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Commissioner	:	Michel Florio
Admin. Law Judge	:	David Gamson
DRA Project Mgr.	:	
	:	
DRA Witnesses		Robert M. Fagan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

REPLY TESTIMONY OF ROBERT M. FAGAN ON BEHALF OF DRA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans Track 4 – SONGS Outage

(R.12-03-014)

San Francisco, California
September 30, 2013

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Q1. What is the purpose and scope of this testimony?

A1. This testimony is in reply to the California Independent System Operator (CAISO), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) Track 4 testimonies submitted on August 5, 2013 (CAISO) and August 26, 2013 (SCE, SDG&E). This testimony focuses on certain input assumptions, methodology, and results of the transmission system modeling (power flow modeling) conducted by the CAISO, and conducted jointly by SCE and SDG&E. In particular, it focuses on mitigation options that include use of special protection systems (SPS) under certain contingency situations, and it explains why reactive power support considerations are critical in any examination of San Onofre Nuclear Generating Station (SONGS) area local reliability. It also contains recommendations on Track 4 procurement needs as they exist at this time.

Q2. Have you testified before in this proceeding and related proceedings?

A2. Yes. I testified in Track 1 of this proceeding, and in the A.11-05-023 SDG&E Power Purchase Tolling Agreement (PPTA) proceeding on behalf of the California Division of Ratepayer Advocates (DRA).

Q3. Please summarize the main Track 4 procurement recommendations contained in the CAISO, SCE, and SDG&E testimonies.

A3. All three of the testimonies consider the need for additional resources in the SONGS study area (which consists of the SDG&E service area and the Los Angeles (LA) Basin portion of the SCE service territory) by 2022 to preserve reliability. The CAISO conducted its own study; SCE and SDG&E conducted joint studies, but each utility makes its own separate assessment and procurement recommendation for its portion of the SONGS study area rather than considering a solution that optimizes procurement in the entire SONGS study area.

The CAISO testifies that a residual need exists for the entire SONGS study area ranging from 2,399 to 2,534 megawatts (MW) (net of Track 1 authorization and net of the A.11-05-023 authorization for Wellhead Escondido and Pio Pico). The upper end of this range includes a residual need of 1,922 MW for the LA Basin, and 612 MW for

San Diego (SD) reflecting an 80% LA / 20% SD resource split.[1] This residual need could be met, at least in part according to the CAISO, by preferred resources and new transmission and reactive resources, and the CAISO indicates it is continuing to study the issues as part of the 2013/14 transmission planning process.[2] Notably, the CAISO recommends that the California Public Utilities Commission (CPUC) wait to make a finding of need for additional resources until the CAISO has "completed its studies of potential transmission mitigation solutions (including the need for additional reactive support)".[3]

SCE indicates that its studies resulted in a residual need of 1,055 MW in the LA Basin (assuming CAISO's 80/20 LA/San Diego resource allocation split),[4] less than the amount of gas-fired generation authorized in Track 1,[5] and thus indicating no incremental Track 4 need;[6] SCE requests an additional 500 MW of Track 4 authorization only to meet CAISO's requirements, which it states are higher due to CAISO's: i) not using SDG&E service territory load shed special protection system (SPS) for N-1-1 conditions, and ii) because of "residual" differences in planning criteria and load and resource assumptions.[7]

SDG&E recommends a range of new resource need of 620 MW to 1,470 MW in the San Diego LCR area, and proposes new procurement of an unspecified quantity of preferred resources in the energy efficiency (EE) and demand response (DR) proceedings,[8] and 500-550 MW of "renewable resources, energy storage and

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[1] The lower end reflects a 67%/33% LA/SD split.

[2] Track 4 Testimony of Robert Sparks on behalf of the California Independent System Operator Corporation, August 5, 2013 (CAISO Opening Testimony) at 30: 1-13.

[3] CAISO Opening Testimony at 31: 1-4.

[4] As noted, CAISO's upper end of residual resource need – 2,534 MW – includes 612 MW need for San Diego, and 1,922 MW for the LA Basin.

[5] Track 4 Testimony of Southern California Edison Company, August 26, 2013 (SCE Opening Testimony) at 11: 2-4.

[6] "The development of Mesa Loop-in and the strategically located Preferred Resources could displace the need for any additional new LCR resources, while still meeting NERC Reliability Standards. However, about 500 MW of new resources is still needed to meet CAISO's higher expectation of need." SCE Opening Testimony at 3: 10-13.

[7] SCE Opening Testimony at 6: 21 – 7: 4.

[8] SDG&E Opening Testimony/Anderson, 4: 6-22.

conventional resources"[9] (but not demand response) in this Track 4 through a request for offers (RFO) issuance. SDG&E notes that new transmission between SCE and SDG&E territories will result in a reduction in an overall need of roughly 1,000 to 1,400 MW.[10] SDG&E does not directly include the effect of any load shedding SPS when considering the range of need[11] even though it acknowledges the presence of a Western Electricity Coordinating Council (WECC)-approved SPS for the key N-1-1 contingency event.[12] SDG&E does not attempt to reconcile SCE's use of load-shedding SPS in the event of the N-1-1 contingency event, with SDG&E's failure to assume an SPS. SDG&E includes some EE, solar photovoltaic (PV), combined heat and power (CHP), and local renewables – but no demand response - in its model as reductions to identified need.[13]

The three testimonies use different assumptions for different parameters in estimating resulting Track 4 procurement recommendations; the key differences essentially revolve around i) the method of study used and related assumptions for use of an N-1-1 special protection scheme (SPS) that allows controlled load drop, ii) reactive power and transmission assumptions, and iii) the way in which preferred resource deployment levels are assumed or used in the different models.

Q4. What is "load shed" or "controlled load drop?"

A4. "Load shed" or "controlled load drop" are terms used to indicate a series of actions that a transmission operator (e.g., the CAISO, SCE or SDG&E) can utilize, if necessary, to open circuits and shed load in response to certain severe or multiple contingency events on the system, such as loss of multiple transmission or generating elements during stressed grid conditions. Load shed or controlled load drop can be done automatically or on a manual basis. It can occur almost instantaneously in the case of automatic load

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[9] SDG&E Opening Testimony/Anderson, 5: 1-5.

[10] SDG&E Opening Testimony (Anderson), 2: 14-16.

[11] SDG&E Opening Testimony (Jontry) at 1: 18-19 and 6: 20-21. Mr. Jontry specifically states, without explanation, that "a load-shedding Special Protection Scheme (SPS) was not assumed to be allowed" for the N-1-1 event. Mr. Jontry does state that the load-shedding SPS is used for the worst G-1/N-1 contingency to mitigate the N-1-1 event (6:21 – 7:3) which appears to indicate that he uses the load-shed for an overall G-1/N-1-1 circumstance, where two 500 kV lines are lost sequentially during a time when the largest generator is out of service, during a peak load period.

[12] SDG&E Opening Testimony/Jontry, at 7: 1-3.

[13] SDG&E Opening Testimony (Anderson), 10:17 – 11:10.

shed, or can take place over a period of minutes or hours if done manually. Controlled load drop can be part of a special protection system (SPS) or a remedial action scheme (RAS).

Q5. What is a special protection system (SPS) or a remedial action scheme (RAS)?

A5. The North American Electric Reliability Corporation (NERC), proposed the following definition for an SPS:

> "A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading. Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration."[14]

Thus, an SPS is an operational tool that is designed to detect a particular system condition that is known to cause unusual stress to the power system and to take some type of predetermined action to counteract the observed condition in a controlled manner. In some cases, SPSs are designed to detect a system condition that is known to cause instability, overload, or voltage collapse. The action prescribed may require the opening of one or more lines, tripping of generators, intentional load shed or controlled load drop, or other measures that will alleviate the problem of concern.

Q6. Why would an SPS be selected over building new transmission facilities or new generation to maintain grid reliability?

A6. Implementing an SPS can occur more quickly and at a lower cost than building new infrastructure. As noted by CAISO in its June 23, 2011 CAISO Planning Standards:[15]

> "The primary reasons why SPS might be selected over building new

[14] NERC, proposed definition in "Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards: Revision 0.1 – April 2013 at 11 and appended as Attachment A and available at http://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/SAMS-SPCS_SPS_Technical_Reference_Final_Rev0_1.pdf.

[15] Track 1 Exhibit (Ex.) ISO 19 (CAISO Planning Standards, June 23, 2011, p. 7) Available at http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

> transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions."

SPSs can be especially attractive to address low-likelihood events that might not merit the investment of major transmission or generation assets, but nonetheless could be a threat to reliability. SPSs can also serve as a "bridge" mitigation measure to ensure reliability prior to the completion of planned infrastructure assets. The CAISO also notes its concern with SPS's:

> "While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical."[16]

[16] Track 1 Ex. ISO 19 at 7.

Q7. The most critical N-1-1 contingency in the SONGS study area is the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink. Does the CAISO's Track 4 analysis include the use of load shedding in response to this N-1-1 contingency?

A7. No. As shown in the attached August 22, 2013 Data Request response from the CAISO, it did not.[17]

Q8. Do reliability standards permit the use of SPS's in response to an N-1-1 contingency event?

A8. Yes, explicitly. CAISO indicates this, for example, in the 2018 Local Capacity Technical Analysis, Final Report and Study Results, April 30, 2013.[18] At page 11, the C3 (N-1-1) event is listed adjacent to the box that identifies "Planned and Controlled Load Shedding Allowed."

Q9. Does the CAISO have discretion to implement SPSs that include load shed, for transmission planning purposes, in order to reduce the supply or load-side resources needed to meet LCR?

A9. Yes, for severe multiple contingency conditions such as the N-1-1 that defines the LCR need estimate in this proceeding, in accordance with its planning standards.

Q10. Would use of controlled load drop or a SPS in response to this N-1-1 contingency impact the total resource need resulting from loss of SONGS?

A10. Yes. SCE has indicated the need would be lowered by 436 MW in the LA Basin.[19] SDG&E indicated that without the possibility of load shed arrangements, the LCR requirements for the San Diego LCR area increase by over 1,000 MW.[20] The specific

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[17] August 22, 2013 Data Request response from the CAISO to question 4, fourth set of data requests from DRA, California Justice Alliance, Sierra Club California and the Clean Coalition, appended as Attachment B.

[18] 2018 Local Capacity Technical Analysis, Final Report and Study Results, April 30, 2013, p. 11 appended as Attachment C.

[19] SCE Opening Testimony at 8 (Figure II-1) and at 6: 19-20.

[19] SCE Opening Testimony at 8 (Figure II-1) and at 6: 19-20.

[20] SDG&E references the CAISO Final 2013 LCT Technical Study that indicates an over 1,000 MW difference in LCR when load-shedding is not included as part of the mitigation. SDG&E Opening Testimony/Jontry at 7: 11-14.

effect depends upon the circumstances. Implementing a SPS to address the contingency loss of Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink would be far less costly than procuring either 1,000 MW or 436 MW of new generation. Using $1,363/kW as the installed capital cost for a combustion turbine (from SCE’s Track 4 testimony workpapers, Exhibit No. SCE-01 / Ch. IV.A page 4, which rely on the California Energy Commission cost of generation data), the costs for installing new gas-fired generation in lieu of use of an SPS for the N-1-1 would range from roughly $595 million (436 MW) to $1.36 billion (1,000 MW) using these quantities as bookends.

Q11. When considering use of an SPS, versus adding at least hundreds of MW of incremental supply resource to cover infrequent contingency events, would it be reasonable to assess the comparative costs and benefits of each option?

A11. Yes. Ultimately, the question is one of “service reliability,” rather than grid reliability. The CAISO can ensure grid reliability – e.g., protect the overall CAISO grid against catastrophic voltage instability, and an accompanying large-magnitude loss of load (e.g., on the order of tens of thousands of MW) – by instituting a WECC-approved SPS for the N-1-1 event in question at a cost much lower than that required if hundreds of additional MW of supply resource are deployed instead. But the amount of money spent to preserve “service reliability,” or the extent to which relatively limited outages might infrequently occur effecting groups of customers, belongs in the domain of the CPUC –what costs are reasonable for ratepayers to bear to ensure a certain level of insurance against extreme contingency events?

Q12. As part of its Track 4 analysis, does CAISO or SDG&E conduct any form of cost/benefit analysis of planning to address the most critical contingency in the SONGS study area by investing in hundreds of MW of new generation, rather than considering use of a SPS or RAS to shed load in certain extreme event circumstances? Do they provide a cost/benefit ratio for improved "service reliability?"

A12. CAISO does not, to my knowledge; SDG&E states that it has not performed such an analysis.[21] There is no direct analysis that compares the likely benefits to ratepayers of planning to either the more conservative guideline that CAISO uses, or planning that includes use of a load-shedding SPS or RAS to ensure system reliability in the event of the N-1-1 contingency that drives SONGS area reliability need in this case.

Q13. Are the CAISO standards simply guidelines or formal standards, when concerning the use of SPSs?

A13. Based on the CAISO Planning Standards document itself, my understanding is that the CAISO standards *as they relate to SPS use at least* are guidelines. The document states

> "It needs to be emphasized that these are guidelines rather than standards. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgment will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications."[22]

The NERC requirements allow the use of load-shedding remedial action schemes (RAS), or special protection systems (SPS), in the event of a sequential loss of both 500 kV lines into the San Diego region (i.e., N-1-1 Category C3 contingency event).[23] As noted, SDG&E's recommended resource need excludes the possibility of using SPS as part of

[21] "SDG&E has not conducted any studies quantifying the cost effectiveness of load-shedding versus new in-basin generation resources." SDG&E response to DRA-Sierra Club- CEJA data request second set, response to question 2, appended as Attachment D.

[22] Track 1 Ex. ISO 19 at 7.

[23] SCE Opening Testimony at 27: 9-15.

mitigation for the N-1-1 contingency event. CAISO does not include use of an SPS to mitigate against the category C3 N-1-1 contingency event of the sequential loss of the two 500 kV lines into the SDG&E area.

Q14. Do the studies indicate that load shed would be needed during any instance of a contingency loss of both 500 kV lines?

A14. No. I note that both CAISO and the joint studies conducted by SCE and SDG&E model the N-1-1 event occurring at the same time as the system experiences a 1-in-10 summer peak load.[24] In the event that the N-1-1 event occurs at other times, required mitigation measures to ensure reliability during those times would be less than what is seen in the Track 4 modeled studies.[25] No estimates of the likelihood of the N-1-1 event occurring simultaneous with a 1-in-10 year summer peak were included in the testimony of the CAISO, SCE or SDG&E.

Q15. How frequently does the load reach the level indicted by the use of 1-in-10 peak loads, and how high is the load during other times during the summer?

A15. By definition, the 1-in-10 peak load is reached relatively infrequently,[26] and the pattern of loading that exists for the rest of the summer can be described in aggregate by a load duration curve. The following graph is a summer load duration curve taken from the posted CAISO presentations for the preliminary results of the 2013/14 transmission planning process. As seen, it illustrates the relationship between duration and magnitude of load in the key part of the affected region over the course of the summer, and shows (for example) that the highest 700 MW of load on the combined Orange County SCE/SDG&E region occurs for no more than (roughly, as gauged visually) 89 hours over the course of the 3,672-hour period between May 1 and September 30th, or less than 2.5% of the total hours in the period.

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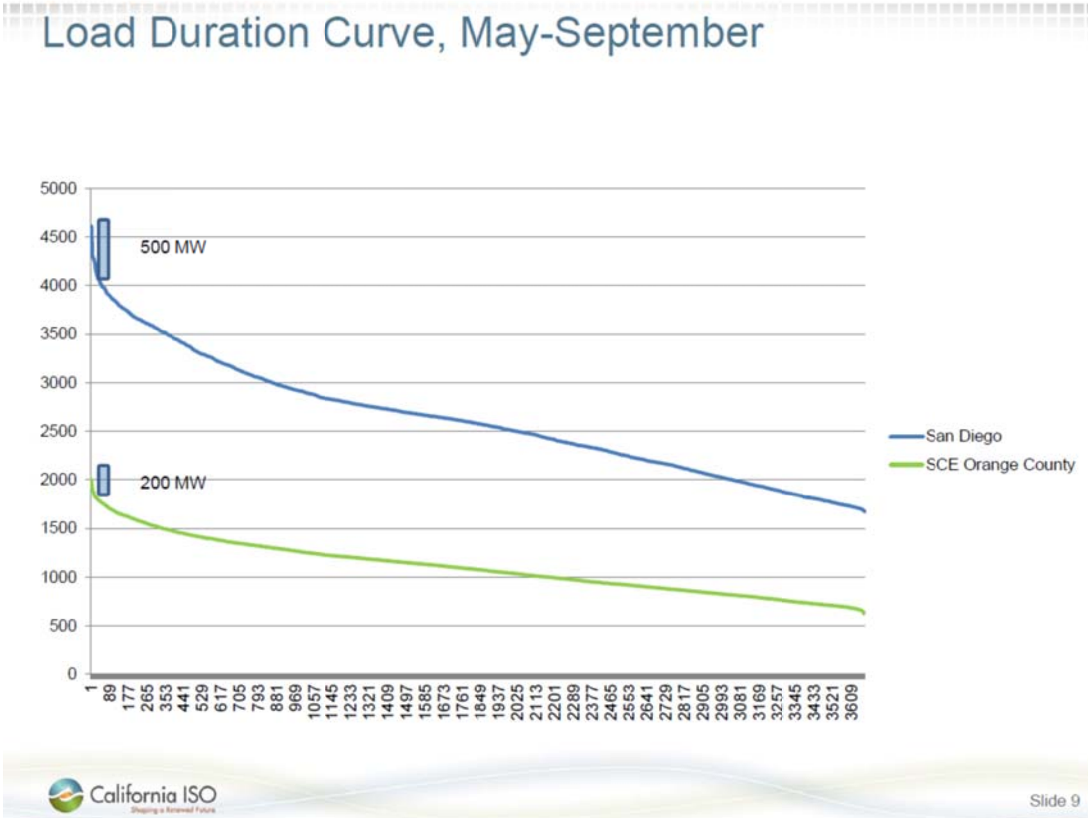
[24] A 1-in-10 summer peak load is the forecasted peak load from the CEC forecast Form 1.5d. *See e.g.* Atttachment E.

[25] Assuming the same supply resource availability at the time of the contingency, the required mitigation amounts would be lower than computed needs by roughly the level of peak load at the time of the event.

[26] The Replicating TPP Scenario of Track 2 used a 1-in-5 peak load, and the hourly load profile used in that CAISO-run scenario indicated that one hour of one summer day exhibited the peak load value.

Figure 1. CAISO Presentation of Summer Load Duration Curve for San Diego and Orange County Portion of LA Basin



Source: CAISO Presentation, "Determining an Effective Mix of Non Conventional Solutions to Address Local Needs in the TPP", Robert Sparks, Regional Transmission, 2013/2014 Transmission Planning Process Stakeholder Meeting September 25-26, 2013. Slide 9. Full presentation available at http://www.caiso.com/Documents/Presentation-PreliminaryReliabilityAssessmentResults-Sep25_2013.pdf

Q16. Are you explicitly recommending at this time that CAISO allow the use of a load-shedding SPS for the N-1-1 event that drives SONGS area grid reliability?

A16. No. I am not in a position to fully evaluate all of the nuances of this particularly extreme transmission contingency event. Only the CAISO and the affected utilities have all the relevant information and experience to carefully and comprehensively assess all dimensions of the issue. However, the CAISO has not yet demonstrated that excluding SPS consideration for this particular N-1-1 event is clearly called for. In Mr. Sparks' testimony in A.11-05-023, he indicated:

> "With the more likely N-1-1 contingency we did not think it would be prudent to plan the system that would rely on the same type of load shedding SPS."[27]

But there was no documentation provided that supported the asserted greater likelihood of that particular N-1-1 event; and to the extent the "prudent" applies to economic prudence, no cost/benefit information was provided to support such a planning decision as necessary to maintain grid reliability. To the extent the CAISO's recommendation includes its judgment about service reliability, such a determination more properly belongs with this Commission.

CAISO has not yet supported a case where the applicable planning criteria should be more stringent than NERC standards on category C3 events. Unless the CAISO does this, I recommend that the Commission consider LCR needs based on a default assumption that uses the NERC Category C3 minimum requirements, which allow for a load-shed SPS for the N-1-1 event in question.

Q17. Are there other circumstances relevant to this Track 4 proceeding that support consideration of using an SPS as part of the mitigation for this N-1-1 contingency?

A17. Yes. The SPS could be in place, if needed, only as a "bridge" measure, depending on future transmission and/or preferred resource development circumstances. For example, if a new 500 kV transmission connection between SCE and San Diego (or a similarly equivalent project such as SDG&E's proposed Direct Current line between Imperial Valley and SONGS Mesa) 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, say, 2020, but would reach such a level a few years later, the SPS could serve as a bridge during that period. Essentially, the SPS could serve as a cost-avoidance measure to bridge the gap between when need is first seen, and when preferred resources (and/or transmission) come online.

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[27] Supplemental Testimony of Robert Sparks, served April 6, 2012 in A.11-05-023, at 4:18-19, appended as Attachment F.

Q18. What is the constraint that drives LCR need and what reactive resources have not yet been modeled by CAISO to assess their effect on need?

A18. The constraint that drives LCR resource need for the SONGS area is post-transient voltage instability under a N-1-1 contingency scenario.[28] Reactive resources in the SONGS area are critical for avoiding voltage instability in the event of the driving contingency events, sequential loss (N-1-1) of the two 500 kV lines into the San Diego area. CAISO has included some, but not all reactive resources identified by SCE and SDGE in this Track 4 analysis,[29] and recognizes and anticipates that additional reactive resource analysis will be conducted as part of the 2013/14 TPP analyses.[30] Among the reactive resources not yet considered analytically that the CAISO should model are i) additional synchronous condenser facilities (totaling 480 MVAR) at Cannon/Encina and Suncrest,[31] and ii) additional synchronous condenser facilities at SONGS.[32] It is understandable that CAISO may consider additional or substitute facilities beyond these two items during the course of the 2013/14 TPP.

Q19. Aside from the difference in whether to consider use of an SPS, what are the main differences across the studies undertaken jointly by SCE/SDG&E, and CAISO?

A19. DRA has identified several notable differences between the Track 4 studies undertaken by CAISO and by SCE/SDG&E.

- **Reactive power and transmission**. SCE and SDG&E's studies included a number of additional transmission and reactive support projects in different combinations in their

[28] CAISO Opening Testimony at 18: 17-22.

[29] 320 MVAR shunt capacitors (Johanna, Santiago, Viejo); 480 MVAR SVC (near SONGS); 240 MVAR synchronous condensers (Talega); 150 MVAR shunt capacitors (Penasquitos). CAISO Opening Testimony at 15: 12-24.

[30] CAISO Comments on Track 2 and Track 4 schedules, September 10, 2013.

[31] SCE Opening testimony Table III-3at 28.

[32] Southern California Reliability Preliminary Plan, joint presentation by CEC (Sylvia Bender), CPUC (Edward Randolph), CAISO (Phil Pettingill), September 9, 2013, slide 8, appended as Attachment G, "Evaluate conversion of one San Onofre unit to a synchronous condenser." *See also Preliminary Reliability Plan for LA Basin and San Diego*, DRAFT, August 30, 2013(indicating at page 4that conversion is possible by the summer of 2015 (appended as Attachment A to DRA's Testimony of Nika Rogers)).

scenarios that were not modeled in the CAISO analyses[33] and that have the effect of lowering SONGS area local resource need. Those projects, many of which are likely to be online by or before the modeled year 2022, or the end of 2020 (the year for once- though cooling (OTC) retirement for West Los Angeles Basin OTC units), or even before the end of 2017 (the Encina OTC steam units retirement date)[34] include the following, in rough order of impact on "residual" resource need in the region:

- Mesa substation build-out and loop-in of 500 kV lines. This project could reduce local capacity requirements (LCR) need by 1,196 MW in the LA Basin.[35]
- Suncrest and Cannon/Encina synchronous condenser alternatives. These projects will add a total of 480 MVAR of dynamic reactive support incremental to the suite of reactive resource increases that CAISO modeled in its studies.
- Increasing Ellis-Johanna and Ellis-Santiago lines to their full conductor ratings. Upgrading limiting elements at the terminal points of these lines will allow for fuller utilization of these 230 kV transmission assets. Alternatively, or additionally, synchronous condensing at the SONGS facility itself is feasible.
- New Escondido-Talega 230 kV line in the San Diego region.
- Potential new 500 kV connection between the SCE and SDG&E service territories.

- **Method of power flow study**. CAISO uses more stringent reliability criteria in determining the LCR need for the LA Basin and the San Diego regions than that used by SCE and SDG&E in the joint study. In addition to the SPS use limitations discussed above, CAISO uses "applicable WECC voltage stability criteria"[36] which includes

[33] SCE Opening Testimony, Table III-3 at 28, items 6 through 11.

[34] It is my understanding, based on the scope of the work that the Ellis-Johanna and Ellis-Santiago line improvements could be in place by or before 2017. The synchronous condensers at Cannon/Encina are conceptual at this stage but similar sized units are contained in SDG&E's Five-Year Studies (*see* SDG&E 2012 Grid Assessment Results, CAISO Stakeholder Meeting, September 26-27, 2012, presentation at pages 5 and 20-23, appended as Attachment H). Thus, it is reasonable to think a Cannon/Encina location could be completed by or before 2022. SCE indicates the Mesa loop-in by 2020 may be feasible. SCE Opening Testimony at 47: 1-5. A SONGS conversion to synchronous condenser could be in place by 2015. A new 500 kV connection between SCE and SDG&E would likely take at least 10 years to plan, permit and construct and thus is not likely to be available by 2022, but could potentially be available shortly thereafter.

[35] SCE Opening Testimony at 8: 5-7.

[36] CAISO Opening Testimony at 18:21-22.

increasing the load by 2.5% above the 1-in-10 peak forecast in order to test for sufficient reactive margin.[37] SCE's study did not use this criterion.[38] SCE studies are based on meeting NERC minimum requirements. While SDG&E recommendations from the studies exceed NERC minimum requirements because they do not assume use of an SPS for the N-1-1 event.

- **Treatment/Consideration of Preferred Resources**. SCE and SDG&E's studies incorporate at least one scenario with greater levels of preferred resource use than used by the CAISO. The CAISO's analysis used a "low" level of incremental energy efficiency and relatively low levels of demand response, per the Scoping memo.[39] CAISO also assumed increased distributed generation of 457 MW of effective capacity (NQC).[40] SCE indicates that its starting point, used in its "LA basin generation" scenario, is also the "low" level of incremental EE.[41] SCE then indicates (in its preferred resource scenario) that its use of preferred resources including EE and DR and storage and PV will reduce LCR need in the LA Basin by 551 MW. This 551 MW arises from the presence of 678 MW of preferred resources in SCE's preferred resource scenario.[42] SDG&E indicates that it uses the mid-case level of uncommitted EE in its studies.[43] While the preferred resource scenario executed by SCE does not necessarily include all potentially available preferred resource, both SCE and SDG&E are intending to "aggressively pursue"[44] preferred resources.

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[37] See. e.g., SCE opening testimony at 27: 3-15, and CAISO response to First Set of Data Requests of DRA, CEJA, Sierra Club, and the Clean Coalition, question 16 (b). Appended as Attachment I.

[38] SCE Opening Testimony at 27: 8.

[39] CAISO Opening Testimony at 5: 1--7: 12.

[40] CAISO Opening Testimony, Table 5, at 9:1-2.

[41] SCE Opening Testimony at 13: 21-22.

[42] SCE Opening Testimony Table III-1 at 18: 3-4.

[43] SDG&E Opening Testimony/Anderson at 6: 11-12.

[44] SCE Opening Testimony at 4: 19, and SDG&E Opening Testimony/Anderson at 4:6 and 4: 13.

Additionally, CAISO uses different "planning criteria" and some differences in load and resource assumptions, compared to the SCE/SDG&E studies.[45] This leads to a further difference (beyond the load shed effect of 436 MW) in CAISO vs. SCE's determination of LCR need for the LA Basin of 484 MW.[46]

Q20. Do CAISO studies recognize the need to consider reactive power solutions when examining SONGS local area reliability needs?

A20. Yes. As indicated in the June 28, 2013 motion DRA jointly filed with the California Environmental Justice Alliance, and Sierra Club California to Amend the Revised Scoping Memo to Reflect the Closure of the San Onofre Nuclear Power Station Generating Facilities,[47] CAISO had recognized that SONGS might remain off line for an extended period of time, analyzing the possibility in its 2013 Local Capacity Technical Analysis, Addendum to the Final Report and Study Results, Absence of San Onofre Nuclear Generating Station (LCT Study without SONGS Addendum),[48] in its briefing to the CAISO Board of Governors at the General Session Meeting on December 13-14, 2012,[49] and its 2012-2013 Transmission Plan, approved by the CAISO Board of Governors in March of this year. The studies and CAISO's presentation to its Board of Governors underscore the key role that reactive power should play in replacing SONGS. The LCT Study without SONGS Addendum determined that the absence of

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[45] As we note, these differences are related to the use of WECC voltage stability criteria (CAISO Opening Testimony at 18: 17-23) and differences in "load and resource assumptions" (SCE Opening Testimony footnote 7 at 7) used in the specific modeling.

[46] SCE Opening Testimony at 6: 22 – 7: 1.

[47] Motion of the Division of Ratepayer Advocates, California Environmental Justice Alliance, and Sierra Club California to Amend the Revised Scoping Memo to Reflect the Closure of the San Onofre Nuclear Power Station Generating Facilities, June 28, 2013.

[48] 2013 Local Capacity Technical [LCT]Analysis, Addendum to the Final Report and Study Results, Absence of San Onofre Nuclear Generating Station, August 20, 2012 (LCT Study without SONGS Addendum Appended as Attachment J). Available at http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf.

[49] Briefing on Nuclear Generation Studies Preliminary Results, presented by Neil Millar, Executive Director of Infrastructure Development, to the Board of Governors Meeting General Session on December 13-14, 2012 (Briefing on Nuclear Generation). Slides 8-11 are appended to these comments as Attachment K and the full presentation is available at http://www.caiso.com/Documents/BriefingNucl … sPreliminaryResults-Presentation-Dec2012.pdf.

SONGS created voltage support deficiencies in both the LA Basin[50] and in the San Diego local capacity areas.[51] CAISO therefore recommended "[a]mixture of dynamic (i.e., synchronous condensers) and static (shunt capacitors) reactive support … in order to satisfy fast voltage recovery need at the SONGS 230 bus without causing further operational concerns."[52]

The December 13-14, 2012 Briefing to the CAISO Board of Governors also highlighted the importance of reactive power by including continuous use of synchronous condensers and SVC [static var compensators] support in the primary options for mitigating the loss of SONGS.[53] More recently, the "Preliminary Reliability Plan for LA Basin and San Diego, produced jointly by CAISO, the CPUC and the CEC (Draft, August 30, 2013) lists "Additional Reactive Power Support" as the first item in the "Transmission" category when discussing mitigation for near-term needs, and indeed four of the five items in that category are reactive power or voltage-related measures.

I expect the 2013/14 transmission planning process to effectively update and revise what is already contained in CAISO's 2012-2013 Transmission Plan, which focused on mid-term (2018) and long-term (2022) solutions for maintaining grid reliability in the absence of SONGS. The 2012-2013 Transmission Plan considered two mid-term alternatives. The first mid-term alternative recommends installation of 650 MVAR of dynamic reactive support, while the second recommends installation of "a total of 1,460 MVAR of SVC or SC for dynamic reactive support at SONGS, Talega, Penasquitos, San Luis Rey and Mission Substations."[54] The two long-term generation mitigation strategies show a need for dynamic reactive support ranging from 1,460 – 2,010

[50] "Overall the LA Basin LCR needs are now driven by a new overlapping Category C contingency in the San Diego's electric system, due to voltage support needs that arise in the area." LCT Swithout SONGS - Addendum at 3.

[51] "The San Diego sub-area requirements have increased significantly, by 966 MW, and the San Diego – Imperial Valley area requirements have increased also by 447 MW, due to voltage support needs in the absence of SONGS." LCT Study without SONGS Addendum at 3.

[52] LCT Study without SONGS Addendum at 4.

[53] Briefing on Nuclear Generation, slides 8-11.

[54] CAISO 2012-2013 Transmission Plan, March 20, 2013, at 173. Appended as Attachment L and available at http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

MVAR.[55] The two combined transmission and generation alternatives show a total of 1460 MVAR of support needed.[56]

The precise amount of reactive support of reactive support needed in the absence of SONGS depends on the assumptions used, including the type of contingency, but in all cases, reactive power is an essential component of any mid- or long-term solution to SONGS retirement.

Q21. Please summarize the overall effect these differences in modeling between CAISO and the joint SCE/SDG&E, and related issues of reactive power availability and preferred resource deployment can have on procurement need for Track 4?

A21. Taking these modeling differences into account, recognizing that reactive resources and new transmission will affect all estimates of need, and appreciating that preferred resources can constitute a significant part of any overall residual need, the power flow study results put forth by SCE and SDG&E do not show a definitive need (beyond Track 1 authorizations) in 2022 for new fossil-based resources in the LA Basin or San Diego area to make up for perceived shortfalls due to an early SONGS retirement (if one uses the NERC reliability requirements as a guide and allows for use of a load-shedding SPS in the event of an N-1-1 contingency event). This is the case even if one does not assume any new 500 kV connection between the SCE and SDG&E regions, as residual needs after Track 1 authorization can be made up by some combination of reactive support, near-term (by 2020 or earlier) transmission project completion, and preferred resources comprised of EE, DR, PV, storage, and CHP.

The modeling results show a likely need for preferred resources if no new fossil procurements are to be considered at this time, although until the updated power flow studies are completed by CAISO as part of the 2013/14 TPP the levels of preferred resources required cannot be confirmed.

[55] CAISO 2012-2013 Transmission Plan, Table 3.5-10 Summary of Generation & Dynamic Reactive Support Need (No SONGS Analyses) Mid- and Long-Term (Generation) Options, at 85.

[56] 2012-2013 Transmission Plan, Table 3.5-11 Summary of Generation & Dynamic Support Needed (No SONGS Analyses) Mid- and Long-Term Combined Transmission and Generation Alternatives, at 188.

Q22. Should the Commission approve CAISO's recommendation to "wait to make a decision about the need for additional resources until the ISO has completed its studies of potential transmission mitigation solutions (including the need for additional reactive support)?"[57]

A22. Yes. Track 4 procurement considerations should be informed by CAISO modeling of these reactive power and other transmission solutions that improve the overall utilization of the transmission system in either area, or between SCE and SDG&E's service areas. The effect of such infrastructure must be considered and modeled before a final need determination is made especially given how sensitive resource need is to reactive power and transmission related issues. This is the case because the driving constraint for the SONGS area local reliability concern is a grid voltage stability issue that can be addressed at least in part – perhaps significant part - by means other than raw MW fossil-based supply additions. The analysis that CAISO completed in the 2012-2013 Transmission Plan demonstrates that many hundreds of megawatts (MWs) of procurement can be avoided by effectively deploying more reactive power.[58] Failing to examine a reasonable range of reactive power options in the modeling effort will frustrate the Commission's and parties' work to identify the best solutions to replace SONGS and could lead to significant, expensive over procurement that undermines California's greenhouse gas (GHG) reduction goals.

Improving transmission and reactive power resources allows real power (MW) from outside the area to more easily, and reliably (i.e. without causing unacceptable voltage instability), flow around and into the SONGS local reliability area during stressed grid conditions. Such modeling should account for the possibility of synchronous condenser installation at SONGS, other synchronous condenser installations considered in the SCE and SDG&E studies, and other transmission improvements beyond those already included in CAISO's Track 4 model.

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[57] CAISO Opening Testimony at 32:1-4.

[58] 2012-2013 Transmission Plan at 190-193.

Q23. What changes do you recommend to any future power flow analysis CAISO undertakes as part of the Track 4 or in the 2013/14 TPP in consideration of the issues in this testimony?[59]

A23. I recommend that CAISO model all reasonable reactive power and other transmission infrastructure options across SCE and SDG&E's service areas (as noted in this testimony, and in SCE and SDG&E's testimony) to ensure that all elements of a least-cost, best-fit solution to SONGS early retirement have been explored.

CAISO should also include as sensitivities to its 2013/14 TPP studies, more aggressive assumptions for preferred resources than have been used in Track 4, to help parties understand the effect that such deployment could have on residual resource need by 2022. Specifically, the assumptions should include the following:

- Use of mid-level incremental energy efficiency in the SCE and SDG&E service territories.[60] These values should be aligned with data that will be available in the 2013 Integrated Energy Policy Report (IEPR).[61]
- Options for "2nd contingency" DR resources to be presumed to be available to reduce anticipated demand on the highest-load days of the year through pre-contingency dispatch of the resource.[62]

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[59] ALJ Gamson asked parties to comment on updates to assumptions that should be considered. Reporter's Transcript, September 4, 2013, Prehearing Conference 4 (RT) at 318. This response addresses that question. Reporter's Transcript, September 4, 2013, Prehearing Conference 4 (RT) at 318.

[60] It is not unreasonable to consider (even if just as a sensitivity) mid-level incremental EE assumptions for the SCE service territory even though the local area benefit will accrue only from EE deployment in a sub-portion of SCE's territory. In general, over the long-term, EE programs are designed to be deployed throughout service territories and participation should be seen across all of SCE's service areas.

[61] Energy Efficiency estimates should rely on best available information, including the results from the 2013 California Energy Efficiency Potential and Goals Study, available at: http://demandanalysisworkinggroup.org/documents/2013_08_16_ES_Pup_EE_Pot_final/2013_California_Energy_Efficiency_Potential_and_Goals_Study_Final_Draft_20130807.pdf

This new 2013 Potential and Goals Study indicates at page 5 of the Executive Summary that EE market potential is 50% greater in 2024 than what was forecasted in the 2011 Potential Study. *See* Attachment M.

[62] DR program design, incentive structure, and operating parameters needs to recognize and include this form of use of DR resource. While this is best explored in the DR proceeding, there is no reason the LTPP proceeding has to presume only a limited form of DR resource availability (i.e., 30-minute response or better) for resource planning purposes.

- Inclusion of some level of storage resource beyond the 50 MW authorized in Track 1.[63]

- Sensitivity runs that include higher levels of PV and CHP than is currently assumed in the models (as is currently specified by the Track 4 scoping memo assumptions).

Lastly, even though CAISO does not currently support use of an SPS load-shedding scheme when considering the effect of the specific N-1-1 contingency event that is the binding constraint for SONGS local area reliability, the Commission would benefit from understanding the specific LCR need effect (or range of effect) that results if an SPS was to be part of local area mitigation for the sequential loss of the two 500 kV lines.

Q24. Should the effect on SONGS area LCR need also be modeled with a new 500 kV connection in place between SCE and SDG&E?

A24. Yes. The Commission should be aware of the effect such a new connection would have on local area needs, even if just at a relatively high level priority to obtaining a detailed understanding of routing or cost concerns, for example. It is possible that investment in such a project could minimize or eliminate the need for incremental investment in local supply-side conventional resources in support of local area needs, and it might not be cost-effective, or logical, to invest in any new fossil resources at this time if such a transmission project were to be in place by, say, 2025.

Q25. What is your overall recommendation?

A25. I recommend that the Commission base any determination of LCR need in Track 4 on power flow study results that include scenarios with additional reactive power support, SCE and SDG&E's conceptual transmission solutions, and other relevant transmission system solutions identified by CAISO or the utilities. Such study results should show residual LCR needs – if any - when near-term reactive support solutions and longer-term transmission solutions are present, along with different levels of preferred resource

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[63] A recent proposed decision (PD) in R.10-12-007 outlines energy storage procurement targets of 580 MW each for Pacific Gas and Electric Company (PG&E) and SCE and 165 MW for SDG&E through 2020. Proposed Decision Adopting Energy Storage Procurement Framework and Design Program, issued September 3, 2013 in R.10-12-007, available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=76387254

deployment. This information should help guide the Commission in identifying the specific resource combination that ensures local reliability for the entire SONGS study area (not just for LA Basin and SDG&E service area separately), that does so cost-effectively, and that aligns with the state's policy goals on loading order and greenhouse gas emission reduction.

If the Commission decides to move forward with consideration of Track 4 procurement authorization without comprehensive information on how incremental reactive power support and SCE and SDG&E's conceptual transmission solutions can minimize overall resource need in the SONGS study area, then it should adopt a cautious approach to such authorization. This is especially so given the expectation in the September 16, 2013 "Assigned Commissioner and Administrative Law Judge's Ruling regarding Track 2 and Track 4 Schedules" that "any procurement authorization will not be subject to further review based on additional evidence in this proceeding."[64] If any interim finding is to be made, it should be limited to authorization for preferred resources only.

[64] Assigned Commissioner and Administrative Law Judge's Ruling regarding Track 2 and Track 4 Schedules, September 16, 2013, pp. 3-4.

WITNESS QUALIFICATIONS – ROBERT M. FAGAN

Q1. Please state your name, position and business address.

A1. My name is Robert M. Fagan. I am a Principal Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since 2005.

Q2. Please state your qualifications.

A2. My full qualifications are listed in my resume, on the following pages. I am a mechanical engineer and energy economics analyst, and I have examined energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, especially economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives including on-shore and off-shore wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives.

I hold an MA from Boston University in Energy and Environmental Studies and a BS from Clarkson University in Mechanical Engineering. I have completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design and mechanical and aerospace engineering.

Q3. Have you testified before the CPUC before?

A3. Yes, in Track 1 of this proceeding, and in the A.11-05-023 SDG&E need case. I have also testified in numerous state and provincial jurisdictions, and the Federal Energy Regulatory Commission (FERC), on various aspects of the electric power industry including renewable resource integration, transmission system planning, resource need, and the effects of demand-side resources on the electric power system.

Q4. On whose behalf are you testifying in this case?

A4. I am testifying on behalf of the California Public Utilities Commission's Division of Ratepayer Advocates (DRA).

Robert M. Fagan

Principal Associate
Synapse Energy Economics, Inc.
485 Massachusetts Ave., Suite 2, Cambridge, MA 02139
(617) 453-7040 • fax: (617) 661-0599
www.synapse-energy.com
rfagan@synapse-energy.com

SUMMARY

Mechanical engineer and energy economics analyst with over 25 years of experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind power integration into utility systems.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based tools, industry standard tools for production cost and resource expansion, building energy analysis, understanding of power flow simulation fundamentals).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.

- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Principal Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of PJM and MISO wind integration and related transmission planning and resource adequacy issues.
- Analysis of California renewable energy integration issues and related long-term procurement policies.
- Analysis of Eastern Interconnection Planning Collaborative processes, including modeling structure and inputs assumptions for demand, supply and transmission resources.
- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM’s economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative; and ongoing analysis of the energy efficiency programs of New Jersey Clean Energy Program (CEP) and various utility-sponsored efficiency programs (RGGI programs).
- Analysis of California renewable integration issues for achieving 33% renewable energy penetration by 2020, especially modeling constructs and input assumptions.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy “firming” premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.

- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations.

Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training and Academic Coursework
Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).

Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)

Illuminating Engineering Society courses in lighting design (1989).

Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).

Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY

Nova Scotia Utility and Review Board. Testimony on co-authored evidentiary report in Matter M05419, Application by NSP [Nova Scotia Power] Maritime Link Inc. for approval for a HVDC transmission link between Newfoundland and Nova Scotia. *Economic Analysis of Maritime Link and Alternatives*, Complying with Nova Scotia's Greenhouse Gas Regulations, Renewable Energy Standard, and Other Regulations in a Least-Cost Manner for Nova Scotia Power Ratepayers, April 18, 2013. Joint authores Robert Fagan, Rachel Wilson, Tommy Vitolo, David White, Nehal Divekar and Kenji Takahashi.

California Public Utilities Commission. Direct and reply testimony in the proceeding RM.12-03-014, "Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans", filed on June 25, 2012 (direct) and July 23, 2012 (reply). Testimony filed on behalf of the California Division of Ratepayer Advocate.

California Public Utilities Commission. Supplemental testimony in the proceeding A.11.05.023, "Application of San Diego Gas & Electric Company for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power." May, 2012. Testimony filed on behalf of the California Division of Ratepayer Advocate.

Prince Edward Island Regulatory and Appeals Commission
Jointly-authored (with Nehal Divekar) Expert report, "Analysis of the Proposed Ottawa Street – Bedeque 138 kV Transmission Line Project, November 5, 2012. Filed in Docket UE30402 - Summerside Electric - Application for the Approval of Transmission Services connecting Summerside Electric's Ottawa Street substation to Maritime Electric Company Limited's Bedeque substation.

New Jersey Board of Public Utilities. Direct testimony in the matter of the petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown gas for authority to extend the term of energy efficiency programs with certain modifications and approval of associated cost recovery. Docket No. GO11070399. Hearing conducted December 16, 2011.

New Jersey Board of Public Utilities. Oral testimony before the Board, on certain aspects of the Board's inquiry into capacity and transmission interconnection issues, Docket No. EO11050309. Hearing conducted October 14, 2011.

New Jersey Board of Public Utilities. Certification before the Board, I/M/O a Generic Stakeholder Proceeding To Consider Prospective Standards for Gas Distribution Utility Rate Discounts and Associated Contract Terms, Docket Nos. GR10100761 and ER10100762. Issues addressed included SBC charge rates associated with gas generation. Testimony filed January 28, 2011.

New Jersey Board of Public Utilities. Oral testimony before the Board, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. Docket No. ER10040287. Hearing conducted September, 2010.

Virginia State Corporation Commission. Pre-filed Direct Testimony filed October 23, 2009 on behalf of the Sierra Club on the need for the Potomac-Appalachian Transmission Highline (PATH), a 765 kV proposed transmission line across West Virginia, Virginia and Maryland. Proceedings are currently terminated as filing party (American Electric Power and Allegheny Power) withdrew the application pending additional RTEP analyses by PJM scheduled for 2010. Testimony addressed issues of need and modeling of DSM resources as part of the PJM RTEP planning processes.

Pennsylvania Public Utility Commission. Direct Testimony filed June 30, 2009 on behalf of the Pennsylvania Office of Consumer Advocate on the need for the Susquehanna-Roseland 500 kv proposed transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties. Testimony assessed the modeling for the proposed line, including load forecasts, energy efficiency resources, and demand response resources. Docket number A-2009-2082652. Surrebuttal testimony filed August 24, 2009.

Delaware Public Service Commission. Report on Behalf of the Staff of the Delaware Public Service Commission, filed in Docket No. 07-20, Delmarva's IRP docket, "Review of Delmarva Power & Light Company's Integrated Resource Plan", April 2, 2009. Jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi of Synapse Energy Economics.

State of Maine Public Utilities Commission. Pre-filed Direct Testimony on the Application of Central Maine Power for a Certificate of Public Convenience and Necessity for the proposed Maine Power Reliability Project (MPRP), a $1.55 billion transmission enhancement project. Direct testimony focus on the non-transmission alternatives analysis conducted on behalf of CMP. Maine PUC Docket 2008-255, filed January 12, 2009 (direct) and surrebuttal (February 2, 2010) on behalf of the Maine Office of Public Advocate. Docket proceeding 2008-255, hearings completed in February 2010.

New Jersey Board of Public Utilities. Oral testimony before the Board, jointly with Bruce Biewald, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. Docket No. ER08050310. Hearing conducted on September 29, 2008.

Wisconsin Public Service Commission. Direct and Surrebuttal Testimony in Docket 6680-CE-170 on behalf of Clean Wisconsin in the matter of an application by Wisconsin Power and Light for a CPCN for construction of a 300 MW coal plant. The testimony focused on the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant. The CPCN was denied by the WPSC in December 2008. Testimony filed in August (Direct) and September (Surrebuttal), 2008.

Ontario Energy Board. Pre-Filed Direct Testimony filed on behalf of Pollution Probe in the matter of the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process, Docket EB-2007-0707. The testimony addressed issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process. Testimony filed on August 1, 2008. Docket is open; additional Power System Plan and Procurement filings expected from the Ontario Power Authority.

Ontario Energy Board. Direct and Supplemental Testimony filed jointly with Mr. Peter Lanzalotta on behalf of Pollution Probe in the matter of Hydro One Networks Inc. application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. Docket EB-2007-0050. The testimony addressed issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line. Testimony filed on April 18, 2008 (Direct) and May 15, 2008 (Supplemental).

Federal Energy Regulatory Commission. Direct and Rebuttal Testimony on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues in Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al. The testimony addressed merchant transmission cost allocation issues. Testimony filed on behalf of the New Jersey Department of the Public Advocate, Ratepayer Division. Testimony filed on January 23, 2008 (Direct) and April 16, 2008 (Rebuttal).

Minnesota Public Utilities Commission. Supplemental Testimony and Supplemental Rebuttal Testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. Testimony filed December 21, 2007 (Supplemental) and January 16, 2008 (Supplemental Rebuttal).

Pennsylvania Public Utility Commission. Direct testimony filed before the Commission on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. Docket Nos. A-110172 *et al*. Testimony filed October 31, 2007.

Iowa Public Utilities Board. Direct testimony filed before the Board on wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. Docket No. GCU-07-01. Testimony filed October 21, 2007.

New Jersey Board of Public Utilities. Direct testimony before the Board on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. Docket No. EO07040278. Testimony filed September 21, 2007.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing a proposed Duke – Vectren IGCC coal plant. Testimony focused on wind power potential in Indiana. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 43114 May 14, 2007.

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the “firming premium” associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI’s Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

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State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

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Fagan B., P. Luckow, D. White, R. Wilson, *The Net Benefits of Increased Wind Power in PJM.* Synapse Energy Economics for Energy Future Coalition, May 2013.

Hornby R., R. Fagan, D. White, J. Rosenkranz, P. Knight, R. Wilson, *Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity.* Synapse Energy Economics for the Iowa Utilities Board (IUB), September 2012.

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Woolf T., M. Wittenstein, R. Fagan, *Indian Point Energy Center Nuclear Plant Retirement Analysis.* Synapse Energy Economics for Natural Resources Defense Council, and Riverkeeper, October 2011.

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Peterson P., E. Hausman, R. Fagan, V. Sabodash, *Synapse Report and Ohio Comments in Case No. 09-09-EL-COI, "The Value of Continued Participation in RTOs.* Synapse Energy Economics for Ohio Consumers' Counsel, May 2009.

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Fagan R., P. Spinney, *Demand-side Management Information Systems (DSMIS) Overview*. Electric Power Research Institute Technical Report TR-104707. Prepared by Charles River Associates for EPRI, January 1995.

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Fagan R., P. Spinney *Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports*. (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates reports prepared for Northeast Utilities, June and July 1994.

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ATTACHMENT A

EXCERPTS FROM NERC "SPECIAL PROTECTION SYSTEMS (SPS) AND REMEDIAL ACTION SCHEMES (RAS): ASSESSMENT OF DEFINITION, REGIONAL PRACTICES, AND APPLICATION OF RELATED STANDARDS"

f. Load Tap Changer (LTC) controls,

g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and

h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and

2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed "to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading" would be excluded by definition, regardless of whether it is installed to assist an operator.

Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

> *Special Protection System (SPS)*
>
> A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.
>
> Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

ATTACHMENT B

RESPONSE OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
TO THE FOURTH DATA REQUEST OF THE
DIVISION OF RATEPAYER ADVOCATES (DRA);
CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE (CEJA);
SIERRA CLUB, CALIFORNIA;
AND CLEAN COALITION IN TRACK 4 OF THE LTPP PROCEEDING
AUGUST 22, 2013

VIA ELECTRONIC MAIL

August 22, 2013

Diana Lee
Matt Miley
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Deborah Behles
Environmental Law and Justice Clinic
Golden Gate University School of Law
536 Mission Street
San Francisco, CA 94105-2968

William Rostov
Staff Attorney
Earthjustice California Office
50 California Street, Suite 500
San Francisco, CA 94111

Shana Lazerow
Staff Attorney
Communities for a Better Environment
1904 Franklin Street, Suite 600
Oakland, CA 94612

Kenneth Sahm White
Director, Economic & Policy Analysis
Clean Coalition
2 Palo Alto Square
3000 El Camino Real, Suite 500
Palo Alto, CA 94306

Re: ISO Response to the Fourth Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014

Dear Ms. Lee, Mr. Miley, Ms. Behles, Mr. Rostov, Ms. Lazerow, and Mr. White:

Enclosed please find the California Independent System Operator's response to the fourth set of data requests served by the Division of Ratepayer Advocates (DRA); California Environmental Justice Alliance (CEJA); Sierra Club, CA; and Clean Coalition in Track 4 of the LTTP proceeding.

Please feel free to call me if you have any questions.

Sincerely,
/s/ Judith B. Sanders
Judith B. Sanders
Senior Counsel
California Independent System
Operator Corporation

BEFORE
THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	**R.12-03-014**

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO THE FOURTH SET OF DATA REQUESTS RELATED TO TRACK 4 OF THE DIVISION OF RATEPAYER ADVOCATES; CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE; SIERRA CLUB, CA; AND CLEAN COALITION

Below are responses to the third set of Data Requests served by the Division of Ratepayer Advocates (DRA); California Environmental Justice Alliance (CEJA); Sierra Club, CA; and Clean Coalition in Track 4 of the LTTP proceeding.

RESPONSE

Request No. 1.

Does CAISO's Track analysis 4 include the use of load shedding in response to an N-1 contingency?

ISO RESPONSE

No.

If the answer to this question is no, please explain how CAISO's failure to include the use of load shedding in response to an N-1 contingency is consistent with the following CAISO transmission planning standard from page 6 of California ISO Planning Standards, June 23, 2011, which allows the loss of up to 250 MW load that may need to be dropped after the first contingency.

> **"6. Planning for New Transmission versus Involuntary Load Interruption Standard**
> This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.
>
> 1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system

adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency."

ISO RESPONSE TO No. 1.

As explained on page 5 of the California ISO Planning Standards, the language cited above applies to consequential loss of load condition resulting in the loss of a radial facility. Specifically, on the same page it states that "This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements". The electric transmission configuration in the SONGS Study Area is a looped-not radial- transmission configuration.

The reference to "load that may need to be dropped after the first contingency" is linked to NERC Reliability Standard TPL- 002, Footnote b. This footnote states:

> *Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.*

As stated, this footnote only applies to radial or some local Network customers. It is generally interpreted that local Network customers applies to a very small electrical and geographic area. The San Diego metropolitan transmission system area is not a local area Network.

In addition, this footnote has been under review by FERC and NERC for some time to either eliminate it or limit its applicability. Given the uncertainty around the future use of this footnote, the current ISO practice is to minimize the use of this footnote, even for local area Network customers.

Request No. 2.

Does CAISO's Track analysis 4 include the use of load shedding in response to an N-1-1 contingency?

ISO RESPONSE

No.

If the answer to this question is no, please explain why load shedding is not included in the Track 4 analysis.

ISO RESPONSE TO No. 2.

Please see Robert Sparks' response in the Rebuttal Testimony of the California ISO (A.11-05-023) under "Load Shedding and Special Protection Schemes" section.

Request No. 3.

If the CAISO's Track 4 analysis does not include the use of load shedding in response to an N-1 or the N-1-1 contingency, then please explain why the CAISO does not value controlled load shedding in the same manner as demand response for grid reliability planning purposes.

ISO RESPONSE TO No. 3.

Load shedding involves involuntary load curtailment, while demand response utilizes voluntary load curtailment. Demand Response customers agree to a reduced level of reliability in exchange for financial compensation.

At the July 15, 2013 CEC/CPUC workshop regarding Electricity Infrastructure resulting from SONGS closure, CAISO's slide 8 mentioned the use of load shedding for N-1-1 outages.

a) Please explain and describe the load drop that is referenced in this slide. Please explain why CAISO found this load drop to be an acceptable assumption.

ISO RESPONSE TO No. 3 (a).

Regarding the ISO's presentation at the CEC/CPUC Joint Workshop on Electricity Infrastructure Issues Resulting from SONGS Closure, load shedding mentioned on page 8 was referred to as a short-term last resort mitigation in case flex alert and demand response were not adequate in mitigating reliability concerns. This is intended as a stopgap measure until more permanent mitigation can be implemented, and not as a transmission planning mitigation solution.

b) If the CAISO's Track 4 analysis does not include the use of load shedding in response to an N-1-1 contingency, then please explain why it did not consider loading shedding in response to it. Please explain CAISO's decision to rely on load shedding in the analysis presented in its slides, but not in its Track 4 analysis.

ISO RESPONSE TO No. 3 (b).

Please see the responses to questions # 2 and 3(a).

c) The Track 4 Scoping Memo states, at page 2, ""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". Please confirm, or explain otherwise, that the CAISO testimony at 29: 9-26 is referencing use of additional DR and small PV after a third contingency event, loss of a generator after the loss of two transmission lines.

ISO RESPONSE TO No. 3 (c).

The ISO confirms that the testimony at 29: 9-26 is in reference to using additional DR and small PV for the post second contingency of an overlapping outage of two transmission lines (i.e., N-1-1), in preparation for the third contingency (i.e., G-1 of the most critical combined cycle facility).

d) Please confirm (or explain if otherwise) that the testimony at 29: 9-26 presumes that the only use of load shedding contemplated by CAISO would be in the case of a Category D contingency.

ISO RESPONSE TO No. 3 (d).

In the testimony, the ISO was attempting to explain the use of voluntary load curtailment via demand response assumptions (for post second contingency), as well as small PV, to mitigate reliability concerns that arise from the third contingency after an overlapping N-1-1. It is correct that if the additional demand response, and small PV, did not materialize, then the ISO would rely on involuntary load curtailment to mitigate Category D reliability concerns as needed if no other mitigations could be identified and implemented in their place.

e) Please state whether or not CAISO believes it would be acceptable under its reliability planning obligations to plan for the use of an approved load-shedding SPS as part of its response to the specific N-1-1 contingency event of the loss of the SWPL and the Sunrise 500 kV lines. Please discuss and explain as necessary to fully clarify CAISO's position on this issue.

ISO RESPONSE TO No. 3 (e).

Please see the responses to questions #2 and 3(a).

Request No. 4.

Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N-1-1 transmission contingency? If so, please explain where this criteria is documented. If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable.

ISO RESPONSE TO No. 4.

Please see the responses to questions #2 and 3(a).

Request No. 5.

In Mr. Sparks' Track 4 Testimony, he lists recently approved transmission projects in the SONGS Study Area. In addition to those projects listed, what new transmission projects were included in the 2018 and 2022 studies without SONGS that impact the SONGS study area? Please identify each transmission project, and whether it is included in the 2018 and/or the 2022 study.

ISO RESPONSE TO No. 5.

In addition to major transmission projects listed on Table 6 of the testimony for the SONGS Study Area, the ISO also included the following approved transmission projects (as part of the ISO 2012/2013 Transmission Plan) for both the 2018 and 2022 power flow study cases in San Diego sub-area:

- *Sweetwater Reliability Enhancement*
- *TL 13820 Sycamore – Chicarita Reconductoring*
- *TL674A Loop-in (Del Mar – North City West) and Removal of TL666D (Del Mar – Del Mar Tap).*

Request No. 6.

Please identify the "informal inputs," as described in Mr. Sparks Testimony, p. 19, line 1, used for determining additional resource needs in Table 9.

ISO RESPONSE TO No.6.

The "informal inputs" are suggestions from the utility resource planning staffs of SCE and SDG&E regarding exploratory locations for additional resource needs such as peaking generation or combined cycle generation. This information cannot be provided publicly due to confidentiality concerns. For these reasons, the ISO provided general locations in the form of the sub-areas rather than specific bus bar information in Tables 9 – 12 in the testimony.

Request No. 7.

In Table 13, please explain why Mr. Sparks states that preferred resource and DG modeling assumptions were only "included for informational purposes" (Sparks Testimony, p.25, line 11-12).

ISO RESPONSE TO No. 7.

The preferred resources and DG modeling assumptions were already described in earlier sections of the testimony and repeated in Table 13 for the reader's convenience and information so the reader does not have to go back to search for these values in earlier Qs and As.

Request No. 8.

What analysis did CAISO rely upon to determine why reactive support was not capable of offsetting the permanent SONGS outage (Sparks Testimony, p.16-17)? Please provide all calculations and analysis that CAISO is relying on for Mr. Sparks' testimony on page 16, line 20 through page 17, line 8. Please also identify the basis of Mr. Sparks' testimony on page 16, line 20 through page 17, line 8.

ISO RESPONSE TO No. 8.

The ISO evaluated various locations for siting dynamic reactive supports as part of the ISO 2012/2013 transmission planning process. These evaluations were part of the reliability assessment in the "nuclear generation backup plan studies" which were reported in the ISO 2012/2013 Transmission Plan. The ISO does not have separate documentation for the iterative analyses that determined the optimal locations for dynamic reactive support. Rather, these evaluations were performed as part of the ISO evaluations for determining the amount of resource needs or combined resource and transmission mitigation scenarios. Various locations in the LA Basin and San Diego were tested with dynamic reactive supports modeled to help the ISO determine the best electrical locations for siting. As part of this evaluation, the ISO determined that the best locations are, (i) at or near San Onofre switchyard, and (ii) other nearby locations in southern Orange County and northern San Diego County within two to three buses away from San Onofre. The further from San Onofre switchyard, the less effective these locations turned out to be. However, the ISO found out from discussion with the utility planning staffs that not all locations would have adequate property to accommodate these dynamic reactive supports without triggering further CPCN process for substation expansion and rights-of-way acquisition. Another variable in determining the best sites for dynamic reactive support is the locations are dependent on future resource development/siting, as well as the siting of major transmission mitigation solutions.

In addition, as indicated on page 31 of the Track 4 testimony of ISO witness Robert Sparks, the ISO is in the process of studying potential transmission solutions, including additional reactive support. Preliminary results of those studies, in addition to the work described above, are the basis for the finding on page 16 that "additional reactive support at the SONGS location would not be sufficient to offset the permanent SONGS *outage". The ISO will complete and publish those results through the ongoing ISO Transmission Planning Process.*

<u>Request No. 9.</u>

Please provide an excel spreadsheet showing, for the solved final power flow cases presented in Mr. Sparks' Track 4 Testimony, before and after the N-1-1 contingency:.

a) The output of all generators in the LCR area that are dispatched; and

<u>ISO RESPONSE TO No. 9 (a).</u>

The ISO cannot provide unit by unit output of all generators in the SONGS Study Area because this is detailed bus-bar level information due to confidentiality concerns. Instead, aggregated values for all generators dispatched in the SONGS study area are provided below for the solved 2022 study case for the post N-1-1 contingency. Since the objective of the studies is to evaluate local capacity needs, and these needs in planning studies were determined by having adequate resources dispatched or made available in preparation for mitigating the contingency voltage stability concerns, only the values needed for mitigating reliability concerns for post contingency condition are provided below. The year 2022 values are included since they represent higher total capacity needs and are inclusive of 2018 values.

Area	Generation Dispatched (MW)
LA Basin	10,046
San Diego sub-area	3,055
Total SONGS Study Area	13,101

b) The power flows, and direction, on all transmission tie lines connecting into the SONGS LCR area

<u>ISO RESPONSE TO No. 9 (b).</u>

Typically, in a local capacity analysis, the only information that is provided is the total capacity need for a local capacity area to mitigate identified reliability concerns. Therefore, consistent with information in the annual LCR study, the ISO provided the total local capacity need in a local capacity area for meeting applicable reliability criteria as indicated in the response to section (a) above. The aggregated flows on all transmission tie lines connecting to the SONGS LCR area can be estimated as the following:

(Total loads and losses + 2.5% margin at substation load levels) – (Incremental EE modeled) - local dispatched resources – DR (post first contingency) =

(28,973 + 704^) – 983 - 13,101 - 198 = 15,395 MW (estimated total imports into SONGS Study Area post N-1-1 condition)

Notes:
^ 704 MW = see Question 10 below for factoring 2.5% margin at substation loads for voltage stability analyses

<u>Request No. 10.</u>

Please explain whether CAISO's Track 4 analysis incorporates a 2.5% margin in the results discussed in Mr. Sparks' Track 4 Testimony. If a 2.5% margin is incorporated, please explain whether the 2.5% is factored in as additional load on top of the 1-in-10 peak demand forecast. Also, please explain and describe the additional MW that were added to account for the 2.5% margin.

<u>ISO RESPONSE TO No. 10.</u>

The 2.5% margin in loads was factored on top of 1-in-10 peak demand forecast at the substation levels for the SONGS Study Area only to comply with the WECC Voltage Stability criteria. LA Basin loads and San Diego loads typically peak at the same time. All loads at individual substations modeled in the LA Basin and San Diego local capacity areas were raised uniformly by 2.5%. The additional loads to incorporate 2.5% margin for voltage stability analyses are 670 MW and 704 MW for years 2018 and 2022, respectively, for the SONGS Study Area.

<u>Request No. 11.</u>

Are the results summarized in Tables 11-13 of Mr. Sparks' Track 4 testimony based on an 8,000 or 7,800 amp restriction for Path 44?

<u>ISO RESPONSE TO No. 11.</u>

Tables 11 - 13 do not have assumptions of either 8,000 or 7,800 Amp limit on SONGS Separation Scheme. This scheme is disabled for the Without SONGS scenario.

<u>Request No. 12.</u>

How much would the addition of the 997 MW demand response resources described by the Commission in the attachment to the Revised Scoping Ruling for Track 4 lower the values presented in Table 13 of Mr. Sparks' testimony?

ISO RESPONSE TO No. 12.

The Revised Scoping Ruling specified that this amount of additional DR is to be used for post second contingency condition. Therefore this amount of additional DR for post second contingency is not applicable to Table 13 because the results were based on mitigating reliability concerns due to voltage stability issue from an overlapping N-1-1 contingency. The ISO evaluated this additional 997 MW of DR, as well as additional 796 MW of customer-connected PV to mitigate potential reliability concerns due to post second contingency (i.e., G-1 of the most critical generating facility following an N-1-1 contingency condition) at 29:9-26. Additionally, please see the ISO response to question #3c above which is related to the use of additional DR for post second contingency condition.

Request No. 13.

How much would the addition of the 796 MW of customer-connected small PV described by the Commission in the attachment to the Revised Scoping Ruling for Track 4 reduce the values presented in Table 13 of Mr. Sparks' testimony?

ISO RESPONSE TO No. 13.

Please see the ISO response to question #12 for the use of 796 MW for post second contingency as indicated in the Revised Scoping Ruling.

Request No. 14.

Please explain whether CAISO tested other assumptions and MW values in different areas to solve the 2018 without SONGS scenario other than the results presented in Table 9 of Mr. Sparks' Track 4 testimony.

ISO RESPONSE TO No. 14.

As mentioned in the testimony, the ISO's study objectives included: (a) minimizing the OTC generation repowering or replacement need; and (b) minimizing residual new resource needs. To meet these objectives, the ISO used an iterative process to determine the general vicinity of optimal resource locations to mitigate reliability concerns. In doing so, the ISO relied on a number of factors: (i) power flow studies; (ii) inputs from the state energy agencies regarding forecasted preferred resources at specific load substations; (iii) inputs from the utilities regarding potential sites for resource development (i.e., small peaking units); and (iv) known generation development in the area.

ATTACHMENT C

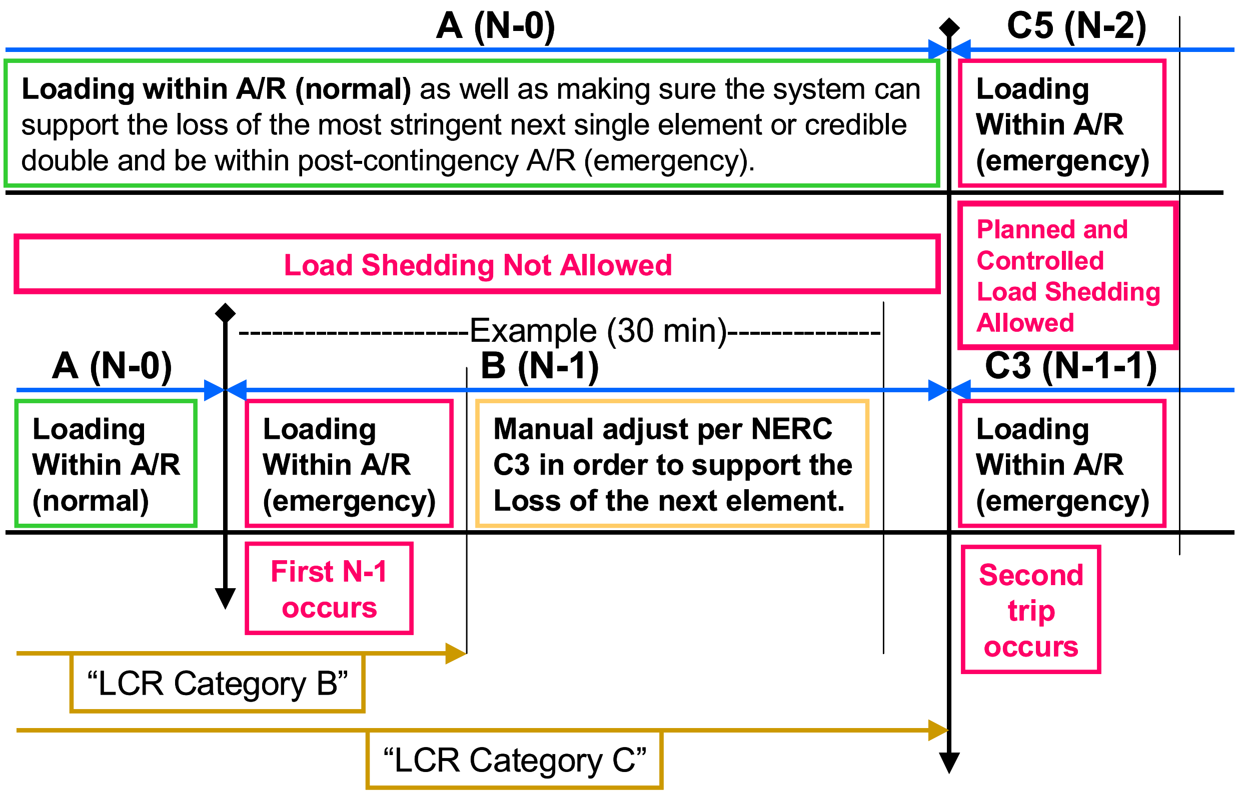
EXCERPT FROM 2018
CAISO
LOCAL CAPACITY TECHNICAL ANALYSIS
FINAL REPORT AND STUDY RESULTS
APRIL 30, 2013

California Independent
System Operator

2018
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2013



The following definitions guide the CAISO's interpretation of the Reliability Criteria governing safe mode operation and are used in this LCT Study:

Applicable Rating:

This represents the equipment rating that will be used under certain contingency conditions.

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another

ATTACHMENT D

SDG&E RESPONSE TO
DRA-CEJA-SIERRA CLUB DATA REQUEST
DRA-SDG&E-DR-02
LTPP – TRACK 4 – R.12-03-014
DATE RECEIVED: SEPTEMBER 6, 2013
DATE RESPONDED: SEPTEMBER 19, 2013

DRA-CEJA-Sierra Club DATA REQUEST
DRA-SDG&E-DR-02
SDG&E LTPP – TRACK 4 – R.12-03-014
SDG&E RESPONSE
DATE RECEIVED: SEPTEMBER 6, 2013
DATE RESPONDED: SEPTEMBER 19, 2013

2. Has SDG&E conducted any studies to evaluate the relative cost-effectiveness of noncritical load shedding in place of the cost of new generation? If so, please provide them.

SDG&E Response 02:

SDG&E has not conducted any studies quantifying the cost effectiveness of load-shedding versus new in-basin generation resources. Also NERC, WECC, CAISO, and SDG&E do not distinguish between ‘critical’ and ‘non-critical’ load.

ATTACHMENT E

CALIFORNIA ENERGY COMMISSION FORM 1.5d

Form 1.5d
California Energy Demand 2010-2020 Staff Revised Forecast
1-in-10 Net Electricity Peak Demand by Agency and Balancing Authority

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average Annual Growth 2010-2020
PG&E Service Area - Greater Bay Area	8,082	8,114	8,199	8,300	8,400	8,467	8,535	8,605	8,684	8,757	8,828	8,912	0.9%
Silicon Valley Power	509	512	520	529	536	541	546	551	557	562	567	572	1.1%
NCPA - Greater Bay Area	286	288	292	297	301	304	307	310	314	317	320	324	1.2%
Other NP15 LSEs - Greater Bay Area	6	6	6	6	6	6	6	6	6	6	6	6	0.4%
CCSF	114	114	115	116	117	117	117	117	118	118	118	118	0.3%
Greater Bay Area Local Area	8,997	9,034	9,131	9,247	9,360	9,435	9,511	9,590	9,679	9,760	9,839	9,932	1.0%
North of Path 26	23,112	23,278	23,594	23,959	24,323	24,598	24,878	25,166	25,484	25,784	26,084	26,423	1.3%
Turlock Irrigation District Control Area	684	692	705	719	734	746	759	772	786	800	813	829	1.8%
SMUD/WAPA Control Area	4,932	4,963	5,032	5,120	5,207	5,279	5,347	5,410	5,475	5,540	5,607	5,679	1.4%
SCE Service Area - LA Basin	17,770	17,874	18,114	18,394	18,689	18,928	19,182	19,442	19,716	19,978	20,243	20,529	
Anaheim	606	608	616	625	634	641	649	657	665	672	680	688	1.2%
Riverside	638	645	657	671	686	698	712	725	739	753	768	783	2.0%
Vernon	191	191	192	194	196	198	200	201	203	204	206	207	0.8%
MWD	23	22	22	22	22	22	22	22	22	22	22	22	-0.3%
Other SP15 LSEs - LA Basin	228	230	234	238	243	247	251	255	260	264	268	273	1.7%
Pasadena	326.078	327.084	329.131	330.995	331.546	331.283	331.813	332.473	333.024	333.554	333.942	334.428	0.2%
LA Basin Local Area	19,782	19,898	20,164	20,475	20,800	21,064	21,346	21,634	21,937	22,227	22,520	22,836	1.4%
SCE Service Area - Big Creek Ventura	4,229	4,254	4,311	4,377	4,447	4,504	4,564	4,626	4,690	4,753	4,816	4,883	1.4%
CDWR-S	200	300	300	300	300	300	300	300	300	300	300	300	0.0%
Big Creek/Ventura Local Area	4,425	4,556	4,613	4,680	4,749	4,806	4,866	4,928	4,993	5,055	5,118	5,186	1.3%
Total SCE TAC Area	25,293	25,545	25,878	26,266	26,675	27,008	27,362	27,725	28,106	28,472	28,842	29,240	1.4%
SDG&E Service Area	4,935	4,967	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673	1.3%
Total South of Path 26	30,331	30,617	31,019	31,497	31,996	32,394	32,814	33,239	33,691	34,123	34,563	35,032	1.4%
LADWP Control Area	6,999	6,975	7,040	7,139	7,209	7,250	7,289	7,330	7,370	7,410	7,453	7,501	0.7%
Imperial Irrigation District Control Area	1,040	1,062	1,091	1,123	1,151	1,175	1,201	1,230	1,260	1,290	1,321	1,354	2.5%
Total CAISO Noncoincident Peak	53,443	53,895	54,612	55,456	56,319	56,992	57,692	58,405	59,175	59,907	60,647	61,455	1.3%
Total CAISO Coincident Peak	52,160	52,601	53,302	54,125	54,967	55,624	56,307	57,004	57,754	58,469	59,192	59,981	1.3%
Total Statewide Noncoincident Peak	67,098	67,588	68,480	69,557	70,619	71,442	72,288	73,148	74,066	74,947	75,842	76,818	1.3%
Total Statewide Coincident Peak	65,487	65,965	66,836	67,887	68,925	69,727	70,553	71,392	72,288	73,148	74,022	74,975	1.3%

*Balancing Authority Tables exclude LSEs located in non-California-based control areas.

ATTACHMENT F

EXCERPT FROM
SUPPLEMENTAL TESTIMONY OF
ROBERT SPARKS
A.11-05-023
APRIL 6, 2012

Application No.: A.11-05-023
Exhibit No.:
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

As can be seen in the results table, the continuing need for generation at the existing OTC site (Encina) or in an electrically equivalent location is reduced from 950 MW to 730 MW for the Trajectory 33% RPS portfolio study scenario. This assumes that the 8000 Amp limit due to the SONGS separation scheme is removed from being a binding constraint. With the 419 MW of SDG&E proposed generation procurement, the need amount is reduced from 531 MW to 311 MW. Need amounts are also provided with the 8000 Amp limit on the Path 44 (SONGS separation scheme) as a binding constraint and with a 2.5% margin from hitting that constraint. Need amounts based on the other three 33% RPS portfolio study scenarios are also provided in the table.

Q. Did this change cause the ISO to change its LCR study methodology in any way?

A. No. However, because the G-1/N-2 contingency is a severe contingency we conceptually assumed that an automatic load shedding scheme (SPS) would be installed and available to prevent voltage collapse for that contingency in our earlier results. With the more likely N-1-1 contingency we did not think it would be prudent to plan the system that would rely on the same type of load shedding SPS.

Q. Please explain how the change in the WECC criterion impacted the ISO's 2013 local capacity studies for the San Diego area.

A. Similar to the OTC 2021 studies, prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-

ATTACHMENT G

EXCERPT FROM
SOUTHERN CALIFORNIA RELIABILITY
PRELIMINARY PLAN
EDWARD RANDOLPH, ENERGY DIVISION DIRECTOR, CPUC
SLYVIA BENDER, DEPUTY DIRECTOR, CEC
PHIL PETTINGILL, DIRECTOR OF STATE REGULATORY STRATEGY, CAISO
SEPTEMBER 9, 2013

California Public Utilities Commission

California Energy Commission

California ISO
Shaping a Renewed Future

Southern California Reliability

Preliminary Plan

Edward Randolph, Energy Division Director, CPUC
Sylvia Bender, Deputy Director, CEC
Phil Pettingill, Director of State Regulatory Strategy, CAISO

September 9, 2013

Specific near term actions (2013 - 2018)

VARs	MW	VARs & MW
Review permits for Talega & San Onofre Mesa projects	Flex-Alert funding beyond 2014	Maintain capacity at Cabrillo II
Extend Huntington Beach synchronous condensers	Permit construction of Sycamore-Penasquitos 230kv line	Timely action on Pio Pico
Modify San Onofre voltage criteria (w/SCE)	Authorize acceleration of EE, DR, DG, and storage procurement in target areas	Authorize procurement to replace Encina
Evaluate conversion of one San Onofre unit to a synchronous condenser	Evaluate transmission alternatives	Timely decisions to license replacements for OTC capacity
	Develop & implement multi-year auction for DR and EE	Create contingency permitting process

Color	Agency
(olive hatched)	CPUC
(orange)	CEC
(blue-gray)	ISO

ATTACHMENT H

SDG&E
2012 GRID ASSESSMENT RESULTS
CAISO STAKEHOLDER MEETING
SEPTEMBER 26-27, 2012

2012 Grid Assessment Results

CAISO Stakeholder Meeting
September 26-27, 2012

2012 Study Scope

- Five-Year Studies (2013-2017)
- Ten-Year Study (2022)

Additional Benefits:

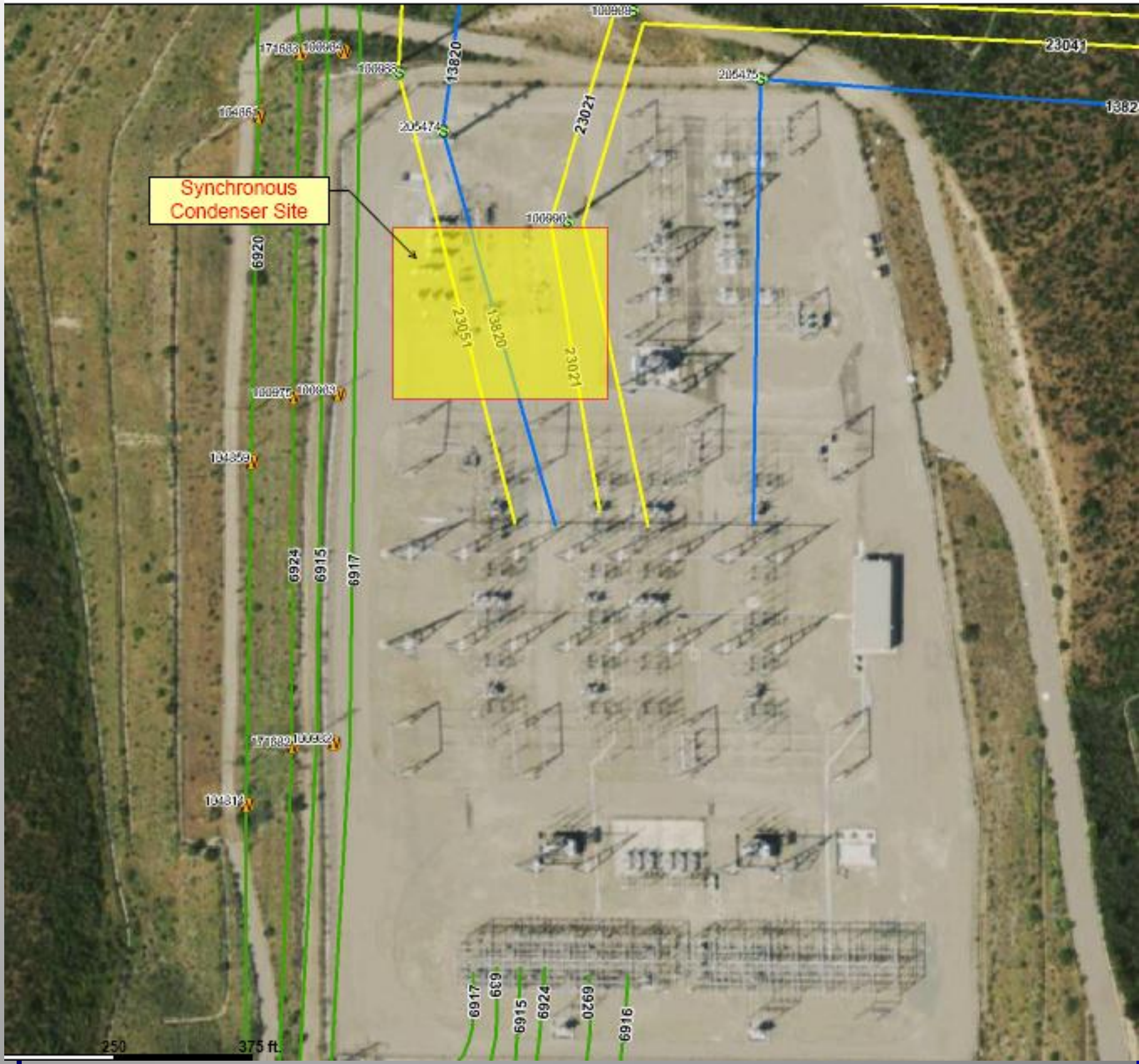
- Mitigates extreme system voltages.

Cost: $56 - $70 Million.

Alternatives:

- SVCs
- STATCOM

Sycamore Canyon Synchronous Condenser Site



Project Title:

Add 230kV Reactive Power Support: Mission

Need-Date:

June 2017

Cost: $58 - $72 Million.

Alternatives:

- SVCs
- STATCOM

Cost: $56 - $70 Million.

Alternatives:

- SVCs
- STATCOM

Project Title:
Add 230kV Reactive Power Support: Talega

Need-Date:
June 2018

SDGE
A Sempra Energy utility

Additional Benefits:
-Enhance operators' ability to maintain the SONGS 230 kV bus voltage within the narrow prescribed limits.

Cost: $58 – $72 Million.

Alternatives:
- SVCs
- STATCOM is not feasible at Talega site

ATTACHMENT I

ISO RESPONSE 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 IN
DOCKET NO. R.12-03-014

VIA ELECTRONIC MAIL

July 31, 2013

Matt Miley
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Deborah Behles
Environmental Law and Justice Clinic
Golden Gate University School of Law
536 Mission Street
San Francisco, CA 94105-2968

William Rostov
Staff Attorney
Earthjustice California Office
50 California Street, Suite 500
San Francisco, CA 94111

Shana Lazerow
Staff Attorney
Communities for a Better Environment
1904 Franklin Street, Suite 600
Oakland, CA 94612

Kenneth Sahm White
Director, Economic & Policy Analysis
Clean Coalition
2 Palo Alto Square
3000 El Camino Real, Suite 500
Palo Alto, CA 94306

Re: ISO Response 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 in Docket No. R.12-03-014

Revisions to questions 16(b) and 17(a) through 17(b)

Dear Mr. Miley, Ms. Behles, Mr. Rostov, Ms. Lazerow, and Mr. White:

Enclosed please find the California Independent System Operator's revised response to the first set of data requests served by the Division of Ratepayer Advocates (DRA); California Environmental Justice Alliance (CEJA); Sierra Club, CA; and Clean Coalition in Track 4 of the LTTP proceeding.

In the original response, the ISO provided general objections to questions 16(b) and 17 and all its subparts. The ISO is submitting revised answers to these specific questions. By providing this response, the ISO acknowledges that its objections to 16(b) and 17(a) through 17(d) have been waived.

Please feel free to call me if you have any questions.

Sincerely,
/s/ Judith B. Sanders
Judith B. Sanders
Senior Counsel
California Independent System
Operator Corporation

BEFORE
THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	**R.12-03-014**

REVISED 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

REVISIONS TO QUESTIONS 16(b) AND 17(a) THROUGH 17(d)

Below are revised responses to questions 16(b) and 17(a) through 17(d) in the first set of Data Requests served by the Division of Ratepayer Advocates (DRA); California Environmental Justice Alliance (CEJA); Sierra Club, CA; and Clean Coalition in Track 4 of the LTTP proceeding. The ISO previously provided general objections to Request No. 16b and Request No. 17 and all its subparts. With this response, the ISO's general objections to Request 16b and Request 17a through 17d have been waived.

RESPONSE

<u>Request No. 16.</u>

As related to the overall analytical approach for CAISO's Track 4 analysis:

a) Please describe CAISO's overall analytical approach in assessing the local reliability impacts without SONGS. In particular, please confirm or explain otherwise if the process will be similar or identical to LCR needs analysis conducted by CAISO for the Track 1 part of this proceeding, and/or similar to LCR needs analysis conducted on an annual basis for local reliability areas.

<u>ISO RESPONSE TO No. 16(a).</u>

As set forth in the Revised Scoping Ruling, the ISO confirms that the analyses for Track 4 will follow the LCR study methodology.

b) Based on the information in Table 3.5-12 of the 2012/13 ISO Transmission Plan, it appears that post-transient voltage instability could be a primary identified reliability concern without SONGS. Please explain in detail the sequence of analyses that CAISO will conduct to identify potential reactive additions. In particular, explain if, and how, iterative processes uses power flow tools will be considered to help ensure use of sufficient and/or appropriate levels of reactive resources not currently in place.

ISO RESPONSE TO No. 16(b).

To perform these analyses described in the 2012/2013 Transmission Plan, the ISO followed the WECC Voltage Stability Criteria, specifically:

- *For load areas, voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A), and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modeled at a minimum of 102.5% of the reference load level. For this criterion, the reference load level is the maximum established planned load limit for the area under study (WECC TPL 001-004TPL-001-WECC-RBP-2.1 System Performance Criteria WR3S 3.2). Since the critical contingency for the SONGS Study Area is the Category C overlapping N-1-1 contingency of the Sunrise Powerlink and Southwest Powerlink 500kV lines, a 2.5% load incremental study case was developed for the voltage stability assessment.*

- *To meet the WECC Voltage Stability Criteria, positive reactive margin (i.e., power flow solution) needs to be obtained for the critical contingency with applicable loads as described in the above bullet.*

- *During the 2012/2013 transmission planning cycle, the ISO performed iterative processes to determine which substations would be the most optimal electrical locations for siting additional dynamic reactive supports. The most effective locations for reactive support would enable more real power (MW) reduction with fewer amounts of reactive supports (MVAR) as possible, while still maintaining voltage stability for the system under study.*

- *Based on the above studies, several locations were identified as having effective locations for voltage supports. This was further verified with the utilities for feasibility of constructing and installing additional reactive supports. Due to tight real estate in the SONGS Study Area, it is not always feasible to construct and site dynamic reactive support at first choice locations.*

- *During study processes, the ISO also monitored line or facility loading, under critical contingency and reference load level (i.e., 1-in-10), to ensure that transmission facility loading stays within its established emergency rating as well. For example, if generation in a local capacity area is reduced too much which would cause loading* *concerns, the ISO would redispatch local generation, as required, to mitigate identified loading concerns. Both voltage stability and facility loadings would need to be monitored to ensure that mitigation for one problem would not adversely affect the other.*

c) Please provide any additional information, if or as relevant, on how CAISO will analyze the need to ensure sufficient real power or reactive power resources to mitigate against voltage instability concerns.

ISO RESPONSE TO No. 16(c).

See response to part (b) above.

d) What assumptions does CAISO make, or are embedded in the power flow input data, about the power factor at each of the load take-off buses throughout the modeled CAISO system? Are there threshold levels (e.g., such as power factor equal to or greater than .95) that are maintained in CAISO's power flow runs on the assumption that downstream power factor correction would be in place by the individual utilities? Please explain as appropriate.

ISO RESPONSE TO No. 16(d).

The power factor at individual loads is provided by the utilities during the ISO annual transmission planning cycle. Based on the utility planning staff's inputs, power factor for SCE loads is about 0.996 leading and 0.991 lagging for SDG&E loads modeled at the subtransmission voltage level (i.e., 66kV, 69kV or 115kV).

Request No. 17.

As related to reactive resource location, type, and magnitude to best mitigate against voltage instability concerns:

a) Please provide any perspective CAISO has on the preferred electrical location (by substation and voltage level) of additional reactive resources in the LA Basin and San Diego areas to help ensure mitigation against voltage instability concerns.

ISO RESPONSE TO No. 17(a).

Based on the ISO's studies in the 2012/2013 planning cycle, the ISO found that reactive supports, on 230kV voltage level, are effective in mitigating post transient voltage instability concerns due to the overlapping N-1-1 contingency in San Diego if they were located at substations in southern Orange County and northern San Diego area. The most effective location for dynamic reactive support is at San Onofre 230kV substation.

b) Please provide any perspective CAISO has on a preference for different types of reactive resources (e.g., static vs. dynamic, and different types of dynamic reactive resources) preferred at these locations.

ISO RESPONSE TO No. 17(b).

Due to the nature of the reliability concern (i.e., post-transient voltage instability and the San Onofre minimum voltage requirements per the NERC NUC-001 Standards), the ISO would prefer dynamic reactive support, which was provided when SONGS was operating. However, in terms of implementation, the ISO understands that the project sponsors and vendors can design the targeted dynamic reactive support using combination of dynamic and static reactive supports as known as Static VAR System (SVS) in an effort to reduce total costs.

c) Please provide any perspective CAISO has on the "least regrets" magnitude (MVAR) of reactive resource requirements in the LA Basin and San Diego areas both separately and combined, with a focus on how to best minimize the need for new real power (MW) requirements by securing a sufficient level of reactive resources in the area.

ISO RESPONSE TO No. 17(c).

When the ISO came up with the "least regrets" magnitude of reactive resource requirements in the LA Basin and San Diego local capacity areas, which were approved by the ISO Board as part of the 2012/2013 Transmission Plan, there was much uncertainty to which new generation would be authorized in the San Diego area for the mid-term (2018) time frame. In addition, at the time of the studies in the 2012/2013 transmission planning cycle, the status of SONGS was uncertain as there was no announcement of SONGS retirement until later time frame. All these reasons factored in the ISO's "least regrets" magnitude of reactive resource requirements in the LA Basin and San Diego areas at the time.

d) Please summarize how a new 500 kV line between the SCE and SDGE regions could affect the need for either reactive or real power resources in the region if such a line were to be in place by 2022.

ISO RESPONSE TO No. 17(d).

The ISO evaluated the addition of a new 500kV line between SCE and SDG&E as exploratory studies in the 2012/2013 transmission planning cycle to determine, on preliminary basis, the impacts of having transmission line vs. local generation requirements. Based on the preliminary studies completed for this exploratory 500kV new line, it could potentially reduce total local generation need in the SONGS Study Area by about 1,000 MW. There was no reduction in reactive support need associated with this new line concept.

ATTACHMENT J

2013 LOCAL CAPACITY
TECHNICAL ANALYSIS
ADDENDUM TO THE FINAL REPORT AND STUDY RESULTS
ABSENCE OF SAN ONOFRE NUCLEAR GENERATING STATION (SONGS)
AUGUST 20, 2012

California ISO
Shaping a Renewed Future

2013
LOCAL CAPACITY TECHNICAL ANALYSIS

ADDENDUM TO THE FINAL REPORT AND STUDY RESULTS

Absence of San Onofre Nuclear Generating Station (SONGS)

August 20, 2012

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Addendum to the 2013 Local Capacity Technical Analysis, dated April 30, 2012 includes the results and recommendations of the 2013 Local Capacity Technical (LCT) Study in the absence of the San Onofre Nuclear Generating Station (SONGS). The results and recommendations affect the LA Basin and San Diego-Imperial Valley local areas.

This Addendum does not change the 2013 LCR allocations already provided to Load Serving Entities (LSEs) based on the 2013 Local Capacity Technical (LCT) Study report dated April 30, 2012. Instead, the ISO issues these results and recommendations to provide Load Serving Entities (LSEs) with advance notice of LCR needs in the absence of SONGS in order to facilitate a more informed 2013 Resource Adequacy (RA) procurement. It is also the intention of the ISO to mitigate any reliability conditions that will remain, even if the LSEs procured all the available resources in these local areas. These results, in the absence of SONGS, will also provide a basis to allocate the costs of any ISO procurement needed to mitigate reliability conditions notwithstanding the resource adequacy procurement of LSEs.[1]

Please note that these studies assume that both SONGS units 2 and 3 are completely unavailable for operation in 2013. At the time this study was completed, SONGS was on an extended forced outage and the expected date that it would return to service was undetermined.

This study includes the most updated data available on July 15, 2012, namely the 2012 Net Qualifying Capacity (NQC) list and the California Energy Commission (CEC) adopted load forecast that was published in June 2012.

[1] For information regarding the conditions under which the CAISO may engage in procurement of local capacity and the allocation of the costs of such procurement, please see Sections 41 and 43 of the current CAISO Tariff, at: http://www.caiso.com/238a/238acd24167f0.html.

Below is a comparison of the LCR need with and without SONGS:

2013 Local Capacity Requirements with SONGS

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
LA Basin	4452	8675	13127	10295	0	**10295**	10295	0	**10295**
San Diego/ Imperial Valley	158	3991	4149	2938	0	**2938**	2938	144*	**3082**
Total	**4610**	**12666**	**17276**	**13233**	**0**	**13233**	**13233**	**144**	**13377**
Local Sub-Area Name									
Ellis	0	458	458	0	0	0	0	0	0
Western	3457	6118	9575	N/A	0	N/A	5540	0	5540
San Diego	158	2911	3069	2192	0	2192	2570	0	2570

2013 Local Capacity Requirements without SONGS

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
LA Basin	2206	7710	9916	9745	0	**9745**	9916	1241	**11157**
San Diego/ Imperial Valley	158	3991	4149	3385	0	**3385**	3385	467*	**3852**
Total	**2364**	**11701**	**14065**	**13130**	**0**	**13130**	**13301**	**1708**	**15009**
Local Sub-Area Name									
Ellis	0	458	458	0	0	0	458	360	818
Western	1211	5153	6364	N/A	0	N/A	4597	0	4597
San Diego	158	2911	3069	2462	0	2462	3069	467	3536

* San Diego-Imperial Valley area is not "overall deficient". Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs.
** Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.
N/A - It is feasible that Western sub-area has Category B needs however they are smaller than the Category C needs and overall irrelevant due to high Category B need in the entire LA Basin.

Compared to the final 2013 Local Capacity Technical (LCT) report, the total available capacity in the LA Basin has decreased by 3,211 MW, representing the capacity from SONGS, El Segundo # 3 retirement and El Segundo Repower (because of the in-service date delay from June1 to August 2013). The Ellis sub-area requirements have increased significantly by 818 MW, while the Western sub-area LCR needs have decreased by about 943 MW. Overall the LA Basin LCR needs are now driven by a new overlapping Category C contingency in the San Diego's electric system, due to voltage support needs that arise in the area. Without SONGS in operation, the LA Basin reflects a net increase of 862 MW in LCR need. The need for existing resources has decreased, however, by 379 MW due to the retirement or shut-down of other units. Basically, all existing available resources are needed for LCR in this area and additional deficiencies exist. For further details please see pages 5-19 below.

The total available capacity remains unchanged in the San Diego-Imperial Valley LCR area. The San Diego sub-area requirements have increased significantly, by 966 MW, and the San Diego-Imperial Valley area requirements have increased also by 447 MW, due to voltage support needs in the absence of SONGS. Overall for the San Diego-Imperial Valley LCR area, the additional resources needed for LCR has increased by 447 MW; however, there is a shift of sub-area needs and all available existing resources in the San Diego sub-area are now required for LCR. For further details, please see pages 19-27 below.

Even though resource procurement is the responsibilities of the LSEs in the area, the ISO is proposing mitigation for all new deficiencies created due to the absence of SONGS as a contingency plan for summer 2013. This mitigation is described in chapter II below.

II. Mitigation Plan for LA Basin and San Diego-Imperial Valley LCR areas and sub-areas due to the absence of SONGS

Ellis sub-area:

The following transmission upgrade plan has been identified which mitigates the identified reliability concerns in this sub-area:

Barre-Ellis 230k V lines reconfiguration from 2 to 4 circuits.

In addition to the mitigation measures needed for the adjacent LCR areas described below, reconfiguring the Barre-Ellis 230 kV lines from 2 to 4 circuits prior to next summer will mitigate the identified reliability concern in this sub-area, which is the loss of the Imperial Valley-North Gila 500 kV line followed by the loss of the Barre – Ellis #1 or #2 230 kV lines. Re-configuring the Barre-Ellis lines from 2 to 4 circuits will mitigate this issue by allowing three of the new Barre–Ellis circuits to remain in operation under this contingency.

LA Basin area and San Diego sub-area – common mitigation plan:

The following upgrade plan has been identified which mitigates the identified reliability concerns in this common area:

Install shunt capacitors (1 x 80 MVAR each) at Johanna and Santiago, (2 x 80 MVAR) at Viejo Substation (or 1 x 80 MVAR at Talega as an alternate location for the second 1 x 80 MVAR at Viejo) and convert Huntington Beach units 3 and 4 to synchronous condensers.

Together these projects will mitigate the post-transient voltage stability concerns in the San Diego sub-area and low voltage concern in the LA Basin LCR area[2]. A mixture of dynamic (i.e., synchronous condensers) and static (shunt capacitors) reactive support is required in order to satisfy fast voltage recovery need at the SONGS 230 kV

[2] The NERC NUC-001 Standards require that the post-contingency voltage at San Onofre 230 kV switchyard be recovered to a minimum of 218 kV after a major contingency in less than 80 seconds.

bus without causing further operational concerns (i.e., capacitor “hunting” issue and slow response time if only static reactive support is installed).

Huntington Beach units 3 and 4, as generating units, will no longer be available due to lack of air emission credits, however due to their proximity to San Onofre switchyard they are best suited for dynamic voltage support which they can still provide without air emission credits or water permits by being converted to synchronous condensers.

As an added benefit, the shunt capacitors eliminate the need for a new SPS in the Johanna-Santiago area that is required to protect against voltage instability for the loss of 230 kV double circuit tower line (DCTL) of Ellis-Johanna and Ellis-Santiago when generating resources in the San Diego area are at medium to low output level. As a second benefit, this alternative will reduce the single contingency resource need to 3,069 MW in the San Diego-Imperial Valley LCR area. This amount of LCR need is equivalent to the need based on meeting Category C contingency requirement for the San Diego sub-area, effectively reducing the procurement target in the SDG&E service area by 316 MW.

The reduction in SDG&E service area need will consequently increase the LA Basin single contingency need to the point where a new small 83 MW deficiency exists. Mitigation for this new single contingency deficiency is twofold:

1. Some units at Imperial Valley (not required for local RA without SONGS and these mitigation measures) may be under un RA contract therefore satisfying this need, and

2. The ISO has received Demand Response (DR) program information from the Participating Transmission Owners (PTOs). It is possible that about 48 MW in Orange County and another 252 MW in the South of Lugo area could be used if available within 30 minutes of a transmission line loss or overload. If possible, the ISO will rely on them for the first part of summer 2013 until El Segundo Repower or Sentinel become commercially operational in August 2013 in order to mitigate this single contingency need that causes South of Lugo loading concerns. However, even if available within 30 minutes, these DR programs and the new generating resources are insufficient in mitigating the double contingency need as addressed above, however.

ATTACHMENT K

EXCERPTS FROM CALIFORNIA ISO
BRIEFING ON NUCLEAR GENERATION STUDIES
PRELIMINARY RESULTS
DECEMBER 13-13, 2013

Briefing on Nuclear Generation Studies Preliminary Results

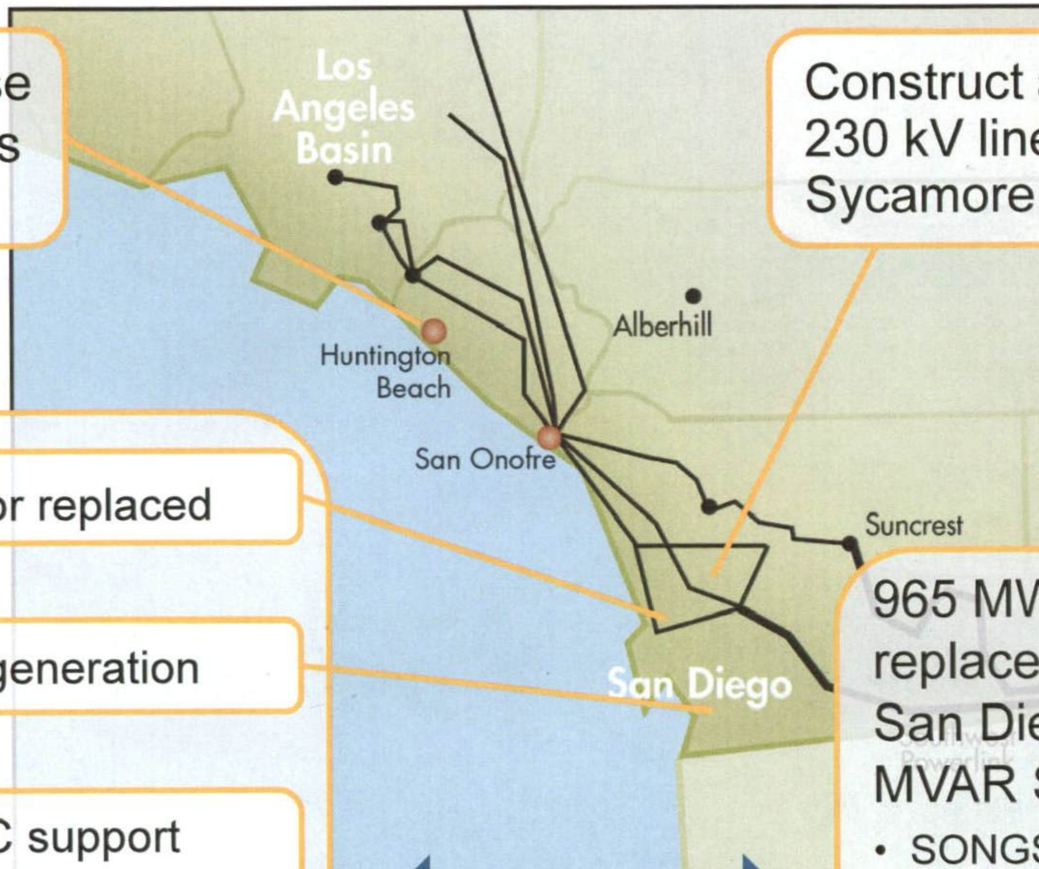
Neil Millar
Executive Director of Infrastructure Development

Board of Governors Meeting
General Session
December 13-14, 2012

Mid term mitigation alternatives for loss of SONGS:

Continue use synchronous condensers

Construct an 11-mile 230 kV line from Sycamore to Penasquitos



820 MW new or replaced

+

300 MW new generation

+

650 MVAR SVC support

- SONGS and Talega

OR

965 MW new or replaced in northwest San Diego, and 1460 MVAR SVC support

- SONGS, Talega, Penasquitos, San Luis Rey, Mission

Long term generation mitigation alternatives – no added transmission lines (in addition to mid term plan)

Replace & add new generation totaling ~4,300 - 4,600* MW

*May be reduced by adding another 550 MVAR SVC at San Onofre and shifting the locations of the new generation.

OR

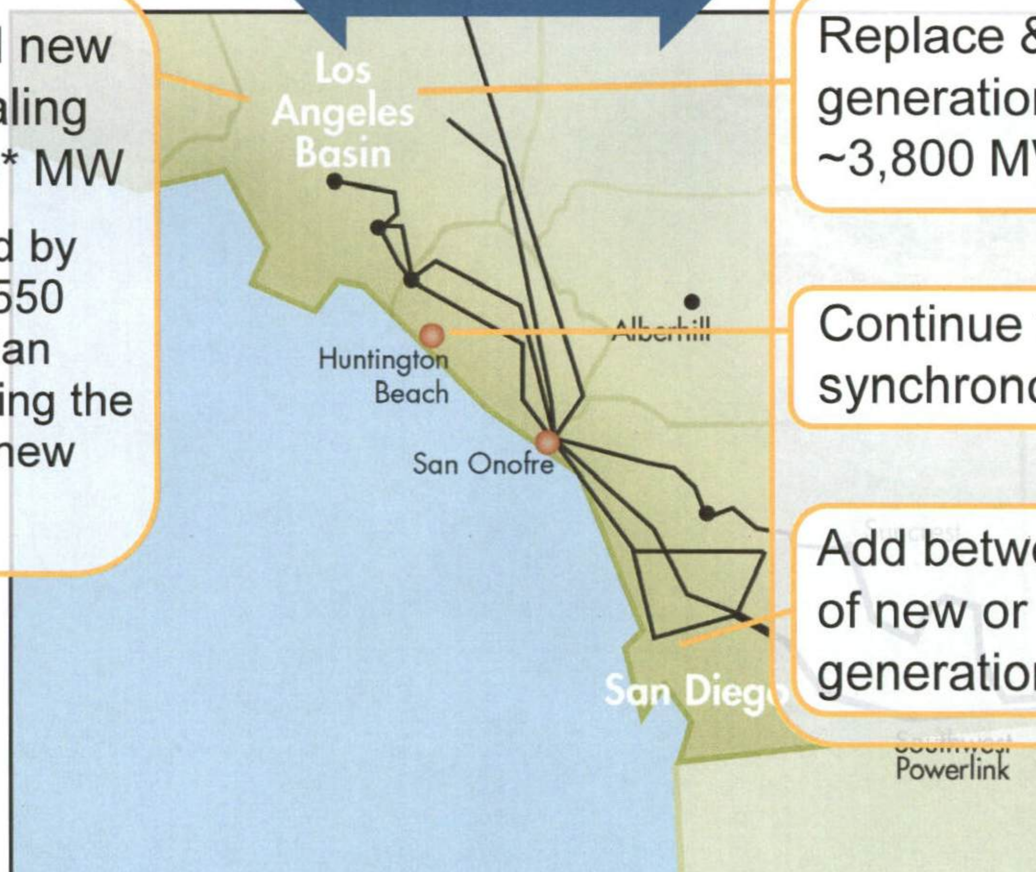
Replace & add new generation totaling ~3,800 MW

+

Continue to rely on synchronous condensers.

+

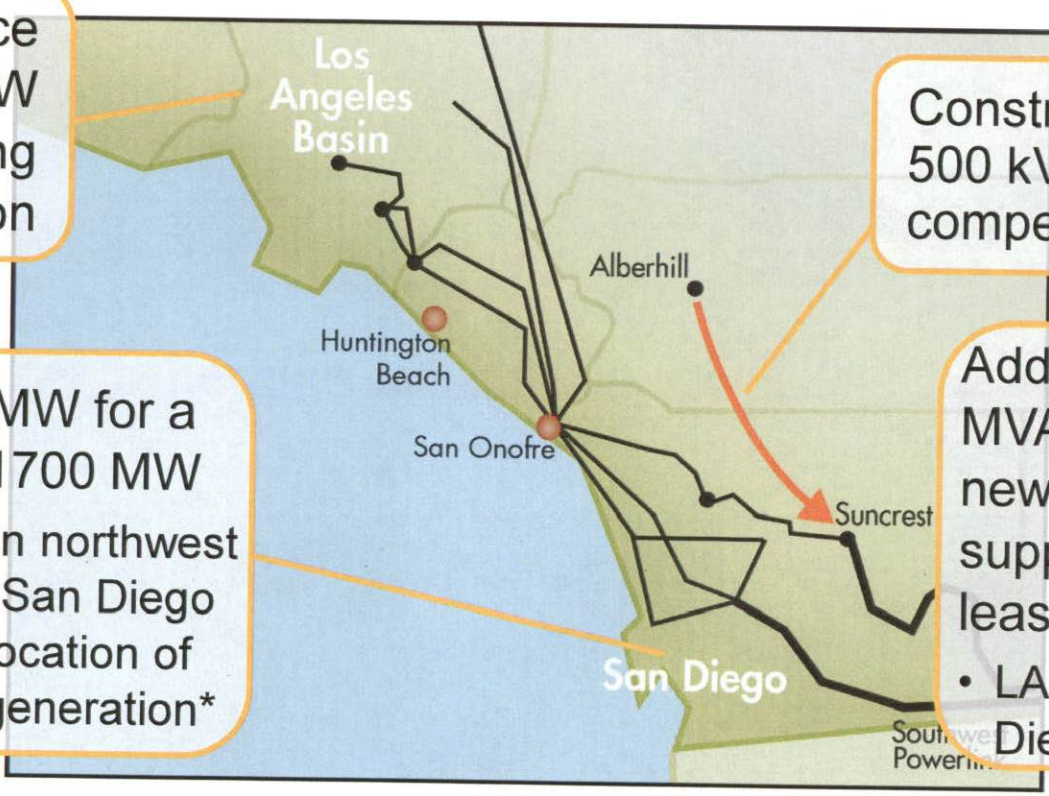
Add between 765-920 MW of new or replaced generation



Long term transmission and generation alternative (in <u>addition</u> to mid term plan)

Replace 3,000 MW of existing generation

Construct a 65-mile 500 kV line (70% compensation)



Add up to 660 MW for a total of 1600 - 1700 MW

- Spread between northwest and southwest San Diego depending on location of mid term plan generation*

Add up to 850 MVAR to bring new reactive support up to at least 1,500 MVAR

- LA Basin & San Diego

***Approximately 700 MW of generation in San Diego can be displaced by additional reactive support, transformer upgrades and 66 kV transmission upgrades in the LA Basin and upgrading line series capacitors and additional transformer upgrades.**

ATTACHMENT L

EXCERPTS FROM THE
2012-2013 ISO TRANSMISSION PLAN
MARCH 20, 2013

- The ISO assumed that the Huntington Beach synchronous condensers will be available for the intermediate (i.e., 2018) time frame and will assume their continued use or equivalent support. This was identified as part of the need for the SONGS absence scenario for summer 2013.
- Installation of 80 MVAR of shunt capacitor each for Johanna and Santiago Substations, and 160 MVAR of shunt caps for Viejo Substation. This was identified as part of the mitigation for the SONGS absence scenario for summer 2013
- Reconfiguration of the Barre – Ellis 230kV lines from two to four circuits. This was also identified in the SONGS absence scenario for summer 2013.
- Constructing an 11-mile 230 kV line from Sycamore to Penasquitos will mitigate over half of the identified thermal loading concerns. This was identified as common mitigation for the Mid-Term alternatives.

Given the long lead time for the Sycamore to Penasquitos line and the need for this line in a reasonable range of possible alternative mitigation plans, next steps for proceeding with the development of this line would need to commence immediately to address the identified mid-term and long-term needs. It is also important to note that, although it was assumed that the Huntington Beach synchronous condensers would be available through 2018, it is still uncertain if this project can be completed. In addition, the ISO has identified that a dynamic reactive support located at SONGS would provide equivalent reactive support. Therefore, in addition to a mid-term and long-term need for dynamic reactive support at SONGS, there is also a potential short-term need as a backup project to the Huntington Beach synchronous condenser project.

Mid-Term Alternative #1

- Add new or replace 820 MW of northwest San Diego generation.
- Add new 300 MW of generation in the southeast San Diego area.
- Install a total of 650 MVAR of dynamic reactive support (i.e., static VAR compensator or synchronous condensers) at SONGS (or its proximity) and San Luis Rey[20] Substations.
- Common mitigations (Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line)

Mid-Term Alternative #2

- Add new or replace 965 MW of northwest generation in San Diego.
- Install a total of 1,460 MVAR of SVC or SC for dynamic reactive support at SONGS, Talega, Penasquitos, San Luis Rey and Mission Substations.
- Common mitigations (Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line)

The figure below provides an illustration of the above mitigation alternatives.

[20] San Luis Rey is the first preferred location; if this is not feasible, second preferred location is Talega Substation. SDG&E submitted the proposed Talega synchronous condensers into the ISO Request Window.

Table 3.5-10– Summary of Mid-Term and Long-Term (generation) options

Summary of Generation & Dynamic Reactive Support Need (No SONGS Analyses) - Mid-Term and Long-Term (Generation) Options

	2018 (Mid-Term)^			2022 (Long-Term) - Generation Options (Incremental Need)			Total Generation & Dynamic Support Need By 2022	
Area	**OTC Replacement Assumptions (MW)**	**New Generation* (MW)**	**Dynamic Reactive Support Need (MVAR)**	**OTC Replacement Assumptions (MW)**	**New Generation* (MW)**	**Dynamic Reactive Support Need (MVAR)**	**Total Dynamic Support Need (MVAR)**	**Total Generation Need (MW)**
Alternative #1								
Southwestern LA Basin	0	0	280 (HB) ! + 400/500**	2900	1000 - 1200	550 #	500 - 1050 #	3915 - 4115
Northwestern LA Basin	0	0	0	0	300	0	0	300
Eastern LA Basin	0	0	0	0	100 - 200	0	0	100 - 200
Subtotal LA Basin			*280 (HB) ! + 400/500 *****	*4315 - 4615 ◊ #*		*550 #*	*500 - 1050*	*4315 - 4615 #*
Northwest San Diego	620/820 +	0	240 !!	++ ◊	0	240 !!	480	620/820 ++ ◊
Southwest San Diego	0	0	!!	0	0	2x240 !!	480	0
Southeast San Diego	0	300	0	0	0	0		300
Subtotal San Diego	*920/1120*		*240 !!*	*(Minimum 920 carried from 2018)*		*720 !!*	*960*	*920/1120 ◊*
Alternative #2								
Southwestern LA Basin	0	0	280 (HB) ! + 500	2460	0	0	280 (HB) ! + 500	2460
Northwestern LA Basin	0	0	0	1360	0	0	0	1360
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin	*0*		*280 (HB) ! + 500*	*3820*			*280 (HB) ! + 500*	*3820*
Northwest San Diego	965 $	0	2x240 (new)	520 $	0	0	480	1485
Southwest San Diego	0	0	2x240 (new)	0	0	0	480	0
Southeast San Diego	0	0	0	400 $	0	0	0	400
Subtotal San Diego	*965*		*960*	*920*			*960*	*1885*

Table 3.5-11– Summary of Mid-Term and Long-Term (combined transmission & generation) alternatives

Summary of Generation & Dynamic Reactive Support Need (No SONGS Analyses) - Combined Transmission & Generation Alternatives

	2018 (Mid-Term)^			2022 (Long-Term) - Combined Transmission Line and Generation Option (Incremental Need)			Total Generation & Dynamic Reactive Support Need by 2022	
Area	OTC Replacement Assumptions (MW)	New Generation* (MW)	Dynamic Reactive Support Need (MVAR)	OTC Replacement Assumptions (MW)	New Generation* (MW)	Dynamic Reactive Support Need (MVAR)	Total Dynamic Support Need (MVAR)	Total Generation Need (MW)
Alternative #1								
Southwestern LA Basin	0	0	280 (HB)! + 400/500 **	2915	0	0	500	2915
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin	*0*		*280 (HB)! + 400/500 ** *	*2915*			*500*	*2915*
Northwest San Diego	820	0	240 !!	360	0	240 !!	480	1180
Southwest San Diego	0	0	!!	0	0	2x240 !!	480	0
Southeast San Diego	0	300	0	0	100	0	0	400
Subtotal San Diego	*1120*		*!!*	*460*		*720 !!*	*960*	*1580*
Alternative #2								
Southwestern LA Basin	0	0	280 (HB)! + 500 (new)	2915	0	0	500	2915
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	0	0	0	0	0	0
Subtotal LA Basin			*280 (HB)! + 500 (new)*	*2915*			*500*	*2915*
Northwest San Diego	965	0	2x240	215	0	0	480	1180
Southwest San Diego	0	0	2x240	0	0	0	480	0
Southeast San Diego	0	0	0	0	400	0	0	400
Subtotal San Diego	*965*		*960*	*615*			*960*	*1580*

The following two figures illustrate the generation and combined transmission and generation alternatives. Note that both assume the mid-term mitigations were put in place and remain in place.

Figure 3.5-4: Long-term generation alternatives

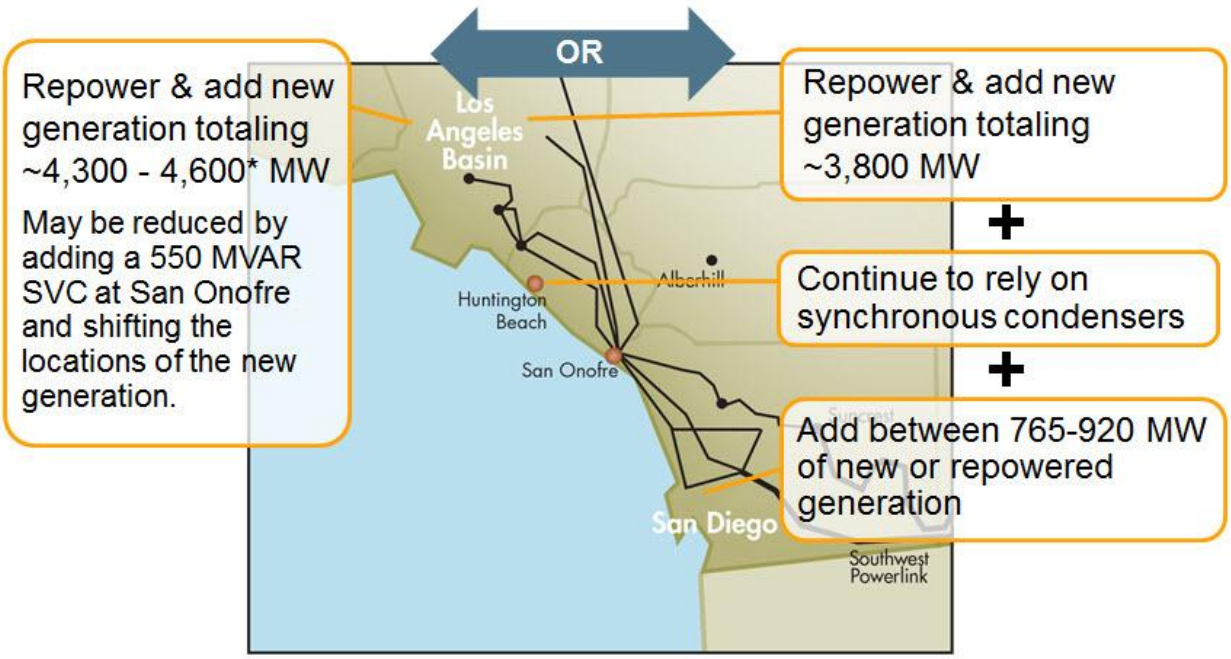
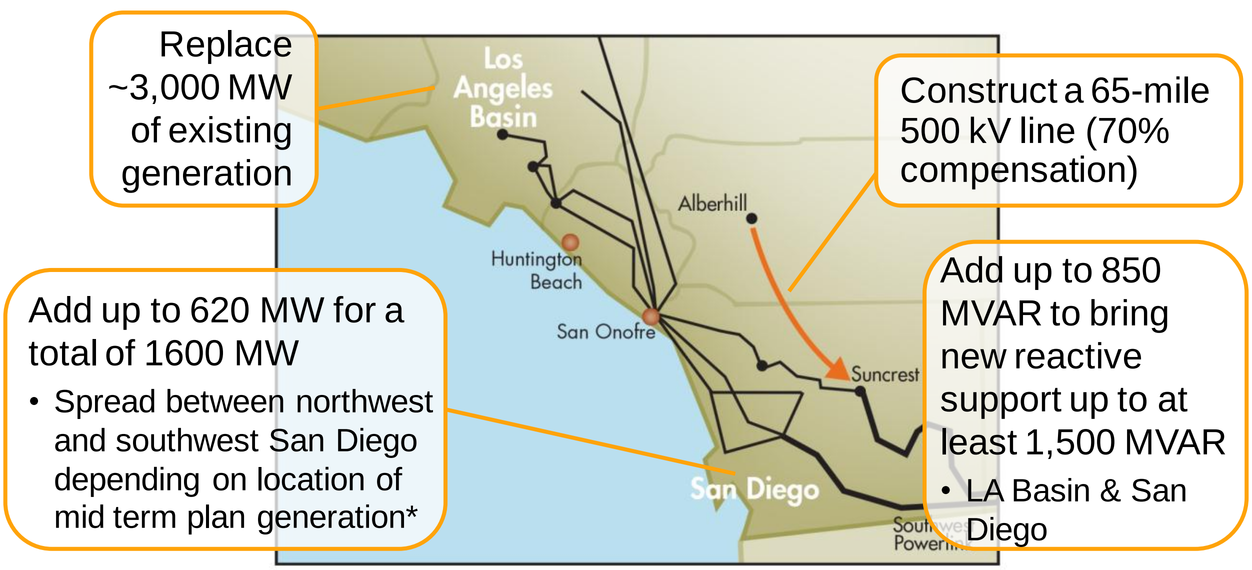


Figure 3.5-5: Long-term combined transmission and generation alternative



***Approximately 700 MW of generation in San Diego can be displaced by additional reactive support, transformer upgrades and 66 kV transmission upgrades in the LA Basin and upgrading line series capacitors and additional transformer upgrades.**

Table 3.5-12: 2022 Local reliability assessment of LA Basin and San Diego areas

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Total Generation (MW)	7,112	2,734		3,100	4,361
Category A	N/A	N/A	One Category A – normal overloads	N/A Category C contingency is the overriding contingency for LCR need for this sub-area	N/A None other than the ones identified in the San Diego sub-area
Identified Reliability Concerns			Barre-Lewis 230kV line (7% overloads)		
Required Generation (MW)			543 MW (386 MW thermal/157 MW DG)		
Deficiency (MW)			(386)* *This is mitigated by any of the mitigation plans for Category C (N-1-1) for LA Basin and San Diego areas if this portion of generation addition is in the southwest area of LA Basin		
Category B	N/A Category C contingency is the overriding contingency for LCR need for this area	N/A Category C contingency is the overriding contingency for LCR need for this sub-area	N/A	Same notes as above	G-1/N-1: Otay Mesa/IV-N.Gila 500kV
Identified Reliability Concerns	Category C reliability concerns established LCR needs	Category C reliability concerns established LCR needs	Category A reliability concerns establish LCR needs	Same notes as above	Post-transient voltage deviation beyond 7% at SCE's Viejo 230kV

	LA Basin	W. LA	Ellis	San Diego	SD/IV
Required Generation	See notes above	See notes above	See notes above	N/A	5,304* *The deficiency of 943 MW (=4361-5304) would be mitigated by any of the mitigation plans for Category C (N-1-1) for LA Basin and San Diego areas
Category C	N-1-1: Sunrise, system adj., followed by SWPL	N-1-1: Serrano-Lewis #1, followed by Serrano-Villa Park #2 230kV	See notes above	N-1-1: Sunrise, system adj., followed by SWPL	Category B contingency is the overriding contingency for LCR need for this area
Identified Reliability Concerns	Post-transient voltage instability	Overloading concern on the Serrano-Villa Park #1 230kV line (36% overloads)	See notes above	Post-transient voltage instability	See notes above
Description of Mitigations – **Generation Options**	(1) Replace and add new generation totaling 4,300 – 4,600 MW* Notes: * the maximum generation level may be reduced by adding another 550 MVAR SVC at San Onofre 230kV bus (or in new substation in proximity of the existing switchyard) (2) Replace and add new generation totaling 3,800	In association with LA Basin mitigation, if 2,460 MW of OTC generation is replaced or new generation is added in the southwestern part of the LA Basin, the thermal loading concern for Western LA sub-area would be mitigated.		Generation Options (see LA Basin for coordinated plan) (1) No new additional generation in San Diego area (2) Add between 765 – 920 MW of new or replaced generation	

	LA Basin	W. LA	Ellis	San Diego	SD/IV
	MW, AND Continue to rely on HB synchronous condensers, AND Add between 765 – 920** MW of new or replaced generation in San Diego (**lower number corresponds to higher generation addition/replacement in 2018 in San Diego area and vice versa), AND Add 820 MVAR of additional dynamic reactive support in LA Basin and San Diego areas if 2018 plan has minimum amount of voltage support				
LCR Area's Total Required Generation – for Generation Options	(1) Total 11,412 – 11,712 MW (included 251 MW DG) – lower number corresponds to scenario if additional 550 MVAR SVC can be installed at San Onofre 230kV bus (2) Total 10,912 MW in LA Basin	Total 5,099MW		(1) Total 3,100 MW (2) Total 3,865 – 4,020 MW (=3,100+765 or +920)	See notes above

ATTACHMENT M

EXCERPTS FROM

2013 CALIFORNIA ENERGY EFFICIENCY POTENTIAL
AND GOALS STUDY
FINAL DRAFT REPORT
PREPARED FOR:
CALIFORNIA PUBLIC UTILITIES COMMISSION
AUGUST 6, 2013

NAVIGANT

2013 California Energy Efficiency Potential and Goals Study

Final Draft Report

Prepared for:
California Public Utilities Commission

Navigant Consulting, Inc.
1990 North California Blvd.
Suite 700
Walnut Creek CA, 94596

925 930 2716
www.navigant.com

August 6, 2013

In collaboration with:

Heschong Mahone Group

sound data management

Executive Summary

The Navigant Consulting, Inc. team (the Navigant team) developed the 2013 Potential and Goals Study to analyze energy and demand savings potential in the service territories of four of California's investor-owned utilities (IOUs) during the post-2014 energy efficiency (EE) portfolio planning cycle. This report includes results for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Southern California Gas (SoCalGas). The primary product of the 2013 Potential and Goals Study is the Potential and Goals (PG) Model, which provides a single platform in which to conduct robust quantitative scenario analysis that reflects the complex interactions among various inputs and Policy Drivers.

ES.1 The Purpose of this Study

The *Analysis to Update Energy Efficiency Potential and Goals for 2013 and Beyond* is a statewide assessment of energy efficiency potential,[1] which considers key policy mechanisms that the State is employing to drive the energy efficiency market. It serves several important roles in the state regulatory framework:

1. To provide guidance for the utilities' 2015 energy efficiency portfolios[2]
2. To update the forecast for energy procurement planning[3]
3. To inform strategic contributions to California's greenhouse gas reduction targets[4]
4. To inform the development of benchmarks for Efficiency Savings and Performance Incentive[5]

The 2013 Potential and Goals Study updates and expands upon Track 1 of the Analysis (referred to as the "2011 Potential Study") by addressing the following research questions:

[1] Navigant. May 8, 2012. Analysis to Update Energy Efficiency Potential and Targets for 2013 and Beyond, Track 1 Statewide Investor Owned Utility Energy Efficiency Potential Study. Prepared for California Public Utilities Commission (CPUC).

[2] The energy efficiency goals were first adopted in Decision D.04-06-090 to set the benchmark that the IOU energy efficiency programs were expected to achieve. The goal-setting process set a framework for the program planning cycle, determining the targets for utility energy efficiency program portfolio performance.

[3] As the Energy Action Plan established energy efficiency as first in the loading order, the state must adopt a long-term benchmark that can be used in utility energy procurement planning. The IOUs' energy efficiency goals adopted from this study will be incorporated into the California Energy Commission's (CEC) *Integrated Energy Policy Report* (IEPR), which establishes the demand forecast for long-term procurement planning. This forecast is an input into the CPUC's Long Term Procurement Planning proceeding, which determines the generation resources that energy efficiency is expected to offset in order to minimize costs to ratepayers.

[4] The California Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) relies on intensified energy efficiency efforts across California. The California Air Resources Board's Scoping Plan for AB 32 establishes a statewide energy efficiency target for the year 2020.

[5] The Efficiency Savings and Performance Incentive is considered in R.12-01-005.and can be found at http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:809728160393201::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1201005.

- What additional incremental potential can be quantified from the policy initiatives implemented from the California Energy Efficiency Strategic Plan, and by other statewide policies such as Assembly Bill (AB) 758?
- What additional quantifiable potential may be available from emerging technologies that has not been included in past portfolios or in the 2011 Potential Study?
- How can the methodology to quantify EE potential for the agricultural, industrial, mining, and street-lighting (AIMS) sectors be refined to use existing market data?

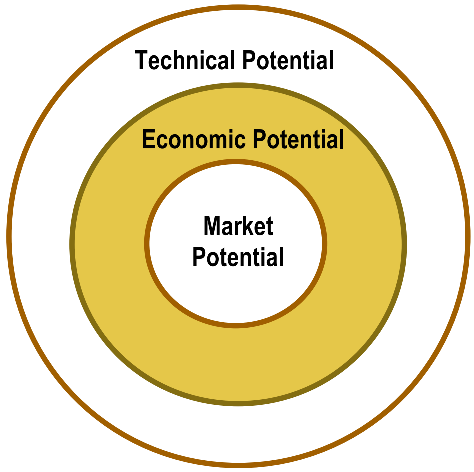
The Navigant team calculated potential energy efficiency savings for the 2013 Potential Study using a similar modeling methodology as the previous potential studies used to establish goals starting in 2004, and updated in 2008 and 2011. This methodology uses a bottom-up approach to identify and quantify the savings of all energy efficiency "measures", which are any possible change that can be made to a building, equipment or process that could save energy. The PG Model calculates the possible energy savings available above a baseline that is determined by a regulatory (i.e., code or standard) or market driver.

Consistent with the 2011 Potential Study, the 2013 Potential and Goals Study forecasts energy efficiency potential on three levels, as illustrated in Figure ES-1.

1. **Technical Potential Analysis:** Technical potential is defined as the amount of energy savings that would be possible if the highest level of efficiency for all technically applicable opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures.
2. **Economic Potential Analysis:** Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost-effective measures.[6] All components of economic potential are a subset of technical potential. The technical and economic potential represent the total energy savings available each year that are above the baseline of the Title 20/24 codes and federal appliance standards.
3. **Market Potential Analysis:** The final output of the potential study is a market potential analysis, which calculates the energy efficiency savings that could be expected in response to specific levels of incentives and assumptions about market influences and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as "maximum achievable potential." Market potential is used to establish the utilities' energy efficiency goals, as determined by the California Public Utilities Commission (CPUC).

[6] The default scenario for this study includes all non-emerging technologies with a total resource cost (TRC) test of 0.85 or greater; emerging technologies are included if they meet a TRC of 0.75 in a given year and achieve the TRC for non-emerging technologies (0.85) within ten years of market introduction.

Figure ES-1. Diagram of Types of Energy Efficiency Potential



Source: Navigant team, 2011 Potential Study

Market potential can be quantified by three different approaches, which each serve separate needs and provide necessary perspectives.

1. **Incremental savings** represent the annual energy and demand savings achieved by the set of programs and measures **in the first year** that the measure is implemented. It does not consider the additional savings that the measure will produce over the life of the equipment. A view of incremental savings is necessary in order to understand what additional savings an individual year of EE programs will produce. This has been the basis for IOU program goals.
2. **Cumulative savings** represent the total savings from energy efficiency program efforts from measures installed since 2006[7] and including the current program year, and are still active in the current year. It includes the decay of savings as measures reach the end of their useful lives. Cumulative savings also account for the timing effects of codes and standards that become effective after measure installation. This view is necessary for demand forecast, but creates challenges in accounting for IOU program goals.
3. **Life-cycle savings** refer to the expected trajectory of savings from an energy efficiency measure (or portfolio of measures) over the estimated useful life of the measure(s), taking account of any natural decay or persistence in performance over time. Whereas cumulative savings are a backward look at all measures installed in the past that are producing current savings, life-cycle savings accounts for all future savings from measures installed in the current year. Life-cycle

[7] Part of the calibration process for any potential model involves reviewing historic program data to assess various market characteristics such as measure saturation, incentive levels, and adoption patterns. This model is calibrated on program reported data from 2006 through 2011, and savings estimates for the 2013-2014 program cycle. As such, 2006 is the beginning of the calibration period.

savings is used in the cost-effectiveness evaluations and may be an appropriate basis for IOU program goals.

A large number of variables drive the calculation of market potential. These include assumptions about the manner in which efficient products and services are marketed and delivered, the level of customer awareness of energy efficiency, and customer willingness to install efficient equipment or operate equipment in ways that are more efficient. The Navigant team used the best available current market knowledge and followed these guidelines in developing the recommended market potential:

1. Provide a view of market potential where data sources and calculation methods are transparent and clearly documented.
2. Avoid assumptions and model design decision that would establish goals and targets that are aspirational, but for which the technologies or market mechanisms to attain these goals may not yet be clearly defined.

With these precepts in mind, the Navigant team considers that the market potential presented in this study is a viable target for energy efficiency to which load forecasters, system planners, and resource procurement specialists could agree. However, this study may not capture the upper bound on the total amount of energy efficiency that can be achieved. There may be additional energy savings to capture, particularly from systems efficiency and behavior change, which could not be reliably quantified based on past evaluation results available at the time of this study.

ES.2 Findings

This section discusses two high-level findings of the results of the analysis. Section 5 includes a more detailed set of overarching findings.

ES.2.1 Technical and economic potential increased from the 2011 Potential Study as a result of the new measures and methodologies included in the 2013 Potential and Goals Study

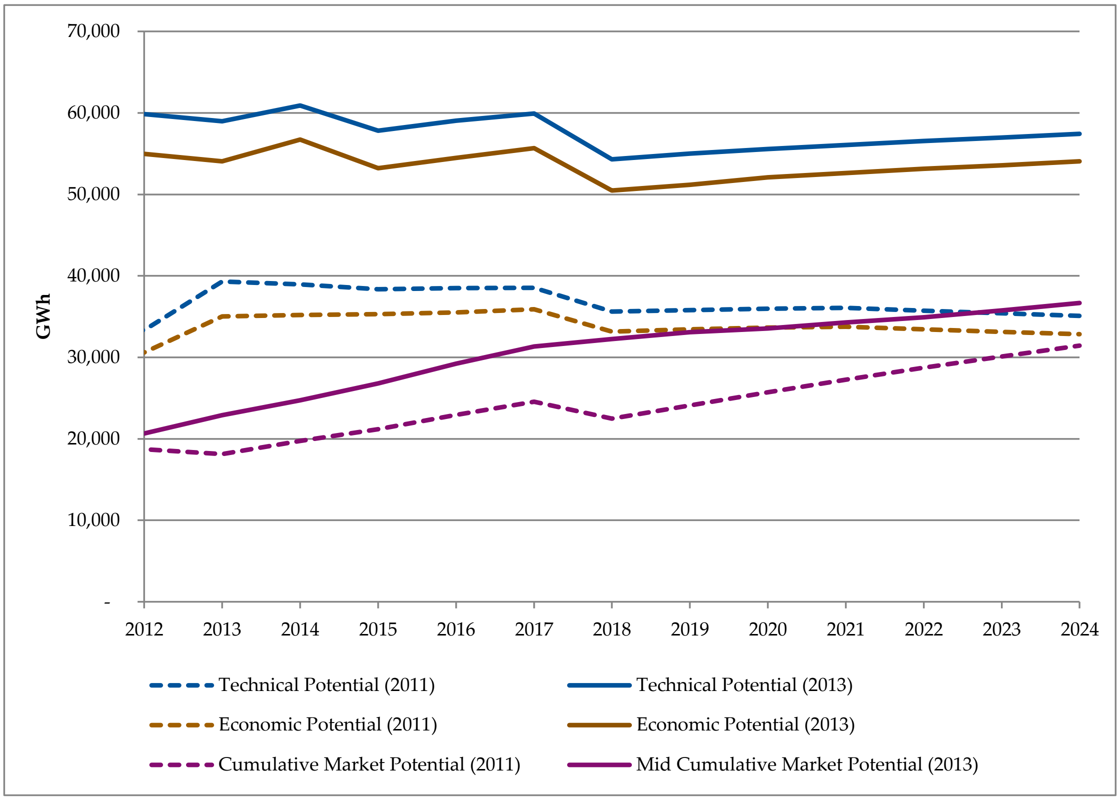
Technical and economic potential are about 50 percent higher than reported in the 2011 Potential Study, as seen in Figure ES-2. This increase is primarily driven by a change in the approach to modeling technical and economic potential. The approach to modeling technical potential used in the 2013 Potential and Goals Study demonstrates a best-case scenario for technical potential given what is known about the market today. Due to barriers such as payback considerations or split incentives, it is unlikely that all customers would replace baseline equipment with the most efficient technology in a competition group, but technical potential is intended to represent the savings possible if all technically available changes were made. This change was made to expand our view of potential from emerging technologies.

The 2013 Potential and Goals Study defines technical potential by the most efficient equipment option within a competition group. The technical and economic potential in the 2011 Potential Study was calculated based on the efficiency level of the measure that was most commonly adopted in IOU programs. For example, the 2011 model would assess technical potential for residential heating, ventilation, and air-conditioning (HVAC) based on the average efficiency being installed through IOU programs, such as a Seasonal Energy Efficiency Ratio (SEER) 15 HVAC unit. In comparison, the 2013

Study calculates the potential for all residential HVAC units to be replaced by SEER 22 machines, the most efficient equipment currently visible on the market.

The addition of the mining and street-lighting sectors to the 2013 Potential and Goals Study also added approximately 1,800 gigawatt-hours (GWh) to the technical and economic potential. These sectors were not included in the 2011 report.

Figure ES-2. Comparison of Technical, Economic, and Cumulative Market Potential in the 2011 and 2013 Studies



Source: PG Model release on 5/22/2013.
Note: 2013 Cumulative Potential includes behavioral savings and C&S savings to make a consistent comparison with the 2011 results.

ES.2.2 Gap between economic and cumulative market potential indicates that there are additional savings opportunities not being captured by current adoption patterns.

The trajectory of cumulative market potential toward economic potential in Figure ES-2 indicates the degree to which the market, using IOU program incentives and financing, is expected to capture the available potential of cost-effective energy efficiency.

The cumulative market potential shown in Figure ES-2 includes voluntary adoption of energy efficient measures due to rebates and behavior-based initiatives from the 2011 and 2013 models. This definition of cumulative market potential does not include savings from codes and standards (C&S) that are attributable to IOUs. In addition, cumulative market potential excludes savings from energy efficiency financing programs because those programs are still in the pilot phase. Estimates of savings from financing programs will be better informed by more evaluation data and by more information about the structure of the programs in future program cycles. Considering savings due to financing separately from the cumulative market potential shown in Figure ES-2 enables policy makers and stakeholders to explicitly consider the effects of these factors on the estimated savings; Section 5.3 includes a discussion about the additional potential that could be realized by financing programs.

As shown in Figure ES-2, cumulative market potential in the base forecast achieves approximately 64 percent of the revised technical potential by 2024. This market potential estimate in 2024 is roughly 16 percent higher than the 2011 model estimate due to two initiatives that expanded adoption rates:

1. An expanded set of emerging technologies for which market adoption is expected to be moderately aggressive
2. An incremental gain in the adoption of energy efficiency through whole-building project delivery, including both retrofit and zero net energy new construction initiatives

CERTIFICATE OF SERVICE

I hereby certify that I have on this date served a copy of **REPLY TESTIMONY OF ROBERT M. FAGAN** to all known parties by either United States mail or electronic mail, to each party named on the official attached service list in **R.12-03-014**:

I hand-delivered a hard copy to the assigned Administrative Law Judge's mail slot.

Executed on **September 30, 2013** at San Francisco, California.

/s/ CHARLENE D. LUNDY

Charlene D. Lundy

A. CALIFORNIA PUBLIC UTILITIES COMMISSION
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VI. Parties

ADAM GUSMAN
CORPORATE COUNSEL
GLACIAL ENERGY OF CALIFORNIA, INC.
EMAIL ONLY
EMAIL ONLY, VI 00000
FOR: GLACIAL ENERGY OF CALIFORNIA, INC.

ANDREW WANG
SOLARRESERVE, LLC
EMAIL ONLY
EMAIL ONL Y, CA 00000
FOR: SOLARRESERVE

KATHY TRELEVEN
LARGE-SCALE SOLAR ASSOCIATION
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: LARGE-SCALE SOLAR ASSOCIATION

KENNETH SAHM WHITE
CLEAN COALITION
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: CLEAN COALITION

LISA BOND
ATTORNEY
RICHARDS WATSON GERSHON
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: CITY OF REDONDO BEACH

MARCUS V. DA CUNHA
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: MARCUS V. DA CUNHA

SCOTT BLAISING
BRAUN BLAISING MCLAUGHLIN P.C.
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: KINGS RIVER CONSERVATION DISTRICT (KRCD)

SIERRA MARTINEZ
ATTORNEY
NATURAL RESOURCES DEFENSE COUNCIL
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: NATIONAL RESOURCES DEFENSE COUNCIL

TAM HUNT
ATTORNEY
(908)

GENERAL MANAGER
PLUMAS SIERRA RURAL ELECTRIC COOP.

EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: COMMUNITY ENVIRONMENTAL COUNCIL

EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: PLUMAS SIERRA RURAL ELECTRIC
CORP

ANDREW O. KAPLAN, ESQ.
BROWN RUDNICK LLP
ONE FINANCIAL CENTER
BOSTON, MA 02111
FOR: BEACON POWER, LLC

ABRAHAM SILVERMAN
ASSIST. GEN. COUNSEL - REGULATORY
NRG ENERGY, INC.
211 CARNEGIE CENTER DRIVE
PRINCETON, NJ 08540
FOR: NRG ENERGY, INC.

RICK C. NOGER
PRAXAIR PLAINFIELD, INC.
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON, DE 19808
FOR: PRAXAIR PLAINFIELD, INC.

KYLE W. DANISH
VAN NESS FELDMAN, P.C.
1050 THOMAS JEFFERSON ST., N. W.
WASHINGTON, DC 20007-3877
FOR: COALITION FOR EMISSION
REDUCTION

POLICY

VICTOR GONZALES
CONSTELLATION NEW ENERGY, INC. (1359)
111 MARKET PLACE, SUITE 500
BALTIMORE, MD 21202
FOR: CONSTELLATION NEW ENERGY, INC.

ALRINE WILLIAMS
LEGAL COUNSEL
LIBERTY POWER DELAWARE LLC
1901 W. CYPRESS CREEK ROAD, SUITE
600
FORT LAUDERDALE, FL 33309
FOR: LIBERTY POWER DELAWARE LLC

ALRINE WILLIAMS
LEGAL COUNSEL
LIBERTY POWER HOLDINGS LLC (1371)
1901 W. CYPRESS CREEK ROAD, SUITE 600
FORT LAUDERDALE, FL 33309
FOR: LIBERTY POWER HOLDINGS LLC

TRACY PHILLIPS
VP OF MARKETING
TIGER NATURAL GAS, INC.
1422 E. 71ST., STE J
TULSA, OK 74136
FOR: TIGER NATURAL GAS, INC.

JASON ARMENTA
CALPINE POWERAMERICA-CA, LLC
717 TEXAS AVENUE, SUITE 1000
HOUSTON, TX 77002
FOR: CALPINE POWERAMERICA-CA, LLC

KEVIN BOUDREAUX
ENERCAL USA LLC
7660 WOODWAY DRIVE, STE. 471A
HOUSTON, TX 77063
FOR: ENERCAL USA, LLC

KARA MORGAN
TRANSWEST EXPRESS, LLC
555 SEVENTEENTH STREET, SUITE 2400
DENVER, CO 80202
FOR: TRANSWEST EXPRESS, LLC

BRIAN FICKETT
VALLEY ELECTRIC ASSOCIATION
800 E. HWY 372
PAHRUMP, NV 89048
FOR: VALLEY ELECTRIC ASSOCIATION

PAUL SHEPARD
WILDFLOWER ENERGY
333 S. GRAND AVENUE, SUITE 1570

MICHAEL MAZUR
PRINCIPAL
3 PHASES RENEWABLES LLC (1373)

LOS ANGELES, CA 90071
FOR: WILDFLOWER ENERGY

2100 SEPULVEDA BLVD, SUITE 37
MANHATTAN BEACH, CA 90266
FOR: 3 PHASES RENEWABLES, LLC

INGER GOODMAN
COMMERCE ENERGY INC
1 CENTERPOINTE DRIVE, SUITE 350
LA PALMA, CA 90623-2520
FOR: COMMERCE ENERGY, INC.

DANIEL W. DOUGLASS
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS, CA 91367
FOR: CONEDISON SOLUTIONS, INC./WESTERN POWER TRADING FORUM

AKBAR JAZAYEIRI
DIR OF REVENUE & TARIFFS
SOUTHERN CALIFORNIA EDISON COMPANY (338)
2241 WALNUT GROVE AVE. / PO BOX 800
ROSEMEAD, CA 91770
FOR: SCE

AIMEE SMITH
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH STREET, HQ-12
SAN DIEGO, CA 92101
FOR: SAN DIEGO GAS & ELECTRIC COMPANY

DANIEL KING
SEMPRA U.S. GAS & POWER, LLC
101 ASH STREET, HQ-15B
SAN DIEGO, CA 92101
FOR: SEMPRA U.S. GAS & POWER, LLC

GREG BASS
NOBLE AMERICAS ENERGY SOLUTIONS, LLC
401 WEST A STREET, STE. 500
SAN DIEGO, CA 92101
FOR: NOBLE AMERICAS ENERGY SOLUTIONS LLC

DONALD C. LIDDELL
COUNSEL
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO, CA 92103
FOR: STARWOOD POWER-MIDWAY, LLC / CALIFORNIA ENERGY STORAGE ALLIANCE / CAMCO INTERNATIONAL GROUP, INC ./ TAS ENERGY

DAVID A. PEFFER, ESQ.
PROTECT OUR COMMUNITIES FOUNDATION
4452 PARK BOULEVARD, STE. 209
SAN DIEGO, CA 92116
FOR: PROTECT OUR COMMUNITIES FOUNDATION

MARCIE MILNER
SHELL ENERGY (1374)
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121
FOR: SHELL ENERGY NORTH AMERICA (US), L.P. (SHELL ENERGY)

SARAH TOMEC
SR. ADVISOR, REGULATORY AFFAIRS WEST
CAPITAL POWER CORPORATION
9255 TOWNE CENTRE DRIVE, STE. 900
SAN DIEGO, CA 92121
FOR: CAPITAL POWER CORPORATION

THOMAS R. DARTON
PILOT POWER GROUP, INC. (1365)
8910 UNIVERSITY CENTER LANE, STE. 520

GLORIA BRITTON
REGULATORY AFFAIRS MGR.
ANZA ELECTRIC CO-OPERATIVE, INC (909)

SAN DIEGO, CA 92122
FOR: PILOT POWER GROUP, INC.

PO BOX 39109 / 58470 HIGHWAY 371
ANZA, CA 92539-1909
FOR: ANZA ELECTRIC CO-OPERATIVE,
INC.

KRISTINE MICHAELS
CHIEF FINANCIAL OFFICER
SOUTHERN CALIFORNIA TELEPHONE & ENERGY
27515 ENTERPRISE CIRCLE WEST
TEMECULA, CA 92590
FOR: SOUTHERN CALIFORNIA TELEPHONE &
ENERGY
ENERGY

ANDREA MORRISON
DIRECTOR - GOV'T. AND REGULATORY
AFFAIRS
DIRECT ENERGY SERVICES, LLC (1341)
415 DIXON STREET
ARROYO GRANDE, CA 93420
FOR: DIRECT ENERGY, LLC/DIRECT
SERVICES

MONA TIERNEY-LLOYD
DIR., WESTERN REGUALTORY AFFAIRS
ENERNOC, INC.
PO BOX 378
CAYUCOS, CA 93430
FOR: ENERNOC, INC.

DAVID ORTH
SAN JOAQUIN VALLEY POWER AUTHORITY
ADMIN OFF @KINGS RIVER CONSERV
DISTRICT
4886 EAST JENSEN AVENUE
FRESNO, CA 93725
FOR: SAN JOAQUINVALLEY POWER
AUTHORITY

EVELYN KAHL
ALCANTAR & KAHL, LLP
33 NEW MONTGOMERY STREET, SUITE 1850
SAN FRANCISCO, CA 94015
FOR: ENERGY PRODUCERS & USERS COALITION

DAVID MACMILLAN
PRESIDENT
MEGAWATT STORAGE FARMS, INC.
3931 JEFFERSON AVE.
WOODSIDE, CA 94062
FOR: MEGAWATT STORAGE FARMS, INC.

SUE MARA
PRINCIPAL
RTO ADVISORS, LLC
164 SPRINGDALE WAY
REDWOOD CITY, CA 94062
FOR: ALLIANCE FOR RETAIL ENERGY MARKETS
(AREM) /DIRECT ACCESS CUSTOMER
COALITION

MARC D. JOSEPH
ADAMS BROADWELL JOSEPH & CARDOZO
601 GATEWAY BLVD., SUITE 1000
SOUTH SAN FRANCISCO, CA 94080
FOR: COALITION OF CALIFORNIA
UTILITY
EMPLOYEES

DIANA L. LEE
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

THERESA L. MUELLER
CITY AND COUNTY OF SAN FRANCISCO
CITY HALL, ROOM 234
1 DR. CARLTON B. GOODLETT PLACE
SAN FRANCISCO, CA 94102-4682
FOR: CITY AND COUNTY OF SAN
FRANCISCO

MATTHEW FREEDMAN

ETHAN RAVAGE

THE UTILITY REFORM NETWORK
785 MARKET ST., STE. 1400
SAN FRANCISCO, CA 94103
FOR: THE UTILITY REFORM NETWORK

BRIAN CHERRY
DIRECTOR - REGULATORY RELATIONS
PACIFIC GAS AND ELECTRIC COMPANY (39)
77 BEALE STREET ROOM 1087
SAN FRANCISCO, CA 94105
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DEBORAH N. BEHLES
ENVIRONMENTAL LAW AND JUSTICE CLINIC
GOLDEN GATE UNIVERSITY SCHOOL OF LAW
536 MISSION STREET
SAN FRANCISCO, CA 94105-2968
FOR: THE CALIFORNIA ENVIRONMENTAL
JUSTICE ALLIANCE

JACK STODDARD
MANATT PHELPS & PHILLIPS, LLP
ONE EMBARCADERO CENTER, 30TH FL.
SANFRANCISCO, CA 94111
FOR: PANOCHE ENERGY CENTER, LLC

MICHAEL B. DAY
ATTORNEY
GOODIN, MACBRIDE, SQUERI, DAY & LAMPREY,
505 SANSOME ST., STE. 900
SAN FRANCISCO, CA 94111
FOR: ABENGOA SOLAR, INC./CALENERGY
GENERATION

WILLIAM KISSINGER
BINGHAM MCCUTCHEN LLP
THREE EMBARCADERO CENTER, 28TH FL.
SAN FRANCISCO, CA 94111
FOR: COMPETITIVE POWER VENTURES/POWER
DEVELOPMENT, INC.

MARTIN A. MATTES

WEST COAST LEAD - US
INTERNATIONAL EMISSIONS TRADING
ASSN.
456 MONTGOMERY ST., 18TH FLOOR
SAN FRANCISCO, CA 94104
FOR: INTERNATIONAL EMISSIONS
TRADING
ASSOCIATION (IETA)

NORA SHERIFF
ALCANTAR & KAHL
33 NEW MONTGOMERY ST., STE. 1850
SAN FRANCISCO, CA 94105
FOR: CALIFORNIA LARGE ENERGY
CONSUMERS
ASSOCIATION (CLECA)

BRIAN T. CRAGG
GOODIN, MACBRIDE, SQUERI, DAY &
LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: INDEPENDENT ENERGY PRODUCERS
ASSOCIATION (IEPA)

JEANNE B. ARMSTRONG
ATTORNEY
GOODIN MACBRIDE SQUERI DAY &
LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: SOLAR ENERGY INDUSTRIES
ASSOCIATION

SETH D. HILTON
ATTORNEY AT LAW
STOEL RIVES LLP
THREE EMBARCADERO CENTER, STE. 1120
SAN FRANCISCO, CA 94111
FOR: AES SOUTHLAND/ZEPHYR POWER
TRANSMISSION

WILLIAM V. ROSTOV
EARTHJUSTICE
50 CALIFORNIA ST., STE. 500
SAN FRANCISCO, CA 94111
FOR: SIERRA CLUB CALIFORNIA

LISA A. COTTLE

ATTORNEY
NOSSAMAN, LLP
50 CALIFORNIA STREET, 34TH FL.
SAN FRANCISCO, CA 94111-4799
FOR: NOSSAMAN, LLP

ATTORNEY AT LAW
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO, CA 94111-5802
FOR: GENON ENERGY, INC.

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: SOUTH SAN JOAQUIN IRRIGATION
DISTRICT

JEFFREY P. GRAY
DAVIS WRIGHT TREMAINE, LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: CALPINE CORPORATION

MARK HUFFMAN
LAW DEPT
PACIFIC GAS & ELECTRIC COMPANY
PO BOX 7442, B30A
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

SARA STECK MYERS
ATTORNEY AT LAW
122 - 28TH AVENUE
SAN FRANCISCO, CA 94121
FOR: CENTER FOR ENERGY EFFICIENCY
AND
RENEWABLE TECHNOLOGIES (CEERT)

JENNIFER CHAMBERLIN
LS POWER DEVELOPMENT, LLC
5000 HOPYARD ROAD, SUITE 480
PLEASANTON, CA 94588
FOR: LS POWER

JOHN L. GEESMAN
ATTORNEY
DICKSON GEESMAN LLP
1999 HARRISON STREET, STE. 2000
OAKLAND, CA 94612
FOR: ALLIANCE FOR NUCLEAR
RESPONSIBILITY (A4NR)

LAURENCE G. CHASET
KEYES FOX & WIEDMAN, LLP
436 14TH STREET, STE. 1305
OAKLAND, CA 94612
FOR: INTERSTATE RENEWABLE ENERGY
COUNCIL, INC. / FRIENDS OF THE EARTH

MARGIE GARDNER
EXECUTIVE DIRECTOR
CAL. ENERGY EFFICIENCY INDUSTRY
COUNCIL
436 14TH STREET, SUITE 1123
OAKLAND, CA 94612
FOR: CALIFORNIA ENERGY EFFICIENCY
INDUSTRY COUNCIL (CEEIC)

PATRICK VANBEEK
DIR - CUSTOMER SUPPORT
COMMERCIAL ENERGY OF CALIFORNIA
7677 OAKPORT STREET, STE. 525
OAKLAND, CA 94621
FOR: COMMERCIAL ENERGY OF CALIFORNIA

GREGG MORRIS
DIRECTOR
GREEN POWER INSTITUTE
2039 SHATTUCK AVENUE, STE 402
BERKELEY, CA 94704
FOR: GREEN POWER INSTITUTE

LAURA WISLAND
SENIOR ENERGY ANALYST
UNION OF CONCERNED SCIENTISTS
2397 SHATTUCK AVE., STE. 203
BERKELEY, CA 94704

NANCY RADER
EXECUTIVE DIRECTOR
CALIFORNIA WIND ENERGY ASSOCIATION
2560 NINTH STREET, SUITE 213A
BERKELEY, CA 94710

FOR: UNION OF CONCERNED SCIENTISTS

FOR: CALIFORNIA WIND ENERGY
ASSOCIATION

R. THOMAS BEACH
CROSSBORDER ENERGY
2560 9TH ST., SUITE 213A
BERKELEY, CA 94710-2557
FOR: THE CALIFORNIA COGENERATION COUNCIL

ELIZABETH KELLY
LEGAL DIRECTOR
MARIN ENERGY AUTHORITY
781 LINCOLN AVENUE, SUITE 320
SAN RAFAEL, CA 94901
FOR: MARIN ENERGY AUTHORITY

BRAD BORDINE
DISTRIBUTED ENERGY CONSUMER ADVOCATES
516 WHITEWOOD DRIVE
SAN RAFAEL, CA 94903
FOR: DISTRIBUTED ENERGY CONSUMER
ADVOCATES

BARBARA GEORGE
WOMEN'S ENERGY MATTERS
PO BOX 548
FAIRFAX, CA 94978-0548
FOR: WOMEN'S ENERGY MATTERS

JAN REID
COAST ECONOMICS CONSULTING
3185 GROSS ROAD
SANTA CRUZ, CA 95062
FOR: L. JAN REID

DAVID KATES
DAVID MARK & COMPANY
3510 UNOCAL PLACE, SUITE 200
SANTA ROSA, CA 95403
FOR: THE NEVADA HYDRO COMPANY

JUDITH B. SANDERS
SR. COUNSEL
CALIF. INDEPENDENT SYSTEM OPERATOR CORP
250 OUTCROPPING WAY
FOLSOM, CA 95630
FOR: CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

MARGARET MILLER
BROOKFIELD RENEWABLE ENERGY GROUP
513 SAN MARCO PLACE
EL DORADO HILLS, CA 95762
FOR: BROOKFIELD RENEWABLE ENERGY
GROUP

STEPHEN T. GREENLEAF
V.P. & COMPLIANCE DIRECTOR
J.P. MORGAN CHASE BANK, N.A.
2864 ABERDEEN LANE
EL DORADO HILLS, CA 95762
FOR: J.P. MORGAN VENTURES ENERGY
CORPORATION (JPMVEC) / BE CA LLC

DOUGLAS E. DAVIE
V.P.
WELLHEAD ELECTRIC COMPANY, INC.
650 BERCUT DRIVE, STE. C
SACRAMENTO, CA 95811
FOR: WELLHEAD ELECTRIC COMPANY

RONALD LIEBERT
ATTORNEY AT LAW
ELLISON SCHNEIDER & HARRIS LLP
2600 CAPITOL AVENUE, STE. 400
SACRAMENTO, CA 95816
FOR: THE VOTE SOLAR INITIATIVE

CHRISTOPHER T. ELLISON
ATTORNEY
ELLISON, SCHNEIDER & HARRIS, L.L.P
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO, CA 95816-5905
FOR: PATHFINDER RENEWABLE WIND
ENERGY,
LLC

KAREN MILLS

DANIEL SILVERIA

CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833
FOR: CALIFORNIA FARM BUREAU FEDERATION

GEN MGR
SURPRISE VALLEY ELECTRIC CORP.
516 US HIGHWAY 395 E
ALTURAS, CA 96101-4228
FOR: SURPRISE VALLEY ELECTRIC CORPORATION

DONALD BROOKHYSER
ALCANTAR & KAHL
1300 SW FIFTH AVE., SUITE 1750
PORTLAND, OR 97210
FOR: COGENERATION ASSOCIATION OF CALIFORNIA

GIFFORD JUNG
POWEREX CORPORATION
666 BURRARD STREET, SUITE 1400
VANCOUVER, BC V5R 4Y2
CANADA
FOR: POWEREX CORPORATION

VII. Information Only

ANDRA PLIGAVKO
FIRST SOLAR DEVELOPMENT, INC.
EMAIL ONLY
EMAIL ONLY, CA 00000

ARMANDO INFANZON
SMART GRID POLICY MANAGER
SAN DIEGO GAS & ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000

BARBARA R. BARKOVICH
BARKOVICH & YAP, INC.
EMAIL ONLY
EMAIL ONLY, CA 00000

BRAD MEIKLE
SOVEREIGN ENERGY, LLC
EMAIL ONL Y
EMAIL ONLY, CA 00000

CASE COORDINATION
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000

CATHIE ALLEN
REGULATORY MGR.
PACIFICORP
EMAIL ONLY
EMAIL ONLY, OR 00000

DANIEL PATRY
RECURRENT ENERGY
EMAIL ONLY
EMAIL ONLY, CA 00000

DAVID FELIX
DIR - DEVELOPMENT
NORTHLIGHT POWER
EMAIL ONLY
EMAIL ONLY, CA 00000

DAVID HICKS
DIAMOND GENERATING CORPORATION
EMAIL ONLY
EMAIL ONLY, CA 00000

DAVID WEIDBERG
JOHNSON CONTROLS
EMAIL ONLY
EMAIL ONLY, CA 00000

DIANE FELLMAN
DIR - GOVERNMENTAL & REGULATORY AFFAIRS
NRG ENERGY, INC.
EMAIL ONLY

DYANA MARIE DELFIN-POLK
CLEAN COALITION
EMAIL ONLY
EMAIL ONLY, CA 00000

EMAIL ONLY, CA 00000

ERIN GRIZARD
BLOOM ENERGY
EMAIL ONLY
EMAIL ONLY, CA 00000

GEORGE ZAHARIUDAKIS
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000

JAMIE L. MAULDIN
ADAMS BROADWELL JOSEPH & CARDOZO, PC
EMAIL ONLY
EMAIL ONLY, CA 00000

JERRY BROWN
WORLD BUSINESS ACADEMY
EMAIL ONLY
EMAIL ONLY, CA 00000

JODY S. LONDON
JODY LONDON CONSULTING
EMAIL ONLY
EMAIL ONLY, CA 00000

JOHN W. LESLIE, ESQ.
MCKENNA LONG & ALDRIDGE LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

JULIEN DUMOULIN-SMITH
UBS INVESTMENT RESEARCH
EMAIL ONLY
EMAIL ONLY, NY 00000

KATY ROSENBERG
ALCANTAR & KAHL
EMAIL ONLY
EMAIL ONLY, CA 00000

KELSEY SOUTHERLAND
TAS ENERGY
EMAIL ONLY
EMAIL ONLY, TX 00000

LYNN HAUG
ELLISON SCHNEIDER & HARRIS L.L.P.
EMAIL ONLY
EMAIL ONLY, CA 00000

MATT KLOPFENSTEIN
GONZALEZ QUINTANA & HUNTER LLC
EMAIL ONLY
EMAIL ONLY, CA 00000

MATTHEW BARMACK
CALPINE CORPORATION
EMAIL ON LY
EMAIL ONLY, CA 00000

MICHAEL EVANS
SHELL
EMAIL ONLY
EMAIL ONLY, CA 00000

MIKE CADE
ALCANTAR & KAHL, LLP
EMAIL ONLY
EMAIL O NLY, OR 00000

MIYUKI IWAHASHI
PACIFIC GAS & ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000

OLIVIA PARA
DAVIS WRIGHT TREMAINE LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

RACHEL MCMAHON
EMAIL ONLY
EMAIL ONLY, CA 00000

RANDY KELLER
DIRECTOR OF DEVELOPMENT
CALENERGY OPERATING CORPORATION
EMAIL ONLY
EMAIL ONLY, CA 00000

ROBERT GEX
DAVIS WRIGHT TREMAINE LLP
REGULATION
EMAIL ONLY
EMAIL ONLY, CA 00000

ROBIN SMUTNY-JONES
DIR. - CALIFORNIA POLICY &

IBERDROLA RENEWABLES, LLC
EMAIL ONLY
EMAIL ONLY, OR 00000

SHALINI SWAROOP
REGULATORY COUNSEL
MARIN ENERGY AUTHORITY
EMAIL ONLY
EMAIL ONLY, CA 00000

STEPHANIE WANG
DIRECTOR
CLEAN COALITION
EMAIL ONLY
EMAIL ONLY, CA 00000

STEVE ZURETTI
MANAGER, CALIFORNIA
SOLAR ENERGY INDUSTRIES ASSOCIATION
EMAIL ONLY
EMAIL ONLY, CA 00000

SUJATA PAGEDAR
PACIFIC GAS & ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000

TAM HUNT
CLEAN COALITION
EMAIL ONLY
EMAIL ONLY, CA 00000

TOUSSAINT.S BAILEY
RICHARDS WATSON GERSHON
EMAIL ONLY
EMAIL ONLY, CA 00000

VIDHYA PRABHAKARAN
DAVIS WRIGHT & TREMAINE, LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

WILLIAM J. KEESE
EMAIL ONLY
EMAIL ONLY, CA 00000

AES SOUTHLAND
EMAIL ONLY
EMAIL ONLY, CA 00000

DAVIS WRIGHT TREMAINE LLP
EMAIL ONLY
EMAIL ONLY, CA 00000

MRW & ASSOCIATES, LLC
EMAIL ONLY
EMAIL ONLY, CA 00000

ALICE GONG
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY, CA 00000-0000

KAREN TERRANOVA
ALCANTAR & KAHL
EMAIL ONLY
EMAIL ON LY, CA 00000-0000

ERIC HSIEH
A 123 SYSTEMS INC.
155 FLANDERS RD
WESTBOROUGH, MA 01581-1032

MIKE BERLINSKI
BEACON POWER, LLC
65 MIDDLESEX ROAD
TYNGSBORO, MA 01879

RACHEL WILSON
SYNAPSE ENERGY ECONOMIS, INC.
485 MASSACHUSETTS AVE., 2ND FLOOR
CAMBRIDGE, MA 02129

PATRICK LUCKOW
SYNAPSE ENERGY ECONOMICS, INC.
485 MASSACHUSETTS AVE., 2ND FL.
CAMBRIDGE, MA 02139

ROBERT FAGAN
SYNAPSE ENERGY & ECONOMICS
485 MASSACHUSETTS AVE., 2ND FLOOR
CAMBRIDGE, MA 02139

THOMAS J. VITOLO
SYNAPSE ENERGY ECONOMICS, INC.
485 MASSACHUSETTS AVENUE, STE. 2
CAMBRIDGE, MA 02139

ALEXANDER DABERKO
CALPEAK POWER, LLC
591 PUTNAM AVENUE
GREENWICH, CT 06830

ADAM FAIRBANKS
DIR - REGULATORY AND RETAIL STRUCTURING
CONEDISON SOLUTIONS, INC.
100 SUMMIT LAKE DRIVE, STE. 410
VALHALLA, NY 10595

RICHARD J. HUDSON, JR.
DIR. - REGULATORY & LEGISLATIVE
AFFAIRS
CONEDISON SOLUTIONS, INC.
100 SUMMIT LAKE DR., STE. 410
VALHALLA, NY 10595

KENDRA ULRICH
NUCLEAR CAMPAIGNER
FRIENDS OF THE EARTH
1100 15TH STREET, NW, 11TH FL.
WASHINGTON, DC 20005

S.DAVID FREEMAN
C/O FRIENDS OF THE EARTH
1100 15HT STREET, NW, 11TH FLOOR
WASHINGTON, DC 20005

YANIRA M. GOMEZ
LIBERTY POWER CORP.
1901 W. CYPRESS CREEK RD., STE. 600
FORT LAUDERDALE, FL 33309

KIM L. JOHNSON
EVP AND AGENT
RIVERBANK PUMPED STORAGE, LLC
2000 S. OCEAN BLVD., STE. 703
DELRAY BEACH, FL 33483
FOR: RIVERBANK PUMPED STORAGE, LLC

SHAWN NICHOLS
SUMMIT POWER GROUP
1324 CLARKSON CLAYTON CENTER, STE. 119
BALLWIN, MO 63011-2145

JIM ROSS
RCS, INC.
500 CHESTERFIELD CENTER, SUITE 320
CHESTERFIELD, MO 63017

CHRIS HENDRIX
TEXAS RETAIL ENERGY
2001 SE 10TH STREET
BENTONVILLE, AR 72716

ERIN SZALKOWSKI
CORPORATE COUNSEL
CLEAN LINE ENERGY PARTNERS, LLC
1001 MCKINNEY STREET, SUITE 700
HOUSTON, TX 77002
FOR: CENTENNIAL WEST CLEAN LINE LLC

CHARLES PURSHOUSE
CAMCO INTERNATIONAL GROUP, INC.
390 INTERLOCKEN CRESCENT, SUITE 490
BROOMFIELD, CO 80021

CAROLINE SCHNEIDER
PROLOGIS
4545 AIRPORT WAY
DENVER, CO 80239

DREW TORBIN

PUNEET PASRICH

V.P.- RENEWABLE ENERGY
PROLOGIS
4545 AIRPORT WAY
DENVER, CO 80239

COLORADO STATE UNIVERSITY
350 N. COLLEGE AVE.
FORT COLLINS, CO 80524

CAITLIN COLLINS LIOTIRIS
ENERGY STRATEGIES, LLC
215 SOUTH STATE STREET, STE 200
SALT LAKE CITY, UT 84111

GIANCARLO ESTRADA
KIS MAYES LAW FIRM
ONE EAST CAMELBACK ROAD, STE. 550
PHOENIX, AZ 85012

PAUL THOMSEN
DIR. - POLICY & BUSINESS DEVELOPMENT
ORMAT TECHNOLOGIES INC.
6225 NEIL ROAD
RENO, NV 89511
FOR: ORMAT TECHNOLOGIES

RON KNECHT
1009 SPENCER ST
CARSON, NY 89703-5422

STEVEN HRUBY
SOUTHERN CALIFORNIA GAS COMPANY
555 W. FIFTH ST., GT14D6
LOS ANGELES, CA 90013

SARAH FRIEDMAN
SIERRA CLUB
714 W. OLYMPIC BLVD., STE. 1000
LOS ANGELES, CA 90015

DARIUSH SHIRMOHAMMADI
CALIFORNIA WIND ENERGY ASSOCIATION
10208 CIELO DRIVE
BEVERLY HILLS, CA 90210

MICHAEL W. WEBB
CITY ATTORNEY
CITY OF REDONDO BEACH
415 DIAMOND STREET
REDONDO BEACH, CA 90277

ADAM GREEN
SOLARRESERVE
2425 OLYMPIC BLVD., STE. 500E
SANTA MONICA, CA 90404

MARILYN LYON
SOUTH BAY CITIES COUNCIL OF
GOVERNMENTS
SOUTH BAY ENVIRONMENTAL SERVICES
CTR.
20285 S. WESTERN AVE., STE. 100
TORRANCE, CA 90501

GREGORY KLATT
DOUGLASS & LIDDELL
411 E. HUNTINGTON DR., STE. 107-356
ARCADIA, CA 91006
FOR: TIGER NATURAL GAS, INC.

FRED MOBASHERI
CONSULTANT
ELECTRIC POWER GROUP, LLC
201 SOUTH LAKE AVE., SUITE 400
PASADENA, CA 91101

CAROL SCHMID-FRAZEE
ATTORNEY AT LAW
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91765

AMANDA KLOPF
SOUTHERN CALIFORNIA EDISON COMPANY
PO BOX 800/2244 WALNUT GROVE AVE.
ROSEMEAD, CA 91770

CASE ADMINISTRATION

MELISSA A. HOVSEPIAN

SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE, RM. 321
ROSEMEAD, CA 91770

NGUYEN QUAN
MGR - REGULATORY AFFAIRS
GOLDEN STATE WATER CO. - ELECTRIC OP.
630 EAST FOOTHILL BOULEVARD
SAN DIMAS, CA 91773

CHRISTOPHER SUMMERS
REGULATORY AFFAIRS
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT
SAN DIEGO, CA 92101

CENTRAL FILES
SAN DIEGO GAS AND ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP31-E
SAN DIEGO, CA 92123

REMEDIOS SANTOS
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK CT., CP31E
SAN DIEGO, CA 92123

THOMAS C. SAILE
ENERGY CONTRACTS ORIGINATOR
SAN DIEGO GAS & ELECTRIC COMPANY
8315 CENTURY PARK COURT, CP21D
SAN DIEGO, CA 92123-1548

CRAIG POSPISIL
EDISON MISSION ENERGY
3 MACARTHUR PLACE, STE. 100
SANTA ANA, CA 92707

RINALDO BRUTUCO
WORLD BUSINESS ACADEMY
308 E. CARRILLO STREET
SANTA BARBARA, CA 93101

RANDY SHILLING
4886 EAST JENSEN AVENUE
INC.
FRESNO, CA 93725

SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE. / PO BOX 800
ROSEMEAD, CA 91770

TY TOSDAL
TOSDAL LAW FIRM
777 S. HIGHWAY 101, SUITE 215
SOLANA BEACH, CA 92075
FOR: SAN DIEGO ENERGY DISTRICT
FOUNDATION

SHAWN BAILEY
DIRECTOR - PLANNING & ANALYSIS
SEMPRA US GAS AND POWER
101 ASH STREET
SAN DIEGO, CA 92101-3017

JENNIFER PIERCE
CALIFORNIA REGULATORY AFFAIRS
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT
SAN DIEGO, CA 92123

DESPINA NIEHAUS
REGULATORY CASE MGR.
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32D
SAN DIEGO, CA 92123-1530

CATHERINE SULLIVAN
EZ2BGREEN
27479 VIA RAMONA
SAN JUAN CAPISTRANO, CA 92675

JEFF HIRSCH
JAMES J. HIRSCH & ASSOCIATES
12185 PRESILLA ROAD
SANTA ROSA VALLEY, CA 93012-9243

RON DICKERSON
CALIFORNIA CONSUMERS ALLIANCE
PO BOX 3751
CLOVIS, CA 93613

NICOLAI SCHLAG
ENERGY & ENVIRONMENTAL ECONOMICS,

101 MONTGOMERY ST., STE 1600

SAN FRANCISCO, CA 94101

DENNIS J. HERRERA
CITY AND COUNTY OF SAN FRANCISCO
CITY HALL, ROOM 234
1 DR. CARLTON B. GOODLET PLACE
RM. 234
SAN FRANCISCO, CA 94102

JEANNE M. SOLE
DEPUTY CITY ATTORNEY
CITY AND COUNTY OF SAN FRANCISCO
1 DR. CARLTON B. GOODLETT PLACE,

SAN FRANCISCO, CA 94102-4682

BREWSTER BIRDSALL, P.E.
ASPEN ENVIRONMENTAL GROUP
SOLAR
235 MONTGOMERY STREET, STE. 935
SAN FRANCISCO, CA 94104

JIM BAAK
DIRECTOR-POLICY FOR UTILITY SCALE

THE VOTE SOLAR INITIATIVE
101 MONTGOMERY ST., STE. 2600
SAN FRANCISCO, CA 94104

MARIA STAMAS
PROGRAM ASST. - CA ENERGY CLIMATE
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO, CA 94104

AHMAD FARUQUI
THE BRATTLE GROUP
201 MISSION ST., STE. 2800
SAN FRANCISCO, CA 94105

BARNEY SPECKMAN
VP - GRID MANAGEMENT
NEXANT
101 SECOND STREET, 11TH FLOOR
SAN FRANCISCO, CA 94105

CARA GOLDENBERG
DIAN GRUENEICH CONSULTING, LLC
201 MISSION STREET, SUITE 1200
SAN FRANCISCO, CA 94105

FRED WELLINGTON
NAVIGANT CONSULTING, INC.
1 MARKET ST., SPEAR ST. TOWER, STE 1200
SAN FRANCISCO, CA 94105

KIMBERLY C. JONES
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B9A, ROOM 904
SAN FRANCISCO, CA 94105

MATHEW VESPA
SIERRA CLUB
85 SECOND STREET, 2ND FLOOR
SAN FRANCISCO, CA 94105

MATTHEW GONZALES
SENIOR CASE MANAGER
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., RM. 918, B9A
SAN FRANCISCO, CA 94105

MICHAEL ALCANTAR
ATTORNEY AT LAW
ALCANTAR & KAHL LLP
33 NEW MONTGOMERY STREET, SUITE 1850
SAN FRANCISCO, CA 94105

WADE GREENACRE
REGULATORY CASE COORDINATOR
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., MC B9A
SAN FRANCISCO, CA 94105

TOM JARMAN
ENERGY
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, RM. 909, MC B9A

DAVID A. ZIZMOR
GRADUATE FELLOW
ENVIRONMENTAL LAW & JUSTICE CLINIC
536 MISSION STREET

SAN FRANCISCO, CA 94105-1814

SAN FRANCISCO, CA 94105-2968

JAMES J. CORBELLI
STAFF ATTORNEY
ENVIRONMENTAL LAW AND JUSTICE CLINIC
GOLDEN GATE UNIVERSITY SCHOOL OF LAW
536 MISSION STREET
SAN FRANCISCO, CA 94105-2968

STEVEN MOSS
SAN FRANCISCO COMMUNITY POWER
2325 THIRD STREET, STE. 344
SAN FRANCISCO, CA 94107

ADENIKE ADEYEYE
EARTHJUSTICE
50 CALIFORNIA ST., STE. 500
SAN FRANCISCO, CA 94111

MONICA A. SCHWEBS
BINGHAM MCCUTCHEN LLP
THREE EMBARCADERO CENTER
SAN FRANCISCO, CA 94111

PAUL R. CORT
EARTHJUSTICE
50 CALIFORNIA ST., STE. 500
SAN FRANCISCO, CA 94111

ROSICELI VILLARREAL
EARTHJUSTICE
50 CALIFORNIA STREET, SUITE 500
SAN FRANCISCO, CA 94111

SARAH BARKER-BALL
BINGHAM MCCUTCHEN LLP
3 EMBARCADERO CENTER
LAMPREY LLP
SAN FRANCISCO, CA 94111

SUZY HONG
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY &

505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111

WILL MITCHELL
COMPETITIVE POWER VENTURES, INC.
505 SANSOME STREET, STE. 475
SAN FRANCISCO, CA 94111

IRENE K. MOOSEN
ATTORNEY AT LAW
CITY AND COUNTY OF SAN FRANCISCO
53 SANTA YNEZ AVE.
SAN FRANCISCO, CA 94112

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. STE 303
SAN FRANCISCO, CA 94117-2242

CHARLES R. MIDDLEKAUFF
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442, MC-B30A-2475
SAN FRANCISCO, CA 94120

DONNA BARRY
ENERGY PROCEEDINGS
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MC B9A
SAN FRANCISCO, CA 94120-7442

MEGAN M. MYERS
LAW OFFICES OF SARA STECK MYERS
122 - 28TH AVENUE
SAN FRANCISCO, CA 94121

CHRISTOPHER SMITH
PACIFIC GAS & ELECTRIC COMPANY
PO BOX 770000
SAN FRANCISCO, CA 94177

ED LUCHA
CASE COORDINATOR
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO, CA 94177

ANDY SCHWARTZ
SOLARCITY
3055 CLEARVIEW WAY
SAN MATEO, CA 94402

BETH VAUGHN
CALIFORNIA COGENERATION COUNCIL
4391 N. MARSH ELDER COURT
CONCORD, CA 94521

SEAN BEATTY
DIRECTOR - WEST REGULATORY AFFAIRS
NRG WEST
PO BOX 192
PITTSBURG, CA 94565

AVIS KOWALEWSKI
VP - GOV'T & REGULATORY AFFAIRS
CALPINE CORPORATION
4160 DUBLIN BLVD, SUITE 100
DUBLIN, CA 94568

ROBERT ANDERSON
OLIVINE, INC
2010 CROW CANYON PLACE, STE. 100
SN RAMON, CA 94583

SCOTT DAYER
REGION SALES MGR.- GE POWER & WATER
GE PACKAGED POWER, INC.
6140 STONERIDGE MALL RD.
PLEASANTON, CA 94588

GREGORY BLUE
PRINCIPAL
COUNCIL
GTB CONSULTING
3161 WALNUT BLVD
WALNUT CREEK, CA 94596

ANTHONY HARRISON
CAL. ENERGY EFFICIENCY INDUSTRY

436 14TH ST., SUITE 1020
OAKLAND, CA 94612

SHANA LAZEROW
ATTORNEY
COMMUNITIES FOR A BETTER ENVIRONMENT
1904 FRANKLIN STREET, STE 600
OAKLAND, CA 94612
FOR: CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

THADEUS B. CULLEY
KEYES, FOX & WIEDMAN LLP
436 14TH STREET, STE. 1305
OAKLAND, CA 94612
FOR: FRIENDS OF THE EARTH

TIM LINDL
.
INTERSTATE RENEWABLE ENERGY COUNCIL, INC
436 14TH ST., STE. 1305
OAKLAND, CA 94612

DAVID MARCUS
PO BOX 1287
BERKELEY, CA 94701

LINDA AGERTER
LARGE-SCALE SOLAR ASSOCIATION
51 PARKSIDE DRIVE
BERKELEY, CA 94705

ERIC G. GIMON
TECHNICAL CONSULTANT
THE VOTE SOLAR INITIATIVE
2727 MARIN AVE.
BERKELEY, CA 94708

JEREMY WAEN
REGULATORY ANALYST
MARIN ENERGY AUTHORITY
781 LINCOLN AVENUE, STE. 320
SAN RAFAEL, CA 94901

CARLOS LAMAS-BABBINI
CEN-CA PROGRAM MGR.
COMVERGE, INC.
58 MT. TALLAC CT.
SAN RAFAEL, CA 94903

PHILIP MULLER
SCD ENERGY SOLUTIONS
436 NOVA ALBION WAY
SAN RAFAEL, CA 94903

RICH QUATTRINI
DIR. PRODUCT MANAGEMENT
JOHNSON CONTROLS
901 CAMPISI WAY, STE 260
CAMPBELL, CA 95008-2348

PUSHKAR G. WAGLE
FLYNN RESOURCE CONSULTANTS, INC.
2900 GORDON AVENUE, SUITE 100-3
SANTA CLARA, CA 95051

DEVRA WANG
STAFF SCIENTIST
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO, CA 95104

JEFFREY SHIELDS
GEN MGR.
SOUTH SAN JOAQUIN IRRIGATION DISTRICT
PO BOX 747
RIPON, CA 95366-0747

JAMES CALDWELL
1650 E NAPA STREET
SONOMA, CA 95476

DOUGLAS M. GRANDY, P.E.
CA ONSITE GENERATION
1220 MACAULAY CIRCLE
CARMICHAEL, CA 95608

MARTIN HOMEC
PO BOX 4471
DAVIS, CA 95617

DELPHINE HOU
CALIF. INDEPENDENT SYSTEMS OPERATOR
250 OUTCROPPING WAY
FOLSOM, CA 95630

JACQUELINE M. DEROSA
DIRECTOR OF REGULATORY AFFAIRS - CA
CUSTOMIZED ENERGY SOLUTIONS
101 PARKSHORE DRIVE SUITE 100
FOLSOM, CA 95630

SHUCHENG LIU
CORP.
CALIFORNIA ISO
250 OUTCROPPING WAY
FOLSOM, CA 95630

CAL. INDEPENDENT SYSTEM OPERATOR

250 OUTCROPPING WAY
FOLSOM, CA 95630

BRIAN THEAKER
NRG ENERGY
3161 KEN DEREK LANE
PLACERVILLE, CA 95667

PAUL D. MAXWELL
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670-6078

DANIEL KIM
WESTLANDS SOLAR PARK
RENEWABLE
PO BOX 582844
ELK GROVE, CA 95757

DAVID MILLER, PHD
CTR. FOR ENERGY EFFECIENCY &

1100 ELEVENTH ST., STE. 311
SACRAMENTO, CA 95814

KEVIN WOODRUFF

NICOLE WRIGHT

WOODRUFF EXPERT SERVICES
1100 K STREET, SUITE 204
SACRAMENTO, CA 95814
FOR: THE UTILITY REFORM NETWORK

BRAUN BLAISING MCLAUGHLIN & SMITH
915 L STREET, SUITE 1270
SACRAMENTO, CA 95814

STEVE KEENE
BRAUN BLAISING MCLAUGHLIN P.C.
915 L STREET, SUITE 1270
SACRAMENTO, CA 95814

STEVEN KELLY
POLICY DIRECTOR
INDEPENDENT ENERGY PRODUCERS
ASSCIATION
1215 K STREET, STE. 900
SACRAMENTO, CA 95814

SAMANTHA G. POTTENGER
ELLISON, SCHNEIDER AND HARRIS L.L.P.
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO, CA 95816

ANDREW BROWN
ATTORNEY AT LAW
ELLISON & SCHNEIDER
2600 CAPITOL AVE, SUITE 400
SACRAMENTO, CA 95816-5905

CHASE B. KAPPEL
ELLISON SCHNEIDER & HARRIS LLP
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO, CA 95816-5905

DOUGLAS K. KERNER
ATTORNEY AT LAW
ELLISON, SCHNEIDER & HARRIS, LLP
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO, CA 95816-5905

GREGGORY L. WHEATLAND
ATTORNEY
ELLISON SCHNEIDER & HARRIS L.L.P.
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO, CA 95816-5905

RACHEL GOLD
LARGE-SCALE SOLAR ASSOCIATION
2501 PORTOLA WAY
SACRAMENTO, CA 95818

SHANNON EDDY
EXECUTIVE DIRECTOR
LARGE SCALE SOLAR ASSOCIATION
2501 PORTOLA WAY
SACRAMENTO, CA 95818

ANN TROWBRIDGE
ATTORNEY
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., STE. 205
SACRAMENTO, CA 95864

JACK ELLIS
1425 ALPINE WAY / PO BOX 6600
LAKE TRAHOE, CA 96145-6600

LISA SCHWARTZ
REGULATORY ASSISTANCE PROJECT
429 NE NORTH NEBERGALL LOOP
ALBANY, OR 97321

DONALD SCHOENBECK
RCS INC.
900 WASHINGTON STREET, SUITE 780
VANCOUVER, WA 98660

ROBIN FRASER
INTERNATIONAL EMISSIONS TRADING
ASSN.
100 KING STREET WEST, SUITE 5700
TORONTO, ON M5X 1C7
CANADA
FOR: IETA

DANIEL JURIJEW
SR. MGR - REGULATORY AFFAIRS WEST
CAPITAL POWER CORPORATION
1200 - 10423 101 ST. NW
EDMONTON, AB T5H 0E9
CANADA

PETER CAVAN
PULSE ENERGY
576 SEYMOUR ST., STE. 600
VANCOUVER, BC V6B 3K1
CANADA

VIII. State Service

CHRIS UNGSON
CPUC
COMMISSION
EMAIL ONLY
EMAIL ONLY, CA 00000

DAVID PECK
CALIFORNIA PUBLIC UTILITIES

EMAIL ONLY
EMAIL ONLY, CA 00000

JORDAN PARRILLO
CALIFORNIA PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING AND POLICY BRANCH
COMMISSION
EMAIL ONLY
EMAIL ONLY, CA 00000

LILY CHOW
REGULATORY ANALYST
CALIFORNIA PUBLIC UTILITIES

EMAIL ONLY
EMAIL ONLY, CA 00000

VALERIE KAO
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL ONLY
EMAIL ONLY, CA 00000

WILLIAM DIETRICH
SR. ANALYST - ENERGY DIV.
CPUC
EMAIL ONLY
EMAIL ONLY, CA 00000

ALAN WECKER
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
PERMITTING B
ROOM 4102
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

ALEXANDER COLE
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND

AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

ALOKE GUPTA
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B
PERMITTING B
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

ARTHUR J. O'DONNELL
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND

ROOM 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

BRIAN STEVENS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
PERMITTING B
AREA 4-A

CARLOS A. VELASQUEZ
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND

AREA 4-A

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

CHLOE LUKINS
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
BRANCH
ROOM 4102
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

CHRIS UNGSON
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY
ROOM 4104
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

DAMON A. FRANZ
CALIF PUBLIC UTILITIES COMMISSION
PROCUREMENT STRATEGY AND OVERSIGHT BRANC
JUDGES
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

DAVID M. GAMSON
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW
ROOM 5019
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

DAVID SIAO
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
BRANC
ROOM 4101
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

ED CHARKOWICZ
CALIF PUBLIC UTILITIES COMMISSION
PROCUREMENT STRATEGY AND OVERSIGHT
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

EDWARD F. RANDOLPH
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
ROOM 4004
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

IRYNA KWASNY
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JOANNA GUBMAN
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JULIE A. FITCH
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5214
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

KARIN M. HIETA
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
BRANCH
ROOM 4102
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

KE HAO OUYANG
CALIF PUBLIC UTILITIES COMMISSION
UTILITY & PAYPHONE ENFORCEMENT
AREA 2-E
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

KEITH D WHITE

LEWIS BICHKOFF

CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B BRANC
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

CALIF PUBLIC UTILITIES COMMISSION
PROCUREMENT STRATEGY AND OVERSIGHT
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MARCELO POIRIER
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5025
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MATT MILEY
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 5135
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MEGHA LAKHCHAURA
CALIF PUBLIC UTILITIES COMMISSION
PROCUREMENT STRATEGY AND OVERSIGHT BRANC
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MERIDETH STERKEL
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MICHELE KITO
CALIF PUBLIC UTILITIES COMMISSION
DEMAND SIDE ANALYSIS BRANCH
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

NIKA ROGERS
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
ROOM 4101
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

NOUSHIN KETABI
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PATRICK L. YOUNG
CALIF PUBLIC UTILITIES COMMISSION
INFRASTRUCTURE PLANNING AND PERMITTING B
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PETER SPENCER
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
ROOM 4104
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RADU CIUPAGEA
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PRICING AND CUSTOMER PROGRAM
ROOM 4104
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

SEAN A. SIMON
CALIF PUBLIC UTILITIES COMMISSION
PROCUREMENT STRATEGY AND OVERSIGHT BRANC
AREA 4-A
505 VAN NESS AVENUE

SEPIDEH KHOSROWJAH
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5201
505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3214

STEPHEN ST. MARIE
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
PROGRAM
ROOM 5203
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

YAKOV LASKO
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
ROOM 4101
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

MARC S. PRYOR
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814

REBECCA TSAI-WEI LEE
CALIF PUBLIC UTILITIES COMMISSION
DRA - ADMINISTRATIVE BRANCH
BRAN
770 L Street, Suite 1250
Sacramento, CA 95814

SAN FRANCISCO, CA 94102-3214

XIAN "CINDY" LI
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PRICING AND CUSTOMER

ROOM 4104
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

CONSTANCE LENI
CALIFORNIA ENERGY COMMISSION
MS-20
1516 NINTH STREET
SACRAMENTO, CA 95814

MICHAEL JASKE
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-20
SACRAMENTO, CA 95814

KEVIN S. NAKAMURA
CALIF PUBLIC UTILITIES COMMISSION
UTILITY AUDIT, FINANCE & COMPLIANCE

180 Promenade Circle, Suite 115
Sacramento, CA 95834