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STATE OF CALIFORNIA
STATE ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: MISSION ROCK ENERGY CENTER	Docket No. 15-AFC-02 **RESPONSE TO NOTICE OF SUSPENSION OF APPLICATION FOR CERTIFICATION**

In accordance with 20 CCR § 1211.5, Wishtoyo Foundation ("Wishtoyo") files this timely response to Mission Rock Energy Center, LLC's ("Calpine")[1] Notice of Suspension of Application for Certification ("Motion to Suspend"), docketed on March 9, 2018,[2] and Calpine's subsequent Response to Committee Request for Comments on Applicant's Notice to Suspend Proceedings ("Subsequent Response"), docketed on March 19, 2018.[3] Wishtoyo respectfully requests that the Committee deny the Motion to Suspend and issue an order terminating this proceeding.

In its Motion to Suspend, Calpine sought to suspend its Application for Certification ("AFC") for an unspecified period of time and without an indication of what it will do to pursue the AFC with "due diligence" as required by 20 CCR § 1720.2. Calpine's Subsequent Response did little to change that. As set out below, instead of failing to specify the length of its requested suspension, Calpine has clarified that it is asking for a nearly three-year suspension of its AFC. Calpine's requested suspension is unreasonable and should be rejected.

Calpine acknowledges that it "does not appear" that there is "an opportunity for the Mission Rock Energy Center, as presently before the Commission, to participate" in the Southern California Edison ("SCE") Request for Offers ("RFO") to meet local area need. As Wishtoyo has already pointed out, it is *clear* that there is no need for this proposed project.[4] SCE's Procurement Plan for the Moorpark Sub-Area was first served on December 12, 2017, and amended on December 21, 2017.[5] The Procurement Plan was approved by the California Public Utilities Commission ("CPUC")'s Energy Division on February 7, 2018, and explicitly excludes procurement of a fossil-fueled power plant in Ventura County such as Mission Rock regardless of its

[1] Mission Rock Energy Center, LLC, "is a wholly owned subsidiary of Calpine Corporation." Mission Rock Energy Center Preliminary Staff Assessment at 3-1.
[2] TN# 222975.
[3] TN# 222999.
[4] TN# 222767-1 at 4-5.
[5] TN# 222767-1 at Attachment 1.

size or configuration.[6] As has been *clear* for some time, there is no way that the Applicant's project will be selected by SCE nor is it even eligible to bid in to the RFO. There is *no uncertainty* as to whether there is an "opportunity for the Mission Rock Energy Center" to participate in SCE's RFO—there is none.

Calpine also suggests that maybe—just maybe—there will be an opportunity for the project to move forward because it is "unclear" whether "reliability issues in the Moorpark Subarea created by the departure of 2,000 megawatts of local generation will be resolved by the proposed transmission solutions and procurement from the RFO." Calpine continued to feign uncertainty in its Subsequent Response, writing: "[t]he solutions to resolving local reliability issues in the Moorpark Subarea and overall system reliability are still being determined." Despite Calpine's suggestion, there is neither uncertainty about how to address the departures in the Moorpark Subarea, nor is there uncertainty about the viability of the proposed transmission and procurement solutions.

During the 2012 Long Term Procurement Process ("LTPP"), the CPUC considered the exact question that Calpine points to here. Specifically, the CPUC considered what the long-term local capacity requirements ("LCR") for the Big Creek/Ventura local area would be given that "the Ormond Beach and Mandalay power plants are [Once-Through Cooling] plants with four units that are scheduled to shut down per [State Water Resources Control Board] regulations before 2021. In total, these units currently have approximately 2000 MW of capacity."[7]

In fact, Calpine participated in that proceeding and argued that transmission alternatives could completely eliminate energy need in the Big

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[6] TN# 222767-1 at 4-5.

[7] California Public Utilities Commission, Decision 13-02-015, February 13, 2013, at 68. ("February 2013 CPUC Decision") (Appended hereto as Attachment 1.) (https://www.sce.com/wps/wcm/connect/259e4c0f-14a9-4c11-af81-ec3d896843af/D1302015_AuthorizingLongTermProcurementforLocalCapacityRequirements.pdf?MOD=AJPERES)

Creek/Ventura local area. As reported in the Decision Authorizing Long-Term Procurement for Local Capacity Requirements:

> Calpine sponsored an analysis that "suggests that there are potential transmission upgrades that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura local area." Specifically, Calpine argues that one of several transmission alternatives was identified by the ISO that can reduce the LCR need to 100 MW, while other transmission alternatives suggested by Calpine can reduce the LCR need to from zero to 230 MW.[8]

Ultimately, in its 2013 Track 1 decision, the CPUC decided—over Calpine's and others' objections—that it would "authorize SCE to start the process to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local area."[9] SCE undertook that process and selected NRG's Puente Power Project ("Puente") to fill that Track 1 decision. Now, Puente has been suspended and the California Independent System Operator ("ISO") has approved the transmission solutions like those Calpine identified during the 2012 LTPP.[10] Specifically, ISO approved the 2017-2018 Transmission Plan during its March 22, 2018, meeting, including Recommendation 2.7.5.6 which reads, in part:

> The Moorpark-Pardee 230 kV No. 4 Circuit Project was submitted by SCE to address the projected local capacity deficiency in the Moorpark local capacity sub-area. The project has an estimated cost of $45 million and involves

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[8] February 2013 CPUC Decision, at 70. *See also*, Track 1 Opening Brief of Calpine Corporation, March 22, 2012, at 6 ["The record does not support the near-term procurement of any new OTC replacement generation in the Big Creek/Ventura area as part of the Commission's Track 1 decision. As a next step in the evaluation of local reliability needs in the Big Creek/Ventura area, the Commission should direct SCE and the CAISO to perform further analysis of the Moorpark subarea, particularly with respect to transmission upgrades. Calpine agrees that potential transmission upgrades exist that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura area."] (Appended hereto as Attachment 2.)

[9] February 2013 CPUC Decision, at 73.

[10] California ISO, Board of Governors Meeting, (http://www.caiso.com/Documents/Agenda-Board_GovernorsMeeting-Mar21-22_2018.pdf)

> stringing a new Moorpark-Pardee 230kV circuit on existing structures and installing terminal equipment at Moorpark and Pardee Substations. The project was reviewed in light of the expected retirement of more than 2000 MW generation in the area and the suspension of proceedings for the Puente Power Project. The project was found to be needed and is recommended for ISO approval as it is the most effective and economic alternative in addressing the voltage stability and thermal loading impacts of the critical Moorpark sub-area contingency.[11]

As a result of this transmission upgrade, the CPUC has authorized SCE to procure a mere 76 MWs to meet local area need—all of which will be met with non-fossil preferred resources due on-line by 2021.[12] The new transmission line has a required in-service date of December 31, 2020.[13] Further, because the project will use existing structures and will not require a Certificate of Public Convenience and Necessity, there is little chance of significant delay in project completion.[14]

In its Motion to Suspend, Calpine points vaguely to processes occurring at the CPUC and ISO to suggest that there "policy changes currently under evaluation may further shape markets" in a way that would allow its proposed project to be revived. While it may be true that market shaping policy discussions are happening at those venues, it seems very unlikely that outcomes there will revive California's desire to build new gas-fired power plants. Indeed, the movement away from fossil-fueled power plants and the search for alternatives has only accelerated between the 2012 LTPP and now. A strong example of this shift can be seen in a concurrence to the CPUC's decision to reject a 10-year contract with the fossil-fuel fired Ellwood facility in

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[11] California ISO, 2017-2018 Transmission Plan, March 14, 2018, at 195. ("Transmission Plan") (Appended hereto as Attachment 3.)
[12] TN# 222767-1 Attachment 1, at 3.
[13] Transmission Plan at 196.
[14] Transmission Plan at 192.

the same general area[15], Commissioner Clifford Rechtschaffen summed up like this:

> The administrative law judge and President Picker conducted a careful examination of the unique energy needs in the Santa Barbara/Goleta area and rightly concluded that SCE did not demonstrate that this natural gas-fired peaker facility was a reasonable use of ratepayer dollars. More broadly, approval of this contract would have funded a 30-year refurbishment of the facility at a time when—absent a compelling reason to the contrary—all of our long-term investments in energy and infrastructure should be directed towards resources that provide the environmental and local benefits we need to achieve our clean energy and pollution reduction mandates. We may not always find the fossil-free alternatives that we are looking for, but we should always engage in a very hard look first to see if we can.

Of course, subsequent to this September 2017 concurrence, "fossil-free alternatives" were identified in the Moorpark area which resulted in the SCE RFO acknowledged by Calpine.

Calpine has requested that the Committee "suspend the processing of this Application to provide time for these issues to resolve." The reality is that the "issues" to which Calpine points have already been resolved. This project will not be able to bid into the current SCE RFO; the CPUC long-ago determined the long-term energy needs that would result because of the departure of 2,000 MWs of local generation; the solutions to address the local-area needs have been selected; and California is decisively moving our energy system into the 21st century, meaning that fossil-fueled power plants like Calpine's will likely be asked to provide a "compelling reason" to move forward. Calpine has not, and cannot offer any reason to expect that there will be a

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15 Public Utilities Commission, Decision 17-09-034, September 28, 2017, concurrence at 1. (Appended hereto as Attachment 4.) (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K810/196810195.PDF) Subsequently, and in line with Commissioner Rechtschaffen's concurrence, the CPUC did order SCE to secure preferred resource to meet the energy need in Moorpark sub area.

change that will result in a "compelling reason" for this project to be built in any configuration.

There is nothing Calpine can do during the 2 years, 9 months, and 9 days between now and January 1, 2021, to diligently pursue this Application. Given everything we know about California's energy policies and the constant progress of non-fossil energy technology, there is no reason the believe that this project will be more viable in 2021 than it is now. Therefore, Wishtoyo respectfully requests that this Committee terminate this proceeding.

DATE: March 23, 2018

/s/ Angela Johnson Meszaros
Angela Johnson Meszaros
Byron Jia-Bao Chan

Attorneys for Wishtoyo Foundation

ATTACHMENT 1

Decision **PROPOSED DECISION OF ALJ GAMSON**
(Mailed December 21, 2012)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

TABLE OF CONTENTS

TITLE **PAGE**

TABLE OF CONTENTS
(cont.)

TITLE **PAGE**

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

1. Summary

In this decision, we authorize Southern California Edison Company (SCE) to procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles (LA) basin local reliability area to meet long-term local capacity requirements (LCRs) by 2021. SCE is also authorized to procure between 215 and 290 MW of the Moorpark sub-area of the Big Creek/Ventura local reliability area. The LCRs require resources be located in a specific transmission-constrained area in order to ensure adequate available electrical capacity to meet peak demand, and ensure the safety and reliability of the local electrical grid.

For the defined portion of the LA basin local area, at least 1000 MW, but no more than 1200 MW of this capacity must be procured from conventional gas-fired resources. At least 50 MW must be procured from energy storage resources. At least 150 MW of capacity must be procured through preferred resources consistent with the Loading Order in the Energy Action Plan, or energy storage resources. SCE is also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In addition, SCE will continue to obtain resources which can be used in these local reliability areas through processes defined in energy efficiency, demand response, renewables portfolio standard, energy storage and other relevant dockets.

The long-term LCRs are expected to result from the retirement of thousands of MW from current once-through cooling generators due to compliance with State Water Quality Control Board regulations. We anticipate

that much of the additional LCR need currently forecast by the California Independent System Operator can be filled by preferred resources, either through procurement of capacity or reduction in demand. Preferred resources include energy efficiency, demand response, and distributed generation including combined heat and power. Energy storage resources may also be available.

In the next long-term procurement proceeding, expected to commence in 2014, we will evaluate whether there are additional LCR needs for local reliability areas in California.

SCE is directed to begin a solicitation process to procure authorized LCR resources. The first step is a plan to issue one or more Request for Offers and/or to enter into cost-of-service contracts per Assembly Bill 1576 (Stats 2005, ch. 374). SCE should also actively pursue locally-targeted and cost-effective preferred resources. SCE's procurement plan shall be consistent to the extent possible with the multi-agency Energy Action Plan, which places cost-effective energy efficiency and demand response resources first in the Loading Order, followed by renewable resources and then fossil-fuel resources. Energy storage resources should be considered along with preferred resources. SCE's procurement plan should take into account the technical reliability requirements of the California Independent System Operator. Energy Division will review SCE's adherence to these and other requirements before SCE commences its public solicitation process.

We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there will be no need for further LCR procurement based on current assumptions. If circumstances change, there may be a need for further LCR procurement in the next long-term procurement proceeding. We are confident that today's decision is the appropriate and considered step at this time.

SCE is directed to file an Application for each local reliability area seeking approval of contracts arising from the procurement process we authorize today. The Applications are expected in late 2013 or early 2014. Separately and earlier, SCE may also file applications for gas-fired generation in order to expedite review of such contracts. This decision establishes criteria for review of SCE's forthcoming Applications. A significant aspect of that review will be to ensure consistency with the Loading Order.

2. Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics[1]:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to

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[1] Scoping Ruling at 5.

consider authorization of investor-owned utility (IOU) procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling technology (OTC);

2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code § 454.5;[2] and
3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo divided the proceeding into three Tracks:

1. Track 1: Local Reliability
2. Track 2: System Reliability
3. Track 3: Procurement Rules and Bundled Procurement Plans

This is the decision for Track 1 of this proceeding. In recent years the California Independent System Operator (ISO or CAISO) has performed an annual Local Capacity Requirements (LCR) study, which is filed in the Commission's RA proceeding. This study is used to adopt local RA procurement requirements for the next year; for example, requirements for 2013 were adopted in Decision (D.) 12-06-025, in the 2012 RA proceeding (R.11-10-023).

In RA decisions, the Commission has focused on LCR for local reliability for one forward year. In the Local Reliability track of this proceeding, we consider authorizing long-term procurement of new infrastructure for local

[2] All statutory references are to the Public Utilities Code, unless otherwise noted.

reliability purposes for the years 2021 and beyond.[3] As the Scoping Memo stated, the end result of this track of the proceeding should be that the IOUs and/or other load-serving entities (LSEs) will be authorized or required to contract for local reliability needs over the next several years, to the extent that the Commission finds there is such a need.

The main driver of local capacity requirements is that around 4900 megawatts (MW) of OTC plants in the local transmission-constrained areas of the Los Angeles (LA) basin local area may retire in the next several years, as well as other OTC plants in the Big Creek/Ventura and San Diego local areas because of State Water Resources Control Board (SWRCB) regulations.[4][5] By 2021, approximately 7000 MW of OTC capacity is expected to retire in the LA basin local area and the Big Creek/Ventura local area.

"Once-through cooling" is a method to dispose of waste heat produced by a power plant (heat not converted into electricity) in which cold ocean or river water is pumped one time through the plant, absorbing and carrying out the plant's waste heat back into the ocean or river. Because the water pumped through the plant and back into the ocean or river can cause considerable stress on the local aquatic ecosystems, the result is considered as water pollution under Section 316(b) of the Federal Clean Water Act. In California, the SWRCB is the

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[3] A local capacity area is a geographic area that does not have sufficient transmission import capability to serve the customer demand in the area without the operation of generation located within that area.

[4] *See* State Water Resources Control Board Resolution No. 2010-0020, adopted on May 4, 2010, effective 9/28/2010; Attachment 1, Milestone No. 26 at 14.

[5] Issues related to infrastructure needs for the San Diego local area are being considered in Application (A.) 11-05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record.

state agency that enforces the Federal Clean Water Act. As part of such regulation, the SWRCB now requires that most of these aging coastal fossil-fuel plants become compliant with their policy by the end of the year 2020, with some exceptions with different dates. Compliance can occur either through changing cooling intake to no longer use once-through cooling, or by reducing entrainment by 93%. Most generators in their plans filed with the SWRCB have indicated that they are pursuing the first option, which implies retirement or repowering of the facility.

Table 1 shows the plants, locations and expected compliance dates for OTC plants in the LA basin and Big Creek Ventura local areas.[6]

[6] The San Onofre Nuclear Generating Stations (SONGS) plants are OTC plants, but are not included in this analysis.

TABLE 1

Once-Through Cooling Plants Compliance Schedule Per State Water Resources Control Board

Los Angeles Basin Local Reliability Area

Unit Name	Owner	NQC	Compliance date
		175	12/31/20
		175	12/31/20
		332	12/31/20
		336	12/31/20
		498	12/31/20
		495	12/31/20
El Segundo Unit 3	NRG	335	12/31/15
El Segundo Unit 4	NRG	335	12/31/15
Huntington Beach Unit 1	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 2	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 3	Edison Mission Energy	225	12/31/12
Huntington Beach Unit 4	Edison Mission Energy	227	12/31/12
Redondo Beach Unit 5	AES	179	12/31/20
Redondo Beach Unit 6	AES	175	12/31/20
Redondo Beach Unit 7	AES	493	12/31/20
Redondo Beach Unit 8	AES	496	12/31/20

Big Creek - Ventura Local Reliability Area

Unit Name	Owner	NQC	Compliance date
Mandalay Unit 1	GenOn	215	12/31/20
Mandalay Unit 2	GenOn	215	12/31/20
Ormond Beach Unit 1	GenOn	741	12/31/20
Ormond Beach Unit 2	GenOn	775	12/31/20

Units and compliance dates from:
http://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling0811.pdf

As noted, Table 1 excludes SONGS

* Net Qualified Capacity (NQC) from:
http://www.cpuc.ca.gov/NR/rdonlyres/C6BE7182-D647-4C70-B1AC-5D3A1CE207C3/0/CPUCNQCLocalAreaData_ComplianceYear2012.xls

In a settlement agreement approved by the Commission in D.12-04-046 in the previous long-term procurement plan Rulemaking,[7] parties to the agreement found that in the first quarter of 2012 the ISO would present a study of integration of renewable resources into local transmission-constrained areas, along with a study of the effect of potential OTC plant retirements. The adopted settlement included a recommendation that the Commission issue a decision by the end of 2012 on the need for sufficient resources to integrate the number of renewable resources coming online to meet a 33% renewable portfolio standard by 2020 and the retirement of OTC plants.

[7] This settlement was entitled: "Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green

Footnote continued on next page

Section 454.5(b)(9)(C) states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Consistent with this code section, the Commission has held that all utility procurement must be consistent with the Commission's established Loading Order, or prioritization. The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, was presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission (CEC) in October 2005. The Loading Order, which has been reiterated in multiple forums (including D.12-01-033 in the predecessor to this docket), requires the utilities to procure resources in a specific order:

"The 'Loading Order' established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (Energy Action Plan 2008 Update at 1.)

In the 2008 Energy Action Plan Update at 20, the Commission further interpreted this directive to mean that the IOUs are obligated to follow the loading order on an ongoing basis. Once procurement targets are achieved for preferred resources, the IOUs are not relieved of their duty to follow the Loading

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Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum."

Order. In D.07-12-052 at 12, the Commission stated that once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing. (D.12-01-033 at 19.) In D.12-01-033 at 21, the Commission recognized that procuring additional preferred resources is more difficult than "just signing up for more conventional fossil fuel generation," but consistency with the Loading Order and advancing California's policy of fossil fuel reduction demand strict compliance with the loading order.

This clarified Loading Order is a departure from the Commission's previous position of procuring energy efficiency and demand response, then renewable energy, and then allowing "additional clean, fossil-fuel, central-station generation," because "preferred resources require both sufficient investment and adequate time to 'get to scale.'" (D.04-06-011, footnote 22 at 31). Instead of procuring a fixed amount of preferred resources and then procuring fossil-fuel resources, the IOUs are required to continue to procure the preferred resources "to the extent that they are feasibly available and cost effective." (D.12-01-033 at 21.) While procuring a fixed amount of preferred resources provides flexibility and a clearer idea of how to approach the procurement process, the ongoing Loading Order approach is more consistent with Commission policy. (*Id.*)

A prehearing conference (PHC) was held on April 18, 2012. At the PHC, the ISO stated that it had completed a study of LCRs through 2016 in its Transmission Planning Process. The ISO also completed a study of local capacity needs related to expected or potential retirements of OTC plants through 2021. These studies are consistent with the studies anticipated in the settlement agreement adopted in D.12-04-046. In its comments on the scope of this proceeding and at the PHC, the ISO maintained that it cannot evaluate any additional renewable portfolio scenarios beyond those already in the record of R.10-05-006 in time for a decision by the Commission by the end of 2012.

In this proceeding, parties were given the opportunity to present evidence that the ISO's studies should be modified, or that the Commission should consider additional factors beyond the ISO's studies, for the purposes of determining local reliability needs. The Scoping Memo presented a list of specific issues for this phase of the proceeding.

The ISO served its testimony on May 23, 2012. Parties served testimony in response to the ISO and on issues from the Scoping Memo on June 25, 2012. The assigned Commissioner issued a Ruling on July 13, 2012 seeking clarification on certain issues raised in opening testimony. Parties (including the ISO) served reply testimony (including issues from the assigned Commissioner's Ruling) on July 23, 2012.[8] Evidentiary hearings were held August 7-10 and August 13-17, 2012. Briefs were filed on September 24, 2012 and Reply Briefs were filed on October 7, 2012. Per a Ruling issued September 14, 2012, comments were filed on October 9, 2012 regarding certain implementation issues arising from a workshop on September 7, 2012. This track of the proceeding was submitted on October 9, 2012.

The parties which served testimony in Track 1 of this proceeding are[9]: AES Southland (AES); Alliance for Retail Energy Markets, Direct Access Customer Coalition and Marin Energy Authority (collectively, AReM); California

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[8] Certain parties served supplemental and other versions of testimony on other dates with permission of the Administrative Law Judge (ALJ).

[9] Parties serving testimony that was subsequently stricken from the record are not included in this list.

Cogeneration Council (CCC); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA); CAISO or ISO; California Large Energy Consumer's Association (CLECA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); EnerNOC, Inc. (EnerNOC); GenOn Energy, Inc. (GenOn); Independent Energy Producers Association (IEP); Natural Resources Defense Council (NRDC); Pacific Gas and Electric Company (PG&E); San Diego Gas and Electric Company (SDG&E); Southern California Edison Company (SCE); South San Joaquin Irrigation District (SSJID); The Utility Reform Network (TURN); The Vote Solar Initiative (Vote Solar); and Women's Energy Matters (WEM). Testimony from each of these parties was received into evidence at the evidentiary hearing.

Each of these parties also filed comments and/or briefs. In addition, comments and/or briefs were filed by Alliance for Nuclear Responsibility (ANR); Beacon Power, LLC; City and County of San Francisco; Clean Coalition; Community Environmental Council; Distributed Energy Consumer Advocates; Ormat Technologies; and Sierra Club California (Sierra Club).

3. Long-Term Local Capacity Requirements for the LA Basin Local Area – Party Positions

3.1. ISO

Overall, the ISO recommends the long-term procurement of approximately 2400 MW in the LA basin local area to meet LCR needs in 2021, if the generation is selected from the most effective sites. This amount includes a specific identified need for 225 MW in the Ellis sub-area of the LA basin local area.[10] The ISO recommends that the Commission authorize this procurement by the end of 2012 and that SCE begins a contracting process in 2013. The ISO found that potential retirement of OTC generation in the PG&E service territory is not expected to create local capacity deficiencies.[11]

The ISO performed local capacity technical studies to determine the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system.[12] The ISO used power flow modeling as the basis for its recommendations. The ISO's recommendations for the amount of local capacity required to ensure that there is sufficient capacity to keep the lights on at all times are based on load circumstances that are projected by the CEC to occur once in 10 years,[13] and the assumption that the two largest generation or transmission failures occur nearly simultaneously in a local area.

In the previous Rulemaking (R.10-05-006), Commission staff provided the ISO with four scenarios consistent with the 33% renewables portfolio standard[14] (RPS).[15] These scenarios provided information for models tested by the ISO in

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[10] Exhibit ISO-1 (Sparks) at 17.

[11] Exhibit ISO-1 (Sparks) at 3.

[12] Exhibit ISO-1 (Sparks) at 3.

[13] Exhibit ISO-1 (Sparks) at 16.

[14] *See* Pub. Util. Code §§ 399.11-399.31.

[15] The four scenarios are: 1) Trajectory, or the current procurement path; 2) Environmentally-constrained, which focused on reducing land-use impacts; 3) the ISO Base Case, which was a modified version of the CPUC's cost-constrained case wherein cost was the primary consideration; and 4) the time-constrained case, which focused on attaining 33% renewables as quickly as possible.

that proceeding, based on analysis developed in the Commission's RPS proceeding. Due to the settlement adopted in D.12-04-046, such models were not used as the basis for a Commission decision, but these models remain available for use in this proceeding.

In opening testimony, ISO witnesses Rothleder and Sparks describe how in this proceeding they again modeled a number of possible outcomes for the ISO based on the same RPS portfolios. An important part of the modeling was the use of demand forecasts provided by the CEC in its 2010 Integrated Energy Policy Report (IEPR), which used 2009 demand forecast data. Rothleder describes certain modeling changes that led to different results from those produced in R.10-05-006.[16]

The ISO performed a local capacity technical study that "determined the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system."[17] While the ISO has performed annual short-term (one year out) local capacity studies for a number of years that are used in the Commission's RA proceedings, here the ISO performed a local capacity study that looked at a 10-year planning horizon.[18] This is the first time the ISO has performed this 10-year study.[19]

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[16] Exhibit ISO-4 (Rothleder) at 5-6.

[17] Exhibit ISO-1 (Sparks) at 3.

[18] Exhibit ISO-1 (Sparks) at 5.

[19] Reporter's Transcript (RT) 117.

The ISO performed its studies assuming that generation to meet LCR needs stemming from the assumed retirement of OTC plants would be met via repowering or replacement in the same locations as the OTC plants.[20] The ISO provided a range of forecasts for each RPS portfolio. The lower end of the range for the four RPS scenarios corresponds to the amount of generation needed if it were located at existing OTC sites that are the most effective at mitigating the identified transmission constraint. The higher end of the range corresponds to the amount of generation needed if it were located at existing OTC sites that are the least effective at mitigating the identified transmission constraint.[21] In the various studies, the ISO found an LCR need of at least 1870 MW for the most effective sites, and up to 3896 MW for less effective sites in the LA basin local area served by SCE. Specifically, the LCR need would be in the Western LA portion of the LA basin local area (a transmission-constrained sub-area of the LA basin).

Several parties challenged the ISO's methodology, as discussed herein. The ISO maintains that no party presented a valid alternative to the ISO's methodology, which it describes as "a deterministic approach based on Northern American Electric Reliability Council/Western Electricity Coordinating Council planning criteria and ISO tariff requirements."[22]

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[20] Exhibit ISO-1 (Sparks) at 2.

[21] Exhibit ISO-1 (Sparks) at 6.

[22] ISO Opening Brief at 2.

No capacity from demand response[23] was included in any ISO analysis because the ISO "does not believe that demand response can be relied upon to address local capacity needs, unless the demand response can provide equivalent characteristics and response to that of a dispatchable generator." The ISO claims "demand response does not have these characteristics at this time."[24]

Nor does the ISO include any demand reduction for uncommitted energy efficiency or uncommitted combined heat and power (CHP) in its forecasts.[25] Uncommitted energy efficiency and uncommitted CHP are potentially viable energy efficiency programs or CHP installations not already included in the 2009 CEC demand forecast, regardless of actions taken after that forecast. The ISO contends that it has "no basis for expecting that uncommitted energy efficiency and uncommitted CHP generation can be counted upon for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[26]

Table 2 shows the various outcomes of the ISO studies.

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[23] There appears to be price-responsive demand response built into the CEC demand forecast, but not other demand response programs.

[24] Exhibit CEJA x ISO-1 at 3.

[25] These resources are termed either "incremental" or "uncommitted." Either term refers to resources beyond the amounts embedded in the CEC's demand forecast.

[26] Exhibit ISO-1 (Sparks) at 15.

TABLE 2

Summary of ISO Studies by RPS Portfolio

Local Area	Local Area Requirements (MW)				Replacement OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes sub-area below)	10,743	11,246	11,010	12,165	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin (sub-Area of the larger LA Basin)	7,797	7,564	7,517	7,397				
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)			
					430	430	430	430

In each of the four RPS scenarios, the ISO model included assumptions of distributed generation MW, and non-distributed generation MW for 2021; all scenarios assumed the same demand forecasts from the CEC. Tables 3 - 6 show the ISO's distributed generation and non-distributed generation assumptions for each scenario.[27]

[27] Exhibit ISO-1 (Sparks) at 7-9.

TABLE 3

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Trajectory	Overall LA Basin	12,961	339	13,300	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western	7,529	268	7,797	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	59	284	Yes	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 4

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western	6,695	869	7,584	Yes	Serrano- Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	124	349	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 5

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	Local Area Reqm't D.G. (MW)	Local Area Reqm't Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Base	Overall LA Basin	12,659	271	12,930	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western	7,325	192	7,517	Yes	Serrano-Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Ellis	225	39	264	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 6

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	Local Area Reqm't D.G. (MW)	Local Area Reqm't Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western	6,954	443	7,397	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	61	286	Yes	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

The ISO recommendation is based on the Trajectory scenario because "the Trajectory scenario studied in the OTC studies is the scenario most aligned with commercial interest."[28] The ISO also believes this scenario best reflects future

[28] Exhibit ISO-1 (Sparks) at 17.

load growth and renewable generation development.[29] The Trajectory scenario forecasts a need for 2370 MW in the LA basin local area, which Sparks rounds up to 2400 MW.[30] This forecast includes a specific need for 225 MW in the Ellis sub-area.

In supplemental testimony, Sparks describes a sensitivity analysis performed at the request of this Commission, the CEC and the California Air Resources Board (CARB), to study a variation on the Environmentally Constrained portfolio. As part of the sensitivity analysis, demand reduction from 1950 MW of uncommitted energy efficiency and 201 MW of additional CHP was included in the model,[31] as provided by the three state agencies and adjusted for the LA basin local area (as part of 2461 MW of uncommitted energy efficiency and 209 MW of uncommitted CHP for the entire SCE territory).[32] For the Western LA basin sub-area, 1121 MW of uncommitted energy efficiency was included in this analysis, and 180 MW of CHP.[33]

According to this testimony, the results of this sensitivity analysis show a need of 1042 MW needed in the Western LA section of the LA basin local area for 2021 for effective sites, with the range reflecting the same effectiveness considerations as described above.[34] This compares to 1870 MW for effectives sites for 2021 in the Environmentally Constrained scenario in Table 2 herein. The

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[29] ISO Opening Brief at 3.

[30] RT 197-198.

[31] Exhibit ISO-9 at (Table 3.4-1).

[32] Exhibit ISO-2 (Sparks) at 2-3.

[33] RT 137-143; Exhibit CEJA x ISO-1 at 2-3.

[34] Exhibit ISO-2 (Sparks) at Table 2.

sensitivity analysis also models the Del Amo-Ellis 230 kilovolt line loop-in project in service, based on updated information in the ISO's supplemental testimony that the ISO Board has now approved this project for 2012. This project eliminates the need for local generation in the Ellis sub-area in this scenario.[35]

The ISO does not recommend relying upon its sensitivity analysis to make a determination as to local area needs in this proceeding. Sparks testified that the ISO does not believe it is prudent to rely on uncommitted resources (such as uncommitted energy efficiency and CHP) for assessing future local needs. Further, Sparks testified that "deliberately conservative forecasts must be employed in the assessment of reliability requirements for capacity in constrained areas since the consequences of being marginally short versus marginally long are asymmetric. A marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[36] Further, Sparks testified that there is "uncertainty" concerning both uncommitted energy efficiency and incremental CHP which makes it imprudent to include these potential resources in the ISO forecasts.[37]

Sparks testified that it is necessary to begin the procurement process for 2021 local capacity needs in 2013 "to ensure we don't forgo the best options, and also to make sure that the options that are available are actually feasible."[38]

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35 Exhibit ISO-2 (Sparks) at 2-3.

36 Exhibit ISO-2 (Sparks) at 3-4.

37 Exhibit ISO-2 (Sparks) at 5-6.

38 RT 199.

3.2. SCE Position

SCE generally agrees with the ISO's analysis identifying a 2021 need for up to 2370 MW of existing LCR generation in the LA basin local area to remain in service or be replaced with similarly located generation (also known as, or up to 3741 MW if new generation cannot be placed at the most effective sites in the local area.[39] SCE seeks authority to start a process in 2013 to enter into contracts for between zero MW and 3741 MW in the LA basin local area.

SCE seeks flexibility in conducting any LCR procurement that is needed. In general, SCE would prefer not to procure resources to meet system needs and to make long-term commitments that would subsequently be rendered less valuable by changed circumstances.[40] SCE "prefers procurement of new LCR generation through a new multi-year forward procurement auction, such as a capacity market or a new generation auction administered by the CAISO" but acknowledges that such a mechanism is not currently available.[41]

Due to uncertainty in forecasts, SCE describes input assumptions in the ISO models that may change based on new information, and which could lead to a higher or lower need for LCR resources than the ISO identified. These include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options.[42] SCE witness Minick testified that another variable in determining long-term LCR needs is accurate

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[39] Exhibit SCE-1 (Cushnie/Silsbee/Minick) at 1, 3-5. SCE uses a slightly different definition of "effective" and "less effective" sites than the ISO.

[40] Exhibit SCE-1 (Cushnie) at 2.

[41] Exhibit SCE-1 (Cushnie) at 1.

[42] Exhibit SCE-1 (Minick/Cabbell) at 5-9.

identification of when the OTC plants are expected to close. He points to the potential for extensions of SWRCB deadlines and other changes surrounding OTC regulations as uncertainties in determining need.[43]

Minick also testified that the ISO did not recognize the potential for increased distributed generation, assumptions for uncommitted energy efficiency or increased localized generation, all of which would lower the load on the transmission system.[44] In reply testimony, SCE cites concerns raised by many parties about the ISO's assumptions regarding the availability and use of preferred resources, agreeing with claims by parties that higher levels of preferred resources than forecasted by the ISO will reduce or eliminate the need for new LCR generation in SCE territory.[45]

Despite these uncertainties, SCE witness Silsbee testified that at least some new generation procurement needs to occur to meet LCRs in the LA basin local area. He points to difficulties in constructing new generation in the LA Basin local area, which mean that it might take 7 to 9 years to develop new replacement generation. While there are uncertainties about the dates when OTC plants will cease to operate, there are also uncertainties around the lead time for generation permitting and construction. Therefore, Silsbee testified that there is a need to start initial procurement processes soon; for example, with a Purchased Power Agreement (PPA) entered into and approved by the Commission in 2013, it would potentially take until 2020 or longer for the plant to become operational.[46]

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[43] Exhibit SCE-1 (Minick) at 10.

[44] Exhibit SCE-1 (Minick) at 7.

[45] Exhibit SCE-2 (Silsbee) at 4.

[46] Exhibit SCE-1 (Silsbee) at 16-17.

3.3. DRA Position

DRA recommends the Commission defer a decision on SCE's LCR procurement, in order to allow the Commission to take into account final adopted planning standards in Track 2 of this proceeding that relate to distributed generation standards. DRA also recommends a transmission study to determine if there is further potential to increase imports into constrained areas, and ways to upgrade current transmission facilities. If the Commission authorizes SCE to procure LCR resources, DRA recommends authorization of no more than 169 MW for the LA basin local area for 2021 and no more than 278 MW for this area for 2022.[47]

DRA witness Fagan testified that "the risk of not procuring now is minimal if not zero," and that there is not a technical reliability risk in waiting another two years to make the LCR determination.[48] DRA's concern is that the Commission could authorize procurement of fossil-fuel plants now, when preferred resources may materialize soon which would obviate the need for some fossil fuel resources. Alternatively, DRA recommends that there be an opportunity to revise the LCR need determinations after 2012 planning assumptions are finalized.[49]

DRA has significant concerns about the ISO models for LCR needs. Fagan testified:

> …the CAISO's modeling analyses overestimate the range of deficiency of resources needed to meet 2021 local capacity

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[47] Exhibit DRA-6 (Fagan) at 4.

[48] RT 924.

[49] Exhibit DRA-3 (Spencer) at 12.

> requirements in the LA basin…primarily by either excluding or minimizing the effect that preferred demand side resources, including uncommitted energy efficiency and demand response, can have on projected peak load in these areas by 2021."[50]

Fagan calculates that LCR needs are lowered by more than 40% from the ISO's estimates of 1870 to 2664 MW in the Environmentally Constrained scenario (*see* Table 2) to only 828 to 1207 MW when the additional resources are included in the Environmentally Constrained scenario sensitivity analysis (*see* Table 3).[51]

Fagan testified that the ISO's primary modeling estimates are too high primarily because they exclude all uncommitted energy efficiency and all demand response resources. He believes these resources will be available and should be considered when planning for future year procurement needs.[52] Fagan recommends reducing the ISO forecast by 957 MW of uncommitted energy efficiency and 1550 MW of demand response.[53] Fagan acknowledges that these figures are part of a load and resources table, which is a simpler tool than the ISO's power flow model, and does not consider sub-areas; nevertheless, he contends that DRA's method is appropriate for a procurement proceeding.

DRA witness Spencer testified that the ISO has not properly accounted for the amount of preferred resources (including demand response, energy efficiency and renewable resources) expected to be available to reduce load or

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[50] Exhibit DRA-1 (Fagan) at 2-3.

[51] Exhibit DRA-1 (Fagan) at 2-3, 12-20. There are some methodological differences which cause a variation between DRA's figures and the ISO's figures.

[52] Exhibit DRA-1 (Fagan) at 17.

[53] Exhibit DRA-1 (Fagan) at 18, Table RF-2.

meet electricity demand. He maintains that "failure to adequately account for such resources increases the risk of over-procurement,"[54] including underutilized assets and "crowding out" of preferred resources. Further, over-procurement poses the risk of additional expenses for ratepayers.[55] In other words, ratepayers would pay to reduce load and increase supply, but would then (under the ISO recommendation) also be required to pay for additional supply as if the first set of funded initiatives did not exist.

Spencer also contends State policy goals should be given weight when considering the ISO 2021 local capacity needs recommendations. Specifically, California Governor Brown recently called for the development of 12,000 MW of distributed generation by 2020.[56] While the ISO recommendation of the Trajectory scenario includes 339 MW of distributed generation for the LA basin local area, it also modeled (but did not recommend) the Environmentally Constrained scenario with 1519 MW of distributed generation. DRA supports using the Environmentally Constrained scenario because DRA contends it is in line with California's commitment to distributed generation goals.[57]

3.4. TURN Position

TURN recommends that the Commission authorize procurement sufficient to satisfy 2/3 of the LCR needs sought by the ISO, due to problems with the ISO forecasts. Specifically TURN witness Woodruff contends that the ISO forecasts are "moving targets" that can vary significantly with each new iteration of the

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54 Exhibit DRA-3 (Spencer) at 1.

55 Exhibit DRA-3 (Spencer) at 3.

56 Governor Jerry Brown, Clean Energy Jobs Plan at 3; June 2010.

57 Exhibit DRA-3 (Spencer) at 8-9.

study.[58] TURN contends that both over-procurement and under-procurement would be costly, but that the ISO ignores the potential costs to ratepayers and focuses only on the "extremely low risk of criteria violations that could potentially result from significant shortage under extraordinarily stressed system conditions."[59]

TURN recommends that the Commission task SCE with procurement of any new local resources authorized in this docket, as the only practical option. TURN recommends that the Commission adopt one or more mechanisms to mitigate potential market power issues and other LCR procurement challenges. Possible mitigations measures include:

- Holding RFPs to seek the most competitive replacements for OTC resources, even in sub-areas in which there are currently no known alternatives to an OTC unit. Such RFPs should solicit both conventional generation and non-fossil alternatives.
- Providing minimum and maximum procurement targets to ensure truly needed amounts are procured but prevent procurement of capacity that will not necessarily be needed.
- Implementing some type of "circuit breaker" mechanism to allow procurement of lower amounts of capacity should prices of one or more bids greatly exceed a reasonable cost.
- Providing procurement in the most logistically challenging areas first, such as the Ellis and Moorpark sub-areas.[60]

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58 Exhibit TURN-1 (Woodruff) at 7-9.

59 TURN Opening Brief at 6.

60 Exhibit TURN-1 (Woodruff) at 2-3.

3.5. Environmental Parties' Positions

CEJA, NRDC, Sierra Club and WEM all contend that the ISO local capacity methodology should not have excluded significant amounts of uncommitted energy efficiency, CHP, demand response and energy storage. CEJA claims that "CAISO's results are inherently conservative and call for greater MW than will actually be needed."[61] NRDC claims "the amount of efficiency included in the CAISO's assessment of local capacity needs is unreasonably low because it excludes all savings from future energy efficiency policies, as well as some that were recently adopted."[62] Sierra Club contends that the ISO "uses worst case, unrealistic assumptions," such as modeling for outages which have not occurred in the last 10 years.[63] WEM argues that omitting certain categories of uncommitted energy efficiency "will lead to major forecast errors."[64]

Vote Solar recommends the Commission make a finding of LCR need for the total of the LA basin local area and the Big Creek/Ventura local area of between 800 MW and 1700 MW, depending on location.[65] However, Vote Solar recommends authorizing SCE to procure some of the identified LCR needs via gas-fired plants (preferably in the most efficient locations), but to wait a few years to see how much uncommitted energy efficiency, demand response and

[61] Exhibit CEJA-1 (Powers) at 4.

[62] Exhibit NRDC-1 (Martinez) at 1.

[63] Sierra Club Opening Brief at 5-6.

[64] Exhibit WEM-1 (George) at 10.

[65] Vote Solar Opening Brief at 2, 4-5.

distributed photovoltaic installations will be available for delivery to reduce LCR needs by 2020.[66]

CEJA's analysis foresees additional resources, including additional transmission fixes, which can lower the LCR need in the LA basin local area for 2021. CEJA contends that these added resources tend to be available when most needed and are distributed geographically. CEJA claims that the ISO's failure to consider or include uncommitted energy efficiency, demand response, incremental CHP and all available distributed generation is unreasonable. CEJA concludes that, after including these additional resources, the actual LCR need under each of the four RPS scenarios is "likely zero."[67] Sierra Club also recommends a finding of zero LCR need for the LA basin local area.[68]

CEERT contends that the ISO assumed higher customer loads than adopted as State policy, inconsistent with the Loading Order. While CEERT is concerned that the ISO's forecasts are based upon relatively rare contingencies, CEERT does recommend finding procurement of no more than 1800 MW for LCR needs in this proceeding.[69] However, CEERT wants the Commission to identify eligibility requirements and performance metrics for preferred resources that can meet LCR needs, before authorizing LCR procurement.[70] CEERT would

[66] Exhibit Vote Solar-1 (Gimon) at 4-5.

[67] Exhibit CEJA-3 (May) at 2-3.

[68] Sierra Club Opening Brief at 19.

[69] CEERT Opening Brief at 30.

[70] CEERT Opening Brief at 4-5.

allow non-traditional resources (those other than gas-fired resources) to submit bids in any solicitation to fill this need, consistent with the Loading Order.[71]

3.6. Other Party Positions

PG&E recommends that the LCR need determination should be based on the ISO study, because the ISO uses a conservative approach without modification for uncertain resource availability. PG&E also recommends that the Commission not establish any preferred resources set-asides in this proceeding.[72] SDG&E recommends that the ISO's LCR determinations should be accorded considerable weight by the Commission. SDG&E endorses SCE's position that SCE be authorized to procure up to the LCR amounts recommended by the ISO, with review by the Commission of SCE proposed contracts.[73]

CLECA contends that new generation can be operational in less than 7 to 9 years in some circumstances, such as by getting plants to the point of construction but only paying for an option to build if necessary. CLECA suggests the Commission could authorize development contracts that include permitting and site development but do not include construction, effectively creating an option for expedited development of new generation if and when it is needed.[74] CLECA also contends that the ISO, due to its obligations with respect to grid reliability, recommends over-procurement compared to what are required under NERC/WECC standards, leading to excessive ratepayer costs.[75]

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71 Exhibit CEERT-1 (Caldwell) at II-3 - II-4.

72 PG&E Opening Brief at 4-9.

73 SDG&E Opening Brief at 3-11.

74 CLECA Opening Brief, p. 28.

75 CLECA Opening Brief, pp. 12-19.

IEP contends there is a need for some form of replacement capacity for the potential retirement of at least some OTC units, and that IOUs should procure LCR resources through competitive solicitations, or cost-of-service contracts.[76] IEP recommends a "somewhat more conservative approach" to determining LCR needs in order to ensure that firm load curtailments do not occur.[77] IEP proposes an "Incremental Need" calculation to set procurement targets; the Commission would authorize IOUs to procure resources at the level recommended by the ISO, but acknowledge that other resources might become committed in the future.[78]

EnerNOC criticizes the ISO for leaving various preferred resources out of its forecasts, focusing on the exclusion of demand response resources.[79] EnerNOC recommends the Commission find an LCR need for the LA basin local area of 2400 MW minus a MW amount reflective of expected growth of preferred resources in the local area, as an interim target. EnerNOC recommends the Commission reconsider the level of LCR need in the next long-term procurement proceeding, expected in 2014.[80]

Calpine recommends that any procurement authorized in this proceeding to satisfy LCR needs not be granted until system needs have also been determined in Phase 2 of this proceeding. Calpine contends that such an approach will put the IOUs in a better position to identify the least cost/best fit

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[76] Exhibit IEP-1 (Monsen) at 5-11.

[77] Exhibit IEP-1 (Monsen) at 20-21.

[78] Exhibit IEP-1 (Monsen) at 5-11.

[79] EnerNOC Opening Brief at 4-15.

[80] EnerNOC Opening Brief at 15.

mix of resource options to satisfy both local and system needs.[81] Calpine also recommends adopting procurement rules to ensure all viable technologies, resources and solutions are considered by the IOUs to satisfy local and system reliability needs. This would include gas-fired plants, preferred resources and transmission alternatives and upgrades.[82]

AES calculates a need for approximately 2300 MW at certain OTC locations in the LA Basin local area. Therefore, AES finds the ISO recommendation for approximately 2400 MW at effective locations to be consistent with its own analysis.[83]

CCC disagrees with the ISO that uncommitted energy efficiency and CHP should be excluded from LCR forecast models. CCC argues that the ISO's reliance on the CEC's IEPR misses more recent developments with regard to CHP. Specifically, CCC points to Commission approval of the "QF/CHP Settlement Agreement" in D.10-12-035 which has led to IOUs conducting their initial Request for Offers (RFOs) to procure 2000 MW of CHP capacity.[84] CCC also cites to more recent CEC efforts to update its projections for future CHP development in California.[85]

ANR endorses the ISO's Trajectory scenario estimate for the LA basin local area, but has strong reservations about the future availability of SONGS and a 600 MW transmission transfer. ANR contends the risk of over-capacity is smaller

[81] Exhibit Calpine-1 (Barmack) at 1, 4.

[82] Exhibit Calpine-1 (Barmack) at 5.

[83] Exhibit AES-1 (Ballouz) at 1-2.

[84] Exhibit CCC-1 (Beach) at 6-7.

[85] Exhibit CCC-1 (Beach) at 7-8.

than the risk of under-capacity.[86] ANR recommends that Track 1 of this proceeding be continued after the Commission decision issues for the purpose of adjusting the determined LCR need, in order to take into account new information contained in the upcoming ISO 2012-2013 Transmission Plan.[87]

4. Long-Term Local Capacity Requirements for LA Basin Local Area – Discussion

4.1. Statutory Guidance

The Legislature has stated its policy goals relating to reliability, reasonableness of rates, and a commitment to a clean environment in the "Reliable Electric Service Investments Act," codified as § 399(b). This statute protects these divergent interests by ensuring investments in the integrity of the grid, in a sizeable and well trained utility workforce, in cost-effective energy efficiency improvements, in a sustainable supply of renewable energy, and in research and development that will advance the public interest.

The Commission is also bound by the RA Requirements in § 380. Section 380(c) states:

> Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

The implementation of RA serves to ensure system reliability as well as siting and construction of new resources. Section 380 requires LSEs to maintain 100% of forecast load available as well as a 15% reserve. LSEs are also required

[86] ANR Opening Brief at 21.

[87] ANR Opening Brief at 22.

to demonstrate to the Commission that sufficient Local RA resources have been procured in order to meet the needs of transmission constrained Local Areas.

A primary responsibility of this Commission is to ensure reliability in the electrical system. It would neither be prudent nor responsible to allow the system to fail and the lights to go out when we reasonably could have avoided such deleterious outcomes. Similarly, the primary mission of the ISO is to ensure reliability in the California electrical grid. Section 345 states:

> The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council.

A significant difference between the ISO's reliability mission and the Commission's reliability emphasis is that the Commission must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates and a commitment to a clean environment. These considerations stem from both statute and Commission policy consistent with statute.

Regarding reasonableness of rates, § 451 states in pertinent part:

> All charges demanded or received by any public utility… shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Further, § 454 states:

> Except as provided in Section 455, no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

There are a number of statutes which require the Commission to implement procurement-related policies to protect the environment. As a primary example, the Commission's RPS program is established in §§ 399.11-399.31. As discussed in Section 2, the Loading Order was established both in the Energy Action Plan and in statute.

In this decision, we strike a balance among the Commission's three primary statutory directives for ensuring reliability, reasonable rates and a clean environment. We cannot, and will not, sacrifice or ignore any of these imperatives. Nor need we do so; the record in this case supports outcomes which enable us to accomplish all our goals, meet statutory requirements and direct utilities to procure sufficient levels of diverse resources in a timely manner at a reasonable cost so as to ensure reliability. We now turn to the specific details.

4.2. Assumptions

ISO witness Sparks acknowledged that forecasting one year ahead is easier than 10 years out, with the 10-year forecast entailing more uncertainty on many factors.[88] Referring to the sensitivity analysis of the Environmentally Constrained scenario (which includes assumptions of more distributed generation, more uncommitted energy efficiency and more demand response than the Trajectory scenario), Sparks testified that the ISO study methodology "would need to be revisited if we were to actually see these types of changes to the resource supply in the area."[89] Because of the difficulty in assessing forecasts 10 years into the future done for the first time, it is necessary to carefully assess

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[88] RT 79.

[89] RT 81.

the assumptions in such forecasts and to build in a method to revisit the forecasts when more information is available.

Sparks further testified:

> The ISO has no basis for expecting that uncommitted energy efficiency and uncommitted combined heat and power generation can be counted on for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[90]

However, we do have a basis for considering an estimate of such resources in our analysis. We discuss such estimates below.

Sparks claims that "the consequences of being marginally short versus marginally long are asymmetrical" because "a marginal shortage means a loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[91] DRA disagrees. DRA witness Spencer cites costs reaching over one billion dollars (plus annual maintenance costs) as being very significant and not simply marginal.[92] In addition, there are significant environmental detriments to building and running more fossil-fuel power plants than necessary.

ISO witness Millar agrees that if reliability needs are met through natural gas generation, but more distributed generation occurs than the ISO forecasts, this would increase ratepayer costs (although he contends "that is a consequence

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[90] Exhibit ISO-1 (Sparks) at 15.

[91] Exhibit ISO-2 (Sparks/Millar) at 4; Exhibit DRA-3 (Spencer) at 16, citing Rebuttal Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, A.11-05-023, June 4, 2012 at 3.

[92] Exhibit DRA-3 (Spencer) at 16, citing PG&E's pending Oakley power plant Application (A.12-03-026).

of having to move forward in the face of uncertainty.")[93] Presumably, increased ratepayer costs would also occur if more energy efficiency or other resources than in the ISO models came to fruition. On the other hand, as already noted herein, the ISO contends that delaying procurement can result in lost opportunities due to a potential seven to nine year lead time for certain plants to go from proposal to operational.

We agree with the ISO that under-procurement entails significant risks. We also agree with DRA and others that over-procurement entails significant risks. We do not agree with the ISO that one error is necessarily more problematic than the other; neither error is desirable if avoidable. Nor can the consequences of either outcome be easily quantified; neither the ISO nor anyone else has quantified these consequences.[94]

Our intent is to neither authorize over-procurement nor under-procurement. However, the procurement process is of necessity imperfect because it relies on future forecasts. One benefit of a long planning horizon is the opportunity to adjust to the inevitable changes in circumstances. We will balance the potential for lost or limited opportunities to procure certain resources with long lead times against the opportunities to reconsider circumstances in the future.

The ISO used power flow modeling to develop its scenarios to forecast LCR needs. SCE agrees with this approach because it takes into consideration transmission constraints and limitations in specific local areas.[95] DRA proposes

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93 RT 474.

94 RT 499-503.

95 Exhibit SCE-2 (Cabbell) at 16.

using a load and resources table. While DRA's approach has its benefits, there is general agreement that the ISO's modeling is more sophisticated and precise. We find the use of the ISO's power flow modeling to be reasonable for these purposes.

Sparks agreed that the precision of the ISO's power flow simulation is "completely dependent" upon the accuracy of the input assumptions, and that if the input assumptions vary, then the results would vary.[96] Therefore, it is important to consider whether any major assumptions used by the ISO should be revisited.

4.2.1. One-in-Ten Year Load, with Two Major Contingencies

The first question is whether the ISO's general methodology is reasonable. In our RA proceedings, we use ISO forecasts with a one-in-10-year load forecast, with two major contingency outages, to assess LCR needs one year in advance. In this proceeding, the ISO for the first time extended this methodology out to 10 years in advance.

A number of parties question whether the ISO's approach is appropriate. CEERT and others raise the issue of whether we should authorize procurement of up to several thousand MW of capacity based on a rare set of circumstances – essentially (as CEJA puts it) a "scenario that two import pathways to SCE's territory are unavailable on the hottest day in 10 years."[97] ISO witness Sparks testified that this situation in the LA basin local area has never

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[96] RT 167.

[97] CEJA Opening Brief at vii, 6-8.

occurred in the last 10 years.[98] The ISO did not analyze any scenario with only one contingency.

We recognize that the ISO models use assumptions of rare and unusual circumstances, which may never occur. However, this methodology is well-tested in our RA proceedings as a means of procurement of resources for local reliability purposes. As PG&E points out, the Commission must ensure the system will be reliable under a variety of possible future states, including a high load stress condition.[99] While the circumstances underlying the methodology are (hopefully) rare, the consequences of not having sufficient resources in such a rare situation would be extremely serious. We generally will use the ISO methodology for consideration of LCR needs, with the caveats concerning inputs discussed herein.

4.2.2. OTC Plant Compliance Schedule

The next question to consider is whether the OTC plants are likely to retire according to the compliance schedule presented in Table 1 herein. The schedule determined by the SWRCB is beyond our jurisdiction. However, we can consider relevant factors in the record that might influence whether the schedule will hold.

ISO witness Sparks testified that the ISO participates in a SWRCB committee called the Statewide Advisory Committee on Cooling Water Intake Structure (SACCWIS). In that committee, Sparks stated that the ISO "would seek to adjust the [OTC retirement] schedule" if it determines that reliability cannot be

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[98] RT 120.

[99] PG&E Opening Brief at 6.

met within the schedule.[100] If the retirement schedule is delayed for one or more plants past 2020, there could be a reduction in the local reliability need for the LA basin local area. In addition, Sparks testified that the continued operation of OTC plants was one possible way to meet local needs.

ISO witness Millar testified that there are a range of mitigation options in lieu of the addition of generation by SCE, if reliability cannot be met. He continued that these options may "fall within our current framework and our current authorities as well as should we be seeking additional authorities in order to advance the necessary reinforcements." For example, continuation of procurement already under ISO contract and consideration of load-shedding are other options. However, he also stated that while "[t]here is no framework to simply delay compliance with once-through cooling" retirement deadlines, working with the SWRCB to consider changing deadlines would be an option (but not "a given").[101]

If the Commission authorizes procurement based on the current OTC plant closure schedule, there could be over-procurement to the detriment of ratepayers and the environment if the plants do not close as scheduled. DRA contends that several OTC plants in the LA basin local area have asked for partial deadline extensions of up to six years.[102] DRA claims that the SACCWIS in March 2012 recommended considering extension deadlines on a unit-by-unit basis.[103] CEJA contends that SWRCB OTC policy does not require any coastal OTC plants to

[100] RT 193 - 194.

[101] RT 447-456.

[102] Exhibit DRA-2 (Siao) at 5.

[103] Exhibit DRA-9.

actually retire, but allows these plants to remain operating should they comply with one of two tracks in the OTC policy (new cooling technologies or unit-by-unit measures to reduce marine impacts). CEJA claims many OTC units will not retire but will comply with one of the two tracks.[104] CLECA points out that delaying implementation of the OTC policy is an option for some limited period of time if it takes a little longer to implement full mitigation of the LCR consequences of this policy or to resolve some of the uncertainties that are currently driving the expected cost of LCR mitigation.[105]

We are aware of some efforts by specific OTC plant owners to comply with one of the SWRCB tracks to avoid retirement. However, there is at this time insufficient evidence that any change to the OTC deadlines in Table 1 will occur. As CLECA suggests, it may be that the ISO will request a delay in the OTC closure schedule in order to ensure ongoing reliability. While we do not anticipate such a delay, if any extensions to OTC closure deadlines do occur, this can be taken into account in future procurement proceedings or in review of a procurement application by SCE. At this time, it is reasonable to accept as a fact that, based on information available today, OTC plants will close as per the SWRCB schedule in Table 1.

4.2.3. Transmission

DRA contends that there are transmission fixes that may be able to offset some of the local capacity needs identified by the ISO. However, DRA acknowledges that it remains unclear whether additional cost-effective

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[104] Exhibit CEJA-1 (Powers) at 27-30.

[105] CLECA Opening Brief, p. 25.

transmission solutions are available that can reduce LCR need, and recommends further study. [106]

SCE agrees with DRA that the ISO did not consider certain transmission mitigation that could reduce LCR need,[107] but contends that the ISO's transmission infrastructure assumptions are reasonable.[108] SCE witness Cabbell testified that every year SCE evaluates the transmission grid and (with the ISO) looks for feasible and cost-effective transmission fixes.[109] However, she also asserts that there are challenges to reducing the local capacity need through transmission fixes, including the viability of construction of new transmission lines in the LA basin local area, increased need for voltage support for upgraded transmission, and a 7-to-10 year lead time to put in new transmission lines.[110] ISO witness Millar testified that "we have identified the…low-hanging fruit where transmission reinforcement was a viable way to reduce local capacity requirements" and these reinforcements were included in the ISO forecasts.[111]

CEJA contends that the ISO should have assumed in its models a 600 MW transmission load transfer to resolve the most critical contingency for the overall LA basin involving the Mira Loma West transmission line. According to CEJA, this transfer would significantly lower levels of LCR in the LA basin, if

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106 Exhibit DRA-1 (Fagan) at 4-5. Also *see* RT 907-910 and DRA Opening Brief at 24.

107 Exhibit SCE-1 (Cabbell) at 8-9.

108 Exhibit SCE-2 (Cabbell) at 16.

109 RT 778.

110 Exhibit SCE-2 (Cabbell) at 17-18; RT 798.

111 RT 421.

feasible.[112] The ISO states that "it is a reasonable assumption to base the 2021 local area generation on the proposed [600 MW] mitigation." The ISO also states that it has had preliminary discussions with SCE on this matter, but needs to obtain a cost and schedule for such an upgrade from SCE.[113] SCE witness Cabbell testified that SCE has not performed any technical analysis or power flow modeling on this proposal, which would require further investigation with the ISO. However, she understands that this mitigation measure could be useful for reducing the LA basin local area LCR but not necessarily the Western LA basin sub-area LCR.[114]

We find there is no conclusive evidence that any assumptions used by the ISO with regard to transmission capacity and contingencies are not appropriate. It is possible or even likely that there are certain mitigation options for transmission constraints or certain transmission upgrades which were not fully considered by the ISO and which may become feasible. It is also possible that certain transmission fixes may become feasible and cost-effective, including the use of synchronous condensers, static var compensators and shunt capacitors, all of which SCE considers annually.[115] In future procurement proceedings and in SCE's procurement application, we may be able to incorporate new information about transmission upgrades and new transmission capacity.

We find the ISO's transmission assumptions to be reasonable for use in this proceeding in determining LCR procurement authorizations.

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[112] Exhibit CEJA-3 (May) at 4-7.

[113] Exhibit CEJA-3 (May) at 6 (from ISO response to CEJA request No. 8).

[114] RT 782; 828.

[115] RT 173; 780-781.

4.2.4. Demand Assumptions

The ISO used the 2009 mid-energy demand case of the Final California Energy Demand Forecast of the CEC for 2010 - 2020, prepared as part of the CEC's 2010 IEPR, as the basis for its demand assumptions in its power flow models.[116] In and of itself, no party disputed that this forecast was reasonable. We agree. However, this is not the end of the analysis. We now consider whether there are elements of demand that should be considered in addition to or as supplements to that forecast.

4.2.4.1. Energy Efficiency

The ISO included in its modeling the amount of energy efficiency included in the CEC 2009 demand forecast (mid-energy forecast). This amount includes a significant amount of energy efficiency stemming from programs approved by the Commission through the IOUs (such as lighting programs and appliance efficiency programs)[117] and statewide programs approved by the CEC (such as building standards). This amount does not include any uncommitted energy efficiency. Several parties recommend adding in some forecast of uncommitted energy efficiency, which would decrease demand and, if located effectively, decrease local capacity needs.

As SCE witness Cushnie notes: "Energy efficiency can't address all of the needs of the electric system."[118] This includes meeting all technical requirements to directly reduce LCR needs. However, energy efficiency does directly reduce

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[116] This forecast was posted on May 30, 2012 on the CEC website.

[117] *See* D.12-11-015 for the most recent Commission-approved energy efficiency programs for IOUs.

[118] RT 688.

electrical demand, which indirectly reduces local capacity requirements. The question before us is whether some amount of uncommitted energy efficiency is certain enough to reduce demand through 2021.

IOU energy efficiency programs are funded on a three-year cycle basis (with occasional one-year extensions.) After the three-year cycle concludes, these resources are not considered committed in the CEC demand forecast analysis used by the ISO. As DRA witness Fagan points out, this does not mean the resources are not available. He testified that, due to the State policy of placing energy efficiency first in the Loading Order, "it is a relatively safe bet that funding will continue and that those resources will show up."[119]

NRDC contends that uncommitted energy efficiency levels in the CEC's 2009 Incremental Impacts Report[120] is what the CEC stated should be subtracted from the its base forecast. The CEC uncommitted energy efficiency forecast from 2009 included all anticipated energy efficiency programs from 2013-2020, all building code improvements between 2006 and 2020 and all appliance standards improvements between 2005 and 2020.[121] NRDC and CEJA list a number of energy efficiency programs which have already been adopted and are already saving energy, but which were excluded from the ISO forecasts because they were categorized as uncommitted.

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[119] RT 904-906.

[120] *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, CEC, May 2010. See* excerpts in Exhibit CEJA-2 at 75-77.

[121] Exhibit NRDC-1 (Martinez) at 3-4.

CEJA contends that the CEC's 2009 Incremental Impacts forecast for uncommitted energy efficiency is actually conservative, as it includes a low realization rate for "Big Bold Energy Efficiency Strategies" (BBEES) adopted as goals by this Commission in D.07-10-032 and in our 2008 Energy Efficiency Strategic Plan.[122] One of the BBEES is that all new commercial construction will be zero net energy by 2030.[123] As evidence that the BBEES are becoming more likely to be realized, CEJA points to Governor Brown's Executive Order B-18-12 which calls for 50% of California state government commercial buildings to reach zero net energy by 2025.[124]

ISO witness Millar agreed that the CEC demand forecast from the 2009 IEPR used by the ISO did not include BBEES or other uncommitted energy efficiency programs.[125] Examples of such programs already adopted or already in place include:[126]

- California's 2008 Title 24 Building Code;
- California's 2010 Title 20 Lighting Standard;
- California's 2010 Television Efficiency Standard;
- California's 2012 Title 20 Battery Charge Standard;
- California's 2013 Title 24 Building Code; and

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[122] Exhibit CEJA-1 (Powers) at 5.

[123] The other BBEES are: a) All new residential construction in California will be zero net energy by 2020; b) Heating ventilation and air conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and c) all eligible low-income customers will be given the opportunity to participate in the low income energy efficiency program by 2020.

[124] Exhibit CEJA-1 (Powers) at 3.

[125] RT 445-447.

[126] Exhibit NRDC-1 (Martinez) at 4-5.

- Several Federal standards on appliances such as water heaters and clothes washers.

Energy efficiency is first in the Loading Order set forth in the Energy Action Plan. Our commitment to cost-effective energy efficiency has been consistent, and the resources we have approved for IOU energy efficiency programs have grown considerably over the last several years. In D.09-09-047, we approved approximately $3.2 billion in energy efficiency funding for 2010 through 2012. As required by statute, we fully expect to continue to fund all cost-effective energy efficiency into the foreseeable future. Recently, in D.12-05-014, we adopted 2013-2014 IOU energy efficiency portfolios, with estimates of 576 MW of energy savings statewide and 293 MW in SCE territory specifically.[127] Thus there is good reason to expect that California's commitment to energy efficiency will continue, if not strengthen. The likelihood that stretch energy efficiency goals will be achieved was enhanced by the November 6, 2012 passage of California Proposition 39, which (among other things) provides for $500 million per year in additional energy efficiency funds.

SCE's practice for many years has been to include certain components of uncommitted energy efficiency in doing its own internal load forecasts.[128] The ISO agrees that, to the extent uncommitted resources ultimately develop, they can be helpful in reducing overall net demand.[129] It is entirely consistent to assume that our ongoing energy efficiency efforts will result in continuation of successful programs and development of improved programs. We have no

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[127] D.12-05-015, section 4.5.8. Savings here are from programs, not including standards.

[128] RT 1032.

[129] Exhibit ISO-2 (Sparks/Millar) at 4.

doubt that the California Public Utilities Commission, CEC and federal programs and standards incorporated into uncommitted energy efficiency amounts will occur, as these are already in place.

We find that amounts of uncommitted energy efficiency in programs and standards already approved by this Commission and other agencies, but not yet in the demand forecast used by the ISO, should result in adjustments to demand forecasts for the purpose of authorizing LCR procurement levels.[130] There is a significant amount of uncommitted energy efficiency in such programs and standards that is certain to exist in the future. Many approved actions were included in the 2009 CEC uncommitted energy efficiency forecasts. Not all uncommitted energy efficiency is as certain to occur. For example, the Commission's BBEES are goals that may well materialize – and we intend to actively pursue these goals -- but achievement of these laudable goals is still somewhat speculative at this time. The CEC 2009 forecast of uncommitted energy efficiency properly evaluates the potential savings from uncommitted energy efficiency.

We now turn to the question of how much demand in the LA basin local area should be reduced by uncommitted energy efficiency. NRDC recommends a minimum amount of 2461 MW of uncommitted energy efficiency for the SCE territory.[131] This figure is derived from the Scoping Memo in R.10-05-006[132] (the

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[130] The CEC may wish to consider eliminating the distinction between forecasted energy efficiency and forecasted uncommitted energy efficiency in the future in favor of a single forecast of anticipated levels.

[131] Exhibit NRDC-1 (Martinez) at 6-7.

predecessor to this proceeding and part of the record in this proceeding), and is based on the CEC's analysis of the total amount of energy efficiency that is incremental to its 2009 demand forecast. However, this amount is for all of the SCE territory, not just the LA basin local area. DRA uses the same information as the ISO uses in the Environmentally Constrained Scenario sensitivity analysis, and recommends assuming 2305 MW of uncommitted energy efficiency in the LA basin local area by 2021. CEJA estimates 1934 MW of uncommitted energy efficiency in the LA basin local area by 2021.[133]

There is a difference between using uncommitted energy efficiency levels for projecting future demand levels and using uncommitted energy efficiency levels for forecasting local capacity requirements. Lower demand levels do not reduce LCRs on a one-to-one basis, but must be modeled. In addition, uncommitted energy efficiency may not occur uniformly across the state. Amounts must be allocated or assigned to specific areas to model outcomes. A sophisticated power flow model can show the impacts of different demand levels with accuracy and detail. This is exactly what the ISO did in the Environmentally Constrained scenario sensitivity analysis. For the LA basin local area, the ISO determined that the LCR need for 2021 is 1042 MW in that scenario sensitivity analysis for effective sites, after including the CEC's uncommitted energy efficiency forecasts.

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[132] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, R.10-05-006 (December 3, 2010), Attachment 1; and Corrections to December 3, 2010 Long-Term Procurement Plans (LTPP) Scoping Memo (February 10, 2011).

[133] Exhibit CEJA-3 (May) at 2.

The ISO determination of 1042 MW in the sensitivity analysis is 828 MW below its determination for the Environmentally Constrained scenario (*See* Table 2). The only difference between these scenarios is modeling of uncommitted energy efficiency and CHP resources. We can impute that a similar 828 MW reduction in LCR needs would occur in other scenarios.

We find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local area. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.2. Demand Response

The ISO did not include any demand response in its forecast beyond the amount embedded in the CEC IEPR forecast.[134] As with energy efficiency, there are various demand response programs that already exist, but were not included in the ISO models. There are also a number of demand response programs under development. Demand response is equal with energy efficiency at the top of the Loading Order in the Energy Action Plan.

CEJA contends the ISO should have included more demand response in its analysis estimating that up to 2224 MW of demand response resources may be available in the LA basin.[135] CEJA cites D.12-04-045 stating "demand response will be an increasingly valuable resource as we pursue future policy challenges."[136] CEJA lists a number of recent developments at the Commission

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[134] SCE witness Silsbee testified that price-responsive demand may be embedded in the CEC demand forecast. RT 1040.

[135] Exhibit CEJA-1 (Powers) at 6 – 14; Exhibit CEJA-3 (May) at 2.

[136] D.12-04-045 at 77.

and the ISO to facilitate integration of demand resources into ISO electricity markets. In its Opening Brief, CEJA estimates that 1064 MW of demand response should be considered in the LCR calculation.[137]

EnerNOC claims that SCE has identified an opportunity to nearly double its existing demand response portfolio by 2017 as a result of such technologies as SCE's Smart Grid Deployment Plan by adding an additional 1500 MW of demand response potential, to approximately 3000 MW. EnerNOC contends that at least some of this should be assumed to be in the LA Basin and have capability of reducing that area's LCR need.[138]

DRA presented evidence that SCE's most recent load impact report predicts 942 MW of demand response for 2020 for the Western LA Basin.[139] This forecast does not identify a level of locally dispatchable demand response resources nor does it evaluate the effectiveness of demand response resources in reducing LCR needs. SCE witness Silsbee testified that at least 549 MW of demand response is currently available in the Western LA Basin, with 102 MW in the most effective locations.[140] It is unclear how much of these resources are locally dispatchable.

EnerNOC objects to the ISO's LCR need assessment for its "failure to include or adequately consider demand response resources in (its) need assessment, either in terms of meeting or reducing its need."[141] EnerNOC

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[137] CEJA Opening Brief, p. 35.

[138] Exhibit EnerNOC-1 (Tierney-Lloyd) at II-8.

[139] Exhibit DRA-6 (Fagan), p. 8 (Table RF-1)

[140] RT 1079, referencing Exhibit CEJA x SCE 03.

[141] EnerNOC Opening Brief at 16.

witness Tierney-Lloyd testified with regard to demand resources that "the filter for evaluating preferred resources must not only be what is feasible and reliable by today's standards; but, what is likely to be available during the planning window."[142]

We agree that demand response programs are important resources in the California electricity system. However, there are differences between demand response and energy efficiency. The ISO contends that demand response programs should not be counted for local reliability purposes because there are limitations on the use of these programs, customers are not required to shed load when called upon, demand response programs generally do not have the necessary characteristics (such as voltage support) of supply-side resources,[143] and the effects of demand response programs may not materialize at the times and in the locations needed.[144]

ISO witness Sparks allows that demand response "could be used to reduce the replacement OTC needs if the demand response is in electrically equivalent locations and if they materialize and are determined to be feasible for mitigation."[145] ISO witness Millar also testified that it may be possible to develop specific demand response programs which would be able to count for reliability purposes, possibly including programs targeted to specific local areas,[146] or to shave peak load (which would reduce the load forecast).[147]

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[142] Exhibit EnerNOC-3 (Tierney-Lloyd) at III-2.

[143] Exhibit ISO-4 (Rothleder) at 9; RT 287.

[144] RT 350 - 352.

[145] Exhibit ISO-1 (Sparks) at 15; RT 204-205.

[146] RT 352-355.

However, there are no demand response programs at this time which the ISO believes meet reliability criteria.

In D.11-10-003 in the RA proceeding, we adopted protocols for counting demand response resources for reliability purposes. In that decision, we required that, effective in 2013, demand response resources must be dispatchable locally to count as RA resources. Millar contends that, even with this requirement, there is "no basis yet to have…sufficient comfort that (demand response resources) will actually reduce our local capacity needs" because it is unclear that there will be any locally dispatchable demand response programs.[148]

In other proceedings, we are moving forward to promote cost-effective demand response and to integrate demand response programs as reliability resources. SCE acknowledges the potential of demand response resources to address the transmission contingencies in the ISO's analysis.[149] SCE witness Silsbee testified that he sees "no reason" why a small amount of demand response which now counts for local RA requirements cannot be counted toward meeting LCR needs (although there may be limits to the ability of demand response to meet LCR needs).[150] However, SCE recommends additional work regarding the economics and viability of demand response programs for reliability purposes, and for meeting the needs of the grid and fitting in with the

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147 RT 423-425.

148 RT 433-434.

149 Exhibit SCE-2 (Silsbee) at 12-13.

150 RT 1044-1045.

transmission system. Therefore, SCE recommends more study to see if such programs can reduce the LCR need.[151]

We fully expect that innovative demand response programs will continue to develop, including those that possess characteristics that are consistent with ISO local reliability criteria. In R.10-05-006, the predecessor to the proceeding, the Scoping Memo (Appendix 1 at 60) estimated 2842 MW of demand response resources would be available in the SCE territory in 2020. In D.12-04-045, our recent demand response decision, we stated:

> The California Clean Energy Future plan expressly acknowledges that in addition to its historic role as an emergency and peak demand management tool, DR will be able to provide a range of services that can support grid integration of large quantities of intermittent and variable renewable resources. The plan also articulates our collective commitment to integrating DR into the CAISO's wholesale energy markets.

We reiterate our commitment to a strong demand response program consistent with D.12-04-045. We agree with parties who contend that demand response resources are likely to be able to provide capabilities which should reduce LCR needs recommended by the ISO. While the ISO did not study a scenario with additional demand response resources, it is reasonable to assume that some amount of demand response resources will be located in the LA Basin, be locally dispatchable, and available to meet LCR needs by 2020. Estimates of 2000 to 3000 MW of demand response are clearly overly optimistic for local reliability purposes, as these estimates are not specific to the LA Basin, may not be locally dispatchable and may not effectively reduce LCR needs.

[151] RT 607; 646.

In order to determine a reasonable level of demand response likely to be available by 2020 to reduce LCR needs, we take a conservative approach. We will assume a nominal level of 200 MW of dispatchable demand response resources that will be available in the LA Basin to reduce LCR needs by 2020. Since there appears to be at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now in that area), by 2020 it is likely that the actual amount available to reduce LCR needs in the LA Basin will be significantly higher – perhaps closer to DRA and CEJA's estimates of around 1000 MW. As the Commission, the ISO and the industry work together over time to clarify the technical characteristics for the circumstances in which demand response resources should count for meeting local capacity requirements (such as local dispatchability), our confidence in the viability of these resources for such purposes should grow. In the future, it is likely that there will be more consensus about how to include demand response resources in LCR forecasts.

4.2.4.3. Distributed Generation

Under Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 6500 MW of new CHP would be added to the grid over the next 20 years with a plan to add 12,000 MW of distributed generation statewide by 2020. The Assembly Bill (AB) 32 Scoping Plan sets a goal of 4000 MW of new CHP by 2020.

The Commission's commitment to expanded distributed generation is supported by a multitude of programs, including the California Solar Initiative, Net Energy Metering, Self-Generation Incentive Program (SGIP), the Renewable Auction Mechanism (RAM), Renewable Market Adjusting Tariff (Re-MAT), Combined Heat and Power tariffs, and the Utility Photovoltaic and

Fuel Cell Programs. In 2013 the Commission will implement Senate Bill (SB) 1122 expanding offerings to bioenergy distributed generation projects. These programs commit IOU customers to substantial investment in distributed generation and promise to deliver thousands of megawatts.

The ISO scenarios assume between 271 MW and 1519 MW of distributed generation actually will be developed in the LA basin local area over the next 10 years, based on the standardized planning assumptions developed in R.10-05-006.[152] Most of this appears to be rooftop solar and other small solar installations. ISO witness Millar testified that if distributed generation increased beyond what the ISO is forecasting, that generally would lower the local capacity need. However, the ISO does not recommend relying on the 1519 MW distributed generation forecast in the Environmentally Constrained scenario, but on a range from 271 MW to 687 MW embedded within the other three scenarios. This is because the ISO claims the distributed generation level in the Environmentally Constrained scenario may be an "admirable goal" but "it is not a capacity amount that can be depended on for ensuring reliability of the bulk power system."[153]

The ISO does not consider it reasonable or prudent to rely on incremental CHP programs beyond what has been considered in the 2009 CEC forecast due to uncertainty that exists with regard to future increases in CHP development. However, Millar also contends that CHP should not be excluded from meeting reliability needs if such facilities can meet ISO technical characteristics. Further,

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152 DRA similarly estimates between 347 MW and 2468 MW of new CHP in SCE's region by 2020.

153 Exhibit ISO-2 (Sparks/Millar) at 6-7.

Millar testified, in the context of state policy objectives supporting CHP: "We want to support [CHP] if there's some work we can do to help those programs or those resources meet these [reliability] needs providing they have the like characteristics."

As ISO witness Millar states, with regard to including energy efficiency in a demand forecast, "we would turn largely to the judgment of the CEC in developing their forecast."[154] We agree, and find that similar consideration should be given with regard to distributed generation forecasts by state agencies. We do not agree with the ISO's decision to unilaterally dismiss the CEC forecast of 1519 MW of distributed generation under the Environmentally Constrained scenario. This forecast has the same validity as CEC forecasts in the other three scenarios and should be considered as part of our analysis. However, we will adopt the ISO's recommendation to use the 339 MW projection of distributed generation, except for uncommitted CHP.

SCE witness Cushnie testified: "CHP has some of the same characteristics that conventional gas-fired resources would have, but they are not going to be as effective as (gas-fired resources) in meeting the need."[155] CEJA contends the ISO should have considered more CHP in its analysis, citing to the Governor's goals and a CARB 2008 Scoping Plan adopting a CHP goal of an additional 4000 MW of installed CHP capacity by 2020. Specifically, CEJA recommends inclusion of at least 285 MW of incremental CHP should be included in the ISO forecast for the LA basin local area, which is a proportion of 360 MW of incremental CHP for SCE's total territory (this amount is taken from the Scoping Memo in

[154] RT 492.

[155] RT 731.

R.10-05-006.) CCC presents a report showing a medium projection of 621 MW of additional CHP by 2020.

We find that there is the potential for additional CHP to be realized over the ISO's Trajectory scenario. The exact amount that can be assumed is not clear from the record; however, it is reasonable to assume that some amount of uncommitted CHP will come to fruition in the LA basin local area before 2021. Thus, we find there will be more distributed generation than was included in the ISO Trajectory scenario. SCE's point that CHP may not be as effective as gas-fired generation in meeting LCR needs is important; it is necessary to model the impacts of increased CHP. This is what the ISO has done in the four scenarios it studied; Table 3 – 6 herein show that the ISO assumed between 271 MW (Base scenario) and 1519 MW (Environmentally Constrained scenario) of distributed generation. The ISO's recommended Trajectory scenario includes 339 MW of distributed generation.

As with uncommitted energy efficiency, we are convinced that the ISO should have included some projection of uncommitted CHP into its models. As with energy efficiency, a significant amount of what the CEC categorized in 2009 as uncommitted CHP is now more certain to exist. As discussed in Section 4.2.4.1 herein, we find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted energy efficiency for the LA basin local area. This same forecast also includes the full amount of uncommitted CHP in the CEC forecast. The combination of uncommitted energy efficiency and uncommitted CHP led to a reduction in LCR needs of 828 MW in the one ISO scenario which modeled this modification. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.4. Energy Storage

Under California Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 3000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation.

CESA recommends that the Commission closely coordinate this proceeding with the Energy Storage Rulemaking, R.10-12-007. CESA calls for the full integration of storage into long-term procurement planning as "a powerful and resource adequacy-improving asset class."[156] CESA contends that energy storage can meet LCR needs and, like generation, is dispatchable.[157]

CEJA contends it is not reasonable that the ISO did not consider any energy storage in its analysis.[158] CEJA claims that energy storage has been found to be more effective than conventional peaking generation, and that both SCE and the ISO recognize the value of storage and the increasing viability of storage technology.

ISO witness Millar testified that, at this time, there are no energy storage facilities on the net qualifying capacity (NQC) list for local capacity[159] (i.e., eligible to be counted for RA purposes) and that the ISO has not identified any energy storage projects in its transmission planning process.[160] However, he stated that there is a process by which any energy storage facilities which emerge could be placed on the NQC list and be eligible to provide local reliability for RA

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156 Exhibit CESA-1 (Lin) at 8.

157 Exhibit CESA-2 (Lin) at 2.

158 Exhibit CEJA-1 (Powers) at 14-19.

159 RT 347.

160 RT 404.

purposes.[161] Similar to demand response resources, Millar testified that if energy storage technologies met certain performance requirements, they could count for reliability purposes.[162] However, he testified that "we don't know" if energy storage can meet ISO technical characteristics in the next ten years.[163]

SCE witness Minick testified that there are "only a few test programs for energy storage on our system, and they are not specifically located in areas that would be of any benefit for LCR analysis." He continued: "We have looked at 20 to 30 different energy storage technologies, and we have presented that information to the Commission, and I don't think we have found many, if any, cost-effective."[164]

We are examining the feasibility of energy storage technologies in R.10-12-007. In that proceeding we are considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time we do not have sufficient information to determine how many viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes in the LA basin local area (or elsewhere). We will not consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

However, we intend to promote the inclusion of energy storage technologies in SCE's upcoming procurement process. CEJA details a number of SCE energy storage initiative and projects underway that will increase energy

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161 RT 348-349.

162 RT 355.

163 RT 461.

164 RT 948.

storage capacity in its territory (although largely outside of the LA Basin).[165] As a result, CEJA recommends a minimum procurement level of 48 MW of energy storage resources, based upon a storage assumption of 100 MW for the LA Basin, with the Western LA Basin as approximately 48% of the LA Basin.[166] As explained below, we will require that SCE procure at least 50 MW of energy storage resources for LCR purposes in the LA basin local area. We view this as a reasonable and modest level of targeted procurement of an emerging resources, and as an opportunity to assess the cost and performance of energy storage resources.

5. Minimum and Maximum Procurement Authorizations

As noted above, SCE recommends that we authorize a range of procurement from zero to 3871 MW. While SCE and many parties have significant concerns about the LCR procurement levels recommended by the ISO, SCE proposes the widest possible range of procurement flexibility. Other parties find fault in SCE's expansive proposal. CEJA, for example, recommends that SCE's proposal be rejected as "a bad idea to take an economically risky (and environmentally harmful) scenario, and simply shift the burden of this risk to ratepayers."[167]

To address this concern, TURN recommends both a minimum and maximum procurement authorization level, partially to "provide purchaser flexibility when negotiating with bidders."[168] SCE contends that a minimum

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165 CEJA Opening Brief, pp. 55-56.

166 CEJA Reply Brief, p. 2.

167 Exhibit CEJA-5 (May) at 2.

168 Exhibit TURN-1 (Woodruff) at 22.

LCR procurement target is not useful as the specific proposals and options available to meet the LCR need are not known at this time; instead SCE would have the Commission finalize appropriate LCR levels in SCE's future application for approval of proposed LCR projects.[169]

We agree with SCE that not all information is known. We can and will further refine LCR authorization requirements in future long-term procurement planning proceedings. However, we take seriously the ISO's concern (seconded by SCE and others) that there are some procurement opportunities associated with gas-fired power plants which may be lost if there is a delay in moving forward, due to a likely seven to nine year lead time. We do not agree with DRA that "there is zero reliability risk of waiting to procure additional fossil resources" for 2021.[170] Gas-fired resources are appropriate resources to procure for their technical reliability characteristics and for cost considerations; however, we discuss below that procurement should be consistent with the Loading Order to the extent possible.

We will set a minimum LCR procurement level. There is some uncertainty about what how much uncommitted energy efficiency will be available to reduce demand by 2021, and how much uncommitted CHP will be available to fill LCR needs. However the forecast of zero for these resources included in the ISO Trajectory scenario is not reasonable. Therefore, the LCR need is less than the ISO forecasts in its Trajectory scenario. At the same time, the record establishes that there is a significant need for LCR resources to replace retiring OTC plants

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[169] Exhibit SCE-2 (Cushnie) at 7.

[170] RT 912.

by 2021 under every ISO scenario and sensitivity analysis. It is reasonable to require a minimum procurement level to ensure reliability.

TURN recommends a "circuit breaker" mechanism if the Commission allows procurement of a lower amount of capacity than the ISO recommends (which is the maximum level SCE recommends.) The "circuit breaker" would occur "if the prices of one or more bids greatly exceed a reasonable cost."[171] SCE argues this proposal is not needed if the Commission does not adopt a minimum LCR procurement target.[172] However, we do adopt a minimum LCR procurement level. While we are cognizant of the potential for bids with excessive cost, already existing mechanisms such as cost-of-service contracts and reliance upon requests for offers provide some ratepayer protection. Further, the Commission-established Procurement Review Groups, Independent Evaluators and Energy Division staff review also provide important and substantive ratepayer protections.

Adjustments to the ISO forecasts to include the maximum reasonable level of uncommitted energy efficiency and CHP, lead to the ISO's Environmentally Constrained scenario sensitivity analysis. As shown in Table 2, this analysis leads to a forecast of 1042 MW of LCR need for effective sites. However, this scenario is a derivative of the Environmentally Constrained scenario. The difference between the Trajectory scenario and the Environmentally Constrained scenario is that the latter included 1519 MW of supply-side distributed generation,[173] as compared to 339 MW in the Trajectory scenario. There is no

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[171] Exhibit TURN-1 (Woodruff) at 22.

[172] Exhibit SCE-2 (Cushnie) at 9-10.

[173] Some distributed generation is embedded in the CEC's demand forecast.

credible evidence in the record that there will be 1519 MW of supply-side distributed generation in the LA Basin by 2020.

We agree with the ISO, SCE and others that the Trajectory scenario is appropriate for determining LCR needs. However, we have determined herein that it is appropriate to reduce the ISO forecasts to account for the likelihood that 828 MW of uncommitted energy efficiency and CHP will exist, and that at least 200 MW of locally-dispatchable demand response will exist.

The ISO did not provide a sensitivity analysis for the Trajectory scenario. It is possible to roughly calculate the impact of including more energy efficiency, CHP and demand response resources into the Trajectory scenario. The sole difference between the ISO Environmentally Constrained scenario and the sensitivity study for this scenario is the inclusion of uncommitted energy efficiency and CHP. The ISO shows that these resources would decrease LCR needs by 828 MW. It is reasonable to assume that modeling uncommitted energy efficiency and CHP into the Trajectory scenario would result in at least this much reduction in LCR needs (given that the Trajectory scenario starts with a higher LCR need). We will assume that inclusion of 100% of uncommitted energy efficiency and 100% of uncommitted CHP will reduce the LCR need in the Trajectory scenario by 800 MW (with rounding). In addition, we have determined that we will assume a conservative projection of 200 MW of locally dispatchable demand response resources.

In sum, the Trajectory scenario LCR forecast should be reduced by a maximum of 1000 MW to account for undercounted resource availability. We therefore adopt a minimum LCR need of 1400 MW for the West LA sub-area of the LA basin local area.

We have stated herein that potential demand response and energy storage resources are likely to be able to reduce LCR needs in the future. A way of looking at this is that even if some uncommitted energy efficiency and/or CHP resources included in the ISO forecast do not ultimately appear, there is a reasonable likelihood that other resources including locally-dispatchable demand response (beyond our conservative forecast of 200 MW) and/or energy storage resources will appear which can similarly fill or reduce LCR needs. Alternatively, there may also be transmission-related improvements which can decrease LCR needs. These additional potential resources strengthen our determination that far lower levels of new generation procurement are needed to satisfy LCR needs in the LA basin local area than recommended by the ISO in the Trajectory scenario.

We will also set a maximum procurement level. SCE's proposal for a maximum procurement level is based on the highest ISO forecast level, given less efficient locations.[174] Our analysis of the demand forecast used by the ISO convinces us that the ISO's recommendations for procurement of LCR needs in the LA basin local area are too high. Further, we are convinced that inevitably changing circumstances over the next several years must be taken into consideration. By adopting a lower maximum procurement level than the ISO recommends, the maximum levels are unlikely to turn out to be too high. If our adopted maximum procurement level is too low, there will be timely

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[174] SCE's method for recommending maximum LCR levels appears to be slightly different than the ISO's method for calculating the upper bound for LCR needs in each scenario. The ISO considered the least effective OTC sites in each local area, while SCE used less effective locations in each local area.

opportunities to obtain additional resources in future long-term procurement planning proceedings.

For determining the maximum procurement level, we reiterate that this projection should include a reasonable amount of uncommitted energy efficiency and uncommitted CHP. Again, this projection should also include information regarding potential demand response and energy storage resources which can meet LCR needs. In addition, the location of energy efficiency and CHP installations in the LA Basin local area (unknown at this time) may not be as effective in reducing LCR needs than other resources, such as gas-fired generation located at current OTC sites. For both of these reasons, TURN's suggestion of assuming 50% achievement is reasonable.

As with our determination of a minimum procurement level, we will assume subtraction of 1000 MW of uncommitted energy efficiency, uncommitted CHP and demand response resources from the Trajectory scenario forecast. For the maximum procurement level, we will add back 400 MW to reflect possible effectiveness factors. Therefore, we adopt a maximum LCR need of 1800 MW for the West LA sub-area of the LA basin local area.

The ISO forecasts provide a range of LCR needs depending upon location of new capacity. The low end of the ISO forecasts assume the new capacity is located at the most effective current OTC sites, and the high end assumes less effective OTC sites. Our determination of the minimum procurement level implicitly assumes that new capacity will be sited at the most effective sites. However, this may not be the case. SCE shall use the most up-to-date effectiveness ratings in its solicitation process.

As discussed further below, we will revisit LCR needs in the next long-term procurement proceeding, expected to commence in 2014. It is possible that in the next long-term procurement proceeding there will be shown to be a need for more LCR procurement than the maximum procurement levels we establish today. We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there may be no need for further LCR procurement in this time period. If circumstances change, there may be a need for further procurement. We are confident that today's decision is the appropriate and considered step at this time.

6. Long-Term Local Capacity Requirements for Big Creek/Ventura Local Area

In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units that are scheduled to shut down per SWRCB regulations before 2021. In total, these units currently have approximately 2000 MW of capacity.

The ISO recommends LCR procurement of 430 MW in the Moorpark sub-area of the Big Creek/Ventura local area under all RPS scenarios, without a range for effectiveness of sites. This results from a need to mitigate reliability issues in the Moorpark sub-area of the Big Creek/Ventura local area, caused by a contingency of voltage collapse from a potential loss of area transmission lines.[175] The ISO analysis for the Big Creek/Ventura local area is consistent with the methodologies discussed above for studying long-term local capacity needs for the LA Basin local area.

SCE recommends deferring authorization for procuring additional local capacity in the Big Creek/Ventura local area until the next LTPP cycle (expected

[175] Exhibit ISO-1 (Sparks) at 13-14.

to commence in 2014). SCE contends that barriers to construction of new LCR generation is not as difficult in the Big Creek/Ventura local area as in the LA basin local area, because "this area does not have as many, or as stringent, siting restrictions as the LA basin."[176] SCE further argues that newer technology of various sizes is more likely to be the replacement generation in the Moorpark sub-area, which may be able to be built in 5 to 7 years.[177]

DRA contends that there is no immediate need for LCR generation in the Big Creek/Ventura local area and that ongoing review of LCR needs is required. DRA acknowledges that there would be a loss of 1946 MW in the area due to OTC retirements by 2020.[178] However, based on a load and resources table, DRA contends that there is a surplus of resources (up to 1820 MW) in the Big Creek/Ventura local area when considering the effect of demand side resources.[179] DRA believes that it would not take as long to go through the process to start running a new fossil-fueled power plant in the Big Creek/Ventura local area as in the LA basin local area, due to fewer concerns about siting.[180] DRA maintains that this timeframe would allow the Commission to revisit whether alternative preferred resources materialize in the area. Therefore, DRA contends the risk of not procuring now is minimal if not zero.

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[176] Exhibit SCE-1 (Minick) at 10-11.

[177] Exhibit SCE-2 (Cabell) at 20.

[178] Exhibit DRA-1 (Fagan) at 19.

[179] Exhibit DRA-1 (Fagan) at 17-22 and Table RF-3.

[180] RT 920-922.

CEERT agrees with SCE and DRA that no LCR procurement is required to be considered until the expected 2014 long-term procurement proceeding.[181]

Calpine agrees with DRA that further analysis of the Moorpark sub-area is needed before LCR authorization in the Big Creek/Ventura local area is granted. Calpine sponsored an analysis that "suggests that there are potential transmission upgrades that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura local area."[182] Specifically, Calpine argues that one of several transmission alternatives was identified by the ISO that can reduce the LCR need to 100 MW, while other transmission alternatives suggested by Calpine can reduce the LCR need to from zero to 230 MW.[183]

GenOn contends that Calpine's examples of transmission projects are not feasible or desirable solutions for addressing local reliability needs.[184] GenOn contends it is necessary to adopt an LCR need determination for the Big Creek/Ventura local area by the end of 2012 because of plant closures expected in 2020.[185] GenOn contends that it will take seven years or more until commercial operation of new gas-fired plants can commence. GenOn does not agree with SCE that it is not as challenging to develop new LCR generation in the Big Creek/Ventura local area.[186] GenOn also discusses implementation plans it

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181 CEERT Opening Brief at 31.

182 Exhibit Calpine-2 (Calvert) at 2, details in at 2-11.

183 Calpine Opening Brief at 7.

184 GenOn Opening Brief at 8.

185 Exhibit GenOn-2 (Beatty) at 2.

186 Exhibit GenOn-2 (Beatty) at 7-9.

submitted to the SWRCB for several OTC plants, including the Mandalay and Ormond Beach Generating Stations in the Big Creek/Ventura local area. While GenOn originally intended to keep the plants open via a compliance track acceptable to the SWRCB, it now intends to retire (and potentially replace) the plants by the SWRCB compliance deadline.[187]

6.1. Discussion

As with the LA basin local area, there are questions about the ISO forecasts for the Big Creek/Ventura local area. Here, the ISO also did not include any values for uncommitted energy efficiency and uncommitted CHP. As with the LA basin local area, it is likely that the ISO models overstate the LCR need for the Big Creek/Ventura local area for this reason. Similarly, it is more likely that at least some amount of demand response and/or energy storage will emerge in the Big Creek/Ventura area which can be used to meet LCR needs in the next decade, then that there will be zero amount of these resources.

Calpine has shown that there are several transmission possibilities which might reduce LCR needs in the Big Creek/Ventura local area. It is not clear that all of Calpine's suggestions are feasible. However, the ISO did identify a non-generation (transmission) alternative similar as feasible to be completed.[188] This transmission option would result in a total OTC need of 100 MW, instead of 430 MW as proposed by the ISO.[189] The ISO disagrees with Calpine about whether this option is a superior mitigation solution in the Moorpark area,

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[187] Exhibit GenOn-1 (Beatty) at 3-5.

[188] Exhibit ISO-23 (Sparks) at 2.

[189] Exhibit ISO-23 (Sparks) at 3.

contending that either way there would still be a need for replacement generation.

While it may be mathematically possible to show that some combination of preferred resources and transmission solutions could reduce the LCR need to zero (or near zero), there are technical issues and operational benefits from having specific types of in-area generation with the characteristics of the current OTC plants for the Moorpark area. We find that the ISO has shown that there is a need for this type of in-area generation in the Moorpark area, in order to avoid adverse impacts on transmission voltages and loadings under some operation conditions.

The ISO contends that there is a need for 430 MW of total in-area generation in the Moorpark area, even with a viable transmission alternative (or any preferred resources which do not have similar operating characteristics to OTC plants.) The ISO recommendation appears to be conservative on this point, as the ISO has not shown that 430 MW is the minimum amount of LCR need necessary to maintain vital operational characteristics. While some in-area generation similar to existing plants appears to be necessary, some combination of transmission alternatives and preferred resources will necessarily reduce the LCR need below the ISO's projections.

We cannot agree with DRA, SCE and others that it is reasonable to wait to authorize procurement in the Big Creek/Ventura local area. Depending on assumptions, the ISO forecasts a need for the Moorpark sub-area of the Big Creek/Ventura local area, at least some of which must be filled by generation with similar characteristics to the current OTC plants. The most likely locations for new OTC-like generation are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

The combination of likely preferred resource options and at least one viable transmission solution lead to the conclusion that less than 430 MW is needed for the Moorpark sub-area. It is reasonable to provide SCE with a range of procurement levels to allow SCE to take advantage of different technologies and combinations of potential solutions. TURN's recommendation to allow SCE to procure up to 2/3 of the ISO's recommendation leads to a total of approximately 290 MW. Two of the retiring Mandalay OTC plants have an NQC of 215 MW.[190] It is reasonable to assume that there is a need for approximately the same size replacement generation. Therefore the minimum procurement level for the Moorpark sub-area will be 215 MW. A reasonable maximum level is the 290 MW level per the TURN recommendation. We will authorize SCE to start the process to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local area, consistent with the process described herein.

7. Procurement Process

7.1. Technical requirements for local capacity

In this decision, we have determined that SCE should be authorized to start a process in 2013 to enter into contracts for between 1400 MW and 1800 MW in the LA basin local area, and 215 to 290 MW in the Big Creek/Ventura local area. Our determination accounts for a reduced demand level due to more

[190] As shown in Table 1, the Ormond Beach plants have a much higher NQC than the 435 MW recommendation from the ISO. Therefore, it is not reasonable to expect plants of this larger size to be replaced.

energy efficiency and demand response resources than assumed by the ISO, and additional CHP resources. Here we discuss the process for procurement of resources to meet these needs.

One significant issue is what technologies and resources SCE should be authorized to procure. The ISO does not assume any particular technology would be required to fill the local capacity needs, according to ISO witness Sparks: "As long as the resources are in the location where they are needed in these local areas, and they have characteristics of gas-fired generation, I don't believe the ISO has a preference on exactly what type of resources."[191] Regarding distributed generation, the ISO studied a scenario with a high level of renewable distributed generation (the Environmentally Constrained scenario). Referring to distributed generation, Sparks suggested that further study would be needed "to the extent that some of these nonflexible resources are very large, and these large magnitudes are meeting local needs…we would probably need to study all seasons and all load levels to ensure the system can continue…to reliably operate."[192]

SCE witness Cushnie testified that SCE is technology neutral in terms of the resources that it would acquire.[193] In general, SCE would procure resources that will meet ISO criteria for local reliability. However, as ISO witness Millar testified, there is no specific written protocol or tariff that can be referenced to determine the ISO's performance criteria for local reliability.[194] The ISO finds

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[191] RT 201.

[192] RT 208–209.

[193] RT 604.

[194] RT 355-356.

that gas-fired generation meets its criteria, as well as any other resources (or combination of resources) which have the same performance criteria as gas-fired generation. Demand response resources and CHP may meet the ISO's criteria, but not at this time. It is possible that other resources will pass the ISO test as well in the future. Of course, acquisition of more energy efficiency and demand side resources would reduce the LCR need.

Our concern is, without knowing upfront exactly what the ISO would find acceptable, that SCE could procure resources that would not past ISO muster. In that case, the ISO -- consistent with its reliability mandate -- could seek Commission action authorizing additional resources (thus lowering the value to ratepayers of already-procured resources) or could use its own authority (or seek new authority) to contract with resources to meet local needs (also increasing total costs). Either of these approaches is sub-optimal, both in cost terms and in environmental terms.

SCE proposes to use existing RA program rules to assess the effectiveness of proposed generation solutions for meeting LCR need. SCE proposes to identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.[195] We will adopt SCE's proposal.

The ISO states that it will work with SCE and the Commission to develop the requirements needed for resources to compete in the procurement process.[196] We will require SCE to consult with the ISO regarding ISO performance characteristics (such as ramp-up time) for local reliability. In its application to procure specific resources to meet local reliability needs (discussed herein), SCE

[195] Exhibit SCE-2 (Silsbee) at 5.

[196] ISO Opening Brief at 3.

shall provide documentation of such efforts and how SCE meets ISO performance requirements.

7.2. Consistency with the Loading Order

SCE proposes to demonstrate that any proposed contract is consistent with the Loading Order by identifying each preferred resource and then assessing the availability, economics, viability and effectiveness of that supply in meeting the LCR need.[197] Per SCE witness Cushnie, SCE would also perform a cost/benefit analysis of the various procurement options.[198] This study would be performed in parallel with any RFO and/or bilateral negotiations for supply.[199]

Several parties have raised concerns that SCE's procurement process might not be consistent with the Loading Order in the Energy Action Plan. Vote Solar contends that preferred resources are endowed with advantages that are difficult to monetize or otherwise capture in an all-source RFO; for example, modularity (ability to be deployed in smaller MW), less environmental impact, smaller sites, and avoidance of outages and losses.[200] CEJA contends that implementation of the ISO recommendations for how to meet LCR needs will lead to excessive and unnecessary natural gas-fired capacity.[201] Similarly, Sierra Club contends that the ISO's models "turn the Loading Order upside down by creating a framework that favors conventional generation over preferred resources."[202]

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[197] Exhibit SCE-2 (Silsbee) at 4; RT 612-613; RT 627 (Cushnie).

[198] RT 626-627.

[199] RT 650.

[200] Exhibit Vote Solar-2 (Gimon) at 2–3.

[201] Exhibit CEJA-1 (Powers) at 31-32.

[202] Sierra Club Opening Brief at 13.

CAC claims there are about 60 MW of existing CHP capacity in the Western LA basin sub-area, and 70 MW of existing CHP in the Big Creek/Ventura local area, which were not included in ISO studies. In order to be consistent with the Loading Order and obtain this capacity to meet LCR needs, CAC recommends that the Commission establish a rebuttable presumption that existing resource offers (presumably CHP) priced no greater than the cost of new conventional fossil generation be deemed reasonable in the IOU procurement process.[203]

CEERT recommends a process for SCE to procure preferred resources as part of its solicitation. This process includes consultation with the ISO and prospective bidders to establish metrics and protocols for dispatchability and performance of preferred resources. Next, SCE would issue a Request for Qualification to establish the likely quantity and price range of available qualified preferred resources. Then, a cost-effective level of transmission and load-shedding which could meet LCR need would be established by the Commission based on existing and new studies. Through this process, CEERT contends there will be sufficient data available to conduct a "directed procurement" of LCR need.[204]

IEP recommends an all-source RFO in which all resources can compete on an equal basis.[205] IEP proposes that any uncommitted energy efficiency and similar resources which are unable to qualify to compete in an all-source RFO would remain outside of the procurement mechanism until they materialize. At

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[203] Exhibit CAC-1 (Ross) at 3, 8-9.

[204] Exhibit CEERT-2 (Caldwell) at 3-4.

[205] Exhibit IEP-1 (Monsen) at 15.

that point, these resources would be considered as committed, and reduce the amount of demand and amount of procurement needed in future procurement proceedings.[206]

7.3. Discussion

We have already determined herein the need to modify the ISO's recommendations for LCR needs in the LA basin local area to take into account reasonably-expected levels of energy efficiency, demand response resources and CHP (and the potential for more demand response resources as well as energy storage resources to become available which can meet LCR requirements). By assuming higher levels for these resources than the ISO, we are promoting the policies of the Loading Order, and reducing the anticipated LCR need.

Because the range of LCR need we establish herein includes between 50% and 100% of uncommitted energy efficiency and uncommitted CHP resources as well as a conservative forecast of demand response resources, SCE will need to ensure that these resources do exist in the future in order to ensure local reliability. As part of our review of SCE's procurement plan, and when considering SCE's procurement application, we will require SCE to show that it has done everything it could to obtain cost-effective demand-side resources which can reduce the LCR need, and cost-effective preferred resources and energy storage resources to meet LCR needs. This task includes efforts already underway and approved in other Commission proceedings, with an eye to focusing such efforts in the specific local geographic areas where LCR needs exist. In other words, for the purposes of meeting LCR needs, it will do no good

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[206] IEP Opening Brief at 5-6.

to procure preferred resources such as energy efficiency outside of specific portions of the LA basin or Big Creek/Ventura local areas.

With respect specifically to SCE's procurement of RPS-eligible resources to meet some or all of the LCR needs identified in this decision, this decision does not set up any new RPS procurement processes. SCE should follow existing RPS program procurement authorizations, rules, and processes in its procurement of resources to meet these LCR needs. In SCE's procurement plan discussed below, we require SCE to detail the RPS procurement authorizations and processes that support its plans to acquire RPS-eligible resources to meet these LCR needs.[207]

We recognize that requirements regarding preferred resources must be reconciled with the additional requirement to consult with the ISO on performance criteria. We are confident that the dual objectives of reliability and adherence to the policy objectives of the Energy Action Plan can both be met.

In addition to meeting reliability criteria and consistency with the Loading Order, LCR procurement by SCE must be at least cost to ratepayers. SCE witness Cushnie testified that SCE "has every interest to do this in the least possible cost to the customers (because) there's no upside to the utility in doing this

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[207] In its 2012 RPS procurement plan, SCE proposed that it would not hold a solicitation for RPS-eligible resources in the period covered by the 2012 RPS procurement plan. In D.12-11-016, the Commission allowed SCE not to hold a solicitation for RPS-eligible resources and put in place a parallel restriction on SCE's ability to enter into bilateral contracts for RPS-eligible resources during the same period. In D.12-11-016 at 57, the Commission stated that "should SCE determine it has an unmet RPS need during the 2012 solicitation cycle, we will revisit SCE's request to not hold a solicitation and the corresponding restriction adopted today on bilateral contracts." SCE should indicate in its procurement plan whether it intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan.

procurement."[208] We will review SCE's efforts at cost minimization in SCE's forthcoming Application. However, balancing the three criteria of ensuring reliability, consistency with the Loading Order and cost-minimization is a challenge.

SCE explains that it intends to capture all cost-effective energy efficiency that can meet LCR needs.[209] Overall, SCE further explains its intention for load reduction resources:

> For preferred resources, SCE will assess the cost-effectiveness of such resources relative to supply-side options. If load reduction in the local area appears to be cost-effective, SCE will engage the CAISO to conduct transmission modeling load flow analysis to determine the operational effectiveness of load reduction programs and technology. SCE will reduce its procurement of supply-side resources to accommodate the future procurement and/or development of load reduction programs and technologies to the extent that they are determined to be cost-effective and operationally effective in reducing the identified LCR need.[210]

SCE's process for balancing objectives with regard to demand reduction resources is reasonable. We will also require SCE to apply a similar balancing to all preferred resources; we agree with SCE's recommended approach to pursue the most competitively-priced CHP and renewable resources, consistent with meeting LCR locational needs and technical characteristics. The remainder of SCE's LCR need will need to be met by supply-side resources and cost-effective transmission upgrades.

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[208] RT 760-761.

[209] RT 609-610.

[210] SCE Opening Brief at 5-6.

The record shows that there may be a significant amount of energy storage capacity and/or demand reduction from demand response resources in the next several years which are not included in any ISO model. We have determined that a significant amount of these resources may be available to meet or reduce LCR needs by 2021, even beyond the projections in the ISO models. We recognize there may be barriers to integration of these resources, including technical issues regarding whether such resources can meet ISO LCR criteria. At the same time, the prospect of additional resources to meet or reduce LCR needs provides an opportunity to further our Energy Action Plan through additional procurement of resources other than conventional gas-fired generation.

Because there is a strong likelihood that additional preferred and energy storage resources not included in our maximum procurement authorization (and potential changes to the transmission system) will be available to effectively meet or reduce LCR needs by 2021, we will require that SCE procure no more than 1200 MW from conventional gas-fired resources in the LA basin local area. The record shows that the most certain technology which can meet LCR needs (from the ISO's perspective) is gas-fired generation. In order to ensure a base level of procurement certain to ensure reliability under the most stringent criteria, we will require that at least 1000 MW in the LA basin local area be from gas-fired generation. In addition, because we intend to promote promising technologies with a strong potential to effectively meet LCR needs, we will require that SCE procure at least 50 MW of energy storage resources as part of its procurement plan for the LA basin local area.

Several parties, in their comments on the Proposed Decision, recommend that we include a requirement that some specified amount of preferred resources be required to be procured. One rationale is that if we have a minimum procurement level for gas-fired and energy storage resources, we should also do so for preferred resources consistent with the Loading Order. Because the Proposed Decision has been modified to increase the minimum procurement level, there is an opportunity to specify further how the minimum procurement level will be achieved. We will require that at least 150 MW of the minimum procurement level be procured through preferred resources.

To summarize: SCE shall procure at least 1400 MW to meet 2021 LCR needs in the west LA sub-area of the LA basin, using the process delineated herein. Included in that 1400 MW shall be 1000 - 1200 MW of conventional gas-fired generation,[211] at least 50 MW of energy storage capacity, and at least 150 MW of capacity from preferred resources. All additional resources beyond the minimum requirement must also be from preferred resources, or from energy storage resources. SCE is not authorized to procure more than 1800 MW of capacity to meet 2021 LCR needs in this part of the LA basin. All resource procurement is expected to follow the principles of least cost/best fit within these constraints. For example, if more than 50 MW of energy storage resources bids into the solicitation process, the most cost-effective and best-located projects should be used to fill the 50 MW requirement.

In addition to authorizing SCE to procure new generation resources, SCE continues to be authorized or required to obtain other resources, as detailed in decisions in the Commission's energy efficiency demand response, RPS and other proceedings. Nothing in this decision is intended to supersede or limit any authority or requirement stemming from any other commission proceeding.

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[211] Conventional gas-fired generation includes CHP resources that are electrically equivalent to conventional generation.

SCE's efforts to obtain these resources are critical to ensuring that the assumptions embedded in this decision will become reality and the reliability needs in SCE's territory will be met.

7.3.1. RFOs and Bilateral Negotiations

One way for SCE to procure the LCR resources we authorize in this order will be to issue one or more RFOs.[212] For example, an RFO to fill LCR needs could specify the amounts needed, the location needed, and technical requirements.

SCE agrees with TURN that an RFO can be very effective in determining the most competitive options for meeting LCR needs. However, SCE requests the flexibility to determine whether it should hold an RFO or not in local capacity areas with limited or no alternatives, because in such a case an RFO may not yield competitive or cost-effective results. SCE contends that such problematic results could occur because the existing generation location has numerous inherent advantages that it can seek to increase costs in a solicitation process.[213]

TURN agrees that some cost-of-service contracts may be needed for OTC unit owners in certain sub-areas where market power exists, in order to ensure reasonable costs to ratepayers.[214] Vote Solar contends that an all-source RFO could give rise to market power mitigation issues to address potentially unreasonable costs, irreversible outcomes, and a cumbersome process to take

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[212] SCE witness Cushnie testified that SCE conducts numerous RFO solicitations for procurement, including all-source solicitations, RPS solicitations and CHP solicitations. RT 686.

[213] Exhibit SCE-3 (Cushnie) at 8.

[214] Exhibit TURN-2 (Woodruff) at 3.

into account unique characteristics of preferred resources. CEJA proposes a phased RFO process, starting with a solicitation aimed at energy efficiency, then one for demand response, and on through the Loading Order.[215]

IEP recommends annual all-source solicitations after setting clearly defined performance requirements and obligations for various resource types, but cautions that there might be concerns about whether energy efficiency and demand response resources can be relied upon for firm capacity and deliverability.[216] IEP supports cost-of-service contracts if there is an IOU showing and a Commission finding of local market power.[217] GenOn also supports use of cost-of-service contracts in the situation where a solicitation does not yield robust results.[218]

AB 1576[219] (codified as § 454.6) authorizes the use of cost-of-service contracts to facilitate investment in the replacement or repowering of older, less-efficient thermal generation facilities when the ISO certified that the project is needed for local reliability. Section 454.6 states:

> (a) A contract entered into pursuant to Section 454.5 by an electrical corporation for the electricity generated by a replacement or repowering project that meets the criteria specified in subdivision (b) shall be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner

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215 CEJA Opening Brief at 43.

216 Exhibit IEP-1 (Monsen) at 12-17, 21.

217 Exhibit IEP-1 (Monsen) at 8-11.

218 Exhibit GenOn-2 (Beatty) at 12.

219 Stats. 2005, ch. 374.

determined by the commission to provide the best value to ratepayers.

(b) To be eligible for rate treatment in accordance with subdivision (a), a contract shall be for a project which meets all of the following criteria:

1. The project is a replacement or repowering of an existing generation unit of a thermal powerplant.
2. The project complies with all applicable requirements of federal, state, and local laws.
3. The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities.
4. The project will result in significant and substantial increases in the efficiency of the production of electricity.
5. The Independent System Operator or local system operator certifies that the project is needed for local area reliability.
6. The project provides electricity to consumers of this state at the cost of generating that electricity, including a reasonable return on the investment and the costs of financing the project.

In situations where an RFO may not result in a reasonably priced contract, SCE proposes a targeted bilateral negotiation that may result in a cost-effective cost-of-service PPA option.[220] SCE contends that § 454.6 provides the option of using cost-of-service contracts to replace or repower existing generation. SCE witness Cushnie describes the relationship between an RFO solicitation and bilateral negotiations:

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[220] Exhibit SCE-3 (Cushnie) at 8.

> If Edison was to negotiate separately through bilateral negotiations, the potential for a cost of service contract consistent with the legislation…the counterparty will not necessarily know what Edison's options are with respect to pursuing preferred resources with respect to transmission solutions. So it gives Edison more leverage in those negotiations that if we can't negotiate a contract that is reasonable, that we can then move to these other forms of procurement. But if we conduct the solicitation first and conclude that the solicitation was not competitive, we now have reduced any sort of leverage we might have in a subsequent bilateral negotiation because that will have informed the counterparty that there were no competitive options and now Edison just wants to negotiate on price. So it's a judgment call at the end of the day as to what makes the most sense.[221]

It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement process. Both methods are intended to fill the LCR needs identified in this order, and to do so consistent with the Loading Order and cost minimization. We agree with SCE and other parties that cost-of-service contracts (also called bilateral contracts) are allowed under § 454.6 under specified circumstances which are likely to result in a procurement process as a result of this decision. Therefore, § 454.6 cost-of-service contracts are an option that SCE will be able to use in situations where there is significant market power that would be detrimental to ratepayers.

SCE opposes requiring all resources to bid into a single all-source RFO. SCE witness Cushnie contends: "Certain preferred resources just aren't going to be viable in (an all-source) solicitation," and that he is not aware of a preferred

[221] RT 641.

resource ever prevailing against a conventional resource in an all-source RFO.[222] Instead, SCE recommends studying ways to assess the effectiveness and potential use of preferred resources separate from an RFO.[223] SCE maintains that these studies are necessary because such programs cannot be reasonably expected to be developed and bid into a utility solicitation to meet a need that begins in 2020 and extends for ten years or more.

We agree that load reduction programs may not fit well into a typical RFO. SCE witness Cushnie testified that "to the extent we can get comfort that the economics and the viability are there, we can do studies to see if that can reduce the LCR need to meet with supply side resources."[224] It is not clear exactly what SCE intends through this study process. However, we have already assumed a significant amount of preferred resources in determining the minimum and maximum LCR levels for the LA basin local area. SCE should continue to assess and implement all ways to include cost-effective and viable preferred resources to reduce LCR needs. As more preferred demand side resources are available to meet these needs, SCE's LCR needs will be reduced toward the minimum authorized procurement level.

In various other dockets, we have established programs to promote the development of cost-effective energy efficiency and demand response resources. In order to ensure these resources will best be available to meet LCR needs, DRA recommends that SCE should be directed to work with the ISO to determine a

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[222] RT 628-629.

[223] RT 628.

[224] RT 612.

priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.[225] We agree and will require SCE to do so.

Cushnie testified that before SCE undertakes any procurement method, it would take into account updated load forecasts and all available current information.[226] Thus, he recommends not locking down all the assumptions to use for LCR procurement at this time.[227] We agree with this approach. We have set minimum and maximum LCR procurement levels herein. Within this range, SCE will need to consider a variety of issues. These issues include (but are not necessarily limited to) effectiveness of siting, changes in load forecasts, potential cost-effective transmission upgrades, availability of SONGS and other existing resources, and potential market power of bidders. Within the parameters we set today, we will allow SCE managerial discretion to seek the best mix of resources. However, as set forth below, Energy Division will review SCE's procurement in advance, and SCE will need to file an application for approval of its procurement contracts.

One specific consideration is that the requirement to procure at least 50 MW of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers. TURN recommends allowing SCE to "invoke a price circuit-breaker for storage procurement if storage providers cannot provide resources that help meet local reliability at a reasonable price."[228] We agree. While we see considerable value in pursuing the experiment to

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[225] DRA Opening Brief at 30.

[226] RT 757-758.

[227] RT 760.

[228] TURN Opening Comments on Proposed Decision, p. 4.

procure energy storage resources, we do not intend that SCE be required to sign contracts from energy storage suppliers at all costs. In its application to implement this decision, SCE shall present the required contracts for energy storage resources to the Commission for approval, or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

CEJA and DRA urge the Commission to consider OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring as potential resources to meet SCE's local procurement needs.[229] Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers. We find that it is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process. SCE may negotiate with existing OTC plant owners, either through an RFO or consistent with § 454.6, to finance retrofits that will reduce these plants' environmental harm sufficiently to be in compliance with SWRCB policy. Any proposed retrofit of an OTC facility shall compete with other least cost/best fit options.

7.3.2. Energy Division Review of SCE Procurement Plan

SCE seeks flexibility to choose the exact circumstances and timing under which it would utilize an RFO process or a bilateral contract negotiation in its LCR solicitation process, including parallel use of both methods. We agree with SCE that it is difficult in advance to know which method would be most advantageous to ratepayers, and that SCE is in the best position to administer

[229] CEJA Opening Comments on Proposed Decision, p. 7. DRA Reply Comments on Proposed Decision, p. 2.

this process. We will allow SCE the flexibility it seeks, subject to review of its procurement plan by Energy Division and a subsequent Commission application.[230]

SCE shall provide its procurement plan for all required and authorized resources in the LA Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE may provide parts of its procurement plan to Energy Division earlier than 150 days. Specifically, we encourage SCE to present its plan for procurement of up to 1200 MW of gas-fired generation in the LA Basin and up to 290 MW of gas-fired generation in the Big Creek/Ventura local area earlier than 150 days. Due to the long lead time for these particular resources, it is imperative that SCE begin the procurement process (including Energy Division review) as soon as possible.

The procurement plan(s) shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;

[230] Nothing in this decision exempts SCE from previously adopted Commission rules on RFOs in D.07-12-052 and elsewhere.

- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities

We have reviewed the comments of parties filed in response to the September 7, 2012 energy storage/long-term procurement workshop. Based on those comments and the overall record in this proceeding, any RFO should include the following elements:

a) The resource must meet the identified reliability constraint identified by the California ISO;

b) The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c) The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d) A requirement that resources offer the performance characteristics needed to be eligible to count as local RA capacity;

e) No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized through this decision);

f) No provision limiting bids to any specific contract length;

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;

h) Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources;

i) A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j) An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k) A method to consider flexibility of resources without a requirement that only flexible resources be considered; and

l) Use of the most up-to-date effectiveness ratings.

SCE shall not begin its public solicitation process until Energy Division determines in writing that SCE has complied with the provisions of this Decision. Separate Energy Division approvals are needed for the procurement plan and any request for offers. Because the process for soliciting gas-fired capacity may be simpler than for other capacity, Energy Division may provide that the gas-fired capacity portion of SCE's procurement plan can go forward first. The determination of the Energy Division shall be final.

7.3.3. SCE Application

SCE estimates that it would take anywhere from one to two years after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.[231] At that

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[231] RT 719-720; 733-735.

time, SCE witness Cushnie foresees that "parties may choose to challenge the resources we're proposing to utilize to meet the LCR need."[232] In addition, he agrees that SCE would not object if a party wanted to assert that there were other preferred Loading Order resources that were available to SCE on a cost-effective basis that SCE failed to incorporate.

All contracts stemming from the LCR procurement authorization we establish today shall be brought to the Commission for approval in a single application for the LA basin local area and a single application for the Big Creek/Ventura local area (these applications may be combined if SCE chooses). Under SCE's schedule, the applications will be forthcoming sometime in late 2014. However, it is not self-evident why this process should take this amount of time. We expect that SCE's applications could be filed earlier than late 2014. Given the likely 7 to 9 year procurement process for gas-fired resources, we implore SCE to file its applications as soon as practical.

In its applications, SCE shall show:

- Cost-effectiveness;
- Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
- Procurement of between 215 and 290 MW to meet local capacity requirements in the Big Creek/Ventura local reliability area;
- Procurement of between 1400 and 1800 MW to meet local capacity requirements in the Los Angeles local reliability

[232] RT 758.

area (including specific provisions for conventional gas-fired and energy storage resources);

- For bilateral contracts negotiated under § 454.6, that the project will provide electricity at the cost of generation, including a reasonable return on the investment and the costs of financing the project; and
- A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding "or winning" in SCE's solicitation process, except as authorized through this decision. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

8. Flexible Capacity

The ISO recommends that any capacity to fill LCR needs "should have flexibility characteristics similar to the OTC generation" that needs to be replaced.[233] ISO witness Rothleder testified that flexible resources should:

> [p]rovide dispatch flexibility between minimum and maximum operating level[s]…can be used to respond to quick changes in load and variations of generation from renewable resources…can provide ancillary services…have inertia or governor control to respond to changes in frequency and a faster start, to respond more quickly when needed.[234]

Rothleder further testified that LCR resources would also need to meet other attributes of flexible conventional generation including "voltage support, flexibility, frequency response, sustained energy supply, reliable responsiveness,

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[233] Exhibit ISO-1 (Sparks) at 17.

[234] Exhibit ISO-4 (Rothleder) at 8-9.

no significant use limitations and the ability to provide energy regulation, operating reserves and load following."[235]

SCE believes that all resources that have high NQC ratings -- as determined through the Commission's RA proceedings -- have the potential to meet local area needs (although some are more effective than others). SCE witness Minick testified: "In reality, an LCR resource doesn't need to have flexibility. They could be a baseload resource at a certain location and meet LCR requirements. But, it would be very nice from an operational perspective to have flexibility."[236] SCE witness Cushnie testified that "you might not want to have very stringent standards [for flexibility] in your solicitations" and SCE "can then look at various permutations of resource mixes including preferred resources."[237]

IEP recommends that the Commission wait for the completion of studies by the ISO necessary to determine the need for, and the preferred characteristics of, flexible resources before authorizing specific procurement of flexible resources.[238] EnerNOC believes that the Commission must define flexible attributes before requiring such attributes to be procured for LCR purposes.[239] EnerNOC contends that there are demand resources that provide several operational characteristics that the ISO considers in its description of flexibility.[240]

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[235] Exhibit ISO-4 (Rothleder) at 8-9.

[236] RT 972-973.

[237] RT 696-697.

[238] IEP Opening Brief at 10-11.

[239] EnerNOC Opening Brief at 22.

[240] Exhibit EnerNOC-2 (Huffman) at II-1 – II-6.

TURN does not believe that it is important to explicitly incorporate flexible capacity attributes into the LCR procurement process, because it is a serious challenge to establish specific values for different dimensions of flexibility. Further, TURN contends that new combined cycle plants and combustion turbines likely to bid into RFOs will possess tremendous flexibility, thus likely leading to procurement of flexible resources even without any explicit requirement.[241]

CEJA recommends that the Commission not limit potential procurement to resources that meet the ISO's flexibility definition, as LCR procurement in RA proceedings has never been equated with flexible capacity. CEJA points out that the ISO's modeling in R.10-05-006 (which is in the record of this proceeding) showed no flexibility need for 2020.[242]

WEM recommends that the Commission consider that various preferred resources (including demand side resources) should be able to provide certain flexibility characteristics. WEM recommends that the Commission establish final flexibility needs after completion of the ISO's flexibility analysis in Track 2.[243]

8.1. Discussion

SCE will be starting a procurement process as a result of this decision. In procuring resources, SCE will be able to determine what flexibility components various resources contain. At this time there is considerable uncertainty in both the types and quantities of flexible resources that may be needed to balance future resource needs. Preliminary ISO studies indicated a need with all OTC

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241 TURN Opening Brief at 19-20.

242 CEJA Opening Brief at 51.

243 WEM Opening Brief at 6.

resources compliant of 0 MW in the mid load scenarios, but a need of 4600 MW in the high load trajectory scenario.[244] The combined cycle gas turbine resources added from the local areas to a subsequent run of the renewable integration modeling had high capacity factors, over 75%, while combustion turbines had capacity factors close to 13%.[245] These results indicate that while flexibility is an important consideration, it is unclear what exact attributes and blend of flexible versus baseload resources are needed.

The issue of flexibility and determination of flexible attributes for LCR needs is also currently being considered in the RA proceeding, R.11-10-023. A decision in the RA proceeding is expected in the first half of 2013. There is no need to make a determination on flexibility issues in this track of this proceeding. There is also an insufficient record at this time. We cannot currently define flexibility for LCR procurement purposes with any specificity or determine what flexible attributes should or should not be procured by SCE.

Therefore, we will not require SCE to take into account any particular flexible attributes in its procurement process, and will not make acquisition of any flexible attributes a condition of approval of SCE's forthcoming LCR procurement application. However, SCE should identify any known flexible attributes or characteristics of resources bid into its RFO or considered in bilateral negotiations. To the extent that SCE can obtain flexibility in LCR contracts consistent with other requirements, it should do so.

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[244] Exhibit ISO-4 (Rothleder) at 2, 11-19.

[245] Exhibit ISO-4 (Rothleder) at 5, 7-20.

9. Cost Allocation Methodology (CAM)

9.1. CAM Overview

In D.04-12-048, the Commission adopted the IOUs' 2004 long-term procurement plans. As part of its efforts to ensure a long-term, reliable energy supply for California customers, the Commission authorized the IOUs to recover stranded costs associated with new PPAs and utility-owned generation (UOG) from all customers, with the goal of providing "the need for reasonable certainty of rate recovery."[246] By doing so, the Commission sought to address utilities' concern that they could end up over-procuring resources and incurring the associated stranded costs given the potential for a significant portion of their load to take service from a different electric service provider (ESP).

D.04-12-048 did not specify the actual implementation mechanism for recovering these costs. D.06-07-029 in the 2006 long-term procurement proceeding decision adopted the CAM, which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term PPAs, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[247]

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[246] D.04-12-048, Conclusion of Law 14.

[247] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the net of the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The

Footnote continued on next page

The basic framework for the CAM was set forth in D.06-07-029 as follows: The IOU would contract with an Independent Evaluator to oversee an RFO for new resource contracts. At the conclusion of the RFO, the IOU would sign a long-term contract with the generator of a new resource. The IOU would seek contract approval from the Commission, and at that time, select whether or not it intends for the CAM to apply to the contract. The Commission's decision on the IOU's application determines the applicable CAM based on allocating the appropriate net capacity costs to all benefiting customers in the IOU service area.[248] The IOU would then request Commission approval to conduct periodic auctions with an Independent Evaluator for the energy rights of the resource, essentially selling the tolling right – the energy component – and retaining the RA benefit, which it then shares with all customers paying for the capacity.[249] D.06-07-029 at 26 explained that "benefiting customers" referred to all bundled service, direct access (DA), Community Choice Aggregator (CCA) customers and "other customers who are located within a utility distribution service territory but take service from a local publicly-owned utility subsequent to the date the new generation goes into service." D.06-07-029 at 26 (footnote 21) specified that current customers of publicly-owned utilities were exempt from the CAM.

Subsequent decisions clarified and amended the CAM. D.07-09-044 presented in greater depth the procedures for the energy auctions. The procedures established a backstop for the auctions. Should an auction fail to

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non-bypassable change levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

[248] D.06-07-029 at 52-53.

[249] D.06-07-029 at 31-32.

produce a successful bid for the energy products, the capacity costs would be calculated via a specified alternative mechanism.[250] D.08-09-012 set forth that customer generation departing load was exempt from the CAM. That decision clarified that only large municipalizations were subject to the CAM, while exempting other classes of municipal departing load.

Senate Bill 695, signed into law in 2009, requires that the net capacity costs of new generation resources deemed "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory" must be passed on to bundled service customers, DA and CCA customers.[251] In order to align the CAM with the requirements of SB 695, D.11-05-005 did the following:

(1) Removed the right for the utility to elect or not elect CAM treatment for a resource that meets the conditions of the statues;

(2) Widened the scope of the CAM to apply to utility-owned generation resources, and

(3) Extended the duration of CAM treatment to match the duration of the underlying contract, eliminating the 10-year cap.[252]

SB 790 in 2011 codified the Commission requirement that the costs to ratepayers for CAM procurement are allocated to ratepayers in a "fair and equitable" manner.[253]

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[250] *See* D.07-09-044, Appendix A for specifics relating to the Joint Parties' Proposal, the alternative to the auction mechanism.

[251] Stats. 2009, ch. 337.

[252] D.11-05-005 reaffirmed that SB 695 does not require any revisions to the determinations made in D.08-09-012 regarding non-bypassable charges and the CAM process.

The Scoping Memo posed three questions related to the CAM:

(1) How should the costs of any additional local reliability needs be allocated among LSEs in light of the CAM?

(2) Should the CAM be modified at this time? and

(3) Should LSEs be able to opt-out of the CAM, and if so, what should the requirements be to permit such an opt-out?

In addition to the questions posed by the Commission, SSJID raised specific questions regarding its classification as a large municipalization and the CAM's application in its particular case. SSJID also questioned whether the CAM applies to municipal departing load in general.

9.2. Allocating Costs of Local Reliability Needs Among LSEs in Light of the CAM

The three IOUs, TURN and DRA all assert that the CAM should apply to all generation authorized in Track 1,[254] and net capacity costs should be allocated to all benefitting customers, including bundled service, DA, and CCA customers.[255] DRA explains that "since LCR resources would provide reliability benefits to all customers, the net capacity costs should similarly be allocated to all customers."[256]

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[253] Stats. 2011, ch. 599.

[254] Nothing in this decision is intended to imply or state that the CAM applies to bundled procurement.

[255] *See* Exhibit SDG&E-2 (Anderson) at 9; Exhibit SCE -2 (Cabbell/Cushnie/Minick/Silsbee) at 20-23; Exhibit TURN-2 (Woodruff) at 16; Exhibit DRA-5 (Ciupagea) at 1.

[256] Exhibit DRA-5 (Ciupagea) at 1.

AReM asserts that the Commission's goal should be to minimize CAM procurement.[257] AReM testified that it is only fair to allocate CAM costs when the need creating the costs can be attributed to all customers, and not solely to IOU bundled load. To that end, AReM maintains that the Commission must evaluate the characteristics of the load served by the IOUs versus the characteristics of the load served by the other LSEs in the IOU service area to determine the different rates at which they grow. If this analysis finds that bundled customer load is driving the peak or decreasing the system load factor, then AReM contends bundled customers should pay for the resources necessary to meet that need.

Further, AReM states that per its obligation under § 454.5, the Commission should ensure that CAM procurement is needed to meet a specified reliability need as defined by § 365.1(c)(2)(B). AReM contends that this means that the reliability need must be incremental to the needs associated with LSEs. For example, AReM argues that if a generation plant that "primarily" served bundled load retired or shut down and the IOU filed for approval for CAM procurement to replace the unit, the Commission should reject this application. According to AReM, while "incidental reliability benefits [from the replacement unit] would likely accrue to '*all*' customers, bundled customers would benefit disproportionately more, because the customers of other LSEs would subsidize their '*unmet needs*.'[258] Therefore, AReM reasons, CAM procurement should not be authorized.

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[257] Exhibit AReM-1 (Mara) at 5, 20.

[258] Exhibit AReM-1 (Mara) at 28.

AReM sets forth a two-step proposal for the Commission to determine whether a particular CAM project should be approved: (1) calculate the MWs of unmet need, and identify what portion of the unmet need is driven by the bundled load, and (2) if MWs of unmet need exist and are attributable to all benefiting customers in the service area, then AReM propose six criteria to ascertain whether the CAM should be applied in the particular case.[259] The proposed criteria are:

1. The IOU's Application requests, as required by § 365.1(c)(2)(A), the following: (i) approval for a specific contract with a third party to procure generation resources; or (ii) an order to procure a specific UOG resource.
2. The Commission has previously determined that the MWs in the Application may be subject to CAM procurement.
3. The Commission determines that the project identified in the Application fulfill an unmet need that is not attributable to any individual LSE.
4. The Commission determines that the project identified in the Application is required by the ISO to meet a specific System or Local RA need that cannot be reasonably met by other existing resources, demand response, energy efficiency or other alternatives and is required to be operational as of the timeline proposed in the IOU's Application to avoid degrading grid reliability.
5. The Commission determines that the project identified in the Application benefits all customers within the IOU's

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[259] AReM proposes this criteria as a less restrictive alternative to a "benefits test" as a means of determining when to authorize CAM procurement per § 365.1(c)(2)(A). SDG&E and DRA both recommend that the Commission explore creating a defined "benefits test" for CAM procurement. *See* Exhibit SDG&E-1 (Anderson) at 10-11 and Exhibit DRA-5 (Ciupagea) at 4. SDG&E suggests that "the Commission should find that benefitting parties are those parties that have load in the reliability area." Exhibit SDG&E-1 (Anderson) at 11.

service territory, including DA and CCA customers, by the way in which it meets the reliability needs specified by the ISO, as required by § 365.1(c)(2)(B).

6. Local RA projects in an IOU's Local RA Area provide comparable reliability benefits, as specified by the ISO, to all customers located in the entire IOU's service area, as required by §§ 365.1(c)(2)(A), 365.1(c)(2)(B), and 366.2 (g). Projects that provide the specified reliability benefits primarily to customers located within the Local RA Area where the project will be developed must be rejected as inconsistent with the statutes noted.[260]

The three IOUs and DRA oppose AReM's cost causation principle, stating that LCR resources would provide reliability benefits to all customers, and thus, the net capacity costs should similarly be allocated to all customers.[261]

SDG&E proposes that the Commission explicitly adopt a rebuttable presumption that the net capacity costs of generation resources authorized to meet system and local reliability requirements should be allocated via the CAM to all customers within the IOU's service territory.[262] SDG&E acknowledges that while CAM procurement must receive careful consideration, minimizing CAM should not be the overriding consideration. As long as state policies and interests are served through utility procurements that provide benefits beyond the IOU's bundled customers, the Commission should allocate the costs via the

[260] Exhibit AReM-1 (Mara) at 30-31.

[261] Id. at 8-9; Exhibit SCE-2 (Cushnie) at 27-28; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 8 (PG&E asserts that if AReM's cost causation proposal is accepted, then DA and CCA providers should be willing to agree to submit procurement plans to the Commission alongside IOUs); Exhibit DRA-5 (Ciupagea) at 1-2.

[262] Exhibit SDG&E-2 (Anderson) at 6.

CAM to all benefitting customers.[263] SDG&E also takes issue with what it perceives as AReM presupposing that utility bundled load drives growth in peak demand and decrease in system load factors, when these assumptions are debatable. SDG&E states that AReM fails to address the complicated reality that there is no "objective formula that can be devised for quantifying and allocating reliability benefits among different customer groups."[264]

SCE states that the costs of any SCE procurement to meet system reliability needs must be "fully recoverable and allocated appropriately" to DA and CCA customers via the CAM.[265] SCE asserts that it would prefer not to procure beyond its bundled customers for system reliability,[266] and maintains that it will not procure system reliability resources unless "all benefitting customers pay their fair share."[267]

PG&E recommends allocating the costs of LCR procurement in Track 1 to "all customers in the service area where LCR resources are added, whether bundled, DA, or CCA customers."[268] PG&E believes that LCR procurement in the LA basin should be allocated to all benefiting customers in SCE's service territory, but not to any customers in PG&E's service territory.[269]

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[263] Exhibit SDG&E-2 (Anderson) at 1-3.

[264] Exhibit SDG&E-2 (Anderson) at 8.

[265] Exhibit SCE-1 (Cushnie) at 25.

[266] Exhibit SCE-1 (Cushnie) at 21-22.

[267] Exhibit SCE-1 (Cushnie) at 21.

[268] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 6.

[269] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 4.

TURN asserts that "the most reliable means of getting any needed new capacity built is for Edison take on the responsibility of contracting for such capacity and allocate the costs to all benefit[ting] customers via the CAM."[270] TURN states that AReM's suggestions for CAM implementation would result in DA and CCA customers paying for less than a proportionate share of the reliability costs, and should thus, be rejected.[271]

9.3. Discussion

Section 365.1(c)(2)(A)-(B) holds that in instances when the Commission determines that new generation is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the net capacity costs for the new capacity shall be allocated in a fair and equitable manner to all benefiting customers, including DA, CCA and bundled load. Simply put, each customer must pay their fair share for the benefits that flow to them from the new generation for the full life of the asset.[272]

AReM's driving peak/decreasing load proposal fails to recognize the interrelated nature of the electric system and the reality that some individual customers of ESPs, CCAs and IOUs have static load profiles, while others are driving the need for new resources. In addition, the retirement of existing resources creates the need for new resources to serve customers that may not be driving increases. Therefore, we continue the current Commission policy of allocating CAM costs and benefits at the IOU service area level.

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[270] Exhibit TURN-1 (Woodruff) at; Exhibit TURN-2 (Woodruff) at 16.

[271] Exhibit TURN-2 (Woodruff) at 4.

[272] We note that SB 695 relieves the IOUs of limiting CAM treatment to 10-year contracts.

In addition, we do not adopt AReM's two-step/six criteria framework. AReM's approach imposes additional requirements designed to limit CAM allocation, and appears to create a precise determination of "benefitting customers." However, precision is not the same as fairness. The Commission's previously adopted criteria fairly apportion costs to customers as envisioned by past Commission and the legislature actions. While creating more complexity, nothing in AReM's proposal improves on the fairness of the current allocation. Thus, the costs of local reliability needs shall continue to be allocated in accordance with previous Commission decisions.

9.4. Should the CAM be Modified at This Time?

AReM proposes several further modifications to the CAM, including changes to energy auction terms and the adopted program's proxy calculation. AReM suggests that the Commission make the current five-year maximum ceiling on energy auctions products to a five-year minimum floor. AReM contends that longer term tolling would more accurately reflect "the incremental hedging value of the PPA."[273]

AReM also opines that the net capacity cost calculation from the adopted program should be changed to better reflect the increased ancillary service value and value of "other products and services" provided by the new PPAs or UOG plants beyond non-spinning reserves.[274] In addition, AReM proposes that the Commission modify the adopted program in order to account for the options value associated with a long-term tolling contract. By failing to incorporate this

[273] Exhibit AReM-1 (Fulmer) at 39.

[274] Exhibit AReM-1 (Fulmer) at 39-41.

value, AReM contends, the current CAM framework "ignores one of the primary driver of PPA cost: the opportunity value of purchasing energy with agreed-upon terms in a market characterized by energy price volatility.[275]

AReM also supports a levelized annual revenue requirement for UOG plants in order to account for the reality the imputed capacity costs of a UOG generating plant changes over time as the plant is depreciated.[276] Finally, AReM asserts that the CAM should be capped, as a "backstop to ensure reasonable results."[277] AReM recommends that the Commission convenes workshops to discuss the details of implementing some of their suggested design modifications.

SDG&E believes that the current auction mechanism is administratively unwieldy and not necessarily conducive to efficient capacity costs.[278] SDG&E supports the use of the adopted program[279] as an alternative to the use of an energy auction to determine the net capacity costs for CAM resources. SDG&E suggests that the Commission eliminate the IOUs' obligation to auction the right to the energy, unless the Commission directs otherwise; toward that end, SDG&E opines that the Commission should convene workshops to construct a permanent alternative to energy auctions.[280] In addition, SDG&E specifically

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[275] Exhibit AReM-1 (Fulmer) at 42-43.

[276] Exhibit AReM-1 (Fulmer) at 44.

[277] Exhibit AReM-1 (Fulmer) at 48.

[278] Exhibit SDG&E-1 (Anderson) at 10-11. TURN, on the other hand, expressed its support for CAM's current energy auction approach. Exhibit TURN-2 (Woodruff) at 3.

[279] The adopted program refers to the current CAM program, adopted in D.06-07-029, and amended in subsequent decisions as previously laid out in this decision.

[280] Exhibit SDG&E-2 (Anderson) at 10.

rejects AReM's proposal to amend the adopted program to include all major ancillary service products currently available in the ISO market, levelize the annual revenue requirement for utility-owned generation, and cap the CAM.[281]

DRA supports SDG&E's proposal to change the energy auctions. DRA encourages the Commission to convene workshops to explore possible modifications to the net capacity cost allocation, the valuation for energy and ancillary services and pursue the reduction of capacity costs for all parties.[282]

The three IOUs and TURN oppose AReM's proposal to incorporate ancillary services in calculating energy dispatch value.[283] SCE and PG&E align with SDG&E in objecting a levelized annual revenue requirement,[284] while all three IOUs and TURN expressly object to AReM's proposal to cap the CAM.[285]

We reject the proposed cap on CAM. We find that AReM's proposal to levelize the annual revenue requirement obviates the plain language of § 365.1(c)(2)(C), which states that the net capacity costs shall be determined by "subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation

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[281] SDG&E-2 (Anderson) at 6-12.

[282] Exhibit DRA-5 (Ciupagea) at 4.

[283] SDG&E-2 (Anderson) at 6-12; Exhibit SCE-2 (Cushnie) at Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 9-10, Exhibit TURN-2 (Woodruff) at 9.

[284] Exhibit SCE-2 (Cushnie) at 37; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 10.

[285] Exhibit SCE-2 (Cushnie) at 32, 37-38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 11; Exhibit TURN-2 (Woodruff) at 8-9 (TURN contends that imposes a cap on CAM without simultaneously imposing a floor would be discriminatory).

directly owns the resource." (emphasis added.) Once the CAM contract has lapsed, bundled customers would overpay for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value. Further, the proposal to cap the CAM contradicts its central purpose: apportioning system and local reliability costs to all benefiting customers in an IOU service area so that each benefitting customer pays their fair share.

We have stated an openness to revisit the energy auction mechanism adopted in D.07-09-044.[286] Toward that end, we appreciate the suggestions from parties in the current proceeding to consider improvements toward the current auction mechanism structure, including valuing net capacity costs. The record, however, fails to provide an adequate basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism. We may consider taking a more focused look at these issues in the future.

9.5. CAM Opt-Out

In D.06-07-029, the Commission found the concept of a CAM opt-out mechanism for LSEs appealing, upon the demonstration that an LSE is fully resourced with new generation for ten years forward. However, D.06-07-029 stated "the reality is that we have no viable enforcement program or mechanism for doing so," such as a "multi-year RA program where an LSE could demonstrate it is fully resourced for the next four or 10 years."

AReM strongly supports an LSE opt-out, asserting that it is essential to maintaining market choice. AReM's opt-out would function as follows. Once

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[286] For example, *see* D.11-05-005.

the Commission determines unmet need subject to the CAM, an ESP or CCA would have the option to request an opt-out from the CAM. The LSE has until the IOUs submit any proposed CAM projects to request an opt-out. In order to qualify for an opt-out, an LSE would make a showing to the Commission that it has procured adequate generation resources for a five-year period.

AReM proposes three types of out-out: (1) Load Ratio Share Opt-Out; (2) Load-Based Opt-Out; and (3) Customer-Based Opt-Out, which are described in detail in its testimony. [287] The three IOUs, TURN and DRA all categorically reject AReM's opt-out proposals.[288] Each asserts that AReM's proposed five-year forward contract term showing is insufficient time to procure and finance new generation resources given the reality of long lead time for building new generation.[289] SDG&E contends that a CAM opt-out would encourage LSE free riding at the expense of utility ratepayers.[290] SCE asserts that a CAM opt out stands in direct contrast to the Legislature's intent to pass along costs to all benefiting customers in a fair and equitable manner.[291] PG&E points out that keeping track of all the potential LSEs who choose to opt out of the CAM via one of the three ways proposed by AReM will result in high administrative costs.[292]

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[287] *See* Exhibit AReM-1 (Mara), starting at 57.

[288] Exhibit SDG&E-2 (Anderson) at 13-14; Exhibit SCE-2 (Cushnie) at 38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12; Exhibit TURN-2 (Woodruff) at 6-7; Exhibit DRA-5 (Ciupagea) at 5.

[289] Exhibit DRA-5 (Ciupagea) at 5.

[290] Exhibit SDG&E-2 (Anderson) at 12.

[291] Exhibit SCE-2 (Cushnie) at 39-40, which excerpts § 365.1(c)(2)(A)-(B).

[292] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12.

TURN asserts that AReM's proposal would result in DA and CCA customers paying for less than a proportionate share of the costs of local reliability needs, with virtually no responsibility for new capacity needed to meet load reliably.[293] DRA argues that it is unclear how AReM's proposal would be enforceable to "ensure that 'there will be no free riders' vis-à-vis the cost of capacity of new generation,"[294] and disagrees with AReM that only non-IOU LSEs should be allowed to opt out of the CAM.[295]

9.6. Discussion

The issue of a CAM opt-out is complex. AReM has properly raised legitimate questions regarding equity of the current CAM structure. However, while AReM's detailed proposal of a potential opt-out structure is helpful, it is unclear how its five-year contract term/project life requirement would adequately ensure investment in new resources. Further, it is not at all clear that a CAM opt-out could be implemented without undue administrative burden. After considering comments from parties, we find the record insufficient to resolve these questions, and therefore do not adopt an opt-out at this time.

We will not rule out consideration of a CAM opt-out at a future date. However, we have considered parties' positions on more than one occasion, and declined to adopt a CAM opt-out. Therefore, we are disinclined to relitigate this issue in the future unless all or nearly all impacted parties can agree on a specific, detailed and implementable proposal, or there are significant changed circumstances.

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[293] Exhibit TURN-2 (Woodruff) at 7.

[294] Exhibit DRA-5 (Ciupagea) at 5, quoting Exhibit AReM-1 (Mara) at 19.

[295] Exhibit DRA-5 (Ciupagea) at 5.

9.7. SSJID Proposal

SSJID asserts that it should be exempt from the CAM. Specifically, SSJID recommends the Commission should "exempt all existing and future [publicly-owned utility departing load], including large municipalizations, from CAM responsibility."[296]

PG&E argues that SSJID should be subject to the CAM. PG&E asserts that the Commission has already decided in D.08-09-012 at 27-30 that the CAM applies to all large municipalization departing loads, and that SSJID fits into the Commission's stipulated definition of a large municipalization.[297]

SSJID's argument against CAM application is that: (1) SSJID's Municipal Departing Load (MDL) should not be classified as a large municipalization as defined by the Commission in D.08-09-012; (2) California law does not require that Public-Owned Utilities (POUs) or MDL of any size (including large) be included as "benefiting customers" for the purposes of the CAM; (3) POUs do not present the same capacity procurement risks as DA or CCA loads; (4) POU customers may not be able to RA credits allocated under CAM; and (5) the Commission's alternative methodology for allocating RA costs and benefits to large municipalizations is an approximation and is impractical.[298]

Most of the matters raised by SSJID were addressed in D.08-09-012 and will not be relitigated here. Regarding the definition of "large municipalization," D.08-09-012 at 26-27 stated:

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[296] Exhibit SSJID-1 (Shields) at 4.

[297] Exhibit PG&E-2 (Rubin) at 2.

[298] Exhibit SSJID-1 (Shields) at 3-4.

> While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts."

As indicated, D.08-09-012 did not specify the exact parameters for "large municipalization." It is not within the scope of this proceeding to determine whether SSJID is a large municipalization. SSJID has not convinced us that other issues it raised require any further action at this time.

10. Cost of Capital (COC)

SCE witness Hunt testified that SCE seeks Commission authorization to file a separate application to adjust its capital structure to take into account debt equivalence issues arising from additional PPAs.[299] Debt equivalence occurs when rating agencies determine that the capacity costs of PPAs are equivalent to debt for the IOUs because the payments cannot be avoided without defaulting on the PPA.

Hunt contends PPAs arising from this decision will create significant debt equivalents or debt equivalence on SCE's balance sheet that may need to be mitigated to preserve SCE's creditworthiness. Hunt estimates that SCE's 2013 debt equivalence will be about $2.5 billion, while LCR procurement contracts could increase that amount by $900 million to $2.9 billion.[300]

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[299] RT 834.

[300] Exhibit SCE-1 (Hunt) at 27.

DRA opposes SCE's request. DRA recommends that SCE should wait to have the Commission consider any changes in SCE's debt equivalence resulting from LCR procurement until the next COC proceeding. DRA asserts that since debt equivalence is only one of many credit risk drivers impacting SCE's credit rating, debt equivalence should be considered together with those other credit risk drivers.[301] TURN points out that the Commission has addressed this issue in several previous procurement-related proceedings and declined to approve the relief requested by the utility. TURN cites D.09-06-018 at 58, stating that "we will take action to address negative impacts on any utility's balance sheet or credit profile when warranted and necessary, and will do so in a manner consistent with the urgency of the matter."

SCE's capital structure is typically determined in its COC proceeding. On April 20, 2012, SCE filed its most recent COC application. SCE's next COC proceeding is expected in early 2015. SCE witness Hunt testified that the point at which SCE's procurement PPAs stemming from this order would be included in rating agencies' rating as debt equivalence is generally when energy deliveries begin under a contract.[302] Mr. Hunt also testified that to the extent that the contract will simply replace an expiring contract, Standard and Poor's rating agency will impute debt as though the future contract is a continuation of the existing contract.

SCE itself expects the process from today's decision to Commission-approved contracts to take about two years, or until late 2014. Any potential impact on SCE's COC will not commence until at least the time of the

[301] Exhibit DRA-8 (Lasko) at 3.

[302] RT 839.

Commission's decision on SCE's LCR procurement application, if not for several years afterwards.

We will not change our policy from D.09-06-018 and previous decisions. SCE should use its next COC application, or other venue for consideration of COC, to seek any changes it considers appropriate due to debt equivalence for the contracts foreseen from today's decision.

11. Motion of Megawatt Storage Farms (MSF)

On October 5, 2012 MSF filed a motion asking the Commission to rule that energy storage should be ranked first in the Loading Order. MSF argues that this proceeding is evaluating and deciding on quantities of resources to be procured, and that energy storage must be considered here. MSF notes that energy storage is not mentioned explicitly by name in the current Loading Order, and that it is impossible for the LTPP Proceeding to analyze or decide on procurements unless a decision is made on energy storage's ranking within the Loading Order.

MSF articulates several reasons why it contends energy storage should be first in the Loading Order. First, MSF contends that energy storage reduces natural gas needs for renewables integration. Second, MSF claims energy storage reduces natural gas needs for frequency regulation. Third, MSF argues that energy storage promotes energy efficiency by time shifting. Finally, because energy storage does not fit into other specified categories (these categories are entitled "new generation" and "fossil fuel, central station generation"), MSF contends energy storage is properly placed in the first category.

Several parties filed in opposition to MSF's motion. Opposing parties argue that the MSF motion is untimely, that energy storage issues are being considered in another proceeding, and that the Loading Order should not be modified in this proceeding.

The MSF motion is denied. In this decision, we establish a solicitation process for SCE to procure for long-term LCR needs. In this process, there will be opportunities for potential energy storage facilities to participate; we specifically require SCE's solicitation process to be technologically-neutral. Further, we require SCE to procure at least 50 MW of energy storage.

However, it is premature to consider where energy storage should be placed in the Loading Order. As MSF acknowledges and as discussed herein, we are considering issues related to energy storage in R.10-12-007. In that proceeding, it is possible (though not guaranteed) that the Commission will establish procurement targets for energy storage or otherwise provide a method to facilitate the development of energy storage technologies. At this time, no decisions have been made concerning the viability, cost-effectiveness or public interest nature of energy storage technologies in that docket. If and when such action is taken, the role of energy storage technologies in the procurement process can be considered.

We also note that, as discussed herein, the Loading Order was developed in a multi-agency process and is, in part, established in statute. We do not intend to unilaterally reconsider the multi-agency Energy Action Plan in this decision; certainly, we cannot alter a statute here.

12. Categorization, Need for Hearings and Assignment

The assigned Commissioner is Michel Peter Florio and the assigned Administrative Law Judge (ALJ) is David M. Gamson. ALJ Gamson is the Presiding Officer.

13. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on January 14, 2013, and reply comments were filed on January 22, 2013.

Based on comments, the PD has been modified as follows:

- The minimum procurement level for the LA Basin has been increased from 1050 MW to 1400 MW;
- The maximum procurement level for the LA Basin has been increased from 1500 MW to 1800 MW;
- For the LA Basin, SCE is now required to procure at least 150 MW of preferred resources (as opposed to no requirement in the PD);
- For the LA Basin, SCE may procure up to 600 MW of preferred resources (as opposed to an authorization of 250 -450 MW in the PD), subject to the overall 1800 MW cap;
- As with the PD, SCE is required to present contracts for at least 50 MW of energy storage resources in the LA Basin to the Commission for approval, or (in the revised PD) to have the burden of proof to show that it should procure less than 50 MW because the bids it received were unreasonable;
- The PD's authorization for SCE to procure up to 1519 MW of distributed generation (less amount already expected to be procured) in the LA Basin is deleted;
- The ISO Trajectory scenario is used as a starting point for forecasting LCR needs for the LA Basin (instead of the ISO Environmentally Constrained scenario sensitivity analysis in the PD). The ISO Trajectory scenario is adjusted to account for 100% of uncommitted energy efficiency and CHP forecasts by the CEC, and to account for a conservative forecast of 200 MW of demand response resources;
- SCE is now required to consider retrofits of a power plant cooling system undertaken to comply with State Water

Resources Control Board Statewide OTC Policy as a new resource in considering resources to meet its LCR needs;

- A footnote in the PD is modified to allow certain CHP resources to qualify as part of the 1000 to 1200 MW requirement for conventional gas-fired resources in the LA Basin;
- Clarification of the relationship between procurement requirements in this proceeding and Commission procurement decisions in the RPS docket;
- Clarifications to requirements for SCE's Procurement Plan (reviewed by Energy Division) and subsequent procurement Applications;
- Other minor changes and clarifications to the PD are made as appropriate;
- Various Findings of Fact, Conclusions of Law and Ordering Paragraphs are modified to effectuate the changes to the PD listed above.

Findings of Fact

1. It is reasonable for the Commission only to consider LCR forecasts by the ISO using renewable portfolio scenarios already in the record of R.10-05-006.

2. It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting.

3. The ISO used demand forecasts provided by the CEC in its 2009 IEPR, which used 2009 demand forecast data. It is reasonable to use this data for LCR forecasting in this proceeding.

4. In the LA basin local area, the Alamitos, El Segundo, Huntington Beach, Redondo Beach power plants use OTC technology. Sixteen OTC units are required to comply with SCRWB regulations to substantially reduce water use before 2021. In total, these units currently have more than 4900 MW of capacity.

5. In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units which are required to comply with SWRCB regulations to substantially reduce water use before 2021. In total, these units currently have more than 2000 MW of capacity.

6. The ISO forecasted LCR needs 10 years into the future for the first time; these forecasts (like other forecasts) are subject to error due to input assumptions and significant changes in circumstances in the future.

7. Both under-procurement and over-procurement entail significant risks. Under-procurement entails risks of reliability problems and the impacts of mitigating such problems in a short timeframe. Over-procurement entails risks of excessive costs and unnecessary environmental degradation. It is not possible to quantify whether the risks of over- or under-procurement are greater.

8. It is reasonable to use the CEC's one-in-10-year load forecast, combined with the contingencies identified by the ISO, for the purpose of LCR forecasting in this proceeding.

9. It is reasonable to use the ISO's analysis of transmission for the purpose of LCR forecasting in this proceeding.

10. It is reasonable to assume that the OTC plants in the SCE territory required to comply with SWRCB regulations will comply through retirement or repowering consistent with the SWRCB schedule, for the purpose of LCR forecasting in this proceeding. However, no finding on this point is intended to apply to SONGS.

11. Each of the four RPS scenarios analyzed by the ISO contain a reasonable minimum level of energy efficiency from CEC forecasts which can be used for the purposes of determining LCR needs for the LA basin local reliability area.

12. The four RPS scenarios analyzed by the ISO do not include any uncommitted energy efficiency or uncommitted CHP resources analyzed by the CEC.

13. To the extent uncommitted energy efficiency and uncommitted CHP resources ultimately develop, they can be helpful in reducing overall net demand. However, these resources are not likely to be as effective in reducing LCR needs as repowered gas-fired resources at existing OTC locations. Reducing overall net demand reduces LCR needs.

14. A significant amount of what is categorized by the CEC as uncommitted energy efficiency is certain to occur because it is based on standards already adopted by the CPUC, the CEC and federal agencies.

15. In the ISO's Environmentally Constrained scenario sensitivity analysis, the impacts of uncommitted energy efficiency and uncommitted CHP significantly reduced LCR needs for the LA basin local reliability area compared to other ISO scenarios.

16. There will be more uncommitted energy efficiency available in the LA basin local reliability area than was included in the ISO Trajectory scenario. The ISO Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local reliability area.

17. There is at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now).

18. By 2020 it is likely that the actual amount of demand response resources available to reduce LCR needs in the LA Basin will be considerably more than 100 MW, and possibly closer to DRA and CEJA's estimates of around 1000 MW.

19. There will be more uncommitted CHP available in the LA basin local reliability area than was included in the ISO Trajectory scenario.

20. The ISO's Trajectory scenario includes a reasonable minimum level of distributed generation for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding, except that it does not include a sufficient estimate for uncommitted CHP.

21. The ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted CHP for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding.

22. In R.10-12-007, the Commission is considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time there is not sufficient information to determine how much viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes.

23. It is premature to consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

24. It is reasonable to expect that some unidentified amount of energy storage resources will be available in the future, and it is likely that some amount of energy storage resources will be available to meet future LCR needs. It is unclear whether the costs of energy storage resources will be reasonable.

25. It is likely that some LCR procurement opportunities would be lost if there is a delay in approving a procurement process for the LA basin local reliability area and the Big Creek/Ventura local reliability area, due to a seven to nine year lead time for conventional gas-fired resources.

26. Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs. Other resources can also meet or reduce LCR needs, but may not be effective in doing so.

27. There is a significant need for LCR resources to replace retiring OTC plants in the LA basin local area by 2021 under every ISO scenario, as well as under the Environmentally Constrained scenario sensitivity analysis.

28. Even if some uncommitted energy efficiency and/or uncommitted CHP resources included in the ISO Environmentally Constrained scenario sensitivity analysis do not ultimately appear, there is a reasonable likelihood that some demand response and/or energy storage resources and/or other distributed generation resources will be viable and able to similarly meet or reduce LCR needs.

29. The ISO's Environmentally Constrained scenario sensitivity analysis includes the highest reasonable levels of uncommitted energy efficiency and uncommitted CHP. This forecast shows an LCR need of 1042 MW for the LA basin local area for effective sites, which is 828 MW below the LCR need in the Environmentally Constrained scenario (everything else being equal).

30. It is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met.

31. In order to determine a minimum LCR procurement level for the LA basin local area with 100% of the CEC's forecast of uncommitted energy efficiency and uncommitted CHP, and 200 MW of demand response resources, it is reasonable to subtract the effects of these resources from the ISO's Trajectory scenario. Thus (with rounding), the ISO's projected need of 2400 MW in the Trajectory scenario would be reduced by 800 MW to account for 50% of

uncommitted energy efficiency and CHP, and by 200 MW to account for a conservative estimate of demand response resources. This leads to a minimum procurement level of 1400 MW.

32. A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement.

33. In order to determine a maximum LCR procurement level for the LA basin local area it is reasonable to include an additional 400 MW authorization to reflect potential reduced effectiveness.

34. If SCE procures more than the minimum MW amount for the LA basin local area, it will be consistent with the Loading Order to require some additional capacity to come from non-fossil-fueled sources.

35. The ISO did not include any values for uncommitted energy efficiency and uncommitted CHP for the Big Creek/Ventura local area.

36. The ISO did not include any values for demand response or energy storage resources in the Big Creek/Ventura local area.

37. The ISO evaluated and found feasible a transmission alternative for the Moorpark sub-area of the Big Creek/Ventura local area.

38. The ISO has shown that there is a need for in-area generation with operational characteristics similar to retiring OTC plants in the Moorpark sub-area of the Big Creek/Ventura local area.

39. The most likely locations for to meet LCR needs in the Moorpark sub-area are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

40. The most likely size for at least one replacement plant in the Moorpark sub-area of the Big Creek/Ventura local area is 215 MW, as this is the size of two existing OTC units in that area.

41. There may be a need to procure up to 290 MW in the Moorpark sub-area, after accounting for the likelihood of preferred resources and/or transmission upgrades which are likely to exist in that area and be able to reduce or meet LCR needs.

42. There is an immediate need to begin a procurement process to meet LCR needs of between 215 and 290 MW in the Moorpark sub-area.

43. SCE will need to undertake technical studies to integrate certain preferred resources (including energy storage resources) so that they meet local reliability needs, and to work with the ISO to assess the impacts of such resources to meet or reduce LCR needs.

44. A requirement to procure a modest level of energy storage resources, such as 50 MW provides an opportunity to assess the cost and performance of energy storage resources.

45. A requirement to procure at least a minimum level of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers.

46. OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring are potential resources to meet SCE's local procurement needs. Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers.

47. It may take one year or more after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.

48. Purchased power agreements arising from this decision may create significant debt equivalents on SCE's balance sheet that may need to be mitigated

to preserve SCE's creditworthiness. Such additional debt equivalence will not come into effect until the start of commercial operations of the plant, unless the contract is considered by a rating agency as a continuation of a current contract.

49. The cost allocation mechanism in effect today was established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005.

50. AReM's driving peak/decreasing load CAM proposal is inconsistent with the principle that each customer must pay their fair share for the benefits that flow to them from the new generation.

51. AReM's two-step/six criteria framework for CAM allocation imposes additional requirements designed to limit CAM allocation, but does not improve on the fairness of the current allocation.

52. AReM's proposal to levelize the annual revenue requirement would result in bundled customers overpaying for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value.

53. The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism.

54. In AReM's CAM opt-out proposal, it is unclear how AReM's five-year contract term/project life requirement would adequately ensure investment in new resources.

55. It is not clear that a CAM opt-out could be implemented without undue administrative burden.

Conclusions of Law

1. A significant difference between the ISO's reliability mission under § 345 and the Commission's reliability emphasis under § 380(c) is that the Commission

must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates under § 451 and § 454 and a commitment to a clean environment under Pub. Util. Code sections including § 399.11 (Renewables Portfolio Standard) and § 454.5(b)(9)(C) (Loading Order).

2. Consistent with § 454.5(b)(9)(C), which states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible," and the Commission's Loading Order established in the Energy Action Plan, utility LCR procurement must take into account the availability of preferred resources before procuring non-preferred resources.

3. The record in this proceeding supports outcomes which enable the Commission to meet statutory requirements and policy goals with regard to reliability, ratepayer costs and environmental protection, as well as to require the procurement of sufficient levels of diverse resources in a timely manner.

4. SCE's procurement process should have no provisions specifically or implicitly excluding any resource from the bidding process due to technology, except for specific requirements in this decision for the LA basin local area. Except as otherwise required by this decision, SCE's procurement process must have provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and § 454.5(b)(9)(C).

5. The ISO models overstate the LCR need for the LA basin local area and the Big Creek/Ventura local area.

6. It is reasonable to assume that 100% of the CEC's forecast of uncommitted energy efficiency and CHP levels will exist in order to determine minimum and maximum LCR procurement level for the LA basin local area.

7. It is reasonable, as a conservative approach, to assume a nominal level of 200 MW of locally-dispatchable demand response resource will be available in the LA Basin to reduce LCR needs by 2020.

8. Adoption of an LCR need range which takes into account for potential differences in the effectiveness of different resources, 100% of uncommitted energy efficiency and uncommitted distributed generation resources, and allows for the potential of demand response resources and energy storage resources which may meet ISO technical criteria for meeting LCR needs, is consistent with the applicable statutory and regulatory requirements for procurement of preferred resources, including the Loading Order.

9. SCE should be required to procure a minimum of 1400 MW and a maximum of 1800 MW in the West LA sub-area of the LA basin local reliability area. No more than 1200 MW should be from conventional gas-fired sources. At least 150 MW should be from preferred resources. Up to 600 MW of capacity may be from preferred resources or energy storage resources (in addition to resources already authorized or required to be obtained via Commission decisions in energy efficiency, demand response, RPS, energy storage and other relevant dockets), subject to the maximum procurement level.

10. SCE should be required to procure at least 50 MW of energy storage resources in the LA basin local area to meet LCR needs, subject to a showing that the costs of some or all of such procurement would not be reasonable.

11. SCE should be required to procure a minimum of 215 MW and a maximum of 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area.

12. SCE should be required to provide a procurement plan to Energy Division for compliance review of the requirements of this decision.

13. SCE should be required to file one or more Applications for approval of contracts to procure LCR resources consistent with this decision.

14. If there is additional information about the viability of preferred resources and/or transmission alternatives in the Moorpark sub-area of the Big Creek/Ventura local reliability area and West LA sub-area of the LA basin local reliability area when SCE files its Application for approval of contracts, that information should be considered at that time.

15. SCE should be required to determine the availability and cost-effectiveness of preferred resources, and energy storage resources, that can offer the necessary characteristics to meet or reduce LCR needs. SCE should then be required to work with the ISO to re-run its transmission modeling load-flow analysis to determine the impacts of such resources. To the extent such resources meet or reduce LCR needs, SCE should reduce procurement of non-preferred resources.

16. Cost-of-service contracts (also called bilateral contracts) allowed under § 454.6 are an option that SCE should be able to use in situations where there is significant market power that would be detrimental to ratepayers.

17. It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement solicitation process.

18. It is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process.

19. All contracts stemming from the LCR procurement authorization we establish today should be brought to the Commission for approval by application for each local reliability area, anticipated sometime in 2014. It is reasonable to allow an earlier application for gas-fired procurement due to the long lead time for such resources.

20. If any extensions to the OTC closure do not occur, this can be taken into account in future procurement proceedings or in a review of a procurement application by SCE.

21. The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005 remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B).

22. The appropriate procedural venue for SCE to seek any changes it considers appropriate due to debt equivalence related to contracts foreseen from today's decision is its next COC application.

23. The record is insufficient to resolve outstanding questions about a CAM opt-out at this time.

24. It is not within the scope of this proceeding to determine whether SSJID is a large municipalization for the purposes of the CAM.

25. The Motion of MSF should be denied because it seeks to modify a policy adopted by the Commission along with other state agencies, and may conflict with statute.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021. Procurement must abide by the following guidelines:

a. At least 1000 MW, but no more than 1200 MW, of this capacity must be from conventional gas-fired resources, including combined heat and power resources;

b. At least 50 MW of capacity must be procured from energy storage resources;

c. At least 150 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;

d. Subject to the overall cap of 1800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (a), (b) and (c) above, may be procured through preferred resources consistent with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtain by the Commission through decisions in other relevant proceedings) and/or energy storage resources.

2. Southern California Edison Company shall procure between 215 and 290 Megawatts of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area by 2021.

3. Southern California Edison Company (SCE) shall use existing Resource Adequacy (RA) program rules (as developed in Rulemaking 11-10-023 and successor proceedings) to assess the effectiveness of proposed generation solutions for meeting the local capacity requirements need established in this Order. SCE shall identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.

4. Any Requests for Offers (RFO) issued by Southern California Edison Company pursuant to this Order shall include the following elements, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052) and the authorization and requirements of this decision:

a. The resource must meet the identified reliability constraint identified by the California Independent System Operator (ISO);

b. The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c. The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d. A requirement that resources offer the performance characteristics needed to be eligible to count as local Resource Adequacy capacity;

e. No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized in this Order);

f. No provision limiting bids to any specific contract length;

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;

h. Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources consistent with a least cost/best fit analysis;

i. A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j. An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k. A method to consider flexibility of resources without a requirement that only flexibility of resources be considered; and

l. Use of the most up-to-date effectiveness ratings.

5. Southern California Edison Company (SCE) shall provide a procurement plan for all required and authorized resources in the Los Angeles Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE shall show that its proposed procurement plan is consistent with Ordering Paragraph 4. SCE shall not go forward with any public procurement process until Energy Division approves the process in writing, except that SCE may proceed with parts of its procurement plan if so authorized. SCE also shall adhere to previous Commission decisions regarding this proposed procurement process, including consultation with the Procurement Review Group and Independent Evaluators.

6. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall show that it has a specific plan to undertake integration of energy efficiency, demand response, energy storage and distributed generation resources in order to meet or reduce local capacity requirement needs through 2021.

7. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A statement as to whether or not SCE intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan;
- A detailed list of the RPS procurement authorizations and processes that support SCE's plans to acquire RPS-eligible resources to meet LCP needs;

- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;
- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities.

8. Southern California Edison Company may provide the conventional gas-fired resources portion of the procurement plan for review ahead of its full procurement plan. If Energy Division approves this portion of the plan Southern California Edison Company may go forward with that procurement.

9. Southern California Edison Company is authorized to procure bilateral cost-of-service contracts to meet authorize local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code § 454.6.

10. Southern California Edison Company shall work with the California Independent System Operator to determine a priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.

11. Southern California Edison Company (SCE) shall file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision for the Los Angeles basin local reliability area, and one Application for these purposes for the Big Creek/Ventura local reliability area. An exception to the requirement of this paragraph is if SCE's procurement plan, as approved by Energy Division, provides for one separate and earlier Application to procure gas-fired generation for both local reliability areas. SCE shall not receive recovery in rates for the costs related to any such contract before Commission review and approval of these Applications. In addition to currently applicable rules, the Applications shall specify how the totality of the contracts meet the following criteria:

a. Cost-effectiveness;
b. Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
c. Compliance with Ordering Paragraphs 1 and 2;
d. For applicable bilateral contracts, compliance with Public Utilities Code Section 454.6; and
e. A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding in SCE's solicitation process. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

12. In its application regarding the Los Angeles Basin local reliability area to implement this decision pursuant to Ordering Paragraph 11, Southern California Edison Company shall present contracts for at least 50 MW of energy storage resources (pursuant to Ordering Paragraph 1) to the Commission for approval,

or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

13. Southern California Edison Company shall treat the retrofitting of a power plant cooling system, which is undertaken to comply with State Water Resources Control Board Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling and has a compliance deadline before December 31, 2022, as a new resource in considering resources to meet the needs in Ordering Paragraphs 1 and 2.

14. Southern California Edison Company (SCE) shall provide documentation in its Applications required by Ordering Paragraph 11 of efforts to consult with the California Independent System Operator to develop performance characteristics for local reliability, and how SCE meets any such performance characteristics.

15. Southern California Edison Company shall allocate costs incurred as a result of procurement authorized in this decision and approved by the Commission consistent with the cost allocation mechanism approved in Decisions (D.) 06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005.

16. The October 5, 2012 Motion of Megawatt Storage Farms, Inc. is denied.

17. This proceeding shall remain open.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT 2

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

FILED
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Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	R. 12-03-014 (Filed March 22, 2012)

TRACK 1 OPENING BRIEF OF CALPINE CORPORATION

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September 24, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	R. 12-03-014 (Filed March 22, 2012)

TRACK 1 OPENING BRIEF OF CALPINE CORPORATION

Pursuant to Rule 13.11 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Calpine Corporation ("Calpine") respectfully submits this opening brief addressing Track 1 local reliability issues.

I. EXECUTIVE SUMMARY[1]

The primary purpose of Track 1 is to evaluate the need for "new infrastructure for local reliability purposes"[2] – in particular, local reliability needs in the Los Angeles basin ("LA Basin") and Big Creek/Ventura local areas. To the extent the Commission finds there are local reliability needs, investor-owned utilities ("IOUs") and other load serving entities may be authorized or directed to undertake certain actions to address these needs.[3] Within this context, the *Scoping Memo* identifies several issues that bear directly on how local reliability needs should be determined and, if a need is identified, how the Commission should move forward in light of the need.

Establishing coherent and integrated long-term procurement planning ("LTPP") and resource adequacy ("RA") programs is fundamental to maintaining local and system reliability,

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[1] The section headings denominated in the common briefing outline are set forth in bold type. Calpine has not included headings for the sections it is not addressing in its Opening Brief.

[2] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* ("*Scoping Memo*") at 3.

[3] *Scoping Memo* at 3-4.

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and ensuring that environmental objectives are pursued in the most efficient, cost-effective manner. While local reliability needs have traditionally been treated as a distinct set of reliability requirements apart from system needs, the procurement of resources to meet local needs implicates much broader system issues. For example, transmission upgrades may be used to reduce local reliability requirements more cost-effectively and with less environmental impacts than constructing new local generation.[4] The opportunity to utilize such cost-effective options, however, may be lost if procurement decisions approach local reliability needs myopically. Thus, it is important that the Commission and the California Independent System Operator ("CAISO") take a coordinated approach to address local and system reliability needs.

Currently, the framework used to ensure electric reliability relies primarily on the Commission's RA and LTPP programs. While these programs are interrelated, they are not well coordinated and, as a result, are inefficient tools for identifying and ensuring the continued availability of needed resources. As Commissioner Ferron noted earlier this year:

> a "hole" in [the] market and planning structure [exists] whereby there are insufficient economic incentives for generating plants which provide useful flexible attributes to cover the cost of maintaining these plant[s] in operation.
>
> I believe that the Commission, in consultation with the CAISO, needs *to immediately work to create a coordinated approach across our own Resource Adequacy and Long Term Procurement Planning procedures and the CAISO's system and reliability planning process to address this market shortcoming*.[5]

To address these "market shortcomings," the Commission must make fundamental changes to the current RA and LTPP programs to incorporate non-discriminatory procurement

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[4] Exh. Calpine-1 (Barmack) at 2.

[5] Resolution E-4471, mimeo at 23 (Dissent of Commissioner Mark J. Ferron) (emphasis added).

practices that foster competition between new and existing resources of all types; or, alternatively, replace these programs with an integrated multi-year forward capacity market that would fully level the playing field among all capacity resource types.

In Tracks 2 and 3 of this proceeding, the Commission has begun (or will soon begin) examining issues related to system needs associated with renewable integration, such as flexible resource procurement and multi-year forward procurement requirements.[6] The resolution of these issues will help ensure that more efficient and cost-effective procurement decisions are made at both the local and system levels, and put the IOUs in a much better position to identify and procure the least-cost/best fit mix of resource options to satisfy all reliability needs.

Given the incomplete picture currently before the Commission (system requirements and flexibility needs have yet to be determined) and the need for LTPP and RA reforms, Calpine agrees with Southern California Edison Company ("SCE") that "[t]he Commission should avoid making long-term commitments to new generation procurement [in Track 1] that could subsequently be rendered significantly less valuable by changed circumstances."[7] Accordingly, the Commission should not authorize the procurement of any *new* resources to meet local reliability needs in the LA Basin and Big Creek/Ventura areas until, at a minimum, system reliability needs have also been determined.

With respect to the Big Creek/Ventura local area, the record demonstrates that there is no immediate need to procure any *new* resources to satisfy local reliability requirements.[8] While there is some disagreement regarding the need to procure some amount of new resources for the

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[6] *Scoping Memo* at 8-13.

[7] Exh. SCE-1 (Minick) at 4.

[8] *See e.g.*, Exh. SCE-1 (Minick) at 10; Exh. DRA-1 (Fagan) at 23; Exh. Calpine-2 (Calvert) at 5-10.

LA Basin, the record supports taking a cautious approach to mitigate the long-term adverse consequences associated with new resources that may be rendered significantly less valuable by subsequent circumstances.

To the extent the Commission authorizes the IOUs to undertake some procurement to meet local reliability needs in Track 1, it is critical that procurement rules be adopted that consider and foster direct competition among all types of resources and infrastructure investments. The goal of procurement should be to satisfy reliability needs with least-cost/best fit resources and the most effective way to accomplish this goal is to consider local and system reliability needs together, and to not limit the universe of options to meet these needs.

II. DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) STUDIES

A. CAISO's LCR and once-through cooling (OTC) generation studies

In its OTC studies, the CAISO identifies local area capacity needs for the LA Basin and Big Creek/Ventura areas under each of four renewables portfolio standard ("RPS") scenarios. Several parties in the proceeding have questioned the reasonableness of certain assumptions and inputs used by the CAISO in the OTC studies and the related results of the studies.[9] For purposes of Track 1, Calpine has not taken a position on the reasonableness or adequacy of the CAISO's modeling; but rather, has primarily focused on potential non-generation alternatives that may reduce or completely eliminate the need for new replacement generation identified by the CAISO. As discussed in more detail below, the record demonstrates that several alternatives exist for the Big Creek/Ventura area, including one alternative identified by the CAISO itself, that would not require significant amounts of OTC replacement generation. These same types of

[9] *See e.g.*, Exh. CEJA-3 (May) at 34; Exh. DRA-1 (Fagan) at 17; Exh. NRDC-1 (Martinez) at 4; Exh. TURN-1 (Woodruff) at 14.

alternatives could potentially be utilized to similarly reduce the need for OTC replacement generation in the LA Basin as well.

D. Transmission and other means of mitigation

As discussed below, the record demonstrates that transmission upgrades and other infrastructure investments may reduce or eliminate the need for OTC replacement generation. Accordingly, SCE[10] and the CAISO should continue to evaluate cost-effective transmission alternatives as part of any Track 1 procurement authorization.

III. DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

A. LA Basin

The CAISO identifies a local need for the LA Basin of between 1,870 MW - 3,896 MW of new OTC replacement generation depending on the RPS scenario modeled.[11] While Calpine did not undertake an analysis of the LA Basin similar to the analysis it performed with respect to the Big Creek/Ventura area (*see infra*, Section III.B), transmission upgrades and other non-generation alternatives may exist for the LA Basin that potentially could reduce the need for OTC replacement generation.[12] As SCE testified, however, "the CAISO has not investigated adding transmission facilities beyond the 2021 transmission configuration used in its analysis of need for [local capacity] resources in the LA Basin."[13]

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[10] During the evidentiary hearings, SCE testified that it evaluates potential transmission upgrades on an ongoing basis. SCE/Cushnie Tr. at 751.

[11] Exh. CAISO-1 (Sparks) at 6.

[12] For example, the CAISO is considering entering into a reliability must-run contract for the conversion of Huntington Beach units 3 & 4 to synchronous condensers in anticipation of San Onofre Nuclear Generating Station units 2 and 3 being unavailable for the summer of 2013. *See* http://www.caiso.com/Documents/Decision_on_RMRContracts-Memo-Sep2012.pdf

[13] Exh. SCE-1 (Cabbell) at 8.

Given that system requirements and flexibility needs have yet to be determined, the Commission should take a cautious approach with respect to new procurement in the LA Basin. As part of this approach, additional analysis should be performed to identify and evaluate transmission alternatives before the procurement of significant amounts of new OTC replacement generation is authorized. To the extent some Track 1 procurement is authorized prior to the Commission identifying system requirements and flexibility needs, it should be the smallest amount necessary to ensure reliability while further analysis is undertaken.

B. Big Creek/Ventura area

The record does not support the near-term procurement of any new OTC replacement generation in the Big Creek/Ventura area as part of the Commission's Track 1 decision.[14] As a next step in the evaluation of local reliability needs in the Big Creek/Ventura area, the Commission should direct SCE and the CAISO to perform further analysis of the Moorpark sub-area,[15] particularly with respect to transmission upgrades. According to SCE:

> [s]ome cost effective transmission modifications could also lower the LCR need [in the Big Creek/Ventura area]. Potential transmission mitigation option need further study in order to minimize cost and possible emissions. Smaller size generation may be able to be built in 5-7 years. Therefore, the LCR solicitation for this area can most likely wait until the next LTPP regulatory cycle.[16]

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[14] *See e.g.*, Exh. SCE-1 (Minick) at 10 ("SCE sees no immediate need to consider procurement of resources in the Big Creek/Ventura area."); Exh. DRA-1 (Fagan) at 27 ("[W]hen considering the effect of demand-side resources there is a surplus of resources in both areas in 2021.")

[15] The potential need for OTC replacement generation in the Big Creek/Ventura local area is created by the need to support reliability requirements in the Moorpark sub-area. *See* Exh. CAISO-1 (Sparks) at 14; Exh. Calpine-2 (Calvert) at 4.

[16] Exh. SCE-2 (Minick) at 20. DRA also supports further review of local reliability needs in the Moorpark sub-area before the Commission authorizes any procurement of new OTC replacement generation. *See* Exh. DRA-1 (Fagan) at 27.

Calpine agrees that potential transmission upgrades exist that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura area. Specifically, the record demonstrates there are several potentially cost-effective alternatives - including one alternative identified by the CAISO itself - that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura area:

Option		OTC Replacement Generation (MW)	Post-Contingency Load Shedding (MW)	Estimated Transmission Cost
	CAISO OTC Study	430	340	
1	CAISO Alternative[17]	100	700	unknown
2	Vincent-Santa Clara Loop-in[18]	215	390	$13 Million[19]
3	Vincent/Pardee-Santa Clara Series Capacitors[20]	0	590[21]	$28 Million
4	New Pardee-Moorpark Line[22]	0	300	$32-40 Million

Based on initial power flow analyses,[23] each of the above options would provide a similar level of system performance and local reliability as 430 MW of new OTC replacement generation[24] but at a fraction of the approximately $500 million it would cost to develop and build such replacement generation.[25] Given the lack of any near-term need and the potential benefits to be realized from transmission and other non-generation alternatives, the Commission

[17] *See* Exh. CAISO-1 (Sparks) at 14; Sparks/CAISO, Tr. at 104-105.

[18] *See* Exh. Calpine-2 (Calvert) at 7-8.

[19] Calpine/Calvert, Tr. at 1309.

[20] *See* Exh. Calpine-2 (Calvert) at 8-9.

[21] For Option 3, the additional retirement of Mandalay Unit 3 (130 MW combustion turbine) may be accommodated with additional shunt capacitor installations of 50 MVAR each at the Goleta and Santa Clara substations, along with a post-contingency load shedding expectation of 725 MW.

[22] *See* Exh. Calpine-2 (Calvert) at 9-10.

[23] *See* Exh. Calpine-2 (Calvert) at 2-4 (describing initial power flow analyses performed by Calpine).

[24] Exh. Calpine-2 (Calvert) at 5-6.

[25] *See* Exh. Calpine-2 (Calvert) at 7.

should not authorize the procurement of OTC replacement generation for the Big Creek/Ventura area at this time.

IV. PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

C. If a need is determined, how the Commission should direct LCR need to be met

If the Commission determines that some procurement is necessary to address Track 1 local reliability needs, all types of resources and infrastructure investments should be considered, including: new generation; existing generation (including upgrades to add flexibility, increase capacity and/or extend the useful life of the resource); transmission; demand response; energy storage; and distributed generation. With respect to transmission related options, this approach will require the analysis and evaluation of such options prior to the IOUs conducting resource solicitations.[26] The goal of procurement should be to satisfy reliability needs with least-cost/best fit resources and the most effective way to accomplish this goal is to consider local and system reliability needs together, and to not limit the universe of options to meet these needs.

D. Appropriate method(s) of procurement

As discussed above, fundamental changes to the current RA and LTPP programs are necessary to address the market structure and procurement policy flaws noted by Commissioner Ferron. Key among these changes is the need to incorporate non-discriminatory procurement practices that foster competition between new and existing resources of all types; or, alternatively, to replace these programs with an integrated multi-year forward capacity market. Until such changes can be implemented, however, all types of resources and infrastructure

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[26] *See* SCE/Cushnie, Tr. at 750 ("So similar to certain preferred resources, transmission options that the utility would be undertaking would need to be considered outside of a solicitation process.")

investments must be considered to the extent the Commission finds that some level of procurement is necessary to address local reliability needs as part of Track 1.

E. Timing of procurement

The record demonstrates that the Commission can defer authorizing the procurement of new OTC replacement generation in the Big Creek/Ventura area until at least the next LTPP cycle,[27] at which time system requirements and flexibility needs will have likely been determined and changes to the current RA and LTPP programs possibly implemented. If the Commission finds that some procurement in the LA Basin is necessary prior to the Commission issuing decisions on system requirements and flexibility needs, such procurement should be limited to lowest amount necessary ensure near-time reliability while further analysis is undertaken.

V. INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If a need is determined, should flexible capacity attributes be incorporated into procurement

The procurement of flexible capacity attributes should not be undertaken within the context of addressing Track 1 local reliability needs. As an initial matter, the need for flexible capacity is driven primarily by system requirements related to renewable integration needs. The CAISO, however, has not completed its studies of potential system flexibility requirements[28] and the Commission will not be considering renewable integration needs and flexible resource procurement until Tracks 2 and 3 of this proceeding. As a result, the analysis necessary to support the potential incorporation of flexible attributes into Track 1 procurement has not been completed. Furthermore, as the record shows, procuring flexible capacity attributes prior to

[27] *See* Exh. SCE-1 (Minick) at 10-11; *see also*, Exh. DRA-1 (Fagan) at 23 ("it is not at all clear that any resource procurement authorization beyond that already in place is necessary at this time.").

[28] Exh. CAISO-4 (Rothleder) at 7.

determining system needs and flexibility requirements could lead to inefficient and unnecessarily costly procurement decisions.[29] The Commission can reduce the risk of long-term commitments for new resources that are not needed – and the significant costs to ratepayers associated with such commitments - if the Commission waits until both local and system reliability needs have been determined before authorizing IOU procurement of flexible capacity attributes.

VII. OTHER ISSUES

B. Coordination of Overlapping Issues between R.12-03-014 (LTPP), R.11-10-023 (RA), and A.11-05-023

As a general matter, most, if not all, issues to be addressed in the LTPP proceeding implicate issues being addressed in the RA proceeding, including Track 1 issues. As described above, local reliability issues have traditionally been considered distinct from system issues. The procurement of resources to meet local reliability (*i.e.*, RA) needs, however, affects much broader system RA needs.

Ultimately, procurement to satisfy local and system reliability needs requires a coordinated approach across reformed LTPP and RA programs. Currently, the lack of a functioning capacity market (or other non-discriminatory procurement mechanism), the exclusion of existing resources from long-term resource solicitations, and various other procurement policies and market rules have effectively prevented the creation of a truly compensatory wholesale power market. The Commission is examining ways to address these market and policy flaws in the RA proceeding and Tracks 2 and 3 of this proceeding.[30]

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[29] *See* Exh. Calpine-1 (Barmack) at 3-4.

[30] Cf. Decision 12-06-025, mimeo at 36 (Findings of Fact No. 3) ("There is a need for refinements to the RA program to further define elements of flexibility with regard to multi-year contracts for local capacity requirements.") with *Scoping Memo* at 8-13 (describing Track 2 and 3 issues as including consideration of

Continued on the next page

However, authorizing the procurement of new local resources *prior to* the Commission making necessary reforms to its RA and LTPP programs is inefficient and could potentially strand some existing resources while saddling the state with long-term commitments for others that are subsequently rendered less valuable by changed circumstances.

The current RA and LTPP programs must be changed to incorporate non-discriminatory procurement practices that advance competition between new and existing resources of all types; or, alternatively, replaced with an integrated multi-year forward capacity market. SCE supports such an approach[31] and recommends that the Commission "establish a proceeding in conjunction with the CAISO to implement a long-term solution by developing a forward procurement mechanism."[32] Whether the Commission addresses the issue in the LTPP proceeding, RA proceeding or some new proceeding, it is critical that the Commission move forward quickly so that the IOUs and other load serving entities will be in the best position to identify and procure a least-cost/best fit mix of resources to satisfy all reliability needs.

VIII. CONCLUSION

For the reasons discussed above, the Commission should not authorize the procurement of any *new* resources at this time to meet local reliability needs in the LA Basin and Big Creek/Ventura areas until, at a minimum, system reliability needs have been determined. To the

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Continued from the previous page
procurement rules for system resources, flexible resource procurement, and multi-year forward procurement requirements.).

[31] Exh. SCE-1 (Cushnie) at 1 ("SCE strongly prefers procurement of new LCR generation through a new multi-year forward procurement mechanism, such as a capacity market or a new generation auction administered by the CAISO.")

[32] Exh. SCE-1 (Cushnie) at 17.

extent the Commission authorizes the IOUs to undertake some procurement to meet local reliability needs in Track 1, it is critical that non-discriminatory procurement practices be adopted that will foster competition between new and existing resources of all types.

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Dated: September 24, 2012

Attorneys for Calpine Corporation

ATTACHMENT 3

Table 2.7-6: Local Capacity Deficiency in the Moorpark and Santa Clara Sub-areas

	Moorpark Sub-area	Santa Clara Sub-area
2022 LCR[75]	554 MW	289 MW
Resources available post 2020[76]	236 MW	203 MW
- Existing generation	2336 MW	808 MW
- Expected retirements[77]	(2076) MW	(560) MW
- Ellwood assumed unavailable[78]	(54) MW	(54) MW
- Existing/approved preferred resources and storage	30 MW	9 MW
Deficiency[79]	~318 MW	~86 MW

In addition, SCE has identified a 105 MW resiliency target in the Santa Barbara/Goleta area associated with the loss of both Goleta-Santa Clara 230 kV transmission lines.[80] New resources procured to address the Santa Barbara/Goleta resiliency objective will address Moorpark and Santa Clara LCR needs.

2.7.5.4 *Request Window Project Submissions*

The ISO received one request window submittal in the SCE Metro Area in this planning cycle. Below is a description of the proposal followed by ISO comments.

Moorpark-Pardee 230 kV No. 4 Circuit Project

The project is submitted by SCE to address the projected local capacity deficiency in the Moorpark sub-area. It involves stringing a fourth Moorpark-Pardee 230 kV circuit approximately 26 miles on existing structures and installing terminal equipment at Moorpark and Pardee Substations. The project has an estimated cost of $45 million and an in-service date of December 31, 2020, which coincides with the retirement of OTC generation in the area. SCE anticipates the project will not be subject to a Certificate of Public Convenience and Necessity (CPCN).

[75] http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf

[76] Amount does not include the 10 MW energy storage project SCE submitted to the CPUC for approval in Application 17-12-002.

[77] Ormond Beach units 1 and 2 and Mandalay units 1 and 2 are expected to retire by December 31, 2020 to comply with OTC regulations. NRG announced that all three Mandalay units would be retired on December 31, 2017, and that retirement was deferred to February 6, 2018.

[78] SCE's contract with NRG to refurbish the Ellwood generating station, which is 43 year old, was denied by the CPUC.

[79] Deficiency amounts are approximate as they are dependent on the location, reactive power capability and other characteristics of the resources that are used to fill the deficiency and are subject to change in the future due to changes in the CEC load forecast.

[80] Moorpark Sub-Area Local Capacity Requirements Procurement Plan of Southern California Edison Company Submitted to Energy Division Pursuant to D. 13-02-015

The Moorpark-Pardee project was found to be needed as it results in the most effective alternative to address the voltage stability as well as the thermal loading impacts of the Moorpark sub-area critical contingency while having the least capital and overall cost and lower impact on operational complexity.

The ISO has categorized the Moorpark-Pardee project as a reliability-driven project, as it is part of basket of mitigations in a local capacity area necessary to provide the level of reliability dictated by the NERC standards, the ISO Planning Standards, and the local capacity technical criteria set out in the ISO tariff. As the reliability need could otherwise be served by acquiring additional new resources – alternative 2 described above – the transmission project could also have been categorized as "economic-driven" due to the economic comparison made in selecting the transmission project as part of the comprehensive solution.[83] Rather than unnecessarily bifurcating the discussion of the local area needs between chapter 2 dealing with reliability issues and chapter 4 dealing with economic-driven issues, the local area needs have been addressed comprehensively here in chapter 2.

2.7.5.5 *Consideration of Preferred Resources and Energy Storage*

Preferred resources and storage were considered in the SCE Metro Area assessment as follows.

- As indicated earlier, projected amounts of up to 1,347 MW of additional energy efficiency (AAEE), and up to 3,383 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 14 percent.
- The existing and planned fast-response demand response amounting 236 MW and energy storage amounting 352 MW were used in the base or sensitivity cases to mitigate Category P6 related thermal overloads on Serrano 500/230 kV transformers and the Mesa-Laguna Bell No.1 230 kV line.
- Incremental preferred and renewable resources and energy storage are considered in conjunction with the Moorpark-Pardee transmission project to address local capacity needs in the Moorpark sub-area.

2.7.5.6 *Recommendation*

The Moorpark-Pardee 230 kV No. 4 Circuit Project was submitted by SCE to address the projected local capacity deficiency in the Moorpark local capacity sub-area. The project has an estimated cost of $45 million and involves stringing a new Moorpark-Pardee 230 kV circuit on existing structures and installing terminal equipment at Moorpark and Pardee Substations. The project was reviewed in light of the expected retirement of more than 2000 MW generation in the area and the suspension of proceedings for the Puente Power Project. The project was found to be needed and is recommended for ISO approval as it is the most effective and economic

[83] Section 24.4.6.7 of the ISO tariff, that states: *"...the CAISO will conduct the High Priority Economic Planning Studies selected under Section 24.3.4 and any other studies that the CAISO concludes are necessary to determine whether additional transmission solutions are necessary to address: ...(b) Local Capacity Area Resource requirements;"*

alternative in addressing the voltage stability and thermal loading impacts of the critical Moorpark sub-area contingency. The required in-service date is December 31, 2020 to coincide with the retirement of OTC generation in the area.

The SCE Metro area assessment also identified several category P6 related thermal overloads. Operating solutions, which are described in more detail in Appendix B, including dispatching existing and planned preferred resources and energy storage under contingency conditions are recommended to address those issues.

ATTACHMENT 4

ALJ/RMD/lil **Date of Issuance 10/4/2017**

Decision 17-09-034 September 28, 2017

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 Moorpark Sub-Area.	Application 14-11-016

DECISION IN PHASE 2 ON RESULTS OF SOUTHERN CALIFORNIA EDISON COMPANY LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR MOORPARK SUB-AREA PURSUANT TO DECISION 13-02-015

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Table of Contents

DECISION IN PHASE 2 ON RESULTS OF SOUTHERN CALIFORNIA EDISON COMPANY LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR MOORPARK SUB-AREA PURSUANT TO DECISION 13-02-015

Summary

In Phase 2 of this proceeding, we reject the 54 megawatts (MW), 10-year gas-fired generation, 30-year refurbishment Ellwood contract and 0.5 MW, energy storage contract (linked to the Ellwood contract) to give the Commission an opportunity to explore a more complete portfolio of resources to meet any identified need in the Santa Barbara/Goleta area. Southern California Edison Company (SCE) is directed to determine whether any identified need can be met in a manner more consistent with the Commission's goals of reduced reliance on fossil fuel. SCE may identify scenarios that include Ellwood as part of a solution. We further find that no reliability need justifies approval of the Ellwood contract at this time. This proceeding is closed.

1. Procedural Background

On November 26, 2014, Southern California Edison Company (SCE) filed Application 14-11-016 seeking approval of the results of its 2013 Local Capacity Requirements Request for Offers (RFO) in the Moorpark sub-area of the Big Creek/Ventura local reliability area (Moorpark sub-area) to meet long-term capacity requirements by 2021, as directed by the Commission in Decision (D.) 13-02-015.[1]

Specifically, D.13-02-015, issued on February 13, 2013, ordered SCE to procure via a RFO a minimum of 215 megawatts (MW) and a maximum of 290 MW of electrical capacity in the Moorpark sub-area to meet identified long-term local capacity requirements by 2021.[2] The Commission found this local capacity requirement need existed, in large part, due to the expected retirement before 2021 of the Ormond Beach Units 1 and 2 and Mandalay Units 1 and 2 once-through-cooling generation facilities located in Oxnard, California.

The assigned Commissioner issued a Scoping Memo on March 13, 2015.[3] Evidentiary hearings were held, and parties submitted legal briefs on July 22, 2016 and August 5, 2016. On May 26, 2016, the Commission issued D.16-05-050[4] in this proceeding, which approved SCE's contract for the 262 MW Puente Project and, in addition, approved contracts for 12 MW of preferred resources.

The Commission, in D.16-05-050, deferred consideration of the 54 MW Ellwood project (RFO contract #447021) and a linked 0.5 MW energy storage project (RFO contract #447030) to Phase 2 of this proceeding. In deferring consideration of these two contracts, the Commission stated:

> … the record in this proceeding does not appear to be fully developed enough to decide whether to approve the Ellwood contract at this time.
>
> To determine if the Ellwood contract is reasonable, it is necessary to determine if there is a **reliability need** that it would meet. D.13-02-015 required that SCE procure new resources to fill the Moorpark sub-area reliability need. Goleta is within the Moorpark sub-area, but the current Ellwood facility was

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1 D.13-02-015, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements* (February 13, 2013).

2 D.13-02-015 at 131 (Ordering Paragraph 2).

3 On December 4, 2014, the Commission issued Resolution ALJ 176-3347 to preliminarily determine that this proceeding was ratesetting and that evidentiary hearings would be necessary. These preliminary findings were confirmed in the Scoping Memo.

4 D.16-05-050 was modified on rehearing by D.16-12-030, *Order Modifying Decision (D.) 16-05-050 and Denying Rehearing, as Modified*.

> considered by the CAISO [California Independent System Operator] to be an existing operational resource in the 2012 LTPP proceeding in which D.13-02-015 was decided. Thus, the Ellwood peaker would not be eligible to fill the identified reliability need in the Moorpark sub-area.[5] (Emphasis added.)

The Commission stated, in the Findings of Fact, as follows:

> **Finding of Fact 15**: The record is incomplete regarding evaluation of the reliability need for the Ellwood contract and whether the Ellwood contract is the best way to meet any such need.
>
> **Finding of Fact 16**: Under the terms of the contracts, the energy storage contract with NRG California South, located at the site of Ellwood, is not available if the Commission refrains from approving Ellwood at this time.[6]

Thus, as directed by D.16-05-050, the second phase of this proceeding addresses SCE's request for approval of the 54 MW Ellwood contract and the linked 0.5 MW energy storage project with NRG California South LP (NRG).[7]

Earlier in this proceeding, parties filed protests. These protests addressed all the issues in the proceeding, including the issues related to the 54 MW Ellwood contract and the related energy storage project. A public participation hearing was held in Oxnard on July 15, 2015. A second Scoping Memo was issued on August 18, 2016 in Phase 2. Evidentiary hearings were held in Phase 2

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[5] D.16-05-050 at 30-31.

[6] D.16-05-050 at 36.

[7] As SCE explained in prior testimony in this proceeding, while it is seeking approval of the Ellwood Refurbishment contract in this Application, the Ellwood contract is not considered an incremental resource and does not count toward the procurement targets for the Moorpark sub-area. SCE Application 14-11-016 at 3, fn. 6. More details regarding this project are available in SCE's prepared testimony, referred to as Exhibit SCE-1 (Testimony of Southern California Edison Company on the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area – Chapter VII, Section A.1).

on November 1 and 2, 2016. Briefs and Reply Briefs were filed on December 1, 2016 and December 15, 2016, respectively. The evidentiary record of Phase 2 includes all materials entered into the record in Phase 1 and Phase 2.

2. Scope of Issues

The issues to be determined are:[8]

1. Is the 54 MW Ellwood Refurbishment contract reasonable?
2. Is the 0.5 MW storage project contract reasonable?

2.1. Standard of Review

We review SCE's Application and request therein under a reasonableness standard. Pursuant to D.16-05-050 and the August 18, 2016 Phase 2 Scoping Memo, the question presented in Phase 2 of this proceeding is whether the Ellwood contract and linked energy storage contract are reasonable. However, as explained in D.16-05-050, in order to determine if the Ellwood contract is reasonable, it is necessary to determine if there is a need that it will help meet. The need is described in D.16-05-050 as a reliability need.[9]

2.2. Burden of Proof

The burden of proof is on the Applicant in this proceeding to support its request by a preponderance of evidence. In short, the preponderance of evidence burden of proof standard is met if the proposition is more likely to be true than not true. The standard is also described as being met by the evidence presented when the proposition is more likely than not.

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[8] August 18, 2016, *Assigned Commissioner's Ruling and Scoping Memo* at 4.

[9] D.16-05-050 at 30-31.

3. Ellwood Contract

Today's decision considers the 10-year tolling agreement for the operation of the Ellwood facility in Goleta (in Santa Barbara County), a 54 MW existing gas-fired generation peaker plant. The contract includes the refurbishment of the Ellwood plant.[10] The refurbishment will extend the life of the plant by an additional 30 years, to 2048. Ellwood is a combustion turbine generating unit built in 1974. Historically, Ellwood has not been a reliable resource.[11] The Ellwood plant is located adjacent to a residential area and school.[12] The people that live in this area do not, generally, support the continued operation of Ellwood.[13] June 2018 is the start date set forth in the Ellwood contract.[14] Ellwood is currently operating under a short-term contract between SCE and NRG.[15]

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[10] Phase 1 Exhibit SCE-1 at 57.

[11] Phase 1 Exhibit SCE-1 at 57. *See also*, ORA August 5, 2015 Reply Brief at 3, suggesting that because Ellwood has not historically been a very reliable resource, the need for Ellwood to maintain reliability is unclear and further weakens any assertion that Ellwood is necessary to maintain reliability.

[12] The project is located at 30 Las Amas Road, Goleta, California 93117 and the commercial operation date is June 1, 2018. Phase 1 Exhibit SCE-1 at 55. The project is located approximately 1000 ft. from a public school, the Ellwood School.

[13] Public Participation Hearing July 15, 2015. Also, numerous letters from the public are located in the case file.

[14] Phase 2 Exhibit SCE-11C at 3 (fn. 7).

[15] Ellwood is currently subject to a short-term bilateral contract approved by the Commission in Resolution E-4781 (May 26, 2016). The contracting parties are SCE and NRG Energy, Inc. through GenOn Energy Management, LLC. According to the Commission's Resolution, the term of the contract is August 2016 – May 2018. In approving the contract (and denying the Mandalay 3 contract), the Commission stated: "The Ellwood Peaker is needed to cure a 2016 deficiency identified by the California Independent System Operator for 42 MW in the Santa Clara sub-area, which may persist through 2018. In addition, the Ellwood Peaker serves local load in Santa Barbara County and would help meet local reliability needs in the event of an outage on the Goleta-Santa Clara 230 kV transmission lines. With the Ellwood contract in place, there is no residual need for the Mandalay 3 Peaker to meet SCE's local area or sub-area needs in 2016 or 2017."

4. Parameters of RFO in Phase 1

The Ellwood contract falls outside of the parameters of the RFO and the long-term local capacity requirement need determination, as defined D.13-02-015. In D.13-02-015, the Commission ordered SCE to procure a maximum of 290 MW in the Big Creek/Ventura local reliability area. The capacity of the Ellwood contract would result in SCE contracting for amounts that exceed this limitation.[16] D.13-02-015 set this MW limitation to reflect the maximum amount of potential costs that the Commission found reasonable to impose on ratepayers. In addition, the maximum MW amount was the limit of the local capacity requirement need, as determined by the Commission. After the Commission approved the Puente Project contract and the other smaller preferred resource projects totaling 274 MW, the remaining amount identified in D.13-02-015 is 16 MW.

Moreover, Ellwood is not an incremental resource, as required by the terms of the RFO. Under the terms of the RFO approved by the Commission in D.13-02-015, all contract capacity needed to be "incremental." In D.14-02-040, the Commission found that only incremental capacity (i.e., new capacity or additional capacity of existing plants) or repowered plants could participate in long-term RFO.[17] The rationale behind this RFO requirement was to create a level playing field among bidders, which is an essential component to a well-functioning market. All parties agree that Ellwood is not new or incremental capacity.

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[16] ORA July 22, 2015 Opening Brief at 5.

[17] D.14-02-040 at 28.

However, the Commission in D.16-05-050 concluded that consideration of Ellwood in this proceeding was, nevertheless, appropriate but found that the record in Phase 1 of this proceeding did not appear to be developed enough to decide whether to approve of the Ellwood contract. Therefore, D.16-05-050 directed the Commission to revisit the Ellwood contract in Phase 2 to determine if the contract is reasonable.[18] To determine reasonableness, it is necessary to determine "if there is a reliability need that it would meet."[19] The Commission further stated, "[i]f we determine there is an additional unmet local reliability need in the Goleta area that needs to be filled, we will consider if the Ellwood refurbishment contract is the best resource to do so."[20]

5. Existing Reliability Standard

In accordance with the directive in D.16-05-050, Phase 2 of this proceeding examines whether a reliability need exists for Ellwood. Based on the evidence presented, no reliability need exists that justifies the Ellwood contract.

The parties supporting the approval of Ellwood acknowledge that no existing Commission-requirement or standard exists under which consideration of this project would result in approval, including reliability.[21] The Commission could, on this basis alone, deny the contract in this phase of the proceeding since the contract does not meet the approval standard set forth in D.16-05-050.

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[18] In Phase 2, some parties continue to dispute the appropriateness of whether Ellwood should be considered in this proceeding and suggest, among other things, that the contract is more aligned with a bilateral contract and the Commission should review Ellwood under a bilateral standard. *See, e.g.,* ORA December 1, 2016 Opening Brief at 4. We do not address this argument based on the Commission's directive in D.16-05-050 to address Ellwood here.

[19] D.16-05-050 at 30.

[20] D.16-05-050 at 32.

[21] SCE December 15, 2016 Reply Brief at 8.

However, SCE presented a new and different standard by which to evaluate the reasonableness of the Ellwood contract. This new standard is referred to by SCE as the resiliency standard and is purportedly based on the unique geographic area and transmission challenges related to serving the Santa Barbara/Goleta area in the event of an emergency. Our review of Ellwood does not rely on this proposed resiliency standard because no such standard has been vetted and approved by the Commission. We do, however, review Ellwood within the context of the unique geographic area and transmission challenges related to serving the Santa Barbara/Goleta area because the parties supporting Ellwood raise safety considerations related to this geographic area that may arise in the event of an emergency.

6. Unique System Constraints in the Santa Barbara/Goleta Area

SCE states that the purpose of its testimony in Phase 2 is to explain the "unique resiliency need in the Santa Barbara/Goleta area."[22] SCE states that it needs to provide safe and reliable electric service to its customers and employees, and in doing so there may not always be a specific standard supporting SCE's efforts.[23] SCE further argues that "[r]esiliency refers to the ability of the electrical system to respond to an emergency event so that customers maintain service" and SCE can provide safe service to its customers and employees.[24]

SCE asserts that it developed an integrated mitigation strategy to provide for resiliency in the Santa Barbara/Goleta area to address the potential shortfall

22 SCE December 15, 2016 Reply Brief at 3.

23 SCE December 15, 2016 Reply Brief at 4.

24 SCE December 1, 2016 Opening Brief at 12 (fn. 55).

of 105 MW[25] that could cause rolling blackouts in the area. The cornerstone of SCE's mitigation strategy to support this 105 MW shortfall is Ellwood. According to SCE the 54 MW provided by Ellwood will be available when it is needed in June 2018, and that Ellwood will provide, some – but not all – of the 105 MW needed capacity and support short circuit duty, which will allow SCE to quickly clear faults and reduce the risk of electrocution to the public and its employees in a cost-effective manner. In addition, SCE's mitigation strategy includes the pursuit of cost-efficient local distributed generation resources and consideration of upgrades to the electric system.[26]

The CAISO supports the project, with a caveat, stating: "[t]he CAISO has not independently studied these scenarios because the reliability concerns are not related to the bulk electric system."[27] The CAISO further states that, SCE's subtransmission system is unable to fully restore service to the Santa Barbara/Goleta area after an identified N-2 Contingency,[28] and though this issue is not within CAISO's purview, SCE should not ignore the issue and nor should the Commission.

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[25] The 105 MW shortfall is calculated based on the upgraded Santa Clara 66 kV distribution system scheduled to be completed in August 2018. This upgrade is discussed below in further detail.

[26] SCE December 1, 2016 Opening Brief at 12.

[27] March 8, 2016 Reply Comments of CAISO on Alternate Proposed Decision at 3.

[28] The loss of the Goleta-Santa Clara 230 kV transmission lines is also referred to as an N-2 Contingency. The N-2 of the Goleta-Santa Clara 230 kV lines is compliant with the North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4, which allows customer load to be dropped without a stated timeframe for restoration. Exhibit SCE-11C, SCE's Phase 2 Opening Testimony, at 2; *see also* SCE, Chinn, Transcript, Vol. 5 at 815:15-22 (November 1, 2016) ("[T]he issue we're trying to address is not specific to a NERC or [CA]ISO standard[] in that NERC and [CA]ISO standards don't provide a restoration time…those standards allow for the loss of the transmission system, and basically the systems allow the blackout that is permitted under…both NERC and [CA]ISO standards.").

NRG supports the arguments of SCE and CAISO and argues that continued operation of Ellwood is compatible with the development of new preferred resources, and is appropriately characterized as a reliability backstop that would help ensure local reliability during an emergency.[29]

While we decline to review Ellwood under SCE's proposed resiliency standard, we find that SCE provides convincing evidence that unique and localized transmission grid issues exist in this part of SCE's service territory and that, in the event of the loss of the two Goleta-Santa Clara 230 kilovolt (kV) transmission lines (also referred to as an N-2 Contingency), customers in the Santa Barbara/Goleta area will likely lose service.[30] The evidence further establishes that, depending on the circumstances of the outage and when it occurs, in the absence of additional resources, SCE would not be able to meet peak load, and customers could face rolling blackouts.[31]

Below we evaluate the arguments of the parties opposing and supporting the Ellwood contract and further evaluate the questions raised by an N-2 Contingency in the Santa Barbara/Goleta area.

7. N-2 Contingency

The evidence presented during this proceeding establishes that the 54 MW provided by Ellwood offers, some – but not all - of the 105 MW needed capacity to prevent possible blackouts, together with short circuit duty which will allow SCE to quickly clear faults and reduce the risk of electrocution to the public and

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[29] NRG December 1, 2016 Opening Brief at 9.

[30] Phase 2 Exhibits SCE-1 at 6-7 and SCE-11C at 7. This area is relatively isolated and bound by the Pacific Ocean to the south and west, and the Los Padres National Forest to the north and east.

[31] SCE December 1, 2016 Opening Brief at 5.

its employees. The evidence is less convincing that Ellwood is the only or the best option to provide these MWs and address these service issues.

7.1. Ellwood does not fulfill any NERC Standard or CAISO Standard

The Office of Ratepayer Advocates (ORA) and Sierra Club argue that the need for Ellwood in the Santa Barbara/Goleta area in the event of an N-2 Contingency is not sufficient to justify approval of Ellwood in this proceeding because this need is not based on any NERC standards, CAISO standards, or Commission standards.[32] We agree with the undisputed fact that Ellwood does not present a solution to any unmet NERC or CAISO standard.

7.2. Probability of an N-2 Contingency

A critical question in evaluating the reasonableness of Ellwood is the probability of an N-2 Contingency. Helping Hand Tools (HHT)[33] asserts that a loss of both 230 kV transmission lines would be a "rare" event, and the local transmission system can be activated to meet 180 MW of local demand, which, according to HHT, is a reasonable solution.[34] In fact, all parties generally agree that the loss of both lines would be a rare event, but SCE responds that such a loss could happen.[35]

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32 Reporter's Transcript (RT), Vol. 6 (ORA/Li) at 1050:18-22.

33 HHT filed a Motion for Party Status on October 3, 2016, describing itself as "a California non-profit organization focused on preventing community deterioration. Pollution, environmental injustice, and excessive energy costs contribute to community deterioration. HHT has members who live, work, recreate, and pay electricity rates in Southern California Edison Company's service territory. The Commission's disposition of this Application will materially impact the interests of 2HT's [HHT's] members." The Motion for Party Status was granted on October 6, 2016.

34 HHT December 1, 2016 Opening Brief at 3-4.

35 No exact probability or risk factor was presented.

The unknown but rare possibility of an N-2 Contingency event occurring makes it difficult to justify the Ellwood contract and demands consideration of other options and constraints related to Ellwood and the remote N-2 Contingency.

7.3. Dropping Load is Permissible in an N-2 Contingency

In the event of an N-2 Contingency NERC permits customer load drop without a stated timeframe for restoration.[36] Also, simultaneous loss of both lines has not occurred for more than 4 hours.[37] In the past, when these rare outages occur, the duration is under 90 minutes and the existing distribution system is able to reroute power within an hour and able to meet demand in 75 percent of the annual hours (non-peak load)[38] where demand is under the 180 MW supplied by the 66 kV system.[39]

7.4. Air Permit Restrictions

The second question is whether Ellwood would be available to run in the event of an N-2 Contingency. The operation of Ellwood is restricted by its existing Air Permit from the Santa Barbara County Air Pollution Control District. Ellwood's Air Permit allows only 380 hours (or 16 full days) of operation per

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[36] Exhibit SCE-11 Phase 2 at 2, which states at fn. 6: The loss of the Goleta-Santa Clara 230 kV transmission lines is also referred to as an N-2 Contingency. The N-2 of the Goleta-Santa Clara 230 kV lines is compliant with NERC Reliability Standard TPL-001-4, which allows customer load to be dropped without a standard timeframe for restoration.

[37] Phase 2 Exhibit Sierra Club-2C (Data Request Sierra Club – SCE-1, Q.2d); RT 809; 1-4 (SCE, Chinn).

[38] Sierra Club December 1, 2016 Opening Brief at 5; HHT December 1, 2016 Opening Brief at 4.

[39] Sierra Club December 1, 2016 Opening Brief at 5. SCE agrees that MW from Ellwood may not be required during 75 percent of annual hours where demand is under 180 MW but states

Footnote continued on next page

year.[40] The restrictions on Ellwood's operation raise questions about whether it would even be available to operate in the event of an N-2 Contingency. SCE predicts weeks (not days) of blackouts in the event of the failure of the Goleta-Santa Clara 230 kV lines.[41] In other words, it would need Ellwood to be available for weeks but its Air Permit only allows 16 days. NRG attempts to minimize the impact of this restriction, stating that "Having 54 MW of capacity available for dispatch for 380 hours per year is obviously better than not having the capacity available at all. Further, if it were not run continuously 24 hours per day, the Ellwood Generating Station could operate for more than 16 consecutive days, which would cover a transmission outage lasting more than two weeks."[42]

However, NRG's argument fails to take into account that Ellwood's availability for a 16-day transmission outage depends on whether or not Ellwood has already used its 380 annually-permitted operating hours before the failure of the Goleta-Santa Clara 230 kV lines.[43] In addition, while it appears probable that Ellwood would need to run in the event of an N-2 Contingency, SCE has not negotiated a price with NRG for Ellwood should it be called upon to exceed the 380 hours.[44]

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that Ellwood is still required to provide adequate short circuit duty in order to safety utilize the 66 kV tie lines from Santa Clara to supply 180 MW. SCE December 15, 2017 Reply Brief at 6.

40 Phase 2 Exhibit SCE-11C at 15-16.

41 HHT December 15, 2016 Reply Brief at 11.

42 HHT December 15, 2016 Reply Brief at 11, citing to NRG December 1, 2016 Opening Brief at 13.

43 ORA December 1, 2016 Opening Brief at 6; Sierra Club December 1, 2016 Opening Brief at 6, 11; WBA Opening Brief at 2-3; HHT December 1, 2016 Opening Brief at 5-6.

44 HHT December 1, 2016 Opening Brief at 6, citing to RT November 1, 2016 at 991:28, 992:1-6. SCE states, in response, that, while price for operating beyond the Air Permit restrictions has

Footnote continued on next page

7.5. Air Permit Variance

A further question is whether NRG or SCE would be able or even attempt to seek a variance from the Santa Barbara County Air Pollution Control District for permission to operate Ellwood beyond the existing limitation of 380 hours (or 16 full days) per year. During this proceeding, NRG and SCE suggested that a variance would be the logical course of action but questions remain.[45]

The Santa Barbara County Air Pollution Control District has a procedure for requesting such variances but the record does not show the frequency of such requests or the circumstances under which such requests are approved.[46] No clear answer appears regarding Ellwood's ability to qualify and obtain a variance based on the evidence in the record.[47] Nevertheless, NRG and SCE suggest that a clear path to obtain a variance exists. Sierra Club, HHT, and ORA all disagree.

Moreover, Sierra Club, HHT, and ORA argue that, from a planning perspective, the need for a variance from the Santa Barbara County Air Pollution Control District to address a possible N-2 Contingency is not an optimal solution, especially due to the actual air pollution impacts that might occur by operating

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not been agreed upon, it expects NRG to negotiate in good faith and present a fair price. SCE December 15, 2016 Reply Brief at 14.

[45] SCE December 15, 2016 Reply Brief at 12.

[46] As shown in Phase 2 Late-Filed Joint Exhibit SCE/NRG-1: "An Emergency Variance may be granted for good cause, including, ***but not limited to***, breakdown conditions." Breakdown conditions can allow a variance of only 15 days, an emergency variance based on other showings of good cause (in this case, a potential reliability crisis) could be granted for up to 30 days.

[47] SCE December 15, 2016 Reply Brief at 12; SCE explains that the Santa Barbara County Air Pollution Control District would need to address potential health and safety risks before granting the variance.

Ellwood for excess hours near residential communities and a school.[48] The record reflects that Ellwood is a highly polluting resource permitted to emit as much as 103.59 pounds per hour of nitrogen oxide — which is over 20 times the normal emission rate of a modern peaking unit with modern emission controls.[49]

The Santa Barbara County Air Pollution Control District would likely need to balance the benefits and the harms before issuing a variance. The outcome of such an analysis and the result of a request by NRG for an Air Permit variance are not clear and weigh against concluding that Ellwood is the appropriate resource to address an N-2 Contingency event.

7.6. Short Circuit Duty

The argument is also made that Ellwood presents value, in addition to mitigating an N-2 Contingency, by providing short circuit duty. Again, any value from providing short circuit duty would need to be provided consistent with the limitations placed on Ellwood's operation under the restrictions in its Air Permit. Moreover, based on the record, it remains unclear whether a long-term contract, providing for additional 10 years of operation and an additional 30-year lifespan, can be justified based solely on the provision of short circuit duty.

In support of the value of the potential for Ellwood to provide short circuit duty, SCE claims that it strives for an approximate short circuit duty amount in the thousands of amps.[50] SCE further claims that, while no Commission or other

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48 Ellwood is located less than 1,000 feet from an elementary school. Sierra Club December 1, 2016 Opening Brief at 6.

49 HHT December 1, 2016 Opening Brief at 6, citing to Phase 2 Exhibit 2HT-1 at 6, 7.

50 RT 825:5-6 (SCE, Chinn).

standard exists to demonstrate the need for Ellwood to address short circuit duty, SCE has identified a need as part of its responsibility to maintain safe and reliability electrical service.[51]

Based on the evidence, it remains unclear whether an amount of amps lower than that approximated by SCE may be acceptable and whether other means of addressing this short circuit duty exist. The absence of a clear standard applicable to short circuit duty further complicates, rather than clarifies, this matter and weighs against concluding that Ellwood can be deemed reasonable based solely on SCE's need to address short circuit duty. That said, SCE has demonstrated the import of short circuit duty in case of an N-2 contingency in the Santa Barbara/Goleta area, which presents unique geographic challenges for the provision of electric service. SCE is encouraged to evaluate alternative sources of short circuit duty, including both conventional sources like synchronous condensers and non-conventional sources like inverter-based technologies, energy storage, and solar photovoltaics (PV).

7.7. Planned Upgrade of 66 kV Distribution System

During the proceeding, the question arose of whether the planned upgrade to the Santa Clara 66 kV distribution system in the Santa Barbara/Goleta area would minimize or eliminate the need for Ellwood. The evidence indicates that the upgrade would minimize but not eliminate the need for additional generation in the event of an N-2 Contingency for the purpose of serving peak load.

Plans exist to improve the Santa Clara 66 kV distribution system in the Santa Barbara/Goleta area. This upgrade is known as the Santa Barbara County

[51] SCE December 15, 2017 Reply Brief at 8-9.

Reliability Project. If both 230 kV transmission lines go down, re-routing power through the 66 kV system would allow service of 100 MW of load today, this will increase to 180 MW after the Santa Barbara County Reliability Project is completed in April 2018.[52]

However, rerouting even the full 180 MW through the 66 kV system would not allow for all of the local peak load to be entirely served. Based on SCE's estimates, a 105 MW shortfall would continue to exist, even after the 66 kV upgrade, to serve peak load in the event both 230 kV transmission lines go down.[53] As noted by SCE, even if 180 MW of power are rerouted through the upgraded 66 kV system, the rerouted power would not meet peak load in an N-2 Contingency,[54] 105 MW of peak load would remain at risk.

We find that the planned upgrades to the Santa Clara 66 kV distribution system will limit the extent of any potential service interruptions that result from an N-2 Contingency by reducing the unmet peak load need from 285 MW to 105 MW. We further find that the interruptions to service identified by SCE related to not being able to meet 105 MW of peak load could be partially addressed by Ellwood, provided compliance with the operating hour restrictions under its Air Permit or a variance. In short, the upgrade does not provide a complete solution to the need of 105 MW, but neither does Ellwood.

7.8. No Urgent Timeline

While parties argue over the probability of an N-2 Contingency and the value of Ellwood in responding to an N-2 Contingency under the operating limits

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[52] Phase 2 Exhibit SCE-11 at 2, 9 & 10.

[53] Phase 2 Exhibit SCE-11 at 2, 3 & 10.

[54] Phase 2 Exhibit SCE-11 at 10.

placed on Ellwood by its Air Permit, no party presents an urgent timeline to resolve this potential need.[55] In the absence of urgency, we find that rather than extend the life of a gas-fired plant for an additional 30 years, potentially displacing preferred resources and failing to fully realize the benefits of an upgraded 66 kV distribution system, other options should be reviewed, including preferred resources, to improve upon service in the event of an N-2 Contingency.

8. CAISO Need Assessment of Local Capacity Requirement

The CAISO data presents a separate need related to Ellwood – a reliability need. The most recent assessment by the CAISO shows that, without Ellwood, a residual 29.6 MW need for local capacity resources will exist. This 29.6 MW need will arise after the retirement of Ormond Beach and Mandalay once-through-cooling unites that are slated to retire before 2021 and is driven by the voltage collapse caused by the N-2 Contingency.[56] The CAISO explains that because the need is driven by the potential for voltage collapse in a N-2 Contingency, some types of resources, such as demand response, are not sufficient because reactive power is needed to maintain system voltage.[57]

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[55] SCE does not dispute the assertion by Sierra Club that no deadline exists to meet the 105 MW target but points out that Ellwood is essential to resolve unique issues presented in the Santa Barbara/Goleta area. SCE December 15, 2017 Reply Brief at 7.

[56] CAISO December 1, 2016 Opening Brief at 1-2.

[57] CAISO December 1, 2016 Opening Brief at 2. Reactive power is needed in when voltage collages occurs to regulate voltage. For example, reactive power is measured in volt-ampere reactive. If voltage declines on the electrical system, a generator is able to inject reactive power in the system which tends to raise the system voltage.

ORA disputes the CAISO's findings. ORA states that this estimate should have included Mandalay Unit 3 (discussed below) and inappropriately excluded certain demand response.[58]

The CAISO clarifies that it included demand response with less than or equal to 20-minute response time but ORA suggests that the CAISO should include demand response in a manner consistent with D.16-06-045, which might result in a greater amount of demand response being found available.[59] ORA states that, potentially, only 16 MW would be needed, if the CAISO relied on a different means of calculating the availability of demand response to meet local capacity reliability needs.[60] In addition, ORA and Sierra Club both point to recent studies of the CAISO that appear to overestimate the need in the Moorpark sub-area.

Taking these factors into consideration and giving weight to the CAISO's findings of a reliability need of 29.6 MW in the Moorpark sub-area in an N-2 Contingency, we find it is, nevertheless, premature to approve Ellwood without first evaluating the situation in the smaller Santa Barbara/Goleta area and determining whether other resources exists to address this 29.6 MW need, which is smaller than the 54 MW provided by Ellwood.

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[58] ORA December 1, 2017 Opening Brief at 7. According to ORA, the CAISO's analysis only included demand response with less than or equal to a 20-minute response time.

[59] ORA December 1, 2017 Opening Brief at 7.

[60] ORA December 1, 2017 Opening Brief at 7 and 8, stating that "The CAISO has identified 37.5 MW of slow DR in the Moorpark sub-area with a response time of greater than 20 minutes for a total of 55.5 MW of DR."

9. Generation Alternative to Ellwood - Mandalay Unit 3

While we have found that no reliability need exists for the Ellwood contract, as required by D.16-05-050, and we have further found that the operating characteristics of Ellwood do not present an optimal solution to the need presented by SCE, our review of the need for Ellwood evaluates the bigger generation picture presented by the Santa Barbara/Goleta area.

Parties presented evidence on whether other resources in the area, such as the Mandalay Unit 3, would be a better option. The evidence indicates that that the 130 MW Mandalay Unit 3 could fill the 29.6 MW need identified by the CAISO.[61] In fact, the CAISO testified that the 130 MW Mandalay Unit 3 - if it remains available – would satisfy the 29.6 MW need identified in the Moorpark sub-area.[62] No definitive evidence in the record exists that Mandalay Unit 3 will remain available for continued operation.

Therefore, until more information is known about the future of Mandalay Unit 3 and the potential for preferred resources to meet any local area need, it is reasonable to reject the long-term Ellwood contract, a 10-year contract (and 30-year refurbishment).

10. Conclusion

For all of the reasons discussed herein, the Ellwood contract is rejected. However, the unique circumstances in the Santa Barbara/Goleta area remain. Within six months, SCE shall provide a letter to the Director of the Energy Division and the Commissioners with an update on efforts, actions, and resources under review to address the unique needs in the Santa Barbara/Goleta

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[61] HHT December 15, 2016 Reply Brief at 2-3.

[62] HHT December 15, 2016 Reply Brief at 2-3, citing to RT Vol. 6 at 1023: 3-7.

that may arise in the event of the loss of the two Goleta-Santa Clara 230 kilovolt transmission lines (referred to as an N-2 Contingency). This letter may include scenarios with Ellwood but shall include review of scenarios without Ellwood.

11. 0.5 MW NRG Energy Storage Project

The Commission found in D.16-05-050 that the 10-year, 0.5 MW energy storage project contract between SCE and NRG at the Ellwood site should be considered in Phase 2 of this proceeding together with the Ellwood contract. In reviewing this contract in Phase 2, we conclude that the approval of the Ellwood contract is a prerequisite for approval of the new 0.5 MW energy storage facility at the Ellwood site, as the two contracts were linked together by NRG as a mutually exclusive offer.

Because the Ellwood contract is not approved today, we must, under the terms of the contract, reject the linked storage contract located at Ellwood. In the future, we expect bidders to abide by the Commission's procurement rules, including the rules that prohibit offers that combine existing generation with incremental energy storage capacity. These rules, and others, function to prevent market distortions and ensure a level playing field among bidders.

12. Motions

The May 11, 2017 motion by NRG is denied. The May 16, 2017 motion by SCE is denied. All outstanding motions to file pleadings confidentially are granted. NRG's and SCE's November 18, 2016, joint motion to admit into evidence a late-filed joint exhibit is granted. SCE's November 21, 2016 motion for leave to correct transcript errors is granted. The motions dated November 21, 2016 and November 29, 2016 by ORA to admit into evidence late-file exhibits and submit exhibits under seal are granted.

13. Comments on Proposed Decision

The proposed decision of Administrative Law Judge (ALJ) DeAngelis in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 27, 2017, and reply comments were filed on May 2, 2017. Revisions have been made to the extent required by law.

14. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Regina M. DeAngelis is the assigned ALJ in this proceeding.

Findings of Fact

1. Pursuant to D.16-05-050 and the August 18, 2016 Phase 2 Scoping Memo, the question presented in Phase 2 of this proceeding is whether the Ellwood contract and linked energy storage project are reasonable.
2. As explained in D.16-05-050, in order to determine if the Ellwood contract is reasonable, it is necessary to determine if a reliability need exists.
3. No reliability need exists that justifies the Ellwood contract.
4. The Commission could deny the Ellwood contract since it does not meet the approval standard set forth in D.16-05-050.
5. SCE presents a new standard by which to evaluate Ellwood, referred to as the resiliency standard.
6. The resiliency standard is not relied upon because it has not been vetted and approved by the Commission.
7. The reasonableness of the Ellwood contract is reviewed within the context of the unique service issues in the Santa Barbara/Goleta area that implicate safety considerations in the event of an N-2 Contingency.

8. Unique and localized transmission grid issues exist in the Santa Barbara/Goleta part of SCE's service territory and, in the event of the loss of the two Goleta-Santa Clara 230 kV transmission lines (referred to as an N-2 Contingency) customers in the Santa Barbara/Goleta area will likely lose service.

9. Depending on the circumstances of the outage and when it occurs, in the absence of additional resources, SCE would not be able to meet 105 MW of peak load and customers could face rolling blackouts.

10. The undisputed fact is that Ellwood does not present a solution to any unmet NERC or CAISO standard.

11. The N-2 Contingency would be a rare event but is possible. No exact probability or risk factor was presented.

12. Options other than relying on Ellwood exist to address an N-2 Contingency, including dropping load.

13. The availability of Ellwood for an N-2 Contingency is unclear based on its existing Air Permit from the Santa Barbara County Air Pollution Control District, and the unknown price for operating beyond the hours set forth in the Air Permit.

14. A balancing of the harms may need to occur before the Santa Barbara County Air Pollution Control District issues a variance to the Air Permit, and the outcome of such an analysis is unknown.

15. It remains unclear whether an amount of amps lower than approximated by SCE may be acceptable for providing short circuit duty.

16. No clear standards applicable to short circuit duty exist.

17. Ellwood cannot be justified as reasonable based solely on SCE's need to address short circuit duty.

18. SCE is encouraged to evaluate sources of short circuit duty for the Santa Barbara/Goleta area from both conventional sources, such as, synchronous condensers, and non-conventional sources, such as, inverter-based technologies, energy storage, and solar PV.

19. No urgent timeline exists for resolving the 105 MW deficiency which could result during peak hours of an N-2 Contingency.

20. Without Ellwood, a residual 29.6 MW need for local capacity resources will exist in the Moorpark sub-area when there is a voltage collapse caused by the N-2 Contingency.

21. The 130 MW Mandalay Unit 3 could fill the 29.6 MW need.

22. No definitive evidence exists that Mandalay Unit 3 will remain available but the record indicates that continued operation is possible.

23. A 105 MW shortfall would continue to exist even after the 66 kV upgrade to serve peak load in the event both 230 kV transmission lines go down.

24. Because the Ellwood contract is not approved, the issue of whether costs are reasonable need not be addressed.

25. The approval of the Ellwood contract is a prerequisite for approval of the 0.5 MW energy storage project located at the Ellwood site.

Conclusions of Law

1. The burden of proof is on the Applicant in this proceeding to support its request by a preponderance of evidence.

2. The argument that Ellwood should be approved because it presents a solution to the outages that could accompany a potential N-2 Contingency is rejected.

3. The argument that Ellwood should be approved to provide short circuit duty is rejected.

4. Ellwood is not the preferred way to resolve the safety and service problems that may arise under an N-2 Contingency.

5. It is premature to approve Ellwood for the purpose of meeting a reliability need of 29.6 MW in the Moorpark sub-area.

6. Until more information is known about the future of Mandalay Unit 3 and the potential for preferred resources to meet any local area need, it is reasonable to reject a long-term contract with Ellwood, a 10-year contract and 30-year refurbishment.

7. The upgrade to the 66 kV subtransmission system does not provide a complete solution to the need of 105 MW.

8. The Ellwood contract between SCE and NRG should not be approved.

9. SCE is not precluded from seeking Commission approval for short circuit duty solutions, particularly from alternative sources, such as, synchronous condensers and inverter-based technologies.

10. SCE is not precluded from seeking Commission approval for a contract to meet Santa Barbara/Goleta needs in the future, and is encouraged to focus any such efforts on preferred resources.

11. SCE is not precluded from seeking Commission approval for a contract with NRG or Ellwood in the future.

12. Whether the costs of the Ellwood contract are reasonable is not addressed because no need for the contract is established.

13. The 0.5 MW energy storage project of NRG, which is linked with the approval of the 54 MW Ellwood contract, should not be approved.

O R D E R

IT IS ORDERED that:

1. The contracts between Southern California Edison Company and NRG California South LP, referred to as the Ellwood contract (RFO contract #447021, with the linked Energy Storage Project contract (RFO contract #447030), are not approved.

2. Within six months, Southern California Edison Company shall provide a letter to the Director of the Energy Division and the Commissioners with an update on efforts, actions, and resources under review to address the unique needs in the Santa Barbara/Goleta that may arise in the event of the loss of the two Goleta-Santa Clara 230 kilovolt transmission lines (referred to as an N-2 Contingency). This letter may include scenarios with Ellwood but shall include review of scenarios without Ellwood.

3. The May 11, 2017 motion by NRG California South LP is denied. The May 16, 2017 motion by Southern California Edison Company is denied. All remaining motions are granted.

4. All rulings issued by the Administrative Law Judge during the proceeding are adopted.

5. Application 14-11-016 is closed.

This order is effective today.

Dated September 28, 2017, at Chula Vista, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

I will file a concurrence.

/s/ CLIFFORD RECHTSCHAFFEN
Commissioner

Concurrence of Clifford Rechtschaffen on Decision in Phase 2 on Results of Southern California Edison Company Local Capacity Requirements Request for Offers for Moorpark Sub-Area Pursuant to Decision (D.) 13-02-015

I support the decision to reject Southern California Edison's (SCE) 10-year contract with NRG's 52 megawatt (MW) Ellwood facility. The administrative law judge and President Picker conducted a careful examination of the unique energy needs in the Santa Barbara/Goleta area and rightly concluded that SCE did not demonstrate that this natural gas-fired peaker facility was a reasonable use of ratepayer dollars. More broadly, approval of this contract would have funded a 30-year refurbishment of the facility at a time when—absent a compelling reason to the contrary—all of our long-term investments in energy and infrastructure should be directed towards resources that provide the environmental and local benefits we need to achieve our clean energy and pollution reduction mandates. We may not always find the fossil-free alternatives that we are looking for, but we should always engage in a very hard look first to see if we can.

These reasons lead me to write this concurrence. I would have preferred that today's decision also address potential procurement contingencies in the area in order to best position SCE for a successful procurement of preferred resources in the event that the contingencies come to pass.

In particular, as several of the parties to this proceeding note, there is currently uncertainty surrounding the ultimate fate of the Puente Project, which was previously approved in this proceeding and is now before the California Energy Commission seeking authority to construct and operate the 262 MW natural gas-fired facility in Oxnard, California. Given this uncertainty and the need to ensure that new resources in the Moorpark local capacity subarea are procured before 2021, pursuant to D.13-02-015, these parties recommend that

SCE pursue a request for offers for the Santa Barbara/Goleta area (as planned), as well as the broader Moorpark local capacity sub area.

I would have preferred that the Commission require SCE to prepare to promptly initiate a procurement process to identify all preferred and conventional resources available to meet the reliability and resiliency needs in the Moorpark local capacity sub area, including the Santa Barbara/Goleta area. The final scope of that procurement would depend on the ultimate outcome of the Puente Project. The preparatory work could have taken a number of forms, including those short of specific requests for offers, such as a request for interest from developers, or having SCE share information with developers and local governments in the Moorpark local capacity sub area about optimal locations for interconnecting new capacity and distributed energy resources to meet any identified need. I believe that requiring this now would give SCE and developers the maximum time and flexibility needed to deal with local system needs going forward.

I respectfully concur in the decision.

Dated October 2, 2017 at San Francisco, California.

/s/ CLIFFORD RECHTSCHAFFEN
Clifford Rechtschaffen
Commissioner