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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

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Re: 2012 Integrated Energy Policy Report Update/Renewables: Comments of Pacific Gas and Electric Company on Identifying and Prioritizing Geographic Areas for Renewable Development in California

## I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments in the California Energy Commission's ("CEC") 2012 Integrated Energy Policy Report ("IEPR") Update on identifying and prioritizing geographic areas for renewable development in California. PG&E's comments respond to specific CEC questions on the preferred characteristics of priority areas, regional strategies, and the methodology for creating the soft local targets to build toward the 12,000 megawatt ("MW") goal for localized energy resources.

PG&E appreciates the CEC's focus in this IEPR on strategic renewables issues. Our focus today is on how to achieve the 33% Renewables Portfolio Standard ("RPS") in a manner that balances cost to our customers, ensures system reliability, and protects the environment. Furthermore, we have a lot to learn about how to operate the electric grid with significantly more intermittent renewables connected to both the transmission and distribution grids. We also have significant decisions to make about how to cost-effectively upgrade the distribution grid (and at what cost) and how to best integrate higher levels of intermittent renewable generation. The CEC recently approved several research projects that can help inform the future direction of these important issues.

Given the significant operational tasks before us to successfully achieve 33% RPS, the CEC's suggestion that parties comment on what is needed to go beyond 33% RPS, perhaps to 40%, seems premature. While PG&E has been supportive of achieving higher levels of renewable energy, PG&E does not support policies calling for ever-higher levels of renewables. Fundamentally, California is better served by adopting an overarching goal of reducing greenhouse gas ("GHG") emissions, and providing flexible policy choices that allow the selection of the most cost-effective alternatives to achieve those reductions. Renewable resources are just one of several ways to achieve GHG emission reductions – energy efficiency, demand response, combined heat and power, and cap and trade programs – are among the many other tools available to reduce GHG emissions in the electric sector.

The best GHG emission reduction tools for the post-2020 timeframe are unclear at this time. Should the CEC choose to evaluate what is needed to achieve 40% RPS, PG&E respectfully suggests that the CEC investigate two things about going from 33% to 40% RPS. Those two items are: 1) what would be the projected quantity of GHG emission reductions (in tonnes) achieved by going from 33% to 40% RPS; and 2) what is the implied carbon cost per tonne of reduction (in dollars). With this information, the CEC, through the 2013 IEPR, could investigate alternative ways to achieve the same amount of GHG emissions reductions, and assess the associated carbon cost for each alternative. This type of analysis would be invaluable to policymakers in developing flexible tools to reduce GHG emissions in the most cost-effective way for customers and the State. PG&E cautions against simply creating more mandates, carve outs and set-asides, which have only served to increase customer costs over what they might otherwise need to be to achieve a GHG emission reduction goal.

Finally, PG&E has previously noted its concern that very little information on the actual cost impact on customers of the numerous -- and sometimes overlapping -- public policies regarding power supply exist. Nor have many studies been done about whether customers actually need the volume of power that utilities would be required to procure under these numerous mandates. (For example, the California Clean Energy Future team currently tracks 16 different energy initiatives, including greenhouse gas emissions reductions, renewables supplies, energy efficiency, distributed generation, electric vehicles, transmission expansion, and demand response, to name a few.) By focusing the 2013 IEPR on the cost of the tools to achieve GHG emission reductions beyond 2020, as well as an assessment of the cost and rate impacts of the myriad energy initiatives already adopted to get to 2020, the CEC can provide a meaningful analysis of the cost to the state and electric customers of various paths forward. This information can help California choose the most cost-effective means to achieve its goals, and may help guide the implementation timelines for various initiatives, particularly when considering the cost to refurbish other aging infrastructure in the state. We should ensure that our efforts to transition to an ever-cleaner energy supply do not saddle customers with ever-higher costs for decades to come.

To allow for easier review of PG&E's comments, the questions attached to the Workshop Agenda (as applicable to PG&E) are repeated below, along with PG&E's responses. PG&E is happy to discuss these comments with the CEC staff should additional information be needed.

## II. A CONSENSUS ON PRIORITY AREAS FOR DEVELOPMENT WILL PROVIDE GREATER CERTAINTY TO UTILITIES AND DEVELOPERS

PG&E is committed to meeting California's aggressive renewable energy goals while delivering safe, clean, cost-effective energy to our customers. In 2011, 19.4% of the energy delivered to PG&E's customers met the RPS requirement, and over half of PG&E's energy supply was carbon-free. PG&E is well-positioned to achieve RPS compliance in the first and second compliance periods and is seeking energy from projects that will deliver in the third compliance period.

The number of developers offering RPS projects has grown significantly since the RPS program began. The 2011 RPS Request for Offer ("RFO") was a record breaking year – more than 300 offers were submitted. As part of the RFO process, PG&E conducts an environmental due diligence of the offers. The assessment considers the environmental aspects and impacts of a proposed project and how these factors may impact project viability.

PG&E recognizes the importance of and supports strategic collaboration in meeting RPS objectives in an environmentally sustainable manner. PG&E strives to procure from viable, cost-effective projects for our customers and has been working through a number of collaborative forums on these issues. These forums include the Desert Renewable Energy Conservation Plan ("DRECP"), the Solar Programmatic Environmental Impact Statement ("PEIS"), the American Wind Wildlife Institute ("AWWI"), the California Transmission Planning Group ("CTPG"), and the US Fish and Wildlife Service ("USFWS") pole retrofit. As a result, PG&E has been able to translate implications of these planning efforts into institutional knowledge, while ensuring utility considerations are addressed.

Consensus around priority areas for renewable energy and development (including storage) may help provide certainty for utilities on many levels: development of generation, procurement of energy resources, and transmission planning. Likewise, consensus on inappropriate areas for renewable energy development would be also helpful. Stakeholder processes that determine priority areas will help minimize siting and investment risks for developers and utilities.

## III. PREFERRED CHARACTERISTICS OF PRIORITY AREAS MUST BE BALANCED

1. ***From your perspective, what are the specific preferred site characteristics for the three categories (interconnection, permitting, economic development) and which are the highest priority? Are the three categories mutually exclusive?***

   Specific preferred site characteristics will vary depending on the category, as noted below.

   - Interconnection: sites near existing distribution or transmission lines.
   - Permitting: sites with low biological value and low value agricultural land, brownfields, mechanically disturbed or degraded lands.
   - Economic development: projects that bring benefits to local communities, utilize local workers during the installation phase, and create a skilled workforce that will be available in the future.

These characteristics must be balanced in a way that also minimizes overall rate impact. As more renewables are added to the portfolio, PG&E seeks to acquire the most cost-effective resources possible. While many tout rooftop systems over ground-mounted systems, rooftop systems are much more expensive than ground mounted projects (as E3 has noted). Therefore, when developing allocations across different areas, the primary consideration should be what is most cost efficient as determined by land cost, proximity to distribution lines, and ground mounted systems, which are less impactful than rooftop systems.

Finally, permitting sites should be highest priority for utility-scale renewable energy planning. There should be a focus to identify potential renewable energy areas that utilize impaired or degraded lands (low biological value and low value agricultural land, brownfields). Long-term renewable energy planning will help to remedy interconnection issues (if utilities know where the renewables will be located, then upgrades can be planned accordingly). PG&E generally supports a zone approach for development that is informed by and could drive future transmission planning.

2. ***What data sets, information, and resources currently exist that could be useful in identifying geographic areas with preferred site characteristics? What additional data sets, information, and resources will be needed?***

A wealth of information currently exists, although it is not likely that the data are captured in any one place. This information includes renewable resource data (e.g., solar insolation, wind speed), farmland designation, Williamson Act status (which may not always be current), California Natural Diversity Database ("CNDDB") data, floodplains, and slopes.

Other data that would be useful if it were publicly available include updated farmland information, availability of water, average value of crops on the property (wheat/dry farmed), current and updated agricultural information, species presence/habitat areas (e.g., avian aerial habitat, migration routes), location of existing Habitat Conservation Plans ("HCPs") and conservation areas, water districts and irrigation canals. A central database for protocol-surveyed areas might also be helpful.

Environmental non-governmental organizations ("NGOs") have provided recommendations for preferred siting criteria but consensus and mapping is needed to develop specific corresponding data. Delineating the following on maps would be helpful: mechanically disturbed and impaired lands, brownfields, idle or underutilized industrial areas, "appropriate locations" near load centers, public lands of low resource value, landscape level biological linkage areas that should be avoided, areas with appropriate visual suitability. Agencies and NGOs could conduct additional studies to generate this data.

A central database of renewable energy projects and their status (e.g., proposed, application submitted, approved, constructed) would be helpful. Information should include project issues, pending litigation, and mitigation measures.

Lastly, geographic information system ("GIS') data should be made available for any public planning processes so that the most up-to date information from agencies can be easily utilized.

3. ***Transparent, publicly available data are needed for state and local governments, utilities, and other stakeholders to make informed, integrated energy planning decisions about priority areas. What are the barriers to making needed data sets more transparent and publicly available?***

PG&E has national security obligations so the data that PG&E is authorized to make public may be limited. PG&E's Corporate Security Office screens data requests and may require execution of non-disclosure agreements ("NDAs") prior to release of certain information. Confidential data may be redacted in public disclosures or may require summarization to mask any confidential information. In any event, PG&E does not publicly release wholesale information about its electric system infrastructure.

For renewable development purposes, however, PG&E has publicly released a map tool to help contractors and developers identify potential project sites for the photovoltaic ("PV") and Renewable Auction Mechanism ("RAM") RFOs. The map is updated monthly and shows selected electric transmission lines, electric distribution lines and substations within the PG&E service area. In addition, the map also provides specific information, such as operating voltages, line capacity and substation names. The maps can be found at:
http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/

4. ***How can more transparent publicly available data be used in the future to better inform an integrated energy planning process?***

More transparent publicly available data will better inform decision making and renewable energy planning processes and help reduce potential siting conflicts. Projects developers that utilize such data to choose least-conflict sites may face less risk of permitting delays and litigation and result in lower-cost projects.

Early planning with all players involved is recommended (e.g., transmission planning for the DRECP involved all investor-owned utilities ("IOUs") to develop scenarios and assumptions for transmission needs of the DRECP).

## IV. REGIONAL STRATEGIES TO IDENTIFY PRIORITY GEOGRAPHIC AREAS FOR RENEWABLE DEVELOPMENT REQUIRE MULTI-STAKEHOLDER PARTICIPATION

PG&E continues to participate in a multi-stakeholder committee to help develop the DRECP, a plan to streamline environmental permitting to expedite solar, wind, and geothermal projects in southern California while minimizing impacts to threatened and endangered species.

PG&E has engaged as an active participant in the DRECP planning process.

- In 2011, PG&E participated in the Covered Activities working group to help identify specific types of development facilities that would be covered by the plan.
- In 2012, PG&E provided recommendations to the CEC on the Renewable Energy Calculator to estimate the amount of land that may be required for renewable energy within the DRECP planning area in 2040 and 2050 timeframes.
- PG&E, along with other utilities, is currently participating in the CEC/CPUC/California Independent System Operator ("CAISO")-led Transmission Technical Group to help identify transmission lines and upgrades needed to support renewable energy development within the planning area.

PG&E supports collaborative and comprehensive planning processes that will help provide similar outcomes as the DRECP, including landscape level approaches to programmatic permitting that identifies appropriate mitigation and transmission.

DRECP is an example of a planning process that attempts to address the disconnect between land use and transmission planning. Efficient land use planning will help minimize cost to customers and help inform the need for new transmission lines. The CEC has the ability to bring both land-use and transmission planners together to address renewable energy issues.

5. ***Would conducting programmatic environmental review minimize the level of project-specific environmental review? Can the DRECP be a model for other regions of California? What would be the next steps if we did a programmatic review for another region of California?***

The most effective comprehensive renewable energy planning would result in clearly delineated renewable energy zones that are essentially ready to construct and would require very little project-specific environmental review (or enable substantial tiering of environmental information). A programmatic environmental review should strategically identify renewable energy, transmission needs, and mitigation areas based on a landscape level assessment.

The planning processes should be as simple and straightforward as possible and include incentives to development in zones (such as streamlined permitting, expedited review, etc.). The DRECP concept of renewable energy zones could be a model for the Central Valley. Identification of zones could guide renewable energy and transmission development to appropriate areas and minimize and land use conflicts.

Next steps should include identification of the priority geographic areas that should undergo a programmatic review and the key issues of concern (such as biologically sensitive areas, access to transmission and upgrades needed for build out, agriculture considerations). Both development siting criteria and preferred renewable energy development zones (and exclusion zones) should be identified based on a landscape scale assessment of biology, objectives, impacts, conservation plans, and adaptive management), transmission needs, technical considerations, and cultural resources issues (among others). Zones should be studied in a thorough environmental review process, endangered species act permitting should be completed with wildlife agencies, and best management practices should be identified.

6. ***How are local governments accommodating renewable energy development (i.e., general plans, combining districts, ordinances, development agreements)? Are there any examples of recent procurement programs that reflect site preferences?***

Like other IOU or publicly-owned utility ("POU") procurement programs, some of PG&E's programs prefer that generators be located within PG&E service territory and interconnected to PG&E's transmission or distribution system. These include PG&E's PV Power Purchase Agreement ("PPA") RFO and Feed-in Tariff ("FiT") programs. Other programs, like PG&E's Renewable Auction Mechanism program, require that projects be located in a California IOU service territory.

Other RPS procurement programs, including the annual RFO, prioritize offers that have the best combination of market value, viability, and qualifications based on specific evaluation criteria.[1] One of the inputs to this process is the project's viability score. Project characteristics that merit a higher viability score include placement on disturbed land and simplified transmission interconnection requirements.

There is no requirement that projects participating in the RPS Solicitation locate in renewable energy zones, however, this information will be taken into consideration in the evaluation process to the extent that it accelerates a project's online date for transmission constrained resources, alleviates environmental concerns, or alleviates other potential permitting issues.

In addition, California already incentivizes an array of distributed renewable energy technologies through programs like the Self Generation Incentive Program ("SGIP"), the California Solar Initiative ("CSI"), and the FiT for renewables and combined heat and power. Additional procurement directives, including technology- or location-specific carve-outs, are not needed, particularly given that such a change would likely result in customers paying higher costs for specific renewables than they otherwise would.

Finally, PG&E already procures a diverse portfolio of renewable energy. Additional mandates are unnecessary and are likely to increase costs to PG&E's customers.

PG&E factors land-use and interconnection in the procurement process. PG&E conducts an environmental due diligence process to identify projects that are likely to have a high

[1] As directed by D.09-06-018, PG&E will use a modified version of the Project Viability Calculator (PVC) issued by the CPUC on June 5, 2009, as a screening tool. The Solicitation Protocol explains how the PG&E modified version of the adopted PVC will be used to evaluate bids, as ordered in D.09-06-018.

environmental risk potential or fatal flaw (an unmitigatable impact or risk that may result in failure to achieve commercial operation date ("COD") or may jeopardize continued operation of a facility after COD, or continued operation on an existing facility).

7. ***How are local and state governments balancing renewable energy development and farmland preservation?***

PG&E takes farmland quality into consideration in combination with balancing other environmental considerations on projects.

The Williamson Act is one of many land-use related regulations that PG&E takes into consideration when seeking an optimal site for solar PV. PG&E is committed to being a good neighbor and maintaining and operating facilities to enable adjacent property owners to have "The Right to Farm". PG&E is committed to decommissioning its solar projects at the end of their useful lives and returning the land to agricultural use.

8. ***How can local and state governments advance renewable energy development on EPA tracked sites?***

Federal, state, and local governments could work together to address environmental remediation and liability issues on EPA-tracked sites so that development of these lands is more cost effective. Governments could provide financial or tax incentives to developers for utilizing these sites. Other assurances that provide greater certainty about project viability and reduce project development risks would also be beneficial.

9. ***How are local governments using the land use planning processes to capture economic benefits of renewable energy development? Are local governments providing incentives to attract renewable energy investment?***
   - N/A.

## V. PG&E SUPPORTS THE SOFT TARGETS FOR ALLOCATING THE 12,000 MW GOAL

In general, the CEC has developed a transparent methodology that is based on publicly available data and is easily understood. PG&E also supports allocation of the 12,000 MW of LER goal to "soft" targets, rather than specific county or utility goals.

One area of the allocation methodology, though, that could cause some confusion is the dual-allocation to counties and utility service territories. For instance, where a county is completely within one utility service territory, there generally would not be any tracking or counting issues about "where" a given renewable generator should be "counted." However, there will be many crossover issues whenever the two dimensions of the soft targets (county by utility) are not so clear. These crossover issues could be avoided by simply developing county soft targets; alternatively, if targets are developed for both counties and utilities, extra care may be needed to address accounting issues.

***1. Does the proposed methodology provide a sound mechanism for translating the statewide 12,000 MW goal into local targets? Please propose an alternative if you disagree with this methodology for developing soft targets.***

From PG&E's perspective, implementation of the 12,000 MW goal should be guided by four principles:

- Safe and reliable electric service with consistent power quality;
- Broad resource eligibility;
- Reasonable costs to customers, without cost-shifting; and
- California-wide participation

The allocation methodology incorporates these principles to a greater or lesser extent. First, by allocating statewide based on county- and utility-specific consumption data, the CEC is supporting DG located close to load, or at least making it less likely that significant quantities of DG will be located remotely. This can potentially support the principle of safe, reliable service, but any integration with the distribution grid can be site-specific. Use of this criterion can also support the principle of seeking reasonable costs, due to the reduced likelihood of remote siting.

Second, the weighting by income does not support any of the critical principles. However, PG&E does recognize that there can be positive impacts on job creation. In addition, since this criterion (as with the other three) is used only as an allocation method to a soft target, it does not create a set-aside or a tendency to a set-aside. In that respect, it will not put upward pressure on costs. Consequently, while not directly supportive of any of the critical guiding principles, this criterion is benign, and at least does not undermine them.

Third, the unemployment criterion also does not support any of the critical principles, but also is benign. Further, by assigning a soft target to an area with high unemployment, there could be some positive economic outcome for that area.[2]

[2] PG&E notes that the justification for the inclusion of unemployment statistics to drive allocation was based, at least in part, on PG&E's comments filed last October. The proposed allocation cites the PG&E comments as: "Pacific Gas and Electric (PG&E) suggest that 'net economic impact and job creation' are top priorities for targeting renewable energy development". For the record, PG&E was not commenting on targeting anything, especially allocation of the 12,000 MW, but rather was stating the many impacts of increased amounts of LER that should be considered. The potential impact included in the allocation scheme was thirteenth on a list of thirteen.

Fourth, the last criterion, distribution system capacity, would in theory tend to align with the guiding principles to ensure safe, reliable service at reasonable cost. However, PG&E has some concern that the implementation of this criterion is based on the 100% Learning Curve scenario of E3 study. As the allocation proposal recognizes, the E3 study violates existing Rule 21. The implementation of the fourth criterion is in direct opposition to the first guiding principle: safety and reliability.

Finally, PG&E would continue to express its strong interest in ensuring that whatever soft target allocation is adopted, it can be achieved with the lowest overall cost to customers. For this reason, PG&E expresses recognition of the fact the targets are "soft"; and appreciation of the fact the targets are not based on technology, or any other criteria that would create an expectation of set-asides. Any criteria used to allocate soft targets should support this overarching goal.

***2. Are there additional "levers" or criteria the Energy Commission should include in developing soft targets? If you suggest additional criteria, is information needed accessible, reliable, and accurate?***

The Governor's 12,000 MW goal was proposed in part to bring about the reduction of GHG emissions. PG&E suggests the CEC might allocate MW also by a criterion based on poor air quality.

***a. Please comment on whether you agree with, or describe how you would change, the following "lever" weightings included in this analysis:***

***40 percent for consumption by county***

PG&E supports use of this criterion as the best way to achieve California-wide participation.

***20 percent for low/moderate share of statewide income less than 80 percent of median income***

PG&E finds this criterion to be benign.

***20 percent for statewide share of unemployment***

PG&E finds this criterion to be benign, but suggests relative unemployment rate, rather than percent of statewide unemployment might better reflect the jobs need for a given county. The method chosen by the CEC will concentrate solar along population lines, rather than unemployment lines, whenever the two are not perfectly correlated.

***20 percent to reflect electrical grid requirements***

In theory, a criterion that is attempting to measure grid requirements is a good criteria, but simply looking for maximum capacity may not be the most appropriate measure. PG&E has separately filed comments on interconnection and issued identified in those comments could be used to develop more robust criteria for this element.

3. ***The Energy Commission used the results of the E3 preliminary assessment, Technical Potential for Local Distributed Photovoltaics in California to estimate available distribution and transmission grid capacity. Is the capacity information a proxy for least cost, best fit?***

No, it is not.

The key principle that should guide California's implementation of the 12,000 MW Localized Energy Resources (LER) goal is to provide safe and reliable electric service with consistent power quality. Implementation of this goal should also recognize the cost impact on our customers, and policymakers' actions should focus on reducing those costs wherever possible, and providing flexibility to utilities to help minimize these costs.

For example, when evaluating the cost impact of distributed generation, several costs are often not considered —but must be to fully inform the overall cost to customers. These costs include required upgrades to distribution infrastructure and required upgrades to address potential transmission-level impacts of DG interconnecting at the distribution-level. In addition, the levelized cost ($/MWh) of DG is typically significantly higher than utility-scale projects interconnecting at the transmission level—and these higher generation costs "dwarf" the cost of building incremental transmission. Ultimately, a true "least cost" analysis must reflect both any savings from DG, as well as the cost impacts of DG.

Furthermore, the technical concerns or constraints regarding the amount of DG that may be interconnected to a substation may be understated and may produce greater costs than anticipated. In particular, PG&E does not agree with the assumption that "the existing voltage regulation scheme should be generally sufficient to maintain voltage limits" (p.31) such that when PV output is high, the system should be able to accommodate it. It should not be assumed that the voltage regulation scheme will stay within limits when generation is approximately the same as load, especially given the intermittency of PV and highly variable output fluctuations which are often significantly faster than the voltage regulator equipment.

Additional studies are needed to determine the factors that govern feasibility and to better understand the significant engineering and infrastructure issues associated with integrating 12,000 MW of DG into the distribution and transmission grids. In particular, E3 highlights that actual achievement of the level of LDPV interconnection at the costs estimated in the study is largely dependent on several significant challenges including:

- *Interconnection*—the high level of PV penetration has not been examined in detailed engineering studies and achieving this level of interconnection could incur interconnection or ancillary services costs beyond those included in the study.
- *Geographic Development*—because "local" load is widely distributed in California, the market for LDPV would have to develop in such a way as to widely distribute local development in accordance with available load.
- *Cost to Customers*—the study does not consider economic impact including the public's ability to pay for LDPV which may constrain the technical potential identified in the study.

Studies aiming to evaluate the technical potential of DG should take into account deliverability of DG, particularly if those results will be used to inform the amount and distribution of DG. Further, a "no backflow" constraint may be insufficient to determine deliverability for DG[3] as deliverability of resources in an area where DG reduces load could be adversely affected, irrespective of backflow (which is one of the constraints used in the E3 study).

A better understanding is also needed as to how this 12,000 MW LER goal interacts with existing mandates. 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 and would increase costs to our customers. 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. Also, the tools to address these concerns may vary depending upon the size and location of the generator.

No matter what model is used to recover the cost of interconnection and integration of LERs, in the end, customers will pay higher costs if we do not carefully manage the implementation of the goal. From a utility perspective, it is important to keep the costs as low as possible and that the people who benefit from the generation pay their fair share of costs.

[3] In its draft final proposal for Deliverability of Distributed Generation, the CAISO explains the inaccurate assertion that DG resources connected to a utility distribution system should be considered deliverable as long as the total output of those resources does not exceed the total load below the same node. In particular, the ISO explains that a finding of deliverability for a group of resources depends on the modeled pattern of load that would be served by the resources. When DG resources reduce the load in the area, the collective deliverability of the resources in the area could be adversely affected, irrespective of whether there is any back flow.

***4. Should the Energy Commission continue to include the Department of Water Resources in the development of soft targets (it is not subject to the RPS)?***

Yes, a California program should be an all-of-California program.

## VI. CONCLUSION

PG&E looks forward to continuing discussion of these issues in the 2012 IEPR.

Sincerely,

/s/

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