Decision **PROPOSED DECISION OF ALJ GAMSON (Mailed 2/11/2014)**

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 DUE TO PERMANENT RETIREMENT OF THE SAN ONOFRE NUCLEAR GENERATIONS STATIONS

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DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS DUE TO PERMANENT RETIREMENT OF THE SAN ONOFRE NUCLEAR GENERATION STATIONS

1. Summary

This is the Track 4 decision in the 2012 long-term procurement proceeding. In this decision, we authorize Southern California Edison Company (SCE) to procure between 500 and 700 Megawatts (MW), and San Diego Gas & Electric Company (SDG&E) to procure between 500 and 800 MW by 2022 to meet local capacity needs stemming from the retired San Onofre Nuclear Generation Stations (SONGS). SCE is required to procure at least 400 MW, and may procure up to the full 700 MW of authorized additional capacity, from preferred resources or energy storage. SDG&E is required to procure at least 200 MW, and may procure up to the full 800 MW of authorized additional capacity, from preferred resources or energy storage.

Consistent with Decision (D.) 13-02-015, the 2013 Track 1 decision in this proceeding authorizing procurement by SCE in the LA Basin, this decision provides "buckets" of procurement for preferred resources (such as renewable power, demand response resources and energy efficiency), energy storage and gas-fired resources. Combining Track 1 and Track 4 procurement authority, SCE is authorized to procure between 1,900 and 2,500 MW in the LA Basin. SCE is required to procure up to 60% of new local capacity in the LA Basin from preferred resources. SDG&E is required to procure at least 25% -- and up to 100% -- of new local capacity from preferred resources. SCE and SDG&E are required to procure at least 50 MW and 25 MW, respectively, from energy storage. The following charts show the procurement levels for each utility. The procurement authorized by this decision as well as the Track 1 and Pio Pico

(D.14-02-016) decisions will offset the retirement of the 2,200 MW SONGS facility and nearly 5,900 MW of once-through cooling plants.

SCE Procurement Authorization
And Requirements
(Track 1 + Track 4)

Resource Type	Track 1 LCR Resources (D.13-02-015)	Additional Track 4 Authorization	Total Authorization
Preferred Resources **Minimum Requirement**	150 MW	400 MW	550 MW
Energy Storage **Minimum Requirement**	50 MW	--	50 MW
Gas-fired Generation **Minimum Requirement**	1000 MW	--	1000 MW
Optional Additional From Preferred Resources/Energy Storage Only	Up to 400MW		Up to 400 MW
Additional from any Resource	200 MW	100 to 300 MW	300 to 500 MW
Total Procurement Authorization	**1400 to 1800 MW**	**500 to 700 MW**	**1900 to 2500 MW**

SDG&E Procurement Authorization
and Requirements

Resource Type	D.13-03-029/ D.14-02-016	Additional Track 4 Authorization	Total Authorization
Preferred Resources (including energy storage) **Minimum Requirement**	---	175 MW	175 MW
Energy Storage **Minimum Requirement**	---	25 MW	25 MW
Additional from any resource	300 (Pio Pico)	300 to 600 MW	600 to 900 MW
Total Procurement Authorization	**300 MW**	**500 to 800 MW**	**800 to 1100 MW**

SCE is authorized to use the procurement process approved in Track 1 of this Rulemaking to procure capacity for the purposes of both Track 1 and Track 4. SCE is expected to file an application for approval of up to 2,500 MW of local capacity resources later in 2014. SDG&E is authorized to solicit procurement offers through an all-source RFO and bilateral negotiations, subject to Energy Division approval of its procurement process. SCE and SDG&E may propose options or contingency contracts in their procurement applications, or separate applications, subject to responses to specific inquiries. SDG&E is strongly encouraged to develop a Living Pilot for preferred resources similar to the one proposed by SCE.

Both SCE and SDG&E are authorized to include the costs of the procurement authorized today through the Cost Allocation Mechanism, consistent with its established rules, and/or other applicable procurement cost allocation processes.

2. Background

2.1. Procedural 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 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);

[1] Scoping Ruling at 5.

2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code Section 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. Track 1 considered issues related to the overall long-term need for new local reliability resources to meet long-term local capacity requirements (LCRs) through 2022. Such long-term LCRs are expected to result from the retirement of approximately 5,900 Megawatts (MW) from current once-through cooling generators in the Los Angeles (LA) Basin, and approximately 900 MW in the San Diego local area, to comply with State Water Quality Control Board regulations. Other changes in supply and demand over time will also impact long-term LCRs.

The Track 1 decision, Decision (D.) 13-02-015, authorized Southern California Edison Company (SCE) to procure between 1,400 and 1,800 MW of electrical capacity in the West Los Angeles sub-area of the LA Basin local reliability area to meet long-term local capacity requirements (LCRs) by 2021. For the defined portion of the LA Basin local area, at least 1,000 MW, but no more than 1,200 MW, of this capacity was to be procured from conventional gas-fired resources. At least 50 MW was to be procured from energy storage resources. At least 150 MW of capacity was to be procured through preferred resources[3] consistent with the Loading Order in the Energy Action Plans. SCE

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

[3] Preferred Resources are defined in the State's Energy Action Plan II, at 2, as follows: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and

Footnote continued on next page

was also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In addition, SCE was required to continue to obtain resources that 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. SCE was also authorized to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area.

D.13-02-015, Ordering Paragraph (OP) 11 required that SCE 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 was made if SCE's procurement plan, as approved by Energy Division, provided for one separate and earlier Application to procure gas-fired generation for both local reliability areas. The Applications were to specify how the totality of the contracts met criteria specified in OP 11. SCE's procurement plan was approved by

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demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter." Energy Storage is a potential enabling technology, but is not a Preferred Resource because it stores power regardless of how that power is produced. However, in this decision, we also include Energy Storage in the category of Preferred Resources for ease of use unless otherwise noted.

Energy Division in August 2013. SCE currently expects to file applications resulting from Track 1 solicitations later in 2014.

Track 2 of R.12-03-014 considered procurement of system reliability resources for the three major electric IOUs. D.12-12-010 adopted final Standardized Planning Assumptions and Scenarios for Track 2. Modeling results pertaining to flexible resources have not been formally considered by the Commission because the ISO stated at a September Prehearing Conference (PHC) that it was not prepared to submit testimony on the topic. Therefore, a Ruling issued on September 16, 2013 deferred Track 2 to a new 2014 Long-Term Procurement Plans (LTPP) Rulemaking, stating "[b]efore Track 4 was initiated, it was anticipated that Track 2 would be informed by the Track 1 local capacity requirements decision. With the addition of Track 4, it makes sense to also consider local capacity procurement authorized in Track 4 in determining system flexibility needs." The Ruling anticipated system reliability issues related to flexibility would be considered in the 2014 LTPP Rulemaking.

Track 3 of R.12-03-014 considered a number of rule and policy issues related to IOUs' procurement practices. D. 14-02-040 was approved by the Commission on February 27, 2014.

A revised Scoping Memo dated March 21, 2013 in R.12-03-014 initiated Track 4 in this proceeding to consider additional resource needs relate to the long-term outage (and subsequent permanent closure in June 2013) of the San Onofre Nuclear Generation Station, Units 2 and 3 (SONGS). This is the decision for Track 4 of this proceeding.

This decision is a follow-up to the Track 1 decision in this proceeding, but is more narrowly focused on local capacity requirements in what is known as the

SONGS study area. This area consists of all of the territory of San Diego Gas and Electric Company (SDG&E), and the LA Basin portion of SCE's territory.

Generally, we consider new developments related to supply and demand as a matter of course in our bi-yearly LTPP proceedings. The June 2013 permanent retirement of SONGS (following its initial shutdown in 2012) presented a unique and highly significant event. Until 2012, SONGS had supplied 2,246 MW of greenhouse gas (GHG)-free base load power to the LA Basin and San Diego and played an important role in system stability in the San Diego Local Area. The issues of ensuring local reliability and system stability in San Diego and the LA Basin while continuing to meet the State's GHG goals justified expedited reconsideration of capacity needs in the SONGS study area. Track 4 of the 2012 LTPP was opened to grapple with these issues.

At the September 4, 2013 PHC, Administrative Law Judge (ALJ) Gamson noted that the California Independent System Operator (ISO or CAISO) in its August 5, 2013 Track 4 testimony called for deferring Track 4 until after results of the ISO's 2013/2014 Transmission Planning Process (TPP) would be available. The ISO stated that it would be able to provide testimony as to the transmission alternative study results (including reactive power needs) as soon as January 2014.[4] However, the final TPP was not expected to be available until March 2014. Per the ISO's initial recommendation, a decision on Track 4 would not occur until the 2nd or 3rd quarter of 2014.[5]

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[4] A draft 2013/2014 TPP was issued in early February 2014.

[5] The ISO now recommends authorization of procurement amounts at this time, as discussed herein.

The September 16, 2013 Assigned Commissioner/ALJ Ruling noted that the 2013/2014 TPP is expected to provide useful information to inform the Commission regarding a decision on both the level and type of resources to replace SONGS capacity in the long run. The Ruling agreed with the comments of most parties that the determination of the level and type of need to replace SONGS capacity over the long-term should take the TPP into account in making this decision. At the same time, due to long lead times for new resources, the Ruling determined that there it was urgent to start identify and fill any identified need as soon as possible. Therefore, the Ruling established a streamlined schedule to provide guidance and direction to SCE and SDG&E to allow these utilities to move forward on a complex and multi-year procurement process. Under this process, this Track 4 decision will not include the TPP results expected in the first quarter of 2014.

Some parties continue to argue that the Commission should not make a decision on additional procurement related to the SONGS retirement at this time. For example, CEERT states: "The bottom line is, particularly without the benefit of updated assumptions to mirror critical near-term information (i.e., the 2013-2014 TPP results) that can impact mitigation options that could reduce or meet LCR need other than procuring more conventional gas-fired generation, the Commission simply does not now have a reliable record for making any Track 4 GFG procurement authorization for either SCE or SDG&E in January 2014, whether "interim" or not."[6]

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[6] CEERT Opening Brief, at 20.

As discussed herein, we determine that it is necessary to authorize additional procurement at this time. The 2013/2014 TPP results are expected to be complete by March 2014. However, further procedural activities in this docket would necessitate at least several months to fully develop a record to incorporate the new TPP results. With long lead-time resources requiring several years of effort, and potential reliability issues surfacing starting in 2018, we cannot wait for further information at this point. Further, additional information inevitably becomes available as time passes. It is simply not possible to both incorporate all information and make timely decisions. However, knowing the TPP results are soon to be available and that additional transmission solutions may impact future LCR needs (by lowering local procurement requirements), we will take a cautious approach to avoid over procurement.

The ISO served its testimony on August 5, 2013. SCE, SDG&E, Office of Ratepayer Advocates (ORA) and the City of Redondo Beach served testimony including modeling studies on August 26, 2013. Comments on questions from the ALJ at the September 4, 2013 PHC were filed on September 30, 2013, with reply comments on October 14, 2013. Opening testimony and testimony in response to modeling parties' testimony was served on September 30, 2013. Rebuttal testimony was served on October 14, 2013.[7] Evidentiary hearings were held October 28 through November 1, 2013. Briefs were filed on November 25, 2013 and Reply Briefs were filed on December 16, 2013. This track of the proceeding was submitted on December 16, 2013.

[7] Certain parties served supplemental and other versions of testimony on other dates with permission of the ALJ.

The parties which served testimony in Track 4 of this proceeding are[8]: AES Southland LLC (AES Southland), Alton Energy Inc. (Alton Energy), California Energy Storage Association (CESA), California Environmental Justice Alliance (CEJA), California Large Energy Consumers Association (CLECA), Calpeak Power, LLC (Calpeak), Center for Energy Efficiency and Renewable Technologies (CEERT), City of Redondo Beach (Redondo Beach), Clean Coalition, Direct Access Customer Coalition/Alliance for Retail Energy Markets (DACC/AReM or AReM/DACC), Eagle Crest Energy Company (Eagle Crest), EnerNOC, Independent Energy Producers Association (IEP), the ISO, Environmental Defense Fund (EDF), Marin Clean Energy (also known as Marin Energy Association or MEA); Natural Resources Defense Council (NRDC), NRG Energy (NRG), ORA,[9] Pacific Gas & Electric (PG&E), Protect Our Communities Foundation (POC), SCE, SDG&E, Sierra Club California (Sierra Club), The Utility Reform Network (TURN), Western Power Trading Forum (WPTF), The Vote Solar Initiative (Vote Solar) and Wellhead Electric Company, Inc. (Wellhead). Testimony from each of these parties was received into evidence at the evidentiary hearing.

2.2. Statutory Requirements, Energy Action Plan and the Loading Order

In considering long-term procurement, the Commission must address a variety of policy and legal concerns. While a primary responsibility of the Commission is to ensure safety and reliability in the electrical system, that

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

[9] Formerly known as Division of Ratepayer Advocates.

responsibility must be balanced with other statutory and policy considerations.[10] Specifically, the Commission has a statutory duty to ensure that customers receive reasonable services at just and reasonable rates,[11] and to protect the environment from deleterious impacts from utility facilities under our jurisdiction.

California law repeatedly emphasizes the importance of maintaining the reliability of the electric grid. For example:

- "Reliable electric service is of utmost importance to the safety, health, and welfare of the state's citizenry and economy." (§ 330(g).)
- "It is important that sufficient supplies of electric generation will be available to maintain the reliable service to the citizens and businesses of the state." (§ 330(h).)
- "Reliable electric service is of paramount importance to the safety, health, and comfort of the people of California." (§ 334.)
- The CAISO "shall ensure efficient use and reliable operation of the transmission grid" (§ 345) and shall "ensure the reliability of electric service and the health and safety of the public." (§ 345.5(b).)
- The Commission "shall ensure that facilities needed to maintain the reliability of the electric supply remain available and operational." (§ 362(a).)

The Commission also has a statutory mandate to implement procurement-related policies to protect the environment. 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

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[10] D.13-02-015 at 35.

[11] Pub. Util. Code § 454.5. All statutory references are to the Public Utilities Code unless otherwise noted.

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, and D.13-02-015 in 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 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.[12] 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

[12] D.12-01-033 at 19.

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.'"[13] 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."[14] While procuring a fixed amount of preferred resources provides flexibility and a clearer idea of how to approach the procurement process, the Loading Order approach is more consistent with Commission policy.

In D.13-02-015, Ordering Paragraph 4 required that any Requests for Offers (RFO) issued by SCE pursuant to that decision must include 12 elements, including "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." Ordering Paragraph 11 (which required SCE to file one or more applications for resource procurement authorized by that decision) required that SCE follow five criteria including: "Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics,

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13 D.04-06-011, footnote 22, at 31.

14 D.12-01-033 at 21.

viability and effectiveness of that supply in meeting the LCR need." We maintain our commitment to the Loading Order in this decision.

2.3. Motions to Strike Briefs and Reply Briefs

As discussed in detail in this section, several Motions were filed to strike all or part of Opening or Reply Briefs. SCE filed Motions to Strike the Opening Briefs of Nevada Hydro and MEA, and a Motion to Strike Portions of the Opening Brief of Redondo Beach. SCE and SDG&E jointly filed a Motion to Strike the Opening Brief of POC. PG&E and SDG&E both filed Motions to Strike Portions of the Opening Brief of MEA. In addition, SCE and SDG&E jointly filed a Motion to Strike the Reply Brief of POC.

The revised Scoping Memo stated at page 4:

> "Track 4 will consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) generators, which are currently not operational. The CAISO is developing a study to assess both the interim (2018) and long-term (2022) local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from an extended SONGS outage."

Generally, all relevant evidence is admissible unless otherwise provided by law. (Cal. Evid. Code, Sec. 350.) Per Rule 7.3 of the Rules of Practice and Procedure, the explanation of the issues to be considered in a particular Commission proceeding is ordinarily provided in a scoping memo. Here, the assigned Commissioner issued an initial scoping memo on May 17, 2012 and a revised scoping memo on May 21, 2013. The revised scoping memo specifically at 4-5 noted that Track 4 would not address general system operational needs and procurement processes.

Rule 13.6(a) provides that although not all technical rules of evidence need be applied in Commission proceedings, "substantial rights of the parties shall be preserved." Rules 13.7 and 13.8 provide details regarding the submission of exhibits and prepared testimony as evidence in Commission proceedings. Rule 13.8(b) provides that substantially modified testimony beyond that provided in prepared testimony shall not be admitted into evidence absent explanation of why the additional testimony could not have been included with the original testimony or other reason why the additional testimony should be admitted. Rule 13.8(d) requires that prepared testimony must be served on parties.

On December 2, 2013, SCE filed a motion to strike portions of Opening Brief of Redondo Beach regarding Track 4 (SCE/Redondo Motion) on the basis that various sections of the Brief relied upon evidence not supported by the record of the proceeding. Such allegedly unsupported analysis included specific details regarding Redondo Beach's power flow analysis. (*See* SCE/Redondo Motion at 2.)

On December 12, 2013, Redondo Beach filed an opposition to the SCE/Redondo Motion (Redondo Response), urging that the motion should be denied because the evidence that is the subject of SCE's motion was submitted as, or attached to the testimony of, Redondo Beach's expert witness Firooz and/or was submitted as part of Redondo Beach's production of analysis in response to SCE data request. (*See* Amended Opening Testimony of Jaleh Firooz on behalf of the City of Redondo Beach, dated October 25, 2013 and Attachment; and *see* Redondo Response at 5.) Redondo Beach further argues that because SCE included argument in its Track 4 Rebuttal Testimony criticizing the substance of Redondo Beach's power flow analysis, it would violate due process of law to both strike Redondo Beach's analysis as well as attempt to bolster its own case by attacking the same testimony.

Here, the evidence that is the subject of the SCE/Redondo Motion is directly related to studies of the local reliability of the SCE and SDG&E local areas by various parties. Such information appears in Redondo Beach's Amended Opening Testimony, allowing SCE the opportunity to attack the validity of such analysis. SCE did in fact attack the validity of Redondo Beach's testimony, and thus was not deprived of the ability to review and criticize such evidence. Thus, the SCE/Redondo Motion is denied in its entirety.

SCE and SDG&E each filed Motions onto strike large portions of the opening brief of MEA on December 4 and December 5, 2013, respectively. SDG&E's filing expressed that it supported SCE's Motion to strike in its entirety (we therefore refer to the two motions as the SCE/MEA Motion). PG&E also filed a Motion supporting SCE's Motion to Strike, and also identifying additional segments of the MEA brief that it urged should be stricken due to lack of factual basis in the record. The Motions claim that specified portions of MEA's brief are not supported by the evidentiary record and that MEA improperly introduces for the first time in Section VIII.C. of its opening brief a new proposal regarding the general application of the CAM to Community Choice Aggregators (CCAs). The SCE/MEA Motion observes that MEA presented no testimony in Track 4 of this proceeding.

MEA filed a response (MEA Response) to all of the IOU's Motions to strike on December 12, 2013, including responses to each IOU's individual criticisms. MEA also included a chart containing its explanations for the admissibility of each portion of its opening brief that SCE requested to be stricken, attached to its Motion as Appendix A.

As reflected in Appendix A of MEA's response to the SCE/MEA Motion, all of MEA's discussion that the utilities requested to be stricken are discussions of the effects of CAM on CCA's in general rather than discussion of the subject of Track 4: local reliability issues raised by the closure of the SONGS facility. For example, MEA argues, "CAM exists as a separate procurement mechanism that must be integrated into the larger whole of the Commission's RA procurement processes in order to ensure fair implementation of all procurement tools." (MEA Response, Appendix A at 18.) MEA itself acknowledges that "the Commission will examine CAM methodology in Track 3 of this proceeding." (MEA Response, Appendix A at 14.) Similarly, regarding MEA's allegedly new proposal regarding how the CAM should be applied to CCA customers, MEA concedes that its opening brief in Track 4 addresses "the greater issue of whether and how the CAM should be applied to CCA customers." (MEA Motion at 2.)

Further, many of the alleged bases for the admissibility of MEA's assertions of fact are legally problematic. California rules of evidence provide that only "[f]acts and propositions of generalized knowledge that are so universally known that they cannot reasonably be the subject of dispute" may be admitted into evidence through judicial notice. (Cal. Evid. Code, Sec. 451, subd. (f); see generally Cal. Evid. Code, Secs. 450 and 451.) The fact that MEA cites to various online news articles and websites to support many of its factual assertions tends to indicate that such matters are not in fact universally known.

The IOU Motions to strike filed against MEA are granted because the stricken language is not relevant to the scope of Track 4. The briefing of issues that are not relevant to the express subject of a particular stage of briefing wastes the time and resources of both parties and Commission staff.

POC filed a Motion for Official Notice of three documents on November 4, 2013. Specifically, those documents were "Reliability Performance Evaluation Working Group – Phase I Probabilistic Based Reliability Criteria

Implementation Procedure," dated June 14, 2001 (Previously marked for the record as POC-4); "Seven Step Process for Performance Category Upgrade Request," Dated October 2004 (Previously marked for the record as POC-5); and "WECC Board of Directors Request Regarding Performance Category Upgrade Request," Dated February 20, 2013 (Previously marked for the record as POC-6). The Joint Utilities filed on November 6, 2013 a Joint Response to the Motion of POC on the basis that the documents did not qualify for Judicial Notice pursuant to Commission Rules of Practice and Procedure, Rule 13.9 and California Evidence Code, Sections 450 et seq.; and further, were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand. ALJ Gamson issued an e-mail Ruling on November 14, 2013, denying POC's request for Official Notice of those exhibits. This Ruling is affirmed.

On December 4, 2013, SCE and SDG&E filed a joint motion (Joint Motion) to strike portions of the POC Opening Brief because the specified portions relied upon evidence which the ALJ had deemed inadmissible by the November 14 Ruling. POC filed a response to the Joint Motion arguing that the Joint Motion was overly broad and that some of the materials that were requested to be stricken properly relied upon evidence in the record.

POC's Response belies the content of its Opening Brief. In fact, the sections referenced in the Joint Motion discuss the stricken exhibits POC-4, POC-5, as well as an unnamed source (POC Opening Brief, at 16, fn. 27 provides the source of a quote as "xxxxx at 8."). The Joint Motion is thus granted, and the referenced portions of the POC Opening Brief are stricken.

SCE filed a Motion to Strike Portions of the Opening Brief of Nevada Hydro (SCE/NHC Motion) on December 4, 2013, on the basis that specified segments of the brief attempted to support Commission approval of two proposed grid additions (known as LEAPS and TE/VS Interconnect) that NHC urged would help fulfill resource needs created by the shutdown of SONGS. SCE argued that parties "have not been provided the opportunity to examine LEAPS or the TE/VS Interconnect projects through discovery, testimony or evidentiary hearings." (NHC Motion at 2.)

NHC filed its Motion Opposing the SCE/NHC Motion (NHC Opposition) on December 10, 2013, in which it argued that the specified discussion of the LEAPS and TE/VS projects should not be stricken because the Commission should allow projects proposed by non-IOU entities to be considered to fulfill local reliability needs rather than letting SCE build replacement generation facilities in order to remedy a reliability problem that SCE itself caused. (NHC Opposition at 3-4.)

NHC concedes that, "the Commission did not intend this proceeding to be used to advocate for the merits of any particular solution to the loss of the San Onofre Nuclear Generating Station (SONGS) to SCE's ratebase and to the local generating capacity of the basin[]" and that "this proceeding was not the venue to debate facts supporting the worth of Nevada Hydro's LEAPS and the closely related TE/VS Interconnect." Rather, Nevada Hydro noted that it will make factual assertions in connection with the value of these projects to ratepayers in Certificate of Public Convenience and Necessity applications it will make for each project, through which the merits of each project can be fully vetted." (NHC Opposition at 2-3.) Thus, NHC essentially admits that the characteristics of two particular projects are not matters of factual dispute within the scope of Track 4, which was designed to determine the local reliability resource needs required by the shutdown per the revised Scoping Memo at 4, rather than to identify specific projects that should be developed to fulfill such local reliability needs. Therefore, the SCE/NHC Motion is granted; discussion of the capabilities of the designated sections of NHC's Opening Brief are stricken because they are not relevant to the evaluation of reliability needs.

3. Long-Term Local Capacity Requirements in the SONGS Study Area

3.1. Joint Comparison Exhibit

Per the instructions of the ALJ, parties prepared a Joint Comparison Exhibit, admitted as Exhibit 1. Exhibit 1 shows each party's recommendations for Track 4 needs by utilities, and the basis for the need recommendations. Exhibit 1 is attached as Appendix 1 to this decision.[15]

3.2. Discussion Overview

The early retirement of SONGS removed over 2,200 MW of capacity from southern California. Replacing the capacity from SONGS is not a simple matter. SONGS was located in a critical spot on the coast straddling the SCE and SDG&E territories, providing energy, capacity and ancillary services such as Voltage Ampere Reactive (VAR) support to both territories.

Each year, the RA proceeding (currently R.11-10-023) considers utility capacity needs across California for the upcoming year. In June 2013, D.13-06-024 (among other things) considered capacity needs for 2014. That decision adopted higher capacity requirements for southern California for 2014 than otherwise needed if SONGS was still active. Specifically for the SDG&E local area, D.13-06-024 adopted a local capacity requirement of about 450 MW more than if both SONGS plants were operational.

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[15] The contents of Exhibit 1 were based upon parties Opening Testimony for Track 4, unless otherwise cited from a different source.

Over the medium-term – a period of greater than the one year considered in RA proceedings, but shorter than the 10-year view in LTPP proceedings – both SCE and SDG&E have sufficient supplies to meet projected demands in the SONGS service area through at least 2018, even with the unexpected early retirement of SONGS. Significant supplies have come online in recent years, while overall demand is lower than anticipated several years ago (due to both weakness in the economy and the success of demand side management and energy efficiency programs). In addition, SCE has procured additional capacity to fill the gap left by SONGS over the medium-term. For example, on May 9, 2013 the Commission approved a bilaterally negotiated capacity sale and tolling agreement between SCE and BE CA LLC (BECA) for 3,690 megawatts (MW of contracted capacity in the LA Basin for the period October 2013 to May 2018. (*See* Resolution E-4584.)

Starting in 2015, around 4,900 MW of OTC plants in the local transmission-constrained areas of the LA Basin local area may retire over the next several years, as well as other OTC plants in the San Diego local areas, because of State Water Resources Control Board (SWRCB) regulations.[16] (*See* D.13-02-015 at 6-7 and Section 4.2.2 for a discussion of potential OTC plant closures.) These potential retirements formed much of the basis of the ISO's analysis of 2,400 MW of need in the LA Basin in Track 1.

In this Track 4 proceeding, the ISO modeled retirement of OTC plants in the SONGS study area, along with the retirement of SONGS, to produce an analysis of need for the area. The ISO essentially used the same models as in

[16] *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.

Track 1 to determine LCR needs for 2022 (including the expected retirement of OTC plants), but modified its modeling to reflect the loss of SONGS. Thus, the ISO did not narrowly attempt to identify how much local capacity will be needed to replace SONGS, but modeled overall LCR needs in the SONGS service territory through 2022.

Developing a forecast of needs several years into the future requires incorporation of a number of assumptions. In this proceeding, the ISO based its long-term LCR study on a 1-in-10 year annual peak load and a Category C Contingency.[17] In D.12-12-010 in this proceeding, the Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, the Commission approved the use of a 1-in-10 year peak weather forecast for transmission planning and local area planning.[18] In Track 1 of this proceeding the Commission determined that the ISO's use of a scenario in which two import pathways to SCE's territory would be unavailable on the hottest day in 10 years was an acceptable methodology for determination of LCR needs.[19] Similarly, in D.13-03-029 (the SDG&E Power Purchase Tolling Agreement) the Commission based its LCR determination, in part, on an ISO study that included a power flow model of an outage of the Imperial Valley-Suncrest portion of the Sunrise transmission line followed by the non-simultaneous loss of the ECO-Miguel portion of the Southwest Powerlink transmission line.

On May 21, 2013, the revised Scoping Memo (in its Attachment A) for this proceeding set forth a series of assumptions for the ISO to use in modeling

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[17] A Category C contingency.

[18] D.12-12-010, Attachment A at 23.

[19] D.13-02-015 at 40.

long-term capacity needs in the absence of SONGS. The assumptions are established consistent those in D.12-12-010, D.13-02-015, and D.13-03-029. The revised Scoping Ruling determined that certain revised study assumptions were appropriate, including using a 1-in-10 year versus 1-in-2 year peak weather forecast for transmission and local area planning, and allocation methodologies for assigning energy efficiency and demand response to busbars.

The ISO study is based upon the assumptions in the revised Scoping Memo and forecasts a need of between 4,507 MW and 4,642 MW, respectively depending upon whether the capacity is split 80/20 or 67/33 between SCE and SDG&E.[20] The ISO analysis takes into account the recent Commission authorizations in Track 1 and in D.13-03-029 to calculate an LCR need for the SONGS study area for 2022. Table 1 below (which is also Table 13 in the testimony of ISO witness Sparks) identifies the ISO's calculation of the residual resource needs in 2022 without SONGS:[21] As can be seen in the table, the ISO calculates that between 2,399 MW and 2,534 MW (depending on the allocation between SCE and SDG&E) will be needed in the SONGS study area by 2022. The ISO does not recommend authorization of these levels of procurement at this time.

Certain parties disagree with the ISO's modeling efforts, as discussed in sections below. After detailed review, we agree with the ISO's contention[22] that it correctly modeled the input assumptions described in the revised Scoping Ruling. At the same time, because any complex forecast several years into the

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20 The ISO also adds a 2.5% reserve margin to its need calculation.

21 Exhibit ISO-1 (Sparks), at 26.

22 ISO Opening Brief, at 12-15.

future is by definition imperfect, the ISO's study results cannot be considered an exact need amount.

Table 1

ISO Table 13 – Residual Resource Needs in 2022 Without SONGS

Scenario	Track 1 Decisions (MW)		Track 4 Studies (2022) (SONGS Study Area = LA Basin + San Diego) (MW)				Residual Resource Needs (Total Track 4 – Maximum Track 1) for SONGS Study Area (MW)
	LA Basin	San Diego	DR Assumptions Modeled for Studies***	Inc. EE Assumptions Modeled for the Studies	System-Connected DGs (Commercial Interest)	Identified Resource Needs Without SONGS	
80%/20% (LA/SD) Total Resource Development Scenario	1,800*	308**	198	983	1,016 (Installed) 457 (NQC)	4,642	4,642 – 1,800 - 308 = 2,534 Breakdown: LA Basin (1,922) San Diego (612)
Two-thirds/One-Thirds(LA/SD) Total Resource Development Scenario	1,800*	308**	198	983	1,016 (Installed) 457 (NQC)	4,507	4,507 – 1,800 – 308 = 2,399 Breakdown: LA Basin (1,222) San Diego (1,177)

The ISO encourages the Commission to move forward with authorizing an interim amount of additional "no-regrets" resource procurement at this time.[23] Specifically, the ISO supports the SCE and SDG&E additional procurement requests.[24] As shown in the Joint Comparison Exhibit, at this time SCE recommends a procurement authorization of 500 MW in the LA Basin and

[23] ISO Opening Brief, at 3.

[24] ISO Opening Brief, at 29-33.

SDG&E recommends a procurement authorization of 500-550 MW in the SDG&E service territory.

The first task at hand in Track 4 is to determine a reasonable and prudent LCR need amount for the SONGS service area by 2022. Several parties argue that the ISO's modeling and reliability assumptions (as well as SCE and SDG&E's assumptions) were at minimum "very conservative."[25] To the extent that the revised Scoping Memo took a conservative approach in its models, so did the ISO.

As the ISO states: "The SCE and SDG&E study results are consistent with the ISO's findings."[26] All of these studies show projected residual long-term local capacity needs ranging from 2,302 – 2,534 MW based on slightly different assumptions and methodologies; certain of these differences we discuss herein. The ISO assumed a significant level of new preferred resources, consistent with the revised Scoping Memo. SDG&E's base case analysis assumes the existence of an incremental 408 MW of not-yet-procured preferred resources.[27] Similarly, the planning assumptions adopted for this track of the proceeding that SCE uses for its studies also assume substantial incremental MW of not yet procured preferred resources for SCE.[28]

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25 Exhibit ORA-1 (Ciupagea), at 8-9; see also, Exhibit CEJA-1 (May), at 2, 4-6, 9, 14, 21, 28; Exhibit CC-1, (Wang/White), at 1; Exhibit EDF-1 (Fine/Moss), at 2; Exhibit EnerNOC-1, (Tierney-Lloyd), at II-5; Exhibit SC-1 (Powers), at 1; Exhibit NRDC-1 (Martinez), at 4-5.

26 ISO Opening Brief, at 29.

27 SDG&E Opening Brief, at 12.

28 SCE Opening Brief, at 21-22.

We will use the ISO models in this decision as the basis for determining authorized procurement. In this decision, we evaluate potential modifications to the ISO's study results. The ISO agrees that its study results do not include a number of supply and demand considerations that would reduce the total LCR need. Other parties point to other considerations for the Commission to consider in authorizing procurement levels at this time. In nearly all cases, parties (PG&E being the exception) recommend that the Commission authorize procurement levels far below the approximately 2,400 – 2,500 MW output from the ISO study, with a number of parties recommending no additional procurement at this time. We discuss various recommended modifications to the ISO study results in detail below in order to determine analytically if the recommendations of parties are reasonable.

3.3. Potential Forecast Adjustments

In the sections below, we consider a variety of factors which impact the needs shown in the ISO study. It is important to note that all potential changes considered in the record are in one direction – a lower level of LCR need. The main question is whether any potential reductions are certain (or at least very likely), reasonably possible or merely speculative. A prudent authorization should take into account reductions to the ISO forecasts which are certain or very likely, should not take into account reductions which are merely speculative, and should consider reductions which are reasonably possible as providing the basis for the range of prudency.

3.3.1. Track 1 SCE Procurement Authorization

In D.13-02-015, the Track 1 decision of this proceeding, SCE was authorized to procure between 1,400 and 1,800 MW in the West LA sub-area of the LA Basin. Other than PG&E, no party challenges an assumption that the full

1,800 MW of this authorization will ultimately be procured by SCE. Since the full procurement authorization would necessarily be undertaken in the West LA sub-area – which is within the SONGS study area -- this figure directly reduces the ISO forecasted need by 1,800 MW. The ISO agrees and includes this adjustment in its forecast.

SCE's procurement plan was approved by Energy Division in August 2013, and SCE has conducted an RFO for this purpose. As directed by D.13-02-015, SCE will file an application with the Commission for approval of procurement contracts. This application is currently expected later in 2014. SCE may or may not seek approval for the full 1,800 MW (or even 1,400 MW) in its application, depending on the viability of the bids it receives. In addition, the application may or may not be approved in whole or in part. SCE witness Cushnie testified that it is SCE's preference to acquire the full 1800 MW of new LCR resources authorized in D.13-02-015, including the 400 MW of additional Preferred Resources. Cushnie also testified that if SCE does not receive cost competitive and/or cost-effective bids for the full 1,800 MW in its first solicitation, it may seek the needed resources through later solicitations or expansion of existing utility Preferred Resource programs.[29]

The authorization we approved in D.13-02-015 was based on SONGS continuing in service; the Track 1 decision can now be seen as a first step in a two or more step authorization process. We determine in this decision that it would be prudent to authorize further procurement due to the retirement of SONGS – adding up to more than 1,800 MW in total. SCE has stated that it plans over time

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[29] RT 2000 – 2001.

to fill the full 1,800 MW from Track 1; no party disagrees that this will occur. Therefore, we find that it is very likely or near certain that 1,800 MW from the Track 1 decision will be procured by SCE and agree with this ISO adjustment in its forecasted LCR need for the SONGS study area.

3.3.2. SDG&E Procurement Authorization

D.13-03-029 determined a local capacity requirement need and directed SDG&E to procure up to 298 megawatts of local generation capacity beginning in 2018.[30] The decision also granted SDG&E authority to enter into a purchase power tolling agreement with Escondido Energy Center. This decision denies authority to enter into purchase power tolling agreements with Pio Pico Energy Center and Quail Brush Power, without prejudice to a renewed application for their approval, if amended to match the timing of the identified need, or upon a different showing of need.

In A.13-06-015, SDG&E sought authority to enter into an amended power purchase tolling agreement with the Pio Pico Energy Center, based upon the authority granted in D.13-03-029. D.14-02-016 in this docket approving the agreement was approved on February 5, 2014. The ISO had already included this adjustment in its study in this record.

We determine in this decision that it would be prudent to authorize further procurement due to the retirement of SONGS. SDG&E has already received approval for procurement based on the authority in D.13-03-029. Therefore, it is clear that SDG&E will procure the amounts authorized in

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[30] Other aspects of that decision push the level to 308 MW. In this decision, we round the D.13-03-029 authorization to 300 MW.

D.14-02-016. We therefore agree with this ISO adjustment in its study for the SONGS study area.

3.3.3. Reactive Power and VAR Support

On June 28, 2013, ORA, CEJA and Sierra Club filed a motion requesting that the Commission ask the ISO to include the full range of reactive power resources identified in ISO's 2012-2013 Transmission Plan in the ISO's local capacity studies without SONGS. These parties argue that power flow modeling results that exclude the full available range of reactive power options make it difficult to identify the true impact that reactive power can have in reducing new procurement need. In response, TURN agreed that the impact of "reactive power alternatives should be considered by this Commission in assessing how to respond to the SONGS retirement." The ISO opposed the motion to include modeling of additional reactive power resources in its Track 4 modeling.

Reactive power must be present in the transmission and distribution system to keep electrical current and voltage in phase and to operate electrical equipment with inductive load, such as motors, magnetic equipment, and transformers. Reactive power capacity is measured in units of volt-ampere reactive (VAR). SONGS was in a strategic location to provide voltage support in southern California. ISO witness Millar testified that SONGS was "critical in supporting voltages and transfers into San Diego."[31]

31 RT 1678.

The ISO modeled 720 MVAR of dynamic reactive support in its Track 4 studies, while SCE/SDG&E (jointly) modeled 1,220 MVAR of dynamic reactive support.[32] The ISO model included some, but not all, resources with potential to mitigate the loss of reactive support provided by SONGS in its Track 4 analysis. The Johanna, Santiago, and Viejo shunt capacitors are completed and included in the ISO's modeling.[33] The Huntington Beach synchronous condensers are also completed.[34] However, while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions.[35]

ORA points to a number of potential resources which may provide additional VAR support but were not modeled by the ISO,[36] including some data from the ISO's 2012/13 TPP.[37] ORA proposes a 350 MW reduction in need to approximate the impact of additional reactive power resources expected to

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32 Exhibit ISO-1 (Sparks), at 15.

33 Exhibit CEJA-2 (May Supporting Documents) at 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 2 (July 12, 2013)).

34 Exhibit CEJA-1 (May) at 8.

35 Exhibit ISO-1 (Sparks) at 9; Exhibit CEJA-2 (May Supporting Documents) at 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 1 (July 12, 2013)).

36 Exhibit ISO-1 (Sparks), at 15.

37 2012/13 TPP, p. 185-186, Table 3.5-10, note identifier "#" (at 186) (Appended as Attachment C to June 28, 2013 Motion).

decrease the need for real power, but ORA recommends that this estimate be confirmed by comprehensive power flow studies in the ISO's 2013-2014 TPP. CEJA shows that SDG&E has proposed two 230 kilovolt (kV) synchronous condenser projects that provide 480 MVARs of dynamic reactive support within the SONGS study area.[38] CEJA contends that a rough estimate of the total need reduction in the San Diego area resulting from these projects is at least 200 MW.[39] SCE has proposed adding another 550 MVAR [Static VAR Compensators] at San Onofre. CEJA shows that the ISO estimates that this addition will reduce need in the LA Basin by 300 MW.[40] This reactive support was not included in the 2022 results of the ISO's Track 4 Opening Testimony.

The June 28, 2013 Motion was not ruled upon during the proceeding. We will now deny this Motion as moot. The revised Scoping Memo did not include any specific amount of reactive power as an assumption for the ISO to model. The record in the proceeding shows that there are sufficient resources to provide VAR support in the SONGS study area without further action at this time.[41] We do not have sufficient information available from the record at this time to determine if additional reactive power resources not modeled by the ISO could be available to reduce LCR needs. Therefore, we find that any estimate of whether or how much additional reactive power support would change LCR

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[38] Exhibit SCE-1, at 28, Table III-3. These projects included a Suncrest 240 MVAR synchronous condenser and a Cannon/Encina 240 MVAR synchronous condenser. (*See* also at 31, Table III-4 notes.)

[39] Exhibit CEJA-1, (May) at 9.

[40] Exhibit CEJA-1 (May Opening Testimony) at 7.

[41] Exhibit ISO-1 (Sparks); at 16-17. Also *see* RT 2046-2050.

needs to be speculative, and will not make any adjustment to the ISO's study for this purpose.

3.3.4. Demand Forecast

The demand input assumptions in the revised Scoping Memo are based on forecasts in the CEC 2012 Integrated Energy Policy Report (IEPR), August 2012 revision.[42] The 2012 IEPR is based on the May 2012 CPUC Energy Efficiency Potential Study and the CEC's California Energy Demand 2012-2022 Final Forecast.[43] The ISO, SCE, and SDG&E studies are all based on demand input assumptions from that same data set.[44]

NRDC argues that the data in these studies provides an incomplete basis upon which to estimate energy savings through 2022 because the data lacks important information such as the effects of the CEC's building efficiency standards set to take effect in 2017 and 2020 and other energy efficiency codes and standards that will produce savings from 2015 and beyond.[45] CEJA also contends that data in the August 2012 IEPR therefore provide an incomplete basis upon which to estimate energy savings through 2022.[46] Sierra Club contends the September 2013 draft update to the CEC demand forecast projects

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[42] Revised Scoping Memo, Attachment A, at 3.

[43] Exhibit NRDC-1 (Martinez); at 7, Diagram 1.

[44] Exhibit ISO-1 (Sparks), at 4; Exhibit SCE-1 (SCE), at 31; Exhibit SDG&E-1 (Anderson), at 6.

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

[46] CEJA Opening Brief, at 19-20.

321 MW less load growth than the 2012 demand forecast that serves as the basis for the Commission-approved load assumptions.[47]

NRDC contends the energy efficiency estimates that the ISO and SCE relied on: (i) were based on an incomplete assessment of energy efficiency potential; (ii) omitted incremental "naturally-occurring" savings that are by definition reasonably expected to occur; and (iii) incorrectly used a low estimate of efficiency in SDG&E's local area instead of the mid estimate.[48] NRDC claims that including these additional energy efficiency savings increases the energy efficiency assumptions used in the ISO's and SCE's modeling by 885 MW in the SONGS study area, with 543 MW in the LA Basin and 342 MW in the San Diego local area.[49]

We will not at this time consider changes or updates related to the CEC's demand forecast. It is not reasonable, at this point in this proceeding, to delay the Track 4 decision until all of the assumptions prescribed in the revised Scoping Memo can be restudied; nor is it reasonable to selectively update assumptions. Both the NRDC proposal and the Sierra Club calculation are based on a CEC staff draft forecast of uncommitted energy efficiency that came out in September 2013. Both the ISO and SCE expressed concern about uncertainty in the updated demand forecast, citing the fact that the revised forecast is not yet

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[47] Sierra Club Opening Brief, at 5. This number is derived from Sierra Club Opening Comments, at 7 & n. 14 (citing California Energy Commission, Mid Case LSE and Balancing Authority – Baseline, Form 1.5d, lines 40 and 49. (Sept. 20, 2013) Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/).

[48] NRDC's item iii is addressed in Section 3.3.10 (Energy Efficiency) in this decision.

[49] Exhibit NRDC-1 (Martinez), at 4-5 (Table 1).

final.[50] Further, any updates after August 2012 were not modeled by the modeling parties, consistent with the revised Scoping Memo. Thus, even if there are changes to the CEC demand forecast, there is nothing in the record to show how or whether any such updates might impact LCR needs.

However, all of the potential demand adjustments in the record point in one direction: lower demand. We find based on the record that updates to the demand forecast are reasonably likely to lower LCR needs. Without quantifying the LCR effect of such potential demand response resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, these factors give us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.5. SPS and Load Shedding[51]

Consistent with guidelines from the Western Electricity Coordinating Council (WECC) and the North American Reliability Corporation (NERC), the ISO has approved Special Protection Systems (SPS), also known as a Special Protection Schemes, on several occasions in California.[52] An SPS allows the use of load shedding as an interim measure when there are insufficient resources to meet more stringent guidelines. The ISO (again consistent with WECC and

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[50] Exhibit SCE-2 (Various Witnesses) at 7; RT 1495.

[51] "Load shedding" in the context of this proceeding means controlled, but immediate, blackouts of one or more 500 MW blocks (affecting approximately 375,000 households) in a defined area, in response to specific critical failures of generation and/or transmission resources.

[52] NERC reliability standard TPL-003 permits load shedding in response to Category C contingencies (ISO Opening Brief, at 17).

NERC guidelines) considers the appropriate reliability level to be an "overlapping" or sequential outage in which one element or "contingency" is lost, there is time for the system to be readjusted (within 30 minutes), and then a second contingency is lost.[53] The two major contingencies usually will be a failure of the largest transmission lines and/or generation resources in the local area. This is known as an N-1-1 contingency. The ISO considers an SPS to be a temporary measure to be in place while long lead-time resources, such as new transmission lines, are being constructed.[54] For example, there is an SPS, with the potential to shed over 100 MW of load, in place for the San Francisco peninsula while PG&E completes several related transmission rebuilding projects.[55] When the new resources are in place, the SPS is ended.[56]

The ISO, SCE and SDG&E calculate the local capacity need for the SONGS study area using different approaches to acceptable mitigation strategies for the limiting N-1-1 contingency consisting of the sequential loss of the ECO-Miguel section of the Southwest Powerlink 500 kV line and the Ocotillo Express-Suncrest section of the Sunrise Powerlink. The ISO did not model the effect of the potential use of an SPS and instead assumes that new resources are needed to resolve the contingency.[57] SDG&E acknowledges the presence of a

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[53] Exhibit ISO-2 (Sparks) at 10.

[54] For large urban areas, the ISO's historic practice has been, as a last resort, to rely on load shedding as an interim measure only until the permanent solution can be put in place (ISO Opening Brief, at 18).

[55] RT 1472.

[56] Two such examples are provided in Exhibit ISO-2 (Sparks), at 5.

[57] Exhibit ORA-3 (Fagan), Attachment B (ISO Data Request Response 2).

WECC-approved SPS in its territory but does not directly model the effect of the SPS when considering the range of need for the N-1-1 contingency.[58] SDG&E and the ISO assume new generation resources (and/or transmission solutions) are needed to resolve the contingency. SCE models and calculates local capacity need assuming the SPS is available to mitigate the limiting contingency, but then requests additional procurement authority because the ISO does not allow reliance on this SPS for long-term planning.[59]

The use of an SPS to mitigate the N-1-1 contingency makes a significant difference in the determination of need. SCE's model shows that reliance on the existing SPS for relevant N-1-1 conditions[60] would decrease SCE's need for new generation by 438 MW in the all generation scenario.[61] Further, the effectiveness of SCE's proposed Mesa Loop-In project reduces the need for new generation from 1,200 MW to 734 MW without load shedding.[62] SDG&E witness Jontry testified that "Planning analyses performed by the CAISO supporting the Final 2013 LCR Technical Study indicate that adherence to the N-1-1 criteria without the possibility of load shedding increases the LCR requirements for the San Diego LCR area by over 1,000 MW, the equivalent of two combined cycle

[58] Exhibit SDG&E-3 (Jontry), at 7.

[59] Exhibit SCE-1 (Chinn) at 6-7.

[60] As noted by ORA witness Fagan (RT 1835-1836) using the SPS to shed load would only be necessary if the relevant conditions occurred simultaneously – very high peak load, and loss of both 500 kV lines. Its consideration in the planning stages does not imply deployment in operation.

[61] Exhibit SCE-1 (Chinn), at 32, Table III-5.

[62] Exhibit SCE-1 (Chinn), at 37.

units."[63] Jontry also testified that reliance on the SPS in the SDG&E territory would decrease the need for new generation by approximately 150 MW to 250 MW.[64] Considering all possibilities in the record, the amount of new generation that reliance on the SPS could displace ranges from about 588 MW (assuming 438 MW for SCE's and 150 MW for SDG&E) to 1,000 MW or more.[65]

ORA, TURN, CEJA, CLECA, Redondo Beach and Sierra Club all question the decision of the ISO, SDG&E and SCE not to consider the use of an SPS to mitigate the SONGS contingency in the absence of more complete information about the costs, benefits risks and affordability of relying on the SPS.[66] ORA witness Fagan testified that that an SPS could serve as a "'bridge' measure, depending on future transmission and/or preferred resource development circumstances. Fagan testified that:

> (if a new 500 kV) transmission connection between SCE and San Diego…was under consideration, there might be a period of time after OTC unit retirement and prior to completion of such a project that the SPS could serve as a bridge to ensure reliability. Or, if preferred resource development is advancing rapidly but has not yet reached a required threshold level by…2020, but would reach such a level a few years later, the SPS could serve as a bridge during that period."[67]

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63 Exhibit SDG&E-3 (Jontry), at 7-8.

64 RT 1714–1715; Exhibit SDG&E-4 (Jontry), at 2-3.

65 Exhibit TURN-1 (Woodruff), Table 4, at 17.

66 Exhibit ORA-3 (Fagan), at 3-10; Exhibit TURN-1 (Woodruff), at 12-27; Exhibit CEJA-1(May), at 34-38; Comments of the CLECA, September 30, 2013, at 10-1; Exhibit SC-1 (Powers), at 1-11.

67 Exhibit ORA-3 (Fagan), at 11.

CLECA posed the question: "Is it a good use of ratepayer money to add yet another roughly 500-1,500 MW in resources that will rarely if ever be used instead of using controlled load shedding by SDG&E in the case of an N-1-1 contingency under a 1-in-10 peak load condition? This is not a matter of failing to meet NERC and WECC requirements. This is a matter of having ratepayers foot the bill for going beyond those requirements."[68] TURN witness Woodruff emphasized that consideration of whether to allow load shedding to mitigate the key N-1-1 contingency should not be confused with a lack of concern about reliability.[69]

Parties dispute whether it would be cost-effective to have an SPS in place in San Diego. ORA witness Fagan testified that the alternative to an SPS would be the cost of new gas-fired generation, estimated to range from $595 million (436 MW) to $1.36 billion (1,000 MW) using $1,363/kW as the installed capital cost for a combustion turbine.[70] Similarly, TURN witness Woodruff estimated that the cost of SCE's Preferred Resource scenario appears to be $595.5 million higher in the absence of using a load shedding SPS as part of a contingency mitigation plan.[71]

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[68] CLECA Comments, at 10-11.

[69] Exhibit TURN-1 (Woodruff), at 26-27.

[70] Exhibit ORA-3 (Fagan) at 7.

[71] Exhibit TURN-1 (Woodruff), Table 4, at 17.

Other parties argue that an SPS is not appropriate and/or is not cost-effective. ISO witness Sparks testified that it is the ISO's position that load shedding in the highly urbanized San Diego area should not be used as a transmission planning tool, due to the significant amount of load that would be subject to load shedding, the sensitivity of urban loads to large blocks of load shedding, the complexity of operating arrangements in the area, and the proximity of particular transmission lines.[72] SDG&E witness Jontry cautioned against the "potentially severe economic and civil consequences"[73] that might result from controlled load shedding. Neither the ISO[74] nor SDG&E[75] conducted studies to compare the cost or risk of relying on its SPS versus the costs of other resources to mitigate the critical contingency.

IEP witness Monson testified that loss of service would result in costs including "spoilage, lost production time, and lost sales" as well as well possible traffic accidents and medical problems.[76] Monson testified that the costs of curtailment of firm load "depend on the frequency and duration of curtailments, the amount of capacity curtailed, and the value of service for customers," but were not calculated.[77] IEP calculates that, using an average financial cost of an

72 ISO-3, at 7.

73 Exhibit SDG&E-4 (Jontry), at 2.

74 RT 1843.

75 Exhibit ORA-3 (Fagan), Attachment D: SDG&E response to DRA-Sierra Club-CEJA data request second set, question 2. ("SDG&E has not conducted any studies quantifying the cost effectiveness of load shedding versus new in-basin generation resources.")

76 Exhibit IEP-2 (Monsen), at 15.

77 Exhibit IEP-2 (Monsen), at 15-16.

outage of the electric system of $40,000/MWh for a 12-hour outage, like the one San Diego experienced in September 2011, the cost of a similar outage would approach a quarter of a billion dollars.[78] However, TURN performed an analysis (which it terms "preliminary") showing under various assumptions that investments to avoid load shedding in case of an N-1-1 contingency are not cost-effective for ratepayers.[79]

Redondo Beach contends that the Commission could find that the costs and possible consequences of any controlled load drop are unacceptable, but the Commission should make such findings based on concrete analytic evidence. Redondo Beach claims such evidence is not present.[80] We agree that the evidence in this proceeding is not conclusive on this point.

In trying to estimate the potential consequences of an SPS, relevant factors include how often the identified N-1-1 contingency in San Diego is likely to occur, the likelihood that the contingency would occur when there were not adequate resources to serve load in the event one of the lines went down, and a range of costs of not serving load. One factor to consider is that the SPS might never be used.[81] ISO witness Sparks testified that there is a significant risk (and historical record) of fire in the area of the two transmission lines (which are as close as four miles apart) which form the N-1-1 contingencies, and that the

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78 IEP Opening Brief, at 16. IEP adds: "The social costs of blacking out 500 MW of customer load, including the disruptions to transportation, traffic control systems, and waste management systems, would be substantial, if difficult to quantify."

79 TURN Opening Brief, at 13-14.

80 Redondo Beach Opening Brief, at 17.

81 RT 1837.

probability of a simultaneous outage of the two lines "trends" towards one in 21 years.[82] Other credible data in the record shows likely intervals between potential failures may be up to 928 years.[83]

As ORA witness Fagan points out, ISO data shows the highest load on the combined Orange County SCE/SDG&E region occurs for no more than 89 hours over the course of the 3672-hour period between May 1 and September 30th, or less than 2.5% of summer hours.[84] Redondo Beach attempted to estimate the probability that two sets of low probability events – i.e., very high peak load and loss of both 500 kV lines in sequence – would occur at the same time on the same day, contending that "the probability of an N-1-1 contingency occurring at the peak hour of a 1-in-10 load forecast is…about 1 in a billion for the peak hour" or about 1 in 5 million if surrounding hours are included. [85] ISO witness Millar testified that "we don't believe this circumstance is one where a straightforward cost benefit analysis is an effective consideration."[86]

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[82] Exhibit ISO-2, at 5-6.

[83] Exhibit ISO-2 (Sparks), at 5– 6; *See* Exhibit TURN x ISO 7, at 56; cf. Ex. TURN x ISO 2, at 3.

[84] Exhibit ORA-3 (Fagan) at 9.

[85] Redondo Beach Report, p. 13; Redondo Beach Opening Brief, p. 14.

[86] RT 1613; *see* also RT 1622: appropriate use of cost benefit information refers to "circumstances lending themselves to producing a meaningful result that can be effectively taken into account by a decision maker in weighing the costs against the calculation benefits of mitigating against the large outage.

Per § 345, the ISO is responsible for operating the transmission grid used by SCE, PG&E, and SDG&E "consistent with achievement of planning and reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Reliability [Corporation]." The Commission is responsible for service reliability and maintaining reasonable rates. In previous decisions, we rejected the notion of "reliability at any cost," indicating instead that "measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability…"[87]

We do not find that long-term reliance on an SPS to resolve LCR need related to the retirement of SONGS is appropriate. We agree with SCE witness Chinn that "load shedding should only be used judiciously as mitigation for contingencies."[88] We also agree with IEP that we should not make a "change to long-term resource planning policy to incorporate blackouts as a standard, planned response to N-1-1 contingencies, a response on par with supply or demand-side additions, to avoid procuring the resources needed to reduce the risk of blackouts."[89]

The crux of the issue before us regarding load shedding is whether we should <u>at this time</u> authorize additional procurement to achieve the level of reliability the ISO recommends: Sufficient resources to mitigate a specific, but unlikely, N-1-1 contingency in the SDG&E territory. We note that an SPS that would allow load shedding is an option permitted by NERC and WECC

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[87] D.05-10-042 at 7.

[88] Exhibit SCE-2 (Chinn) (Revised 10/24/13), at 15.

[89] IEP Opening Brief, at 18.

standards.[90] We find based on the record the following: 1) The ISO has the authority within WECC/NERC guidelines to implement or continue a SPS in the SDG&E territory; 2) Such an SPS in the particular area identified by the ISO has a likelihood of an N-1-1 failure between every 21 and 928 years; 3) Even if such a failure occurs, it will not lead to load shedding except for less than 2.5% of summer hours;[91] 4) There would need to be a minimum of 588 MW fewer resources if there is a temporary SPS in place, as compared to the resources needed to support the N-1-1 contingency identified by the ISO; 5) The cost to ratepayers of these additional resources would be at least $595 million (this amount is the benefit of an SPS approach) and there is evidence that such investment may not be cost-effective; 6) The cost to affected customers of a load shedding event under an SPS approach is estimated at under $250 million per event, and must be weighted by the low probability of the occurrence of load shedding.

We conclude that it is not reasonable at this time to authorize utilities to procure – and ratepayers to pay the cost of -- the additional resources required to fully mitigate the identified N-1-1 contingency without an SPS. This determination does not mean that we favor a lower level of reliability than does the ISO. We agree with SDG&E and IEP that that it is not prudent to take a long-term system planning approach that assumes reliance on load shedding in a

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90 Exhibit ORA-3 (Fagan), at 7: 15 and Attachment B, at 1.

91 We recognize that an outage resulting from an N-1-1 contingency may occur outside of summer hours; however, the summer is generally considered the most likely season for this to occur due to higher temperatures, higher load and greater fire risk near the subject transmission lines.

densely-populated urban area as mitigation for contingency events.[92] Instead, we determine that it is prudent to wait to see what resources develop in the SONGS service area to determine whether an SPS or other load-shedding protocol need serve as a bridge until such resources are in place. In particular, we see the likelihood that the procurement of preferred resources as authorized herein (and as acquired through other means) will develop sufficiently over time to mitigate the need for further resources, so that the SPS in the SDG&E territory can be lifted and reliability at an N-1-1 contingency level can be maintained. In addition and/or alternatively, transmission solutions such as the Mesa Loop-In may mitigate the need for further resources.

We note that ISO witness Millar testified that the ISO intends to address its transmission planning policy regarding load shedding in large urban areas as part of an open stakeholder process in the first half of 2014.[93] While it is unknown what the outcome of this process will be, it is possible that the ISO will adopt a different position that it currently holds regarding when an SPS should be approved and how load shedding should be considered. By not authorizing procurement at this time to the ISO's current policy standard, we retain the option of reconsidering the appropriate level of procurement in the future in the light of future ISO planning policy.

Therefore, we conclude that it is reasonable to subtract a conservative estimate of 588 MW from the ISO's forecasted LCR need because our policy decision entails a certainty that resources will not be procured at this time to

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[92] SDG&E Opening Brief, at 30.

[93] Exhibit ISO-7, at10.

fully avoid the remote possibility of load-shedding in San Diego as a result of the identified N-1-1 contingency.

3.3.6. Category C vs. Category D

Several parties argue that the Category C contingency in San Diego modeled by the ISO is functionally a Category D contingency under WECC reliability standards, using a probabilistic analysis. Sierra Club witness Powers,[94] CEJA witness May and POC witness Peffer presented extensive technical testimony on this point; all claim that the SWPL/Sunrise overlapping N-1-1 contingency is a Category D extreme event for which transmission upgrades are not required under NERC standards.[95] ISO witness Sparks responded that these witnesses seemed to be confusing the overlapping outages of the two lines (loss of one element, system re-adjusted, followed by loss of a second element), with the simultaneous loss of two transmission lines (a Category D contingency).[96]

On cross examination, witness Powers claims the overlapping outage of SWPL and Sunrise is a "functional" Category D because SDG&E could "convert it from a Category C to a Category D" using the WECC process followed by SDG&E in evaluating the performance criteria of the Sunrise route alternatives.[97] However, SDG&E witness Jontry testified that the WECC re-classification process is not available for an N-1-1 contingency.[98] ISO witness Sparks also

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94 Exhibit SC-1 (Powers), at 3; RT at 1931, 1932, 1935.

95 Exhibit SC-1 (Powers), at 2; Exhibit POC-1 (Peffer), at 11; Exhibit CEJA-1 (May), at 30.

96 Exhibit ISO-2 (Sparks), at 11-13.

97 RT 1932. (*See* also Exhibit POC-X-CAISO-3.)

98 RT 1775.

noted that he had never seen the process applied to a Category C3 contingency, and that WECC is moving to eliminating the process altogether.[99]

In relevant past decisions, the Commission has disputed some of the ISO's input assumptions to its modeling (such as megawatts of demand response and incremental uncommitted energy efficiency, and load forecasts). We modify various ISO input assumptions in this decision as well. Yet, the Commission has consistently relied on ISO transmission planning studies which use the ISO's methodology and interpretation of Category C and D contingencies. This is seen in decisions including the 2013 RA decision (D.13-06-024), the Track 1 LTPP decision in this docket (D.13-02-015), and our recent SDG&E procurement-related decision (D.13-03-029). In these decisions we defer to the ISO regarding power flow modeling. For example, D.13-02-015 Findings of Fact 2 states: "It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting. . . ." Similarly, in D.13-03-029, Conclusion of Law 5 states: "The CAISO's modeling assumptions, other than with respect to uncommitted energy efficiency and demand response and incremental CHP, are reasonable." Further, the 2013 RA Decision relies on the ISO's 2014 Local Capacity Requirements Study,[100] which employ the same Category C distinctions that the ISO uses here in Track 4.

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[99] RT 1562.

[100] D.13-06-024, Conclusion of Law 1 states: "The ISO's 2014 Local Capacity Technical Analysis Final Report and Study Results should be approved as the basis for establishing local procurement obligations for 2014 applicable to Commission-jurisdictional LSEs, using the "no SONGS" scenario."

We will use the ISO power flow models as the basis for this decision as well. The ISO power flow modelling was performed consistent with the revised Scoping Memo. The exogenous modifications we make (including assumptions regarding load-shedding) do not affect the modelling directly, but inform our judgment regarding appropriate procurement levels. Changing a Category C contingency to a Category D contingency would directly change the ISO model output. We find that issues regarding whether an ISO-determined Category C contingency should instead be functionally a Category D contingency under WECC reliability standards are more within the expertise of the ISO than the Commission. In any event, we find no credible basis upon which to find that the ISO's analysis is flawed and that the limiting contingency for the SONGS study area is anything but the N-1-1 Category C3 SWPL/Sunrise overlapping outage assumed and modeled by the ISO.

3.3.7. Transmission Solutions

SCE proposes a potential transmission solution to part of the LCR need in the SONGS study area. The Mesa Loop-In project involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 KV and looping the Vincent – Mira Loma 500 kV line and two 230 kV lines into the substation. SCE describes several positive benefits of the Mesa Loop-In: 1) it relieves the loading on the Serrano corridor by delivering power into the LA Basin from the northwest;[101] 2) because of the addition of the new 500 kV substation, the capacity of the transmission grid to import power to the LA Basin would be increased,[102] allowing any new resources to come from outside of the

101 Exhibit SCE-1 (Silsbee), at 36; RT 2160.

102 Exhibit SCE-1, at17; at 36.

LA Basin, where there are fewer impediments to generation development, fostering more competition and reducing procurement costs;[103] 3) the Mesa Loop-In would reduce the amount of gas-fired generation that would need to be sited in the LA Basin by approximately 1,200 MW[104] (734 MW if no load shedding or additional gas-fired generation in the SDG&E territory).

Due to the Mesa Loop-In's characteristics, including the fact that most of the infrastructure changes will take place within the boundaries of the current substations, SCE contends it is reasonably possible the Mesa Loop-In can be constructed by 2020 when significant amounts of OTC generation is expected to retire. We agree with SCE. SCE cautions that this completion schedule will require aggressive scheduling of regulatory agency reviews and minimal public opposition.[105]

The Mesa Loop-In project was submitted to the ISO as part of its 2013-2014 Transmission Planning Process. However, there is no record to determine if the Mesa Loop-In will be approved by the ISO in its TPP. Even if this occurs, it is not possible to know at this time if this project would receive all necessary permits and approvals and be constructed in the timeframe SCE suggests; SCE admits that many significant hurdles would need to be overcome for this to occur. Nevertheless, the Mesa Loop-In proposal is a promising and reasonably likely alternative to other new resources in the LA Basin. While significant uncertainties require that we not adjust the ISO's forecast at this time to assume LCR benefits from the Mesa Loop-In project, it is important to keep in mind that

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103 Exhibit SCE-1, at 36; Exhibit SCE-2, at 4.

104 Exhibit SCE-1, at 36.

105 SCE Opening Brief, at 28.

it may not be necessary to authorize (or if authorized, ultimately approve) funding for various procurement projects if the Mesa Loop-In becomes viable in a timely manner.

AES Southland points out that any reduction of the need for LA Basin generation by the Mesa Loop-In does not reduce overall generation needed to maintain system reliability; rather it just allows the need to be met by resources located over a larger geographic area.[106] For the LA Basin Transmission Scenario, SCE modeled 600 MW of generation outside the LA Basin.[107] Thus, the Mesa Loop-In project may lead to an overall reduced need for 134 to 600 MW, accounting for the 734 to 1,200 MW reduction in LCR in the SONGS service territory, but 600 MW of new generation outside of the SONGS service area. The GHG impacts of the overall impact of the proposed Mesa Loop-In project would be considered in a separate application.

SDG&E examined the addition of two regional transmission projects that could reduce LCR need. The first project SDG&E included is a 500 kV Direct Current (DC) transmission project from Imperial Valley to SONGS.[108] SDG&E's study shows the addition of a DC line would reduce the San Diego generation requirement by 850 MW and would reduce the generation requirement for the LA Basin by 551 MW.[109] The second project is a 500 kV regional transmission project from Devers Substation to a new 230 kV substation in north San Diego

[106] AES Southland Opening Brief, at 7.

[107] Exhibit SCE-1 (Silsbee), at 40.

[108] Exhibit SDG&E-3 (Jontry), at 8-9.

[109] Exhibit SDG&E-3 (Jontry), at 13.

County.[110] SDG&E shows this project would reduce the LCR need for San Diego by 550 MW and reduce the LCR need for the LA Basin by 400 MW.[111] SDG&E witness Jontry noted that both of these projects "may differ slightly [from those submitted to the 2013/2014 Transmission Planning Process], but will be electrically equivalent."[112] SDG&E testified that it submitted two 500 kV options with different routing options from Imperial Valley to North County to the ISO's 2013-2014 Transmission Planning Process.[113] SDG&E witness Anderson testified that "adding major transmission capability in to the load pocket can reduce the need for local generation by approximately 1000 to 1400 MW," but that there was substantial uncertainty as to how quickly those projects could be licensed and built.[114]

There is not enough information available at this time to make a specific finding that any transmission project will be able to reduce the LCR need in the SONGS service territory by 2022. Partially, this is because the ISO's 2013/2014 TPP is not yet final. Beyond this, there are various approval and permit processes – as well as public input – before construction can begin. The construction process can take several years, and is subject to significant delay. We find that there is a reasonable possibility that at least one of the transmission solutions examined by SCE and SDG&E will be operational by 2022. The least

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110 Exhibit SDG&E-3 (Jontry), at 9.

111 Exhibit SDG&E-3 (Jontry), at 13.

112 Exhibit SDG&E-3 (Jontry), at 9.

113 RT 1749.

114 Exhibit SDG&E-1 (Anderson), at 2.

complex of these projects is the Mesa-Loop-In project, which is therefore the most likely to meet this timeframe.

We find based on the record the proposed transmission solutions in the record would most likely lower LCR needs, if completed in the appropriate timeframe. While the LCR effect of such potential transmission solutions has been quantified, we conclude that it is reasonable to consider this potential as a directional indicator rather than a reduction to the LCR needs identified by the ISO. Therefore, potential transmission solutions give us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

TURN points out that it is conceivable that future transmission planning efforts by the two utilities and the ISO will identify additional transmission projects or other measures that can meet local need more cost effectively.[115] We agree; however, this potential is speculative based on the record in this proceeding.

3.3.8. Demand Response

The revised Scoping Memo sets out assumptions for demand response resources for 2018 and 2022. The demand response assumptions are the same for both years, 189 MW of "fast" demand response (potential to be activated in 30 minutes or less after the first contingency) to be modeled as a "First Contingency" resource and 997 MW of demand response which is to be

[115] TURN Opening Brief, at 5.

accounted for as a "Second Contingency Resource."[116] According to the revised Scoping Memo, the studies "shall model 'First Contingency' resources as addressing the first contingency to prepare for the second contingency." Second Contingency resources "are not modeled but would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies." The revised Scoping Memo states an expectation that these demand response programs could become more capable of meeting needs by 2022 while also noting that further action would be needed to make that a reality, and that the study results "shall provide a broad assessment of local area needs that inform the programs of 'second contingency' resources such that they can adapt to meet the residual need."[117]

CEJA argues that the ISO's treatment of 'second contingency' demand response is problematic for two reasons: first, the ISO appears to assume that the character of the demand response programs that exist today are the same as will exist in 2022; second, the Commission recently instituted R.13-09-011 to enhance the role of demand response programs. CEJA notes that R.13-09-011 makes it clear that the Commission does not intend for demand response programs to remain in stasis for the next 9 years.[118] Sierra Club makes similar points.[119]

NRDC argues that all of the model results presented by the ISO and the utilities should be adjusted downward in order to account for the amount of

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[116] Per the revised Scoping Memo, price responsive and day-ahead demand response programs or demand response programs outside the geographic areas of most concern (the west LA Basin and the SDG&E territory) fit the "Second Contingency" category.

[117] Revised Scoping Memo, Attachment A, at 2.

[118] CEJA Opening Brief, at 11.

[119] Sierra Club Opening Brief, at 8-1 l.

demand response that is reasonably expected to occur. NRDC contends that the ISO only used the 'first contingency' resources in its studies, which NRDC contends are only a portion of the demand response input assumptions that the revised Scoping Memo directed it to use in its studies. NRDC maintains that "second contingency" resources identified in the revised Scoping Memo should be counted toward meeting LCR needs.

We disagree with these parties. The revised Scoping Memo specifically indicated that: "'Second Contingency' consists of assumptions representing residual resources that could be used to meet subsequent post-contingency needs. <u>'Second Contingency' resources are not modeled</u> but, would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies (emphasis added)."[120] Consistent with the instructions of the revised Scoping Memo, the 997 MW of 'second contingency' demand response in the ISO modeling was not available to avoid the second contingency, but would be available to respond to the second contingency.

As ISO witness Sparks stated:

> "…our understanding, is the existing (demand response) that doesn't have characteristics that -- at least currently doesn't have characteristics that meet the needs. Not to say that we couldn't find some other (demand response) or modify that (demand response), but at this point in time we didn't want to cause confusion that that (demand response), as it exists today, could meet the need. And so that was not included in the residual calculation."[121]

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120 Revised Scoping Memo at 2.

121 RT 1456.

The ISO's modeling followed the revised Scoping Memo's instructions, which reflected the operating and performance characteristics of 'second contingency' demand response resources. In the ISO's reliability rubric, these resources should not be counted because they cannot be relied upon to activate within 30 minutes after the first contingency. We find that, consistent with the revised Scoping Memo, the ISO properly did not model 'second contingency' demand response resources for determining LCR needs. We will not revisit these demand response assumptions here for the purpose of changes to the ISO study itself, but instead consider whether potential additional demand response should affect authorized procurement amounts.

SCE had already started its analysis prior to the issuance of the revised Scoping Memo. SCE found that, "[o]verall there is about a thousand megawatts of [demand response] assumed in the overall Los Angeles Basin." In the smaller West LA Basin (where the revised Scoping Memo is focused for demand response resources), SCE assumed 620 MW of demand response available as a reasonable estimate and discounted that amount by 50%, because those programs were initially developed to meet system, not local, needs. In addition, SCE augmented this amount by 283 MW of additional demand response in the Johanna/Santiago Substations (also in the west LA Basin), again discounted by 50%. In total, SCE assumed 451 MW of demand response in the Track 4 modeling.[122]

[122] RT 2121 – 2122.

We will not modify the ISO's LCR analysis based on 'second contingency' demand resources. However, the expectation of over hundreds of MWs of 'second contingency' demand response resources identified by the revised Scoping Memo cannot be disregarded. SCE's model assumed that some of this demand response would be available to meet LCR needs. EnerNOC points out that the ISO in some cases does count demand response resources that do not activate in under 30 minutes as counting toward reducing the LCR need.[123] While the ISO contends (consistent with the revised Scoping Memo) such resources would not mitigate the N-1-1 contingency under its rubric, the revised Scoping Memo took a conservative view of the potential of demand response resources in this regard.

There may be a transient design issue with demand response resources at this time. CEJA is correct that we expect demand response programs to evolve and improve. In the future, it is reasonable to expect that some amount of what is now considered 'second contingency' demand response resources can be available to mitigate the first contingency, and therefore meet LCR needs. ISO witness Millar agrees that it is possible that additional demand response resources with more notice would also be able to respond within the time frame expected to meet the N-1-1 contingency within 30 minutes.[124] For example, demand response customers may have provisions which, when they are alerted in advance of a potential need for these resources to activate (such as a very hot weather forecast), require such resources to be activated within 30 minute when called. Further, ISO witness Sparks testified that, in "the current ISO planning

123 EnerNOC Opening Brief, at 15.

124 RT 1692.

process," the ISO is "also working on identifying the necessary characteristics of preferred resources such as demand response such that it can meet local needs."[125]

We do not at this time assume additional demand response resources, beyond those modeled by the ISO, will be available to meet LCR needs. We do find that there is a reasonable likelihood that more demand response resources will be available for such purposes in the future. While we cannot quantify the LCR effect of such potential demand response resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, this gives us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.9. Energy Storage

On October 17, 2013, the Commission issued D.13-10-040, the "Decision Adopting Storage Procurement Framework and Design Program". That decision, in Appendix A, at 1., states that a "guiding principle" for energy storage is: "The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments." D.13-10-040, Appendix A, at 2, sets energy storage targets of 580 MW for SCE and 165 MW for SDG&E. These targets are to be procured gradually through biennial solicitations from 2014 through 2020.[126] Though the utilities may defer up to 80% of their MWs to later procurement periods,[127] they

[125] RT 1553.

[126] D.13-10-040 at Appendix A, at 5, Section 3(a).

[127] D.13-10-040 at Appendix A, at 3, Section 2(c).

must ultimately have 100% of their respective storage targets online no later than December 31, 2024.[128]

The ISO presumes "the Commission will consider energy storage targets identified in" the energy storage decision, but is concerned about "the ultimate amount, location and timing of energy storage actually developed."[129] SCE similarly suggests that some portion of the targeted storage resources will end up in the LA Basin and be available to meet LCR needs, but as SCE witness Nelson testified, the "timing is unknown. It's not clear to me…what the accounting will be for LCR purposes of storage."[130]

SDG&E contends there are many issues related to energy storage procurement that require resolution, including the operational characteristics that energy storage must satisfy in order to be relied upon to meet LCR need. SDG&E witness Anderson noted that "some amount of energy storage – the right kind of energy storage at the right locations – may play a role in meeting some of SDG&E's identified LCR need."[131] He noted that energy storage procurement undertaken in order to meet to targets adopted in the dedicated energy storage proceeding may or may not be procurement capable of meeting LCR need.[132]

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[128] D.13-10-040 at Appendix A, at 1, Section 2(a) ("Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall procure (i.e., pending contract, under contract, or installed) 1,325 MW of energy storage by 2020 with the requirement that the overall procurement goal of 1,325 MWs will be installed and delivering to the grid by no later than the end of 2024….").

[129] ISO Comments, at 3.

[130] RT 1903.

[131] Exhibit SDG&E-2 (Anderson), at 1.

[132] Exhibit SDG&E-2 (Anderson), at 2.

CEJA contends that with storage procurement anticipated by D.13-10-040 complete by 2020 and energy storage deploying relatively quickly,[133] most if not all of the decision's storage targets should be available by 2022. Therefore, CEJA recommends that the Commission include SCE's and SDG&E's energy storage targets to lower LCR needs within the SONGS study area by 612 MW.
Sierra Club similarly would reduce Track 4 procurement by 745 MW to account for energy storage in SDG&E's and SCE's territories by 2020.[134]

In D.13-02-015, we required procurement of 50 MW of energy storage as part of SCE's 1,400-1,800 MW procurement requirement. This procurement level is already included in the ISO, SCE and SDG&E calculations of LCR needs. In D.13-02-015 we indicated that energy storage procurement was an experiment; Finding of Fact 44 in D.13-02-015 stated: "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." The decision also provided ratepayer safeguards: Ordering Paragraph 12 provides, in part, that SCE: "shall present contracts for at least 50 MW of 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."

We agree with SDG&E, SCE and the ISO that the energy storage targets adopted in D.13-10-040 cannot be assumed to count toward LCR need on a megawatt-for-megawatt basis. We confirm the intent of D.13-10-040 to jumpstart the use of energy storage resources in California. We strongly believe energy storage will be useful to meet LCR resources in the future; in general, we expect

133 Exhibit CEJA-1 (May); at 54.

134 Sierra Club Opening Brief, at 11-14.

development of these resources to have an environmentally beneficial impact on energy supply and reliability in California.

D.13-10-040, Ordering Paragraph 3, orders SCE and SDG&E (as well as PG&E) to file applications containing a proposal for procuring energy storage resources by March 1, 2014, with the solicitation to occur no later than December 1, 2014. Ordering Paragraph 4 of that decision requires these utilities to file applications for future biennial energy storage procurement periods in 2016, 2018 and 2020, with any proposed modifications based on data and experiences from previous procurement periods. Much more will be known about procurement of energy storage resources and their impact on reliability as these processes develop.

The incipient nature of energy storage resources, uncertainty about location and effectiveness, and unknowns concerning timing provide insufficient information at this time to assess how and to what extent energy storage resources can reduce LCR needs in the future. At the same time, the targets and requirements of D.13-10-040 lead to a conclusion that energy storage resources will reduce LCR needs in the SONGS service area in the future. While we cannot quantify the LCR effect of potential energy storage resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, this gives us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.10. Energy Efficiency

SDG&E assumed 338 MW of energy efficiency peak reductions on a hot summer peak load basis.[135] Specifically, SDG&E reduced the load in its model by the mid-case forecast for uncommitted energy efficiency amounts adopted in the 2012 LTPP planning assumptions. This reduction is different than the one used by the ISO in its study. The ISO used the low-case uncommitted energy efficiency amount in the 2012 LTPP planning assumptions, per the revised Scoping Memo, which called for 187 MW of energy efficiency peak reductions.[136]

NRDC agrees with SDG&E's methodology, arguing that the Commission should reduce ISO's need estimates by 152 MW (338 minus 187, with rounding) in the San Diego local area because the evidence in this proceeding demonstrates that the revised Scoping Memo mistakenly assumed that SDG&E's local area was different from its service territory area. The revised Scoping Memo directed the ISO to use the "low level of [energy efficiency] savings for use in this set of studies" in SDG&E's local capacity area.[137] Normally, the low estimate would be used to account for the uncertainty of locational impacts of energy efficiency within a utility's service area.[138] As NRDC's witness Martinez testified, "The amount included in the local area should simply be the amount reasonably

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135 Exhibit SDG&E-1 (Anderson), at.10.

136 May 21, 2013 revised Scoping Memo in R.12-03-014, Attachment A, at 4.

137 Scoping Memo, Attachment A at 4.

138 Scoping Memo, Attachment A at 4. "When the service territory of a large utility that has areas both inside and outside a local capacity area is unlikely to have savings spread completely evenly throughout the territory, the CPUC will make a low savings estimate of energy efficiency to account for the possibility that the local capacity area might not get a proportional share of territory-wide savings; a "mid" estimate would reflect the CEC's best estimate across the entire territory. "

expected to occur in SDG&E's service territory, since they are the same geographical area."[139]

We agree with SDG&E and NRDC that the revised Scoping Memo should have used a different methodology with the mid-level energy efficiency estimate. The revised Scoping Memo stated: "across the SCE and SDG&E areas we expect the mid-level of savings to occur."[140] The revised Scoping Memo erroneously decreased energy efficiency estimates by assuming that the SDG&E service territory was not the same as the SDG&E portion of the SONGS service area. This is incorrect: they are one and the same. SDG&E properly applied the mid case estimate of 318 MW in its study.[141] Because we have data from SDG&E showing the LCR difference for the more appropriate mid-level energy efficiency estimate, it is reasonable to adjust the ISO study results by 152 MW.[142]

3.3.11. Solar Photovoltaic (PV)

The revised Scoping Memo designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built. The revised Scoping Memo directs the ISO to determine the most effective busbars where customer-side PV should be located in order to address those contingencies: "[o]nce those locations are

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139 Exhibit NRDC-1 (Martinez), at 11-12.

140 Revised Scoping Memo, Attachment A, at 4.

141 Exhibit SDG&E-1 (Anderson), at 5.

142 We note that this is the one exception we will make to the assumptions in the revised Scoping Memo, as this adjustment is due to an error and the LCR adjustment is clearly available in the record.

identified, the Commission can then direct customer-side generation programs, like the California Solar Initiative or other efforts, to target those locations."[143]

ISO witness Sparks testified: "The incremental small PV is actually a load modifier, it's typically behind the meter; and again, because it's not really known where the locations are, it was not included either. Not to say that it couldn't be used to meet the need if the characteristics are appropriate and it becomes more certain."[144]

CEJA contends that by 2022, with the likely implementation of smart inverters and a smarter grid in general, distributed generation such as customer side PV will provide manageable power located in the affected area that can reduce peak loads, reduce transmission line loss, and provide ancillary services such as reactive power and voltage support.[145]

CEJA may be correct about what will occur in the future; we are confident that our programs and the marketplace will increase the amount of solar PV in the future. However, we have no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs. We are hopeful that solar PV can be useful in reducing LCR needs in the future, but it is too speculative to make any changes to the ISO study results on this basis at this time.

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143 Revised Scoping Memo, at 10.

144 RT 1456.

145 CEJA Opening Brief, at 43.

3.3.12. Living Pilot

SCE describes its plan for an aggressive pursuit of preferred resources through the "Preferred Resource Living Pilot Program" (Living Pilot) in the vicinity of the Johanna and Santiago substations in the LA Basin (these substations are in Orange County, in the west LA portion of the LA Basin). The purpose of the Living Pilot is to aggressively pursue energy efficiency, demand response and distributed generation resources in this high impact area. SCE intends to use the Pilot to demonstrate the value that preferred resources can contribute to meeting LCR needs.[146] SCE anticipates that development of the Pilot will be a collaborative process undertaken with substantial input from the ISO and other stakeholders.[147] SCE is not seeking approval of the Living Pilot in this proceeding; SCE intends to file a future application on this topic.

As the Living Pilot is not before us at this time, we cannot make any determination about its viability or ability to meet LCR needs in the LA Basin.[148] To the extent that new resources are eventually procured through this effort, we will need to look closely to determine how they interact with other

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[146] Exhibit SCE-1, at 52.

[147] Exhibit SCE-1, at 51.

[148] In order to support the implementation of the Living Pilot while still maintaining local reliability should the Living Pilot not achieve its goals, SCE states that it plans to develop gas-fired generation sites near the Johanna and Santiago substations. SCE states that it will work to obtain the necessary sites and associated permits; these sites would only be utilized only if the Pilot is unsuccessful and an LCR need continues to exist. If a contingency arose, SCE would put the sites out to bid to Independent Power Producers (IPP). The successful IPP would be awarded a power purchase agreement to finish the development of the project. SCE is not requesting approval of this plan at this time. SCE plans to file an Application with the Commission which will provide additional information regarding contingency siting. We do not opine about these potential contingent site development plans at this time.

authorizations (e.g., do Living Pilot procurements count toward SCE's LTPP preferred resources requirements?). At the same time, in concept the Living Pilot is promising both as a way to meet LCR needs and as a laboratory for innovation regarding preferred resources. We intend to take a close look at the Living Pilot when SCE files its application. For now, we simply note that projects which may become part of the Living Pilot may have the potential to reduce the need for other resources to meet LCR needs in the LA Basin. [149]

In addition, we strongly encourage SDG&E to pursue its own Living Pilot, or a tailored version of it. When asked by Commissioner Florio whether, if the Commission requested SDG&E could do something similar to SCE's preferred resources RFO or Living Pilot, SDG&E witness Anderson testified: "I'm sure if the Commission asked, we will find a way to do it."[150] SDG&E should consider this decision as the Commission's request.

4. Need Determination

The only party to recommend a local capacity requirement (LCR) need level at or above the amount in the ISO study, without any downward adjustment at this time, is PG&E. PG&E recommends adopting an identified, incremental LCR need of 5,070 MW in southern California. PG&E recommends this adopted incremental LCR need "should not be artificially reduced by assuming that other not-yet-approved generation and transmission projects will come to fruition." PG&E recommends adopting an incremental LCR need for SCE of 3,300 MW of resources, and an incremental LCR need for SDG&E of

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[149] The Commission held a Symposium on the SCE Living Pilot concept on November 6, 2013.

[150] RT 1815-16.

1,770 MW of resources. PG&E would count toward these procurement amounts Commission authorizations for "all incrementally procured resources that have been demonstrated to be effective in meeting the identified incremental LCR need including." These would include (at some point), resources procured by SCE in response to the Track 1 authorization (D.13-02-015) and by SDG&E in response to the D.13-03-029 authorization now approved in D.14-02-016, as well as transmission solutions verified to reduce local reliability needs without building new generation and on track to be completed in the necessary timeframe.[151]

In D.13-02-015, Finding of Fact 7, we addressed concerns about over-procurement and under-procurement: "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." In Finding of Fact 32 in that decision, we stated: "A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement." We continue to be concerned about the potential excess ratepayer costs resulting from over-procurement.

PG&E's recommendations carry a significant risk of over-procurement. PG&E does not adequately take into account the likelihood of various supply or demand considerations which are either very likely or reasonably likely to occur;

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151 PG&E Opening Brief, at 2-3.

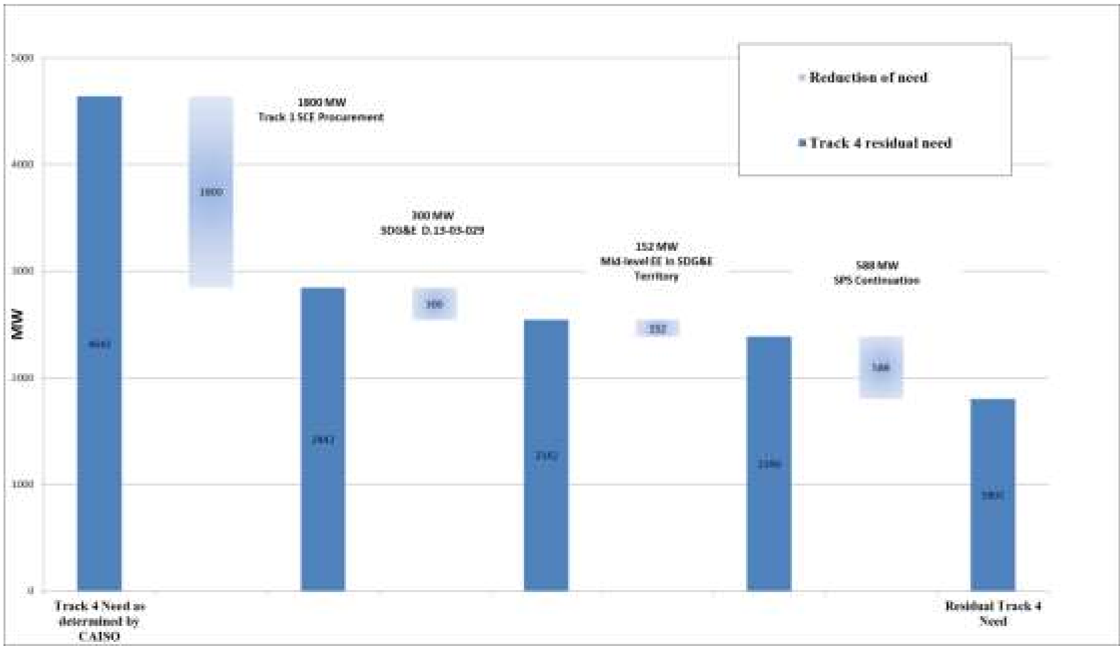
these factor will lower the overall need from the levels modeled by the ISO. PG&E's recommendations also would empower SCE and SDG&E to determine on their own whether further procurement is needed through 2022 in the SONGS service area, beyond amounts authorized in a limited number of Commission decisions. We are not convinced that it is either reasonable or prudent to grant such latitude to the utilities; we note that neither SCE nor SDG&E seek such broad authority. While the procurement objectives of utilities are often aligned with the public interest (e.g., ensuring reliability, consistency with environmental statutes), utilities may also have objectives (e.g., additions to rate base, competitive concerns) that differ from the public interest. Such divergent interests may result in higher ratepayer costs than with more close regulation.

Based upon the foregoing analysis, there is a wide range of possible reasonable and prudent outcomes. We find that the highest reasonable need level must take into account those resources which are very likely to be procured in the time frame between now and 2022. These include the full Track 1 authorizations for SCE (1,800 MW), and the D.13-03-029 and D.14-02-016 authorizations for SDG&E (300 MW). Further, we find that it is reasonable at this time to authorize procurement of at least 588 MW fewer resources than would be necessary to achieve the ISO's current reliability objective, with the understanding that actual load shedding would be a very remote possibility and that the ISO has the authority to continue the current SPS in the San Diego area. We leave open the possibility that additional resources may need to be procured to maintain consistency with ISO transmission policy over the long run, while noting that ISO transmission planning policy may evolve over time. We also find it reasonable to reduce the required LCR procurement level by 152 MW to properly take into account the mid-level energy efficiency forecast in the SDG&E local area.

Taking these very likely or certain modifications into account, the highest prudent level of procurement authorization for the SONGS study area would be 1,802 MW (rounded to 1,800 MW). This calculation is based on the ISO's high starting point of 4,642 MW (based on 80% of resources in the SCE territory), subtracting out SCE Track 1 authorization (1,800 MW), SDG&E's D.13-03-029/D.14-02-016 authorization (300 MW), a potential continued SPS in San Diego (588 MW) and the adjustment for mid-level uncommitted energy efficiency (152 MW). (*See* Chart 1.)[152] Any level above this amount entails too high of a possibility of over procurement. However, it would also be prudent to authorize a lower level of procurement to the extent that other resources that are reasonably likely to be procured are considered, even if their LCR impacts cannot be precisely measured.

[152] Starting from the ISO's lower starting point of 4,500 MW (based on 67% of resources in the SCE territory), the maximum level would be approximately 1,650 MW.

Chart 1
Maximum Procurement Calculation



We have identified a number of resources, at least some of which are reasonably likely to be procured in the SONGS study area by 2022 outside of this procurement proceeding. These include additional transmission (in particular, the Mesa Loop-In), demand response, energy efficiency, solar PV and energy storage resources. In addition, while it is speculative to consider the impacts of resources such as reactive power support, if such resources are available and effective at the right place and in a timely manner, they would have the impact of lowering LCR needs. Further, the future Living Pilot may add additional resources. We find that it is unreasonable to assume that <u>none</u> of these resources will be procured and able to meet local reliability needs in the SONGS service area by 2022. While the exact levels of procurement of these resources via other Commission proceedings, other agency requirements, and various market processes cannot be known with any certainty at this time, assuming that none of these potential resources will be available would not be prudent because it would most likely lead to over-procurement. In our judgment, it is reasonable to assume that at least between 10% and 20% of these resources will be available, in some combination.

Therefore, we find that there is a range of reasonable need levels that we can consider to be prudent.[153] This high end of the range is approximately 1,800 MW; authorization of this level of resources at this time would be the most conservative (but still prudent) action we could reasonably take in terms of reliability – but also the most costly in terms of procurement and most likely the least environmentally sensitive.

It is important to note that the methodology to determine the outer edges of a reasonable procurement range in this decision may not be the only reasonable methodology. In order to test the robustness of our determination that 1,800 MW is the maximum prudent level of procurement that should be authorized at this time, it is useful to consider alternative assumptions. For example, an alternative analysis might determine that we should authorize procurement consistent with the recommendation of the ISO and other parties regarding load-shedding and an SPS (thus not subtracting 588 MW), but at the same time assume that the Mesa Loop-In project would be viable (thus subtracting 734 MW). Or, that we should authorize procurement of 588 MW to fully avoid the N-1-1 contingency, but agree with NRDC that more aggressive

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[153] SDG&E witness Anderson requested flexibility in the utility's request, "We don't know the numbers this precisely. We ought to have some range to be flexible given the size of bids and the size of power plants." (RT 1845.)

energy efficiency assumptions worth up to 733 MW[154] are appropriate. As another possibility, we could have determined that some or all of the 'second contingency' demand response adjustments worth 800 MW should be accounted for.

In determining an alternative maximum prudent procurement amount, determinations should not incorporate more than one potential source to meet or reduce LCR needs into the analysis. In other words, we should consider, for example, whether <u>either</u> not to procure capacity to fully avoid the N-1-1 contingency <u>or</u> whether to assume another resource (or combination of partial achievements of resources) should be counted – but not both. Otherwise, there is too great a likelihood of under-procurement because of the risk that various uncertain or speculative resources will not materialize.

Table 2 shows the upper bound of a reasonable procurement range under different assumptions. Per Chart 1 above, the maximum procurement level is 2,390 MW before the 588 MW adjustment related to load-shedding policy. With various alternative assumptions, the maximum procurement level varies from 1,800 MW (our determination) down to 1,393 MW. Therefore, this sensitivity analysis allows us to confidently conclude that, under either the facts we find today or other reasonable sets of facts, the upper bound of procurement that should be authorized today should in no case be higher than 1,800 MW, and that levels between 1,393 and 1,800 MW could potentially be considered excessive. However, we again note that there is no operational data to determine LCR

[154] NRDC calculates 885 MW of energy efficiency capacity that is not included in the ISO models. However, we subtract for 152 MW of this total in our analysis. The difference is 733 MW.

effectiveness for uncommitted energy efficiency, energy storage, 'second contingency' demand response or total 'second contingency' solar PV. Therefore, a reasonable maximum procurement level should be somewhere between 1,393 and 1,800 MW.

As a check on this methodology, the total of possible resources or assumptions identified by parties included in Table 2 that were not studied by the ISO equals about 4,600 MW. The range of reasonable maximum procurement levels takes into account between 588 and 997 MW of this 4,600 MW, or between 13% and 22% of 4,600 MW. This is very close to our judgment that, in some combination, approximately 10% to 20% of resources will be available, at a minimum. For the purpose of calculating a maximum procurement level, it is reasonable to assume that at least 13% - 22% of the resources or assumptions in Table 2 will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

Table 2
Maximum Procurement Range

Assumed adjustment to 2390 MW Need	**Impact On Need**	**Derived Upper-bound of Procurement Needed**
Temporary Load-shedding	-588 MW	1802 MW
Mesa-Loop in Transmission Project	-734 MW	1656 MW
Uncommitted EE	-733 MW	1657 MW
Energy Storage	-745 MW	1645 MW
Second contingency Solar PV	-800 MW	1590 MW
Second contingency DR	-997 MW	1393 MW

A minimum procurement level must also be defined. Several environmental and ratepayer parties (e.g., NRDC,[155] CEJA,[156] Sierra Club,[157] EDF,[158] CLECA[159])[160] recommend no procurement at this time, based on their analysis that there are likely to be sufficient resources available (and reductions in demand) to obviate any LCR need in the SONGS study area through 2022.[161] We disagree. Our concern in D.13-02-015 included the reliability risks of under-procurement. The analysis in the above sections shows that it is not reasonable to assume that most or all of these resources (or the SCE and potential SDG&E Living Pilots) counted by these parties will be fully procured and in place by 2022, and will meet or reduce LCR needs. For example, even in the unlikely event that all of parties' proposed highest amounts of 800 MW of 'second contingency' demand response resources or 733 MW of remaining 'naturally-occurring' energy efficiency were to exist, the actual LCR impacts are certain to be less than these MW amounts.

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155 NRDC Opening Brief, at 1.

156 CEJA Opening Brief, at vii.

157 Sierra Club Opening Brief, at 2.

158 EDF Opening Brief, at 3.

159 CLECA Opening Brief, at 2.

160 EnerNOC recommends no incremental procurement for SCE at this time, but does not oppose SDG&E's recommendation. EnerNOC Opening Brief, at 13, 14.

161 Other parties, such as CEERT, recommend no procurement authorization at this time for procedural reasons. For example, CEERT argues "The Commission should find that…the current record in Track 4 does not justify any "interim" Track 4 authorization for SCE or SDG&E by January or Q1 2014, especially without consideration of those near-term changes in key assumptions, and, instead, Track 4 should be the subject of a "holistic" final decision that can be issued on a timely basis as early as June or July 2014." (CEERT Opening Brief, at v.)

We have determined that it is reasonable to assume that some combination of these and other (e.g., energy efficiency, energy storage) resources will be available and will mitigate LCR needs, however it is not reasonable to assume this will be true for all (or even most) of these resources. Therefore, while it is mathematically possible to construct an analysis using a series of optimistic assumptions about resource availability that could lead to a finding of zero need (or negative need, which would indicate a surplus through 2022) at this time,[162] we find that a conclusion of zero need is not reasonable. A finding of zero need would not be prudent because it would most likely lead to under-procurement.

At the same time, between all the various resources and assumptions considered in this decision, there are potentially far more than 1,800 MW of additional resources that may be procured and meet or reduce LCR needs by 2022 in the SONGS service area (for example, we have identified 4,600 MW in Table 2). It is not prudent to assume that all of these resources will actually be effective and available at the right places and at the right time. In addition, in most cases we do not have sufficient information in the record to determine the LCR impact of such resources, because no party included these resources in their studies.[163]

A prudent analysis of the minimum procurement levels at this time should take into consideration a higher level of reasonably likely resources than

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[162] For example, Sierra Club calculates a surplus of at least 488 MW. Sierra Club Opening Brief, at 16.

[163] As discussed herein, SDG&E and SCE calculated the LCR impacts of certain transmission projects. However, these projects are not yet approved by the ISO and (even if approved and ultimately constructed), completion dates are uncertain.

included in maximum procurement levels. As a proxy for calculating a minimum LCR need level we can calculate the LCR impact if any two of the most likely potential scenarios (load-shedding, Mesa Loop-In, additional energy efficiency impacts, 'second contingency' demand response, solar PV, energy storage) should occur.[164] This methodology is roughly parallel with the ISO's N-1-1 analysis for LCR needs, which considers the loss of the two largest contingencies, and might be considered an "N+1+1" analysis (although a less rigorous endeavor). It is worth noting that another way of looking at this analysis is that <u>some</u> combination of scenarios could substitute for <u>some</u> LCR reduction from other scenarios. It is not useful or necessary to evaluate all possible scenarios to consider a minimum analysis. Analyzing 100% availability of any two scenarios is a reasonable proxy for the largest amount of available LCR reductions.

Table 3 illustrates a similar methodology as used to consider the reasonable maximum procurement range, starting with a base of 2,390 MW and subtracting for various potential resources not included in the ISO modeling. Table 3 shows that, in each case of 100% availability of any two scenarios not included in the ISO's modeling, the lower bound ranges from 593 to 1,067 MW. Therefore, this analysis allows us to confidently conclude that, under either the facts we find today or a reasonable sensitivity analysis, the lower bound of procurement that should be authorized today should in no case be lower than 593 MW. To be certain that the amounts authorized today will not result in

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164 Assuming for the sake of discussion that, when not studied, a MW decrease in demand equals a MW decrease in LCR needs. In reality, demand reductions are likely to result in less than a one-to-one decrease in LCR needs. This suggests that the minimum procurement level should be higher than calculated in this analysis.

under-procurement, the minimum authorized procurement level should be no less than 593 MW. Authorization of this level of resources at this time would be the most conservative action we could reasonably take in terms of procurement cost and environmental sensitivity – but would be the most risky in terms of reliability.[165]

However, we once again note that there is no data to determine LCR effectiveness for uncommitted energy efficiency, energy storage, 'second contingency' demand response or total 'second contingency' solar PV. Therefore, a reasonable minimum procurement level should be somewhere between 593 and 1,067 MW.

Another way of looking at this methodology is that the total of all possible resources or assumptions identified by parties (and which are included in Table 2) that were not studied by the ISO equals about 4,600 MW. The range of reasonable minimum procurement levels takes into account between 1,322 and 1,797 MW of this 4,600 MW, or between 29% and 39% of 4,600 MW. This is approximately double the minimum level of resources we judge to be available, in some combination. For the purpose of calculating a minimum procurement level, it is reasonable to assume that at least 29% and 39% of these resources or assumptions will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

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[165] There are significant costs involved in any degradation of reliability. The section in this decision on SPS and load-shedding provides a partial discussion of such costs.

Table 3
Minimum Procurement Range

Assumed adjustment to 2390 MW Need	Impact on Needed Procurement	Procurement Still Needed
Load-shedding (588) + Mesa Loop-in (734)	-1322	1068
Load-shedding (588) + Uncommitted EE (733)	-1321	1069
Load-shedding (588) + Energy Storage (745)	-1333	1057
Load-shedding (588) + Second Contingency Solar PV (800)	-1388	1002
Load-shedding (588) + Second Contingency DR (997)	-1585	805
Mesa-Loop In (734) + Uncommitted EE (733)	-1467	923
Mesa-Loop In (734) + Energy Storage (745)	-1479	911
Mesa-Loop In (734) + Second Contingency Solar PV (800)	-1534	856
Mesa-Loop In (734) + Second Contingency DR (997)	-1731	659
Uncommitted EE (733) + Energy Storage (745)	-1478	912
Uncommitted EE (733) + Second Contingency Solar PV (800)	-1533	857
Uncommitted EE (733) + Second Contingency DR (997)	-1730	660
Energy Storage (745) + Second Contingency Solar PV (800)	-1545	845
Energy Storage (745) + Second Contingency DR (997)	-1742	648
Second Contingency Solar PV (800) + Second Contingency DR (997)	-1797	593

We next consider the recommendations of the parties about what amounts should be authorized to fill identified needs, other than PG&E (which recommends above the upper level of prudency) and those parties recommending zero procurement at this time (below the lower level of prudency).

As a starting point, the ISO's August 5, 2013 study yielded a resource need of 612 MW for SDG&E (after consideration of D.13-03-029 authorization of 300 MW) and up to 1,922 MW for SCE, depending on the portion of the LCR study identified need being allocated to the LA Basin and after deducting Track 1 authorization. However, this is not the ISO's recommended procurement level.

SCE and SDG&E each submitted testimony on August 26, 2013 based on power flow studies that reflected transmission upgrades, including reactive power resources, not studied by the ISO. SCE and SDG&E began their studies in advance of the revised Scoping Memo; accordingly, the utilities' assumptions are not identical to those used in the revised Scoping Memo.[166] However, SCE and SDG&E analyzed several scenarios, as shown in Exhibit 1 (the Joint Comparison Exhibit).

Considering all of its scenarios as well as the ISO's forecasts, SCE recommends procurement of 500 MW in the LA Basin. SCE witness Nelson testified that "no new generation is needed to meet NERC Reliability Standards" at this time.[167] We have already determined that it is reasonable to defer procurement of at least 588 MW of additional resources (433 MW in SCE territory) that otherwise would be required to meet N-1-1 requirements and avoid load shedding. Thus, SCE's calculation that no additional procurement is needed at this time in its territory appears consistent with this determination. However, SCE's study assumed that the Mesa Loop-In transmission project would be approved and completed by 2022, thereby reducing LCR needs by 734 – 1,200 MW (depending upon if load shedding is allowed through an extended SPS in the SDG&E territory). We do not make this assumption about the Mesa Loop-In project. Therefore, SCE's recommendation to authorize 500 MW in the LA Basin is consistent with a policy decision to not authorize resources to meet all N-1-1 criteria at this time.

166 Exhibit SDG&E 1 (Anderson), at 2.

167 Exhibit SCE-1 (Nelson), at 6.

SDG&E's technical studies calculate a need for at least 1,028 MW of new local resources between now and 2022 in the San Diego area.[168] SDG&E's minimum base case analysis assumed 408 MW of load reduction/resource additions from incremental preferred resources above current levels (prior to running the transmission models), which effectively reduces minimum local need in the SDG&E sub-area to 620 MW (1,028 MW minus 408 MW).[169] Thus, SDG&E has identified in this Track 4 a minimum need for new local resources in the San Diego sub-area of between 620 MW and 1470 MW by 2022.[170] Of the 620 MW minimum need, SDG&E's procurement strategy holds 70-120 MW open to be filled with demand response and/or energy storage resources (consistent with ISO for operational characteristics that address local reliability needs). For the remaining need, SDG&E requests authority to procure 500-550 MW of long lead-time supply-side resources, including conventional generation and/or renewable resources.[171]

Redondo Beach performed its own technical studies, using power flow analysis. Redondo Beach claims that its studies used the same inputs and assumptions as the ISO. Redondo Beach recommends procurement of 1,140 MW

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168 This analysis assumes Commission approval of SDG&E's A.13-06-015, which seeks authority to enter into a power purchase and tolling agreement with Pio Pico Energy Center for 300 MW of conventional generation.

169 Exhibit SDG&E-1 (Anderson), at 9. The analysis assumes a "dependable" peak reduction of 338 MW of Energy Efficiency, 30 MW of rooftop solar and 20 MW of Combined Heat and Power resources. (*Id.*, at 7, Table 1.) It also assumes 20 MW of dependable peak reduction associated with local renewable generation. (*Id*. at 11, Table 2.)

170 Exhibit SDG&E-3 (Jontry), at 2.

171 SDG&E Opening Brief, at 4.

in the LA Basin and 753 MW in the SDG&E area. For the LA Basin, Redondo Beach recommends all procurement be from preferred resources based on its studies.[172] SCE responds that, while Redondo Beach claims that their proposal is the only solution that addresses both the Western LA Basin sub-area as well as the greater SONGS area, the record shows that Redondo Beach only studied the Western LA Basin and did not perform a study to analyze the impacts on the greater SONGS study area.[173] We do not agree with SCE that Redondo Beach's study is incomplete in this regard. However, significant parts of Redondo Beach's studies rely on interpretations of N-1-1 contingencies that are at odds with the ISO's studies; we have already determined that we will defer to the ISO on this point. While we consider Redondo Beach's recommendations along with those of other parties, we will rely on the ISO study (as modified herein) as the better analytical tool.

The ISO now recommends approval of the recommendations of SCE and SDG&E:

> "Given the importance of maintaining reliability in this heavily populated, urban area of California, and the complex array of actions necessary to meet the residual needs identified by the [ISO], it is urgent for the Commission to authorize an all-source procurement for SCE and SDG&E for the amounts requested. This is much different, of course, than authorizing a comprehensive amount of procurement meant to address all the residual needs, which we advised against in Mr. Sparks' initial testimony."[174]

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[172] Redondo Beach Opening Brief, at 1-4.

[173] SCE Reply Brief, at 47.

[174] Exhibit ISO-7, at 6.

In Opening Briefs, the ISO, TURN, CalWEA, Alton, CESA, WPTF, and Wellhead all support SCE's request for procurement authorization for an additional 500 MW in this Track 4.[175] In a change from its position in testimony (as reflected in Exhibit 1), ORA now recommends[176] that the Commission authorize procurement of between 1,315 and 1,450 MW, with 700 MW in SCE service territory and between 615 and 750 MW in SDG&E service territory.[177] TURN recommends that SCE and SDG&E each be authorized to procure up to 500 MW, plus or minus ten percent within their respective service territories to accommodate the potential "lumpiness" of transmission or generation investments (thus TURN's recommendation is for procurement authorization for 450 – 550 MW for each utility, or 900 – 1,100 MW in total). IEP recommends that the Commission should authorize an interim procurement of at least 706 MW for SCE and 820 MW for SDG&E.[178] CalWEA recommends procurement of 500 MW for SCE and 300 - 350 MW for SDG&E.[179] AES Southland recommends that the Commission authorize SCE to procure an additional 1,440 MW of generation,

[175] ISO Opening Brief, at 33-34, TURN Opening Brief, at 1-2, CalWEA Opening Brief, at 1-2, Alton Opening Brief, at 3, WPTF Opening Brief, at 2, Wellhead Opening Brief, at 1-2.

[176] In its Opening Brief at 11, ORA also recommends that the Commission consider the ISO's 2013/2014 Transmission Planning Process in determining need for the SONGS study area.

[177] ORA Opening Brief, at 13-14.

[178] Exhibit IEP-1 (Monson), at 30.

[179] CalWEA Opening Brief, at 5.

based upon SCE's own need calculation, absent load shed, less the Track 1 procurement already authorized.[180]

Each of these parties' recommendations stem from modestly different methodologies, although each have in common certain subtractions from a total LCR need for procurement already authorized and calculations of expected resources. While varying in some aspects, each of these parties' recommendations fall within the prudent range of procurement we have identified for the SONGS service area: a number significantly greater than zero and less than 1,800 MW. The lowest recommendation of these parties is 800 MW for the SONGS service area, the highest is over 1,400 MW.

Similar to the Track 1 decision in this docket, we will authorize a procurement range. Authorizing a procurement range takes into account a) uncertainties about supply and demand conditions; b) the ability to process new information during the procurement process; c) the need to provide the utilities with flexibility to procure resources which may only be available in large increments; d) increases in requirements to procure preferred resources (as discussed below); and e) the need to provide utilities and the Commission with the ability to protect ratepayers by not forcing certain less economic procurement decisions.

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180 AES Southland Opening Brief, at 5.

We have determined that the outer edges of a reasonable procurement range to be 593 MW to 1,800 MW, but that minimum procurement could be up to 1,067 MW and maximum procurement could be as low as 1,383 MW. The overall procurement level we authorize for the SONGS service area at this time is 1,000 - 1,500 MW. This range is consistent with the recommendations of many parties and is near the center of the overall zone of reasonableness. This range provides greater ratepayer protection against over procurement and simultaneously reduces the likelihood of any reliability impacts from under procurement.[181] These authorized amounts are not the full amounts needed to meet the LCR needs; a significant amount of future procurement in the SONGS service territory will come from the various resources analyzed herein. Further, there may be a need to authorize further procurement in future LTPP proceedings in the event of changes in supply and demand forecasts, to meet ISO reliability criteria, or if circumstances change significantly.

We accept the ISO's analysis that between 67% and 80% of procurement needed to address LCR needs in the SONGS service area by 2022 must be in the LA Basin, which is in SCE territory. The remainder would be in the SDG&E service territory. It is not possible at this time to discern how resources between the 1,000 – 1,500 MW amounts authorized today, and the approximately 4,500 – 4,600 MW level of total procurement need identified by the ISO, ultimately will be distributed between SCE and SDG&E territories. We already have determined that 1,800 MW will be procured from Track 1 by SCE, and 300 MW from D.13-03-029 for SDG&E; thus, over 85% of these authorized resources are

[181] Environmental considerations of procurement levels are addressed in Section 5 of this decision, where we determine the mix of resources to be procured.

already slated for SCE territory. Other opportunities are less clear. For example, it is possible the Mesa Loop-In project goes forward, but the SDG&E proposed transmission projects do not. In that case, at least several hundred MW more resources would be in SCE territory, necessitating a greater procurement requirement for SDG&E to retain a proper allocation. Because of several unknowns, authorized amounts today may need to be adjusted in the future to balance procurement between utility territories.

We authorize SCE to procure between 500 and 700 MW. We authorize SDG&E to procure between 500 and 800 MW. The greater maximum amount for SDG&E reflects several factors. First, SDG&E's recommendations include assumptions for transmission lines which we do not accept as reasonably likely (unlike the Mesa Loop-In for SCE). Second, even with its transmission assumptions, SDG&E's studies show a need for at least 1,028 MW in its territory by 2022. After assuming the Pio Pico plant, SDG&E shows a need for at least 728 W in its territory. Third, as discussed below, we will require SDG&E to procure more preferred resources than the 120 MW it contends are achievable (on top of 408 MW of preferred resources SDG&E expects to procure through other proceedings). In light of all of these factors, it is appropriate and prudent to allow SDG&E to procure up to 800 MW at this time to avoid under-procurement.

Given that the bulk of both total authorized and potential resources are expected to be in SCE territory, authorizing the same procurement range for both utilities should be consistent with the ISO's range that 67 - 80% total procurement needs to be in the SCE territory. In both cases, the high end of the range is above what the utilities requested, but within the range of prudent procurement established in this order. For both utilities, these authorized amounts are subject to conditions established herein.

We note that there are also additional safeguards to ensure that under procurement does not occur, beyond the various expectations for resource procurement discussed herein, and future LTPP proceedings. For example, ORA recommends that, notwithstanding California's commitment to meeting OTC compliance deadliness, the Commission should consider that limited extensions to OTC compliance deadlines of the most electrically effective OTC plant(s) may be available if needed to bridge a short-term gap between when resources are needed, and when they are available.[182]

In D.13-02-015, Finding of Fact 10 stated: "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."[183] We do not revisit this Finding. At the same time, we agree with ORA's observation that it may be possible to extend OTC deadlines if it is necessary to ensure reliability. Any such action will occur through the appropriate process.

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182 ORA Opening Brief, at 27.

183 The reference to SONGS in this Finding of Fact was intended to reference SONGS as an OTC plant. In other words, there was no Finding of Fact about whether SONGS would remain in service, retire, or repower in any given timeframe.

5. Filling the Identified Need

5.1. Requirement for Procurement of Preferred Resources

At the time of the Track 1 decision in this proceeding, the permanent closure of SONGS was not anticipated or factored into the modeling considered in that track. As a nuclear power facility, SONGS has been subject to various safety and environmental concerns over the years, but SONGS did not emit any greenhouse gases during its time in service. To replace a zero emission facility like SONGS with other resources, several parties argue it is necessary to mandate only low-to-no emitting resources as a source of replacement capacity. NRDC, Sierra Club, CEJA, and EDF all urge that any procurement authorized by the Commission should include preferred resources only.[184]

Other parties point out that the complexities of maintaining reliability on the local grid require a sophisticated set of characteristics, which cannot always be met with preferred resources. A number of parties therefore recommend requiring procurement of preferred resources to the greatest extent possible, but providing the utilities with the opportunity and obligation to procure a mix of resources that balances fealty to the Loading Order with meeting grid requirements. For example, CEERT recommends that, consistent with the Loading Order and procurement proportions established in D.13-02-015, no more than 2/3 of the authorized maximum procurement levels should be met by conventional gas-fired resources; the remainder should be preferred resources.[185] Another group of parties – including SCE and SDG&E - recommend allowing the

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[184] NRDC Opening Brief, at 18-19; Sierra Club Opening Brief, at 1-3; CEJA Opening Brief, at vii; and EDF Opening Brief, at 7-8.

[185] CEERT Opening Brief, at 47-48.

utilities to use all-source RFOs to procure authorized resources on a least-cost/best-fit basis, thereby providing the utilities with the ability to choose the resource mix (subject to subsequent Commission approval).

The ISO endorses the idea that substantial portions of the local capacity needs created by the SONGS outage can be filled with preferred resources, with two caveats:

First, the Commission and parties must be diligent in moving ahead to develop the necessary programs that can participate with other supply-side resources (such as demand response) and that will provide load-shaping demand-side benefits (such as energy efficiency and small PV) with the necessary locational data that the ISO can use in its local area capacity studies to offset the need for conventional infrastructure.

> Secondly…the Commission must be diligent and expeditious in tracking the development of preferred resources in order to verify that they are actually materializing in the locations and amounts predicted in the studies and resource procurement efforts that established such forecasts.[186]

NRG points out that local generation must provide a suite of reliability benefits, such as: a) allowing for the regular maintenance of other generation or transmission within the local area; b) continuously following variations in demand or variable renewable generation; c) providing contingency reserve to respond to sudden changes in demand or the loss of a generating or transmission resource; d) maintaining transmission voltages within acceptable levels by producing or absorbing reactive power as needed; e) providing or standing by ready to provide real power output to maintain network flows within safe limits.

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[186] ISO Reply Brief, at 24.

Thus, NRG contends that relying on preferred resources to meet local area requirements and still provide the same level of reliability requires a complex analyses; most LCR needs are currently met by gas-fired resources.[187]

SDG&E also argues against mandating the use of all or nearly all preferred resources in this decision:

> While SDG&E strongly supports inclusion of preferred resources in its portfolio to serve bundled load…it does not perceive that a capacity procurement approach heavily skewed toward reliance on preferred resources is reasonable at this time, while there is still great uncertainty as to the ability of preferred resources to meet local capacity need. In short, placing all of SDG&E's eggs in the single basket of preferred resources is an imprudent planning approach which exposes ratepayers to unreasonable risk.[188]

Some parties contend that SCE and SDG&E should procure only preferred resources and energy storage because these resources can be developed significantly quicker than traditional gas-fired generation. SCE rebuts that it takes about seven years to develop gas-fired generation facilities in the LA Basin and it is now approximately seven years until new LCR resources are needed in 2020. SCE contends that

> "if the Commission authorizes preferred resource procurement only at this time, it is likely precluding gas-fired generation development to meet LCR need in 2020. If this occurs, then gas-fired generation will not even be an option to meet LCR need in 2020 (if it is needed) because it will not be able to be developed quickly enough. Choosing preferred resource procurement only, without any expedited approval of contingent site development and/or options PPAs, would

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[187] NRG Opening Brief, at 7 -8.

[188] SDG&E Reply Brief, at 10.

> likely reduce grid reliability in 2020. This is because the options to replace all OTC generating facilities, including SONGS, would be very limited."[189]

In D.13-02-015, Finding of Fact 30 stated: "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." There is nothing in the record of Track 4 of this proceeding that would require a change to this Finding. While we strongly intend to continue pursuing preferred resources to the greatest extent possible, we must always ensure that grid operations are not potentially compromised by excessive reliance on intermittent resources and resources with uncertain ability to meet LCR needs.

In the Commission's RA proceeding (R.11-10-023), we are currently exploring the ability of various preferred resources and energy storage to meet LCR needs.[190] The ISO is engaged in this effort as well. As this highly technical process develops, we will have a better idea of how such resources can be integrated with gas-fired resources to ensure reliability. In addition, we will learn more about the extent to which non-gas-fired resources can be used instead of gas-fired resources to meet LCR needs. Until this effort is better developed, we will take a prudent approach to reliability, while still promoting preferred resources to the greatest extent feasible. The prudent approach we take entails a

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[189] SCE Reply Brief, at 8.

[190] In the August 2, 2013 Phase 3 Scoping Memo for R.11-10-023 (RA proceeding), the scope of the proceeding includes: "In workshops and comments, stakeholders will develop counting rules, eligibility criteria, and must-offer obligation for use-limited resources, preferred resources, combined cycle gas turbines, and energy storage resources for Commission consideration."

gradual increase in the level of preferred resources and energy storage into the resource mix, to historically high levels.

In the Track 1 decision, Ordering Paragraph 1 included the following requirements for SCE for its authorization to procure 1,400 to 1,800 MW:

a. At least 1,000 MW, but no more than 1,200 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 1,800 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.

We will build upon the Track 1 approach in this decision. As discussed below, we authorize SCE to procure resources for both Track 1 and Track 4 pursuant to its Track 1 procurement plan as approved by Energy Division. This generally entails procurement of additional resources through SCE's already-issued RFO as well as bilateral contracts.[191] Combining Track 1 and Track 4, SCE is now authorized to procure up to 2,500 MW in the LA Basin. SCE proposes to add its additional requirement from Track 4 without any specification of resource type. However, this approach is not consistent with our stated goals here and in Track 1 to adhere to the Loading Order.

Under the terms of the Track 1 decision, if SCE procured the minimum 1,400 MW of total resources, between 200 and 400 MW (or 14% to 29%) would be from preferred resources or energy storage. If SCE procured the maximum 1,800 MW of total resources per that decision, between 600 and 800 MW (33% to 44%) would be from preferred resources or energy storage.

In this decision, we authorize SCE to procure between 1900 MW (the 1,400 minimum from Track 1 plus the 500 minimum from Track 4) and 2,500 MW (the 1,800 maximum from Track 1 plus the 700 maximum from Track 4). Under SCE's approach, SCE could procure as much as 1,700 MW from gas-fired generation: 1,200 MW per Ordering Paragraph 1a in D.13-02-015 plus 500 MW from this decision. If SCE procured the overall minimum amount, between 200 and 900 MW of the 1,900 MW minimum procurement authorization (11%to 47%) would be from preferred resources or energy storage. If SCE procured the

[191] In addition, Ordering Paragraph 9 of D.13-02-015 states: "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."

overall maximum amount, between 600 and 1,500 MW of the 2,500 MW minimum procurement authorization (24%to 67%) would be from preferred resources or energy storage.

SCE's proposal would expand the range of potential procurement of preferred resources and energy storage. On the other hand, SCE could procure up to 89% of authorized resources from gas-fired generation. It is not clear what would actually occur; under its proposal, SCE would control the procurement process consistent with its Track 1 procurement plan. Assuming SCE pursues a least-cost/best-fit approach to the increased discretionary portion of procurement authority[192] (the additional 500 – 700 MW), it is likely that SCE would procure mostly gas-fired resources if such resources are less costly than preferred resources. From a ratepayer perspective, this may be beneficial; however, the Loading Order calls for prioritization of cost-effective preferred resources, in some cases even if they are more expensive than other resources.

We will modify SCE's proposal to ensure that SCE procures a higher percentage of authorized resources from preferred resources and energy storage. For SCE (and SDG&E as delineated below), we will not require any specific incremental procurement from gas-fired resources. This means that all incremental procurement as a result of this decision may be from preferred resources. At the same time, we will not modify the requirements from D.13-02-015 that some procurement must be from gas-fired resources in order to ensure reliability. Further, to provide a level of flexibility to utilities and to

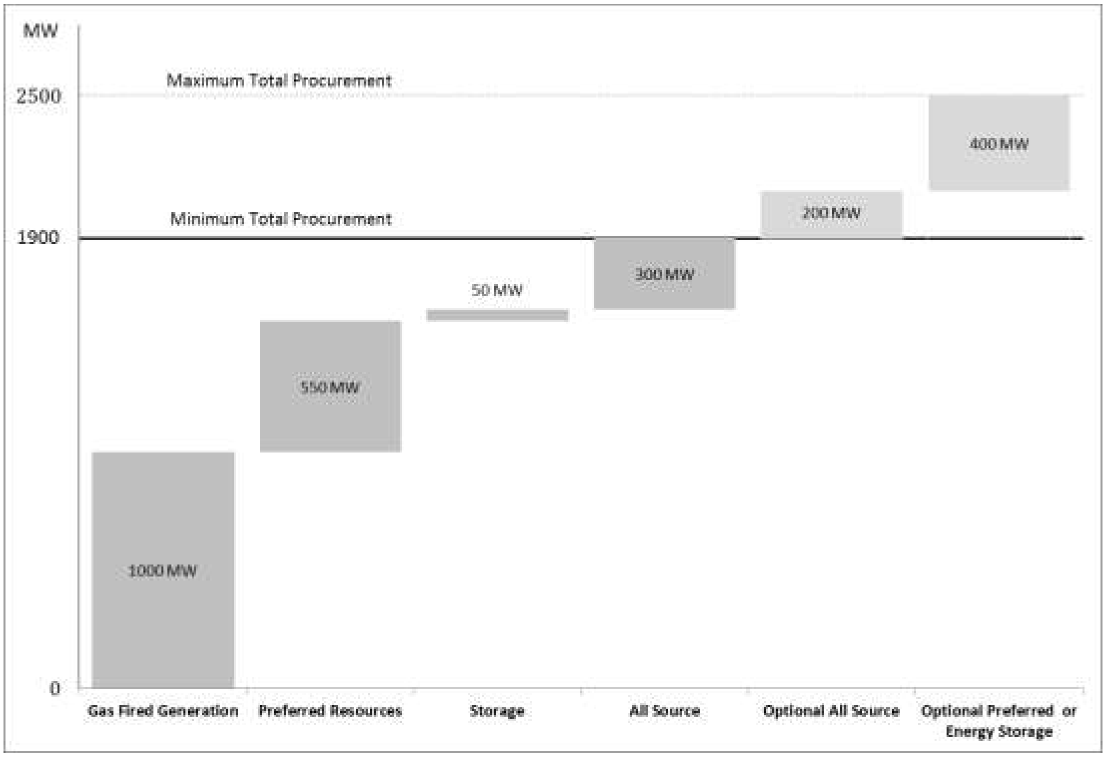
[192] SCE Reply Brief, at 9 ("SCE will use least-cost/best-fit criterion to 'obtain a cost-effective mix of resources to meet SCE's LCR needs in a manner consistent with the Preferred Loading Order.'"). Also *see* Exhibit SCE-2, at 22.

ensure procurement consistent with ISO reliability standards, we will expand the range for both gas-fired resources and preferred resources (as well as energy storage).

SCE is authorized to procure resources as follows, as shown in Chart 2:

a. At least 1,000 MW, but no more than 1,500 MW, of local capacity must be from conventional gas-fired resources, including combined heat and power resources;
b. At least 50 MW of local capacity must be procured from energy storage resources (as defined in D.13-10-040);
c. At least 550 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subsection b of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded.
d. At least 300 MW, but no more than 500 MW, of local capacity, beyond the minimum amounts specified in subparagraphs (a), (b) and (c), must be procured and can be from any resource able to meet local capacity requirements.
e. Subject to the overall cap of 2,500 MW, any additional local capacity, beyond the amounts specified in subparagraphs (a), (b), (c) and (d), may only be procured through preferred resources (including bulk energy storage and large pumped hydro facilities) consistent with the Loading Order of the Energy Action Plan. Such preferred resources shall be in addition to preferred resources already required by the Commission to be procured or obtained through decisions in other relevant proceedings, and/or energy storage resources.

Chart 2
SCE Authorized Procurement
Track 1 + Track 4



This method ensures that at least 400 MW of the additional procurement authorized by this decision will be obtained through preferred resources or energy storage. In total, SCE is now authorized to procure between 400 and 1,500 MW from preferred resources or energy storage, up from 200 to 800 MW in the Track 1 decision. If SCE procures the minimum 1,900 MW of total resources, between 21% and 47% will be from preferred resources or energy storage. If SCE procures the maximum 2,500 MW of total resources, between 40% and 60% will be from preferred resources or energy storage.

SDG&E seeks to issue an all-source RFO or to contract bilaterally. SDG&E contends that moving forward on an expedited basis with a bilateral contract to address a portion of LCR need would support the policy goals of the State related to timely retirement of OTC facilities and would promote system reliability – the sooner new local resources are added to the portfolio, the lower the reliability risk.[193] SDG&E expects that 50 to 120 MW will be procured from preferred resources and energy storage.

There are no requirements from D.13-03-027 for specific resource procurement amounts to meet SDG&E's LCR needs; however, SDG&E now has been approved to fill the authorized 300 MW from the gas-fired Pio Pico project. We will take a similar approach for SDG&E as for SCE. We approve SDG&E's proposal to issue an all-source RFO or enter into bilateral contracts for the additional 500 – 800 MW authorized herein. SDG&E proposes that it procure preferred resources through specific proceedings dedicated to these resources. We agree that SDG&E should continue to follow the Commission's requirements in other dockets; SDG&E already anticipates 407 MW will be procured in this manner. However, as with SCE, it is our intent that SDG&E should also pursue significant percentages of procurement to replace SONGS through preferred resources, energy storage and consistency with the Loading Order. Therefore, SDG&E shall ensure than no less than 200 MW of procurement authorized by this decision is from preferred resources or energy storage. This amount is higher than the 120 MW of preferred resources SDG&E recommends in this proceeding. We believe the record shows that SDG&E's recommendations are conservative. To the extent that SDG&E seeks to procure incremental preferred resources and energy storage (beyond those already expected to be procured elsewhere) through other procedural vehicles authorized by the Commission, it

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193 SDG&E September 30, 2013 Comments, at 5-6.

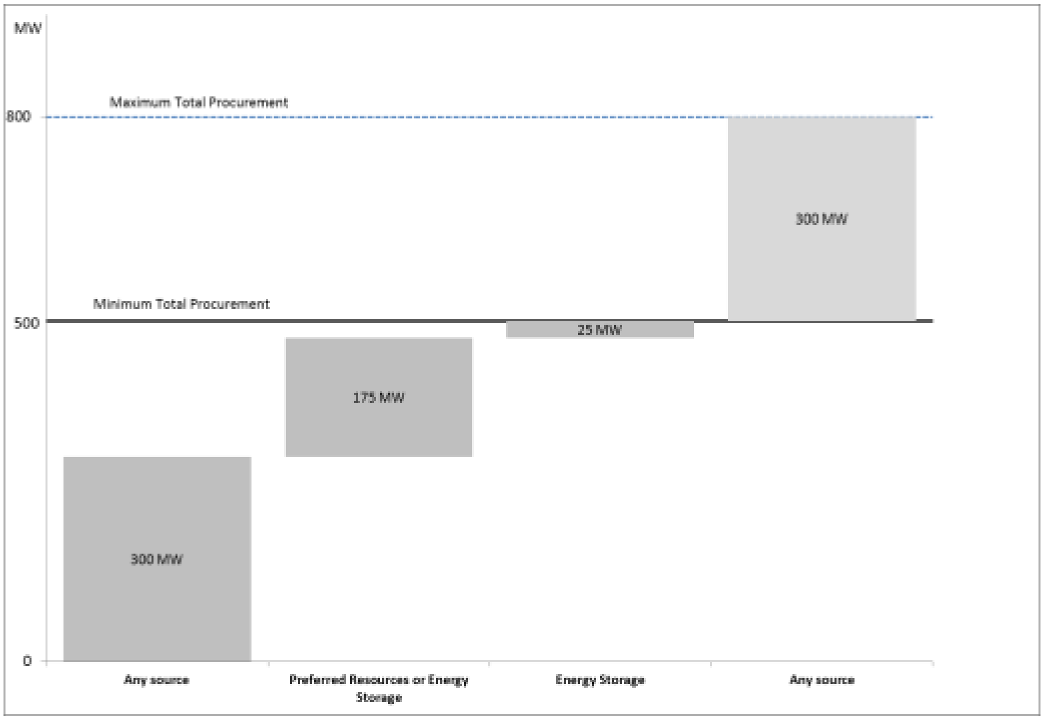
must delineated this process in its procurement plan (discussed below). To summarize, as shown in Chart 3:

a. At least 25 MW of capacity must be procured from energy storage resources;

b. At least 175 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;

c. Subject to the overall cap of 800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (b) and (c) above, may be procured through any set of resources appropriate to meet LCR needs in the SDG&E territory, consistent to extent feasible with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtained by the Commission through decisions in other relevant proceedings).

Chart 3
SDG&E Procurement Authorization



Thus SDG&E may procure from 25%to 100% of additional resources authorized by this decision from preferred resources or energy storage. We provide this wider range of possibilities for SDG&E, as compared to SCE, because SDG&E is already approved to procure about 300 MW from gas-fired generation (Pio Pico). Now that the Pio Pico application is approved, SDG&E's total procurement for LCR purposes will be from 800 to 1,100 MW; thus SDG&E will be authorized to procure from 22%to 79% of additional resources from preferred resources or energy storage, a range reasonably similar to the 21% to 60% range for SCE discussed above.

5.2. Energy Storage

CalWEA contends that requiring SCE and SDG&E to fulfill their storage targets in the process of meeting Southern California's local reliability needs will lower the total cost of meeting both goals, given that the utilities are required to fulfill the storage targets within the 2020-2024 timeframe regardless of viability or cost-effectiveness.[194] SDG&E recommends that all energy storage be procured via the process contemplated in D.13-10-040 and LCR need reduced only to the extent energy storage is shown to meet local need.[195]

D.13-10-040 in section 4.5.3 states:

> "The procurement targets and the schedule for solicitations proposed here are not presently tied to need determinations within the LTPP proceeding. Instead, in the near term, we view the Storage Framework adopted herein as moving in parallel with the ongoing LTPP evaluations of need – system and local, and with the new consideration of the outage at SONGS. In the longer term, we expect that any procurement of energy storage will be increasingly tied to need determinations within the LTPP proceeding."

We do not modify the energy storage procurement targets established in D.13-10-040. It is too early to know if such targets are too high, too low or just right. More information will become available after the first utility solicitations; per D.13-10-040, Ordering Paragraph 3, applications containing a proposal for procuring energy storage resources are due by March 1, 2014, with the solicitation to occur no later than December 1, 2014. Nor will we modify the 50 MW energy storage requirement for SCE in D.13-02-015. That requirement

194 CalWEA Opening Brief, at 7.

195 SDG&E Opening Brief, at 22.

will remain a part of the 1,900 – 2,500 MW combined authorization for Track 1 and 4 of this proceeding. Per D.13-10-040, this will partially meet the energy storage target for SCE. For SDG&E, we will establish a smaller 25 MW energy storage procurement requirement, which will partially meet the lower D.13-10-040 target for SDG&E. Similar to SCE, this new energy storage requirement for SDG&E shall be separate from the preferred resources requirements.

For both SCE and SDG&E, the set energy storage procurement requirements in this decision are minimum, not maximum, levels. Both utilities may also procure energy storage as part of their preferred resources requirements or all-source authorizations, subject to any other conditions in this decision.

5.3. Large Scale Pumped Storage (Bulk Storage) Procurement

D.13-10-040 at 30,34 excluded large-scale (50 MWs or more) pumped storage projects from the energy storage targets, reasoning that "the sheer size of pumped storage projects would dwarf other smaller, emerging technologies; and as such, would inhibit the fulfillment of market transformation goals." The decision at 35 further found that applicable statute indicated a legislative intent "to encourage a broad range of energy storage technologies" and, "to achieve this," placed "a limit on the size of pumped hydro storage systems eligible to participate in the particular mechanisms outlined in this decision." D.13-10-040 at 33 identified this LTPP Track 4 proceeding as the venue for providing a procurement mechanism for large-scale pumped or bulk storage, especially since that technology would have particular application in terms of addressing "local reliability impacts of a potential long-term outage at the SONGS." D.13-10-040 also states: "We strongly encourage the utilities to explore opportunities to partner with developers to install large-scale pumped storage projects where they make sense within the other general procurement efforts underway in the context of the LTPP proceeding or elsewhere."

According to ISO witness Sparks, if "it has the right characteristics," there is no basis to exclude "bulk storage" from being procured by SCE or SDG&E to meet a local capacity requirement in the absence of SONGS.[196] In addition, ISO witness Millar testified that "pump storage can be a very effective mitigation in meeting local needs, whether it's characterized as a preferred resource or not."[197] SCE witness Nelson testified that pumped storage "technology is fairly well understood" and "that there are some significant advances in controls and variable speed pumps that could add additional value to the grid."[198] While witness Nelson was uncertain about the "effectiveness" of "any large pumped hydro storage" in meeting the "West LA Basin LCR," he did believe it could be "bid in" for Track 1 and would contribute to the "balanced approach" of using "all resources" to avoid "the possibility of failure and being overly reliant on anyone."[199]

CEERT contends that large-scale (50 MW or more) pumped storage must be part of any procurement or RFO authorized by this Commission in this decision.[200] CEERT witness Caldwell testified: "[T]here are multiple pumped storage facilities under consideration in Northern San Diego County that could easily provide for LCR need found in Track 4, plus provide other significant grid

[196] RT 1544.

[197] RT 1655.

[198] RT 1917.

[199] RT 1916-1917.

[200] CEERT Opening Brief, at 51.

benefits."[201] ORA agrees that the Commission should ensure that SDG&E and SCE extend bid eligibility to include large scale pumped storage projects.[202] Eagle Crest recommends that nothing in this decision should preclude or restrict opportunities for the utilities to procure bulk energy storage, especially large pumped hydro facilities.[203]

As discussed herein, we require SCE and SDG&E to procure MW ranges of certain types of resources. Each utility should solicit all resources as required by this decision, and may propose for approval any set of resources which can meet the LCR need in its portion of the SONGS service area consistent with the authorized resource ranges herein. Within the categories that include preferred resources, bulk energy storage and large pumped hydro facilities should not be excluded. We have also set aside specific procurement amounts for energy storage. Within the energy storage category, we will limit procurement to the types of energy storage anticipated by D.13-10-040.

5.4. Contingency (Options) Contracts

In its testimony, SCE discussed a conceptual plan to potentially backstop SCE's procurement approach with contingent GFG contracts. The contingent GFG contracts (also known as options contracts) would require the seller to begin the process of developing a power plant, including the necessary pre-development work to site, permit, and construct a specified GFG resource.[204] SCE asserts this pre-development work will reduce development time, if

201 Exhibit CEERT-1 (Caldwell), at II-3.

202 ORA Reply Brief, at 4.

203 Eagle Crest Opening Brief, at 6.

204 Exhibit SCE-1, at 58; RT 1960.

triggered, by two years. However, the entities would not begin actual construction of the power plant without SCE authorization. The contingent contract would contain a buyer's right to terminate the contract, and "SCE would only proceed with completing commercial operation of the contingent contract for GFG if a demonstrated need existed, and after receiving Commission approval to do so."[205]

SCE identifies several reasons for which a need to backstop SCE's procurement may arise: "(1) failure to successfully develop GFG procured in SCE's Track 1 LCR procurement process; (2) inability to develop sufficient Preferred Resources to meet SCE's Track 1 LCR procurement authorization; (3) planned local area grid enhancements are not completed; and (4) planning assumptions on the availability and effectiveness of resources do not materialize."[206] If a need did arise, SCE contends the contingent contracts would reduce the lead-time for developing GFG, thus improving grid reliability in the LA Basin and ensuring preservation of the OTC regulatory compliance dates.

SCE is not requesting approval of this plan in Track 4. Instead, SCE intends to submit any proposed contingent GFG contracts to the Commission for approval, if SCE determines they are cost effective and beneficial, in the third quarter of 2014.[207]

IEP argues that the concept of contingent development contracts could be a practical and cost-effective way to insure against future reliability problems while buying time to see how uncertainties about demand and supply are

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205 Exhibit SCE-1, at 59; RT 1960.

206 Exhibit SCE-1, at 58.

207 RT 1962, 1966, 1982, 1983.

resolved.[208] Vote Solar recognizes there may be some value in SCE's request for permission to enter into gas-fired generation contingency contracts as backup for resources authorized in Tracks 1 and 4. Vote Solar contends SCE's proposal to sign PPAs with gas-fired generation developers that contain opt-out clauses appear to be more reasonable and simpler to implement than the utilities' contingent site preparation proposals, provided the option payment is not exorbitant.[209]

ORA witness Rogers testified that SCE's options contract proposal is an "approach would expose ratepayers to costly termination payments in the event the contracts prove unnecessary."[210] CEERT similarly contends that SCE's proposal is problematic.[211] Alton Energy argues for rejection of SCE's proposal as an inappropriate use of ratepayer funds, and argues it would distract SCE from their other initiatives such as the Living Pilot and Mesa Loop-In.[212]

WPTF does not oppose the SCE proposal, subject to certain caveats. WPTF opposes the concept of using bilateral negotiations for securing the option contracts proposed by SCE, arguing that bilateral negotiations do not ensure that the least cost option will be identified and selected. Further, WPTF argues that such contracts allows utility to pick "winners and losers" on criteria other than least cost.[213] WPTF advocates that the Commission should make it clear that in

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208 IEP Opening Brief, at 34.

209 Vote Solar Comments, at 13.

210 Exhibit ORA-5 (Rogers), at 3, 11.

211 CEERT Opening Brief, at 41.

212 Alton Energy Opening Brief, at 3.

213 WPTF Opening Brief, at 4.

option contracts contingency proposals, SCE should allow existing generators, including OTC unit owners, to offer their sites for redevelopment.[214]

We need not make a determination on the merits of SCE's contingency contract proposal here, as SCE is not seeking any specific approval. We do see potential value in such an approach, because there are many unknowns regarding future supply and demand in the LA Basin; contingency contracts may (if appropriately priced, effectively managed and well-located) reduce/mitigate disruptions and uncertainties in the future.

On the other hand, there are many uncertainties about what SCE may propose, and how such contracts work. There are significant questions that must be answered before we could approve such contracts. Such questions include:

- Would these contingency contracts be in addition to site preparation by SCE in the vicinity of Johanna and Santiago substations, thus potentially leading to costly redundancy?
- What metrics should be used to evaluate the cost-effectiveness of these contracts?
- Should separate RFOs be held to procure contingency contracts? If not, how can it be shown that proposed contracts represent the lowest reasonable rate?
- If SCE waited until the next RFO, might a contingency contract bidder improve its offer?
- How would SCE measure and enforce performance under contingency contracts?
- Would contingency contracts unfairly influence the next RFO? For example, if a contract is terminated after site preparation and permitting have already been completed, it may be more likely that this site will be selected in the next RFO.

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214 WPTF Opening Brief, at 7.

- In its testimony, SCE states "Second, the availability of Preferred Resources typically cannot be assured until much closer to the time of resource need. There is no assurance these Preferred Resources will ultimately be available to meet needs related to OTC closures because it is unlikely that customers will commit in 2014 that they will implement EE or DR in 2021."[215] If the preferred resources ultimately come online as expected, how will SCE avoid paying for both preferred resources and the contingency GFG contract, in light of SCE's assumed EE and DR procurement timeline? If SCE does not know if the preferred resources will perform until much closer to the time of delivery, on what grounds would SCE ever terminate a GFG option contract?
- Would contingency contracts, in practical terms, make it much more likely that there would be additional, unnecessary GFG procurement?
- What potential costs (direct, indirect or stranded) will ratepayers be exposed to if these contracts are pursued?

SCE may propose contingency contracts in its upcoming procurement application, expected in late 2014 or in a separate application. SDG&E may also propose similar contracts in its procurement application stemming from this decision or in a separate application. In either case, the utility must provide clear and full answers to the questions above before we will consider approving such contracts.

[215] Exhibit SCE-1, at 63.

6. Conditions for Procurement

6.1. Procurement Process

SCE recommends combining new LCR all source procurement from Track 4 with its all-source procurement RFO authorized in D.13-02-015. SCE argues this combination will both improve the competitiveness of all source bidding, allow for a more optimal selection of resources, and reduce administrative costs to ratepayers of issuing two separate all source solicitations.

SCE recommends that this solicitation not be limited to any particular resource type or project size. As Exhibit SCE-1 states: "[c]reating carve outs for certain technologies or project sizes shrinks the market for all other potential resources, potentially precluding the opportunity to contract with more cost-effective, better fit resources."[216] SCE contends the use of an all source solicitation for incremental Track 4 procurement authorization with no buckets for certain technologies or project sizes will allow SCE to seek a cost-effective portfolio of resources to meet SCE's LCR need consistent with the Loading Order. SCE plans to use the least-cost/best-fit criteria to choose the most cost-effective portfolio to meet SCE's LCR needs, consistent with the Loading Order.[217]

For procurement authorized in this proceeding, SDG&E requests that the Commission direct it to issue an all-source RFO or to contract bilaterally. SDG&E contends that moving forward on an expedited basis with a bilateral contract to address a portion of LCR need would support the policy goals of the State related to timely retirement of OTC facilities and would promote system

[216] Exhibit SCE-2, at 23.

[217] SCE Opening Brief, at 12.

reliability – the sooner new local resources are added to the portfolio, the lower the reliability risk.[218]

SDG&E argues that the public interest is best served by procurement of preferred resources through the relevant dedicated Commission proceedings. SDG&E contends there are important issues that require stakeholders input that are best addressed in the dedicated proceeding, such as establishing rules for counting of such resources to meet overall procurement targets, separate from LCR need, and developing mechanisms for recovery of costs from all benefitting customers.[219] SDG&E's procurement strategy holds 70-120 MW open to be filled with demand response and/or energy storage resources in the Commission proceedings dedicated to each such resource, provided that these resources satisfy requirements established by the ISO for operational characteristics that address local reliability needs.[220]

IEP and others recommend that procurement of local capacity resources should occur primarily through an all-source solicitation, where all resources that can meet the specified requirements can compete on a fair basis. IEP argues that the focus of procurement of capacity needed for local reliability should be the resource's viability and ability to provide the products and services needed to maintain reliability.[221]

ORA recommends directing each utility to submit a procurement plan explaining how it plans to accomplish the procurement of preferred resources,

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218 SDG&E September 4, 2013 Comments, at 5-6.

219 SDG&E Opening Brief, at 34.

220 SDG&E Opening Brief, at 8.

221 IEP Reply Brief, at 22.

including proposed milestones and evaluation dates, and detailed proposals to back stop the procurement. The plans should explain how the totality of the contracts or programs are cost effective and consistent with the loading order, including a demonstration that each utility has assessed the availability, economics and viability of the preferred resources in meeting LCR need. The plans should demonstrate technological neutrality, so that no resource was prevented from the solicitation process, although SCE and SDG&E may include proposals to solicit preferred resources through different avenues.[222]

CEERT recommends adopting a stakeholder process to permit public input on the development of RFOs for both supply-side (i.e., bulk storage) and preferred resources that permits input from parties on its terms and conditions before approved for the IOUs.[223]

Parties including Sierra Club, ORA and CLECA and Vote Solar share a concern that if the Commission adopts SCE's procurement proposals, only gas-fired resources will win, regardless of SCE's intent to pursue preferred resources solutions.[224] These parties recommend that the Commission, if it authorizes any additional Track 4 LCR procurement, require the utilities to first seek to satisfy that additional need with preferred resources. EDF contends that "[i]n comparison to combustion resources, the siting of [energy efficiency, demand response,] and small and large scale renewable generation is significantly less likely to face time delays and substantial obstacles to

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[222] ORA Opening Brief, at 31.

[223] CEERT Opening Brief, at 54.

[224] Sierra Club Opening Brief, at 26-27; Exhibit ORA-2, at 1; CLECA Opening Brief, at 10-11; Vote Solar Reply Brief, at 3.

implementation."[225] EnerNOC indicates such delays would include "attaining GHG emissions reductions required by Assembly Bill (AB) 32."[226]

We have already determined both in D.13-02-015 and in this decision that authorized procurement should be a combination of gas-fired generation and preferred resources, with ranges of procurement for different resource types. Any all-source RFO (and all other procurement methods) must be consistent with the resource ranges authorized in this decision. As discussed herein, compared to D.13-02-015 for SCE, we do not increase the minimum levels of procurement of gas-fired generation and do increase the minimum levels of procurement of preferred resources.

D.13-02-015 at 3 - 4 noted that that decision was a first step in a longer procurement process related to the retirement of OTC plants and other factors: "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."

There is a need for expeditious action to procure further resources in response to the retirement of SONGS. It will be approximately 18 months form the date for the Track 1 decision to the time SCE files an application for approval of Track 1-authorized procurement. We cannot wait another 18 months or more beyond the date of this decision for consideration of Track 4-authorized procurement. To ORA's point, SCE has already shown how it will procure

[225] EDF Opening Brief, at 7.

[226] EnerNOC Opening Brief, at 8-9.

preferred (and other) resources in a detailed plan, which has already been reviewed and approved by the Energy Division. As SCE has already completed its Track 1 RFO solicitation process, the most efficient and timely method toward approval of new resources in SCE's territory is to use the results of the Track 1 RFO for resources authorized in this decision as well as D.13-02-015. SCE may also propose for approval bilateral contracts for Track 4, consistent with the authority granted in Track 1.

Ordering Paragraph 1 of the track 1 decision, D.13-02-015, states in part: "Southern California Edison Company shall procure between 1,400 and 1,800 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." This track 4 decision concerns the SONGS service territory, which for SCE consists of the entire LA Basin. At the same time, we build upon the track 1 decision and recognize that the resource need identified in that decision continues to exist. Thus, SCE should prioritize procurement in the West Los Angeles sub-area of the LA basin. To the extent that SCE wishes to procure resources in the LA Basin, but not in the West LA sub-area, to meet the incremental authorizations in this decision (i.e., for resources beyond those authorized in D.13-02-015), SCE shall amend its approved procurement plan from Track 1 within 90 days of this decision, subject to Energy Division approval.

SCE shall file an application including procurement authorized in Tracks 1 and 4 in 2014, consistent with its Energy Division-authorized procurement plan from Track 1 (and any approved amendment). This application shall include all procurement contracts stemming from Tracks 1 and 4 for which SCE seeks approval at this time, whether from its RFO or bilateral contracts. The exception is any procurement covered by Ordering Paragraph 8 of D.13-02-015, which states: "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." SCE may include any proposed contingency contracts in its application.

For SDG&E, we also will require an all-source RFO as part of its Track 4 solicitation process, in addition to allowing bilateral contracts. The RFO shall meet the same requirements as for SCE in Ordering Paragraph 4 of D.13-02-015. We will require SDG&E to show that it has a specific plan to procure at least the minimum level of resources authorized by this decision, consistent with this decision's requirements for specific resource categories. We agree with parties' comments that all resources that can meet the specified requirements should be able to compete on a fair basis. An RFO is an effective method to accomplish this goal.[227] While SDG&E witness Anderson contends that the potential for double-counting and cannibalization of existing programs arises when procurement of preferred resources occurs along two parallel paths,[228] we find it better to compare resources procured for the same purpose (meeting LCR needs) in the same process (an RFO). SDG&E maintains the responsibility to ensure that its LTPP procurement process is consistent with other Commission requirements. Therefore, SDG&E's RFO shall provide for at least the 200 MW minimum preferred resources/energy storage components.

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227 We are aware that SCE's Track 1 RFO received a robust response from potential suppliers of various types of resources.

228 RT 1812 – 1813.

To this end, and consistent with the process ordered for SCE in Track 1, SDG&E shall first submit a procurement plan to be reviewed and approved by Energy Division. The SDG&E procurement plan shall meet the procurement plan requirements as required for SCE in D.13-02-015, and be consistent with this decision. The SDG&E procurement plan shall be provided to Energy Division for review no later than 90 days after the effective date of this decision. Consistent with an approved procurement plan, SDG&E shall file an application for all procurement contracts stemming from Track 4 for which SDG&E seeks approval at that time, whether from an all-source RFO or bilateral contracts. As with SCE, SDG&E may propose in its procurement plan a separate, earlier application for gas-fired generation due to long lead times. SDG&E should include any proposed contingency contracts in its application.

Procurement authorized by this decision should begin as soon as possible. Procurement needs may become critical as early as 2018, and certainly by 2020. To the extent authorized, SCE and SDG&E must expeditiously pursue procurement of any gas-fired generation expected to take several years to develop. Other procurement activities may not need as much lead-time to develop. However, the utilities should not wait until very close to when the need is critical to acquire such resources; to the extent that additional preferred resources or energy storage is cost-effective and well suited to meet LCR needs in the subject geographical areas, SCE and SDG&E should work to procure these resources in advance.

6.2. Solicitation Requirements

Ordering Paragraph 4 of D.13-02-015 required SCE to include the following elements in a Track 1 RFO:

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.

As SCE is authorized to use the results of its Track 1 RFO to procure resources for Track 4 as well, the requirements of Ordering Paragraph 4 of D.13-02-015 continue to hold. To the extent that SCE institutes future RFOs for these purposes, these requirements will apply. SCE should include any proposed contingency contracts in its application. In addition, we will apply the same requirements to SDG&E for any RFO it issues for Track 4 procurement.

7. 2013/2014 TPP Update

Some parties urge the Commission to revise any interim procurement authorization for incremental need in the SONGS study area once the 2013/2014 TPP results are available. For example, ORA contends that revising the need (upwards or downwards) based on more accurate information, would allow LCR procurement based on the facts that are more likely to reflect that need that will exist in 2022.[229] A number of other parties echo this sentiment.[230]

As discussed herein, it is necessary to authorize procurement at this time to replace capacity lost by the untimely retirement of SONGS. The authorization approved today does not assume any specific transmission upgrades or new

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[229] ORA Opening Brief, at 8.

[230] *See*, for example, CEERT Opening Brief, at 20: "it is CEERT's position that inclusion of the 'additional evidence' of the TPP results will create a better record than at present to determine both LCR needs without SONGS and the best means (in particular, preferred resources) to reduce or meet that need without jeopardizing timeliness."

projects which might be determined in the 2013/2014 TPP. At the same time, we do not authorize procurement of all resources identified by the ISO as needed to meet LCR needs in the SONGS service area by 2022. As discussed at length herein, we determine that some combination of already-authorized procurement, additional expected preferred resources, and new transmission projects will significantly reduce the need identified by the ISO.

If, at one extreme, no new transmission resources are identified in the 2013/2014 TPP which would reduce LCR needs in the SONGS service area by 2022, the procurement authorized today may need to be supplemented. We anticipate this would occur through some combination of: a) procurement at or near the maximum levels authorized in this decision; b) procurement of additional preferred resources (beyond the assumptions used by ISO in Track 4 models) as anticipated in this decision; c) additional procurement authorized in future LTPP proceedings; and d) potential delay in retirements of OTC plants. In other words, because we assume no new transmission projects in our analysis, a similar outcome from the 2013/2104 TPP does not require any change or update to this decision.

If some level of new transmission resources is identified in the 2013/2014 TPP which would reduce LCR needs in the SONGS service area by 2022 (for example, the Mesa Loop-In project), the total amount of overall procurement needed in the SONGS service area would be reduced. However, we have already considered the possibility of the Mesa Loop-In going forward in analyzing procurement authorizations. Nevertheless, it is possible that the 2103/2014 TPP results would mean that fewer of the resources identified in this subsection ultimately would be needed. However, this does not mean there would be a need to change or update this decision. Instead, some combination of the following would occur: a) procurement at or near the minimum levels authorized in this decision; b) less procurement or no procurement authorized in future LTPP proceedings; and c) less of a need to delay retirements of OTC plants.

The range of procurement authorized for both utilities in this decision is intended to provide flexibility to meet a variety of circumstances. The 2013/2104 TPP is unlikely to result in major changes to the analysis in this decision. Therefore, we will close Track 4 of this proceeding with this decision.

8. Cost Allocation Mechanism

The Cost Allocation Mechanism, or CAM, is designed to ensure that the costs of new resources procured to ensure local or system reliability are shared equally among all utility distribution customers, regardless of their generation provider. CAM is based on the principle that reliability is a collective good and that the customers of Electrical Service Providers (ESPs) and Community Choice Aggregators (CCAs) will also benefit from investments in system reliability made by regulated utilities. The current CAM achieves this goal by subtracting the energy value of new generation out from long-term contracts for new generation and sharing the residual capacity costs equally among all bundled and un-bundled customers within the utility service-area.

SCE[231] and SDGE[232] both argue that all Track 4 procurement should receive CAM treatment. SCE argues that the issue of CAM treatment was already litigated in Ordering Paragraph 21 of D.13-02-015 and therefore should not be re-litigated. SCE argues that Track 4 is intended to maintain local reliability and

[231] Exhibit SCE-1, at 59-60.

[232] Exhibit SDG&E-1 (Anderson), at 12.

therefore, according to Pub. Util. Code § 365.1(2)(B) all procurement coming out of Track 4 is CAM-eligible.

AReM/DACC[233] disputes both of these arguments. First, AReM/DACC suggests that since SONGS replacement was not discussed in Track I any determination of CAM applicability to Track I procurement should not automatically apply for Track 4 procurement as well.[234] AReM/DACC argues that as a general principle, CAMs should be applied with circumspection and the utilities need to justify CAM treatment on a case-by-case basis. For Track 4 procurement, they argue that procurement is to meet the bundled load of SDG&E and SCE customers, as opposed to general local or system reliability needs. Therefore, only utility bundled customers should pay SONGS replacement costs.

In reply briefs, PG&E, SCE, SDG&E and TURN argue that Track 4 procurement is for local reliability and not to meet bundled load, and therefore should be subjected to CAM. These parties argue that any resources the Commission asks the utilities to make to meet local reliability criteria in the SONGS service area will benefit both bundled and unbundled customers.

TURN[235] argues that local reliability needs – including those driven by expected resource retirements – are not solely the responsibility of bundled customers, even when they may be driven in part by the retirement of a resource that served bundled customer needs, such as SONGS. Further, all of the utilities' customers will benefit equally from the resources that may be procured pursuant

[233] Exhibit AReM/DACC-1, at 2-17.

[234] See also Exhibit WPTF-1, at 13.

[235] TURN Reply Brief, at 2-3.

to Track 4 authorization, so all customers should share equally in paying for such resources. Finally, SCE and SDG&E have already met, are continuing to meet and will continue meeting – to the extent the Commission requires and allows – their bundled customers' additional capacity and energy needs arising from the retirement of SONGS. TURN also argue that the utilities are meeting bundled customers' needs at bundled customers' expense, and have no other obligation to make long-term investments in resources to meet local reliability needs other than as directed by the Commission in a docket such as this Long-Term Procurement Plan.

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 new generation for reliability purposes for the full life of the asset.

D.13-02-015, Conclusion of Law 21 states:

> "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)."

Ordering Paragraph 15 of D.13-02-015 states:

> "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."

The basic question related to CAM in this decision is whether procurement authorized in this decision should be treated any differently from procurement authorized in D.13-02-015. There is no significant difference between procurement authorized in this decision and procurement authorized in D.13-02-015. In both cases, procurement is pursuant to local reliability determinations starting with ISO studies for this purpose, as modified by our analysis. We find that the procurement authorized in this decision is for the purpose of ensuring local reliability in the SONGS service area, for the benefit of all utility distribution customers in that area. We conclude that such procurement meets the criteria of Section 365.1(c)(2)(A)-(B). Therefore, SCE and SDG&E shall allocate costs incurred as a result of procurement authorized in this decision, and approved by the Commission. In most cases we expect this allocation to be consistent with D.13-02-015 and the CAM adopted in D.06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005, but there may be resources where an existing alternative method of allocating resources costs may be preferred; for example, cost may be recoverable through the Energy Program Investment Charge. As SCE states in its Reply Comments on the Proposed Decision at 3, it will "propose an RA allocation method in its application for approval of the results of its LCR RFO when those results are fully understood." We will require that, in applications for contract approval, the IOU shall recommend a method of cost allocation appropriate for the resource being procured.

SCE has proposed that some of its procurement for Track 4 could involve contingency or option contracts for GFG, giving SCE the right to terminate the contracts should sufficient renewables or transmission solutions obviate the need.[236] SCE argues that while such contracts are not covered by current CAM rules, the CAM framework could be expanded to cover such option contracts.

AReM/DACC[237] argues that these contracts cannot be subjected to CAM because there is no way to calculate net capacity costs by accounting for revenues from generation or related products. Since this calculation is required by statute (Section 365.1(c)(2)(C)), SCE should not be allowed to use CAM for these option contracts.

TURN[238] argues that it is not possible to make a determination regarding CAM or some similar cost-sharing mechanism for contingent generation contracts until the utilities have filed for approval of such programs. Therefore, there is no need to address the CAM issue for SCE's proposed contingent gas-fired generation contracts at this time.

Contingency or options contracts raise issues concerning cost allocation that have not been contemplated by the Commission to date. SCE does not have a specific proposal for contingency or options contracts before us at this time. SCE and/or SDG&E may propose such contracts in their future procurement applications stemming from this decision. We do not make any determination about whether contingency or options contracts will be eligible for CAM. If and when SSCE and/or SDG&E propose such contracts, they should propose whether certain costs should be allocated through CAM, and, if so determined, propose a methodology for allocation.

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[236] Exhibit SCE-1, at 58.

[237] Exhibit AReM/DACC-1, at 5.

[238] TURN Opening Brief, at 20-21.

9. 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 March 3, 2014, and reply comments were filed on March 10, 2014.

The following changes were made by the Administrative Law Judge based on comments:

1. Increase SDG&E maximum procurement authorization from 700 MW to 800 MW (based on comments from SDG&E, IEP and NRG);
2. Allow SCE to submit an amended procurement plan, if SCE wishes to procure in the LA Basin, but outside of the West LA sub-area as required in D.13-02-015 (based on comments from CEERT);
3. Modify Attachment B to require SDG&E to explain it its procurement plan how it will ensure that energy efficiency and demand response resources procured to meet its LCR needs are incremental to resources that would otherwise develop or be procured in other programs (based on comments from ORA);
4. Add an additional question regarding potential contingency contracts (based on comments from ORA);
5.

   Modifications to discussion of City of Redondo Beach testimony (based on comments from City of Redondo Beach);
6. Editing of Ordering Paragraph 1(e) to clarify requirements for energy storage procurement (based on comments from SCE);

7. Modify Ordering Paragraph 3 to allow bilateral contracts which are not cost-of-service contracts (based on comments of SDG&E);
8. Editing of Finding of Fact 45 regarding ISO modeling of demand response resources (based on comments from EnerNOC);
9. Clarification that the CAM may not be the only Commission-authorized cost allocation method which may be appropriate for certain resources (based on comments of SCE).

Other minor edits and clarifications to the Proposed Decision were made throughout the decision.

10. Assignment of Proceeding

The assigned Commissioner is Michel Peter Florio and the assigned ALJ is David M. Gamson. ALJ Gamson is the Presiding Officer. This proceeding is categorized as ratesetting.

Findings of Fact

1. The Track 1 decision in this docket, D.13-02-015, authorized SCE to procure between 1,400 and 1,800 MW of electrical capacity in the West Los Angeles sub-area of the LA Basin local reliability area to meet long-term local capacity requirements by 2021.

2. The San Onofre Nuclear Generation Station, Units 2 and 3 (SONGS) permanently closed in June 2013.

3. The SONGS study area consists of all of the territory of SDG&E, and the LA Basin portion of SCE's territory.

4. Until 2011, SONGS had supplied 2,246 MW of greenhouse gas -free base load power to the LA Basin and San Diego and played an important role in system stability in the San Diego Local Area.

5. Both SCE and SDG&E have sufficient supplies to meet projected demands in the SONGS service area through at least 2018, even with the unexpected early retirement of SONGS.

6. Starting in 2015, around 4,900 MW of OTC plants in the local transmission-constrained areas of the LA Basin local area may retire over the next several years, as well as other OTC plants in the San Diego local areas, because of State Water Resources Control Board regulations.

7. The ISO modeled retirement of OTC plants in the SONGS study area, along with the retirement of SONGS, to produce an analysis of need for the area.

8. The ISO based its long-term LCR study on a 1-in-10 year annual peak load and a Category C Contingency.

9. On May 21, 2013, Attachment A of the revised Scoping Memo for this proceeding set forth a series of assumptions for the ISO to use in modeling long-term capacity needs in the absence of SONGS.

10. The revised Scoping Ruling established a 1-in-10 year versus 1-in-2 year peak weather forecast for transmission and local area planning.

11. The ISO performed its SONGS Study area LCR study consistent with the assumptions in the revised Scoping Memo.

12. The ISO calculates that between 2,399 MW and 2,534 MW (depending on the allocation between SCE and SDG&E) will be needed in the SONGS study area by 2022.

13. Other parties performed power flow models. While these studies were useful for analytical purposes, they did not conform to the revised Scoping Memo.

14. SCE and SDG&E study results show projected residual long-term local capacity needs ranging from 2,302 – 2,534 MW based on slightly different

assumptions and methodologies from those used by the ISO per the revised Scoping Memo.

15. It is very likely or near certain that 1,800 MW authorized by the D.13-02-015 will be procured by SCE.

16. It is certain that 300 MW authorized D.13-03-029 will be procured by SDG&E, due to the approval given in D.14-02-016.

17. The June 28, 2013 Motion of ORA, CEJA and Sierra Club was not ruled upon before the proceeding was submitted.

18. The revised Scoping Memo did not include any specific amount of reactive power as an assumption for the ISO to model.

19. The record in the proceeding shows that there are sufficient resources to provide VAR support in the SONGS study area without further action at this time.

20. Because there is not sufficient information available from the record to determine if additional reactive power resources not modeled by the ISO could be available to reduce LCR needs, any analysis of whether or how much additional reactive power support would change LCR needs in the SONGS service area is speculative.

21. Consistent with Western Electricity Coordinating Council and North American Reliability Corporation guidelines, the ISO has approved Special Protection Systems (SPS), also known as a Special Protection Schemes, on several occasions in California.

22. An SPS allows the use of load shedding as an interim measure when there are insufficient resources to meet more stringent guidelines.

23. The ISO has the authority within WECC/NERC guidelines to implement or continue a SPS in the SDG&E territory.

24. The most important contingencies identified by the ISO in the SDG&E territory have a likelihood of an N-1-1 failure between every 21 and 928 years.

25. In the unlikely event that an N-1-1 failure would occur in the planning period of this proceeding during summer hours, it will not lead to load shedding except for less than 2.5% of the time.

26. There would need to be a minimum of 588 MW fewer resources if there is a temporary SPS in place, as compared to the resources needed to support the N-1-1 contingency identified by the ISO in the SDG&E territory.

27. The cost to ratepayers of additional resources to mitigate the N-1-1 contingency identified by the ISO in the SDG&E territory would be at least $595 million; there is evidence that such investment may not be cost-effective.

28. The cost to affected customers of a load shedding event under an SPS approach is estimated at under $250 million per event, and must be weighted by the low probability of the occurrence of load shedding.

29. It is likely that the procurement of preferred resources and/or transmission solutions will develop sufficiently over time to mitigate the need for further resources, so that the SPS in the SDG&E territory can be lifted and reliability at an N-1-1 contingency level can be maintained.

30. Exogenous modifications (including assumptions regarding load-shedding) do not affect the ISO modeling directly, but inform our judgment regarding appropriate procurement levels.

31. Changing a Category C contingency to a Category D contingency would directly change the ISO model output.

32. Issues regarding whether an ISO-determined Category C contingency should instead be functionally a Category D contingency under WECC reliability standards are more within the expertise of the ISO than the Commission.

33. There is no credible basis upon which to find that the ISO's analysis, that the limiting contingency for the SONGS study area is the N-1-1 Category C3 SWPL/Sunrise overlapping outage assumed and modeled by the ISO, is flawed.

34. SCE and SDG&E propose potential transmission solutions to part of the LCR need in the SONGS study area.

35. The Mesa Loop-In project involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 KV and looping the Vincent – Mira Loma 500 kV line and two 230 kV lines into the substation.

36. The Mesa Loop-In project would reduce the amount of gas-fired generation that would need to be sited in the LA Basin by approximately 1,200 MW, or 734 MW if there is no load shedding or additional gas-fired generation in the SDG&E territory.

37. The Mesa Loop-In project was submitted to the ISO as part of its 2013-2014 Transmission Planning Process.

38. There is no record to determine if the Mesa Loop-In will be approved by the ISO in its TPP, or to determine whether, even if approved, it would be in service before 2022.

39. The Mesa Loop-In proposal is a promising and reasonably likely alternative to other new resources in the LA Basin, if it is approved by the ISO and if it would be in service before 2022.

40. SDG&E's proposed 500 kV Direct Current transmission project from Imperial Valley to SONGS would reduce the San Diego generation requirement by 850 MW and would reduce the generation requirement for the LA Basin by 551 MW.

41. SDG&E's proposed 500 kV regional transmission project from Devers Substation to a new 230 kV substation in north San Diego County would

reduce the LCR need for San Diego by 550 MW and reduce the LCR need for the LA Basin by 400 MW.

42. SDG&E submitted two 500 kV transmission options with different routing options from Imperial Valley to North County to the ISO's 2013-2014 Transmission Planning Process.

43. There is substantial uncertainty as to how quickly SDG&E's proposed transmission projects could be licensed and built.

44. There is a reasonable possibility that at least one of the transmission solutions examined by SCE and SDG&E will be operational by 2022. The least complex of these projects is the Mesa-Loop-In project, which is therefore the most likely to meet this timeframe.

45. Consistent with the revised Scoping Memo, the ISO determined that demand response resources which cannot respond in 30 minutes should be considered 'second contingency' resources.

46. Consistent with the revised Scoping Memo, 997 MW of 'second contingency' demand response in the ISO modeling was not available to avoid the second contingency, but would be available to respond to the second contingency.

47. It is reasonable to expect that, in the future, some amount of what is now considered 'second contingency' demand response resources can be available to mitigate the first contingency, and therefore meet LCR needs.

48. D.13-10-040 sets energy storage targets of 580 MW for SCE and 165 MW for SDG&E, to be procured gradually through biennial solicitations from 2014 through 2020 and to be online no later than December 31, 2024.

49. The energy storage targets adopted in D.13-10-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis.

Potential amounts of demand response, energy efficiency or solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis.

50. It is likely that some of the energy storage targets will available and effective to meet LCR needs in the SONGS service area before 2022.

51. The incipient nature of energy storage resources, uncertainty about location and effectiveness, and unknowns concerning timing provide insufficient information at this time to assess how and to what extent energy storage resources can reduce LCR needs in the future.

52. The revised Scoping Memo erroneously used the low-level uncommitted energy efficiency estimate instead of the mid-level uncommitted energy efficiency level, because the latter is consistent with the fact that SDG&E's territory is co-existent with its part of the SONGS service territory.

53. LCR study data from SDG&E shows the LCR difference is 152 MW for the more appropriate mid-level energy efficiency estimate.

54. Consistent with the revised Scoping Memo, the ISO correctly designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built.

55. It is likely that Commission programs and the marketplace will increase the amount of solar PV in the future. However, there is no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs.

56. SCE's Living Pilot is a promising concept.

57. The Living Pilot is not being proposed by SCE at this time, therefore it is not possible now to make any determination about its viability or ability to meet LCR needs in the LA Basin.

58. D.13-02-015, Finding of Fact 7, continues to be valid: "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."

59. D.13-02-015, Finding of Fact 32 continues to be valid: "A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement."

60. PG&E does not adequately take into account the likelihood of various supply or demand considerations which are either very likely or reasonably likely to occur, and which will lower the overall LCR need from the levels modeled by the ISO.

61. Redondo Beach's study does not use many of the same analytical methods as the ISO.

62. The highest reasonable LCR need level must take into account those resources which are very likely to be procured in the time frame between now and 2022.

63. Taking very likely or certain modifications into account, the highest prudent level of procurement authorization for the SONGS study area would be 1,802 MW (rounded to 1,800 MW).

64. At least some resources beyond those counted to determine the 1,800 MW maximum procurement level are reasonably likely to be procured in the SONGS study area by 2022.

65. The total of all reasonably possible resources or assumptions identified by parties that were not studied by the ISO equals approximately 4,600 MW.

66. It is reasonable to assume that at least between 10% and 20% of the approximately 4600 MW of resources not studied by the ISO will be available.

67. Using a methodology of subtracting out any one of several possible resources or assumptions not included in the ISO modeling produces a range of maximum procurement levels which takes into account between 588 and 997 MW, or between 13% and 22% of the 4,600 MW in total not studied by the ISO.

68. A maximum prudent procurement analysis which incorporate one of the likely resources or assumptions to meet or reduce LCR needs shows the upper bound of a reasonable procurement range under different assumptions ranges from 1,800 MW down to 1,393 MW.

69. While it is reasonable to assume that some resources not accounted for in the calculation of maximum need will be available and will mitigate LCR needs, it is not reasonable to assume this will be true for most of these resources.

70. While it is mathematically possible to construct an analysis using a series of optimistic assumptions about resource availability that could lead to a finding of zero or negative need, we find that a conclusion of zero need is not reasonable.

71. A proxy for calculating a minimum LCR need level is to calculate the LCR impact if any two likely potential scenarios (load-shedding, Mesa Loop-In, additional energy efficiency impacts, 'second contingency' demand response, energy storage, 'second contingency' solar PV) should occur.

72. Using a methodology of subtracting out any two of several possible resources or assumptions not included in the ISO modeling produces a range of minimum procurement levels which takes into account between 1,322 and 1,797 MW, or between 29% and 39% of 4,600 MW.

73. In each case of 100% availability of any two likely scenarios not included in the ISO's modeling, a minimum procurement level ranges from 593 to 1,067 MW (not taking into account uncertainties of effectiveness of various resources in meeting or reducing LCR needs).

74. Parties' recommendations (other than those recommending zero procurement or over-procurement) have in common certain subtractions from a total LCR need for procurement already authorized and calculations of expected resources. These parties' recommendations range from approximately 800 MW to 1,500 MW for the SONGS service area.

75. An overall authorized procurement level for the SONGS service area at this time of 1,000 -1,500 MW is consistent with the recommendations of many parties and is near the center of the overall zone of reasonableness.

76. Authorized procurement levels of 1,000 to 1,500 MW will not provide the full amount needed to meet the LCR needs in the SONGS service territory through 2022; a significant amount of future resources to meet LCR needs in the SONGS service territory will come from procurement authorized in other Commission proceedings, the marketplace and other regulatory forums.

77. Between 67% and 80% of procurement needed to address LCR needs in the SONGS service area by 2022 must be in the LA Basin, which is in SCE territory. The remainder would be in the SDG&E service territory.

78. It is not possible at this time to discern how resources ultimately will be distributed between SCE and SDG&E territories.

79. Between D.13-02-015 and D.13-03-029/D.14-02-016, over 85% of authorized resources are already slated for SCE territory.

80. Authorizing a similar procurement range for SCE and SDG&E, with a 100 MW higher maximum for SDG&E, should be consistent with the requirement that 67 -80% total procurement needs to be in the SCE territory.

81. Authorizing SCE to procure between 500 and 700 MW in its portion of the SONGS service area is within the range of prudent procurement. Authorizing SDG&E to procure between 500 and 800 MW in its portion of the SONGS service area is within the range of prudent procurement.

82. D.13-02-015, Finding of Fact 30 continues to be valid: "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."

83. Pursuing procurement of preferred resources consistent with the Loading Order must be balanced by ensuring that grid operations are not potentially compromised by excessive reliance on intermittent resources and resources with uncertain ability to meet LCR needs.

84. It is not necessary to require any specific incremental procurement for SCE from gas-fired resources, beyond that specified in D.13-02-015. However, expanding the range of potential gas-fired procurement from 1,000 – 1,200 MW (per D.13-02-015) to 1,000 – 1,500 MW provides greater flexibility to SCE to meet reliability needs.

85. SCE's procurement proposal would expand the range of potential procurement of preferred resources and energy storage, but would allow SCE to procure up to 89% of authorized Track 1 and Track 4 resources from gas-fired generation.

86. Requiring SCE to procure at least 400 MW additional procurement from preferred resources or energy storage, beyond the amount required by

D.13-02-015, increases the percentage of procurement from these resources to 21% to 60%, which is above the 14% to 44% range authorized in D.13-02-015.

87. Requiring SDG&E to procure from at least 200 MW of additional resources authorized by this decision from preferred resources and/or energy storage would result in 22%to 78% of additional resources from preferred resources and/or energy storage, after consideration of procurement authorized by D.13-03-029 and approved by the Commission in D.14-02-016.

88. Because the process for utility solicitations of energy storage per D.13-10-040 has not yet started, it is too early to know if such targets are too high, too low or just right.

89. It will be approximately 18 months form the date for the Track 1 decision to the time SCE files an application for approval of Track 1-authorized procurement. It would likely be another 18 months or more beyond the date of this decision for consideration of Track 4-authorized procurement, unless SCE is allowed to combine Track 4 procurement with its Track 1 procurement process.

90. SDG&E can potentially procure the required amount of preferred and other resources needed to meet the LCR need in its portion of the SONGS service area through an all-source RFO and bilateral contracts.

91. Procurement needs may become critical as early as 2018, and certainly by 2020.

92. The procurement authorized in this decision is for the purpose of ensuring local reliability in the SONGS service area, for the benefit of all utility distribution customers in that area.

93. The resource need identified in D.13-02-015 continues to exist in the West Los Angeles sub-area of the LA Basin. Resources in other portions of the LA Basin may also meet incremental LCR needs identified in this decision.

Conclusions of Law

1. While a primary responsibility of the Commission is to ensure safety and reliability in the electrical system under § 380(c), § 330(g), § 330(h), § 362(a), and § 334, that responsibility must be balanced with other statutory and policy considerations. Specifically, the Commission has a statutory duty to ensure that customers receive reasonable services at just and reasonable rates per § 451 and § 454, and to protect the environment under Pub. Util. Code sections including § 399.11 (Renewables Portfolio Standard) and § 454.5(b)(9)(C) (Loading Order).

2. The ISO has statutory responsibility for the efficient use and reliable operation of the transmission grid under § 345 and shall "ensure the reliability of electric service and the health and safety of the public" under § 345.5(b).

3. The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, and presented in the Energy Action Plan II adopted by this Commission and the CEC in October 2005, 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.

4. It is reasonable for the Commission to use LCR forecasts modeled by the ISO using assumptions pursuant to the revised Scoping Memo as the starting point for analyzing long-term LCR requirements in the SONGS study area.

5. The ISO study adjustment of forecasted LCR need for 1,800 MW from D.13-02-015 for the SONGS study area is reasonable and should be included in determining how much local capacity to procure for the SONGS study area.

6. The ISO study adjustment of forecasted LCR need for 300 MW from D.13-03-029 for the SONGS study area is reasonable and should be included in determining how much local capacity to procure for the SONGS study area.

7. The June 28, 2013 Motion of ORA, CEJA and Sierra Club should be denied as moot.

8. The ISO study of LCR needs for the SONGS service area should not be adjusted to account for speculative amounts of additional reactive power support.

9. Load shedding through an SPS instituted or continued by the ISO should only be used judiciously as mitigation for contingencies.

10. It is not reasonable to authorize procurement of additional resources at this time to mitigate load-shedding for the N-1-1 contingency identified by the ISO in the SDG&E territory.

11. It is prudent to wait to see what resources develop in the SONGS service area to determine if an SPS or other load-shedding protocol can serve as a bridge until such resources are in place.

12. It is reasonable to subtract 588 MW from the ISO's forecasted LCR need to account for resources that will not be procured at this time to fully avoid the possibility of load-shedding in San Diego as a result of the identified N-1-1 contingency.

13. In decisions including D.13-06-024, D.13-02-015, and D.13-03-029, the Commission has deferred to the ISO regarding power flow modeling.

14. It is reasonable to use the ISO power flow models as the basis for this decision, with certain exogenous modifications.

15. There is not enough information available at this time to make a specific finding that SCE or SDG&E's proposed transmission projects will be able to reduce the LCR need in the SONGS service territory by 2022.

16. Due to significant uncertainties, the ISO's forecast should not be adjusted at this time to assume LCR benefits from the SCE Mesa Loop-In project or SDG&E's proposed transmission projects.

17. Potential transmission solutions provide more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

18. The ISO's forecast should not be adjusted to assume 'second contingency' demand response resources will be available to meet LCR needs.

19. The likelihood that some demand response resources, currently considered 'second contingency' resources, will be available to meet LCR needs in the future provides more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

20. While the LCR effect of potential energy storage resources cannot be quantified at this time, the targets and requirements of D.13-10-040 lead to a conclusion that energy storage resources will reduce LCR needs in the SONGS service area to some extent in the future.

21. The potential of energy storage to meet LCR needs provides more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

22. The revised Scoping Memo should have used the mid-level uncommitted energy efficiency estimate for SDG&E instead of the low-level estimate.

23. It is reasonable to adjust the ISO study results by 152 MW consistent with the mid-level uncommitted energy efficiency level for SDG&E.

24. It is too speculative to make any changes to the ISO study results to account for solar PV.

25. PG&E's recommended procurement levels carry a significant risk of over-procurement.

26. Any procurement level above 1800 MW entails too high of a possibility of over procurement.

27. It would be prudent to authorize procurement of less than 1,800 MW because other resources are reasonably likely to be procured, even though in some cases their LCR impacts cannot be precisely measured. To do otherwise would most likely lead to over-procurement.

28. For the purpose of calculating a maximum procurement level, it is reasonable to assume that at least 13% - 22% of resources or assumptions not studied by the ISO will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

29. To account for uncertainties about effectiveness of LCR reductions for certain resources, a reasonable maximum procurement level should be somewhere between 1,383 and 1,800 MW.

30. A finding of zero LCR need for the SONGS service area for 2022 would not be prudent because it would most likely lead to under-procurement.

31. Analyzing 100% availability of any two sets of resources or assumptions not included in the ISO models is a reasonable proxy for the largest amount of available LCR reductions from the ISO analysis.

32. For the purpose of calculating a minimum procurement level, it is reasonable to assume that at least 29% to 39% of resources or assumptions not studied by the ISO will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

33. To be certain that authorized procurement levels will not result in under-procurement, the minimum authorized procurement level should in no

case be no less than 593 MW, but could be reasonably set anywhere between 593 and 1,067 MW.

34. Authorizing a procurement range takes into account a) uncertainties about supply and demand conditions; b) the ability to process new information during the procurement process; c) the need to provide the utilities with flexibility to procure resources which may only be available in large increments; d) increases in requirements to procure preferred resources (as discussed below); and e) the need to provide utilities and the Commission with the ability to protect ratepayers by not forcing certain less economic procurement decisions.

35. An overall authorized procurement level for the SONGS service area at this time of 1,000 -1,500 MW provides reasonable ratepayer protection against over procurement and simultaneously provides reasonable protection from reliability impacts from under procurement.

36. It is reasonable to authorize SCE to procure between 500 and 700 MW in its portions of the SONGS service area. It is reasonable to authorize SDG&E to procure between 500 and 800 MW in its portions of the SONGS service area.

37. It is prudent to promote preferred resources to the greatest extent feasible, subject to ensuring a continued high level of reliability.

38. A prudent approach to reliability entails a gradual increase in the level of preferred resources and energy storage into the resource mix.

39. Consistent with D.13-02-015, it is reasonable to provide a level of flexibility to SCE and to ensure procurement consistent with ISO reliability standards by expanding the range of procurement specified in D.13-02-015 for gas-fired resources, preferred resources and energy storage.

40. A similar range of procurement flexibility should be provided to SDG&E as to SCE.

41. SCE's proposal to add its additional Track 4 procurement requirement to its Track 1 authorization from D.13-02-015, without any specification of resource type, is not consistent with Commission policies to adhere to the Loading Order.

42. Requiring SCE to procure between 400 and 1,500 MW (or 21% to 60%) from preferred resources or energy storage in total between D.13-02-015 and this decision is more consistent with the Loading Order than SCE's proposal.

43. SDG&E should be authorized some flexibility to procure gas-fired, preferred and energy storage resources to meet reliability needs.

44. Requiring SDG&E to procure at least 200 MW from preferred resources or energy storage is consistent with the authority granted to SCE herein and consistent with the Loading Order.

45. There is insufficient information to modify the energy storage procurement targets established in D.13-10-040.

46. It is reasonable to allow SCE to use the same procurement process for both Track 1 and Track 4-authorized procurement, consistent with SCE's approved Track 1 procurement plan.

47. SDG&E should be required to show that it has a specific plan to procure the resources authorized by this decision, consistent with the procurement categories and other requirements of this decision.

48. Procurement authorized by this decision should begin as soon as possible.

49. SCE should prioritize procurement in the West Los Angeles sub-area of the LA Basin.

50. The procurement authorized in this decision meets the criteria of Section 365.1(c)(2)(A)-(B) for the purposes of cost allocation.

51. The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-004, D.08-09-012 and D.11-05-005 (and as applied in D.13-02-015)

remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B). Other Commission-authorized cost allocation methods may instead be appropriate for certain resources.

52. The November 14, 2013 e-mail Ruling of ALJ Gamson denying a November 4, 2013 Motion for Official Notice of Protect Our Communities should be affirmed because the requested materials do not meet the criteria for Official Notice or Judicial Notice.

53. The SCE Motion to Strike the Opening Brief of the City of Redondo Beach should be denied because the brief addresses record issues related to local reliability.

54. The SCE and SDG&E Joint Motions to Strike the Opening Brief and Reply Brief of Protect Our Communities should be granted because the brief is substantially based on non-record evidence.

55. The SCE, SDG&E and PG&E Motions to Strike the Opening Brief of Marin Energy Authority should be granted because the brief is substantially concerned with matters outside of the scope of the this track of the proceeding.

56. The Southern California Edison Company Motion to Partially Strike the Opening Brief of Nevada Hydro Company is granted because the portions of the brief to be stricken are outside of the scope of this track of the proceeding.

O R D E R

IT IS ORDERED that:

1. In combination with procurement authorizations totaling 1,400 to 1,800 Megawatts (MW) in Ordering Paragraph 1 of Decision 13-02-015, Southern California Edison Company is authorized to procure between 1,900 and

2,500 MW of electrical capacity in the Los Angeles Basin local reliability area to meet long-term local capacity requirements by the end of 2021. Procurement must abide by the following guidelines and table:

a. At least 1,000 MW, but no more than 1,500 MW, of local capacity must be from conventional gas-fired resources, including combined heat and power resources;

b. At least 50 MW of local capacity must be procured from energy storage resources (as defined in Decision 13-10-040);

c. At least 550 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subsection b of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded.

d. At least 300 MW, but no more than 500 MW, of local capacity, beyond the minimum amounts specified in subparagraphs (a), (b) and (c), must be procured and can be from any resource able to meet local capacity requirements.

e. Subject to the overall cap of 2500 MW, any additional local capacity, beyond the amounts specified in subparagraphs (a), (b), (c) and (d), may only be procured through preferred resources (including bulk energy storage and large pumped hydro facilities) consistent with the Loading Order of the Energy Action Plan and/or energy storage resources. Such preferred resources shall be in addition to preferred resources already required by the Commission to be procured or obtained through decisions in other relevant proceedings,.

Resource Type	Track 1 LCR Resources (D.13-02-015)	Additional Track 4 Authorization	Total Authorization
Preferred Resources **Minimum Requirement**	150 MW	400 MW	550 MW
Energy Storage **Minimum Requirement**	50 MW		50 MW
Gas-fired Generation (including CHP) **Minimum Requirement**	1,000 MW		1,000 MW
Optional Additional: Only From Preferred Resources /Energy Storage	Up to 400MW		Up to 400 MW
Additional from Any Resource	200 MW	100 to 300 MW	300 to 500 MW
Total Procurement Authorization	**1,400 to 1800 MW**	**500 to 700 MW**	**1,900 to 2,500 MW**

2. San Diego Gas & Electric Company is authorized to procure between 500 Megawatts (MW) and 800 MW of electrical capacity in its territory to meet long-term local capacity requirements by the end of 2021. Procurement must abide by the following guidelines:

   a. At least 25 MW of local capacity must be procured from energy storage resources (as defined in Decision 13-10-040);

   b. At least 175 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subparagraph (a) of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded from this category.

3. Southern California Edison Company and San Diego Gas & Electric Company are authorized to procure bilateral contracts to meet authorized local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code Section 454.6.

4. Southern California Edison Company and San Diego Gas & Electric 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.

5. Southern California Edison Company shall prioritize any procurement authorized by this decision in the West Los Angeles sub-area of the Los Angeles Basin local reliability area to the extent possible, and shall document efforts to comply with this Ordering Paragraph in its Application(s) required by Ordering Paragraph 8.

6. San Diego Gas & Electric Company (SDG&E) shall issue an all-source Request for Offers (RFO) for some or all capacity authorized by this decision in Ordering Paragraph 2. The RFO shall include the elements specified by Ordering Paragraph 4 of Decision (D.) 13-02-015, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including D. 07-12-052) and the authorization and requirements of this decision.

7. No later than 90 days after the effective date of this decision, San Diego Gas & Electric Company (SDG&E) shall submit a procurement plan to be reviewed and approved in writing by the Director of the Energy Division. SDG&E may propose in its procurement plan a separate, earlier application for gas-fired generation. The procurement plan shall include a proposed Request for

Offers as required by Ordering Paragraph 6. SDG&E shall not commence any procurement activities until the Director of the Energy Division approves its procurement plan, which shall be reviewed consistent with this decision. The SDG&E procurement plan shall be subject to the same procurement plan requirements of Ordering Paragraphs 6, 7 and 8 in Decision 13-02-015 as were required of Southern California Edison Company. In addition, SDG&E shall provide to Energy Division all of the information listed in Attachment B to this decision. If SCE issues one or more additional Requests for Offers to procure capacity pursuant to this decision, it shall also provide to Energy Division all of the information listed in Attachment B to this decision.

8. Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall each file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision. The requirements of Ordering Paragraph 11 of Decision 13-02-015 shall apply to both utilities. Neither SCE nor SDG&E shall 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 or 2 (as applicable);
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 or SDG&E'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 and SDG&E shall show that it has contracted with these preferred resources first.

9. In its Application to implement this decision pursuant to Ordering Paragraph 8, Southern California Edison Company shall present contracts for at least 50 Megawatts (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. The same requirements shall apply for San Diego Gas & Electric Company, except the requirement for energy storage resources shall be 25 MW.

10. Southern California Edison Company and San Diego Gas & Electric 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 procurement authorized in Ordering Paragraph 1 and 2.

11. Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall provide documentation in their respective Applications required by Ordering Paragraph 8 of efforts to consult with the California Independent System Operator to develop performance characteristics for local reliability, and how SCE and SDG&E meet any such performance characteristics.

12. Southern California Edison Company (SCE) may modify its procurement plan approved by Energy Division per Decision 13-02-015 solely so that

resources in portions of the Los Angeles Basin beyond the West Los Angeles sub-area may also be procured to meet incremental local capacity needs identified in this decision. Any such modification shall be submitted by SCE to Energy Division within 90 days of the effective date of this decision and shall be subject to the written approval of the Director of the Energy Division.

13. In applications for contract approval, Southern California Edison Company and San Diego Gas & Electric Company shall recommend a method of cost allocation appropriate for the resources being procured as authorized in this decision, either consistent with the cost allocation mechanism approved in Decision (D.) 06-07-029, D.07-09-044, D.08-09-012, D.11-05-005 and D.13-02-015 or through another Commission-authorized method.

14. The November 4, 2013 Motion of the Protect Our Communities Foundation for Official Notice of Exhibits, identified as Exhibits POC-3, POC-4 and POC-5, is denied.

15. The Southern California Edison Company Motion to Strike the Opening Brief of the City of Redondo Beach is denied.

16. The Southern California Edison Company and San Diego Gas and Electric Company Joint Motions to Strike the Opening Brief and Reply Brief of Protect Our Communities are granted.

17. The Southern California Edison Company, San Diego Gas & Electric Company and Pacific Gas and Electric Company Motions to Strike the Opening Brief of Marin Energy Authority are granted.

18. The Southern California Edison Company Motion to Partially Strike the Opening Brief of Nevada Hydro Company is granted.

19. Rulemaking 12-03-014 is closed.

This order is effective today.

Dated _____________________________, at San Francisco, California.

ATTACHMENT A

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
1. a)	**CAISO 80%**	1,922 MW	612	From the results of CAISO's LCR study assuming 80% of the needed identified in the SONGS area is allocated to the LA Basin and after deducting Track 1 authorization	From the results of CAISO's LCR study assuming 80% of the needed identified in the SONGS area is allocated to the LA Basin and after deducting Track 1 authorization
1. b)	**CAISO 2/3rds**	1,222 MW	1,177 MW	From the results of CAISO's LCR study assuming 2/3rds of the identified need in the SONGS Area is assumed to be in the LA Basin, and after deducting Track 1 authorization	From the results of CAISO's LCR study assuming 2/3rds of the identified need in the SONGS Area is assumed to be in the LA Basin, and after deducting Track 1 authorization
2.	**SCE**	500	NA	Incremental to preferred resources and transmission Needed to meet the higher reliability standards used by CAISO particularly relating to voltage support and to mitigate uncertainty in assumptions including load growth	NA

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
3.	SDG&E	NA	1,320 – 1,470 MW without transmission improvement, could be reduce to 370 – 820 MW with major new transmission (Jontry at 10-11)[239]	NA	From results of SDG&E power flow study cases which included 408 MW of load reduction or new supply by 2022 from preferred resources that currently do not exist.

239 Assumes approval of 300 MW Pio Pico Application currently before the Commission in A.13-03-019.

4.	**AES Southland[240] (AES)**	1000 MW (at 11)	MW Number Not Provided	Recommends that SCE be authorized to procure an additional 1,000 MW of generation in addition to what was approved at the conclusion of the Track 1 process. (at 11) AES strongly urges its recommendation for the following reasons: (1) procuring generation from outside the LA Basin area to replace SONGs may not be the most reliable nor cost-effective solution, (2) transmission solutions to reduce the need for procurement of generation from the most effective LA Basin generation locations may not result in the most robust or reliable system configuration. (3) Importing large amounts of generation, particularly when system demand undergoes sudden changes, will expose the system to voltage collapse conditions. (4) In addition, permitting and construction timelines for repowering existing OTC sites are likely to be considerably shorter than the timeline for developing greenfield transmission such as the Mesa Loop-In project and/or new generation. (at 10.)	NA

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
5.	**AREM/DACC**	MW Number Not Provided	MW Number Not Provided	Takes no position on need to replace energy and capacity from loss of SONGS. (at 2)	Takes no position on need to replace energy and capacity from loss of SONGS (at 2)
6.	**Center for Energy Efficiencies and Renewable Technologies (CEERT)**	0 MW (at II-2)	0 MW (at II-2)	Recommends that the Commission make a final, not interim, Track 4 need determination based on consideration of the CAISO's 2013-2014 TPP, projected success of the 33% RPS program, and results of SCE's Track 1 preferred resource procurement and "living pilot" in order to avoid a piecemeal or premature overreliance on fossil procurement. (at II-2 – II-6). CEERT recommends a schedule to achieve that end that will permit a timely Proposed Decision in Track 4 by June 2014 and achieve the "early 2015" goal for any needed procurement by acceleration of the process *after* the issuance of that decision. (p. II-6, citing CEERT 9-10 Comments on Track 4 Schedule, at 5-6; see also, CEERT 10-14 Reply Comments on ALJ Questions, at 1-7).	

[240] Witness Hala N. Ballouz's Testimony

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
7.	**California Environmental Justice Alliance (CEJA)**	0 MW (at 2)	0 MW (at 2)	CAISO's modeling assumptions were too conservative: • Updated 2013 CEC demand forecast for LA Basin and San Diego for 2022 is 1,320-3,200 MW lower than the 2012 CEC forecast CAISO used. • Transmission fixes, especially for reactive support, were found to reduce need by at least 1,500 MW and CAISO transmission planning results should be considered. • Preferred resources include 50 MW storage, 997 MW of DR, and 496 MW of DG. New CPUC storage proceeding targets should be considered in Track 4. (at 2) All resources authorized in Track 1should be assumed to be available in considering local capacity requirements for SONGS. California Energy Demand 2014-2024 Revised Forecast, and in particular the CEC's draft Estimates Of Additional Achievable Energy Savings should be considered. Contingency planning should not favor new GFG over renewable resources or short-term solutions.	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
8.	**California Energy Storage Alliance (CESA)**	MW Number Not Provided	MW Number Not Provided	CESA asserts that Energy storage is an important technology class for meeting LCR needs in general, including those in SCE's service territory. If the Commission finds need, it should allocate procurement authority to SCE that includes the procurement of Energy Storage. (at 2) CESA asserts that energy storage is an extremely diverse and modular resource class that addresses many of SCE's stated needs, including facilitating transmission upgrade deferral, and does so effectively (especially given SCE's definition of effectiveness for Preferred Resources). Storage resources are controllable and dispatchable (sometimes providing services almost instantaneously) and can provide services "across all or most of the times when needed," needed. Energy storage also has multiple resource subsets with diverse durations. (at 2)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
9.	**City of Redondo Beach**	1,140 MW (1,140 = 2,940 MW SCE total need - 1800 MW, authorized for SCE in Track 1)	757 MW (757= 1,100 MW SDG&E total need – 343 MW authorized for SDG&E currently authorized)	Iterative power flow studies show that 940 MW of conventional gas-fired generation added at the Huntington Beach generating station PLUS 2,000 MW of preferred resources added throughout the Western LA Basin can meet the Western LA Basin sub-area LCR.	CAISO's 2012-2013 transmission plan for the no-SONGS case (City of Redondo Beach's original testimony [241]) and the CAISO's Track 4 base case (comments submitted by the City of Redondo Beach).
10.	**Clean Coalition (CCC)**	0 MW (at 8)	0 MW (at 8)	No new conventional generation and transmission investments until full value of renewable resources assessed through public procurement and planning process. (at 8)	

[241]. The (About 900 MW) mentioned in the City's original testimony for the generation assumed in the San Diego area by year 2022 for the no-SONGS study in the CAISO's 2012-2013 transmission plan is a typographical error. The correct number is 1,100 MW.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
11.	**Environmental Defense Fund (EDF)**	EDF presented data indicating that no additional combustion resources are needed with the use of preferred resources, such as EE and demand response.	EDF presented data indicating that no additional combustion resources are needed with the use of preferred resources, such as EE and demand response	EDF commended SCE's "Preferred Resources Scenario" approach, innovative pilot, and clear identification of the uncertain need for additional capacity. Recommends that the Commission refrain from rendering a decision until a comprehensive a set of analyses becomes available. (at 2-3)	EDF points to the ability of demand response, including time-variant rates, as well as energy efficiency, distributed generation and other clean resources, to address the range of capacity needs currently identified by different parties.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
12.	**EnerNOC Testimony**	MW Number Not Provided	MW Number Not Provided	It is reasonable to authorize additional capacity procurement for SCE, for as much as 500 MW, because SCE has adequate capacity, according to its studies, between the Track I authorization and the planned Mesa Loop-In transmission project unless the likelihood of realizing the transmission project is low. (at II-2-3; II-7-9). Before authorizing SCE to procure additional resources beyond its Track I authorization, the Commission must resolve the calculation difference between SCE's and CAISO's analysis. (at II-2, II-7-6-8) The Commission should not authorize additional capacity procurement until the CAISO has completed its 2013-14 Transmission Planning Process. (at II-3, II-9-11) Further, the Commission should reject the CAISO's and utilities' objections to updating assumptions and any efforts to impose inappropriate conditions on demand response reducing or meeting local need. Any Track 4 need determination must be consider all updated assumptions (i.e., CAISO's TPP results, Track 1 solicitations/pilots results, and further development of DR programs) through at least the first quarter of next year before any Track 4 procurement is authorized.	SDG&E's calculation of its incremental resource need appears to be reasonable. (at III-31, II-12.) SDG&E's analysis of need is consistent with CAISO's, which shows an incremental need between 620 and 147 MW, after adjusting for Track 1 authorized procurement. (at II-12.) SDG&E's proposal is only partially consistent with the loading order. (at II-11-12). As in the case of SCE, the Commission should also use updated assumptions in identifying

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
13.	**Independent Energy Producers (IEP)**	2,506 MW (including the Track 1 solicitation of 1,400-1,800 MW). If full 1,800 MW from Track 1 is procured, then Track 4 authorization should be 706 MW (2,506 – 1,800) (at 30)	820 MW However, if Commission does not approve the Pio Pico application, then resource need would increase to 1,118 MW (820 + 298). (p. 30)	Factors in SCE's and SDG&E's service area drive uncertainty in forecasting, which can result in under-estimating need and threatening grid, include (1) net load forecasts in local resources are subject to significant uncertainty because of energy reduction and uncertainty as to demand; (2) slow economic recovery could accelerate increasing demand; (3) some preferred resources may not prove viable skewing load forecasts; (4) new and upgraded transmission may be delayed. (at 12-14) While over-capacity might result in slightly higher costs, under-capacity would come with a very high social cost. (at 15) Track 4 authorization should be based on total resource need in Track 4 studies. (PHC Comments, at 2.)	
14.	**National Resources Defense Council (NRDC)**	SCE's local capacity need for LA Basin should be reduced by 543 MW under either CAISO or SCE models. (at 13)	SDG&E's local capacity need should be reduced by 211 MW as compared to SDG&E's model results or 342 MW as compared to CAISO's modeling results. (at 13)	Reductions justified because energy efficiency assumptions were substantially underestimated. (at 13) Further reductions may be justified from inclusion of CAISO's 2012/2013 transmission plan results and the CEC's 2013 managed demand forecast results. (Testimony, at 9; Comments, at 2)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
15.	**NRG Testimony**	MW Number Not Provided	MW Number Not Provided	Loss of SONGS creates substantial need for new resources in LA and San Diego areas. (at 5.) The loss of 2,246 MW of real power support and 1,100 MVAR of reactive power support degrades the reliability of the local bulk power system. (at 6.)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
16.	**Office of Ratepayer Advocates (ORA)** [242]	MW Number Not Provided	MW Number Not Provided	CPUC should deny SCE's and SDG&Es request for authorization. (at 8-9.) Recommends conservative procurement authorization that while ensuring reliability would minimize costs to ratepayers. (at 13) Recommends need determination and procurement authorization should be based on supplemental joint power flow studies that show the effect of all SCE and SDG&E identified LCR need reduction solutions on the entire SONGS study area. Studies submitted by SCE and SDG&E are insufficient. (at 14-15) The current record lacks adequate information to determine need and optimize procurement allocation for the SONGS study area, so ORA recommends that the Commission find 0 MW of need at the present time. (10/17 email) Although ORA believes that the current record is inadequate to determine need in the SONGS study area, if the Commission nevertheless finds need, it should allocate procurement authority to SCE and SDG&E in manner that minimizes overall procurement, ratepayer costs and greenhouse gas emissions while maintaining reliability in the SONGS study area. (For example, the CAISO determined that overall procurement would be less if 33.3% were located in SDG&E's service territory and 66.7% in SCE's service territory.) (10/17 email)	

[242] Witness Radu Ciupagea.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
17.	**PG&E**[243]	3,302 MW (Table 2-1, at 2-4 of reply testimony)	1,770 MW (Table 2-1, at 2-4 of reply testimony)	Figure II-1 of SCE Track 4 opening testimony, at 8. For SCE, PG&E uses the LA Basin Generation scenario and recommended additional 500 MW of procurement authorization as the identified need.	Table 3 of SDG&E Track 4 opening testimony of John M. Jontry, at 12

243 The numbers cited for Track 4 need by utility represent PG&E's recommendation for a need determination. The need determination should identify the full incremental need (in MW) to meet southern California's local reliability needs given the Track 4 power flow study assumptions made by SCE and SDG&E. These numbers are not incremental to procurement authorized in Track 1 of the 2012 LTPP. To the extent that resources are procured through authorization granted in Track 1 of the 2012 LTPP or other recent procurement authorizations, this need can be met by those estimated amounts to the extent deemed effective at meeting the identified need. Likewise, to the extent that transmission solutions are approved, verified to reduce local reliability needs without building new generation, and on track to be completed in the necessary timeframe, the need can also be met by those estimated amounts to the extent deemed effective at meeting the identified need.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
18.	**Protect Our Communities (POC)**	NA	0 MW	NA	No additional authorization should be made at this time. Current CAISO N1-1 criterion is an unreasonable reliability measure to base Local Capacity Requirement need for SDG&E. In addition, the retirement of the Encina OTC should not be assumed when determining LCR need. Further, the San Diego local area must include the 1080 MW in generation assets connected to SDG&E's Imperial Valley substation.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
19	**Sierra Club**	0 MW (at 1)	0 MW (at 1)	Considering load shedding, the latest CEC demand forecast, and the Mesa Loop-In Transmission Upgrade eliminates the need that CAISO identified in its Track 4 studies. Also, the assumptions do not include enough energy efficiency, demand response, energy storage, or distributed generation; accounting for these resources would eliminate need. Finally, CAISO's N-1-1 reliability standard is overly conservative and resulted in an overinflated estimate of need.	Assuming use of the standard G-1, N-1 SDG&E limiting contingency (which would add 1,080 MW of existing combined cycle generation to LCR capacity), the latest CEC demand forecast, and load shedding eliminates the need that CAISO identified in its Track 4 studies. Also, the assumptions do not include enough energy efficiency, demand response, energy storage, or distributed generation; accounting for these resources would eliminate need. Finally, CAISO's reliability standard (N-1-1 contingency) is overly conservative, and resulted in an overinflated estimate of need.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
20.	**The Utility Reform Network (TURN)**	500 MW (at 9)	500 MW (at 9)	TURN believes there is no "grand plan" to answer the Southern California Reliability needs but that the Commission will need to incrementally consider from a series of competing measures to gradually meet such needs. (at 4-5.)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
21.	Vote Solar	Before authorizing any additional resource procurement in Track 4, SCE should first fulfill entire Track 1 Preferred Resources (PR) procurement authorization and develop the Mesa Loop-In.	Before authorizing any additional resource procurement in Track 4, SDG&E should first fulfill entire Track 1 PR procurement.	If additional resources are still needed, Vote Solar recommends using only PR and storage, phased-in over time as needed with annual solicitations; leverage Distributed Energy Resources (DER), storage & PV-DG to meet LCR in-basin and ensure reliability; use Living Pilot to test interoperability; include smart grid in Living Pilot; and ensure pilot-to-deployment process is developed. Too maximize PV-DG, orient PV to west to address afternoon ramp and use intelligent inverters to provide voltage support on distribution grid; include both in Living Pilot. No need for land set aside for future generation development or options contracts for gas (though preferable to SDG&E Energy Park proposal)	If additional resources are still needed, Vote Solar recommends using only PR and storage, phased-in overtime as needed with annual solicitations; leverage Distributed Energy Resources (DER), storage & PV-DG to meet LCR in-basin and ensure reliability; and develop a parallel pilot to SCE's Living Pilot or participate in SCE's Living Pilot. No need for Energy Park proposal.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
22.	**Wellhead Electric**	MW Number Not Provided	MW Number Not Provided	In comparison to conventional gas-fired generation, the fast acting attribute of energy storage is valuable to the grid with fewer efficiency losses; is also more accurate at tracking fast changing regulation signals. Any procurement authorization should include all resources with attributes able to meet local area needs and ensure that certain classes of resources are not excluded from participation and, as a result, from consideration by the utility customer.(at 7. tyvm. Kerner)	
23.	**Women's Energy Matters (WEM)**	NA	NA	NA	NA
24.	**Western Power Trading Forum (WPTF)**	500 MW (at 4) Recommends all-source RFO as opposed to mandating which specific resources should be used.	NA	SONGS is now permanently retired and the Commission and the affected utilities need to move forward expeditiously to meet the affected need. (at 4)	NA

(END OF ATTACHMENT A)

ATTACHMENT B

SDG&E Procurement Plan Requirements

In the proposed procurement plans to be reviewed by Energy Division, SDG&E shall include all of the following:

1. **Overall description of procurement process:** Major procurement steps, such as soliciting bids, bid evaluation, selection of bids/signing contracts, filing application for Commission approval, expected decision, on-line date. Also include details on contingent contract process including triggers that would necessitate the execution of contingent contracts, option cost, contract terms, and a detailed break up of costs. Describe which elements of the solicitation will be made public.

2. **Timeline**: The procurement plan should contain a detailed timeline that includes an estimate for when resources with specific megawatt quantities are expected to come online up to the year of authorization. The timeline should also include:

   a. Major procurement steps, such as soliciting bids, bid evaluation, selection of bids/signing contracts, filing application for Commission approval, expected decision, and on-line date

   b. A sub-timeline for any contingent contracts

   c. Major decision points for backup procurement when resources do not materialize

3. **Locational details**: Indicate the substations and the locational effectiveness of the sites where the utility plans to procure resources.

4. **Description and quantification of how authorized demand-side resources are incremental**: Detail plans to distinguish resources procured for the purpose of meeting LCR capacity/ energy from resources procured within existing IOU-DSM programs like energy efficiency and demand response.

   a. **For energy efficiency**: Establish baseline planning assumptions that reflect LTPP planning assumptions. Detail how the utility will direct bidders to propose resources whose procurement would exceed the baseline, such as resources with strong economic potential that face a market barrier, resources that are cost-competitive with other resources because of transmission constraints, or vendor identification of "to energy efficiency program baseline" and "above energy efficiency program baseline" savings. State the methodology and assumptions by which the utility will conduct an assessment to quantify the energy efficiency program baseline and the capacity and energy saving values of the incremental resources, including such data sources as impact evaluation studies, engineering estimates, before-and-after operational data using advanced metering infrastructure, or approved measure-based M&V. Document how the assessment uses methods and assumptions consistent with current Commission adopted policy concerning the estimation of savings for energy efficiency projects and measures.

b. **For demand response:** Similar to energy efficiency, demand response load impact from the selected bids should be incremental to the CEC load forecast and the supply assumptions used for this decision. In addition, establish RFO criteria that are consistent with all approved Commission decisions in the demand response rulemaking (R.13-09-011), Commission resolutions addressing demand response, Electric Rule 24, and any approved California ISO determinations of operational characteristics required of demand response to meet local reliability needs. The RFO criteria should provide flexibilities for meeting future adopted demand response policy if the Commission decisions in the demand response rulemaking (R.13-09-011) are pending. Detail how the utility will direct bidder to propose resources capable of meeting these criteria. State the methodology by which the utility will quantify and verify the operation of demand response resources to meet local reliability needs.

5. **LCR and flexible attributes**: Describe the LCR and flexible attributes of the various technology-specific resources considered for procurement. Apply RA counting rules and the ISO "Non Transmission Alternatives"

study in most cases. In cases where there are no defined attributes for a resource, propose attributes with a detailed rationale.

6. **Procurement Process**: Include detailed description of the procurement process resources, specifying the structure of any RFO, bilateral contract, existing procurement programs or alternative procurement process and related timelines. Include information on structure of offers, selection, short listing, and cost competitiveness threshold.
7. **Include evaluation details**. Include a detailed description for evaluating resources which contains the following information:
   a. A process to evaluate different resources in a non-discriminatory fashion
   b. A method to quantify costs and benefits related to capacity, energy, flexibility, GHG, ancillary services etc. for all resources
   c. Standardized assumptions for costs and benefits across resource type
   d. A method to capture non-energy and other quantitative benefits
8. **Include CAM details:** Indicate which resources should be subject to CAM treatment. Indicate which procured resources will count towards IOU program goals.
9. **Project details**: Include details on how its plans to evaluate the viability of preferred resource projects. Also include the following project details for each technology type:
   a. Desired start dates for delivery
   b. Acceptable contract durations
   c. Minimum size in terms of capacity
   d. Interconnection requirements
10. **Other Details**: Include information on the following.

a. Bidder outreach before and after the solicitation including details like bidder conferences, advertisements, and webinars

b. Participation of disadvantaged business enterprises

c. Independent Evaluator (IE) details and IE role

11. **Other statutes affecting procurement:** Cite relevant state laws and Commission decisions influencing this procurement. List potential challenges.

12. **Documents:** Include non-binding pro form as and draft solicitation documents.

(END OF ATTACHMENT B)