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 CALENERGY GENERATION OPERATING COMPANY ON RENEWABLE PORTFOLIO STANDARD PLANS AND NEW PROPOSALS FOR RPS IMPLEMENTATION

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Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission") and the Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals, CalEnergy Generation Operating Company (CalEnergy) hereby submits its comments on renewable portfolio standard ("RPS") plans and proposals for implementing the RPS program.

CalEnergy is a leader in the operation, development and production of energy from diversified fuel sources including natural gas and geothermal. CalEnergy has operations in the United States that generate more than 1,460 megawatts of electric power and steam. CalEnergy operates 10 geothermal generating plants in the Salton Sea Known Geothermal Resource Area in Southern California's Imperial Valley, which deliver RPS eligible energy to investor-owned and publicly-owned utilities.

CalEnergy is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC") and operates plants owned by CE Generation, LLC, which is indirectly owned by each of MEHC and TransAlta Corporation ("TransAlta"). MEHC, a consolidated subsidiary or Berkshire Hathaway, Inc., is a privately-held company that is incorporated in Iowa. Its primary business is the global production and delivery of energy via several subsidiaries. MEHC's major energy subsidiaries include CalEnergy and:

- MidAmerican Energy Company - provides electric service to more than 729,000 customers and natural gas service to more than 709,000 customers in Iowa, Illinois, Nebraska and South Dakota.
- MidAmerican Renewables, LLC - includes MidAmerican Wind, LLC; MidAmerican Hydro, LLC; MidAmerican Geothermal, LLC; and MidAmerican Solar, LLC. These companies operate wind, geothermal and solar renewables projects.
- PacifiCorp - serves approximately 1.7 million customers, and operates as Pacific Power in Oregon, Washington and California; and as Rocky Mountain Power in Wyoming, Utah and Idaho. PacifiCorp's generating plants have a net owned capacity of 10,623 megawatts from thermal, hydroelectric, wind and geothermal resources.
- Northern Powergrid - is one of the largest distribution companies in the United Kingdom. It serves 3.8 million customers in an area covering about 10,000 square miles in northeastern England.
- Kern River Gas Transmission Company- brings natural gas into Utah, Nevada and California. Extending approximately 1,700 miles from the gas-producing fields in Wyoming to Bakersfield, Calif., Kern River delivers more than 1.9 billion cubic feet of natural gas per day to customers along the pipeline system.
- Northern Natural Gas Company - operates an interstate natural gas pipeline system extending from southern Texas to Michigan's Upper Peninsula. Northern provides transportation and storage services to 78 utilities and numerous end-use customers in the Upper Midwest.

TransAlta, headquartered in Calgary, Canada and listed on the New York Stock Exchange, is the largest investor-owned generator of renewable energy in Canada, with an operating history of over 100 years. It maintains operations in Canada, United States and Australia including over 4,000 megawatts of coal-fired generation, 1,800 megawatts of gas-fired generation, 1,000 megawatts of wind-powered generation, and 900 megawatts of hydro-powered generation.

Executive Summary

CalEnergy appreciates the opportunity to comment on the framework for Renewable Portfolio Standard (RPS) plans and offers comments on four main areas of concern to renewable generation developers:

a. Imperial Valley Resource Adequacy Issues

The definition and quantification of available Resource Adequacy (RA) capacity, specifically related to power imported from the control area of the Imperial Irrigation District (IID), requires additional specific remedial measures by the Commission as previous efforts by the Commission and the California Independent System Operator (CAISO) have not resulted in adequate responses from the Investor-Owned Utilities (IOUs) in the current proposed RPS Plans. Specifically, CalEnergy urges the Commission to retain the requirement that for purposes of determining the RA of imports that the IOUs assume a Maximum Import Capacity of 1400 MW from the Imperial Irrigation District (IID) Balancing Authority Area as set forth in the 2011 Assigned Commissioner's Ruling.[1] In addition, the Commission should require RPS Plans to be modified to eliminate provisions that discriminate against Imperial Valley renewable resources, and continue to urge the CAISO to ensure that its transmission planning process supports an adequate MIC from the IID control area.

b. Integration Costs for Intermittent Resources

Integration costs for various categories of renewable resources are being widely discussed, but no concrete figures for the annual cost of integrating such resources have been adopted for inclusion in the RPS plans of the utilities. While parties may continue to develop more sophisticated analyses of integration costs and how to allocate them, CalEnergy urges the

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[1] R.11-05-005, *Assigned Commissioner's Ruling Regarding Resource Adequacy of RPS Projects in the Imperial Irrigation District Balancing Authority Area*, June 7, 2011.

Commission to take action in this RPS Plan cycle to adopt some level of integration costs, and to mandate that such costs should not be imposed on renewable resources that are not intermittent, as such generators do not contribute to the need for additional generation for integration. This would exclude geothermal power projects and other renewable resources that can demonstrate the ability to offer consistent deliveries of power at baseload levels.

c. Excess Energy and RPS Compliance Obligations

CalEnergy seeks clarification that deliveries of excess energy cannot be used by the IOUs to reduce RPS-eligible capacity needed to meet the utility's obligations in a future compliance period. Such a rule will enable California to take better advantage of the limited opportunity to build lower cost renewable energy projects while expiring tax incentives are still available.

d. Increased Transparency in RPS Procurement

There is an urgent need for increased transparency in the implementation of the RPS plans. If the IOUs were directed to specify how they value price, technology, or deliverability in constructing their RPS portfolios, renewable generation developers could offer resources that more closely fit the IOUs' needs, and these "better fit" generation proposals would increase competition and help reduce the cost of renewable resources to the benefit of the IOUs and their ratepayers. The Commission should modify its balancing of the interests for and against disclosure of the IOUs specific procurement targets in favor of providing the market with the specific criteria the IOUs will use to select renewable energy products.

I. <u>Resource Adequacy and Import Capacity from the Imperial Irrigation District</u>

One of the most important challenges facing developers of renewable energy projects in California is meeting the requirements for RA when the IOUs request that the RPS eligible energy they purchase be provided from a source that is determined to be resource adequate. Such a determination depends on the adequacy of transmission capacity to interconnect the generation with the IOU grid, and involves a determination by the CAISO as to the availability of sufficient capacity over a full year of deliveries. Such a determination of available RA is a difficult task, as the CAISO must attempt to determine the available capacity on a transmission line, in the future, while making assumptions about other planned power plants, not yet in service, that may also seek to transmit power over the same facilities.

The process of determining the Maximum Import Capacity (MIC) RA capacity for projects which import power to the CAISO grid from other Balancing Authority Areas (control areas), such as that of the IID, is complicated by the fact that the IID control area is not under the supervision of the CAISO. Both the CAISO and the CPUC have expressed concern about the quantity of RA capacity assigned to existing and planned generation in the IID control area, and taken steps to encourage utility procurement from the IID control area. As explained below, these efforts have not yet resolved concerns that the IOUs may not be willing to treat generation from the IID control area as sufficiently resource adequate, resulting in an underutilization of such resources. Accordingly, CalEnergy recommends that the Commission renew the existing requirement that the IOUs use an assumed MIC of 1400 MW of RA qualified import capacity from the IID control area.

a. CPUC Decisions and Actions Supporting Renewable Development in the Imperial Valley

In recognition that the Sunrise Powerlink Transmission Project (Sunrise) represented an significant expenditure of resources and involved substantial environmental impacts, the Commission has repeatedly indicated that it was prepared to take steps to ensure that reasonable cost effective renewable resources enabled by the Sunrise transmission capacity (which resources are mainly located in the IID control area) can be developed. This necessarily means the IOUs must be willing to contract for such renewable energy. In decisions addressing both the 2009 and 2011 RPS Procurement Plans the Commission identified various remedial actions that it will consider taking if sufficient procurement does not result under existing long term procurement procedures in effect.

In D.09-06-018, at pp. 16-18, the Commission stated,

> "…[I]f Imperial Valley projects resulting from the 2009 solicitation are not approved by the Commission prior to our approval of the 2010 RPS Procurement Plans then we will consider remedial measures for the 2010 Plans. We identified three:
>
> - Require utilities to automatically shortlist all Imperial Valley proposals that are received in the solicitation so that the projects receive special consideration;
> - Include an Imperial Valley bid evaluation metric in the LCBF methodology to give preference to Imperial Valley resources, and;
> - Require each utility to conduct a special Imperial Valley RPS solicitation.
>
> Several parties support some or all remedial measures if there are an inadequate number of Imperial Valley projects resulting from the 2009 solicitation. For the reasons explained below, however, we are persuaded by CalWEA, SCE and others that it is premature to adopt remedial measures now. We encourage parties to recommend remedial measures later if the 2009 solicitation produces an unacceptable result….
>
> Nonetheless, we will consider remedial measures if future evidence shows the [Least Cost Best Fit] 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. The expense and environmental consequences of Sunrise, just as with any significant infrastructure project, demand nothing less. *We will not hesitate to use all*

regulatory tools at our disposal so that reasonable, cost-effective renewable resources enabled by Sunrise are developed. (See D.08-12-058, at 263., emphasis added)"

In D.09-06-018 the Commission required IOUs to hold a special Imperial Valley bidders conference, and to perform specific proposal and project monitoring, as part of the 2009 RPS solicitation. Later, in D.11-04-030 the Commission restated its intention to continue specific monitoring of Imperial Valley proposals and projects to ensure adequate consideration of such projects by the utilities.[2]

In April, 2011 both the CPUC and the CAISO advised the Governor's office of their joint concerns that renewable energy projects' development was being hampered by an inability for such projects, particularly those outside the CAISO control area, to qualify as RA capable under the present mechanism. The two agencies outlined a potential solution that would involve redefining the MIC for imports from control areas using forecasted transmission capacity rather than historical deliveries, combined with a commitment by the CAISO to ensure adequate incremental transmission capacity to maintain the new higher MIC level is included in all future transmission plans.[3]

In a further step to address this issue and ensure that the IOUs did not undervalue renewable projects in the Imperial Valley, the June 7, 2011 Assigned Commissioner's Ruling in the RPS proceeding required that the utilities adopt a minimum import capacity for such projects.[4] The key ordering paragraphs stated,

> 1. It is unreasonable for Pacific Gas and Electric Company, Southern California Edison Company, and/or San Diego Gas & Electric Company to use a maximum import capability of less than 1,400 MW for imports from projects within the Imperial Irrigation District Balancing Authority Area as part of the

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[2] D. 11-04-030, at pp. 24-26.

[3] See Attachment A: CPUC/CAISO Letter to Michael Picker, April 18, 2011.

[4] *Assigned Commissioner's Ruling Regarding Resource Adequacy of RPS Projects in the Imperial Irrigation District Balancing Authority Area*, *supra*.

evaluation of projects and bids within the 2011 Renewables Portfolio Standard solicitation currently underway pursuant to Decision 11-04-030.

2. If Pacific Gas and Electric Company, Southern California Edison Company, or San Diego Gas & Electric Company nevertheless assigns zero or near zero resource adequacy value to any project located in the Imperial Irrigation District Balancing Authority Area that bids in the 2011 Renewables Portfolio Standard solicitation, that utility must present clear and convincing evidence why it did so as part of each advice letter or application seeking Commission approval of any contract resulting from the 2011 Renewables Portfolio Standard solicitation.[5]

The Assigned Commissioner's Ruling also stated that it anticipated that future CAISO actions would resolve this issue in the near future by adopting a "forward looking approach" to the calculation of the MIC from the IID control area, and by including sufficient transmission in future transmission plans to maintain a deliverability of 1400 MW for purposes of RA evaluation.[6]

However, there are clear indications that additional action to ensure successful renewable development in the IID control area is necessary. On May 16, 2012, the CPUC, represented by Commissioners Peevey and Florio, and the California Energy Commission (CEC), represented by Commissioner Weisenmiller, jointly issued a letter to CAISO President Steven Berberich addressing the Revised Base Case and Alternative Scenarios for the CAISO 2012-2013 Transmission Planning Process.[7] In addition to discussing various transmission planning assumptions, the two Commissions made "a policy-driven recommendation regarding transmission infrastructure in the IID Balancing Authority Area." Specifically, the Commissions jointly referenced the earlier ACR that required the IOUs to use a minimum MIC of 1400 MW from the IID control area, and recommended that the CAISO consider "and

[5] *Id.*, at p. 7.
[6] *Id.*, at p. 4.
[7] See Attachment B: CPUC/CEC letter to Steve Berberich, dated May 16, 2012.

advance as necessary additional transmission reinforcements into the region to enable delivery of at least 1400 MW of renewable generation from IID."[8]

b. The Commission Should Require that the RPS Plans Submitted by the IOUs Adequately Address Imperial Valley Renewable Resource Development

While the Commission has consistently recognized the importance of the Imperial Valley resources, supported by both the CEC and the CAISO, it is striking that the RPS Plans submitted by the IOUs' do not contain any assessment of their success in obtaining offers from their 2011 RPS solicitations, and do not address Imperial Valley renewable resource development in any substantive way. For example, none of the utilities give any indication in their RPS Plan of an intent to follow the requirement of the June 2011 ACR requiring the use of a minimum 1400 MW MIC for imports from the IID control area.

CalEnergy strongly recommends that the Commission require that the IOUs supplement their RPS Plans to address the Imperial Valley issues in the same manner as the Commission has required in the last two RPS proceedings. First, the IOUs should be required to report on offers and executed PPAs related to Imperial Valley renewable resource projects so that the Commission can evaluate the relative success of its efforts to encourage renewable development in the IID control area and determine whether any additional remedial measures should be adopted. Second, the Commission should renew the specific requirement from the June 2011 ACR that mandates that the utilities assume a MIC of at least 1400 MW from the IID control area for purposes of determining the RA characteristics of the Imperial Valley projects. The Commission should also continue to urge the CAISO to ensure that its adopted transmission plans include sufficient network upgrades to maintain that target MIC from the IID control area.

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[8] *Id*. at pp. 3-4.

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c. IOU Preferences for Renewable Resources within Their Service Territory or within the CAISO Control Area Should Not Discriminate Against Imperial Valley Renewable Resources

Each of the IOUs has expressed a strong preference to contract for RPS-eligible resources from specified locations. SCE states that, "SCE has a strong preference for . . . projects that are or will be interconnected to the CAISO's Balancing Authority Area."[9] PG&E's RPS Plan states that, "Consistent with earlier Solicitations, PG&E's preference is for resources in PG&E's service territory, and then for projects within the CAISO."[10] SDG&E states a similar preference and offers a complex set of numeric adders for "system deliverability" or "full deliverability" depending on where a project is located. Projects located within SDG&E's service territory benefit by receiving no adder. Both non-SDG&E area CAISO projects and non-CAISO projects are disadvantaged with the burden of a "system deliverability adder".[11] CalEnergy is concerned that SDG&E's system of adders may doubly discriminate against resources which lie outside of SDG&E's service territory *and* are connected to a non-CAISO balancing area, such as the IID. At the very least, this is unclear, as SDG&E indicates that it intends to exercise discretion with respect to projects which do not interconnect directly to the CAISO, stating that "SDG&E may consider offers without CAISO system impact studies . . . at its sole discretion on a case-by-case basis."[12]

Other aspects of the IOUs' RPS Plans may discriminate against imports from the Imperial Valley. The proposed LCBF methodology will use CAISO "or equivalent" calculations for transmission costs. However, there are no CAISO calculations for transmission costs for projects interconnecting to other balancing areas. SDG&E goes so far as to acknowledge that,

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[9] SCE 2012 Request for Proposals from Eligible Renewable Energy Resource Suppliers for Renewable Products, Article One, at page 3.
[10] PG&E 2012 Renewable Energy Procurement Plan (Draft Version), R.11-05-005, May 23, 2012, at p. 57.
[11] SDG&E 2012 Draft Renewable Procurement Plan, Appendix C, pp. 3-4.
[12] *Id.*, Request for Offers for Eligible Renewable Resources, p. 5.

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"this method could unfairly bias the evaluation process in favor of projects with CAISO study data." [13] Such a bias is unreasonable. The CAISO's deliverability studies are performed for the very purpose of ensuring that the renewable energy has adequate transmission capacity to reach the load it will serve. If the CAISO determines that a resource is deliverable (such as the 1400 MW of MIC from the Imperial Valley) then there is no justification for the IOUs to impose an additional barrier against contracting for such resources based upon a location preference, and the Commission should reject such barriers.

Allowing the IOUs' RPS Plans to proceed with provisions that are biased against deliveries from non-CAISO control areas, such as the Imperial Valley, is directly contrary to the line of Commission decisions and rulings cited above which indicate that the Commission intends to carefully monitor utility RPS procurement to see that sufficient renewable development occurs in the region. The Commission has repeatedly endorsed a policy of ensuring that the state must be able to take advantage of the renewable energy import capacity built into the Sunrise Project, which has just been energized this month. As a result, CalEnergy urges the Commission to require the IOUs to modify their RPS Plans to either remove preferences that discriminate against RPS-eligible projects which lie outside their service territory or outside the CAISO control area, *or* order that a remedial measure be adopted to require that the IOUs adopt a *preference* for imports from the Imperial Valley that would place them in an equivalent status to a project in the CASIO control area with CAISO-approved interconnection studies.

II. <u>Determination of Renewable Resource Integration Costs</u>

As all parties are aware, the CAISO is considering whether to impose charges on renewable generators for the costs of integrating increasing levels of intermittent renewable

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[13] SDG&E 2012 Draft Renewable Procurement Plan, *supra*, at p. 30.

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resources into the grid. The CAISO and other parties have been examining studying renewable integration issues for some time. In addition, other utilities across the country have begun to adopt specific rate adders to account for the cost of integrating renewable resources.[14]

In D.11-04-030, the Commission chose not to approve SCE's and SDG&E's proposed use of "non-zero integration cost adders" in the last RPS cycle. However, in their 2012 RPS Plans, PG&E and SCE both recommend inclusion of integration cost adders in their RPS Plans by including integration costs in their respective Least Cost Best Fit evaluations. SCE proposes 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)…."[15] SCE refers to Public Utility Code Section 399.13 (a)(4)(A)(i) to support its proposal, noting that the statute allows LCBF criteria to consider costs resulting from "integrating" renewable resources, and states that it will consider integration costs in its next RPS solicitation "to the extent allowed by the Commission."[16]

In its Draft 2012 RPS Plan, PG&E has proposed the use of a fixed integration rate for all intermittent renewable generation resources, based upon an integration rate used in the 2010 Long Term Procurement Proceeding. PG&E calculates that this rate would result in a charge of $8.50 MWhr in 2013.[17] PG&E proposes to impose this charge on all intermittent resources, with the caveat that reduced charges could be considered for particular generation on a case-by-case basis.

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[14] Westar has adopted a tariff charge for regulation and frequency response services for intermittent generators. See *Order Conditionally Accepting Proposed Tariff Revisions*, EL12-4-00, 130 FERC ¶61,215, issued March 18, 2010. In addition, the Bonneville Power Administration has adopted a Variable Energy Resource Balancing Service which can vary between $3.37 per MWhr to $5.62 per MWhr for generators with capacity factors ranging from 30% to 50%. Bonneville Power Administration Tariff BP-12-A-02C, at p. 65.
[15] SCE 2012 Renewables Portfolio Standard Procurement Plan, *supra*, Comments on New Proposals, at p. 2.
[16] *Id*., at Appendix F, p; 5.
[17] PG&E 2012 Renewable Energy Procurement Plan (Draft Version), R.11-05-005, May 23, 2012, at pp. 15,63.

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The SCE and PG&E proposals arise in a context where neither the Commission nor the CAISO have reached a final decision about the level of integration costs, either on a statewide basis, or for specific renewable technologies. The issue of how to allocate such costs is also undetermined at this time. As with the difficulties involved in ensuring that a renewable resource is RA-eligible, the lack of an established regulatory policy for integration costs creates tremendous uncertainty for renewable energy developers who invest substantial resources in project development in California. Planning, permitting, financing, and most importantly contracting to sell renewable energy is extremely difficult while critical elements of the cost of delivering such resources remain unresolved. Integration costs represent a very important variable in the financing and marketing of renewable power. This variable needs to become visible and predictable for renewable developers. The Commission should use this cycle of RPS Plans to begin to bring some certainty to the integration cost issue by requiring some form of integration cost adder to be included in the IOUs' RPS Plans. Even if this preliminary adder is later supplanted after further studies of integration costs, it will benefit both the renewable market and the IOUs and their customers to begin accounting for integration costs in procurement decisions.

The rationale for integration costs is based on the notion that certain types of renewable resources produce variable amounts of energy due to the inherent characteristics of their technology, such as wind and solar power, whose generating capacity varies with the strength of the wind or the intensity of the sun's rays, respectively. To the extent that a large quantity of intermittent renewable generation is constructed, additional costs will very likely be incurred in the form of dispatchable power required to smooth out variations in the delivery of such power. Recognition of those costs in the procurement process is reasonable.

However, CalEnergy also believes that it is important for the Commission to set the framework for any discussion or implementation of integration costs by clarifying in this RPS Plan cycle that renewable resources that are not intermittent, and which can generate at consistent, predictable levels (such as geothermal projects) should not be subject to integration costs. Otherwise, the specter of substantial, yet unspecified, integration costs creates substantial uncertainty that disadvantages even developers of renewable resources that can generate at baseload levels, particularly when seeking financing for their projects. CalEnergy recommends that the Commission adopt a clear policy that any integration cost adder shall only apply to intermittent renewable resources.

III. Excess Energy and RPS Compliance Obligations

The IOU RPS plans are neither clear nor consistent in their description of how excess energy will be treated under their proposed plans. PG&E's RPS Plan describes an intent to use surplus energy as a "bank" to provide a cushion for RPS compliance and to smooth shortfalls in delivery of energy from contracted RPS eligible resource.[18] PG&E also reserves the right to plan for voluntary over-contracting to provide a minimum margin above the compliance targets, and to meet the statutory requirement for a sufficient margin to assure RPS compliance.[19]

SCE's RPS Plan includes a provision, in Section 1.06(c) of SCE's Pro Forma PPA, that would result in a reduced or no payment to a seller for deliveries in excess of a 110% of contract capacity limit. SCE indicates that it will not pay for excess deliveries, on the grounds that to do otherwise provides an incentive for developers to overbuild their projects.

CalEnergy believes that the Commission should adopt a common rule regarding excess energy delivered under RPS-eligible contracts, and that rule should prohibit the banking

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[18] PG&E 2012 Renewable Energy Procurement Plan (Draft Version), *supra*, at p. 50.
[19] *Id*. at pp. 51-53.

of excess deliveries for the purpose of reducing the quantity of RPS-eligible resources that can be contracted in the next year, or in the next compliance period. The rationale for this policy is based on the long-term public interest in encouraging renewable energy investment.

In the next few years there will continue to be opportunities for renewable energy projects to take advantage of the current Investment Tax Credit (ITC) before it expires, as well as accelerated depreciation rules, that together greatly assist the financing for such projects.[20] To take maximum advantage of the limited time that such tax benefits may be available, California should not allow the potential RPS market to be reduced by banking a marginal amount of excess energy delivered in previous periods. The long-term value to California of building additional renewable resources with favorable tax credit and depreciation rules in place will far outweigh the short term savings from carrying over a small quantity of excess deliveries.

If one or more additional renewable energy projects were constructed in California as a result of the availability of the ITC and accelerated depreciation, the environmental benefits of that generation would last for the 40 year plus useful life of the project. Banking of excess deliveries will not help reduce greenhouse gas (GHG) emission in the same way that additional incremental renewable energy development will. Banking will instead reduce the IOUs' compliance targets and allow more fossil-generated energy to be consumed.

The benefits of maximizing the available capacity under the compliance targets will provide far greater value than the savings that might accrue because a utility contracted for marginally less renewable energy in one year because it "banked" an over-delivery from a preceding year. In other words, the Commission should not allow banking of excess deliveries

[20] The current 30% Investment Tax Credit that applies to geothermal resources will expire on 12-31-13, and for wind on 12-31-12. The ITC then reverts to 10%. The existing bonus depreciation tax treatment, including a 50% bonus depreciation provision, will also expire on 12-31-12. Extension of the ITC and depreciation provisions is subject to further legislative action in Congress, and any extension is not anticipated to be indefinite in duration.

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to diminish the maximum potential scope of renewable resource development. The opportunity for the IOUs to contract for RPS-eligible resources at a lower price due to the benefits of the favorable tax treatment makes sense for ratepayers as well. The opportunity to take advantage of the ITC and accelerated depreciation is likely to be limited in scope, and California will benefit if a larger percentage of its renewable resources have been financed at a lower cost using these beneficial tax programs.

IV. Increased Transparency in RPS Procurement

CalEnergy recommends that the Commission should require increased transparency in the IOUs RFP Plans by requiring disclosure of the specific criteria by which the IOUs select renewable resources for their RPS portfolios. While there is considerable material in the IOU RPS Plans, the key information about the utilities' net short position for renewables in the near term is redacted from the Plans, as are details about the actual workings of the Least Cost Best Fit analysis. As a result, a developer seeking to build a project in California and offer its output to an IOU is reduced to guessing about the type of renewable resources the IOU may actually require. The Commission should mandate fuller disclosure of the RPS procurement process.

a. The IOU RPS Plans Contain Limited Resource Information

The draft RPS Plans of the three IOUs contain only basic information about their anticipated requirements for RPS-eligible resources, and do not enable renewable developers to tailor their development plans to address the specific needs of the utilities. For example, PG&E's draft RPS Plan states a long term need of 1000 GWhrs in the 2012 RPS Solicitation,

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with a preference for Category 1 resources over Category 2 or 3.[21] PG&E states that it is seeking RPS-eligible power deliverable in 2019, 2020 or later.[22] There are few other details offered as to the technology, type, dispatchability, or location of generation that PG&E seeks.

SCE's 2012 Renewables Portfolio Standard Procurement Plan similarly offers only an outline of the utility's net short position for RPS-eligible resources. SCE states that in the compliance period immediately preceding 2020 it will have a need for 11,000 GWhrs of RPS capacity, and further unspecified needs in 2020 and later. SCE states that it intends to only contract for Category 1 resources. However, all other details regarding the delivery characteristics of the RPS power that SCE seeks are left unspecified, to be determined in the Least Cost Best Fit process. These key characteristics which are unseen to project developers include whether the resource is peaking, dispatchable, baseload, firm or as-available, as well as the location and on-line date.[23]

SDG&E's 2012 Draft Renewable Procurement Plan discloses that SDG&E has no need for RPS-eligible resources in the first two compliance periods, and a need for approximately 3320 GWhrs in the third compliance period ending January 1, 2020.[24] SDG&E states that bidders can offer products that can include peaking, baseload, dispatchable, as-available characteristics or include unbundled RECs. However, no indication is given as to what quantities of such resources would be preferred by SDG&E.[25]

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[21] Under SB 2 (1X) Category 1 resources are generally defined as being bundled with a Renewable Energy Credit (REC) and having a first point of interconnection within the WECC or a direct connection to a utility, all within a California Balancing Authority.
[22] PG&E 2012 Renewable Energy Procurement Plan (Draft Version), R.11-05-005, May 23, 2012, at pp. 12-13.
[23] SCE 2012 Renewables Portfolio Standard Procurement Plan, R.11-05-005, May 23, 2012, at pp. 4-7.
[24] SDG&E 2012 Draft Renewable Procurement Plan, pp. 9-10, 18-22.
[25] *Id.*, SDG&E 2012 Request for Offers, p. 5.

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b. Increased Information Will Enable Bidders in RPS Solicitations to Better Meet the IOUs RPS Portfolio Needs

CalEnergy recommends that the Commission require that the IOUs disclose the specific criteria by which they value price, technology, and deliverability of renewable resources in constructing their RPS portfolios. Opening the "black box" that is the Least Cost Best Fit analysis will result in a more efficient market for renewable energy by allowing developers to determine if their projects will meet the IOUs' specific needs. Does an IOU prefer renewable resources of a particular technology? Or does it make its decision based primarily on the price of the resources? If California genuinely seeks to encourage continuing investment in the development of renewable resources to serve the state, it must recognize that developers require basic information about the type of renewable generation sought by the IOUs, the degree of dispatchability or intermittency of generation, and characteristics as baseload vs. peaking power deliverability are equally important.

In recent years, such information has been withheld from market participants due to concerns that disclosure of the IOUs' resource needs would somehow disadvantage the IOUs and their ratepayers by providing information that would allow prospective sellers of energy to outmaneuver the IOUs in negotiations over purchased power agreements (PPAs). CalEnergy strongly believes that the Commission should alter the current policy regarding confidential treatment of information related to renewable procurement. The balance of interests should tip in favor of disclosing the specific needs identified by the IOUs and the criteria by which Least Cost Best Fit resources will be identified. Disclosure of the key criteria for renewable procurement will *not* result in a competitive disadvantage for electric customers. Renewable developers will still have a strong incentive to compete on price and other attributes. The Commission is well familiar with the challenges of delay and regulatory uncertainty facing companies who attempt to develop new renewable generation in California, as they have been debated again and again in recent decisions regarding approval of PPAs. These challenges are daunting enough without forcing developers to guess as to the specific resource needs the IOUs are seeking to fill.

The Commission could promote increased transparency in RPS Plans submitted by the IOUs by requiring the utilities to disclose their actual net short position, identifying the amount of capacity sought (within a range of probability) and a description of how the key generation characteristics are weighted in the Least Cost Best Fit analysis, including variables such as generation type, baseload vs. intermittent, dispatchability, location, etc. Such information would only be an approximate guide for renewable project sponsors, as it is recognized that the IOU could be expected to alter its targeted needs as it contracts for power and as its forecasted needs change over time. CalEnergy contends that the disclosure of this information would provide valuable assistance to the renewable development community and allow developers to focus on providing the type and quantity of renewable generation of most use to the utility. In turn, this should produce more direct competition between renewable generators for the specific needs of the IOUs and result in lower overall resource costs for ratepayers.

V. Conclusion

CalEnergy urges the Commission to require that the IOUs modify their RPS Plans (1) to ensure sufficient resource adequacy for renewable resources imported into the CAISO control area from the IID control area by eliminating RPS Plan provisions which discriminate against such imports and by adopting a 1400 MW MIC value for the purpose of determining the RA of imports from the IID control area; (2) implement some form of integration cost

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recognition in this RPS Plan cycle, while ensuring that non-intermittent renewable resources, such as geothermal, are exempt from any form of integration cost adder applied to intermittent renewable resources; (3) to clarify that excess energy deliveries cannot be "banked" to reduce the amount of RPS-eligible capacity required to meet the RPS compliance requirements in each compliance period; and (4) to require that the IOUs disclose the specific criteria by which they value price, technology, and deliverability of renewable resources in constructing their RPS portfolios.

Respectfully submitted June 27, 2012 at San Francisco, California.

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By *＿＿＿/s/ Michael B. Day＿＿＿*
Michael B. Day

Counsel for CalEnergy Generation Operating Company

3449/001/X141990.v1

VERIFICATION

I am the attorney for CalEnergy Generation Operating Company in this matter. CalEnergy Generation Operating Company is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of CalEnergy Generation Operating Company for that reason. I have read the attached "Comments of CalEnergy Generation Operating Company on Renewable Portfolio Standard Plans and New Proposals for RPS Implementation" dated June 27, 2012. I am informed and believe, and on that ground allege, that the matters stated in this document are true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 27th day of June, 2012, at San Francisco, California.

/s/ Michael B. Day

Michael B. Day

3449/001/X142022.v1

ATTACHMENT A

California ISO
Shaping a Renewed Future

California Independent System Operator Corporation

April 18, 2011

Mr. Michael Picker
Senior Advisor
Governor's Office
State Capitol
Sacramento, CA 95814

Re: Resource Adequacy Deliverability Issues for New Renewable Generation

Dear Mr. Picker:

Recently you asked the California Independent System Operator (ISO) and California Public Utilities Commission (CPUC) to look into the issue of resource adequacy for new generation projects that can help the state meet its renewable resources goals. As we understand, a number of projects are seeking power purchase agreements with load serving entities within California but are having difficulty coming to acceptable terms. The principal issue is whether the project can provide resource adequacy value and when this will be available.

In response to your request, we have prepared the following information for your use and feel it will provide valuable clarification for the project developers and interested parties.

Introduction

The following describes proposals to address two distinct issues that have been raised regarding the ability of new renewable generating resources to provide resource adequacy (RA) capacity to buyers (load-serving entities or LSEs) within the ISO balancing authority area (BAA). In both cases, the expressed concern is that the resources' limited ability to provide RA capacity will adversely affect their ability to obtain contracts with LSEs that provide a sufficient and predictable revenue stream to support project financing.

The ability of resources to provide RA capacity hinges on an ISO determination that they are "deliverable," which means that during peak system load conditions, the ISO grid is able to receive energy and reserves from all designated RA capacity simultaneously without exceeding any grid capacity limits or having other adverse reliability impacts. ISO engineers assess and quantify deliverability on an annual basis for all capacity resources located inside the ISO BAA and for each of the inter-ties connecting the ISO to adjacent BAAs.

Issue 1. For resources located outside the ISO BAA, the total amount of RA capacity they collectively can offer is limited to a quantity called the maximum import capability (MIC), which is determined by the ISO annually based on historical energy imports during peak system conditions. Parties have indicated that the historical approach yields excessively conservative MIC values on some inter-ties, which hinder development of new external renewable resources.

Issue 2. For certain renewable resources connecting directly to the ISO grid, there is a lag of up to five years between their start of commercial operation (production of energy) and the completion of the transmission network upgrades required to make them fully deliverable for RA purposes. During these interim years the resources would be ineligible, or only partially eligible, to provide RA capacity to their LSE buyers.

Proposed Solution For Issue 1

The ISO has developed and is working to implement a proposed solution for issue 1 that is comprised of two components:

1. **Revise the ISO procedure for determining the MIC values for each inter-tie to provide for additional RA import capability above the historically-based level.**
   a. The additional MIC on each inter-tie would be based on the in-progress or potential development of renewable generation that would utilize each inter-tie for delivering energy and providing RA capacity, subject to the operational requirement that all RA capacity can be utilized simultaneously and reliably to meet ISO peak load conditions when needed.
   b. The new MIC procedure will provide additional RA import capability in areas that are viewed as overly constrained under the existing procedure. However, it will not modify the rules for annually determining and allocating the additional MIC capacity to LSEs for their use in contracting with RA suppliers. Although this approach does not allocate RA import capacity directly to the resources themselves as some would like, it will enable contracting to go forward, and it has the important benefit of not requiring changes to the ISO tariff. The new procedure can be developed and codified in the ISO Business Practices Manual (BPM) within a matter of several months, after conducting a short stakeholder process.
2. **Use the ISO's annual comprehensive transmission planning process (TPP) to identify and approve any transmission additions or upgrades needed to maintain the expanded MIC values.**
   a. The ISO's new public policy-driven transmission category approved by FERC last December provides the basis for the ISO to identify and approve the needed transmission. In other words, if the ability to provide RA capacity is needed in order for renewable developers to obtain contracts with LSEs that will support project financing, then RA deliverability for these resources is needed to achieve the state's renewable policy objectives. Once approved by the ISO, these transmission elements would be open to a competitive solicitation process in which non-incumbent transmission developers would be able to submit proposals to build and own transmission under certain conditions.

ISO approval is sufficient to identify the necessary transmission facilities to support the import deliverability and to authorize cost recovery for these facilities through transmission rates. However, there are two additional requirements. First, the additional necessary transmission upgrades would still require permitting by the CPUC or other siting authority to proceed with construction. Second, the host BAAs for these external resources would need to ensure that their own transmission systems will support the resources' deliverability to the appropriate ISO inter-tie point.

In terms of timing, the ISO has already initiated a stakeholder process to develop component 1, the revised MIC procedure, and expects to complete a final proposal by mid May. The ISO will formally codify the new procedure in BPM language that would be finalized in August. The ISO will discuss component 2 in the context of the 2011/2012 TPP cycle, specifically through the publication of the draft planning assumptions published March 31, 2011. Initially, the renewable generation scenarios used in the 2010/2011 TPP cycle will provide preliminary target MIC values. In parallel, the ISO will be working with the CPUC to identify updates, if any, to the renewable generation scenarios and on that basis will confirm the target MIC values on each inter-tie during the TPP cycle. If additional transmission upgrades are needed to be permitted by the CPUC, those upgrades will require additional time to complete the permitting and construction process.

Proposed Solution For Issue 2

This solution is proposed to apply only to projects that meet the terms for the ARRA cash grants and which already have contracts with the LSEs that are under renegotiation after additional deliverability analysis from the ISO. In addition, the projects must not be located in a resource-constrained local capacity area.

The expected gap of up to five years with limited or no RA deliverability, for these specific projects, is fairly short relative to the full duration of the bilateral contracts currently being negotiated, e.g., 20 years. Therefore, we believe some LSEs would be willing to execute contracts with these resources conditional on RA capacity being provided by a date certain when the deliverability network upgrades would be in service, and would manage any interim impacts on their annual RA procurement through other means.

The proposed time period in which the LSEs would agree to provide replacement RA capacity would be limited to the time period up to three years after the date of full deliverability agreed to in the signed large generator interconnection agreement (LGIA).

In the interim, the LSE would be willing to procure additional RA capacity, or may directly own some generation that it could offer to complete its annual or monthly RA requirements. In determining the amount of replacement capacity required, the LSE will apply the CPUC rules for determining RA capacity. The LSE would provide this RA capacity, and would bill the developer the market price for the replacement capacity, at a cost not to exceed the per-MW price of the ISO's backstop procurement authority (e.g., $55 per kw/yr). This has the benefit of capping the potential cost to the renewable projects for RA value they are unable to initially provide.

As a further backstop, the LSE may in some months be short of its RA requirement, in which case the ISO could procure backstop RA capacity under its tariff provisions to make up the shortfall and bill the cost of this capacity to the deficient LSE, who would in turn bill the renewable generator at the tariff defined backstop level. In that event where an LSE is short of its RA requirement because it was unable to procure replacement capacity, the LSE may then ask the CPUC to waive any associated RA deficiency charges.

We hope that this is responsive to your request and can provide clarification for all parties. If you have any questions or require additional information, please do not hesitate to contact us.

Sincerely,

Karen Edson
Vice President, Policy and Client Services
California ISO

Julie Fitch
Director, Energy Division
CPUC

ATTACHMENT B

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

	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