BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

COMMENTS OF THE
CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES
ON RPS PLANS AND NEW PROPOSALS

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The Center for Energy Efficiency and Renewable Technologies (CEERT) respectfully submits these Comments on the Investor-Owned Utilities' (IOUs') Renewable Portfolio Standard (RPS) Program Plans and the New Proposals required and identified in the Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Section 399.11 Et Seq. and Requesting Comments on New Proposals issued on April 5, 2012 (April 5 ACR). These Comments are timely filed and served pursuant to the Commission's Rules of Practice and Procedure and the April 5 ACR.

I.
THE IOUS' RPS PLANS REVEAL AN IMMEDIATE NEED FOR FURTHER COMMISSION GUIDANCE TO ENSURE COMPLIANCE WTH *ALL* APPLICABLE SB 2 1X REQURIEMENTS AND COMMISSION PRECEDENT ON A UNIFORM BASIS.

A. Widespread Differences Between the IOUs' 2012 RPS Plans in Interpreting, Applying, or Even Ignoring SB 2 1X Requirements Create Unnecessary Conflicts with the Law and Undermine Needed Certainty in the RPS Procurement Process.

In early 2011, Senate Bill (SB) 2 1X was enacted adding or amending portions of the RPS Program (Public Utilities (PU) Code §399.11, et seq.[1] As stated in the Scoping Memo and

[1] SB 2 (Stats 2011, Ch. 1), adding or amending portions of the RPS Program (Public Utilities (PU) Code §399.11, et seq.)

Ruling of Assigned Commissioner (Scoping Memo) issued on July 8, 2011, the purpose of this proceeding is to serve as "the vehicle for the Commission's continuing administration and oversight of the renewables portfolio standard (RPS) program" and, more specifically, to "implement major changes in the RPS program resulting from the enactment of Senate Bill (SB) 2 (1x) (Simitian), Stats. 2011, ch. 1."[2] According to the Scoping Memo, those "changes" "most notably" include "extending the RPS goal from 20% of retail sales of all California investor owned utilities (IOUs), electric service providers (ESPs), and community choice aggregators (CCAs) by the end of 2010, to 33% of retail sales of IOUs, ESPs, CCAs and publicly owned utilities (POUs) by the end of 2020."[3]

Unfortunately, the April 5 ACR, which launches the important task of RPS procurement planning for all RPS-obligated retail sellers (i.e., IOUs), provides little direction or information related to the impact of the SB 2 1X changes on the "specific requirements for 2012 RPS Procurement Plans,"[4] which, in general, are addressed in PU Code §399.13.[5] Yet, additions not only to §399.13, but also related requirements of other amendments to the RPS Program by SB 2 1X, have significantly altered the required scope and purpose of RPS Plans, including its use in establishing the "procurement expenditure limitations" required for each IOU pursuant to §399.15 (c), as added by SB 2 1X. On that point, the Legislature has expressly directed the Commission to "rely on" the IOU's "most recent energy procurement plan" in establishing these limitations.[6]

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[2] Scoping Memo, at p. 2. See also, April 5 ACR, at p. 4.
[3] Id.
[4] April 5 ACR, at p. 8.
[5] The April 5 ACR does note one "new requirement" in PU Code §399.13(a)(5)(D), namely, for the plans to provide a "project development status update." (April 5 ACR, §6.3, at p. 9).
[6] PU Code §399.15(c)(1).

In reviewing the requirements for RPS Plans added by SB 2 1X, it is clear that the Legislature intended that much greater attention be paid to when and whether projects that are selected by the IOUs in this planning and procurement process are likely to become reality. Thus, the RPS plans, in addition to the "status update on the development schedule of all eligible renewable energy resources currently under contract," mentioned in the April 5 ACR, must now also identify "potential compliance delays," provide "price adjustments" for projects with online dates more than 24 months after the date of contract execution, and assess the "risk" that the project will not be built or construction delayed so that electricity will not be delivered as expected.[7] Some of these requirements have been lumped together by the April 5 ACR as "quantitative information," when, in fact, the clear intent of the Legislature is to ensure plans not just list, but in fact, account for these requirements.

Missing from the August 5 ACR is also any instruction to the IOUs as to how these provisions should be factored into the new "compliance periods" by which IOU progress toward the 33% RPS goal is to be measured (as implemented by the Commission in D.11-12-020) or how the new "portfolio content categories" (D.11-12-052) or the RPS Compliance Rules (D.12-06-038) should be treated. The latter decision is in fact one that, as Pacific Gas and Electric Company (PG&E) notes in its Public 2012 RPS Plan, could "impact the amount and timing of PG&E's procurement efforts."[8]

The April 5 ACR also disregards the new requirements of the "least cost best fit" methodology that now specifically mandates that this methodology must account for project viability, inclusive of factors indicating the likelihood of success and, conversely, the risk of delay or failure, and for workforce recruitment, training, retention, and employment growth,

[7] PU Code §399.13(a)(5)(B), (D), (E), and (F).
[8] PG&E Public 2012 RPS Plan (May 23, 2012), at p. 7.

especially with reference to women and minorities, from the project.[9] Further, a provision completely neglected by the August 5 ACR is the significant change *requiring* the IOUs to give preference to the following renewable projects in their solicitations:

> "In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation *shall give* preference to renewable energy projects that provide *environmental and economic benefits* to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants and greenhouse gases."[10]

As evidence of the broad impact of the SB 2 1X on RPS planning and procurement, the Commission need only look to the "redlined" versions of the IOUs' RPS Plans, in which nearly all of the IOUs' 2011 RPS Plans, criteria, and protocols, have been "redlined" out in favor of new replacement sections and text. In the absence of specific guidance by the Commission on how the SB 2 1X amendments and additions are to be accounted for in the RPS Plans, the IOUs have been given wide leeway and discretion in "interpreting" this law and, in some instances, doing so in a manner that is neither uniform or consistent with the law and applicable Commission precedent.

The result, as examples, are varying interpretations and significant differences in how each utility defines its need, least cost best fit methodology, and applicable protocols, including completely neglecting provisions like the mandate of PU Code §399.13(a)(7) above;[11] "targeting" solicitations to a narrow, but different, pre-defined group of bidders; providing varying approaches to the use or quantification of "integration costs," and using differing calculations of the assumed "risk of project failure."[12] In this latter regard, SCE, consistent with the most recent projections by the Energy Division, assumes a 60% "success rate" (or 40%

[9] PU Code §399.13(a)(4)(A)(iii) and (iv).
[10] PU Code §399.13(a)(7); emphasis added.
[11] See, e.g., SCE Public 2012 RPS Plan, App. F.1
[12] SCE Public 2012 RPS Plan, at pp. 3, 18.

failure rate) for signed contracts that have yet to come online, while PG&E divides projects not yet on-line into sub-categories of risk and assumes a 100% delivery of contract volumes outside of a "closely watched" sub-category.[13]

In addition, while the IOUs state that they worked together in organizing their plans, the plans are not uniformly presented and similar issues are addressed in different texts or appendices. Of note, SCE offers its position on "new proposals" presented by the April 5 ACR in a separately filed set of "Comments."

These outcomes and approaches not only confuse this process, but ultimately could inject uncertainty and undermine the purpose of a robust competitive RPS solicitation to yield viable, reasonably priced projects. Such uncertainty in the development of RPS procurement plans and protocols is also not consistent with the emerging role of RPS solicitations and bids as serving as cost reasonableness benchmarks. Thus, while Commissioners have debated the merits of relying on "bids," as opposed to executed contracts, as a point of price comparison, it has nevertheless been increasingly the case that such comparisons are being made.[14] Yet, if this is the direction that is to be taken in comparing "bids" with executed contracts, it is imperative that the RPS plans and solicitations approved by the Commission fully reflect all legislative requirements for those plans and rely on appropriate, and to the extent possible, uniform assumptions and criteria that provide the best opportunity to stimulate broad competition and yield viable bids from viable projects.

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[13] SCE Public 2012 RPS Plan, at p. 18; PG&E Public 2012RPS Plan, at pp. 43-44.

[14] See, e.g., Resolution E-4501 (June 7, 2012) (approving an SCE RPS PPA, which SCE contended was "of comparable or better value to other RPS market *offers*.") (Resolution E-4501, at p. 2; emphasis added .)

B. No Utility Has Addressed Imperial Valley Issues as Required By D.09-06-018 and D.11-04-030.

Both the April 5 ACR and, in turn, the RPS Plans filed by the IOUs also fail to address critical "Imperial Valley Issues," as directed by D.09-06-018 and D.11-04-030. Specifically, by D.09-06-018, the Commission adopted RPS solicitation requirements that were an outgrowth of its authorization of a Certificate of Public Convenience and Necessity (CPCN) for the Sunrise Powerlink in D.08-12-058 and that were to yield "prompt proposals from RPS-eligible renewable developers for viable, competitively priced projects in the Imperial Valley."[15]

To that end, for the 2009 RPS solicitation cycle, the Commission ordered each utility to hold a special Imperial Valley bidders conference and the Energy Division to conduct special monitoring to determine "whether attractive Imperial Valley projects" make it through the solicitations.[16] While other "remedial measures" were not adopted in D.09-06-018, the Commission made the following commitment:

> "Nonetheless, we will consider remedial measures if future evidence shows the LCBF methodology fails to properly value Imperial Valley resources and their unique access to transmission, or that there are other infirmities. Those measures might include automatic shortlisting, a special bid evaluation metric, special solicitation, or other remedies a party may propose."[17]

In D.11-04-030, in reviewing and approving the IOUs' 2011 RPS Plans, the Commission assessed the "Sunrise/Imperial Valley Remedial Measures," which had been required by D.09-06-018 (e.g., "a special Imperial Valley bidders conference" and "specific proposal and project monitoring") as part of the 2009 RPS solicitation. The Commission reiterated its commitment to '"consider remedial measures if future evidence shows the LCBF methodology fails to properly

[15] D.09-08-018, at pp. 10-11.
[16] Id., at pp. 11-16.
[17] Id., at p. 18.

value Imperial Valley resources.'"[18] However, for purposes of the 2011 RPS plans, the Commission concluded that such additional measures were not necessary due to the "robust response" ("offers") from such resources in the 2009 RPS solicitation and a "confiden[ce] that IOUs will select all reasonable bids within the LCBF process."[19] The Commission nevertheless committed to "continue specific monitoring of Imperial Valley proposals and projects" and "encourage[d] all three IOUs to do outreach, and take all reasonable and necessary action to secure optimal RPS development and reach RPS targets" and "to continue to ensure robust response in this important region."[20]

Despite this ongoing recognition by the Commission of the importance of the Imperial Valley resources, *none* of the IOUs' RPS Plans provide any assessment of any "response" (offers) from these resources in their 2011 RPS solicitations or any indication of whether those earlier offers actually resulted in procurement from this region. As the redlined plans of SCE and PG&E reflect, the entire discussion of "Imperial Valley Issues" has been eliminated from their 2012 RPS Plans, [21] and no utility has provided any protocols or even included the resource adequacy (RA) valuation required by a Assigned Commissioner's Ruling (ACR) issued in June 2011 (discussed below) in their LCBF methodologies or criteria.

SDG&E similarly redlines this entire section, stating in its table of "Important Plan Changes" that its 2012 RPS Plan "does *not* include Imperial Valley bidders Conference and Project Development Period Security waiver" because "SDG&E is currently in compliance with its pledge (referenced in D.08-12-058) to maintain a certain level of deliveries from projects in

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[18] D.11-04-030, at p. 25.
[19] Id.
[20] Id., at p. 26.
[21] SCE Public 2012 RPS Plan, Appendix A (Redline of RPS Written Plan), at pp. 25-27; PG&E Public 2012 RPS Plan, Appendix A, at p. 133.

the Imperial Valley region."[22] Yet, in another part of its 2012 RPS Plan, SDG&E states that development in the Imperial Valley has been stymied by "significant permitting challenges" and the need to build "interconnection and network facilities necessary to interconnect and deliver this renewable energy to the transmission system."[23]

The decision by the IOUs (and even the April 5 ACR) to neglect "Imperial Valley Issues" was *not* what the Commissioner ordered in D.11-04-030. Continued attention to these issues in the 2012 RPS Plans was clearly intended by D.11-04-030, which placed those issues among its "Summary of *Key* Items" in Appendix A to that order, as follows:

> "4. Sunrise/Imperial Valley Issues: Decline to order any remedial measures, *but* continue monitoring of Imperial Valley proposals and projects, encourage each IOU to do appropriate outreach, including possible special Imperial Valley bidder's conferences."[24]

Such direction was specifically incorporated in Conclusion of Law 12 of D.11-04-030, which made clear that "specific monitoring of Imperial Valley proposals and projects should continue; and IOUs should be encouraged to do outreach and take all reasonable action to secure *optimal* resource development,…"[25]

The absence of any attention to Imperial Valley resource in the IOUs 2012 plans is also counter to two even more recent Commission actions. First, on June 7, 2011, Assigned Commissioner Ferron issued a ruling (June 2011 ACR) to specifically address and redress the IOUs intention to "apply a zero or near zero RA [resource adequacy] value as part of the LCBF [least cost best fit] analysis of bids for RPS projects in the Imperial Irrigation District (IID) Balancing Authority Area (BAA), based on the maximum import capability (MIC) current

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[22] SDG&E Public 2012 RPS Plan, Appendix D; emphasis added. See also, SDG&E Redlined 2012 Request for Offers (RFO), at page 12 of 31.
[23] SDG&E Public 2012 RPS Plan, at p. 12.
[24] D.11-04-030, Appendix A, at p. 2.
[25] Id., Conclusion of Law 12, at p. 62; emphasis added.

assigned to the interties between the California Independent System Operator (CAISO) and IID."[26] The ACR specifically finds this approach to be "unreasonable," especially based on expected revisions by the CAISO to MIC values. To that end, the ACR instructs the IOUs not to use a MIC less than 1,400 MW for imports from the IID BAA as part of its LCBF evaluation of project bids within the 2011 RPS solicitation," unless the IOU could "present clear and convincing evidence" for not doing so.[27] The ACR in reaching this finding also *specifically* noted the ongoing commitment of the Commission to "consider any and all remedial measures going forward as necessary" to further and foster "Imperial Valley resource development.[28]

Second, on May 16, 2012, CPUC Commission President Michael R. Peevey and Commissioner Michel P. Florio, jointly with California Energy Commission (CEC) Chair Robert B. Weisenmiller, wrote to Steven Berberich, the CAISO's President and CEO, to express concern, among other things, regarding Imperial Valley renewable development and related transmission infrastructure requirements. Thus, the Commissions state in that letter (attached hereto as Appendix A) that, while there had been expectations that IID could "upgrade its transmission system to support greater export from IID to the CAISO footprint," the "Commissions now understand the cost of IID reinforcements recovered from generation development in the area may be a further impediment to the development of renewable generation resources in the region north of the Imperial Valley substation."[29]

Clearly, the issue of Imperial Valley resource development is at a critical stage and *must* be addressed in the IOUs' 2012 RPS Plans, including any recommended "remedial measures." The absence of this issue from the April 5 ACR and the IOUs' 2012 RPS Plans is a significant

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[26] June 2011 ACR, at p. 1.
[27] June 2011 ACR, at pp. 6-7.
[28] June 2011 ACR, at p. 6.
[29] Appendix A hereto, at p. 3.

oversight and must be corrected. In Section II.C. below, CEERT offers an initial recommendation on appropriate remedial measures that should be considered in this 2012 RPS solicitation cycle.

C. Commission Correction of and Further Guidance on IOU RPS Plans Must Take Place Now To Ensure Uniform Compliance with the RPS Program Law and Foster Regular, RPS-Compliant Solicitations That Yield Procurement from Viable, Realistically Priced, Diverse Renewable Electric Generation Resources.

For the reasons enumerated above, and further detailed with respect to each of the IOU's 2012 RPS Plans below, CEERT believes that the IOUs' 2012 RPS Plans submitted on May 23, 2012, are in need of a thorough review by the Commission and its staff to determine: (1) whether those plans comply with *all applicable provisions* of the RPS Statute, inclusive of all *applicable* amendments and additions to that law resulting from SB 2 1X and *Commission* interpretation and implementation of that law to date, (2) whether and to what extent uniformity can be achieved in these plans on key provisions, including critical assumptions related to "success" or "failure" rates, compliance delays, and "integration costs," among others, (3) whether and to what extent "targeted" solicitations are lawful or restrict competition inappropriately, and (4) whether and to what extent the plans comply with applicable Commission precedent, most notably, that affecting Imperial Valley resources. While CEERT has attempted to identify shortcomings in the IOUs' plans in these respects, it certainly does not have the resources to make a much needed "checklist" against which compliance and Commission expectations for such plans can be measured.

Why is this important? As noted above, the role played by offers in RPS competitive solicitations, especially as a reasonableness benchmark for signed contracts, has become increasingly prevalent as Commissioners review and approve individual RPS Power Purchase Agreements (PPAs). While CEERT shares the view that has been expressed by Commissioner

Sandoval regarding the significant difference between an "offer" (bids), which is simply a proposal, and a signed contract, which forms a commitment to perform, it cannot ignore this trend.

In these circumstances, the RPS competitive solicitation must, therefore, be based on credible, supportable, and, to the extent possible, uniform assumptions and protocols between the IOUs that advance a fair, transparent procurement process that is geared to yielding the most realistically and reasonably priced, viable, and diverse projects. If this result is achieved, then regular RPS competitive solicitations should certainly occur every year, especially to the extent that the "procurement expenditure limitations" (PU Code §399.15(c)(1)) for renewable generation procured by each IOU in meeting the 33% RPS target are set with reference to those plans.[30] Not only will such regular solicitations offer a "fresh" look at the renewable market every year, but it will also tap into technology growth and resources with the greatest value to each IOU and its ratepayers. In this regard, the Commission precedent has already highlighted the value of "frequent, if not continuous, RPS solicitations in a competitive market."[31]

Finally, while the Commission has stated that it employs "the presumption that each utility may apply its own reasonable business judgment in running its solicitation," it is the Commission that establishes the "parameters" and "guidance" for those plans.[32] The Commission has also encouraged IOUs toward "standardization and uniformity" in their plans.[33] As re-confirmed by the Commission in D.11-04-030: "'Additional uniformity will make the

[30] See, CEERT Comments on RPS Procurement Expenditure Limitations (February 16, 2012), at p. 5.
[31] D.11-04-030, at p. 52. See also, SDG&E Public 2012 RPS Plan, which specifically notes that the absence of a solicitation in any given year could increase instances of "bilateral procurement" that would be "benchmarked to outdated solicitation data." (SDG&E Public 2012 RPS Plan, at p. 35.) Similarly, PG&E notes the value of solicitations providing "more regular market information." (PG&E Public 2012 RPS Plan, at p. 69.)
[32] D.11-04-030, at p. 3.
[33] Id., at p. 33.

overall RPS structure more transparent, efficient, and competitive.'"[34] This sentiment is repeated in the April 5 ACR.[35]

Unfortunately, the April 5 ACR has simply not done enough in terms of identifying the multiple changes and impacts to RPS Plans resulting from SB 2 1X, including new statutory requirements related to "content categories," compliance periods, compliance rules, or procurement expenditure limitations, to avoid discretion among the IOUs as to interpreting these provisions or ignoring them altogether, as noted above, or electing to present their plans in a disparate manner. Similarly, the April 5 ACR has not provided continuity in furthering Commission precedent for RPS Plans, notably that affecting Imperial Valley resources. For these reasons, CEERT strongly recommends that the Commission hold a workshop immediately for the purpose of creating a compliance checklist for the IOUs' 2012 RPS Plans *relative to and based on* SB 2 1X provisions, Commission implementation decisions of SB 2 1X to date, and Commission precedent that is still applicable to these plans (e.g., Imperial Valley resources).

II.
IOU 2012 RPS PLANS

CEERT incorporates herein its above-stated overarching concerns with both the April 5 ACR and the IOUs' 2012 RPS Plans filed on May 23, 2012. Below CEERT focuses on its initial issues related to the IOUs' plans, addressed in the order in which direction on the content of the RPS Plans was given by the April 5 ACR. CEERT also reserves the right to address these issues further in its reply comments. A separate section deals with Imperial Valley remedial measures, for which separate provision was not made by any plan.

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[34] D.11-40-030, at p. 34, citing D.08-02-008, at p. 38. See also, D.11-04-030, Finding of Fact 15, at p. 58.
[35] The April 5 ACR specifically notes the importance of uniformity to permitting "the Commission to easily access, review and compare plans." (April 5 ACR, at p. 5.)

A. Assigned Commissioner's Ruling (ACR) General Requirements for 2012 RPS Procurement Plans (ACR Section 2)

This section of the April 5 ACR references "that recent legislation, SB 2 1X, made a number of changes to the RPS Program," modified or changed many details of the RPS Program," and "modified certain requirements applied to the RPS Procurement Plans."[36] Unfortunately, this section does not detail what those changes are, save one ("status update"), including the many that have been implemented by the Commission and impact the RPS Procurement Plans. The result is extensive interpretation by the IOUs in their 2012 RPS Procurement Plans as to which of these changes, in addition to those specifically related to these plans, impact their 2012 RPS Plans and how those changes, including the 33% targets and compliance periods, will be reflected in their plans.[37] These "interpretations" of what these terms and Commission decisions mean or require has significantly influenced how each IOU sees its needs and has crafted its 2012 RPS plan, especially in a manner that bears little resemblance, as each redlined version reflects, to any prior RPS plan.

CEERT believes that it is imperative that the Commission review these "interpretations" to ensure that these results were the ones it believes are intended by statute and its own decisions. Again, CEERT asks for an immediate workshop to be held, with a draft checklist of statutory requirements and Commission decisions, detailing which of these provisions, to what extent, and how each should impact, if at all, the IOUs' competitive solicitations and protocols. Right now, as an example, CEERT has little confidence that conclusions reached by at least two utilities – that the Commission's decision implementing SB 2 1X "content categories" can be used to limit or "target" solicitations or identify "preferred" resources are correct or legal.

[36] April 5 ACR, at p. 4.
[37] See, e.g., PG&E's Public 2012 RPS Plan, at pp. 1-29.

B. ACR Specific Requirements for 2012 RPS Procurement Plans (ACR Section 6)

1. Assessment of RPS Portfolio Supplies and Demand (Assessment of Need) (ACR Section 6.1)

The IOUs have characterized their "need" as largely long-term, but have sought to restrict competition by limiting solicitations to projects in "preferred" locations or "categories." Thus, PG&E, while stating that it will accept offers from the 3 portfolio content categories, will exercise a preference for Category 1 products and a further preference for projects in PG&E's service territory.[38] SCE makes clear that it will only consider proposals that qualify as Category 1.[39]

CEERT questions the merits or support for restricting participation in RPS solicitations, especially to the extent that it creates a discriminatory burden on the development of viable, eligible projects throughout California or out-of-state, prevents otherwise cost-effective, diverse renewable resources from bidding, and, in turn, inappropriately limits competition. In addition, given that the IOUs have had only recent experience with the "content categories" since their implementation and adoption by the Commission in *December 2011* (D.11-12- 052), broad claims by the IOUs regarding the "success" or "certainty" of *new procurement* of Category 1 projects over other categories seem premature at best. Further, application of the "content categories" in this manner or for this use (to limit competition) is not an approach endorsed by the Commission in implementing those categories nor is it suggested by the legislation.

CEERT, however, does strongly support "new steel in the ground" renewable projects, but steps such as restricting offers to specific categories or service territories should only be taken if it can be demonstrated that they provide an incentive or benefit to improving the success rate for renewable projects, without suppressing competition that has the benefit of lowering

[38] PG&E Public 2012 RPS Plan, at pp. 13, 21-22, 57.
[39] SCE Public 2012 RPS Plan, at pp. 3, 26.

prices and stimulating innovation. In this regard, CEERT does support PG&E's and SDG&E's commitment to regular RPS solicitations to "procure steady and moderate volumes of incremental long-term volumes over the next several years to help it reach, and then sustain the 33 percent RPS goal."[40] CEERT further notes that SDG&E takes the broadest view of the solicitation process and does not seek to limit procurement by category; will enter both long and short-term contracts, as their need requires; and does commit to fill identified need for Compliance Period 3 "with viable low-cost opportunities from solicitations in 2012, 2013, and 2014."[41]

Of course, CEERT does not support a decision by the IOUs, or the Commission for that matter, "stopping" renewables procurement at 33% by 2020. Renewable generation remains *first* among generation resources in the Commission's "loading order" to meet need that cannot be met by cost-effective energy efficiency and demand response. While the RPS remains a key mandate in this state guiding procurement decisions, greenhouse gas (GHG) emission reductions also mandated by state law (AB 32) will require increased reliance on clean, renewable electric generation.[42]

Even in the case of achieving a 33% RPS, the "success" of signed contracts becoming viable electric generation projects that can meet this goal is not assured, and adoption of realistic "success" and "failure" rates is critical to ensure the "steady" progress required to meet that goal. Yet, in assessing their need, the IOUs are not consistent as to their methodologies or assumptions of a "success rate" for delivered energy from contracts that are executed, but not yet online. This

[40] PG&E Public 2012 RPS Plan, at p. 2; see also, SDG&E 2012 RPS Public Plan, at pp. 9-10.
[41] SDG&E 2012 RPS Public Plan, at pp. 9-10.
[42] Further, SB 2 1X does not create an automatic cut-off on renewables procurement at 33%. Not only does it direct procurement above that level "to mitigate the risk that renewable projects planned or under contract are delayed or canceled," but nothing in the law "preclude[s] an electrical corporation form voluntarily proposing a margin of procurement above the appropriate minimum margin established by the commission." (PU Code §399.13(a)(4)(D).)

assumption is critical and must be fairly and appropriately accounted for in determining the IOUs' need and progress toward a 33% RPS.

In this regard, at the Commission's Business Meeting of June 7, 2012, Energy Division Director Ed Randolph had to caution one of the Commissioners from relying on a slide used in a presentation by Energy Division to the Western Interstate Energy Board (WIEB) Committee on Regional Electric Power Cooperation (CREPC) on June 6, 2012. Specifically, Commissioner Florio, while noting that there might be "some failure" in RPS projects, pointed to this slide as forecasting a "compliance position" for the IOUs as already having sufficient contracted power to meet the 33% goal now, with only a "gap" in 2020. Mr. Randolph, in response, stated that this slide was not risk adjusted and that Energy Division did not simply forecast "some" failure, but rather estimated, based on experience and history, a 40% failure rate or a 60% success rate.[43]

This rate is clearly more than a mere adjustment, but could significantly reduce the projections of compliance based on executed contracts and, in turn, increase need. For this reason, it is important for the Commission and its staff to carefully assess (i.e., in a public forum) the assumed failure and success rates used by the IOUs to define need.

That assessment is particularly important since the IOUs do not reach consistent conclusions or assumptions as to this risk. SCE and SDG&E continue to rely on the historically demonstrated estimate of a 60% success and 40% failure rates on average,[44] with SDG&E noting, in particular, that "the monitoring of development status [is] the most critical aspect of SDG&E's need assessment methodology."[45] SCE states that the 60% success rate factors in

[43] CPUC Business Meeting, June 7, 2012 (Archived Webcast at: http://www.californiaadmin.com/cpuc.shtml).
[44] SDG&E Public 2012 RPS Plan, at p. 4; SCE Public 2012 RPS Plan, at pp. 4, 17.
[45] SDG&E Public 2012 RPS Plan, at p. 4.

"project development success rates" and "any contingency that would make meeting the State's RPS goals less likely," including transmission delays, and curtailment.[46]

However, PG&E departs from these rates based on its "observation" of a "general trend" toward higher rates toward higher rates of success in reaching key development milestones, despite the fact that it still could only confirm a 60% success rate for 2011 forecasted deliveries.[47] Nevertheless, PG&E elects to use its own "deterministic approach," that places its "contracts for renewable projects under development into four project risk categories," the highest risk being the "Closely Watched" category for projects experiencing considerable development challenges."[48] PG&E then excludes this category to assume delivery of "100% of contract volumes over their respective terms" for all other projects. PG&E otherwise "currently estimates a long-term volumetric success rate of approximately 78% for its portfolio of executed-but-not-operational projects."[49] PG&E does acknowledge that this "success rate" is simply a "'snapshot' in time and is highly dependent on the very dynamic conditions of the renewable energy industry."[50]

In these circumstances, CEERT believes that Commission assessment of the "adopted" rates is required. Until that time, CEERT recommends that a uniform "success" or "failure" rate of 60% and 40% should be adopted consistent with historical trends unless an individual IOU can demonstrate, based on the last two years of experience, that a specific "portfolio" has in fact produced a different rate of success.

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[46] SCE Public 2012 RPS Plan, at p. 18.
[47] PG&E Public 2012 RPS Plan, at pp. 44-45.
[48] Id., at p. 44.
[49] Id., at p.44.
[50] Id.

2. Potential Compliance Delays (ACR Section 6.2)

This section focuses on factors that can cause or create a delay or failure of a project. SDG&E fairly sums up the issue as follows: "The market for renewable energy is dynamic; multiple factors can impact project development and SDG&E's attainment of RPS goals."[51] Among those affecting both developers and the utility are "transmission, permitting, and financing hurdles faced during project development" through the "challenges experienced as a project matures – viability, debt equivalence, accounting issues, and regulatory uncertainty."[52] Of note, SDG&E identifies the "interconnection study process" as "still under development" and an "area" that "will continue to be a potential challenge."[53]

These circumstances only underscore the need for regular and broadly subscribed competitive solicitations as a necessary component to ensuring that the 33% RPS by 2020 is in fact achieved. Each also demonstrates the need to develop appropriate, uniform assumptions regarding "success" and "failure" rates of signed contracts for projects that are not online, and to adopt a meaningful and "appropriate" minimum margin of procurement above the minimum level required to comply with the 33% RPS to "mitigate the risk" of planned or contracted-for projects being "delayed or canceled."[54] The interconnection "hurdle" is also well known and makes SCE's requirements restricting its solicitation only to bidders with a completed interconnection study a hurdle that could eliminate potentially viable, competitive, and successful projects.

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[51] SDG&E 2012 RPS Plan, at p. 11.
[52] Id.
[53] Id., at p. 13.
[54] PU Code §399.13(a)(4)(D).

3. Status Update, Risk Assessment, Quantitative Information, and "Minimum Margin" of Procurement (ACR Sections 6.3 - 6.6)

Each of these factors affect and relate to whether or if an IOU's procurement contracts will in fact yield deliveries of electric generation at all or, at the least, as planned and priced. In this regard, "SDG&E has observed some dynamic factors that may affect power production from delivering projects."[55] In addition to the hurdles referenced above, these factors also include resource availability, regulatory changes (i.e., loss of a production tax credit that lowers the revenue stream for the developer), economic environmental, operational performance, and evolving technology.[56]

Clearly, in recognition of these known procurement risks affecting renewable development, the Legislature in SB 2 1X sought to address such potential gaps by requiring the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[57] This statute goes even further by expressly *not* precluding IOUs from voluntarily procuring over this amount.[58]

The IOUs each address this requirement in their 2012 RPS Plans, but the actual commitment being made by each of them is left vague or inextricably tied to projected "failure rates." Thus, PG&E does not recommend any specific MW amount above the 33% RPS to be adopted as its minimum margin, but rather asks that the Commission simply use its projected,

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[55] SDG&E 2012 RPS Plan, at p. 18.
[56] Id.
[57] PU Code §399.13(a)(4)(D).
[58] Id.

"observed" "failure rate" of 22% as satisfying this requirement.[59] As to any "voluntary" over-procurement margin, PG&E states that it should only "be equal to an additional 1% or 2% of total retail sales."[60] However, PG&E does not propose to incorporate any margin of over-procurement, for either purpose, in its 2012 RPS Solicitation, relying instead on "expected excess procurement in the near term to smooth the annual variations."[61]

From CEERT's perspective, "expectations" and "observations" do not meet or support the legislative mandate of an "appropriate" minimum margin required to be adopted by the Commission pursuant to PU Code §399.13(a)(4)(D). With ever-present permitting risks associated even with the best projects, among other things, CEERT strongly encourages the Commission to undertake further assessment and evaluation of the factors that impact a meaningful and "appropriate" minimum margin of over-procurement and adopt a "margin" that relies on reasonable and consistent "failure" rate assumptions.

4. Bid Solicitation Protocol (i.e., Least Cost Best Fit Methodologies) (ACR Sections 6.7)

Each IOUs proposes a Least Cost Best Fit (LCBF) methodology that includes "market valuation" cost criteria. Among the costs listed in the April 5 ACR's Proposal for "Standardized Variables in LCBF Evaluation" (see below) are "integration costs."[62]

In D.11-04-030, the Commission declined to adopt SCE's and SDG&E's proposed use of "non-zero integration cost adders" in their RPS plans, noting that the Commission had previously rejected such proposals and that "such costs, if any, need to be developed with public review and comment."[63] In fact, the Commission agreed with the California Wind Energy Association

[59] PG&E Public 2012 RPS Plan, at p. 51. Again, PG&E, unlike SDG&E and SCE, has asked that a much lower "failure" rate than is historically supported be used based on its "observation" of a "decrease in the expected failure rate of its overall portfolio." (Id., at n.38, p. 51.)
[60] PG&E Public 2012 RPS Plan, at pp. 52-53.
[61] Id., at p. 53.
[62] April 5 ACR, at p.
[63] D.11-04-030, at pp. 22-23.

(CalWEA), the Large-Scale Solar Association (LSA), and The Utility Reform Network (TURN) that "an adder should only be used if it is developed in a public forum and, in addition, with Commission supervision."[64] In this regard, in D.11-04-030, the Commission not only declined to adopt an integration cost adder, but permitted the IOUs to file an advice letter to amend its 2011 RPS plan to use such an adder for LCBF evaluations only if one were developed in the Long Term Procurement Plan Rulemaking (R.) 10-05-006.

In their 2012 RPS Plans, PG&E and SCE renew the request for such integration cost adders to be included in their LCBF evaluations. According to SCE, the IOUs "should be able to factor these costs into their procurement decisions so they can appropriately value resources that do not cause additional integration costs (e.g., geothermal and biomass) in relation to those that do (e.g., wind and solar photovoltaic)" and that, in doing so, each IOU will be able to select projects "that provide the most overall value to its customers."[65] While noting that the Commission has previously declined to adopt an integration cost adder, SCE argues that such an adder has merit based on PU Code Section 399.13 (a)(4)(A)(i), which allows LCBF criteria to take into account expenses resulting from "integrating" renewable resources. SCE also states its belief that "current levels of intermittent renewable resources will require an increase in the provision of ancillary services" for load following and frequency regulation.[66]
SCE concludes that it "will consider integration costs in its next RPS solicitation to the extent allowed by the Commission."[67]

PG&E goes further by stating that it "plans to include an explicit adjustment for integration cost …to account for the increased costs of dispatching additional generators and

[64] D.11-04-030, at p. 23.
[65] SCE Comments on New Proposals, at p. 2.
[66] SCE Public 2012 RPS Plan, Volume 2, Appendix F.1, at p. 5.
[67] Id.

procuring sufficient ancillary services from flexible resources to integrate an increased amount of renewable generation into the grid."[68] Although PG&E, like SCE, does note that the Commission has not permitted such an adder to be included in previous RPS Plans, PG&E argues that "significant work" has been undertaken before the CAISO and the Commission and points to an ALJ's Ruling from R.10-05-006 (LTPP) that had included integration costs among the "standardized planning assumptions" to be used in that proceeding. In turn, PG&E proposes, for purposes of the 2012 RPS solicitation, "to use an integration cost adder of $7.50/MWh (2008$), the same value for integration cost as used in the 2010 LTPP proceeding" and to apply that adder to "resources that are considered intermittent, although resources with some reduced levels of intermittency may be subject to lower integration cost adders, as determined on a case-by-case basis."[69] PG&E further notes that the $7.50/MWh adder used in that context would translate to "approximately $8.50/MWh in 2013."[70]

Despite PG&E's reference to a ruling in R.10-05-006, no decision in that proceeding resulted in the adoption of any "integration cost adder" that was developed in a public forum and designated for use in RPS procurement. In fact, the "integration cost" referenced by PG&E was one assumed by the consulting firm "E3" that was to be used for purposes of scenario planning and modeling as part of the System Track 1 phase of R.10-05-006. For PG&E, to suggest that this equates to the development of an "integration cost adder" to be used in the RPS LCBF in a "public forum" "with Commission supervision" as required by D.11-04-030 is not supportable. At this point, this figure is also dated.

To the extent that the Commission intends that an "integration cost adder" is to be considered in this RPS Planning cycle, it is incumbent upon the Commission to hold that

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[68] PG&E Public 2012 RPS Plan, at p. 63.
[69] Id., at p. 54.
[70] Id., at p. 54, n.43.

promised "public forum" where all stakeholders can participate in the development of this adder. It is clear from the statements made by both utilities that use of such an adder in evaluating bids will be a powerful tool in creating winners and losers based on resource type. CEERT believes that, in those circumstances, great caution should be exercised to ensure that any resulting "adder" reflects and is commensurate with actual costs created by "renewables integration" into the grid and certainly should be uniform and uniformly applied among the IOUs.

With respect to the LCBF criteria of all IOUs generally, as noted in Section I above, SB 2 1X mandated that, in soliciting and procuring RPS eligible resources, the IOUs' "*shall give* preference to renewable energy projects that provide *environmental and economic benefits* to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants and greenhouse gases."[71] In a search of both the April 5 ACR and the IOUs' RPS Plans and LCBF criteria, CEERT has not found reference to this law or this required preference. This oversight must be addressed and cured in both.

Finally, CEERT does believe that project viability scores and criteria are essential to improving the "success" rate for renewable projects. Obviously, the "selection" process embodied in each IOU's Least-Cost Best-Fit methodology is key to ensuring that "winning" bids become "new steel in the ground." While CEERT has concerns with up-front restrictions on participation in solicitations in terms of reducing competition (i.e., completed interconnection studies, specific location, or content category), CEERT does support close scrutiny of those projects that do bid as to their expected success. For this reason, CEERT does share the IOUs' focus in their LCBF methodologies on assessing each proposals' "qualitative attributes," which

[71] PU Code §399.13(a)(7); emphasis added.

include "company/development team, technology, and development milestones,"[72] as a basis "to eliminate non-viable Proposals or add projects with high viability to the final short-list of Proposals."[73] However, this assessment should also extend to an examination of whether the project can be financed, constructed, and permitted and whether the developer has the experience to do so.

5. Estimating Transmission Cost for RPS Procurement & Bid Evaluation (ACR Section 6.8)

In its 2012 RPS Plan, SCE has made a condition precedent to participation in its solicitation that potential sellers must "have an existing Interconnection Study (e.g., Facilities Study, Phase I or documentation demonstrating that the project has passed the Fast Track screens) or an equivalent or better study, or a signed Interconnection Agreement."[74] SCE also intends to require that "projects must have completed a Phase II Interconnection Study (or equivalent or better) prior to execution of the contract."[75] According to SCE, these "changes will provide more certainty around potential network upgrade and interconnection costs, and a more accurate evaluation of such costs in the LCBF evaluation process."[76] PG&E, while not as stringent, nevertheless indicates that it "will require that Sellers have at least the equivalent of a Phase 1 study from the CAISO."[77]

As noted above, CEERT is concerned about "absolutes," such as a *completed* Phase 1 interconnection study, limiting participation in an RPS solicitation. If this approach is taken, however, it should be clear that completion of a study before a bid can be offered shows strong developer commitment. Further, it will be very important for the CAISO to work with the IOUs

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[72] SCE Public 2012 RPS Plan, Volume 2, Appendix E.1 (2012 Procurement Protocol), at p. 21.
[73] Id., at p. 22.
[74] SCE Public 2012 RPS Plan, Volume 1, at p. 21.
[75] Id.
[76] Id.
[77] PG&E Public 2012 RPS Plan, at p. 57.

to ensure that such studies are completed appropriately and in a timely manner and that both work together to eliminate inconsistencies between CAISO interconnection guidelines and IOU solicitation protocols or criteria to avoid confusion or inequality among bidders.

6. Cost Quantification (ACR Section 6.9)

Based on the April 5 ACR, CEERT understands that the primary purpose of this section is for the IOUs to provide information to the Legislature, pursuant to SB 836, on the costs of all electricity procurement contracts for eligible renewable energy resources that have been approved by the Commission.[78] However, CEERT is concerned that the April 5 ACR suggests that this information shall also be used to establish the procurement expenditure limitation adopted for each IOU pursuant to §399.15(c). While the April 5 ACR states that this information will "supplement" the comments that have already been filed on the implementation of this section in January 2012, CEERT is concerned that, in fact, this approach will diminish the input many parties, including CEERT, provided on the detailed interpretation of that statute as specifically solicited in January. The Commission must make clear that the primary "record" for interpreting Section 399.15 (c) will come from the language of that statute itself coupled with comments expressly directed toward its implementation.

C. Need for the Commission to Require Compliance with Commission Precedent Governing Imperial Valley Resources.

By their joint letter to the CAISO dated May 16, 2012 (attached hereto as Appendix A), the CPUC and CEC collectively recognize the ongoing need to address Imperial Valley renewable resource development. Not only has this examination been required by D.09-06-081 and D.11-04-030 (Imperial Valley remedial measures) and the June 2011 ACR (appropriate

[78] April 5 ACR, at p. 14.

Imperial Valley RA valuation), as noted above, but this recent letter is confirmation of the Commissions' joint position as follows:

> "The Commissions now understand that the cost of IID [Imperial Irrigation District] reinforcements recovered from generation development in the area may be a further impediment to the development of renewable generation resources in the region north of the Imperial Valley substation. In light of the continued objective of effectively and efficiently meeting California's 33 percent RPS goals and the identification of parts of the Imperial Valley in the Desert Renewable Energy Conservation Plan as a Renewable Energy Study Area, the Commissions encourage the CAISO to consider (or investigate) and advance as necessary additional transmission reinforcements into the region to enable delivery of at least 1,400 MW of renewable generation from IID."[79]

Clearly, the Commission's previous "remedial measures" to consider and remove barriers to development of renewable resources in the Imperial Valley have not been wholly successful and much more needs to be done to meet the Commissions' joint objective of delivering electricity from the vast and abundant renewable resources in the Imperial Valley. The transmission upgrades needed to enable export of energy from IID's Balancing Authority (BA) will yield significant system reliability benefits to the CAISO BA and significantly improve the integration of SDG&E and SCE owned transmission systems. However, these upgrades will not be realized , unless/until there are sufficient projects that are guaranteed to pay for the upgrades. The developers who ordinarily would pay for such upgrades, without PPAs, cannot put up the money given their own uncertainty of recovering their costs.

In this environment, "remedial measures" to procure Imperial Valley renewable resources must be considered for inclusion in a 2012 RPS solicitation. Among them, the Commission should consider the previously identified "remedial measure" of a "special solicitation" for the procurement of a level of renewable resources within the IID balancing authority that can stimulate the financing required to achieve the needed upgrades. CEERT believes that this

[79] May 16 Commissions Letter (Appendix A hereto), at pp. 3-4.

issue should and can be further explored by bringing together key representatives of the CPUC, CEC, CAISO, IID, and the IOUs, along with all stakeholders to work toward solutions to this pressing problem and need.

III.
CEERT COMMENTS ON NEW PROPOSALS

CEERT understands the merits of the Commission continuing to explore changes to RPS Planning and procurement that could create efficiencies or improve evaluation. However, in this year, where the Commission is dealing with significant additions and amendments to the RPS Program resulting from the passage of SB 2 1X, many of which the Commission has yet to implement, the focus in this planning cycle should be on getting those requirements vetted and in place. That alone will take significant time and could impede a solicitation being held this year. The Commission should avoid this outcome and only undertake changes as necessary to implement the law as currently written.

A. Standardized Variables in LCBF Market Valuation (ACR Section 7.1)

The ACR states that the IOUs' LCBF analysis of 2012 bids must allow bids to be ranked by their net market value metrics. The ACR proposes a calculation that incorporates the benefits and costs of the resources offered.

While perhaps not all variables can or should be standardized, the position stated above on "integration costs" (especially an "adder" which can create immediate winners and losers and was intended to be developed in the overall LTPP proceeding) seems an obvious "variable" that requires standardization or uniformity among the IOUs. To the extent that this process of standardization moves forward, it should not be left to the discretion of any utility as to picking and choosing which "standardized variable" it will use in its LCBF. Further, to ensure a full record on this topic, CEERT recommends that the topic of "standardized variables" be addressed in a prompt workshop. If the Commission so directs, however, the timing should not delay authorizing the IOUs to hold a 2012 RPS solicitation.

B. Preliminary Independent Evaluator Report (ACR Section 7.2)

The ACR appears to be proposing that the current Independent Evaluator Report, which assesses the entire IOU bid solicitation, evaluation, and selection process and is submitted with the IOU's shortlist, should now involve both "before-the-fact" and "after-the-fact" reports. In this regard, CEERT shares the concerns expressed by SCE questioning the need for and potential duplication required by such reporting.[80] As stated previously, CEERT's believes that regular, timely, and robust RPS procurement solicitations are central to achieving this state's energy goals. This proposal could easily create unnecessary delay in that process.

C. Use of CAISO Transmission Cost Study Estimates in LCBF Evaluations (ACR Section 7.3)

CEERT reserves the right to respond to this proposal in its reply comments. CEERT again emphasizes, however, the importance of the CAISO and the IOUs working together to ensure that interconnection studies are completed in a timely and cost-effective manner. What does not seem reasonable, as PG&E notes, is adoption of "an inflexible rule that would require IOUs to use CAISO studies if they are available to the exclusion of other indicators of interconnection costs."[81]

D. Create Two Shortlists Based on Status of Transmission Study (ACR Section 7.4)

This ACR proposal would require the IOUs to divide their shortlisted bids into a Primary Shortlist (bids that have obtained CAISO Phase II study results or executed Interconnection Agreements) and a Provisional Shortlist (bids that do not meet those requirements). While CEERT reserves the right to address this proposal further in reply comments, it initially agrees

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[80] SCE Public 2012 RPS Plan, at pp. 4-5.
[81] PG&E Public 2012 RPS Plan, at pp. 71-72; see also, SCE Comments on New Proposals, at p. 6.

with the concerns expressed by SCE. Specifically, SCE opposes this proposal as "overly complicated" and administratively burdensome. While CEERT does not agree with SCE's solution (to require "all potential sellers" to have "at least a Phase 1 study" completed before submitting a bid), CEERT does not believe that the "two list" approach, as defined by the ACR, streamlines the process.

E. Shortlists Expire After 12 Months (ACR Section 7.5)

The ACR proposes that shortlisted bids be executed within 12 months from the day the IOU submits its final shortlist. Again, while CEERT reserves the right to address this further in reply comments, it does agree that reliance on "stale" bids is not beneficial, but shares SCE's and PG&E's concerns that "a firm expiration date serves as an unnecessary constraint on the bidding process"[82] and could delay execution of PPAs or impose an unnecessary burden on bidders.[83]

F. Two-Year Procurement Authorization (ACR Section 7.6)

On the surface, CEERT does understand that a two-year procurement authorization sounds desirable as a potential means of creating administrative efficiencies. However, component parts of this proposal – from simultaneous solicitations to use of the informal, but relatively opaque, advice letter process for authorization of the second year – may not be sufficiently open and transparent to support certainty and confidence in the process. Further, RPS solicitations today offer a snapshot (or more) of the current RPS market, as to prices and technologies. As SDG&E has noted, market/transmission risks could result in the need for an IOU to procure additional resources in a year in which it will not hold an RFO and could

[82] SCE Comments on New Proposals, at p. 8.
[83] PG&E Public 2012 RPS Plan, at pp. 67-68.

increase instances of bilateral procurement that, in turn, would be "benchmarked to outdated solicitation data."[84]

G. Utilize the Commission's RPS Procurement Process to Minimize Transmission Costs (ACR Section 7.7)

CEERT reserves the right to address this issue further in its reply comments. CEERT does believe that the reservations voiced by SCE with respect to this process, especially the risk of bids being selected through the application of "subjective and vague standards" by the Commission, suggest that legitimate concerns exist regarding this proposal. The proposal also does not appear to be sufficiently transparent and would involve multiple steps where most stakeholders (advocates like CEERT) would be excluded from the process.

IV.
CONCLUSION

CEERT appreciates the opportunity to offer its opening comments on IOUs' RPS Plans and the ACR's new proposals. CEERT looks forward to further consideration of the issues raised herein in reply comments and public forums, such as the workshops recommended herein.

Respectfully submitted,

June 22, 2012

/s/ SARA STECK MYERS

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[84] SDG&E Public 2012 RPS Plan, at p. 35.

VERIFICATION

(Rule 1.11)

I am the attorney for the Center for Energy Efficiency and Renewable Technologies (CEERT). Because CEERT is absent from the City and County of San Francisco, California, where I have my office, I make this verification for said party for that reason. The statements in the foregoing Comments of the Center for Energy Efficiency and Renewable Technologies on RPS Plans and New Proposals, have been prepared and read by me and are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct and executed on June 22, 2012, at San Francisco, California.

Respectfully submitted,

/s/ SARA STECK MYERS

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Attorney for the
Center for Energy Efficiency and Renewable Technologies

APPENDIX A

LETTER FROM MICHAEL R. PEEVEY (CPUC PRESIDENT), ROBERT B. WEISENMILLER (CEC CHAIR), AND MICHEL P. FLORIO (CPUC COMMISSIONER TO STEVE BERBERICH (CAISO PRESIDENT AND CEO)
MAY 16, 2012

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

May 16, 2012

Steve Berberich
California Independent System Operator
President and Chief Executive Officer
P.O. Box 639014
Folsom, CA 95763-9014

Re: Revised Base Case and Alternative Scenarios for CAISO 2012-2013 Transmission Planning Process

Dear Mr. Berberich:

The California Public Utilities Commission (CPUC) and California Energy Commission (Energy Commission) would like to thank the California Independent System Operator (CAISO) and stakeholders participating in the CAISO's Transmission Planning Process (TPP) for this opportunity to revise the renewable scenarios presented in the March 23, 2012 update letter.

On March 12, 2012, the CPUC and the Energy Commission sent a letter formally transmitting recommended scenarios for the CAISO's 2012-2013 TPP in fulfillment of our ongoing commitment under the May 2010 Memorandum of Understanding to ensure a coordinated planning process. These scenarios were updated in a March 23, 2012 letter. At the April 2, 2012 CAISO 2012-2013 TPP stakeholder meeting, the CPUC and Energy Commission presented the proposed scenarios. Many stakeholders participated in the meeting and twenty-two stakeholders filed detailed written comments with CAISO on the proposed scenarios. Based on the careful consideration of the stakeholder comments, the CPUC and Energy Commission (the "Commissions") have revised the four scenarios as depicted in Attachment 1.

Stakeholder comments fell largely into three categories: (a) issues with the process through which the scenarios were developed, (b) issues with use of the "cost-constrained" scenario as the base case, and (c) issues with specific assumptions used in the 33% Renewable Portfolio Standard (RPS) Calculator. In response to concerns with the process, the Commissions agree with stakeholders that additional stakeholder input on the development of the scenarios for 2012-2013 would have been beneficial. In order to ensure greater stakeholder input in the future, the CPUC will address the development of the 2013-2014 scenarios in its current Long Term Procurement Plan rulemaking, R.12-03-014. The Energy Commission will commit its staff to assist in updating the environmental information in this proceeding. The Commissions may provide further policy guidance based on the record and stakeholder comments in the rulemaking proceeding.

Many of the stakeholders expressed concerns about using the "cost-constrained" scenario as the base case in the CAISO TPP because the scenario did not reflect the considerable steps developers and utilities have taken to pursue projects through power purchase agreements and licensing procedures. In response to these concerns, the Commissions now recommend the CAISO use the "commercial interest" scenario as the base case for the 2012-2013 TPP. We also encourage the CAISO to study the "cost-constrained," the "environmentally-constrained," and the "high distributed generation (DG)" scenarios.

Stakeholders also expressed concern over the accuracy of the assumption that projects located in non-CREZ areas would be able to deliver their energy over existing transmission facilities. Under such assumptions, these non-CREZ projects would incur low transmission costs in the 33% RPS Calculator biasing the portfolios towards non-CREZ resources. The Commissions agree that this assumption, while correct for some of the non-CREZ resources, is not appropriate for many of them. Therefore, CPUC staff updated the 33% RPS Calculator after working with CAISO staff to assign most of the non-CREZ resources to CREZs that would use the same transmission facilities. The transmission costs of some of the remaining non-CREZ resources are captured by the addition of four new "transmission areas" that are similar to CREZs: Central Valley North, Merced, Los Banos and El Dorado (Nevada). The result of the changes can be seen in the new scenarios. For example, the number of non-CREZ resources decreased from 4,661 MW in the March 23, 2012 "commercial interest" scenario to 530 MW in the revised scenario. It is a reasonable assumption that the remaining resources not included in any CREZ nor in the four new "transmission areas" could use existing transmission.

In addition, the inclusion of the CAISO's revised Westlands CREZ transmission capacity in conjunction with the changes for non-CREZ resources has increased the generation in Westlands to 1,500 MW in all but the "High DG" scenario. Further, the 33% RPS Calculator was updated to reflect an increased cost for the transmission upgrades for the Riverside East CREZ, using $650 million to represent the estimated cost of the West of Devers reconductoring. Another revision is that the permitting scores of all CPUC Energy Division database resources have been updated to reflect more current information (specifically the February 2012 Project Development Status Reports).

The Commissions acknowledge that in adopting these scenarios the CAISO may need to give further consideration to well-advanced generation projects located in Nevada being connected to the Valley Electric transmission system. This may be necessary to ensure those projects are reflected on a comparable basis to discounted core projects in California, addressing differences in generation permitting practices between the two states.

The Commissions have several policy recommendations to the CAISO related to the Desert Renewable Energy Conservation Plan's findings that the West Mojave region is a favorable location for future renewable generation development and that nearby Department of Defense facilities may also be favorable locations. Given these findings, the Commissions anticipate the need for additional CAISO analysis of the area in the context of utility applications for certificates of public convenience and necessity expected to be filed in the next twelve months. By anticipating this analysis, we do not prejudge any future CPUC findings about the need for any transmission upgrades.

The Commissions also have a policy-driven recommendation regarding transmission infrastructure in the Imperial Irrigation District (IID) Balancing Authority Area. In the CPUC's current RPS rulemaking, R.11-05-005, the June 7, 2011 Assigned Commissioner Ruling Regarding Resource Adequacy Value of RPS Projects in the Imperial Irrigation District Balancing Authority Area[1] found that it would be unreasonable for Pacific Gas and Electric, Southern California Edison Company, and/or San Diego Gas and Electric to use a maximum import capability of less than 1,400 MW for imports from projects within the IID Balancing Authority Area as part of the evaluation of projects and bids within the 2011 Renewables Portfolio Standard (RPS) solicitation. The CPUC relied on the CAISO's revised forward-looking Maximum Import Capability calculation process, the planned transmission capabilities inside the CAISO footprint, the renewable scenarios provided to the CAISO by the CPUC staff and the intentions and ability of IID to upgrade its transmission system to support greater export from IID to the CAISO footprint.

The Commissions now understand that the cost of IID reinforcements recovered from generation development in the area may be a further impediment to the development of renewable generation resources in the region north of the Imperial Valley substation. In light of the continued objective of effectively and efficiently meeting California's 33 percent RPS goals and the identification of

[1] R.11-05-005, June 7, 2011 *Assigned Commissioner Ruling Regarding Resource Adequacy Value of RPS Projects in the Imperial Irrigation District Balancing Authority Area*, available at: http://docs.cpuc.ca.gov/efile/RULINGS/136670.pdf.

parts of the Imperial Valley in the Desert Renewable Energy Conservation Plan as a Renewable Energy Study Area, the Commissions encourage the CAISO to consider (or investigate) and advance as necessary additional transmission reinforcements into the region to enable delivery of at least 1,400 MW of renewable generation from IID.

If you have any questions about the details of the scenarios, please contact Kevin Dudney at 415-703-2557 or kevin.dudney@cpuc.ca.gov or Roger Johnson at 916-654-5100 or roger.johnson@energy.ca.gov.

Sincerely,

Michael R. Peevey
President, CPUC

Robert B. Weisenmiller
Chair, CEC

Michel P. Florio
Commissioner, CPUC

Cc. Mark Ferron, Commissioner CPUC
Paul Clanon, CPUC Executive Director
Edward Randolph, CPUC Energy Division Director
Keith Casey, CAISO VP for Market and Infrastructure Development
Karen Edson, CAISO VP for Policy and Client Services
Robert Oglesby, Energy Commission Executive Director
Roger Johnson, Energy Commission's Siting, Transmission, and Environmental Protection Division Deputy Director

Attachment 1 - Transmission Summary (MW) by CREZ (5/16/2012)

	Commercial Interest	Cost	Environment	High DG
Weight on Cost	0.1	0.7	0.1	0.7
Weight on Evironment	0.1	0.1	0.7	0.1
Weight on Commercial Interest	0.7	0.1	0.1	0.1
Weight on Permitting	0.1	0.1	0.1	0.1
Major transmission upgrades	Merced - 1	n/a	Los Banos - 1	n/a
	Kramer - 1		Merced - 1	
	Los Banos - 1			
Portfolios in MW				
Discounted Core	7,396	7,168	7,168	12,474
Commercial Non-Core	4,027	2,254	2,291	2,214
Generic	5,706	7,422	7,931	3,045
Total	17,130	16,844	17,390	17,734
Alberta	450	450	450	450
Arizona	550	550	550	550
Baja	100	-	-	-
Carrizo South	900	900	900	900
Distributed Solar - PG&E	1,047	1,047	1,837	3,641
Distributed Solar - SCE	599	599	1,978	3,226
Distributed Solar - SDGE	405	405	426	490
Imperial	2,125	1,125	2,125	1,125
Kramer	762	62	62	62
Mountain Pass	665	1,045	365	665
Nevada C	142	142	116	142
NonCREZ	529	1,077	655	721
Northwest	330	330	290	290
Palm Springs	198	188	198	83
Riverside East	1,400	1,400	805	1,060
Round Mountain	-	-	34	-
San Bernardino - Lucerne	101	261	108	187
San Diego South	384	384	384	-
Solano	535	535	535	535
Tehachapi	3,390	4,556	3,370	2,429
Westlands	1,500	1,500	1,500	990
Central Valley North	183	268	268	168
El Dorado	400	-	-	-
Merced	65	20	65	20
Los Banos	370	-	370	-
Total	17,130	16,844	17,390	17,734