Docket:	:	A.14-11-012
Exhibit Number	:	
Commissioner	:	Michel P. Florio
Admin. Law Judge	:	Regina DeAngelis
ORA Project Mgr.	:	Zita Kline
	:	
ORA Witnesses		Rosanne O'Hara
		Sudheer Gokhale

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

(SECOND AMENDED) TESTIMONY ON SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF THE RESULTS OF ITS 2013 LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR THE WESTERN LOS ANGELES BASIN

[PUBLIC VERSION]

San Francisco, California
April 21, 2015

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3	The use of BUGs to provide Demand Response is inconsistent with the CPUC's policy on back-up generation (Scoping Memo Issue 4b).	Sudheer Gokhale
4	SCE's Demand Response contracts are vulnerable to derating (Scoping Memo Issue 4c).	Sudheer Gokhale
5	The 100 MW Cap on in-front of the meter energy storage is unreasonable (Scoping Memo Issue 4d).	Rosanne O'Hara

CHAPTER 1. INTRODUCTION

Witness: Zita Kline

On November 21, 2014, Southern California Edison Company ("SCE") filed its *Application of SCE (U 338 E) for Approval of the Results of Its 2013 Local Capacity Requirements (LCR) Request for Offers (RFO) for the Western Los Angeles Basin*, Application (A.) 14-11-012 (Application) and concurrently submitted Prepared Testimony[1] in support of the Application. On January 12, 2015, the Office of Ratepayer Advocates (ORA) filed a Protest to the Application. ORA respectfully urges the California Public Utilities Commission (CPUC) to either deny certain contracts in the Application or deny the Application without prejudice "as an unreasonable means to meet the 1,900 to 2,500 MW of identified LCR need determined by D.13-02-015 and D.14-03-04" (Scoping Memo Issue 4).[2] ORA recommends:

- The terms and conditions of the Demand Response (DR) contracts are unreasonable (Scoping Memo Issue 4a) and should be modified as discussed below;
- The use of fossil fuel based back-up generators (BUGs) to provide DR is inconsistent with the CPUC's policy on BUGs (Scoping Memo Issue 4b) and DR contracts that use BUGs to provide DR should be denied;
- The DR contracts are vulnerable to derating (Scoping Memo Issue 4c) and should be modified as discussed below; and
- SCE's RFO process arbitrarily limited in-front of the meter (IFOM) energy storage (ES) resources with a 100 MW procurement cap (100 MW IFOM ES cap) (Scoping Memo Issue 4d). ORA recommends removing this cap because it results in the inclusion of unreasonable offers and the exclusion of reasonable alternatives. ORA also recommends [redacted]

[1] Testimony of SCE (U 338-E) on the results of its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Moorpark Sub-Area ("Prepared Testimony"), November 26, 2014.

[2] Assigned Commissioner's Ruling and Scoping Memo for the 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 (Scoping Memo), March 5, 2015, p. 4.

Chapter 2 discusses the reasonableness of terms and conditions for the DR contracts. Chapter 3 discusses the consistency of DR contracts with the CPUC's policy on backup generation. Chapter 4 discusses the vulnerability of DR contracts to derating. Chapter 5 discusses the unreasonableness of the 100 MW IFOM ES cap.

CHAPTER 2. THE DR CONTRACT'S TERMS AND CONDITIONS ARE UNREASONABLE AND ORA RECOMMENDS SEVERAL CHANGES TO THE DR CONTRACTS.

Witness: Sudheer Gokhale

The terms and conditions of the DR LCR contracts insufficiently protect SCE ratepayers from potential under or non-performance of NRG's DR contracts. In the Application SCE states that the DR contract for the LCR RFO is based largely on SCE's current Aggregator Managed Portfolio ("AMP") contracts.[3] ORA identified multiple issues with the terms of the AMP program contracts that persist with DR contracts in this proceeding (Offers 447200 – 447205 and 447250).[4] Here, ORA provides specific recommendations to improve the performance of these contracts.

- The DR service provider ("Seller") Should provide a list of participating accounts to support at least 50% of contract capacity for the month.
- SCE should pay for capacity based on all event hours during a month instead of the average Best-Performing Hours.
- SCE should modify the contract's default provisions to motivate performance and to help ensure participating accounts provide at least 50% of their contract capacity for each month.
- SCE should be required to conduct a test event within the first month to verify a contract's available capacity.
- SCE should revise the terms of the Seller Dispatch provision to require SCE to call the event within a 30 day period.
- SCE should clarify that the contracts are categorized as Supply DR resources under the CPUC's bifurcation categories.
- SCE should modify their contracts to prohibit dual participation of other DR programs with contracts.

[3] SCE Testimony, p. 69.

[4] These Offer numbers were designated by SCE.

A. THE SELLER SHOULD PROVIDE A LIST OF PARTICIPATING ACCOUNTS THAT CAN SUPPORT AT LEAST 50% OF THE CONTRACT CAPACITY FOR THE MONTH

In 2014, several of SCE's AMP contracts demonstrated that they had 0 MWs of customers.[5] [redacted][6] [redacted][7] ORA is concerned that the current SCE LCR RFO contracts could fail to achieve the goals of the RFO in avoiding procurement[8] if the Seller provides no customers, as discussed further in Chapter IV.

The contract terms in the Application similarly state that the Seller shall provide a list of "participating accounts" (i.e. customers) each operating month that will constitute the DR resource for that month.[9] The performance of the participating accounts is used to determine capacity and energy payments.[10] Similar to prior AMP contracts, if the Seller performs poorly, it faces no capacity penalty but may have an energy penalty. However, if the Seller provides no participating accounts for that month, it faces no energy penalties. SCE has stated that it is technically feasible for the DR contracts submitted in the Application to provide no participating accounts.[11]

ORA recommends that a default provision be added to Section 8 of the contracts stating that the Seller must have participating accounts in each month that are capable of providing at

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[5] Resolution E-4695, p. 11.

[6] November 25, 2014, Confidential Data Request Response R.13-09-011 DR OIR-ORA-SCE-04 Question 3, included as Attachment 2.1.

[7] *Id.*

[8] D.13-02-015, OP 4(g) "Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs."

[9] DR Pro Forma Contract Terms, Section 1.5(c).

[10] DR Pro Forma Contract Terms, Section 3.2 and 3.3.

[11] February 11, 2015, Data Request Response SET A.14-11-012 LCR RFO-ORA-SCE-005, Question 6. Included as Attachment 2-2.

least 50% of the contracted capacity.[12] ORA's Attachment 2-3 includes recommended redlines to the pro forma contract on this issue and other issues discussed within this testimony. The 50% is consistent with default provisions in Section 8.1(b) of the DR contract which requires 50% capacity to be delivered in three consecutive months or the contract would subject to default.[13] This default provision would penalize the Seller for failing to recruit and nominate participating accounts.

B. SCE SHOULD MODIFY ITS CONTRACT TO REQUIRE PAYMENT FOR CAPACITY BASED ON ALL EVENT HOURS DURING A MONTH INSTEAD OF THE AVERAGE BEST-PERFORMING HOUR.

ORA has previously expressed concerns regarding whether DR contract terms motivate the aggregators to provide a response for all hours of DR events and all events in a month.[14] Terms that calculate payments based on the best performing hour allow the Seller to simply provide a good response in one hour but the terms provide no incentive for the Seller to produce a consistent response across all hours.

The DR contracts in the Application determine payment based on calculations of performance in each Sub-Load Aggregation Point (SLAP). They add the performance in each SLAP to arrive at the calculation of performance for the entire portfolio of the contract.[15] Section 3.2 of the standard language in the DR contracts specifies that the calculations of performance are based on the average of each SLAP's *best* performing hour rather than all hours of each SLAP. For example, if a SLAP is called for multiple events in a month, only the best performing hour in each event would be averaged to determine the performance of the contract in that SLAP for that month. SCE would not consider poor performance across the other hours in these events to determine capacity payments.

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[12] DR Pro Forma Contract Terms, Section 1.5(c) the list of participating accounts the Seller shall provide to SCE includes an estimate of the total load drop capacity of the participating accounts.

[13] DR Pro Forma Contract Terms Section 8.1(b)(ii): "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 Full-Portfolio Dispatches have occurred."

[14] March 3, 2014, ORA Comments on Proposals for Revisions to Demand Response Program for Bridge Fund Years, p. 4-5.

[15] DR Pro Forma Contract Terms Section 3.2(c).

SCE claimed it remedied the LCR DR contract by the use of the average resource performance across the entire month to establish payment amounts.[16] Although this addresses the issue ORA raised with SCE's AMP contracts regarding the Seller's ability to receive full payment based on a single test event even if it performed poorly during rest of the month, it still fails to incent performance across all event hours during the month.

SCE should modify its contract to require payment for capacity based on all event hours during a month and not just based on the average of the best performing hour for each event in each SLAP. To assure performance in all event hours is also consistent with the CPUC's resource adequacy (RA) requirement that specifies that DR needs to perform a minimum of 24 hours a month and 4 hours per day for three consecutive days to receive RA credit.[17]

C. MODIFY THE CONTRACT DEFAULT PROVISIONS TO MOTIVATE PERFORMANCE AND TO HELP ENSURE PARTICIPATING ACCOUNTS PROVIDE AT LEAST 50% OF THEIR CONTRACT CAPACITY FOR EACH MONTH.

Section 8.1 (b) of the DR contact specifies that Sellers will default on the contract if they deliver less than 50% of contract capacity for three consecutive months during which Full-Portfolio Dispatches[18] occur.[19] ORA is concerned that this default provision is too easy to avoid. The Seller could simply provide a response for every third month to avoid default. Additionally, if SCE only calls a few specific SLAPs in a given month rather than the full portfolio, even with poor performance that drops the total recorded capacity to less than 50% of the contract capacity, the default provision would not be met because it was not the Full-Portfolio Dispatch required under the default provision.

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[16] A.14-11-012 SCE's Reply to Protests, p.9.

[17] CPUC Resource Adequacy requirements for DR (per 2015 Final RA Guide (DOCX) 9/10/2014: http://www.cpuc.ca.gov/NR/rdonlyres/70C64A46-89DE-4D90-83AB-93FD840B4251/0/Final2015RAGuide.docx).

[18] DR Pro Forma Contract Terms Definitions "Full-Portfolio Dispatch" means a Dispatch or Seller Dispatch of all Participating Accounts submitted and verified pursuant to Section 1.5 for a given Operating Month.

[19] DR Pro Forma Contract Terms Section 8.1(b)(ii) – "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 Full-Portfolio Dispatches have occurred."

While SCE states that the new requirement in its contracts for posting collateral will "motivate Sellers to perform at levels promised in their contracts,"[20] motivation for the Seller to perform is dependent on utility administration. If the utility is aware of issues with contracts but does not take action to resolve them, there is no real consequence to the Seller. In 2014, SCE was aware that multiple AMP contracts had no participating accounts for several months.[21] SCE had the ability to terminate these AMP contracts by calling and demonstrating that these contracts could not perform for consecutive months, but SCE did not call events and therefore the contract's default provisions were not applied.[22]

The default provision should be modified to make it more likely to motivate performance. ORA proposes the default provision, "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." This, in addition to the default provision discussed in Section 2.A of this testimony will help ensure there are at least enough participating accounts that can be expected to provide 50% of the Contract Capacity each month.

D. SCE SHOULD BE REQUIRED TO CONDUCT A TEST EVENT WITHIN THE FIRST MONTH OF A CONTRACT TO VERIFY A CONTRACT'S AVAILABLE CAPACITY

Under the contract terms, 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.[23] Therefore, ORA recommends a test event within the first month of the contract to verify a contract's available capacity. The CPUC recognized ORA's concern and adopted this testing requirement for SCE's 2015-2016 AMP contracts in Resolution E-4695.[24]

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[20] SCE's Reply, p. 9.

[21] September 17, 2014, Supplemental Response of the Office of Ratepayer Advocates to Southern California Edison Company's Re-Negotiated Aggregator Managed Portfolio Program Contracts in Compliance With Decision 14-05-025. (AL 3078-E), p. 3-5.

[22] SCE AMP contract Article 10: Events of Default; Termination.

[23] DR Pro Forma Contract Terms, 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."

[24] Resolution E-4695, p. 15.

It should similarly be applied to these contracts. ORA recommends the addition of an obligatory test event within the first month of the contract.

E. SCE SHOULD REVISE THE TERMS OF THE SELLER DISPATCH PROVISION TO REQUIRE SCE TO CALL THE EVENT WITHIN A 30 DAY PERIOD

The DR contracts allow the Sellers to set a three-day period in which SCE must call an event, called a "Seller Dispatch." SCE adjusts the Total Recorded Capacity[25] used to determine payments based on the Seller Dispatch.[26] The terms of the Seller Dispatch provide SCE discretion over when to call events but are not consistent with an actual dispatch event, which is called with at most 24 hour notice. Allowing the Seller to specify a short three day period during which the Seller knows an event will be called by SCE casts doubt on whether the Seller would perform equally well when SCE called an actual dispatch event.

ORA objects to the Seller Dispatch terms because they allow Sellers to game the system by knowing the exact three-day period in which an event will occur. As such the Seller will be able to prepare participants for the three-day period in advance so that the Seller can plan to meet their contracted capacity. Seller Dispatch event conditions should mimic actual dispatch conditions as much as possible. ORA recommends that SCE revise the terms of the Seller Dispatch provision to allow Sellers to request an event but require SCE to determine when the event occurs. ORA also recommends that SCE commit to call the event within 30 days of the request to deter the Seller's opportunity for gaming.

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[25] DR Pro Forma Contract Terms Section 3.2(c) "The "Total Recorded Capacity" for any particular Operating Month shall equal (i) if a Full-Portfolio Dispatch has occurred in such Operating Month, the sum of each SLAP's Average Best-Performing SLAP Hour for such Operating Month, and (ii) if a Full-Portfolio Dispatch does not occur in such Operating Month, subject to Section 3.2(a), the "Total Recorded Capacity" for such Operating Month shall equal the "Total Recorded Capacity" which was calculated with respect to the most recent Operating Month during which a Full-Portfolio Dispatch occurred."

[26] DR Pro Forma Contract Terms Section 3.2.

F. SCE should clarify that the contracts are categorized as Supply DR resources under the CPUC's bifurcation categories and meet all CPUC and CAISO requirements for receiving RA and LTPP credits as a Supply DR resource

In Decision ("D.") 14-03-026 the CPUC determined that all DR programs will be bifurcated into either Supply DR resources or Load-modifying DR resources.[27] In D.14-12-024, the CPUC determined that the bifurcation shall be implemented beginning in 2018.[28] D.14-12-024 ruled that only Supply resources that are integrated into CAISO's energy markets will count towards meeting the RA requirement while Load-modifying resources will need to meet the RA rules to reduce to RA requirement.[29] Although the Application does not state if these contracts will be Supply DR or Load-modifying DR, it appears from the RA Benefit provisions of the contracts that they are meant to meet all the compliance obligations to receive RA credit.[30] ORA recommends that SCE clarify that the contracts are categorized as Supply DR resources under the CPUC's bifurcation categories and meet all CPUC and CAISO requirements for receiving RA and LTPP credits as a Supply DR resource.

G. SCE should modify their contracts to prohibit dual participation of other DR programs with contracts

The CPUC allows dual participation in both energy and a capacity DR 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 is not allowed for two capacity programs in order to avoid paying twice for the same capacity. For example, a customer in the Base Interruptible Program ("BIP", a capacity program) could

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[27] D.14-03-026, p. 28.

[28] D.14-12-024, p. 84.

[29] *Id.*

[30] DR Pro Forma Contract Terms, Section 5.1(a). "Seller grants, pledges, assigns, and otherwise commits to SCE the full Contract Capacity of the DR Resource and all Resource Adequacy Benefits associated with the DR Resource in order for SCE to meet its Compliance Obligations. The Parties shall take all actions (including amending this Agreement and complying with all current and future CAISO Tariff provisions and decisions of the Commission, CAISO, and or any other Governmental Body that address resource adequacy performance obligations and penalties), and execute all documents or instruments necessary, to effect the use of the Resource Adequacy Benefits of the DR Resource for SCE's sole benefit throughout the Delivery Period."

also participate in the Demand Bidding Program ("DBP"), an energy program. Section 1.5(d) of the contract describes rules for dual participation of the contracts with SCE's current DR programs.[31] However, the CPUC's direct participation rules prohibit any dual participation of customers participating in CAISO's market, consistent with CAISO's resource registration rules. Rule 24, which addresses direct participation in the CAISO's market, states that, "Non-Utility DRPs[32] are also prohibited from enrolling and registering a customer service account in DR Services if the customer is already enrolled in a SCE's event-based demand response program."[33] Also, according to Decision 12-11-025, Ordering Paragraph ("OP") 8: "Demand 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, SCE should modify its contracts to clarify that any dual participation is prohibited.

H. NRG CONTRACT 447250 SHOULD BE MODIFIED TO PROHIBIT THE USE OF BUGS.

In SCE's testimony SCE states that NRG contract 447250 provides load reduction by curtailing customer energy consumption.[34] However, this curtailment could also be delivered through the use of BUGs. As discussed later, the use of BUGs to provide or enable DR that qualifies for RA credits is not allowed under the CPUC's policy on such use and the DR contract terms should not remain ambiguous. Therefore, ORA recommends inclusion of the following term in SCE's NRG contracts: "Seller will represent and warrant that none of its contracts use fossil fueled BUGs to provide or enable demand response load reduction."

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[31] DR Pro Forma Contracts 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."

[32] Demand Response Providers.

[33] 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.

[34] SCE Testimony, p. 70.

CHAPTER 3. NRG CONTRACTS 447200-447205 AND 447250 ARE INCONSISTENT WITH THE CPUC'S POLICY ON THE USE OF FOSSIL-FUEL BASED BUGS AS A MEANS OF PROVIDING DR.

Witness: Sudheer Gokhale

The use of BUGs in DR contracts is contrary to the CPUC's and the State's environmental policy goals and loading order and ORA recommends that DR contracts that use BUGs should be rejected.

SCE has included two distinct categories of DR contracts:[35]

(1) Contracts explicitly relying on the use of BUGs (NRG contracts 447200-447205): SCE states that these contracts provide load reduction from behind-the-meter ("BTM") backup natural gas fired generation. During a DR dispatch, backup generators would serve the customer's load and reduce the amount of energy served by the grid.

(2) Contracts allowing the use of BUGs (NRG contract 447250): SCE states that this type of contract provides load reduction by curtailing customer energy consumption but is silent whether such curtailment could be provided by BUGs.

A. CPUC POLICIES PROHIBIT THE USE OF BUGS IN DR PROGRAMS THAT RECEIVE RA CREDIT.

In CPUC decisions from 2006 to 2014, DR programs are prohibited from utilizing BUGs. In D.06-11-049 (Decision Adopting changes to 2007 DR programs), the CPUC addressed PG&E's proposal to initiate a DR program based on the use of BUGs and stated at p. 58.

> Our objective in funding demand response programs is to reduce system demand, not to substitute system 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 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.

[35] SCE's Testimony, p. 70.

Additionally, in D.06-11-049 the CPUC found in Finding of Fact ("FOF") 26 at p. 69, "Our objective in funding demand response programs is to reduce system demand, not to substitute system electricity with electricity generated by off-grid natural gas facilities."

More recently, in D.14-12-024, OP 10, the CPUC made a broad policy statement on the use of BUGs in DR: "Fossil-fueled back-up generation is antithetical to the efforts of the Energy Action Plan and the Loading Order." In OP 11, the CPUC explicitly prohibited the use of BUGs in DR that receives resource adequacy credits such as would be sought for SCE's NRG contracts in this RFO: "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."

B. THE CPUC SHOULD REJECT SCE'S ARGUMENTS THAT THE CPUC'S CURRENT POLICY ALLOWS THE USE OF BUGS IN DR

SCE argues that until the CPUC makes a final determination in Rulemaking ("R.")13-09-011 on the issue of whether it is prudent to allow the use of backup generation in DR programs, it is premature and improper to reject these contracts.[36] However, SCE ignores that the CPUC has *already* determined that fossil-fuel emergency back-up generation resources should not be allowed as part of a DR program for *RA* purposes and what remains is simply reflecting this policy in the next RA proceeding. SCE ignores the CPUC's direction on this issue and wants the ratepayers to take the risk that these contracts may not receive any RA credit. The value of the RA credit is the very foundation for having these contracts in the first place. This is especially galling given the term of these contracts extend all the way to 2026 and the next RA proceeding may ban the use of BUGs for RA purposes in DR programs even before these contracts begin in 2017. Therefore, the CPUC should reject SCE's arguments that the record is insufficient to make a determination of whether it is prudent to prohibit the use of backup generation in demand response programs at this time.[37]

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[36] *Id.*

[37] SCE's Reply, p. 7.

C. NRG OFFERS 447200-447205 SHOULD BE REJECTED BECAUSE THEY ARE BASED ON THE USE OF BUGS

D.14-12-024 demonstrates the CPUC's concern that BUGs may be participating in DR. It orders the collection of information on the extent of the use of BUGs in the current DR programs so the CPUC has information on that usage before those DR programs are modified.[38] However, in *this* Application there is no ambiguity about the extent of use of BUGs in NRG contracts (447200-447205). Even SCE stated that for DR contracts based on offers 447200-447205, backup generators *would* serve the customer's load while reducing the amount of energy served by the grid.[39] In fact, SCE differentiates these contracts from its only one other contract – NRG offer 447250, which is based on providing DR by *curtailing* customers' energy use.[40] There is simply no ambiguity about whether customers would be using BUGs in contract offers 447200-447205. They would. There is, therefore, no need to collect information on the use of BUGs to determine if they will be used as part of DR in *these* NRG contracts. SCE's testimony is clear that that DR provided in NRG's contract offers 447200-447205 is entirely based on the use of BUGs.

SCE's demand response contracts based on NRG offers 447200-447205 are inconsistent with the CPUC's policy on the use of BUGs in DR that receives RA credits and should be rejected.

D. DR CONTRACTS USING BUGS ARE NOT PREFERRED RESOURCES AND CANNOT BE RECLASSIFIED AS DISTRIBUTED GENERATION (DG) CONTRACTS.

In its reply to Sierra Club's protest, SCE argues that NRG DR contracts 447200-447205 do not need to qualify as DR to qualify as Preferred Resources. SCE states that these projects are distributed generation (DG) projects and DG projects qualify as Preferred Resources.[41] SCE is wrong. Although the BUGs used in these contracts are physically distributed in a way similar to DG, they are not considered DG under the State's Energy Action Plan II (EAP II). EAP II

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[38] In D.14-12-024, OP 14 requires collection of information about hourly usage of the customer's back-up generator and mapping the information against demand response events and load reductions.

[39] SCE Testimony, p. 70.

[40] *Id.*

[41] SCE's Reply, pp. 7-8.

distinguished clean and efficient fossil-fired generation from DG in its loading order and should not be listed as a preferred resource.[42] BUGs used in the Application would be considered fossil-fired generation and not DG resources under EAP II. Also, as noted earlier, in D.06-11-049 the CPUC has already rejected PG&E's request to initiate a BUGs-based DR program. Finally, if SCE wanted these BUGs-based contracts to qualify as DG, SCE should have presented them as such and not seek CPUC approval on an ad-hoc basis. Therefore, the CPUC should reject SCE's attempts to gain CPUC approval for contracts 447200-447205 as DG preferred resources.

[42] EAP II, p. 2. September 21, 2005,"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."

CHAPTER 4. THE DR CONTRACTS ARE VULNERABLE TO SIGNIFICANT DERATING. SCE SHOULD IMPLEMENT ORA'S RECOMMENDATION FOR CHANGES IN THE CONTRACT TERMS TO IMPROVE CONTRACT PERFORMANCE AND MINIMIZE POTENTIAL DERATING.

Witness: Sudheer Gokhale

All of the NRG DR contracts are vulnerable to significant derating. As discussed in Chapter 2, ORA found a number of deficiencies in terms and conditions of all of the NRG contracts regardless of the use of BUGs. If these deficiencies are not corrected prior to CPUC approval of the contracts, performance of the NRG contracts could be poor, similar to the poor performance of some of SCE's current AMP contracts. Poor performance adversely affects the ratepayers by 1) the ratepayers do not receive the full amount of capacity expected, and 2) poor performance of local capacity requirements ("LCR") contracts will result in reduction in the RA credit the contracts would have received if they performed well and the procurement they would have avoided in LTPP. The RA derating could require SCE to procure the RA capacity not provided by the contracts to meet its RA obligation.

Because SCE's contracts that rely on BUGs are contrary to the CPUC's policies, they are further vulnerable to a full derating. As noted above, OP 11 of D. 14-12-024 states that 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 DR program for resource adequacy purposes, subject to rules adopted in future RA proceedings. There is no indication that in any future RA proceedings the CPUCwill ignore its own policy (only recently adopted in D.14-12-024) and allow the use of BUGs as DR as is the case here with SCE's contracts 44700-447205. Even if the CPUC adopts an RA policy that allows partial or limited use of BUGs (which is not the case with SCE's contracts), significant derating of contracted RA capacity could still occur depending on the extent to which SCE relies on BUGs to provide DR.

The CPUC should not approve SCE's DR contracts based on the use of BUGs because such use is contrary to CPUC policy opposing the use of BUGs in DR. At a minimum, these contracts – and subsequently the ratepayers – will be subject to high risk of derating. The CPUC should require SCE to implement ORA's recommendations for changes to contract terms to improve contract performance and minimize potential derating because of poor performance.

CHAPTER 5. ORA RECOMMENDS REMOVING THE 100 MW IN FRONT OF THE METER ENERGY STORAGE CAP AND SELECTING THE 200 MW IFOM ES OFFER AT THE ALAMITOS SUBSTATION

Witness: Rosanne O'Hara

Due to SCE's inability to quantify the uncertainty prescribed to IFOM ES and its cost impacts, the resulting 100 MW cap is arbitrary. ORA recommends removal of this cap and alternatively proposes selecting [redacted]

A. THE 100 MW CAP ON IFOM ES IS BASED ON A SUBJECTIVE, QUALITATIVE ASSESSMENT

Utilizing least-cost, best-fit principles, SCE's offer evaluation process employs a net present value ("NPV") analysis when it evaluates offers submitted through an RFO.[43] The quantitative component of the evaluation entails forecasting: 1) the value of the contract benefits; 2) the value of the contract costs; and 3) the net difference between 1) and 2).[44] SCE calculates the value of the contract benefits by first forecasting each offer's quantity of RA capacity, electrical energy, and ancillary services ("AS") and then multiplying these quantities by the respective market price forecasts.[45]

Specifically for IFOM ES energy and AS contract benefits, SCE developed an economic dispatch model to determine optimal charge and dispatch of IFOM ES devices.[46] SCE's valuation of IFOM ES offers assumed unconstrained operations in CAISO markets leading to significant assessed AS revenues from participating in AS markets during all hours.[47] Inputs into this model include contractual terms and forecasted price streams for energy and AS.[48] The

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[43] SCE Testimony, p. 41.

[44] SCE Testimony, p. 41.

[45] SCE Testimony, p. 41.

[46] SCE Testimony, p. 43.

[47] SCE Testimony, p. 53.

[48] SCE Testimony, p. 43.

output of the model is the optimal operation and revenue earned by using the IFOM ES projects to arbitrage prices through time based on SCE's forecast of market conditions.[49]

In addition to the quantitative component of the LCR RFO evaluation process, SCE conducted a qualitative analysis of each project. SCE had IFOM ES qualitative concerns that resulted in SCE's decision to impose a 100 MW cap on the resource. These concerns included:

- The costs for necessary upgrades for ES charging;
- Unknown IFOM ES discharging and charging tariff details;
- Uncertainty around the interconnection of IFOM ES and how IFOM ES will actually participate in CAISO markets; and
- The additional risk for potential capital lease accounting and higher amounts of debt equivalence due to the possible inflated valuation of AS revenue for IFOM ES resources.[50]

SCE's uncertainty around the interconnection and market profitability of IFOM ES led SCE to assume that its IFOM ES valuation results may be higher than what will be achieved.[51] As such, SCE chose to limit the amount of procurement of IFOM ES in its optimization by imposing a 100 MW cap on IFOM ES. [redacted].[52] Therefore, SCE's imposition of the 100 MW cap is based purely on qualitative factors.

B. SCE's 100 MW Cap on IFOM ES is Arbitrary

Based on IFOM ES' nascent character, lack of historical participation in AS markets, and possible interconnection and market participation uncertainty, SCE assigned a 100 MW cap on IFOM ES procurement for its LCR RFO selection. SCE lacks a reasonable basis for imposing the 100 MW cap on IFOM ES. While SCE considered these risks as "qualitative concerns," they are more properly characterized as "costs" since the uncertainty SCE points to concerns cost impacts.[53] As such, SCE should have articulated and justified these cost constraints in SCE's

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[49] SCE Testimony, p. 43.

[50] SCE Testimony, pp. 16 and 53.

[51] SCE Testimony, p. 53.

[52] SCE Testimony, p. 62.

[53] For instance, higher debt equivalence could lead to a lower credit rating, which in turn could make

(continued on next page)

contract cost evaluation. SCE failed to propose parameters or probabilities for the cost impacts that uncertainty from interconnection, tariff treatment, treatment in the AS markets, and debt equivalence will have on IFOM ES costs or benefits. Also, SCE failed to identify incremental risks associated with uncertainty that warrants a 100 MW cap on IFOM ES as opposed to a lower cap. As such, choosing to cap IFOM ES without a quantifiable showing of how this constraint leads to a least cost, best fit solution is arbitrary.

1. SCE failed to substantiate its concern regarding interconnection uncertainty

SCE failed to qualify why uncertainty regarding how IFOM ES will interconnect weighed heavily enough to warrant a 100 MW cap on IFOM ES. In particular, SCE points to potential transmission upgrade[54] and interconnection costs,[55] the application of the CAISO's Transmission Access Charge (TAC),[56] and IFOM ES' tariff treatment[57] as barriers to IFOM ES project procurement. SCE failed to substantiate these concerns because: 1) SCE failed to quantify how the risk of excessive and unknown transmission upgrade costs would impact overall costs or how a 100 MW cap on IFOM ES would alleviate this risk; 2)IFOM ES Developers, not SCE, bear the risk of higher than anticipated interconnection costs; 3) the CAISO does not apply a TAC to ES; and 4) SCE's concern regarding uncertainty related to SCE's Rule 21, the Wholesale Distribution Access Tariff, or the Transmission Owner Tariff interconnection processes is unwarranted. As such, SCE's 100 MW cap on IFOM ES is unjustified.

(continued from previous page)

borrowing capital more costly for the utility and ratepayers.

[54] SCE Testimony, p. 16.

[55] SCE Testimony, p. 53.

[56] SCE Testimony, p. 16.

[57] SCE Testimony, p. 16.

a. SCE failed to quantify how the risk of excessive and unknown transmission upgrade costs would impact costs overall or how a 100 MW cap would alleviate this risk

SCE cites to IFOM ES procurement challenges that include uncertainties surrounding the costs associated with “necessary upgrades for the charging of ES.”[58] Nevertheless, SCE’s choice to cap IFOM ES procurement is not justified in light of the absence of quantitative cost impacts from this uncertainty.

SCE did not quantify how the risk of excessive and unknown transmission upgrade costs would impact costs overall. As elaborated by SCE in its response to an ORA’s Data Request, SCE did not require ES bidders to have interconnection studies initiated or completed for [redacted][60] [redacted][61] [redacted][62]

[redacted]

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[58] SCE Testimony, p. 16.

[59] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 03a, attached here as Attachment 5-1. [redacted]

[60] [redacted] February 20, 2015 Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 03a.

[61] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 01b(i), attached here as Attachment 5-2.

[62] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 01b(i).

[redacted][63] [redacted][64] Rather than resorting to an arbitrary cap because of "unknowns," SCE could have developed parameters for interconnection costs by considering existing transmission connections and load on the circuit when evaluating IFOM ES offers. From SCE's testimony and data request responses, it is unclear whether resource characteristics, i.e. substation location, cannot be the sole factor providing the risk mitigation SCE is seeking. It is even less clear why a 100 MW cap, as opposed to, say a 150 MW or 200 MW, provides the level of risk mitigation SCE is seeking since SCE has not articulated the incremental risks between varying MW constraints on IFOM ES.

b. IFOM ES Developers, not SCE, bear the risk of higher than anticipated interconnection costs

SCE's decision to cap IFOM ES at 100 MW due to uncertainty related to interconnection studies was unjustified because SCE expects IFOM ES developers to assume the risk of additional costs. [redacted][65] Under the RFO terms, IFOM ES developers are expected to bear the risk of higher interconnection costs. The Independent Evaluator report noted:

> ES bidders were encouraged to develop transmission cost estimates and translate these into transmission cost caps in the contracts and final offers. These transmission cost caps represent the limit for reimbursable network upgrade costs that a counterparty might encounter in the interconnection process. If the study's network upgrade costs ended up higher than the cap, SCE had the right to terminate the contract. Thus, bidders did not want to set this cap

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[63] February 20, 2015 Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 01b(ii). The characteristics of the resource were a single resource at the existing Alamitos site that will be interconnected at the transmission level (220 kV) in an area where there is less likelihood of charging restrictions and congestion. SCE Testimony at p. 75.

[64] February 20, 2015 Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 01b(ii) and (iii).

[65] SCE Testimony, Appendix D, pp. D-68 – D-69. See also SCE Testimony, p. 14.

> too low…. SCE (and Sedway Consulting) used the cap to calculate transmission cost adders in the evaluation of the final offers.[66]

In other words, the conservative estimates of transmission and interconnection costs were not only included in the final offers for IFOM ES resources, these costs were born by the developers, rather than SCE. This was consistent with the application process for other generation resources. Even with the transmission cost adders included in the bid prices, [redacted]

> [redacted][67]

This excerpt describing [redacted] further illustrates [redacted]

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[66] SCE Testimony, Appendix D, p. D-12.

[67] SCE Testimony, Appendix D, pp. D-68 – D-69.

c. SCE's concern as to whether the CAISO would assess a Transmission Access Charge (TAC) to IFOM ES in addition to the Locational Marginal Price is invalid

SCE noted that because the CAISO's charging and discharging tariffs "are not clear on whether grid-connected storage will pay transmission access charges,"[68] SCE imposed a 100 MW cap on IFOM ES. With the CAISO's clarification that a TAC will not apply to ES, there is no basis for SCE's concern and therefore, the 100 MW cap is arbitrary.

The CAISO released guidance on whether a TAC would apply to grid-connected storage on November 18, 2014 in its Final Draft Proposal on Energy Storage Interconnection. As noted by SCE, the CAISO clarifies the applicability of TAC in the "Draft Final Proposal:"

> Regarding the question of whether storage charging is subject to ISO charges normally assessed to load such as TAC and measured demand uplifts, storage charging is not subject to these under the [non-generator resources] NGR model.[69] The ISO does not allocate TAC to NGRs because NGRs are treated as generators and the TAC is allocated to load and exports, not generators.[70]

Furthermore, the CAISO "does not consider NGR resources in the charging mode as 'consuming' energy, but rather storing energy" for later resale in the CAISO's markets.[71] As part of its justification, the CAISO elaborated that "a storage resource fully dedicated to serving a reliability function and receiving all of its compensation through the TAC would be a woefully underutilized asset prohibited from participating in the market, and therefore unable to provide its full potential."[72] The CAISO clarified that IFOM ES will not be assigned a TAC. As a result, SCE's concern that a TAC applied by the CAISO may impact valuation of IFOM ES is negated.

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[68] SCE Testimony, p. 16.

[69] The NRG model was the initial model for ES devices to participate in ISO markets. NRGs are generation resources (As defined by the ISO tariff) with a MWh limitation that can be seamlessly moved within an operational range consisting of positive generation only, negative generation (charging) only, or positive and negative generation. November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 26.

[70] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 02a and b, attached here as Attachment 5-5. See also November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 27.

[71] November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 26.

[72] November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 32.

d. SCE's concern regarding uncertainty related to SCE's Rule 21, the Wholesale Distribution Access Tariff, the Transmission Owner Tariff, and the CAISO Tariff interconnection processes is unwarranted

SCE stated that there is uncertainty associated with interconnection of IFOM ES charging and discharging tariffs that contributed to the decision to cap IFOM ES procurement at 100 MW.[73] SCE identified the following interconnection tariffs:

- SCE's Rule 21 Tariff;
- SCE's Wholesale Distribution Access Tariff ("WDAT");
- SCE's Transmission Owner Tariff ("TOT"); and
- The CAISO Tariff.

SCE's decision to limit procurement of IFOM ES due to uncertainty related to SCE's Rule 21, WDAT, or TOT interconnection processes is not justified, as SCE did not require bids to follow these interconnection processes. Of the four tariffs SCE listed as contributing to interconnection uncertainty, only the CAISO Tariff applied to IFOM ES bids considered in the LCR RFO.[74]

Moreover, the CAISO did not need to change its existing Tariff rules to accommodate IFOM ES. Consistent with how energy storage is treated in the NGR model, the CAISO developed an approach whereby it treated energy storage resources as a "generator" for both aspects of its operation, i.e. charging and discharging.[75] By doing so, the existing Tariff rules accommodated ES interconnection. Furthermore, after examining ES' ability to behave as either a negative or positive generator, and to quickly switch between both, CAISO determined that its interconnection process[76] would be able to accommodate energy storage interconnection requests

[73] SCE Testimony, p. 16.

[74] Per phone conversation with SCE including Jesse Bryson and Tristan Reyes Close, at 3:30 P.M. PST on March 13, 2015.

[75] November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 3.

[76] This includes the Phase I Interconnection Study, which Queue Cluster 7 ES developers have already completed and Queue Cluster 8 ES developers will be required to complete.

without any further tariff charges.[77] Therefore, SCE's concerns regarding IFOM ES tariff treatment is insufficient to justify a 100 MW cap on IFOM ES.

2. SCE did not quantify the cost impact from potential over-valued IFOM ES ancillary service revenue and did not justify whether this potential cost outweighed the benefit of lower-cost IFOM ES bids

Contrary to SCE's assertions, the 100 MW cap on IFOM is arbitrary considering the transmission capacity of the Alamitos substation and SCE's failure to quantify incremental uncertainty that a larger IFOM ES project would have on SCE's costs. Uncertainty related to AS revenues from IFOM ES was one of the key reasons SCE decided to limit procurement of IFOM ES to 100 MWs. [redacted] nd [redacted][78] [redacted][79] [redacted][80] With these concerns in mind, SCE decided that AS revenue forecasts were overly optimistic and thus, decided to limit the procurement of IFOM ES. Nevertheless, the 100 MW cap on IFOM is unnecessary given the transmission capacity of the Alamitos substation and SCE's failure to quantify incremental uncertainty that a larger IFOM ES project would have on costs.

SCE mitigated AS market revenue concerns by selecting the AES Alamitos 100 MW storage project because the transmission interconnection at this particular circuit was less likely to experience congestion or charging constraints. The Independent Evaluator noted that:

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[77] November 18, 2014, CAISO Draft Final Proposal on Energy Storage Interconnection, p. 5.

[78] SCE Testimony, Appendix D, p. D-72.

[79] [redacted] SCE Testimony, Appendix D, p. D-72.

[80] SCE Testimony, Appendix D, p. D-72.

[redacted][81] [redacted][82]

SCE's decision to favor IFOM ES located at the Alamitos Substation is reasonable; however, it is not clear from the evidence provided by SCE whether the Alamitos substation does not also have sufficient available capacity for more than 100 MW of IFOM ES charging and discharging. [redacted][83]

Furthermore, SCE did not quantify or study the possible impact on profit from uncertainty stemming from the "optimistic" AS market performance and how IFOM ES will actually participate in CAISO markets. This unduly skews SCE's final assessment of IFOM ES. SCE also did not evaluate the duration or frequency that IFOM ES may be curtailed or the impact of curtailment on total revenues. Without any kind of sensitivity analysis, it is not possible to justify whether SCE's decision to cap procurement of IFOM ES at 100 MW and procure other more expensive resources was reasonable. SCE's decision to ignore better-valued ES resources in favor of other projects increases ratepayer costs without providing even an estimate of possible impacts to justify the additional expense. [redacted]

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[81] SCE Testimony, Appendix D, p. D-88.

[82] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 03b.

[83] SCE Testimony, Appendix D, p. D-89.

[redacted][84] Instead, the decision to cap IFOM ES at 100 MW resulted in additional procurement of [redacted][85] [redacted][86]

Similarly, the additional 100 MW of IFOM ES could have deferred the procurement of the 98 MW of peaking Gas-Fired Generation (GFG) from Stanton Energy Reliability Center, LLC (Wellhead). Replacing 100 MW of peaking GFG capacity with IFOM ES would directly contribute to the state's policy objectives, such as the 1.3 GW Energy Storage mandate. Replacing peaking GFG capacity with IFOM ES would also benefit ratepayers by reducing greenhouse gas emissions and diversifying SCE's preferred resources portfolio.

3. SCE assigns undefined risk to IFOM ES because of the effects of capital lease accounting treatment on IFOM ES contacts

SCE notes that its former IFOM ES contracts would result in capital lease accounting treatment, "which has an unacceptable level of debt equivalents."[87] [redacted][88] While credit ratings are important to utilities and ratepayers alike, SCE mitigated this concern through its inclusion of the Embedded Put Option into IFOM ES contracts.

Debt equivalence refers to a credit rating agency's practice of assigning risk factors and imputed amounts of debt to the fixed financial obligation of long-term contracts. Rating agencies modify their calculations of the utility's capital structure and related credit statistics by adding debt equivalence to the debt that is already on the utility's balance sheet.[89] Increased debt equivalence makes SCE's balance sheet more leveraged and reduces the quality of SCE's cash

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[84] SCE Testimony, Appendix D, p. D-89.

[85] SCE Testimony, p. 58.

[86] SCE Testimony, Appendix C, pp. C-1 – C-4.

[87] SCE Testimony, p. 33.

[88] SCE Testimony, Appendix D, p. D-21.

[89] SCE Testimony, p. 31.

flow in credit rating calculations.[90] Per D.04-12-048 and D.08-11-008, utilities can recognize the effect of debt equivalence on the utility's credit quality and cost of borrowing during its contract valuation processes. Consistent with these decisions, SCE considers debt equivalence in its valuation process using the 20 percent risk factor authorized by the CPUC, but does not believe that the risk factor is sufficient to capture the impact of debt equivalence here.[91] As such, SCE included an "Embedded Put Option" into IFOM ES contracts to disqualify it from capital lease accounting treatment.

SCE did not quantify how a 100 MW cap on IFOM ES procurement reduces the risk of greater debt equivalence. Nor does SCE evaluate the selection of offers with lower NPV or higher levelized net costs resulting from the imposition of a 100 MW cap against the risk of greater debt equivalence, especially considering that debt equivalence is generated for all resources that have a Power Purchase Agreement. For instance, GFG contracts for combined-cycle gas turbines also result in capital lease accounting treatment.[92] [redacted].[93] It is unclear what additional aspect of debt equivalence the 100 MW cap on IFOM ES will mitigate that was not already captured in the least-cost, best-fit evaluation process.

Moreover, SCE mitigated its underlying concern of a credit rating downgrade[94] by adding an Embedded Put Option to IFOM ES contracts. SCE determined the value of the Embedded Put Option to the seller, and the cost to the customer, by using results from a distribution analysis to derive the energy and AS value associated with dispatchable ES units.[95] The Embedded Put Option allows the seller to transfer annual control of the energy rights to SCE at a "put" price that SCE can modify up until CPUC approval of the contract. This results in

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[90] SCE Testimony, p. 32.

[91] SCE Testimony, p. 47.

[92] SCE Testimony, p. 33.

[93] SCE Testimony, Appendix D, p. D-70.

[94] SCE Testimony, p. 32.

[95] SCE Testimony, p. 47.

lower debt equivalence than the original assessed capital lease accounting treatment.[96] As stated by SCE, the Embedded Put Option "mitigated much of the identified risk associated with capital lease accounting"[97] because it results in lower debt equivalence than the original assessed capital lease accounting treatment.[98]

4. SCE did not sufficiently justify why it assigned additional risk to IFOM ES contracts stemming from the potential affect AS market prices might have on SCE IFOM ES contracts

SCE asserts that, due to the uncertainty of future AS market prices, the 100 MW cap mitigates excessive consequences from the put option that SCE incorporated into IFOM ES contracts. While SCE might face uncertainty, it did not quantify the cost impacts that seller action would have on IFOM ES NPV or justify why a 100 MW cap on IFOM ES is any more beneficial than a larger MW cap.

Specifically, SCE states that the put option "watered down the potential energy and AS benefits that would normally flow to benefitting customers"[99] because it could lead the seller to always either retain or put the dispatch rights to SCE.[100] The put option gives sellers the right to either retain or to give SCE the seller's dispatch and scheduling rights at a pre-set strike price.[101] The strike price considers IFOM ES' valuation in the AS market and would be established by SCE at contract execution.[102] SCE finds this problematic because, depending on AS market trends, market prices could make long-term strike price "always look decidedly favorable or

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[96] SCE Testimony, p. 33. SCE's Least-Cost, Best-Fit optimization model accounts for debt equivalents in the NPV of each offer. March 9, 2015 Data Request Set A.14-11-012 LCR RFO-ORA-SCE-008, Question 01c, attached here as Attachment 5-6.

[97] February 20, 2015, Data Request Set A.14-11-012 LCR RFO-ORA-SCE-006, Question 01d(i), attached here as Attachment 5-7.

[98] SCE Testimony, p. 33.

[99] SCE Testimony, Appendix D, p. D-21.

[100] SCE Testimony, Appendix D, p. D-21.

[101] SCE Testimony, Appendix D, p. D-21. If the option is exercised, the dispatch capability will be conveyed to SCE. If it is not, the seller will retain the dispatch rights and SCE will not receive any market revenues associated with the contract and will allocate 100 percent of the cost of the contract to all benefitting customers. SCE Testimony, p. 86.

[102] SCE Testimony, Appendix D, p. D-21.

unfavorable, causing the seller to always retain the dispatch rights . . . or always put the dispatch rights to SCE.[103]

SCE did not justify why the above detailed concerns warranted a 100 MW cap on IFOM ES. First, SCE set the strike price, not the seller, and thus, could have reasonably controlled the probability of the seller exercising the strike price. [redacted][104] Lastly, SCE did not quantify or identify what impact IFOM ES performance and participation in energy and AS markets or SCE's possible overvaluation of IFOM ES would warrant a cap specifically set at 100 MW. Therefore, the 100 MW cap on IFOM ES arbitrarily limits IFOM ES projects.

C. ORA RECOMMENDATIONS

ORA recommends that the 100 MW cap on IFOM ES be removed because it includes unreasonable projects and excludes reasonable offers. Furthermore, [redacted]

1. The 100 MW cap on IFOM ES should be removed because it results in the selection of unreasonable alternatives

With a cap on IFOM ES, SCE necessarily chose more offers from different energy sources, including GFG peakers and BTM ES, at a significant cost.[105]

The selection of the Wellhead GFG peakers, with a combined contract capacity of 98 MW, is an unreasonable option compared to other IFOM ES offers, including [redacted] because the Wellhead project incurs similar capital lease treatment as does IFOM ES [redacted] Similar to IFOM ES contracts, GFG contracts for combustion turbines also "result in capital lease accounting

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[103] A seller would always retain the dispatch rights if long-term market prices move higher than SCE forecasted while a seller would always put the dispatch rights to SCE if long-term market prices move lower than expected. SCE Testimony, Appendix D, p. D-21.

[104] SCE Testimony, Appendix D, p. D-72.

[105] SCE Testimony, p. 58.

treatment with unacceptable level of debt equivalents."[106] SCE was unable to use an Embedded Put Option for the 98 MW peakers because the energy and AS values associated with the low utilization peakers were too low and did not represent more than a minor amount of output.[107] In order to address the peakers' debt equivalence issue, SCE restructured its GFG contract into a RA contract. Therefore, debt equivalence concerns should not restrict bid acceptance. [redacted][108] [redacted][109] however, this results in a less cost-effective outcome. For instance, IFOM ES [redacted][110] [redacted] As an illustration, [redacted][111] [redacted][112] [redacted][114] Similarly, the NPV of [redacted]

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[106] SCE Testimony, p. 33.

[107] SCE Testimony, p. 61.

[108] SCE Testimony, Appendix D, pp. D-79 and D-89.

[109] [redacted] SCE Testimony, p. 62.

[110] Capacity payments represent the total fixed contract payments SCE is expected to make under the contract for delivery of the energy and capacity benefits. SCE Testimony, p. 46.

[111] Ice Bear SPV, LLC offer No. 431049.

[112] Hybrid-Electric Building Technologies, LLC offer No. 467009.

[113] Stem Energy Southern California, LLC offer No. 402039. [redacted]

[114] SCE Testimony, Appendix C, pp. C-1 – C-4.

[redacted][115] The table below illustrates this comparison.

Table 5.1[116]

Offer	LCR MW[117] and Technology	Capacity Price per kW-mo	Net Present Value (million)
AES ES Alamitos, LLC	[redacted]	[redacted]	[redacted]
Ice Bear SPV, LLC	[redacted]	[redacted]	[redacted]
Hybrid-Electric Building Technologies, LLC	[redacted]	[redacted]	[redacted]
Stem Energy Southern California, LLC	[redacted]	[redacted]	[redacted]

2. The 100 MW cap should be removed because it excludes reasonable alternatives

By limiting IFOM ES procurement, SCE excludes cheaper, better fit options. In addition to the 100 MW IFOM ES offer that SCE selected, [redacted] and [redacted]

In terms of locational benefits, SCE selected the AES 100 MW IFOM ES offer located at the Alamitos substation in part because of its locational benefits.[118] These locational benefits hold true for [redacted] In addition, CAISO determined that the Southwest sub-area of the Western LA Basin[119] is the most effective location, [redacted][120]

[115] [redacted]. SCE Testimony, Appendix C, pp. C-1and C-4.

[116] All cost information can be found at SCE Testimony, pp. C-1 to C-4.

[117] LCR MW is defined as the forecasted August 2021 net qualifying capacity ("NQC").

[118] [redacted] and are in a preferred location in regards to congestion, transmission capacity, and charging restrictions. SCE Testimony, pp. 57-58.

[119] SCE Testimony, p. 19.

[120] SCE Testimony, Appendix D, p. D-66.

Turning to the cost characteristics of [redacted] it is important to note that "in addition to meeting reliability criteria and consistency with the Loading Order, LCR procurement by SCE must be at least cost to ratepayers."[121] [redacted][122] [redacted][123] [redacted].[124]

3. [redacted] presents ratepayers with a more cost-effective option while also furthering the State's greenhouse gas reduction objectives

[redacted] offer presents ratepayers a more cost-effective option while also reducing reliance on GFG peaking resources compared to the combined selection of the 98 MW Wellhead project and the 100 MW IFOM ES offer. [redacted] results in an [redacted] savings as compared to the combined levelized costs of the 98 MW peakers and the 100 MW IFOM ES project.

This selection is also congruent with D.14-03-004.

> 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 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

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

[122] The levelized net cost is similar to SCE's $/kW-mo net cost metric except that SCEdoes not levelize the total dollar net costs but instead divides them by the sum of the of the kW-months of capacity associated with each offer. SCE calculated the net cost of offers by subtracting the net present value of the contract payments and debt equivalence costs from the net present value of the energy and capacity benefits. SCE Testimony, Appendix D, p. D-26.

[123] SCE Testimony, Appendix D, p. D-89.

[124] [redacted] SCE Testimony, Appendix D, pp. D-79 and D-89.

> proposal to ensure that SCE procures a higher percentage of authorized resources from preferred resources and energy storage.[125]

While ES is not defined as a “preferred resource” yet, it shares similar characteristics and the CPUC treats it in line with “preferred resources.”[126] 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 GFG resources in this LCR RFO.

In addition to the locational benefits and lower levelized net cost discussed above, the NPV [redacted] FG [redacted][127] [redacted] provides a [redacted] to ratepayers. Table 5-2, below, illustrates SCE’s selection of the 98 MW GFG project and the 100 MW IFOM ES project in comparison to the [redacted]

Table 5-2

	Wellhead 98 MW GFG CT and AES 100 MW IFOM ES projects	[redacted]	Difference between SCE’s selection and the [redacted]
Total Levelized Net Cost[128]	[redacted]	[redacted]	[redacted]
Total Net Present Value[129]	[redacted]	[redacted]	[redacted]

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

[126] 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).

[127] [redacted] SCE Testimony, Appendix C, p. C-1. [redacted] February 26, 2015 Data Request Set A.14-11-012 LCR RFO-Sierra Club- SCE-003, Question 09, at sheet titled [redacted] attached here as Attachment 5-4. See also, SCE Testimony, Appendix D, pp. D-79 and D-89.

[128] SCE Testimony, Appendix D, pp. D-79 and D-89.

[129] February 26, 2015, Data Request Set A.14-11-012 LCR RFO-Sierra Club- SCE-003, Question 09, at sheet titled “LCR Summary All Offers,” column J, line 1570.

Furthermore, [redacted] does not necessarily add risk in comparison to the combination of a 98 MW peaker and a 100 MW IFOM ES. 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. Similarly to the selected 100 MW IFOM ES project, the [redacted] set at [redacted][130] Furthermore, if [redacted], AES would have to assume the excess costs. [redacted] is a reasonable selection in light of the project's location, levelized net cost and capacity costs, NPV, cap on transmission upgrade costs, and the Embedded Put Option built into all IFOM ES contracts. Selecting [redacted] instead of the Wellhead peakers and the AES 100 MW IFOM ES project not only saves ratepayer money, but also reduces GHG emissions. Therefore, [redacted] is a more reasonable option than the cap proposed by SCE.

[130] February 26, 2015, Data Request Set A.14-11-012 LCR RFO-Sierra Club- SCE-003, Question 09, sheet titled "Component Discounted All Offers," at column I lines 69 and 543, attached here as Attachment 5-3.

APPENDIX A
QUALIFICATIONS OF WITNESSES

QUALIFICATIONS AND PREPARED TESTIMONY

OF

SUDHEER GOKHALE

Q.1. Please state your name and address.

A.1. My name is Sudheer K. Gokhale. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission (CPUC) as a Senior Utilities Engineer in the Office of Ratepayer Advocates (ORA) in the Electricity Resources and Pricing Branch.

Q.3. Briefly describe your educational background and work experience.

A.3. I have Bachelor of Science Degrees in Mechanical and Electrical Engineering from the University of Bombay and a Masters of Science Degree in Mechanical Engineering from the University of California at Berkeley.

From November 1980 to June 2005, I was employed by Pacific Gas and Electric Company (PG&E) in various capacities. I have testified before the CPUC as an expert witness for PG&E in several CPUC proceedings in the following areas: Nuclear and Fossil Plant Decommissioning, Depreciation Expense and Reserve, and Rate Base. I have been employed by the CPUC since July 2005. Since joining the CPUC, I have prepared protests and comments for ORA in numerous Demand Response proceedings before the CPUC.

Q.4. Are you a registered professional engineer?

A.4. Yes, I am a registered Professional Engineer in Mechanical Engineering and Electrical Engineering in the State of California.

Q.5. What is your area of responsibility in this proceeding?

A.5. I am responsible for ORA's testimony in SCE's Application No. 14-11-012 for the Demand Response contracts.

Q.6. Does that complete your prepared testimony?

A.6 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

ROSANNE O'HARA

Q.1. Please state your name and address.

A.1. My name is Rosanne O'Hara. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission (CPUC) as a Public Utilities Regulatory Analyst I in the Office of Ratepayer Advocates' (ORA) Electricity Planning and Policy Branch.

Q.3. Please briefly describe your educational background and work experience.

A.3. I received a Bachelor of Arts in International Studies, with an emphasis in Economics and Political Science from the University of California, San Diego. The relevant course work included economic policy and statistics. I also received a Master of Science from the London School of Economics in Development Management and a law degree from the University of California, Hastings College of the Law. Prior to joining ORA, I was a judicial extern and law clerk for the Administrative Law Division of the CPUC. As such, I reviewed comments, testimony, and briefs on a variety of water, transportation, telecommunication, and energy proceedings unrelated to the current proceeding. In March 2015, I joined ORA's Electricity Planning and Policy Branch and have been examining energy storage related issues.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 5.

Q.5. Does this conclude your statement of qualifications?

A.6. Yes.