Long Beach, CA 90803	1/1/2021	20
Total ES IFOM				100 MW			
2	431049	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	7/1/2016	20
3	431052	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	10/120/16	19 8
4	431055	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	1/1/2017	19 5
5	431058	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	4/1/2017	19 2
6	431061	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	7/1/2017	19
7	431064	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	10/1/2017	18 8
8	431067	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	1/1/2018	18 5
9	431070	Ice Bear SPV #1, LLC	ES BTM PLS	2 15	Johanna/ Santiago Substations	4/1/2018	18 2
10	431145	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	1/1/2018	20
11	431148	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	4/1/2018	19 8
12	431151	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	7/1/2018	19 5
13	431154	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	10/1/2018	19 2
14	431157	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	1/1/2019	19
15	431160	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	4/1/2019	18 8
16	431163	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	7/1/2019	18 5
17	431166	Ice Bear SPV #1, LLC	ES BTM PLS	1 43	Johanna/ Santiago Substations	10/1/2019	18 2
Total ES BTM PLS				28.64 MW			
18	467009	Hybrid-Electric Building Technologies Irvine 1, LLC	ES BTM	5 00	Johanna/ Santiago Substations	1/1/2017	10 5
19	467010	Hybrid-Electric Building Technologies Irvine 2, LLC	ES BTM	5 00	Johanna/ Santiago Substations	1/1/2017	10 5
20	467022	Hybrid-Electric Building Technologies West Los Angeles 1, LLC	ES BTM	25 00	Western LA Basin Substations	1/1/2018	10
21	467025	Hybrid-Electric Building Technologies West Los Angeles 2, LLC	ES BTM	15 00	Western LA Basin Substations	1/1/2018	10
22	402039	Stem Energy Southern California, LLC	ES BTM	7 00	Johanna / Santiago Substations	10/1/2016	10
23	402040	Stem Energy Southern California, LLC	ES BTM	78 00	Western LA Basin Substations	1/1/2018	8
Total ES BTM				135.00 MW			
Total ES				263.64 MW			

1 (1) AES ES Alamitos, LLC (Offer: 475127)

2 AES ES Alamitos, LLC (“AES Alamitos”) offer was for a 100 MW IFOM battery storage device
3 at their existing Alamitos site.⁸⁴ The installation will consist of large arrays of lithium ion battery racks
4 housed in newly constructed buildings. Interconnection will be at the existing Alamitos substation. As
5 per the contract, SCE will have complete dispatch and charging rights to the facility. Although there is
6 uncertainty about the interconnection process and charging restrictions associated with ES, AES’ ES
7 project will interconnect at a transmission-level voltage (220 kV) substation, which should mitigate
8 some of those concerns. AES Alamitos has a proven track record in ES and has a number of projects
9 already in operation around the country.

10 (2) Ice Bear SPV#1, LLC (Offers: 431049, 431052, 431055, 431058, 431061,
11 431064, 431067, 431070, 431145, 431148, 431151, 431154, 431157,
12 431160, 431163, and 431166)

13 The Ice Bear SPV#1, LLC (“Ice Bear”) offers will result in installations of thermal storage units
14 (typical installations are



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20 This may provide additional value should SCE’s peak hours shift
21 over the course of the 20 year contract.

⁸⁴ The project is co-located with AES’ GFG project, but will be separately interconnected.

1 (3) Hybrid Electric Building Technologies Irvine 1, LLC, Hybrid Electric
2 Building Technologies Irvine 2, LLC, Hybrid Electric Building
3 Technologies West Los Angeles 1, LLC, and Hybrid Electric Building
4 Technologies West Los Angeles 2, LLC (Offers: 467009, 467010,
5 467022, and 476025)

6 The Hybrid Electric Building Technologies Irvine 1, LLC, Hybrid Electric Building
7 Technologies Irvine 2, LLC, Hybrid Electric Building Technologies West Los Angeles 1, LLC, and
8 Hybrid Electric Building Technologies West Los Angeles 2, LLC (collectively “HEBT”) offers will
9 result in installation of battery storage (typical installations are between [REDACTED])

10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED] HEBT is a wholly-owned subsidiary of Advanced Microgrid
19 Solutions, Inc., which is a women-owned business, and thus will help further SCE’s GO 156 goals of
20 contracting with WMDVBE entities.

21 (4) Stem Energy Southern California, LLC (Offers: 402039 and 402040)

22 Stem Energy Southern California, LLC’s (“Stem”) offers will result in small battery installations
23 (typical installation [REDACTED])
24 [REDACTED]
25 [REDACTED]

1 [REDACTED]

2 [REDACTED] 85

3 **2. Gas-Fired Generation**

4 As described in Section VI.B, SCE considered both quantitative and qualitative factors when
5 selecting all product types, including GFG. SCE ultimately selected GFG resources that offer both site
6 and technology diversity through contracts for a CCGT at Alamitos and a CCGT at Huntington Beach.
7 In addition, SCE selected an RA-only offer for the Wellhead Stanton project and will provide peaking
8 capacity at the Barre substation, which was identified as a beneficial location for GFG as described in
9 more detail below.

10 SCE took two different approaches to contracting for GFG resources due to debt equivalency
11 concerns. As detailed in IV.I above, SCE determined that the original GFG pro forma contracts that
12 were part of the RFO launch were likely to be assessed as capital leases. In order to minimize debt
13 equivalency, SCE incorporated the Embedded Put Option in the GFG contracts for CCGTs. However,
14 SCE determined that the Embedded Put Option would not resolve the debt equivalency issues for CTs
15 and thus converted the CT GFG contracts to RA-only contracts. Both the GFG with Embedded Put
16 Option and the RA-only contracts have a delivery date security of \$90/kW prior to the start of deliveries,
17 and performance assurance of \$130/kW after the start of delivery under the contract.

18 One consideration for the amount of SCE's selection of GFG was GFG's long development
19 cycle. SCE was concerned that if this solicitation resulted in GFG near the lower end of the GFG-
20 allowed authorization, it may be a challenge to add additional resources in future solicitations and have
21 them online before the OTC compliance deadline. Based on an immediate need to procure GFG to meet
22 the Commission's 2021 deadline and SCE's Transmission Planning personnel communicating that two
23 GFG peakers connected at Barre Substation will provide a substantial enhancement to local area
24 reliability, SCE included two additional peakers in its final selection.

⁸⁵ This amount is not materially different from the pro forma calculation and was modified for ease of contracting based on the phasing of contract capacity.

Table VII-25
Summary of Gas-Fired Generation Selected Offers

GFG Contracts							
Line #	Offer Number	Counterparty	Description of Technology	LCR MW	Location	COD	Contract Term (Years)
1	475028	AES Alamitos Energy, LLC	GFG	640.00	690 North Studebaker Road, Long Beach, CA 90803	6/1/2020	20
2	475029	AES Huntington Beach Energy, LLC	GFG	644.00	21730 Newland Street, Huntington Beach, CA 90803	5/1/2020	20
3	473237 473238	Stanton Energy Reliability Center, LLC	GFG	98.00	Stanton, CA (Exact location TBD)	7/1/2020	20
Total GFG				1,382 MW			

a) AES Alamitos Energy, LLC and AES Huntington Beach Energy, LLC (Offers: 475028 and 475029)

SCE entered into separate GFG contracts with AES Alamitos Energy, LLC (“AES Alamitos”) and AES Huntington Beach Energy, LLC (“AES Huntington Beach”) for two clean, efficient CCGTs. Both projects are brownfield developments, with one CCGT being constructed at the existing Alamitos site and one CCGT being constructed at the existing Huntington Beach site. The units will both be 2x1 GE 7FA combined cycles, which offers best available operating technology parameters. Each location has a current gas-fired facility with existing interconnection and transmission infrastructure. The existing generation facilities are projected to be closed by 2020 due to OTC regulations. Both sites have an easier permitting path than a greenfield site as they can rely on the South Coast Air Quality Management District’s Rule 1304 which provides access to PM-10 credits through MW-for-MW replacement, and currently have electric and fuel interconnections in place.

1 b) Stanton Energy Reliability Center, LLC (Offers: 473237 and 473238)

2 SCE entered into an RA-only contract with Stanton Energy Reliability Center, LLC (“Stanton
3 Energy”), a subsidiary of W Power, for two GE LM6000 simple cycle combustion turbines, each with a
4 nameplate capacity of 49.9 MW⁸⁶, for a total expected contract capacity of 98 MW. SCE will not
5 control the dispatch rights under the contract and does not receive any energy or ancillary service
6 benefits. However, under the RA-only agreement, the resource must bid into the CAISO market as an
7 RA resource pursuant the CAISO tariff. The Stanton Energy peaker project will be located in Stanton,
8 California, interconnecting to SCE's Barre substation.

9 As identified in the Track 1 decision, “[uncommitted energy efficiency and uncommitted CHP]
10 are not likely to be as effective in reducing LCR needs as repowered gas-fired resources at existing OTC
11 locations.”⁸⁷ The two AES projects fit this description. In addition, the procurement of two GFG
12 peakers at the Barre substation contributes to meeting local capacity needs stemming from the retirement
13 of SONGS and meets LCR requirements. Barre substation is located within the Southwest sub-area of
14 the Western LA Basin. As discussed in Section IV.G.2, the CAISO identified this area as having the
15 highest LEFs, so resources located in this area will be most effective at relieving the critical N-1-1
16 contingency affecting the combined LA Basin and San Diego local capacity areas.⁸⁸ Based on the
17 CAISO’s latest LCR studies, the limiting constraint just affecting the Western LA Basin is the Serrano –
18 Villa Park 230 kV line.⁸⁹ As identified in the CAISO’s study report, generation sited at Barre had the
19 highest effectiveness factor at meeting this Western LA Basin constraint.⁹⁰

⁸⁶ Although the nameplate capacity is 49.9 MW for each unit, SCE was only offered 49 MW of contract capacity for each unit.

⁸⁷ D.13-02-015 at 121 (FOF 13).

⁸⁸ CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 4-5.

⁸⁹ CAISO, *Final 2015 Local Capacity Technical Report*, April 30, 2014, at 75.
CAISO, *Final 2019 Local Capacity Technical Report*, April 30, 2014, at 71.

⁹⁰ CAISO, *Final 2015 Local Capacity Technical Report*, April 30, 2014, at 75.
CAISO, *Final 2019 Local Capacity Technical Report*, April 30, 2014, at 71.

1 Stanton Energy is a wholly-owned subsidiary of W Power, LLC, a California certified woman-
2 and-minority owned business enterprise, which will help further SCE’s GO 156 goals of contracting
3 with WMDVBE entities.

4 **C. Interim Emissions Performance Standard**

5 The California Legislature passed Senate Bill (“SB”) 1368 on August 31, 2006, and Governor
6 Schwarzenegger signed the bill into law on September 29, 2006. Section 2 of SB 1368 adds Public
7 Utilities Code Section 8341(a), which provides, “No load-serving entity or local publicly owned electric
8 utility may enter into a long-term financial commitment unless any baseload generation supplied under
9 the long-term financial commitment complies with the greenhouse gases emission performance standard
10 established by the commission, pursuant to subdivision (d), for a load-serving entity. . . .”⁹¹

11 In order to institute the provisions of SB 1368, the Commission instituted Rulemaking 06-04-
12 009. That proceeding resulted in the establishment of a greenhouse gas (“GHG”) emissions
13 performance standard (“EPS”) for carbon dioxide (“CO₂”). In D.07-01-039, the Commission noted,
14 “SB 1368 establishes a minimum performance requirement for any long-term financial commitment for
15 baseload generation that will be supplying power to California ratepayers. The new law establishes that
16 the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a CCGT
17 powerplant.”⁹² The decision further explains:

18 SB 1368 describes what types of generation and financial commitments will be subject to the
19 EPS (“covered procurements”). Under SB 1368, the EPS applies to “baseload generation,”
20 but the requirement to comply with it is triggered only if there is a “long-term financial
21 commitment” by an LSE. The statute defines baseload generation as “electricity generation
22 from a powerplant that is designed and intended to provide electricity at an annualized plant
23 capacity factor of at least 60%.” . . . For baseload generation procured under contract, there
24 is a long-term commitment when the LSE enters into “a new or renewed contract with a term
25 of five or more years.”⁹³

⁹¹ Cal. Pub. Util. Code § 8341(a).

⁹² D.07-01-039 at 2-3.

⁹³ *Id.* at 4.

1 All of the LCR RFO contracts entered into for the Western LA Basin are greater than or equal to
2 five years, and therefore, qualify as long-term financial commitments. Next, the EPS applies to
3 baseload generation, which as explained above is “electricity generation from a powerplant that is
4 designed and intended to provide electricity at an annualized plant capacity factor of at least 60%.” All,
5 but one, of the LCR RFO contracts for the Western LA Basin have expected annualized capacity factors
6 below the threshold baseload capacity factor of 60 percent, above which the EPS rules would apply.

7 The one exception is the AES facility in Huntington Beach (Offer Number 475029), which is
8 expected to have an annualized capacity factor of [REDACTED] based on SCE’s
9 forecasting models. Since it has been established that the AES facility in Huntington Beach is a
10 “covered procurement,” that is not subject to any of the automatic exemptions from EPS, the emissions
11 rate of the proposed facility must be no higher than the EPS Performance Level of 1,100 lb CO₂/MWh.
12 SCE’s analysis of the future facility’s heat rates and emissions profiles along with the forecasted
13 dispatches results in an emissions rate of approximately [REDACTED] lb CO₂/MWh, which is significantly lower
14 than the EPS Performance Level. Thus, the AES Huntington Beach facility is EPS compliant.

15 An additional GFG contract, for the AES facility in Alamitos (Offer Number 475028), is
16 expected to have a capacity factor of around [REDACTED] percent. Although not required per D.07-01-039, SCE
17 also reviewed the Alamitos facility for EPS compliance purposes because it is relatively close to a [REDACTED]
18 baseload facility. SCE found that the emissions rate for the AES Alamitos facility is approximately [REDACTED]
19 lb CO₂/MWh, which is significantly lower than the EPS Performance Level.

20 The Stanton Energy Reliability Center (Offer Number 473237 and 473238), the only other GFG
21 project selected, is expected to have an annualized capacity factor of [REDACTED]. This facility
22 will have an RA only agreement and as such, the “as-bid” heat rates were used in SCE’s calculation of
23 the capacity factor. Since the heat rate is not part of the current contracts, they have no contractual
24 requirement on those heat rates. However, this is a peaking facility so the annualized capacity factor
25 will be very low, and well under 60 percent.

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VIII.

ALLOCATION OF BENEFITS AND COSTS

A. Overview

The contracts that are the subject of this Application are necessary to meet local reliability needs for the benefit of all customers in SCE’s distribution service area. Thus, the Track 4 decision instructs SCE to propose a cost allocation methodology for the resources procured through the LCR RFO:

Therefore, SCE and SDG&E shall allocate costs incurred as a result of procurement authorized in this decision, and approved by the Commission. In most cases we expect this allocation to be consistent with D.13-02-015 and the CAM adopted in D.06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005, but there may be resources where an existing alternative method of allocating resources costs may be preferred; for example, cost may be recoverable through the Energy Program Investment Charge. As SCE states in its Reply Comments on the Proposed Decision at 3, it will “propose an RA allocation method in its application for approval of the results of its LCR RFO when those results are fully understood.” We will require that, in applications for contract approval, the IOU shall recommend a method of cost allocation appropriate for the resource being procured.⁹⁴

Pursuant to this requirement, SCE recommends methods of cost allocation for each resource type for which SCE is seeking procurement approval. That said, D.14-10-051 is clear that this Application is not an appropriate venue to reconsider cost allocation of these contracts to all benefitting customers in SCE’s service area.

Within this Application, SCE is seeking authorization to procure resources of varying technology types. Cost allocation will vary by type of resource. SCE recommends following existing cost allocation practices, such as CAM, where applicable. Table VIII-26 below describes how SCE proposes to treat each type of resource from a cost allocation perspective. A detailed description of how SCE plans to recover the costs of the LCR resources, ratemaking treatment, and revenue allocation is contained in Chapter IX.

⁹⁴ D.14-03-004 (Track 4 decision) at 120.

Table VIII-26
LCR RFO Cost Allocation Methodology

Description of Technology	Total Contracts	Ratemaking Treatment*		Net Cost Determination
		Balancing Account	Sub-Account	
PREFERRED RESOURCES AND ES				
EE (Non-Dispatchable)	26 Contracts (See Table VII-20)	LCR Products Balancing Account (“LCRPBA”)	Public Purpose Program (“PPP”) Rate Component	Allocate contract costs; no market revenues to offset contract costs
DR (Dispatchable)	7 Contracts (See Table VII-21)	LCRPBA	Distribution Rate Component	Calculate net market revenue as the difference between CAISO market revenues less contract strike price; credit net market revenues to contract capacity cost and allocate net costs to all benefitting customers
Renewable DG BTM (Non-Dispatchable)	4 Contracts (Refer to Table VII-22)	LCRPBA	PPP Rate Component	Allocate contract costs; no market revenues to offset contract costs
ES IFOM (Dispatchable)	1 Contract (See Table VII-23)	LCRPBA	New System Generation (“NSG”) Rate Component	Calculate net market revenue as the difference between potential energy revenue from discharge at the highest price hours of the day less the charging costs at the lowest cost hours of the day; credit net market revenues to contract capacity cost and allocate net costs to all benefitting customers
ES BTM (like DR) (Dispatchable)	6 Contracts (See Table VII-23)	LCRPBA	Distribution Rate Component	Calculate net market revenue as the difference between CAISO market revenues less contract strike price; credit net market revenues to capacity contract cost and allocate net costs to all benefitting customers
ES BTM PLS – (like EE) (Non-Dispatchable)	16 Contracts (See Table VII-23)	LCRPBA	PPP Rate Component	Allocate contract costs; no market revenues to offset contract costs
GFG RESOURCES				
GFG (Dispatchable)	3 Contracts (See Table VII-24)	LCRPBA	NSG Rate Component	Apply Joint Parties Proposal (JPP) to calculate market revenue; credit net market revenues to capacity contract cost and allocate net costs to all benefitting customers
* A detailed description of how SCE plans to recover the costs of the LCR resources, ratemaking treatment, and revenue allocation is contained in Chapter IX.				

1 While SCE has procured GFG resources to meet system reliability need, in this LCR RFO, SCE
2 is also procuring EE, DR, and ES resources to meet local reliability need. For each resource type, SCE
3 proposes a cost allocation that follows the “Joint Parties Proposal”⁹⁵ (“JPP”), or is in a manner
4 consistent with the JPP. The JPP addresses how to account for expected market energy revenues
5 associated with potential CAISO market sales in the event that the dispatch capability of the resource is
6 not sold to a third party. The methodology used to accomplish this in the JPP is specific to GFG. As
7 this methodology is not applicable to all of the resources procured in the LCR RFO, SCE proposes a
8 methodology to account for market revenues for non-GFG resources that is designed to capture the
9 intent of the JPP. SCE also proposes how the cost allocation will be calculated where market revenues
10 are not expected.

11 **B. Allocation of Benefits and Costs By Technology**

12 The sections below describe the allocation of benefits and costs for each type of resource in
13 greater detail.

14 **1. Preferred Resource Contracts**

15 In this Application, SCE seeks approval of contracts for different categories of Preferred
16 Resources. SCE’s recommended cost allocation varies by the type of Preferred Resource and follows
17 existing cost allocation practices where practical. The following section describes how SCE proposes to
18 treat each of these types of resources from a cost allocation perspective.

19 a) **Energy Efficiency Contracts**

20 The costs for EE programs are currently allocated to both bundled and Direct
21 Access/Community Choice Aggregation (“DA/CCA”) customers through the PPP rate component. SCE
22 proposes continuing this existing treatment for the EE contracts included in this Application.⁹⁶ Bundled
23 and DA/CCA customers are equally eligible to participate in EE programs and benefit from market

⁹⁵ The Joint Parties’ Proposal is defined in D.06-07-029 at 14-18 and D.07-09-044 at 7-9.

⁹⁶ As discussed in Section IX.B, SCE is proposing to provide separate accounting for costs incurred under the EE contracts so that these costs are not co-mingled with SCE’s EE costs subject to balancing account recovery, however, this separate accounting does not affect how costs are allocated.

1 transforming programs that accelerate the availability of energy saving measures that modify
2 participating customer loads. The EE contracts in this Application will enable third-party providers to
3 engage in efforts to reduce participating customer loads without regard to who supplies their electricity.
4 A continuation of current cost allocation is therefore appropriate.

5 Since EE does not provide for the capability to dispatch a resource, there are no CAISO market
6 revenues associated with these contracts. In addition, EE contracts allow all distribution (bundled and
7 DA/CCA) customers to participate in the seller's programs. As such, SCE proposes to allocate the
8 entire cost of the contract through the PPP rate component as there will not be any market revenues to
9 offset such costs. In addition, the contracts will not produce a resource that can be utilized to meet an
10 RA compliance obligation. Rather, they will reduce load, and thus reduce the RA compliance
11 obligation. Thus, the RA program will account for such resources by reducing load rather than requiring
12 a distribution of RA counting rights to all benefitting customers.

13 b) Demand Response Contracts

14 SCE currently allocates the costs of DR programs and contracts, where eligibility is open to all
15 customers, through the Distribution rate component charged to all customers.⁹⁷

16 In the DR contracts, SCE did not restrict customer eligibility to participate based on who
17 supplies their electricity. The LCR contracts for DR programs allow all distribution (bundled and
18 DA/CCA) customers to participate. As such, SCE proposes that DR resources procured through the
19 LCR RFO be recovered from all distribution customers through the Distribution rate component in the
20 same manner as DR costs are now allocated. Doing so will ensure that: (1) methods of allocation are
21 consistent across CPUC authorized proceedings that obtain similar resources; and (2) all benefitting
22 customers are allocated their share of the costs necessary to meet the identified local needs.

23 Historically, DR programs and contracts have had either very minor or no market revenues from
24 being dispatched within the CAISO market.⁹⁸ SCE expects that the DR contracts being submitted in this

⁹⁷ See R.13-09-011, Rebuttal Testimony of SCE at 9; May 22, 2014. For DR programs where eligibility is limited to bundled customers, SCE recovers costs in retail rates associated with bundled service.

1 Application will have the potential for market revenues and that such benefits should be allocated to all
2 customers. A more detailed explanation on the handling of market revenues and the determination of
3 net costs can be found in Section VIII.B.3 below. Any benefit associated with the right to utilize such
4 resources to meet the RA compliance obligation will be allocated to all benefitting customers through
5 the RA process.

6 c) Renewable Distributed Generation Behind the Meter Contracts

7 In this Application, SCE is seeking approval for contracts involving Renewable DG technologies
8 (solar) that will provide preferred loading order generation behind the customer meter. The net effect of
9 Renewable DG (BTM) resources will appear as a reduction in energy consumption at SCE's substations
10 in the Western LA Basin, which will reduce local reliability requirements. For this reason, and because
11 SCE cannot dispatch nor receive CAISO market revenues for these resources, SCE recommends that the
12 Renewable DG (BTM) contract costs be treated in the same manner as EE contracts (see Section
13 VIII.B.1.a above).

14 d) In Front of the Meter Energy Storage Contracts

15 IFOM ES can participate directly in CAISO markets, similar to GFG resources. They are
16 dispatchable and can provide both energy and ancillary services. Similar to certain GFG resources
17 procured in this LCR RFO, the IFOM ES contract SCE is submitting for approval includes an
18 Embedded Put Option. If the option is exercised, the dispatch capability will be conveyed to SCE. If it
19 is not, the seller will retain the dispatch rights. In the case where the option is exercised and SCE
20 receives the dispatch rights, SCE will utilize a methodology to net the contract costs with expected
21 market revenues which reflects the intent of the JPP to value the market revenues and costs associated
22 with those dispatch rights. A detailed description of this methodology is contained in Section VIII.B.3
23 below. In the event that the option is not exercised, SCE will not receive the dispatch rights. In such a

Continued from the previous page

²⁸ Demand Response resources are expected to participate in CAISO markets prior to January 1, 2016.

1 case, SCE will not receive any market revenues associated with the contract and will allocate 100
2 percent of the cost of the contract to all benefitting customers. In either event, the ability to utilize the
3 RA compliance right will be allocated to all benefitting customers through the RA program.

4 e) Behind the Meter Energy Storage Contracts

5 SCE seeks approval for a number of ES contracts that will operate behind the end-use customer
6 meter to reduce customer load during particular periods. Some of these contracts result in a permanent
7 load shift (PLS) from on-peak to off-peak peak periods, while other contracts allow SCE to dispatch the
8 ES device to effectively reduce customer load based on reliability or market needs. In order to align the
9 cost allocation of these ES contracts to existing cost allocation practices, SCE recommends that BTM
10 ES (PLS) contracts be treated in the same manner as EE contracts and dispatchable BTM ES contracts
11 be treated in the same manner as DR contracts. For dispatchable BTM ES treated as a DR resource,
12 SCE will determine and credit net market revenues similar to DR contracts.

13 **2. Gas-Fired Generation Contracts**

14 The CAM has been developed and refined through a series of Commission decisions⁹⁹ to address
15 instances where SCE has procured GFG to meet identified system needs. With this well-established
16 history of utilizing CAM to allocate the costs of GFG to all benefitting customers, SCE proposes
17 utilizing CAM for the GFG contracts at issue in this Application.

18 One of SCE's GFG selected offers was for two peaking facilities through an RA-only contract.
19 This RA-only contract does not convey the right to dispatch the resource or receive energy revenue from
20 the resource. As such, SCE will not receive any market revenues from the CAISO for these contracts
21 and the entire cost of the contract will be allocated to all benefitting customers. While there will not be
22 market revenue benefits associated with these contracts, the right to count such resources as RA against
23 a compliance obligation will be allocated to all benefitting customers through the RA program. Thus,

⁹⁹ See D.14-03-004 at 120.

1 consistent with prior CAM allocations, all costs and benefits will be allocated to all benefitting
2 customers through the NSG rate component.

3 Additionally, as described in Section IV.I., SCE executed contracts that contain an Embedded
4 Put Option that can be exercised by the seller. If the option is exercised, the dispatch capability will be
5 conveyed to SCE. In the case where the option is exercised and SCE receives the dispatch rights, SCE
6 will utilize the JPP to value the market revenues associated with those dispatch rights. That value will
7 then be credited to the contract costs and the net cost will be allocated to all benefitting customers. In
8 the event that the option is not exercised, SCE will not receive the dispatch rights. In such a case, SCE
9 will not obtain any market revenues associated with the contract and will allocate 100 percent of the cost
10 of the contract to all benefitting customers. In either event, the ability to utilize the RA compliance right
11 will be allocated to all benefitting customers through the RA program.

12 **3. LCR RFO Proposal for Determination of Net Costs**

13 In order to address the potential for energy revenues and energy costs associated with DR and ES
14 resources in this application, SCE believes it appropriate to follow the policy of developing a proxy
15 value of the energy as set forth in the JPP. However, the JPP method only specifies a method for
16 developing a proxy value of the energy associated with GFG resources. As such, SCE proposes a
17 methodology for the calculation of dispatch costs and revenues for non-GFG resources in a manner that
18 is consistent with the intent of the JPP.

19 While certain DR and ES contracts at issue in this Application will have the opportunity to
20 deliver energy to the CAISO and thus derive market revenues that should be credited to the costs
21 allocated to all benefitting customers, the appropriate offset in terms of net costs to deliver energy to the
22 CAISO cannot be based upon a natural gas-based proxy as provided for in the JPP. Because SCE's
23 LCR DR and ES contracts specify the costs to be paid for dispatch of energy from these facilities, the
24 contractual costs are the most appropriate to use in the calculation to determine the allocation of net
25 costs to all benefitting customers. As with the allocation methodology for GFG resources, the proxy
26 calculation of net market revenues will be constrained by the physical and contractual limitations
27 associated with each resource including, but not limited to, use limitations.

1 Under the JPP, SCE forecasts annual energy benefits and costs by simulating the dispatch of the
2 resource based on a forecast of expected natural gas and energy prices. These amounts are then trued-up
3 on a proxy basis using actual CAISO market data on a quarterly basis. Forecasting the dispatch on an
4 annual basis, however, is not practical for DR resources because SCE is limited in the number of hours
5 that they are available. Given that forecasting the most effective hours on an annual basis will likely
6 create a result very different than actual value, SCE will allocate the hours available for dispatch on a
7 quarterly basis. To create this quarterly allocation, SCE will utilize the prior year CAISO market
8 clearing prices to determine the most cost effective hours to operate DR. These hours will then establish
9 the percentage of available hours for the DR program for allocation in the current year. Within each
10 quarter, SCE will calculate the costs and revenues from dispatch as follows and true-up the forecasted
11 amount. SCE will utilize the highest day-ahead hourly SP-15 Existing Zone-Generation Trading Hub¹⁰⁰
12 aggregated prices from the CAISO for the number of hours the resource is assumed available and
13 multiply that by the quantity available for dispatch for each quarter. This will then serve as the proxy
14 revenue from dispatch. The proxy cost will be calculated as the contract price multiplied by the
15 assumed dispatch for the resource. The proxy revenue less the proxy costs will then be credited against
16 the capacity costs in the Distribution rate component to create a net cost allocation that is consistent with
17 the methodology utilized for GFG within the JPP.

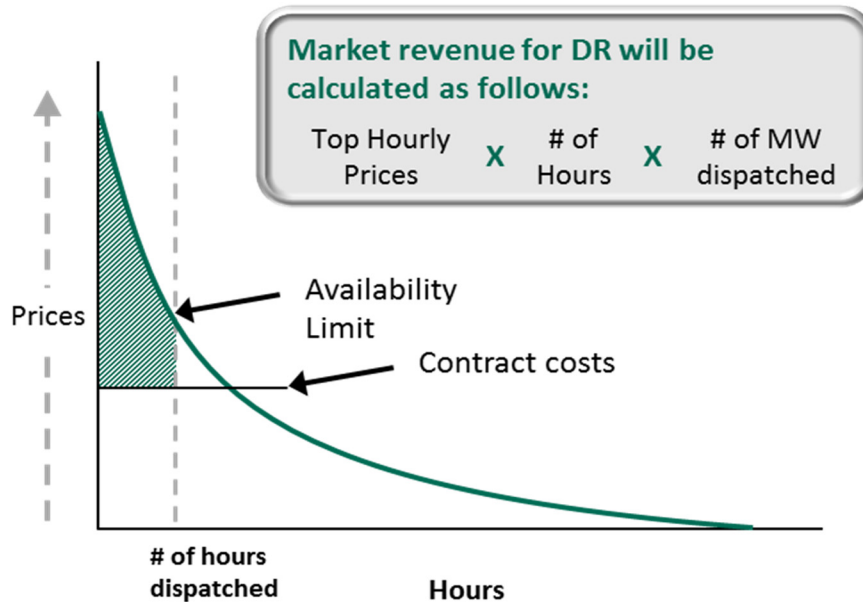
18 This quarterly allocation of dispatch is necessary since there are significant use limitations
19 placed on the resource in the contract. SCE cannot determine in advance which hours of the year will be
20 the most economic to utilize use-limited DR resources. As a reasonable proxy of optimizing the
21 dispatch of such resources, SCE is proposing to use the previous year's integrated forward market¹⁰¹
22 prices to allocate dispatch hours across the four quarters of the calendar year. SCE will use actual
23 market prices in each calendar quarter to ensure the optimal level of dispatch possible is credited to

¹⁰⁰ See Section 27.3 of the CAISO Fifth Replacement FERC Electric Tariff and Appendix A – Master Definition Supplement to the CAISO Fifth Replacement Tariff.

¹⁰¹ See Appendix A – Master Definition Supplement to the CAISO Fifth Replacement Tariff.

1 customers for the hours of dispatch assumed available for each quarter. Figure VIII-7 is a graphical
2 representation of how the market revenue for demand response will be calculated.

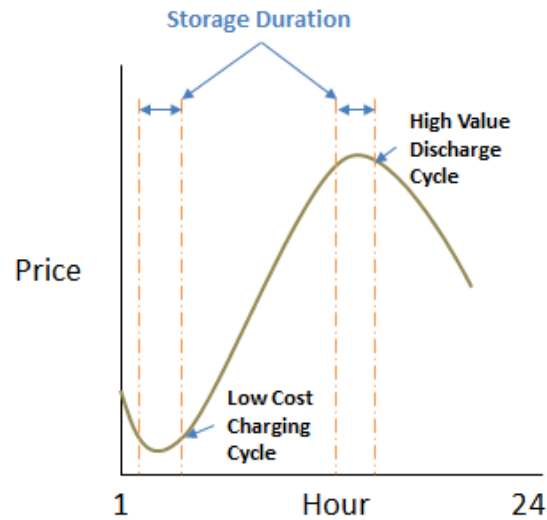
Figure VIII-7
Demand Response Proxy Market Revenue Calculation



3 As with DR, SCE will allocate the hours available for dispatch from ES on a quarterly basis. To
4 create this quarterly allocation, SCE will utilize the prior year CAISO market clearing prices to
5 determine the most cost effective hours to operate ES. These hours will then establish the percentage of
6 available hours for ES to operate for allocation in the current year. Within each quarter, SCE will
7 calculate the costs and revenues from dispatch as follows. SCE will calculate the costs for ES as the
8 wholesale electricity price (*i.e.*, the day-ahead CAISO nodal price for the resource) multiplied by the
9 MW necessary to charge the resource. This would be performed for each hour necessary to fully charge
10 the resource and would utilize the lowest priced hours for the day from the CAISO for this calculation
11 (see Figure VIII-8). Thus, the proxy cost for the resource would represent the lowest possible wholesale
12 cost to charge the resource once each day. To calculate the proxy revenues, SCE will utilize the highest
13 day-ahead hourly prices from the CAISO for the number of hours of discharge and multiply that by the
14 quantity available for dispatch at the resources node. This will then serve as the proxy revenue from

1 dispatch (see Figure VIII-8). The proxy revenue less the proxy costs will then be credited against the
2 capacity costs in CAM to create a net cost allocation that is consistent with the methodology utilized for
3 GFG in the JPP. Thus, the net revenues from the market for ES will be the revenue associated with
4 simulated discharge during the highest priced hours of the day netted with the costs associated with
5 charging during the lowest-priced hours of the day. The net market revenue will be trued up quarterly
6 using actual market prices.

Figure VIII-8
Energy Storage Proxy Market Revenue Calculation



1 IX.

2 **COST RECOVERY AND REVENUE ALLOCATION**

3 As Table VIII-26 above indicates, SCE proposes to recover the costs of the resources procured in
4 the LCR RFO through three of SCE’s existing rate components: the NSG, Distribution, and PPP rate
5 components. The NSG rate component collects the costs of contracts and SCE owned peaker generation
6 units subject to CAM. The Distribution rate component collects the costs of distribution-related
7 operations and maintenance, capital investments, and other programs such as the Commission-
8 authorized demand response, California Solar Initiative, and self-generation incentive programs. The
9 PPP rate component collects the costs of Commission-authorized programs such as, energy efficiency,
10 low income energy efficiency, Electric Program Investment Charge (“EPIC”), and the California
11 Alternate Rates for Energy (“CARE”). As discussed in more detail below, SCE is establishing
12 ratemaking to ensure that customers will only pay the assessed net cost of each of these products.

13 **A. Cost Recovery**

14 SCE proposes to include in its annual Energy Resource Recovery Account (“ERRA”) Forecast
15 proceeding a forecast of the costs of the resources procured through the LCR RFO to be included in
16 rates for the following year. This is consistent with how SCE recovers its forecast of fuel and purchased
17 power expenses. As explained in more detail below, the forecast of the costs of the LCR resources that
18 will be included in rates will be trued-up to their assessed recorded costs through balancing accounts.

19 As shown in Table VIII-26 above, SCE proposes recovering the GFG and IFOM ES resource
20 costs through the existing NSG rate component. SCE recovers all of its CAM, or new generation and
21 certain CHP contracts the Commission has required all benefiting customers to pay for, through the
22 NSG rate component. The calculation for determining the “benefiting costs” for these LCR resources is
23 discussed in Chapter VIII.

24 Like all other DR programs that are offered to all customers, including DA customers, SCE
25 proposes recovering the costs of DR resources procured in the LCR RFO through the Distribution rate
26 component. Specifically, SCE will include the DR and BTM ES (like DR) resource costs through the
27 Distribution rate component.

1 As authorized by the Commission, SCE recovers its EE program costs through the PPP rate
2 component and proposes to similarly recover the costs of EE resources procured in the LCR RFO
3 through the PPP rate component. Specifically, SCE will include the EE, Renewable DG (BTM), and the
4 BTM ES (PLS) (like EE) resource costs in PPP rates.

5 SCE's rate design proposal for recovery of the LCR resources costs is discussed in the Revenue
6 Allocation and Rate Design Section below.

7 **B. Ratemaking**

8 SCE proposes establishing a new LCR Products Balancing Account ("LCRPBA"). Rather than
9 recording the LCR resource costs in various existing balancing accounts, SCE proposes recording the
10 LCR costs in a single balancing account. Included in the LCRPBA will be three sub-accounts, one for
11 each of the three rate components that the LCR resources will be recovered through: (1) NSG; (2)
12 Distribution; and (3) PPP. Each month, SCE will record the actual cost of these resources in their
13 respective sub-accounts. The costs of the GFG and IFOM ES resources will be recorded in the NSG
14 sub-account. The costs of the DR and BTM ES (like DR) resources will be recorded in the Distribution
15 sub-account. And the costs of the EE, Renewable DG (BTM), and BTM ES (PLS) (like EE) will be
16 recorded in the PPP sub-account.

17 SCE proposes to transfer the balance of the NSG sub-account component of the LCRPBA to the
18 existing New System Generation Balancing Account ("NSGBA") each month. In the NSGBA, the cost
19 of the New System Generation LCR-related costs and all other New System Generation costs will be
20 balanced with the recorded New System Generation revenue each month. Any balance recorded in the
21 NSGBA, either over- or under-collection, is included in the New System Generation rates in the
22 following year.

23 Similarly, SCE proposes to transfer the balance recorded in the Distribution sub-account
24 component of the LCRPBA to the existing Distribution sub-account of the Base Revenue Requirement
25 Balancing Account ("BRRBA") each month. In the BRRBA, the cost of the Distribution LCR-related
26 costs and all other distribution costs will be balanced with the recorded Distribution revenue each

1 month. Any balance recorded in the BRRBA, either over- or under-collection, is included in the
2 Distribution rate component in the following year.

3 SCE proposes to transfer the balance recorded in the PPP sub-account component of the
4 LCRPBA to the existing Public Purpose Programs Adjustment Mechanism (“PPPAM”) each month. In
5 the PPPAM, the cost of the PPP LCR-related costs and all other PPP costs will be balanced with the
6 recorded PPP revenue each month. Any balance recorded in the PPPAM, either over- or under-
7 collection, is included in the PPP rate component in the following year.

8 **C. Review of LCR RFO Costs**

9 The LTPP Track 1 and 4 decisions ordered the procurement of the resources considered in this
10 Application. SCE procured these resources pursuant to its Commission-adopted Procurement Plan. As
11 such, if the Commission finds it reasonable for SCE to enter into contracts for procurement of these
12 resources in this docket, there is no further reasonableness review of SCE’s decision to enter into these
13 contracts. That issue will be settled. The only reasonableness issue remaining will be the
14 reasonableness of SCE’s administration of these contracts which will be considered through the annual
15 ERRA Review proceedings.

16 In the annual ERRA proceedings, SCE will include for Commission audit and review all of the
17 entries recorded in the LCRPBA to ensure that such entries are compliant with the LCR RFO decision
18 reached in this proceeding.

19 **D. Revenue Allocation and Rate Design**

20 This section describes the proposed allocation of the costs associated with the LCR RFO
21 contracts to the individual rate groups. As discussed above, the costs of the LCR resources will be
22 recorded in the appropriate LCRPBA sub-account, and then transferred to the NSGBA, Distribution sub-
23 account of BRRBA, and PPPAM, respectively. The balance in these accounts will be allocated to the
24 individual rate groups consistent with the functional revenue allocators adopted in SCE’s General Rate
25 Case (“GRC”) Phase 2 proceedings. Table IX-27 illustrates the capped revenue allocators adopted in

1 SCE's 2012 GRC Phase 2 (D.13-03-031¹⁰²), which will be used for revenue allocation until updated
 2 factors are adopted in its 2015 GRC Phase 2 proceeding or related proceedings involving CAM, DR, or
 3 EE allocations.

Table IX-27
Functional Revenue Allocators Approved in D.13-03-031

Phase 2 Revenue Allocation Agreement
GRC Revenue Allocation
Summary of Revenue Allocators
(Illustrative)

	Uncapped	Capped	Uncapped	Capped	APS & Interruptible Surcharge ¹	CSI/SGIP ²	PPP ³	NDC/PUCRF ⁴	NSGC ⁵
	Distribution		Generation						
Total Domestic	51.0%	51.6%	43.1%	42.3%	38.6%	33.0%	38.7%	34.2%	39.3%
GS-1	6.9%	7.0%	6.7%	7.3%	6.1%	8.2%	7.4%	6.0%	6.8%
TC-1	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
GS-2	18.4%	18.7%	18.6%	18.8%	18.5%	21.8%	19.7%	18.0%	19.0%
TOU-GS-3	8.1%	8.2%	8.3%	8.0%	9.5%	10.1%	9.1%	9.8%	9.8%
Total LSMP	33.6%	34.0%	33.7%	34.1%	34.2%	40.2%	36.4%	33.8%	35.6%
TOU-8-Sec	6.8%	6.5%	8.1%	8.2%	9.6%	10.2%	9.2%	10.3%	9.5%
TOU-8-Pri	3.8%	3.4%	4.6%	4.7%	5.8%	6.0%	5.4%	6.7%	5.4%
TOU-8-Sub	1.1%	0.9%	4.2%	4.2%	5.5%	4.3%	3.9%	7.2%	4.8%
Total Large Power	11.7%	10.8%	16.9%	17.1%	21.0%	20.5%	18.5%	24.3%	19.7%
Total Ag.&Pumping	2.5%	2.5%	3.4%	3.3%	3.1%	3.3%	3.0%	3.4%	2.4%
Total Street Lighting	0.1%	0.2%	0.5%	0.5%	0.4%	0.5%	1.1%	0.9%	0.4%
STANDBY/SEC	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.2%	0.3%	0.2%
STANDBY/PRI	0.6%	0.5%	0.7%	0.7%	0.8%	0.8%	0.7%	0.9%	0.7%
STANDBY/SUB	0.3%	0.3%	1.6%	1.7%	1.7%	1.5%	1.3%	2.3%	1.6%
Total Standby	1.1%	0.9%	2.5%	2.6%	2.7%	2.6%	2.3%	3.4%	2.6%
Total System	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹ APS and interruptible surcharge are allocated based on the marginal cost of generation revenue requirement for all retail sales

² CSI and SGIP are allocated based on each group's proportion of system revenues, excluding CARE and FERA customers, and streetlight facilities

³ PPP revenues are allocated to rate groups on a proportion of system revenues, with DA customers imputed as bundled customers

⁴ NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis

⁵ NSGC is allocated to all retail customers based on the 12-CP allocators

DCARE surcharge is allocated on an equal ¢/kWh basis, excluding the DCARE and streetlight customers

DWRBC is allocated on an equal ¢/kWh basis, excluding the DCARE customers

¹⁰² D.13-03-031 at 58 (OP 1).

1 **1. New System Generation Rate Component**

2 GFG and IFOM ES resource costs recovered through the NSG rate component will be allocated
3 to all retail customers based on the 12-month system coincident peak (“12-CP”) allocators approved in
4 SCE’s GRC Phase 2 proceedings. NSG revenues are recovered through a cents-per-kWh energy charge.

5 **2. Distribution Rate Component**

6 DR and BTM ES resource costs recovered through the Distribution rate component will be
7 allocated based on the allocators approved in SCE’s GRC Phase 2 proceedings. The methodology
8 adopted in SCE’s 2012 GRC Phase 2 (D.13-03-031), and subsequently proposed in SCE’s 2015 GRC
9 Phase 2 (A.14-06-014¹⁰³), allocates the DR revenue requirement to all retail customers such that 50
10 percent of the DR revenue requirements are allocated by each rate group’s proportional share of system
11 revenues, with generation revenues for DA customers imputed as bundled, and the remaining 50 percent
12 of the DR revenue requirements allocated on the basis of distribution marginal cost revenues. These
13 revenues will be collected through a dollar-per-kW demand charge for customers on demand metered
14 rates, and through a cents-per-kWh energy charge for all other customers.

15 **3. Public Purpose Programs Rate Component**

16 EE, Renewable DG BTM and BTM ES PLS resource costs recovered through the PPP rate
17 component will be allocated based on the allocators approved in SCE’s GRC Phase 2 proceeding. The
18 methodology adopted in D.13-03-031, and subsequently proposed in A.14-06-014, allocates the PPP
19 revenue requirement based on each rate group’s percentage share of system revenues for bundled-
20 service and DA customers, with generation revenues for DA customers imputed as if they were bundled
21 service customers. These revenues will be collected through a cents-per-kWh energy charge for all
22 customers.

¹⁰³ A.14-06-014, Testimony Exhibit 3.

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RESIDUAL PROCUREMENT TO MEET WESTERN LA BASIN LCR NEEDS

SCE's proposed procurement of 1,883 MW of new, diverse projects in the Western LA Basin substantially meets the 1,900 to 2,500 MW procurement authorization the Commission provided in the LTPP Track 1 and 4 decisions. However, SCE still needs to acquire 99 MW of Preferred Resources and/or ES to meet the Commission's minimum sub-category requirement of 600 MW of Preferred Resources and ES.¹⁰⁴ Once SCE completes the minimum procurement required for Preferred Resources and ES, SCE's total procurement for the Western LA Basin will exceed the minimum 1,900 MW requirement for the Western LA Basin (*i.e.*, 1,883 MW of proposed procurement in this Application plus 99 MW of additional Preferred Resource and/or ES will exceed the minimum 1,900 MW requirement).

Before undertaking any major procurement initiatives to secure additional Preferred Resources, SCE will request that CAISO update its LCR studies to account for planned transmission upgrades, load forecast updates, and SCE's proposed LCR procurement to determine what residual reliability need may exist, including needed resource attributes and changes to locational effectiveness. Notwithstanding SCE's plan to seek updated CAISO LCR studies, SCE will continue to target additional LCR resources through its existing procurement mechanisms (although any such procurement will need to be demonstrated to be incremental to what would have otherwise occurred to be considered an eligible LCR resource).¹⁰⁵ SCE may also issue targeted solicitations for certain Preferred Resources to meet LCR needs in advance of determining if a comprehensive second LCR RFO should be pursued. All incremental LCR procurement where SCE is seeking CAM treatment conducted after SCE's initial LCR RFO will be submitted to the Commission for approval through an application process along with a specific request that it count toward SCE's minimum LCR procurement requirements.

¹⁰⁴ D.14-03-014 at 141-143 (OP 1). The specific minimum procurement requirement consists of 50 MW of ES (which SCE has satisfied with its proposed ES procurement in this application) and an additional 550 MW of Preferred Resources and ES.

¹⁰⁵ See SCE's Procurement Plan for additional discussion of ways in which SCE will continue to target additional LCR resources through its existing procurement mechanisms. Track 1 Procurement Plan of Southern California Edison Company Submitted to Energy Division Pursuant to D.13-02-015 at 48-59.