

**PRELIMINARY STAKEHOLDER
EVALUATION OF THE CALIFORNIA
RENEWABLES PORTFOLIO STANDARD**

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CHAPTER 1: INTRODUCTION

Policy Background

The California Renewables Portfolio Standard (RPS) was established by Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher), effective January 1, 2003. SB 1078 requires certain retail electricity sellers to increase their purchases of eligible renewable energy resources by at least one percent each year so that 20 percent of their retail sales come from renewable energy resources by 2017. The state's *Energy Action Plan* and the California Energy Commission's *Integrated Energy Policy Report*¹ have since expressed a state goal of accelerating the implementation of the RPS such that the 20-percent goal is met seven years early—by 2010. The Governor has endorsed this accelerated schedule and has set a goal of achieving a 33-percent renewable energy share by 2020 for the state as a whole.²

Much has already been accomplished under the state's RPS. Regulatory rules implementing major portions of the statute have been completed by the California Public Utilities Commission (CPUC) and the California Energy Commission. The state's three major investor-owned utilities (IOUs), through interim renewable energy solicitations issued in 2002 and through bilateral contracts signed since that time, have increased their purchases of renewable energy.

- San Diego Gas & Electric (SDG&E) had the farthest to go to meet the state's RPS, with just one percent of its electricity supply coming from eligible renewable sources in 2002. Since that time, SDG&E has signed renewable energy contracts totaling approximately 275 MW of capacity, and 4.5 percent of the utility's retail sales in 2004 were from renewable energy sources.
- Southern California Edison (SCE) was heavily invested in renewable energy even before the establishment of the state's RPS. Nonetheless, SCE has increased its renewable energy purchases from 17 percent in 2002 to 18.2 percent in 2004. In March 2005, SCE filed with the CPUC six new renewable contracts, totaling 142 to 428 megawatts (MW) of capacity and representing 0.9 to 2.9 percent of SCE's retail sales.³ Also in March 2005, SCE filed contract amendments that will allow the repowering of four existing wind projects.
- Pacific Gas and Electric (PG&E) has also increased its renewable energy purchases over this time period (from 10.4 percent in 2002 to 12.4 percent in 2003, dropping to 11.7 percent in 2004 in part due to a poor hydro year), through purchases under its 2002 interim renewable energy solicitation, through bilateral negotiations with several existing biomass projects, and with two wind projects seeking to repower their facilities. Nonetheless, PG&E has lagged behind the one-percent-per-year targets and is currently carrying a significant deficit into the 2005 compliance year.⁴ In 2004, PG&E physically purchased just 30 percent of its incremental renewable procurement target for

that year. In April 2005, PG&E filed with the CPUC three new wind power contracts, with a total capacity of 142 to 158 MW and aggregate deliveries of 490 gigawatt-hours (GWh) per year (representing about 70 percent of PG&E's 2004 incremental procurement target).

Despite these successes, the state has also experienced implementation challenges. Most of the initial utility renewable energy purchases were with existing and already operating renewable energy generators, and only recently has the RPS begun to stimulate renewable capacity additions. The first "formal" RPS solicitations were issued by PG&E and SDG&E in July 2004, a full year and a half after the RPS became effective, and contract announcements did not begin until late April 2005. Regulatory delays have slowed the process, and important elements of the state's policy remain unresolved, such as the application of the RPS to energy service providers (ESPs) and community choice aggregators (CCAs). Concerns have been raised not only on the substance of the state's RPS design, but also on the timeliness of implementation and the transparency of the overall process.

Objectives

This report provides a preliminary stakeholder assessment of early experience with California's RPS. The report does not seek to address every element of RPS design and implementation. Instead, three general areas are covered:

- **Overall Policy Design and Regulatory Process:** This area covers the overall policy design and the regulatory process of establishing the state's RPS, and areas of needed policy improvement.
- **Utility Solicitations:** This area highlights experience with the three most recent utility solicitations (SCE 2003, PG&E 2004, SDG&E 2004).
- **Deliverability:** This area covers the rules for renewable energy "delivery" for both out-of-state and in-state renewable generators.

Guided by stakeholder interviews, and focused on the areas listed above, the goals of this report are to identify lessons learned with early implementation of California's RPS and to highlight areas of policy improvement that stakeholders believe are necessary for the state to achieve its aggressive commitment to renewable energy. This report also, where appropriate, benchmarks California's experience with that of the other 20 RPS policies enacted in the United States.

Methods

This report is based primarily on stakeholder interviews, supplemented with a review of relevant statutes, regulatory decisions, party testimony, and utility solicitation documents. Where relevant, experience from other state RPS policies is contrasted with that of California.

In conducting the interviews, a loose interview guide was used, a copy of which is provided as Appendix A. Each interview lasted from 40 minutes to two hours, and all interviews were conducted from April 22 to June 8, 2005.

We sought to interview only those stakeholders likely to be familiar with the state's RPS, focusing initially on the state's three major IOUs, renewable energy developers, developer associations, and other parties (nonprofits, ESPs, CCAs, and distributed generation interests). Ultimately, we were successful in interviewing 21 different stakeholders, including three utilities, 10 developers, three developer associations, three nonprofit groups, and two ESP/CCA representatives (see Table 1). Our sample is clearly dominated by developers and developer associations, a point that should be remembered when reviewing the interview results.

Table 1. Interview Respondents

Utilities	Developers	Developer Associations	Nonprofit Organizations	ESPs/CCAs
Southern California Edison (SCE)	Calpine CalEnergy	California Wind Energy Association (CalWEA)	Union of Concerned Scientist (UCS)	ESP Representative
Pacific Gas & Electric (PG&E)	Vulcan Power Ridgewood	Independent Energy Producers Association (IEP)	The Utility Reform Network (TURN)	CCA Representative
San Diego Gas & Electric (SDG&E)	Sierra Pacific Industries PPM Energy AES/SeaWest FPL Energy Oak Creek Energy Systems Solel	Center for Energy Efficiency and Renewable Technologies (CEERT)	Green Power Institute (GPI)	

Source: KEMA Inc.

Report Outline

The remainder of this report is structured as followed:

- Chapter 2 begins with an overview of the regulatory processes used to implement California's RPS and a brief comparison of California's implementation processes with those employed by other states with RPS requirements. The chapter then summarizes stakeholder interview comments on the overall RPS design and the RPS implementation process in California.

- Chapter 3 provides an overview of the three most recent IOU renewable energy solicitations, discusses the results of those solicitations and the delays that have been experienced, reviews plans for solicitations in 2005, and summarizes stakeholder interview results on these solicitations.
- Chapter 4 briefly describes the current procedures for ensuring "delivery" of renewable energy under California's RPS, identifies alternative delivery standards that might be applied, and highlights stakeholder interview results on this topic.
- Chapter 5 concludes the report with a summary of recommendations and conclusions, informed by the interview results but also influenced by the opinions of the authors.
- Appendix A includes the interview protocol used to guide the stakeholder interviews.

CHAPTER 2: POLICY DESIGN AND IMPLEMENTATION PROCESSES

Overview of California RPS Implementation

The California RPS was signed into law on September 20, 2002 (SB 1078), and became effective on January 1, 2003. Regulatory implementation responsibilities are shared by the CPUC and the Energy Commission.

The CPUC has since established the foundation of the RPS for the state's three large investor-owned utilities. On June 19, 2003, the CPUC made threshold decisions on the basic structure and application of the RPS; laid out the general approach to be used for utility solicitations; and set compliance schedules, flexibility mechanisms, and penalties for noncompliance (D.03-06-071). On June 9, 2004, the CPUC established its methodology for establishing market price referents (MPRs) (D.04-06-015), and adopted standard contract terms and conditions that govern power purchase agreements signed under the state's RPS (D.04-06-014). The CPUC also established methods for ranking bids based on their expected transmission costs with transmission ranking cost reports (TRCRs) (June 9, 2004; D.04-06-013) and developed a process by which the state's major IOUs are required to submit annual renewable energy procurement plans and RPS compliance reports. The approach to evaluating bids under a least-cost, best-fit (LCBF) framework was defined on July 8, 2004 (D.04-07-029), and a decision clarifying the participation of renewable distributed generation under the state's RPS was completed on May 5, 2005 (D. 05-05-011).

As specified in SB 1078, the Energy Commission has responsibility for renewable resource eligibility determinations, administration of supplemental energy payments (SEPs), and establishment of a regional renewable energy tracking and accounting system. In implementing these duties, the Energy Commission has published its Renewable Portfolio Standard Eligibility Guidebook, its New Renewable Facilities Program Guidebook, and its Overall Program Guidebook for the Renewable Energy Program, as well as related policy decisions, which are implemented through the Guidebooks.⁵ In addition, the Energy Commission has led the development-effort for the Western Renewable Energy Generation Information System (WREGIS), and has supported CPUC staff in its duties.

Despite these regulatory actions, after more than two years since SB 1078 took effect, the process of designing the state's RPS is still ongoing. Among other issues, the CPUC and Energy Commission have ongoing deliberations to:

- Establish the regulatory and compliance framework for ESPs and CCAs
- Establish the regulatory and compliance framework for the smaller IOUs
- Consider the use of time-of-delivery differentiated MPRs, and other changes to the MPR calculation methodology

- Consider updating integration cost estimates
- Further define the role of distributed generation under the RPS
- Develop a functional west-wide tracking system for renewable energy
- Reconsider whether unbundled renewable energy certificates (RECs) might be allowed
- Consider revising the implementation procedures for the TRCR
- Encourage transmission expansion to renewable resource-rich areas of the state.

Perhaps most notably, compliance requirements for ESPs and CCAs, which began by law on January 1, 2003 for at least some ESPs, have yet to be implemented by the state's regulatory agencies. Also notable is that the regulatory scaffolding now developed for IOUs is unlikely to hold for ESPs and CCAs, and different procedures may be required.⁶

Comparison with Other States

Nineteen states and Washington, D.C. have established RPS requirements. These standards have not been operating long enough to come to definitive conclusions on the best design and approach to RPS implementation.⁷

What is clear is that the framework and process for implementing California's policy bears little resemblance to those used in other states and has not only experienced substantial delays,⁸ but has also taken longer than implementation processes used in most other states. Indeed, we are unaware of any state RPS implementation process that comes close to approximating the detail, complexity, and duration of the process in California.

Table 2 compares some of the attributes of the implementation timeframe in California to those used in other states. As shown, California's regulatory agencies were given a very difficult implementation schedule. With the Governor's signature on September 20, 2002 and renewable energy purchase requirements that nominally began on January 1, 2003, there was little hope that the state's RPS could be implemented in time for the first year of purchase requirements. With some foresight, the CPUC had already directed the utilities in 2002 to issue interim renewable energy solicitations, allowing those purchases to qualify for the utilities' early-year RPS obligations. Nevertheless, California is unique in the short period of time between enactment of the legislation and the state's first RPS obligations (see "enactment to first obligation" in Table 2).

Also evident is that the California implementation process has been more time consuming than those in most other states. From the date of enactment, it took nearly two years for the regulatory framework for the state's IOUs to be developed, and after more than two-and-one-half years, little progress has been made in developing such a framework for the state's other obligated parties. Many other RPS design elements also remain unresolved. Table 2 suggests that the initial design

process in other states has also been slow, as shown by the number of months between enactment and regulations, but here the table is misleading. Because the period of time between the enactment of the law and first obligation under the law is often generous in other states (see "enactment to first obligation" in Table 2), there has been no need to proceed immediately in the drafting of regulations. As such, in many cases the number of months shown in the table for "enactment to regulation" is significantly greater than the time actually spent in the development of regulatory rules.

Table 2. Implementation Timeline for State RPS Policies †

State	RPS Enactment	Initial Completion of Regulations	First Obligation	Enactment to Regulation (months)	Enactment to First Obligation (months)
CA	Sept. 2002	July 2004 - large IOUs Not completed - others	Jan. 2003	22 33+	4
AZ	Apr. 2000	Mar. 2001	Jan. 2001	11	9
CO	Nov. 2004	Mar. 2006 deadline	Jan. 2007	16 (planned)	26
CT	Apr. 1998	Dec. 1998	July 2000	8	27
DC	Apr. 2005	Not completed	Jan. 2007	2+	21
HI	June 2004	Dec. 2006 deadline	Dec. 2003 [#]	30 (planned)	(6)
MA	Nov. 1997	Apr. 2002	Jan. 2003	53	62
MD	May 2004	Draft April 2005	Jan. 2006	11 (draft)	22
ME	May 1997	Sept. 1999	Mar. 2000	28	34
MN	May 2003	June – Oct. 2004	Jan. 2005	17	20
MT	April 2005	June 2006 deadline	Jan. 2008	14 (planned)	33
NM	Mar. 2004	Jan. 2005	Jan. 2006	10	22
NJ	Feb. 1999	June 2001	Sept. 2001	28	31
NV	June 2001	May 2002	Jan. 2003	11	19
NY	Feb. 2003*	Sept. 2004	Jan. 2006	19	35
PA	Nov. 2004	Not completed	Mar. 2007	7+	28
RI	July 2004	Not completed	Jan. 2007	11+	30
TX	May 1999	Dec. 1999	Jan. 2002	7	32
WI	Oct. 1999	Nov. 2000	Jan. 2001	13	15

† Current as of early June 2005. Iowa's "RPS" has already been fully met, and is not included in the table.

* Date on which regulatory proceeding to consider RPS began.

Not binding until 2010.

Source: KEMA Inc. Collected through multiple channels, including review of state RPS legislation and subsequent regulations.

The implementation process associated with California's RPS is unique in several respects:

- **Extensive Oversight of Renewable Energy Procurement:** The degree of regulatory oversight of California's IOUs in renewable resource procurement and bid evaluation has simply not been replicated in any other state's RPS, and no other state has imposed these types of oversight requirements on their competitive ESPs. As discussed in greater depth below, these oversight responsibilities are, in part, required by statute, and many are caused by the separation of payment between the MRP and the SEP.
- **Little Consolidation of Decisions:** Many other states have consolidated multiple RPS design issues into single decisions, speeding the overall design process, while California's implementation agencies have chosen to address these issues within a large number of individual decisions.
- **Separation of Rules for IOUs from Rules for ESPs and CCAs:** Other states with retail electricity competition have typically developed RPS rules that apply equally to both still-regulated and competitive market players.⁹ In California, not only has the CPUC chosen to separate the regulatory implementation processes for IOUs and ESPs/CCAs, but the regulatory process now developed for IOUs cannot easily be applied to ESPs and CCAs.
- **Distributed Responsibilities Between Two State Agencies:** With some exceptions (e.g., New York and, to a lesser extent, New Jersey and Connecticut), implementation responsibility for RPS requirements in other states is primarily vested with a single state agency, typically the public utilities commission. In California, SB 1078 called for distributed responsibilities between the CPUC and the Energy Commission.

In addition to these process differences, the unique design of California's RPS legislation has required the state's regulatory agencies to address issues that have simply not arisen in other states. Consider what the California RPS has that other state RPS policies do not:

- **Procurement Review Groups:** Procurement review groups (PRGs), consisting of non-market participants willing to sign nondisclosure agreements, have been established by the CPUC for each of the state's IOUs to help oversee procurement decisions. No other state RPS includes external stakeholders in ongoing procurement oversight in this fashion, though regulatory contract pre-approval processes (and stakeholder comments within those processes) are not uncommon.

- **Transmission Ranking Cost Reports:** SB 1078 requires that transmission costs be considered in bid evaluation, but does not specify the process by which this should occur. To satisfy this legislative requirement, the IOUs in California are obliged by the CPUC to conduct TRCRs. The TRCRs are intended to estimate the cost of needed transmission expansion for potential renewable energy projects. These reports, completed by the IOUs with information submitted to them by potential future renewable energy bidders in advance of renewable energy solicitations, are then used to help evaluate renewable energy project proposals. Utilities required to meet RPS obligations in other states consider transmission expansion costs, but not through formal TRCRs that are approved by the regulatory commission and that are then formally applied in bid evaluation.
- **Market Price Referents and Supplemental Energy Payments:** California's RPS statute caps utility payments for renewable energy at the MPR (reflecting the all-in cost of baseload and peaking gas-fired generation), with eligible above-MPR costs covered by the state's renewable energy fund through SEPs, administered by the Energy Commission. Utilities are not required to achieve the RPS targets if SEP funding is not sufficient. No other state uses an MPR-SEP process to separate payments between the utility and a state agency, though two states (New York and Arizona) rely on less complex mechanisms to explicitly use system-benefits charge funds to help pay for the RPS.¹⁰
- **Least-Cost, Best-Fit Evaluation:** The CPUC has identified criteria the IOUs must use to select winning bidders based on the "least cost, best fit" evaluation described loosely in SB 1078. Though California's utilities are provided discretion in how they apply LCBF considerations in bid evaluation, and some other states also impose bid-evaluation requirements on their regulated utilities, the CPUC gives California's utilities somewhat less latitude in their evaluation practices than utilities in most other states. For example, California utilities must incorporate CPUC-approved bid-evaluation protocols, integration cost estimates, TRCRs, and qualitative evaluation factors into their bid evaluation processes.
- **Standard Contract Terms and Conditions:** As required by statute, the CPUC has developed a limited set of standard contract terms and conditions for use by the state's IOUs in procuring renewable energy. Some states impose some contracting requirements on their regulated utilities (e.g., minimum contract term requirements are imposed in Colorado, Nevada, Montana, Connecticut), but standard contract terms and conditions are thus far atypical. No other state with competitive ESPs imposes detailed contracting requirements, including requirements on contract duration, on those participants.

- **Renewable Energy Certificates:** The CPUC does not currently allow RECs to be unbundled and sold separately from the underlying electricity for the purpose of RPS compliance (debate exists on whether SB 1078 would allow unbundled RECs). Instead, the CPUC requires that the state's IOUs purchase renewable electricity with its associated RECs in a bundled transaction. Most, but not all, other states allow at least some use of unbundled renewable energy certificates for compliance demonstration. In all states with competitive ESPs, unbundled RECs are allowed.

Perhaps of most importance, separating payments between electricity suppliers (up to the MPR) and SEPs creates regulatory responsibilities that would not otherwise exist. This practice directly imposes MPR and SEP process requirements on the CPUC and Energy Commission. Perhaps less obvious, it is also indirectly responsible for the level of regulatory oversight of utility procurements (and, therefore, LCBF requirements, standard terms and conditions, transmission ranking costs reports, procurement review groups, etc.). This is because, without such oversight, the state's electric utilities and competitive energy service providers may have an incentive to purchase renewable energy at high costs (their own costs capped by the MPR), thereby depleting the state's SEP funds more rapidly than might be socially optimal.

In states without such a separation of payments, the perceived need for detailed regulatory oversight is reduced. As a result, in a large number of states, the public utility commissions' primary responsibilities are (or will be) to review compliance after the fact and, in some cases, to pre-approve renewable energy contracts.¹¹ In other states, the legislature and/or the regulatory commission often establish some limited contracting requirements, and contract-pre-approval is the norm.¹² In no state is the degree of oversight or the corresponding number of detailed and complex RPS design issues similar to that experienced in California.

These unique attributes of California's RPS statute have no doubt substantially contributed to the regulatory delays that have been experienced; however, just because California's RPS imposes requirements that are atypical does not automatically mean that the state's RPS is "overly" complex or detailed. California is a large state with an established renewable energy industry and a hybrid market structure, and the state's RPS is among the most aggressive in the country. Whether the legislative and regulatory requirements imposed by California's RPS are excessive is and should be the subject of debate.

Some have also argued that the implementation of California's RPS by the state's IOUs has not been sufficiently transparent. Ongoing work at Lawrence Berkeley National Laboratory to review 12 major western utility resource plans shows that utility resource plans in California are less transparent (and more redacted) than in any other state in the west that imposes public planning processes.¹³ The renewable energy procurement plans of the IOUs in California also contain significant amounts of information that is not made public, even though the state's utilities clearly state

that the plans are merely indicative. The amount of information released on California's utility baseline renewable energy purchases and on new renewable energy contracts has also been criticized, though in recent filings California's utilities appear to be providing more of this data than previously. Finally, some stakeholders have called for more consistency and transparency in the bid evaluation protocols used by the state's IOUs in their renewable energy requests for offers (RFOs).

As in California, renewable energy contract prices are—with some exceptions—rarely revealed in other states. Details on contracted capacity, term, quantity, counter-parties, and other details are commonly revealed upon contract signature; over time, California's utilities also appear to be providing these data on new renewable energy contracts. The level of information being provided on renewable energy contracts is therefore similar among states.

A broader comparison of the transparency of RPS implementation in California to that in other states is challenging, however, because other states simply do not impose the same requirements on their electric utilities as those imposed in California (e.g., few states have pre-approved evaluation protocols or procurement plans). Of course, neither do other states have publicly funded SEP payments that are used to support the contracts that are awarded. Experience from other states therefore provides little guidance on issues of transparency and the advantages and disadvantages of enhanced information release for the purposes of renewable energy procurement plans and bid evaluation protocols, especially in a market with SEP payments.

Stakeholder Interview Results

As one might expect, respondents had widely ranging views of the effectiveness and design of the state's RPS and on the regulatory process used to implement the policy.

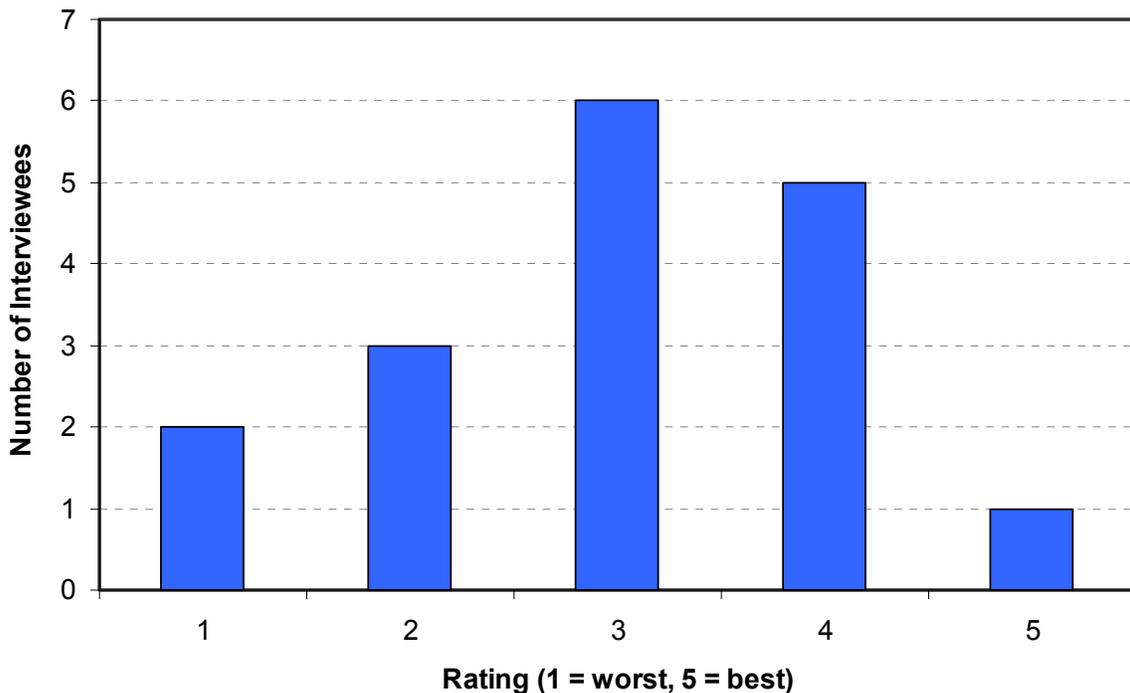
Policy Design

General Views of the Overall Policy Design

Views of how the RPS policy is working in general range from observations that the policy is structured appropriately and that California is off to a good start, to the viewpoint that the policy is an unmitigated disaster. Many respondents reported that the process has been overly complex and lengthy and that the outcome is far from ideal, but that solicitations are now occurring and contracts are being signed. As a result, several developers, utilities, and others cautioned that patience is required, that tweaks to the design should be made, but that a total redesign of the RPS (or a major re-examination of completed decisions) would not be appropriate until additional experience is gained with the current framework. There appears to be little stomach for initiating a complex, policy redesign process that may further delay new renewable energy additions.

When asked to rate the overall design and effectiveness of the California RPS (where 1 means the policy is broken and not working and 5 means the policy is operating flawlessly), respondents assigned the policy an average rating of 3.0. Generally, ESP/CCA representatives, developers, and developer associations had the most pessimistic views of the state's RPS (average rating of 2.0, 3.0, and 2.5, respectively). Nonprofit associations and electric utilities had more favorable impressions of the policy (average ratings of 3.8 and 3.7, respectively).¹⁴

Figure 1. Overall Rating of the California RPS



Source: KEMA Inc. Derived from interview results.

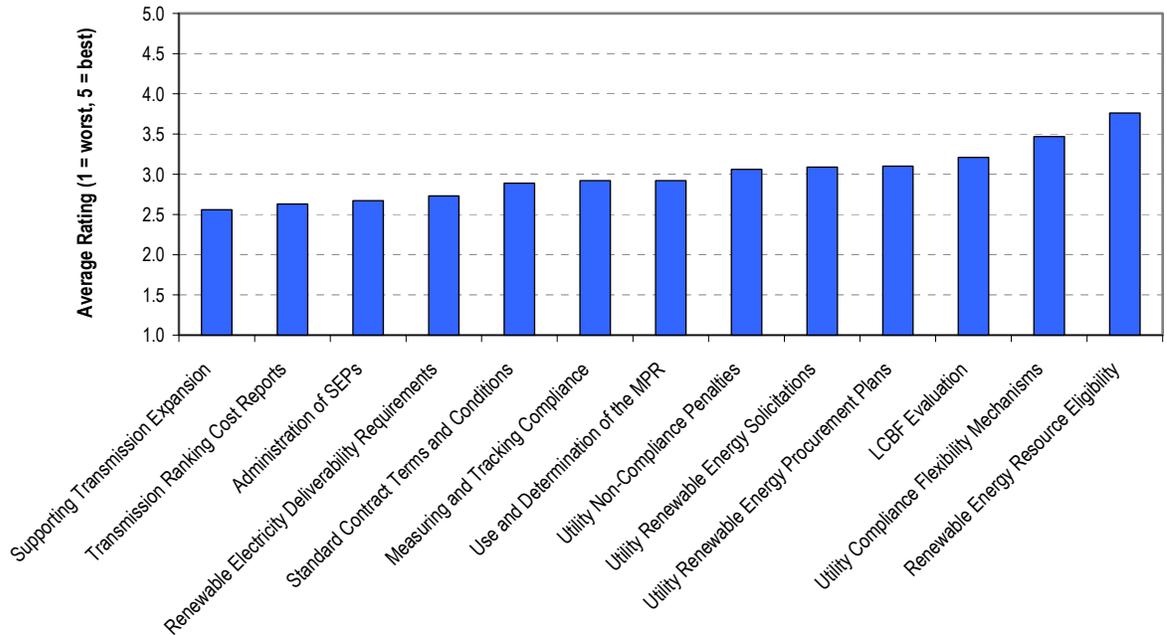
Policy Element Ratings

There are many elements of the California RPS, and a subsequent question asked how the respondents felt these various elements were working (1 meaning the element is not working and needs immediate change; 5 meaning the element is working effectively and doesn't need to be altered). Figure 2 presents the average rating for each of these elements, while Table 3 presents the same results by respondent type. Because many of our respondents are developers, segmentation of response by respondent type is arguably more informative than the overall ratings, which are dominated by the larger number of developers in our sample.

As expressed through the overall ratings, stronger elements of the policy's design include the renewable energy eligibility rules, utility compliance flexibility mechanisms, and the LCBF evaluation process. Areas of greatest concern included

support for transmission expansion, the TRCRs, administration of SEPs, and the renewable electricity deliverability requirements.

Figure 2. Ratings of RPS Design Elements



Source: KEMA Inc. Derived from interview results.

Though sample size is problematic, Table 3 appears to confirm the statement made earlier that developers and developer associations are, to some degree, less sanguine than other parties about the design of the California RPS. In particular, developer representatives rate the standard contract terms and conditions, the TRCRs, the utility renewable energy solicitations and procurement plans, the measurement and tracking of compliance, and the LCBF evaluation process substantially less favorably than the utility respondents. The utility respondents rate the noncompliance penalties far lower than other respondents. The respondents representing nonprofit organizations generally rated the following elements more favorably than the developer respondents: LCBF evaluation, utility compliance flexibility, noncompliance penalties, and the utility renewable energy solicitations. The nonprofit organizations identified the current deliverability rules and the TRCRs as substantially more problematic than any other respondent type.

Table 3. Ratings of RPS Design Elements by Respondent Type

Design Element	Overall Avg.	Developers/ Developer Assoc. (n = 13)	Nonprofits (n = 3)	Utilities (n = 3)
Supporting Transmission Expansion	2.6	2.7	2.0	2.0
Transmission Ranking Cost Reports	2.6	2.5	2.0	3.7
Administration on SEPs	2.7	2.8	n/a	2.0
Deliverability Requirements	2.7	2.9	2.3	2.8
Standard Contract Terms and Conditions	2.9	2.6	3.0	4.0
Measuring and Tracking Compliance	2.9	2.8	2.7	3.7
Use and Determination of the MPR	2.9	3.0	2.7	2.8
Utility Noncompliance Penalties	3.1	3.0	4.7	1.0
Utility Renewable Energy Solicitations	3.1	2.7	4.0	4.0
Utility Renewable Procurement Plans	3.1	2.9	3.0	3.7
LCBF Evaluation	3.2	2.9	4.0	3.8
Utility Compliance Flexibility	3.5	3.1	4.7	3.7
Renewable Energy Resource Eligibility	3.8	3.8	4.3	3.5
Overall Average	3.0	2.9	3.3	3.1

Note: ESPs and CCAs are not included here because the two ESP/CCA representatives offered relatively few ratings of these design elements.

Source: KEMA Inc. Derived from interview results.

Positive and Negative Aspects of the RPS

In a separate open-ended question interview respondents were asked more generally what aspects of the state's RPS design they viewed as most useful. The most common response by far was the **overall renewable energy targets**: eight developers/developer associations, one nonprofit, and one utility identified these targets as one of the most useful elements of the policy. No other design element was mentioned by more than five respondents. Positive elements noted by two to five respondents included:

- Solicitations and the ability to do bilateral deals between the formal solicitations (three developers/developer associations, two utilities)
- Compliance flexibility mechanisms (two ESP/CCA representatives, one utility)
- The fundamental design of the entire policy (one developer, one utility)

- Long-term contracting requirements (two nonprofits)
- The open process by which the policy has been designed (two developers),
- The MPRs and SEPs (one developer, one utility),
- The LCBF evaluation process (one developer, one utility).

Respondents were more vocal when asked in an open-ended fashion to identify the design elements that are most problematic.

- **Transmission Expansion (nine of 21 respondents):** Issues associated with transmission expansion were identified as a principal weakness by a wide range of respondent types. Developers and developer associations often expressed concern with the CPUC-required TRCR process (see Chapter 4 for additional details on the nature of these concerns). Three developers/developer associations voiced frustration with the track record of the CPUC in encouraging transmission expansion and implementing sections of the RPS statute that require the CPUC to encourage that expansion. One developer representative reported that he was unhappy with the level of integration of transmission planning in the utilities' long-term renewable energy procurement plans. Another developer noted that transmission study groups should be expanded beyond Tehachapi and the Imperial Valley to also cover other prospective renewable resource areas. One utility respondent expressed frustration with the speed of the transmission expansion approval process, but also highlighted the mixed jurisdiction of the CPUC and FERC in this area and the difficult "chicken and egg" problem of expanding transmission without firm developer commitments to build facilities in that area. Another utility noted that delays in transmission expansion may impede their ability to achieve the 20-percent by 2010 target, and that greater recognition of this fact was needed.
- **Design Complexity (eight of 21):** Six developer/developer associations and two utilities specifically noted the complexity of the overall policy design as one of its principal weaknesses. As one developer and one developer association described, California's policy is notable for its number of regulatory decisions and small number of resulting renewable energy contracts. One utility noted that all of the rules and processes surrounding the RPS were bogging things down and that the combination of aggressive goals and a proscriptive process just does not fit with the goal of doing things quickly. Another utility respondent thought that the policy could be streamlined somewhat as more experience is gained, in part by limiting regulatory review and in part by reducing overlap between CPUC and Energy Commission responsibilities. As discussed in more depth below, the complexity that derives from the existence of the MPRs and SEPs was also highlighted by some as a weakness of the policy.
- **Utility Solicitation Structure (eight of 21):** Six developer/developer associations identified the overall structure of the utility solicitations as a

principal weakness of the policy. Specific concerns were that the solicitations were slanted towards wind power (two responses), that the terms and conditions imposed by the solicitations were onerous (two responses), that the complexity of the solicitations was too great (four responses), and that many of the contracts being signed were with projects that were unlikely to be developed (two responses). More detailed information on each of these issues, including concerns with contract terms and conditions, is offered in Chapter 3. Two utilities, on the other hand, felt that the current solicitation schedule is too rigid, and that utilities should be allowed to conduct solicitations more flexibly as need arises and to also enter into bilateral contracts as they see fit. The desirability of simultaneous RFOs was also questioned.

- **Application of RPS to ESPs/CCAs and Municipal Utilities (seven of 21):** A wide variety of respondents also expressed deep concerns about the failure of the state's regulatory authorities to apply the RPS to non-IOUTs, noting that after more than two years, the CPUC has made little progress in designing compliance mechanisms for ESPs and CCAs. A number of ESP/CCA representatives, nonprofit respondents, and developer associations admitted, however, that the current statutory requirements for the RPS simply do not fit well with the typical business model of ESPs/CCAs, including lack of unbundled RECs, long-term contracting requirements, and CPUC procurement oversight. Similarly, the regulatory rules established for the state's IOUTs are viewed as being incongruous with the compliance needs of ESPs/CCAs. In addition, one nonprofit respondent expressed substantial concern that currently proposed legislation, designed in part to facilitate ESP/CCA compliance, would impose so many restrictions on RECs trade as to prove unworkable. A utility respondent, meanwhile, identified the need to not only address ESPs and CCAs, but also to fold municipal utilities into the state's RPS, which would require legislative action.
- **Deliverability and RECs (six of 21):** Six respondents (three developers/developer associations, one nonprofit, and two ESP/CCA representatives) identified the current strict deliverability requirements and disallowance of unbundled RECs as a key hindrance to the state's RPS.

Though not reported to be among the most problematic features of the policy, the calculation of the **market price referent** was criticized by a number of parties. Among the developer and nonprofit communities, the prevailing view seems to be that the assumptions used by the CPUC are conservative and that the MPR should be higher. Several developers also highlighted the lack of transparency in **LCBF evaluation** as somewhat problematic. Two utility respondents, however, proffered the opposite views: that the MPR is too high relative to current conditions (or is at least not too low) and that the current "hands off" approach to LCBF evaluation is working well.¹⁵ One of these utility respondents also noted that changes to the MPR could open up all new issues to resolve. An additional utility noted that the timing of

the MPR is somewhat problematic and suggested that the MPR be released after bids are due but before the short list is announced so as not to slow the overall process. Developers and nonprofit respondents also expressed some concerns with lack of transparency in the current RPS **compliance verification** process used by the Energy Commission and with the perceived expansion of the policy's **compliance flexibility rules** being sought by PG&E.¹⁶ Two utilities, on the other hand, described the acceleration of the **20-percent goal to 2010** as somewhat problematic, especially if transmission expansion does not proceed rapidly, and that the acceleration of targets may lead to a sellers market and higher contract prices. Finally, one party reported concerns with the possibility of "**carve-outs**" under the state's RPS that would favor certain generation technologies, for example, wind repowering, though two other respondents specifically noted that resource-specific set-asides should be pursued. Another utility expressed some concerns about the cost of **integrating wind power**, and wondered if current evaluation procedures needed to be updated to reflect these costs.

Possible Policy Design Changes

When asked what policy design changes, if any, are required to make the RPS more effective, responses followed closely with the key limitations of the state's RPS, as identified above. Five developers/developer association, two nonprofit, and one ESP/CCA respondent highlighted the need for **additional delivery flexibility**, and the possible use of unbundled RECs. Some of these parties believe that limited forms of additional delivery leniency should be allowed (e.g., utility purchase of renewable energy outside of their service territory, or allowing developers to shape the delivery of their product), while others suggest more wide-ranging changes to allow west-wide unbundled RECs. Some of these proposed changes could be achieved through regulation, but others would likely require new legislation. Utility respondents also expressed some openness to relaxing delivery requirements. Five developers/developer associations specifically noted that **transmission expansion** policies need to be fixed, including changes to the CPUC-defined TRCR process and more aggressive support by the CPUC for ratepayer-funded transmission expansion to renewable-resource-rich areas of the state. One utility also identified transmission expansion as critical for the achievement of the accelerated targets, and called for more CPUC leadership on this issue, and expedited transmission siting and permitting. (Issues of delivery, RECs, and transmission are discussed in more depth in Chapter 4). Additionally, one developer/developer association, two nonprofits, and one ESP/CCA respondent noted the importance of designing RPS compliance structures appropriate for **ESPs and CCAs**. Two utilities expressed concerns with the current CPUC-imposed **noncompliance penalties**, suggesting that these penalties be reconsidered. A variety of other recommendations were also offered, but none by more than two respondents.

Given concerns about the complexity of California's RPS, it perhaps comes as little surprise that a number of respondents expressed some openness to a fundamental revision of the policy: **elimination of the market price referents and supplemental energy payments**. Like most other state RPS policies, utilities would instead simply

be required to purchase renewable energy to meet the state's RPS targets, with costs recovered from ratepayers. Seven developers/ developer associations reported some support for this concept, as did one nonprofit respondent. These supporters identified the following possible advantages:

- **Increased funding certainty:** Elimination of SEPs would also eliminate the uncertainty over the sufficiency of SEP funds to achieve full RPS compliance and the uncertainty of the payout of SEPs to individual developers.
- **Reduced policy design complexity:** The CPUC would no longer need to establish the MPR for each solicitation cycle, and the Energy Commission would be relieved of SEP administration responsibilities.
- **Diminished need for detailed regulatory oversight:** Some respondents noted the skewed incentives created by the MPR/SEP: utilities may be indifferent to the cost of different contracts if those contracts exceed the MPR and may instead seek to select projects based on factors other than cost, leading to a premature drawdown of SEP funds. Elimination of the MPR and SEP avert such perverse incentives and thereby relieve the CPUC from at least some of its procurement oversight responsibilities.
- **Bargaining power:** As described in Chapter 3, some concerns have been raised about the impact of the MPR on solicitation responses and bid prices. Consistent with these concerns, two developers that voiced support for the MPR noted that the MPR offered a useful starting point for price negotiations, exactly what the state's policymakers have tried to guard against. By this line of reasoning, elimination of the MPR might be expected to lower renewable energy contract prices somewhat.

Though a certain amount of support was expressed for these changes in theory, these views are not shared by all; some respondents reported strong support for the current system, including at least two of the utility respondents. In fact, the utility respondents noted that the MPR offers a useful benchmark of reasonableness and that using SEPs to cover any "above-market" costs is appropriate. Perhaps more telling, many of those respondents that suggested the elimination of the MPRs and SEPs expressed concern about the possible delays that might be required to shift the policy towards a new system; some of these respondents felt that more experience with the present system was needed before making a fundamental policy shift.

Issues with Supplemental Energy Payments

The interviews also addressed the issue of SEPs, specifically whether SEPs are viewed as being financeable given risks to the underlying revenue stream and whether any other actions are recommended to improve the administration and application of SEPs.

To date, no utility has submitted a contract to the CPUC that would require SEPs, making these issues somewhat speculative. Nonetheless, six of the respondents tentatively said that they thought that the SEPs would be financeable. Another six respondents, however, expressed reservations, noting that projects that rely on SEPs may require more equity (and, correspondingly, less debt) and higher debt interest rates and coverage ratios, creating higher renewable energy prices. Three of these respondents thought that the Energy Commission should consider establishing escrow accounts to improve the certainty of SEP payments to renewable projects with RPS contracts. As a side note, it deserves mention that the Energy Commission has explored this possibility and has concluded that it does not have the legal authority to put SEP funds aside in an escrow account.

In addition, two respondents expressed dissatisfaction with the fact that a project obtaining SEPs would have to abide by the state's tough prevailing wage requirements, and one wind developer said that a project requiring SEPs would therefore come in at perhaps a 0.5¢ per-kilowatt-hour (kWh) premium to projects that do not require SEPs. Another three respondents urged the Energy Commission to formally address how 20-year renewable energy contracts are to be reconciled with 10-year SEP payments, and two ESP/CCA representatives highlighted their desire to ensure that SEPs are proportionately allocated to ESPs/CCAs and are applicable to shorter-term unbundled REC contracts; one utility respondent also expressed the desire for clear, proportional allocation of SEPs. Another respondent explained that the Energy Commission should not be entirely passive but should also not delay the process by second-guessing renewable energy contracts that have been approved by the CPUC in the process of making SEP determinations. Several additional respondents reported concern about SEP sufficiency, given the prices that have been seen in the initial round of RFOs. Two utility respondents noted a desire for the Energy Commission to tighten its confidentiality rules to ensure that utility contract prices are not released, which could affect future renewable energy bids. Finally, three developers/developer associations expressed a desire to go back to the earlier production-incentive auctions administered by the Energy Commission, rather than continue to employ the current SEP structure.

Regulatory Process

Overall Views of the Regulatory Process

Implementation delays and complexity, especially at the CPUC, are the principal concerns of the respondents regarding the regulatory process as a whole. A number of respondents also noted that the complexity of the regulatory process largely precludes smaller parties from participating. Two respondents cited regulatory uncertainty as stalling renewable energy development in the state and expressed concern that there is no end in sight to the implementation process.

Several respondents reported that the CPUC has offered too little leadership on RPS design issues, instead relegating undue responsibility to the parties, and that an overall roadmap for the resolution of issues had not recently been provided.

Another respondent noted that the CPUC could do a better job eliciting coherent, comprehensive design proposals from parties. Several respondents cited the large time lags between RPS decisions as reflective of a lack of focus at the CPUC and a tendency to operate in "fits and starts." One respondent highlighted the need for the CPUC to more consistently issue orders that require the utilities to act, while a final respondent identified the overlap between the RPS and the general procurement proceeding as awkward.

In general, it was recognized that the Energy Commission's responsibilities have been easier to implement than those of the CPUC, and there was near universal agreement that the Energy Commission had done a good job so far. One party, however, expressed concern about the lack of clarity on how the Energy Commission incorporates written party comments into its decision making; this respondent noted that simply approaching and discussing issues with Energy Commission commissioners and staff was apparently a more productive use of time than writing and filing comments on draft decisions. One utility respondent also noted some unnecessary overlap between the responsibilities of the CPUC and the Energy Commission. And, as described earlier, two utility respondents expressed a desire for tighter confidentiality protections in the administration of SEPs.

Both of the ESP/CCA representatives stated that ESP/CCA compliance should have been addressed on a parallel track to the state's IOUs, as there is now concern that the rules already established for the IOUs will be applied to ESPs/CCAs without sufficient thought.

Despite the time and complexity of the regulatory process, at least one element of the process was specifically mentioned as a positive aspect by eight respondents: the open workshops used by the CPUC and the Energy Commission in some instances to bring parties together and discuss issues in a more collaborative fashion than evidentiary hearings and testimony. Also mentioned as a positive element of the process by three respondents was the transmission study processes developed for Tehachapi, though one respondent noted that similar processes should be ongoing for other renewable resources areas. The PRG meanwhile, is seemingly somewhat controversial: two utilities mentioned the PRG as an extremely useful element of the process, while four developers/developer associations expressed concern that elements of the RPS policy are being shaped in part by the PRG, outside of the public eye, and some of these respondents suggested abolishing the PRG. Two respondents specifically noted the collaborative relationship between the CPUC and Energy Commission as helpful, and one utility noted that the CPUC's and Energy Commission's willingness to resolve RFO issues as they arise has been helpful.

On a going-forward basis, a number of respondents mentioned the need for the CPUC to exercise more leadership and ongoing focus on RPS implementation issues, and many of those same respondents acknowledged that greater staffing and staff consistency at the CPUC would facilitate that more active role. As

discussed in Chapter 4, a number of respondents urged the CPUC to act more aggressively on transmission expansion needs. One respondent believes that the process of issuing decisions and orders has gotten out of hand and that the CPUC just needs to act on the remaining issues. Another respondent felt that the CPUC's Energy Division should play a more active role in the PRG earlier in the process, rather than acting in a more reactive fashion after the filing of advice letters.

An additional respondent felt that regular solicitations are the best learning tool and that with each solicitation, improvements will be made naturally. A number of respondents also suggested that the CPUC "get out of the way," allowing utilities to comply with the RPS as they see fit and penalizing those same utilities for any lack of compliance. Others felt that the enabling RPS statute, as well as current legislative proposals, include too many detailed and complex provisions and would prefer that the CPUC and Energy Commission be given more discretion in policy implementation. Two respondents noted that the CPUC should try to act on utility advice letters and procurement plans more rapidly, and one of these respondents also said that the overall process should be slowed down somewhat to allow for more rational planning. A final utility respondent expressed the view that the CPUC should not continuously revisit issues that have already been decided, or else further delays will be experienced.

Procurement Oversight and Process Transparency

When asked whether greater or lesser regulatory oversight of utility renewable energy procurement and evaluation processes would be optimal, respondents gave a mixed response: five respondents thought that less oversight would be appropriate, four voted for more oversight, and seven for the same level of oversight. Clearly, little agreement exists on this point, and there seemed to be little segmentation in response by respondent type.

A number of respondents expressed deep concerns with the perceived lack of transparency in the overall process. Of those interviewed, 11 noted a desire for greater transparency, one for less transparency, and six for about the same level of transparency. Additional transparency in bid evaluation practices (nine respondents) and renewable energy procurement plans (eight respondents) were cited most frequently. Three respondents specifically highlighted a desire to reveal contract prices, though others expressed concerns with revealing such information. Though calls for greater transparency generally came from developers, developer associations, and nonprofit organizations, a few developers also observed that increased transparency should not be pursued if it would further slow the contracting process. The three utility respondents cited concerns about the impact of additional information release on bid prices and the creation of a sellers market, which may disadvantage ratepayers.

CHAPTER 3: RECENT UTILITY RENEWABLE ENERGY SOLICITATIONS

Solicitation Overview

In advance of formal RPS requirements, each of California's major IOUs was required to issue "interim" renewable energy solicitations in 2002, leading to more than 620 MW of contracted renewable energy capacity and more than 4,200 GWh of proposed annual deliveries.¹⁷ Much of this contracted generation was with existing renewable energy facilities that were previously selling to other parties in California, however, and a number of the new renewable energy projects with which utilities contracted have yet to come on line. California's IOUs have also had (and continue to have) the opportunity to execute contracts via bilateral negotiations, outside of formal solicitations, as long as certain conditions are met. As reported in the introduction, these efforts have successfully led to an increase in each utility's renewable purchases, though these increases have so far come with little increase in the state's overall use of renewable energy.

California's first formal RPS solicitations were issued in July 2004 by PG&E and SDG&E. SCE was not required to issue a solicitation in 2004, in part because it was still completing its 2003 renewable energy request for offers (RFOs). Table 4 provides a high-level overview of the parameters of each of these recent solicitations. As shown, each solicitation differed on several parameters, e.g., whether utility ownership or ownership options were considered, minimum contract capacity and delivery commencement, whether time-of-day (TOD) factors were used, and the bid evaluation approach employed. Indicative schedules provided in each RFO suggested that the period from solicitation release to Advice Letter contract filings to the CPUC would be four months (SCE), five months (PG&E), or up to nine months (SDG&E).

Table 4. Summary of Utility Solicitation Parameters

	SDG&E 2004	PG&E 2004	SCE 2003
“Formal” CPUC-Directed RPS Solicitation	Yes	Yes	No
Executed Contracts May Be Eligible for SEPs	Yes	Yes	No
Original Stated Schedule RFO Issuance Closing Date Preliminary Short List Final Short List Advice Letter to CPUC	7/1/2004 8/12/2004 9/16/2004 ~10 weeks after closing date Goal: 1 st Quarter 2005	7/15/2004 8/23/2004 n/a 9/29/2004 Goal: 12/17/2004	8/29/2003 9/23/2003 (later extended to 10/02/03) 10/24/2003 10/31/2003 12/23/2003
Eligible Resources	All RPS-Eligible Resources**	All RPS-Eligible Resources	All RPS-Eligible Resources
Procurement Options	PPA (10, 15, 20 yr) PPA (15 yr) with Buyout Option (year 5)* SDG&E Ownership*	PPA (10, 15, 20 yr)	PPA (10, 15, 20 yr)
Product Type	As Available Firm: Peaking, Baseload, Dispatchable	As Available Firm: Peaking, Baseload, Dispatchable	Baseload (firm or as-available), Peaking, Dispatchable, Ancillary Services
Delivery Commencement	2010 (Imperial Valley resources) 2005-2008 (all other resources)	2005 and later	Not stated
Minimum Contract Capacity	1 MW (within service territory) 5 MW (outside service territory)	1 MW (all other) 25 MW (dispatchable)	1 MW
Power Sales Contract	Modified EEI Agreement	Modified EEI Agreement	Modified EEI Agreement
Procurement Quantity	Not stated, other than goal of 20% by 2010	Approx. 711 GWh/yr (1%), or more	Not stated
Delivery Point	SP15	Prefers NP15	SP15
Evaluation Approach	LCBF (primary considerations: energy costs, overall fit, transmission costs; preference to in-service territory resources)	LCBF (primary considerations: market value adjusted for transmission and integration costs, overall fit, credit quality, other factors)	LCBF (primary considerations: all-in costs by product type, transmission, integration costs, market value considering energy and capacity value, scope of required changes to EEI Agreement, overall fit)
Use of TOD Payment Factors	No	Yes	Yes
Status	Advice letter not filed as of June 9, 2005	First advice letter filed April 26, 2005	Advice letter filed on March 8, 2005

* Only new in-service territory wind and solar, and Imperial Valley geothermal.

** Resources in the Imperial Valley and without adequate transmission are contingent upon SDG&E successfully obtaining approval and constructing a 500 kW line to area.

Source: KEMA Inc., based on review of original solicitation documents and relevant regulatory filings.

Solicitation Results to Date

As of June 9, 2005, both SCE and PG&E had filed proposed renewable energy contracts to the CPUC as a result of their most recent RFOs (2003 for SCE; 2004 for PG&E); contracts resulting from SDG&E's 2004 RFOs had not yet been submitted.

- **SCE:** In its public Advice Letter filing (1876-E-A, March 25, 2005), SCE indicated that it received 53 proposals from 37 different organizations in response to its 2003 solicitation, totaling 5,300 MW of renewable energy capacity. Approximately 1,200 MW of projects were placed on the short list, and the six contracts filed for approval include two biomass, one geothermal, and three wind projects with expected on-line dates of December 2006 to March 2008. A total of 142 MW of renewable capacity was submitted for contract approval (643 GWh/year), with expansion potential to 428 MW (2,127 GWh/year), representing 0.9 percent of SCE's 2004 retail sales (2.9 percent if expansion potential is considered).
- **PG&E:** In its public Advice Letter filing (2655-E, April 26, 2005), PG&E seeks approval for three wind power contracts, with a total capacity of 142 to 158 MW and aggregate deliveries of 490 GWh per year, of which 472 GWh represents incremental deliveries (about 70 percent of PG&E's 2004 incremental procurement target). One contract represents a project repowering in Altamont Pass, another contract is for a new wind project planned near Lompoc, California, and a final contract is for wind generation from the Solano wind resource area. Delivery commencement for each contract is not stated, but all contracts are expected to commence delivery from 2006-2008. Additional contracts may be announced at a later date as a result of PG&E's 2004 RFO.

Solicitation Delays

Solicitation and contracting delays have been significant. With an initially proposed Advice Letter filing date of December 23, 2003, SCE's actual filing date of March 8, 2005 represents a 14-1/2-month delay. PG&E's delay was four months, while SDG&E is a minimum of two months behind its originally stated schedule (as of early June 2005).

Looking specifically to SCE's solicitation, delays occurred at multiple stages of the process, including: the closing date (delayed by less than a month due to an "emergency" motion by CalWEA¹⁸); the development of the initial short list (an additional delay of about two months); completion of the final short list (an additional delay of about four months); the period between the completion of the short list and the commencement of negotiations (an additional delay of about two months); and negotiations themselves (an additional delay of about six months).

In PG&E's case, the final shortlist was announced one month behind schedule, with an additional delay of more than three months due to protracted negotiations with short-listed bidders.

These delays, though not insignificant, should be viewed in context:

- First, each of the utilities clearly stated that its RFO timeline was indicative only, and SCE's solicitation was done voluntarily prior to a formal RPS RFO.
- Second, there is little doubt that a number of "kinks" in the RPS solicitation process had to be ironed out in this first round of RFOs, especially issues associated with contract terms and conditions.
- Third, it is not altogether uncommon for renewable energy solicitations to take some time between issuance and ultimate contract signature, with deadlines regularly slipping from those provided in the original solicitation documents. A brief comparison of the California RFO timelines to those of other recent renewable energy solicitations is provided in Table 5. As shown, California's recent solicitation timelines (with the possible exception of SCE 2003) have not been dramatically out of line with experience elsewhere. This is not to say that the delays have not been excessive, just that they are consistent with recent industry experience with utility renewable energy solicitations. This is particularly notable in that the standard form contracts used by California's utilities appear more complex and more in need for negotiation than the form contracts used in some other states.
- Fourth, while it is true that some all-source and conventional electricity solicitations have proceeded more rapidly, it is not uncommon for these solicitations to also take some time from issuance to final contract award. PG&E, for example, in its recent 2004 long-term all-source RFO, has an expected time period from solicitation release to regulatory contract filings of 9 months. SDG&E's 2003 reliability RFO took just 5 months from issuance to contract filing, while SCE's 2005 RFO for new generation capacity has a planned schedule of 6 months. Outside of California, recent time periods from solicitation release to contract filings for all-source or conventional RFOs include Northwestern (7 months), Portland General Electric (11+ months), Xcel/Minnesota (24 months), and PacifiCorp (17 months).
- Finally, though some have argued that the CPUC should establish formal deadlines for future solicitations,¹⁹ we note that this is uncommon among other RPS states. Instead, these states have generally not yet found it necessary to tightly oversee procurement processes, instead assuming that the prospect of RPS noncompliance penalties, if present and enforced, will motivate timely action.

Table 5. Implementation Timeline for Renewable Energy RFOs*

Utility	Solicitation Release to Announcement of Winning Bid		Notes
	Expected (months)	Actual (months)	
SCE 2003	4	18	
PG&E 2004	5	9	<i>initial projects announced</i>
SDG&E 2004	9	11+	<i>projects not yet announced</i>
Great River Energy	5	6	
American Electric Power	3-4	6	
Public Service Company of Colorado/Xcel Energy	9	7	
City Public Service of San Antonio	n/a	7	
We Energies	n/a	7	
Madison Gas & Electric/Wisconsin Public Power Inc.	6	8	
Alliant	n/a	12	
Puget Sound Energy	n/a	10-12	
Nevada Power/Sierra Pacific 2001	n/a	13	
PacifiCorp	5	15	
Southwestern Public Service	n/a	15	
Nevada Power/Sierra Pacific 2003	n/a	17	
Portland General Electric	n/a	18	
NorthWestern	n/a	25	
Oklahoma Gas & Electric	4	5+	<i>projects not yet announced</i>
Sacramento Municipal Utility District	n/a	11+	<i>projects not yet announced</i>
Los Angeles Department of Water and Power	n/a	11+	<i>projects not yet announced</i>

* Based on data collected through early June 2005.

Source: KEMA Inc.

In recent filings, both SCE and PG&E identified some of the reasons for the delays.

- **SCE:** In Advice Letter 1876-E-A (March 25, 2005), SCE lists a large number of issues that increased the complexity and duration of contract negotiations. These include:

1. Anticipated changes in ISO tariffs and evolving changes in market design²⁰
2. The allocation of risk between renewable energy developers and utility purchasers related to transmission curtailment or outages that may affect the delivery of electricity from the project
3. The allocation of risk for scheduling renewable generation into the California ISO and any penalties that might apply for inaccurate schedules
4. Seller inability to obtain financing due to project performance requirements (e.g., delivery quantity requirements)
5. Allocation of risk in the event of contingencies, such as permitting and assessment of resource potential, which may ultimately yield infeasible projects or project delays
6. Sellers' desire to build projects in phases
7. Uncertainty about the federal production tax credit (PTC)
8. The risk of fuel resource adequacy
9. Uncertainty about the ISO's Participating Intermittent Resource Program (PIRP) program for wind power, which eases the scheduling burden on wind power generators
10. Credit and collateral requirements
11. The unanticipated increase in the cost of wind turbines
12. The definition of events of default
13. Sellers' desire to sell power to third parties during extended periods of force majeure or after SCE default
14. Sellers' desire to increase their offer prices as a result of the foregoing factors.

SCE also notes that many sellers wanted significant changes to the form contractual agreement provided in the RFO, requiring significant negotiations.

- **PG&E:** In its 2005 Renewables Procurement Plan, Part 2 (April 15, 2005), PG&E notes that it largely adhered to its 2004 RFO schedule to the point of short-listing bids and conferring with its PRG. However, PG&E argues that events after that point were not within the utility's control, and that negotiations were more time consuming than originally envisioned. In Advice Letter 2655-E, PG&E identifies some of the issues that created protracted negotiations: contract terms and conditions of agreement, delivery point given uncertainties in California ISO market design, mitigation of imbalances from scheduling intermittent generation, development milestones, and project performance security.

Solicitation Plans for 2005

By April 15, 2005, PG&E, SCE, and SDG&E had filed their proposed plans for renewable energy procurement in 2005, including their draft procurement plans and associated RFOs. A common concern expressed by PG&E and SDG&E (implicitly by PG&E and more explicitly by SDG&E) is the possible emergence of a "sellers" market for renewable energy in California, resulting in upward price pressure and caused in part by the state's aggressive goals for renewable energy and by the transmission constraints that hinder access to certain resource areas.

- **PG&E** notes a desire to attract more renewable energy bidders, higher quality offers, and better prices. PG&E also highlights California Independent System Operator (CA ISO) market redesign efforts as adding complexity to bid negotiation because the historic pricing zones in California may no longer exist under the new market design and notes certain changes to bid evaluation that are merited. In its Renewable Energy Procurement Plan (Part 1) filing, PG&E discusses the value of inter-utility renewable energy swaps (effectively, an unbundling of RECs with a subsequent rebundling of those RECs with system power), which would better allow PG&E to access renewable generation from projects located in Southern California by entering into energy swap agreements with SCE. PG&E also discusses the possible use of unbundled RECs, including those from projects located outside of the state. Proposed changes to its 2005 renewable energy RFO (relative to its 2004 RFO) reflect some of these concerns (Table 5), and include consideration of project ownership options, reduced bid deposits, consideration of delivery to SP15 and ZP26 (in addition to NP15), and allowing "busbar" delivery in the event of the redesign of the CA ISO market. PG&E's draft RFO also contemplates the purchase of renewable energy to serve one to two percent of the utility's retail load, compared to a procurement goal of one percent in 2004.
- **SDG&E** expresses deep concerns with transmission access to out-of-service-territory resources and notes that some in-territory resources also face potentially costly transmission needs. Use of unbundled RECs and the development of new transmission are both viewed as essential. SDG&E also expresses concerns about the timing and process of the TRCRs and discusses its desire to retain the flexibility to sign bilateral agreements from unsolicited proposals. SDG&E also proposes to move solar energy up in its resource stack and highlights concerns with the present evaluation process used for as-available renewable generation, which SDG&E believes does not sufficiently account for the intermittency of wind relative to renewable generation with flat output profiles. Proposed changes to SDG&E's 2005 RFO reflect these concerns (Table 6) and include two solicitations: one for about one MW distributed solar and wind (with expansion to as much as four MW) and another for in-territory utility-scale renewable energy. Reflecting severe transmission constraints into their service territory and transmission constraints within their territory, SDG&E's 2005 RFOs strictly limit bids to

projects located in certain areas of SDG&E's service territory. SDG&E also notes concern with the TRCR process, indicating that virtually all of the projects that bid into their 2004 solicitation were not consistent with those evaluated earlier under the TRCR process. To simplify project evaluation under its 2005 RFO, SDG&E requires that project proposals be consistent with the 2005 TRCR.

- **SCE**, through its proposed 2005 solicitation, seeks to purchase renewable energy to serve approximately one percent of its retail load. Some of the challenges faced during negotiations under its 2003 RFO were discussed earlier. Despite the considerable delays in its 2003 RFO, SCE anticipates submitting contracts to the CPUC for approval within eight months of issuing its 2005 RFO. SCE's 2005 RFO seeks to follow the regulatory requirements for "formal" RPS solicitations that have been developed since the utility's 2003 RFO and, unlike the other two utilities, does not solicit proposals for turnkey utility ownership or ownership options (though SCE does note that it will accept bids from its own generation affiliates). Based on experience from its 2003 RFO, SCE's 2005 RFO provides greater clarity on interconnection procedures, imposes bid deposit requirements that mirror those of PG&E's 2004 RFO and simplifies the form agreement to be used in contract negotiations.

Table 6. Significant Proposed Changes to 2005 Utility RFOs

Pacific Gas & Electric	Southern California Edison	San Diego Gas & Electric
<ul style="list-style-type: none"> • Seeks to procure 1-2% of annual retail sales • Allows project ownership and ownership options • Reduces bid deposit requirements • Allows fewer discrete offers for each project • Makes allowance for “busbar” delivery in the event of market redesign • Accepts offers in NP15, SP15, ZP26* • Places more weight on portfolio fit, less on market valuation, in bid evaluation • Considers debt equivalency and impact of long-term contracts on PG&E financial strength in evaluating bids • Modifies TOD period definitions and factors • Simplifies form agreement • Changes performance requirements and adjustments • Clarifies some standard terms and conditions 	<ul style="list-style-type: none"> • Follows regulatory requirements developed since issuance of 2003 RFO • Prefers commercial operation date of Jan. 2006 through Dec. 2008 • Simplifies form agreement • Plans to use independent evaluator if SCE’s affiliates participate in the RFO • Changes bid deposit to \$25k or \$5/kW, whichever is greater (similar to PG&E 2004 RFO) • Considers debt equivalency in bid evaluation • Provides greater clarity on interconnection procedures and cost allocation (requires interconnection applications before bid submittal) 	<ul style="list-style-type: none"> • Provides two RFOs: in-territory RE, and solar/wind DG on SDG&E sites • <u>In-territory renewable energy</u> <ul style="list-style-type: none"> – Limits bids to only in-territory projects – No renewables accepted from eastern 69 kV territory – Offers PPA (all resources); ownership or ownership options (new wind) – Requires projects to have same characteristics as those in TRCR • <u>Solar or wind on SDG&E sites</u> <ul style="list-style-type: none"> – Seeks 1-4 MW distributed PV (PPA with ownership option) – Allows 2.5 – 50 kW wind turbines (ownership) to bid

* PG&E prefers delivery to NP15, and in its form contract, specifies that the delivery point shall be NP15, in disagreement with other parts of its proposed RFO where delivery to SP15 and ZP26 is allowed.

Source: KEMA Inc., based on the regulatory filings of California’s IOUs.

Stakeholder Interview Results

As shown in Appendix A, the interview questions covered a number of aspects of the utility renewable energy RFOs. Here we discuss responses to questions about solicitation delays, price competition among bidders, other concerns with the 2003/2004 RFOs, and changes to the 2005 RFOs. Among our interview sample, familiarity with SCE's 2003 RFO was the highest (14 respondents noted strong familiarity), with slightly less familiarity noted for the 2004 RFOs from PG&E (12

respondents) and SDG&E (12 respondents). Not surprisingly, those most familiar with the solicitations are developers (many of who bid into the solicitations and several of who won contracts), PRG members, and electric utilities.

Delays to the 2003/2004 RFOs

Though the reasons for the solicitation delays vary by utility, there was a considerable amount of agreement among respondents for the source of these delays. Common among all three utilities were the following:

- **Negotiation Timeframe:** The utilities' initial schedules often underestimated the amount of time it would take to negotiate with short-listed bidders, and the uniqueness and complexity of each individual deal.
- **Inadequate Form Contracts, and Terms and Conditions:** There was near universal agreement, at least among the nonutility respondents, that the form contracts were inadequate. Many parties continue to believe that the EEI contract offers a poor starting point, and several respondents reported that at least some of the utilities had to "start from scratch" upon project negotiation in crafting an adequate contract. The amount of flexibility provided to tailor contract language to each individual deal also created delay. As a result, one utility noted that few projects actually bid according to their protocol, resulting in lengthy negotiations.
- **Disputes Over Delivery Point:** Especially with the prospect of CA ISO market redesign, considerable time was spent in negotiating the delivery point for renewable project output. Renewable developers typically wanted to shield their investors from risk with busbar delivery, while the IOUs sought delivery to their load aggregation point.
- **Utility Staffing:** Several respondents close to the bid evaluation and negotiation process noted that utility staffing and staff continuity has been a problem and that utility staff have not consistently received adequate support from upper management.
- **Other Issues:** Other issues noted as helping to slow the process included:
 1. The need to develop bid evaluation protocols
 2. Risks associated with the PTC and the impact of wind turbine shortages, which led to numerous bidders dropping out of the solicitations in midstream
 3. Unresponsive bids and developers that did not respond quickly to utility requests and negotiations

4. Negotiations related to performance standards, development milestones, credit requirements, and wind power scheduling
5. Regulatory delays associated with the release of the MPR.

Several respondents reported that the delay in SCE's 2003 RFO could not be adequately explained by just those factors listed above. Instead, these respondents felt that SCE "sat" on their solicitation for a lengthy period of time, with little progress made during that period. Two respondents felt that this was done consciously to lock-in and control good projects so that they could not effectively bid into other utility solicitations. Once SCE was willing to actively engage in negotiations, conditions had changed: wind turbine prices had risen, additional utility RFOs were on the street, and gas prices had increased. These conditions led to requests for repricing, resulting in still further delays. Several parties also noted that, without the CPUC's February 2005 deadline for contract submission, contract signatures would have been delayed even further. In SDG&E's case, two parties noted that a key reason for the delay was transmission congestion and the unwillingness of SDG&E's transmission group to address these issues creatively. A similar lack of transmission creativity was cited by one respondent as a reason for PG&E's delay.

In part as a result of these challenges, 14 of the respondents felt that much had been learned from the 2003/2004 RFOs and that the 2005 RFOs would likely proceed more smoothly and somewhat more rapidly. Several of these respondents expressed an expectation that the contract terms and conditions used under the 2003/2004 RFOs would be amended so as to make negotiations simpler in 2005. Others felt that the developers and the regulators would also be more prepared for the 2005 RFO cycle. Just three respondents thought that the solicitation timetable would not be accelerated in 2005, with one of these respondents noting that negotiations may take longer now that the "low-hanging fruit" has already been picked. PG&E, in written comments, has also expressed some concern that its 2005 RFO could be more time consuming than the 2004 RFO, due to more aggressive renewable energy purchase goals (one to two percent in 2005 versus one percent in 2004).

Possible Regulatory Responses to the Contracting Delays

When asked whether any policy changes should be made to speed the solicitation process, respondents offered a diverse set of opinions.²¹

- **Regulatory Deadlines:** Five respondents (four developers or developer associations and one PRG member) expressed the view that California's IOUs should be held to a strict schedule for the submission of contracts to the CPUC under each solicitation. These respondents often noted that when SCE faced such a deadline, it motivated more aggressive negotiation and contract finalization, not only by the utility but perhaps more importantly from developers participating in the RFO. Another three respondents (including one developer or developer association, one utility, and one PRG member)

voiced the opposite opinion: imposed deadlines of this sort should not be established at the beginning of a solicitation cycle as they may provide developers the upper hand in negotiations, especially with utilities that are lagging behind their RPS procurement targets.²² Overall, there appeared to be openness by many respondents to consider regulatory deadlines, but many seemed to believe that additional experience should be gained with the current solicitations before standard deadlines are established.

- **Noncompliance Penalties and Limits on Flexibility Mechanisms:** A few nonutility respondents noted that what is needed is not additional regulatory scrutiny over solicitation schedules but, instead, CPUC adherence to the threat and application of noncompliance penalties. These respondents seem to believe that the present flexibility mechanisms and noncompliance penalties should be sufficient to motivate compliance, though some expressed concern that the CPUC may choose to further relax the current compliance flexibility rules. The utility respondents generally disagreed with the need for non-compliance penalties.
- **Contract Terms and Conditions:** Given the challenging negotiations surrounding the first round of solicitations and the perceived inadequacy by many parties of the form contracts and several provisions therein, it should come as no surprise that numerous nonutility respondents (eight in total) expressed a desire for some additional CPUC-required standardization to the contract terms and conditions. Smaller developers and developer associations typically voiced a desire for a greater degree of contract standardization, while larger developers and PRG members typically suggested that "tweaks" were necessary but that wholesale standardization was not required. Some of the utility respondents also acknowledged that some tweaks may be necessary. In either case, changes to the CPUC's earlier decision on standard contract terms and conditions was viewed as important by many respondents, with at least one respondent noting that an open workshop on experience with the 2003/2004 RFO form contracts would be valuable.
- **Re-establishing Fixed-Price "Standard Offer 4"-Like Contracts:** Three developers/developer organizations expressed some support for a requirement that utilities offer standardized, fixed-price contracts to renewable energy generators, perhaps at the MPR.

Notwithstanding these suggestions, several respondents expressed a concern that policy changes, at this stage, might themselves slow the 2005 RFO schedule and that much had been learned under the 2003/2004 RFOs that was already likely to be incorporated in the next iteration. For example, a couple of respondents noted that the state's IOUs were likely to make useful changes to their form contracts for use in their 2005 RFOs without the need for CPUC intervention.

Price Competition and RFO Response

The competitiveness of the 2003/2004 RFOs was generally viewed to be reasonably strong. Despite this, numerous respondents seem concerned that the renewable energy supply curve was not as deep as one might hope and that significant SEP funds may be necessary in the near future, especially if deliverability issues are not addressed.

Two distinct concerns were raised by the respondents:

- 1) **Inadequate Price Competition:** A number of respondents, from developers and developer associations to PRG members and utilities, expressed some moderate concern with contract pricing. Though most believed that prices for contracts signed under the 2003/2004 RFOs have thus far been reasonable, the depth of supply at those prices was of some concern. Several respondents noted that the delivery rules and the current TRCR methodology effectively requires renewable projects to be located within the utility service territory that they are to serve, severely limiting supply competition for SDG&E and PG&E. Others highlighted the fact that some renewable developers appear to be pricing their projects based on supply costs, perceived risk, and current market prices for conventional generation and that the proliferation of utility RFOs and the acceleration of the renewable energy targets may be increasing prices. Still others observed that onerous deposit, credit, and performance terms were raising the cost of doing business and both reducing the number of bids received²³ and increasing the bid prices for those proposals that are received. One PRG member reported that the MPR seems to have created strange expectations among some of the less sophisticated developers, who seem to negotiate at the MPR price with a view that any price below the MPR should be accepted without great debate,²⁴ and the three utilities also expressed some concern that the MPR may be inflating bids and skewing negotiations.²⁵ Finally, one utility mentioned that the initial depth of its response was significant but that a large number of bidders, including most of the landfill gas bids and some of the more attractive wind bids, dropped out of the solicitation, based in part on wind turbine supply and cost issues. To remedy concerns about supply competition, some interviewees recommended the following:

- Changing the TRCR methodology to facilitate bids from resources located outside of a utility's service territory
- Aggressive transmission expansion to resource-rich areas
- Allowing utilities to take renewable delivery outside of their service territory (in state and out of state)
- More regular, frequent solicitations
- More flexible procurement options, including bilateral negotiations and more flexible solicitation schedules

- Slowing down the overall solicitation cycle and RPS targets
- Form contracts that involve lower bid deposits and credit requirements, clearer performance obligations, and allocation of certain risks to utility purchasers (congestion risk, scheduling risk, etc.)
- Requiring utilities to consider utility renewable energy project ownership options to create, at a minimum, the perception of supply competition.

2) **Contracting with Projects that Are Unlikely to be Developed:** A large number of respondents, from developers and developer associations to nonprofits, PRG members and utilities, voiced serious concerns that a number of the renewable energy projects under contract would not ultimately deliver as promised. Though these winning projects undoubtedly offered better prices within the RFO process than the losing bidders, many of the survey respondents questioned how "real" these projects were, citing fuel supply risks, transmission constraints, and other issues. Similar issues have arisen in a number of other states. Experience with the Nevada RPS, for example, shows that the risk of contract failure is all too real; a large number of renewable energy projects under contract to the Nevada utilities have either experienced construction delays or have been terminated altogether. Some developers and developer associations, though not generally fans of aggressive bid deposits and credit requirements, therefore wondered what approaches could be taken to ensure that only "real" projects are offered contracts. Among the 10 respondents that voiced these concerns, some of the nonutility respondents believe that the state's policymakers need to foresee the upcoming "train wreck," and:

- Ensure that utilities are over-contracting for renewable energy to account for project drop-outs
- If utilities are not over-contracting, not bend to later requests for compliance flexibility if and when projects fail.

One utility respondent, however, voiced a strong desire that utilities be offered compliance flexibility in these circumstances.

Utility Solicitation Cycle

The vast majority of respondents believe that the present annual solicitation cycle for the state's IOUs should continue in the near term. More frequent solicitations are viewed by virtually all respondents to be unrealistic, and a less frequent solicitation schedule runs the risk of creating a stop-start cycle that does not do enough to encourage rational, planned, aggressive development efforts by potential renewable energy generators. In addition, some concern was expressed that a less frequent solicitation cycle might result in upward price pressure, given the larger renewable energy needs that each utility would have in each cycle.

Despite this, three respondents noted that the CPUC need not specify a formal solicitation cycle as long as it is willing to penalize those suppliers that fail to meet their RPS obligations. Another respondent expressed some concern about the effort it takes to run solicitations every year and the possible lack of economies of scale involved with smaller procurement goals. To this observer, a less frequent cycle is believed to possibly create more thoughtful bids from larger projects and therefore lead to lower prices. One respondent noted that, regardless of the formal cycle, utilities should be given the opportunity to respond to market events, for example, issuing an unplanned solicitation to take advantage of the production tax credit if that credit is expected to expire. Two utility respondents supported this perspective, noting that a maximum amount of procurement flexibility should be offered, including flexibility on solicitation frequency and timing and the flexibility to pursue bilateral negotiations. Changes to the timing of the present MPR calculations would be needed to accommodate these changes.

Finally, one developer and all three utilities were concerned that with three IOU solicitations occurring at the same time each year, the result may be a somewhat chaotic market for both utility buyers and developers. For utility buyers, the concern was raised that the presence of multiple utility solicitations could yield inflated prices due to competition among utilities for favorable projects. For developers, the ability of a utility to "lock-in" a project by placing it on the short list might preclude the developer from seeking other opportunities and may make it difficult for developers to decide which solicitations to bid into. One of these respondents noted that a near-term CPUC workshop on this subject would be valuable, with a focus on lessons learned from the 2003/2004 RFOs.

Other 2003/2004 RFO Experience, and Proposed Changes for 2005

When asked to compare the three 2003/2004 RFOs, most developers and developer association respondents reported that SDG&E's solicitation was the most "friendly."²⁶ SCE's original form contract was noted by many developers and PRG members to be unworkable, with some developers reporting that SCE ultimately recognized the limitations of that contract and did a major rework of the contract in midstream. One of the winning bidders to SCE's solicitation reported that SCE's original form contract required six months of negotiation and \$200,000 of legal fees to make it workable. PG&E's contract terms were widely viewed as being the "toughest," especially the bid deposit requirements, which apparently kept a number of developers from submitting proposals; several developer respondents also noted an objection to the use of the EEI form contract, with one developer reporting that his firm incurred \$100,000 of legal fees during negotiation. Perhaps as a result of these factors, especially PG&E's bid deposit requirement, two respondents close to the RFOs noted that SDG&E and SCE received the best response in terms of the quantity, price, and diversity of bids, with PG&E's RFO response somewhat less positive.

The developer respondents were also asked to compare the California renewable energy solicitations with those of utilities in other states that they were aware of. In response, four developers/developer associations observed that California has an order of magnitude more "process" surrounding its RFOs, making it far more difficult to do business in the state and raising bid prices. Two of these developers noted that they had little interest in bidding into California RPS solicitations, for this reason. Another developer mentioned that the contract terms and conditions used in California are far more onerous than those used by most other utilities. More positively, one developer reported that significant solicitation delays were being experienced in other states as well, and that California was not unique in that regard. Another developer noted that the solicitations were structured professionally, despite the complexity involved. Additionally, the requirements imposed by California's IOUs were viewed by one respondent as creating a higher likelihood that renewable energy contracts would ultimately yield operating projects.

When asked whether the current 2003/2004 solicitations, if continued in present form, would effectively support the state's RPS, a mixed response was received: seven respondents said yes, six said no.

In response to the question of what changes are critical for the 2005 RFO cycle, the most common response from nonutilities was to allow utilities to take renewable deliveries outside of their service territory or to otherwise pursue the limited use of unbundled RECs; two utility respondents also expressed support for this view. Other common responses included the pursuit of revisions to the form contract and standard terms and conditions, especially vis-a-vis deposit, performance, and credit requirements²⁷ and the generation delivery point (busbar vs. the load aggregation point).²⁸ Also mentioned by two PRG members was the desirability of allowing or requiring utilities to consider renewable energy project ownership options, though CalWEA and IEP (in written comments to the draft 2005 RFOs) have subsequently called for a rejection of this option, given challenges in bid evaluation among independent and utility owned projects. Two respondents noted the need for a clearer articulation of policies towards wind repowering, and several described the possible need for regulatory deadlines and penalties for not achieving those deadlines. One utility respondent, meanwhile, expressed a desire for expedited transmission upgrade approval, approval of its 2003/2004 RFO contracts, and completion of the Energy Commission's integration cost studies. Two utility respondents voiced strong support for additional procurement flexibility, including an ability to conduct solicitations outside of the formal yearly cycle and an ability to engage in bilateral negotiations. One of these utility respondents noted that the geothermal eligibility requirements are overly restrictive, while another expressed the belief that wind integration costs need to be more fully evaluated in future RFOs. Several stakeholders noted that significant changes should not be made, or else further delays would be experienced.

In describing the lessons learned from the last solicitation cycle and what changes are planned for 2005, one utility reported that it had learned a large number of

lessons and that many of those lessons would be incorporated into its form contract for 2005. In addition, to improve the application of transmission bid adders, only projects in the ISO interconnection queue would be allowed to bid into its 2005 RFO. This same utility highlighted the difficult tradeoffs that must be made in determining the form and quantity of any required bid deposit, but ultimately decided that it wanted developers to have some "skin in the game" for its 2005 RFO. A second utility noted that its bid deposit requirements would be altered, its delivery point revised, and its form contract simplified, all based in part on experience with its 2003/2004 RFO. A final utility expressed deep concern with transmission issues, as well as the difficulty in diversifying its purchases between baseload and intermittent generation sources.

Written Party Comments on the Proposed 2005 RFOs

When interviewed, few respondents had yet had a chance to review the IOUs' 2005 proposed RFOs, but one developer noted that evaluation transparency was still lacking and that deliverability issues had not been adequately addressed in light of the 2003/2004 RFO experience. Another developer expressed concern with SCE's bid and development deposits. A final developer association voiced regret that SCE and SDG&E failed to lay out their evaluation criteria as clearly as PG&E.

Subsequent to the interviews, TURN, UCS, CalWEA, IEP, SolarGenix, and ORA submitted written comments or reply comments on the utilities' RFOs. Consistent with some of the findings reported in the previous Chapter, CalWEA and IEP expressed significant concerns with allowing utility ownership in the 2005 RFO process, and IEP also cites difficulties in allowing utility affiliates to compete under the 2005 RFOs. IEP is also dissatisfied with what it perceives to be a lack of transparency in the bid evaluation criteria provided by SDG&E and SCE. CalWEA contends that the EEI Form Agreement should be abandoned altogether, that SCE's bid deposits should be loosened to conform to PG&E's 2005 RFO proposal, that utilities should be required to notify bidders whose bids are rejected shortly after finalizing the short list, and that SCE's delivery point should be the generator busbar in the event of CA ISO market redesign. Among other issues, SolarGenix highlights concerns with PG&E and SCE's bid deposit requirements, requests that the state's IOUs offer to purchase renewable energy under contracts up to 30 years in duration, expresses dissatisfaction with SCE credit and collateral requirements, and suggests that the CPUC establish deadlines for the solicitation schedules.

TURN and UCS, both active participants in the PRG, voice serious concerns with SDG&E's proposed RFOs, which are focused on higher cost solar photovoltaic energy and in-territory resources. Under the assumption that such resources will be offered at high prices, both TURN and UCS describe how SEPs may be rapidly depleted and express concerns that other utilities may follow suit in seeking bids from only resources with a good portfolio fit but also with high costs, leading to a "premature" drawdown of SEPs. To accommodate more flexible delivery rules, both organizations recommend that utilities be required to solicit offers from projects that deliver their output to other parts of the state. UCS and TURN are also active

proponents of allowing, even requiring, utilities to consider renewable energy project ownership options as a way of increasing supply competition.

In response to these comments, PG&E expresses support for more flexible in-state delivery points and extends that reasoning to suggest that such delivery points should be extended to the CA ISO "interface," arguing that to the north, that interface is in Malin, Oregon. SCE and SDG&E, however, do not have an interest in availing themselves of the risk of delivery outside of their service territories and argue that they should not be required to do so. PG&E, SDG&E, and SCE also counter that utility ownership or affiliate purchases can be evaluated fairly, with PG&E and SCE highlighting the fact that they would rely on independent evaluators. All three utilities also defend their form contracts, bid deposit requirements, credit requirements, and other protocols, arguing that these issues were not standardized in the CPUC's earlier decisions and should continue to be left to the utilities' discretion. Finally, SDG&E contends that solar electricity bids will be evaluated based on LCBF principles concurrent with bids received under their all-source renewable solicitation and, therefore, that the concerns raised by TURN and UCS are unfounded.

CHAPTER 4: DELIVERY REQUIREMENTS

Current Procedures and Requirements

Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher) and SB 1038 (SB 1038, Chapter 515, Statutes of 2002, Sher), as clarified by subsequent legislation [Senate Bill 67 (SB 67, Chapter 731, Statutes of 2003, Bowen) and Senate Bill 183 (SB 183, Chapter 666, Statutes of 2003, Sher)], establish the overall framework for the state's renewable electricity delivery requirements, a framework that has been further defined by subsequent regulatory action. Though debate remains on the legal authority of the CPUC to allow unbundled trade in RECs absent new legislation, at present such trade is disallowed. Instead, renewable electricity and its associated attributes must remain bundled. To demonstrate compliance with this requirement, an out-of-state generator is required by the Energy Commission to deliver its generation to an in-state market hub or substation located within the CA ISO's control area through an interchange transaction with the CA ISO that involves a NERC "tag." These requirements are intended to treat the delivery of out-of-state generation in the same way as in-state generation.

To account for the potential cost of network transmission expansion to deliver generation from individual renewable energy projects to utility load, the CPUC requires that each utility develop a TRCR prior to issuing an RPS-driven renewable energy solicitation. These reports estimate the cost of needed transmission expansion for potential renewable energy projects that may subsequently bid into a utility renewable energy RFO. In evaluating the relative economics of different renewable energy proposals, the state's IOUs are to use the results of the TRCR or, if available, System Impact Study and Facilities Studies (SIS/FS) completed through the CA ISO's interconnection process.

California's renewable energy delivery requirements are substantially different from those in other states with RPS requirements, at least in two respects.

- First, as noted earlier, utilities in other states consider transmission expansion costs, but not through formal TRCRs that are approved by the regulatory commission and that are formally applied in bid evaluation.
- Second, most states currently allow or will soon allow unbundled RECs. Five state RPS policies are currently supported by electronic tracking systems and unbundled RECs.²⁹ Nine states allow unbundled RECs, and electronic tracking systems are in development that are likely to formally track such transactions once complete.³⁰ Another two states allow unbundled RECs and currently use contract-path accounting to verify REC transactions.³¹ California is one of only four states that do not currently allow unbundled RECs and is the only state with competitive ESPs that does not allow unbundled RECs.³²

Allowing the use of unbundled RECs does not mean that a state must allow unbundled RECs from out-of-state renewable energy projects, and many state RPS

policies impose restrictions on the eligibility of such generators. Four states, for example, have strictly required that certain eligible renewable generators be located within the state's geographic boundaries.³³ Another two require out-of-state generators to effectively have in-state interconnections.³⁴ Three states encourage in-state location through various means.³⁵ A number of states require electricity delivery into the state or the larger region in which the state is located (often the relevant ISO), somewhat similar to the approach currently used in California.³⁶ By requiring delivery to a larger region, and allowing unbundled RECs after that point; however, many of these states have requirements that are more lenient than those in California.³⁷ Finally, in at least one instance (New York), intermittent generation is not required to deliver electricity on an hour-to-hour basis to an in-region hub but is instead allowed to deliver with a "monthly matching" requirement (effectively allowing out-of-state RECs to be bundled with system power over the border).

Alternative Deliverability Options

Delivery requirements have been the subject of great debate not only in California, but under other state RPS policies as well. More strict delivery requirements hold the potential benefit of providing greater assurance of local economic development benefits (because projects are more likely to be located in state) and environmental benefits (because renewable electricity is more likely to offset conventional generation within the state). At the same time, strict delivery may raise the cost of achieving renewable energy targets. More lenient delivery requirements are likely to reduce costs and ease compliance burdens—perhaps substantially. In addition, due to the interconnected nature of the western electricity grid, more lenient delivery would not entirely eliminate the local environmental benefits of the California's RPS and may actually increase the national and global environmental benefits (to the extent that the renewable generation would be more likely to offset coal plants in other states, as opposed to California's relatively low-emission gas plants).

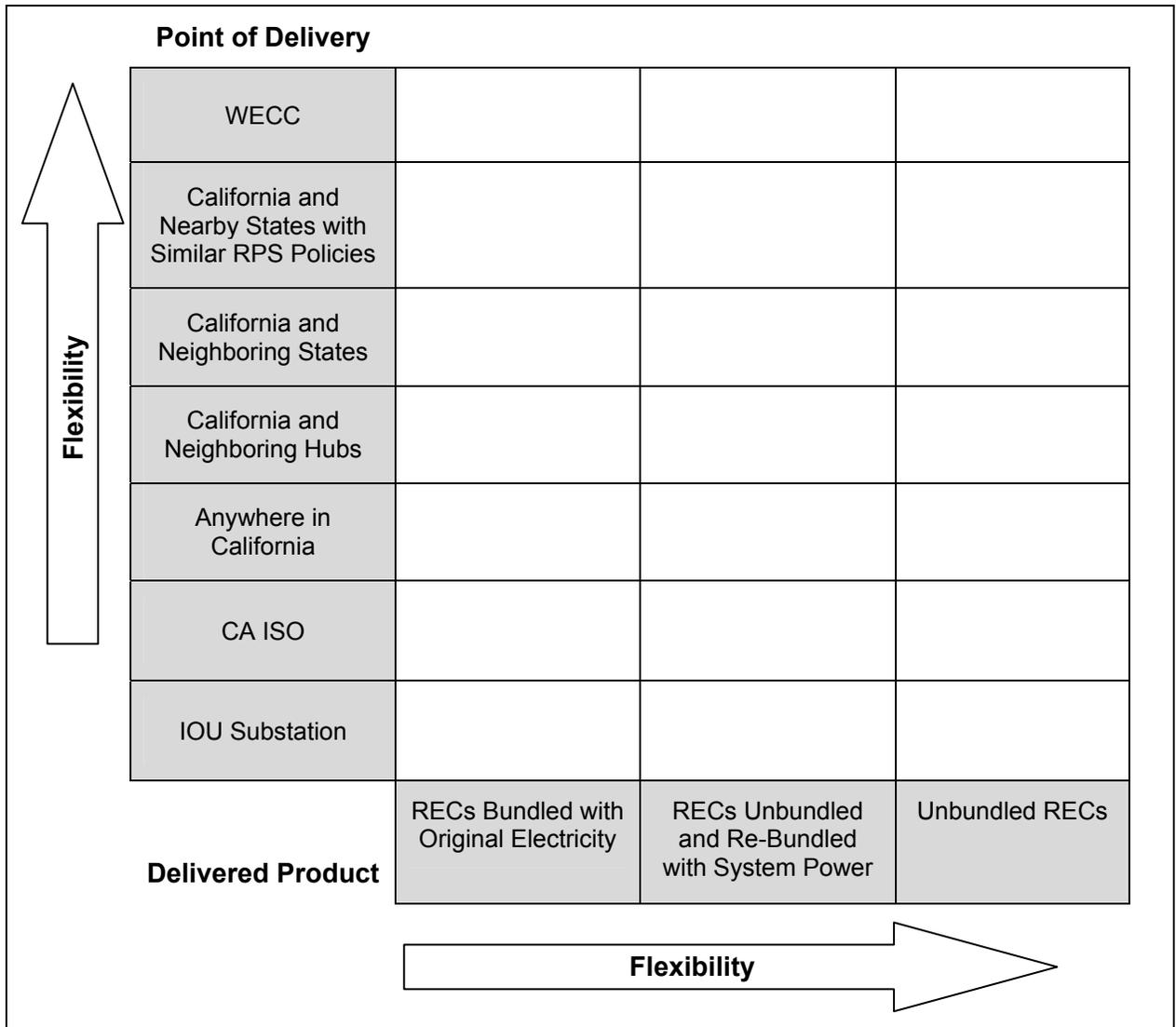
In considering the delivery options, it is perhaps useful to think of delivery requirements varying along two dimensions: delivery point and delivered product.³⁸ Various combinations of delivery options along these two spectrums are shown in Figure 3.

California's current approach requires RECs bundled with the original electricity, delivered to an in-state market hub or substation located within the CA ISO's service territory. To ensure delivery to the load center in question, to date electricity has been delivered to each IOU's service territory. This puts California in the lower, left box in Figure 1, with among the most stringent of possible delivery requirements.

Greater leniency could be provided by expanding the point of electricity delivery to outside of the IOU's service territory, or even outside of the state (to nearby market hubs, to neighboring states, to states with comparable RPS policies, or to the WECC as a whole). Upon delivery to these points, the associated RECs could be wholly unbundled and sold into California, or California could require that the REC be rebundled with system power (on a monthly or annual basis) for sale into California.

Without fundamental changes to the delivery point, greater leniency could also be provided if unbundled RECs were allowed, or if RECs were allowed to be unbundled as long as they were subsequently rebundled with system power (on a monthly or annual basis) for sale into the California RPS. Utility swaps can be considered an example of the latter possibility.

Figure 3. Conceptual Map of Different Delivery Options



Source: California Energy Commission Staff

If unbundled or rebundled RECs were to be allowed, additional restrictions could be applied. Some of the restrictions that have been discussed by California policymakers and RPS stakeholders to date include:

- Imposition of a percentage limit on the use of RECs by retail sellers

- Requirements that unbundled RECs be traded once and only once
- Conditioning the use of RECs upon a demonstration of significant transmission constraints, or the lack of reasonably priced bundled products
- Prohibitions against the sale of "baseline" RECs
- Requirements that only retail sellers that are over-complying with their RPS (purchasing bundled renewable electricity) be allowed to sell unbundled RECs to other parties
- Application of contract duration requirements to REC purchases
- Disallowing SEPs for REC purchases, or applying SEPs to RECs in a different fashion than for bundled products.

Of course, with each additional restriction, greater regulatory oversight burdens would be imposed upon the CPUC and Energy Commission, and liquidity in the REC market would decrease.

Transmission Ranking Cost Reports: Party Comments

The process, content, and application of the TRCRs in California have also been the subject of considerable dispute. Even after their first application in the 2004 RFOs, parties are in little agreement on the effectiveness of this tool, as shown in April 8, 2005 testimony and April 22, 2005 reply testimony to the CPUC.

- **CEERT** argues that the current approach is at odds with the Energy Action Plan's "loading order" by prioritizing all existing uses of the transmission system ahead of renewable energy, thereby constraining "cost-effective" renewable proposals to projects located within each utility's service territory. CEERT argues that new renewable energy projects should be allowed to compete for access on the existing lines. CEERT therefore recommends a number of changes to the TRCR, including: (1) requiring that transmission adders be limited to the proportional cost of upgrades required by the deliverability standards, (2) measuring deliverability in a way consistent with the procedures being developed in the resource adequacy proceeding (which are likely to be somewhat less stringent than those standards applied in the TRCR process), (3) requiring delivery to the CA ISO, not each individual utility service territory, and (4) computing transmission adders based on an "energy only" standard for certain bidders, which would allow generators to interconnect at a minimum cost in terms of transmission expansion, but with no guarantee of the deliverability of a generator's output. In the event that these recommendations are not taken, CEERT recommends that certain unbundled REC transactions be allowed and that other more modest changes to the TRCRs be made.
- **TURN** states that the TRCRs used thus far have not been reasonable, and should be replaced by criteria that more accurately reflect "real-world procurement practices and grid operations." Specifically, TURN argues that

the state's utilities should be allowed to take delivery anywhere within the CA ISO control area, rather than arranging for delivery to their specific service territories, and that bidders should be allowed to choose between "energy only" and "network resource" treatment (with "energy only" service providing no guarantee of deliverability and no contribution to resource adequacy, and "network resource" treatment providing delivery to the CA ISO market and offering a contribution to resource adequacy).

- **SCE, PG&E, and SDG&E** disagree somewhat on the effectiveness of the current approach, though all agree that the approach should remain unchanged for the 2005 solicitations. SDG&E notes that there were anomalies between the renewable projects identified in the TRCR and those that bid into its 2004 RFO, calling into question the viability of the TRCR approach. SDG&E also states that it is not convinced that the TRCR provides valuable signals to developers, though it is willing to use the approach again in its 2005 RFO. SCE and PG&E argue strenuously that the standards for deliverability and curtailability used in the TRCR are consistent with current CA ISO procedures, and therefore should not be changed. They further argue that CEERT's proposed changes would result in inaccurate bid evaluation, and the existing procedures already allow sellers to use any creative solutions the ISO might approve to avoid the need for costly transmission upgrades.
- **CA ISO:** The CA ISO, in draft summary comments, supports the general principals articulated by PG&E that the TRCR methodology should attempt to mirror the CA ISO interconnection process, and thereby identify costs that the CA ISO will impose on successful bidders. The CA ISO acknowledges that developers are not presently able to easily offer curtailable contracts, however, and appears to suggest that the present TRCR requirements impose a far more rigorous standard for congestion relief than required by the CA ISO. The CA ISO also expresses support for allowing utilities to take delivery outside of their service territory.

Stakeholder Interview Results

Consistency of Current Requirements with RPS Goals

The majority of interview respondents believe that some additional leniency on delivery requirements should be considered, though there are significant differences of opinion on what changes should be made. When asked whether the current deliverability requirements are reasonable and support the objectives of the state's RPS, the majority of survey respondents (14 of 21) said that the current delivery requirements are not serving the objectives of the California RPS. These respondents include developers and developer associations, nonprofits organizations, ESP/CCA representatives, and two utilities. Three of these respondents echoed CEERT's written comments that the current rules are in violation of the CPUC's "loading order." One respondent noted the oft-cited view that

the renewable potential is in southern California but that significant demand for renewable energy is elsewhere in the state.

Five respondents (three developers, one nonprofit, and one utility) did not have any significant difficulty with the deliverability requirements as they currently stand, although for very different reasons. One developer, for example, said that they can work with the current deliverability provisions, though they are complicated and add costs. A second developer said the current rules are not that troublesome and that developers need to learn how to make transmission and scheduling arrangements. One utility respondent, though not dissatisfied with the current requirements, did express a belief that the state's policymakers should grapple with this issue and was not opposed to changes to the current deliverability rules.

Concerns with In-State vs. Out-of-State Delivery

Many of the respondents (eight developers/developer associations, one profit, and one ESP/CCA representative) are more concerned about in-state delivery requirements than out-of-state delivery requirements. In fact, though most survey respondents want in-state deliverability requirements relaxed, there was broad support by many respondents for not significantly relaxing the deliverability standards for out-of-state generators, at least not in the near future. Notable exceptions to this general belief included the ESP representative, one utility, and a limited number of other parties. Even among those respondents concerned about out-of-state delivery, there was a general belief by many that California should work to fix its own transmission problems first. Some expressed a concern that, without WREGIS, tracking of unbundled RECs from outside the state may be difficult. Others expressed the view that the purpose of the California RPS is to encourage in-state renewable energy development and the economic and environmental benefits that derive from that development and to do that, out-of-state deliverability requirements are appropriate. One utility, however, highlighted out-of-state delivery flexibility as more important than in-state delivery issues, and another expressed the view that they are equally important.

Possible Near-Term Actions to Ease Deliverability Constraints

Several near-term actions were identified to ease the current deliverability constraints.

In-State Delivery

Widespread support for loosening in-state delivery requirements was expressed by nonutility survey respondents and to some degree by utility respondents as well. Three principal approaches were suggested:

- **Out-of-Region Delivery Point:** Many recommended that the CPUC allow utilities to take delivery of renewable electricity outside of their service territory, but still inside the state, and then arranging for delivery of that electricity (1) directly, through utility swaps or through trade between

scheduling coordinators, or (2) otherwise remarketing the electricity if transmission cannot be arranged. In either instance, the utility purchaser would be able to apply the entire purchase towards their RPS requirements. Survey respondents across all categories generally agreed that the CPUC should make clear that such transactions are allowable under the state's RPS, with a sizable number of nonutility respondents going farther and arguing that the CPUC should require that utilities solicit these types of transactions. Utility respondents, though generally supportive of allowing these transactions, did not want to be required to seek them out. The principal concern of these utilities, expressed through the interviews and also through written comments to the CPUC, is that utilities and their ratepayers would incur the cost and risk of either transporting the power to their load centers or, alternatively, remarketing the power and that these costs and risks are difficult to quantify.

- **Shaped Renewable Electricity Products:** Another approach, suggested by a lesser number of respondents (including developers and two utilities), was for the CPUC and Energy Commission to allow renewable energy developers to offer shaped or firmed renewable electricity products. Effectively, this would allow utilities to purchase RECs bundled with electricity and delivered to the utility's service territory, but delivery of that electricity may not be coincident with the hour-to-hour production of the renewable generator. RECs would be unbundled from their underlying electricity, and rebundled with system power at another time. This places remarketing and congestion risks on the renewable energy developer but also allows that developer to deliver a shaped product to the utility that may avoid the need for costly transmission additions between utility service territories (e.g., Path 15 and transmission into San Diego) because the developer could deliver its product at times when congestion is not present. A related benefit to the utility buyer is a product that may have a more attractive temporal profile than the hour-to-hour output profile of the renewable project itself. Allowance for such shaped products could be limited to in-state transactions, to the extent that in-state delivery is of greater concern than delivery from out-of-state generators. Two respondents reported that this transaction structure may be being employed by SCE in their purchase of geothermal energy from Calpine and questioned why such transaction structures are no longer explicitly sanctioned. Clarification on whether these transaction structures are allowed under the state's RPS was recommended.
- **Busbar Delivery:** Dispute over whether delivery should be effectuated at the generator's "busbar" or at the utility's "load aggregation point," especially in the event of market redesign, was apparently a primary reason for some of the delays experienced under the utilities' 2003/2004 RFOs. In their 2005 proposed RFOs, utilities have responded to this issue in different ways: PG&E, for example, will accept busbar delivery in the event of market redesign, whereas SCE still seeks delivery to their load aggregation point.

Though this was not an issue selected for standardization in the CPUC standard terms and conditions decision, a number of developers and developer associations cited a desire for CPUC-ordered standardization of the treatment of this issue on a going-forward basis. These parties typically expressed the view that utilities are in a better position to manage congestion risk than are developers and that placing the risk on developers would unduly increase contract costs. A much smaller number of developers noted that they are able to manage the current requirements. Consistent with this latter view, in written comments to the CPUC, SCE argues that they have been successful in entering contracts that place this risk on the developer and that this issue should remain at the discretion of the state's utilities.

Out-of-State Delivery

Though there was a lesser amount of concern expressed regarding delivery from out-of-state generators, some developers complained that PG&E's 2004 RFO required delivery to Round Mountain in the northern part of the state and that doing so adds transmission costs that are caused by the sale of renewable energy across multiple utility service territories. One utility respondent cited the inefficiency of transmitting wind power from the Northwest into California. Additionally, in discussing their 2003 RFO experience, SCE, in a May 9, 2005 Energy Commission workshop, reported that the CA ISO was effectively not able to allow out-of-state wind generation to be scheduled into the state.

As a result, several parties described transaction structures that appear consistent with the RPS statute, but that may not be currently allowed by Energy Commission and CPUC rules. Specifically, a number of developers and developer associations expressed a desire to be able to deliver electricity to nearby out-of-state market hubs or substations (e.g., COB, COI), with the purchasing utility arranging for transmission between those hubs and their in-state service territory. Two nonprofit organizations also expressed support for this transaction structure. There is some uncertainty as to whether the Energy Commission's current rules would allow such a transaction, but PG&E has reportedly cited the Energy Commission's deliverability rules as precluding these arrangements, and a simple reading of the current rules supports this claim.³⁹

In subsequent written comments on its 2005 RFO, PG&E proposes a variant on the transaction structure described above. Specifically, PG&E proposes that just as utilities should be allowed to take delivery outside of their service territory but inside the state, so too they should be allowed to take delivery at the outer edges of the CA ISO's reach (the CA ISO interface), in PG&E's case to the north, at Malin, Oregon. Going one step further, however, PG&E proposes that responsibility for arranging for transmission into PG&E's service territory would be negotiated, and *if the power could not be delivered*, PG&E would be allowed to remarket that power and retain credit for the renewable purchases. Whether such a structure is allowable under the current RPS statute is debatable.

Renewable Energy Credits

Many interview respondents suggested a "go slow" approach to unbundled RECs, especially for the state's IOUs. Not surprisingly, the ESP/CCA representatives took a difference stance, noting that in-state RECs, at a minimum, should be allowed. Two utilities also expressed some support for purchasing unbundled RECs from outside of the state, while another utility felt that limited, in-state unbundling of RECs was all that was required. With some notable exceptions, there was little additional support for broadly allowing unbundled RECs from outside of the state to qualify for the state's RPS, at least at this time, though two respondents (one developer, one utility) said that such transactions may be required if California raises its RPS from 20 percent to 33 percent.

Most seemed to believe that the state should begin by experimenting with some of the near-term actions described above. In addition, a large number of respondents supported moving towards a system of unbundled RECs for renewable electricity that is delivered into the state, or certain parts of the state. One respondent, however, expressed discontent with the go-slow, restrictive approach to RECs, and indicated that the state needs to make a choice between a full in-state unbundled RECs system that would accommodate ESPs and CCAs, or the current bundled requirements that could not effectively accommodate these players. The "hybrid" structures under current consideration (which, e.g., might not allow SEPs to apply to RECs, or may limit REC transaction structures) are viewed by this respondent as the worst of both worlds. Two additional respondents described unbundled RECs as merely a band-aid for the more fundamental problem: transmission expansion needs.

Supporting Transmission Expansion

One issue that seemed to unite nearly all the survey respondents is the need for more transmission in the state.

Many urged the CPUC to devote significantly more staff and resources towards this task, and quickly. A number of interviewees expressed frustration that the CPUC had not taken a more active role in supporting this transmission expansion. Some reported that the RPS statute requires the CPUC to make findings, if supported by the record, that new RPS-driven transmission facilities provide benefits to the transmission network and are necessary to facilitate the achievement of the RPS. These respondents also note that the RPS law directs the CPUC to ensure that the cost of new transmission facilities necessary to achieve the RPS targets are recoverable in retail rates in the event that FERC disallows recovery in wholesale transmission rates. Some believe that the CPUC has not done enough to follow these statutory requirements. Other respondents, however, believe that transmission cost recovery is a FERC matter and pointed to past legal troubles between the CPUC and SCE on this issue.

Others noted that the approval process for new transmission is too long and urged a more expedited process.⁴⁰ Following up on the summary of TRCR comments provided previously, some developer respondents argued that transmission practices favor existing users and lock renewables out. They assert that renewables should be given a higher priority on the transmission system, in line with the priority renewables are given in the loading order. Utility respondents disputed this view. Two respondents noted that transmission issues are incredibly complex and highlighted the fact that the CPUC needs further transmission expertise to be able to interpret party comments on either side of the issue.

There was general agreement that the Tehachapi and Imperial Valley transmission working groups were a good, first proactive step to unlock the Gordian knot of transmission in the state. Several respondents believe that the Energy Commission and CPUC should quickly establish additional transmission working groups for other renewables-rich areas of the state.

There were somewhat mixed views on SCE's proposal for a renewable resource trunk facility to address transmission issues in the Tehachapi wind resource area. Some respondents (primarily developers) were quite supportive of the proposal, but others believed that simply coordinating with FERC may have accomplished the same purpose. Others worry that the petition is on shaky legal ground because it does not clearly identify network benefits associated with the entire trunk line and worry that FERC (or subsequent court action) may reject SCE's filing. These parties believe that the CPUC and SCE should file with FERC an argument that the entire trunk line offers network benefits.

CHAPTER 5: POLICY RECOMMENDATIONS

California's RPS is unique in its design and complexity, requiring a great number of regulatory implementation decisions. It should come as little surprise that implementation of the law has taken time.

And yet, after two and a half years of implementation, utilities are now conducting solicitations and signing contracts under the state's policy. Much has been accomplished in implementing the RPS, and California may now be poised to enter a period of rapidly growing renewable energy supply. Before fundamental changes to the policy are contemplated, one should recognize that the policy has been operating for only a brief period of time.

At the same time, our stakeholder interviews yielded widespread agreement on one point: that the state's policy is not optimal and that numerous challenges remain. There was also general agreement that no one wanted policy changes to invite a protracted regulatory redesign of the RPS. The problem: there are dramatically differing views on exactly what changes are needed to improve the policy's design.

Lacking consensus among stakeholders on these design changes, here we offer our own tentative recommendations, based on the interview results and on our understanding of the California RPS and similar policies in other states. Each of these recommendations derives, in part, from our stakeholder interviews, and each recommendation would therefore have the support of some number of our survey respondents. A review of the earlier chapters would reveal the level and type of support offered by the survey respondents on these recommendations.

Because consensus was not reached on these issues, however, we emphasize that these final recommendations are our own, and are not consensus opinions from the survey respondents. The recommendations also do not necessarily reflect the views of the Energy Commission.

Our specific recommendations are summarized in Table 7, and are described in the pages that follow. These recommendations are segmented into four categories: process recommendations, near-term actions on utility solicitations, near- to mid-term policy decisions, and long-term policy issues.

Table 7. Recommendations

Process Recommendations

- Additional staffing at the CPUC and the Energy Commission dedicated to the RPS
- Additional focus and leadership from the CPUC on RPS
- Enhanced expertise at the CPUC on transmission, and heightened involvement of the California ISO
- Emphasis on workshop processes where possible, and consolidation of decisions
- Clearer prioritization of critical-path items

Near-Term Actions on Utility Solicitations

- Consider relaxing delivery for in-state generators:
 - allow delivery anywhere in state
 - allow developers to offer shaped products
- Consider relaxing delivery for out-of-state generators, allowing delivery to nearby market hubs and substations, with utilities managing delivery into the state
- Consider making policy decisions on elements of utility RFOs, e.g.: (1) delivery point in event of market redesign, (2) bid deposits, (3) other issues with form contracts, and (4) utility ownership, etc.
- Consider waiting for additional RFO experience before developing rigid deadlines, but ensure that threat of noncompliance penalties is credible
- Though not critical path items: (1) consider a workshop on the solicitation cycle, procurement flexibility, and developer bids into multiple RFOs, and (2) track the financeability of SEPs and the possible future need to firm-up the SEP revenue stream

Near- to Mid-Term Policy Decisions

- Immediately focus on RPS for ESPs and CCAs
- Address deliverability issues, TRCR, and support for transmission expansion
 - identify additional resource areas in need of proactive transmission planning processes
 - continue analysis of present TRCR process, with the help of the CA ISO
 - greater involvement and leadership from CPUC on transmission expansion
- Consider use of unbundled RECs and application of SEPs to RECs
- Address the potential for contract failure: (1) organize workshop, (2) consider requiring over-contracting, and (3) consider clarifying application of penalties and flexibility mechanisms in event of contract failure
- Consider clarifying rules for penalties and flexibility mechanisms

Longer-Term Policy Issue

- Consider eliminating SEPs and the MPRs altogether

Source: KEMA Inc.

Process Recommendations

In terms of the regulatory process, many survey respondents agreed that **additional staffing at the CPUC** (and to a lesser extent, the Energy Commission) is essential for the timely and effective implementation of the state's policy and that a **more consistent level of regulatory focus and leadership** on the RPS is required. For example, some survey respondents noted that the CPUC's implementation of the RPS had come in "fits and starts", not reflecting a consistent level of focus, and that a comprehensive roadmap for RPS implementation had not been developed and adhered to. Others noted that it would be helpful for the CPUC to propose comprehensive, alternative implementation strategies for ESP/CCA compliance that parties could then react to, and that greater leadership on transmission expansion was critical. Related, to carry out the CPUC's transmission responsibilities, and the TRCR more specifically, additional regulatory expertise may be required. More active **involvement by the CA ISO** may also be necessary to sort out dueling views on the appropriate methodology for the TRCRs.

Stakeholder interviews revealed a strong belief that the **more informal workshop process** is often the most productive way for stakeholders to discuss and come to some agreement on issues and, where possible, we recommend this approach. In addition, to speed the process of regulatory implementation, the CPUC may want to **consolidate multiple RPS issues into single decisions**, rather than continue the current "incremental" approach to RPS decision-making. Finally, we would observe that some **further prioritization of critical-path decisions** might be warranted. As one example, few respondents identified the current MPR as a critical shortcoming of the RPS, or highlighted changes to the MPR as essential to the achievement of the RPS. At the same time, after two and half years, we are seemingly not much closer to applying the RPS to ESPs and CCAs than we were on day one, even though the statute was applicable to ESPs and CCAs starting on January 1, 2003. Additional regulatory prioritization of implementation details appears warranted.

Near-Term Actions on Utility Solicitations

Much has been learned in the first round of utility renewable energy RFOs, and much more will no doubt be learned in the 2005 solicitation cycle. As experience is gained, most expect future RFOs to proceed more rapidly. Among the more worrisome aspects of the 2003/2004 RFOs, however, was that the amount of viable low-cost renewable energy supply that bid into these solicitations appears somewhat limited. Though the filed contracts have, so far, been below the MPR, such a fortuitous situation may well not last forever.

Considering this circumstance, as well as other aspects of the stakeholder interview results, we recommend the following:

- **Consider relaxing delivery for in-state generators: allow delivery anywhere within the state.** Virtually all parties agree that the state's IOUs should be allowed to purchase renewable energy for delivery anywhere within the CA ISO or the state, whether that electricity is subsequently transmitted to

the utility's load or otherwise remarketed. As a result, we believe that the state's regulatory bodies should confirm that these transactions are allowable under the state's RPS. There is disagreement about whether utilities should be required to ask for such transactions in their RFOs. On this point, we have no strong recommendation, but we acknowledge that the state's utilities have legitimate concerns about the risks that such transactions may pose. At the same time, the existence of the MPR and SEPs may mute the incentives of the state IOUs to minimize overall contract costs through such creative structures. We recommend that the CPUC and Energy Commission carefully consider the arguments on both sides, and make a decision on this point in the near future.

- **Consider relaxing delivery for in-state generators: allow developers to offer shaped renewable energy products.** Though not recommended by as many of the survey respondents, to mitigate the risk for utility shareholders and ratepayers from out-of-territory delivery, we encourage the CPUC and Energy Commission to consider allowing renewable energy developers to offer "shaped" and "firmed" products. Effectively, this would allow utilities to purchase RECs bundled with electricity and delivered to the utility's service territory, but delivery of that electricity may not be coincident with the hour-to-hour production of the renewable generator. RECs would be unbundled from their underlying electricity, and rebundled with system power at another time. This places remarketing and congestion risks on the renewable energy developer, but also allows that developer to deliver a shaped product to the utility that may avoid the need for costly transmission additions between utility service territories. If shaped delivery of renewable energy is allowed only for in-state generators, and for generation that is delivered into the state under the current strict delivery rules, we see little downside from these transaction structures. On the longer-term basis, the state's policymakers may also want to consider whether out-of-state generators should be allowed to offer shaped products.
- **Consider relaxing delivery for out-of-state generation at nearby market hubs.** Similar to in-state delivery flexibility, and as supported by a number of survey respondents, we recommend that the CPUC and Energy Commission find that out-of-state renewable generators that deliver to a nearby but out-of-state market hub or substation are eligible under the state's RPS if the utility purchaser commits to arranging for transmission from that hub or substation to an in-state location. We see little downside from such a transaction structure because, as with the present rules, out-of-state generation is delivered in real time to an in-state market hub or substation. We have no opinion on whether such transactions should merely be allowed, or whether utilities should be required to solicit such proposals. PG&E's recent proposal goes one step farther than that suggested above as it would allow PG&E to remarket that power and retain credit for the renewable purchases. We recommend that the CPUC and Energy Commission consider this proposal

carefully as it would allow out-of-state renewable generation to never reach the state and yet still allow the state's utility to retain credit for the purchases, somewhat akin to an unbundled RECs transaction. Whether sufficient in-state benefits derive from such a transaction should be the subject of debate; one possibility might be to strictly limit the amount of remarketing that would be allowed in this instance.

- **Consider making policy decisions on elements of utility RFOs.** As reported in the survey responses, some of the most contentious issues related to the utilities 2003/2004 RFOs included the generation delivery point in the event of market redesign and the size and nature of the bid deposit requirements. The former was a significant causal factor in the contracting delays experienced under the 2003/2004 RFOs, and the latter apparently had an impact on the amount and type of bid response received under the RFOs. Legitimate arguments exist on both sides of each issue. Utilities and developers would each naturally like to avoid the congestion risk associated with market redesign, and bid deposits, though they can discourage real projects from submitting proposals, also serve a useful purpose in avoiding frivolous bids. Similarly difficult tradeoffs exist for other hotly contested elements of the form contracts, including credit requirements, performance obligations, scheduling risks, and other matters. In many cases, these issues come down to an allocation of risk among parties; in general, the party best able to manage the risk should be the one on which the risk falls. Though some utility flexibility on these issues is warranted (after all, noncompliance penalties will ultimately fall on these parties), it is also useful to recognize that unduly onerous contract terms may yield higher ratepayer costs and higher SEP payments than necessary. The CPUC may wish to weigh both sides of these debates, establish workshops to discuss 2003/2004 RFO experience more generally, and decide whether revisions to the standard contract terms and conditions are warranted in these or other cases (if not for the 2005 RFO cycle, for the 2006 cycle). An additional issue worthy of CPUC consideration is that of utility ownership of renewable energy projects.
- **Consider waiting for additional experience before developing rigid RFO deadlines.** A number of parties have suggested that the CPUC establish rigid deadlines for the completion of utility RFOs, though other parties felt that such deadlines were not necessary. We do not believe that broadly applicable deadlines of this sort are warranted at this stage.⁴¹ Experience is still being gained, and most survey respondents felt that future RFOs would proceed more rapidly than the more recent ones. Additionally, the delays in California are not altogether atypical—other utilities have experienced similar delays with renewable and all-source RFOs, in large part because negotiations can take time. Finally, rigid deadlines may place some upward price pressure on bids during negotiations, especially for utilities that are behind in meeting their RPS targets. All that said, we do believe that deadlines can and should be employed for specific utilities on a case-by-case basis in cases of undue

delay. In addition, we would recommend that the CPUC reconsider the issue of deadlines after the 2005 RFO cycle. If deadlines are employed in the near term, we recommend that those deadlines not be overly proscriptive. Instead, the CPUC might consider a more general deadline that the previous year's RFO must have resulted in Advice Letter contract filings before the CPUC will approve a present-year RFO.

- **Address other issues as time allows.** Though not a critical-path item, the CPUC might consider conducting a workshop on the treatment of renewable energy projects that bid into multiple RFOs and solicitation cycle issues more generally. Several survey respondents noted that experience from the 2003/2004 RFOs might inform a more nuanced treatment of these issues than the requirements imposed by current CPUC rules. Several additional stakeholders suggested giving utilities more procurement flexibility, and this too should be the subject of discussion. Given some concerns about the financeability of SEP payments, the Energy Commission may also wish to track this issue as SEP payments begin. Though the Energy Commission has already determined that it does not have the current legal authority to establish escrow accounts for SEPs, if serious financeability issues do arise, alternative solutions should be considered to firm-up SEP revenue streams. Other issues raised by parties on SEP administration, discussed in Chapter 2, should also be addressed.

The state's regulatory bodies should ensure, however, that the above actions do not unduly delay the release of the utilities' 2005 RFO. The timely release of these RFOs is arguably more important than any improvements that might be made as a result of the recommendations above.

Near- to Mid-Term Policy Decisions

Outside of the context of the immediate RFOs, several larger policy issues deserve near-term attention.

- **ESP/CCA Compliance:** Perhaps most importantly, after two and half years, it is time to address ESP/CCA compliance. Many survey respondents admit that the regulatory framework established for the state's IOUs is not a good match for ESPs/CCAs. New structures may be required, but survey respondents also observe that that cannot be an excuse for inaction. Though the appropriate design of the state's RPS for ESPs/CCAs was not addressed in this report, we note that several alternative approaches are available, ranging from various centralized procurement agent options to providing additional contracting flexibility to ESPs/CCAs. Some of these issues are more fully addressed in Wisner (2005).⁴²
- **Transmission Issues:** Many survey respondents observed that transmission may be the most severe constraint to the state achieving its renewable energy targets. Given that context, we agree with several of our survey

respondents that the Tehachapi and Imperial Valley transmission working groups offer a useful operating model, and we recommend that the CPUC and Energy Commission explore expanding this process to additional renewable resource areas that are identified by stakeholders as potentially deserving similar scrutiny. We also recommend continued analysis of the present TRCR methodology. Stakeholders have offered widely divergent views on the appropriateness of the current methods, with little common ground among the opposing viewpoints. Assessing these differences requires specialized transmission expertise. Consequently, the CA ISO should be encouraged to participate more actively in the RPS proceedings. In recently filed summary testimony, the CA ISO appears to reject arguments on both sides of the current TRCR debate, perhaps portending a useful middle ground. Further insight from the CA ISO may be required before a decision can be made on this matter. Finally, it goes without saying that the CPUC should do everything in its power to meet its statutory requirements to support RPS-driven transmission investment in the state.

- **Unbundled RECs:** Beyond the loosened delivery requirements suggested earlier, many parties believe the state should go farther and allow unbundled RECs to count towards meeting RPS targets, at least for generation that is delivered into the state. Whether this can be accomplished through regulation—or requires legislation—is hotly debated. Certain ESP/CCA compliance options may ultimately require the use of unbundled RECs, but if SEP payments are not to apply to RECs, it remains to be seen whether RECs become a common compliance alternative for either IOUs or for ESPs/CCAs. Clearly, with the existence of SEPs, the use and applicability of unbundled RECs is more complicated than in other states. As a result, we believe that the question of whether unbundled RECs should be allowed deserves considerable attention by the state's legislators and regulators. At the same time, we would encourage policymakers to broaden that discussion to include the possible application of SEPs to RECs, or the application of SEP funds to ESPs and CCAs more generally. After all, if ESPs and CCAs do not have ready access to SEPs through their REC purchases, then it is not entirely clear what value unbundled RECs will provide to these market participants.
- **Contract Failure:** As reported in Chapter 3, a wide variety of survey respondents expressed deep concern that a number of renewable energy projects under contract will not ultimately deliver as promised, due to transmission constraints, fuel supply limits, permitting difficulties, or overly aggressive bid prices. California's policymakers should consider anticipating and addressing this all-too-real risk now, rather than being in the unenviable position of addressing it after the fact, at which point the only alternatives will be to impose burdensome noncompliance penalties on the state's IOUs, or otherwise give the IOUs a "free-ride" by forgiving the lack of compliance. Neither approach is altogether satisfactory. Instead, we recommend that the CPUC organize a workshop in which these issues could be discussed. Topics

of discussion would necessarily include how RFOs and contract terms can balance the desire to maximize developer participation in the RFOs with a concomitant desire to only sign contracts with projects that have a high probability of realization. Experience from other states in addressing this issue through bid deposits, development milestone requirements, credit requirements, performance penalties, and evaluation techniques may also be of some relevance. Additionally, given the ever-present risk of contract failure, we strongly recommend that the CPUC consider requiring the state's utilities to "over-procure" renewable energy under the expectation of some contract failure. In the event that the CPUC chooses not to establish this requirement, it may wish clarify how its noncompliance penalty and compliance flexibility rules will apply when the inevitable occurs—one or more of the state's utilities petitions for a waiver of the penalties and use of liberal compliance flexibility because some number of its renewable energy contracts fail to yield operating projects.

- **Consider clarifying rules for penalties and flexibility mechanisms.**

Several of the developers and developer associations expressed considerable impatience with the lengthy, complex and protracted regulatory process associated with the California RPS and urged the CPUC to rely less on process and to instead issue clear direction via regulatory orders and to back these up with penalties or noncompliance fees. Utility representatives, meanwhile, voiced concern about the threat of penalties. On whatever side one falls in this debate, one thing is relatively clear: the current rules for when compliance flexibility is allowed and when penalties are to apply are not altogether certain. PG&E's recent proposal to count future contracted deliveries towards present-year renewable energy targets, under the compliance flexibility rules, highlights these uncertainties. To provide more certainty to all market players, the CPUC should consider clarifying these rules.

Longer Term Policy Issue: Consider Eliminating SEPs and the MPR

The existence of supplemental energy payments makes the California RPS unique. More troubling and less recognized, however, is that SEPs create regulatory responsibilities and complexities that are caused by the perverse incentives inherent in the separation of payment between retail suppliers and the Energy Commission. To be clear, as presently structured, SEPs can and should be used: we do not believe that SEP funds should be conserved for their own sake. However, the state's IOUs—their payments capped at the MPR—are currently (in theory) indifferent to the cost of different renewable contracts that exceed the MPR, and may instead seek to select projects based on factors other than cost. Though some of these factors, including portfolio fit, certainly should play a role in evaluation, the current incentive structure could yield undue emphasis on portfolio fit at the expense of total societal cost, resulting in renewable energy contracts with high prices and a premature draw down of the SEP funds. Transparent and approved bid evaluation processes, PRG

oversight, and CPUC contract pre-approval can all help counteract these incentives, but each of these comes at the cost of added complexity.

The elimination of the MPR and SEP payments would not relieve the state's regulatory bodies from oversight but may significantly simplify those oversight burdens. The state's retail suppliers would still be required to meet the RPS percentage targets but, like most other RPS policies, total costs would be recovered directly in retail rates based on contract costs. Utilities and other suppliers would presumably seek to minimize these costs in order to keep rates down, without the same skewed incentives created by the MRP and SEPs. Various forms of cost caps could be applied if there was concern about the potential "unlimited" cost impacts of such a policy approach. Given the concern of survey respondents, including the state's IOUs, about the potentially negative impact of the MPR on bid prices, elimination of the MPR may also yield lower renewable energy contract costs. In addition, with SEPs eliminated, the role for unbundled RECs may become more obvious.

Despite these potential advantages and the fact that a number of survey respondents are open to the elimination of SEPs, many of those same respondents are also naturally reluctant to do away with the present system, which is finally yielding renewable energy contracts, to move towards a system that may have its own complexities and time consuming design processes. Cognizant of this concern, if the state's policymakers wish to consider eliminating SEPs, we would recommend that the present system continue until the new system is fully operational.

Meanwhile, if the state chooses not to move in this direction, we recommend continued vigilance of utility RFO design, evaluation, and bid selection processes, with a keen eye on whether the MPR/SEP incentive problems described here warrant other forms of policy response. We are hopeful that they will not require such response. If problems do arise, however, the CPUC might consider increased consistency and transparency in bid evaluation, more comprehensive oversight of RFO design, additional standardization of the form contracts, and perhaps even the use of independent evaluators.

ENDNOTES

¹ See: (1) California Energy Commission. 2003. "2003 Integrated Energy Policy Report." Pub No: 100-03-019. Sacramento, California: California Energy Commission. (2) California Energy Commission. 2004. "Integrated Energy Policy Report: 2004 Update." Pub No: 100-04-006CM. Sacramento, California: California Energy Commission.

² Governor's Budget Summary 2005-06, page 148, and Governor's Budget Highlights 2005-06, page 92.

³ The range in installed capacity and energy generation is due to the existence of project expansion options.

⁴ Note, however, that due to its previous financial condition, PG&E's first obligatory RPS compliance year is 2005.

⁵ See: (1) California Energy Commission. 2003. Renewables Portfolio Standard: Decision on Phase 1 Implementation Issues. Pub No: 500-03-023F. Sacramento, California: California Energy Commission. (2) California Energy Commission. 2003. Renewables Portfolio Standard: Decision on Phase 2 Implementation Issues. Pub No: 500-03-049F. Sacramento, California: California Energy Commission.

⁶ See, e.g., Wiser, R. 2005. "California RPS Compliance Options for ESPs and CCAs: Review of Issues and Options." Prepared for the California Energy Commission.

⁷ For an overview of state RPS experience, see Wiser, R., Porter, K. and R. Grace. 2004. "Evaluating Experience with Renewables Portfolio Standards in the United States." LBNL-54439. Presented at Global Windpower 2004. Chicago, Illinois.

⁸ In its 2003 Renewable Resources Development Report (500-03-080F), for example, the Energy Commission provided a timeline for implementing California's RPS that would have begun RPS implementation for ESPs/CCAs by the end of 2003; a delay of one year and counting has therefore been experienced.

⁹ The exception is Connecticut, where the state's regulated utilities are obliged to meet contracting requirements that the state's ESPs are not.

¹⁰ Other states use system-benefits charge funds to support RPS-eligible projects, or use RPS noncompliance penalties to support the renewable energy market. Only the New York and Arizona system-benefits charge funds, however, are explicitly used to cover the cost of the states' RPS policies.

¹¹ Arizona, Connecticut, District of Columbia, Maine, Maryland, Massachusetts, New Jersey, Pennsylvania, Rhode Island, Texas, and Wisconsin.

¹² Colorado, Minnesota (for Xcel), Montana, Nevada, New Mexico, and Connecticut (for the 100 MW long-term contracting requirement for IOUs).

¹³ Bolinger, M. and R. Wiser. 2005 (DRAFT). "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Berkeley, California: Lawrence Berkley National Laboratory.

¹⁴ Note that here, and elsewhere, conclusions on the views of ESPs/CCAs, developer associations, nonprofits, and utilities are hampered by the small sample size.

¹⁵ Issues associated with the 2005 MPR are currently being addressed before the CPUC. Some of the areas of most significant disagreement among parties include: (1) the natural gas price forecast, (2) the consistency of the capital, operating and financing assumptions, (3) the way in which time-differentiated MPRs might be applied, and (4) whether adjustments should be made to the MPR based on intermittency and dispatchability.

¹⁶ Under the compliance flexibility rule, PG&E is seeking to allow renewable contracts for future delivery to count towards RPS compliance in the year in which the contracts are signed (or the year in which the RFO was issued).

¹⁷ These totals were calculated by the CPUC's Energy Division and presented to the Joint Agency Energy Action Plan Meeting: "Accelerate the State's Goal for Renewable Energy." Presented by Dan Adler and Marwan Masri. November 7, 2003.

¹⁸ See "Administrative Law Judge's Ruling Shortening Time for Responses to Motions." R. 01-10-024. October 25, 2001.

¹⁹ See, for example, TURN's April 21, 2005 comments on the renewable energy procurement plans of PG&E and SCE. TURN specifically recommends a deadline in the case of PG&E, because PG&E proposes to allow future contracts to be eligible for meeting current-year RPS purchase obligations under the flexible compliance rules.

²⁰ The CA ISO is currently re-designing its markets, which may lead to a locational-based market pricing regime. This complicated issues associated with the delivery point of renewable generation because the current NP15 and SP15 pricing zones may not be supported under the new market design.

²¹ In addition to the suggestions listed here, one utility respondent noted that the CPUC should release the MPR earlier in the solicitation cycle, to minimize time delays.

²² PG&E, in remarks to a May 9, 2005 Energy Commission workshop, expressed a similar concern.

²³ A number of developer respondents reported that they and others had chosen not to bid, as a result of cumbersome and onerous requirements imposed by the solicitations. Some of these developers reported that they preferred to bid into renewable energy RFOs from California's municipal utilities or from out-of-state utilities.

²⁴ As described in Chapter 2, two developers in our sample effectively corroborated this view.

²⁵ At least one of these utilities believes that they were successful in "disciplining" the market.

²⁶ One PRG member also identified SDG&E as most forthcoming in its dealings with its PRG.

²⁷ A number of developers expressed dissatisfaction with the bid deposit requirements, in particular.

²⁸ Several developers noted that utilities are better equipped to handle congestion risk, and therefore supported a requirement that utilities offer to purchase power at the generator's busbar, especially in the event of market redesign of the CA ISO market.

²⁹ Texas, Massachusetts, Maine, Connecticut, Rhode Island

³⁰ New Jersey, Pennsylvania, Maryland, District of Columbia, Arizona, Nevada, New Mexico, Colorado, Montana

³¹ Wisconsin, New York

³² The others are Iowa, Hawaii, and Minnesota (note that Minnesota is exploring the use of unbundled RECs)

³³ Arizona (non-solar resources), Iowa, Minnesota (earlier requirement on Xcel), Hawaii

³⁴ Nevada (out-of-state facilities must have a dedicated transmission line to the state shared by at most one other party), and Texas (out-of-state facilities must have a dedicated transmission line to the state).

³⁵ Arizona (credit multipliers for in-state solar), Colorado (credit multipliers), and New Mexico (stated preference for in-state projects).

³⁶ Massachusetts, Connecticut, Maine, Rhode Island, Wisconsin, Minnesota, Colorado, Arizona, New Mexico, New York, New Jersey, Maryland, District of Columbia, Pennsylvania, Montana

³⁷ New Jersey, Pennsylvania, Maryland, District of Columbia, and even Massachusetts, Connecticut, Maine, Rhode Island

³⁸ For a somewhat different - but more detailed - treatment of deliverability options, see: Grace, R. and R. Wiser. 2002. "Transacting Generation Attributes Across Market Boundaries: Compatible Information Systems and the Treatment of Imports and Exports." LBNL-51703. Berkeley, California: Lawrence Berkeley National Laboratory.

³⁹ Specifically, the Energy Commission's guidebooks require that a renewable facility demonstrate "delivery of its generation to an in-state market hub or in-state substation located within the CA ISO control area." What is unclear is whether the generator must ensure and demonstrate such delivery, or whether the utility might arrange for the delivery.

⁴⁰ One respondent urged that transmission planning be done for ten years into the future with transmission facilities identified as necessary moved all the way through the CPCN process so that the transmission facilities are in place when needed as the RPS targets increase over time. This same respondent believed that the legislature should require the CPUC to act on transmission CPCN applications within 12 months. In addition, this respondent suggested that utilities should be required to proactively announce future transmission CPCN plans and that utilities should be required to meet those dates.

⁴¹ Similarly, we do not believe that complete contract standardization, or the creation of a Standard Offer 4 equivalent, are warranted until additional experience is gained with the present compliance mechanisms.

⁴² Wiser, R. 2005. "California RPS Compliance Options for ESPs and CCAs: Review of Issues and Options." Prepared for the California Energy Commission.

ACRONYMS AND ABBREVIATIONS

CA ISO	California Independent System Operator
CalWEA	California Wind Energy Association
CCAs	community choice aggregators
CEERT	Center for Energy Efficiency and Renewable Technologies
CPUC	California Public Utilities Commission
ESPs	energy service providers
GPI	Green Power Institute
GWh	gigawatt-hours
IEP	Independent Energy Producers Association
IEPR	Integrated Energy Policy Report
IOUs	investor-owned utilities
kWh	kilowatt-hours
LCBF	least-cost, best-fit
MPRs	market price referents
MW	Megawatts
PG&E	Pacific Gas and Electric
PIRP	Participating Intermittent Resource Program
PRGs	Procurement review groups
PTC	production tax credit
RECs	renewable energy certificates
RFOs	requests for offers
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEPs	supplemental energy payments
SIS/FS	System Impact Study and Facilities Studies
TOD	time-of-day
TRCRs	transmission ranking cost reports
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists
WREGIS	Western Renewable Energy Generation Information System

APPENDIX A: FINAL INTERVIEW GUIDE

As part of the 2005 Integrated Energy Policy Report (IEPR), the California Energy Commission will be summarizing early results of the state's RPS. In this interview, four elements of the RPS will be emphasized: (1) the overall design of the policy, (2) the regulatory process associated with the RPS, (3) the implementation of the most recent set of utility solicitations, and (4) rules for deliverability into and within the state.

The purpose of this interview is to get your feedback on these subjects. The interview results will be summarized in a report to the Energy Commission, and some of the report's content may be included in the IEPR. The Energy Commission will not be making legislative proposals based on these interviews.

You may also want to know that in our report to the Energy Commission we will identify the organizations that we interviewed, but we will not associate any specific comments to the interviewees or the organizations that they represent. That said, because this work is being conducted for a public agency, we cannot guarantee absolute confidentiality.

Overall RPS Design

We would like to start by briefly getting your overall views on California's RPS design.

1. What is your overall view of how the state's RPS policy is working?
2. On a scale of 1 to 5, with 1 meaning that the policy is broken and is not working, and 5 meaning that it is operating flawlessly, how would you rank the overall California RPS?
3. There are many elements to the California RPS. On a scale of 1 to 5, with 1 meaning that the element is not working and needs immediate change, and 5 meaning that the element is working effectively and doesn't need to be altered, how would you rate the following:

	← worse					better →	No opinion
	1	2	3	4	5		
Standard contract terms and conditions							
Use and determination of the market price referents							
Least-cost, best-fit evaluation							
Renewable electricity deliverability requirements							
Transmission ranking cost reports							
Supporting transmission expansion							
Renewable energy resource eligibility							
Utility compliance flexibility mechanisms							
Utility non-compliance penalties							
Measuring and tracking compliance with the RPS							
Utility renewable energy procurement plans							
Utility renewable energy solicitations							
Administration of supplemental energy payments							

4. What elements of the state's RPS policy design are most useful?
5. What elements of the state's RPS policy design do you find most problematic?
6. What policy design changes, if any, do you believe are required to make the RPS more effective?

Regulatory Implementation Processes

The development of California's RPS has required heavy regulatory involvement by the PUC and CEC: developing rules at the CPUC, and developing guidebooks at the CEC. These processes have taken a considerable amount of time, and certain elements of the policy design are not yet complete.

7. What specific elements of the regulatory process have been most useful?
8. What specific elements of the regulatory process have been most problematic?
9. Some concerns have been raised about the speed of the regulatory process. What would you recommend to streamline and speed the regulatory process?

10. Would you recommend greater or lesser regulatory oversight of utility renewable energy procurement and evaluation processes? In what ways, and why?

11. Some concerns have been raised about the transparency of the overall process, e.g., MPR creation, advice letter filings, bid evaluation protocols, etc. Do you believe that greater transparency should be sought? If so, in what ways and why?

Utility Solicitations

Three renewable energy solicitations have either recently been completed or are underway by California's investor-owned utilities (IOUs): SCE 2003, SDG&E 2004, and PG&E 2004.

12. Which of these three recent IOU solicitations are you familiar with?

13. Each solicitation has taken longer from issuance to Advice Letter filing of contracts than originally expected.

a. What are the principal reasons for these delays?

b. Would you recommend any policy changes to speed the solicitation process? What and why?

c. Do you believe the next round of solicitations will proceed more rapidly? Why? How much so?

14. Do you believe that the prices bid into these solicitations reflect healthy price-competition among a broad range of bidders in a robust competitive market? If not, why not? What changes in policy or in the utility solicitations would you recommend to bring prices down?

15. What are the advantages and disadvantages to an annual solicitation cycle compared to one in which each utility would issue solicitations less frequently, or more frequently?

16. In general, do you believe that the current solicitations, if continued in present form, will effectively support the state's RPS? Why or why not?

17. What policy changes (not noted already) would improve the renewable energy procurement process? Are any of these absolutely critical for the 2005 solicitations?

18. (For renewable energy developers, developer associations, and PRG members)

a. If you are familiar with more than one of the utilities' 2003/2004 solicitations, what are your views on the relative advantages and disadvantages of each?

b. If you are familiar with renewable energy solicitations in other states, how would you compare the California RPS solicitations with those that you have been involved with elsewhere?

c. For each of the recent California IOU solicitation that you are aware of:

i. What did you like most about the solicitation?

ii. What did you find to be the top three problems with the solicitation?

19. (for the three utilities) What were the most important pitfalls that you experienced and lessons that you learned from your most recent solicitation? How do you plan to change your next solicitation to respond to these pitfalls and lessons?

20. SDG&E, PG&E, and SCE have now submitted proposed renewable energy solicitations for use in 2005? Are you familiar with these proposed solicitations? Relative to the 2003/2004 solicitations, what are the key advantages and disadvantages of the 2005 proposals?

21. Some renewable contracts may require supplemental energy payments (SEPs) from the CEC. In your view, is the revenue stream behind the SEPs financeable? Are there actions that you would recommend to improve the administration and application of the SEPs?

Deliverability

The state's RPS - by law and by regulation - currently imposes electricity deliverability requirements for both out-of-state and in-state renewable energy projects. Transmission ranking cost reports are used to evaluate transmission costs for the purpose of bid evaluation.

22. Do you believe that the current deliverability requirements are reasonable and support the objectives of the state's RPS? Why or why not?

23. Are you most concerned with the delivery and transmission requirements for out-of-state generators, or for in-state generators? Why?

24. Would you recommend any near-term changes to utility solicitations or to policy regarding requirements for delivery and transmission? What are they?