BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

THE DIVISION OF RATEPAYER ADVOCATES' OPENING BRIEF ON TRACK I AND TRACK III ISSUES

[PUBLIC VERSION]

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TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

CPUC Decisions

Statutes

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

The Division of Ratepayer Advocates (DRA) submits this Opening Brief following the hearings on Track I and III issues held on August 11 through 30, 2011. This brief will also address the Settlement Agreement submitted for approval in this proceeding on August 3, 2011. This brief is timely submitted in accordance with the schedule established by Administrative Law Judge Peter Allen at the conclusion of the hearings.

DRA requests that the Commission adopt the recommendations made by DRA in this opening brief, which are summarized as follows:

1. The Commission should approve and adopt the Settlement Agreement entered into by most parties in this proceeding.
2. SDG&E's request for procurement authority should be denied.
3. The Commission should not adopt Calpine's proposal to require the IOUs to procure.
    1. GHG Issues
        a. The Commission should authorize the IOUs to begin procuring GHG allowances and offsets when the ARB cap-and-trade regulations are final.
        b. The Commission should require the IOUs' GHG procurement plans to address contract evaluation issues related to GHG cost exposure and GHG compliance responsibilities, or require the IOUs to identify specifically where these matters are addressed in their long term procurement plans.
        c. The Commission should require that the IOUs provide in the next LTPP cycle an analysis that captures the effects of reducing GHG emissions (as opposed to simply purchasing GHG allowances and offsets each year).
        d. The Commission should adopt the upfront standards for procurement of GHG products proposed by each IOU, with DRA's recommended limitation of SCE's proposed forward transaction limits in years 2012 and 2013.
        e. The Commission should allow the IOUs to procure GHG offsets up to the eight percent limit allowed by ARB, on the condition that any purchase of offsets is confined to those explicitly

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allowed under the ARB regulation at the time of purchase, or that include a seller guarantee.

f. The Commission should require each IOU to report all of its GHG market transactions for at least the first year of GHG procurement.

g. The Commission should review the IOUs' GHG procurement activities after the first year to determine whether the upfront standards should be modified.

h. The market-sensitive information in the IOU's GHG procurement plans should be kept confidential.

5. OTC Issues

   a) The Commission should not adopt the staff proposal for a one year limitation on IOU contracts with once through cooling facilities, and should streamline the existing proposal for greater clarity.

6. Rules Governing IOU Procurement

   a) The Commission should adopt DRA's proposal to eliminate conflicts of interest for Independent Evaluators by having the Energy Division contract with and manage the Independent Evaluators.

   b) Either Energy Division, or the IOU's Procurement Review Group, should determine the assigned Independent Evaluators, not the IOUs themselves.

   c) The Commission should adopt DRA's recommendation that all UOG opportunities for both fossil fuel and preferred resources be tested through the competitive solicitation/RFO process. The following measures will help "level the playing field" when comparing independently owned generation (PPAs) with UOG:

      i) For purposes of comparing costs, assume the same amortization period for UOG projects and PPAs;

      ii) Provide additional guidance to IOUs on input assumption and forward costs curves used in UOG valuations;

      iii) Establish cost caps for capital costs and O&M for UOG projects;

      iv) Establish clear pay for performance mechanisms in UOG projects, as in PPAs;

      v) Hold shareholders responsible for financing bid development costs for UOG projects and for the bid development costs of UOG projects that are not approved and put in service.

7. The Commission should not initiate a new proceeding to consider SCE's proposal for a new generation auction run by the CAISO.

II. TRACK I ISSUES

A. The Settlement Agreement Should Be Approved

DRA is a party to the Settlement Agreement that was submitted for approval on August 3, 2011 in this proceeding. The fundamental basis for the Agreement is that "[t]here is general agreement [among the parties] that further analysis is needed before any renewable integration resource need determination is made."[1] The Settlement recommends a process and timeline for completing that analysis.

The Settlement also provides that "the Commission does not need to authorize procurement authority relating to LCR for SCE's and PG&E's service areas at this time."[2] The Settling Parties did not reach agreement on SDG&E's request for procurement authority. That issue is expressly excluded from the Settlement.

DRA supports the Settlement for the reasons stated in the motion for approval of the settlement.

B. SDG&E's Request for Procurement Authority for New Generation Should Be Denied

SDG&E seeks authorization to procure 415 MW of new generation in the 2012-2020 planning period, citing a Local Capacity Reliability (LCR) need of 180 MW in 2020.[3] SDG&E states that this request would be satisfied by Commission approval of SDG&E's separate pending application for approval of three new power plants that would provide a combined total of 450 MW (A.11-05-023).[4]

The Commission should deny SDG&E's request for procurement authority for new generation because the record shows new generation is not needed to meet LCR need during this planning period. SDG&E's need analysis using CPUC-mandated

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[1] *Motion for Expedited Suspension of Track I Schedule, and For Approval of Settlement Agreement Between [numerous parties listed]* (filed August 3, 2011), p. 4.

[2] Id.

[3] Ex. 310 (SDG&E's Prepared Track I Testimony), pp. 11-12.

[4] Id.

assumptions shows capacity exceeding its LCR need by almost 400 MW in 2020 even without the addition of 415MW of new generation requested in this LTPP, or the 450 MW requested in A.11-05-023.[5] SDG&E's case for an LCR need of 180 MW in 2020 is based on faulty and unsupported assumptions. Moreover, SDG&E has shown no basis for authorizing more than 200MW over and above the 180MW SDG&E says it needs.

1. SDG&E Has No Need For Additional Capacity During the Planning Period

Earlier in this proceeding the Commission established Standardized Planning Assumptions and selected four scenarios that achieve the potential operational and resource capacity needs driven by California's 33% renewable portfolio standards (RPS) by 2020.[6] The Commission also permitted the IOUs to perform need analyses using alternative assumptions (in addition to the CPUC-required assumptions), provided they explained how their assumptions differed and why the alternative assumptions were used.[7]

The analysis performed jointly by the IOUs and the CAISO using the four CPUC-Required Scenarios (and assumptions) resulted in findings of no need for new generation under all four scenarios.[8] The IOUs also performed an analysis using three alternative scenarios (and assumptions) (the "IOU Common Scenarios") and one extreme temperature sensitivity analysis. The results were wide ranging, from no need for new resources to 3900 MW for one of the alternative scenarios and 8700 MW of need for the

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[5] Id., Table 1, p. 5.

[6] Ex. 310 (SDG&E), p. 2; *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling* (in R.10-05-006) and Attachment 1, Standardized Planning Assumptions for System Resource Plans, Load and Resource Tables (December 3, 2010) ["Scoping Memo"], as modified by *Corrections to December 3, 2010 LTPP Scoping Memo*, (February 10, 2011); Populated L&R Tables for Required Scenarios, available at: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm.

[7] Scoping Memo, p. 38 (parties are expected to provide "justification for changes from the standardized planning assumptions"; "Parties must explain any departures from the common value assumptions.")

[8] Ex. 106 (Joint IOU Supporting Testimony), Table 3-1, on page 3-3.

extreme temperature sensitivity case.[9] The IOUs' overall conclusion was that "the analysis conducted by the CAISO and the IOUs is not robust enough to allow the CPUC to reach firm conclusions regarding future resource needs."[10]

With respect to LCR need, only SDG&E requested authorization for new generation. According to SDG&E's testimony, it has approximately 400 MW more capacity than it needs for local reliability in 2020, based on the CPUC-required "trajectory" case.[11] SDG&E stated that the results would be similar for the other CPUC-Required Scenarios.[12]

Based on the IOU Common Scenario assumptions and on SDG&E's own assumptions regarding the contribution of certain resources including energy efficiency (EE), Demand Response (DR), and new renewable resources and distributed generation, SDG&E concluded that it will have a need for 41 MW of new generation beginning in 2017 and increasing to 180 MW in 2020.[13] It requests authorization to procure this 180 MW plus a "cushion" of 235 MW, for a total of 415 MW.[14]

By relying on the Joint IOU alternative assumptions, SDG&E significantly departs from the CPUC scenarios' expectations of system load, energy efficiency (EE), demand response (DR) and availability of resources.[15] In general, the joint IOU alternative assumptions make several significant changes to the CPUC assumptions simultaneously, which makes it difficult to discern the main drivers of changes in results or assess the overall Joint IOU scenarios for realism. Further, in developing the CPUC required scenarios, the Energy Division staff invested substantial time and energy into ensuring

[9] Id.

[10] Id., p. 1-4.

[11] Ex. 310 (SDG&E), p. 4 (as corrected by SDG&E witness Robert Anderson during evidentiary hearings) and Table 1 (on p. 5).

[12] Ex. 310 (SDG&E), p. 3.

[13] Id., Table 2, p. 8.

[14] Id.., pp. 11-12.

[15] Ex. 106 (Joint IOU), pp. 5-1 through 5-24.

that its assumptions were realistic and well-aligned with Commission policies and positions. The IOU scenario assumptions have not been vetted in this way.

SDG&E has not met its burden of justifying these reduced assumptions, especially for ratepayer-funded EE and DR preferred resources. Furthermore, SDG&E also did not account for other planned, preferred resource additions including energy storage and 100 MW of planned solar photovoltaic generation (over and above the solar facilities added through the California Solar Initiative (CSI) program). Because the alternative assumptions used by SDG&E are faulty or unsupported, as discussed below, its assessment of LCR need is unreliable and the Commission should reject it.

2. SDG&E's Need Showing Is Based on Faulty and Unsupported Assumptions

a) Energy Efficiency

The CPUC-Required Scenarios assume, for SDG&E's service territory, an energy savings of 544 MW[16] from "uncommitted" EE resources by 2020 (i.e., from programs not yet funded and other measures, such as improved efficiency standards for appliances, that have not been factored in to the Energy Commission (CEC)'s load forecast and are therefore "incremental" to the load forecast adjustments for EE that the CEC has made).[17] SDG&E assumed only 284 MW in 2020.[18] As SDG&E's witness acknowledged, if the omitted EE savings were achieved, they would more than meet SDG&E's asserted 180 MW need in 2020, assuming other factors remained the same.[19]

SDG&E's much lower assumption for EE resources is unjustified and inappropriate for many reasons which are well explained in the prepared testimony of

[16] The 544 MW figure is based on the CPUC Assumptions in the Final Scoping Memo, and differs from the 598 MW assumption SDG&E used Table 1 of Ex. 310. SDG&E explained in workpapers that this figure was "grossed up to be 1-in-10 impacts." See Ex. 1600, Natural Resource Defense Council's Opening Testimony of Sierra Martinez, p. 6, fn. 26 for further explanation.

[17] Ex. 310 (SDG&E), Table 1.

[18] Ex. 310 (SDG&E), Table 2.

[19] Tr. vol. 4, p. 217:24 through p. 218:4.

Pacific Environment[20] and the Natural Resources Defense Council (NRDC)[21] and in the opening brief NRDC plans to file on September 16. DRA supports NRDC's conclusion that the energy efficiency estimate required by the Scoping Memo is the minimum amount that should be used in any scenario, because it is a conservative estimate and actual energy savings will quite likely be higher. DRA agrees that SDG&E's reduction of energy efficiency savings beyond the amount required by the ACR is unfounded.[22]

SDG&E's aggressive reduction of the Commission's EE and DR assumptions flies in the face of the Commission's EE and DR program goals, and is unfair to the ratepayers who fund these programs. EE and DR programs are of value to ratepayers to the extent they reduce the need for conventional resources, especially new power plants. If ratepayer-funded EE programs burden ratepayers with additional costs without achieving offsetting cost reductions from a reduced need for conventional resources, why should ratepayers continue to fund these IOU programs?[23]

b) Demand Response

SDG&E also reduced the DR resource assumptions by about one-third. The CPUC-Required Scenarios assume 302 MW in 2020; SDG&E assumed 219 MW.

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[20] Ex. 504 (Pacific Environment (Rory Cox)), pp. 1-6.

[21] Ex. 1600 (NRDC).

[22] Gross savings estimates (rather than net) do not necessarily impact the demand forecast, however, in this case, the CEC correctly addresses this issue by separating out "naturally occurring adoption" and "net savings." The CEC incorporates "naturally occurring adoption" into its demand forecast, while applying IOU net-savings to its incremental EE savings projections. The Scoping Memo uses IOU net-savings in its incremental EE savings projections, so NRDC correctly states that there is no need to (re-) apply the net-to-gross ratio, as SDG&E recommends. Additionally, DRA agrees with NRDC that the application of a net-to-gross ratio is further unwarranted because much of the efficiency savings are not programs at all, but rather, codes, standards, and legislation. Applying a net-to-gross ratio (derived from program data) to these other efficiency policies is illogical and would be unprecedented. See the Opening Brief of the Natural Resources Defense Council on Track I System Resource Plans (September 16, 2011).

[23] SDG&E's 2010-2012 budget for EE programs (electric only) is $223.7 million. (SDG&E Compliance Advice Letter 2127-E, Attachment C, pp. 27 (available at http://www.sdge.com/tm2/pdf/2127-E.pdf.

In 2009, The Commission approved a monthly budget of $8.17 million for SDG&E's EE programs ($97.2 million for 12 months). (D.08-10-027, Table 2, page 18, and Ordering Paragraph 1(b), p. 28. And for the 2006-2008 program cycle, SDG&E shareholders received approximately $16. 2 million in incentives for its gas and electric EE programs. (Total EE incentives for all four IOUs including SoCalGas was $211 million). See D.10-12-049, Appendix A.

SDG&E provided almost no justification for this reduction, saying only that, "the CPUC's "DR assumptions were based on early estimates of the impact of future DR programs. Subsequent filings have forecasted peak reductions that were significantly less than those included in the CPUC-scenarios."[24] The Commission should reject this alternative assumption because SDG&E has failed to meet its burden of justifying it.

c) Energy Storage

SDG&E did not include in its alternative scenario any contribution from energy storage resources, even though SDG&E has requested millions of dollars in ratepayer funding for energy storage projects that will, if approved, come online during the 2012-2020 LTPP planning period.[25]

d) Planned PV Additions

SDG&E also failed to include in its LCR analysis many distributed generation resources in the Local Area. For example, SDG&E did not account for a 100 MW photo-voltaic project that is separate from resources funded through the California Solar Initiative (CSI) and has been approved by the Commission.[26]

e) Reliance on Year-Ahead LCR Methodology

The CAISO has developed a methodology for determining the Local Capacity Requirements (LCRs) need on a year-ahead basis. The Commission relies on the CAISO's year-ahead LCR determination to set Local Resource Adequacy requirements for load-serving entities. SDG&E used the CAISO's LCR methodology to assess its LCR need for 2020, but as SDG&E's witness acknowledged, that methodology was not designed for long-term need assessments.[27] SDG&E has not justified its reliance on a tool designed for a one year-ahead need assessment to forecast need in 2020.

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[24] See Ex. 310 (SDG&E), p. 6:16-18; Tr. vol. 4 (SDG&E/Anderson), p. 227:17 through p. 229:18.

[25] Tr. vol. 4 (SDG&E/Anderson), p. 234:12 through p.237:10.

[26] Id. at p. 238.

[27] Tr. vol. 4, p. 231.

3. SDG&E's Request For A "Cushion" Over and Above its Asserted Need Is Unsupported

SDG&E's request for a "cushion" of more than 200 MW above its calculated need is mystifying. For one thing, what is a "cushion"? The Commission has established a planning reserve margin (PRM), currently 15-17% percent above forecasted need. The primary purpose of the PRM is to ensure that adequate supply is available in the event of forecast error and outages. The extra capacity required by the Commission's Resource Adequacy program also makes it more difficult for sellers to exercise market power. It is unclear to DRA what SDG&E has in mind when it speaks of a "cushion" or why the Commission should authorize SDG&E to procure new conventional generation that is not needed.

4. Setting the Record Straight About Resources That Have Come on Line Recently

In reviewing the testimony discussing how many MW have come online in SDG&E's territory in recent years, DRA finds the record unclear. SDG&E has since provided DRA with a response to a data request listing the plants that have come on line since 2006, the date each plant came on line, and the number of MW. DRA requested the same information for plant retirements. To clarify the record, DRA reproduces that information below. According to the information provided by SDG&E, since 2006, the power plants listed below have added a total of 1365 MW of capacity in San Diego's Local Area, while 706 MW have been lost due to retirements, as shown in the following table.

Resource Name-Year	New MW	Retired MW
Palomar -2006	565	
Otay Mesa-2009	604	
Miramar II-2009	48	
Orange Grove-2010	100	
Wellhead El Cajon-2010	48	
South Bay 3 & 4-2009		395
South Bay 1,2 & CT-2010		311
Total	**1365**	**706**
Source: SDG&E's September 17, 2011 Response to DRA's Data Request (No. R.10-05-006-SDG&E-005) dated August 23, 2011.		

For the reasons discussed above, the Commission should find that SDG&E has failed to justify its alternative assumptions and its LCR need assessment. The record shows that SDG&E's LCR need for 2020 is zero, based on the CPUC-Required Scenarios and assumptions. Accordingly, the Commission should deny SDG&E's request for LCR procurement authorization.

C. Calpine's Proposal Lacks Evidentiary Support

Calpine proposes that the Commission require the IOUs to procure additional capacity through an intermediate term (3 to 5 years) RFO solicitation that would include existing resources, using the existing Cost Allocation Mechanism (CAM) to allocate any procurement for system needs.[28] DRA opposes Calpine's proposal primarily because Calpine has not demonstrated that there is a problem that needs to be solved.

Calpine argues that existing resources lack a sufficient a revenue stream to recover their going forward costs and to secure the future availability of existing resources.[29] According to a Calpine estimation, 2,600 to 3,200 MWs of resources could potentially shut down due to lack of sufficient revenues, with cost implications in the high range of $3.12 billion to $5.52 billion.[30] Yet Calpine makes these claims without any proof that its resources or others are not meeting their forward costs, are unable to secure a contract, and/or at risk of retirement. At the hearings, TURN's counsel asked Calpine's witness whether Calpine was asking the Commission to take Calpine's word for its argument that current market conditions do not allow for recovery of its going forward costs. Calpine responded that such information is "commercially sensitive" and provided no further support for its position.[31] Calpine has provided no evidence to support its claim that existing California power plants are closing for economic reasons.

[28] Exh. 601, Direct Track 1 Testimony of Calpine Corporation, p. 15.

[29] Exh. 601 (Calpine Corporation), p. 2.

[30] *Ibid* at p. 13.

[31] Tr. vol. 8, p. 851. Calpine admitted that it had provided no specifics on the economics of its resources. Tr. vol. 8, p. 845; then later testified that it had provided this information to an unnamed person within the Commission's Energy Division (Tr. vol. 8 pp. 854-55.)

In fact, most of Calpine's California resources do have contracts. At hearings, Calpine could not name a single Calpine resource in the Bay Area that did not have a contract, nor could it identify any combined cycle plant in the United States that has shut down for the economic reasons that Calpine uses to justify its proposal.[32]

Furthermore, Calpine's 2010 Annual Report shows a very different picture — Calpine's stock price increased by over 20% in 2010.[33] Moreover, as Calpine acknowledges, there are regulatory initiatives underway at the CAISO that would help increase compensation for existing generation.[34] Proposals under consideration in the CAISO Renewables Integration Market and Product Review stakeholder process, and the CAISO's proposal for a new Non-Generic (Resource Adequacy) Capacity Procurement product are aimed at developing additional regulation and ancillary service products. These reforms should generate additional revenues for owners of resources that can provide the newly-defined products.

Calpine also acknowledged that the FERC recently approved the CAISO's updated Capacity Procurement Mechanism (CPM) tariff revision, which provides a new source of revenue for resources designated by the CAISO that are not needed in the RA compliance year, but will be needed for reliability in the following year. Under this new CPM category, resources designated by the CAISO will receive the CPM resource adequacy "backstop capacity" CPM price for their full capacity value for periods up to a full year.[35]

In sum, Calpine claims that existing combined cycle plants do not have enough revenue to continue operations and/or are in some kind of financial distress are belied by the fact that Calpine seems to be making a profit , and there are several mechanisms through which owners of merchant plants can be compensated if the plants are needed for

[32] Tr. vol. 8, p. 868 ; 860-61.

[33] Calpine Corporation 2010 Annual Report, p. 3. See http://www.calpine.com/docs/CPN_Annual_Report.pdf.

[34] Ex. 601 (Calpine), p. 11.

[35] Tr. vol. 8, p. 847:14-21.

reliability. Calpine offers no proof that its resources are not meeting their forward costs, are unable to secure contracts, and/or are at risk of retirement. For these reasons, among others, the Commission should deny Calpine's request outright.

III. TRACK III ISSUES

A. GHG Procurement Plans

The IOUs request approval of plans for procurement of products they will need to comply with the GHG cap and trade regulations promulgated by the California Air Resources Board (ARB) pursuant to AB 32.[36] The IOUs were advised that their testimony in support of their GHG procurement plans:

> "should provide a proposed greenhouse gas management framework (including evaluation of greenhouse gas risks associated with utility-owned generation, bilateral contracts, and spot market purchases), and should also explain how such a greenhouse gas management framework would govern the utility's proposed upfront achievable standards for greenhouse gas allowance and offset procurement."[37]

The August 4 ruling clarified that "issues related to GHG risk management, procurement, and compliance costs" remain within the scope of the LTPP proceeding as it was originally scoped, rather than in the GHG rulemaking proceeding, R.11-03-012, which was opened to address how revenues from the auctioning of allowances freely allocated to the IOUs will be flowed back to ratepayers.

The proposed GHG plans seem acceptable to DRA in many respects, as DRA indicated in its testimony.[38] In this section of its brief, DRA identifies some gaps in the GHG procurement plans that the Commission should require the IOUs to remedy, or to

[36] Cal. Health and Safety Code § 38500 et seq.

[37] *Joint Administrative Law Judges' Ruling Clarifying Venue for Consideration of Costs Related to Procurement of Greenhouse Gas Allowances* (issued August 4, 2011 in R.10-05-006 and R.11-03-102) "August 4 Ruling"), p. 5. The August 4 Ruling affirmed a June 13, 2011 ruling specifying that GHG procurement issues will be addressed in the LTPP, as well as the earlier scoping of GHG issues to be addressed in R.10-05-006.

[38] Ex. 405 (Division of Ratepayer Advocates' Testimony on the 2010 Long-Term Procurement Planning Track I System Plan of San Diego Gas & Electric Company (SDG&E) and Track III Procurement Rules), pp. 46-47.

identify specifically where these matters are addressed elsewhere in their long term procurement plans. In particular, the plans should address how the IOUs will evaluate power contract terms related to GHG cost exposure and GHG compliance responsibilities and compare them in a competitive bidding context. Other issues addressed in this section of DRA's brief are:

- the timing of a Commission decision on the GHG procurement plans;
- the need for an analysis that captures the effects of reducing GHG emissions (as opposed to simply procuring allowances without reducing emissions);
- issues concerning upfront standards in the plans;
- some questions concerning risk management;
- the use of offsets;
- reporting requirements; and
- what information should be kept confidential.

1. The Commission Could Issue a Decision on GHG Procurement in Early 2012

As DRA, Pacific Environment, and other parties noted in testimony, the ARB recently delayed the initial compliance date for the new GHG cap and trade regulations by one year (to January 1, 2013) and the first auction of GHG allowances by 6 months (to August 15, 2012).[39] Accordingly, the Commission has about six more months to issue a decision than was thought earlier in this proceeding. SCE and SDG&E have indicated that a Commission decision on GHG procurement plans in the first quarter of 2012 would allow adequate time.[40] The Commission could address the proposed plans in its end-of-year decision in this proceeding but, if the Commission finds that the plans should be

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[39] Ex. 405 (DRA), p. 38; Ex. 505 (Prepared Track III Testimony of Pacific Environment), pp. 33-35; Ex. 2200 (Testimony of the Green Power Institute on the 2010 Long-Term Procurement Plans, Track III), p. 2, p.4; Ex. 215 (Reply Testimony of Southern California Edison Company on Track I and III Issues), p. 6; Ex. 109 (Pacific Gas and Electric Company's Track III Reply Testimony, pp. 15-16.

[40] Ex. 215 (SCE), p.6; Ex. 315 (Prepared Track III Rebuttal Testimony of San Diego Gas & Electric Company), p.2.

clarified and supplemented to address certain issues that have not been addressed (as recommended by DRA), there is sufficient time to do so.

Because the ARB's GHG regulations are not yet final and are not expected to be finalized until the third quarter of 2011,[41] DRA further recommends that the Commission wait until the regulations are final before authorizing the IOUs to begin procuring GHG allowances or offsets. If the final regulations differ from the proposed regulations in ways that would necessitate modifications to the IOUs' GHG plans or impact the timing of the IOUs' compliance obligations, it may be appropriate to allow the IOUs and other parties in this proceeding an opportunity to submit written comments on how those changes should be addressed.

2. The GHG Procurement Plans Should Address Some Additional Issues

The advent of GHG regulation has made the allocation of GHG costs and risks in power contracts a significant procurement issue. AS DRA indicated in its testimony, the IOUs GHG plans should address how they will approach these issues in their procurement. In particular, the plans should present a proposed method for evaluating this aspect of power contracts. For example:

- How, in general, will GHG contract terms factor into bid evaluations?
- When negotiating contracts on a case-by-case basis, what factors do the IOUs consider in determining which counterparty will accept the responsibility for GHG compliance?
- When choosing among competing bids, what rules or guidelines govern the IOUs' evaluations of GHG cost exposure? For example, what assumptions regarding the price of future GHG emissions allowances are the IOUs currently using?
- Given the information in the ARB's July 2011 Discussion Draft[42] regarding replacement electricity that substitutes for electricity

[41] The ARB's Final Statement of Reasons is due to the Office of Administrative law on October 28, 2011. See ARB's August 26, 2011 presentation on "Compliance Obligation for First Deliverers of Electricity", slide 13.

[42] ARB July 2011 Cap-and-Trade Discussion Draft, p. A79-A-82.

> from a variable renewable resource, how will the IOUs evaluate out-of-state renewable contracts that are not physically delivering the variable renewable resource (VRR) energy into California? To the extent fossil-fuel replacement power is delivered pursuant to such contracts, how will the IOUs ensure that ratepayers are not overpaying for renewable contracts that also include a GHG compliance obligation for the associated replacement power?

The proposed GHG procurement plans do not address these issues.[43] The IOUs have taken the position that contract evaluation issues are more appropriately addressed in other proceedings, such as those that address RPS contracts and policies.[44] The August 4 scoping ruling quoted at the beginning of this section, however, made clear that this long term procurement planning proceeding is the forum for addressing not only procurement of GHG compliance products, but a "greenhouse gas management framework (including evaluation of greenhouse gas risks associated with utility-owned generation, bilateral contracts, and spot market purchases)."[45] The ruling makes it reasonably clear that the Commission has decided to use the LTPP proceeding as the forum for issues concerning GHG costs and risks (as well as upfront standards) that arise in the procurement planning context. Moreover, it could be argued that it would be difficult to establish upfront standards that are sufficiently clear without addressing these questions. These issues should therefore be resolved in the LTPP proceeding.[46]

To develop the necessary record expeditiously, DRA recommends that the Commission direct the IOUs to provide supplemental information on how they will evaluate GHG risks and cost exposure in power contracts and how those factors will be

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[43] On page 30 of SCE's Reply Testimony (Ex. 215), SCE states that it provides information on how it accounts for the cost of GHG in its bid evaluation methodology in its 2010 LTPP Track II, Exhibit SCE-2, but does not provide a specific citation. Likewise, SDG&E states on page 5 of its Reply Testimony (Ex. 315) that GHG risks and responsibilities in long-term contracts and evaluating bids are important matters, but they do not affect SDG&E's strategy or methodology for GHG procurement. SDG&E does not clarify where these issues are addressed in its 2010 Long Term Procurement Plan.

[44] Ex. 215 (SCE), pp.11, 30; Ex. 109 (PG&E), pp. 18-19.

[45] August 4 Ruling, p. 5.

[46] Regardless of which proceeding is the best forum for these issues, the Commission should make explicitly clear that GHG compliance responsibility and GHG cost exposure (including the GHG price assumptions used to determine the GHG cost exposure) are criteria involved in the evaluation of power procurement contracts, including contracts for out-of-state renewable resources.

considered in the bid evaluation process. If any of the IOUs believe they have already provided this information, they should be directed to indicate where in the record that information can be found. As discussed in the beginning of this section, there is adequate time to address these issues, in light of the implementation delay announced by the ARB.

3. An Analysis That Captures the Effects of Reducing GHG Emissions Is Needed for Procurement Planning Purposes

The proposed plans address the IOUs' strategies or methodologies for procuring the amount of GHG products they will need for compliance purposes. The Commission's review of the IOUs' proposed GHG procurement plans in Track III of the current LTPP proceeding is correspondingly fairly narrow in scope. To further the goals of AB 32 effectively, however, future procurement planning should be done with the benefit of an analysis that captures the effects of *reducing* GHG emissions (as opposed to simply purchasing GHG allowances or offsets). Reducing GHG emissions associated with IOU procurement could be a more cost-effective way of meeting AB 32 emission reduction goals than purchasing GHG compliance products each year. We need to determine how to conduct such an analysis in time for the next planning cycle.

In DRA's "Track II" testimony and briefs concerning the IOUs' procurement plans for their bundled customers, DRA called for a more developed analysis of (1) how to maximize the use of preferred resources and (2) the GHG emissions implications of each procurement decision, to inform the next round of procurement plans.[47] In connection with that effort, the Commission should direct the IOUs to develop an analytic method of capturing the value of reducing emissions for purposes of their GHG procurement planning framework. The analytic tool should enable the IOUs to determine, for example, when procurement of additional energy efficiency resources would be more cost-effective than procuring more GHG products at a given price.

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[47] Ex. 400 (DRA's Testimony on the 2010 Long-Term Procurement Planning Track II Bundled Procurement Plans of Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company), p.16-23; Brief of the Division of Ratepayer Advocates on the IOU's Long Term Procurement Plans for Bundled Customers (June 17, 2011), p.6-7.

4. The Proposed Upfront Standards Are Reasonable With One Change

The IOUs have proposed upfront standards for procurement of GHG products that include position limits and transaction limits for forward procurement.[48] In large part, the proposed standards appear to be reasonable and appropriate. Issues specific to each IOU's proposed standards are addressed next.

SCE

In the case of SCE, the proposed standards give SCE very broad authority to procure GHG products. SCE proposes forward procurement transaction limits that in DRA's view are too aggressive in light of the uncertainties surrounding GHG regulation, particularly in the early years of the developing carbon market when prices can be most volatile. SCE's witness acknowledged during cross-examination that these uncertainties include the possibility that the new California regulatory framework governing GHG emissions will change by becoming regional or national in scope, or preempted by federal law.[49] SCE's witness acknowledged as well that GHG allowances could lose value as a result of such regulatory changes.[50] DRA proposed more conservative parameters for forward procurement of allowances (and offsets) in a confidential portion of DRA's testimony. As DRA explained in that testimony, DRA's proposed limits are based on an assessment of the uncertainties and risks of cap-and-trade, as they have been observed in other carbon markets.

SCE proposes forward procurement and sales transaction limits that DRA supports in part. DRA opposes forward procurement of GHG products in years 2012 and 2013 for the third compliance period as "too much, too soon," in light of the uncertainties surrounding GHG regulation noted in DRA's testimony and brief. For the sake of clarity,

[48] Ex. 107-C (PG&E Procurement Rules Testimony (Conf. Ver.)), p.3-12 to p.3-14; Ex. 210-C (Southern California Edison Company's Testimony on Track III Issues – GHG Procurement Plan (Conf. Ver.)), Appendix B; Ex. 313-C (San Diego Gas & Electric Company's Prepared Track III Testimony (Conf. Ver.)), Appendix B.

[49] Tr. vol. 5, p. 510:14-19.

[50] Id. at p. 511:3-6.

below are two tables: 1) SCE's Proposed GHG Transaction Rate Authority Limits on Forward Procurement and Sales,[51] and 2) DRA's Proposed GHG Transaction Rate Authority Limits on Forward Procurement and Sales.[52] DRA recommends that the Commission adopt DRA's proposed forward transaction limits for SCE.

SCE's Proposed GHG Transaction Rate Authority Limits on Forward Procurement and Sales

Transaction Year	Compliance Period 1 (2012-2014)	Compliance Period 2 (2015-2017)	Compliance Period 3 (2018-2020)
2011	AN*	50%	33%
2012	AN	50%	33%
2013	AN	75%	33%
2014	AN	AN	50%
2015	AN	AN	50%
2016	N/A	AN	75%
2017	N/A	AN	AN
2018	N/A	AN	AN
2019	N/A	N/A	AN
2020	N/A	N/A	AN
2021	N/A	N/A	AN
*AN: As Necessary to close out open GHG position and meet compliance obligations			

[51] Ex. 210-C (SCE), p.16.

[52] The recommendation contained in the second table is consistent with the recommendations DRA made in its Track III testimony, although they were not presented in this form. DRA's testimony included an example of transaction rate authority limits on forward procurement and sales for years 2011 and 2012, which may not have been entirely clear as presented. The Table presented in this brief is DRA's comprehensive recommendation for SCE's transaction rate authority limits on forward procurement and sales, based on DRA's assessment of GHG procurement risks. DRA's table does not include the transaction year 2011.

DRA's Proposed
GHG Transaction Rate Authority
Limits on Forward Procurement and Sales

Transaction Year	Compliance Period 1 (2012-2014)	Compliance Period 2 (2015-2017)	Compliance Period 3 (2018-2020)
2012	AN*	50%	0%
2013	AN	50%	0%
2014	AN	AN	50%
2015	AN	AN	50%
2016	N/A	AN	75%
2017	N/A	AN	AN
2018	N/A	AN	AN
2019	N/A	N/A	AN
2020	N/A	N/A	AN
2021	N/A	N/A	AN
*AN: As Necessary to close out open GHG position and meet compliance obligations			

<u>SDG&E</u>

The upfront standards proposed by SDG&E appear to be reasonable and appropriate. SDG&E indicates that it will forecast its needs for the entire compliance period and will procure a percentage of that forecast each year. The confidential target ranges and volume limits for minimum and maximum procurement authority, as DRA understands them, reasonably balance the risks associated with having either a short or a long GHG position. Hence, DRA supports SDG&E's position limits and transaction limits, contingent upon the fact that DRA's understanding discussed in the subsequent paragraph is correct.

In its testimony, DRA asked SDG&E to clarify whether SDG&E is requesting authority to procure GHG products only for the current compliance period or for future compliance periods as well. In its rebuttal testimony, SDG&E confirmed that it is "requesting authority to purchase GHG products as far out as are offered in ARB's Advance Auctions, which may include GHG products for future compliance periods."[53]

[53] Ex. 315 (SDG&E), p.5.

DRA supports the Commission granting SDG&E this authority. However, DRA still remains uncertain as to SDG&E's request for years farther ahead of the vintage year auctioned at a given ARB Advance Auction (i.e. procurement of 2016 GHG Allowances in 2012). This uncertainty stems from another sentence in SDG&E's rebuttal testimony, which goes on to say, "SDG&E's procurement for allowances in years outside of the current compliance plan will not exceed the minimum obligation forecasted that given year."[54] One could interpret this as a very broad authority in which SDG&E could procure in the year 2012, 2020 GHG Allowances up to its forecasted minimum obligation for that year. DRA does not support forward procurement beyond what is explicitly authorized by the minimum and maximum volume limits presented in SDG&E's confidential Appendix B.[55]

PG&E

DRA supports the proposed standards presented in PG&E's GHG Procurement Plan. PG&E's strategy balances the flexibility to react to short-term allowance needs and price fluctuations with the risks of long term over-procurement. DRA supports PG&E's proposal to file an advice letter seeking Commission approval of transactions for GHG products with vintage years more than four years into the future, and would support this requirement for all three IOUs.

5. Risk Management/Hedging

Each IOU has presented information related to financially hedging the price risk of GHG compliance products. DRA does not oppose any of the IOUs' plans regarding financially hedging its GHG price risk. However, DRA remains unclear as to the authorization SCE is seeking at this time, and suggests that it may be premature to authorize the type of financial hedging that SCE is proposing.

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[54] Id.

[55] Ex. 313-C (SDG&E), Appendix B.

SCE

SCE includes in its GHG Procurement Plan a discussion on portfolio risk assessment and TEVaR, as they relate to GHG compliance. SCE identifies the uncertain GHG compliance cost, related to both the electric revenue and costs streams, as a new component not currently modeled or accounted for in the current TEVaR framework.[56] SCE further states that any value derived from GHG allowances given to the utility[57] needs to be accounted for as a potential offset to increased procurement costs.[58] Given that the market for GHG compliance instruments has not developed, and SCE has not provided a forecast for the costs of future GHG compliance instruments, and a decision is not expected in the GHG Revenue proceeding (R.11-03-012) until May 2012[59], it is unclear to DRA exactly what authorization SCE is seeking regarding financially hedging its GHG price risk. DRA does not oppose SCE's process for developing its TEVaR framework, but seeks clarity about when SCE anticipates (1) implementing changes to its TEVaR model to include GHG compliance, and (2) being "able to define a robust stochastic process for GHG compliance costs."[60]

SDG&E

SDG&E requests authority to use GHG hedging instruments once markets for such products develop, and if the markets for allowances and futures do not provide the same liquidity as the financial market for GHG products. SDG&E discusses its potential use of financially settled swaps to protect its exposure to potentially volatile GHG prices, as well as call and put options to protect ratepayers from future price moves without

[56] Ex. 210-C (SCE), p.12.

[57] The allocation of allowance revenues by IOUs will be addressed in R.11-03-012, Order Instituting Rulemaking to Address Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions (filed March 24, 2011).

[58] Ex. 210-C (SCE), p.12.

[59] R.11-03-012, *Assigned Commissioner and Administrative Law Judges' Joint Scoping Memo and Ruling*, (September 1, 2011).

[60] Ex. 210 (SCE), p.12-13

actually trading allowances and offsets.[61] Xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxx."[62] xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxx. ****SDG&E confidential****

PG&E

xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxx."[63] xxxxxxxxxxxxxxxxxxxxxxxxxxxxx. ****PG&E confidential****

6. DRA Supports Limited Use of Offsets as A Cost Containment Measure

Each IOU seeks Commission authorization to procure GHG Offsets (offsets) up to the maximum limit allowed by the ARB, which is equivalent to 8 percent of each IOU's GHG compliance obligation.[64] DRA supports this limited use of offsets as a cost-containment mechanism under ARB's cap-and-trade program (i.e. when offsets are cheaper than GHG allowances) and advocated for the 8 percent limit at ARB. DRA believes that the 8 percent limit balances potential cost containment benefits with the environmental integrity of the program and achieving significant GHG reductions in sectors of California's economy that are covered by the cap-and-trade program.

[61] Ex. 313-C (San Diego Gas & Electric Company's Prepared Track III Testimony), p.8, p.16.

[62] Ex. 313-C (SDG&E), Appendix B – Confidential.

[63] Ex. 107-C (Pacific Gas & Electric Company Procurement Rules Testimony (Conf. Ver.), p.3-19.

[64] Ex. 210 (SCE), p.7; Ex. 107 (PG&E), pp.18-19; Ex. 313-C (SDG&E), p.15.

DRA does not support the Commission restricting an IOU's authority to purchase offsets up to 8 percent of its compliance obligation. An IOU's offset procurement authority should not be constrained any more than the limit imposed by the ARB regulation in its current form.[65] The potentially limited supply of offsets available to the market may keep IOU purchases under the limit.

DRA supports the IOU's request to procure offsets up to the 8 percent limit, on the condition that any purchase of offsets is confined to those explicitly allowed under the ARB Regulation (i.e. ARB-certified offsets) at the time of purchase. SCE seeks authorization to engage in transactions for offsets that SCE reasonably believes will be certified by CARB.[66] DRA opposes this request unless the offset seller guarantees it will replace uncertified offsets with certified compliance instruments.

Additionally, in the most recent revised draft of the proposed cap-and-trade regulations, the ARB included a provision that will make offset buyers liable for faulty offset credits.[67] For example, ARB has the ability to invalidate offset credits if the project overstates its actual GHG emissions reductions by more than 5 percent, or if the credits were found to be double-counted in another registry.[68] SCE states that the risk of revoking offsets is small and limited to situations where fraud occurs or a certification mistake was made.[69] DRA believes that ratepayers should not be on the hook for offsets that an IOU purchases and are later invalidated. The IOUs as purchasers of the offsets should bear these risks and hence if an offset is invalidated, the IOUs, and not ratepayers, should pay to replace them.

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[65] Should the ARB materially change this standard at some point, the Commission should reconsider its upfront standards regarding IOU procurement of offsets.

[66] Ex. 210 (SCE), p.7.

[67] ARB July 2011 Cap and Trade Discussion Draft, Sec. 95985, pp. A-241 to A-244.

[68] Id., p. A-241.

[69] Ex. 215 (SCE), p.8:22-26.

7. The Commission Should Review GHG Procurement After the First Year to Determine Whether Upfront Standards Should Be Modified

The Commission should review the IOUs' GHG procurement activity after the first year (i.e., from the first ARB auction in August 2012 through August 2013), as recommended by DRA in its testimony.[70] The review proposed by DRA is not an after-the-fact reasonableness review; it would serve a different purpose. The California carbon market is a developing market, and there is currently a lack of market information to inform GHG procurement strategies. The regulatory framework governing GHG emissions could change for a variety of political and legal reasons. These unknowns create certain risks for the IOUs' GHG Procurement Plans. The Commission should review and assess the plans to determine whether experience indicates that changes are warranted. The data would, for example, enable the Commission to compare GHG procurement costs among IOUs (i.e. average price per ton of GHG). This information may be useful in determining which strategies appear to be most successful and what, if any, changes in strategy are warranted.

To facilitate this review, DRA recommended in its testimony that the Commission require each IOU to report all of its GHG market transactions for at least the first year of GHG procurement.[71] DRA reiterates that recommendation here.[72] DRA further recommends that in its decision addressing the IOUs' GHG procurement plans, the Commission order a process to develop a template for providing the required GHG procurement data.

8. Market-Sensitive Information Should Be Protected

The IOUs have requested that certain market-sensitive information in their GHG procurement plans be kept confidential. The time period for which confidential treatment

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[70] Ex, 405 (DRA), pp. 49-50. PG&E supports this recommendation. Ex. 109 (PG&E), p.18:11-16.

[71] Ex. 405 (DRA), p. 49.

[72] The proposed GHG transactions reporting would be in addition to the information currently provided in Quarterly Compliance Report (QCR) Advice Letter Filings and in ERRA Compliance proceedings. See id.

is requested is usually three years, although for certain information the time period is not specified.[73] DRA agrees with the IOUs that some of the information in their GHG procurement plans is market-sensitive and should be kept confidential for that reason. The IOUs make up a significant part of the GHG market, especially in the first compliance period. With such a large share of the market, the IOUs' market activity could easily impact the whole market. It is not in the best interests of ratepayers to give other market participants access to the IOU's net GHG positions and bidding and risk management strategies.

The record is not altogether clear on how long this information remains market sensitive and for how long it should be protected. The duration of confidential treatment should be made clear in the final decision.

B. The Commission Should Not Adopt Staff's Proposal to Impose a One-Year Limit on Contracts With Once Through Cooling Facilities

Appendix A to the Commission's June 13, 2011 Ruling[74] includes proposed standards for utility contracting with resources that rely on Once-Through Cooling (OTC) technology. The proposal provides in part that IOUs would be limited to one-year contracts with Once-Through Cooling (OTC) facilities identified in the State Water Resources Control Board's (SWRCB) May 4, 2010 policy statement. It also provides that IOUs should refrain from entering into contracts with such OTC facilities that extend beyond the plant's compliance deadline as identified in the SWRCB's policy statement (with some exceptions).[75]

DRA agrees with the IOUs and several other parties in this proceeding that the one-year limitation on utility contracting does not appear to produce any identifiable

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[73] Ex. 212, Declarations of Marc Chazaud and Raymond B. Johnson Regarding Confidentiality of Certain Information (at end of volume, pages not numbered); Ex. 313-C, Declaration of Ryan Miller Regarding Confidentiality of Certain Data in Information.

[74] *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule and Rules Track III Issues* (June 13, 2011) in R10-05-006.

[75] Proposed Amendment to the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (May 17, 2011 Draft).

benefits to ratepayers. As pointed out by SCE, if implemented the proposal would impact a large portion of IOU local capacity procurement, as OTC facilities currently provide approximately 40% of installed capacity.[76] Limiting contracting with OTC facilities to one-year contracts would likely drive up transaction costs for IOUs, reduce the IOUs' ability to manage contract costs through multi-year agreements, and could lead to anti-competitive market pricing opportunities by generators.[77] In short, the proposal appears to have only negative impacts on OTC contracting and costs, and no clear benefits. Therefore, DRA recommends that the rule be that utilities may not enter into contracts with any OTC facility that would extend beyond the final date the facility is scheduled to retire or repower under the SWRCB policy statement. If a counter-party can demonstrate that the OTC facility will continue to operate and be in compliance with SWRCB requirements after its compliance deadline, this restriction should not apply.

A more complicated proposal was made by SDG&E,[78] supported by DRA in its testimony, and discussed during evidentiary hearings. Upon further consideration, DRA recommends a simpler solution: that the Commission direct the IOUs to refrain from entering into contracts with OTC facilities that extend beyond the facility's retirement/repower compliance deadline.

PG&E proposes to consider the environmental attributes of OTC bids and offers in the RFO bid/offer evaluation process.[79] DRA supports this proposal in concept. As PG&E explains, considering the environmental consequences of contracting with an OTC facility would enable the utility buyer to balance environmental impacts, system needs, and resource costs.[80] As environmental attributes would be only one factor considered in

[76] Ex. 211, Testimony of Southern California Edison Company on Track III Issues – Rules Track III Procurement Policy (SCE) p. 9.

[77] Ex 211 (SCE), p. 9-11; Ex. 313 Prepared Track III Testimony of San Diego Gas & Electric Company (SDG&E), p. 18.

[78] Ex. 313 (SDG&E) p. 19.

[79] Ex. 109 (PG&E Track III Reply Testimony), p. 2; Ex. 107 (PG&E Procurement Rules Testimony), p. 1-3.

[80] Ex. 107 (PG&E), p. 1-3.

the scoring process, this approach would not necessarily result in the rejection of bids from OTC plants.

SCE argues in its reply testimony that PG&E's proposal will result in a form of economic penalty for the OTC facility that could lead to "sub-optimal economic outcomes for SCE's customers."[81] While DRA acknowledges that the consideration of environmental attributes of resources in the RFO evaluation process may lead to increased contract prices in the short run, these upfront costs must be weighed against the long-term ratepayer benefits of this policy, including avoided costs. For example, contracting with an OTC facility without taking environmental attributes into consideration might result in a higher GHG obligation for the IOU in the long run.

C. Procurement Oversight Rules

1. The Commission Should Adopt DRA's Proposal to Eliminate Conflicts of Interest for Independent Evaluators

In Appendix B to the Commission's June 13, 2011 Ruling, Energy Division Staff Proposes Procurement Oversight Rules for adoption by the Commission.[82] These rules were originally included as Section O of the "AB 57 Procurement Plan Implementation Manual," also known as the "Rulebook." DRA is not in favor of adopting a Rulebook that would supersede existing Commission authority, for the reasons set forth in its previous comments.[83] However, DRA has reviewed Energy Division Staff's proposed Procurement Oversight Rules regarding Independent Evaluator Oversight, and is generally supportive of staff's proposed rules, with the following two recommendations.

First, DRA recommends a change in the current rules that provide that the IOU contract and hire the IEs. Instead, the Commission should require Energy Division Staff

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[81] Ex. 215 (Reply Testimony of Southern California Edison Company on Track I and III Issues), p. 24.

[82] For purposes of the current LTPP decision, only Attachment 1 to the June 13, ruling, entitled "Proposed Procurement Oversight Rules" are being submitted for adoption. These rules contain requirements for Independent Evaluator Oversight, Procurement Review Group practices, provisions for a new Cost Allocation Mechanism Group, and Standards of Conduct for IOUs.

[83] See Comments of the Division of Ratepayer Advocates on Resource Planning Assumptions Part 1: Procurement Planning Assumptions and "Rulebook" (June 21, 2010), pp. 8-10.

to contract, hire and manage IEs.[84] Under the current process, the IOUs directly contract with and compensate the IE. The IE's opinion and report on the IOU's bid evaluation and selection process is a major, if not determinative factor in whether the Commission approves a given project. This presents the IE with a conflict between its role as an impartial evaluator who must objectively critique and monitor IOU procurement activities, and its financial interest in getting paid by the IOU. Even if the IE is able to manage these two competing interests, this arrangement creates the appearance of impropriety and the potential for a conflict of interest. Under this alternative, the IOU's would be removed from the process of contracting with the IEs. Both PG&E and SCE have stated that they are not opposed to this alternative, and TURN, Pacific Environment, and WPTF have made similar proposals.[85] DRA recommends this alternative proposal, which avoids both potential and actual conflicts, and is far preferable to the current arrangement.

Second, DRA recommends that Energy Division, or alternatively, the IOU's Procurement Review Group (PRG), determine the assigned IE rather than the IOUs. The current rules allows the IOUs to develop a pool of prospective IEs (with input from their PRG and Energy Division), but the IOU chooses which IE from their pool will be assigned to a task or procurement solicitation.[86] This creates similar conflict of interest situation as discussed above, as the IE has a financial interest because it is getting paid by the IOU, and thus is not be wholly impartial. For example, it is not difficult to imagine a situation where an IE would be reluctant to provide a report that questions an IOUs procurement decision, as could impact its chances of being selected for future

[84] This proposal is similar the staff's proposal which allows for the Executive Director to hire contractors to perform IE tasks, with management oversight of the IEs to be provided by the Energy Division (*Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule and Rules Track III Issues* (June 13, 2011) Appendix B, Attachment 1, p 8.).

[85] Ex. 107 (PG&E), p. 22:1-4; SCE Testimony, Tr. vol. 6, p. 565:20-25; Ex. 1504 (TURN), pp. 7-9; Pacific Environment – Ex. 505 (Pacific Environment), pp. 31-32; and Ex. 2300 (WPTF), pp. 19-20.

[86] *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule and Rules Track III Issues* (June 13, 2011) Appendix B, Attachment 1, page 11 (IOU IE Pool Requirements), 8 (General IE).

assignments. Again, it preferable to remove the IOU from the selection and contracting process, and avoid this conflict of interest.

2. Utility Owned Generation *Can* be Compared with Independently Owned Generation and *Should* Be Tested by the Competitive Solicitation Process

The Commission identified refinements to bid evaluations in competitive solicitations with both utility-owned generation (UOG) and power purchase agreements (PPA) from independent power producers (IPPs) as an issue to be addressed in this proceeding.[87] Parties are divided on in their support for the Commission's existing policy on the treatment of UOG vs. PPA in the bid evaluation process, and disagree on whether it is even possible, if not practical, to compare the two. PG&E argues that its current RFO evaluation structure, process and methodology is "robust and effective" in comparing UOG and PPA offers.[88] Similarly, SDG&E does not see a need to alter the existing approach for evaluating UOG vs. PPA bids because it argues that the Commission has demonstrated that it is fully capable of weighing the record (of UOG vs. PPA offers) to determine what is in the ratepayers' best interest.[89] On the other hand, SCE states that UOG and PPAs are fundamentally different products and that the process of trying to compare the two in competitive solicitations is "conceptually unworkable."[90] SCE goes as far as saying that UOG projects should be proposed only when competitive processes cannot deliver the products that the utility needs to serve its customers in a cost-effective manner. Similarly, WPTF argues that bid comparisons of UOG and PPA projects in the RFO process are "impossible."[91]

In actuality, the current state of UOG and PPA comparison falls squarely in the middle of the extreme viewpoints of the IOUs and WPTF. That is, PG&E and SDG&E

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[87] *Assigned Commissioner and ALJ's Joint Scoping Memo and Ruling* (December 3, 2010), p. 44.

[88] Ex. 107, (PG&E), p. 2-1.

[89] Ex. 313, (SDG&E), p. 20.

[90] Ex. 211 (SCE), p.13.

[91] Ex. 2300 (Western Power Trading Forum's Track I Testimony on Track III Issues), p. 7.

are wrong in portraying the process of comparing UOG and PPA offers as needing no refinements. Likewise, SCE and WPTF are wrong in suggesting that the process of comparing UOG and PPA offers is utterly impossible and should not even be attempted. The fact is, the Commission has repeatedly demonstrated that it will entertain UOG applications an in most circumstances approve them.[92] But in all cases, the evaluation and comparison of UOG opportunities to market alternatives has been highly contentious and problematic. Given this reality, it behooves the Commission and parties to focus our efforts in improving and refining the process rather than ignoring the problems, as PG&E and SDG&E seem to do, or giving up on trying to address them, as WPTF and SCE suggest. To this effect, DRA offers the following recommendations for refining the process of comparing UOG and PPA bids.

a) All UOG Opportunities Should Be Tested Through A Competitive Solicitation

The Commission has indicated its ground rules for consideration of UOG projects in D.07-12-052. Specifically,

> We want to make it clear that we continue to believe in a "competitive market first" approach. As such we believe that all long-term procurement should occur via competitive procurements, rather than through preemptive actions by the IOU, <u>except in truly extraordinary circumstances</u>.
>
> (D.07-12-052, p. 208)

In addition, Ordering Paragraph 31 of D.07-12-052 states that:

> UOG applications by the IOUs outside of an RFO must fit into a unique circumstance, which are limited to market power mitigation, reliability, preferred resources, expansion of existing facilities, or be a unique opportunity, as described in the decision, and each application will be considered on a

[92] Ex. 405 (DRA), pp. 29-30.

> case- by-case basis. The IOU is required to make a showing that holding a competitive RFO is infeasible.[93]

The Commission's expectations are clear. That is, all UOG opportunities should be tested against a competitive Request for Offer (RFO) unless holding a competitive RFO is infeasible. Since D.07-12-052 mandated this expectation, many UOG opportunities have been brought to the Commission without being tested against a competitive RFO and in all these cases, the IOUs have not shown that holding a competitive RFO was infeasible.[94] In all the examples cited, the Commission ultimately approved the applications even though the IOUs did not comply with the Commission directive.

DRA believes that it is possible to develop a process where UOG and PPAs can be compared side by side, and recommends as an important first step that all UOG opportunities for both fossil fuel and preferred resources be tested through the competitive solicitation/RFO process. Putting the UOG opportunity in a competitive solicitation would test the attractiveness of its price against all other bidders. This is the only legitimate way to determine if the UOG opportunity is the best deal for ratepayers. Moreover, comparing UOG opportunities through competitive solicitations is feasible from a timing perspective and from a competitive solicitation design perspective.

In most cases, Commission application proceedings for UOG projects span nearly 1 to 2 years.[95] This is more than enough time for an IOU to develop a solicitation, perform market outreach, conduct the RFO, and develop a short list of winning bidders. For example, the recent 2011 RPS RFO was completed within roughly 4 months.[96] Likewise, the IOUs design and implement RFOs of many types and some to a very

[93] D.07-12-052, Ordering Paragraph 31, p. 306.

[94] *See, e.g.* A08-03-015 SCE Solar PV Program, A08-07-017 SDG&E Solar Energy Program, A09-02-013 PG&E Fuel Cell Project, A09-02-019 PG&E PV Program, and A.09-04-018 SCE Fuel Cell Program.

[95] *See, e.g.,* A08-03-015 SCE Solar PV Program (15 months), A08-07-017 SDG&E Solar Energy Program (26 months), A09-12-002 PG&E Oakley (12 months).

[96] D.11-04-030 *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements, Appendix B Adopted Schedule for 2011 Solicitation.*

narrow set of bidders.[97] Given the IOUs vast experience designing and holding RFOs of many different flavors, there is no excuse for IOUs forgoing the Commission mandate to test all UOG opportunities with a competitive solicitation.

b) The Process of Comparing UOG and PPA Bids Should Be Refined

DRA offers the following additional recommendations to the Commission regarding its current protocol for fair, transparent, and equal treatment of UOG and PPA bids to ensure a level playing field in the California hybrid market:

- **For assessment purposes, UOG project costs should be amortized over the same term as the PPA contract.**

One of the most difficult determinations has been in making an apples-to-apples comparison of UOG opportunities to IPP bids. One issue that the Commission is commonly confronted with is comparing the uncertain life time of a UOG facility as compared to a 10-20 year PPA.[98] Increasing the length of time over which the costs of a UOG project are amortized can have the immediate effect of making a UOG project appear substantially more cost competitive than a PPA.[99] DRA recommends that the Commission take the approach suggested in D.11-03-036 when comparing a UOG bid to a PPA. Specifically, for assessment purposes, amortize the UOG project costs over the same period that reflect the term of the PPA contracts against which the UOG is being compared.[100]

[97] *See, e.g., SCE Advice Letter 2608-E* which includes bids from an RFO that sought Qualifying Facility (QF) bids from respondents seeking to change the energy price within their existing QF Power Purchase Agreements from Short-Run Avoided Cost (SRAC)-based energy payments to a fixed energy price agreement; Also see, Tr. vol. 6(August 17, 2011), pp. 682-684.

[98] D.10-07-045, p. 37; D.11-03-036, pp. 28-32.

[99] D.11-03-036, *Decision Denying PG&E's Manzana Purchase and Sale Agreement (PSA)*, pp. 27.

[100] The question arises of how to address (for purposes of this comparative assessment) the value to ratepayers of the residual value of the UOG facility at the end of the assumed amortization period. It would be necessary to find a way to address this question.

- **The Commission should provide specific guidance to IOUs regarding on input assumptions and forward cost curves used in UOG valuations.**

Another issue that confronts the Commission when comparing UOGs against PPAs is that evaluating a UOG project over a long time horizon (20-30 years) involves greater uncertainty than with a shorter term PPA, because the uncertainties about input assumptions increase with time. For example, the value of capacity and estimates of land lease costs have been contentious issues in recent UOG Decisions.[101] DRA recommends that the Commission provide specific guidance to the IOUs on what input assumptions or forward cost curves are reasonable to use for UOG valuations. This guidance should be developed and vetted through a public stakeholder process held at the Commission. This guidance will help to level the playing field for comparing UOG and PPA bids.

- **The Commission should establish cost caps for capital costs and O&M for UOG projects.**

DRA recommends that the Commission establish hard cost caps for capital costs and Operation & Maintenance (O&M) for UOG projects, so that the IOUs will not underbid these costs and then attempt to recover higher costs after the UOG project has been approved.

- **The Commission should establish clear pay for performance mechanisms in UOG projects similar to PPAs**

The Commission should establish clear pay for performance mechanisms in UOG projects similar to those included in PPAs (i.e., incentives and penalty mechanisms that reward and penalize a utility based on its performance). With most PPAs, compensation is determined primarily on a delivery basis (e.g., $/MW hour). The Commission has attempted to introduce this UOG cost recovery concept in a recent Proposed Decision and Alternate Decision.[102] If California's experiment with a hybrid market is to continue, the

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[101] D.10-07-045; D.11-03-036.

[102] A.09-02-019, *ALJ Ebke Proposed Decision and President Peevey Alternate Proposed Decision Adopting a Solar Photovoltiac Program for Pacific Gas and Electric Company, Appendix B, Alternative Ratemaking Treatment Example Calculations*. Both the Proposed Decision and Alternate Proposed

the Commission should hold IOUs to the same pay for performance standards as independent power producers.

- **Shareholders should finance the costs for IOUs to develop a UOG bid and should absorb costs on failed UOG bids.**

Finally, shareholders, not ratepayers, should finance the costs of developing a UOG bid and should absorb the costs of UOG bids that are not approved. IPPs must fund project development costs for proposed new projects, so IOUs should too.[103] Stated another way, UOG project development costs should only be recovered from ratepayers if the project is approved and put in service. Costs associated with unsuccessful UOG bids should be the responsibility of IOU shareholders just as it is for IPPs. To do otherwise would create an uneven playing field for competitors.

D. The Commission Should Reject SCE's Request for a New Proceeding To Consider a CAISO-run Capacity Market

SCE proposes that the Commission open a new proceeding to consider its proposal for a CAISO-run auction for new generation that would "exclusively focus on the urgency of needed new generation" to meet Resource Adequacy (RA) requirements due to Once-Through Cooling (OTC) plant retirements and increased renewable generation coming online. (SCE-3, p. 8.) There are two problems with SCE's proposal: First, there is no demonstrated need for new resources in this proceeding due to planned OTC retirements or for other reasons, thus, there should be no rush to implement a new auction for procurement of new generation. Indeed, SCE is a party to the Settlement Agreement[104] stating that there is no need at this time for the Commission to consider authorizing procurement for SCE to meet local capacity requirements (LCR), or for renewable integration needs. Second, even if there were a need to procure new generation, SCE has not shown why these products cannot continue to be procured

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Decision adopted a cost recovery mechanism where PG&E would only be able to recover costs based on the output of the UOG facilities.

[103] Ex. 405 (DRA), p. 34; Ex. 2000 (IEP), pp. 28-29 ; Ex. 2300 (WPTF), pp. 11-14.

[104] Settlement Agreement attached to the *Motion for Expedited Suspension of Track 1 Schedule, and for Approval of Settlement Agreement Between and Among Pacific Gas & Electric Company, et al.* (August 3, 2011) (pending Commission approval).

through the existing bilateral framework, with a fair allocation of costs to all customers through the existing Cost Allocation Mechanism (CAM).

Furthermore, the initiation of a new Commission proceeding to consider SCE's proposal comes close on the heels of the Commission's recent rejection of very similar proposals for a centralized auction run by the CAISO. In June of 2010, the Commission issued a decision on long-term Resource Adequacy market design (D.10-06-018),[105] declining to adopt a centralized capacity auction mechanism for procuring RA capacity, for very good reasons.

For example, the Commission observed that the design and implementation of a new auction process would be "costly, complex, and resource intensive."[106] The Commission expressed its preference to maintain the Commission's jurisdiction over the Resource Adequacy program.[107] This is an important consideration. After all, it is the Commission, not the CAISO, that has the statutory responsibility and authority to establish, implement and enforce resource adequacy requirements, to review and approve the IOUs procurement plans, and in doing so, to ensure that rates remain just and reasonable.[108] The CAISO's core responsibility is to operate the transmission grid. It has never been demonstrated that the Commission's procurement oversight responsibilities can, under current state law, be handed over to the CAISO. Moreover, as parties have pointed out, if the responsibility for procuring new generation were shifted to the CAISO, such procurement decisions would be reviewable by the FERC, where the Commission is "just another party," rather than a decisionmaker[109] SCE admitted at hearings that its new generation auction proposal would be a FERC jurisdictional process, and though the

[105] *Decision on Phase 2 – Track 2 Issues: Adoption of a Preferred Policy for Resource Adequacy*, D.10-06-018 (June 3, 2010), p. 3.

[106] *Id.* at p. 59.

[107] *Id.* at p. 78, FOF No. 13.

[108] Public Utilities Code §§ 380, 451, § 454.5.

[109] Ex. 1900 (Testimony of Dr. Barbara R. Barkovich on Behalf of the California Large Energy Consumers Association on Track III Issues), pp. 5-6.

CPUC would have a role to play, the CAISO would determine the need for new generation due to local capacity needs and renewable integration.[110]

After an extremely lengthy proceeding, the Commission concluded that proponents of the centralized auction approach had not demonstrated how renewable and other preferred resources would be prioritized under an auction mechanism.[111] The Commission found that a centralized capacity market would tend to promote the development of generic capacity[112] and could result in unnecessary and duplicative procurement.[113] Although SCE's proposal is for new generation only, these considerations still apply, that is, even SCE's scaled down version of the centralized capacity market proposal would be expensive and complicated to set up, would be administered by the CAISO and subject to FERC jurisdiction, and would be ill-suited to the development of California's preferred resources.

As SCE admits, "the last debate on centralized capacity markets continued for over five years."[114] This issue was considered and ultimately rejected only last year. Now is not the time to re-open this debate.

IV. CONCLUSION

In conclusion, the Commission should approve the Settlement Agreement and consider the Settling Parties' recommendations for a process and timeline for completing the further analysis needed to determine what new resources will be needed in 2020, assuming that 33 percent of California's delivered electricity will be obtained from renewable sources. In addition, DRA recommends that the Commission deny SDG&E's request for procurement authority. Finally, DRA asks the Commission to consider its recommendations concerning GHP procurement plans, contracting with OTC facilities, procurement oversight, and the related recommendations set forth in this brief.

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[110] Tr. vol. 5, pp. 518-520.

[111] D.10-06-018, p. 78, FOF 14, 16.

[112] *Id.* at p. 60.

[113] *Id.* at FOF 15.

[114] Ex. 215 (SCE), p. 5:11-12.

Respectfully submitted,

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