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VIA E-MAIL DOCKET@ENERGY.CA.GOV

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 13-IEP-1A
1516 Ninth Street
Sacramento, CA 95814-5512

Re: 2013 Integrated Energy Policy Report: Comments of Pacific Gas and Electric Company on Draft 2013 Integrated Energy Policy Report

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the California Energy Commission's (CEC or Commission) Draft 2013 Integrated Energy Policy Report (IEPR),[1] which was discussed at a CEC Workshop on October 15.[2] The IEPR is the leading energy policy report for the State of California and impacts energy policy discussions among elected officials, public agencies, stakeholders, and the public.

Two common themes run through the diverse subject matter of the Draft 2013 IEPR: addressing climate change and the reliability of the state's electric system. This is a timely and important focus, as a major transformation is underway in how electricity is generated and distributed. In a relatively short period, California has instituted a number of major energy policies: 33 percent of all retail electricity sales will come from eligible renewable resources in 2020; greenhouse gas (GHG) emissions must be reduced to 1990 levels by 2020; once-through cooling regulations will result in the potential retirement of more than 17,000 megawatts (MW) of capacity by 2020; and the state has set a goal of 12,000 MW of renewable energy from distributed generation, to name just a few. Implementation of these and other programs brings to the forefront issues about how to reliably and affordably meet customers' energy needs as more and increasingly intermittent resources are added to the electric grid.

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[1] California Energy Commission. (2013). *Draft 2013 Integrated Energy Policy Report* (No. CEC-100-2013-001-LCD). Sacramento, CA. Retrieved from http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-LCD.pdf

[2] Workshop Page: http://www.energy.ca.gov/2013_energypolicy/documents/#10152013

To support these two key initiatives, PG&E recommends that the Commission establish a transparent, cost-based framework to prioritize the many assorted programs, technologies, and pathways to improve system reliability and address climate change.

Such a framework would help ensure that state goals are met with an appropriate mix of cost-effective policies. Specifically, the framework would offer the following key benefits: encourage stakeholder engagement around a standardized analytical framework, focused on cost-effectiveness; provide a high-level "status-check" on technologies, policies, and goals; provide a tool that can be used to prioritize activities in the post-2020 timeframe; and promote a constructive dialogue about a sensible and affordable energy policy. PG&E's Carbon Metric Framework[3] presented at the August 19 IEPR Workshop provides a structure for such a discussion.

In addition to these introductory comments, PG&E offers detailed comments on the Draft 2013 IEPR in Sections II through VI below. The following summarizes PG&E's key points:

Energy Efficiency (Chapter 1):

- PG&E was glad to see the CEC propose a definition for Zero Net Energy (ZNE) buildings in the Draft 2013 IEPR, which is an important step towards the 2020 and 2030 ZNE goals. However, there are significant uncertainties underlying the distributed generation (DG) component of ZNE implementation that are not reflected in the Draft 2013 IEPR's discussion of, or definition for, ZNE.

- In light of these uncertainties, PG&E recommends that the CEC modify the final ZNE definition by: (1) adding flexibility to allow for both on-site and off-site renewables dedicated to the building, until further research can illuminate the impacts and merits of each; and (2) clarifying that Time Dependent Valuation (TDV) requires enhancement to appropriately value DG system production.

Nuclear Power Plants (Chapter 6):

- The discussion of seismic hazards at Diablo Canyon Power Plant (DCPP) in the Draft 2013 IEPR is outdated and contrary to information available to the CEC. Unfortunately, having ignored PG&E's July 3, 2013 comments on the June 19, 2013 Nuclear Workshop, the Draft Report contains inaccurate, unsupported and incomplete factual statements. The significant omissions and incomplete factual record undermine the overall credibility and accuracy of the seismic discussion in the Draft 2013 IEPR.

[3] Williams, R. (2013, August). Finding Cost-Effective Greenhouse Gas Reductions (2030). Presented at the Workshop on Evaluation of Electricity System Needs in 2030, California Energy Commission. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-19_workshop/presentations/11_Pacific_Gas_and_Electric_130816_Draft_CEC_IEPR_Workshop_Slides.pdf

- The Draft 2013 IEPR addresses nuclear safety and operational issues that are subject to direct and exclusive oversight by the U.S. Nuclear Regulatory Commission (NRC) under the Atomic Energy Act. While PG&E is fully supportive of sharing information, there is no legal basis for the CEC's review. These operating issues are within the exclusive jurisdiction of the NRC and recommendations that address nuclear safety and operating issues should be deleted or modified to propose monitoring of NRC action.

Bioenergy Status and Issues (Chapter 3):

- PG&E is the largest purchaser of bioenergy in the state. Bioenergy projects play an important role in PG&E's Renewables Portfolio Standard (RPS) portfolio and are sourced from both biomass and biomethane generation.

- PG&E proposes that support for the bioenergy industry should be shared by all Californians, since many of the benefits associated with bioenergy serve all Californians. The Draft 2013 IEPR's recommendation that the CPUC modify its procurement practices would not ensure that the responsibility of supporting the industry across the state is spread across all Californians, as the CPUC does not have jurisdiction over the entire state. The Draft 2013 IEPR should also consider broader policy actions to more fairly allocate the costs of societal benefits associated with bioenergy projects.

Demand Response (Chapter 2):

- In accordance with the state's loading order, PG&E is very supportive of enhancing the role of demand response (DR). At the same time, PG&E is concerned that any hasty and premature changes to the current structure may jeopardize the very existence and scope of DR and its function as a preferred resource.

- PG&E wholeheartedly supports the Commission's decision to analyze the "technical, economic, market, and policy barriers to the use of demand response to support reliability and the integration of renewable resources."[4] Moreover, PG&E values the CEC's thoughtful analysis on DR and agrees with the majority of the 2013 IEPR's assessments and recommendations. However, as stated in its comments on the CEC's July 17 Workshop on DR, PG&E is disappointed that the CEC restricted its analysis to automated, supply-side DR. PG&E reiterates its recommendation that the CEC analyze the full range of DR programs.

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[4] McAllister, A. (2013). 2013 Integrated Energy Policy Report Scoping Order (No. 13-IEP-1A). Sacramento, CA: California Energy Commission. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-03-07_scoping_order_2013_IEPR.pdf. Pg. 2.

Natural Gas (Chapter 7):

- PG&E provided comments on the CEC's initial estimates of potential natural gas demand from new Combined Heat and Power (CHP).[5] PG&E appreciates that the staff revised the assumptions of installed CHP demand downward to reflect the current values. However, the upper range of 3,273 MW of new CHP by 2024 may still be too high. PG&E recommends that this value be reduced further in the Final IEPR forecast to be more consistent with other recent planning studies.

[5] 2013 Integrated Energy Policy Report: Lead Commissioner Workshop on 2013 IEPR Natural Gas Issues, Trends, and Forecast Scenarios – Comments of Pacific Gas and Electric Company - http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-17_workshop/comments/PGandE_Company_Comments_2013-07-31_TN-71776.pdf

II. ENERGY EFFICIENCY IS A CRITICAL TOOL TO REDUCE ENERGY USE

Chapter 1, "Energy Efficiency," of the Draft 2013 IEPR discusses the CEC's efforts to develop a comprehensive program to increase energy efficiency savings in existing buildings and the development of a definition for and the Commission's efforts around ZNE buildings, among other topics. As emphasized in the Draft 2013 IEPR, energy efficiency is the first resource in the loading order established in the 2003 Energy Action Plan.[6] Accordingly, energy efficiency's place in the loading order is a critical consideration for future ZNE policy decisions. PG&E has long supported the energy efficiency programs and has actively participated in several CEC workshops to develop the Comprehensive Energy Efficiency Program for Existing Buildings (EEPEB) Draft Action Plan (Action Plan)[7] and incorporates its comments on the Action Plan by reference.[8] PG&E looks forward to providing further input once the CEC releases the Final Action Plan. PG&E's comments on this Chapter focus on the Commission's proposed definition for ZNE.

PG&E was glad to see the CEC propose a definition for ZNE in the Draft 2013 IEPR, which is an important step towards the 2020 and 2030 ZNE goals[9]. However, there are significant uncertainties underlying the DG component of ZNE implementation that are not reflected in the IEPR's discussion of, or definition for, ZNE. Recent collaborative ZNE research projects[10] have highlighted these uncertainties, which include: market preferences, cost effectiveness, and grid impacts. These uncertainties must be captured in the Draft 2013 IEPR's discussion of, and definition for, ZNE.

For the reasons noted below, PG&E recommends that the CEC modify the final ZNE definition by: (1) adding flexibility to allow for both on-site and off-site renewables dedicated[11] to the building until further research can illuminate the impacts and merits of each; and (2) clarifying that TDV requires enhancement to appropriately value distributed generation system production.

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[6] Consumer Power and Conservation Financing Authority, California Energy Commission, & California Public Utilities Commission. (2003). 2003 Final Energy Action Plan. Sacramento, CA. Retrieved from http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

[7] Workshop Page: http://www.energy.ca.gov/ab758/documents/#2013_june

[8] Winn, V. J. (2013). Comprehensive Energy Efficiency Program for Existing Buildings: Staff Workshop on the Comprehensive Energy Efficiency Program for Existing Buildings Draft Action Plan–Comments of Pacific Gas and Electric Company. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/ab758/documents/2013-06_workshops/comments/PG_and_E_Comments_on_the_Comprehensive_Energy_Efficiency_Program_for_Existing_Buildings_2013-07-12_TN-71638.pdf

[9] Op. cit., 2013 Draft IEPR, pp. 11.

[10] The "Road to ZNE: Mapping Pathways to ZNE Buildings in California" (Heschong Mahone Group, 2012) and "Technical Feasibility of ZNE Buildings in California" (Arup, 2012) were statewide Investor Owned Utility-funded research projects that were overseen by the California Public Utilities Commission with input from the California Energy Commission.

[11] Dedicated refers to least-cost on-site and off-site options for associating a renewable energy source with a building that do not result in cost shifts to other customers. These options would need to be vetted through the Title 24 Rulemaking process and concurrently would likely require revisions to existing rate and tariff structures under California Public Utilities Commission jurisdiction.

A. CEC Should Adopt a Flexible Definition for ZNE

The definition for ZNE proposed in the Draft 2013 IEPR introduces uncertainty as to how the ZNE definition will be implemented for building types that cannot logistically accommodate sufficient renewable energy generation systems to offset on-site energy consumption and thereby achieve ZNE. While the Draft 2013 IEPR discusses the possibility of an exception for the "use of off-site renewable energy sources where the site cannot accommodate co-located generation of any sort,"[12] this example represents an extremely rare situation. Many sites can accommodate *some* form of DG, just not enough to sufficiently offset onsite consumption.

PG&E recommends that the 2013 Draft 2013 IEPR instead focus its attention on the various building types—such as large offices, multifamily buildings, and sit-down restaurants—that recent research[13] indicates will have significant trouble meeting the proposed ZNE definition. Failing to show how these building types will be expected to comply with the proposed ZNE definition introduces uncertainty into the market place. To this point, the California Building Industry Association (CBIA) and California Business Properties Association (CBPA) jointly conveyed their concern that it is "hard to envision a ZNE building that is three or more stories in height that could reach ZNE without the ability to utilize off-site renewables."[14]

This uncertainty demonstrates the need for the final ZNE definition to remain flexible until sufficient data can be collected. A flexible definition would allow all stakeholders to better understand the many DG components of ZNE: namely, market preferences, cost effectiveness, and grid impacts related to on-site and off-site DG systems, among others.

Research into these issues has commenced through various arenas, such as the California Solar Initiative Research, Development, Demonstration, and Deployment (RDD&D) program.[15] Furthermore, preliminary findings from recent CPUC research demonstrated that there is a significant cost shift associated with Net Energy Metering,[16] the accounting mechanism for ZNE that exists today.

It will be critical to allow sufficient time for stakeholder consideration and dialogue on these and other future research findings as the CPUC progresses through proceedings that will

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[12] Op. Cit., 2013 Draft IEPR, pp. 29

[13] "Technical Feasibility of ZNE Buildings in California (ZNE Technical Feasibility)", Arup, December 2012, Table 2, pp. 6

[14] California Building Industry Association, & California Business Properties Association. (2013). Comments on Zero Net Energy Definition. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-18_workshop/comments/CBIA_and_CBPA_Comments_08-01-13_TN-71782.pdf, pp. 3.

[15] The California Solar Initiative (CSI) Fourth Grant Solicitation for the Research, Development, Demonstration, and Deployment (RD&D) Program provides $7 million in funding for photovoltaic system grid integration research.

[16] "Draft California Net Energy Metering Cost Effectiveness Evaluation (NEM Study)", prepared for the California Public Utilities Commission by Energy+Environmental Economics, September 26, 2013, pp. 7

have implications for ZNE, such as rate reform[17] and any modifications to the current Net Energy Metering framework.[18] The determinations made in these various proceedings will inform the sustainability of the ZNE goals including the choice of potential DG system configurations. Moreover, previous cost effectiveness research on DG systems[19] will need to be updated to reflect the outcomes of these and any other rate reform activities as well as relevant research findings. A flexible definition will allow for all stakeholders to consider the outcomes of various research projects and CPUC proceedings before taking further policy steps beyond the Draft 2013 IEPR toward ZNE.

Lastly, a flexible definition at this stage in the road to ZNE would harness competitive market forces to explore the most viable renewable energy generation options for achieving ZNE. Encouraging developers and builders to explore various on-site (e.g., rooftop DG photovoltaics) and off-site (e.g., local district or community scale photovoltaic) renewable energy generation options through a flexible ZNE definition would allow these market actors, who will be charged with implementing ZNE in California, to try all available solutions to identify least cost options for the consumer. Furthermore, it would allow market actors to interact with utilities to ensure those options also represent least cost options to maintaining the reliability and stability of the California electric grid. The current definition's limitation to on-site systems would foreclose on this opportunity by stifling exploration into various least cost renewable energy solutions.

Therefore, to reduce uncertainty for market actors, allow for consideration of further research into the DG component of ZNE, and encourage exploration of various least cost renewable energy solutions, the Final Report should emphasize the need for flexibility by including off-site renewable energy generation dedicated to the building in the ZNE definition. This will then minimize activities focusing on exceptions to the definition, and keep the focus on identifying the most cost-effective means to reduce energy usage and maximizing GHG reductions.

B. Modifications to TDV to Value Distributed Generation

PG&E supports the CEC's decision to use the TDV metric for ZNE. As indicated in the Draft Report, the California Building Energy Efficiency Standards has used the TDV metric since 2005 making it the logical choice for calculating ZNE. However, the description of TDV[20] does not address the fact that it is a societal energy *consumption* metric that requires modification to appropriately value distributed generation *energy production* before it can be

[17] CPUC R.12-06-013, Order Instituting Rulemaking on Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.

[18] California Assembly Bill No. 327 (Perea), "Electricity: natural gas: rates: net energy metering: California Renewables Portfolio Standard Program."

[19] "Draft Cost-Effectiveness of Rooftop Photovoltaic Systems for Consideration in California's Building Energy Efficiency Standards", prepared for the California Energy Commission by Energy+Environmental Economics, May 2013.

[20] Op. cit., Draft 2013 IEPR, pp. 30

used to value outputs from those systems.[21] This is because TDV on average associates reduced onsite consumption with decreased utility infrastructure costs to serve the commensurate load; however, the presence of DG systems carries with it the need for sufficient utility infrastructure to accommodate both system outputs and the ability to meet customer demand when a renewable generator is not producing energy (such as at night, or when a rooftop solar photovoltaic system has a failure). While the full extent of these costs is not clear, and will require future research, PG&E recommends that the Final IEPR Report recognize that TDV is *not* currently configured to handle these costs.

In addition, as stated in the Joint-IOU comments on the Draft 2013 IEPR ZNE Workshop, PG&E recommends that the Final IEPR report recognize the need for further research to inform modifications to the TDV metric, including but not limited to: potential cost shifts to non-ZNE customers associated with the metric's equal treatment of energy consumed and produced onsite; the impact of overvaluation of the benefits of renewable energy generation in one code cycle compared to future cycles; and the need to develop a comprehensive test method and performance rating system for DG systems to produce accurate TDV values by climate zone.[22] PG&E further recommends that the Final IEPR report recognize that previous cost effectiveness research on DG systems[23] will need to be updated to reflect these modifications that are critical to ensure that the societal TDV metric can appropriately value distributed generation production.

For additional clarity, PG&E further recommends that references to "societal value," "societal cost," or "net societal cost" should be either removed from the report or qualified to refer to the set of values specifically considered under the TDV metric and not sets of values considered under any other cost effectiveness metric.

Lastly, the expectation that ZNE code buildings will provide "improved statewide energy system reliability"[24] requires further research into the grid impacts of high penetrations of distributed generation photovoltaics (DGPV), by far the most popular customer-side renewable generation option in California at more than 99 percent of Net Energy Metering accounts.[25] Such grid impact research was recommended in the ZNE Technical Feasibility[26] and Road to ZNE[27] studies. The Draft Report does not substantiate the "improved reliability" assertion and research has not yet addressed this issue. Thus, PG&E disagrees that DG systems *inherently* and

[21] ZNE Technical Feasibility, Arup, December 2012, pp. 17
[22] "2013 Integrated Energy Policy Report: Lead Commissioner Workshop on the Definition of Zero Net Energy in Newly Constructed Buildings in California—Joint Utility Comments", Docket No. 13-IEP-1F, August 1, 2013
[23] "Draft Cost-Effectiveness of Rooftop Photovoltaic Systems for Consideration in California's Building Energy Efficiency Standards", prepared for the California Energy Commission by Energy+Environmental Economics, May 2013.
[24] Op. cit., Draft 2013 IEPR, pp. 28.
[25] NEM Study, pp. 4
[26] ZNE Technical Feasibility, pp. 9
[27] "Road To ZNE: Mapping Pathways to ZNE Buildings in California (Road to ZNE)", Heschong Mahone Group, December 2012, pp. 17

in all cases improve statewide energy system reliability and suggests that more research is needed into optimized and least cost methods of integrating DG into grid operations at the scale suggested by the ZNE goals.[28]

PG&E recognizes that the establishment of a ZNE definition in the Final Draft 2013 IEPR represents a critical moment in time within which stakeholders should coordinate to ensure that activity and investments to achieve ZNE are done in a manner that ensures a sustainable and reliable energy future for California.

[28] CSI RDD&D projects may prove to have useful contributions to this knowledge gap.

II. NUCLEAR POWER PLANTS

In Chapter 6, "Nuclear Power Plants," the Commission discusses progress toward implementing recommendations made in the Assembly Bill 1632 Report, the 2011 IEPR, and by the NRC Near-Term Task Force. Several of the recommendations in the Draft 2013 IEPR address nuclear safety and operational issues that are subject to direct and exclusive oversight by the NRC under the Atomic Energy Act. While PG&E is fully supportive of sharing information submitted to the NRC with state agencies, there is no legal basis for the CEC to undertake an independent review of these safety and operating issues that are within the exclusive jurisdiction of the NRC. Recommendations that address nuclear safety and operating issues should be deleted or modified to propose monitoring of NRC action.

A. Seismic Discussion

The discussion of seismic issues at DCPP in the Draft 2013 IEPR is outdated and contrary to information available to the CEC. Page 135 to 136 of the Draft 2013 IEPR cites, in isolation, certain testimony presented by the Alliance for Nuclear Responsibility (A4NR) before the CPUC, and inaccurately focuses on an internal NRC issue regarding the *process* for addressing new seismic information at the NRC. PG&E is disappointed that the Draft fails to include the responsive information PG&E provided in its July 3, 2013 comments on the June 19, 2013 Nuclear Workshop.[29] Unfortunately, having ignored PG&E's comments, the Draft Report contains inaccurate, unsupported and incomplete factual statements. Additionally, the Draft presents as legal conclusions, and adopts as the position of the CEC, unsupported testimony that is inconsistent with NRC decisions and federal court decisions. Most significantly, the Draft 2013 IEPR (footnote 245) references an NRC staff Task Interface Agreement (TIA) from August 2011. The Draft Report fails to recognize that the TIA has been superseded by a revised TIA issued November 19, 2012, to coincide with the conclusions and expectations discussed in the NRC's letter of October 12, 2012, to PG&E on seismic safety. The NRC indicated in the November 19, 2012 TIA (at 2) that the Shoreline Fault is to be considered to be "a lesser included case under the [licensing basis] Hosgri evaluation" and that the NRC's request for information letter dated March 12, 2012 to all nuclear power plant licensees requesting a reevaluation of seismic hazards, "provides guidance for assessing new seismic information."

The CEC should acknowledge PG&E's position in the Final 2013 IEPR. According to Cal. Pub. Res. Code § 25301, the objectives of the IEPR include providing an analytical foundation for regulatory and policy decision-making. Without accurately characterizing the internal NRC process issue and by ignoring PG&E's (and the NRC's) position on this issue, the IEPR assessment and accompanying recommendations fail to comport with minimum requirements for policymaking. The CPUC may appropriately refuse to consider information in the 2013 IEPR if there is a reasonable basis for an objection to a policy recommendation, such as a lack of substantial evidence.[30] Moreover, any CPUC decisions based on the incomplete

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[29] See comments at: http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-19_workshop/comments/PGandE_Comments_2013-07-05_TN-71525.pdf

[30] Cal. Pub. Res. Code § 25302(f).

discussion in the 2013 IEPR would not satisfy the requirements of California administrative law.[31] The significant omissions and incomplete factual record in the Draft 2013 IEPR discussion — coupled with other faulty assumptions in the A4NR testimony that were addressed in PG&E's response — undermine the overall credibility and accuracy of the seismic discussion in the Draft 2013 IEPR.[32] This section of the Draft 2013 IEPR should be deleted or, at a minimum, substantially revised to accurately reflect the issues involved.

B. Specific IEPR Recommendations

1. **Complete and make available *AB 1632 Report* recommended studies.** PG&E should continue to provide updates on its progress in completing the *AB 1632 Report*-recommended studies to the Energy Commission and make its findings and conclusions available to the Energy Commission, the CPUC, and the Nuclear Regulatory Commission during their reviews of the Diablo Canyon license renewal application.

   Response: The studies recommended by AB 1632 are ongoing. PG&E has completed the 2D/3D Low Energy Seismic Surveys and the 2D Onshore High Energy Studies. Data processing and interpretation are continuing. The final report is currently expected to be complete in June 2014 and will be provided to state and federal agencies.

2. **Update evacuation time estimates**. PG&E should provide updated evacuation time estimates, including an evacuation scenario following a seismic event.

   Response: In a final rule published on November 23, 2011 (76 Fed. Reg. 72560), the NRC amended its regulations to require the periodic updating of evacuation time estimates (ETEs) following publication of the decennial census data from the U.S. Census Bureau. During the years between decennial censuses, PG&E is required to conduct an annual review of population changes in emergency planning zones and update the ETE analysis if a population change causes certain ETE values to increase by 25 percent or 30 minutes, whichever is less.

   In accordance with the revised 10 CFR Part 50, Appendix E, Section IV.4, PG&E submitted the Diablo Canyon Power Plant Emergency Planning Zone Evacuation Time Estimate (DCPP EPZ ETE) study on December 12, 2012. PG&E provided a copy of this submittal in its June 18, 2013 Supplemental Data Request Response to the CEC. As indicated in that response, additional ETE analyses for seismic events are being developed as part of a supplemental report. PG&E expects to issue this supplemental report to address such events by December 2013.

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[31] Ann.Cal.C.C.P. § 1094.5(b), (c).
[32] *Pacific Gas & Electric Co. v. Zuckerman*, 189 Cal.App.3d 1113, 1135 (1987).

PG&E suggests this recommendation be modified as follows:

PG&E should provide a copy of any updated evacuation time estimates, including an evacuation scenario following a seismic event, submitted to the NRC.

3. **Assess liability coverage adequacy**. Based on mounting clean-up costs for the 2011 Fukushima accident, prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission, PG&E should provide to the Energy Commission and CPUC a comprehensive study on whether the Price-Anderson liability coverage for a severe event at Diablo Canyon would be adequate to cover liabilities resulting from a large offsite release of radioactive materials in San Luis Obispo County, and if not, identify and quantify other funding sources that would be necessary to cover any shortfall. The CPUC should consider requiring PG&E to complete such a study as a condition of License Renewal funding approval.

   Response: First, the adequacy of the federal Price-Anderson Act liability insurance regime is an issue unrelated to the CEC's core resource planning function. This recommendation should be deleted from the report.

   Second, there is no link between liability coverage and license renewal. PG&E currently maintains all nuclear liability insurance required by law and will continue to do so for the current licensed term and any renewed license term.

   Third, the recommendation appears to be based on an incorrect premise. The Price-Anderson Act establishes a *comprehensive* federal scheme to assure that funds will be available to compensate injured members of the public if a nuclear incident were to occur despite all precautions. Each licensee of a large nuclear power plant licensed by the NRC must maintain an amount of primary financial protection against public liability claims equal to the maximum amount of liability insurance available at reasonable cost and on reasonable terms from private sources.[33] Each large reactor licensee also must participate in a secondary insurance plan that provides additional contributions (*i.e.*, retrospective premiums) from all large reactor licensees in the United States if claims exceed the amount available in primary insurance.

   If sufficient funds may not be available from primary and secondary insurance to pay claims for an actual event, the Price-Anderson Act further provides that the President must submit a report and proposals for compensation to Congress.[34] Congress is authorized to allocate additional federal funds and charge licensees and others additional amounts to provide for full and prompt compensation for claims. Price-Anderson therefore already addresses potential funding sources in the event that the primary and secondary insurance amounts are exceeded. In light of this

[33] 42 U.S.C. § 2210.b(1).
[34] 42 U.S.C. § 2210.i.

comprehensive federal statutory scheme, the report recommended in the Draft 2013 IEPR would result in unnecessary expenditure of funds without providing a benefit.

4. **Evaluate seismic hazard analysis against the licensed design.** To help ensure plant reliability and minimize costs to ratepayers, prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission[35], PG&E should evaluate all seismic hazard analyses for Diablo Canyon against the licensed design basis elements for the Design Earthquake and the Double Design Earthquake, in addition to the Hosgri earthquake element.

   Response: There is no basis for linking a seismic evaluation to license renewal. Independent of license renewal, PG&E will continue to evaluate the seismic hazards related to Diablo Canyon, as required by its operating licenses and the NRC. This will include appropriate consideration of the licensing basis earthquakes — the Design Earthquake (DE), the Double Design Earthquake (DDE), and the Hosgri Earthquake (HE) — as directed by the NRC. This ongoing evaluation of seismic information establishes operational safety for the current licensed term and any renewed license term. In accordance with NRC regulations and precedent, there is no nexus between the seismic evaluation and resumption of the relicensing process, issuance of a renewed license, or operation in an extended period of operation. Instead, issues that are related to current operations, including seismic safety, are addressed through ongoing regulatory processes and are not deferred until the license renewal period.[36] The NRC has stated, particularly with regard to post-Fukushima evaluations and license renewal, that "[t]he NRC's ongoing regulatory and oversight processes provide reasonable assurance that each facility complies with its 'current licensing basis,' which can be adjusted by future Commission order or by modification to the facility's operating license outside the renewal proceeding (perhaps even in parallel with the ongoing license renewal review)."[37]

   The Draft 2013 IEPR also unnecessarily focuses on the NRC's *process* issue of how to evaluate new seismic information and proposes that new information be evaluated against the outdated licensing basis analysis of the DDE, rather than NRC's conclusions regarding operational safety. Since initial NRC licensing of Diablo Canyon, PG&E has continued to study seismic hazards at the Diablo Canyon site under the Long Term Seismic Program (LTSP). That program has remained active

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[35] On April 10, 2011, PG&E requested that the NRC defer issuance of renewed operating licenses until updated seismic studies were completed (see http://pbadupws.nrc.gov/docs/ML1110/ML111020618.pdf). The NRC responded on May 31, 2011 (see http://pbadupws.nrc.gov/docs/ML1113/ML11138A315.pdf) by revising the remaining review schedule for the license renewal application to "To Be Determined" and instructing PG&E to update the NRC on the schedule of completion of the 3-D seismic studies and estimated receipt of a coastal consistency certification.

[36] 10 CFR § 54.30.

[37] *Pacific Gas and Electric Co.* (Diablo Canyon Nuclear Power Plant, Units 1 and 2), CLI-11-11, 74 NRC __ (October 12, 2011) (slip op. at 44) *citing Union Electric d/b/a/ Ameren Missouri* (Callaway Plant, Unit 2), CLI-11-5, 74 NRC __ (Sept. 9, 2011) (slip op. at 26).

and been an industry leader in assessing geoscience issues. As part of that work, on January 7, 2011, PG&E provided the NRC with a report on its analysis of the potential seismic hazard of the Shoreline Fault. Based on its extensive review of that report, the NRC concluded on October 12, 2012, that it had confirmed that the ground motions from the Shoreline Fault are at or below those for which the plant was evaluated previously. The NRC further confirmed at that time that the plant could be operated with the required reasonable assurance of safety. However, the NRC also noted the need for further ongoing analysis to respond to the agency's March 12, 2012, request for information following the accident at the Fukushima Daiichi nuclear plant in March 2011.

Specifically, as discussed in the Draft 2013 IEPR (at 134-136), the NRC's post-Fukushima Near-Term Task Force (NTTF) Recommendation 2.1 involves seismic hazard and risk evaluations in accordance with the Senior Seismic Hazard Analysis Committee (SSHAC) Level 3 process. The first phase is to perform a reevaluation of the seismic hazards at the site using updated seismic information, as well as present day regulatory guidance and methodologies. The NRC will also require a comparison to the current seismic design basis (which reflects information available at the time of licensing, and methodologies and assumptions utilized at that time). NRC expectations were documented in the October 12, 2012 letter to the company. The NRC has established schedule milestones for PG&E's Recommendation 2.1 response. In accordance with the NRC's regulations, the need for any design or licensing basis changes will be evaluated based on the Recommendation 2.1 response.

The Draft 2013 IEPR (at 135-136) cites in isolation certain testimony presented by the Alliance for Nuclear Responsibility before the CPUC, and inaccurately focuses on an internal NRC issue regarding the *process* for addressing new seismic information at the NRC. PG&E has responded to the issues addressed in that testimony, but the company's response is not referenced in the Draft Report. Moreover, the reference in the A4NR testimony and the Draft 2013 IEPR (footnote 245) to an NRC staff Task Interface Agreement (TIA) from August 2011 fails to recognize that the TIA has been superseded by a revised TIA issued November 19, 2012, to coincide with the conclusions and expectations discussed in the NRC's letter of October 12, 2012. In the November 19, 2012 TIA, the NRC indicated that the Shoreline Fault is to be considered to be "a lesser included case under the [licensing basis] Hosgri evaluation" and that the NRC's request for information letter dated March 12, 2012 to all nuclear power plant licensees requesting a reevaluation of seismic hazards, "provides guidance for assessing new seismic information."

While PG&E does not agree with the NRC that the DDE should be considered to be the licensing basis "safe shutdown earthquake" (that distinction belongs to the HE), the company acknowledges that the NRC does expect PG&E to use the licensing basis DDE for "comparison" to the reevaluated seismic hazard ground motion response spectrum. Given the age and conservatisms of the assumptions and methodologies used in the DDE evaluations, the NRC in the October 12, 2012, letter also acknowledged that the Shoreline Fault earthquake and Hosgri Fault earthquake may be reported as having greater ground motions than the DDE. The comparison along with the results of a PG&E updated seismic probabilistic risk analysis (SPRA) will be considered in evaluating the need for additional regulatory actions. But the NRC also acknowledged in the same letter that the HE and LTSP ground motions have been previously reviewed, and the NRC concluded that they provide assurance of safe operation. Those ground motions should be considered to be the appropriate benchmarks going forward.

At bottom, this recommendation addresses safety and operational issues that are subject to exclusive NRC jurisdiction. The radiological safety oversight role, including assessment of the seismic design and determinations related to seismic safety, is reserved to the NRC. Likewise, the internal process that the NRC uses to evaluate seismic information is for the agency alone to decide. Oversight by the CEC is not necessary for protection of the public health and safety with respect to radiological risks and is not legally appropriate. The recommendation should be modified to propose monitoring of NRC action on this topic.

5. **Comply with applicable fire protection regulations.** PG&E should, as expeditiously as possible, bring Diablo Canyon into compliance with the applicable 2004 National Fire Protection Agency fire protection regulations and report to the Energy Commission on their progress until full compliance is achieved.

   Response: This recommendation addresses safety and operational issues that are subject to the exclusive jurisdiction of the NRC. A directive regarding compliance with NRC fire protection requirements is not necessary for protection of the public health and safety with respect to radiological risks and is not legally appropriate. The recommendation should be modified to propose monitoring of NRC action on this topic.

   PG&E submitted a fire protection License Amendment Request to the NRC on June 26, 2013. Upon approval, the DCPP fire protection program will transition to a new Risk-Informed, Performance-Based alternative in accordance with 10 CFR 50.48(c), which incorporates by reference NFPA 805. PG&E will inform the CEC upon NRC approval of the License Amendment Request.

6. **Evaluate long term impacts and costs of spent fuel storage options.** PG&E should evaluate the potential long term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels[38] in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite and submit the findings to the Energy Commission and CPUC.

[38] I.e., Average assembly burn-ups exceeding 45 gigawatt days per metric ton of uranium (GWd/MTU).

Response: This recommendation addresses safety and operational issues that are subject to direct and exclusive NRC jurisdiction. Storage of used fuel in pools and in dry storage have both been identified by the NRC as safe storage methods.[39] The radiological safety oversight role, including assessments of spent fuel storage, is reserved to the NRC. In light of the ongoing and comprehensive reviews of spent fuel storage conducted by the NRC, oversight by the CPUC is not necessary for protection of the public health and safety with respect to spent fuel pool risks and is not legally appropriate. The recommendation should be deleted.

The NRC is also currently evaluating this issue for the U.S. reactor fleet. In a Draft memorandum entitled "Staff Evaluation and Recommendation for Japan Lessons-Learned Tier 3 Issue on Expedited Transfer of Spent Fuel," the NRC Staff concludes that the expedited transfer of spent fuel to dry cask storage would neither provide a substantial increase in the overall protection of public health and safety nor sufficient safety benefit to warrant the expected implementation costs. The outcome of the NRC's Tier 3 regulatory analysis indicates that undertaking additional study of the low-density spent fuel pool storage alternative is not justified. Therefore, the NRC staff recommends that no regulatory actions be taken to require the expedited transfer of spent fuel.[40]

In the Draft Generic Environmental Impact Statement for Waste Confidence (NUREG-2157), dated September 2013, the NRC addressed fuel degradation during wet and dry storage. The NRC concludes that "degradation of the fuel cladding occurs very slowly over time in the spent fuel pool environment" and that degradation of the spent fuel should be minimal for dry cask storage if conditions inside the canister are appropriately maintained (*e.g.*, consistent with the technical specifications for storage).

7. **Evaluate the structural integrity of the spent fuel pools.** To help ensure plant reliability and minimize costs to ratepayers, prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission, PG&E should provide to the Energy Commission and CPUC an evaluation of the structural integrity of the concrete and reinforcing steel in the spent fuel pools, including any increased vulnerability to damage resulting from a seismic event.

[39] The recommendation, as written, suggests consideration of "dry cask storage of higher burn-up fuels in densely packed pools" (note omitted). This is a confusing formulation.

[40] This conclusion is consistent with prior PG&E evaluations of the rate at which used fuel is moved from the spent fuel pools into dry cask storage. PG&E determined that moving fuel at a faster rate would accelerate ratepayer costs and employee exposure to radiation with no significant increase in safety. As a result, PG&E will continue to transfer used fuel from the spent fuel pools to ISFSI dry cask storage as needed to maintain the full core offload capability.

Response: This recommendation addresses safety and operational issues that are subject to direct and exclusive NRC jurisdiction. The NRC ensures that spent fuel pools are designed and licensed to maintain a large inventory of coolant to protect and cool fuel under accident conditions, including earthquakes. The radiological safety oversight role, including assessment of the spent fuel pool design and determinations related to seismic safety, is reserved to the NRC. Oversight by the CEC and CPUC is not necessary for protection of the public health and safety with respect to spent fuel pool risks and is not legally appropriate.

In a letter to the Nuclear Regulatory Commission (NRC) dated July 19, 2010, PG&E provided an evaluation of the leakage from the Unit 2 Spent Fuel Pool (SFP). PG&E indicated that the effect of leakage on the concrete and steel liner over an extended period of time would be negligible, because boric acid would only result in slight surface scaling of the concrete and not cause the concrete to crack. In addition, the concrete will protect the reinforcing steel from coming into contact with the boric acid. This is consistent with EPRI Report TR 1019168 "Boric Acid Attack of Concrete on Reinforcing Steel in PWR Fuel Buildings," dated June 2009. PG&E will continue to conduct inspections of the SFP leak chase channel through the period of extended operation, and committed to a one-time video inspection of the Unit 2 leak chase prior to entering the PEO in a letter to the NRC dated January 7, 2011. Based on the above, and that the leakage is confined to the SFP leak chase channel, the NRC found PG&E's aging management approach to be acceptable.[41]

PG&E will evaluate the structural integrity of the SFP following a beyond design basis seismic event in accordance with the NRC's Recommendation 2.1 requirements.

Independent of license renewal, PG&E will continue to evaluate the safety of the spent fuel pools. This ongoing evaluation establishes operational safety for the current licensed term and any renewed license term. There is no link between spent fuel pools and resumption of the relicensing process, issuance of a renewed license, or operation in an extended period of operation. Issues that are related to current operations, including spent fuel pools, must be addressed through ongoing regulatory processes. In light of the ongoing and comprehensive reviews of spent fuel pools conducted by the NRC and the absence of a nexus with license renewal, the recommendation should be deleted.

8. **Evaluate the annual capability of moving spent fuel bundles to dry cask storage.** PG&E should perform, and report to the Energy Commission and CPUC as part of the 2014 *IEPR Update*, an evaluation of the inventory of the spent fuel pools to determine the maximum number of spent fuel bundles it can move on a per year basis

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Safety Evaluation Report Related to the License Renewal of Diablo Canyon Nuclear Power Plant Units 1 and 2, June 2, 2011, ML 111338A274.

from the spent fuel pools into dry cask storage, taking into consideration the following constraints:

- Thermal limits of the dry casks imposing a minimum threshold on the age of the spent fuels;
- Federal requirements on older spent fuels surrounding newer spent fuels;
- Availability of dry casks;
- Building schedule(s) of dry cask storage pads;
- Coordination of refueling outages and dry casks loading schedules; and
- Availability of plant staff and contractors for dry cask loadings.

9. **Transfer spent fuel to dry casks as expeditiously as possible.** To reduce the volume of spent fuel packed into Diablo Canyon's storage pools (and consequently the radioactive material available for dispersal in the event of an accident or sabotage), PG&E should, as soon as practicable, transfer spent fuel from the pools into dry casks, while maintaining compliance with Nuclear Regulatory Commission spent fuel cask and pool storage requirements and report to the Energy Commission on its progress until the pools have been returned to open racking arrangements.[42]

   Response: Recommendations 8 and 9 addresses safety and operational issues that are subject to direct and exclusive NRC jurisdiction. The radiological safety oversight role, including assessment of the spent fuel pool and dry storage design, is reserved to the NRC. As noted above, the NRC has found that the expedited transfer of spent fuel to dry cask storage would neither provide a substantial increase in the overall protection of public health and safety nor sufficient safety benefit to warrant the expected implementation costs. Oversight by the CEC and CPUC is not necessary for protection of the public health and safety with respect to spent fuel pool or dry cask storage risks and is not legally appropriate. These recommendations should be deleted.

   In any event, storing spent fuel in pools is a safe, proven, and effective strategy that is employed successfully throughout this country and around the world. The storage methods used at Diablo Canyon follow industry's best practices and have been approved, and are continuously monitored, by the NRC. While PG&E regularly moves fuel from the pools to our dry cask facility, speeding up the transfer does not serve the interests of public safety or our customers. Moving fuel from pools to dry storage is very complex and takes years to plan and perform. PG&E's spent fuel management program is guided by a well-considered strategy and relies on an established process. For example, there are safety and operational reasons for keeping the fuel in the pools for longer than the minimum number of years before moving it to dry storage:

[42] Open racking arrangements would reduce the density of spent fuel assemblies stored in the pools to levels consistent with their original design capacity (prior to re-racking).

- Keeping older, colder assemblies in the pools provides important advantages as they are strategically placed around younger, hotter assemblies to help absorb and dissipate heat. This added thermal barrier makes it easier to maintain constant pool temperatures, which aids in the cooling of the younger assemblies. In addition, the NRC requires that spent fuel in pools be arranged in a "checkerboard" fashion to reduce the potential for fuel to burn if the assemblies were ever exposed in an emergency.

- To ensure the safety of the dry cask storage system, the heat load in the casks must be effectively managed. To accomplish this, PG&E strategically loads the casks with a mixture of older and younger fuel — with cooler assemblies surrounding hotter assemblies. To maintain this configuration when loading casks, PG&E needs to have available an adequate supply of spent fuel at various ages in the pools.

- From an industrial safety perspective, minimizing the amount of time spent during the actual fuel transfer and the number of transfers PG&E performs reduces worker exposures and reduces interference with the day-to-day operations and schedules of the plant.

- Some assemblies have useable energy left. It is desirable to have them available for reload into the reactors as a contingency if a damaged assembly is identified during a refueling outage.

10. **Complete the evaluation of laminar flaws on Unit 2 pressurizer nozzles.** The Diablo Canyon Independent Safety Committee should monitor PG&E's progress in completing the root cause evaluation of laminar flaws on the Unit 2 pressurizer nozzles and identification of required corrective actions over the next cycle of operation, and follow the issue until it is resolved.

    PG&E has no comment on this recommendation.

Appendix I to the IEPR repeats several recommendations from the 2011 IEPR. PG&E provides the following comments on those recommendations where the status is noted as "Action Needed."

- **2011-2:** PG&E should submit to the Atomic Safety and Licensing Board (ASLB), as part of PG&E's final seismic report to the ASLB in the Diablo Canyon license renewal proceeding, the findings and recommendations from the California IPRP on PG&E's seismic studies. These studies include PG&E's onshore and offshore seismic studies funded by CPUC Decision 10-08-003.

  STATUS: PG&E's AB 1632 seismic studies on-going; NRC SSHAC analysis on-going and scheduled for completion March 2015.

Comments: PG&E recommends the status of this recommendation be modified as follows: The studies recommended by AB 1632 are ongoing. PG&E has completed the 2D/3D Low Energy Seismic Surveys and the 2D Onshore High Energy Studies. Data processing and interpretation are continuing. The final report is currently expected to be complete in June 2014 and will be provided to state and federal agencies.

- **2011-6:** PG&E and SCE should investigate adding safety-related instrumentation (capable of withstanding design basis natural phenomena) to monitor in the control room key spent fuel pool parameters, for example, water level, temperature, and radiation levels, during a severe accident in which radiation levels within the spent fuel pool building are unsafe.

  Comments: This recommendation addresses safety and operational issues which are subject to exclusive NRC jurisdiction.

  On March 12, 2012, the NRC issued Order EA-12-051, "Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation". The order mandated that all licensees equip SFPs with wide-range level instrumentation capable of withstanding a beyond-design-basis external event. On February 27, 2013, PG&E submitted its Overall Integrated Plan for Reliable SFP Instrumentation, and provided an equipment description and design criteria to the NRC in a letter dated July 3, 2013. In accordance with Order EA-12-051, this equipment is scheduled to be installed in October 2015 for Unit 1, and May 2016 for Unit 2. This recommendation should be deleted or modified to propose monitoring of NRC action on this topic.

- **2011-7:** To reduce the volume of spent fuel packed into storage pools, and consequently the radioactive material available for dispersal in the event of an accident or sabotage, PG&E and SCE should, as soon as practicable, transfer spent fuel from pools into dry casks, while maintaining compliance with NRC spent fuel cask and pool storage requirements and report to the Energy Commission in the *2012 IEPR Update* on their progress.

  Comments: *See* Response to Recommendations 8-9.

- **2011-8:** PG&E and SCE should evaluate, as part of the *2012 IEPR Update*, the potential long-term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite.

  Comments: *See* Response to Recommendation 6.

- **2011-11:** Based on the Fukushima experiences, PG&E and SCE should provide a comprehensive study to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of Price-Anderson Act liability coverage for a severe event at Diablo Canyon or San Onofre resulting in large offsite releases of radioactive materials.

Comments: *See* Response to Recommendation 3.

- **2011-20:** Since the regulatory changes and requirements recommended by the NRC Near-Term Task Force on Fukushima could result in higher costs, for example, seismic retrofits, PG&E and SCE should provide cost estimates to the CPUC for complying with NRC's requirements and the costs of potential replacement power in the event of an extended outage. The CPUC should consider these additional costs during its license renewal evaluations for Diablo Canyon (and San Onofre, if SCE applies for license renewal).

  Comments: PG&E provided cost estimates for compliance with the NRC's Fukushima-related requirements in its 2014 General Rate Case Application, A.12-11-009. There is no pending review of license renewal occurring at the CPUC. Even if the CPUC were reviewing license renewal, because the cost to implement Fukushima-related requirements will be incurred regardless of whether the plant operates an additional 20 years beyond expiration of the current licenses, these costs are not relevant to the cost-benefit analysis for license renewal.

III. BIOENERGY STATUS AND ISSUES

In Chapter 3, the Draft 2013 IEPR reports on the status of the bioenergy industry and the challenges to operating and developing bioenergy facilities in California. PG&E is the largest purchaser of bioenergy in the state. Bioenergy has played an important role in PG&E's Renewables Portfolio Standard (RPS) portfolio and are sourced from both biomass and biogas generation. Biomass resources include forest biomass, agriculture residues, and urban waste, whereas biogas resources include animal waste, municipal waste, and landfill gas. PG&E remains focused on achieving the RPS requirements in a manner that balances safety, reliability, and affordability for customers. Given the recent focus on bioenergy in the state, PG&E appreciates this timely discussion and offers specific input below.

A. Technical Corrections are Needed to the CEC Biomass Facility Study

In its discussion of the status of biomass facilities in California, the Draft 2013 IEPR highlights a number of facilities that have idled since 2010, attributing their retirement to unfavorable economic conditions and unsuccessful attempts to amend power purchase agreements (PPA).[43] PG&E believes the analysis presented in the report fails to capture additional critical drivers behind the idling of facilities. A number of the facilities listed in the report are idled as a result of operational and project development challenges, rather than PPA price terms.[44]

PG&E recommends updating the report to appropriately reflect these challenges. For example, PG&E understands that the Mount Lassen Power facility cannot continue operating due to damage to the generator's turbine. Similarly, Big Valley suffered extensive damages from thieves stealing copper components. Additionally, it is unclear why Eel River is noted as an idled facility in this report, since news reports dating from May 2013 suggest the plant is online.[45] Furthermore, it should be noted that Wheelabrator Hudson Energy facility was restarted as a new contract under the name Shasta Renewable Resources. Lastly, as a point of clarification, SPI Loyalton is under contract with another utility.

The Draft 2013 IEPR largely overlooks new bioenergy capacity additions and contracts executed by California load serving entities over the same time period. Since 2008, PG&E has signed 21 bioenergy contracts representing over 250 MW in capacity.[46] Inclusion of this information in the Final 2013 IEPR will more appropriately reflect the continued and significant role that bioenergy plays in PG&E's portfolio today and in the future.

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[43] Op. cit., Draft 2013 IEPR, pp. 56.
[44] Ibid., page 56.
[45] Power Engineering Magazine, "Biomass-fired cogeneration plant back online in California," May 16, 2013. (http://www.power-eng.com/articles/2013/05/biomass-fired-cogeneration-plant-back-online-in-california.html)
[46] PG&E Comments on June 3, 2013 CEC "Bioenergy Development in California" Workshop, June 19, 2013. (http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-03_workshop/comments/PGE_Comments_on_the_Status_of_Bioenergy_Development_in_California_2013-06-19_TN-71316.pdf)

B. Bioenergy Prices

The Draft 2013 IEPR attributes PPA pricing terms as a challenge to biomass facilities. It goes on to highlight that fuel and transportation costs impact the economics of biomass. Specifically, the Draft 2013 IEPR notes that a biomass facility must dedicate two-thirds of a contract price of $90 per megawatt-hour (MWh) towards fuel and transportation cost.[47] In today's competitive renewable energy market, however, $90 per MWh is uneconomical when compared to other renewable energy resources available to PG&E to meet the RPS targets, and some biomass projects are interested in short-term extensions, which is not the best match with PG&E's incremental RPS need. Recent published prices illustrate this issue. For example, the March 2013 CPUC RPS Quarterly Report indicates that Renewable Auction Mechanism (RAM) 2 executed PPAs had a weighted average post-TOD price of less than $90 per MWh.[48] More recent projects signed this year have come in at even lower prices. In June 2013, Palo Alto Municipal Utility secured three solar contracts for 80 MW for approximately $69 per MWh over 30 years.[49] Similarly, Riverside Public Utilities approved two new solar PPAs in September 2013, both under $70 per MWh.[50]

The costs of purchasing energy go directly to PG&E's customers, and PG&E must therefore work to manage costs to protect customer interests. This objective is clearly articulated in the California Public Utilities Code Section 399.15(c).[51] In implementing the RPS legislation, the CPUC has provided guidance to the IOUs to promote competitive procurement in a competitive solicitation process and to procure in a least cost, best fit manner to manage customer costs.

C. Bioenergy Benefits

The Draft 2013 IEPR highlights the importance of bioenergy in achieving California's environmental, waste reduction, and greenhouse gas reduction goals.[52] PG&E does not dispute these benefits and acknowledges the benefits bioenergy resources provide. However, these important societal benefits, such as reduction in forest fires, investment in disadvantaged communities, and job creation, should be part of a larger discussion focused on the ways a multitude of stakeholders can collaboratively achieve these societal goals. PG&E would welcome the opportunity to participate in such a discussion.

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[47] Op. cit., Draft 2013 IEPR, pp. 57

[48] Renewables Portfolio Standard Quarterly Report, 3rd and 4th Quarter 2012, California Public Utilities Commission, March 2013, page 12. (http://www.cpuc.ca.gov/NR/rdonlyres/4F902F57-78BA-4A5F-BDFA-C9CAF48A2500/0/2012_Q3_Q4RPSReportFINAL.pdf)

[49] City of Palo Alto News Release, June 17, 2013. (http://www.cityofpaloalto.org/news/displaynews.asp?NewsID=2243&TargetID=235,310)

[50] Riverside Public Utilities Board Memorandum, Item number 7, September 6, 2013.

[51] (http://law.onecle.com/california/utilities/399.15.html)

[52] Op. cit., Draft 2013 IEPR, pp. 54

The Draft 2013 IEPR also lays out stakeholder claims that the value bioenergy projects are able to provide outweighs the costs of bioenergy when compared to other renewable electricity sources.[53] PG&E notes that, while it does not dispute this claim, it is simply not aware of any comprehensive studies that have quantified broader bioenergy benefits, necessary to determine if these assertions are correct. PG&E would welcome further investigation into the value of these benefits for bioenergy *and* other renewable resources to better understand how they may interact with project costs. In fact, an assessment of the broader benefits of renewable energy—including bioenergy—is already slated for discussion at the CPUC as part of Least Cost Best Fit proceeding. However, it should be noted that many of the benefits raised by the bioenergy industry, like energy firmness[54] or GHG reduction, are already captured in PG&E's existing, extensive valuation methodology and in existing markets.

PG&E has been a major purchaser of bioenergy for many years and recognizes the importance of supporting California's bioenergy industry. PG&E supports sharing the costs of bioenergy with all who benefit from this industry: that is, all Californians and not just IOU bundled customers. The Draft 2013 IEPR's recommendation that CPUC modify its procurement practices would not ensure that the responsibility of supporting the industry across the state is spread across all Californians, since the CPUC does not have jurisdiction over the entire state. California should consider alternative ways to support the bioenergy industry, including the use of Assembly Bill 32 and the Electric Procurement Investment Charge (EPIC) to help address some of the costs associated with bioenergy production. At the same time, any use of renewable subsidies should be of a finite duration and renewable policy should work towards a level playing field and competition across all renewable technologies.

D. Baseload Capacity

The 2013 Draft IEPR accurately captures the critical need in California for flexible capacity.[55] The CPUC and the California Independent System Operator (CAISO) have determined that by 2015, the electric system will be lacking sufficient flexible capacity to accommodate the integration of renewables into the grid as part of California's goal of 33 percent RPS.[56] Given the changing needs of the electric system, California requires flexible capacity. In PG&E's valuation of offers, projects that are able to provide such flexibility are valued accordingly.

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[53] Ibid., page 58

[54] In the June 28, 2013 Draft 2013 RPS Plan, PG&E notes its preference for renewable energy offers which can provide energy firmness.

[55] Op. cit., Draft 2013 IEPR, pp. 60

[56] California Public Utilities Commission, "Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program," June 27, 2013 (see http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF). California Independent System Operator, "Flexible Resource Adequacy Criteria and Must-Offer Obligation: Market and Infrastructure Policy Third Revised Straw Proposal," October 3, 2013 (see http://www.caiso.com/Documents/ThirdRevisedStrawProposal-FlexibleResourceAdequacyCriteria-MustOfferObligation.pdf).

The 2013 Draft IEPR report notes that some bioenergy technology is able to provide flexible baseload capacity. More information is needed to support the statement that "new biopower gasification and digester technologies can ramp up and down quickly."[57] The value of flexible capacity is a complex issue and this statement in the 2013 Draft IEPR requires further investigation and clarification. PG&E would value any studies or descriptions of existing operational facilities that demonstrate the flexible ramping capability of bioenergy gasification technologies. Specifically, PG&E would be interested in the quantity, ramping rates, and minimum curtailment time that can be expected from such projects. A comparison of how bioenergy ramping capabilities relate to other renewable technologies would be extremely useful to enhance valuation methodologies.

E. Renewable Market Adjusting Tariff Program Design

PG&E recommends deletion of a statement in the Draft 2013 IEPR that indicates very few biopower projects in the current interconnection queue would pass the requirement that feed-in tariff (FIT) projects be "strategically located" because of their location in rural regions that are not near large load centers.[58] The Draft 2013 IEPR cites a draft report by Black & Veatch commissioned by the CPUC regarding the "strategically located" definition in Renewable Market Adjusting Tariff (ReMAT) program, as it relates to bioenergy projects. However, the Draft 2013 IEPR's conclusion is flawed because it is an "apples and oranges" comparison. The costs assessed in the draft Black & Veatch report are in fact interconnection and network upgrade costs,[59] whereas the $300,000 threshold for the "strategically located" definition under ReMAT applies only to network upgrades (on the transmission system), not other work such as interconnection facilities and distribution upgrades.[60] Thus, the cost estimates cited by the draft report are misleading in this context and PG&E recommends they be deleted. Additionally, the ReMAT power purchase agreement allows counterparties to remain eligible if the seller funds any network upgrade costs exceeding the $300,000 limit, which undermines the comparison made in the Draft 2013 IEPR.[61]

Additionally, the Draft 2013 IEPR states that the current ReMAT starting price and mechanism structure, if applied to bioenergy projects in the implementation of Senate Bill 1122, would result in delays of one to three years for projects to reach a price that would incentivize development. Such an assessment is premature considering the fact that the ReMAT program was only launched on October 1, 2013, and there is therefore no data or experience with the new

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[57] Op. cit., Draft 2013 IEPR, pp. 61

[58] Op. cit., Draft 2013 IEPR, pp. 60

[59] California Public Utilities Commission Draft Consultant Report, "Small-scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment," April 9, 2013, page 1-7.

[60] PG&E informal Pre-Workshop Comments to the California Public Utilities Commission on Senate Bill 1122 implementation, April 24, 2013.

[61] California Public Utilities Commission, "Decision 13-05-034 Adopting Joint Standard Contract for Section 399.20 Feed-in Tariff Program and Granting, In Part, Petitions for Modification of Decision 12-05-035," May 23, 2013. (http://wwwregrel/Docs/RenewablePortfolioStdsOIR-IV/Final-Decisions/CPUC/2013/RenewablePortfolioStdsOIR-IV_Final-Dec_CPUC_20130523_D-13-05-034_278388.pdf)

program design to make such an assessment. PG&E recommends the statement be deleted from the Final 2013 IEPR.

F. California Biomass Resources

The Draft 2013 IEPR includes an estimate of renewable energy potential in California. In Chapter 3's Table 2 on page 55, the 2013 Draft IEPR estimates that the technical potential for California's biomass is equivalent to 3,820 MW of electricity generating capacity. PG&E urges the CEC to examine its assessment of not only what is technically available, but what is technically *and economically* available to ensure the estimates accurately capture the resource potential available in California. It is important to distinguish technical availability of feedstock from economic availability. Incorporating commercial viability into the assessment is critical to identify resources available to advance the state's bioenergy goals in a cost-effective manner. Technical potential does not necessarily equate to economically viable resources that make sense to commercially utilize or transport and could therefore be a misleading tool for policy making. It should be recognized that, while large amounts of biomass may be technically available in California, the costs to purchase, collect, and assemble biomass, including regulatory costs, are high and limit its use significantly.

G. Biomethane Technical Potential and Development Goals

PG&E supports the CEC's efforts to establish the regulatory framework needed to implement AB 1900 for the expanded, safe use of biomethane in California. PG&E is supportive of biomethane development, having signed a number of contracts with biomethane facilities. However, the health, safety, and pipeline integrity impacts must be better understood, as biomethane is a relatively new gas supply source in California. PG&E would like to gain more experience with biomethane constituents and confidence in the effectiveness of the treatment processes designed to remove harmful constituents from biomethane. PG&E also needs to better understand how the BTU level of the biomethane interacts with existing gas supplies on PG&E's system.

PG&E agrees with the major challenges facing biomethane development as characterized by the CEC: interconnection costs, the cost of treatment to make pipeline quality gas, and the issue of who will bear these costs. The cost issue will be addressed by the CPUC in a second phase of the proceeding next year. In PG&E's view, consistent with the framework of AB 1900 which seeks non-discriminatory access for all gas supplies, and consistent with existing utility tariffs, biomethane project developers should pay for the cost of treatment and interconnection costs, not utility customers.

In addition to this input, PG&E offers the following technical or clarifying corrections. Note that additions are shown in bold and deletions in strikethrough.

- On page 66: "Although high BTU biomethane **in California (generally above 1020 BTU)** has been more expensive to produce than natural gas, it has a lower carbon intensity value (at about 11 to 13 grams of carbon dioxide per mega joule)."

- On page 69: "For example, while there is little debate that AB 1900 will benefit development of biomethane in California, some have raised concerns regarding the **new** ~~increased~~ costs to meet new biomethane pipeline quality standards."

- On page 70: "Pipeline safety is another issue for biomethane. Utilities have said that it is imperative to monitor and test biomethane going into their pipelines. While **some** utilities have **limited** experience injecting biomethane into their pipelines, they still lack data, especially for interconnections into low—demand pipelines."

  "Some of the utilities also feel that lowering the 990 BTU per cubic foot minimum gross heating value requirement **(if set specifically in the Utilities' tariff)** could potentially threaten the pipeline as it goes against standards set by the CPUC."

- On page 170: "While the bill is intended to ease restrictions, some stakeholders have expressed concern that it could create new barriers by expanding the scope of standards beyond ~~vinyl chloride~~ **what is included in the Utilities' current gas quality tariffs** to include any compounds that may create health and safety hazards, damage pipeline facilities, or inhibit the marketability of the gas."

IV. DEMAND RESPONSE

PG&E is an active supporter of DR and a leader in the field. PG&E has over 600 MW of operational DR, of which approximately 500 MW are dispatchable within 30 minutes and approximately 200 MW are automated. Moreover, PG&E was the first to bid Proxy Demand Resources (PDR) into the wholesale energy market in 2011 and 2012; in 2014, PG&E will bid flexible DR into the wholesale market through PG&E's Intermittent Renewables Management 2 pilot.[62]

In accordance with the state's loading order, PG&E is very supportive of enhancing the role of DR. At the same time, PG&E is concerned that any hasty and radical changes to the current structure may jeopardize the very existence and scope of DR and its function as a preferred resource.

As outlined in the 2013 IEPR Scoping Memo, PG&E wholeheartedly supports the Commission's decision to analyze the "technical, economic, market, and policy barriers to the use of demand response to support reliability and the integration of renewable resources."[63] Moreover, PG&E values the CEC's thoughtful analysis on DR and agrees with the majority of the 2013 IEPR's assessments and recommendations. However, at both the CEC's July 17 Workshop on DR and in the Draft 2013 IEPR, PG&E is disappointed that the CEC restricted its analysis to automated, supply-side DR. As a result, PG&E recommends the following specific changes to the Draft 2013 IEPR, many of which were noted in PG&E's earlier DR comments.

PG&E values the CEC's thoughtful analysis on DR and agrees with the majority of the Report's assessments and recommendations, as show on pages 50 to 53. These include the Commission's recommendation to resolve the CPUC's Rule 24 process, identify and explore tariff approaches, develop a multi-year reliability framework, and conducting an independent assessment to help advance DR market outreach. The following five sections provide some clarification and suggestions on a few of the topics discussed in the DR section of the Draft 2013 IEPR.

A. The State Should Focus on Providing a Wide Range of DR Programs for Customers

Page 52 of the Draft 2013 IEPR recommends that "the agencies should focus their efforts on advancing fast-response DR". While PG&E supports the exploration of this idea, the move to fast and flexible DR should be done carefully, only after the costs and benefits are clearly identified and quantified.

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[62] Note Advice Letter 4077-E, as modified by 4077-E-B, below:
Randolph, E. (2013, April 2). Proposed Demand Response 2012-2014 Pilot Projects in Compliance with Decision 12-04-045. Retrieved from http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4077-E-B.pdf

[63] McAllister, A. (2013). 2013 Integrated Energy Policy Report Scoping Order (No. 13-IEP-1A). Sacramento, CA: California Energy Commission. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-03-07_scoping_order_2013_IEPR.pdf. Pg. 2.

The State should focus on providing a wide range of opportunities for customers to participate in DR, rather than focusing attention narrowly on fast-response DR. Fast response DR should be one of many DR tools, but not the only one. A broad focus on multiple DR opportunities would be more likely to retain and attract the participation of as many customers as possible. Efforts to convert DR to a fast-responding and flexible wholesale market resource ignore the continued need for the existing retail DR programs, as well as the fact that there is no DR currently participating in the wholesale market. The CEC should also consider conventional DR, EE, dynamic rates and permanent load shifting as tools to manage increasing renewable resource integration.

B. Existing DR Programs Provide Tremendous Value to the Grid and Ratepayers

PG&E urges the Commission to recognize that existing DR programs are valuable and should not be replaced by supply-side DR, but rather complemented by it. These existing programs represent the vast majority of DR in California. Consequently, addressing key barriers to both existing DR programs, as well as supply-side DR, will enable the IOUs to better improve and grow DR programs in the next budget application cycle. Additionally, transitioning DR programs into supply- side resources must provide clear ratepayer benefits that justify the costs and potential risks associated with the transition.

To this point, the 2013 Draft IEPR does not dedicate much space or consideration to existing IOU efforts, which is unfortunate since PG&E and the other IOUs have invested significant time and energy into their existing DR programs. Various utility DR programs have made noteworthy accomplishments. For example, a majority of PG&E's DR programs (over 500 MW in July 2013) can respond within 10 or 30 minutes, including Smart AC (response within 10 minutes), Base Interruptible Program (BIP) (within 30 minutes), and two thirds of the AMP contracts (within 30 minutes). However, the 2013 Draft IEPR makes no mention of these successful programs.

Additionally, page 50 of the Draft 2013 IEPR notes that "given the long lead time required to develop generation and transmission, the need to prove DR is urgent." This sentence contains an incorrect assumption that DR is not (sufficiently) proven. DR has been a valuable resource for several decades and has been an integral part of long-term procurement planning and resource adequacy analysis processes, to name a few. DR's benefits should not be discounted due to a comparative analysis with other markets that have inherently different features (see PJM market analysis below). Currently, BIP is being used to respond to transmission emergencies and Smart AC is being used to prevent distribution-level overload. These important benefits should be acknowledged.

C. The CEC's Analysis of DR Should be Customer Focused

PG&E is concerned about the over-emphasis in the 2013 Draft IEPR on DR that is bid into the CAISO markets as a supply-side resource and substantially de-emphasizes the value of

DR as a demand-side resource. The emphasis does not appear to be based an analysis of the relative costs and benefits of wholesale market participation or the challenges of applying CAISO market requirements. PG&E is concerned that an exclusive emphasis on “fast, flexible DR” will ignore the value for DR that is not quite as fast and flexible, yet still highly valuable.

It is important to consider the importance of: 1) DR programs’ reliance on customer willingness to participate, 2) clearly defined benefits to ratepayers outweighing the cost of developing new DR programs, and 3) providing a wide range of options to attract participation by many customers. The Draft 2013 IEPR should reflect the fact that all types of DR are customer-focused and *cannot exist without participating customers*. PG&E is concerned that if the goal of creating fast and flexible wholesale DR resources is placed above all others, the State risks alienating current and future DR customers.

Moreover, PG&E supports Auto DR and using the OpenADR standard developed by Demand Response Research Center (DRRC) to make it easier for our customers to participate in DR programs. As mentioned in the Draft 2013IEPR, PG&E is piloting the expansion of auto DR technologies to mass market customers, such as small and medium businesses, to help them prepare for the future default dynamic pricing and better manage their energy use.

D. There are Significant Differences Between the CAISO and PJM That Must be Understood for a Useful Comparison

The CEC cites the PJM Interconnection (PJM) as an example of a successful market for DR. While the PJM receives significant attention as a competitive market that could be emulated, there are major differences between the PJM and the CAISO run market under discussion. First, PJM is compromised largely of reliability DR (approximately 77 percent), most of which is similar the California IOUs’ BIP. Second, PJM’s reliability DR program requirements are less onerous for customers and aggregators to participate in than are CPUC and CAISO programs.[64] Third, the PJM does not have DR “bid” into its energy market as supply, as envisioned for the CAISO run market. Instead, for the PJM, “bid into the market” means the 3-year ahead capacity market, not the day-ahead energy market. For CAISO, bid into the market means the day-ahead energy market. Finally, the PJM utilizes unique customers California does not have (for example, an 80 MW aluminum plant).

The 2013 Draft IEPR also notes that “intentionally enabling multiple market options in the near term decreases the risk of ongoing anemia of DR resources.” The Draft 2013 IEPR appears to assume that utilities are fully capable of procuring resources under CPUC guidance. The expression “ongoing anemia” is inappropriate considering the variety and quantity of existing DR resources in California. PG&E recommends this phrase be restated as: “intentionally enabling multiple market options in the near term will expand the opportunities for DR resources.”

[64] For example, PJM has simpler telemetry requirements and provides longer notification times (1-2 hours vs 30 min in the CAISO market).

E. The Benefits of a CAISO DR Auction Are Unclear

Page 52 of the Draft 2013 IEPR recommends "the ISO DR auction could be developed in parallel, and in coordination, with CPUC efforts to update investor owned utility-driven DR procurement." PG&E is under the impression that the CPUC DR OIR is intended to explore the best options for DR. The proposed CAISO DR auction has not been proven to be the most suitable procurement mechanism, as no finding has been made that a CAISO-run auction will be beneficial to customers. Under CPUC guidance, PG&E already employs competitive procurement mechanisms for a significant amount of its DR programs.

V. NATURAL GAS

Chapter 7, "Natural Gas," of the 2013Draft IEPR presents the results of the Commission's 2013 preliminary forecasts of natural gas supply, demand, infrastructure issues, and prices. Chapter 7 also discusses major issues affecting gas supply. Throughout the 2013 IEPR proceeding, the CEC has discussed updates and innovations to its natural gas demand and price forecasts. PG&E has participated actively in discussions around the CEC's natural gas price forecast and incorporates by reference its comments on the February 19,[65] April 24,[66] and July 17[67] 2013 IEPR Workshops. Additionally, PG&E filed comments on the Commission's October 1 Workshop,[68] which included a discussion of the CEC's forecast of Natural Gas Demand. PG&E provides additional input on natural gas issues below.

A. Natural Gas Pipeline Safety

In Chapter 7, the Commission discusses natural gas pipeline safety on pages 165 to 166. In this section of the 2013 Draft IEPR, the CEC includes the following statement: "Notably, PG&E indicated at the Show Cause hearing that significant curtailments of natural gas service to power plants, noncore customers on the San Francisco Peninsula, and core customers in San Francisco's Financial District would be triggered at cold temperatures expected to occur once in every ten years." PG&E believes this sentence should be deleted or modified as shown below. The statement does not represent the current state of PG&E's system. The potential customer impacts PG&E noted were only one of several scenarios PG&E presented and would only occur if the CPUC ordered additional pressure reductions on the Peninsula.

If the Commission chooses to keep this statement, PG&E recommends that it be modified as follows: "Notably, PG&E indicated at the Show Cause hearing that significant curtailments **of natural gas service to power plants, noncore customers** on the San Francisco Peninsula, and core Customers in San Francisco's Financial District **could occur** ~~would be triggered~~ at cold

[65] Plummer, M. (2013). 2013 Integrated Energy Policy Report: Comments of Pacific Gas and Electric Company on the Lead Commissioner Workshop on Economic, Demographic, and Energy Price Inputs for Electricity, Natural Gas and Transportation Fuel Demand Forecasts. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-02-19_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_on_Workshop_on_Economi_Workshop_2013-03-05_TN-69834.pdf

[66] Plummer, M. (2013). 2013 Integrated Energy Policy Report: Staff Workshop on Natural Gas Issues and Forecast Scenarios – Comments of Pacific Gas and Electric Company. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-04-24_workshop/comments/PGandE_Comments_2013-05-08_TN-70694.pdf

[67] Plummer, M. (2013). 2013 Integrated Energy Policy Report: Lead Commissioner Workshop on 2013 IEPR Natural Gas Issues, Trends, and Forecast Scenarios – Comments of Pacific Gas and Electric Company. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-17_workshop/comments/PGandE_Company_Comments_2013-07-31_TN-71776.pdf

[68] Plummer, M. (2013). *2013 Integrated Energy Policy Report: Lead Commissioner Workshop on Revised Electricity and Natural Gas Demand Forecasts–Comments of Pacific Gas and Electric Company*. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/comments/PG_and_E_Comments_2013-10-15_TN-72080.pdf

temperatures expected to occur once in every ten years **if the CPUC were to order additional pressure reductions.**"

B. PG&E Supports the Commission's Focus on Biogas Combined Heat and Power

PG&E supports the recommendation to "monitor changes in the natural gas and electricity generation interface"[69] especially with respect to CHP. As California continues to move toward a cleaner electric grid, it is becoming increasingly difficult for conventional natural gas-fired topping cycle CHP to contribute to GHG emissions reduction goals.[70] Non-dispatchable baseload resources, including conventional CHP, cannot provide the flexibility needed to support integration of intermittent renewable resources.[71] Due to these issues, PG&E believes that conventional CHP's place in the broader framework of California's energy policies is deserving of additional study.

With respect to assuring long-term GHG reductions, PG&E agrees that renewable CHP—such as CHP fueled by biogas from wastewater treatment facilities—is more attractive than conventional topping-cycle CHP fueled by fossil fuels. Bottoming-cycle CHP may also be attractive in certain applications as a GHG reduction measure. PG&E also note that both of these forms of CHP should not create additional demand for natural gas.

The 2013 Draft IEPR discusses the assumptions imbedded in CEC Staff's natural gas price forecasts. For CHP, these assumptions projects a range of 13 to 133 Bcf of increased natural gas demand due to installation of 210 to 3,273 MW of new CHP systems in California by 2024 in commercial and industrial applications.[72] PG&E participated in the "2013 IEPR Natural Gas Issues, Trends and Forecast Scenario Workshop" and provided comments on the potential natural gas demand from new CHP.[73] PG&E appreciates that—directionally in-line with our suggestions—the staff revised the assumptions of installed CHP demand downward to the current values. However, PG&E believes that the upper range of 3,273 MW of new CHP by

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[69] Op. cit., Draft 2013 IEPR, pp. 172.

[70] *Topping-cycle CHP* generates electric power first and uses excess heat for a productive purpose. *Bottoming-cycle CHP* generates process heat first, typically for an industrial application, and subsequently captures excess heat to generate power. The vast majority of the total installed capacity in the state is natural gas-fired topping cycle units. See: California Energy Commission, 2012, *Combined Heat and Power: 2011-2030 Market Assessment Report,* p. 35-36.

[71] The Draft IEPR clearly identifies this issue stating that, "because of the intermittent nature of renewable generation, natural gas-fired units may be needed to fill in short-term mismatches between supply and demand." 2013 Draft IEPR, page 162

[72] 2013 Draft IEPR – Table 12, page 159 and Figure 17, page 164. Note that the Draft IEPR restates the CHP targets in Governor Brown's Clean Energy Jobs Plan (6,500 MW of new CHP by 2020), see page 163 and 170

[73] 2013 Integrated Energy Policy Report: Lead Commissioner Workshop on 2013 IEPR Natural Gas Issues, Trends, and Forecast Scenarios – Comments of Pacific Gas and Electric Company - http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-17_workshop/comments/PGandE_Company_Comments_2013-07-31_TN-71776.pdf

2024 may still be too high. PG&E recommend that this value be reduced further in the Final IEPR forecast to be more consistent with other recent planning studies.[74]

The 2013 Draft IEPR states that "despite the overall decline in natural gas for power generation in California, a significant amount of this gas could be redirected to generate electricity for California's industry and commercial sectors";[75] and that, "Electricity produced by CHP facilities that is used on site is not counted toward utility natural gas procurement and effectively reduces the amount of renewable generation the local utility has to procure. It is in this fashion that CHP may *increase* the demand for natural gas."[76] PG&E requests that the Final IEPR include a table to clearly present both (1) forecasted increased use of natural gas from CHP applications and (2) the offsetting decreases from displaced non-CHP natural gas power generation and non-CHP commercial and industrial gas use. Calling out the forecasted net savings (or increases) in natural gas and GHG emissions would provide greater transparency about CEC's assumptions employed in the natural gas forecasting exercise regarding CHP efficiency and the efficiency of avoided separate heat and power.

In addition to these comments, PG&E offers the following technical or clarifying corrections.

- **Natural Gas Outlook:** In Table 12 on page 159, the total U.S. Natural Gas Demand forecast for 2024 is 30.5 Tcf/yr in the Reference Case, 29.9 Tcf/yr in the Low Demand/High Price Case, and 28.3 Tcf/yr in the High Demand/Low Price Case. The High Demand/Low Price Case demand of 28.3 Tcf/yr is lower than the Reference Case demand of 30.5 Tcf/yr, so the title does not reflect the demand values.

  Additionally, the price forecast curves in Figure 12 on page 160 are inconsistent with gas prices for 2013, 2014, and 2025, discussed in the paragraph above Figure 12. Figure 12 shows gas prices drop in 2014, whereas the paragraph above states: "In 2013, prices drop in all three cases." In reality, the gas prices were the lowest in 2012 at the average $2.80 per MMBtu, and have rebounded in 2013 from 2012 levels.

- **Natural Gas from Shale Formations:** CEC's discussion of hydraulic fracturing and regulations in California on page 162 does not reflect latest developments in regulations in California, including the approval of Senate Bill 4. PG&E suggests

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[74] For example, the 2012 Long-Term Procurement Plan (LTPP) assumptions assumed a total of 1,416 MW of Incremental CHP by 2024 in the high-case (768 MW of demand side CHP and 648 MW of supply side CHP). The mid-case assumed a total of 736 MW of incremental CHP by 2024 (653 MW of demand side CHP and 83 MW of supply side CHP). The base-case assumed no incremental CHP. While PG&E is not endorsing the CHP values in the LTPP as the correct values, PG&E uses this as an example to note the significant difference in the amounts used in the CPUC's LTPP as compared to the CEC's value of 3,273 MW. Refer to the "Scenarios" tab in the 2012 LTPP Scenario Tool Spreadsheet - http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

[75] 2 Op. cit., Draft 2013 IEPR, pp. 163

[76] 2013 Draft IEPR, page 172, emphasis added

that the CEC expand the background on hydraulic fracturing in California in the 2013 Draft 2013 IEPR, as provided below:

> "In California, hydraulic fracturing has been used as a production stimulation method for more than 30 years, mostly in vertical wells. Recently, oil producers have been attempting to decode California's Monterey Shale formation, as it is considered one of the largest oil shale deposits in the U.S. However, due to the complex geological formations in California, hydraulic fracturing with horizontal drilling, which are used in other shale fields, has not appeared to be applicable in California. Other techniques such as "acidization" are under consideration, as reported in the press."

Also, on September 20, 2013, Governor Brown approved Senate Bill 4 which strengthens California Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR) regulation of drilling to include hydraulic fracturing and acidizing. The bill requires drillers to disclose the amount of water and chemicals that will be used, receive hydraulic fracturing permits, and inform neighboring properties prior to hydraulic fracturing the wells. The bill will also require that DOGGR to develop regulations to address hydraulic fracturing and the Secretary of Natural Resources Agency to complete a study on hazards and risks by January 1, 2015.

- **Natural Gas Infrastructure:** CEC states that two LNG export facilities (Cheniere and Freeport) have been approved in the U.S. in the past three years. With the recent approval of Lake Charles and Cove Point projects, a total of four U.S. LNG export facilities have been approved as of September 2013. In addition, El Paso Natural Gas pipeline's expanded infrastructure to transport gas to Mexico through pipeline connections from South Texas, New Mexico, and Arizona. These projects will significantly increase U.S. exports to Mexico in the years ahead.

VI. ELECTRICITY, TRANSMISSION, AND CLIMATE CHANGE

In Chapters 4, 5, and 9, the CEC topics related to the state's electricity system, discusses transmission challenges and opportunities, and climate change, among other topics. As stated in the Introduction to these comments, PG&E appreciates the Commission's efforts to address climate change and the reliability of the state's electric systems in the Draft 2013 IEPR. Below is substantive and technical input of specific sections of these chapters.

C. PG&E Supports Innovations in the CEC's Forecasting Efforts

PG&E supports and appreciates the CEC's efforts to forecast load at a more granular geographic, which will help improve the accuracy of the CAISO's Local Capacity Studies, particularly given the new emphasis on demonstrating whether or not preferred resources can contribute toward meeting local capacity needs. Additionally, PG&E agrees that at higher temperatures, power plant cooling is less efficient, which in turn reduces the plant's ability to generate at its nameplate capacity. However, the attribution of this temperature-based rate to climate change is overstated in the Draft IEPR. Even under current climate conditions, high temperatures have this impact on fossil generation. Only the incremental rate associated with the "extra hotness" from a warming climate should be attributed to climate changes.

PG&E does not necessarily dispute the Lawrence Berkeley National Lab (LBNL) results, but suggests that the result be framed more appropriately in the IEPR so that readers do not get the impression that the full temperature rate of fossil generation is due to climate changes.

D. The Need for New Electricity Infrastructure

PG&E continues to emphasize the importance of ensuring local reliability in Southern California through the procurement of sufficient resources to meet the full needs identified in the local reliability studies submitted by SCE, SDG&E, and the CAISO as part of the 2012 Long-Term Procurement Plan (LTPP). PG&E acknowledges the potential of preferred resources and new transmission to fill the identified needs, but also supports the plan's suggestion that off-ramps and contingency permitting be set up in case these resources and transmission alternatives do not materialize as expected.

PG&E suggests that the CEC clarify in the Final 2013 IEPR whether the 50/50 target of preferred resources and conventional resources refers to nameplate capacity or effective capacity, as this distinction is critical and could result in a much different portfolio for meeting the SONGS replacement needs.

E. The Need for New Electricity Infrastructure

PG&E cautions against comparing apples to oranges when looking at trends in the levelized cost of generation across different resources types. Given the increasing penetration of renewable energy, PG&E expects that the fossil fleet will run at much lower capacity factors than it has historically. Because costs of conventional generation will be levelized over a smaller number of MWh, PG&E would expect the levelized cost of energy (LCOE) to increase for the fossil fleet even if there is no change to the fundamental cost structure of building these resources. Therefore, the charts on p.102-103 may overstate the relative cost trends and give the false impression that the cost of fossil generation is increasing more than it is.

LCOE is the right metric for comparing different types of renewable resources that rely on fixed per MWh payments to cover the entirety of their fixed and variable costs. The chart on p.100 appropriately illustrates the dramatic cost decline of solar PV in comparison to solar thermal and wind.

Additionally, PG&E suggests that all references to LTPP Track 2 should be removed, since Track 2 of the LTPP was canceled.

F. Transmission Opportunities to Enable Higher Levels of Renewables

There is a disproportionate emphasis on Wyoming wind in Chapter 5. For example, in the section discussing the benefits of EIM, the Draft 2013 IEPR gives the impression that wind power from Wyoming is uniquely suited to add geographic diversity to the California portfolio, as opposed to wind from the Northwest. Wind power from Wyoming is not unique in its ability to complement in-state generation through geographic diversity, and PG&E suggests that the 2nd paragraph on p.121 be removed.

Similarly, there is a significant discussion given to potential regional transmission projects. While regional transmission may have a role in bringing new resources to California, these transmission lines seem very preliminary, and are appropriately studied in the CAISO's transmission planning and interconnection processes.

G. Need Capacities to Meet 40 Percent Target

In Chapter 9 of the 2013 Draft IEPR, CEC staff provides guidance on the potential of moving the RPS target of 33 percent by 2020 to 40 percent by 2030. Staff estimates that the 40 percent by 2030 need to be about 25,000 GWh. While PG&E believes it is still premature to discuss any modifications to RPS targets at this time, PG&E provides the following recommended edits to the section to help clarify intent.

To meet a 40 percent RPS target, CEC Staff provides (in Table 21) technology specific guidance for estimating needed capacities. The information presented in this table seems to suggest a prescriptive procurement approach and gives the impression that recommended capacity is what would be required per technology to meet the 25,000 GWh target. PG&E recommends either deleting the table or modifying the table to clearly show that if an IOU were to procure all of the 25,000 GWh by using only one technology how much capacity would be needed (e.g., for Distributed Solar, assuming a 24 percent capacity factor, the needed capacity would be 11,891 MW) from that specific technology.

Given that it is highly unlikely that a single technology would be used to procure all of an assumed need for meeting a 40 percent target, this table is of very limited value and should be deleted.

VII. CONCLUSION

PG&E thanks the CEC for considering these comments and is happy to meet with CEC staff on these important topics.

Sincerely,

/s/

Matthew Plummer

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