Decision **PROPOSED DECISION OF ALJ ALLEN** (Mailed 11/10/2011)

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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

# DECISION APPROVING MODIFIED BUNDLED PROCUREMENT PLANS

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# DECISION APPROVING MODIFIED BUNDLED PROCUREMENT PLANS

## 1. Summary

This decision approves with modifications the plans of the three major California electric utilities to procure electricity for their bundled customers, consistent with Pub. Util. Code section 454.5. The utilities' bundled plans are approved as proposed by the utilities, except as modified by this decision. In addition, we provide guidance to the utilities for their future bundled procurement plans.

## 2. Background

The Commission, in Decisions (D.) 04-12-048 and D.07-12-052, has previously reviewed and approved the long-term procurement plans of the utilities under Assembly Bill (AB) 57 (Stats. 2002, ch. 835),[1] which enacted Pub. Util. Code section 454.5. AB 57 established the method by which the utilities would resume electricity procurement, replacing the California Department of Water Resources, which had taken on that responsibility in the wake of the California Energy Crisis. Those prior Commission decisions indicate that the review and approval of utility procurement plans as required under section 454.5 is both complex and continuing to evolve, and they provide a thorough background which need not be repeated here. We anticipate that the processes utilized by the

[1] Amended by Stats. 2005, ch. 366 and Stats. 2006, ch. 685.

utilities and this Commission in developing, reviewing, and approving procurement plans will continue to evolve in future proceedings.

The Order Instituting Rulemaking (OIR) that opened this proceeding established three separate tracks. The track addressed in this decision (Bundled Track II) was described in the OIR:

> In one track, we shall consider adoption of "bundled" procurement plans pursuant to AB 57 (codified as Pub. Util. Code §454.5) for the three major electric IOUs [investor owned utilities] (Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison) to authorize their procurement needs for their bundled customers. (OIR at 2, citation and footnotes omitted.)

The OIR also provided the following definition:

> We define "bundled" as pertaining to an investor-owned utility's (IOU's) load and resources in its role as a Load Serving Entity (LSE). To distinguish filings related to bundled Assembly Bill (AB) 57 obligations from separate filings related to system reliability needs, we will refer to these as "procurement plans." (*Id*., footnote 1.)

The January 13, 2011 Scoping Memo generally described the scope of this track of the proceeding:

> As discussed at the pre-hearing conference, Bundled Track II procurement is focused on the short-to-medium term operational needs of the utilities, and should not result in construction of new generation facilities. As a practical matter, in order to meet their short and medium term needs, such as replacing expiring contracts, the utilities will need to be contracting with existing facilities, rather than with proposed new facilities. Accordingly, approval of the utilities' Bundled Track II procurement plans will not indirectly lock in a longer-term resource commitment by causing new generation to be built. (*Id*. at 3.)

Written testimony in Bundled Track II was presented by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC), Citizens for a Better Environment (CBE), Center for Energy Efficiency and Renewable Technologies (CEERT), Division of Ratepayers Advocates (DRA), Marin Energy Authority (MEA), Pacific Environment, L. Jan Reid (Reid), and Women's Energy Matters (WEM). Evidentiary hearings were held on May 23 and 24, 2011, primarily to deal with administrative and evidentiary matters, including the admission of testimony and exhibits. Opening briefs were filed by Alliance for Retail Energy Markets (AReM), CAC and EPUC, CEERT, DRA, MEA, Pacific Environment, PG&E, SCE, SDG&E, Sierra Club California (Sierra Club), The Utility Reform Network (TURN), and WEM, and reply briefs were filed by AReM, CBE, CEERT, DRA, MEA, PG&E, Reid, SCE, SDG&E, Shell Energy North America (Shell), Sierra Club, and WEM.

## 3. Adequacy of Procurement Plans

This decision renews and updates the utilities' procurement authority on behalf of their bundled customers, consistent with the policies of this Commission and the State of California. The changes to the utilities' procurement authority that are made in this decision are largely technical revisions based on our recent experience, adjustments to reflect changed circumstances, and clarifications based on past experience and issues raised by the parties.

Because this decision largely follows existing policies rather than make new policies, the scope of this decision is relatively narrow. This decision is not intended to result in any new generation facilities being constructed, and it continues to implement the Commission's loading order and Energy Action Plan.

There is one area, however, that reflects a fundamental tension in the process that we need to address. The basic idea that forms the foundation of this proceeding is that the Commission will pre-approve a utility procurement plan, and subsequent utility procurement consistent with that plan is considered reasonable. In proposing their procurement plans, the utilities were directed by the December 3, 2010 Scoping Memo (reiterating the OIR) to base their submissions upon a set of standardized planning assumptions:[2]

> Based on the record in R.08-02-007, we find it reasonable to direct the IOUs' filing of bundled LTPPs [long-term procurement plans] to be based on a limited set of standardized planning assumptions, consistent with those adopted here, using the best information available as described in the Track II Scoping Memo. While we envision that Track II plans will be based on currently effective conformed LTPP plans, our intent is to ensure that the IOUs' plans can be more easily compared to each other and to maintain consistency across utilities to the extent possible. (Scoping Memo at 39-40.)

The standardized planning assumptions that are being used in this proceeding were developed through an exhaustive and open process, involving a wide range of stakeholders. (See, e.g., Scoping Memo at 7-8, 24.) As described above, one important purpose for the standardized

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[2] The OIR had generally referred to these standardized planning assumptions as "planning standards." (See OIR at 14.)

planning assumptions was to allow for the utilities' plans to be more readily comparable. Absent some common basis, it would be impossible for the Commission to perform a meaningful comparative analysis of the utilities' procurement plans, and more difficult for the Commission to ensure that those plans are consistent with the requirements of section 454.5. Basing the plans on a known starting point also helps evaluate the scope and effect of any subsequent proposed changes to the plans.

Accordingly, the record in this proceeding relies heavily upon the standardized planning assumptions that the utilities were required to use in preparing their proposed procurement plans.[3] Those standardized planning assumptions necessarily contain numerous forecast elements, and any forecast, no matter how carefully made, will end up being at least somewhat off the mark. The utilities need to procure the amount of electricity that is actually needed for the reliable operation of the grid, regardless of the level of need that was forecast in this proceeding. Accordingly, the utilities' actual procurement is likely to vary from that assumed in the standardized planning assumptions.

While we should not force utility procurement to precisely conform to the standardized planning assumptions, the utilities cannot just disregard the standardized planning assumptions and procure whatever they want. Doing so would make this whole process - and more importantly, Pub. Util. Code section 454.5, which we are implementing

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3 The utilities were also allowed to present their own alternate planning assumptions.

here - pointless. The Commission has a legal duty to ensure that ratepayers pay just and reasonable rates, and accordingly the utilities' procurement activities must have some correlation to the procurement plan approved by the Commission.

A level of procurement and associated costs that closely correspond to those forecast in this proceeding would be ideal. Significant under-procurement that maintains adequate reliability would also be acceptable (while showing that there was a flaw in forecasting), as the cost to ratepayers is likely to be less than the forecast cost.

To the extent that the cost of procurement is higher than forecast, however, there is a potentially significant problem, as the Commission cannot be said to have found the correspondingly higher rates to be just and reasonable, as required under section 454.5(d).

The utilities differ in their positions on how to address this tension. SCE's position is:

> The purpose of the Track II planning analysis for SCE was to set position limits and ratable rates (i.e., maximum rates of transaction) to provide an upper boundary on the amount of procurement SCE can engage in without prior Commission approval. (SCE Opening Brief at 23.)

As a general matter, this approach is reasonable – the Commission sets an upper boundary, and the utilities can procure up to that level without coming back to the Commission. This makes it easier for the Commission to find that the resulting rates are just and reasonable, as there is effectively a cap on procurement amounts and associated costs.

PG&E, however, takes a very different approach, as it explains in response to other parties:

> More fundamentally, MEA and AReM ignore the fact that PG&E expressly explained that it is not seeking procurement authority based on the energy and capacity tables in the BPP [bundled procurement plan]. Whether CCA [community choice aggregation] and DA [direct access] load is or is not included in the energy and capacity tables in Appendix A of PG&E's BPP will not impact or change PG&E's procurement decisions. Rather, PG&E procures to meet its bundled customer needs based on the products and processes included in the BPP, not based on the energy and capacity tables. SDG&E takes a similar approach, as it explained in detail in its opening brief. (PG&E Reply Brief at 9-10.)

As PG&E observes, SDG&E provided the most detailed description of its position on this issue:

> As noted above, the Track II Scoping Memo requires the IOUs to base their respective Track II bundled plans upon a set of Standardized Planning Assumptions prepared by Commission staff. While, as explained by Mr. Anderson, SDG&E has serious reservations concerning the accuracy of the Standardized Planning Assumptions, it notes that as a practical matter, it will often be the case that actual resource needs differ from forecasted need included in an IOU's bundled plans (whether such forecasted need is based upon Commission-developed or IOU-developed assumptions). Thus, while the Bundled Plan includes assumptions designed to provide a context for establishing upfront standard consistent with AB 57, the plan makes clear that these assumptions are not intended to establish specific procurement targets:
>
> "Consistent with Commission direction, SDG&E's resource plan serves as an "umbrella" document, incorporating and consolidating inputs from other Commission proceedings and, in some cases, necessarily making assumptions about the outcomes of proceedings currently underway or assumptions regarding the amount and timing of resource additions. For

example, energy savings and demand reductions from the EE [energy efficiency] programs are based on the Commission's adopted targets for committed programs. *However, the capacity shown in the Plan for these higher priority resources is based on forward-looking assumptions that are not intended to operate to set minimum or maximum capacity targets*." [Citing Ex. 304 at 66.]

SDG&E's Bundled Plan notes that "SDG&E will procure capacity based on *actual* resource needs, which may deviate significantly from the assumptions included in the Plan." It emphasizes that "while the Plan sets forth necessary guidelines and upfront standards for procurement, and may include certain assumptions regarding need, the procurement ultimately undertaken by SDG&E pursuant to the Plan will reflect actual need rather than assumptions that may be included in the Plan." Mr. Anderson echoed this point, cautioning that the energy and capacity tables provided with the Bundled Plan "must be viewed as being illustrative because many of the assumptions that go into these tables change frequently and are outside of SDG&E's or the Commission's control." He noted that the tables provided "should be viewed as one possible outcome based on a given set of assumptions," and further that "[a]ctual procurement will vary over time, based on the best available data at that time." He pointed out that given the high probability that actual need will differ from what is projected in the Bundled Plan, the outcome contemplated in the Bundled Plan should not be considered SDG&E's preferred resources or be relied upon to establish procurement targets:

"[T]he bundled plan resources needs will constantly be changing based on new information regarding loads, resources and costs. The Scoping Memo provided a set of assumptions that SDG&E was directed to use in preparing its LTPP filing. There are a large number of other assumptions that may have the same or an even higher probability of occurring in the future. *Thus, the one outcome contemplated in the LTPP, based on this one set of assumptions, should not be*

> *viewed as SDG&E's preferred or the most likely set of resources over the next ten years. Likewise, the assumptions referenced in the Plan should not be viewed as targets, or as setting a ceiling or floor on SDG&E's procurement authority*." [Citing Ex. 301-E at RBA-11.]
>
> Thus, while SDG&E included the Standardized Planning Assumptions in its 2012 LTPP, consistent with Commission direction, it is important that the Commission remain mindful of the fact that reliance on these assumptions produces a forecasted need in the Bundled Plan that may, but most likely will not, be accurate, and that the outcome of the Bundled Plan should not be used to identify SDG&E's preferred set or resources or to establish procurement targets or limits. (SDG&E Opening Brief at 11-13. Footnotes omitted, emphasis in original.)

In essence, SDG&E and PG&E are saying that it does not matter what comes out of this proceeding – they will procure whatever they want, in whatever quantity they think best. In a historic context, this would not be particularly problematic – the utility had the authority to procure adequate electricity to serve its customers. The Commission would provide oversight by pre-approving certain costs to be covered in rates, and would also perform after-the-fact reasonableness reviews to ensure that the utilities made proper and prudent use of ratepayer money.

But under the new section 454.5 paradigm, the Commission pre-approves a more general procurement plan, and gives up its after-the-fact review. Under section 454.5, the Commission's approval of the utility's procurement plan must provide for just and reasonable rates. If, as PG&E and SDG&E claim, the utilities are free to procure any amount or mix of resources regardless of what the Commission bases its decision upon, the Commission cannot be sure that the resulting rates will be just and reasonable. In short, this approach would render the Commission's approval largely meaningless, but could potentially insulate the utilities from subsequent reasonableness reviews. Such an abdication of responsibility is not consistent with California law, sound public policy, or the best interests of the ratepayers. The position of PG&E and SDG&E means that their procurement plans, as initially submitted, do not comply with the requirements of section 454.5.

In addition, having utilities take radically different approaches to procurement makes it difficult, if not impossible, for the Commission to ensure that its pre-approval of utility procurement plans complies with the requirements of section 454.5(d):

> (d) A procurement plan approved by the commission shall accomplish each of the following objectives:
>
> (1) Enable the electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.
>
> (2) Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.
>
> (3) Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan. The commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. The commission shall

> establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. […]
>
> (4) Moderate the price risk associated with serving its retail customers, including the price risk embedded in its long-term supply contracts, by authorizing an electrical corporation to enter into financial and other electricity-related product contracts.
>
> (5) Provide for just and reasonable rates, with an appropriate balancing of price stability and price level in the electrical corporation's procurement plan.

Accordingly, on a going forward basis, for the Commission to be pre-approving utility procurement plans, it would make sense for those plans to be at least roughly equivalent. The current plans are not equivalent.

SCE's approach is fundamentally more consistent with the code than the approach recommended by PG&E and SDG&E. The Proposed Decision, based on the record of this proceeding at the time, did not order PG&E and SDG&E to completely revise their procurement approach to mirror that of SCE, but indicated that future phases of the LTPP proceeding may require PG&E and SDG&E to move their procurement approaches towards that taken by SCE in order to ensure compliance with section 454.5.

Since the Proposed Decision found that rigid compliance with the Standardized Planning Assumptions was not viable, and was not ordering PG&E and SDG&E to adopt SCE's approach, it proceeded to develop a methodology for ensuring that the procurement activities of PG&E and SDG&E would be consistent with the requirements of section 454.5.

Section 454.5(c) expressly allows the Commission to reject a utility's procurement plan. If the Commission were to do so here, there would not be adequate time for the utilities to prepare new plans in compliance with the law and submit those for Commission approval. If the Commission did simply reject PG&E's and SDG&E's procurement plans, the appropriate default would be for the utilities to continue under the Commission's prior procurement regime, including after-the-fact reasonableness reviews.

At the same time, it would be more consistent with the intent and policy of section 454.5 to approve procurement plans for PG&E and SDG&E. The Proposed Decision correctly noted that we cannot approve the plans as submitted, but section 454.5 also expressly allows the Commission to modify a utility's procurement plan. The Proposed Decision then proceeded to modify the procurement plans of PG&E and SDG&E in order to ensure compliance with the requirement of section 454.5 (and the fundamental duty of this Commission) to provide for just and reasonable rates by imposing a 10% cap on increases in system average rates due to procurement costs.

The Proposed Decision found that procurement activities (consistent with this and other Commission decisions) that result in no more than a 10% system average rate increase over a rolling 18-month period are reasonable, although it noted that a rate increase of that size was highly unlikely, and that a 10% system average rate increase due to procurement costs was significantly higher than what the utilities forecast in their procurement plans.

The Proposed Decision found that a utility that exceeds the cap is no longer operating under a Commission-approved procurement plan, and accordingly would only have allowed PG&E and SDG&E to recover in rates procurement costs to the point those costs would result in no more than a 10% system average rate increase over a rolling 18-month period. Any costs above that level would only be recovered after a reasonableness review that examines all utility procurement.

In their Opening Comments on the Proposed Decision, PG&E and SDG&E (supported by SCE) criticize this approach, arguing that it is unclear, unnecessary, and inconsistent with the intent of section 454.5. These criticisms are baseless, and PG&E and SDG&E ignore the fact that their proposed procurement plans did not comply with the requirements of section 454.5.

The Proposed Decision's cost cap approach would be consistent with the Commission's responsibility and authority under section 454.5, and would be less disruptive than the alternatives that this Commission could adopt. EPUC argues that the Commission should reject PG&E's proposed plan in its entirety, and subject PG&E to a traditional after-the-fact reasonableness review. (EPUC Opening Comments at 2-3.) Sierra Club argues that the Commission should reject the utilities' proposed plans and require them to refile conforming plans. (Sierra Club Opening Comments at 1, 4-5.) EPUC and Sierra Club are correct that the Commission could adopt either of these approaches.

PG&E and SDG&E, however, propose (in almost identical language) an alternative approach, under which they would use an approach based on that of SCE:

> PG&E [SDG&E] is willing to modify its BPP in order to establish position limits similar to those of SCE. Specifically, the portion of SCE's methodology that PG&E [SDG&E] is willing to adopt is contained in Section 3 ("Procurement Limits and Ratable Rates") of SCE's proposed 2012 bundled plan. PG&E [SDG&E] proposes to follow the methodology set forth in subsection (b) of Section 3, which applies to bundled system capacity procurement, and subsection (f), which applies to transaction compliance accounting and limit updates. PG&E [SDG&E] would adopt these aspects of SCE's bundled plan and apply them to PG&E's [SDG&E's] bundled procurement in the same manner as detailed in SCE's bundled plan. (PG&E Opening Comments at 6; SDG&E Opening Comments at 10-11.)

This proposed approach provides additional protection to ratepayers, and allows us to find that the utilities' proposed bundled procurement plans, as modified by this decision, are reasonable under section 454.5. Accordingly, we adopt the alternative approach proposed by PG&E and SDG&E, modeled on SCE's bundled procurement plan, rather than the cost cap approach set forth in the Proposed Decision.

For all utilities, there is also a modified reporting requirement. Consistent with quarterly Procurement Review Group (PRG) processes from previous LTPPs, each utility shall also review their current position relative to their Commission-approved limit on a rolling 24-month forward basis, compare it to their positions in the previous quarter, and include that information in their quarterly PRG meeting.

## 4. Standardized Planning Assumptions

Because PG&E and SDG&E assert that they are generally free to ignore the standardized planning assumptions, they largely do not take issue with those assumptions. SCE, on the other hand, would be bound by its approved procurement plan, and accordingly takes issue with a number of the standardized planning assumptions. In a number of areas, SCE seeks to use its own assumptions, which generally would provide SCE more procurement flexibility, particularly for conventional resources, than the standardized planning assumptions.

The use of standardized planning assumptions is necessary, if for no other reason than to ensure that the procurement plans of the utilities (and positions of other parties) are comparable. Here, however, because PG&E and SDG&E are largely disregarding the existence of the standardized planning assumptions, that purpose is frustrated. In the future, as we move more towards SCE's approach, it makes sense to have the Commission adopt standardized planning assumptions for the utilities in the LTPP proceeding. Parties may advocate, as SCE did in this proceeding, for variations from staff-developed or staff-proposed assumptions.

SCE's proposal, which SCE refers to as its "preferred analysis," requests variations from the standardized planning assumptions. In addition, other parties have proposed changes to specific standardized planning assumptions. SCE is authorized to generally use its preferred analysis methodology, but only for up to five years from the date of this decision, and with certain exceptions as described below.[4] Beyond that date, SCE must use the standardized planning assumptions, except as

[4] See "Combined Heat and Power."

otherwise noted.[5] This ensures that SCE's longer-term procurement strategies are consistent with the broader Standardized Planning Assumptions, while allowing SCE the flexibility to procure resources at just and reasonable rates.

## 5. Compliance with Loading Order

All utility procurement must be consistent with the Commission's established loading order. The loading order, first set forth in the Commission's 2003 Energy Action Plan, and subsequently reiterated in multiple forums (including D.07-12-052), requires the utilities to procure resources in a specific order:

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

Pacific Environment argues that the loading order sets forth the priority sequence that should govern all utility procurement actions:

> Under this order, energy efficiency and demand response should first be utilized to meet need. Should these resources be unsuccessful in meeting need, then renewable energy and distributed generation should be employed. Only after all preferred resources fail to satisfy demand can utilities resort to using conventional fossil fuel-generated energy. (Pacific Environment Opening Brief at 6, citations omitted.)

[5] See "Direct Access and Community Choice Aggregation."

The utilities do not contest the applicability of the loading order to their procurement, but describe the mechanics of applying it in a different way. SCE describes its operation as follows:

> Therefore, SCE's AB 57 Bundled PP addresses the procurement required to serve the *residual* energy requirements of SCE's bundled customers, *after* first fully accounting for all of SCE's committed and forecasted preferred resources (*i.e.*, Energy Efficiency (EE), Demand Response (DR), renewables, Qualifying Facility (QF) contracts, Combined Heat and Power (CHP), and Distributed Generation (DG)) and utility owned generation (UOG). SCE fully considers all cost-effective preferred resources before committing to conventional resources. Indeed, SCE's residual procurement is open to all resource technologies that can meet SCE's procurement requirements, including preferred resources. SCE provided a comprehensive description of its adherence to the Preferred Loading Order in its AB 57 Bundled PP. (SCE Opening Brief at 6, emphasis in original, citations omitted.)

SDG&E takes a slightly different position:

> As Mr. Anderson observed "the Commission determines the amounts of cost-effective EE and DR in separate proceedings that look at the full range of options and then approves specific programs and funding for the next program period, usually a two- or three-year period. Thus, by the time SDG&E seeks to fill its bundled customers' near-term net short position, it has already incorporated reductions from these resources." (SDG&E Opening Brief at 9-10, quoting Exhibit 306, citations omitted.)

The utilities are fundamentally correct that the Commission analyzes and sets goals for programs such as energy efficiency and demand response in other proceedings, and the results of those other proceedings inform the procurement plans to be approved in this proceeding. There is no need to re-analyze or re-litigate those same issues here, particularly since the results of those other proceedings have largely been incorporated into the standardized planning assumptions.[6]

The question raised by the utilities' arguments is whether the obligation to procure resources in the sequence set forth in the loading order is finite or if it is ongoing. The utility position is that the obligation is finite – once the required levels of preferred resources are reached, the obligation to procure more of those resources ends, and the utility is free to procure any needed residual amounts from conventional sources (although it may procure additional preferred resources).

Under the Pacific Environment interpretation (also supported by Sierra Club), even if enough of the preferred resources have been procured to meet the utilities' obligations under the Commission's program-specific decisions, any residual procurement should also follow the loading order.

Each of these two interpretations has plusses and minuses. The utility interpretation would result in a simpler approach, as it would provide the utilities a clearer idea up front of how they will procure generation resources. On the other hand, the Pacific Environment interpretation would tend to maximize the procurement of preferred resources under the loading order.

In D.07-12-052, this Commission stated what appears to be a somewhat intermediate position:

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[6] The primary exceptions are the recent decisions relating to Direct Access/Community Choice Aggregation and Combined Heat and Power.

> The priorities, or "loading order" is as follows: energy efficiency (EE), demand response (DR), renewable power, distributed generation (DG), clean and efficient fossil-fired generation. EE and DR are considered the highest priority and should be employed first by a utility in making procurement decisions since they are demand-side resources. Once a utility captures the targeted EE and DR opportunities, the utility is to procure renewable generation to the fullest extent possible. (*Id*. at 12.)

In other words, once the pre-established targets for energy efficiency and demand response are hit, the utility is no longer required to procure more of those resources. But once the utility gets to the procurement of renewable power, the utility is under a continuing obligation to maximize its procurement of cost-effective renewable generation, even if it has hit the target set by this Commission in another proceeding.

Given the differing interpretations of the loading order offered in this proceeding, it is important that we clarify the correct implementation of the loading order. Based on the record of this proceeding, the Commission could apply a number of different interpretations in implementing the loading order, but our goal is to clarify existing policy and ensure its implementation, not adopt a new policy or approach.

Accordingly, to clarify the Commission's position, we expressly endorse the general concept that the utility obligation to follow the loading order is ongoing. The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved. This is only a clarification of our existing policy, and does not modify any Commission decision relating to procurement of specific resources, such as energy efficiency or renewable generation.

In addition, because the standardized planning assumptions are based upon the Commission's loading order, the position of PG&E and SDG&E that the standardized planning assumptions do not reflect their preferred (or even a likely) set of resources raises some concerns regarding utility compliance with the loading order. This is reinforced by the Commission's finding in D.07-12-052 that:

> 7. We find that in general all three LTPPs do not fully reflect our goals in regards to addressing preferred resources and the EAP [Energy Action Plan] loading order and GHG [greenhouse gas] reductions. (*Id*., Finding of Fact 7, at 271.)

That same decision also found that the utilities planned and projected to fill their net short positions with conventional resources, rather than the preferred resources. (*Id*., Finding of Fact 6, at 271.) It appears necessary to reiterate here the centrality of the loading order, and to direct the utilities to procure all of their generation resources in the sequence set out in the loading order. While hitting a target for energy efficiency or demand response may satisfy other obligations of the utility, that does not constitute a ceiling on those resources for purposes of procurement.

We understand that opportunities to procure additional energy efficiency or demand response resources may be more constrained than just signing up for more conventional fossil generation, but the utilities should still procure additional energy efficiency and demand response resources to the extent they are feasibly available and cost effective. If the utilities can reasonably procure additional energy efficiency and demand response resources, they should do so. This approach also continues for each step down the loading order, including renewable and distributed generation.

## 6. Energy Efficiency and Demand Response

The standardized planning assumptions and SCE's proposed alternative assumptions on energy efficiency and demand response issues received significant attention from a number of parties. We note that any procurement assumptions or targets approved in this proceeding do not alter the energy efficiency and demand response requirements that this Commission has imposed on the utilities in other proceedings. This decision does not alter any prior Commission decision on those issues, nor does it alter the policies or goals for those programs.

In this proceeding we are taking those programs into consideration in the context of procurement. Our priority here is ensuring that there is adequate overall procurement within the requirements of section 454.5. For example, if the Commission, in an energy efficiency proceeding, ordered the utilities to obtain 1000 units of energy efficiency, that order is still in effect, and the utilities still need to comply with that order. But if for some reason the utilities only obtained 900 units of energy efficiency, the utilities do not need to pretend that they actually got 1000 and refrain from procurement to make up the shortfall. For procurement purposes, the utilities need to make up the shortfall. The utilities may have to explain to the Commission elsewhere why they failed to comply with the energy efficiency requirement, but if the procurement needed to make up the shortfall is within the parameters specified in this decision, for procurement purposes the utilities do not need to seek Commission approval for the variation.

### 7. Hedging

DRA and Pacific Environment raise issues relating to the utilities' hedging costs and practices. DRA specifically questions what it considers to be the relatively high costs of hedging incurred by the utilities. While DRA acknowledges the need for hedging, it argues that the cost of utility hedging has been too high relative to the value received. (DRA Opening Brief at 9-10.)

DRA, SCE and PG&E fundamentally agree on a change to the method of calculating the Customer Risk Tolerance (CRT), which is used as a metric to guide the utilities in determining their appropriate level of hedging against potential electric rate increases. Currently, the CRT is set at one cent per kilowatt-hour (kWh). DRA, SCE and PG&E propose shifting from this flat rate to indexing the CRT to a percentage of the individual utility's system average rate. (See, e.g., DRA Opening Brief at 10-11; SCE Reply Brief at 16-17; PG&E Reply Brief at 28-29.) SDG&E opposes this change. (SDG&E Opening Brief at 17.)

Under the current flat rate CRT, the utilities' hedging levels (as a percentage of system average rates) will vary as rates change. For example, if rates rise, the utilities effectively end up hedging a smaller proportion of electric rates, and vice versa. By shifting to a percentage of the system average rate, the hedging level adjusts in correspondence to rate changes.

Using a percentage of the system average rate is a more logical and consistent approach. We adopt this proposal, and change the CRT from one cent per kWh to a percentage of the utility's system average rate. The calculation of the CRT would be updated every two years in each LTPP filing. If for some reason the LTPP filing is delayed or not made, the utilities are directed to update their CRT two years from the filing of the previous LTPP via a Tier 1 Advice Letter.[7]

There is less agreement as to the appropriate level at which to set the CRT, and there appears to be some confusion regarding how the CRT is used. Before we determine the appropriate level for the CRT, we need to clarify what the CRT actually means.

DRA and SDG&E assert that the utilities' hedging is supposed to "keep consumer prices from rising more than twenty-five percent above the CRT value." (DRA Opening Brief at 10; SDG&E Reply Brief at 9.) Under this understanding, if the CRT was set at 10% of the system average rate, a utility would engage in hedging to protect against consumer prices rising more than 12.5%. But DRA and SDG&E also seem to use the actual CRT, not the CRT plus 25%, as the hedging target. For example, SDG&E calculates its current CRT to be 6.2% of its system average rate, and describes its hedging as "guarding against the risk of a temporary 6.2% increase in the customer's electric bill…" (SDG&E Opening Brief at 18.)

This confusion likely results from the language in D.07-12-052, which referred to a threshold metric of 125% of CRT. (D.07-12-052 at 174-178.) This 125% of CRT figure represented the rate level at which a PRG meeting would be required and remedial action would be considered, such as additional hedges. (*Id.*) In other words, even if the

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[7] If for some reason there is no LTPP filing that is usable for this purpose, then the two years will run from the date of Commission approval of the previous CRT.

utility's forecasted value at risk would appear likely to result in rates increasing beyond the 1 cent per kWh CRT, no action was required until there was a forecast that rates were likely to increase by 1.25 cents per kWh. This gap has caused confusion, and may also have resulted in a *de facto* CRT that is 25% higher than the stated CRT. Accordingly, we are eliminating the difference between the CRT level and the PRG notification trigger level. If the CRT is expected to be hit or exceeded within the next quarter, the PRG is to be notified and additional remedial action is to be considered, consistent with the process described in D.07-12-052.

DRA proposes that the CRT be set at the equivalent of 10% of each utility's system average rate. (DRA Opening Brief at 11.) SCE proposes a level of 7.04%. (SCE Opening Brief at 13.) SDG&E recommends keeping its current level of 6.2%. (SDG&E Opening Brief at 18.) PG&E does not recommend a specific level, and does not expressly oppose any of the proposed CRT levels. (PG&E Reply Brief at 29.)

As DRA and the utilities note, hedging is a useful tool that protects ratepayers from "intolerable price spikes." (DRA Opening Brief at 9.) One question we need to look at here is what constitutes an "intolerable price spike" – what level of price increase would be intolerable? This question is necessarily subjective, and the record is not highly developed, with the parties largely suggesting numbers without much supporting analysis. DRA applies a brief common-sense analysis to show that hedging against a 6.5% increase on an average monthly bill of $95.97, taking into consideration the $3.00-plus cost of the hedging, means that the customer is being protected against the risk of anything more than an approximately $3.00 bill increase. (Ex. 400 at 26-27.)

DRA correctly notes that an effective $3.00 increase on a $96.00 bill is not a shocking or intolerable change. Based on a data response DRA received from PG&E, DRA recommends a CRT set at an indexed level of 10%. (Exhibit 400, Attachment 5.) Even without taking hedging costs into consideration, this would protect against an increase of more than $9.60 on the average $95.97 bill, as opposed to something near $6.23. When the costs of hedging are taken into consideration, this becomes even clearer, as the cost of hedging against a 10% rate increase should be lower than the cost of hedging against a 6.5% increase.

We agree with DRA that our currently authorized hedging appears to have resulted in ratepayers purchasing hedging to protect against relatively minor rate increases. In short, ratepayers have been paying for too much hedging. Raising the CRT to 10% of each utility's system average rate should reduce both the amount and cost of hedging. While this potentially increases the risk to ratepayers of rate increases, that risk remains relatively limited. In addition, with the elimination of the previous 25% gap between CRT and remedial action, the utility and PRG will be more closely monitoring hedging activities at the critical times when markets become more volatile.

To clarify, SCE notes correctly that:

> The CRT is used in conjunction with the TEVaR metric to measure the market sensitive bundled procurement cost at a given confidence level. The Commission adopted a 95% TEVaR in D.07-12-052. TEVaR is calculated and compared to the CRT each month and reported to the Commission and the Procurement Review Group. The …adoption of a CRT rate equal to 10% of the IOU's system average rate…is only a component of the required CRT analysis.

The CRT is derived as follows:

1. A base load forecast scenario in kWh for the applicable rolling forward 12-month period is prepared.

2. The total 12-month load forecast is multiplied by the current CRT rate, which is expressed in cents/kWh. This represents the CRT that is compared to the monthly TEVaR calculation.

The CRT rate metric, which used to be 1 cent/kWh, will now be 10% of each IOU's system average rate at the time of submittal of the conformed bundled procurement plan. (SCE Opening Comments at 11-12.)

PG&E is also correct in its similar clarification:

[T]he CRT value is derived by multiplying the 10% system average rate value by the forecasted sales for the rolling 12-month period. This resulting CRT value is then compared to the VaRto- Expiration ("VtE") value at a 95% confidence interval. Thus, the risk metric calculation is CRT – VtE (95%)…(PG&E Opening Comments at 8.)

DRA also proposes that the Commission should retain a third party, supervised by the Energy Division, to evaluate how the Commission oversees hedging. In particular, DRA recommends that the Commission order an independent third party review of utility To-Expiration Value at Risk (TeVaR) models and practices. (DRA Opening Brief, at 12-14.) Pacific Environment similarly recommends the Commission contract with an Independent Evaluator to evaluate hedging and risk management practices. (Pacific Environment Opening Brief at 29-30.) Finally, DRA proposes that the Commission should "conduct a stakeholder process to define the circumstances under which exceptions to limits outside of the approved IOU hedging plans will be authorized, and how these requests will be reviewed." (*Id*. at 14.)

The utilities question the need for and value of these additional processes at this time. (See, e.g., PG&E Reply Brief at 29-30.) We agree. While these may be reasonable activities for the Commission to undertake, it is not clear that there is a need for them now, particularly with the changes we are making in the use of the CRT. We may, however, consider undertaking a more comprehensive review of utility hedging practices in the future, as our practices under the LTPP stabilize.

## 8. Renewable Integration Products

SCE requests Commission approval to add "Renewable Integration Products" to the list of approved procurement products. (Ex. 202 at 65-66; SCE Opening Brief at 18.) SCE's description of these Renewable Integration Products is very general, and notes that they could consist of either financial or physical transactions. (Ex. 202 at 66.) SCE does not provide a clear definition of Renewable Integration Products, but rather provides examples of what the products "may be" or "could include." (SCE Opening Brief at 18.)

PG&E supports SCE's request, and provides a definition of Renewable Integration Products as: "Structured, physical or financial, products to allocate the risk associated with the variable output of intermittent resources. Products include, but are not limited to, those offered directly from a Balancing Authority." (Ex. 103 at II-7–II-9.)

Pacific Environment opposes this request, arguing that "it is unclear exactly what types of physical resources and financial arrangements SCE and PG&E are asking the Commission to approve…" (Pacific

Environment, Opening Brief at 28.) According to Pacific Environment, SCE's and PG&E's definitions of Renewable Integration Products are neither clear nor informative, and accordingly do not meet the requirements of AB 57. (*Id.*) CBE takes a similar position, arguing that SCE has not adequately explained what the Commission would be approving. (CBE Reply Brief at 6.)

DRA appears to be of several minds on this issue. DRA states that in its opening testimony it did not object to the use of renewable integration products, but opposed SCE's request to add them to the list of approved procurement products, on the grounds that it was not clear which renewable generation contracts they would apply to, there was no list or definition of what products would fit into the category, there was no calculation or estimate of the costs, there was no description of how the products related to the California Independent System Operator's (CAISO) 33% renewable integration study, and it was unclear exactly what authority SCE was actually seeking. (DRA Opening Brief at 20.)

DRA goes on to state that, based on additional information it obtained from SCE in subsequent conversations with SCE staff and in responses to data requests, DRA no longer objects to SCE's request. (*Id.*) But in its Reply Brief, DRA agrees with Pacific Environment that SCE and PG&E have not provided sufficient detail to clearly identify what Renewable Integration Products actually consist of, and asks the Commission to direct SCE and PG&E to provide more detail. (DRA Reply Brief at 6-7.)

We agree with Pacific Environment, CBE and DRA. While there will certainly be a need for renewable integration, and there may or may not be anything wrong with the products that SCE and PG&E might seek to procure for that purpose, the request of SCE and PG&E is simply too vague and broad for the Commission to know what it would actually be approving. Accordingly, we decline to add "Renewable Integration Products" to the list of approved procurement products at this time.

## 9. Direct Access and Community Choice Aggregation

MEA criticizes PG&E's proposed plan on the grounds that it contains inaccurate forecasts of the load served by MEA. Specifically, MEA argues that PG&E's plan improperly excludes the load of MEA. (MEA Opening Brief at 1.) According to MEA, PG&E's plan does not reflect the passage of Senate Bill (SB) 695 (Stats. 2009, ch. 337), and the correspondingly increased certainty regarding future direct access loads. (*Id*., at 3.). AReM notes that SCE updated its assumptions for direct access load based on SB 695 and D.10-03-022, but that PG&E and SDG&E did not. (AReM Opening Brief at 2-4.) Sierra Club and Shell fundamentally agree with MEA and AReM.

PG&E does not dispute the substance of MEA's argument, but states that it was just using the Commission mandated standardized planning assumptions. (PG&E Reply Brief at 8-10). PG&E also argued that this issue would more appropriately be addressed in Track I, rather than here in Track II. (Ex. 103 at III-1 – III-2.) Administrative Law Judge Allen ruled that the issue would be addressed in Track II (Transcript vol. EH-3 at 150-151).

SCE's approach is more closely aligned with MEA than with PG&E on this issue. Under its alternate analysis, SCE includes in its forecast the maximum allowable phase-in of new direct access sales permitted under SB 695, which are greater than under the Standardized Planning Assumptions. (SCE Opening Brief at 30-31.) Specifically, SCE forecasts that the Commission-authorized increase in direct access would be fully subscribed in each year until 2013, consistent with D.10-03-022. (*Id.*) SCE argues that their assumptions are more consistent with SB 695 and D.10-03-022 than the standardized planning assumptions.

We agree with MEA and SCE on this issue. It is appropriate to use more accurate load forecasts for MEA, consistent with SB 695, instead of the load forecast in the standardized planning assumptions. SCE is authorized to use its direct access assumptions for purposes of establishing position limits and ratable rates for its bundled procurement plan. The other utilities should engage in procurement consistent with SCE's assumptions for direct access.

## 10. Combined Heat and Power (CHP)

In D.10-12-035, the Commission approved a broad-ranging settlement between the three major utilities, consumer groups, and associations of Qualifying Facilities (QFs) generating electricity from CHP facilities. That settlement included forward-looking agreements by the utilities to procure certain amounts of electricity from QF/CHP resources. Future procurement was divided into an Initial Program Period, which is currently estimated to end by December 2015,[8] and a Second Program

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[8] The Initial Program Period runs 48 months from the effective date of the QF/CHP Settlement.

Period, which runs from expiration of the Initial Program Period until December 31, 2020.

For the Initial Program Period, SCE proposes to use the megawatt (MW) target numbers from the QF/CHP Settlement, as approved in D.10-12-035, rather than the standardized planning assumptions. (SCE Opening Brief at 33-34.) For the Second Program Period, however, SCE proposes a MW target of zero, on the grounds that the amount of CHP that will ultimately need to be procured during that period is subject to change, based on a number of factors. (*Id*. at 34-35.) PG&E generally concurs with SCE's position. (PG&E Reply Brief, at 11-13.) CAC and EPUC take issue with the assumption of zero CHP procurement in the Second Program Period. (See EPUC Opening Brief at 3-5.)

For the Initial Program Period, we find that it is reasonable to approve SCE's proposal to use the MW targets approved in D.10-12-035, rather than the standardized planning assumptions. Each utility should use its specific MW procurement targets from the QF/CHP Settlement as the basis for their procurement activities through 2015.

SCE's proposal to assume zero MW of CHP for the Second Program Period is less reasonable, however. First, CHP comes before conventional fossil generation in the loading order, so SCE's forecast of zero CHP would be credible only if SCE is also forecasting to procure zero conventional fossil generation. This is not the case, as SCE is forecasting that it will procure fossil generation in the Second Program Period. (See Exhibit 200 at 8, and Exhibit 201C at Appendix J.)

Second, there will continue to be a mandatory Public Utilities Regulatory Policies Act program for CHP facilities less than 20 MW that may execute contracts after 2015. And third, while there is uncertainty about how much CHP SCE or the other utilities may need to procure in order to satisfy the utility-specific GHG reduction targets in the QF/CHP Settlement, it is far from clear that the utilities will have achieved all of their required GHG reductions from CHP in the Initial Program Period.

Accordingly, SCE and PG&E should use the standardized planning assumptions for CHP megawatts for the Second Program Period. SDG&E should use the specific megawatt number for the second program period set forth in D.10-12-035.

## 11. Gas Supply Plan

PG&E presented an Electric Portfolio Gas Supply Plan, which included a proposal to procure biomethane for use in its electric generation plants. Specifically, PG&E proposes that: 1) it be authorized to pay a premium for biomethane over current forward gas prices; 2) that its procurement of biomethane be determined to be renewables portfolio standard (RPS) eligible for purposes of PG&E's compliance obligations under the California RPS; and 3) that PG&E not be required to file a separate advice letter or otherwise obtain Commission approval to count the purchase and use of biomethane towards PG&E's RPS requirements. (Ex. 101-C at D-13.)

TURN opposes PG&E's biomethane proposal, and makes alternative proposals as to how biomethane would count towards RPS compliance. (TURN Opening Brief at 1-5.) In the alternative, TURN recommends that this issue be addressed in the Commission's RPS proceeding, Rulemaking 11-05-005. (*Id*., at 5.)

This is not an appropriate forum for the Commission to make a finding of RPS eligibility. First, the determination of what resources are RPS-eligible is to be made by the California Energy Commission, not by this Commission. To the extent that this Commission does make any determination as to whether a particular resource can be counted for RPS compliance, the appropriate place for such a determination is in the RPS proceeding, not in this proceeding.[9] Accordingly, we decline to find that procurement of biomethane for use in electric generation facilities is eligible for RPS compliance.

PG&E's request for authority to pay a premium price for biomethane is based upon the additional value of its environmental attributes. Because we do not reach the issue of biomethane's RPS eligibility, we also decline to pre-authorize payment of a premium for biomethane over conventional gas. PG&E is free to purchase biomethane for use in its power plants, and may do so under the same conditions that it purchases conventional gas, but only to the extent that the price it pays for biomethane is no higher than the price of conventional gas. If PG&E wishes to pay a premium price for biomethane, independent of whether the biomethane may be RPS-eligible, it must obtain Commission approval via a Tier 3 advice letter process.

## 12. Nuclear Fuel Procurement Plan

PG&E is requesting approval of a Nuclear Fuel Procurement Plan that provides for forward contracting authority for obtaining uranium,

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[9] Even if such a determination could be made in this proceeding, there is

*Footnote continued on next page*

along with related conversion and enrichment services, for its Diablo Canyon Power Plant. (Ex. 100-C at 7-8.) PG&E states that its proposed Nuclear Fuel Procurement Plan "adjusts its existing procurement strategy to ensure that [Diablo Canyon Power Plant] reload requirements are adequately met in the future." (*Id*., Appendix C at 127.)

PG&E describes the current world market for nuclear fuel and related services, and trends in that market, and accordingly states that it is "requesting approval to enter into longer term contracts." (*Id*.) The record is somewhat unclear on what the currently approved contract duration is. PG&E's testimony does not clearly identify the current contract duration, but PG&E says its current Commission-approved Nuclear Fuel Procurement Plan has the same authorized contract duration as PG&E is requesting here. (PG&E Reply Brief at 27.)

DRA and Pacific Environment, however, argue that PG&E's proposal constitutes a significant expansion of the permitted contract duration, and that PG&E does not need the longer contract duration that it is proposing. (See, DRA Opening Brief at 17-19.)

Regardless of its currently-authorized contract duration, the contract duration requested by PG&E would extend beyond the expiration of the current operating license for Diablo Canyon. It is not clear why PG&E needs contracting authority that outlasts the operating license for the plant supplied by those contracts. While PG&E may be assuming that its license will be renewed, we cannot make such an assumption here. Accordingly,

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inadequate record support to make that determination here.

PG&E is granted authority to enter into contracts with a duration no longer than the expiration of the operating license.[10]

PG&E requests that it be allowed to seek authority for transactions outside of those pre-approved here by means of an "expedited" advice letter process, but does not specify what that means. (PG&E Reply Brief at 26-27.) Rather than create a new type of advice letter, PG&E may file under the standard advice letter process pursuant to General Order 96-B, and may request an expedited review if necessary.

PG&E notes that some suppliers of nuclear fuel and services are beginning to seek caps on their liability, which would result in significantly higher levels of potential liability exposure for PG&E and its ratepayers. (Ex. 100-C, Appendix C at 132-133.) PG&E proposes that any contract that seeks to impose this additional liability on PG&E would require Commission approval by means of its proposed expedited advice letter process.

TURN argues that the advice letter process is inappropriate for allocating liability for nuclear accidents. According to TURN, this issue is too controversial and raises too many policy questions to be addressed via advice letter. The allocation of risk for nuclear accidents, the potential magnitude of such risks, and the availability of insurance for such risks would all be more appropriately addressed in an application process. (TURN Opening Brief on Nuclear Fuel Procurement Plan at 2-4.) We agree

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[10] To the extent that contracts are unit-specific, the contract duration is linked to the license for the particular unit. If the contracts are not unit-specific, their duration is linked to the date of the later-expiring unit license.

with TURN. Any contract that seeks to impose additional liability on PG&E would require Commission approval, but by means of an application, rather than an advice letter.

## 13. Convergence Bidding

SCE proposes modifications to its existing convergence bidding authorization. (SCE Opening Brief at 20-23.) The Commission authorized the utilities to participate in convergence bidding in the CAISO markets in December, 2010 in D.10-12-034.[11]

The authority granted to the utilities was both interim and specifically limited:

> This interim authority is subject to a uniform set of three authorized bidding strategies for all IOUs. Uniform rules will provide broad consistency among the IOUs where applicable. Each IOU will have the discretion to allocate their bidding activities among these three bidding strategy categories. (D.10-12-034 at 2.)

Because convergence bidding was new, and this was the first time that the utilities have been authorized to participate in convergence bidding in CAISO markets, the Commission made it clear that it would be looking for information to revise the interim authority, based on the experience gained:

> Finally, we identify metrics and IOU reporting requirements by which the Commission and non-market participants can evaluate the effects of convergence bidding. This reporting is required because we are only granting interim authority for

[11] In D.11-06-004, the Commission granted a Petition to Modify from PG&E, seeking limited clarification of D.10-12-034.

> IOU participation in convergence bidding. These reports will provide the Commission with the information necessary to make any changes to IOU convergence bidding authority in any subsequent decision extending or modifying such authority. (*Id*. at 3.)
>
> We recognize that the outcome of IOU participation in convergence bidding activities is uncertain. However, the authority granted through this decision is only interim authority, and will continue to be reviewed. The ultimate scope of IOU authority, whether in this proceeding or a subsequent proceeding, may increase or decrease the authority granted here based on the experience gained during this interim period. (*Id*. at 12.)

SCE is asking for broader authority for convergence bidding, relaxing the existing Commission-established limits on locations, strategies, and reporting requirements. Specifically, SCE requests that the Commission:

> (1) remove the Commission-authorized strategy specific limitation on SCE's participation in convergence bidding, but still subject SCE's strategies to PRG review prior to implementation; (2) revise the eligible locations for submission of convergence bids to comport with SCE's physical supply, physical load, transmission assets (including CRRs), or transmission usage; and (3) limit SCE's reporting requirements to information associated with its *cleared* (as opposed to *all submitted*) convergence bidding transactions. (SCE Opening Brief at 21.)

Under this proposal, SCE would be allowed to bid at a much wider range of locations, for a much wider range of purposes, and would provide less information about its convergence bidding activities.

DRA opposes SCE's request, arguing that it is too soon to be making changes to the convergence bidding program. According to DRA, the

Commission should wait until there has been at least one year's experience under the interim authority to provide an informed basis for any significant changes or modifications to that authority. (DRA Opening Brief at 23-27.)

DRA is correct. It is simply too soon to be changing the fundamental rules of convergence bidding. We need to gain a more thorough understanding of how convergence bidding works in practice before we make significant changes to this program, especially changes as significant as those proposed by SCE. We do not address the merits of SCE's proposed changes, but rather decline to consider them at this time. SCE (and other parties) may seek appropriate changes to the convergence bidding rules in the future.

### 14. Short-Term Renewable Contracts

SCE requests Commission authorization to enter into short-term renewable energy transactions, for either bundled generation or stand-alone renewable energy credits (RECs). (SCE Opening Brief at 15-17.) SCE proposes a methodology under which the Commission would pre-approve SCE entering into renewable contracts lasting up to five years to purchase "up to a predetermined amount" of renewable generation or RECs. (Ex. 202 at 52-53.)[12]

CEERT strongly supports SCE's request. (CEERT Opening Brief at 1-11.) DRA opposes this proposal. (DRA Opening Brief at 21-23.) TURN also opposes it, arguing that SCE is asking for authority to procure up to

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[12] This amount is not clearly identified in SCE's testimony or briefs.

3750 gigawatt hours of energy that may in fact not be eligible for RPS compliance. (TURN Opening Brief at 5-8.)

This issue is more appropriately addressed in the Commission's RPS proceeding (R.11-05-005), where the Commission is comprehensively examining issues relating to the implementation of the recently amended RPS statute, including contracting issues. Accordingly, we do not consider the merits of SCE's proposal here. SCE's proposal to enter into pre-approved short-term renewable energy transactions is not approved, but SCE may request that (or similar) authority in the RPS proceeding.

### 15. Bilateral Contracts

PG&E proposes revisions to the existing criteria for bilateral contracts. PG&E recommends the removal of the Commission's existing "strong showing" standard for justification of bilateral contracts, along with other changes. PG&E argues that the existing standards are unclear. (PG&E Opening Brief at 16-19.)

DRA and Pacific Environment oppose PG&E's proposal to remove the "strong showing" standard, arguing that it is sound policy and that it is not unclear. (See, Pacific Environment Opening Brief at 18-20.) While there may be some ambiguity in the precise meaning of "strong showing," we decline to remove this requirement at this time. To the extent parties may wish to clarify the "strong showing" standard, they may do so in future LTPP proceedings.

### 16. Contract Duration

SCE proposes to procure contracts of "5 years or less" in duration, rather than the currently-approved "less than 5 years" standard applicable to bundled procurment. (SCE Opening Brief at 10.) Under the "less than 5 years" standard, SCE is not preapproved to sign a standard five-year contract, but rather could only sign a four- year and 364-day contract. PG&E has a similar proposal, allowing it to contract further in advance. (PG&E Opening Brief at 31-33.)

On its face, SCE's proposal appears to be a simple, minor and common-sense change, and it was not opposed by any party. (Pacific Environment opposed PG&E's proposal.) At the same time, we are concerned that there are multiple previous decisions and existing regulations that contain provisions that specifically apply to contracts of "less than 5 years." On a policy level, SCE's proposal makes perfect sense, but on a practical level we are concerned that there may be unforeseen consequences of the change. The record in this proceeding is not adequate to evaluate those potential consequences. Accordingly, we decline to make either SCE's or PG&E's proposed changes now, but we invite parties to address this issue in more detail in future LTPP proceedings.

## 17. Participation in RFOs and RFPs and Electronic Solicitations

PG&E is currently authorized to participate in Requests for Proposals (RFPs) issued by generators. In this proceeding, PG&E proposes to expand this authority to include RFPs and Requests for Offers (RFOs) issued by other market participants, such as other load serving entities (LSEs). (PG&E Reply Brief at 21-22.)

Pacific Environment opposes this request, while SCE supports PG&E. (See, SCE Reply Brief at 37-39.) PG&E and SCE argue that the authority they request would allow them to engage in transactions, such as the sale of excess resource adequacy (RA) capacity, which would provide ratepayer benefits.

Based on the record before us, it appears reasonable to allow the utilities to participate in RFPs and RFOs issued by other market participants, including other LSEs. Existing Independent Evaluator (IE) rules and procurement oversight rules would apply, including use of an IE for solicitations over two years, or for solicitations that involve a utility affiliate. An application must be filed and Commission approval obtained for the sale of products that are five years or more in duration.

PG&E also proposes to participate in electronic solicitations, expanding upon the previously authorized "electronic auctions." (PG&E Opening Brief at 15-16.) Pacific Environment opposes this request, arguing in particular against the potential use of sealed bids as decreasing transparency. (Pacific Environment Opening Brief at 25-26.) PG&E's proposal would allow PG&E (and presumably the other utilities) to participate in sealed-bid solicitations, and also to participate in a wider range of electronic platforms, including e-mails and instant messaging. (PG&E Opening Brief at 15.)

While this is a potentially significant expansion, and the language describing the types of transactions that could be participated in is both broad and vague, we acknowledge that solicitations may be conducted in a range of electronic formats in the future, and it seems reasonable to allow the utilities to participate. PG&E states that:

> The electronic solicitations that PG&E would conduct or participate in do not involve bids related to the development of utility-owned generation. Rather, these solicitations are for

short- and medium-term products, not new utility-owned resources. (PG&E Reply Brief at 20-21.)

In addition, PG&E states that all solicitations authorized would in fact be competitive processes, as opposed to bilateral negotiations. (PG&E Opening Brief at 15.)

With these conditions - no utility-owned resources, and only competitive processes – the utilities are authorized to engage in appropriate electronic solicitations. Again, existing IE rules would apply, including use of an IE for solicitations over two years, or for solicitations that involve a utility affiliate, and pre-approval is limited to transactions involving contracts that are less than five years in duration.

## 18. Independent Evaluator

PG&E proposes language that would "clarify that an IE is not required for other non-supply-side RFOs, such as for natural gas physical and financial products and other non-electric products." (PG&E Opening Brief at 20-21.) PG&E argues that this is consistent with D.07-12-052. Pacific Environment opposes this proposal, arguing that it is not consistent with prior Commission decisions, is not clear, and arbitrarily limits the types of projects reviewed by IEs. (Pacific Environment, Opening Brief at 23-25.)

Pacific Environment in turn proposes that the Commission's Energy Division use an IE to evaluate utility hedging and risk management "to ensure that unnecessary expenses are not being incurred." (Pacific Environment, Opening Brief at 29-30.) In addition, Pacific Environment recommends that an IE review the loading order and overall need, and urges the Commission to give IE reports "significant weight." (*Id.*, at 23-25.) SCE opposes Pacific Environment's proposals, arguing that the proposals to expand the role of the IE are inappropriate and inconsistent with section 454 and Commission decisions. (SCE Reply Brief at 35-37.)

We decline to make the changes to the role of IE suggested by both PG&E and Pacific Environment. PG&E's proposal is vague, and may in fact inappropriately narrow the role of IE previously established by this Commission, while Pacific Environment's proposal would unnecessarily expand the role of the IE. We leave in place our existing rules for use of an IE.

## 19. Floating Swap

SCE proposes to use a voluntary fixed price for short-run avoided cost (SRAC) floating swap mechanism that would allow QFs to obtain a fixed price rather than a price that changes with the price of natural gas. SCE argues that this swap would provide a hedge to the natural gas price exposure of SCE's customers. (SCE Opening Brief at 19-20.) No party opposed this proposal. We authorize SCE's proposed fixed price for SRAC floating swap.

## 20. Expiration of Procurement Authorization

PG&E notes that historically, utility procurement plans would expire at the end of their approved duration. According to PG&E, this has caused concerns about the utility's ongoing ability to procure in the event of a delay in approving a new procurement plan. PG&E proposes that any bundled procurement plan approved in this decision remain in effect until superseded by a subsequent Commission-approved plan. (PG&E Opening Brief at 12.)

This should not be a major concern, particularly since both D.04-12-048 and D.07-12-052 allowed for utilities to request updates or modifications to their procurement plans. (See, D.07-12-052 at 184-185.) We will not implement the change sought by PG&E, but rather we reiterate here that utilities may utilize this existing process to request any necessary extension of their procurement authorization.

## 21. Comments on Proposed Decision

The proposed decision of ALJ Allen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 30, 2011 by CAC and EPUC, CBE, CEERT, DRA, IEP, Pacific Environment, PG&E, Reid, SCE, SDG&E, Sierra Club and TURN, and reply comments were filed on December 5, 2011 by CAC and EPUC, DRA, Large-scale Solar Association, Pacific Environment, PG&E, Reid, SCE, SDG&E, Sierra Club and WEM. Changes were made to the proposed decision in response to comments.

## 22. Assignment

The assigned Commissioner is Michael R. Peevey and the assigned Administrative Law Judge is Peter V. Allen.

## Findings of Fact

1. SCE's proposed bundled procurement plan incorporates position limits and maximum rates of transactions that provide an upper boundary on the amount of SCE's pre-approved procurement.

2. The proposed bundled procurement plans of PG&E and SDG&E initially did not include position limits or maximum rates of transactions, but were revised to include them.

3. The proposed bundled procurement plans of PG&E and SDG&E initially did not incorporate an upper boundary on the amount of their pre-approved procurement, but were revised to include one.

4. The standardized planning assumptions developed by Commission staff are the foundation of the record in this proceeding.

5. SCE proposes alternative assumptions to some of the standardized planning assumptions.

6. PG&E and SDG&E initially largely disregarded the standardized planning assumptions.

7. Utility procurement must comply with the Commission's established loading order.

8. The past flat-rate utility hedging methodology has been very protective, but expensive and confusing.

9. Hedging levels indexed to system average rates will result in more consistent hedging levels.

10. Increasing the CRT should result in lower hedging costs.

11. Elimination of the 125% of CRT threshold for utility and PRG action will increase ratepayer protection and reduce confusion.

12. The Renewable Integration Products sought to be procured by SCE and PG&E are not clearly defined.

13. Including the maximum allowable phase-in of new direct access sales permitted under SB 695, as recommended by SCE and MEA, is a

more accurate approach than using the Standardized Planning Assumptions.

14. Using the CHP megawatt targets approved in D.10-12-035 for the Initial Program Period is more accurate than the standardized planning assumptions.

15. Using an assumption of zero megawatts for the Second Program Period is likely to be less accurate than the standardized planning assumptions, and is inconsistent with the loading order.

16. SDG&E has a specific CHP megawatt target for the Second Program Period set forth in D.10-12-035.

17. The California Energy Commission determines what resources are RPS-eligible.

18. This Commission has an open RPS docket (R.10-05-005) that may address how certain resources are counted for RPS compliance.

19. PG&E's Nuclear Fuel Procurement Plan seeks authorization to contract beyond the expiration of the operating license for Diablo Canyon.

20. Some suppliers of nuclear fuel and services are seeking to cap their own liability, shifting liability for nuclear accidents onto the utilities.

21. The Commission recently approved convergence bidding in D.10-12-034.

22. Issues relating to the duration of RPS contracts are being addressed in R.11-05-005.

23. The Commission currently applies a "strong showing" standard for justification of bilateral contracts.

24. The Commission currently limits pre-approval of bundled procurement contracts to "less than five years."

25. Other Commission decisions and regulations apply to contracts of less than five years.

26. The utilities are currently authorized to participate in RFPs issued by generators.

27. Other market participants, including other LSEs, also issue RFPs and RFOs.

28. The utilities have been authorized to participate in electronic auctions, but not in other forms of electronic solicitations.

29. The Commission has existing rules directing when and how an IE is to be utilized.

30. Gas-fired QFs receive payments that vary based on the price of natural gas.

31. A voluntary fixed price for SRAC floating swap mechanism would provide a hedge against natural gas price exposure for gas-fired QFs.

32. Existing processes allow the utilities to request extension of their procurement authorization.

## Conclusions of Law

1. Commission-approved procurement plans must result in just and reasonable rates under section 454.5.

2. The structure of SCE's proposed bundled procurement plan, which includes position limits and maximum rates of transactions, is generally consistent with section 454.5.

3. The structure of the proposed bundled procurement plans of PG&E and SDG&E was initially inadequate to ensure just and reasonable rates under section 454.5.

4. The structure of the revised proposed bundled procurement plans of PG&E and SDG&E, incorporating position limits and maximum rates of transactions, is generally consistent with section 454.5.

5. Standardized planning assumptions are necessary and useful for the Commission to evaluate utility procurement plans.

6. It is sometimes appropriate to adjust or depart from the standardized planning assumptions in order to improve forecasting accuracy.

7. Satisfying Commission-established targets for certain resources does not alter their place in the loading order.

8. Utility hedging should shift from a flat-rate to being indexed to system-average rates.

9. Utility hedging should be made simpler and less expensive.

10. The CRT should be increased to 10% of system average rates.

11. The 125% of CRT threshold for utility and PRG actions should be eliminated.

12. There is inadequate information on the record to approve utility procurement of "Renewable Integration Products."

13. Direct access forecasts should comply with SB 695.

14. CHP forecasts should comply with D.10-12-035, the loading order, and the standardized planning assumptions.

15. This is not an appropriate proceeding for addressing whether biomethane is RPS eligible.

16. Nuclear fuel procurement authority should not extend beyond expiration of the nuclear plant's operating license.

17. An expedited advice letter process provides an insufficient basis for utility ratepayers to assume potential liability for nuclear accidents.

18. It is too soon to revisit issues relating to convergence bidding.

19. This is not an appropriate proceeding for addressing the duration of RPS contracts.

20. It is not necessary to change the current standard for justification of bilateral contracts.

21. Other requirements relating to procurement contracts of less than five years must be taken into consideration before altering that existing limit.

22. It is reasonable to allow the utilities to participate in RFOs and RFPs issued by other market participants, including other LSEs.

23. It is reasonable to allow the utilities to participate in other forms of electronic solicitation as long as those are competitive, and are not for utility-owned resources.

24. It is not necessary at this time to change the existing rules applicable to IEs.

25. It is reasonable to allow SCE to offer a voluntary fixed price for SRAC floating swap mechanism.

26. It is not necessary to change the existing method for utilities to request extension of their procurement authorization.

# O R D E R

**IT IS ORDERED** that:

1. The bundled procurement plans of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company are approved as modified by ordering paragraphs 2 through 22 below.

2. Approval of Pacific Gas and Electric Company's and San Diego Gas & Electric Company's bundled procurement plans includes the incorporation of position limits and maximum rates of transactions, as proposed by the companies in their comments on the Proposed Decision.

3. The Commission approves the use of standardized planning assumptions.

4. Utility procurement must comply on an ongoing basis with the Commission's loading order.

5. The Customer Risk Tolerance applicable to utility hedging is changed from one cent per kilowatt-hour to 10% of a utility's system average rate.

6. The 125% of Customer Risk Tolerance threshold metric is eliminated.

7. The request of Southern California Edison Company and Pacific Gas and Electric Company to procure "Renewable Integration Products" is denied.

8. Southern California Edison Company is authorized to use its proposed direct access assumptions, and the other utilities should procure consistently with those assumptions.

9. Southern California Edison Company and Pacific Gas and Electric Company are authorized to use combined heat and power megawatt target numbers from Decision 10-12-035 for the Initial Program Period, and from the standardized planning assumptions for the Second Program Period. San Diego Gas & Electric Company should use combined heat and power megawatt target numbers from Decision 10-12-035 for both the Initial and Second Program Periods.

10. The Commission declines to find biomethane to be Renewables Portfolio Standard eligible in this proceeding.

11. Pacific Gas and Electric Company is authorized to enter into nuclear fuel contracts with a duration no longer than the expiration of the operating license for its nuclear power plant.

12. Any contract that seeks to impose additional liability for nuclear accidents on Pacific Gas and Electric Company and its ratepayers must be approved by an application, not an advice letter.

13. Southern California Edison Company's proposed modifications to its convergence bidding authorization are denied.

14. Southern California Edison Company's proposal to enter into short-term renewable energy transactions is not approved, but may be addressed in the Renewables Portfolio Standard proceeding, Rulemaking 11-05-005.

15. Pacific Gas and Electric Company's proposed revisions to the existing criteria for bilateral contracts are denied.

16. Southern California Edison Company's and Pacific Gas and Electric Company's proposals to alter allowable contract length are denied.

17. Pacific Gas and Electric Company's request to allow utilities to participate in requests for proposals and requests for offers issued by market participants, including other load serving entities, is granted. Existing Independent Evaluator rules will apply.

18. Pacific Gas and Electric Company's request to allow utilities to participate in competitive electronic solicitations other than auctions that do not involve utility-owned resources is granted. Existing Independent Evaluator rules will apply.

19. Pacific Gas and Electric Company's and Pacific Environment's proposals to change the role of the Independent Evaluator are denied.

20. Southern California Edison Company's proposal to offer a voluntary fixed price for short-run avoided cost floating swap mechanism is granted.

21. Pacific Gas and Electric Company's proposal to eliminate the expiration of utility procurement authorization is denied.

22. Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company shall each file a Tier 3 Advice Letter conforming their bundled procurement plans to incorporate the modifications made in this decision no later than 90 days from the effective date of this decision.

23. This proceeding remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California.