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VIA E-MAIL DOCKET@ENERGY.CA.GOV

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

Re: 2013 Integrated Energy Policy Report: Lead Commissioner Workshop on Revised Electricity and Natural Gas Demand Forecasts – Comments of Pacific Gas and Electric Company

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the October 1 California Energy Commission (CEC or Commission) Lead Commissioner Workshop on the Revised Electricity and Natural Gas Demand Forecasts 2014-2024 (October 1 Workshop). PG&E has participated actively in the development of the 2014-2024 California Energy Demand (CED) Forecasts, both through the 2013 Integrated Energy Policy Report (IEPR) proceeding and the Demand Analysis Working Group (DAWG). PG&E thanks the Commission and Staff for their commitment to an open public process and willingness to consider stakeholder input.

The purpose of the October 1 Workshop was to present revisions to the Commission's initial CED Forecasts that were discussed at a May 30 Workshop.[1] In its subsequent comments on the May 30 Workshop,[2] PG&E provided a comprehensive review of the Preliminary CED Forecasts. PG&E's comments today, on the October 1 Workshop, identify remaining revisions to the CEC's forecast and update its comments on the May 30 Workshop, where necessary.

[1] See workshop page: http://www.energy.ca.gov/2013_energypolicy/documents/#05302013

[2] Plummer, M. (2013). *Lead Commissioner Workshop on Preliminary Electricity and Natural Gas Demand Forecasts – Comments of Pacific Gas and Electric Company* (13-IEP-1C). Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/comments/PG_and_E_Comments_on_Preliminary_Electricity_and_Natural_Gas_Demand_Forecasts_2013-06-13_TN%2071263.pdf

II. PG&E SPECIFIC COMMENTS ON REVISED CED

- **Electric Peak Demand Forecast:** The forecast of peak demand is an important assumption in generation and transmission planning, affecting procurement of new resources and identification of needed transmission lines, respectively. As such, PG&E believes that it is important that the CEC work with PG&E and the other investor owned utilities (IOU) to reconcile differences in their outlooks prior to finalizing the CED Forecast.

  Currently there is a significant difference between the CEC revised forecast and PG&E's forecast of future peak demand. The difference is partly due to the updated energy efficiency assumptions and partly related to different methods used for weather normalization of the base year. The weather normalization issue was also raised by Southern California Edison (SCE) at the workshop and has been raised by PG&E and other stakeholders in prior IEPR workshops and goes back several IEPR cycles.

  PG&E urges the CEC to convene a stakeholder meeting to discuss how consensus can be achieved on this critical issue prior to finalizing the peak demand forecast. If there is not sufficient time to reach a consensus on a weather normalization approach before the finalization of the forecast then PG&E recommends the CEC staff adjust the 2013 peak demand based on observed data for 2013 and an agreed upon weather correction method with the IOU's for that year only. The remainder of the peak demand forecast can then be calibrated to 2013 normalized demand. Since both the CEC and PG&E agree that 2013 was close to a 1 in 2 recurrence interval year, such an approach will help to minimize methodological differences around temperature normalization and produce a forecast which is more consistent between PG&E and the CEC.

- **PG&E Supports Including All Reasonably Expected Energy Efficiency and Demand Side Savings:** In its comments on the May 30 Workshop, PG&E recommended that the CEC incorporate all energy efficiency reasonably expected to occur in its baseline High, Medium, and Low CED Forecasts. This includes both committed efficiency savings and the additional achievable energy efficiency (AAEE), previously referred to as uncommitted energy efficiency.

  In these comments, PG&E reiterates this recommendation. Continuing to adopted baseline forecasts that do not include all energy efficiency savings that are reasonably expected to occur is confusing for CED forecast users. The baseline CED forecasts should represent the CEC's best estimate of what is likely to occur and a reasonable range bounding that most likely projection. To the extent that stakeholders agree that the AAEE Mid-Case, High-Case and Low-Case scenarios represent reasonable projections of the most likely, high case and low case reductions due to future improvements in energy efficiency those reductions should be included in the baseline forecasts that are adopted and used for infrastructure planning purposes.

All reasonably expected to occur energy efficiency savings from IOU programs, along with other demand side measures, should be included as reductions on the demand side and incorporated into the CEC's baseline forecast. This ensures these programs enter into the California Public Utilities Commission (CPUC) and California Independent System Operator (CAISO) long-term infrastructure planning processes, because those agencies use the CEC's baseline forecast as an input to their planning processes. In essence these projected savings from IOU programs represent "business as usual" reductions in demand. Additional energy efficiency and demand side savings opportunities should be considered to address shortfalls that are identified after the business as usual energy efficiency and demand side reductions are accounted for. These additional energy efficiency and demand side savings opportunities will likely require very specific interventions at the subsystem level targeted to enhance local area reliability.

- **PG&E Supports Changes to the Gas and Electric Rate Forecast:** In its comments on the Preliminary CED Forecasts, PG&E expressed its concern that the CEC's electric and gas rate projections, which showed a sustained annual growth at roughly twice the rate of projected general inflation, was not reasonable.

  The CEC staff relied on the Energy and Environmental Economics (E3) calculator in creating the rate forecast. As outlined at the October 1 Workshop, the CEC made a number of significant and positive changes to the assumptions used in the E3 calculator.[3] These include incorporating updated 2013 base-year information, natural gas hub prices, carbon auction prices, and transmission and distribution revenue requirement forecasts, among others into the analysis. As a result, the revised gas and electric rate forecasts are roughly 20 percent lower in the High and Mid-Case, and 15 percent lower in the Low-Case compared to the values in the Preliminary CED. While, as mentioned by CEC Staff, there is significant uncertainty surrounding any rate forecast, PG&E supports the changes made in the Revised CED.

- **Electric Consumption Forecast:** During the October 1 Workshop and in conversations with CEC Staff, two important changes were noted related to 1) the decay assumptions and 2) the Quarterly Fuel and Energy Report (QFER) data. With these corrections, PG&E believes the range of possible future energy demand between the low and the high scenarios represent a reasonable range for planning purposes. PG&E's notes that its own projections tend to be in the high end of that range.

[3] Weng-Gutierrez, M. (2013, October 1). *Revised 2013 IEPR Electricity and Natural Gas Demand Forecast*. Presented at the Lead Commissioner Workshop on the Revised Electricity and Natural Gas Demand Forecasts 2014-2024, Sacramento, CA. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/presentations/03_Weng-Gutierrez_Electricity_Rate_Assumptions.pdf

- **PG&E Supports Assessing Extreme Temperature Peak Demand in Future Forecasts Cycles:** At the October 1 Workshop, CEC Staff placed a high priority on assessing whether the current 1 in 5, 1 in 10 and 1 in 20 extreme temperature peak demand forecasts are reasonable given the underlying dynamics of climate change. PG&E agrees with this emphasis and supports the recommendation to further evaluate this dynamic.

  These recurrence interval forecasts are as important as the 1 in 2 forecasts for the purpose of long-term infrastructure planning. As discussed at the June 4 Joint Lead Commissioner Workshop on Climate Change and the Energy Sector[4] and reiterated at the CED forecast workshop, there is a real need to begin assessing how climate change may impact not only energy usage through increasing average temperatures but also peak energy demand and the need for peak capacity due to more regular occurrence of peak events, longer duration of peak events (including higher minimum temperatures) and possibly higher coincidence of peak events across California and the greater Western Electric Coordinating Council region.

- **Distributed Generation (DG):** PG&E notes and appreciates the level of sophistication used by the CEC in forecasting customer adoption of both photovoltaic (PV) and non-PV self-generation. In particular, PG&E appreciates the efforts by CEC staff to make its forecast as transparent as possible, including sharing data in advance of the October 1 Workshop. However, there are a number of modifications around PV assumptions that would make the forecast more robust.

  Firstly, in Appendix B of the accompanying Draft Staff Report, the CEC states that the California Solar Initiative (CSI) program was the major driver of the growth in PV since 2007.[5] This is only partially true. While very effective, the incentives from CSI are very small and will end soon. Equally importantly to increased deployment of PV are: 1) utility rates continue to rise in California, especially in the upper rate tiers; 2) PV prices continue to fall; and 3) the use of lease or power purchase arrangements for PV systems continues to grow. All of these drivers affect PV penetration rates.

  Additionally, on page B-3 of the Draft Staff Report, the cost information in Figure B-3 is described as "utility subsidies." The reader could reach the conclusion that the CSI incentives are the only utility subsidy. This is not true. The final report should clarify two things: first, customers who install distributed generation receive a host of

[4] Please see: http://www.energy.ca.gov/2013_energypolicy/documents/#06042013

[5] Kavalec, C., Fugate, N., Alcorn, B., Ciminelli, M., Gautam, A., Sullivan, K., & Weng-Gutierrez, M. (n.d.). *California Energy Demand 2014-2024 Revised Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency.* California Energy Commission, Electricity Supply Analysis Division. Retrieved from http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC_200-2013-004-SD-V1-REV.pdf. Pg. B-3.

subsidies; and, second, other non-participating customers pay for these subsidies (not utilities).

With respect to the forecast trends, two assumptions about the solar PV rates should be further clarified: 1) solar adoptions rates after the investment tax credit (ITC) ends; and 2) the CEC's capped annual growth rate. First, the CEC estimates that solar PV adoption rates after the ITC ends in 2016 are driven by increases in utility rates. The CEC should model different rate structures to reflect the ongoing consideration of modifications in residential rate structures. Otherwise, the assumption that residential rate tiers remain unchanged will result in a DG penetration forecast that is likely to be too high after the elimination of the ITC. If residential rate tiers continue as they currently are and ITC credits are extended, the CEC's capped 12 percent annual growth rate of solar PV penetration may be too conservative. Because these two assumptions tend to influence the forecast in opposite directions, it is not possible to discern the net impact.

- **PG&E Strongly Recommends That the CED Permanent Load Shifting Estimates be Corrected:** PG&E has reviewed the demand response (DR) portfolio component of the Revised CED Forecasts and compared the figures to the load impact estimates PG&E filed on April 1, 2013 with the CPUC under Rulemaking (R.) 07-01-041.[6] PG&E has identified a discrepancy between the Permanent Load Shifting (PLS) Program load impact estimates used in the IEPR and those filed with CPUC under R.07-01-041. Specifically, the IEPR PLS estimates are approximately 18,000 kilowatt (kW) to 21,000 kW greater than those PG&E submitted in R.07-01-041. PG&E strongly recommends that the Revised CED Forecast estimates be corrected to reflect those listed below in Table 1, for the reasons below.

  The load impact estimates PG&E filed in R.07-01-041 are produced in compliance with the DR Load Impact Protocols (the Protocols) approved in CPUC Decision (D.) 08-04-050[7] and achieve a standardized level of rigor, transparency and accuracy. Impacts produced under the Protocols are used as inputs for numerous CPUC proceedings, including resource adequacy, the long term procurement plan and cost-effectiveness testing. These impact estimates are also used in the load impact evaluations that feed into the Executive Summary of PG&E's DR Portfolio Overview, which is the primary source of input into the DR section of the Revised CED Forecast.[8]

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[6] California Public Utilities Commission, Rulemaking 07-01-041, "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols," January 31, 2007.

[7] California Public Utilities Commission, Decision 08-04-050, "Decision Adopting Protocols for Estimating Demand Response Load Impact," April 24, 2008.

[8] Pacific Gas and Electric Company, Rulemaking 07-01-041, "Executive Summary: 2013-2023 Demand Response Portfolio of Pacific Gas and Electric Company," April 2, 2013.

The PLS load impact evaluation PG&E filed on April 1, 2013 under R.07-01-041 shows that estimated reductions for August 1-in-2 peak days in 2014 are 2,534 kilowatt (kW). For 2015-2019, the estimated impacts increase to 5,055 kW, and then the estimates decline gradually to 4,550 kW by 2023.[9]

Table 1: PG&E PLS Ex Ante Impact Estimates
12-6 PM on Monthly Peak Days for August 1-in-2 Peak Days for 2014-2023 (kW)

Year	2014	2015-2019	2020	2021	2022	2023
kW	2,534	5,055	4,929	4,802	4,676	4,550

The estimates developed in the impact evaluation take into account PG&E's approved 2012 to 2014 PLS program budget of $13.5 million and an $875/kW incentive amount for thermal energy storage. Importantly, the evaluation also accounts for customer enrollments, standardized system weather conditions, as well as reasonable assumptions regarding how much of the approved budget could be spent by the end of 2014.

The PLS load impact estimates used in the IEPR for 2014 to 2023 are 23,430 kW for August peak days. For 2014, this estimate is approximately 21,000 kW greater than those PG&E filed, and for 2015 and beyond, they are about 18,000 kW larger. The PLS program load impact estimates currently presented in the Revised CED Forecast do not match with the Protocol-compliant PLS estimates that PG&E filed on April 1, 2013 under R.07-01-041. Since the IEPR estimates do not aligned with the standardized estimates embodied in the Protocols, PG&E strongly recommends that the IEPR PLS estimates be corrected to reflect those listed in Table 1 which do adhere to the Protocols. Including the IEPR PLS load impact estimates currently in place would lead to having estimates that are both inconsistent with the other DR impact estimates contained within the forecast and inconsistent with PLS estimates on file elsewhere in the regulatory space.

- **Natural Gas Demand Forecast:** The California Energy Demand Mid-Case for natural gas in PG&E's planning area matches closely with PG&E's internal forecast and has a similar trajectory of flat to extremely slow growth in Non-Electric Generation gas demand. PG&E commends the Commission for incorporating climate change into the natural gas demand forecast and urges the Commission to include the effect of additional, achievable energy efficiency within the baseline natural gas forecast as well.

[9] Freedman, Sullivan and Co., Rulemaking 07-01-041, "2012 Load Impact Evaluation for the Proposed California Statewide Permanent Load Shifting Program," Table 3-6, page 19, April 1, 2013.

There are some differences to note between PG&E's internal gas demand forecast and the forecast that is a part of the CED when looking at individual sectors. PG&E notes that in its forecast, residential and commercial demand are very flat compared to the slow growth shown in the CED forecast. This can be explained by PG&E's use of a slightly more aggressive warming pattern in accounting for climate change. Second, the decline in manufacturing demand shown in the CED is not shown in PG&E's forecast which shows flat demand after several years of observed sectorial rebound which was driven by increased refinery demand due to historically low natural gas prices. If commodity prices stay low more growth could be expected in the industrial demand sector. PG&E also notes that the CEC has not taken into account any potential changes in non-commodity cost of natural gas which includes distribution and transmission rates. Future changes to these rates will have an effect on gas demand.

III. CONCLUSION

PG&E is committed to continuing to work with CEC Staff on the CED forecasts and is very appreciative of their willingness to share information and build understanding.

Sincerely,

/s/

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