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

I. Introduction

A. Establishment of the Least Cost Best Fit 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 which will ultimately result in energy procurement of approximately 1,000 GWh of long-term renewable PPAs.

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. Contract Term Length (Tenor)
    e. 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, contract term length (tenor) 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:

Net Market Value: R = (E + C) – (P + T + G + I)
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 levelized dollars per MWh. NMV is Benefits minus Costs, and is expressed in terms of levelized dollars per MWh.

Offers are classified into two types based upon how they are financially modeled: 1) forward contracts and 2) dispatchables. How benefits and costs are calculated varies with each of the two types of Offers. Below describes the calculation of Benefits, Costs, and Market Value.

b. Calculation of Benefits and PPA Costs

- **Forward Contracts**

The term "forward contract" is used to describe an Offer that provides energy with no dispatch flexibility. This type of Offer includes Baseload, As-Available, and REC plus Energy products.

Energy benefit (E), for each hour of delivery, is the quantity of energy delivery for an hour times the forward energy price at the corresponding Trading Hub (NP15, SP15, or ZP26), adjusted for Losses for that hour. The quantity of energy delivery for each hour is determined by the hourly generation profile of the Offer. Losses vary by location of the project and are assessed using the Locational Marginal Price (LMP). The Loss Multipliers were calculated from the Loss and Energy component of the historical MRTU LMP data (Day-ahead Market for the period July 2009 to August 2012). For each Offer, the Loss Multipliers for the corresponding load zone are multiplied by the LMP price of the corresponding Trading Hub to produce energy benefit per MWh for each hour. The average Loss Multipliers for Onpeak and Offpeak 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.

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

For offers providing Buyer Curtailment, **energy benefit** will include the expected value of the difference between the (presumably negative) wholesale market spot price avoided when Buyer Curtailment occurs and the contractual payments to the Seller 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 to 2013 dollars and summed across years. The total discounted capacity benefit is then divided by total discounted MWh of energy and expressed in terms of levelized dollars per MWh. There currently exists significant uncertainty regarding design of 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 is assumed to be zero for offers classified as forward contracts.

PPA Payments (P) are determined by the expected payments under each Offer. For forward contracts, an Offer's price for each hour is multiplied by the appropriate Time of Delivery (TOD) factors if applicable, as specified in the RPS Solicitation Protocol. The PPA Payment for each hour is then calculated by multiplying expected delivery quantity to the Offer's price. The hourly PPA Payment is summed over the contract term and then divided by the discounted MWh to be expressed in units of levelized dollars per MWh.

- **Dispatchables**

The term "Dispatchables" is used to describe Offers which provide some flexibility in their dispatch.

Energy benefits (E) of a dispatchable type of Offer are calculated as a daily exercise of European call options. Additional details depend on the nature of the particular characteristics of a specific Offer.

Capacity benefit (C) for a dispatchable type of Offer is calculated the same way as described above for the forward contracts type of Offer. The projected monthly quantity of qualifying capacity is determined by the performance requirements of the Offer and the characteristics of a specific Offer.

Ancillary services benefit for a dispatchable type of Offer depends on the characteristics of a specific Offer.

PPA Payments (P) represented by a dispatchable type of Offer is calculated the same way as described above for the forward contracts type, except that PG&E's capacity payments for each Offer are determined by the Offer's pricing multiplied by the appropriate Time Of Availability (TOA) factors. Cost is measured in units of levelized 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. However, depending on the timing of and results of the Cluster IV Phase II studies, and the Cluster V Phase I studies, PG&E may use the TRCR results in place of the Phase I study results if more appropriate.

A Present Value Revenue Requirement (PVRR) is calculated from the Interconnection Study or Transmission Ranking Cost table 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 levelized dollars per MWh by dividing the PVRR by the Discounted 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 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 net present valued over the contract period and then divided by the present value of expected energy quantity (MWh) to arrive at the Congestion Cost in levelized dollars per MWh.

A summary of Congestion Cost Multipliers for each load zone is included in Table 1. These Congestion Cost Multipliers were obtained from historical MRTU LMP data (Day-ahead Market for the period July 2009 to August 2012) by taking a ratio of negative of the Congestion component of LMP in each load zone to the LMP of the corresponding Trading Hub. 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.

TABLE 1
Congestion Cost Multipliers and Loss Multipliers[1]

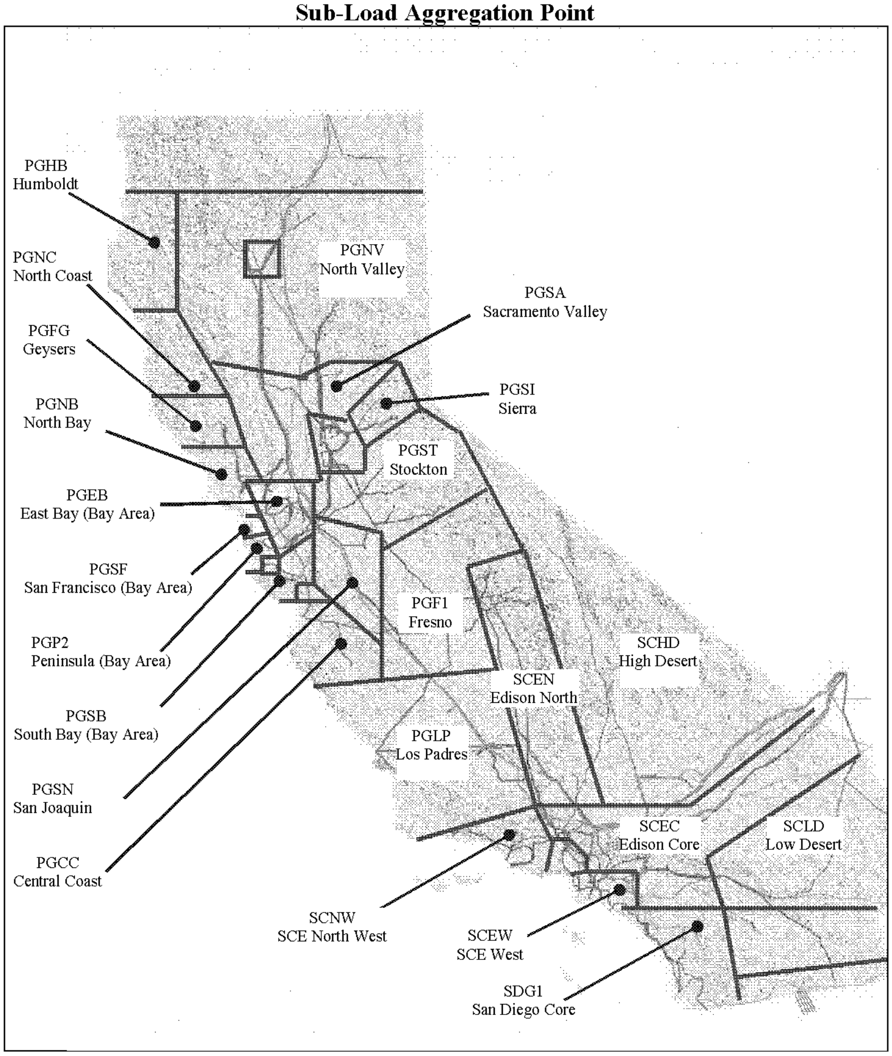
			Loss Multipliers for E		Congestion Cost Multipliers for G		LMP Multipliers for E-G	
	Descriptive Names	CAISO APNodes	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
1	PG&E Central Coast	PGCC	102.2%	101.9%	1.7%	1.7%	100.4%	100.2%
2	PG&E East Bay	PGEB	101.5%	101.1%	1.5%	1.1%	100.0%	100.0%
3	PG&E Fresno	PGF1	101.2%	101.7%	1.6%	1.1%	99.5%	100.6%
4	PG&E Fulton Geysers	PGFG	101.2%	100.1%	1.7%	1.1%	99.5%	98.9%
5	PG&E Humboldt	PGHB	103.1%	105.1%	-0.4%	-0.5%	103.5%	105.7%
6	PG&E Los Padres	PGLP	99.3%	98.5%	1.6%	1.1%	97.7%	97.4%
7	PG&E North Bay	PGNB	101.7%	100.9%	1.6%	1.1%	100.1%	99.8%
8	PG&E North Coast	PGNC	103.7%	101.1%	2.6%	1.3%	101.1%	99.8%
9	PG&E North Valley	PGNV	97.6%	98.3%	1.3%	0.8%	96.3%	97.5%
10	PG&E Peninsula	PGP2	102.7%	102.0%	1.6%	1.1%	101.1%	100.9%
11	PG&E Sacramento Valley	PGSA	99.7%	100.2%	0.5%	0.4%	99.3%	99.8%
12	PG&E South Bay	PGSB	102.3%	101.8%	1.5%	1.1%	100.7%	100.7%
13	PG&E San Francisco	PGSF	104.6%	103.2%	1.1%	0.7%	103.4%	102.4%
14	PG&E Sierra	PGSI	98.9%	99.4%	-0.3%	0.9%	99.2%	98.5%
15	PG&E San Joaquin	PGSN	96.0%	96.9%	1.7%	1.4%	94.3%	95.5%
16	PG&E Stockton	PGST	100.4%	100.4%	1.1%	1.0%	99.3%	99.4%
17	So Cal Edison Core	SCEC	98.0%	98.8%	-0.8%	-0.7%	98.9%	99.5%
18	So Cal Edison North	SCEN	97.2%	98.7%	-1.5%	-0.6%	98.7%	99.3%
19	So Cal Edison West	SCEW	99.9%	100.1%	-2.0%	-0.8%	101.9%	100.9%
20	So Cal Edison High Desert	SCHD	93.0%	94.2%	-0.1%	-0.5%	93.1%	94.7%
21	So Cal Edison Low Desert	SCLD	97.2%	97.7%	-0.9%	-0.7%	98.1%	98.4%
22	So Cal Edison North West	SCNW	98.5%	99.6%	-1.0%	-0.6%	99.5%	100.2%
23	San Diego Gas & Electric Core	SDG1	99.4%	99.4%	-2.3%	-2.0%	101.7%	101.4%

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 the Central Coast 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 Central Coast. On the other hand, Offer A has lower Congestion Cost (G) because the Congestion Cost Multiplier for the Central Coast 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 the Central Coast.

The map for CAISO APNodes is for illustrative purposes only.

[1] Congestion multipliers shown are a simple average over hours and months. Contract valuations use disaggregated values for different months and peak and off-peak periods.

Sub-Load Aggregation Point



e. Integration Costs

Pursuant to D.12-11-016, integration costs are assumed to be zero.

2. Portfolio Adjusted Value

Portfolio Adjusted Value (PAV) adjustments include the following components: Location, RPS Portfolio Need, Energy Firmness, Contract Term Length (Tenor), 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 need for new resources in PG&E's service territory is also more likely to be mitigated by a new resource in NP15 than a new resource located in SP15. The calculation of PAV effectuates this by adjusting the value of energy and capacity for offers from resources in SP15.

The PAV Energy Benefit for offers from resources in SP15 is calculated using the minimum of the SP15 energy forward price and the NP15 energy forward price, 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 for offers from resources in SP15 is calculated using a short-run avoided cost of capacity rather than a long-run avoided cost of capacity, even when the PAV Capacity Benefit for offers from resources in NP15 is calculated using a long-run avoided 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. 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 2019-2020. 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 Energy Benefit of that offer's RPS-eligible energy will be increased using PG&E's

forward price curve for Renewable Energy Credits (RECs). However, for each delivery year in which PG&E's portfolio (augmented by the offer) is projected to be long RPS-eligible energy, no additional value will be attributed to the offer's RPS-eligible energy; in other words, that RPS-eligible energy will be valued using an energy price curve for non-renewable energy. 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 those years, and only those years, when the energy actually is projected to be needed to meet 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 need RPS 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. Contract Term Length (Tenor)

PG&E prefers long-term transactions to match the portfolio's long-term RPS need, and so is seeking contracts with delivery periods 10 years or greater. A countervailing consideration is that longer-term transactions may pose greater project risk because of uncertainty in market conditions. PG&E has therefore expressed a preference for offers with delivery periods of 10 to 15 years rather than delivery periods lasting 20 years or more.

In calculating PAV, the value of an offer is adjusted for the length of the delivery period being offered (i.e., the "contract term length" or "tenor") using an adder. The adder takes on values between -10 and +10 dollars per MWh. Provided that an offer has contract term length at least 10 years, the shorter is the contract term length, the higher is the value of the adder, and consequently the higher is the PAV of the offer and the better is the ranking of the offer.

The contract term length adjustment is not duplicative of the Net Market Value calculation. PG&E's Net Market Value calculation is not directly affected by contract term length. Net Market Value is determined by the year-by-year differences between an offer's contract price (including the time-of-delivery factors) and the forward curves for energy and capacity. The present value of these year-by-year differences matter, but contract term length itself does not matter. PG&E's Net Market Value calculation is an expected value calculation. In contrast, the PAV calculation quantifies, in the context of PG&E's portfolio, how contract term length affects the riskiness of an offer.

Thus, offers with shorter contract term lengths (but contract term length at least 10 years) will have higher PAV and rank better than equivalent offers with longer contract term lengths.

e. Curtailment Hours Offered

PG&E prefers offers that provide PG&E flexibility in scheduling a resource's generation. PG&E values the flexibility associated with Buyer Curtailment. The PPA requires a Seller to offer at least 250 hours of Buyer Curtailment, for which the Seller will be compensated. The PPA also allows a Seller to offer more hours of curtailment, and to specify the price the Seller would be paid for energy deemed delivered in those hours.

For offers providing additional hours of Buyer Curtailment beyond the 250 required hours, PG&E's Net Market Value calculation of Energy Value will include, for the additional hours of Buyer Curtailment, the expected value of the difference between the (presumably negative) wholesale market spot price avoided when Buyer Curtailment occurs and the contractual payments to the Seller when Buyer Curtailment occurs. 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.

However, additional hours of Buyer Curtailment provide incremental value to PG&E's portfolio, above and beyond the expected value included in Net Market Value. Such incremental value may include reducing the portfolio's costs for imbalance energy charges from the CAISO, avoiding involuntary curtailment orders issued by the CAISO to PG&E, avoiding extreme volatility in spot market prices for ancillary services, and similar benefits associated with managing the portfolio. The PAV curtailment adjustment is the estimated value of these incremental benefits to PG&E's portfolio, minus the estimated value of contractual payments to the Seller for any incremental curtailment situations not already included in the Net Market Value calculation. 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 PG&E's 2012 RPS RFO. 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 greater amounts of additional hours of Buyer Curtailment with lower contractual payments to the Seller will have higher PAV and rank better than equivalent offers that provide lesser amounts of additional hours of Buyer Curtailment with higher contractual payments to the Seller.

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.

C. Criteria Weightings

1. If a weighting system is used please describe how each LCBF component is assigned a quantitative or qualitative weighting compared to other components. Discuss the rationale for the weightings.

PG&E does not apply a weighting system to the LCBF components in the overall evaluation and selection of Offers.

2. If a weighting system is not used please describe how the LCBF evaluation criteria are used to rank bids.

As described above, PG&E ranks according to Portfolio-Adjusted Value (PAV). Final shortlisting decisions are made with judgment using the scores and assessments from the other evaluation criteria. Also, PG&E solicits PRG and IE feedback on the recommended shortlist.

3. Discuss how the IOU LCBF methodology evaluates project commercial operation date relative to transmission upgrades required for the project.

As described in the Project Viability section above, the effect of the scope and timing of transmission upgrades on the timing of a project's commercial operation date is considered in the viability evaluation.

4. Discuss how the LCBF methodology takes into account bids that may be more expensive, but have a high likelihood of resulting in viable projects.

The LCBF process considers all Offers on multiple criteria, not just price. All Offers are scored in each of the criteria and ranked as described above. The Project Viability score has significant qualitative impact on the final ranking of the Offers. PG&E notes that the LCBF process is a screening tool that helps with an initial selection of projects. It is only upon shortlisting that substantive discussions with bidders can begin.

III. Bid Evaluation and Selection Process

A. What is the process by which bids are received and evaluated, selected or rejected for shortlist inclusion, and further evaluated once on the shortlist?

When bids are received and opened, a processing team reviews each Offer to identify and summarize key characteristics, and to note any major areas of missing or unclear information. PG&E has set up evaluation teams for each of the evaluation criteria, as described above. Each team reviews the entire population of Offers in its evaluation area in order to ensure consistency in scoring across Offers. A lead person for each Offer ensures that the scores for that Offer make sense across evaluation teams. If there are any additional information needs from a bidder, the PG&E lead makes such requests. Responses are taken into account prior to ranking Offers. An evaluation committee oversees the integrity of the evaluation process and makes a shortlist recommendation to the steering committee. The steering committee has the authority to approve the shortlist and additionally to rule on issues of eligibility. Following shortlisting, the steering committee approves the priority of negotiations. Offers and their respective valuations are updated as new information becomes available in the course of negotiations.

B. What is the typical amount of time required for each part of the process?

For the 2012 RFO, the interval between the issuance of the request for Offers to the receipt of Offers is approximately six to eight weeks; from the date of bid receipt until notification of bidders eligible for shortlisting, the interval is about eight weeks; from the date of notification to transmission of the short list to the CPUC is two weeks. In PG&E's experience, negotiations can take from three to six months, or longer, depending on the complexity of the transaction and the differences between the seller and the IOU. The time from contract execution until CPUC Approval is generally six to twelve months.

C. How is the size of the shortlist determined?

The shortlist is sized to create a population of Offers large enough to satisfy PG&E's procurement target of 1,000 GWh. PG&E takes into account that Offers may be withdrawn and that negotiations with others may not result in executed contracts.

D. Are rejected bidders told why they were rejected? If so, what is the process?

PG&E notifies rejected bidders by email and provides an opportunity for feedback by phone. The emails do not specify the reason, but PG&E Offers to discuss the reasons for rejection if the bidder desires. Several bidders took advantage of PG&E's Offer.

E. Describe involvement of the Independent Evaluator.

The Independent Evaluator (IE) reviews the evaluation criteria, detailed protocols, and the market valuation and PAV models prior to bid opening. The IE provides feedback on potential areas for improvement. The IE is present at bid opening and receives a copy of all bid documents. The IE monitors all email communications with bidders. PG&E uses email exclusively to make supplemental information requests, and all responses are provided to the IE upon receipt. The IE may submit additional questions that are not raised by the PG&E team. The IE participates in all meetings of PG&E's RPS steering committee and in all PRG meetings related to PG&E's RPS solicitation. The IE performs an independent evaluation of the Offers. If any substantive differences exist between the IE's evaluation and the utility's evaluation, the IE discusses these areas with the utility to determine the reason and to correct the difference.

F. Describe involvement of the Procurement Review Group.

For the 2011 RFO, PG&E presented its initial summary and general highlights of solicitation results to the PRG shortly after bid receipt. PG&E presented a detailed summary and preliminary shortlist to the PRG about six weeks after bid receipt. Key project characteristics were discussed. The PRG raised questions and provided initial feedback. PG&E incorporated the PRG's feedback into its selection of the final shortlist about eight weeks after bid receipt. PG&E expects to follow the same process in 2012.

G. Discuss whether and how feedback on the solicitation process is requested from bidders (both successful and unsuccessful) after the solicitation is complete.

Although PG&E has not established a process to receive feedback from bidders, PG&E is open to providing/receiving feedback, and would consider holding a post-solicitation workshop or an IE- sponsored survey in order to allow all bidders to express concerns and to provide/receive feedback. As described above, PG&E talked with several rejected bidders. In addition, PG&E solicited feedback from all bidders who withdrew from the solicitation, in order to understand their reasons for withdrawal.