Docket No.: R.12-03-014

Exhibit No.: ____________________

Date: September 30, 2013

Witness: William A. Monsen

TESTIMONY OF WILLIAM A. MONSEN ON BEHALF OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION CONCERNING TRACK 4 OF THE LONG-TERM PROCUREMENT PLAN PROCEEDING
(with Errata)

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I. Introduction and Summary of Testimony

Q. Please state your name and business address.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Please describe your professional background.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including California, Oregon, Colorado, New England, Wisconsin, and Nevada. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison. Additional information about my qualifications is provided in Attachment A.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Independent Energy Producers Association (IEP).

Q. What is the purpose of Track 4 in this proceeding?

A. Track 4 was added to this Long-Term Procurement Plan (LTPP) proceeding in May 2013 to address the local reliability impacts in the service areas of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) in the event that Units 2 & 3 of SCE's San Onofre Nuclear Generating Station (SONGS) were to remain offline for an extended period of time.[1] On June 7, 2013, SCE announced that it was permanently retiring SONGS 2 & 3. At that point, the focus of Track 4 changed from evaluating a hypothetical long-term outage to responding to the actual shutdown of SONGS 2 & 3 and determining the need for long-term resources to replace SONGS 2 & 3.

Q. Were local capacity requirements considered previously in this proceeding?

A. Yes. In Track 1 the Commission authorized SCE to procure local capacity in two local reliability areas (LRAs): 1,400 – 1,800 MW in the Los Angeles Basin Local Reliability Area (LRA) and 215 – 290 MW in the Moorpark sub-area of the Big Creek/Ventura LRA.[2] At this point, Track 4 of this proceeding is essentially an

[1] "Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge," in R.12-03-014, May 21, 2013.
[2] The Commission evaluated the need for resources in the SDG&E LRA in A.11-05-023. In that proceeding, SDG&E sought approval of power purchase tolling agreements with the Pio Pico Energy

expansion of Track 1 in light of the definitive closure of SONGs, except that it is focusing on the need for resources in the southern part of the SCE system and in the SDG&E system.

Q. Why has the shutdown of SONGS 2 & 3 caused a significant change in the scope of the LTPP proceeding?

A. SONGS is sited at a key location in the southern California electricity grid: at the single point of direct interconnection between SCE's and SDG&E's transmission systems. It not only provided a significant amount of capacity (over 2,200 MW) and energy (it operated at an average annual capacity factor of 82 percent between 2001-2011), it also provided critical network services to the electric grid.[3] These services included voltage support and inertia. Track 4 is now considering the intermediate- and long-term resources that should be procured to replace the various functions of SONGS.

Q. What is IEP's interest in this proceeding?

A. IEP represents the interests of independent power producers (IPPs). IEP members collectively own and operate approximately one-third of California's installed generating capacity, which includes renewable products derived from biomass, geothermal, small hydro, solar, and wind; highly efficient cogeneration; and gas-

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Center, Quail Brush Power, and the Escondido Energy Center. The Commission authorized SDG&E to procure up to 298 MW of local generation capacity to come on-line beginning in 2018.

[3] "Overview of Southern California Electricity Infrastructure Issues." Presentation by M. Jaske of the California Energy Commission, Joint CEC/CPUC Workshop on Southern California Electricity Infrastructure Issues in Los Angeles, California, July 15, 2013. See Attachment B for excerpt.

fired merchant facilities. IEP has been active in the Commission's procurement proceedings for many years. IEP's interests include fostering, to the maximum extent practical, truly competitive solicitations for resources in order to lower consumers' costs; ensuring that a competitive, level playing field exists for various technologies and ownership types (*e.g.*, cost-of-service utility-owned generation (UOG) vs. market-based IPPs); and ensuring that the products sought by policy-makers and the grid operator are clearly and transparently defined so that competitive markets can plan for and respond to specific resource needs in a timely and cost-effective manner.

Q. Have you submitted testimony in this proceeding?

A. Yes. I submitted reply testimony in Track 1 of this proceeding on behalf of IEP.

Q. What is the purpose of your testimony in this phase of the proceeding?

A. There are two main parts to this testimony. First, I present broad policy and planning recommendations as they relate to the current situation for southern California's electric infrastructure. Second, I respond to the opening testimony of the California Independent System Operator (CAISO), SCE, and SDG&E in this track of the instant proceeding.

Q. Do you have any general concerns with the analysis and proposals contained in the opening testimony of CAISO, SCE and SDG&E?

A. Yes. As I will address in greater detail in my testimony below, I am concerned that some of the assumptions made in the analyses presented to the Commission thus far are overly optimistic and may result in estimates of resource need that do not fully address the reliability needs resulting from the shutdown of SONGS. Specifically, my concerns are as follows:

- There is a great deal of uncertainty in the "net" load forecasts in the local areas affected by the SONGS closure;
- There is a large reliance on "uncommitted" energy efficiency, demand response, distributed generation, and storage resources to meet identified resource needs;
- There is a similar reliance in the utility assessments of resource need on "uncommitted" transmission projects that face significant development risks;
- The consequences to ratepayers of either having too many resources or too few are highly asymmetric, with under-procurement potentially leading to curtailment of firm load;
- If handled incorrectly, the addition of Track 4 procurement has the potential to sidetrack the ongoing procurement through the Track 1 authorization, at a time when it is essential to promptly secure new resources;
- Potentially relying on SCE's "Living Pilot" program as a critical piece of SCE's efforts to meet its resource needs is highly risky; and
- There is no evidence that the contingency plans proposed by SCE and SDG&E, which could involve the utilities "pre-permitting" certain sites, are necessary and they may be counterproductive.

Q. Please summarize your recommendations.

A. In this testimony, IEP makes the following recommendations regarding the assessment of need for new resources to replace SONGS 2 & 3 and specific proposals made by the CAISO, SCE and SDG&E:

1) When considering the need for new resources to replace SONGS 2 & 3, the Commission should rely on the following conservative planning assumptions to avoid potentially being in the position of having to order "just in time procurement" to ensure grid reliability:
   - Rely on the CAISO's reliability criteria to determine local area resource need;
   - Recognize the risks associated with uncommitted resources;
   - Assume long lead-times for transmission projects; and
   - Do not assume that new generation projects can come online sooner than proposed, or that existing plants will operate beyond the deadlines for compliance with once-through cooling (OTC) regulations.
2) Procurement by SCE and SDG&E should proceed as follows:
   - Continue with LTPP Track 1 procurement activities that are already underway.
   - Authorize interim procurement under Track 4 (i.e., Phase 1 procurement from Track 4) based on current analysis and assumptions; and

- After the CAISO completes its updated transmission assessment as part of the 2013/2014 TPP, potentially provide additional procurement authority to the IOUs (Phase 2 procurement from Track 4).

3) The Commission should employ a "no regrets" policy for the Track 4 Phase 1 interim procurement authorizations:
   - This "no regrets" level of procurement should be procured through an all -source solicitation, which would allow all resource categories to compete on a level playing field to meet a portion of the expected need for resources in the local area;
   - The utilities should be ensured full cost recovery for reasonable resource costs resulting from this initial procurement; and
   - The authorized level of procurement should not be reduced as a result of future analyses.
4) The Commission should reject SCE's and SDG&E's site banking proposals in this proceeding or, at a minimum, exclude utility affiliates or "build -own-transfer" projects from bidding to develop projects at energy parks or utility substations.
5) To satisfy CAISO reliability criteria, the Commission should order SCE to procure a total of 2,506 MW of local capacity between its Track 1 solicitation and any interi m "no regrets" procurement authorized in the first phase of Track 4.
   - SCE should be allowed to pursue its proposed "Living" Pilot, but only as a test project to measure potential impacts. Absent empirical results, the

Pilot should not be relied upon as a critical component of SCE's plan to ensure local grid reliability; and

- The Commission should modify SCE's proposal for contingent procurement of gas-fired resources to explicitly include that option as part of the competitive solicitation of resources.

6) The Commission should authorize SDG&E to procure an additional 820 MW in the initial phase of Track 4 based on CAISO reliability criteria and to reflect more conservative transmission addition assumptions than proposed by SDG&E:

- Given the significant risks associated with building a transmission line from Imperial Valley to the SONGS Mesa substation, the SDG&E resource need should, *at most*, be based on assuming just the addition of a line from Devers to a substation in the North County of San Diego;
- If the Commission does not authorize SDG&E's Pio Pico application or there are problems with the approved Wellhead project, then the Commission should increase SDG&E's interim procurement by up to 308 MW; and
- The Commission should order SDG&E to supplement its testimony to provide cost estimates of different scenarios, to provide a basis for deciding among the various options.

II. Overarching Policy and Planning Recommendations

Q. What are the policy and planning issues that you address in this section of your testimony?

A. I discuss five broad policy and planning issues in this section:

1. For local reliability assessment, a conservative approach that does not risk placing the Commission in the position of ordering "just in time" procurement is reasonable. Accordingly, an approach based on CAISO's reliability requirements is appropriate.
2. The Commission should encourage fair competition among resource types to ensure ratepayers receive the lowest-cost service consistent with reliability and policy goals.
3. Planning assumptions will change over time. The Commission should not put customer reliability at risk by delaying procurement of needed resources while it awaits updated information.
4. The Commission should reject SCE's and SDG&E's site banking proposals in this proc eeding or, at a minimum, exclude utility affiliates or build -own-transfer projects from bidding to develop projects at energy parks.

I discuss each of these issues in turn below.

A. For local reliability assessment, a conservative approach such as that proposed by CAISO is appropriate

Q. Why is a conservative planning approach appropriate in this track of the proceeding?

A. There is an immediate and critical need for action to ensure the reliability of electric service to the customers of SCE and SDG&E. When it became clear that

SONGS would not be online during the peak summer months in 2012, the state's energy agencies (i.e., the Commission, the California Energy Commission (CEC), and the CAISO) took immediate steps to ensure the reliability of service in southern Orange County and SDG&E's service area. These steps included bringing Units 3 and 4 of the Huntington Beach plant out of retirement to provide replacement power; approving new demand response programs for SDG&E and SCE;[4] and promoting energy conservation and energy efficiency programs through targeted communication campaigns.[5] Peak demands in 2012 were somewhat lower than expected and that helped to avoid load curtailments in the areas around SONGS. SCE, SDG&E, and the state's energy agencies took additional steps to prepare for 2013, such as converting the Huntington Beach units from steam generators to synchronous condensers. Also, some new generation has come online in the LA Basin. Nevertheless, load has continued to grow, and the region faces the shutdown of several once-through cooling (OTC) units over the next seven years as a result of current state regulations. In order to ensure continued reliable electric service in the area, more steps need to be taken soon.

Q. What are some of the options being considered to meet the local reliability concerns arising from the shutdown of SONGS?

[4] California Public Utilities Commission Resolutions E-4502 (May 24, 2012) and E-4511 (July 12, 2012).
[5] "Compliance Report for Meeting the Needs of Customers Most Affected by Emerging Energy Needs for Summer 2012," filed by Southern California Edison in A.11-03-002, July 2012.

A. All resource options are on the table: energy efficiency (EE), demand response (DR), behind-the-meter distributed generation (DG), grid-connected renewable and efficient gas-fired generation, and storage technologies. Aside from these resource options, various transmission upgrades and improvements, including construction of new transmission facilities and synchronous condensers, are under consideration. Finally, even curtailment of firm load has been discussed.[6]

Q. **How does uncertainty in load forecasting complicate resource planning?**

A. If electricity demand is under-forecast, then the need for resources will be under-forecast as well. If the system has significant excess resource capacity, then an under-forecast of need does not pose a substantial risk to reliability and the ability to meet demand. However, because the local areas in the LA Basin and San Diego are short of resources, under-forecasting resource need could result in having to take extreme measures to ensure system reliability. Such measures might include emergency authorization of new generation facilities or curtailment of firm load.

Q. What are the critical factors driving uncertainty in forecasting the need for resources and the online date for new generation?

A. A number of factors drive uncertainty in forecasting, which can result in under-estimating the need for new resources and threaten future grid reliability. First, the

[6] "Track 4 Testimony of Southern California Edison" (SCE Track 4 Testimony), filed by Southern California Edison in R.12-03-014, August 26, 2013, p. 27.

"net" load forecasts in the local area are subject to significant uncertainty.[7] There are two main sources of uncertainty in net load forecasts: (1) uncertainty in measures to either reduce the end-use level of energy usage or to promote self-supply electricity behind the meter and (2) uncertainty in the underlying demand for electricity at the end-use level. It is difficult to know how much energy efficiency and distributed generation will occur in the local areas since, historically, energy efficiency and distributed generation programs were not targeted at small geographic areas but were aimed at the overall service territory of an investor-owned utility (IOU). Because of this past approach to program design, it is not known with certainty how much energy efficiency and behind-the-meter distributed generation will result from statewide programs in the local areas of concern.

Second, the uncharacteristically slow economic rebound from the recession could accelerate and the economy could grow faster than expected, which would increase the demand for electricity.[8] In the 2002-2006 timeframe, before the recession, statewide electricity demand was increasing on average by 2,755 MW per year.[9] Under current conditions, the CEC forecasts annual demand growth in

[7] Net load is the gross demand for electricity less energy efficiency, demand response, and behind-the-meter DG.
[8] Arns, Christopher. "U.S. Economy Somewhat Stagnant, but California, Not So Much," Sacramento Business Journal, August 1, 2013. http://www.bizjournals.com/sacramento/news/2013/08/01/us-economy-stagnant-california-not-affec.html. See Attachment C.
[9] *Adopted Energy Demand Forecast Report 2012-2022*, Mid-Form 1.4, "Peak Demand (MW)," California Energy Commission, updated on November 6, 2012. See Attachment D for excerpt.

the LA Basin of only 200-300 MW.[10] In light of state and federal policies to spur economic growth, 200-300 MW/year may underestimate future demand.

Third, some of the preferred resources[11] may not prove as viable as hoped. Currently, the amount of "uncommitted " resources assumptions embedded in the net load forecasts being used in the Track 4 analyses for the total SONGS study area (LA Basin and SDG&E) total about 1600 MW (see Table 1), and policymakers are pushing to significantly expand the procurement of EE, DG, and storage resources. If these uncommitted resources fail to deliver as planned, the CAISO will not be able to rely on the level of load reductions expected in the area and system reliability could be affected.

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[10] *Adopted Energy Demand Forecast Report 2012-2022*, Mid-Form 1.5b, "1 in 2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)," California Energy Commission, updated on November 6, 2012. See Attachment E for excerpt.

[11] Preferred resources typically refer to those identified at the top of the Loading Order described in Energy Action Plan II:

> The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. (*Energy Action Plan II*, California Energy Commission, September 21, 2005, p. 2. See Attachment F for excerpt.)

Table 1 – Uncommitted Resource Assumptions (MW)

	CAISO & SCE[12]	SDG&E[13]
LA Basin		
Incremental Uncommitted EE	787	787
Demand Response at Most Effective Locations	181	181
Distributed Generation Net Qualifying Capacity	247	247
Total Uncommitted Preferred Resources	1,215	1,215
SDG&E		
Incremental Uncommitted EE	196	338
Demand Response at Most Effective Locations	17	0
Distributed Generation Net Qualifying Capacity	210	136
Total Uncommitted Preferred Resources	423	474
Total SONGS Study Area (LA Basin + SDG&E)		
Incremental Uncommitted EE	983	1,125
Demand Response at Most Effective Locations	198	181
Distributed Generation Net Qualifying Capacity	457	383
Total Uncommitted Preferred Resources	1,638	1,689

Fourth, the completion and availability of new or upgraded transmission facilities might be delayed. As a result, grid-connected resources might not come online or be deliverable to load in the expected timeframe.

Overall, there are significant factors that suggest economic demand may accelerate over the 10 -year planning horizon, while state policy is increasing the state's reliance on uncommitted and emerging technologies to meet demand. These countervailing forces suggest the need to consider the significant uncertainties on both the demand- and supply-side of the load-resource balance.

[12] Sparks Track 4 Testimony, p. 5-9.
[13] "Prepared Track 4 Direct Testimony of SDG&E" (Anderson Track 4 Testimony), Robert B. Anderson on behalf of San Diego Gas & Electric Company, filed in R.12-03-014, August 26, 2013, p. 12 for SDG&E values; LA Basin values are assumed to be unchanged from values presented in the Sparks Track 4 Testimony, p. 5-9.

Q. Are the consequences to ratepayers and the overall economy the same if the electric system has too much supply as opposed to too little?

A. No. The consequences to ratepayers are highly asymmetric. An over-capacity condition might result in slightly higher costs to electric customers. An under-capacity condition would likely result in curtailment of firm load, which has a very high social cost.[14] In this respect, procuring sufficient capacity to meet conservative assumptions of supply and demand is akin to buying insurance. The hedging *cost* is known annually, but the hedging *value* is only known when the catastrophic events (i.e., firm load curtailments) occur. Prudent planners buy insurance in order to mitigate against the financial/economic hardship associated with the catastrophic event.

Q. Given the asymmetric damages that might result, what do you recommend?

A. I believe that the Commission should take a conservative approach when developing its authorized levels of procurement in this proceeding. This approach would likely result in a lower overall expected cost to ratepayers and society. Such an approach is consistent with that proposed by CAISO.

Q. Why do you say that the CAISO has used a "conservative" approach to planning in this proceeding?

[14] For example, E3 calculated a cost penalty of $40,000 per MWh for unserved energy. See E3's presentation on Renewable Energy Flexibility (REFLEX) Results presented at the August 26, 2013, Commission workshop, p. 30. See Attachment G for excerpt.

A. The CAISO develops reliability standards for its Balancing Area. At a minimum, the CAISO must conform to the standards established by the North American Electricity Reliability Council (NERC). However, the CAISO can propose and implement standards that are more stringent than those required by NERC. In the CAISO's testimony, Mr. Sparks uses the CAISO's current reliability standards based on the applicable WECC voltage stability criteria when assessing the need for resources in the local area.[15]

Q. Aside from the reliability standards being applied to determine need for resources, are there other areas in which the Commission should recognize the somewhat optimistic assumptions being used in the initial analyses in Track 4?

A. Yes. The Commission should understand that the underlying net load forecasts that were used in the initial Track 4 analyses included significant levels of uncommitted resources.[16] These uncommitted resources are inherently less certain than committed generation or approved transmission projects.[17]

[15] "Track 4 Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation," (Sparks Track 4 Testimony) filed by the California Independent System Operator Corporation in R.12-03-014, August 5, 2013, p. 18.

[16] Uncommitted demand-side resources include energy efficiency and demand response resources that are expected but have not yet been funded by the Commission. Other uncommitted resources include behind-the-meter generation resources (e.g., rooftop photovoltaics or combined heat and power) that have not been fully authorized by the Commission. Finally, potential transmission lines that have not been approved by the CAISO should also be considered uncommitted.

[17] In addition, some preferred resources (e.g., energy efficiency) are not flexible and likely cannot provide ancillary services as can certain generating resources.

Q. What uncommitted resource assumptions have been used in the initial Track 4 analyses presented by the CAISO, SCE, and SDG&E?

A. Table 1 above summarizes the uncommitted resource assumptions embedded in the net load forecasts being used in the Track 4 analyses.

Q. Do you contend that these forecasts are *unreasonable*?

A. Not necessarily. However, it is important to note that a 25% reduction in the availability of these uncommitted resources (e.g., from 1,669 MW to 1,252 MW in the case of the analysis performed by SDG&E) would result in an increase in need of 303 MW and 114 MW for SCE and SDG&E, respectively.

Q. What do you conclude about the potential risks ratepayers face because of the uncertainty about the forecast of uncommitted resources?

A. Because of the very tight load-resource balance in the LA Basin and in San Diego, if uncommitted resources do not appear as expected, then there is a real risk of resource shortages. To mitigate this risk, the Commission should ensure that any interim procurement authorization is toward the high end of the range of potential procurement levels. I discuss my recommended levels for interim procurement below.

Q. Are there other uncommitted resources that the IOUs have used in their analyses in Track 4 that you believe the Commission should view skeptically?

A. Yes. The IOUs have presented planning scenarios that rely on "uncommitted" transmission projects.

Q. Why do you call the transmission projects "uncommitted?"

A. I consider these transmission projects uncommitted since they have not yet been approved by the CAISO through its Transmission Planning Process (TPP). Moreover, the CAISO has committed to study non-conventional alternatives to new transmission projects in the current transmission planning cycle and will be applying this approach specifically to the LA Basin and San Diego areas.[18] Thus, there is no firm commitment to construct the projects, the environmental attributes of the projects have not been tested, and the economic costs of the projects are unknown.

In addition, the siting of new transmission projects in California has historically been fraught with controversy. This tendency toward controversy poses a real risk that at least some proposed transmission projects (expansion and/or upgrades) may not be built or completed within an expected time frame. Given this history, the Commission should be conservative when assuming that specific transmission projects will be online and available to help meet local reliability requirements.

Q. What are these uncommitted transmission projects?

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[18] CAISO. *Consideration of Alternatives to Transmission or Conventional Generation to Address Local Needs in the Transmission Planning Process.* September 4, 2013, pp. 3-4. See Attachment H for excerpt.

A. There are a number of transmission projects being discussed in this proceeding or in public forums discussing the electric infrastructure needs of the LA Basin and San Diego areas. These include:

- Alamitos to South Bay undersea High Voltage (HV) Direct Current (DC) line;
- Imperial Valley to SONGS HVDC;
- Alberhill-Suncrest 500 kV Alternating Current (AC) line; and
- Talega/Escondido – Valley/Serrano (TE -VS) – New Case Springs 500 kV line.

Q. Can you give examples of past transmission projects that have experienced delays coming on-line relative to the initial project on-line dates?

A. Yes. Table 2 below lists specific projects that did not meet their initial projected on-line dates or have never been built.

Table 2 – Past Transmission Projects

Project	Proponent	Discussion of Proposed and Actual Development Timeline
Sunrise Powerlink	SDG&E	Sunrise Powerlink began operations two years later than initially proposed by SDG&E in its permitting application to the CPUC. SDG&E initially proposed an on-line date of 2010 in its CPCN application. The actual on-line date was 2012.
Devers-Palo Verde 2 / West of Devers Upgrades	SCE	AZ Corp. Commission denied project in AZ. Required alternative route west of Devers substation due to inability to obtain right-of-way from Morongo.
Tehachapi Renewable Transmission Project	SCE	SCE filed the first CPCN application (Segments 1-3) in 2004 and the second CPCN application (Segments 4-11) in 2007. Segments 1-3A were completed in 2009 (i.e., 5 years). The entire project is expected to be completed by 2015 (i.e., 6 years after CPCN filed for Segment 4-11).
Valley-Rainbow 500 kV	SDG&E	This project was never built. The CPUC denied SDG&E's application for a CPCN in 2002.
TE-VS	Nevada Hydro	Originally proposed in 2004. Remains a proposed project only.
British Columbia to Northern California Transmission Project	PG&E	This project was never built. PG&E studied a BC to Northern CA transmission line in the 2007-2008 timeframe and proposed an in-service date of 2015.

As the table shows, major transmission projects often experience delays in the permitting and regulatory approval phase or never get past the design and permitting phase. Even SDG&E admits that there is significant uncertainty about "how quickly transmission projects can be licensed and built."[19]

Q. How should the Commission assess the likelihood that some of the proposed transmission projects will ultimately reduce need for new resources in the LA Basin and San Diego areas?

A. The Commission should use conservative assumptions to assess when various transmission projects might be online in evaluating the magnitude of any interim procurement.

[19] Anderson Track 4 Testimony, p. 2.

Q. What do you assume is a reasonable yet conservative estimate of the time needed to design, permit, and construct the large transmission projects being discussed by the IOUs?

A. The Commission estimates the three phases – planning, permitting, and construction – could last between 7 and 13 years.[20] For the proposed projects, a reasonable estimate is 7 years for permitting and construction.[21]

Q. Why is your recommended timeline reasonable for these transmission projects?

A. The risk of delay in a transmission project can occur during design, permitting, or construction. However, the greatest uncertainty in the schedule occurs during the process for receiving permits and approval for cost recovery. Depending on the route initially proposed for the project, it might even become necessary for the Proponent to develop new alternatives (e.g., undergrounding). Since the permitting and regulatory approval process could occur one or more years after a project is initially approved by the CAISO and included in resource assessment studies, a delay in that permitting might preclude other long-lead time resources from replacing the delayed transmission project (e.g., to meet a 2022 online date).

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[20] With planning taking 3-4 years; permitting taking 3-4 years; and construction taking 1-5 years. See the presentation "General Information on Permitting Electric Transmission Projects at the California Public Utilities Commission," June 2009, p.8, available at http://www.cpuc.ca.gov/puc/energy/environment/. See Attachment I for excerpt.

[21] 7 years = 3.5 years for permitting and 3.5 years for construction. This assumes that projects are fully planned and ready to start preparing applications and permitting documents. If this is not the case, project lead times would be longer.

Thus, making conservative planning assumptions for the timing of transmission projects is prudent.

Q. What other ways should the Commission be conservative in this proceeding?

A. While some IPP generation has shown an ability to come online quickly when needed, the Commission should acknowledge that generation projects can be delayed by the same type of opposition that I discussed previously with regards to transmission projects. As a result, the Commission should make conservative assumptions about the time it takes to develop, permit, and construct new generation projects. As IEP has noted previously, it can take 6-8 years or more to bring new generating facilities online.[22] It is telling that at least one opponent to the repowering of an existing unit has already presented testimony in this proceeding about why that project should not move ahead due to lack of need.[23] Therefore, the Commission should not assume that developers will be able to bring on new generation projects faster than expected.

Q. How might the uncertainty in assumptions regarding uncommitted resources affect the timing for authorization of interim procurement?

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[22] "Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding," filed by the Independent Energy Producers Association in R.12-03-014, July 23, 2012, p. 13.

[23] "Testimony of Jaleh Firooz and Analysis of Local Capacity Requirements in the Western Los Angeles (LA) Basin Sub-Area Submitted on Behalf of the City of Redondo Beach" (Firooz Track 4 Testimony), filed by the City of Redondo Beach in R.12-03-014, August 25, 2013, p. 13.

A. Table 3 presents hypothetical development schedul es for resources authorized in Track 1 and Track 4 (Phase 1). The table also shows potential schedules for transmission projects that might result from CAISO's 2013/2014 TPP.

Table 3 - Potential Schedules for Procurement and Construction of Generation and Transmission Projects

Action		Expected Completion Date	Extended Completion Date
SCE Track 1 Procurement			
Issue RFO		Sep-13	Sep-13
Receive offers		Dec-13	Dec-13
Assemble Short List		Jan-14	Jan-14
Negotiate Agreements		May-14	May-14
Commission Approval		Aug-14	Oct-14
Permitting projects		Aug-16	Oct-17
Construct projects		Feb-19	Oct-20
Commission and testing		Apr-19	Dec-20
Duration (years)		5.6	7.2
Track 4 Phase 1 Decision		Jun-14	Jun-14
Issue Track 4 Interim RFO		Jul-14	Jul-14
Receive offers		Sep-14	Sep-14
Assemble Short List		Oct-14	Oct-14
Negotiate Agreements		Apr-15	Apr-15
Commission Approval		Jun-15	Aug-15
Permitting projects		Jun-17	Aug-18
Construct projects		Dec-19	Aug-21
Commission and testing		Feb-20	Oct-21
Duration (years)		5.7	7.3
Track 4, Phase 2			
CAISO TPP Approval		Jun-14	Jun-14
Prepare CPCN and PEA		Dec-15	Dec-15
Approve CPCN and issue permit		Jun-18	Jun-19
Construct project		Jun-21	Dec-22
Duration (years)		7.0	8.5

The schedules presented in Table 3 assume reasonable ranges for development schedules for generation and transmission projects.

Q. What do you conclude from these schedules?

A. If we assume that resources must be online by July 1, 2021 [24], then the Track 1 projects should all be online in time and the Track 4 (Phase 1) generation projects should be online either in time or only slightly after July 2021. However, for transmission assets, it is clear that any delays would put the online date for the project well after the date needed to meet need resulting from the expected dates for OTC compliance.

Q. In summary, what type of conservative assumptions should the Commission use when considering the need for new resources to replace SONGS 2 & 3?

A. The Commission should adopt the following conservative assumptions:

- Rely on the CAISO's reliability criteria when determining resource need in the local area;
- Recognize the risks associated with uncommitted resources;
- Assume seven year lead-times for transmission projects; and
- Do not assume that new generation projects can come online sooner than proposed by project proponents, or assume that existing OTC regulations fostering generation retirements will be amended or compliance deadlines extended.

[24] I use June 2021 as the target date since the State Water Resources Control Board's Compliance Dates for Alamitos, El Segundo, Huntington Beach, Redondo Beach, and Encina are all on or before the end of 2020.

Together, these assumptions would ensure that the final determination of need is conservative and will not put the Commission in the position of ordering "just in time procurement" to ensure grid reliability.

Q. Aside from ordering the use of conservative assumptions in studies that follow Track 4, how should the Commission mitigate the risks of higher-than-expected loads, delays in transmission projects, and long development periods for generation?

A. The Commission should hedge the risk of resource shortfalls by authorizing SCE and SDG&E to procure local resources above and beyond the level already authorized in Track 1 of this proceeding for SCE and in A.11-05-023 for SDG&E.[25] Both SCE and SDG&E recommend some form of interim procurement and the CAISO does not object to some amount of interim procurement.[26] This interim procurement authorization would ensure that some amount of long lead-time resources are procured quickly.

Q. What are your specific recommendations regarding procurement from Track 4 of the proceeding?

A. The Commission should account for the overlapping schedules of the Track 1 RFO and procurement activities that result from Track 4 of this proceeding. As

[25] For convenience, I refer to both of these initial procurement decisions as Track 1 decisions.
[26] SCE Track 4 Testimony, pp. 3-4; Anderson Track 4 Testimony, pp. 4-5; "Comments of the California Independent System Operator Corporation on Proposed Track 2 and Track 4 Procedural Schedules," filed in R.12-03-014, September 10, 2013, p. 6.

discussed below, the Commission should authorize interim procurement based on the identified need from this proceeding. Because SCE's Track 1 procurement authorization is a range (i.e., 1,400 – 1,800 MW), there is some uncertainty about how much local capacity will ultimately be procure d from the SCE RFO. For that reason, I recommend the Commission determine the overall amount of procurement needed to meet both the Track 1 and interim Track 4 needs and then adjust the interim Track 4 procurement levels based on the results of the Track 1 procurement.

Q. What is your specific proposal?

A. I propose a three -part procurement program for SCE and SDG&E. These three parts are:

1. Continue with Track 1 procurement activities that are already underway.
2. Authorize interim procurement under Track 4 (i.e., Phase 1 procurement from Track 4) based on current analysis and assumptions;
3. After the CAISO completes its updated transmission assessment as part of the 2013/2014 TPP, potentially provide additional procurement authority to the IOUs (i.e., Phase 2 procurement from Track 4).

I discuss each part of the procurement program below.

Q. Please explain the first part of your proposed process.

A. The Commission, in its Track 1 decision, authorized SCE to procure between 1,400 MW and 1,800 MW in the western LA Basin. SCE issued a Request for

Offers (RFO) on September 12, 2013 to begin that procurement process. The following schedule itemizes key dates in SCE's Local Capacity Requirements RFO:[27]

Table 4 – SCE Local Capacity Requirements RFO Schedule for Track 1 Procurement

Date:	Event:
December 2, 2013	Deadline to submit non-binding notice of intent to offer
December 16, 2013	Deadline to submit indicative offer and complete offer submittal package
January 30, 2014	Shortlist notification
May 22, 2014	Deadline to complete negotiations of agreement
May 29, 2014	Deadline to submit final offer
June 26, 2014	Last date for notification of successful offers and to sign agreements

While it is unclear exactly how much capacity will be procured in this RFO, the Commission should allow SCE to continue its procurement efforts pursuant to the Track 1 authorization.

Q. Please explain the second part of your proposed process.

A. As part of Track 4, the Commission should authorize interim procurement for SCE and SDG&E and direct both utilities to procure local capacity from all sources. I refer to this as a Track 4, Phase 1 procurement authorization.

[27] "Local Capacity Requirements ('LCR') RFO," available from SCE's Energy Procurement website, accessed September 25, 2013. See Attachment J. Available from: https://www.sce.com/wps/portal/home/procurement/LCR-RFO/!ut/p/b1/rVJNb4JAFPwr9NAj2YfL1x7XSHCtoSo2FS5kXReKgQURm_rvi5SrWhP39D5mJ28mg2K0QbHi33nG27xSvLj0sZ3M2IQavjlivulhoDAP7bHlG5Q4HSDqAHDlUej_G65PpywEBs6cABsvVh5ZE2y_GegTxSgWqq3bLxQdhUxEpVqp2kSqVxjqV5BKNtlZq5tKnBpZ9rOiErzQBK-5yNuz1sjDKf_bHbVCNFqTVhfummdyJ495pvpO5DsUYY7N0U5sdWtrgW4awtUJTrFOuM1NQvDWGBmDshun33GmV3adwR1bdwAOHgDEB286ewfmr5cYGF5CEFKKAewBcMP-YFqVEkWdFufqsQuMwgfNuU1omc8mtB8mnP0jufn-cIhpl79Lzn5atHl6AOvyo3T36dxeeelknZZlEgR6HL38AvEOjmU!/dl4/d5/L2dBISEvZ0FBIS9nQSEh/

Q. When would this interim procurement take place?

A. I expect a Phase 1 proposed decision in Track 4 by December 2013 or the first quarter of 2014. After the Commission issues its decision in Phase 1 of Track 4, the IOUs should be given approximately 30 days to issue a new RFO for all source capacity located in the local areas. Thirty days should be sufficient since the IOUs should be preparing their RFOs in parallel with Phase 1 of Track 4. The Track 4, Phase 1 solicitation under this schedule should occur no later than mid-2014.

Q. Should losing bidders in the Track 1 solicitations be allowed to participate in the solicitation resulting from Phase 1 of Track 4?

A. Yes. However, to simplify bidding rules and to ensure bidders provide their most current proposal, I recommend that projects that bid in the Track 1 RFO be required to submit a new bid in the Phase 1 RFO from Track 4.[28]

Q. Please explain the third part of your proposal.

A. I refer to this part as Track 4, Phase 2. The primary purpose of Phase 2 would be to enable the IOUs and the CAISO to refresh their resource need analyses. This would include evaluation of possible transmission projects (through the CAISO's TPP). Based on these updated analyses (and stakeholder testimony and hearings, if needed), it may be necessary for the Commission to provide additional

[28] If the final contracts from the Track 1 solicitations are not sent to the Commission prior to the due date for offers in the RFO for Phase 1 of Track 4, bidders from Track 1 should be allowed to submit bids in both RFOs. If a project with bids in both RFOs is ultimately selected as a winning bidder in the Track 1 RFO, then the bidder must withdraw its bid from consideration in the solicitation for Phase 1 of Track 4.

procurement authorization to the IOUs (i.e., authorize a Phase 2 procurement in Track 4).

Q. Should the results of resource need analyses finalized in Phase 2 of Track 4 affect the procurement authorization from Track 1 or Phase 1 of Track 4?

A. No. Suggesting that bidders might have winning projects terminated based on additional information would have a chilling effect on participation in the Track 1 and Track 4, Phase 1 solicitations.

Q. What types of resources should be procured in the Phase 1 procurement in Track 4?

A. The Commission should authorize procurement of all resource types. The all-source solicitation would allow project proponents to propose a range of resources including EE, DR, DG, storage, and grid-connected generation (both renewable and clean gas-fired).[29]

Q. How much capacity should each utility procure in Phase 1 of Track 4?

A. Table 5 presents the amount of all-source capacity that the IOUs should procure. As explained above, the amount of capacity procured in Phase 1 of Track 4 ultimately depends on the amount procured in Track 1.

[29] This would include both conventional and Combined Heat and Power (CHP) resources.

Table 5 - Recommended Phase 1 Procurement for Track 4 (MW)

	SCE (LA Basin)	SDG&E	Total
Track 1	1,400 - 1,800	0*	1,400 - 1,800
Phase 1 of Track 4	706 – 1,106	820	1,526 – 1,926
Overall Procurement from Track 1 and Phase 1 of Track 4	2,506	820	3,326

* Assumes SDG&E's Pio Pico Application is approved.[30]

Table 6 presents IEP's recommended procurement levels by resource type for Track 1 and Phase 1 of Track 4:

Table 6 - Recommended Procurement by Resource Type (MW)

	SCE (LA Basin)	SDG&E	Total
Storage	50	0	50
Preferred	150	0	150
Gas	1,000 – 1,200	308*	1,308 – 1,508
Additional Storage and Preferred	0 - 600	0	0 – 600
All-Source	706	820	1,526
Total	2,506	1,128	3,634

* Pio Pico and Wellhead

Q. Do you have additional specific recommendations?

A. Yes. The Commission should employ a "no regrets" policy to these initial procurement authorizations. Under this policy approach, the utilities are ensured full cost recovery for reasonable resource costs utilized for this initial procurement. This "no regrets" level of procurement would allow all resource categories to compete on a level playing field to meet a portion of the expected need for resources in the local area.

[30] "Prepared Track 4 Direct Testimony of San Diego Gas & Electric Company" (Jontry Track 4 Testimony), John M. Jontry on behalf of San Diego Gas & Electric Company, filed in R.12-03-014, August 26, 2013, p. 11. (N-1-1)

B. The Commission should encourage competition among resource types to ensure ratepayers receive the lowest-cost service consistent with reliability and policy goals.

Q. Under your "no regrets" procurement approach, what resource types should be allowed to bid to meet the incremental needs identified in Track 4?

A. As noted above, I believe that procurement should take place through an all-source solicitation. This would allow project proponents to propose a range of resources, including EE, DR, DG, storage, and grid-connected generation (both renewable and clean gas-fired).

Q. Why do you believe that your approach is reasonable?

A. Resources selected to serve load would count against individual utility portfolio mandates and provide a means by which the utilities may exceed those mandates based on the cost-effectiveness of the resource as generally prescribed by the California Legislature.

Q. Why will an all-source procurement result in the lowest-cost resource mix consistent with reliability goals?

A. Allowing the IOUs to compare and contrast different resources to meet their needs will allow the IOUs to finally optimize their resource procurement activities, rather than having to optimize different pieces of the procurement plan but to never know that the final portfolio is, in fact, the least-cost and best-fit set of resources. It is important to note that "least-cost/best-fit" should also attempt to account for as many quantifiable attributes as possible as well as to qualitatively factor in externalities.

Q. How should the IOUs proceed with such an all-source procurement?

A. I proposed an all-source solicitation in Track 1 of this proceeding. Consistent with that proposal, the Commission will need to provide the IOUs with guidance about the characteristics of the resources that they should procure. These characteristics might include preferred locations, ramping speed, ability to cycle, energy density for the resource,[31] emissions, and other factors. Ideally, the IOUs would assign a value to each attribute to ensure that all attributes are valued in the various proposals that the IOUs may receive. The IOUs should also provide form contracts to bidders to ensure that each resource type understands the delivery obligations associated with making a bid. The Requests for Offers (RFOs) should also clearly spell out any online date requirements and penalties for failure to meet those dates.

Q. Should the requirements for online dates, performance, and persistence of the resource be consistent across resource types?

A. The CAISO must be able to rely on the delivery of energy, capacity, ancillary services, and other attributes from the resources being procured. If a resource cannot provide all of those attributes, then the scoring of that bid should reflect that fact.

[31] Energy density refers to the amount of energy that can be supplied by an energy-limited resource such as storage.

Q. Do you have other recommendations?

A. Yes. IEP recommends that the Commission should institute an expedited process to further develop an appropriate least-cost/best-fit methodology for valuing a combination of attributes given the diversity of technologies that will fill out the 21st century grid.

C. Even though assumptions will change over time, the Commission should not put customer reliability at risk by delaying procurement of critical resources.

Q. Would it make sense to delay the Track 4, Phase 1 interim procurement until after the CAISO has completed the 2013-2014 TPP cycle?

A. No. It is enticing to believe that a delay might help resolve key uncertainties such as the type and level of resource need. But other uncertainties are likely to persist beyond the completion of the CAISO's TPP cycle.

Q. Why do you believe that?

A. Completion of the CAISO's TPP is not going to resolve uncertainties such as the future levels of local net loads, the operational characteristics of certain preferred resources, the pace at which emerging technologies move into the market and become accepted, future fuel prices, and the time to permit, construct, and energize high-voltage transmission projects. Furthermore, the CAISO TPP study is expected to evolve throughout 2014. The Assigned Commissioner has recognized that it would not be prudent to delay action on long-lead-time resources until 2015 or beyond.[32]

Q. Would it make sense to delay the interim procurement until after the Commission updates its least-cost/best-fit (LCBF) methodology as proposed by IEP?

A. IEP does not believe that a delay is warranted or necessary. Any updates of the LCBF methodology should be completed on an expedited basis but the Phase I interim procurement, however, should not be delayed beyond mid-2014 as recommended by IEP.

Q. Do you have specific reasons for supporting an interim procurement now?

A. Yes. The loss of SONGS means the loss of over 2,000 MW of baseload capacity. In addition, approximately 7,000 MW of OTC units are scheduled to shut down. An interim procurement now, supplemented by additional procurement as needed based on further studies, is a low-risk, high-value strategy for securing the resources necessary to ensure grid reliability.

Q. Are there additional reasons that an interim Track 4 procurement authorization incrementally above that already authorized in Track 1 ultimately reduces risk for utility customers?

[32] "Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules," filed in R.12-03-014, September 16, 2013, p. 3.

A. Yes. First, it would provide the lead-time needed by project developers to develop, permit, and construct cost-effective resources with relatively longer lead times. Second, it would also allow the IOUs and the Commission to determine whether forecasted amounts of uncommitted resources will be developed in local areas in a timely and cost-effective manner. Third, it would allow the IOUs and the Commission to understand the operational and delivery flexibility that preferred resources might provide (e.g., can renewable resources provide certain ancillary services?) in order to help maintain overall grid reliability. It is better to start to resolve these uncertainties soon, rather than wait until there is insufficient time to develop and construct backstop resources.

D. The Commission should reject the IOUs' site banking proposals in this proceeding or, at a minimum, exclude utility affiliates from bidding to develop projects at energy parks

Q. Please describe some of the approaches being proposed to reduce the time to bring on new conventional resources.

A. Both SCE and SDG&E have proposed novel approaches that they claim will reduce the time between when the need for a new conventional power project is identified and when the project can be online. SCE proposes to "prepare GFG [Gas-Fired Generation] sites near its Johanna and Santiago substations as a backstop[] to preserve local reliability should [its proposed "Living"] Pilot not achieve its goals. This effort will develop 'construction ready' sites to reduce the lead times needed to construct GFG in the LA Basin."[33] SDG&E is "currently exploring the feasibility of developing an energy park that would be made available to independent generators in future RFOs to meet local resource need. The goal of the energy park would be to reduce the time between a finding of generation need and the in-service date of generating plants necessary to meet that need."[34] Both proposals hope to develop fully licensed locations that would have transmission and natural gas available for new generation projects to utilize.

Q. What evidence do the IOUs present to support their requests to develop these energy parks?

A. The IOUs claim that this approach is needed because it would allow new generation to come online much more quickly than under the traditional development model for IPPs.

Q. **Do you have concerns about the IOUs' recommended approaches?**

A. Yes. The IOUs present no evidence that the traditional project development process, in conjunction with a rational planning and procurement program, cannot bring on generating capacity in time to meet identified resource needs.

Q. Are there risks associated with reliance on the "energy park" proposals?

A. Yes. First, while the CEC staff appears to believe that it could obtain authority to undertake permitting facilities absent a project proposal (or that it could expedite

[33] SCE Track 4 Testimony, p. 61.
[34] Anderson Track 4 Testimony, p. 16.

the approval process under the traditional siting procedures), it is not at all clear that the CEC currently has the authority to provide pre-approval of projects that are not really projects.[35] If the CEC needed to obtain new siting authority from the Legislature, this could delay project development at a time when the need for action is immediate.

Second, siting power plants is a very time-intensive process. It involves extensive environmental review of the proposed project as well as review of alternatives to the project. It is not exactly clear how the proponents of the energy park would address all of the siting issues that might come up without having a specific project in mind.

Q. What other concerns do you have?

A. Aside from the need for legislative action before the CEC can embark on contingency permitting of potential sites, there are even greater policy concerns to consider. First, utility ownership of project sites could give the IOUs a much greater level of market power when negotiating price, terms, and conditions than if project developers brought fully independent projects to the IOUs through RFOs. Second, if IOUs are competing with developers for the few locations that are suitable for gas-fired generation, this competition would increase the cost of sites for IPPs, making them less competitive with projects located at energy

[35] "Presentation at Workshop on Southern California Electricity Infrastructure and Reliability Issues, "Southern California Reliability: Preliminary Plan," September 9, 2012, p. 20. See Attachment K for excerpt.

parks.[36] Third, self-dealing concerns will arise if the IOUs' affiliates attempt to develop projects at the energy park owned by their affiliate. Fourth, even if the IOUs provide access to the energy parks at "market -based" prices, if the IOU is setting the market price for land and is also evaluating the prop osals it receives, any hope of a transparent market transaction is unlikely at best. Fifth, the energy park proposals would give the IOUs additional leverage in California's hybrid market structure. It would firmly place the IOUs in the middle of many (if not all) of the gas-fired power projects that would be needed to meet local needs.

Q. Is there evidence that there is a shortage of IPP projects being developed in the LA Basin or San Diego?

A. No. There are projects under development in both regions toda y. For example, the Carlsbad Energy Center in northern San Diego County is a fully permitted project that appears to be ready to begin construction once it obtains a Power Purchase Agreement. There are also projects in the LA Basin that have submitted applications to the CEC for permits, including Huntington Beach and Redondo Beach. Based on this, it does not appear that there is a significant shortage of Independent Power Projects that have sites and can move quickly to meet need.

[36] Presumably, the IOUs would request cost recovery for any land acquired for the energy parks. If this were the case, then the IOUs would have little incentive to control its costs for acquiring sites. This is completely different than IPPs, which have to obtain site control even though they are not guaranteed cost recovery for their investments in land.

Q. Would the traditional independent power project development model mitigate some of the risks you have identified with the IOUs' energy park proposals?

A. Yes. Rejecting the "energy park" model and retaining the traditional project development model would mean there is no need to rely on legislative action. It would also help to mitigate the significant market power that the energy park proposals would give to the IOUs. It would allow the continuation of the current power procurement program, which at least provides a degree of transparency. Project developers would have a known path forward for siting, permitting, and obtaining a commercial agreement, which would reduce the perceived risk associated with a new and unknown process. All of these benefits clearly outweigh the highly uncertain benefits of the "energy park" proposals.

Q. What do you recommend?

A. The Commission should not support the energy park proposals presented by SCE and SDG&E. The proposals provide little or no details.[37] They likely require legislative action before being implementable, meaning that there is a significant risk that they will take a great deal of time to put in place. The energy park proposals skew the delicate market balance between independent generators and the IOUs. The proposals raise concerns about self-dealing. Furthermore, they likely will undermine transparency and belief by the power project developers in the procurement process. In sum, the Commission should not rely on the ill-

[37] In fact, the IOUs both indicate that they would plan to bring separate applications forward associated with their energy park concepts.

formed energy park proposals to help meet local reliability needs identified in this proceeding.

Q. What do you recommend if the Commission decides to consider the energy park proposals?

A. In order to avoid any appearance of self-dealing, the Commission must exclude utility interests from any opportunity to develop projects at energy parks developed by the parent utility. In addition, the Commission should exclude "build-own-transfer" projects from using these locations.

III. Response to Opening Testimony

Q. What is the purpose of this section of your testimony?

A. In this section, I respond to certain parts of the opening testimony of the CAISO, SCE, and SDG&E.

A. Response to the CAISO's Opening Testimony

Q. Please describe the CAISO's testimony.

A. Mr. Sparks evaluated a number of scenarios based on assumptions specified by the Commission. He evaluated resource need for two years: 2018 and 2022. He examined resource need under different assumptions about the location of new resources (e.g., 80% of new resources in the LA Basin versus 67% of new resources in the LA Basin).

Q. What are the key conclusions from Mr. Sparks' testimony?

A. Mr. Sparks identified the following resource need in the "SONGS Study Area" for 2022:

Table 7 - CAISO Estimate of Resource Need in SONGS Study Area

Scenario	Track 1 Decisions (MW)			Residual Resource Need
	LA Basin	San Diego	Resource Need without SONGS	Need Net of Track 1 Procurement
	(1)	(2)	(3)	(4) = (3) - (1) - (2)
80%/20% LA/SD)	1,800	308	4,642	2,534
67%/33% LA/SD)	1,800	308	4,507	2,399

As can be seen from Table 7, the CAISO's preliminary results show that there is a baseline need for new resources of between 2,399 and 2,534 MW by 2022. This is in addition to the 1,800 MW that have been previously authorized for procurement by SCE and SDG&E in the prior Commission Track 1 decision.

Q. Does the CAISO's testimony recommend that the Commission authorize procurement based on these results?

A. No. The CAISO recommends that the Commission should wait until the CAISO has completed its transmission studies as part of the 2013/2014 TPP before authorizing incremental procurement for 2022.

Q. Has the CAISO modified its position since it submitted its testimony in Track 4?

A. Yes. In comments filed on September 10, 2013, the CAISO indicated that it "would not object" to an interim Commission decision regarding SCE and

SDG&E's interim procurement proposals. However, the CAISO also notes that the amount of capacity authorized in the interim decision could either increase or decrease based on the results of the CAISO's ongoing transmission studies.[38] Hence, the CAISO apparently suggests that an interim procurement decision by the Commission be contingent and subject to reversal.

Q. Do you agree with the CAISO's updated recommended approach for interim procurement?

A. No. Contingent procurement decisions would prove completely unworkable from the perspective of project developers. Viable developers would be highly unlikely to devote time, personnel, and development capital to participate in a competitive solicitation that might well be declared null and void as the result of future CAISO transmission studies. SCE also agrees that the CAISO's proposal is untenable.[39]

Q. How would you modify the CAISO's proposal to make it more workable for project developers?

A. I recommend that the Commission authorize a "no regrets" amount of procurement for both SCE and SDG&E. As discussed above, the level of procurement authorized in this proceeding should not be reduced as the result of

[38] "Comments of the California Independent System Operator Corporation on Proposed Track 2 and Track 4 Procedural Schedules," R.12-03-014, September 10, 2013, p. 4.
[39] "Opening Comments of Southern California Edison," filed in R.12-03-014, September 10, 2013, p. 3.

future analysis. Also, the IOUs would be granted cost recovery associated with their no regrets procurement.

B. Response to SCE's Opening Testimony

Q. Please summarize SCE's testimony.

A. SCE presented studies that were slightly different than the studies presented in the CAISO's opening testimony. In addition to a scenario using gas -fired generation to meet resource need, SCE examined two other sets of scenarios: transmission upgrade scenarios and an aggressive Preferred Resource scenario. SCE's analysis relied on NERC reliability criteria that are less stringent than assumptions used by the CAISO in its Local Capacity Technical studies. SCE acknowledges that the level of reliability assumed in its studies is not the same level of reliability that the CAISO deems necessary. SCE claims that it needs to procure approximately 1,000 MW of resources beyond the Track 1 authorization, while the CAISO recommends procurement of about 1,922 MW.

SCE believes that construction of the Mesa Loop -In Transmission Project plus a very aggressive development of strategically placed Preferred Resources could eliminate the need for all but 500 MW of gas -fired generation using the CAISO's reliability standards (and that there would be no need for additional gas-fired generation resources using the NERC reliability standards .) As a result, SCE proposes an interim procurement of 500 MW to ensure meeting the CAISO's estimate of LCR under its assumed plan with the Mesa Loop -In and an aggressive Preferred Resource acquisition program (i.e., the "Living Pilot Program".)

SCE estimated the "net indicative cost" of four different resource procurement scenarios: (1) a s cenario relying primarily on incremental gas -fired generation scenario, (2) a scenario with gas-fired generation and the Mesa Loop -In project, (3) a scenario relying on an aggressive build -out of Preferred Resources plus gas - fired generation, and (4) a scenario relying on extensive development of new transmission projects. The following table summarizes the amount of new gas - fired generation as well as SCE's estimated cost of each scenario:

Table 8 - SCE-Identified Resource Need

Scenario Number		Gas Generation[40] (MW)	Indicative Cost[41] (2013 Billion $)
1	LA Basin Generation	2,802	1.25
2	LA Basin Transmission (Mesa Loop-In)	1,606	1.55
1S	Case 1 without SDG&E Load Shed	3,240	n/r/a
2S	Case 2 without SDG&E Load Shed	2,506	n/r/a
3	Preferred Resources	1,055	1.9
4	Regional Transmission	1,198	2.5
	n/r/a = Not Readily Available		

This table presents the amount of new gas-fired generation assumed i n each scenario. There are several important points to note about this table:

[40] SCE Track 4 Testimony, p. 32.
[41] Estimated from SCE Track 4 Testimony, Figure IV-7, p. 42.

- The table presents results using both the CAISO's reliability standards (i.e., Scenarios 1S and 2S) and SCE's assumed level of reliability based on NERC standards (i.e., all other Scenarios).[42] As can be seen, the level of gas-fired generation required under the CAISO reliability standards (Scenarios 1S and 2S) is between 440 MW and 900 MW higher than assumed by SCE in its modeling for Scenarios 1 and 2, respectively.
- The gas-fired procurement levels in the table include the Track 1 procurement authorization (e.g., Scenario 1 requires an additional 1,002 MW – 1,402 MW beyond the 1,400 MW — 1,800 MW of Track 1 procurement to meet the assumed NERC reliability standards).
- The net cost of the Preferred Resource Plan option is about $650 million greater than Scenario 1, which relies on clean in-basin gas-fired generation. The regional transmission scenario costs about twice what Scenario 1 costs ($2.5 billion versus $1.25 billion).
- Although SCE did not provide cost data for Scenarios 1S and 2S, presumably they would be several hundred million dollars more expensive than Scenarios 1 and 2, respectively, since they would require greater levels of incremental resources.

Q. How do you respond to SCE's testimony?

A. There are several issues in SCE's testimony that require response. First, it appears that SCE's recommended 500 MW for its interim procurement in Track 4 is not

[42] The scenarios without load shedding use the CAISO reliability standards.

sufficient. Second, the untested "Living Pilot" places ratepayers at risk and should not be the cornerstone of SCE's procurement program.. Finally, SCE's "contingent procurement" proposal needs clarification. I address each issue below.

1. Additional procurement is needed but SCE's proposal is too conservative

Q. What does SCE propose for its interim procurement?

A. SCE proposes to supplement its Track 1 procurement with an additional 500 MW of procurement from all sources. Thus, for the LA Basin, SCE proposes to procure 1,900 - 2,300 MW, with the breakdown of technologies as follows[43]:

- 50 MW of storage
- 150 MW of Preferred Resources
- 1,000 MW of gas-fired generation
- Up to 400 MW of additional Preferred Resources and storage
- A minimum of 700 MW from an all-source procurement

Q. Do you agree that SCE should pursue incremental resources through an extension of its Track 1 procurement?

A. Not exactly. Instead of extending SCE's Track 1 procurement authorization, the Commission should ensure that SCE continues with its Track 1 procurement efforts (which are now underway)[44], and order SCE to hold an additional

[43] SCE Track 4 Testimony, p. 56.
[44] "Local Capacity Requirements ('LCR') RFO," available from SCE's Energy Procurement website, accessed September 25, 2013. See Attachment J. Available from:

solicitation as a result of Phase 1 of Track 4. As noted above, there is a clear need for additional resources in the local area, and delaying the Track 1 solicitation would potentially put the local area at risk. At the same time, it is reasonable to authorize an interim procurement based on the facts now before the Commission (i.e., before the CAISO completes its 2013/2014 TPP).

Q. Why do you believe that separating the Track 1 procurement from the Track 4 procurement is necessary?

A. Melding the two procurement authorizations increases litigation risk. As I understand the proposal, SCE is suggesting that projects selected in the Track I solicitation should be considered for Track 4 in order to expedite decision-making. Potentially, this raises a host of issues that may result in delay. It is much cleaner procedurally to conduct any Track 4 solicitations separately from the Track 1 solicitation, so that the RFOs, the responsive bids, and the determination of winners of the two solicitations are contemporaneous.

Q. Do you agree with SCE's proposed level of incremental procurement?

A. No. SCE has understated the amount of incremental procurement that should be authorized in Phase 1 of Track 4. SCE claims that it recommends procurement of

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https://www.sce.com/wps/portal/home/procurement/LCR-RFO/!ut/p/b1/rVJNb4JAFPwr9NAj2YfL1x7XSHCtoSo2FS5kXReKgQURm_rvi5SrWhP39D5mJ28mg2K0QbHi33nG27xSvLj0sZ3M2IQavjlivulhoDAP7bHlG5Q4HSDqAHDlUej_G65PpywEBs6cABsvVh5ZE2y_GegTxSgWqq3bLxQdhUxEpVqp2kSqVxjqV5BKNtlZq5tKnBpZ9rOiErzQBK-5yNuz1sjDKf_bHbVCNFqTVhfummdyJ495pvpO5DsUYY7N0U5sdWtrgW4awtUJTrFOuM1NQvDWGBmDshun33GmV3adwR1bdwAOHgDEB286ewfmr5cYGF5CEFKKAewBcMP-YFqVEkWdFufqsQuMwgfNuU1omc8mtB8mnP0jufn-cIhpl79Lzn5atHl6AOvyo3T36dxeeelknZZlEgR6HL38AvEOjmU!/dl4/d5/L2dBISEvZ0FBIS9nQSEh/

500 MW in Track 4 in order to "assure sufficient resources available to meet CAISO expectations of need."[45] However, as SCE readily admits, the proposed shedding of firm load in the SDG&E area in case of an outage on the Southwest Powerlink, system adjusted, and then an outage on the Sunrise Powerlink is not acceptable to the CAISO as a means to address this set of outages.[46] Thus, it is unreasonable for SCE to count on using load shedding in the SDG&E area when it assesses need from Track 4.

Q. What should the amount of procurement be for the recommended interim procurement?

A. The "no regrets" procurement should ultimately result in SCE procuring 2,506 MW of local capacity between its Track 1 solicitation and any procurement authorization from this Phase 1 of Track 4. In other words, the Commission should authorize SCE to procure between 706 MW and 1,106 MW in the decision on Phase 1 of Track 4.[47] This is what SCE finds that it needs using the CAISO's reliability requirements.[48]

2. The Living Pilot is Untested and Risky. The Commission Should Give it Little Weight

[45] SCE Track 4 Testimony, p. 7.
[46] SCE Track 4 Testimony, p. 27.
[47] 706 MW = 2,506 MW (Scenario 2S) – 1,800 MW (upper bound on Track 1 procurement)
1,106 MW = 2,506 MW (Scenario 2S) – 1,400 MW (lower bound on Track 1 procurement)
[48] This level of procurement assumes that the Mesa Loop-In is approved by the CAISO in the 2013/2014 TPP and that SCE decides to pursue the project. If this does not occur, then the Commission may need to give SCE additional procurement authorization in Phase 2 of Track 4.

Q. How has SCE described its "Living Pilot" to procure Preferred Resources?

A. SCE's Track 4 testimony provides a general description of the Living Pilot. SCE's testimony describes the general location for the Living Pilot, how the pilot does not, at this point, have any specific MW target, that SCE will rely on contingent development of sites for gas-fired generation, and that the Living Pilot should be developed through a collaborative process.[49]

Q. Do you think that SCE's proposal to initiate a pilot program to test the ability of Preferred Resources to meet LCR is reasonable?

A. Yes. A small-scale pilot program to test the capabilities of Preferred Resources to deliver capacity in the appropriate location at the appropriate time is warranted. Such a pilot would provide the Commission with useful information regarding future resource procurement efforts.[50]

Q. Is it prudent to rely on the Living Pilot to meet LCR at this time?

A. No. First, as discussed above, SCE's proposal is not fully formed. SCE even admits that it would rely on an open, collaborative process to develop the pilot. That hardly sounds like a fully-formed project that is ready to deliver capacity to meet the immediate local reliability requirements resulting from the shutdown of SONGS.

[49] SCE Track 4 Testimony, pp. 49-54.

[50] It might be appropriate for SCE to bring such a pilot to the Commission through an application, rather than proposing it during the LTPP proceeding. This would force SCE to fully describe the Living Pilot and allow all interested parties to help SCE vet the proposal.

Second, SCE has linked its Living Pilot with contingent development of sites for generation. If the Living Pilot is not successful, then SCE apparently would then turn to developers to propose to build gas -fired generation at SCE's contingent generation sites. As noted above, SCE's contingent development program (as well as SDG&E's energy park proposal) has serious flaws. Because of those flaws, the Commission should not adopt the IOUs' proposals as a tool to meet local area reliability needs at this time.

To the extent that the Commission finds value in the Pilot Project, IEP recommends treating it as a pilot test project subject to empirical analysis of the results over the next several years . Absent the ill -conceived contingent development proposal, the Living Pilot places ratepayers at too much risk of resource shortages when the OTC units come offline.

3. Contingent contracting/options

Q. What has SCE proposed regarding using contingent contracts or options for the solicitation resulting from Track 4?

A. SCE proposes to enter into contingent contracts for development of gas -fired generation. These contracts would allow SCE to terminate the agreement and make a payment to the counter-party (i.e., the developer). SCE contends that since these contingent contracts would be very heterogeneous, "a competitive solicitation will not be conducive for selecting and contracting for such a commercial arrangement."[51]

Q. Do you have concerns about SCE's proposal?

A. Yes. First, the proposal is even less clearly explained than SCE's proposal to develop contingent sites for gas-fired generation projects. While the proposal may be reasonable, it is very difficult to know since SCE's description of the option is so limited.

Second, I am concerned about how SCE proposes to pursue this product. Rather than asking bidders in its RFOs to bid on providing optional off-ramps (and the costs for SCE to exercise those off-ramps), SCE proposes to use a bilateral procurement approach for these contingent contracts. Such an approach could limit the supply of potential offers. It would also make determining the reasonableness of the option contracts very difficult.

Q. Why do you say that a bilateral approach might limit the supply of offers?

A. The success of a bilateral approach hinges on the level of effort that SCE makes to obtain a broad set of proposals. Unless SCE publicizes its efforts and is willing to accept a wide variety of proposals, it is possible that some developers might not provide SCE with an option to decide if a project is better suited for full development or as a back-up option.

[51] SCE Track 4 Testimony, p. 59, note 35.

Q. Why do you say that SCE's proposal will make it difficult to test the reasonableness of the selected offers?

A. If SCE only receives a small set of option offers, then it will have only a small sample of potential options to compare and present to the Commission and the Independent Evaluator (IE). This could put the Commission and IE in the position of having to opine on the reasonableness of SCE's actions without having an extensive set of offers to serve as comparables.

Q. What do you recommend?

A. SCE's proposal might be a reasonable approach but it requires some modification. First, in its Track 4 RFOs, SCE should allow developers to provide an option to have their projects considered as contingent development/termination options. The option should allow the developer to specify the payments that it would need in order to terminate development of its project at different points (e.g., after submitting its application for a si ting permit, after obtaining its permits, before purchasing major equipment). The scoring of the option offer should then be part of the RFO's bid evaluation. SCE's actions should be reviewed by the IE as part of the IE's evaluation of the RFOs.

C. Response to SDG&E Opening Testimony

Q. Please summarize SDG&E's testimony.

A. SDG&E, like SCE, presented studies that were slightly different than the studies presented in the CAISO's opening testimony. In addition to a scenario using gas - fired generation to mee t resource need, S DG&E examined two other scenarios: (1) a transmission upgrade scenario in which SDG&E would construct a new 500 kV Direct Current (DC) regional transmission project from Imperial Valley to SONGS Mesa and (2) a transmission upgrade scenari o in which SDG&E would construct a 500 kV Alternating Current regional transmission project from Devers substation to a new 230 kV substation in north San Diego County . SDG&E analyzed the scenarios using two different reliability criteria: (1) an N -1-1 criteria (as used by CAISO) and (2) a N -1/G-1 criteria (which SDG&E claims meets NERC and CAISO requirements). SDG&E's analysis is relatively consistent with the CAISO's when SDG&E uses the same reliability criteria. However, when SDG&E uses the N-1/G-1 reliability standard, it projects about 150 MW less need than the CAISO (when the CAISO uses the N-1-1 standard).

Table 9 presents SDG&E's modeling results (using an N-1-1 reliability criteria):

Table 9 - SDG&E Modeling Results

		Gas Generation
Scenario		(MW)
1	Conventional Generation	1,470
2	Imperial Valley-SONGS DC Line	620
3	Devers-North County AC line	820

As can be seen from the above results, SDG&E sees a potential need of between 620 and 1,470 MW, depending on whether or not a major transmission project (that SDG&E has yet to submit to the CAISO's Reliability Project Window for the 2013/2014 TPP[52]) can come online by 2022.

Based on these modeling results, SDG&E proposes an interim procurement of 500-550 MW from all sources "to account for possible growth in demand response with the characteristics needed to address local grid reliability needs."[53] Apparently, SDG&E believes that one of its proposed regional transmission projects will be approved by the CAISO, planned, permitted, granted a Certificate of Public Convenience and Necessity, and constructed by 2022.

Q. How do you respond to SDG&E's testimony?

A. There are several issues in SDG&E's testimony that require response. First, SDG&E's recommended 500-550 MW for its initial procurement is not sufficient. Second, SDG&E presents absolutely no information regarding the relative costs of its various scenarios, making it impossible to develop even an order of magnitude estimate of the cost-effectiveness of the various scenarios. I address each of these issues below.

1. SDG&E's Interim Procurement Request is too Low

Q. What is SDG&E's interim procurement request?

[52] Jontry Track 4 Testimony, p. 9.
[53] Anderson Track 4 Testimony, p. 12. This assumes that SDG&E's Pio Pico application is approved.

A. SDG&E requests approval to procure 500-550 MW of all sources as an interim procurement step. SDG&E makes this request because it realizes that gas -fired generation can take more than 7 years to develop.[54]

Q. Is this a reasonable level for procurement for SDG&E?

A. No. SDG&E's proposed procurement level assumes that a major regional transmission project will come online by 2022. If this does not occur and all of SDG&E's other assumptions are correct (e.g., both the Pio Pico and Wellhead projects are successfully developed and brought online), then SDG&E would need to procure 1,470 MW of additional capacity. If SDG&E only procures 500 - 550 MW in the Phase 1, Track 4 solicitation, then SDG&E would still have a resource need of 920 – 970 MW.[55]

Q. What are your concerns regarding SDG&E's Transmission Proposal.

A. While SDG&E has been successful at developing major transmission projects in the past, it is far from clear that it will be successful with these projects given the time constraints. The proposed DC line from Imperial Valley to SONGS Mesa would almost certainly run into similar opposition and challenges that the Sunrise Powerlink faced during siting and construction. However, unlike the Sunrise Powerlink, this DC line would have to avoid the Sunrise Powerlink, meaning that it might be necessary to find a new corridor for the DC line. Given the difficulties in finding an acceptable corridor for Sunrise, this could prove very challenging. In addition, the western end of the Sunrise Powerlink faced very stiff opposition

[54] Anderson Track 4 Testimony, p. 16.
[55] 920 MW = 1,470 MW – 550 MW; 970 MW = 1,470 MW – 500 MW.

from local community groups and, as a result, that final link was not part of the approved project. It is certainly possible that the DC line would face similar types of opposition, especially in regions that are relatively built up.

It is possible that the AC line from Devers to the North County substation might face less opposition. However, routing to the west from the Devers substation has been a challenge, as was seen when the Devers-Palo Verde 2 line ran into challenges when trying to gain approval for routing across the Morongo tribal lands.[56] Assuming that the AC line is constructed, SDG&E's own analysis shows that it needs 820 MW of additional generation by 2022. Thus, SDG&E's proposed 500-550 MW interim procurement would be about 300 MW short of SDG&E's own estimate of need.

Q. What do you recommend?

A. The Commission should authorize an interim procurement of 820 MW for SDG&E.[57] This is the level of need identified by SDG&E using the CAISO's reliability criteria and assuming that the Devers-North County regional transmission project comes online. This is the appropriate level of procurement based on the CAISO's reliability standards. If the Commission does not authorize SDG&E's Pio Pico application or there are problems with the Wellhead project, then the Commission should increase SDG&E's interim procurement.

[56] After 5 years of negotiations, SCE and the Morongo Band finally reached agreement on a route. However, it appears clear that SCE plans to use that route for its proposed West of Devers upgrades.
[57] Jontry Track 4 Testimony, p. 11.

It is important to note that the recommended level of procurement would not be sufficient if SDG&E fails to get any major transmission projects online by 2022. If the CAISO determines in its 2013/2014 TPP that neither of the transmission projects should be pursued, then the Commission should immediately increase SDG&E's procurement level to approximately 1,470 MW.

Q. How should these resources be procured?

A. As part of Track 4, Phase 1, SDG&E should be authorized to conduct an initial "all-source" solicitation for 820 MW in mid-2014.

Q. **Do you have any other suggestions regarding how these resources should be procured?**

A. Yes. Similar to IEP's recommendations regarding SCE's interim Track 4 procurement, SDG&E should plan to conduct a Track 4, Phase 2 procurement. The Track 4, Phase 2 interim procurement would reflect any additional need for SDG&E determined by the Commission based on updated TPP studies from the CAISO (expected first quarter 2014).

2. SDG&E Should Supplement its Proposal With Cost Data

Q. Has SDG&E presented any cost data associated with the various scenarios that it presented in its opening testimony?

A. No. Unlike SCE, SDG&E did not provide any sort of estimate of the cost of each of its scenarios.

Q. What do you recommend?

A. As part of Track 4, Phase 1, the Commission should order SDG&E to supplement its testimony to provide indicative estimates of the net costs of its different scenarios. Without this information, the Commission cannot make a rational decision about the level of interim procurement that is reasonable. This is especially important since SDG&E's entire interim procurement strategy hinges on the approval of a major regional transmission project that would likely cost billions of dollars.

IV. Conclusion

Q. Does this conclude your opening testimony?

A. Yes.

Table of Attachments

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Attachment D: California Energy Commission, *Adopted Energy Demand Forecast Report 2012-2022,* Mid-Form 1.4, "Peak Demand (MW)," Updated November 6, 2012.

Attachment E: California Energy Commission, *Adopted Energy Demand Forecast Report 2012-2022*, Mid-Form 1.5b, "1 in 2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)," Updated November 6, 2012.

Attachment F: California Energy Commission, "Energy Action Plan II," September 21, 2005.

Attachment G: E3, "Renewable Energy Flexibility (REFLEX) Results," presented August 26, 2013.

Attachment H: California Independent System Operator, *Consideration of Alternatives to Transmission or Conventional Generation to Address Local Needs in the Transmission Planning Process*, September 4, 2013.

Attachment I: California Public Utilities Commission Transmission and Environmental Planning Team, "General Information on Permitting Electric Transmission Projects at the California Public Utilities Commission," presented June 2009.

Attachment J: Southern California Edison, "Local Capacity Requirements ('LCR') RFO," issued September 12, 2013.

Attachment K: Edward Randolph (CPUC), Sylvia Bender (CEC), and Phil Pettingill (CAISO), "Southern California Reliability: Preliminary Plan," presented September 9, 2013.

Attachment A: Resume of William A. Monsen

WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1989 - Present)

Specialist in electric utility generation planning, resource auctions, demand-side management policy, power market simulation, power project evaluation, and evaluation of energy cost management options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory efforts pertaining to utility mergers, independent or merchant power, renewable energy resources, and wholesale or retail electric prices; analysis of markets for non-utility generator power in the western U.S., China, and Korea; evaluation of the cost-effectiveness of onsite power generation options; advising large commercial and industrial customers on energy management and cost-reduction options; analysis of the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM; and negotiating non-utility generator power sales contract terms with utilities.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)

Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)

Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

Masters, Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.

Attachment B: M. Jaske, “Overview of Southern California Electricity Infrastructure Issues,” presented July 15, 2013.

Overview of Southern California Electricity Infrastructure Issues

Joint CEC/CPUC Workshop

Los Angeles

July 15, 2013

Michael R. Jaske, PhD
California Energy Commission
Electricity Supply Analysis Division
Mike.Jaske@energy.ca.gov / 916-654-4777

Unique Influence of SONGS

- Located within local reliability area
- Integral to system stability at the interface between SCE and SDG&E systems; especially voltage instability
- SONGS retirement has greater impacts on SDG&E and southern Orange County than SCE as a whole
- Produced baseload energy with an average 82% annual capacity factor for 2001-2011

Attachment C: Christopher Arns, “U.S. Economy Somewhat Stagnant, but California, Not So Much,” August 1, 2013.

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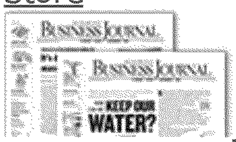
- 

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Aug 1, 2013, 9:59am PDT

U.S. economy somewhat stagnant, but California, not so much

Christopher Arns
Staff Writer- *Sacramento Business Journal*

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Wednesday was a decent day for the nation's economy on a couple of fronts, although California probably wasn't affected.

For starters, the nation's GDP expanded by 1.7 percent in the second quarter according to the U.S. Commerce Department's Bureau of Economic Analysis, beating some economist expectations. The Federal Reserve also promised to keep its $85 billion monthly bond-buying program — part of a strategy known as quantitative easing — to continue stimulating the economy for the near future, according to the Wall Street Journal.

The new data doesn't necessarily mean much for California's economy. Different reports have already forecasted the Golden State's gross state product will grow 3 percent this year and 4 percent in 2014. Both numbers would significantly outperform U.S. output.

Sacramento's regional economy probably also won't be affected. Two different sources indicate continued economic recovery for the area over the upcoming year. The Center for Strategic Economic Research, a local think tank, forecasts increased job growth by September in the center's quarterly review of the regional economy. The Sacramento Business Review also released a report this week predicting continued recovery and better economic performance for the area next year.

For anyone doing business outside of California, there was some concern amidst the good news: the Commerce Department revised first quarter growth down from 1.8 percent to 1.1 percent. According to the Wall Street Journal, anything less than 2 percent growth for two consecutive quarters usually means recession is on the way. The U.S. economy has now grown less than that number for three straight quarters.

In the story, posted before the Commerce Department released the GDP numbers, the Journal reported that some economists think the United States economy's growth in the second quarter would fall to 0.9 percent. It had described the nation as stuck in "stall speed."

Christopher Arns covers state legislation, regulation and contracts, as well as economic news, international trade and economic development for the Sacramento Business Journal.

Related links:

California, Economic Snapshot

Industries:

Banking & Financial Services, Manufacturing

Attachment D: California Energy Commission, *Adopted Energy Demand Forecast Report 2012-2022,* Mid-Form 1.4, "Peak Demand (MW)," Updated November 6, 2012.

Form 1.4 - STATEWIDE

California Energy Demand 2012-2022 Staff Final Forecast - Mid Demand Case

Peak Demand (MW)

Year	Total End Use Load	Net Losses	Gross Generation	Non-PV Self Generation	PV	Total Private Supply	Net Peak Demand	Load Factor (%)
2000	50,803	4,346	55,149	1,445	3	1,449	53,700	58.15
2001	47,353	4,035	51,388	1,490	6	1,496	49,892	59.53
2002	50,567	4,298	54,866	1,711	13	1,725	53,141	56.95
2003	52,560	4,451	57,011	1,813	27	1,840	55,170	56.15
2004	53,552	4,530	58,082	1,835	45	1,880	56,201	57.01
2005	55,796	4,718	60,513	1,857	66	1,923	58,591	54.89
2006	60,926	5,189	66,116	1,862	92	1,954	64,162	51.74
2007	59,885	5,076	64,961	1,860	128	1,988	62,973	53.70
2008	58,809	4,995	63,805	1,923	200	2,123	61,681	54.82
2009	56,200	4,738	60,938	1,867	300	2,167	58,771	55.73
2010	59,865	5,046	64,911	1,937	411	2,348	62,564	51.38
2011	57,993	4,865	62,858	1,953	595	2,548	60,310	54.12
2012	59,570	4,985	64,555	1,998	762	2,760	61,796	53.36
2013	60,962	5,105	66,067	2,001	796	2,797	63,270	52.71
2014	61,871	5,179	67,051	2,004	855	2,860	64,191	52.58
2015	62,742	5,248	67,990	2,008	946	2,954	65,036	52.51
2016	63,668	5,319	68,987	2,011	1,063	3,074	65,913	52.43
2017	64,490	5,390	69,880	2,013	1,074	3,087	66,792	52.34
2018	65,298	5,459	70,757	2,017	1,098	3,116	67,641	52.24
2019	66,178	5,532	71,710	2,024	1,139	3,163	68,548	52.24
2020	67,068	5,603	72,671	2,034	1,218	3,253	69,418	52.24
2021	67,915	5,667	73,582	2,049	1,327	3,376	70,206	52.26
2022	68,763	5,727	74,490	2,070	1,475	3,544	70,946	52.30

Last historic year is 2011.

Attachment E: California Energy Commission, *Adopted Energy Demand Forecast Report 2012-2022*, Mid-Form 1.5b, "1 in 2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)," Updated November 6, 2012.

Form 1.5b - Statewide
Final California Energy Demand Forecast, 2012 - 2022
1 in 2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	CCSF	128	131	135	137	140	142	143	145	146	147	148	148
	NCPA - Greater Bay Area	229	235	240	244	248	252	256	259	262	264	267	268
	Other NP15 LSEs - Bay Area	3	3	3	3	3	3	3	3	3	3	3	4
	PG&E Service Area - Greater Bay Area	7,652	7,836	8,025	8,143	8,254	8,366	8,473	8,576	8,690	8,801	8,904	8,999
	Silicon Valley Power	436	446	457	465	472	477	483	488	491	494	496	496
Greater Bay Area Subtotal		8,448	8,651	8,860	8,992	9,117	9,240	9,357	9,470	9,591	9,710	9,818	9,916
	CDWR-N*	234	234	234	234	234	234	234	234	234	234	234	234
	NCPA - Non Bay Area	217	223	227	231	234	237	240	243	246	249	251	253
	Other NP15 LSEs - Non Bay Area	84	86	88	89	90	92	93	94	95	96	97	96
	PG&E Service Area - Non Bay Area	9,175	9,396	9,621	9,763	9,897	10,030	10,158	10,282	10,419	10,552	10,675	10,790
	WAPA	227	233	237	241	244	247	249	251	253	254	255	255
Total North of Path 15		18,385	18,822	19,268	19,551	19,816	20,078	20,331	20,573	20,837	21,095	21,329	21,545
	CDWR-ZP26*	279	279	279	279	279	279	279	279	279	279	279	279
	PG&E Service Area - ZP26	2,202	2,255	2,309	2,344	2,376	2,408	2,439	2,469	2,502	2,533	2,563	2,591
Total Zone Path 26		2,482	2,534	2,588	2,623	2,655	2,687	2,718	2,748	2,781	2,813	2,842	2,870
Total Valley		12,418	12,705	12,996	13,181	13,353	13,526	13,692	13,851	14,026	14,198	14,353	14,499
Total North of Path 26		20,867	21,356	21,857	22,174	22,471	22,765	23,049	23,321	23,617	23,907	24,171	24,415
	Merced	83	85	87	89	90	91	92	93	93	94	94	93
	Turlock Irrigation District	481	492	504	510	517	522	528	534	540	546	551	555

Balancing Authority	Agency	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Turlock Irrigation District Control Area		564	577	591	599	607	613	619	626	633	640	645	648
	City of Shasta Lake	19	20	20	21	21	21	21	21	21	21	21	21
	Modesto Irrigation District	626	641	656	666	674	681	689	696	704	712	718	723
	Redding	227	233	237	241	244	248	252	255	260	263	267	270
	Roseville	325	333	341	346	351	355	360	365	370	374	378	381
	SMUD	3,024	3,096	3,170	3,213	3,255	3,302	3,345	3,384	3,427	3,467	3,505	3,540
	WAPA (SMUD)	189	193	198	202	205	208	210	212	214	216	216	217
Total SMUD/WAPA Control Area		4,409	4,517	4,622	4,690	4,750	4,814	4,877	4,933	4,995	5,053	5,105	5,152
	Anaheim	554	568	582	591	598	606	614	623	631	636	641	646
	MWD	21	21	21	21	21	21	21	21	21	21	21	21
	Other SP15 LSEs - LA Basin	267	273	280	284	287	291	295	299	303	307	310	313
	Pasadena	287	295	302	305	308	311	314	316	320	324	327	330
	Riverside	545	560	573	581	587	596	604	614	623	630	637	643
	SCE Service Area - LA Basin	16,105	16,524	16,921	17,161	17,378	17,613	17,851	18,085	18,328	18,558	18,775	18,972
	Vernon	162	166	170	174	176	176	177	177	177	177	175	174
LA Basin Subtotal		17,941	18,407	18,848	19,116	19,355	19,614	19,876	20,135	20,402	20,653	20,886	21,098
	CDWR-S*	374	374	374	374	374	374	374	374	374	374	374	374
	SCE Service Area - Big Creek Ventura	3,236	3,320	3,400	3,449	3,492	3,540	3,588	3,635	3,683	3,729	3,773	3,813
Big Creek/Ventura Subtotal		3,610	3,694	3,774	3,823	3,866	3,914	3,961	4,009	4,057	4,103	4,147	4,186
	MWD	210	210	210	209	209	209	210	211	212	211	211	211
	Other SP15 LSEs - Out of LA Basin	9	10	10	10	11	11	11	11	11	11	11	10
	SCE Service Area - Out of LA Basin	671	689	705	714	724	733	743	753	763	773	782	789
Total SCE TAC Area		22,442	23,009	23,548	23,872	24,165	24,480	24,802	25,118	25,445	25,752	26,037	26,294

Balancing Authority	Agency	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SDG&E Service Area		4,435	4,560	4,685	4,776	4,865	4,962	5,068	5,167	5,265	5,359	5,450	5,536
Total South of Path 26		26,877	27,569	28,232	28,647	29,030	29,442	29,870	30,285	30,710	31,111	31,487	31,830
	Burbank	312	319	327	331	336	340	344	348	352	357	361	364
	Glendale	340	349	357	363	367	372	377	382	387	392	398	404
	LADWP	5,946	6,084	6,230	6,315	6,386	6,460	6,532	6,604	6,690	6,774	6,856	6,937
Total LADWP Control Area		6,598	6,752	6,914	7,009	7,090	7,172	7,253	7,334	7,429	7,524	7,615	7,705
Imperial Irrigation District Control Area		995	1,025	1,054	1,071	1,088	1,106	1,123	1,142	1,162	1,184	1,183	1,196
Total CAISO Noncoincident Peak		47,743	48,925	50,089	50,821	51,501	52,208	52,919	53,606	54,328	55,019	55,658	56,245
Total CAISO Coincident Peak		46,597	47,751	48,887	49,601	50,264	50,955	51,649	52,320	53,024	53,698	54,323	54,895
Total Statewide Noncoincident Peak		60,310	61,796	63,270	64,191	65,036	65,913	66,792	67,641	68,548	69,418	70,206	70,946
Total Statewide Coincident Peak		58,863	60,313	61,752	62,651	63,475	64,331	65,189	66,018	66,902	67,752	68,521	69,243

* Entries for California Department of Water Resources are estimated actual peaks. Staff provides slightly higher short-run tot als for California ISO/CPUC Resource Adequacy proceec

Table only developed for the mid case. Table developed based on weather-adjusted 2011 peak estimates

Attachment F: California Energy Commission, "Energy Action Plan II," September 21, 2005.

STATE OF CALIFORNIA

ENERGY COMMISSION

PUBLIC UTILITIES COMMISSION

ENERGY ACTION PLAN II

IMPLEMENTATION ROADMAP FOR ENERGY POLICIES

September 21, 2005

I. INTRODUCTION AND SUMMARY

In 2003, the three key energy agencies in California – the California Energy Commission (CEC), the California Power Authority (CPA), and the California Public Utilities Commission (CPUC) – came together in a spirit of unprecedented cooperation to adopt an "Energy Action Plan" (EAP)[1] that listed joint goals for California's energy future and set forth a commitment to achieve these goals through specific actions.

The EAP was a living document meant to change with time, experience, and need. The CPUC and the CEC have jointly prepared this Energy Action Plan II to identify the further actions necessary to meet California's future energy needs.[2] EAP II supports and expands the commitment to cooperation among state agencies embodied in the original EAP and reflected in the State's coordinated actions over the past two years. The development of EAP II has benefited from the active participation of the Business, Transportation, and Housing Agency, the Resources Agency, the State and Consumer Services Agency, the California Independent System Operator (CAISO), the California Environmental Protection Agency (Cal EPA), and other agencies with energy-related responsibilities.

EAP II describes a coordinated implementation plan for state energy policies that have been articulated through the Governor's Executive Orders, instructions to agencies, public positions, and appointees' statements; the CEC's Integrated Energy Policy Report (IEPR); CPUC and CEC processes; the agencies' policy forums; and legislative direction. This document also is intended to be consistent with the energy policies embodied in the Governor's August 23, 2005, response to the 2003 and 2004 IEPRs.[3] We expect to update or revise this action plan to reflect any changes needed to further implement the Governor's 2004 IEPR response, future energy policies, and decisions related to the forthcoming 2005 IEPR, as well as other relevant events that may arise in the future.

In preparing EAP II, we do not assume that work undertaken in EAP I is complete or, conversely, to dismiss the accomplishments to date of EAP I. Rather, EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I. Appendix A provides a status report on the progress of the EAP I activities to date.

Our overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. Energy must be reliable – provided when and where needed and with minimal environmental risks and impacts. Energy must be affordable to

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[1] EAP I can be viewed at the CPUC's website at <http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm> or at the CEC's website at <http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF>.

[2] The Consumer Power and Conservation Financing Authority was a co-agency in EAP I. Funding for the agency was eliminated in SB 1113 (Chesbro) Chapter 208, the 2004-2005 budget. No additional funding is proposed in the Governor's 2005-2006 budget.

[3] Governor Schwarzenegger's "Review of Major Integrated Energy Policy Report Recommendations" in his August 23, 2005, letter to Senator Don Perata, President pro tempore of the California State Senate.

households, businesses and industry, and motorists – and in particular to disadvantaged customers who rely on us to ensure that they can afford this fundamental commodity. Our actions must be taken with clear recognition of cost considerations and trade-offs to ensure reasonably priced energy for all Californians. We need to develop and tap advanced technologies to achieve these goals of reliability, affordability and an environmentally-sound energy future. These goals affirm the original objectives of EAP I.

The State will achieve these goals by taking specific and measurable actions throughout California's energy sector. To do this we have expanded the scope of the EAP. The fuels used in the transportation of California's goods and population constitute a third energy sector, in addition to electricity and natural gas. We have incorporated into EAP II specific actions reflecting the importance of transportation fuels to California's economy and the need to mitigate the environmental impacts caused by their use. EAP II further expands the scope of the original EAP to describe research, development and demonstration activities that are critical to realizing our energy goals. In addition, EAP II highlights the importance of taking actions in the near term to mitigate California's contributions to climate change from the electricity, natural gas and transportation sectors.

EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.

We also see the need to provide open, transparent, and compelling information and education to all stakeholders and consumers in the State. The agencies are committed to providing more effective information dissemination through increased cooperation among all branches of government, businesses, and energy organizations. In particular, we pledge to remove the remaining barriers to transparency in the electricity resource procurement processes in the State and to increase outreach to consumers by providing improved education and services regarding energy efficiency, demand response, rates, climate change, and opportunities to reduce the environmental impacts of energy use.

The EAP II is intended as an implementation roadmap for the entire State. While some of the electricity and natural gas actions are described in the context of the investor-owned utilities, in general they should be seen as applying equally to all load serving entities, such as customer-owned utilities and energy service providers.

Once this new EAP is adopted, our next step will be to prepare a workplan that ascribes responsibility for each of these key action items, determines the specific roles that will be played by each agency, and develops a timeline that ensures the agencies' prompt attention.

Attachment G: E3, "Renewable Energy Flexibility (REFLEX) Results," presented August 26, 2013.

Energy+Environmental Economics

Renewable Energy Flexibility (REFLEX) Results

CPUC Workshop

August 26, 2013

Scope of E3 Work

+ **Investigate flexibility and capacity needs using REFLEX for PLEXOS and other tools**
+ **2012 Historical Case**
  - 2012 Loads and Renewables
  - Test and refine REFLEX model
+ **TPP/Commercial Interest Case**
  - Develop multi-year datasets with the same build assumptions as the deterministic case
  - Define probabilistic context for CAISO deterministic case
  - Test the need for flexible capacity and determine the value of operational solutions like economic pre-curtailment

Cost Penalties Assumed for Flexibility Violations

+ **Relative cost penalties impose flexibility mitigation strategy "loading order"**

Hourly Violation Penalties

Type of Violation	Test Run Value	Best estimate of final value
Unserved Energy	$100,000/MWh	$40,000/MWh
Overgeneration	$2,000,000/MWh	Linked closely to curtailment cost
Curtailment Cost	Hard constraint	**$250/MWh**; Replace lost revenues
Spinning reserves	Hard constraint	Hard constraint

Intra-hourly Violation Penalties

Type of violation	Test Run Value	Best estimate of final value
Upward Ramping Violation	$10,000/MWh	$1,000/MWh; highly dependent on the degree of shortage experienced
Downward Ramping Violation	$10,000/MWh	**$200/MWh**; Could result in need for curtailment
Insufficient Regulation	$10,000/MW	$1,000/MW; insufficient regulation likely results in CPS violations

Attachment H: California Independent System Operator, *Consideration of Alternatives to Transmission or Conventional Generation to Address Local Needs in the Transmission Planning Process*, September 4, 2013.

Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process

September 4, 2013

Table of Contents

Consideration of alternatives to transmission or conventional generation to address local needs in the Transmission Planning Process

1 Executive summary

In this paper the ISO is presenting a methodology it has developed to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. In addition to developing a methodology to be applied annually in the transmission planning process ("TPP"), this paper also describes how the ISO will apply the proposed methodology in the current (2013-2014) transmission planning cycle. In so doing, this initiative carries out an activity identified in the ISO's draft demand response and energy efficiency roadmap published on June 12.

The approach proposed in this paper will improve upon the ISO's past approach to considering non-conventional solutions, which was very labor-intensive, was reactive to specific proposals, and did not provide any criteria for such alternatives in advance that could serve as guidance to prospective developers of such proposals.

The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan rather than the transmission or generation solution that would be avoided by implementing the non-conventional solution. This would be possible in situations where the timeline for an identified need allows time for monitoring the development of non-conventional alternatives before a conventional solution would be required to be approved. For a grid area where the ISO finds a non-conventional solution to be effective, this new approach will result in a validated non-conventional resource mix that would be selected as the preferred solution in the ISO's draft transmission plan (posted in January of any given TPP cycle), alongside the transmission or conventional generation solution that would be avoided or deferred by implementing the non-conventional solution. Once the comprehensive transmission plan, which includes identification of both the non-conventional solution and the transmission or conventional generation solution that could be avoided or deferred, is approved by the ISO Governing Board, the ISO would monitor the development of the resources that comprise the non-conventional solution to determine whether they will be in operation by the time they are needed. If the ISO determines that the non-conventional resource mix is not developing in a timely manner, then the ISO would consider whether to reinstate the avoided transmission solution or another appropriate alternative in a subsequent TPP cycle. That is how the ISO envisions this methodology being applied in general.

In the current cycle of the 2013-2014 transmission planning process, the ISO proposes to apply this new approach to several specific local areas in southern California: LA Basin, San Diego, and to a lesser extent the Moorpark subarea of the Big Creek/Ventura area. Although the application of this methodology may be relatively straight forward for the Moorpark subarea, the main focus will be on the LA Basin and San Diego where the application of the methodology will be somewhat different in this cycle. Because of the magnitude of the projected reliability needs in the LA Basin and San Diego, transmission options will be pursued to complement non-conventional alternatives (i.e., preferred resources), to reduce the need for conventional generation to fill the gap. Thus, unlike the generic application of the methodology in future transmission planning process cycles where preferred resources are considered as an alternative to transmission, the main focus of this effort with respect to the LA Basin and San Diego is to identify the volume of non-conventional alternatives and the needed performance attributes that could effectively address the local reliability needs in these two priority areas as part of a basket of resources. This information can then inform any CPUC decisions on authorizing procurement of additional preferred resources in these areas and ultimately inform the procurement activities of Southern California Edison and San Diego Gas & Electric. The 2013-14 transmission planning process will also be evaluating various transmission options for addressing the reliability needs of the LA Basin and San Diego areas and potentially recommending certain options for ISO Board approval. The ISO will plan to coordinate this transmission evaluation effort with the ongoing CPUC 2012 LTPP Track 4 proceeding.

Following the release of this paper, the ISO intends to hold a stakeholder web conference on September 18 to discuss the proposed methodology and obtain initial stakeholder feedback. The application of the methodology will be further discussed at the ISO's TPP stakeholder session scheduled on September 25th and 26th.

2 Introduction

To maintain a reliable transmission system that meets NERC and WECC reliability standards, the ISO annually assesses the needs of the transmission system as part of its Transmission Planning Process ("TPP"). As inputs to the studies the ISO relies on the CEC 10-year electricity demand forecast which incorporates energy efficiency programs, and behind the customer load meter distributed generation. Generation under construction is also modeled in the study base cases. These studies assess both system and local needs. The ISO then develops mitigation plans identifying specific solutions to satisfy the reliability standards. Historically, these mitigation plans have predominantly consisted of transmission upgrades and, in situations where planned development

Attachment I: California Public Utilities Commission Transmission and Environmental Planning Team, “General Information on Permitting Electric Transmission Projects at the California Public Utilities Commission,” presented June 2009.

General Information on Permitting Electric Transmission Projects at the California Public Utilities Commission

June 2009

Presentation created by the
Transmission and Environmental Permitting Team

Time Frame to Plan, Permit, and Construct a Transmission Line

Planning	Permitting	Construction
3 to 4 years	3 to 4 years	1 to 5 years

- **Planning includes the IOU evaluating and identifying transmission lines that need to be upgraded or constructed, and putting a plan together for CAISO evaluation and approval.**
- **Permitting includes 1 to 2 years for the IOU to prepare a** Proponent's Environmental Assessment (PEA) and **application. Average time for CPUC decision is 18 months (includes permits from Resource Agencies).**
- **Construction of all segments of Tehachapi will take approximately 5 years. Average construction time is approximately 1 to 2 years.**

Attachment J: Southern California Edison, "Local Capacity Requirements ('LCR') RFO," issued September 12, 2013.

Energy Procurement
Local Capacity Requirements ("LCR") RFO
Energy Supply & Management Power and Gas
ES&M Energy Auction
Renewable & Alternative Power Contract Opportunities
RFP for Independent Evaluators
Cost Allocation Mechanism Group
Procurement Review Group
RFP

Home > Energy Procurement > Local Capacity Requirements ("LCR") RFO

Local Capacity Requirements ("LCR") RFO

In accordance with California Public Utilities Commission ("CPUC") Decision ("D.") 13-02-015, Southern California Edison Company ("SCE") issues this Local Capacity Requirements Request for Offers ("LCR RFO") for incremental capacity in the West LA Basin and Moorpark Sub-Areas. Products solicited include:

- Gas Fired Generation
- Combined Heat and Power
- Demand Response
- Energy Efficiency
- Energy Storage
- Renewable
- Resource Adequacy
- Distributed Generation

D.13-02-015 authorizing the procurement is attached below:

D.13-02-15 Authorizing Long Term Procurement for Local Capacity Requirements (PDF)

SCE's Procurement Plan submitted to Energy Division pursuant to D. 13-02-015 is attached below:

Track I SCE LCR Procurement Plan Pursuant to D.13-02-15 (PDF)

LCR RFO Schedule

Timeline	Event
September 12, 2013	RFO documents issued
December 2, 2013 5:00 PM Pacific Prevailing Time	Deadline to submit Non-binding Notice of Intent to Offer
December 16, 2013 5:00 PM Pacific Prevailing Time	Deadline to submit Indicative Offer and completed Offer Submittal Package
January 30, 2014	Shortlist notification
May 22, 2014	Deadline to complete negotiations of Agreement(s)
May 29, 2014 5:00 PM Pacific Prevailing Time	Deadline to submit Final Offer
June 26, 2014	Last date for notification of successful Offers and to sign Agreements

LCR RFO Materials

Document	Description
Transmittal Letter	RFO products solicited, eligibility requirements, process, offer evaluation
Offer Sheet	Bidder submitted document which includes Seller and project information
CEC's California Power Plants Database	List of CEC recognized power plants
CEC's Energy Facility Status Report	List of current and historical facilities in the CEC approval process
Notice of Intent	Non-binding indication of products that Bidder intends to submit offers for
RFO Definitions	Definitions of various terms used in LCR RFO Materials
Gas Fired Power Purchase Agreement	SCE's form of Power Purchase Agreement for gas fired projects
Gas Fired Power Purchase Agreement	Excel appendix to complement SCE's form of Power Purchase

Excel Appendix*	Agreement for gas fired projects
CHP Power Purchase Agreement	SCE's form of Power Purchase Agreement for combined heat and power projects
CHP Power Purchase Agreement Excel Appendix*	Excel appendix to complement SCE's form of Power Purchase Agreement for combined heat and power projects
Demand Response Agreement	SCE's form of Agreement for demand response projects
Demand Response Agreement Excel Appendix*	Excel appendix to complement SCE's form of Agreement for demand response projects
Energy Efficiency Agreement	SCE's form of Agreement for energy efficiency projects
Energy Efficiency Agreement Excel Appendix*	Excel appendix to complement SCE's form of Agreement for energy efficiency projects
Energy Storage Agreement	SCE's form of Agreement for energy storage projects
Energy Storage Agreement Excel Appendix*	Excel appendix to complement SCE's form of Agreement for energy storage projects
Renewable Power Purchase Agreement	SCE's form of Power Purchase Agreement for renewable projects
Renewable Power Purchase Agreement Excel Appendix*	Excel appendix to complement SCE's form of Power Purchase Agreement for renewable projects
Resource Adequacy Power Purchase Agreement	SCE's form of Power Purchase Agreement for resource adequacy projects
Resource Adequacy Power Purchase Agreement Excel Appendix*	Excel appendix to complement SCE's form of Power Purchase Agreement for resource adequacy projects
Distributed Generation Power Purchase Agreement Excel Appendix*	Excel appendix to complement SCE's form of Power Purchase Agreement for distributed generation projects

**Product Excel Appendices are currently provided in .pdf format. Editable files in .xls format will be provided when they are available.*

Should you have questions regarding the LCR RFO:

Please email LCR.RFO@sce.com or contact
Gene Lee (626) 302-3081
Jesse Bryson (626) 302-3297

In accordance with D.06-05-039, SCE has retained an Independent Evaluator to oversee the preparation and administration of the LCR RFO. The Independent Evaluator must be copied on all correspondences sent by bidders to SCE, including and especially any official submittals. Sedway Consulting, Inc. is the Independent Evaluator and can be contacted at Alan.Taylor@sedwayconsulting.com.

At SCE's discretion, answers to any questions posed to SCE will be posted on a LCR RFO "Frequently Asked Questions" page.

A LCR RFO Bidder's Conference will be scheduled shortly, date and venue to be determined. Conference information, as well as other information or updates, will be posted to this website as available.

Attachment K: Edward Randolph (CPUC), Sylvia Bender (CEC), and Phil Pettingill (CAISO), “Southern California Reliability: Preliminary Plan,” presented 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

6-Month Permitting Process

- Explicit CEC statute authority dates from 2001
- Possible that current CEC authority would allow if same screening criteria being used:
  - Comply with all legal requirements
  - No public health or safety concerns
  - No significant adverse environmental impacts
  - No adverse impacts on electrical system
  - Little or no public controversy
  - Site control
- Would require flexibility within licensing rules and development time frames, but could shorten lead times to operation
  - Previous 100-day determination requirement by local agencies no longer in force

Contingency Permitting Process

- Use CEC's Notice of Intention process to approve potential sites ahead of actual applications
- As resource needs identified and authorized, sites available for a competitive solicitation process
- SDG&E Energy Park and SCE high value reliability sites are possible examples