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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Western Los Angeles Basin.	Application 14-11-012 (Filed November 21, 2014)

OPENING BRIEF
OF THE OFFICE OF RATEPAYER ADVOCATES
(PUBLIC VERSION)

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SUMMARY OF RECOMMENDATIONS

ORA recommends the Commission:

- deny approval of NRG contracts 447200 - 447205 as an unreasonable means to meet the preferred resource procurement authorized by the Decision (D.)13-02-015 (Track 1) and D.14-03-004 (Track 4) Decisions,
- deny contract NRG 447250, unless it is modified to ensure that it will not use backup natural gas-fired generation (BUGs), as an unreasonable means to meet the preferred resources procurement authorized by the Track 1 and Track 4 Decisions,
- alternatively, require the contracts to be modified to ensure performance by Sellers, if NRG contracts 447200-447205 and 447250 are approved despite their use of BUGs, and
- require SCE to remove the 100 MW cap on in-front of the meter (IFOM) energy storage (ES) and reevaluate SCE's shortlist for more cost-effective alternatives to resources selected as a consequence of the cap.

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I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and by order of the Administrative Law Judge, the Office of Ratepayer Advocates (ORA) submits this post-hearing Opening Brief on Southern California Edison Company's (SCE) above-referenced Application.[1] SCE seeks approval of the results of its 2013 Local Capacity Requirements (LCR) Request for Offers (RFO) for the Western Los Angeles Basin.

II. SUMMARY OF DISCUSSION

SCE failed to meet its burden to make an affirmative and verifiable demonstration that the LCR RFO and the resulting 63 contracts are in compliance with Decision (D.) 13-02-015 (Track 1 Decision) and D.14-03-004 (Track 4 Decision). The Track 1 and Track 4 Decisions authorized procurement of a range of resources by resource type, but also provided SCE qualitative discretion, which SCE must exercise in conformity with the Public Utilities Code and relevant Commission decisions. ORA recommends the Commission:

[1] Assigned Commissioner's Ruling and Scoping Memo for the Application of [SCE] (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Western Los Angeles Basin (Scoping Memo), March 5, 2015, p. 5 [Assigned Commissioner's Ruling].

- deny approval of NRG contracts 447200 - 447205 as an unreasonable means to meet the preferred resource procurement authorized by the Track 1 and Track 4 Decisions,[2]
- deny contract NRG 447250, unless it is modified to ensure that it will not use backup natural gas-fired generation (BUGs), as an unreasonable means to meet the preferred resources procurement authorized by the Track 1 and Track 4 Decisions,
- alternatively, require the contracts to be modified to ensure performance by Sellers, if NRG contracts 447200-447205 and 447250 are approved despite their use of BUGs, and
- require SCE to remove the 100 MW cap on in-front of the meter (IFOM) energy storage (ES) and reevaluate SCE's shortlist for more cost-effective alternatives to resources selected as a consequence of the cap.

III. DISCUSSION

A. Background

On November 21, 2014, SCE filed an Application and testimony for approval of the results of its 2013 LCR RFO for the Western Los Angeles Basin. SCE filed the Application to comply with the procurement need determined in the Long Term Procurement Plan (LTPP) proceeding, Rulemaking (R.) 12-03-014.[3]

In R.12-03-014, the Commission issued the Track 1 and Track 4 Decisions, which authorized SCE to procure between 1,900 and 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.[4] Combined, the Track 1 and Track 4 Decisions set minimum procurement authorizations, which included 550 MW of preferred resources; 50 MW of energy storage; 1,000 MW of gas-fired generation; and an additional 300 MW from any resource type.[5] In this proceeding, SCE now seeks Commission approval of the LCR RFO results and a finding that SCE's conduct with respect to the LCR RFO and the resulting contracts is in compliance with the Track 1 and Track 4 Decisions, and to authorize cost recovery for the LCR RFO contracts for the resources in the LA Basin. Specifically, SCE

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[2] *Id.* at p. 4.

[3] R.12-03-014, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans*, March 22, 2012.

[4] D.14-03-004, pp. 141-143, Ordering Paragraph 1.

[5] *Id.*

requests the Commission approve the Application and the related 63 contracts by November 21, 2015.

On December 4, 2014, the Commission issued Resolution ALJ 176-3347 to preliminarily categorize this proceeding as ratesetting and schedule evidentiary hearings. On January 12, 2015, ORA and the Sierra Club filed protests. Multiple parties filed a response to the Application, including California Energy Storage Alliance, EnerNOC, Inc., the Western Power Trading Forum, the Alliance for Retail Energy Markets and the Direct Access Customer Coalition. On January 22, 2015, SCE filed a Reply to the protests and responses. On January 28, 2015, a prehearing conference was held. On February 19, 2015, SCE submitted amended prepared testimony. On May 5-6, 2015, an administrative hearing was held.

B. Evidentiary Standards and Burden of Proof

1. Burden of Proof

The instant proceeding is categorized as ratesetting.[6] The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable; "no public utility shall change any rate...except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[7] Thus, in ratemaking applications, the burden of proof is on the applicant utility.[8]

In a 1980 decision, the Commission stated what has become a frequently quoted position on the burden of proof:

> Of course the burden of proof is on the utility applicant to establish the reasonableness of energy expenses sought to be recovered. We expect a substantial affirmative showing by each utility with percipient witnesses in support of all elements of its application.[9]

In a later ratemaking proceeding, the Commission confirmed:

> ...the fundamental principle involving public utilities and their regulation by governmental authority that the burden rests heavily upon a utility to prove it is entitled to rate relief and not upon the

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[6] Assigned Commissioner's Ruling, p. 6.

[7] *Application of Pacific Gas and Electric [PG&E] Company* (2000) D. 00-02-046, p. 36, 2000 Cal. PUC LEXIS 239.

[8] *Re Energy Cost Adjustment Clauses* (1980) 4 CPUC 2d 693, 701; D.92496.

[9] *Re Southern California Edison Company* (1983) 11 CPUC 2d 474, 475; D.83-05-036.

> Commission, its Staff, or any interested party or protestant, such as TURN, to prove the contrary.[10]

The Commission noted that there is no distinction between types of ratemaking cases with respect to the utility's burden of proof:

> The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs.[11]

The Commission confirmed that the burden is on the utility for all aspects of its application:

> As the Applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. *SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application.* Intervenors do not have the burden of proving the unreasonableness of SCE's showing.[12]

As the applicant in this ratesetting proceeding, SCE has the burden of proving that the LCR RFO results, SCE's conduct with respect to the LCR RFO and the resulting contracts are reasonable and in compliance with the Track 1 and Track 4 Decisions.

2. Standard of Proof

The Commission recently affirmed in D.14-12-025, adopting the new General Rate Case (GRC) framework, that the standard for the degree of proof in General Rate Cases is by a preponderance of the evidence, after the Commission employed the clear and convincing standard for years. The preponderance of the evidence standard, prevalent in civil proceedings, including administrative proceedings, is generally viewed to require that the evidence presented on one side of an issue is more persuasive than that in opposition.[13] The preponderance of the

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[10] *Application of [PG&E]* (2000) D. 00-02-046, p. 36, 2000 Cal. PUC LEXIS 239 citing *Re Pacific Bell* (1987) 27 CPUC 2d 1, 21, D.87-12-067.

[11] Opinion Regarding Proposed General Rate Increase (2004) D.04-03-034, p. 7.

[12] [Emphasis added]. Opinion on [SCE]'s Test Year 2006 General Rate Case Increase Request, D.06-05-016, p. 7.

[13] California Administrative Hearing Practice 2nd Ed. (CEB) § 7.51.

evidence standard does not relieve the applicant of the burden of initially producing evidence that is actually persuasive, and other parties are not required to offer evidence if the applicant fails to meet its initial burden.

C. SCE Failed To Establish that NRG Contracts 447200-447205 and 447250 Are Reasonable Means of Complying With The Track 1 And Track 4 Decisions

SCE bears the burden of establishing the reasonableness of categorizing NRG Contracts 447200-447205 and 447250 as either demand response or distributed generation, which it failed to do. NRG Contracts 447200-447205 and 447250 are thus non-compliant with respect to the preferred resource procurement authorized in the Track 1 and Track 4 Decisions.

1. Approving NRG Contracts 447200-447205 as Demand Response Thwarts the Public Policy Objectives of Demand Response and is Inconsistent with Every Relevant Prior Commission Decision

SCE selected two types of contracts offered by NRG and categorized them both as demand response.[14] The first category, NRG contracts 447200-447205, provides load reduction from behind the meter backup natural gas-fired generation.[15] The second category, NRG contract 447250, provides load reduction by curtailing customer energy consumption, but did not rule out the use of backup gas-fired generation to achieve this goal.

Even a cursory review of Commission decisions yields numerous decisions that repeatedly and unequivocally declared that back up natural gas-fired generation (BUGs) contradicts the entire objective of the demand response program and thus should not be included as demand response.[16] In D.06-11-049, the Commission addressed PG&E's proposal to initiate a demand response program based on the use of BUGs and stated:

> [The Commission's] objective in funding demand response programs is to reduce system demand, not to substitute electricity with electricity generated by off-grid natural gas facilities. We previously found in D.05-01-056 that back-up generation is not a true demand response resource. As TURN states, counting a BUG

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[14] Exhibit SCE 6, p. 12.

[15] Exhibit SCE 1, p. 70; Exhibit SCE 4, revised p. 70.

[16] SCE suggests that the use of a demand response contract should for some unknown reason be determinative of how these contracts are classified. Exhibit SCE 6, pp. 14:8.

> program as demand response would "turn the Commission's preferred resource loading order on its head." We, therefore, deny PG&E's request to initiate a BUG program.[17]

Again, in D.06-11-049, the Commission found in Finding of Fact (FOF) 26, "[o]ur objective in funding demand response programs is to reduce system demand, not to substitute system electricity generated by off-grid natural gas facilities."[18] Most recently, in D.14-12-024, the Commission made a broad policy statement "[f]ossil-fueled back-up generation is antithetical to the efforts of the Energy Action Plan and the Loading Order."[19] The Commission continued:

> It is reasonable to adopt as a policy statement that fossil-fuel emergency back-up generation resources should not be allowed as part of a demand response program for resource adequacy purposes, subject to rules adopted in future resource adequacy proceedings.

Here, SCE intends to seek resource adequacy credit for NRG contracts 447200-447205 in direct contradiction of D.14-12-024.[20] Contract 447250 also contradicts D.14-12-024 unless NRG stipulates to not using BUGs to provide demand response. Simply put, the use of fossil fuel generation, such as natural gas-fired generation, to provide demand response is inconsistent with the long lineage of relevant Commission decisions.

SCE's position in this proceeding, that the Commission should disregard the unanimous public policy statements of prior Commission decisions despite the lack of any distinguishing fact in the instant case, is disingenuous in light of its position in A.14-11-016, another Commission proceeding related to SCE LCR needs. In A.14-11-016, SCE states that if a party "provide[s] no basis upon which to alter the Commission's past practice and precedent," then "their arguments [to do the contrary] should be rejected."[21] Here, SCE fails to provide any evidence explaining why the Commission, in this specific case, should depart from the

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[17] D.06-11-049, p. 58.

[18] *Id.* at p. 69.

[19] D.14-12-024, p. 87, OP 10.

[20] SCE stated that it intends to administer these contracts as supply side resources. Exhibit SCE 6, p. 11.

[21] "[SCE]'s (U 338-E) Reply to Protests to its Application for Approval of the Results of its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area," January 22, 2015, p. 6.

Commission's "past practice and precedent." Accordingly, per the Commission's public policy objectives and SCE's own legal theory, the Commission should deny these contracts.

2. NRG Contracts 447200-447205 are not Distributed Generation

SCE cannot readily reclassify NRG's demand response contracts as distributed generation. While demand response resources are only intended to operate infrequently in response to demand response events, distributed generation is a baseload resource which achieves greenhouse gas efficiency by usually incorporating a waste heat recovery system and operating continuously over other many hours. Therefore, SCE needs to fundamentally renegotiate the operation of NRG's contracted resources to reclassify them as distributed generation; SCE has not submitted those contracts in this Application.

As it is also clear that the Commission's definition of legitimate demand response does not include natural gas-fired generation, SCE pivots and makes a weak attempt to classify NRG Contracts 447200-447205 as distributed generation. SCE relies on the portion of the State's Energy Action Plan II that states:

> 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 application.[22]

In this context, SCE's statement that "the [NRG] projects will utilize DG [distributed generation] technology,"[23] rings hollow, because SCE acknowledges that it does not define "DG technology"[24] and SCE's claims to procure "clean natural gas fired generation"[25] remain unsubstantiated by a specific technology. "[A]t the time the contracts were signed, [SCE] did not know what particular type of machine that NRG was going to rely on,"[26] yet SCE assumed, without any basis, that it would be "DG technology." At hearing, SCE witness Bryson testified

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[22] [Emphasis added]. Exhibit SCE 6, p. 13 FN 33.

[23] Exhibit SCE 6, p. 12:20.

[24] Transcript [TR], p. 103:24-27.

[25] Exhibit SCE 6, p. 6:16.

[26] Exhibit SCE 6, p. 12; TR, p. 104:4-9.

inaccurately that "[SCE] did know that NRG intended to rely on microturbines."[27] However, SCE's statement is contradicted by NRG witness Mr. Nickolay, who stated "we're looking primarily at reciprocating engines, not micro turbines [sic]."[28] Notwithstanding SCE's confusion regarding its own RFO; the fact that NRG contracts 447200-447205 will use fossil fuel backup generators remains undisputed.[29]

Despite ongoing uncertainty with respect to the technology used in the NRG contracts, SCE makes a tenuous leap of logic that NRG Contracts 447200-447205 are distributed generation. SCE's rationale[30] is as follows: 1) combined heat and power use fossil fuel and are considered distributed generation, 2) "distributed generation, such as combined heat and power" is an exemplar clause, which can be interpreted to allow other types of generation to be considered distributed generation, 3) similar to combined heat and power, NRG Contracts 447200-447205 use fossil fuel, 4) "[s]ince these projects are DG because of their *reliance on microturbines*, they qualify as Preferred Resources under the Loading Order."[31] The flaw in SCE's logic is that the projects will utilize reciprocating engines and not microturbines. Thus, even applying SCE's rationale, the projects will not qualify as DG.

Fortunately, to the extent that the portion of the State's Energy Action Plan II cited by SCE is open to interpretation, the remaining portion of the State's Energy Action Plan II makes it apparent that fossil fuel generation is not distributed generation. "To the extent that efficiency, demand response, renewable resources and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil fueled generation."[32] Accordingly, SCE's statement that NRG Contracts 447200-447205, which all rely on fossil fuel generation, will use "DG technology" is unsubstantiated because NRG Contracts 447200-447205 have not been shown to provide the emissions reductions necessary to qualify as a preferred resource.

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[27] TR p. 104:4-9.

[28] TR p. 330:24-26.

[29] Exhibit SCE 1, p. 70; Exhibit SCE 4, revised p. 70. Despite acknowledging that NRG contracts will use fossil fuel, SCE bizarrely requests that the NRG Contracts should not be considered "GFG or back-up generation." Exhibit SCE 6, p. 12:21.

[30] Exhibit SCE 6, pp. 13:8-14:2.

[31] [Emphasis added]. *Id.* at pp. 13:19-14:2.

[32] [Emphasis added]. *Id.* at p. 13, FN 33.

As SCE failed to submit evidence showing that the categorization of NRG Contracts 447200-447205 as either demand response or distributed generation is reasonable, ORA respectfully urges the Commission to deny approval of NRG Contracts 447200-447205 as a non-compliant means to meet the preferred resource procurement authorized in the Track 1 and Track 4 Decisions.

3. SCE Failed to Establish that NRG Contract 447250 is a Reasonable Means of Complying with D.13-02-015 and D.14-03-004

NRG contract 447250 provides load reduction by curtailing customer energy consumption, but did not rule out the use of backup gas-fired generation to achieve this goal. SCE has the burden to establish the reasonableness of the NRG Contract 447250, which it has failed to do. All of ORA's objections and supporting arguments regarding NRG Contracts 447200-447205 apply to NRG Contract 447250, if NRG Contract 442750 relies on backup gas-fired generation. Thus, the Commission should deny NRG Contract 447250 unless the contract is modified to explicitly exclude reliance on backup gas-fired generation

D. If the Commission Approves NRG Contracts 447200-447205 and 447250 as Demand Response Contracts, then ORA Urges the Commission to Adopt ORA's Contract Modification Recommendations

SCE failed to establish the reasonableness of the demand response pro forma contract[33] (DR Contract) upon which NRG Contracts 447200-447205 and 447250 are based. The DR Contract is problematic for multiple reasons. Of foremost concern to the Commission, the DR Contract is vulnerable to resource adequacy credit derating because the DR Contract does not require demand response providers (the Sellers) to perform. SCE asks the Commission to assume Sellers will never exploit the loopholes in the DR Contract performance requirements by arguing that relaxed requirements increase demand response participation. However, the Commission's past history, prudence and simple common sense, advises the Commission differently. Increased participation by unreliable demand response providers threatens the credibility of the demand response program. Adequate performance requirements are necessary to create a program that reliably displaces fossil-fuel generation.

[33] NRG Contracts 447200-447205 and 447250.

SCE attempts to deflect and circumvent criticism of the DR Contract by asserting that parties, including ORA, were part of a procurement review group that reviewed the DR Contract, thus the time for ORA to offer input "has passed."[34] Accordingly, SCE argues that ORA should be barred from challenging the DR Contract in this proceeding.[35] ORA disagrees. By participating in an informal, staff-level working group, ORA did not waive any right to advocate in Commission proceedings and urge the Commission to reject contracts that are not in the ratepayers' interests. The procurement review group is not a substitute for the application process. Moreover, SCE acknowledges they can and do disregard the opinions expressed in the procurement review group.[36]

Perhaps most troubling, SCE attempts to deny the Commission the opportunity to review the DR Contract for reasonableness by stating, "[it] is neither practical, nor reasonable to require SCE to reopen negotiations and revisit contract terms that were developed within Commission guidelines and executed after significant time and effort."[37] The circular logic underlying this objection begs the question, if the RFO is not vetted for reasonableness at the Application stage, then when else would it be reviewed? Furthermore, the Commission guidelines require the *Commission* to determine the reasonableness of the contracts. Regardless of how practical SCE perceives the Application process,[38] the procurement authorized in the Track 1 and Track 4 Decisions does not release SCE of its burden to prove the DR Contract is reasonable. SCE's time and effort to develop the DR Contract is irrelevant to the Commission's responsibility to review the DR Contract for reasonableness.

The loopholes in the DR Contract, undisputed by SCE, must be addressed by the Commission prior to approval. ORA's common-sense recommendations ensure Seller performance, which provides increased protection to ratepayers against resource adequacy credit derating and helps ensure that SCE has a reliable demand response program capable of meeting a portion of SCE's local capacity requirement need.

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[34] Exhibit SCE 6, p. 2:5.

[35] *Id.* at p. 8:5-8.

[36] TR p. 324:6-10.

[37] Exhibit SCE 6, p. 12:9-11.

[38] Under the procurement authorization, SCE was instructed to "propose options or contingency contracts in their procurement applications," but choose not to do so. Decision 14-03-004, p. 4.

1. DR Contract Section 8.1(B)(Ii) Should Require the Seller to Provide a List of Participating Accounts to Support at Least 50% of its Contract Capacity for each Month

SCE and ORA agree the DR Contract calls for a three-step process prior to the beginning of each month: 1) the Seller provides SCE with "recruited accounts,"[39] 2) SCE verifies the recruited accounts meet minimum requirements,[40] and 3) prior to the beginning of the "operating month" the Seller provides a list of "participating accounts" that will be available for dispatch.[41] However, this process creates a loophole for Sellers to avoid a penalty leading to termination if they provide no participating accounts, as opposed to an inadequate number of participating accounts.[42] SCE argues that the lack of payment for these Sellers is penalty enough. ORA disagrees. Nonperforming Sellers allowed to remain in the demand response program undermine the reliability of preferred resources procurement and thus, ultimately, justify additional procurement of gas-fired generation.

SCE acknowledges that the three-step process defined in section 1.5 of the DR Contract "does not directly ensure performance," but incorrectly asserts other contract provisions ensure performance.[43] SCE cites section 3.2(b)(iv), which provides that a Seller will not receive a capacity payment if performance falls below of 75% of the contract capacity amount. ORA agrees that if a Seller does not perform, then they should not be paid a capacity payment, but non-payment for non-performance, is not a substitute for a performance requirement. SCE also cites section 3.3(d), which provides that the Seller's payment will be reduced if they perform less than 100% of the contract capacity amount. Again, ORA agrees that the Seller should be paid in proportion to their performance, which section 3.3(d) requires, but this section does not require performance either, i.e., provide the entire contracted capacity. Lastly, SCE cites section 8.1(b)(ii), which states that the Seller will be in default if all three of the following requirements are met:

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[39] Exhibit SCE 8, Section 1.5(a) of the DR Contract.

[40] *Id.* at Section 1.5(b) of the DR Contract.

[41] *Id.* at Section 1.5(c) of the DR Contract.

[42] TR p. 116:8-15.

[43] Exhibit SCE 6, p. 9.

- Utility calls a full dispatch of participating accounts (Full Portolio Dispatch) for three consecutive months,
- Seller's performance is less than or equal to 50% of contract capacity (non-performance), and
- Seller nonperformance occurs for three consecutive months.

The default provision of section 8.1(b)(ii) can readily be avoided. It does not apply if the Seller submits no participating accounts, which is a major loophole. ORA notes other problems. First, it is the Seller who elects whether to identify participating accounts.[44] If the first two requirements of section 8.1(b)(ii) were met for two consecutive months, then on the third month the Seller could simply not identify any participating accounts and no default would be triggered. Second, section 8.1(b)(ii) only applies to full dispatch of participating accounts; any lesser dispatch events of only a portion of the participating accounts do not trigger the default provision.[45] As the sole default provision of the DR Contract, section 8.1(b)(ii) is toothless and will not ensure performance.

To remedy the lack of a performance requirement, ORA recommends that the Seller provide a list of participating accounts to support at least 50% of contract capacity for each month. If this recommendation is implemented, then the requirements triggering default under section 8.1(b)(ii) would be met each month because the Seller would have to identify participating accounts each month. Thus, Sellers could not avoid default by simply providing no participating accounts. This change, in addition to the one other change to Section 8.1(b)(ii) described in Section D.2, below, will ensure better performance by Sellers and a more robust demand response program for SCE.

2. DR Contract Section 8.1(B)(Ii) Should Apply When Any Dispatch Occurs During Three Consecutive Months Rather Than Only to Full Portfolio Dispatches

ORA recommends that DR Contract section 8.1(b)(ii) should apply when any dispatch occurs during three consecutive months rather than only to Full Portfolio Dispatches. However SCE incorrectly paraphrases ORA's recommendation as "SCE should modify the contract's

[44] Exhibit SCE 8, Section 1.5(c) of the DR Contract.

[45] TR p. 120:18-19.

default provisions to motivate performance and to help ensure participating accounts provide at least 50% of their contract capacity for each month;" SCE dismissed ORA's recommendation as unnecessary and redundant.[46] SCE contends that "[i]n the "Delivered Capacity Payment" provision, the link between performance and capacity payments is the strongest motivation for the seller to perform."[47]

To the contrary, ORA's recommendation is reasonable and necessary. As discussed above, the default provision of section 8.1(b)(ii) can readily be avoided because only Full Portfolio Dispatches trigger this provision. Even if the Seller provides less than 50% of contract capacity during three consecutive months, the Seller would not be in default if any event is not a Full Portfolio Dispatch. The delivered capacity payment provision does not remedy this situation. The only way to ensure performance during all events is to change the default provision to apply not just to Full Portfolio Dispatches but to all dispatches.

ORA's recommended proposed default provision will read, "during the Delivery Period, the measured Total Recorded Capacity is less than or equal to fifty percent (50%) of the contract capacity for three consecutive months during which Dispatches have occurred," [48] Although this still leaves opportunity for the Seller to avoid default, ORA's recommendation will ensure better performance.

3. The DR Contract Should Base a Seller's Capacity Rating on its Performance During All Event Hours During a Month Instead of the Average Best-Performing Hour

SCE states that the "the LCR DR Pro Forma Agreement's use of average best performing hour from all dispatches in a given month is an improvement over the 2013-2014 [Aggregator Managed Portfolio] contracts, because a seller can no longer run a test event on the last day of the month to set their capacity for the entire month and not be penalized for past poor performance."[49] The use of average best performing hour means that in a month with two or more dispatch events, SCE will take the best performing hour of each event and average them.

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[46] SCE Exhibit 6, p. 8.

[47] *Id.* at p. 10.

[48] Exhibit ORA 2, pp. 2-5.

[49] Exhibit SCE 1, pp. 9:17.

Thus all of the other hours, the non-best performing hours, will not be used to determine calculations of performance. So in a four-hour event, if the Seller performs poorly in hours one to three of the event but performs well in hour four, only hour four will be used to determine performance.[50] This results in ratepayers overpaying for capacity during any hour a Seller falls below their average best performing hour during each sub-load aggregation point (SLAP) dispatch event.[51] In addition, the best-performing hour may not be the same hour during each event, which reduces the reliability of the demand response program as a whole.

Also, SCE plans to bid these contracts into the California Independent System Operator's (CAISO) markets.[52] Under the CAISO's Must-Offer Obligation (MOO), demand response capacity under these contracts must be offered to the CAISO for four hours/day, for three consecutive days and for a total of 24 hours per month.[53] If the CAISO dispatches these contracts for all of the hours prescribed in the MOO, the CAISO would expect performance during all of these event hours and the CAISO reviews performance for all hours.[54] Under the average best performing hour approach, SCE has not shown that its demand response contracts will be able to meet the obligations of the CAISO's MOO.

As discussed above, providing capacity payments to Sellers based on the average best-performing hour is excessively generous to Sellers and implicates reliability concerns. ORA recommends that SCE modify the DR Contract to require payment capacity based on all event hours during a month instead of the average best-performing hour.

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[50] TR pp. 122:24-28.

[51] TR p. 123:1-4.

[52] Exhibit SCE 6, p.11.

[53] Commission resource adequacy requirements for demand response (per 2015 Final RA Guide (DOCX) 9/10/2014,http://www.cpuc.ca.gov/NR/rdonlyres/70C64A46-89DE-4D90-83AB-93FD840B4251/0/Final2015RAGuide.docx) PP.2-4 (last visited June 8, 2015). The CAISO has recently revised the Must Offer Obligation for Proxy Demand Response (PDR) in its Reliability Services Initiative (RSI) – Phase 1. The RSI stakeholder initiative was approved by the CAISO Board of Governors on March 26, 2015. This aligns the CAISO' MOO Requirement with the Commission's demand response requirements for resource adequacy credit.

[54] http://www.caiso.com/Documents/DemandResponseandProxyDemandResourcesFrequentlyAskedQuestions, pdf , p.6 (last visited June 8, 2015).

4. The DR Contract Should Require SCE to Conduct a Test Event Within the First Month of a Contract to Verify a Contract's Available Capacity

Under the contract terms, the Sellers can receive full payments based on contract capacity before any events are called if the availability of capacity is not verified at the onset of the contract delivery month.[55] Therefore, ORA recommends a test event within the first month of the contract to verify a contract's available capacity. SCE agreed that this modification should be made.[56]

5. The DR Contract Should Allow SCE to Call a Seller Dispatch Event Any Time in a 30 Day Window, as Opposed to the Current Three Day Window

ORA recommends that the DR Contract should be modified to allow SCE to call a Seller dispatch event any time in a 30 day window, as opposed to a three day window. This recommendation, SCE asserts, is unreasonable and redundant.[57] To support this statement, SCE cites section 3.4 of the DR Contract, and deceptively states that the DR Contract provides SCE with the right to dispatch a test event at any point during the "operating month" with as little as 20 minutes notice." SCE's characterization of section 3.4 is misleading and incomplete.

Section 3.4 provides the Seller the ability to request a Seller dispatch within a three day window in which SCE must dispatch a test event.[58] SCE thus is required to dispatch a test event in a three day window which the Seller identifies and can prepare for.[59] It is within that three day window that SCE is required to give 20 minutes notice. Expanding the window for a Seller dispatch event from three days to 30 days is a sensible modification which more closely resembles the conditions under which a Seller is actually dispatched, which is the entire operating month.

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[55] Exhibit SCE 8, DR Contract, Section 3.2(a). "Before the first Full-Portfolio Dispatch is performed during the Delivery Period, the Delivered Capacity Payment shall equal the applicable Contract Capacity times the applicable Capacity Rate."

[56] Exhibit SCE 6, p. 10:14-16.

[57] *Id.* at p. 10.

[58] Exhibit SCE 8, DR Contract Section (3.4)(1).

[59] In comparison, for a CAISO dispatch, the Seller must be available for the entire operating month

6. SCE Should Clarify that the DR Contracts is a Supply-Side Resource Eligible for Resource Adequacy and LTPP Credit

In response to ORA's recommendation that SCE clarify that the contracts are categorized as supply demand response resources under the Commission's bifurcation categories and meet all Commission and CAISO requirements for receiving resource adequacy and LTPP credits as a Supply DR resource, SCE agreed with ORA's recommendation and stated that they plan "to administer the LCR DR contracts as Supply DR resources."[60]

7. The DR Contract Should Be Modified to Prohibit Dual Participation in SCE's Demand Response Programs

SCE incorrectly states that ORA misinterprets the dual participation requirements of Rule 24 and D. 12-11-025.[61] The Commission currently allows dual participation of a customer in both energy and capacity demand response programs. Energy programs only provide energy payments whereas capacity programs can provide both capacity and energy payments because they require a commitment from the participant. Dual participation in two capacity programs is prohibited to ensure ratepayers do not pay twice for the same capacity. Section 1.5(d) of the DR Contract allows dual participation of the contracts with SCE's current demand response programs, which is consistent with the Commission's rules as long as participating accounts in these contracts are not simultaneously enrolled in SCE's demand response program and participate directly in the CAISO market.[62]

The Commission's direct participation rules prohibit any dual participation of customers participating in the CAISO's market and simultaneously in a utility event-based program, consistent with CAISO's resource registration rules. Rule 24, which addresses direct participation in the CAISO's market, states that, "Non-Utility DRPs [Demand Response Providers] are also prohibited from enrolling and registering a customer service account in DR

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[60] Exhibit SCE 6, p. 11:10-12.

[61] *Id.* at p. 11.

[62] Exhibit SCE 8, DR Contract Section 1.5(d) "Dual Participation. Seller may not identify Customers that participate in other demand response program as a Recruited Account or Participating Account, unless such Customer is in a Dual Participation Program. Additionally, Customers that are enrolled in the Capacity Bidding Program may also be a Recruited Account or Participating Account; provided, during any Operating Month under this Agreement the Customer is a Participating Account they do not place a bid into the Capacity Bidding Program for that month."

Services if the customer is already enrolled in a SCE's event-based demand response program."[63] Also, according to D. 12-11-025, Ordering Paragraph (OP) 8: "[d]emand response providers are prohibited from enrolling customers in a demand response service where the load is bid into the California Independent System Operator's market if that customer is already enrolled in a Utility event-based demand response program." Therefore, ORA recommends that SCE modify its contracts to clarify that any dual participation of customers enrolled in contracts and SCE's event-based demand response program is prohibited.

8. ORA's Recommended Modifications are Necessary, Because the Demand Response Contracts are Vulnerable to Significant Derating

To determine resource adequacy credit, the Commission's Energy Division reviews the contract capacity and the Seller's actual performance under the contract.[64] If the Seller provides 100% of the contract capacity, then the resource adequacy credit equals the contract capacity. However, if the Seller provides less than 100% of contract capacity, then the Energy Division derates the Seller's resource by reducing its resource adequacy credit. SCE acknowledges ORA's concern that SCE demand response contracts are vulnerable to significant derating.[65] If derating occurs, then SCE will need to procure additional resource adequacy eligible resources despite the fact that ratepayers will be paying capacity payments pursuant to the demand response contracts.

SCE correctly states that "[i]f the Commission were to order SCE to make such modifications at this point in time, it would be equivalent of rejecting the contracts."[66] ORA agrees. ORA recommends that the Commission should reject contracts as unreasonable when they are disproportionately generous to Sellers, lack ratepayer protections, and fail to reliably meet SCE's LCR need in the Western LA Basin. If the Commission decides against its own long-standing policy prohibiting the use of fossil fuel backup generation to provide demand response, then the Commission should approve the demand response contracts only if they include ORA's recommended modifications:

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[63] PG&E Advice letter 4298-E (October 10, 2013), p. 9D6-10D6 (Electric Rule 24, Section C.2.d); *see also* D. 12-11-025, Decision Adopting Policies for Demand Response Participation.

[64] Exhibit SCE 6, p. 2.

[65] *Id*. at p. 12.

[66] *Id.* at p. 2:5-6.

- DR Contract section 8.1(b)(ii) should require the Seller to provide a list of participating accounts to support at least 50% of its contract capacity for each month;
- DR Contract section 8.1(b)(ii) should apply when any dispatch occurs during three consecutive months rather than only to Full Portfolio Dispatches;
- the DR Contract should base a Seller's capacity rating on their performance during all event hours during a month instead of the average best-performing hour;
- the DR Contract should require SCE to conduct a test event within the first month of a contract to verify a contract's available capacity;
- the DR Contract should allow SCE to call a Seller dispatch event any time in a 30 day window, as opposed to the current three day window;
- SCE should clarify that the DR Contract provides a supply-side resource eligible for resource adequacy and LTPP credit, and
- the DR Contract should be modified to prohibit dual participation as a direct bid in the CAISO market and in SCE's event based demand response programs.

E. The Commission Should Find the 100 MW Cap on In-Front of the Meter (IFOM) Energy Storage (ES) Unreasonable and Contrary to Least Cost - Best Fit Valuation

SCE failed to establish the reasonableness of the 100 MW IFOM ES cap (100 MW cap). As a result, SCE failed to procure according to Least Cost - Best Fit principles by unreasonably excluding cheaper and better fit resources eligible prior to the imposition of the cap. Therefore, ORA recommends the Commission approve only those projects procured despite the imposition of the 100 MW cap and require SCE to revisit its shortlist based on rerunning the model without the 100 MW cap. This allows SCE to begin construction of selected gas-fired generation resources requiring a long lead time to construct while still enabling sufficient time for SCE to procure additional resources to meet its preferred resources requirement.

SCE undertook significant challenges in implementing the first all-source RFO, which incorporated emerging technologies. Allowing additional procurement in light of reduced uncertainty surrounding IFOM ES, as a supplement to the additional preferred resources procurement SCE already intends to conduct, is equitable to bidders. The Commission should not let short-term uncertainty surrounding IFOM ES undermine the effectiveness of long term procurement decisions affecting ratepayers in the Western LA Basin.

1. Interconnection Risks Do Not Justify the 100 MW Cap

To justify the 100 MW cap, SCE cited interconnection risks and uncertainties. Specifically, SCE relied on the possibility that the CAISO's Transmission Access Charge (TAC) would apply to IFOM ES and that its valuation model did not properly capture network upgrade costs to impose the cap.[67] Before SCE submitted its Application to the Commission, however, SCE was aware that the CAISO definitively stated that a TAC would not apply to IFOM ES either in its charge or discharge mode.[68] The CAISO hosted an energy storage interconnection stakeholder process, in which SCE participated.[69] During the stakeholder process, as early as June 2014 and before SCE made its selection of contracts, the CAISO clarified that its existing Generator Interconnection and Deliverability Allocation Procedures would apply to energy storage and that the CAISO would not support a TAC for unrestricted charging.[70] On November 21, 2014, SCE submitted its Application and cited the uncertainty of the application of TAC to justify the 100 MW cap, but knew that it did not apply to IFOM ES.[71]

Moreover, SCE mitigated risks associated with interconnection uncertainty by: (1) reserving the right to terminate contracts that exceed network upgrade cost caps; (2) reducing the net present value of IFOM ES offers; and, (3) selecting an offer with advantageous interconnection characteristics.

First, SCE required developers to include network upgrade costs estimates in their offer.[72] The IFOM ES contracts treated estimates as network upgrade cost caps and gave SCE the right to terminate the contracts if actual costs exceeded the cap.[73] Thus, SCE does not bear the risk associated with higher than forecasted transmission interconnection costs.

Second, SCE included a transmission cost adder into the net present value of offers.[74] The transmission cost adder incorporated the network upgrade cost estimates based on

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[67] TR p. 19:14-24; Exhibit SCE 1, p. 16.

[68] TR p. 21:4-6; Exhibit Sierra Club 4, p. 27.

[69] TR p. 20:2-4; Exhibit Sierra Club 4, p. 11.

[70] Exhibit Sierra Club 4, p. 3.

[71] TR p. 21:27-21:8.

[72] Exhibit SCE 2-C, Appendix D, p. D-9, Paragraph 4; p. D-12; TR p. 15:6.

[73] Exhibit SCE 2-C, Appendix D, p. D-9, Paragraph 4; p. D-12; TR p. 15:8-13.

[74] Exhibit SCE 2-C, Appendix D, p. D-9, Paragraph 4; p. D-12; TR p. 16:23-28.

interconnection forecasts provided by developers.[75] By including the estimated network upgrade costs into the net present value of IFOM ES offers, SCE effectively reduced the cost-competitiveness of IFOM ES bids. Therefore, bid prices reflected SCE's transmission upgrade cost uncertainty concern.[76]

Third, to mitigate added costs from network upgrades due to charging, SCE also selected an IFOM ES bid that interconnects at the transmission level on a 220 kilovolt line.[77] There is a lower risk of charging restrictions and congestion at a high voltage transmission line, such as 220 kilovolt, then at a lower voltage.[78] SCE consequently was able to mitigate some of the interconnection uncertainty risk by seeking locational benefits that properly accommodate IFOM ES characteristics.[79]

Furthermore, SCE failed to substantiate why its mitigation efforts were insufficient to shelter it from SCE's perceived risk. SCE could not and did not provide the Commission with estimates of incremental costs due to higher than expected network upgrade costs or even the likelihood of incurring such costs if SCE procured larger amounts of IFOM ES. Considering the cost-effectiveness of IFOM ES, SCE did not show how the risk of added IFOM ES contracts was unreasonable in comparison to the cost-effectiveness of the resource. Therefore, ORA recommends that the Commission find the 100 MW cap unreasonable.

2. SCE Failed to Substantiate How Potential Overvaluation of IFOM ES Warrants a 100 MW Cap

To justify the 100 MW cap, SCE cited the possibility that it may have overvalued ancillary service revenues because of possible charging constraints that were not modeled and inaccurate expectations of forward market prices of energy and ancillary service value of energy storage.[80] SCE intends to bid the IFOM ES device into the CAISO's ancillary services market and contends that a large portion of IFOM ES expected value is derived from wholesale market

[75] Exhibit SCE 2-C, Appendix D, p. D-9, Paragraph 4; p. D-12; TR p. 17:5.

[76] TR p. 17:12.

[77] Exhibit SCE 1, p. 75:4-8; TR p. 17:19.

[78] Exhibit SCE 1, p. 75:4-8.

[79] *Id.* at p. 75:9; 17:20-18:8.

[80] Exhibit SCE 2-C, Appendix D, p. D-34.

revenues.[81] Yet, SCE is concerned that it cannot determine to what degree charging constraints will impact IFOM ES revenues.[82] SCE thus does not know to what degree it may have overvalued ancillary services revenue.[83] Accordingly, SCE does not know if a larger cap, compared to the 100 MW cap, would be more effective at mitigating potential overvaluation risks.[84] SCE testified that it made a "judgement call" that 100 MW was the appropriate cap, despite not doing any "study analyses above 100 [MW]" to support the "judgement call."[85] As SCE failed to do any research on the effect of a less restrictive energy storage cap, it cannot reasonably assert that a 100 MW cap mitigates risk more effectively than a less restrictive cap.

SCE was concerned that a "storage asset may not be able to charge unrestricted all of the time."[86] Restricted charging during peak periods could potentially decrease the opportunity for IFOM ES to bid into the CAISO market to provide regulation down services and thus restrict its opportunity to earn revenue.[87] Despite these concerns, SCE did not consider the likelihood or the extent to which IFOM ES would in fact charge during system peak times[88] and did not run sensitivity analyses to determine to what degree such constraints would effect on IFOM ES ancillary service revenue.[89] Moreover, SCE could not determine the percentage of total ancillary service value attributed to regulation down services included in SCE's value because SCE's valuation model aggregated each offer's value of all services into a single net present value without identifying the value attributed to each service individually.[90] Therefore, SCE cannot determine to what degree it actually overvalued IFOM ES ancillary service revenue. As such, ORA recommends that the Commission find the 100 MW cap arbitrary and require SCE

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[81] TR p. 22:19-22.

[82] *Id.* at p. 25:9-21.

[83] *Id.* at p. 25:22-26.

[84] Exhibit SCE 6, p. 6:22-23; TR pp. 25:27-28; 26:23-24.

[85] TR p. 26:15-24.

[86] *Id.* at p. 23:26-24:1.

[87] *Id.* at p. 16:18-22.

[88] *Id.* at p. 15:13-17.

[89] *Id.* at p. 25:22-26.

[90] May 12, 2015 SCE response to Data Request Set A.14-11-012 LCR RFO-Sierra Club-SCE-004, Question 3a. (Sierra Club's Motion to Admit Follow Up Data Request Responses pending at the time this brief was submitted).

to re-run its model after removing the 100 MW cap while leaving all other constraints in place and to select resources that it would have shortlisted but for the cap.

3. SCE's Reliance on Capital Lease Accounting and Debt Equivalence Risk to Impose a 100 MW Cap is Unreasonable

SCE expressed concern that the IFOM ES contracts will be given capital lease accounting treatment by credit rating agencies, which would consequently result in higher amounts of debt on SCE's balance sheets.[91] Higher amounts of total debt, amongst numerous other factors weighed against SCE's total financial portfolio, could cause SCE's credit rating to decrease. As SCE's credit rating falls, its costs to issue debt and preferred equity increase, which ratepayers ultimately pay for. Yet SCE failed to substantiate why a 100 MW cap on IFOM ES remains necessary after SCE addressed these concerns by including the cost associated with the effect of debt equivalence into its contract cost evaluation through a debt equivalent cost adder and an Embedded Put Option.[92]

a) SCE Included the Cost of Added Debt Equivalents into the Net Present Value of IFOM ES Offers

To justify the 100 MW cap, SCE cites the risk associated with higher amounts of debt equivalents.[93] SCE, however, mitigated its concerns over added debt equivalents by including a debt equivalents cost adder to the net present value of IFOM ES offers.[94] Therefore, SCE included in its valuation process, the net of all benefits and costs of energy, including debt equivalence costs. SCE failed to substantiate why the 100 MW cap is necessary to mitigate the risk of added debt equivalence

[91] Exhibit SCE 6, p. 6:7-9; Exhibit SCE 1, p. 53; Exhibit SCE 6, p. 6:6-9; TR p. 28:14-23.

[92] Exhibit SCE 1, p. 47:2-7; TR p. 30:9-12.

[93] Exhibit SCE 6, p. 4:4-5.

[94] Exhibit SCE 2-C, Appendix D, p. D-9.

b) SCE Failed to Demonstrate the Necessity of the 100 MW Cap Even After Including an "Embedded Put Option" into IFOM ES Contracts

SCE included an "Embedded Put Option" into the IFOM ES contracts, which gives the seller the option to sell the dispatch rights to SCE or retain them.[95] The "Strike Price," which is the price the rights are sold at, is determined by SCE and considers IFOM ES' valuation in the ancillary service market.[96] The purpose of the Embedded Put Option is to reduce the likelihood that IFOM ES contracts will incur capital lease accounting treatment.[97] Despite this measure, SCE feared that even with the Embedded Put Option, IFOM ES contacts could still be given capital lease accounting treatment.[98] Nevertheless, SCE failed to justify the necessity of the 100 MW cap in addition to SCE's risk mitigation efforts.

SCE asserts that the 100 MW cap mitigates debt equivalency consequences that could result even with the Embedded Put Option because of discrepancies between the Strike Price that SCE incorporated into IFOM ES contracts and actual market prices. The Strike Price set by SCE considers IFOM ES valuation in the ancillary service market and is established at contract execution.[99] SCE is concerned that depending on ancillary service market trends, market prices could lead the seller to always either sell or retain the dispatch rights to SCE.[100] Regardless, since SCE sets the Strike Price, not the seller, SCE could have reasonably controlled the probability of the seller exercising the Strike Price by setting the price higher or lower according to its market forecasts. SCE also included the additional costs associated with an Embedded Put Option into the net present value of IFOM ES offers.[101] Lastly, SCE also did not show the likelihood or the magnitude that its offered Strike Price would be so misaligned with actual market prices as to warrant a 100 MW cap because a seller may always sell or retain its dispatch rights. SCE failed to substantiate the inaccuracies of its market forecasts. [redacted]

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[95] Exhibit SCE 1, p. 33:9-11; TR p. 30:25-31:3.

[96] Exhibit SCE 1, p. 33:9-11; TR p. 31:20-22; Exhibit SCE 2-C, Appendix D, p. D-21.

[97] Exhibit SCE 1, p. 33:9-11; TR p. 31:23-32:4.

[98] Exhibit SCE 2-C, Appendix D, p. D-21.

[99] *Id.* at Appendix D, p. D-21.

[100] *Id.* at Appendix D, p. D-21.

[101] TR p. 34:17-20.

[redacted][102]

SCE also did not evaluate the duration or frequency that IFOM ES may be curtailed in the ancillary service market or the impact of curtailment on total ancillary service revenues,[103] and thus did not demonstrate the likelihood or extent to which its Strike Price could overvalue IFOM ES.

Given the mitigating steps SCE took, the necessity for the 100 MW cap to reduce debt equivalence risks is unclear. As stated by SCE, the Embedded Put Option "mitigated much of the identified risk associated with capital lease accounting"[104] because it results in lower debt equivalence than the original assessed capital lease accounting treatment.[105]

c) SCE Failed to Justify a 100 MW Cap Given the Likelihood of a Credit Downgrade and the Cost-Effectiveness of IFOM ES in SCE's Valuation

SCE failed to justify how a 100 MW cap is a reasonable solution to the risk of debt equivalency given the magnitude of credit downgrade risk. For example, even if credit rating agencies characterize the selected 100 MW IFOM ES offer as a capital lease, the debt equivalence this contract would add to SCE's total debt is minimal in relation to SCE's total debt, its financial portfolio, and the numerous qualitative factors that are weighed to establish a utility's credit rating. SCE has not substantiated how this minor factor justifies SCE's imposition of the 100 MW cap. SCE also failed to explain how larger amounts of IFOM ES would increase SCE's total debt to such a level that would warrant a credit downgrade.

Finally, SCE did not evaluate the selection of offers with lower net present values and higher levelized net costs that resulted from the imposition of a 100 MW cap against the risk of greater debt equivalence and therefore, SCE's selection set is contrary to the Least Cost – Best Fit valuation methodology. SCE failed to justify its wide-sweeping response to the "unknowns" of IFOM ES and did not consider less-costly solutions such as considering locational attributes

[102] Exhibit SCE 2-C, Appendix D, p. D-72.

[103] TR p. 25:8-26.

[104] Exhibit ORA 2-C, Attachment 5-7.

[105] Exhibit SCE 1, p. 33.

of IFOM ES offers with high net present values that minimize much of the risk SCE is concerned with, as it did with the selected 100 MW IFOM ES offer. Therefore, ORA recommends that the Commission find the 100 MW cap on IFOM ES offers unreasonable.

4. The 100 MW Cap is Unreasonable Because it Excluded Lower Cost-Better Fit Resources

SCE performed multiple runs of its valuation model before coming to its final shortlist. SCE's first model run resulted in a selection set of over 400 MW of IFOM ES, while its 25 model run, SCE had 900 MW of IFOM ES.[106] The 100 MW cap thus significantly limited the amount of energy storage procured.[107] Due to the IFOM ES cap, SCE was required to procure other types of preferred and conventional resources, which in many cases, are more expensive than IFOM ES.[108] SCE has not explained why 100 MW is the appropriate amount of procurement for IFOM ES, as the risks SCE cited to justify the cap are either non-existent or mitigated by other measures. Therefore, the increased costs passed on to ratepayers due to SCE procuring additional, more expensive resources, are unwarranted.

By limiting IFOM ES procurement to 100 MW, SCE unreasonably excluded cost-effective offers. For example, in addition to the 100 MW IFOM ES offer that SCE selected, [redacted] In contrast to the 100 MW IFOM ES offer, [redacted] Just as the 100 MW IFOM ES offer SCE selected, [redacted] The Alamitos substation is on a 220 kilovolt transmission line that offers minimal congestion and charging constraints.[111] In addition, this substation is located within the Southwest LA Basin sub-area.[112] The Southwest LA Basin has the highest locational effectiveness in terms of relieving constraints and meeting

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106 Exhibit SCE 1, p. 57-8; TR p. 34:25-28; 35:8-25.

107 Exhibit SCE 1, p. 57:17; TR p. 36:3-9.

108 Exhibit SCE 1, p. 58, Exhibit SCE 6, p. 7:19-21.

109 Exhibit SCE 2-C, Appendix D, p. D-89.

110 Exhibit SCE 2-C, Appendix D, p. D-89.

111 The Alamitos substation is a preferred location in regards to congestion, transmission capacity, and charging restrictions. Exhibit SCE 1, pp. 57-58.

112 Exhibit SCE 1, p. 7.

the local capacity need compared to resources located in other sub-areas of the Western LA Basin, as determined by the CAISO.[113]

In addition to meeting reliability criteria and consistency with the Loading Order, "LCR procurement by SCE must be at least cost to ratepayers."[114] [redacted]

The 100 MW cap directly resulted in the unreasonable exclusion of cheaper, better fit options by SCE; and therefore should be removed.

5. Alternatively, Removing the 100 MW Cap and Procuring Larger Amounts of IFOM ES is a More Cost-Effective Option and Reduces Reliance on Gas-Fired Generation Peaking Resources

The Commission should recommend that SCE re-run its model without imposing the 100 MW cap on IFOM ES and to select the offers that would have been shortlisted but for the cap. Larger procurement of IFOM ES presents ratepayers with a more cost-effective option and reduces reliance on gas-fired generation peaking resources compared to the combined selection of the 98 MW Wellhead project and the 100 MW IFOM ES offer. For instance, [redacted] as compared to the combined cost of the 98 MW peakers and the 100 MW IFOM ES project.[117] This selection is also consistent with the Commission's policy as stated in the Track 4 Decision:

> Assuming SCE pursues a least-cost/best-fit approach to the increased discretionary portion of procurement authority (the additional 500 – 700 MW), it is likely that SCE would procure

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[113] Exhibit SCE 1, pp. 19 and 25.

[114] D.13-02-015, p. 79.

[115] Exhibit SCE 2-C, Appendix D, p. D-89.

[116] [redacted] Exhibit SCE 2-C, Appendix D, pp. D-79 and D-89.

[117] Exhibit SCE 2-C, Appendix D, pp. D-79 and D-89; Exhibit ORA 2, p. 5-17:14-16.

> mostly gas-fired resources if such resources are less costly than preferred resources. From a ratepayer perspective, this may be beneficial; however, the Loading Order calls for prioritization of cost-effective preferred resources, in some cases even if they are more expensive than other resources. We will modify SCE's proposal to ensure that SCE procures a higher percentage of authorized resources from preferred resources and energy storage.[118]

While ES is not defined as a "preferred resource" yet, it shares similar characteristics and the Commission treats it in line with "preferred resources."[119] Similarly, as found by Assembly Bill 2514 (Stats. 2010, ch. 469), expanding the use of energy storage systems could optimize the use of wind and solar generation, assist in integrating increased amounts of renewable energy resources into the grid, and reduce emissions of greenhouse gases. Therefore, cost-effective IFOM ES should be pursued over more costly gas-fired generation resources in this LCR RFO.

In addition to the locational benefits and lower levelized net cost discussed above, the [redacted] Table 5-2,[121] below, illustrates SCE's selection of the 98 MW gas-fired generation project and the 100 MW IFOM ES project in comparison to the [redacted]

Table 5-2[122]

	Wellhead 98 MW CT and AES 100 MW IFOM ES projects	[redacted]	Difference between SCE's selection and the [redacted]

[118] D.14-03-004, p. 93.

[119] For instance, D.14-03-004 requires SCE to procure "a higher percentage of authorized resources from preferred resources *and energy storage*" while maintaining SCE's minimum procurement authorization for gas-fired generation resources. D.14-03-004, pp. 2 and 93 (emphasis added).

[120] [redacted] Exhibit SCE 2-C, Appendix C, p. C-1. [redacted] Exhibit Sierra Club 1-C. See also, Exhibit SCE 2-C, Appendix D, pp. D-79 and D-89.

[121] Exhibit ORA 2, p. 5-18:15.

[122] For consistency, this table is labeled "5-2," as it was previously labeled Tabled 5-2 in Exhibit ORA 2-C, p. 5-18.

			[redacted]
Total Levelized Net Cost[123]	[redacted]	[redacted]	[redacted]
Total Net Present Value[124]	[redacted]	[redacted]	[redacted]

Furthermore, [redacted] does not necessarily add risk in comparison to the combination of a 98 MW peaker and a 100 MW IFOM ES system. As discussed above, SCE has not quantified the cost impact of any risk associated with IFOM ES. SCE also did not identify why a smaller or larger MW cap is any more or less cost-effective and qualitatively beneficial than a 100 MW cap.[125] The [redacted] provides all of the risk mitigation factors described above. Similarly to the selected 100 MW IFOM ES project, the [redacted]

Removing the 100 MW cap on IFOM ES provides a reasonable solution because it not only saves ratepayer money, but also reduces greenhouse gas emissions. Moreover, by maintaining all other selection constraints imposed,[127] SCE is able to maintain its requisite procurement timeline as mandated by the Track 1 and Track 4 Decisions and is able to ensure that contracts that require long lead times, such as conventional gas-fired generation resources, are accommodated.

ORA respectfully urges the Commission to consider the adverse consequences of the 100 MW cap and require SCE to re-run its model after removing the 100 MW cap while leaving all other constraints in place and to select resources that it would have shortlisted but for the cap. If it becomes impractical for SCE to revisit resource bids offered into the RFO, ORA

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[123] Exhibit SCE 2-C, Appendix D, pp. D-79 and D-89.

[124] Exhibit Sierra Club 1-C.

[125] TR p. 26:15-24.

[126] Exhibit Sierra Club 1-C.

[127] These constraints are listed in Exhibit SCE 1, pp. 57-62 and Table VI-18.

suggests the Commission allow SCE to procure additional resources to meet its preferred resources obligation under the Tack 1 and Track 4 Decisions.

IV. CONCLUSION

For the reasons stated here, ORA's recommendations should be adopted.

Respectfully submitted,

/s/ JAMES M. RALPH

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