Decision **ALTERNATE PROPOSED DECISION OF PRESIDENT PEEVEY**
(Mailed 1/26/2010)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Implement and Recover in Rates the Costs of its Photovoltaic (PV) Program (U39E).	Application 09-02-019 (Filed February 24, 2009)

DECISION ADOPTING A SOLAR PHOTOVOLTAIC PROGRAM FOR PACIFIC GAS AND ELECTRIC COMPANY

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DECISION ADOPTING A SOLAR PHOTOVOLTAIC PROGRAM FOR PACIFIC GAS AND ELECTRIC COMPANY

1. Summary

This decision adopts a five-year solar photovoltaic program (PV Program) to develop up to 500 MWs of solar photovoltaic (PV) facilities in the range of one to 20 MWs in Pacific Gas and Electric Company (PG&E's) service territory. In addition, this decision approves a 2 MW PV pilot project.

The PV Program provides for development of solar facilities through both utility-owned generation (UOG) and power purchase agreements (PPA). Under the UOG portion of the PV Program, PG&E is authorized to install up to 250 MWs of UOG PV facilities from one to 20 MW in size in its service territory at a rate of 50 MW per year, subject to cost of service ratemaking treatment as further described below. Similarly, under the PPA portion of the PV Program, PG&E will be authorized to solicit energy from 250 MWs of PV facilities from one to 20 MW in size located in PG&E's service territory, also at a rate of 50 MW a year. This decision authorizes a revenue requirement of $1.454 billion for the capital costs associated with the UOG portion of its PV Program. This amount is based on a 250 MW PV Program with an average capital cost (in constant 2009 dollars) of $4,312 per kW(DC) inclusive of a 10 percent contingency amount.

Should PG&E develop fewer than 250 MWs over the five year duration of the PV Program, the revenue requirement shall be pro-rata adjusted based the number of MW PG&E does develop. Capital costs in excess of the authorized revenue requirement shall be subject to a reasonableness review.

Pricing under the PPAs will be based on the competitive solicitation with the successful bidders entering into a 20-year PPA with PG&E. To ensure the best price possible for ratepayers for the UOG projects developed by PG&E and

those developed by independent power producers, we require PG&E to enlist the services of an independent evaluator to assess the fairness and robustness of its solicitations for both the UOG and PPA portions of the PV Program. Although the revenue requirement for the UOG portion of the PV Program is based on an average cost per unit capacity, in evaluating bids we require that PG&E also consider cost per unit energy in selecting winning bids under the UOG portion of the PV Program. Appendix A describes the adopted PV Program.

2. Background

On February 2, 2009, Pacific Gas and Electric Company (PG&E) filed this application seeking approval of a Photovoltaic Program (PV Program) and authorization to recover the associated revenue requirements for the PV Program in rates. PG&E's proposed PV Program consists of the installation and operation of up to 500 megawatts (MWs) of one to 20 MWs PV generation facilities in PG&E's service territory over a five-year period. Up to 250 MWs of the PV Program capacity will be utility-owned generation (UOG) and PG&E will procure up to 250 MWs through power purchase agreements (PPAs) with independent power producers (IPPs). PG&E seeks authorization to incur an estimated $1.45 billion in capital costs for the PV Program. In addition, PG&E requests approval of a 2 MW pilot project to be started in 2009 at an estimated capital cost of $11.9 million.

Several parties filed protests and responses to the application. The Commission held a prehearing conference (PHC) on May 14, 2009. Following the PHC, the Assigned Commissioner and Administrative Law Judge (ALJ) issued a Scoping Memo and Ruling (Scoping Memo) which established the scope of issues and the schedule for the proceeding.

Parties served testimony and rebuttal testimony pursuant to the Scoping Memo schedule. Evidentiary hearings were held on September 10 through 14, 2009. The Division of Ratepayer Advocates (DRA), CAlifornians for Renewable Energy (CARE), California Large Energy Consumers Association (CLECA), Western Power Trading Forum (WPTF) and Direct Access Customer Coalition (DACC), Consumer Federation of California (CFC), Coalition of California Utility Employees (CUE), The Solar Alliance, Independent Energy Producers Association (IEP), The Utility Reform Network (TURN), California Farm Bureau Federation (Farm Bureau), and The Greenlining Institute (Greenlining) filed timely opening briefs. DRA, WPTF and DACC, CLECA, CUE, The Solar Alliance and California Solar Energy Industries Association (CALSEIA), CARE, Greenlining filed timely reply briefs. CARE and DRA requested final oral arguments pursuant to Commission Rules of Practice and Procedure. Accordingly, the Commission held a final oral argument on _____, 2010.

On October 11, 2009, the Governor signed Senate Bill (SB) 32, (Stats. 2009, ch. 328) and Assembly Bill (AB) 920, (Stats. 2009, ch. 376) into law to take effect January 2010. SB 32 increases the size of generation facilities eligible for California's feed-in tariff program from 1.5 megawatts (MW) to 3 MW, and raises the program's statewide cap from 500 MW to 750 MW. SB 32 also establishes that the price under this program shall be based on the market price referent adjusted to include all current and anticipated environmental compliance costs subject to a ratepayer indifference test. AB 920 allows net energy metering customers with projects of up to 1 MW to sell any excess electricity they produce over the course of a year to their electric utility at a rate to be determined by the Commission.

Because both pieces of legislation require the utilities to provide compensation for electricity provided to the grid by projects similar in size and technology to those under consideration in this application, the assigned ALJ issued a ruling on October 30, 2009, requesting additional briefs on whether any aspects of SB 32 and AB 920 would impact PG&E's proposed PV Program in a way that should affect the Commission's final decision in this proceeding. DRA, TURN, PG&E, Greenlining, Solar Alliance, CFC, CARE, CALSEIA, and CUE filed timely supplemental briefs.

The proceeding was submitted on _____ upon conclusion of the final oral argument.

3. PG&E's Proposed PV Program

PG&E proposes a five-year PV Program to develop up to 500 MW of PV facilities between one and 20 MW in its service territory in northern and central California. PG&E's proposed PV Program would consist of two separate parts:

- The UOG portion of the PV Program would allow PG&E to develop up to 250 MWs of UOG at an estimated cost of $1.45 billion.
- The PPA portion of the PV Program would allow for PG&E to enter in up to 250 MW of contracts with third party developers for long-term PPAs at a pre-time of delivery (TOD) price of $246/MWh.

In addition, PG&E proposes to build a PV Pilot project of up to 2 MW in 2009, at an estimated capital cost of $11.9 million.

PG&E states that the proposed PV Program supports a number of California and Federal environmental goals including the expanded renewables goal, identified by the Air Resources Board in its scoping plan, of 33% renewables by 2020, thus supporting the greenhouse gas emission reduction goals identified in AB 32. It also supports the federal energy and environmental

policy objectives outlined in President Obama's energy plan.[1] PG&E emphasizes that the PV Program is designed "to expedite and simplify the regulatory approval process and to facilitate the annual, systematic development of PV resources,"[2] thereby helping to meet the 2010 renewables portfolio standards (RPS) target, under flexible compliance. In addition, PG&E asserts that utility ownership of PV, coupled with a PPA program, is beneficial for customers.[3]

The following sections provide more detailed description of the two components of the proposed PV Program.

3.1. UOG Portion of the Proposed PV Program (PV UOG)

The UOG portion of the proposed PV Program would allow PG&E to develop UOG PV projects at a rate of 25 MW in 2010, 50 MW each in 2011, 2012 and 2013, and 75 MW in 2014. PG&E anticipates UOG PV projects to be between 1-20 MW, with a possibility that some projects below 1 MW may also be developed. PG&E offers no details on the total MWs for projects below 1 MW, but states that it does not anticipate these projects to constitute a significant portion of the UOG portion of the PV Program.

The UOG projects would primarily be ground mounted on land PG&E already owns at or near PG&E's existing substations, although PG&E anticipates that additional land may need to be purchased and some roof-top mounted projects may also be developed. PG&E plans to make deposits to secure control of some land in advance of Commission approval of the PV Program and

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[1] Exhibit1 at 1-6.

[2] PG&E Application at 3.

[3] Exhibit 1 at 1-6.

proposes to include these deposits in Plant Held for Future Use (PHFU) account for recovery prior to the operation of the PV facilities.

PG&E proposes to use a competitive procurement process to solicit both bundled turnkey projects and unbundled engineering, procurement and construction (EPC) bids for the UOG PV development.[4]

The proposed cost recovery of the UOG portion of the PV Program would be based on Commission approved capacity price targets for the PV Program. If at the end of the PV Program, the actual total capital costs are at or below the average target plus a contingency, PG&E proposes that it will be allowed to recover the actual capital costs of the PV Program without any further reasonableness review, and customers will be refunded the difference with interest at the memorandum account/commercial paper rate. If, however, PG&E's average installed cost at the end of the UOG portion of the PV Program exceeds the average target, PG&E would be authorized to recover the actual capital costs up to the average target and file an application for recovery of amounts in excess of the average target. PG&E proposes to establish a memorandum account to record the difference between the revenue requirement for the UOG portion of the PV Program booked to PG&E's Utility Generation Balancing Account (UGBA) and the revenue requirement based on the actual capital costs of the UOG portion of the PV Program.

PG&E seeks Commission approval to suspend or scale back the PV UOG Program if it determines that it cannot meet the established capacity price targets or if it finds other factors impacting the use of capital.

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[4] PG&E describes unbundled EPC bids as projects where PG&E could supply owner-furnished major equipment to a construction/installation contractor. *Id.*

PG&E proposes to recover the stranded cost for the UOG portion of the PV Program through a non-bypassable charge for each facility installed for a ten-year period following the commercial operation of the facility.

3.2. PPA Portion of the Proposed PV Program

The PPA portion of the proposed PV Program includes an annual solicitation for projects of 1 to 20 MWs, located in PG&E's service territory. PG&E anticipates selecting projects based on viability and energy delivery criteria. Selected projects will be required to achieve commercial operation within 18 months after the PPA is executed.

PG&E requests that the Commission adopt a standard contract form, including a non-negotiable standard price for these projects. The price for the PPAs would be based on PG&E's estimated levelized cost of energy (LCOE) for the UOG portion of the PV Program. PG&E requests that it be allowed to update both the PPA forms and the price through an advice letter filing.

PG&E seeks approval to recover the costs of the PV PPAs through PG&E's Energy Resource Recovery Account (ERRA), which was established to record, among other things, costs of PG&E's procured power. Stranded costs associated with the PPAs would be recovered over the entire term of the agreement through a non-bypassable charge.

3.3. PV Pilot Project

In addition to the 250 MW of UOG projects, PG&E proposes a 2 MW Pilot Project to "expedite the deployment of the PV Program, demonstrate PG&E's commitment to the Program, and to allow PG&E to develop and refine internal and external processes needed to develop, permit, and operate a PV facility prior

to deployment of the larger PV Program."[5] PG&E proposes to book the $11.9 million revenue requirement for this project to the UGBA after the project achieves commercial operation.

3.4. Parties' Positions

CUE supports PG&E's application and urges the Commission to approve the PV Program. CUE believes the PV Program is a unique project with the potential for distribution system benefits but no transmission connection concerns and could add value in developing an additional potential path toward meeting the RPS goals.

CUE suggests that the PV Program will help the RPS goal because many of the current RPS contracts signed by IOUs have been cancelled, suspended or delayed. As a result, CUE advocates that "more projects than ultimately needed must be pursued in order to have sufficient number of projects succeed."[6] CUE also advocates that in meeting the 33% RPS goal,[7] multiple approaches and strategies must be considered to ensure sufficient amount of renewable resources are available.

CUE believes that by facilitating the development of up to 500 MWs of mid- size PV projects, the PV Program will also help fill the gap that CUE believes exists for these types of PV projects as a result of RPS solicitation. In CUE's view, this gap suggests that viable mid-size projects that could make an

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[5] PG&E's Application at 7.

[6] Exhibit 401 at 5.

[7] The 33% goal was established in Executive Order S-21-09, which directed the California Air Resources Board (CARB) to adopt regulations increasing California's Renewable Portfolio Standard (RPS) to 33 percent by 2020.

incremental contribution to meeting the state's RPS goals will be foregone.[8] CUE believes the Commission should fill this gap by approving the PV Program and facilitating the delivery of renewable energy from these types of projects.

DRA supports UOG as an alternative to the competitive market, but recommends denying the PV Program, because it believes the PV Program introduces heightened risk for ratepayers.[9] To begin, DRA argues that PG&E has already signed enough RPS-eligible contracts to meet its 2010 RPS obligations. Thus, it does not need the PV Program to achieve the RPS goals.[10] DRA disagrees with PG&E's claim that the RPS process is unreliable when it comes to executing contracts. Further, DRA argues that even if some of PG&E's RPS contracts fail to come on line, the PV Program would be "an ad hoc, over-priced solution."[11] DRA notes that the PV Program would be over twice the market price referent (MPR).[12] DRA believes PG&E can meet its renewable energy goals with much cheaper alternatives, consistent with the Commission's least cost best fit (LCBF) procurement directives.[13] DRA suggests several modifications to the PV Program as ratepayer protection measures in the event the Commission decides to adopt the PV Program.

CLECA also recommends that the Commission reject this application, asserting that the proposal is too expensive and cannot be justified. In particular,

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8 CUE's Opening Brief at 5.

9 Exhibit 100 at 1.

10 DRA Opening Brief at 5.

11 DRA's Opening Brief at 5.

12 MPR is the benchmark price for competitive renewable solicitation.

13 Exhibit 100 at 2.

CLECA is concerned that if approved, ratepayers will be burdened with the cost of the PV Program at three times more than the existing portfolio while other less expensive renewable alternatives exist. CLECA disagrees with PG&E's claim that the PV Program will help PG&E meets its RPS goal for 2010. In CLECA's view, the contribution of the PV Program is insubstantial, because it would only add "0.5 percent to renewable energy sales by 2013, and 0.7 percent by 2014 when the UOG portion of the PV Program is fully deployed."[14] Further, CLECA argues that to focus on small PV projects in the one to twenty MW range is not a very efficient way to obtain additional renewable power in a short time frame as these types of projects may face siting and permitting problems due to the need for multiple locations.[15] CLECA also contends that on an annual basis, because of their capacity factor, smaller PV projects produce less per KW installed than other solar and other types of renewable projects. Therefore, CLECA argues more individual PV projects will be needed to meet the RPS goals.[16]

The Farm Bureau recommends rejecting the application, echoing the concern about the cost of the PV Program and the lack of benefit to ratepayers. In the Farm Bureau's view, the PV Program is too expensive and fails to consider other alternatives with better value and benefits.[17] The Farm Bureau is concerned about land acquisition and the threat of eminent domain for land owners. In addition, the Farm Bureau is concerned about the environmental impacts related

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[14] CLECA Opening Brief at 7.

[15] *Id*.

[16] Exhibit 500 at 5.

[17] Farm Bureau Opening Brief at 4.

to the project sites, and the impacts PV projects might have on neighboring agricultural lands. This concern is also echoed by CARE.

TURN only supports the PV Program with modifications. While TURN states that it is supportive of utility procurement mechanisms for small and mid-size PV facilities, it believes ratepayers will not realize the full benefits of such an approach under the PV Program unless the program is based on a competitive process to lead to the selection of the least-cost and highest value projects. TURN recommends several modifications to the proposed PV Program to allow competition, and provide performance measures.

Although initially opposed to the application, IEP now supports PG&E's application, stating the modest progress in the RPS and the opportunity for additional 250 MW of independent power as the reasons for its support.

The Solar Alliance supports the application, stating that the PV Program "will make a positive contribution to the expanded development of renewable energy sources,"[18] but recommends the use of a competitive auction for the PPAs greater than 3 MW. The Solar Alliance agrees with PG&E that projects between one and three MWs should be afforded a fixed price.[19] The Solar Alliance also proposes a slightly different schedule for the deployment of PV capacity under the PPA portion of the PV Program.

Greenlining urges the Commission to reject the application for a number of reasons. First, Greenlining states that PV is one of the least cost effective forms of renewable energy and believes there are less expensive technologies that

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[18] The Solar Alliance Opening Brief at 3.

[19] CFC's Opening Brief at 12.

could deliver renewable energy to meet the RPS goals. Second, the fixed price PPA does not allow competitive pricing. Thus Greenlining argues it prevents savings that can arise from a fully competitive market.

CARE states that the PV Program would allow additional electric generation during peak demands eliminating the need to operate fossil-fueled plants that are often cited in lower-income residential neighborhoods. For that reason, CARE supports the application.

CFC urges the Commission to reject the application. CFC lists a number of issues where it believes PG&E's application lacks detail or specificity needed to determine the reasonableness of the PV Program's capital cost estimate.[20] For example, CFC points out that PG&E has not chosen the sites for the PV facilities and does not know how much land the PV Program will ultimately require. Therefore, CFC asserts PG&E's estimate for the cost of land is unknown. Further, CFC states a number of unknown assumptions such as the technology used, the efficiency of the panels, and whether a tracking system will be installed, could affect the cost estimate. In short, it is CFC's position that there are too many unknowns to find the UOG cost estimates reasonable.

CFC also opposes the fixed price PPA, arguing that it may result in higher costs than a competitive procurement process.

4. Need for the Program

4.1. Discussion

California has long recognized the importance and environmental benefits of renewable energy and has taken a leadership role in implementing programs

[20] CFC Opening Brief at 5 through 12.

to promote the development of renewables in the state. In 2002, the RPS was established under SB 1078 with the goal of increasing the share of the electricity generated from renewable sources to 20% of retail sales by 2017. The deadline for achieving this goal was subsequently accelerated in 2006 to 20% of retail sales by 2010, pursuant to SB 107. As currently implemented, the RPS requires electric corporations to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach the 20% by 2010. The state has also made substantial efforts to promote the deployment of solar generating facilities more specifically, recognizing some of the relative advantages solar offers as a renewable resource, in particular that solar output largely coincides with peak demand. The California Solar Initiative (CSI) was introduced in 2006 to spur the development of distributed solar generation in California. In 2009, in D.09-06-049, the Commission also approved a solar PV Program (SPVP) for Southern California Edison Company (SCE), which authorized SCE to deploy up to 500 MWs of distributed systems through both PPAs and UOG installations on rooftops in its service territory. It is also state policy that the highest priority be given to those renewable resources that can be developed most quickly.[21]

This decision, which adopts, with modifications, PG&E's proposed solar PV Program, represents another significant step in advancing the development of renewable generation in California. By adopting the PV Program as modified here, the Commission reinforces the importance of renewable distributed wholesale generation as an attractive resource option in the utilities' renewable

[21] Executive Order S-21-09.

generation portfolios. Also, this decision emphasizes that procurement mechanisms and strategies other than the RPS solicitations can help facilitate the expeditious installation and operation of additional renewable facilities in California and bring benefits to ratepayers.

Below we discuss why it is prudent to adopt the proposed PV Program subject to certain modifications. We address parties' concerns and find that the PV Program does not interfere or conflict with the RPS program or other renewable energy programs. In addition, we find that the PV Program is in the interest of ratepayers and the adopted prices are just and reasonable.

First, with respect to the RPS compliance, there is significant disagreement among parties about whether the PV Program is needed for PG&E to meet its 2010 RPS compliance obligation. We agree that on a contractual basis, PG&E has signed enough renewable contracts to meet its 2010 RPS compliance obligation, but do not believe that this fact alone indicates that adopting other programs targeting development of additional renewable projects are unnecessary or, as DRA puts it, "discretionary."

It is clear that development of renewable generation to meet the RPS goals for 2010 and beyond is a priority for this state and this Commission. While the record indicates that PG&E has contracted for enough renewable power to meet its RPS target for 2010, even with the RPS' flexible compliance rules, there is a possibility that PG&E may not meet its RPS targets because of various factors that can impede timely development of these facilities. Financing challenges, permitting delays, and transmission access represent risks that have been widely recognized as factors that can compromise the timeliness of renewable deployment, particularly given the scale of the facilities that PG&E has relied on thus far. Many renewable resources require substantial construction activities or

the deployment of new transmission infrastructure to access the renewable resource.[22] Because such additions can have significant environmental impacts, the permitting process and associated uncertainties have the potential to result in significant delays given the type of review to which these projects are subject. Small and mid-size PV projects, like those proposed by PG&E in its application, however, can potentially avoid these risks and be deployed more quickly and with greater certainty insofar as these facilities can be located close to load without the need for transmission additions, and may face fewer environmental barriers and public opposition than larger scale projects. It is worth noting that environmental and public opposition to large scale projects, which can occupy several square miles of land, are not theoretical concerns in California. In 2009, in response to significant commercial interest in developing large scale renewable projects in the Mojave Desert and their potential impact on the desert environment, Senator Dianne Feinstein introduced a bill to establish the Mojave Trails National Monument. If created, the monument would prevent the deployment of large scale solar and other renewable energy facilities on lands within the monument's boundaries.[23] Some of PG&E's proposed solar projects

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[22] For example in its July 2008 RPS quarterly report, Energy Division identified transmission as a key barrier to renewable development in California. Ongoing concerns about transmission needed to access renewable resources led to the creation of the Renewable Energy Transmission Initiative (RETI). RETI seeks to identify high value renewable resource areas in California and the west and the transmission infrastructure needed to reach these areas given both economic and environmental considerations. See http://www.energy.ca.gov/reti/index.html.

[23] Wallstreet Journal, "Green Battle Rages In Desert: Mojave Protection Bill Would Put Prime Solar-Power Sites Off Limits." December 23, 2009. http://online.wsj.com/article/SB126144129302900923.html.

with Brightsource, specifically those located in Broadwell Dry Lake, are among the projects that would be impacted by this proposed designation.[24] Distributed small scale solar PV facilities appear far less likely to elicit this kind of public opposition as they simply do not occupy vast stretches of land. In light of these factors, coupled with the modular nature of solar PV, it is reasonable to conclude that development of smaller projects can be accomplished more quickly and with less risk than larger facilities. Thus, developing these resources can be an efficient and relatively certain way of bringing additional renewable resources on line.

In its testimony, DRA offers a SWOT (strengths, weaknesses, opportunities and threats) technique to determine the reasonableness of the PV Program. We disagree with DRA's analysis because it does not take into account a number of these benefits. DRA also argues that because currently there is no mechanism to quantify the value of solar displacing fossil fuel or shaving off peak demand in

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[24] Resolution E-4269, pages 9-10 http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/107761.pdf BrightSource had been pursing project development for PPAs 5, 6 and 7 in Broadwell Dry Lake, California and has applications pending for site control with the Bureau of Land Management (BLM). PG&E explained in AL 3459-E that the Broadwell Dry Lake Projects are planned for development on BLM land that is currently being considered for national monument status, which could prevent project development. Our Draft Resolution identified Broadwell Dry Lake as the Projects' location and discussed the development risks of the sites. On September 18, 2009, the Los Angeles Times reported a statement from BrightSource that they , "… have ceased all activity at the Broadwell site…" Accordingly, we revised our Final Resolution on AL 3459-E to remove PPAs' 5, 6 and 7 site designation of Broadwell Dry Lake, California. The PPAs allow BrightSource to develop the Projects at other sites, provided certain delivery terms and conditions are met. (See Section "Energy from out-of-state Projects complies with Public Resources Code 25741" and Confidential Appendix B.)

electric rates, ratepayers will not receive any of those benefits. Although the above benefits are not yet quantifiable, they are among the known and unique benefits of PV technology and should not be overlooked. Thus, over the long run, adopting a program that will facilitate development of small and mid-size PV projects and help deliver renewable power to California can benefit ratepayers and help advance the state's policy goals.

Another factor that weighs in favor of adopting the PV Program is our interest in renewable UOG. We have previously addressed the benefits of renewable resources and have emphasized our support for renewable UOG. In D.08-02-008, the Commission stated, "First, there may be a unique and important role for utility-owned RPS generation. UOG from renewable energy resources, for example, can put downward pressure on what are otherwise increasing renewable energy prices." Furthermore, given the current economic environment, it is clear that the utilities, like PG&E, can bring additional financial resources to bear on a market that has faced an increasingly challenging financial climate. Despite our encouragement for California utilities to pursue renewable generation, very few UOG projects have come forward.

Although small and mid-size PV projects offer a number of benefits, several concerns have been raised that need to be addressed. Central among these is the issue of price and the manner in which the higher prices offered under the proposed PV Program may conflict with the RPS program, to the detriment of ratepayers. For example, DRA is concerned that if prices offered in PG&E's PV Program are higher than the prices for projects in the RPS, developers will bypass the RPS solicitation or bilateral negotiations in favor of PG&E's PV Program.

We do not believe the PV Program, as modified herein, would conflict with the existing RPS program, because the PV Program targets only a subset of projects that in our view cannot, as a practical matter, effectively compete in an RPS solicitation owing to their relatively higher cost when compared to large scale projects. However, given the relatively greater viability these projects offer, rather than conflicting with the RPS, we believe the PV Program will be complementary. DRA and others argue that the PV Program would allow more expensive projects to move forward in lieu of lower cost facilities that would otherwise be selected if we continued to rely exclusively on the RPS program for all renewable procurement. This concern, while true to a point, does not undermine the policy rationale for moving forward with this program. As explained above, these projects, while potentially more expensive than the larger scale projects that tend to dominate the RPS solicitations, offer a number of specific benefits that we believe are not accounted for in the RPS program and, in particular, are not offered by projects of a larger scale, namely the relative ease and certainty of deployment these facilities offer. In light of these benefits, we believe the premium ratepayers may pay for these particular resources are justified, provided the price paid is the result of a competitive process and appropriate incentives are in place to maximize system performance. The choice implied by DRA, between building cheaper, large-scale projects on one hand, and more expensive, smaller-scale projects, like those proposed here, on the other, is a false one as it presupposes that the larger scale facilities DRA and other assume would be built in lieu of the solar projects pursued here, would actually come online in a timely manner. Our experience with the RPS thus far suggests that many of these larger projects face substantial risk to timely development.

Potential overlaps with the RPS program are also limited by the narrow focus and eligibility criteria of the PV Program adopted here. Only solar PV projects that are located in PG&E's service territory and can achieve commercial operation within 18 months of signing a contract will be eligible to participate. In contrast, the RPS does not limit projects to a specific location, nor does it require an 18 months online date. RPS projects may be located outside of PG&E's service territory and may have a different online date depending on the negotiated contract. Accordingly, the majority of the projects that are eligible to participate in the RPS would not be eligible to participate in the PV Program. Thus, such projects would continue to be properly considered in the RPS process and would not be able to "forum shop" as DRA supposes. Again, in our view, adopting the PV Program would not hamper the RPS. On the contrary, it would facilitate the expeditious installation and operation of PV facilities that can help PG&E meet its RPS goals.

DRA's other concern, that developers with large projects will have an incentive to divide their projects into 20 MW parcels to take advantage of the PV Program prices, while a reasonable argument in the context of the pricing structure PG&E proposed in its application, is rendered largely irrelevant under the pricing methodology adopted in this decision. Presumably, a developer could fragment large projects into 20 MW parcels and forgo the RPS solicitation process if the fixed price offered under PG&E's PV Program were higher than those a project would receive under the RPS solicitation. However, as described in more detail below, rather than adopting PG&E's fixed price approach, PG&E will be required to hold competitive solicitations for the PPA component of the PV Program. Thus, to the extent these solicitations are competitive, developers will face the same strong incentives to bid into these solicitations at their

marginal cost, just as they do currently under the solicitations conducted in the RPS program.

Overall our view is that the PV Program provides a valuable approach to facilitate expeditious development of renewable generation by independent producers and could result in the timely installation of new renewable facilities in California. As such, it will help meet PG&E's RPS goals and will provide benefits to the ratepayers. For these reasons, we feel that it is reasonable to adopt such a program.

However, given the record evidence regarding the rapidly changing market for solar PV, and the reasonable concerns expressed about cost, we do not believe it is reasonable for the Commission to establish the pricing under the PPA component of the PV Program via an administratively determined price derived from the estimated costs of developing UOG projects. Below we discuss program costs.

5. The PV Program Costs

Although we support the establishment of a solar PV Program to support the deployment of small and mid-sized PV systems as a valuable complement to the existing RPS program, we appreciate the concern raised with regard to program costs, specifically the concerns that the cost estimates provided are not reasonable and that the proposed UOG price does not effectively allow for the benefits of competition. In particular, we agree with the thrust of DRA's view that as proposed "neither the UOG nor the PPA component of the program will create the competitive environment that is supposed to protect the ratepayers

from overpaying for renewable energy."[25] Below, we discuss why our adopted PV Program changes the pricing structure PG&E proposed from a feed-in tariff approach for the PPA portion of the program, to an approach where the price is determined via a competitive solicitation. With regard to the price of the UOG portion of the PV Program, we believe PG&E's proposal with some modifications, under which it will conduct competitive solicitations for turn-key projects or EPC contracts and pass only the actual costs incurred on to ratepayers, is adequate to protect ratepayers from excessive costs.

5.1. PV UOG Capital Costs

PG&E estimates the capital costs for the 250 MW of the UOG portion to be $1.45 billion. This corresponds to the average capital cost target of $4,275/kW direct current (DC) in constant 2009 dollars, including contingency, for the entire UOG portion of the PV Program.[26]

5.1.1. Parties' Positions

In previous sections, we have discussed parties' concern regarding the cost of the PV Program. The main concerns about the cost of the PV UOG are:

1. The estimates are unreasonable and unjustified.
2. The UOG price does not allow benefits from the competition.
3. The PV Program is more costly when compared to the CSI, the RPS, Southern California Edison's solar photovoltaic program (the SPVP) or other UOG projects.

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[25] DRA Opening Brief at 5.

[26] Table 6-9 in PG&E's prepared testimony provides additional information regarding the derivation of the $1.45 billion revenue requirement based on an average capital cost of $4,275/kw(DC).

5.1.2. Discussion

In comments on the Alternate Proposed Decision (APD), both PG&E and SCE argue that the performance based ratemaking approach in APD as issued is unworkable for a variety of reasons. PG&E contends that basing its annual revenue requirement on a weighted average price per unit energy that is calculated from winning PPA bids ignores the fact that whether or not winning bids ultimately come online is far from certain.[27] As such, using bid prices is likely to result in pricing that is unduly aggressive and unrepresentative of the actual cost of energy from the projects developed under the PV Program. PG&E additionally argues that a wholesale shift to the performance based approach undermines the long-term value of UOG projects to ratepayers.[28] Under a PPA, at the end of a given contract's life an IPP can sell its energy at the then available market price. In contrast, ratepayers would only bear the variable cost for energy produced by a fully depreciated utility-owned asset. PG&E also argues that UOG projects serve important policy objectives that will not be realized if PG&E is unable to pursue any of the projects it proposed to deploy through the PV Program. PG&E suggests that UOG projects, pursued under cost of service ratemaking, provide a degree of certainty and speed to market that IPPs do not.[29] Lastly, PG&E along with SCE argue that the dramatic shift in approach from what was approved in SCE's case is unjustified given the broad similarity of the

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[27] PG&E Opening Comments on APD; pp. 2-5.

[28] *Ibid*; pp. 6-7.

[29] *Ibid*; pg. 7.

proposed programs.[30] Solar Alliance/Vote Solar offer additional arguments in favor of more traditional cost of service treatment for UOG projects, specifically arguing that the prices emerging from an IPP solicitation may not be indicative of what is required for PG&E to be willing to pursue these projects thus running the risk that as much as half of the PV Program's overall 500 MW capacity goal may not be pursued at all. They also suggest that the approach proposed in PG&E's application, whereby only actual costs of the UOG projects are passed on to ratepayers, and the stipulation that any costs in excess of the revenue requirement would be subject to a reasonableness review, should be sufficient to protect ratepayer interests.[31] We believe some of these arguments have merit and are particularly concerned that the approach proposed in the APD as issued will not allow PG&E to pursue any UOG projects. Rather than compromise the ability of PG&E to effectively participate in the program it proposed, we will instead revert to the cost of service model as originally proposed by PG&E for the UOG portion of the PV Program, subject to some specific requirements to ensure that the costs ratepayers bear for these projects are reflective of market prices.

As noted above, PG&E has provided an annual capacity price target that, when combined with a contingency amount provides the basis for an overall revenue requirement for the total capacity costs incurred over the course of the program. Under this approach, should PG&E's total capital costs over the 5 year program prove lower than this amount, then the costs would be deemed

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[30] *Ibid*; pp. 7-8; also see Southern California Edison Company Opening Comments on APD; pp. 3-4.

[31] Solar Alliance/Vote Solar Opening Comments on APD; pp. 9-10.

reasonable and PG&E would be allowed to collect those costs from ratepayers without any further reasonableness review. If PG&E's capital costs exceed this benchmark, then it would be subject to a reasonableness review for the costs in excess of the revenue requirement. As a basic approach, we believe PG&E's proposal can serve to reasonably protect ratepayers from excessive costs, provided these costs result from a sufficiently competitive process and PG&E only passes its actual costs on to ratepayers. To the extent PG&E's earnings on projects undertaken pursuant to the PV Program are a function of its capital expenditures, parties are reasonably concerned with the accuracy of PG&E's annual capacity price targets as, under cost of service ratemaking, PG&E would appear to be motivated to pursue projects at or near the cost target. A relatively accurate cost estimate is therefore an important element in ensuring that the costs ratepayers ultimately bear under cost of service are limited to those that are truly reasonable.

PG&E has provided a variety of metrics to assess the reasonableness of its projected costs, including a bottoms-up cost estimate based on the deployment of 5 MW, ground-mounted systems on disturbed agricultural land to fulfill the overall capacity targets of the PV Program, as well as a number of comparisons to other solar projects and initiatives. None of these are perfect, for the reasons described below, however collectively they indicate that PG&E's proposed price benchmark is reasonable, given what data is available today.

With regard to PG&E's indicative cost estimates, there are some notable deficiencies identified by parties. CFC has demonstrated that PG&E's estimates of program costs lack important details including more specific information regarding where PG&E's plants will be built, how much land will be needed, or how much the land will cost. Greenlining also points to some deficiencies in

PG&E's cost estimates. Specifically, Greenlining indicates that PG&E's cost forecast ignores the cost associated with panel disposal at the end of the panels' useful life. According to Greenlining, the panel disposal costs for the UOG portion alone could amount to about $27.5 million.[32]

We are not convinced by PG&E's response regarding the lack of cost estimates, particularly the response that the panel disposal cost was left out because of the uncertainty about how the panels would be disposed of, or the possibility that some panel manufacturers' voluntary take-back programs could reduce the costs of panel disposal. Moreover, PG&E's response that the unknown factors are implementation details is not compelling.

However, because these elements would, if included, presumably increase the capital costs above what PG&E has provided, and excess costs are subject to reasonableness review, we believe ratepayers have recourse should PG&E seek recovery of these costs. Similarly, to the extent these costs impact the O&M estimates, ratepayers again shall have the opportunity to challenge recovery through the Commission's reasonableness review in the context of PG&E's General Rate Case (GRC).

In addition to a bottoms-up estimate of system costs, another approach to determine if capital costs are reasonable is to look to similar projects that have been developed or are being pursued. To the extent analogous projects can be found, their costs can provide a range of costs within which PG&E's proposed projects can be expected to fall. As DRA notes the most useful comparison

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[32] Greenlining's Opening Brief at 13.

would be to projects of a similar size.[33] Ideally they would also be ground mounted, in the same manner as PG&E proposes for the vast majority of projects it intends to undertake. For example RPS projects of a similar size and technology could provide a useful comparison. However, to date relatively few projects have actually come online in the RPS that are comparable to the projects PG&E has proposed, and to the extent they have been, relying on bid prices is potentially problematic given that a bid price is not necessarily reflective of the actual prices that ultimately emerge. Indeed, numerous projects in the RPS have come in for price "reopeners."

The CSI also fails to provide a reasonable comparison because projects under that program represent smaller projects deployed almost exclusively on rooftops. PG&E's PV Program envisions primarily ground mounted systems generally of a much larger scale than those seen in the CSI. Additionally, while from a ratepayer standpoint the cost of the CSI may be lower in that ratepayers provide only a partial subsidy to defray the costs of solar installation, from a societal standpoint, the installations PG&E has proposed are undoubtedly cheaper. As PG&E has indicated in testimony, the cost of CSI projects is almost double that of what PG&E has proposed.

SCE's SPVP while suffering from some of the same problems as the CSI in terms of comparability is perhaps a more useful metric insofar as it was approved to achieve some of the same ends as the program under consideration here. In SCE's case we approved a cost estimate of $3,500 (2008 dollars) per kW, excluding a 10% contingency and lease costs. This compares to PG&E's

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[33] Exhibit 101 at 7.

proposed cost of $3,493 per kW (2008 dollars), if one excludes land costs and contingency. Although PG&E has amortized the cost of the PV Program over 25 years and the SPVP's costs are amortized over 20 years, we believe the fact that PG&E projected costs are relatively close to those of SCE's suggests that, should the price benchmark be reached, PG&E ratepayers will be paying a comparable amount for largely similar benefits as SCE's ratepayers.

PG&E has also presented comparisons to other UOG projects in other states including a comparison to Public Service Electric and Gas Company's (PSE&G) "Solar 4 All Program" and Duke Energy Carolina's approved PV ownership program.[34] PG&E notes that based on public data, the costs of the solar capacity developed under these programs is estimated at $6,442/kW for PSE&G and $5,000/kW for PSE&G and Duke, respectively. PG&E observes that these are substantially higher than the costs it anticipates under its program. The usefulness of these comparisons however, is somewhat limited owing to the lack of detail on the specific nature of these programs and how these programs may differ from that being proposed by PG&E here.

Perhaps the most useful data point we currently have is PG&E's pilot project. This project was developed and completed in 2009. The pilot project is intended to provide PG&E some initial experience developing a project that shares certain fundamental characteristics to those it proposes pursuing through the UOG portion of the program. As such we believe it is perhaps the most analogous of the projects available to us for comparative purposes. That said, it too, is an imperfect comparison as the pilot is relatively small in scale at only 2

[34] Exhibit 3.

MW. Thus, given the much broader range of project sized PG&E intends to pursue and assuming some economies of scale, it is likely that as a cost estimate using the pilot project will be unrealistically high. Also, the fact that the pilot was constructed on utility owned land means that no incremental land costs were involved, something that is not assumed to be the case for the projects PG&E intends to pursue more generally. Regardless of these factors, we believe the costs of the pilot project provide a reasonable upper bound. We note that PG&E's proposed average capacity price target falls below its actual capital costs for the pilot project.

While each of the approaches presented to asses the accuracy of PG&E's proposed price benchmark are imperfect, we believe that taken together they generally show that PG&E's benchmark is within the realm of reasonableness and that it can, along with an appropriate contingency amount, serve as a useful basis for determining whether PG&E can collect monies from ratepayers for its investment in these facilities, or if its request should be subject to additional reasonableness review.

While we adopt PG&E's capacity price target today, we note that this estimate will become increasingly less accurate as time passes. The record in this proceeding strongly suggests that the market for solar PV is a dynamic one, with prices changing rapidly. For example, since the release of the RETI report cited by the Farm Bureau in its testimony the market conditions for solar PV have changed. A more recent RETI report indicates that solar PV costs may be lower than suggested in the earlier report. In fact, the Final RETI Phase 1B report distinguishes PV among all other technologies as one with significant potential for cost reductions in the future:

> "Unlike most other renewable technologies, capital costs in the photovoltaic industry have significant potential to decrease, and there is considerable commercial interest in utility-scale "thin film" systems."[35]

Further, during hearings, PG&E's witness Wan noted that prices for PV have been declining.[36] This statement is also consistent with some of the recent trade publications showing a trend in declining PV prices over time.[37]

Because PG&E has proposed conducting competitive solicitations and will only be passing the actual capital costs resulting from these solicitations through to ratepayers, ratepayers should reap the benefits of these anticipated price declines provided the solicitations PG&E conducts are sufficiently robust. To that end we believe it is appropriate for PG&E to enlist the services of an independent evaluator (IE) to oversee the solicitation process and provide an assessment of the fairness and robustness of each of its solicitations for UOG projects and the degree to which these solicitations conformed to the solicitation protocols. PG&E shall provide the IE reports regarding the UOG project solicitations it has conducted in its annual program compliance report to the Commission. The annual compliance reporting requirements are described in more detail in Appendix A.

We note that that a number of parties have commented that the reasonableness of the costs should not be assessed in terms of dollars per unit capacity, but should instead be assessed in terms of dollars per unit output, as

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[35] Final RETI Phase 1B report (http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF), pages 5-27.

[36] TR Volume 1 at 9.

[37] http://www.solarbuzz.com/FastFactsIndustry.htm.

ultimately, it is the energy production from these facilities that is of value to ratepayers and to the state's renewable energy goals. Although we adopt a capacity price target in this decision and an associated revenue requirement for the recovery of capital costs, we expect PG&E's evaluation of project proposals to explicitly consider cost per unit output (i.e., levelized cost of energy) when comparing competing bids in its UOG solicitations. This information and how it is factored into the determination of which projects are ultimately selected from a given solicitation shall be provided to the IE and included in the IE's report to the Commission.

In addition to adopting a capacity price target we also need to address PG&E's requested contingency amounts. In its testimony PG&E proposes specific contingency amounts for various capital cost components.[38] However, in our view the basis for these estimates appear insufficiently supported. For example, other than vague statements about varying levels of uncertainty and variability in the cost estimates PG&E, offers little in the way of empirical support for the proposed contingencies. A number of parties observed that the contingency amounts proposed by PG&E are higher than what we have approved in other instances. Rather than adopt PG&E's proposed contingencies, we believe a more reasonable approach is to adopt contingency values that correspond more closely to what we have adopted in other cases. We therefore, adopt an overall contingency amount of 10% consistent with what we adopted for SCE's SPVP.

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[38] Exhibit 1, "Prepared Testimony of PG&E," at 4-6, lines 17-23.

Consistent with its request regarding recovery of capital costs for the UOG portion of its program, PG&E shall file for recovery of its capital costs in its GRC. The authorized revenue requirement shall be booked in its Utility Generation Balancing Account (UGBA) and a memorandum account shall be used to track the difference between its actual capital costs and the revenue requirement entered into its UGBA.

5.2. PV UOG Operations and Maintenance Costs

In addition to providing capital cost estimates, PG&E also provides estimates for the Operations and Maintenance (O&M) costs it anticipates incurring annually for the projects it deploys pursuant to the UOG portion of its proposed program. PG&E's O&M cost estimate consists of labor, materials, and contracts for operation and maintenance of the PV facilities and includes a 20% contingency factor due to uncertainties in the ongoing operation of the PV facilities.[39] As with the capital cost estimates, these estimates were developed assuming the unit of deployment under the program will be a 5 MW, fixed panel, ground-mounted facility. PG&E indicates that its estimates are based on information obtained from solar equipment suppliers, consultants, and PG&E's best professional judgment.

PG&E's specific O&M cost estimates were contested by parties. The CFC in particular argues that the Commission cannot determine if the cost estimates are reasonable as many of the variables underlying these estimates are subject to change depending on the technology used and method of deployment.[40] While

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[39] Exhibit 1 at 5-6.

[40] Consumer Federation of California; Opening Brief; pg. 13.

we agree with CFC that there are a number of uncertainties in the underlying assumptions that necessarily translate into some uncertainty regarding PG&E's cost estimates, we find the simplifying assumptions PG&E made in conducting its assessment reasonable. In developing these estimates, assumptions do have to be made as it would be impossible to know, from the outset, exactly what technologies will be used, or where and how those technologies will be deployed without unduly limiting the flexibility of the program.

We note that under ideal circumstances, in addition to the indicative costs PG&E provided for its proposed projects, we would also have access to information regarding the actual O&M costs experienced by comparable facilities that are currently operating. PG&E did not provide any such comparable data on real-world projects, nor did parties, either in support of, or in opposition to PG&E's cost estimates. However, at the same time we recognize the difficulty of obtaining this information, and as such, believe PG&E's request is reasonably supported.

We are not persuaded, however, that PG&E's proposed O&M contingency amount of 20% is reasonable. While certainly there are reasons why O&M costs may vary from the estimates provides, PG&E's arguments in this regard seem to focus exclusively on the circumstances that may lead to higher than anticipated O&M costs. Yet many of these same uncertainties could be equally valid in support of an argument that actual costs may be below what PG&E has estimated. As such we adopt a contingency amount of 10% for PG&E's O&M costs. We believe adopting this lower amount will also encourage PG&E to be mindful of ongoing costs in selecting projects.

PG&E shall file for recovery of its O&M costs for UOG projects deployed pursuant to this program in its GRC, consistent with standard Commission

practice. To ensure that stakeholders have the ability to evaluate the reasonableness of these costs specifically, we require that in its GRC filing the O&M costs associated with this program be consolidated in one section. PG&E should provide sufficiently granular information for parties to understand the nature of the O&M expenses incurred by activity area (e.g., costs associated with panel cleaning, maintenance, vegetation management, security costs, etc.).

5.3. PV PPA Cost

5.3.1. Parties' Positions

In its application, PG&E proposes a fixed price for the PPAs, based on PG&E's expected LCOE for the UOG portion of the PV Program, which equates to a pre-TOD-adjusted contract price of $246/MWh. The Solar Alliance opposes the fixed price PPA for projects larger than three MWs. The Solar Alliance argues that PG&E's proposal for the fixed price PPA is inconsistent with the Commission's stated policy in D.07-12-052, which requires that all long-term procurement occur via competitive procurement mechanisms. The Solar Alliance also points out that the Commission in D.09-06-049 required a competitive process for the MWs to be developed by the IPPs for the SCE PV Program and that similar requirement should apply here. The Solar Alliance shares TURN's view that third party projects could sell energy at prices below the price of the UOG and also points out that PG&E itself has recognized that a competitive solicitation could secure prices lower than the fixed price offered by PG&E. Thus, the Solar Alliance advocates a competitive auction for projects above 3 MW.

While the Solar Alliance recommends against using a fixed price PPA for projects above 3 MW, it does believe a fixed price would work well for projects

under 3 MW, and suggests we conduct a workshop to determine the price for such projects.

Greenlining is opposed to the fixed price for PPAs. It argues that the fixed price works as a disincentive to bidders to lower their price.

WPTF/DDAC also argues that the fixed price conflicts with several Commission decisions, including the Commission's competitive market first approach. It notes that Commission decisions that have encouraged competitive procurement have never mentioned fixed price PPAs. It further adds that such a price would also be inconsistent with the criteria for UOG and Commission policy that encourages merchant generation development.[41] In addition, WPTF/DDAC adds that the fixed price will provide no price competition that could benefit the ratepayers.

CFC also notes that the fixed price may result in higher costs than the competitive procurement.

TURN also opposes the fixed price, stating that the fixed price could create potential windfalls for the developers. TURN argues that third party developers may be able to achieve lower prices than UOG due to many factors including the benefits of federal tax incentives, lower cost of capital, and changing market conditions, but under a fixed price structure, the financial benefits of these lower costs would be realized only by the developers. TURN advocates that to the extent that lower prices can be achieved, ratepayers should be able to benefit from these savings in the form of lower rates. Because a competitive procurement process would allow ratepayers to reap the benefits of the lower

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[41] WPTF/DDAC Opening Brief at 4.

prices, TURN recommends we reject the fixed PPA price and adopt a competitive procurement process instead.

DRA also proposes that PG&E's program be modified to include cost-competitive PPA solicitations. Specifically, DRA recommends that instead of creating another renewable energy PPA solicitation process, the Commission adopt a PPA solicitation process similar to the market-based pricing mechanism, or Renewable Auction Mechanism , proposed by Energy Division Staff in Rulemaking (R.)08-08-009.

In response to the above objections to the fixed price PPA, PG&E argues that if PPA price is not fixed, several aspects of the program including project selections, contract negotiations, execution, and approval process could become more difficult and contentious and result in delays for the program. Furthermore, PG&E asserts that there is a probability that without a fixed price, projects would focus on seeking opportunities to cut costs for the purpose of the bid rather than maximizing the viability of the projects, even though those measures could threaten the long-term viability of the projects.[42] Thus, PG&E argues that the proposed fixed price PPA is what it will reasonably cost in a competitive market to build viable, small and mid-size PV facilities.

5.3.2. Discussion

We will not adopt a fixed price PPA as proposed by PG&E, because it has several shortcomings and there is a risk that paying a fixed price for PPAs could result in higher prices for PPA contracts and lead to overpayment by ratepayers. Furthermore, given that the price proposed by PG&E is derived from an estimate

[42] PG&E Reply Brief at 26.

of solar system costs that are likely to change, we do not feel it would reasonable to adopt this as a basis for the price offered to PPA projects. Instead, we adopt a competitive process for the PPA selection. As we have previously stated our preference for a competitive procurement process, this approach will ensure that this program achieves its objectives at the lowest cost to ratepayers.

Many parties raise concerns with using a fixed price PPA and suggest replacing it with a competitive process. The major criticism of the fixed price approach is that it does not result in the best prices for the ratepayers, as would a competitively-based price. This view is shared not only by those who support the PG&E's PV Program proposal, but also by others who oppose it.

DRA, while urging the Commission to deny the application, stresses that if the Commission were to approve the program, it should require competitive price bidding for the PPA portion to protect ratepayers.[43] Greenlining expresses a similar concern regarding the application and states that "the Commission should not approve a pricing scheme that forgoes savings achievable in a fully competitive market."[44] The Solar Alliance, while supporting the application, recommends a competitive procurement process. WPTF and DACC also suggest the Commission reject PG&E's fixed price approach in favor of truly competitive RFOs in order to attain the best possible price.

At the heart of the concern raised by various parties regarding the fixed price approach for the PPAs is the notion that the benefits that might be achieved through meaningful price competition will not accrue to ratepayers under this

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[43] Exhibit 101 at 24.

[44] Greenlining Opening Brief at 9.

approach. Furthermore, our ability to administratively determine the "right price" that will both encourage projects to come online while also ensure that ratepayers pay no more than they would have otherwise for the same product, is fundamentally limited. As already explained earlier, the market for solar is changing rapidly. The fixed UOG price PG&E proposes is based on an estimate of PG&E's cost for building PV projects and the result of several assumptions specific to utility ownership. These assumptions also introduce significant uncertainty particularly in future years. In addition, as witness Jeung suggests "A number of factors impact projects economics, including location, equipment prices, labor costs, and transmission costs."[45] Thus, there is no basis for adopting a fixed price for projects that not only could vary in size, but also would have different characteristics, including ownership. These project-specific attributes and associated costs are best sorted out via a competitive process where each project's specific circumstance is considered and reflected in its bid.

Second, accepting that the UOG price is a reasonable estimate for what it would cost the utility to develop these projects, PG&E has not provided a clear justification for why the same price would also be reasonable for PPAs. As TURN correctly points out, several factors including lower costs of capital could enable third party developers to offer PPAs at prices below the forecast of UOG. Under PG&E's fixed price PPA, however, the financial benefits of potentially lower third party costs cannot be realized by ratepayers. Finally, there is no reason why PG&E cannot use a competitive price and still select the most viable

[45] Exhibit 4 at 3-2.

projects.[46] The PV PPA evaluation process will be similar to the process used in the RPS RFO evaluation and will include a number of criteria, including project viability. The same evaluation process and steps as described in PG&E's testimony for the fixed price PPA could also be used for the PPAs with the competitive price. PG&E's concern that if the PPA price is not fixed it could impede the focus on selecting projects with the highest viability is not valid, because a viability assessment would remain as a factor in the selection of the projects even with competitive price added as a criterion. In other words, although it is true that adding a new criterion could change the selection process, it does not follow that it will necessarily result in selection of less viable projects. Additionally, we disagree with PG&E's contention that a competitive process engenders additional complexity and will result in delays. These matters can be addressed by adopting a non-modifiable standard contract as well as specific deadlines for when winning projects have to be online.

We also decline to adopt DRA's proposal to incorporate the PPA solicitation into the Reverse Auction Mechanism (RAM) that is being considered in R.08-08-009. We may reconsider whether to incorporate the PV Program solicitation with RAM at a future date, depending on the outcome of the RAM proposal.

With regard to projects sized 1-3 MW, we do not adopt Solar Alliance's proposal that projects in this size range receive an administratively determined price rather than going through a competitive solicitation. No compelling

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[46] In fact, the Commission recently implemented the competitive procurement portion of SCE's Solar PV Program, which includes rigorous eligibility and project viability screens. See Resolution E-4299.

arguments have been presented that suggest that these projects offer substantially different benefits than those offered by the other projects that would be eligible under this program and so we see no reason to accord them special treatment. This program is a means to an end, namely the expeditious deployment of solar facilities to help fulfill the state's renewable energy mandates. In our view there is not sufficient evidence on the record to believe that the smaller projects the Solar Alliance is concerned with are necessarily more effective at achieving this aim, or so much more so as to justify potentially higher costs to ratepayers to support their deployment. Therefore, we believe they should compete alongside other eligible projects. To that end, we reject Solar Alliance's proposal.

Finally, we agree with TURN that PG&E should provide information to potential bidders in the solicitation indicating preferred locations to interconnect. This information could assist project developers to secure suitable locations to minimize the risk of facing unforeseen interconnection costs. In providing this information, PG&E should identify preferred locations on the grid where the deployment of DG could help address anticipated peak load growth or help congestion.

Finally, we shall also require PG&E to enlist the services of an independent evaluator to assess the overall fairness and robustness of the solicitations PG&E holds for PPA projects. This is consistent with the approach taken in the RPS program, as well as what we have adopted here in the context of PG&E's solicitations for turnkey and EPC contracts under the UOG portion of the PV Program. PG&E shall provide the IE reports regarding the PPA project solicitations it has conducted in its annual program compliance report to the Commission.

Consistent with PG&E's requested approach to cost recovery, the costs of energy procured from IPP projects shall be recovered through ERRA pursuant to standard Commission practice.

6. Applicable Commission Decisions and Statutes

6.1. Parties' Positions

Most parties agree that AB 920 does not impact the PV Program. However, DRA urges the Commission to consider PG&E's need for additional RPS resources through PV Program given that both SB 32 and AB 920 will increase the amount of RPS energy that PG&E will be obligated to purchase.[47] In DRA's view, purchases under AB 920 and the "must take" obligation under SB 32 would significantly increase the amount of RPS energy for PG&E, thereby reducing PG&E's RPS obligation to procure additional renewable resources.

DRA also recommends that the PV Program be limited to facilities greater than 3 MW to avoid overlap with SB 32, which also targets facilities up to 3 MW.

PG&E believes neither AB 920 nor SB 32 materially conflict with the PV Program. In PG&E's view, the PV Program is different from AB 920 in that under the PV Program none of the power may be used to offset onsite load, whereas under AB 920 PV facility's outputs must be used to offset the customer's onsite load.[48]

PG&E also believes SB 32 does not conflict with the PV Program, because facilities targeted by the PV Program would likely not want to participate in the FIT. PG&E suggests the price offered under SB 32 may not be adequate to attract

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[47] DRA's Supplemental Briefs at 3.

[48] PG&E's Supplemental Briefs at 4.

new investments. In addition, PG&E believes implementation of SB 32 will likely be on a different schedule from the PV Program.[49]

TURN echoes the view that AB 920 does not conflict with the PV Program, but believes gaming could occur between SB 32 and the PV Program to the extent prices offered under the two programs are different. TURN contends price differential could create a situation where a minimum price guarantee and an opportunity to speculate on higher prices through a competitive process exists.[50] TURN's primary recommendation is to limit PG&E's PPA program to projects greater than three MW to eliminate any potential conflicts between the two programs.[51] CUE also supports excluding one to three MW projects from the PV Program.

CALSEIA disagrees with TURN and cautions the Commission against relying on TURN's argument. CALSEIA maintains that TURN's argument is based on the assumption that the pricing under SB 32 and the PV Program will be significantly different. Such an assumption in CALSEIA's view is speculative because the Commission has not yet determined a price for SB 32.[52]

The Solar Alliance and CFC also believe SB 32 and AB 920 do not impact PV Program. CFC, however, appears to be suggesting the Commission compare the PV Program to SB 32 and AB 920 by listing some of the elements of SB 32 and AB 920 as guidance.

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[49] PG&E's Supplemental Briefs at 2.

[50] TURN's Supplemental Briefs at 1.

[51] TURN's Supplemental Briefs at 4.

[52] CALSEIA's Supplemental Briefs at 2.

CFC also argues that PG&E's application is contrary to law because it asks for an order concerning the method of recovery of costs of new construction before the plant is built.[53] CFC refers to Pub. Util. Code § 454.8 ("Recovery of costs of new construction") and states that the Commission cannot decide the method for recovery of the costs of new construction until after it finds the plant is used and useful to the public. CFC also asserts that the PV Program will not be in compliance with Pub. Util. Code § 454.4 (c)(3), because PG&E will not be buying renewable energy through the renewable energy procurement process. According to CFC, only PPA contracts that are submitted as part of the procurement process would be in compliance with § 454.5 (c).

6.2. Discussion

AB 920 allows net energy metering customers with projects of up to 1 MW to sell any excess electricity they produce over the course of a year to their electric utility at a rate to be determined by the Commission.

Most parties believe that AB 920 does not have an impact on the PV Program because the two programs are different. We share this view. A major difference between the two programs is that PV facilities under AB 920 are required to use the power to offset on site load while under the PV Program no such requirement exists. Thus, we can reasonably conclude that the facilities that participate in AB 920 are not likely to participate in the PV Program. As such, the two programs do not conflict with each other.

The impact of SB 32 on the PV Program, however, is more complicated. SB 32 increases the size of generation facilities eligible for California's feed-in

[53] CFC opening Brief at 26.

tariff program from 1.5 MW to 3 MW, and raises the program's statewide cap from 500 MW to 750 MW. SB 32 also establishes the payment to eligible projects at a price based on the market price referent adjusted to include all current and anticipated environmental compliance costs subject to a ratepayer indifference test. A major concern expressed by the parties with respect to the impact of SB 32 on the PV Program is the potential for forum shopping. Parties are concerned that if prices under SB 32 and the PV Program are significantly different, projects will gravitate toward whichever program offers the greatest value. This can create a situation where projects that would have moved forward at a lower price may receive a higher price by electing to participate in one forum versus the other. PG&E contends that SB 32 price is unlikely to be significantly higher. Further, PG&E asserts that the SB 32 implementation timeline is uncertain. CALSEIA echoes the concern about the implementation timeline and further contends that parties' concern about price differential is speculative at this point since the Commission has not established a price for SB 32.

CALSEIA is correct that the Commission has not presently implemented SB 32, thus SB 32 prices are unknown. Given that the Commission has not yet implemented SB 32 and it is unclear at this point if the price the Commission ultimately develops will be sufficient to drive deployment of projects in the one to three MW size it seems premature to preclude such projects from participating in PG&E's proposed program. We are loathe to exclude projects that may be able to successfully compete in a solicitation because of speculative concerns that such a project might receive a higher price than what it would be offered under SB 32, assuming of course that whatever price is developed in the context of SB 32 is adequate to drive deployment. Therefore, we do not, at this time, find it reasonable to exclude projects and projects sizes that may ultimately be eligible

to participate under the SB 32 mandated feed-in tariff from the PG&E program we authorize here.

We recognize that the jointly submitted standard PPA proposed for this program, and discussed in more detail below, was specifically intended for projects greater than three MW. To ensure that sellers in the one to three MW size range can participate in the program, PG&E shall file a standard contract for these smaller projects with its Tier 3 advice letter ordered herein within 30 days of the effective date of this decision.

With respect to CFC's claim that PG&E's application is contrary to law, Pub. Util. Code § 454.8 states that:

> In any decision establishing rates for an electrical or gas corporation reflecting the reasonable and prudent costs of the new construction of any addition to or extension of the corporation's plant, when the commission has found and determined that the addition or extension is used and useful, the commission shall consider a method for the recovery of these costs which would be constant in real economic terms over the useful life of the facilities, so that ratepayers in a given year will not pay for the benefits received in other years.

It appears that CFC relies on the language in the statute to support its claim that because PG&E has not built the new facility and the Commission has not found the plant to be used and useful, the Commission cannot establish a cost recovery mechanism for the new plant. Nothing in Pub. Util. Code § 454.8 prohibits the Commission from establishing a cost recovery mechanism for an approved utility investment before the plant is built. The only requirement in Pub. Util. Code § 454.8 is that when the Commission considers a cost recovery mechanism for a new plant that is used and useful, it would consider a mechanism that would allow the cost be distributed over the useful life of the

facility so that ratepayers only pay for the benefits received in that year. CFC's interpretation of the Public Utilities Code is therefore inaccurate.

CFC claims that PG&E has failed to demonstrate that its PV Program complies with least-cost and best-fit (LCBF) principles and therefore its application should be rejected. Such an analysis is not required at this time. Section 399.14 requires PG&E to include LCBF analysis in its renewable energy procurement plan (Procurement Plan) filed with the Commission. Accordingly, PG&E shall amend its 2010 Procurement Plan to include its PV Program. The Commission will then review contracts executed under the PV Program for consistency with PG&E's approved Procurement Plan and compliance with all other relevant RPS procurement requirements.

7. PV Program Size and Schedule

7.1. Parties' Positions

PG&E originally proposed to develop UOG projects at about 50 MW annually. PG&E contends that the 50 MW per year target would be a manageable project load for developing UOG projects from one to 20 MW in size. For the PV PPA, PG&E proposed to hold annual solicitation for up to 50 MW from 2010 to 2014 and if less than 50 MW is awarded in a given solicitation, the remainder megawatts would roll over megawatts to the following year's solicitation.

The Solar Alliance and CALSEIA propose a declining schedule with 100 MWs of PPAs in the first year, 75 MWs in the second year, 50 MWs in the third year, and 25 MWs in the fourth year of the program.[54] The Solar Alliance

[54] This proposal was jointly offered by the Solar Alliance and CALSEIA.

contends that front-loading the MWs would be an effective approach to ensuring that the entire 250 MW of the PPA program will be built.

In response to CALSEIA and Solar Alliance's proposal to front-load the MWs, PG&E endorses the concept but recommends a slightly different schedule. PG&E suggests 75 MWs each in the first and second year, and 50 MW each in the third and fourth year of the program, with the fifth year as the "clean-up"" for contract failures.[55] PG&E asserts that this schedule would allow an opportunity to take advantage of future price reductions in PV facilities and also new technologies to develop and bid into the last year of the program.

DRA also proposes that the program be scaled back to half its size to provide ratepayer protection. DRA disputes PG&E's claim that the full size of the program is needed to achieve economies of scale.

TURN proposes to consider reallocating the MWs between the UOG and PPAs after two years.

Regarding the proposal for a two-year evaluation of the allocation between the PPA and UOG portion of the PV Program, PG&E responds that a two-year check point would create uncertainty for bulk purchases as well as administrative costs that ratepayers will have to bear. PG&E argues that some PPA projects may not be fully developed by the end of the two year term. Thus, a comparison between UOG and PPA projects under such circumstance would not be useful. Finally, PG&E argues that a two-year program check will be unnecessary because a program review is intended at the end of the 5-year of the

[55] Exhibit 4 at 3-5.

program when results for both the UOG and PPA portions of the PV Program will be available.

7.2. Discussion

We adopt the PV Program for 500 MWs. PG&E will be authorized to build up to 50 MW of PV UOG and solicit up to 50 MW of PPAs annually, subject to carryover/dropout provisions described below. We note that this adopted deployment schedule does change the estimated average capital cost, before contingency, from what PG&E provided in testimony. PG&E estimated a weighted average capital cost of $3,831/kW, which was based on a deployment schedule under which 25 MW would be deployed in 2010, 50 MW in each of years 2011, 2012, and 2013, and 75 MW in 2014. Under the adopted schedule, because 25 MW will be shifted from the last year of the program, when costs are expected to be lower, to the first year of the program, where costs are expected to be higher, this increases the weighted average capital cost to $3,920/kW before contingency.

We reject both PG&E's revised, and CALSEIA and Solar Alliance's proposed schedules to front load the MWs for PPAs. Neither has presented a convincing argument why front-loading the MWs would be beneficial. In our view, front-loading the MWs would not enable the program to take advantage of future price reductions that could become available due to technological improvements or new developments in the market. As PG&E recognizes "there may be cost effective technologies that can participate in later solicitations that do not exist today."[56] One of the key reasons for an annual solicitation would be

[56] Exhibit 1 at 3-3.

to enable the program to take advantage of additional choices as technology evolves and new companies entering the market. As the above comments suggests, if the program was front-loaded, these potential savings would be forgone as fewer MWs would be left to participate in the future years of the program. Furthermore, as the Solar Alliance has noted, any specific schedule may be somewhat arbitrary.[57] Given these considerations, we will adopt the schedule for an annual solicitation of 50 MWs for PPAs. For the same reasons, we will adopt a 50 MW per year for the UOG portion of the PV Program. We also allow PG&E to accrue unbuilt MWs from a given year to the next year. In other words, if PG&E elects to build less than the authorized annual capacity, or if the PPA solicitation results in the selection of less MW than allotted, the remaining MWs for that year will be added to the next year's solicitation. This will ensure that ratepayers will receive the benefits of potential price decreases in the future.

A different, but related issue concerns the treatment of dropouts, defined here as projects/capacity that were either selected through a solicitation or which PG&E has indicated its intent to develop, but that for various potential reasons, do not come online within the required timeframe. In the interest of helping ensure the program fulfills its overall capacity objectives, any projects and associated capacity that drops-out over the course of the program should be added to the authorized capacity that can be developed in the next available solicitation. This accrual of drop-outs should occur through the last solicitation of the program.

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[57] Exhibit 1100 at 5.

Regarding the size of the PV Program, we are not convinced that DRA's proposal to reduce the program size by half is warranted. First, as discussed earlier, we believe ratepayers are adequately protected against high costs through the competitive processes PG&E will rely on to select both UOG and PPA projects, the requirement that PG&E involve an Independent Evaluator in conducting all of its solicitations, and the adoption of a revenue requirement which, if exceeded, will trigger a reasonableness review for recovery of UOG project costs. For the same reasons we also reject TURN's proposal to reevaluate the allocation of the MWs between UOG and PPAs based on a determination of which is cheaper. Adoption of such an approach would create significant uncertainty and could delay deployment of systems under this program. Second, as DRA acknowledges, there is a lack of analysis in this record as to "(a) what aspects of PG&E's programs might enjoy economies of scale, and (b) what effects changing the size of the program would have on the economies of scale."[58] Without a proper analysis, it would be difficult to draw a conclusion about how much reduction, if any, in the program size would be appropriate.

We reject PG&E's proposal to suspend or scale back the PV Program without Commission authorization. While there may be factors that could justify termination of the PV Program, PG&E will be required to file an advice letter demonstrating the need to do so.

Finally, in its proposal, PG&E indicated that although its UOG program would focus primarily on ground-mounted projects from one to 20 MW in size, it wished to reserve the ability to pursue some projects less than 1 MW and some

[58] DRA's reply Brief at 4.

roof-mounted projects. Given the approaches adopted to ensure price reasonableness, we find allowing PG&E to pursue some limited number of smaller projects and/or roof-mounted projects reasonable. To that end we will allow PG&E to deploy projects less than 1 MW in size as well as some roof-mounted projects, provided that in aggregate these projects represent no more than 5% of the total UOG capacity authorized under this program. To avoid potential conflicts with the CSI, PG&E shall not develop projects on locations that have sufficient onsite load to participate in the CSI program. This is consistent with the comments of the Solar Alliance and Vote Solar on the APD, and what we required of SCE in implementing its SPVP.

8. Cost Caps and Performance Mechanisms

8.1. Parties' Positions

Several parties have recommended that the PV Program cost recovery be contingent upon certain level of performance of the UOG facilities and shareholders share some of the cost savings or cost overruns with ratepayers.

TURN believes PG&E should be accountable for the cost estimates and the performance of its UOG PV facilities similar to requirements in the PPAs. TURN recommends that we establish a levelized cost of energy based on the proposed costs estimates as an overall cost cap for the UOG projects. TURN also recommends a performance mechanism to link cost recovery of PG&E's UOG facilities to the performance of the facilities by assessing a penalty if deliveries fall more than 10% below the initial forecast. TURN believes this would create an incentive for PG&E to select the most cost – effective projects and take all

appropriate actions to properly operate and maintain them. Thus, TURN argues, it protects the ratepayers.[59]

DRA also proposes an 80/20 cost/share mechanism between ratepayers and shareholders with costs overruns above 20% to undergo a reasonableness review. CARE also supports a cost sharing mechanism. DRA suggests that the Commission conduct a reasonableness review of PG&E's capital expenditures and O&M costs after the fact in PG&E's GRC.

PG&E does not believe it should be subject to any performance guarantee or cost sharing mechanisms. It argues that a performance guarantee mechanism would be unfair to PG&E because PG&E would not have the benefit of better-than expected performance of the facilities while it could bear the risk if facilities underperform.[60] PG&E also opposes the cost sharing mechanism as proposed by DRA and CARE, arguing that such an approach is inconsistent with traditional cost-of-service ratemaking where the Commission initially determines the costs and later will have an opportunity to decide if additional costs are reasonable.

In comments on the APD, Solar Alliance/Vote Solar dispute the necessity of establishing a price cap for the PPA portion of the program, arguing that because the APD relies on a competitive solicitation to determine the price cap is unnecessary. They further argue that the methodology used to set the cap is flawed in that it is derived from bids into the 2009 RPS solicitation of projects 20MW or less, which, as the APD itself notes, is generally oriented toward

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[59] TURN Opening Brief at 8.

[60] Rebuttal testimony at 11.

projects of a much larger scale than those being pursued under PG&E's proposed program, and as such, seems an odd choice to use for determining a price cap.[61]

8.2. Discussion

To ensure price protection for ratepayers, we adopt a cost cap as recommended by TURN for the maximum price ratepayers should pay for energy procured under the PV Program through PPAs. In the APD as issued, the price cap was to be based on an average price derived from bids submitted in PG&E's 2009 RPS solicitation for projects of 20 MW or less. While we continue to believe a price cap should be imposed to protect ratepayers, we agree with Solar Alliance/Vote Solar that reliance on RPS bids is problematic. In lieu of that approach, we will instead set the cap using the feed-in tariff price PG&E derived from it costs estimates for the UOG portion of the program. Although PG&E's cost estimate and resulting feed-in tariff price is imperfect, we believe this price can serve as a reasonable cost cap for the PPA side of the program. This amount is $246 per MWh, before application of time of delivery factors. Because we anticipate a relatively robust response to the solicitation, we expect the actual prices to be lower than this amount.

With respect to DRA's proposal for a reasonableness review, we believe the approach we have established herein for the UOG portion of the program is consistent with this approach sufficiently protects ratepayers from the risk of overpayment by subjecting PG&E to a reasonableness review should the capital costs of the program exceed the adopted revenue requirement. Furthermore, because PG&E will be relying on a competitive process for turn-key and EPC

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[61] Solar Alliance/Vote Solar, Opening Comments on APD, pp. 6-9.

contracts and passing only actual costs on to ratepayers, we believe the risk of excessive costs is greatly reduced. Nor do we adopt a performance guarantee mechanism. We believe the utility is already well-motivated to maximize system performance because of the contribution these facilities are expected to make to PG&E's RPS goals. Under the RPS, compliance is assessed on the basis of energy deliveries. Thus, the value of these facilities in helping PG&E meet its RPS is goals is directly related to these facilities' output. We do, however require that PG&E file an annual compliance filing in this proceeding with results of the PPA solicitation and UOG costs, as well available data regarding the all-in levelized cost of energy from projects that actually come online on both the UOG and PPA side of the program. This information will allow the Commission to compare the costs of the UOG and PPA projects and better understand the impacts of the program on the solar market. PG&E shall file annual compliance reports with the Energy Division.[62] The annual report prepared by PG&E shall include the information outlined in Appendix A.

9. PV PPA Contract Forms

On August 21, 2009, PG&E along with the Solar Alliance, Vote Solar Initiative, and CALSEIA submitted a form PPA for projects greater than 3 MW to 20 MW. They refer to this proposal as the Large Project PPA. The Large Project PPA replaces PG&E's original proposal which was submitted on June 19, 2009. The Large Project PPA does not contain pricing or the process for solicitation of projects. There is no agreement on a form contract for projects 3 MW and less.

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[62] The first annual compliance report will be due a year from the effective date of this decision.

9.1. Parties' Positions

DRA recommends PG&E's and the Joint Solar parties' proposed standard Large Project PPA be rejected. DRA asserts that neither DRA nor any other consumer advocate parties participated in PG&E's and the Joint Solar Parties' settlement negotiations to form the proposed Large Project PPA form. As a result, DRA contends that only sellers (i.e., the Joint Solar parties) would benefit from the negotiated contract at the expense of ratepayers.[63] DRA suggests consistent with the Energy Division Staff RAM proposal, the Commission adopt the AB 1969 feed-in tariff (FiT) contract with a few additional terms. For projects between 10-20 MW, DRA recommends that PG&E file a Tier 3 Advice Letter proposing changes to the RPS pro-forma agreement.[64]

CFC also opposes the Large Project PPA. CFC contends that the Large Project PPA as proposed has shifted risks and costs from solar developers to PG&E's customers and "in most cases, the changes increase the cost of purchased power to be paid by customers."[65] Specifically, CFC expresses concern with terms and conditions concerning the Compliance Costs Cap, Guaranteed Production, Modification to Contract Quantity, Project Security, Pollution and Earthquake Insurance objects and Fixed Price.[66]

CUE argues that the Large Projects PPA does not represent the interests of workers and specifically advocates that the PPA should require the independent

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[63] DRA Opening Brief at 12.

[64] DRA Opening Brief at 12.

[65] CFC Opening Brief at 22.

power producers to: (1) hire only state-licensed electricians to perform electrical work; (2) invest in existing training infrastructure by requiring suppliers to hire apprentices enrolled in state-certified apprenticeship programs; and (3) pay construction workers the prevailing wage rate. CUE argues that while these terms are not required by state law, they serve important policy objectives of improved production efficiency, higher quality work product, continuity of a skilled workforce, and a guarantee that workers will receive fair wages and benefits such as health care.[67]

In response, PG&E asserts that the PPA forms "equitably allocates risk between independent developers of PV facilities and PG&E, acting on behalf of its customers, because it was an agreement reached in an arm's length negotiation between a number of parties representing competing interests."[68]

9.2. Discussion

We adopt a modified standard PPA for the PPA portion of the PV Program. We understand DRA's concern that no consumer advocate groups were present during negotiations to form the proposed Large Project PPA form. Nonetheless, we find it reasonable to adopt a modified standard contract for PPAs for this program. As TURN has stated, a standard contract would provide some modest level of development security.[69] A modified PPA will be in

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[66] We note that CFC's Opening Brief appears to refer to an old version of the Large Project PPA and contains several errors. The correct version of the Large Project PPA is Exhibit 13.

[67] CUE Reply Brief at 13.

[68] PG&E Opening Brief at 19.

[69] Exhibit 800 at 5.

ratepayers' interest because it will expedite the negotiation and commission approval of PPAs and could attract more sellers to participate in the solicitation. It will also reduce the administrative costs associated with contracting for individual PV projects due to less review and documentation requirements.

Modeling the standard contracts on the existing RPS standard contracts seems reasonable and we agree with most of the revisions to tailor the RPS standard contract to this program. However, we make a number of revisions to the Large Project PPA to minimize ratepayers' risk exposure.

First, we adopt the proposed compliance cost cap with modifications.[70] We agree with Solar Alliance that complying with changes in law and regulatory requirements may be difficult to quantify and as such may pose additional risk to the project financing. Having certainty in contract terms and obligation not only helps with securing project financing, but also gives the seller an increased ability to offer better prices. We find it is reasonable to identify a limited liability for these costs in order to facilitate financing. Therefore, we adopt the proposed compliance cost, and require that section 3.1(o) be modified to clarify that it would only apply to costs due to changes in the law that occur after the execution of the contract. We make another revision to the Compliance Cost Cap provision and require PG&E to seek Commission authorization through an advice letter prior to making any payments above the cap to ensure that such costs are reasonable. CFC's concern with the compliance cost cap is that PG&E's

[70] The compliance cost cap applies to a seller's costs associated with complying with several regulatory certifications and requirements as described in Section of the Large Project PPA. The compliance cost cap is cap on total costs over the term of the agreement not to exceed $20,000/MW. CFC's brief incorrectly refers to an old version of the proposed Large Project PPA.

ratepayers could be responsible for any compliance costs that exceed the Compliance Cost Cap. PG&E explains that the Large Project PPA does not require that PG&E pay any cost that exceeds the cap. PG&E asserts that it would first assess whether the costs were commensurate with the value of the contract. We believe this is a reasonable measure to ensure that ratepayers are not automatically subject to costs above the cap. We require PG&E to seek Commission authorization through an advice letter prior to making any payments above the cap to ensure that such costs are reasonable. PG&E witness Jeung testified during hearings that major new compliance costs are less likely to occur because compliance rules are generally well established up front. No party has identified a scenario which would indicate that the PV projects are likely to be subject to higher compliance costs or that the compliance cost cap amount is unreasonable. With the above modification, we are comfortable that the risk exposure to ratepayers is low.

With respect to the guaranteed energy production provisions, the Large Project PPA lowered the performance requirements for a seller from an average of 160% of the expected generation over a two year period to 140%. The 160% is an existing provision in the RPS pro forma and standard contracts. CFC asserts that lowering the performance requirements will increase the likelihood that PG&E will need to acquire replacement power at a higher cost to PG&E's customers.

Although we disagree with CFC's analysis, because PG&E did not provide a specific justification for this change, we do not modify the 160% requirement. In conjunction with the lower general performance requirement, the Large Project PPA also proposed lower performance requirements to cure a performance default in a prior two year period. We reject this proposal as well

and require PG&E to employ 90% which is its standard pro forma provision concerning this issue. Accordingly, the Guaranteed Energy Production will be 160% and the Guaranteed Energy Production Cure will be at 90%.

Regarding the contract capacity provision, the Large Project PPA includes an option for the seller to reduce the contracted for capacity of its project in the event it fails to meet delivery requirement set forth in the PPA. Specifically, the Large Project PPA provides that a seller having failed to perform according to the delivery requirements in the PPA, may reduce its contract capacity to no less than 70% percent of the original contact capacity. In addition, if a seller opted to exercise this one-time option, it can avoid paying penalties for past performance shortages but will be required to meet delivery requirements throughout the remainder of the contract term (i.e., 160% of the expected generation over a two year period).

CFC characterizes this new provision as a way for sellers to avoid paying a penalty. PG&E explains in its reply briefs that providing this one-time option for sellers also benefits PG&E's customers because it will allow a project to continue operating and delivering without resulting in an event of default.

We agree that including this flexibility for this program strikes a reasonable balance between buyer and seller without necessarily imposing additional costs on PG&E's customers. Accordingly, the standard PPA may include the one-time option for a seller to reduce the contract capacity to no less than 70% percent of the original contract capacity.

With regard to development security, because the size of the projects in the PV Program is limited and because these projects would be developed over a fairly short time frame, we are comfortable with the lower project development

security amounts and the insurance provision proposed in the Large Project PPA.

With respect to CUE's request for PPAs to provide prevailing wage rates and other labor related requirements, we do not require such conditions, because the California Labor Code pertaining to prevailing wage does not apply to the projects under the PPA portion of the PV Program.

10. Additional Rate of Return

PG&E requests the rate of return (ROR) on rate base for the PV UOG Program be equal to its currently authorized ROR of 8.79 adopted in D.07-12-049 for 2008, plus one percent. PG&E claims the additional one percent is allowed pursuant to § 454.3 and by D.06-05-039 for renewable assets.[71] Alternatively, PG&E requests that if we find that Pub. Util. Code § 454.3 is not applicable, we grant the increase in the rate of return pursuant to § 454(a).

10.1. Parties' Positions

Greenlining opposes the additional rate of return adjustment, arguing that an increase in the rate of return would be justified only if the technology is experimental. Greenlining states that the PV Program relies on solar PV which "has been in relatively widespread use for the last three decades."[72]

CFC opposes the proposed increased rate of return addition for a different reason. CFC argues that D.06-05-039 allows an increase in the rate of return under Public Utilities Code § 454.3, however not without holding a hearing and determining that "the capital costs [of the facility], when added to its costs of

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[71] PG&E's Application at 7.

[72] Greenlining Opening Brief at 12.

operation and maintenance, result in a cost of electricity generated over the useful life of the facility less than that of electricity generated by existing facilities utilizing nuclear power or fossil fuel; and the facility is used and useful." CFC asserts "PG&E has offered no evidence which would support such a finding."[73]

10.2. Discussion

Pub. Util. Code § 454.3 in relevant parts provides that:

> The Commission may, after a hearing, approve an increase of from one-half of 1 percent to 1 percent in the rate of return otherwise allowed an electrical corporation on its electric plant for investment by the corporation in facilities meeting the following requirements: …
>
> (c) …The facility is experimental and is, in the determination of the commission, reasonably designed to improve or perfect technology for the generation of electricity from renewable resources or to more efficiently utilize other resources in a manner which will decrease environmental pollution from and lower the costs of the electricity generated.

This language was explicitly acknowledged by the Commission in D.06-05-039 at page 28:

> "a utility may build a renewable resource and, and under appropriate circumstances, earn between 0.5% and 1.0% increased rate of return on the investment. That is, the Legislature has authorized an increased incentive for utility ownership of renewable generation. We think IOUs should consider taking advantage of this law and, where reasonable and appropriate, we will authorize the increased rate of return."

[73] CFC Opening Brief at 27.

As we noted in D09-06-049, the sole purpose of the above statement was to signal to the utilities the availability of incentives for the utility-owned renewable generation under circumstances authorized by § 454.3. The decision did not automatically authorize an increased ROR for SCE's renewable projects, nor does it do so for PG&E's here.

Section 454.3 provides three categories under which projects would be eligible for additional return. The first and the second categories are irrelevant here. We therefore, consider whether the SPVP meets the requirement of § 454.3(c), quoted above.

Section 454.3(c) does not define the criteria for assessing whether a facility is experimental, however it does say that the facility is "designed to improve or perfect technology for the generation of electricity from renewable resources." PG&E's program is clearly not designed as a means of testing or refining a new generation technology. While the program may take advantage of new technologies as they become available, it is not intended to be a test-bed for experimental technologies. Furthermore, using it as such would be anathema to one of the fundamental rationales justifying this program, namely the relative certainty of deployment and operation the facilities to be deployed under this program offer relative to renewable resources procured under the general RPS program. Given this we do not believe this program fulfills the requirements or intent of 454.3(c).

PG&E asks that if we find that its request for a higher rate of return does not meet the criteria required pursuant to 454.3(c), that we authorize its request pursuant to 454(a). 454(a) requires that in order for a public utility to change "any rate or so alter any classification, contract, practice or rule, as to result in any new rate, except upon a showing before the Commission and a finding by

the Commission that the new rate is justified." In general we are not satisfied that PG&E has made a credible showing that a higher rate of return is justified in this instance. Furthermore, section 454(a) is intended to ensure that utilities do not change their rates without a showing and finding that the new rates are justified. However, rate of return adjustments are traditionally considered in a utility's cost of capital proceeding. We reject PG&E's request here.

11. Non-Bypassable Charge

PG&E requests recovery of any stranded costs associated with the PV Program through a non-bypassable charge.[74] PG&E believes it is allowed to recover the stranded cost associated with the PPAs over the entire term of the agreements. PG&E also believes it is allowed to recover the stranded costs associated with each UOG facility installed for a 10-year period following commercial operation of the facility.[75]

11.1. Parties' Positions

DACC/WPTF argues that the stranded cost recovery established in D.04-12-048 applies only to UOG acquired as a result of the procurement process specified in that decision. DACC/WPTF argues that PG&E has failed to comply with that process, therefore, if the PV Program creates any stranded costs, those costs should be borne by PG&E's shareholders not its ratepayers. In comments, PG&E argues that in rejecting its request to recover stranded costs via a non-bypassable charge (NBC) the APD as issued ignored Commission precedent. In its reply comments, DACC/WPTF reiterates its position that the Commission's

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[74] Exhibit 1 at 6-7.

[75] Exhibit 1 at 6-7.

policies regarding NBC's are inapplicable to this program and also argues that forcing DA customers bear stranded costs associated with this program is unfair to the extent that these customers already bear RPS costs given that Energy Service Providers (ESPs) have their own RPS compliance obligations, and furthermore, that customer migration to ESPs results in a reduced RPS compliance obligation for the IOUs.

11.2. Discussion

Based on comments and further reflection on this issue, we disagree with DACC/WPTF that the approach to stranded cost recovery established in D.04-12-048 and further developed in D.08-09-012 is not applicable to PG&E's Solar program. DACC/WPTF assert that the phrase "acquired as a result of the procurement process" in Conclusion of Law 16 of D.04-12-048[76] limits the applicability of the decision's findings regarding stranded cost recovery to circumstances where a competitive RFO was used to select the contracts or assets that may result in stranded costs. We disagree with this interpretation of Conclusion of Law 16. Had the Commission wanted to confine recovery of

[76] COL 16, in full states, "The utilities should be allowed to recover stranded costs for their non-RPS resource commitments from departing load over either the life of the contract or 10 years, whichever is less. The ten-year recovery period should also apply to any utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation. Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract. The utilities should be allowed the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years for their non-RPS resource commitments. Cost recovery for that portion of a resource acquired by the utilities to meet local reliability needs should be recovered from all customers."

stranded costs associated with UOG facilities to those procured under the competitive process as DACC/WPTF suggests, it could have easily stated so in the decision. The phrase "as a result of the procurement process" is not synonymous with "as a result of a competitive solicitation or RFO."

Therefore, we find that the direction provided by the Commission in D.04-12-048 is applicable to the stranded costs of the PV Program. D.08-09-012 further elaborated which customer groups would be subject to non-bypassable charges to recover stranded costs. Specifically, in that decision the Commission found that "the NBCs, which include any above market costs related to RPS contracts, will not apply to departed load that is excluded from the load forecasts used to the develop the IOUs' Long Term Procurement Plans. The excluded departing load includes municipal departing load, with the exception of large municipalizations, and CGDL. *DA and CCA load are fully subject to the D.04-12-048 NBCs* [italics added]."[77] Ordering Paragraph 1 of this decision is equally clear: "Decision (D.) 04-12-048 and D.06-07-029 non-bypassable charges (NBCs) shall be imposed on direct access (DA) and community choice aggregation customers, as well as new Western Area Power Administration (WAPA) departing load and split wheeling departing load customers."

In light of the forgoing discussion, we agree with PG&E that it should be allowed to recover any stranded costs associated with its Solar PV program pursuant to D.08-09-012 and D.04-12-048, including recovery of these stranded costs via NBCs from DA customers. Furthermore, in making arguments that subjecting DA customers to stranded costs associated with these facilities is

[77] D.08-09-012 at 56.

unfair given that ESPs face their own RPS compliance obligations, DACC/WPTF appears to be litigating issues here that are more appropriately considered in R.06-02-013 and/or through a petition to modify D.08-09-012.

12. Land Deposits

PG&E proposes to include the land deposits for future PV facility in Plant Held for Future Use (PHFU) in order to recover the carrying costs of these deposits prior to the operation of the PV facilities. PG&E plans to transfer the deposits to plant in service after the PV facilities start operation.

12.1. Parties' Positions

DRA opposes PG&E's land deposit proposal. DRA argues that although the Commission may allow a utility to earn a return on the cost of property, land deposits do not qualify for such recovery because they are not "property acquired.[78] In DRA's view, property is only acquired when the land is purchased. DRA is also concerned that "allowing PG&E to earn a rate of return on land deposits would create a perverse incentive for PG&E to put down numerous land deposits in order to pad its rate base, with no risk to its shareholders."[79] DRA urges the Commission to deny PG&E's request, but should the Commission allow PG&E purchases to be treated as PHFU, DRA proposes to limit the time that a property can be held for future use to 18 months, consistent with PG&E's claim of the timeframe for bringing PV projects on line. PG&E is opposed to this treatment, because in its view, it would restrict

[78] DRA's Opening Brief at 9.

[79] DRA's Opening Brief at 9.

its ability to make reasonable purchases for use in later phases of the UOG build-out.[80]

CFC is also opposed to PG&E's land proposal because PG&E has no firm plans for the use of land on which it will pay a deposit. CFC argues PG&E should not be allowed to hold such deposits in its PHFU account.[81]

In response, PG&E states that plants held in PHFU will be for building PV facilities. Therefore, it should be allowed to recover the carrying cost.

12.2. Discussion

We reject PG&E's proposal to recover the carrying costs of land deposits prior to operation of the PV facilities. The Commission allows utility property held for use at a later date to be included in PHFU based the Electric Uniform System of Accounts, Account 105. Paragraph B describes the PHFU as follows:

> This account shall also include the original cost of land and land rights owned and held for future use in electric service under a plan for such use, to include land and land rights: (1) Acquired but never used by the utility in electric service, but held for such service in the future under a plan, and (2) previously held by the utility in service, but retired from such service and held pending its reuse in the future under a plan, in electric service. (See Electric Plant Instruction 7.)

PG&E also describes PHFU as property acquired in advance for future utility use. Both definitions are consistent in that only utility owned land and land rights are eligible to be entered into PHFU. Land deposits prior to purchase of the land do not qualify as acquired or owned property per the above definition. Therefore, such deposits cannot be entered into PHFU. Only after

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[80] PG&E's Opening Brief at 32.

[81] CFC's Opening Brief at 29.

land is purchased pursuant to a plan for PV facility construction, it will become acquired property eligible for inclusion in PHFU account.

It is worth noting that even if land deposits were allowed as PHFU, in this instance, they would not be allowed as PHFU, because PG&E has not met the requirement to provide a plan on how these lands will be used if the PV Program is terminated and PV facilities are not constructed.

13. Pilot Project

We approve the proposed Pilot Project, but adopt the actual capital cost of the project instead of what PG&E has proposed. PG&E proposes to develop a pilot project of up to 2 MW prior to regulatory approval of this application. PG&E states that the Pilot Project will likely be on its land and is intended to expedite the development of the PV Program, demonstrate PG&E's commitment to the PV Program, and allow PG&E to refine internal and external processes needed to develop, permit, construct, and operate a PV facility prior to deployment of the larger PV Program.[82] We agree that given the scale of the overall solar program, as proposed and adopted, the pilot project is a useful undertaking. PG&E estimates the capital cost of the Pilot Project at $11.9 million.

During the hearing, PG&E's witness noted that PG&E has selected a bid for its Pilot Project. The ALJ directed PG&E to file a response to several questions regarding the solicitation process. PG&E submitted its filing on September 23, 2009.

A review of PG&E's response to the ALJ questions indicates that PG&E followed a competitive process for the development of its Pilot Project.

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[82] Exhibit 1 at 1-5.

Specifically, PG&E issued a request for information to several solar PV market participants and then issued a request for proposals to a shortlist of candidates that met specific criteria, including price, system performance and operating costs, developer experience, and ability to comply with standard contract terms and conditions, all of which are common to procurement of capacity and generally used in assessing bids. In light of this, we find that PG&E's selection of the Pilot Project through a competitive process was reasonable.

PG&E will be authorized to record the actual capital cost of the Pilot Project into its UGBA as of the effective date of this decision.

14. Comments on Proposed Decision

Comments on the APD were received from the following parties: PG&E, SCE, TURN, DACC/WPTF, DRA, SCE, IEP, CUE, CLECA, CARE, Solar Alliance/Vote Solar, CalSEIA, and Greenlining. Reply comments were received from the following parties: PG&E, CUE, TURN, DRA, DACC/WPTF, and Solar Alliance. We have considered parties' comments and changes in response to these comments are reflected in the decision.

15. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Maryam Ebke is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Although on a contractual basis PG&E has procured adequate renewable power to meet its 2010 RPS compliance obligations, using flexible compliance, it is unknown at this time the extent of any potential delay or contract failure that may impact these contracts.

2. New renewable projects and transmission additions face a variety of risk factors, including permitting and financing challenges that may result in contract failure or delays.

3. Smaller projects may avoid many of the risk factors that impede the timely development of larger scale renewable projects to the extent these smaller projects do not have the same land impacts, do not require the same level of project financing and permitting, and do not depend on large capacity transmission additions.

4. The output profile of solar PV largely coincides with periods of peak demand.

5. DRA's SWOT technique does not take into account some of the benefits of the small and mid-sized PV projects proposed by PG&E.

6. The PV Program will not conflict with the RPS program as it focuses on a subset of projects and technologies that cannot effectively compete in the RPS program as it is currently designed and implemented.

7. The final RETI Phase 1B Report identifies PV technology specifically as having significant potential for capital cost reductions in the future.

8. Allocating more capacity to earlier years of the program would not necessarily be beneficial given the dynamic nature of the solar industry and the possibility of future solar PV cost reductions.

9. The Commission has expressed its interest in utility proposals for utility-owned renewable projects.

10. Few renewable UOG proposals have come forward to date.

11. The PV Program as modified can help facilitate the expeditious deployment of renewable facilities including UOG projects that would not otherwise be selected through the existing RPS procurement process.

12. PG&E's engineering cost estimates are imperfect.

13. The CSI does not provide a good price comparison to the PV Program given the different deployment model and scale of projects pursued under that program.

14. SCE's SPVP, while generally reflecting projects of a smaller scale and deployment approach than the PV Program was approved by the Commission to pursue similar policy objectives as the PV program and so does provide a useful point of comparison.

15. Comparison to other UOG in other states does not provide useful information because it is unclear how analogous these programs are to PG&E's proposed program.

16. Projects of a comparable size and technology that have bid into the RPS program would provide the most reasonable comparison to the proposed PV Program.

17. Under the RPS program as currently implemented, smaller scale projects, while likely to offer greater viability and speed of deployment relative to large scale projects, are unlikely to be selected owing to their higher price, which may limit the extent to which smaller scale projects participate in the RPS program.

18. Bid prices in the RPS program are not necessarily reflective of the actual prices of projects that ultimately come online.

19. The utilities have submitted contract amendment requests to adjust the price of energy for a number of approved RPS projects upward.

20. PG&E's pilot project provides a reasonable upper bound for the cost of projects PG&E intends to pursue under this program as it involves the same technology and deployment approach albeit at the smaller end of the range of projects that would be eligible under the PV Program.

21. Though imperfect, PG&E's estimated price per kWh, derived from its estimates of UOG project costs, provides a reasonable price cap for PPA projects.

22. Because RPS compliance is measured based on renewable energy generation, PG&E is motivated to maximize the energy production from any renewable facilities it chooses to install.

23. A fixed PPA price may result in overpayment by ratepayers.

24. AB 920 does not overlap with the PV Program.

25. SB 32 could overlap with the proposed PV Program for projects between one1 and three MW.

26. The Commission has not yet implemented SB32 and it is not known at this time how the price the Commission develops will impact the deployment of projects between one and three MW.

27. The price of solar PV is anticipated to decline in the years ahead.

28. A price cost cap for PPA projects is a reasonable way to ensure that the costs of the solar PV Program are not excessive to ratepayers.

29. The revised Large Project PPA is reasonable.

30. Land deposits prior to purchase of the land do not qualify as acquired or owned property for recovery in PHFU account.

31. A pilot project is a useful undertaking given the scale of the approved program and the experience PG&E can gain from pursuing this project, as well as the cost information it provides.

32. PG&E conducted a solicitation process for the Pilot Project that includes criteria commonly used in bid selection.

Conclusions of Law

1. The modified PV Program has many benefits and can help meet the RPS goals and should be adopted.

2. PG&E should own, develop, install, operate and maintain up to 250 MW of solar PV projects up to 20 MW in size and procure 250 MW of solar PV projects up to 20 MW in size from independent solar energy providers.

3. A competitive solicitation should be used to determine which projects are selected and at what price for the PPA component of PG&E's program.

4. Because PG&E's capital price target is below the actual costs of its pilot project and furthermore is in line with what the Commission approved in SCE's SPVP, we believe it can serve as a reasonable basis for the overall revenue requirement for this program.

5. PG&E shall enlist the services of an independent evaluator to review the solicitations it conducts for both the PPA and UOG portions of its PV Program.

6. A price cost cap for PPAs will ensure that the costs of the PV Program are not excessive and should be adopted.

7. The revised Large Project PPA should be adopted with modifications.

8. PG&E should seek Commission authorization through an advice letter prior to making any payments above the compliance cost cap for PPAs to ensure that such costs are reasonable.

9. Because we anticipate market, technical and regulatory issues to arise over the course of the program that could have implications on its effective implementation, the program should be implemented in a manner that provides the flexibility to make changes in response to these issues as they emerge.

10. It is reasonable to expect the adopted standard PPA to require changes over time, for example to address a change in law or in order to respond to lessons learned as the program progresses.

11. The stranded costs resulting from PG&E's PV Program should be recovered pursuant to D.04-12-048 and D.08-09-012.

12. PG&E should not be allowed to include the land deposits for future PV facilities in its PHFU account.

13. PG&E's Pilot Project should be approved.

14. It is reasonable to authorize PG&E to record the capital cost of the Pilot Project into its UGBA as of the effective date of this decision.

15. PG&E's program does not meet the requirements of Pub. Util. Code § 454.3 necessary for the Commission to grant a higher rate of return.

16. The PV Program is consistent with Pub. Util. Code § 454.8.

O R D E R

IT IS ORDERED that:

1. The Photovoltaic Program set forth in Appendix A to this decision is approved.

2. Pacific Gas and Electric Company shall implement the Photovoltaic Program as set forth in Appendix A.

3. Pacific Gas and Electric Company is authorized to recover up to $1.45 billion in capital costs for the utility-owned generation portion of its Photovoltaic Program via cost-of service ratemaking as follows:

   a.) Pacific Gas and Electric Company may book the authorized revenue requirement in its Utility Generation Balancing Account.

   b.) Pacific Gas and Electric Company shall file an advice letter within 60 days of this decision to establish Photovoltaic Program Memorandum Account to track the difference between the estimated and actual capital costs of this program. Should actual capital costs exceed the authorized revenue requirement adopted herein, these excess costs shall be subject to a reasonableness review.

4. The authorized revenue requirement is based on a 250 megawatt (MW) program and a specific capacity price target as approved in this order. Should Pacific Gas and Electric Company develop fewer than 250 MW over the five year life of the program, the revenue requirement used to determine if a reasonableness review is necessary shall be pro-rata adjusted to reflect the reduced amount of deployed capacity.

5. Pacific Gas and Electric Company is authorized to recover its actual operations and maintenance costs in its General Rate Case, subject to a reasonableness review. In its filing for recovery of these costs, Pacific Gas and Electric Company shall consolidate all operations & maintenance costs incurred pursuant to this program and provide a specific breakdown of costs by activity area.

6. Pacific Gas and Electric Company is authorized to recover the costs of energy procured through power purchase agreeements entered into pursuant to the Photovoltaic Program in its Energy Resource Recovery Account.

7. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 3 advice letter with the Energy Division specifying the Photovoltaic Program implementation and administration details needed to implement the program set forth in Appendix A, including:

- Standard contract for facilities less than 3 MW in size;
- Competitive solicitation process and protocols, eligibility, and timeline for the power purchase solicitations;
- Criteria for evaluating conforming bids;
- Process for identifying preferred locations for project development to optimize the locational value of project sites, including impacts on neighboring lands;
- Generation system interconnection application process and protocols; and

- Confidentiality protocols to ensure that information given by developers to Pacific Gas and Electric Company through the interconnection or bidding process is not shared with Pacific Gas and Electric Company's staff working on the utility-owned generation of the Photovoltaic Program.

8. Pacific Gas and Electric Company is authorized to record the actual cost of the Pilot Project into its Utility Generation Balancing Account as of the effective date of this decision.

9. Pacific Gas and Electric Company may not enter land deposits for future utility-owned photovoltaic facilities into the account for Plant Held for Future Use.

10. Pacific Gas and Electric Company may recover stranded costs resulting from this program pursuant to Decision (D.) 04-12-048 and D.08-09-012.

11. Pacific Gas and Electric Company must seek Commission authorization through an advice letter prior to making any payments above the adopted power purchase agreement compliance cost cap.

12. Pacific Gas and Electric Company shall enlist the services of an independent evaluator to oversee the solicitation process and provide an assessment of the fairness and robustness of each of the solicitations it conducts pursuant to this program, for both utility-owned generation projects and power purchase agreement projects, and the degree to which these solicitations conform to the solicitation protocols.

13. Within 60 days of the closing date of each solicitation for power purchase agreements, Pacific Gas and Electric Company shall convene a program forum to identify program solicitation components that may need refinement. Based on the feedback received through these program forums, and in consultation with Energy Division, Pacific Gas and Electric Company may file a Tier 3 advice letter

seeking modifications to the solicitation component of the Photovoltaic Program adopted by this decision.

14. Pacific Gas and Electric Company shall file annual compliance reports with the Energy Division as described in Appendix A. The first compliance report is due on March 1, 2011. Pacific Gas and Electric Company shall include the independent evaluator reports regarding all solicitations conducted pursuant to this program over the reporting period with its annual compliance report.

15. The form power purchase agreement for projects greater than three and up to 20 MW, referred to as the Large Project Power Purchase Agreement, is modified as follows:

- Compliance Cost Cap (Section 3.1(o)) shall state:
  - Costs applicable to the Compliance Cost Cap are only those costs applicable under the term's definition (section 1.26) and are new costs associated with a change in law from the contract's execution date.
  - In the event compliance costs exceed the cap, Pacific Gas and Electric Company will first obtain Commission authorization to incur additional costs.
- Guaranteed Energy Production - (Section 3.1(e)(ii)(A)) shall be 160 percent as the performance metric, as set forth in Pacific Gas and Electric Company's renewables portfolio standard pro forma.
- Guaranteed Energy Production Cure (Section 3.1(e)(ii)(B)) shall be 90 percent as the performance metric, as set forth in Pacific Gas and Electric Company's renewables portfolio standard pro forma.

16. Pacific Gas and Electric Company may propose changes to the adopted power purchase agreement by Tier 3 advice letter and Staff may propose changes by issuing a draft resolution on its own motion. Such changes shall

apply on a prospective basis only to new contracts entered into subsequent to approval of any such changes.

17. Application 09-02-019 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX A
The Photovoltaic Program (PV Program) for Pacific Gas and Electric Company Adopted 2010

General Overview:

The Photovoltaic Program (PV Program) is a five-year program to develop up to 500 megawatts (MWs) of solar photovoltaic (PV) facilities in the range of one to 20 MWs in Pacific Gas and Electric Company (PG&E's) service territory.

Total Size of the PV Program:

500 MW

Utility-owned generation (UOG) Portion of the PV Program:

Size: 250 MW
Project Size: From one to 20 MW[83]
Location: Primarily ground-mounted in PG&E's service territory

Schedule[84]:

Year	2010	2011	2012	2013	2014
MW	50	50	50	50	50

[83] Projects below 1 MW and/or roof-mounted may be pursued but must not constitute more than 5% of the total authorized UOG capacity.

[84] If PG&E elects to pursue less than the amount of capacity authorized in a given year, the balance will be carried forward to the subsequent year.

Power Purchase Agreement (PPA) Portion of the PV Program:
Size: 250 MW
Project Size: From one to 20 MW
Project development timeline: 18 months
Location: Ground-mounted in PG&E's service territory.

Schedule:[85]

Year	2010	2011	2012	2013	2014
MW	50	50	50	50	50

Price: PG&E shall hold a competitive solicitation annually to select winning projects. The levelized cost of energy from any projects bidding into a PPA solicitation may not exceed $246/MWh.

Reporting:

PG&E shall file annual compliance reports with the Energy Division. The first compliance filing is due on March 1, 2011. PG&E shall consult with Energy Division to develop the format and content of the report. The annual report prepared by PG&E shall include, at a minimum, the following information:

Reporting on PPA portion of the PV Program

- Documentation of all solicitations issued for PPA projects;
- A description of all bids received from the PPA solicitations, including the name of bidder, location of project, bid price, and description of proposed facility

[85] Un-awarded MWs shall be added to next year's solicitation. PPA drop-outs, defined as projects that were selected via the solicitation process but which do not come online within the 18 month development timeframe, will be added to the next program solicitation.

(generating capacity, type of technology, annual average expected generation, interconnection point), and identification of winning bids;

- The total electrical output for all systems under PPAs that are currently selling electricity to PG&E, for each month of the previous year;
- A description of the project specific distribution and network upgrades and distribution and network upgrades generally needed to facilitate the PV PPA Program.

<u>Reporting on UOG portion of the PV Program</u>

- Documentation of all solicitations issued for UOG projects, including the criteria PG&E established to evaluate bids; a description of the short list of bids, including name of the bidder and final price in the agreement, a description of offer/facility (generating capacity, type of technology, annual average expected generation, interconnection point), and identification of winning bids;
- A description of all UOG facilities for which work has been initiated or completed in the previous year, including: capital costs, and operations and maintenance expenses, generating capacity, type of technology, annual average expected generation, description of the site (existing PG&E-owned land or newly acquired/leased, land/lease cost, proximity to substation), and progress toward completion;
- A calculation of the levelized cost of energy (LCOE) for each UOG facility that is completed and interconnected to the grid. This calculation shall include work papers showing actual amounts for all cost and electrical output entries used to calculate the LCOE;
- Electrical output by month for the previous year for each PG&E-owned UOG facility that is completed and interconnected to the grid; and
- A description of the project specific distribution and network upgrades and distribution and network upgrades

generally needed to facilitate the PV PPA Program. The known or projected costs of those upgrades, associated with interconnecting each UOG facility, including all distribution and network upgrades, a listing of the UOG projects identified as triggering the need for network upgrades, and identification of the UOG projects implemented notwithstanding the need for network upgrades, and the cost of those network upgrades.

(END OF APPENDIX A)