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California Energy Commission
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Sacramento, CA 95814-5512

Re: 2011 Integrated Energy Policy Report: Comments of Pacific Gas and Electric Company on the Staff Draft Report *Renewable Power in California: Status and Issues*

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC") Staff Draft Report *Renewable Power in California: Status and Issues.* This comprehensive document contains an incredible amount of information on California's past and current efforts to increase the amount of renewable power delivered to customers, along with identification of the challenges we face in achieving our clean energy future. Recommendations for addressing those challenges are also set forth. The well-balanced report covers the range of issues from transmission, permitting, financing, cost, resource development, research and development, governance, along with other topics, and demonstrates that much progress has been made in the less than 10 years since California's first Renewables Portfolio Standard ("RPS") law was passed. Our focus going forward should be to leverage those "lessons learned" to expand the renewable resources available to California's energy users, while balancing the costs to customers. Balanced policies that ensure system reliability, protect the environment, and result in more renewables at a reasonable cost to customers will be critical to ensuring California's clean energy leadership is sustainable and achieves the desired results of creating jobs and reducing greenhouse gas emissions.

PG&E's comments focus on recommendations for implementing future renewable programs, including Governor Brown's proposals calling for 12,000 megawatts ("MW") of Localized Energy Resources ("LER") and also suggest some technical edits to the document to correct speculative information or to incorporate information made available since the report was issued. PG&E looks forward to continuing to work with the CEC and the wide range of stakeholders in developing California's Strategic Renewables Plan and further advancing renewable development in the state. PG&E is happy to discuss these comments with the CEC staff should additional information be needed.

II. CALIFORNIA IS WELL-POSITIONED TO ACHIEVE HIGHER LEVELS OF RENEWABLES

Since California's Renewables Portfolio Standard was first passed into law in 2002, we have learned a lot about the obstacles to renewables development. However, in less than 10 years, we have overcome some of the initial obstacles and have brought online new renewable generation facilities. We are also putting processes in place that will help us in the long-term to add more renewables to the system. In the early years of the RPS, we encountered barriers to development associated with permitting, transmission, interconnection, technology, proximity to military bases (protected air space), and financing. Yet, despite those barriers, PG&E has increased its renewable deliveries to customers from about 11% in 2003 to nearly 16% in 2010.[1] Additionally, numerous projects are under construction that, once completed, will help PG&E achieve significantly higher levels of renewables deliveries in the coming years.

Under the RPS, PG&E has executed more than 115 contracts representing more than 9,000 MW of renewable capacity since 2002.[2] While some of these contracts were with existing facilities, many were for construction of new facilities. Since 2002, PG&E has added more than 10 new facilities to its procurement portfolio, and roughly the same number of projects have terminated for a variety of reasons. Many of these terminated contracts were signed in the early days of the RPS program and since that time, the renewables market has matured considerably. Today, projects are bidding to us at a more advanced stage of development (e.g., applications for interconnection have already been submitted, permitting applications are well underway). Furthermore, while some projects have been delayed, we are now seeing numerous projects that are nearing completion or have completed the permitting process and have started construction. As a result, PG&E has already signed most of the contracts it will need to achieve the state's near-term RPS goals, even after adjusting for some assumed failure rate for those projects not yet under construction. Future contracting activities, however, are subject to limits on product types as set forth in the 33% legislation; at this time, it is unclear how these legislative changes and redefinition of renewables products will affect our ability to procure additional cost-effective renewable resources for our customers.

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1 At page 42 of the Report, it is noted that PG&E achieved 17.7% of its retail sales from eligible renewables in 2010. This figure includes deliveries from contracts that had not yet been approved by the California Public Utilities Commission at the time that PG&E filed its March 1, 2011 RPS Compliance Report. Because these pending contracts either remain pending or have been terminated since March, PG&E removed deliveries associated with them from its August 2011 RPS Compliance Report, resulting in a revised calculation of 15.9% of its retail sales from RPS-eligible deliveries in 2010.

2 It should be noted that in addition to the RPS, California has numerous other programs that support renewables on the customer side of the meter. These programs include the California Solar Initiative, the Self-Generation Incentive Program, the Emerging Renewables Program, among others. The figures noted do not include the capacity secured through these programs.

Given its projections for what is needed to achieve the 33% RPS requirement, PG&E is concerned that the CEC's "renewable net short" ("RNS") calculation may create confusion in the marketplace. On page 31 of the Report, details are provided for the derivation of the "renewables net short" as defined by the CEC. The CEC's RNS reflects only expected output from existing renewables facilities likely to be generating in 2020. The RNS is not adjusted for expected output from facilities that are under construction or otherwise contracted for. Therefore, the RNS overstates the need to procure additional renewables. PG&E suggests that the RNS methodology be modified to capture contracts for new renewables facilities that are expected to be online in 2020. The CEC may wish to assume a certain percentage of the projects are not successful (as has been done recently in the CPUC's Long-Term Procurement Plan ("LTPP") proceeding), but to ignore ongoing and expected contracting activity in its totality will create unfounded perceptions in the marketplace and among regulators and legislators that significant additional procurement of renewables is needed to achieve the 33% RPS goal.

III. KEY TERMS AND ISSUES NEED TO BE DEFINED TO BETTER UNDERSTAND THE IMPACTS OF GOVERNOR BROWN'S 12,000 MW OF LOCALIZED ENERGY RESOURCES (LER)

Chapter 2 of the Report contains the CEC's proposals for implementing the Governor's proposal to obtain 12,000 MW of LER. From PG&E's perspective, four key principles should guide California's implementation of the 12,000 MW of LER goal:

- safe and reliable electric service with consistent power quality;
- broad resource eligibility;
- reasonable costs to customers, without cost shifting;
- California-wide participation.

These key principles will result in a sustainable long-term program that provides flexibility while ensuring no one set of customers bears an undue burden for achieving the goal.

An important objective is to avoid defining LER too narrowly and to avoid undue haste in defining implementation details. This should not be just a solar, wind, or even just a renewable initiative. Furthermore, it is not clear to PG&E that the most cost-effective ways to achieve the goal have been fully evaluated. For example, it was suggested at the September 14 workshop that one "low hanging fruit" proposal would be to increase the net metering cap beyond the current 5 percent of system peak demand. PG&E questions whether such an expansion is within the interest of all customers, given net energy metering results in cost shifting among customers and, in many cases, lower income customers are paying the subsidies for higher-income customers. Furthermore, rooftop projects that qualify for net energy metering are significantly more expensive than larger, ground mounted projects. Additionally, such projects do not contribute to the serving utility's RPS requirements. Since net metering arrangements on PG&E's system currently total about 2.4% of system peak demand, growing at approximately 0.5% per year over the past 2 years, there is ample time available to consider whether further expansion of these arrangements are in the best interest of all customers.

PG&E supports the inclusion of all projects up to 20 megawatts in size, regardless of the date of installation, toward the 12,000 MW LER goal. PG&E notes that the proposed definition set forth in Chapter 2 of the Report does not appear to include 20 MW and smaller contracts executed through the RPS program, nor does it include existing renewable qualifying facilities or other qualifying facilities that are 20 MW or smaller in capacity. Furthermore, there may be other project types and sizes that meet the intent of LER even it those projects are greater than 20 megawatts. The broader the opportunity for diverse resources, the better the chance the state can meet reliability and cost containment goals along with the 12,000 MW of LER goal.

Additional studies are needed to determine the factors that govern feasibility, examine how to achieve the goal in the most cost-effective way for customers, to better understand the significant engineering and infrastructure issues associated with integrating 12,000 megawatts into the transmission and distribution grids, and to identify the appropriate solutions to those issues and their limitations. We also need to better understand how this goal interacts with existing mandates and must manage its implementation in a way that results in investments that benefit the economy. Investment in generation that sits idle, degrades system reliability, or imposes burdensome integration costs relative to larger projects of the same technology type would represent a poor policy choice. The Report acknowledges that "it may make sense to focus on … reforming the permitting and interconnection processes in the early years to take advantage of cost reductions and improved regulatory structures in later years." (p. 2). PG&E supports this statement, and for its part continues to implement improvements in its own interconnection processes, consistent with the safe and reliable operation of the grid. Such efforts will allow us to systematically analyze and address the barriers to adding more generation to the distribution grid, ideally leading to lower customer costs.

Ultimately, California will be best served by achieving the goal in a way that optimally balances environmental, system reliability, and customer cost impacts. These are fundamental tenets of our energy future, and careful study is needed to understand the impact of significantly increased amounts of LER, such as the 12,000 MW goal, on each of these issues and to inform policymakers on how these choices affect the everyday lives of Californians.

- power quality;
- system reliability;
- cost to customers;
- rate impacts;
- changes to the distribution and transmission system needed to accommodate expanded LER;
- California's achievements to date in installing and planning for higher levels of generators under 20 megawatts in size;

- the technology mix, eligibility of project sizes (including projects larger than 20 megawatts), pace for advancing LER, and impact on system operations;
- participation by all load-serving entities;
- the impact of having a significantly larger number of small generators interconnecting to the electric grid;
- processes for small generators to locate in areas that minimize interconnection and transmission and distribution modification costs;
- system need and demand for LER generation;
- resource issues for local governments;
- net economic impact and job creation.

IV. STREAMLINED ENVIRONMENTAL REVIEWS AND PERMITTING CAN HELP SPEED RENEWABLE DEVELOPMENT

Chapter 3 of the report notes many of the current efforts underway to streamline the renewables permitting process, both for utility-scale projects and customer installations. It does a good job of noting where overlapping and duplicative permitting processes slow progress, but lacks any recommendations as to "next steps", aside from noting the numerous processes underway. Chapter 3 also correctly notes that the challenges facing utility-scale projects are quite different from rooftop programs, so different measures are needed to address the development challenges. However, streamlined processes and continued efforts to develop broad, programmatic plans that identify upfront potential areas for development are the keys to success, regardless of the size of a project. PG&E is supportive of efforts to develop countywide or region-wide habitat conservation plans when prepared alongside a programmatic planning effort for new renewable energy projects and/or gen ties.

Programmatic reviews would be most effective if the planning process clearly identifies areas for facilitated development of renewable energy resources and provides take permit coverage for legally protected species. Programmatic permits should also include the ancillary linear facilities (i.e., gen ties) in order to expedite development and cover operations and maintenance of the facility, not just the construction phase.

Programmatic reviews can help streamline the permitting process; however, even with programmatic CEQA analysis, site-specific analysis and environmental review are not precluded. Some environmental data may be unavailable to make accurate predictions of environmental impacts; therefore, programmatic planning processes should aim to identify areas of least conflict. While a number of proposed renewable energy projects have received permits, the full extent of environmental impacts associated with these facilities is not fully known. For example, recently approved (2010) fast track projects are currently under construction, so longer term impacts to species are unknown until construction is completed and biologists have had an opportunity to conduct follow-up studies. Some recently approved projects are suffering from litigation threats, even during construction, further indicating that characterization of environmental impacts of previously approved projects is not a settled issue.

Coordinating programmatic review would require dedicated resources from State and Federal agencies, both of which would likely need additional staff to contribute to the effort. In the past, programmatic NEPA reviews have been time consuming for agencies to finish and not as effective at facilitating permitting as intended.

PG&E also supports efforts to improve the efficiency of LER permitting such as: state and regional governments producing model guidelines/ordinance for use by local governments and state support to assist local governments in implementing/adopting model ordinances.

Other recommendations for streamlining the permitting process could include:

1. **Collocation of solar generation with other infrastructure:** PG&E supports studying the collocation of solar generation panels with existing linear infrastructure rights-of-way. Additional analysis to determine which types of corridors and locations are appropriate for collocation is needed. For example, poles and lines in transmission and distribution corridors cast shadows on solar panels and decrease energy output. In addition, the slope, share and orientation of the corridors themselves could also affect the overall plant efficiency. Potential environmental effects of this concept should be vetted and should examine potential impacts to wildlife that may utilize existing linear corridors; potential impacts to public safety for projects along highway corridors; operations needs to access dual use facilities; and the engineering feasibility of linear solar plant design and the points of interconnection, among others.

2. **Repowering top wind resources**: PG&E supports re-powering of the Altamont and San Gorgonio Pass Wind Resource Areas.

3. **Additional pilot and demonstration projects to learn more about the permitting challenges for the emerging offshore renewable energy industry:** This sort of upfront process could be used to demonstrate different technologies such as offshore wind and wave energy devices and could offer several advantages. Utilizing shared infrastructure, such as a grid-interconnected cable to shore, could help significantly reduce early project costs, and permitting the facility with some flexibility as to the specific devices to be used could match well with the current emerging status of these technologies.

The offshore renewable energy industry, while promising in the long run, faces significant challenges in the near-term, in large part due to the permitting challenges associated with a new and unfamiliar technology. Gaining real-world experience through early pilot and demonstration projects regarding actual environmental effects from these kinds of facilities, and viable solutions and mitigations, will be of great importance to reducing costs and uncertainties for responsibly developing California's great offshore renewable energy potential.

V. STRATEGIC UPGRADES TO TODAY'S TRANSMISSION SYSTEM OFFER MORE FLEXIBILITY FOR FUTURE RENEWABLE DEVELOPMENT

Chapter 4 of the Report summarizes the numerous statewide and regionwide transmission planning initiatives. Most importantly, the Report suggest that the CAISO should be allowed to "upsize" proposed projects beyond the current need demonstrated by individual interconnection requests and that technical fixes should be identified and developed to either increase the capacity or capacity factor of transmission lines (p. 85). PG&E endorses these recommendations.

PG&E supports transmission development to accommodate interconnection of multiple resource areas to provide for robust and competitive markets for renewables. The CAISO should develop a transmission plan that satisfies multiple resource build-out plans. This sort of optionality or "least regrets" planning will allow renewable generation to develop in the most promising areas. By building the infrastructure that allows for development of multiple resource areas, more competition is introduced into the competitive generation market. Because transmission costs less to develop than renewable generation, the expectation is that competition among many generation markets will lead to lower overall costs to customers through lower costs per MWh offered by competing renewable generators. This situation would be similar to what we see in the gas markets today, where multiple pipelines coming into California create a more competitive price outlook for natural gas.

Furthermore, we should be examining how to bolster the existing transmission system to facilitate the flow of renewable power throughout the state. Enhancing the transmission backbone system is essential to allow the renewable power being developed in the southern portion of the state to freely flow to the north. As noted on Table 12 (p. 96), the CAISO is evaluating the Midway-Gregg 500 kv line, which PG&E has proposed to meet this objective, as part of its 2011-2012 planning cycle. Adding this type of flexibility can also help foster system reliability and ensure renewable power can be delivered to load. PG&E is concerned that a plan that focuses only on planning for energy delivery will not lead to the development of a robust, competitive generation market; if energy cannot be delivered to load and additional resource adequacy capacity must be procured, customers will have to pay higher prices than they would if deliverability was assured. Additionally, if energy cannot be delivered to load, and renewable generation must be curtailed because of congestion in the transmission system, renewable generators will face more challenges in financing their projects, given that curtailment without compensation will result in a less clear revenue stream for the project.

Because major transmission projects can take more than 10 years to plan, permit, and construct, it is important to begin these activities now so that achievement of the renewable goals is not delayed. Pursuit of a strategy that results in a little too much transmission today can actually create benefits for customers that would not otherwise accrue.

VI. SUCCESSFULLY ADDRESSING GRID-LEVEL INTEGRATION IS CRITICAL TO ACHIEVING SYSTEM RELIABILITY WITH MORE INTERMITTENT RENEWABLES

Chapter 5 provides a balanced overview of the issues and challenges facing the state in ensuring reliable system operations with more intermittent renewables on the system. The two main drivers of integration need are variability and forecast uncertainty. Better forecasting tools and market incentives to align with the new technical operating requirements will help incent the best technologies to provide more flexibility to the electric system. However, tools that can help identify and measure the system's integration needs, like PG&E's Renewables Integration Model (RIM), need to be developed and improved to better define the integration needs associated with California's renewable generation. PG&E recommends that CEC encourage the development of this type of tool to help analyze and quantify potential integration needs. The RIM, which is publicly available, is simpler and more transparent than other currently-available tools, and provides a faster way to estimate integration requirements and resource need for integration. PG&E is continuing to refine the tool to better estimate integration needs.

PG&E notes below its recommendations regarding grid-integration issues.

1. **Figure 15 on Flexible Services and Timeframes (p. 113)**: Figure 15 identifies many of the types of services and time frames for each that will be needed to ensure system reliability. A variety of solutions are available to provide these services, including demand response, energy storage, combined cycle gas turbines, as correctly noted by the report. PG&E is glad to see the staff report's recognition of the potential need for additional unit commitment to meet forecast error for load and solar or wind generation that extends beyond the hour-ahead uncertainty. Additional unit commitment is needed because it may take more than one hour to start some units providing integration services, and it is not possible to plan on having to cover only up to the hour-ahead uncertainty. Adding this additional commitment need to the list of flexibility requirements better captures the system's operating characteristics.

2. **Contingency and Flexibility Reserves:** The discussion at p. 108 appears to confuse "contingency" with "flexibility reserves" – these terms are not interchangeable. For example, the text indicates that spinning and non-spinning reserves are available to meet solar and wind variability and forecast uncertainty. This is not correct. Today, the CAISO and others in the industry believe the system operator needs to maintain sufficient contingency reserves (spinning and non-spinning) aside from flexibility reserves (regulation and load following or ramping reserves) to cover contingencies (outages of transmission and generation). The text should be modified to clearly indicate the differences in these services.

3. **Ramp Rates:** On Table 15, p. 118, a pumped storage ramp rate of 40 MW per minute is indicated. PG&E notes that this rate was updated to 80 MW per minute in its April 28 comments to the CEC.[3]

4. **CPUC's Energy Storage OIR**: The CPUC's Energy Storage OIR is the appropriate proceeding for developing a consistent framework to assess the benefits and costs of energy storage in the context of other alternative resources that could provide similar services or products as energy storage (*i.e.,* the cost-effectiveness evaluation of storage should not be in a silo, rather it must consider the spectrum of similar products and services). This proceeding may also serve as the forum for evaluating whether market products need to change to accommodate energy storage. However, it is not clear to PG&E that this proceeding will "provide insights about the size and the scope of the energy storage" (p. 120). Rather, PG&E expects that the need for storage will be developed in the CPUC's 2012 LTPP proceeding. In the interim, PG&E will continue to examine storage alternatives through pilots and other means with the goal of being positioned to expand storage options once the need for storage is determined. Adoption of a storage target today, without the need for it first being determined by the CPUC, would like result in dismissal of any application to the CPUC for storage products. For example, PG&E's application to continue feasibility studies for the Mokelumne Pumped Storage projects was recently rejected without prejudice by the CPUC because the need for the project had not yet been established.

PG&E will continue to pursue other pilots to evaluate permanent load shifting (e.g., it currently has a 27 MW pilot underway), and electric vehicle smart charging. Furthermore, the recent Self-Generation Incentive Program ("SGIP") decision authorized $2 per watt incentives for advanced storage devices, which may help storage providers provide market-based services at cost-effective prices. Accordingly, PG&E recommends against adoption of a specific target prior to the conclusion of the CPUC's LTPP proceeding.

5. **Long-Term Procurement Plan**: At pages 132-133, the LTPP discussion needs to be updated to reflect the filing of testimony in July 2011, as well as the August 2011 Settlement Agreement asking the CPUC to work with CAISO to improve modeling and assumptions for integration analysis either as part of the current 2010 LTPP or the next cycle with the goal of a CPUC need determination by the end of 2013.

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[3] See: http://www.energy.ca.gov/2011_energypolicy/documents/2011-04-28_workshop/comments/TN_60782_05-17-11_PGEs_Comments_in_Response_to_the_April_28_Energy_Shortage_for_Renewable_Integration_Workshop.pdf

VII. DISTRIBUTION-LEVEL CHALLENGES MUST BE ADDRESSED TO ENSURE SAFE, RELIABLE SYSTEM OPERATION

Chapter 6 sets forth several of the challenges faced today in adding more generation at the distribution level of the electric grid. Voltage regulation, protection systems, islanding and other safety and reliability concerns must be addressed, and the cumulative impact on grid operations must be better understood. The tools to address these concerns may also be different depending on the size and location of the generator. We need to take the time to understand the system impacts first, then move forward in a systematic way to address interconnection issues.

While we are learning about the operational issues posed by higher levels of distributed generation, we also need to learn more about the costs to upgrade the distribution system. From a customer perspective, how can we best balance the desire for more distributed generation with the cost to upgrade the distribution system? As noted in the Report (at page 158), California has relatively low voltage distribution lines, and converting California's existing distribution feeders to a looped, rather than radial, configuration (as in Germany and Spain) would be costly. Additionally, the CAISO lacks visibility as to the location of various types of distributed generation on the distribution system and any additional requirements for telemetry and remote control for LER requirements could be expensive. However, the CAISO does already require telemetry on wholesale intermittent generators that are 1 MW in size or larger, whether interconnected on the transmission or distribution system.

Other recommendations set forth in the report to address distribution system issues and interconnection challenges may not be technically feasible at this time. For example, at pages 152-53, the Report states that "[b]ased on experience in Germany, if inverters in the US were required to include equipment that allows utilities to actively manage the inverter, then interconnection studies and costs associated with these interconnections could be completed quickly and at lower cost." However, current interconnection study complications go beyond the utilities' ability to control the inverter. Protection schemes and system capacity can present interconnection challenges regardless of inverter operation. Furthermore, even if the utility could control the inverter directly, not many utilities actually have control systems capable of doing that. Such systems are just now being introduced by vendors in early version release. Accordingly, upgrading distribution system operations that could control the inverter are expected to be costly to customers and not readily available in the near-term to help resolve interconnection issues.

Finally, the Report (p. 159) suggests that it may be desirable to limit the amount of distributed generation that can be interconnected to feeders, substations, and or local load areas.[4] PG&E is supportive of this recommendation and has provided data to developers as part of

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[4] PG&E notes the Report cites a KEMA study that has not yet been made publicly available. To the extent that study contains additional recommendations, PG&E reserves the right to supplement the comments submitted on the Report.

PG&E's Photovoltaic Program that allow developers to identify the most desirable areas for interconnecting new distributed generation resources. Interconnecting in areas that can accommodate distribution without significant upgrades to the distribution system provides the best value for customers. However, PG&E is concerned about efforts to change the cost allocation methodologies currently in place for distributed generation (see page 155 where the different cost allocation methodologies are discussed). Efforts to make the cost allocation for distribution upgrades more like the cost allocation mechanisms for transmission upgrades may not be in the best interest of customers because if costs for distribution upgrades are socialized, the developer will not be incented to locate the facility in an area where minimal upgrades are needed. Additional analysis is needed to determine whether it is in customer interests to change the existing cost allocation mechanisms for distribution upgrades.

VIII. FINANCING ALTERNATIVES FOR RENEWABLES MUST BALANCE TRANSPARENCY AND RISK

Chapter 7 of the report identifies many of the financing challenges facing renewable generators. Numerous tools exist today to help meet these financing needs, as noted in the report. Furthermore, as noted on p. 179, one of the best tools for incenting renewables is to develop and maintain stable, predictable regulatory policies. Once implemented, policies must be given time to take hold and gain customer acceptance without continuous tinkering around the edges or creation of even more programs. PG&E suggests the following general principles that should be considered when evaluating financing strategies:

1. **Incentives mask the true cost of power:** Energy prices paid by consumers should reflect the true, underlying costs. Sending the right energy price signals to customers will help them choose how much energy to consume. Subsidies, in whatever form, hide the true cost of energy. The state should employ financial strategies that do not create more subsidies.

2. **Leverage existing structures to provide financing:** American capital markets are robust, with sophisticated, experienced, and knowledgeable investors, many who are experts in the evaluation of energy technologies. Investors in the capital markets have greater experience and knowledge about renewable investments, and are better equipped to assess the investment risks without political bias or influence compared to state run programs. The state should pursue financial strategies that rely on existing market players to evaluate and fund renewable projects.

3. **Existing incentives and incentive mechanisms are sufficient to encourage renewables:** Numerous incentives already exist at the federal and state levels to encourage renewable development. For example, the federal government already has in place substantial incentives, in the form of tax credits, tax grants, loans, and loan guarantee programs for renewable generation projects. California also offers numerous incentives (at both the state and local levels) for solar PV, small renewable generators,

net metering, emerging renewables, among others. The state does not need to further subsidize these technologies.[5]

4. **Great care must be made to not transfer risks to customers that are better borne by banks:** The availability of cheap money combined with poor risk allocation and management were the root causes of the recent financial crisis and ensuing recession. The state should avoid financing strategies that distort the cost of credit, or transfer the financial risk to government agencies ill equipped to assess or manage the risk.

Numerous recommendations for financing strategies are offered in Chapter 7. However, many of these recommendations would violate the principles noted above, and result in customers and taxpayers bearing risks that are more appropriately shouldered by others. Over the years, many proposals have been made and are currently available in the marketplace. PG&E's perspectives on various financing mechanisms are provided below.

1. Production Tax Credits and Investment Tax Credits: Production tax credits are only earned if a facility is generating electricity. They reward efficient production, not the highest cost, and are therefore a good tool for incenting renewable generation. However, the PTC is currently slated to sunset in 2012 for wind, while the incentive tax credit for solar continues until 2016. This mismatch in availability of the PTC for wind may create some uncertainty about whether wind's competitive prices vis-à-vis solar will continue in the post-2012 period.

2. Technology Demonstration Grants/Equity Investments: PG&E supports limited demonstration grants that do not replicate what private industry is doing. These sorts of grants and investments are typical of those made by the CEC through its Public Interest Energy Research ("PIER") program and can help expand the pool of renewables and help us better understand and resolve technology issues. PG&E has been supportive of demonstration projects that can help prove out new technologies, which will then allow them to attract venture capital or other forms of investment, as well as demonstration projects that can help us learn about and address operational challenges. However, the state itself should not make equity investments, which would force taxpayers to be speculative investors without compensation. It is a conflict of interest when the state is an investor and also makes the rules.

3. On-bill Financing: While there may be public policy reasons for offering on-bill financing, this type of financing is generally not preferred, given it forces ratepayers to be lenders with no say on the investment and no return on their investment. Capital markets are much better means to provide funds at the right price to customers, as determined by credit quality. Furthermore, while on-bill financing may be desirable to incent some public policies, when it is used, it is most appropriate for shorter-lived assets that are paid back over a short

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5 To illustrate this point, at p. 196 of the report, it is noted that while costs might be falling for certain technologies (e.g., solar PV), prices in excess of costs are supported by government incentives and developers may just be collecting the difference and increasing their profits, rather than reducing prices to benefit customers.

period, usually no more than 5 years. As an example, on-bill financing may be appropriate for solar water heaters, but it is not appropriate for financing solar panels on customer premises. Longer-term on-bill financing creates more repayment risks for customers who are financing the loan, a risk for which those customers are not compensated.

A correction is needed to the draft Report at page 178. There, the Report states that on bill financing is "debt is linked to the property's utility meter rather than the property owner. This allows for easy transfer of ownership and debt should the property owner choose to sell before the system is paid off." PG&E objects to this characterization of on-bill financing because it is not consistent with on-bill financing in California.

There *are* a few utilities in the nation that tie the on-bill financing debt through a utility tariff to the meter, so that the debt obligation is carried over to future tenants or owners of the property. However, PG&E is aware of only a single utility in Hawaii that funds any renewables with a tariffed on-bill financing program. Such a proposal would like require legislative action to tie the debt to the meter. Kansas took such action to implement its program (the concept is referred to as Tariffed Installation Programs).

However, in most on-bill financing programs, the debt obligation lies with the account holder who signs the loan documents. That is the case for the four California investor-owned utilities, as well as with the more established programs in New England.

Accordingly, PG&E recommends that the text in the Report be modified to reflect on-bill financing requirements in California.

4. PACE for Commercial Customers: Numerous communities are offering PACE programs to commercial customers, with various degrees of adoption and success. However, PG&E is concerned about the sustainability of these types of programs, given PACE programs have typically been seen as high cost loans, and have problems that tend to make them unattractive for consumers and businesses alike. Because commercial properties often have multiple loans, PACE financing, with its requirement to be superior to other loans, is often not practicable since it would require modification of existing loans, likely resulting in higher cost.

Many other financing mechanisms are better handled by the capital markets or would only serve to provide additional incentives or subsidies that distort prices and could result in state tax increases (or decreased state services).

Lastly, the Report correctly notes that several tools exist today that offer greater certainty for project revenues and, as a result, may enhance the ability to finance projects. These tools include power purchase agreements, feed-in tariffs ("FITS"), and the renewables auction mechanism. However, PG&E does not agree with suggestions in the Report (at page 171) that FITs should account for the risk of price increases for obtaining feed-stocks or that there should be a cost-based FIT for each technology. First, providing what would be "revenue guarantees" to generators like biomass that rely on feedstocks would result in a substantial transfer of risk from the developer to consumers. While gas-fired generators may pass their gas costs through directly, there are robust indices for trading natural gas that offer public benchmarks for those costs and protect customers. No such benchmarks exist for technologies like biomass and there are no protections for customers. With respect to technology-based FITS, California has long had a "technology-neutral" policy, seeking to secure the lowest cost resources for customers. PG&E opposes technology-based pricing for FITs, given they will artificially enrich those projects that might have been delivered at a price below the average technology price. The Staff acknowledges this important concern in Chapter 8 of the report, which noted that soft costs and regulatory barriers can significantly affect project cost estimates. When costs fall, developers may just be pocketing the difference between price and costs. Chapter 8 also indicates that PV system prices vary significantly due to government incentives. Therefore, PG&E believes competitive solicitations and benchmarking of transactions against one another are better ways to help secure the lowest cost renewables to serve customers.

IX. FUTURE RESEARCH AND DEVELOPMENT SHOULD FOCUS ON SOLUTIONS TO SYSTEM ISSUES

While the future of California's PIER program is currently in question, given the failure to extend the Public Goods Charge beyond the end of 2011, PG&E is supportive of research and development programs that help us learn more about system operations and that test solutions that could help interconnect and integrate renewable resources and reliably operate the system. Chapter 9 notes the many successes of the PIER program to date.

PG&E does recommend modifications to the language on p. 218 with respect to its SmartMeter program. The language contained in the Report does not reflect the outcome of an independent evaluation conducted by the Structure Group on behalf of the CPUC on this matter. On September 2, 2010, the results of that independent evaluation were announced, indicating that the meters and associated software and billing systems are consistent with industry standards and are performing accurately. The complete findings can be found at the following link: linkhttp://www.cpuc.ca.gov/PUC/energy/Demand+Response/solicit.htm.

X. SET ASIDES AND PREFERENTIAL PRICING NEED TO DEMONSTRATE EFFECTIVENESS AND RETURN ON INVESTMENT IN MEETING PRIMARY GOALS

Chapter 10 is a wide-ranging chapter and highlights concerns in many communities about renewables and the ability of environmental justice communities to participate in the renewables programs. PG&E is supportive of efforts to encourage broad participation in the environmental and economic benefits of renewables, but believes the percentage allocated to these communities, and how they are allocated, should be determined by criteria other than community need (e.g., kWh of production per unit of investment). While some communities may have need and receive secondary benefits of construction jobs, etc., the project still needs to have optimal production to justify the costs to the whole customer base. Additional study is warranted prior to recommendations for any set asides, given set-asides may lead to higher costs to customers without commensurate generation and environmental benefits.

PG&E also cautions against adoption of studies that recommend 24 to 26 cents per kWh to encourage multi-family markets to participate in the renewables arena and would like to see the projected return on investment of such a program (e.g., measured in greenhouse gas emission reductions, avoided new fossil fuel generation, etc.) that would produce measurable cost savings for all customers since such a price is well in excess of what is supported by the current market. PG&E recommends that additional analysis be developed that balances the public policy concerns with the costs to customers. Setting forth recommendations from one stakeholder group in this report without analysis and consideration by other stakeholders (and presentation of those positions) undermines the public policy debate that should first occur.

XI. CONCLUSION

This wide-ranging report offers a robust assessment of renewables assessment in California. PG&E has made limited requests for correction to the Report and has offered several recommendations for "next steps" that should be considered as we develop California's strategic plan for renewables development.

Sincerely,

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