PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria

I. Introduction

A. Establishment of the Least Cost Best Fit ("LCBF") Process

Decision D.03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in RPS solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups (PRG) and the California Public Utilities Commission (CPUC).

In addition, D.06-05-039 required "each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected."

D.06-05-039 also required each IOU to hire an Independent Evaluator ("IE") "to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator's preliminary report should be provided with the IOU's shortlist, and a final report with the AL for approval of selected bids."

The Scoping Memo for R.06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC's Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports ("LCBF Written Report").

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected. D.11-04-030 added that each utility should describe LCBF treatment of congestion, and to certain price data available.

B. Goal of PG&E's bid evaluation, selection criteria, and processes

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations consistent with the procurement goals set forth in the 2013 RPS Plan.

II. Bid Evaluation and Selection Criteria

A. Overview of the Ranking Methodology

PG&E evaluates each bid in terms of the following quantitative and qualitative attributes:

1. Net Market Value
    a. Benefits (Energy, Capacity, Ancillary Services)
    b. Contract Payments
    c. Transmission Network Upgrade Costs (also called a "transmission adder")
    d. Congestion Cost
2. Portfolio-Adjusted Value
    a. Location
    b. RPS Portfolio Need
    c. Energy Firmness
    d. Curtailment
3. Project Viability
4. RPS Goals
5. Supplier Diversity

Solicited bids are evaluated using the following step-by-step process:

The Net Market Value (NMV) is computed for each Offer. NMV will be adjusted by other attributes, such as location, RPS portfolio need, energy firmness, and curtailment, to arrive at the Portfolio-Adjusted Value (PAV). After the calculation of PAV is complete, PG&E considers project viability, contribution to RPS goals, and supplier diversity. Project viability has the greatest qualitative effect on the ranking. The set of highest ranked Offers which allow for a reasonable probability of satisfying PG&E's procurement goal is selected for the Shortlist.

1. Market Valuation

a. Overview of the Market Valuation Criterion

Market valuation considers how an Offer's costs compare to its market benefits. Costs include Transmission Network Upgrade Cost, Congestion Cost and Integration Cost as well as contract payments. Benefits include energy, capacity, and ancillary services values. Specifically, Market Valuation computes NMV for each offer as follows:

$$\text{Net Market Value: } R = (E + C) - (P + T + G + I)$$
$$\text{Adjusted Net Market Value: } A = R + S$$

Where
E = Energy Value

C = Capacity Value
P = Post-Time-Of-Delivery (TOD) Adjusted Power Purchase Agreement (PPA) Price
T = Transmission Network Upgrade Cost
G = Congestion Costs
I = Integration Costs
S = Ancillary Service Value

Costs and Benefits are each quantified and expressed in terms of discounted dollars per MWh. NMV is Benefits minus Costs, and is expressed in terms of discounted dollars per MWh.

The calculation of Benefits, Costs, and Market Value is described below.

b. Calculation of Benefits and PPA Costs

Energy benefit (E), for each hour of delivery, is the value of energy delivered at the market energy price at the corresponding Trading Hub (NP15, SP15, or ZP26), adjusted for Losses. As-available (or must-take) energy delivery for each hour from an Offer is determined by the hourly generation profile of the Offer. To the extent that the Offer provides dispatchable capacity, the value of the option from the dispatchability will be captured in the energy benefit calculation. The option value calculation depends on the particular characteristics of the dispatchable capacity. If an Offer includes energy storage that allows PG&E to schedule the discharge and charge of the storage, the energy benefit will also include the additional value that PG&E can get from being able to shift the RPS energy from the Project to more valuable hours given the constraints of the energy storage.

Losses vary by location of the project and are assessed using the Locational Marginal Price (LMP). The average Loss Multipliers are provided in Table 1. A higher Loss Multiplier implies less loss, thus more value associated with a project located in the corresponding load zone. PG&E may further update the Loss Multipliers prior to the evaluation of bids in the 2013 RPS Solicitation.

Discounted hourly energy benefit is summed across hours of delivery, and summed across years. The total discounted benefit is then divided by total MWh of energy and expressed in terms of discounted dollars per MWh.

For offers providing Buyer Curtailment, **energy benefit** will include the option value of the difference between the (presumably negative) wholesale market spot price avoided for the Project and PG&E's cost when Buyer Curtailment occurs.

Capacity benefit (C) for Resource Adequacy (RA), for year of availability, is the projected monthly quantity of qualifying capacity multiplied by the projected monthly capacity price, discounted and summed across years. To the extent that an Offer provides flexible capacity, the capacity that is expected to count for flexible RA and provide the ISO's must-offer requirement for flexible capacity resources will be evaluated at the projected monthly premium (which can be zero or positive) for flexible RA and then added to the Capacity Benefit. The total discounted capacity benefit is then divided by total MWh of energy and expressed in terms of discounted dollars per MWh. There currently exists significant uncertainty regarding the specifics of generic and flexible RA markets in California, especially for delivery years beyond 2015. Therefore, the calculation of capacity benefit may evolve as more information is known about market design or as uncertainty lingers.

For an Offer in a location that is projected to contribute to PG&E's satisfaction of a Local Capacity Requirement, the capacity attributable to the Offer may be valued at a premium relative to the value of capacity that satisfies only system needs.

Ancillary Services benefit (S) is assumed to be zero if an Offer doesn't provide any Ancillary Services (A/S) capabilitity. For Offers that provide PG&E the ability to schedule Ancillary Services, the incremental benefit of having A/S capability will be captured, not to be double counted with the energy benefit.

PPA Payments (P) are determined by the expected payments under each Offer including associated debt equivalence costs. The PPA Payment for each hour is calculated by multiplying expected delivery quantity by the Offer's price. The Offer's price is the contract price of the Offer multiplied by the applicable Time of Delivery (TOD) factors specified in the RPS Solicitation Protocol. The discounted hourly PPA Payment is summed over the contract term and then divided by the total MWh to be expressed in units of discounted dollars per MWh.

For Offers with capacity payments, the PPA Payment will include PG&E's capacity payments for each Offer as determined by the Offer's capacity price multiplied by the applicable capacity adjusted by appropriate Time Of Availability (TOA) factors specified in the PPA. Cost is measured in units of discounted dollars per MWh.

c. Calculation of Transmission Network Upgrade Costs

The Transmission Network Upgrade Costs (T) is the cost, if any, of bringing the power from the generating facility to PG&E's network. PG&E expects to use results from Participants' interconnection studies.

A Present Value Revenue Requirement (PVRR) is calculated from the Interconnection Study for each evaluated bid. If the Seller is offering an energy-only resource, PG&E will use the reliability network upgrades identified in the interconnection study for calculation of the transmission adder. If the Seller is offering a full deliverability resource, PG&E will use both the reliability network upgrades and delivery network upgrades in the calculation.

The PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades is converted into discounted dollars per MWh by dividing the present value of PVRR by the total MWh.

PG&E may take into account on a qualitative basis the additional value for projects that have Phase 2 interconnection studies or have no transmission risk.

d. Congestion Costs

Congestion cost (G) for each hour is calculated by the multiplication of 1) a Congestion Cost Multiplier for the corresponding time period and load zone, 2) the Locational Marginal Price (LMP) of the corresponding Trading Hub, and 3) expected energy delivery. The hourly congestion costs are discounted over the contract period and then divided by the total expected energy quantity (MWh) to arrive at the Congestion Cost in discounted dollars per MWh.

A summary of Congestion Cost Multipliers for each load zone is included in Table 1. A higher Congestion Cost Multiplier indicates a higher Congestion Cost (G). Specifically, a Congestion Cost Multiplier greater than zero indicates that generation in the corresponding area serves load outside of the area by congested lines and thus a new generation in the corresponding area is expected to increase the congestion. A zero Congestion Cost Multiplier implies there is no congestion in the transmission lines connecting the area. A Congestion Cost Multiplier less than zero indicates that loads in the corresponding area are served by the constrained transmission line(s) and thus a new generation in the area may reduce congestion. PG&E may update the Congestion Cost multipliers prior to evaluation of bids in the 2013 RPS Solicitation.

TABLE 1
Congestion Cost Multipliers and Loss Multipliers[1]

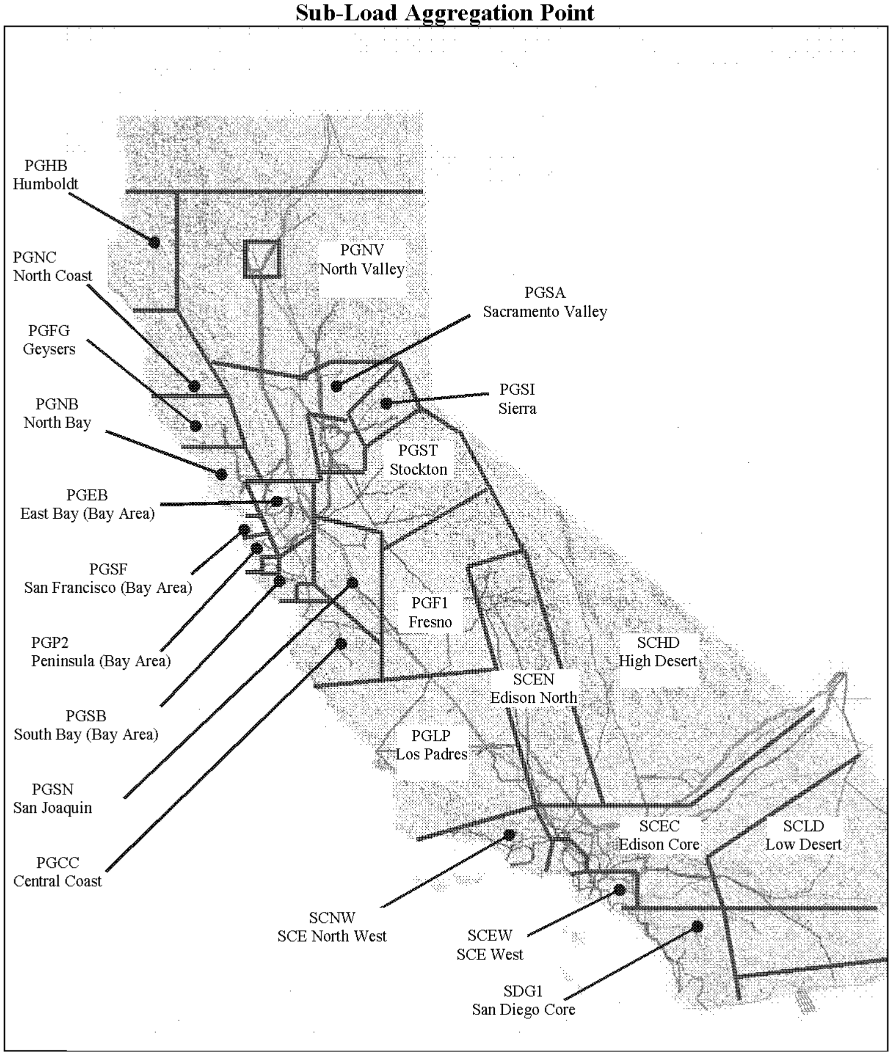
			Loss Multipliers		Congestion Cost Multipliers		LMP Multipliers	
			for E		for G		for E-G	
	Descriptive Names	CAISO APNodes	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
1	PG&E Central Coast	PGCC	103.9%	102.2%	3.5%	2.6%	100.4%	99.6%
2	PG&E East Bay	PGEB	103.3%	101.5%	3.5%	1.9%	99.8%	99.6%
3	PG&E Fresno	PGF1	103.8%	103.7%	2.4%	0.2%	101.4%	103.5%
4	PG&E Fulton Geysers	PGFG	102.8%	100.1%	3.9%	2.0%	98.9%	98.2%
5	PG&E Humboldt	PGHB	105.2%	106.1%	3.7%	1.7%	101.5%	104.4%
6	PG&E Los Padres	PGLP	101.5%	99.7%	3.7%	2.1%	97.7%	97.6%
7	PG&E North Bay	PGNB	103.3%	101.0%	3.8%	1.9%	99.5%	99.1%
8	PG&E North Coast	PGNC	104.2%	100.1%	4.9%	2.3%	99.2%	97.7%
9	PG&E North Valley	PGNV	98.9%	98.6%	3.1%	1.6%	95.8%	97.0%
10	PG&E Peninsula	PGP2	104.4%	102.3%	3.6%	1.9%	100.8%	100.5%
11	PG&E Sacramento Valley	PGSA	101.4%	100.6%	2.3%	1.4%	99.1%	99.2%
12	PG&E South Bay	PGSB	104.0%	102.2%	3.3%	1.7%	100.7%	100.5%
13	PG&E San Francisco	PGSF	106.2%	103.1%	2.2%	1.8%	104.0%	101.3%
14	PG&E Sierra	PGSI	100.6%	100.1%	1.3%	1.7%	99.3%	98.4%
15	PG&E San Joaquin	PGSN	97.9%	97.7%	3.4%	2.1%	94.5%	95.6%
16	PG&E Stockton	PGST	102.0%	101.1%	3.4%	1.9%	98.6%	99.2%
17	So Cal Edison Core	SCEC	96.2%	98.0%	-2.4%	-1.3%	98.6%	99.3%
18	So Cal Edison North	SCEN	95.1%	98.4%	-4.7%	-2.7%	99.8%	101.1%
19	So Cal Edison West	SCEW	98.2%	99.4%	-4.7%	-1.8%	102.8%	101.2%
20	So Cal Edison High Desert	SCHD	91.7%	94.3%	-1.0%	-1.7%	92.7%	96.0%
21	So Cal Edison Low Desert	SCLD	95.3%	96.9%	-0.3%	-1.5%	95.5%	98.4%
22	So Cal Edison North West	SCNW	95.8%	98.1%	-1.9%	-1.8%	97.8%	99.9%
23	San Diego Gas & Electric Core	SDG1	98.1%	98.9%	-3.2%	-0.8%	101.3%	99.8%

Overall locational value of the project should be assessed by looking at the LMP multipliers provided in Table 1. The LMP multipliers imply the relative value of 1 MWh in each load zone compared with the corresponding Trading Hub (NP15, SP15, or ZP26) price. For example, PG&E could consider Offer A located in Sierra and Offer B located in San Francisco, with everything else the same. Offer B will have higher Energy Value (E) because the Loss Multipliers in San Francisco are higher than for the Sierra. On the other hand, Offer A has lower Congestion Cost (G) because the Congestion Cost Multiplier for Sierra is lower than San Francisco. Overall, Offer B scores higher than Offer A, because E-G will score higher due to higher LMP Multipliers in San Francisco compared with Sierra.

The map for CAISO APNodes is for illustrative purposes only.

[1] Multipliers shown are a simple average over hours and months. Contract valuations use disaggregated values for different months.

Sub-Load Aggregation Point



e. Integration Costs

Pursuant to D.13-11-024, integration costs are assumed to be zero. PG&E has not proposed an integration cost adder only because it was prohibited from doing so in D.13-11-024. To the extent that the CPUC adopts an integration cost adder for the least-cost, best-fit (LCBF) methodology as part of LCBF reform in the future, PG&E will apply that adder in its offer evaluations.

2. Portfolio Adjusted Value

Portfolio Adjusted Value (PAV) adjustments include the following components: Location, RPS Portfolio Need, Energy Firmness, and Curtailment.

a. Location

PG&E has a preference for projects in its service territory. This preference is influenced by constraints (either in the marketplace or imposed on PG&E by regulatory agencies) that may limit the amount of capacity in SP15 that PG&E can count toward its RA requirement. Capacity located closer to PG&E's load is likely to deliver energy that has more value for PG&E's bundled electric portfolio, even when market forward prices indicate that energy delivered farther away has greater Market Value. The long-term risk for PG&E's customers is less when resources are located within PG&E's service territory rather than outside of PG&E's service territory. The calculation of PAV effectuates this by adjusting the value of energy and capacity for offers from resources in SP15.

For offers from resources in SP15, the Energy Value component in Net Market Value is adjusted so that the PAV Energy Benefit is not more than the Energy Value component calculated using NP15 energy prices, for each period the value of energy is calculated. This adjustment is not intended to adjust for congestion—that is accounted for in the calculation of Net Market Value in the Congestion Multipliers. This adjustment is intended to account for the relative value, to PG&E's portfolio, of energy that may be used to serve PG&E's bundled customer load. This adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's calculation of Energy Value in Net Market Value represents an offer's value of energy to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

The PAV Capacity Benefit in SP15 is calculated using capacity prices that are no higher than the capacity prices used for offers from resources in NP15. The PAV Capacity Benefit for offers from resources in SP15 will be based on capacity prices that are no higher than the short-run cost of capacity. This adjustment is intended to account for the relative value, to PG&E's portfolio, of capacity that may be used to meet future resource adequacy requirements to serve PG&E's bundled electric customers. The adjustment reflects the fact there is a constraint on how much capacity in SP15 may be counted toward PG&E's RA requriements. This adjustment is not duplicative of the Capacity Value component of Net Market Value. Whereas PG&E's calculation of Capacity Value in Net Market Value represents an offer's value of capacity to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

As a consequence of these adjustments to the value of energy and capacity, offers from resources in NP15 will tend to have higher PAV and rank better than equivalent offers from resources in SP15.

b. RPS Portfolio Need

PG&E has a preference for offers with deliveries beginning in 2020 or later. PG&E will consider how an Offer contributes to PG&E's overall portfolio need for RPS energy For each delivery year in which PG&E's portfolio (augmented by the offer) is projected to be short RPS-eligible energy, the PAV Adjustment for the Offer's RPS-eligible energy will be higher.

This RPS Portfolio Need adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of generic energy in the marketplace, the RPS portfolio need adjustment described here reflects the incremental value of RPS-eligible energy to PG&E's portfolio in meeting the portfolio's RPS requirement.

Thus, Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio does not needRPS energy.

c. Energy Firmness

PG&E's Net Market Value calculation of Energy Value uses energy forward price curves that are associated with firm energy. Offers in the RPS RFO are typically not for firm energy. To value the energy benefit for an offer from a resource that has uncertainty in the minute-by-minute production of energy, a risk-adjusted multiplier is used in calculating PAV. PAV is calculated as the product of an offer's Energy Benefit (as calculated in the Energy Value component of Net Market Value and then adjusted by the locational adjustment and RPS portfolio need adjustment described above) and the PAV risk-adjusted multiplier for that offer. The PAV risk-adjusted multiplier takes on values between 0.8 and 1.0. A multiplier of 1.0 represents an offer's Energy Benefit is the same as if the offer were to provide firm energy. A multiplier of 0.8 represents substantial reduction in an offer's Energy Benefit because of the offer's significant uncertainty in energy production from its resource. The multiplier for an offer from a solar thermal resource will typically be higher than the multiplier for an offer from a wind resource or a solar PV resource. An offer for a solar thermal resource with storage will typically have a higher multiplier than a solar thermal resource without storage. The particular PAV risk-adjusted multiplier applied to an offer will be a function of the relative firmness of the offer's energy and not simply a function of the renewable technology being offered.

The energy firmness adjustment itself will not result in any PAV increase or better ranking for offers providing dispatchability. For offers providing dispatchability, PG&E will either: (1) use option-based approaches to calculate the Energy Value component of Net Market Value, and/or (2) calculate PAV using the curtailment adjustment described below. Nonetheless, offers providing dispatchability will have higher PAV and rank better than equivalent offers that do not provide dispatchability.

The energy firmness adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of firm energy in the marketplace, the energy firmness adjustment described here reflects PG&E's assessment of the reduction in offer value that results from measuring and managing a position with uncertainty in energy production. For the same particular offer, other wholesale market participants might assess lower or higher reductions in offer value, resulting from each wholesale market participant's different portfolio positions and different capabilities, opportunities, and constraints for wholesale market activities.

The energy firmness adjustment is also not a proxy or substitute for a nonzero integration cost adder. The energy firmness adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system. The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

Thus, offers that deliver RPS energy with greater firmness will have higher PAV and rank better than equivalent offers that deliver RPS energy with less firmness.

d. Curtailment Hours

PG&E prefers a Seller to offer its energy as curtailable at any time at Buyer's discretion, for which the Seller will be compensated. PG&E's Net Market Value calculation of Energy Value includes the option value of the difference between the (presumably negative) wholesale market spot price avoided when Buyer Curtailment occurs and the Buyer's cost of Curtailment. This expected value is anticipated to be realized by any wholesale market participant and is not specific to the particular composition or positions of PG&E's portfolio or PG&E's particular capabilities, opportunities, and constraints for wholesale market activities.
When an offer does not conform to PG&E's preference for unlimited Buyer Curtailment and limits the number of hours of curtailment, PG&E may not be able to curtail in the hours that are more valuable to PG&E and its customers. Recognizing increasing operational challenges that additional inflexible resources are placing on the system, PG&E will adjust the PAV of such offers to account for the costs and operational challenges that are added to PG&E's portfolio. The operational challeges include the operational complexity caused by the limits on curtailment hours. The energy that PG&E cannot curtail when needed may increase the portfolio's costs for imbalance energy charges from the CAISO, cause the CAISO to issue involuntary curtailment orders to PG&E that can be costly, cause extreme price volatility in spot market prices for energy and ancillary services and as a result increase the cost of ancillary services, and add similar costs associated with managing the portfolio. The PAV adjustment for Limited Curtailment Hours represents these decremental values to PG&E's portfolio. Defined in this way, the PAV curtailment adjustment is therefore not duplicative of PG&E's calculation of Net Market Value.

The PAV curtailment adjustment is also not duplicative of any integration cost adder that might be used in the future. The curtailment adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system. The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

The PAV curtailment adjustment is also not duplicative of the PAV energy firmness adjustment. The curtailment adjustment reflects a flexibility or dispatchability (emanating from hours of Buyer Curtailment) that is a quality superior to must-take firm energy, whereas the energy firmness adjustment reflects uncertain generation that is typically inferior to must-take firm energy and at best is the same quality as must-take firm energy.

Thus, offers that provide less than full curtailment will have lower PAV and rank worse than equivalent offers that provide the requested hours of Buyer Curtailment.

3. Project Viability

The CPUC developed a Project Viability Calculator (PVC) with stakeholder participation from utilities, renewable project developers and ratepayer advocates. The CPUC's PVC, along with background on its development, instructions for use, and criteria scoring guidelines can be found on http://www.cpuc.ca.gov/PUC/energy/Renewables/procurement.htm and in the PVC itself.

PG&E will evaluate the project viability of each offer using the June 2, 2011 CPUC PVC. Participants are requested to self-score each of their offers using the PVC in Attachment D and provide supporting documentation for each score. PG&E will review all submissions and adjust self-scores as appropriate.

For background, a project's viability score is based on weighted scores in three categories: 1) Company / Development Team, 2) Technology, and 3) Development Milestones. The Project Viability assessment results in a score ranging from 0 to 100 points with 100 being the highest possible score. Offer information required by PG&E for evaluation of project viability is described in this 2012 Solicitation Protocol Section VI. The Participant's claims in all three categories are verified to the extent possible using publicly available data and/or PG&E data.

4. RPS Goals

PG&E assesses the Offer's consistency with and contribution to California's goals for the RPS program and the Offer's support of PG&E's supplier diversity goals (collectively "RPS Goals"). Determination of the extent to which the proposed development supports RPS Goals is based on the information provided in the Offer as well as PG&E's assessment of the project (see RPS Solicitation Protocol Section VI). The RPS Goals assessment considers the factors described below.

1. Legislative direction implemented in 399.13(a)(7):

"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."

2. Consistency with the CPUC's Water Action Plan adopted on December 15, 2005 and updated October 2010.

To the extent a project uses water on site, its impact on California's water quality and consistency with the CPUC's recommended water conservation practices and goals is reviewed.

3. Executive Order S-06-06, signed on April 25, 2006.

In this executive order, Governor Schwarzenegger described the benefits of biomass resources in electricity production and established a goal that the state would meet 20% of its renewable energy needs with electricity produced from biomass. The Participant is encouraged to describe in its Offer how its ERR facility, if applicable, can support the 20% goal.

5. Supplier Diversity

In support of PG&E's supplier diversity goals, the good faith efforts of Participants to subcontract with Women-, Minority-, and Service- Disabled Veteran-owned Business Enterprises (WMDVBEs) and if a Participant is a WBE, MBE, or DVBE are factors that are considered in the bid evaluation process.