Pacific Gas and Electric Company

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VIA E-MAIL DOCKET@ENERGY.CA.GOV

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

Re: 2012 Integrated Energy Policy Report Update: Comments of Pacific Gas and Electric Company on the Draft 2012 Integrated Energy Policy Report Update

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the California Energy Commission's (CEC) draft 2012 Integrated Energy Policy Report Update (draft IEPR).

PG&E is among the most avid and active proponents of policies that will advance California's transition to a low-carbon energy future. While the draft IEPR focuses on renewables, Californians will be best served by a clean energy policy that is wide ranging and supportive of all the tools that can reduce energy use and provide clean energy in a cost-effective manner. Our clean energy policies should consider energy efficiency, demand response, efficient combined heat and power, and renewables, as well as the wealth of carbon-free resources we already have -- like large hydroelectric facilities, and our existing nuclear power facilities. All of these resources together provide a diversified clean energy portfolio to power California in a safe, reliable, and cost-effective way. Clean energy strategies that do not consider the full array of carbon-free and low-carbon alternatives will only serve to increase customer costs.

PG&E is supportive of many of the recommendations in the draft IEPR. However, PG&E's support of a technology-neutral, cost-effective clean energy future causes it to recommend modification or elimination of certain draft IEPR recommendations, in particular the recommendations to assess development of interim 2030 targets under the Renewables Portfolio Standard (RPS) and the use of the California Independent System Operator's (CAISO) nuclear replacement assessment.

Assessing the development of interim 2030 targets under the Renewables Portfolio Standard (RPS) is premature and duplicative of resource planning activities conducted for the investorowned utilities (IOUs) by the California Public Utilities Commission (CPUC). Given the very significant operational work that remains to be done to integrate the increasing amounts of intermittent generation on the electric grid, PG&E does not believe it would be prudent for two regulatory agencies to perform the same resource planning activities.

As suggested below, the CEC could instead develop the tools needed to allow the selection of the most cost-effective clean energy alternatives to achieve greenhouse gas (GHG) emission reductions.[1] Renewable resources are just one of several ways to achieve GHG emission reductions – energy efficiency, demand response, efficient combined heat and power, hydroelectric power, extending the licenses of nuclear power plants like Diablo Canyon, and AB32 programs are among the many other tools available to reduce GHG emissions in the energy sector – and the best GHG emission reduction tools for the post-2020 timeframe are unclear at this time.[2] PG&E recommends this type of analysis be developed before there is a rush to increase the RPS from its current levels. The CEC has the expertise to develop such an analysis that could provide the cornerstone for evaluating post-2020 energy policies and it would fill a notable gap in California's policy analysis.

Additional analysis is also needed on the tools to operationalize and integrate current policy requirements. As part of PG&E's commitment to clean energy policy, it is continuing to gather information and investigate the right tools and resources for creating a diversified portfolio to power California in a safe, reliable, and cost-effective way. For example, in October 2012, PG&E issued an Energy Storage Request For Information (RFI) seeking information from storage purveyors about their technologies' operational capabilities, costs and readiness for commercial deployment. The RFI was open to existing and new storage technologies. Information of this nature is critical in assessing the costs and benefits of storage so that storage can be evaluated against the suite of viable, cost-effective alternatives to integrate renewables. PG&E will provide a summary of the RFI results to the CPUC.

Electric Vehicles (EVs) also have significant potential to provide needed services to the electric grid and help reduce overall costs and integrate renewable resources. Increased use of EVs would also reduce GHG emissions statewide. Increased use of electricity, relative to gasoline, will reduce GHG emissions and local criteria pollutants, and it can be part of a larger strategy to reduce emissions in the state.

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[1] See PG&E's May 21, 2012 Comments "PG&E Comments to the CEC on *Identifying and Prioritizing Geographic Areas for Renewable Development in California"*

[2] For example, if California's current cap-and-trade program is extended beyond 2020, a higher RPS target post-2020 might reduce GHG emissions for the electric sector, but not result in a reduction in GHG emissions across all sectors. A higher RPS for the electric sector would reduce the demand for cap-and-trade allowances from the electric sector, resulting in more allowances remaining in the marketplace, and likely at lower prices. As a result, other sectors will be able to buy more allowances at a lower price instead of investing in tools to curtail their actual emissions.

It is important to understand the critical factors that may lead to cost-effective deployment of EVs. These include:

- The relative cost of electricity versus gasoline;
- Electric vehicle costs, which may be substantially affected by the pace of advancement in battery technology and continuation of the Federal EV Tax Credit; and
- Incremental distribution costs caused by increased flows and changed operation of the distribution system.

In summary, additional analyses in these areas would provide greater benefit and understanding of challenges we face in integrating and advancing current policies to get to 2020. This work should take priority over any efforts to develop more renewable targets for the post-2020 timeframe.

With respect to infrastructure issues, PG&E also suggests modifications to the recommendation on the use of the California Independent System Operator's (CAISO) analysis of the impact to the transmission grid in the absence of nuclear resources. While the analysis may be one of several that policymakers can consider in evaluating cost-effective carbon-free resources, PG&E does not recommend that the CAISO's assessment be used as a substantive basis for debate about policy decisions concerning reserves needed to address nuclear facility outages and the amount, type, and costs of infrastructure to replace these facilities. First, the study has not yet been completed or assessed by stakeholders and it would be premature to assign such importance to a document that has not yet been thoroughly vetted. Second, the CAISO study is expected to provide a limited assessment of the transmission reliability impacts due to an outage at Diablo Canyon. The study does not evaluate other important aspects such as cost impact, environmental impact, effect on the flexibility needs to integrate 33% RPS effect on reserve margin requirements, and other important policy considerations. Therefore, the study will likely not be robust enough to serve as the cornerstone of such an important policy debate on this carbon-free resource.

The draft IEPR casts a very wide net and it sets forth a very comprehensive but challenging multi-agency collaborative approach to implementing the proposed recommendations, particularly with respect to the Renewables Action Plan (RAP). While PG&E may not be in agreement with some of the proposed recommendations in the draft IEPR, PG&E commends the CEC on the thoughtfulness of its approach and the outreach conducted with its sister agencies to help advance the work on many important topics. This process helps to create a roadmap of the many activities needed to implement and refine existing programs. However, given the breadth of these activities, PG&E would prioritize recommendations that focus on implementing existing programs and assessing the cost and operational impacts of those programs and eliminate recommendations that may be duplicative of existing processes.

PG&E appreciates the CEC's support for electric rate design reform and its acknowledgement that rate design should be equitable and sustainable. While the draft IEPR focuses on renewable energy, PG&E believes that renewable energy is part of a broader clean energy policy, and the actions to promote renewable technologies must ensure that the costs and benefits of renewable development are fairly distributed. PG&E is also supportive of recommendations to further monitor and evaluate the need to harmonize electric and natural gas markets and is actively participating in the Federal Energy Regulatory Commission's (FERC) inquiry, "Coordination Between Natural Gas and Electricity Markets" (AD12-12). PG&E also participates in the Western Gas-Electric Regional Assessment Task Force whose members include state utilities commissioners and gas and electricity industry participants in the West, as well as the CEC.

The CEC's support for the development of forward electric procurement mechanisms, along with the CEC's recognition of the planning challenges associated with integrating more intermittent resources, "which will require a combination of complementary resources like energy storage, demand response, smart grid technologies, and flexible natural gas plants to provide the services needed to operate the electric grid safely and reliably" are also important acknowledgments of the operational issues we face today in the electric industry. These recommendations highlight the need to fully understand the operational impacts – and associated cost implications -- of the clean energy goals in the context of an overarching clean energy policy framework. Developing the appropriate mechanisms and addressing the planning challenges are critical to supporting PG&E's goals of providing safe, reliable, environmentally sound, and affordable electricity to all of its customers.

PG&E also agrees with the recommendation in the draft IEPR that the potential impacts of climate change on energy demand and energy supply need to be studied further.

The remainder of PG&E's comments elaborates on its concerns and suggests technical and editorial comments on other sections of the draft IEPR, including distribution system planning and combined heat and power (CHP) issues. PG&E looks forward to continuing its dialog with the CEC on these important issues.

II. OPERATIONS AND INTEGRATION ISSUES MUST BE EVALUATED AND ADDRESSED BEFORE EXPANDING OUR CLEAN ENERGY GOALS

PG&E agrees that reliability, safety, and affordability of electric service are key criteria for successfully achieving California's clean energy and greenhouse gas emission reduction goals. As the state continues to make progress toward its 2020 goals, it will be important to first assess the "reliable" and "affordable" elements of California's clean energy strategy, including the 33% RPS, before further expanding these policies. The focus should be on assessing the cost and operational impacts of the 33% RPS requirement before considering higher RPS levels. This is especially true because it remains unclear today what is needed to maintain system reliability even at the 33% RPS level. A discussion of even higher levels of renewables distracts from the very significant operational work that remains to be done to ensure that the electric grid is safe and reliable at the 33% RPS level.[3]

A. A Better Understanding of the Cost of Carbon Reduction Tools is Needed Before Moving Beyond 33% RPS

The CEC makes several references to RPS as the primary way to meet California's 2050 GHG reduction goals, but nowhere does it address or mention the cost effectiveness of this as the sole means for reducing GHG emissions. Furthermore, the draft IEPR fails to consider the significant uncertainty of the cost and rate impacts associated with achieving a 33% RPS standard. The CEC should consider clean energy policies that give flexibility to minimize costs for our customers. Renewable resources are just one of several ways to achieve GHG emission reductions and solutions to reduce GHG emissions should be viewed comprehensively.

It is critical that the cost to integrate renewables be transparent and that cost causation principles be applied when allocating the costs of integrating renewables. To date, PG&E has been unsuccessful in obtaining approval from the CPUC to include a renewable integration adder in its RPS request for offers.[4] Failure to reflect a renewable integration adder obscures the true cost of integrating renewables onto the system. Cost causation principles should be a cornerstone in allocating the cost of renewables. The CAISO has addressed cost allocation in recent stakeholder initiatives and developed cost allocation guiding principles. These principles provide an increased level of transparency to ensure costs are appropriately allocated.

For these reasons, as noted in the Introduction, PG&E does not support Recommendation 3 of the RAP which calls for going beyond 2020 and evaluating generation needs in 2030. Such an analysis is premature and duplicates efforts of the CPUC, which is performing this sort of analysis in the long-term procurement plan. PG&E recommends instead that the CEC evaluate what would be the projected quantity of GHG emission reductions (in tonnes) achieved by going from 33% to some higher level of RPS, and what is the implied carbon cost per tonne of reduction (in dollars). With this information, the CEC 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 and allow for a meaningful assessment of the cost and rate impacts of the myriad energy initiatives already adopted to get to 2020 and those being considered for the post-2020 period. California could then choose the most cost-effective means to achieve its GHG emission reduction goals, and the CEC's work could help guide the implementation timelines for various

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[3] On December 3, 2012, the Little Hoover Commission issued a study "*Rewiring California: Integrating Agendas for Energy Reform"* with recommendations on California's transformation of the electricity system. Of particular note, the study puts forth the importance of prioritizing current and future energy goals and the need for a moratorium on new energy-related mandates until such a plan is in place (p. ix, Executive Summary).

[4] CPUC Decision 12-11-016, p. 27.

initiatives, particularly when considering the cost to refurbish other aging infrastructure in the state.

B. Consideration of Non-Energy Benefits in Portfolio Development is Important, But A Balancing of Societal and Electric Customer Interests is Also Important

Other recommendations in the RAP include modifying procurement practices to develop a "higher value" portfolio, establishing pilot working groups to create maps (p. 44), and creating a statewide data clearinghouse for renewable planning (p. 62). While PG&E is supportive of the CEC's belief that technology diversification in RPS is important, each load serving entity (LSE) should be allowed to determine the appropriate mix of technology for its portfolio. Legislatively-mandated carve-out programs (such as Senate Bill (SB) 1122) work at odds with efforts to ensure system reliability and to reduce costs to customers. Lastly, PG&E does not support the CEC's definition that a higher-value portfolio must include a value for projects that may yield non-energy benefits like "reduce the risk of forest fires," "encourage investment in disadvantaged communities," and "create jobs in CA." While these non-energy objectives may be important, efforts to monetize these objectives should be part of a larger discussion about ways the government can achieve these goals versus having the electric industry and its customers solely bear these costs. Otherwise, electricity supply costs will increase but there will be no corresponding increase in the ability to deliver safe, reliable service. Furthermore, least-cost, best-fit procurement principles must be considered in the development of the portfolio.

C. PG&E Supports DRECP-type Mapping Initiatives for Utility-Scale Development

With respect to creating maps to identify renewable energy development zones for smaller scale projects (i.e., DG up to 20 MW), PG&E notes significant improvements have been made in this area through the Renewables Auction Mechanisms (RAM) implementation, where maps indicating selected electric transmission lines, electric distribution lines and substations within the PG&E service area have been developed.[5] These maps are updated monthly and also provide specific information, such as operating voltages, line capacity and substation names to aid in identification of preferred areas for interconnection.

As noted in earlier IEPR comments, PG&E supports comprehensive land use planning efforts for utility-scale generation in the Central Valley and the creation of mapping data is a critical first step toward comprehensive land use planning. Identification of zones could guide renewable energy and transmission development to appropriate areas and minimize land use conflicts. However, the usefulness of map zones is unclear. Customers of electric utilities will not receive the benefits of this mapping initiative unless developers choose to site their facilities in these mapped zones. Accordingly, the planning processes should include clear incentives to developing renewable energy projects in zones (e.g., streamlined permitting, expedited review).

[5] http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/

As additional DRECP-type (Desert Renewable Energy Conservation Plan) mapping initiatives are undertaken, however, it is important to note that development patterns and land use issues in the Central Valley differ from those in the DRECP; however, the process used to develop the DRECP (e.g., stakeholder collaboration, identification of zones) will provide the foundational patterns for the next mapping efforts and a clear leader of the effort must be identified.

The mapping of zones should also be prioritized, with a focus on zones near urban areas and on lands with low habitat or agricultural value; however, policymakers must acknowledge that development may still have some effects on species. Accordingly, PG&E recommends that endangered species permitting and mitigation continue to be considered in renewable energy zone planning. These are essential elements of determining preferred areas for development and will provide valuable information to potential developers about the characteristics of the area. The zone mapping should also consider what transmission upgrades may be required for build out and transmission planning should be considered early in the planning and mapping process.

The result of this comprehensive renewable energy planning should be 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. Endangered species act permitting should be completed with wildlife agencies, and best management practices should be identified.

Implementation of some aspects of this recommendation, however, may be challenging. First, identifying preferred spots for Distributed Generation (DG) is challenging. The distribution system is dynamic and as more DG is added to the system, this reconfiguration of resources can change or eliminate zones that may have been previously considered preferred locations. Second, high penetrations of DG may impose additional costs to the system (e.g., integration costs). Careful analysis will be needed to avoid unintended consequences of higher DG penetration. Furthermore, it is not clear to PG&E whether this recommendation is focused on mapping land use for utility-scale generation or if it also includes permitting for endangered species. PG&E is certainly supportive of collaborative and comprehensive planning processes that will help provide similar outcomes as the DRECP, which include landscape level approaches to programmatic permitting that identifies appropriate mitigation and transmission.

Another challenge is the consideration of DG in communities disproportionally burdened by environmental pollutants. The bulk of environmental pollutants and toxic air contaminants come from mobile sources, not power plants.[6] Such a consideration, if performed, must be carefully evaluated to ensure that benefits actually accrue to that community. It will require an analysis

[6] In Los Angeles County, for example, power plants emit 2.09 tons of NOx per day, or about half the amount emitted by recreational boats. Diesel trucks, in contrast, emit over 100 tons of NOx per day. Source: http://www.arb.ca.gov/ei/emissiondata.htm

that would assess or measure the environmental and economic benefits of proposed renewable energy facilities to the identified communities, along with a quantification of lost production and/or additional costs, if any, resulting from siting the facility in a location suboptimal for system needs. The analysis should also include quantifiable economic benefits to the host community over the life of the project (e.g., jobs created). Lastly, the environmental assessment should consider if the facility will provide local environmental benefits.

Finally, it would be more appropriate for utilities to provide technical data and inputs to any mapping process; zones should be identified through a stakeholder process with inputs from local jurisdictions with greater familiarity with local land use requirements and restrictions. Similarly, through this process, there is a need to clearly indicate which parties are responsible for the listed actions to develop renewable overlay maps for DG. Utilities should not be the drivers of the process to develop zones but should be active participants in the process.

D. A Statewide Data Clearinghouse Could Better Inform Planning and Siting Decisions

PG&E is supportive of efforts to develop a statewide data clearinghouse for renewable energy generation planning. The data will better inform decision making and renewable energy planning processes and help reduce potential siting conflicts, potentially advancing the pace of renewables development and reducing costs, particularly where information on environmental issues can be catalogued and each project does not have to "reinvent the wheel." As a result, PG&E recommends that any Geographic Information System (GIS) data gathered be made publicly available so that the most up-to-date information can be easily utilized. However, any effort to collect such data will have to be conducted in a way that protects customer confidentiality and proprietary information. For example, PG&E has national security obligations so the data it may be able to provide in some areas may be limited or the data may need to be redacted or summarized before being made publicly available. Furthermore, the CPUC has already amassed a great deal of information on renewables development through its numerous reporting requirements (e.g., the Project Status Development Report, the newly-required Public Utilities Section 910 report to the legislature to be filed in early 2013, the RPS cost information disclosures required by the legislature, and the annual CAISO transmission plan, among other reports). Accordingly, in developing the clearinghouse, the agencies should carefully evaluate what data may already exist and determine what additional value a new clearinghouse would provide if data already exist elsewhere, given it would take significant effort to consolidate and regularly maintain a new dataset.

E. Increases in Renewables Bring Limited Air Quality Benefits

The draft IEPR notes that renewable generation has the benefit of "improving air quality" (p. A-1). This statement can and should be quantified. The effect of renewables on emissions was examined by the California Air Resources Board (ARB) staff in 2010. ARB staff found that increasing the RPS target for the year 2020 from 20 percent to 33 percent would reduce statewide NOx emissions by 1,000 to 1,300 tons/year[7], which is about one-tenth of 1 percent of current statewide NOx emissions.[8]

III. THE CAISO'S "NUCLEAR REPLACEMENT STUDY" PROVIDES A VERY LIMITED ANALYSIS OF THE IMPACT TO THE GRID IN THE ABSENCE OF SONGS AND DIABLO CANYON AND SHOULD NOT SERVE AS THE SUBSTANTIVE BASIS FOR POLICY DISCUSSIONS

In Chapter 4 on electricity infrastructure needs, it is recommended that a CAISO study on nuclear replacement issues that is currently under development should be used as the substantive basis for future policy decisions on reserve needs to address a nuclear facility outage.[9] PG&E opposes this recommendation because the CAISO capacity replacement study focuses on an extremely narrow set of criteria. The CAISO study should not be used as the basis for a substantive debate about replacement of Diablo Canyon because it provides a limited assessment of the transmission reliability impacts that may occur during an outage at Diablo Canyon. In fact, the CAISO study is not a nuclear replacement study; rather, the CAISO states that its study will "…examine [the] reliability impact to the electric grid in the absence of the two nuclear generating stations within its balancing authority area (i.e., Diablo Canyon Power Plant and San Onofre Generating Station)." The CAISO also explains, "Local and system grid reliability impact due to the absence of these two base-load nuclear generating stations will be evaluated."[10] Furthermore, the study does not evaluate other important considerations including the cost impact, environmental impact, 33% RPS integration impacts, impact on reserve margin requirements, and other important considerations. PG&E is concerned about the rush to accept this study when it will not consider these important issues, nor has the study even been subject to public review and input as to the robustness of the analysis.

PG&E suggests that this recommendation be modified to reflect that the CAISO's study is one of several studies that will be needed to better understand the grid and resource impacts of an extended nuclear outage and to assess alternatives. PG&E supports a CEC-sponsored workshop to evaluate the results of the CAISO study as a first step in developing a more complete assessment of this important issue. Reliance on a single study that was developed for a far more limited purpose will not serve policymakers well.

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[7] See slide 21 of ARB staff's presentation: http://www.arb.ca.gov/board/books/2010/092310/10-7-1pres.pdf .
[8] Statewide total NOx emissions in 2008 were 3,209.7 tons per day, or about 1.2 million tons per year. (Source: http://www.arb.ca.gov/ei/emissiondata.htm)
[9] See pages 38 to 41.
[10] See "2012/2013 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2012.

IV. PG&E SUPPORTS RECOMMENDATIONS TO REVISIT CHP TECHNICAL ASSESSMENTS, ALONG WITH A BALANCED ASSESSMENT OF ANY BARRIERS

PG&E supports efficient CHP that provides a cost-effective and reliable source of electricity to our customers and helps to reduce greenhouse gas emissions statewide. As California continues towards an ever-cleaner energy future, a critical issue is to understand under which circumstances CHP will reduce GHG emissions. In the long run, marginal electricity emission rates will decline making it more challenging for CHP to provide a net reduction in emissions. CHP's place in the broader framework of California's energy policies, and whether CHP will help achieve California's energy and environmental goals, is deserving of additional study.

A more robust analysis prior to policymaking is especially critical because CHP, unlike renewable generation, has the potential to increase GHG emissions if deployed and operated in an inefficient way. To inform understanding of efficient CHP potential, the CEC should revisit the reporting guidelines of thermal output reported by CHP facilities in the CEC's Quarterly Fuels and Energy Report (QFER) so that generators report better quality information more consistently. PG&E provided its suggested changes to Form 1304 in its comments submitted for the CEC CHP workshop on March 12, 2012. This improved data should be made publicly available at the appropriate level of aggregation. CHP's impacts on operational flexibility and the potential for over-generation should be mentioned in the relevant sections of this IEPR update.

In general, PG&E supports the draft policy recommendations for CHP found in Chapter 3 of the draft IEPR. This group of recommendations is much more targeted than those contained in the CEC staff white paper on CHP and appropriately scopes areas of additional review, including revisiting the technical assessment of CHP, acknowledgement of revisions already being considered to the interconnection rules, and continued monitoring of the impacts of existing CHP policy.[11] The draft IEPR appropriately does not include many of the troublesome aspects of the CEC staff white paper, which made numerous financial and regulatory recommendations that would only serve to increase customer costs and shift costs from one customer class to another without any assured reliability or GHG reduction benefits. PG&E is supportive of clean, cost-effective CHP that enhances electric system reliability. PG&E does not support recommendations that will increase costs to customers while subsidizing inflexible, inefficient generators that increase GHG emissions.

In contrast to the recommendations, however, PG&E disagrees with many of the listed "Barriers to CHP development." Some of them, such as the cap-and-trade program's impact on CHP development, are factually incorrect. Others, such as expanding the Net-Energy Metering (NEM) program are not "barriers"; they are simply policies that do not currently subsidize CHP

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[11] PG&E Comments to the CEC on *Combined Heat and Power Staff Paper* – online at http://www.energy.ca.gov/2012_energypolicy/documents/combined-heatpower/comments/Pacific_Gas_and_Electrics_Comments_2012-10-22_TN-67954.pdf

as they do for various renewable technologies, and which are now under critical review by the CPUC. PG&E's October 22, 2012 comments on the CEC staff white paper address these perceived barriers and note that: 1) cap-and-trade is likely to incentivize efficient CHP;[12] 2) CHP already enjoys numerous exemptions from existing demand, standby, and departing load charges and additional exemptions should not be granted; [13] and 3) CHP should remain ineligible for Net-Energy Metering.[14] PG&E incorporates those comments by reference and respectfully requests that the section on "Barriers" be modified to reflect additional analysis is needed in various areas, rather than reaching conclusions not supported by the record.

For example, rather than concluding cap-and-trade will adversely affect CHP development, PG&E suggests this be reworded as "analyze whether cap-and-trade will affect CHP development." This will then allow for an evaluation of how cap-and-trade may affect efficient, as well as inefficient, CHP. A balanced exploration of the true barriers to CHP development will better inform future policy developments.

V. DISTRIBUTION PLANNING PROCESSES ARE IMPROVING, ALTHOUGH MORE UNDERSTANDING IS NEEDED

A. Distribution Planning Processes Improvements

As noted above, significant improvements in providing mapping information to aid in selecting development areas on the distribution system have been made. These maps are updated monthly and show selected electric transmission lines, electric distribution lines, and substations within the PG&E service area. In addition, the maps also provide specific information, such as operating voltages, line capacity, and substation names to aid in identification of preferred areas for interconnection.

Despite these improvements, many stakeholders lack a clear understanding of the operation of the distribution system and the process by which it is planned. Central to the distribution planning process is the reality that each distribution circuit is different and, therefore, each proposed project must be reviewed individually. Current distribution planning processes worked well when the number of units proposing interconnection was limited – for example, if a 20 MW generator needed to interconnect to the distribution system. However, today's diversity of both customer- and utility-scale generation has overwhelmed this process, where the amount of effort to interconnect twenty 1 MW units is significantly in excess of the effort to interconnect a single 20 MW unit. Further complicating things, if a generator earlier in the queue does not materialize and implement expected network upgrades, generators later in the process may be required to perform unanticipated network upgrades and incur more costs.

Many parties are understandably frustrated with the process and parties have and continue to dedicate significant time to improving the process. Key to improving the process is to first

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[12] Ibid, page 9
[13] Ibid, page 4-6
[14] Ibid, page 12

understand the existing process, along with the system safety requirements, concerns about voltage fluctuation, and system reliability issues. Workshops to better illustrate existing processes may be helpful.

Many are evaluating how standards (e.g., IEEE-1547) should be modified to accommodate higher DG levels. The existing IEEE-1547 and UL-1741 were designed to facilitate renewable interconnections for small units at low penetration. They were never intended for the high level of DG penetration that is currently being proposed. Standards modification can take 3 to 5 years to complete and technical issues must be fully understood before moving forward. For example, recent concerns include whether existing inverter certifications will still be valid if the existing default trip settings are changed. The "ripple" effect of changing one part of the standard must be clearly understood. PG&E has encountered similar issues since adopting the provisions of IEEE-1547. Other jurisdictions with high DG penetrations (e.g., Germany) have encountered similar issues. It will be important for California to consider "lessons learned" in other jurisdictions to avoid making similar (and costly) mistakes here.

B. Standards are Needed for Volt-Var Inverters

There has been much discussion on the need for better inverters to respond to system conditions, although there is little consensus at this time as to what are the appropriate solutions. These discussions need to go beyond just the technology issues – cost and payment for volt-var and frequency assistance must be discussed and the appropriate regulatory mechanisms (e.g., tariffs) will need to be developed to provide the right signals for investment in this technology.

In addition to simply requiring volt/var inverters, standards are needed on how to coordinate multiple devices. Rules are needed to make sure that the inverters will not "fight each other" and cause voltage problems for load customers on the feeder systems. Identification of the conditions where inverters can effectively benefit the system is also needed to inform the standards development. These are important issues and even with a requirement for improved inverters, there are unanticipated consequences as DG achieves high penetration. Of note, Germany is now planning to re-program 315,000 inverter trip settings to avoid causing system problems at high penetrations. This re-programming is driven by system reliability standards, and cannot be addressed simply by requiring all systems to have a certain type of inverter.

VI. NATURAL GAS CLARIFICATIONS ARE NEEDED

A few corrections to the natural gas discussions in the draft IEPR are needed to ensure the accuracy of the final IEPR. PG&E details these below.

A. On page 18, the draft IEPR states there is a need for gas nomination opportunities less than 24 hours before gas-fired plants come on line. PG&E notes that such opportunities already exist today. There are two "intra-day" opportunities whereby gas can be nominated for same day flow. These are in addition to the two cycles available the day before flow. PG&E notes that it has made previous proposals to the CPUC to add a third intra-day cycle, however that proposal was not adopted.[15]

B. On page 19, corrections are needed to appropriately characterize the San Bruno event, which occurred on the PG&E gas transmission system. First, in the sentence "…planned pipeline safety enhancements in the wake of the September 2010 explosion in San Bruno, California, of a high-pressure natural gas transmission pipeline and distribution system…", the words "and distribution system" should be deleted. The San Bruno incident occurred on PG&E's gas transmission system, not its gas distribution system.

C. A similar correction is needed to a later sentence on the same page "…pipeline safety enhancement plans to improve the natural gas transportation and distribution system in the state." The words "and distribution" should be deleted from this sentence, because the cited CPUC order refers only to the gas transmission system.

D. Finally, additional clarity can be provided on the additional pipeline capacity available for California's use. PG&E suggests that adding the words "Ruby Pipeline" to the following sentence "Additional pipeline capacity available for California's use "(Ruby Pipeline)" has resulted in more pricing competition and could mean lower natural gas rates for California consumers."

VII. CONCLUSION

PG&E is happy to meet with CEC staff on these important topics.

Sincerely,

/s/

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[15] See PG&E's Gas Transmission and Storage Proceeding, A.09-09-013.