January 9, 2014

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 13-IEP-1A
1516 Ninth Street
Sacramento, CA 95814-5512
Attn: Heather Raitt at Heather.Raitt@energy.ca.gov, docket@energy.ca.gov

Subject: Protect Our Communities Foundation Comments on 2013 IEPR

I. INTRODUCTION

The Protect Our Communities Foundation ("POC") submits the following Comments on the 2013 Integrated Energy Policy Report (IEPR). As discussed below, the 2013 IEPR overstates electricity demand while underestimating the impact of energy efficiency, photovoltaics, demand response, and combined heat and power. The 2013 IEPR further fails to adequately address alternative supply models, such as CHP.

II. 2013 IEPR OVERSTATES ELECTRICITY DEMAND IN 2024

The actual 1-hour peak load in the CAISO control area has followed a pattern of steady decline from 2006 (50,270 MW) through 2013 (45,097 MW).[1] The peak one-hour demand in the CAISO control area in 2013 of 45,097 MW was actually lower than the peak one-hour demand in 1999 of 45,884 MW,[2] despite a statewide population increase of approximately 15 percent over the same period.[3] Peak one-hour demand has followed a declining pattern since 2006 in

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[1] CAISO, *Peak Load History 1998 through 2013*, January 2, 2014:
[2] Ibid.
[3] California population July 1, 1999 = 33,145, 121 (http://www.census.gov/population/estimates/state/st-99-3.txt); California population July 1, 2012 = 38,041,430 (http://quickfacts.census.gov/qfd/states/06000.html). California population growth 1999-2012 = 38,041,430 ÷ 33,145, 121 = 1.15 (15 percent increase).

PG&E and SCE service territories, while the one-hour peak load in SDG&E territory has fluctuated +/- 150 MW above and below 4,500 MW with no pattern of increase or decrease.[4] The CAISO peak one-hour load would have to increase at about 1 percent per year over the entire 2014-2024 timeframe to rise from the 2013 one-hour peak of 45,097 MW back to the 2006 one-hour peak of 50,270 MW.

Despite this reality, the CEC's *California Energy Demand 2014 – 2024 Final Forecast,* the basis for demand projections in the 2013 IEPR, projects substantial 1-in-10 year one-hour peak load increases over historic high one-hour actual peak loads in all three IOU service territories by 2024, even in "CED Final Low" forecasts.

California IOUs are experiencing relatively modest peak one-hour loads even during verifiable 1-in-10 year weather events. For example, the Commission has identified September 14, 2012 as a 1-in-10 year weather event in Southern California, affecting the service territories of SCE and SDG&E.[5] There was no spike in one-hour peak load, relative to the prior six years in either SCE or SDG&E during the 1-in-10 year weather condition. The assertion by the CEC that "While 2012 was a warm year on average, the SDG&E planning area experienced a below average peak temperature"[6] is incorrect and contradicts Commission data regarding the same weather event.

The one-hour peak load history of CAISO and individual IOUs, even at 1-in-10 weather year peaks loads, do not support the peak load growth projections in "CED 2013 Final Low" CED 2013 Final Mid" and "CED 2013 Final High" scenarios. As shown below, the one

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[4] CEC, *California Energy Demand 2014 – 2024 Final Forecast – Volume 2*, December 2013, p. 10 (PG&E), p. 44 (SCE), p. 72 (SDG&E).

[5] CPUC, *Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs – Commission Staff Report*, May 1, 2013, p. 31 and Appendix A: Highlight of 2012 Summer Weather & Load Conditions. See: http://www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf.

[6] At p. 71

exception is the CED 2024 "Draft Low" and "Final Low" forecasts for SCE territory, which reflects no net peak load growth between the 2007 highest actual peak load and the 2024 "Final Low" peak demand forecast. The 2024 "Final Low" peak load forecasts for PG&E and SDG&E should reflect this same trend – no net peak load growth between the highest actual one-hour peak load and the 2024 peak load forecast.

Figure 1. Comparison of IOU Highest Actual One-Hour Peak Loads and 2024 "Low" Peak Demand Forecasts in CED May 2013 Draft and December 2013 Final Reports

Utility	Highest 1-hour peak recorded (MW)	CED 2013 Draft Low 2024 Peak Load (MW)	CED 2013 Final Low 2024 Peak Load (MW)
PG&E	22,650 (2006)	24,390	25,207
SCE	23,831 (2007)	23,499	23,906
SDG&E	4,643 (2010)	5,032	5,009

The CEC peak demand forecast scenarios are in general substantially elevated from real-world electricity consumption trends in California. The "CED 2013 Final Low" forecast for SCE, showing SCE returning to the historic 2006 peak in 2024, appears to be a reasonably accurate reflection of current trends. The CEC should have developed a similar "CED 2013 Final Low" forecast for PG&E and SDG&E as well. There is no reason why PG&E and SDG&E would experience significantly different demand growth trends than SDG&E. <u>Recommendation</u>: The "CED 2013 Final Low" peak demand growth scenario best reflects actual trends and should be considered the Base Case demand forecast in the 2013 IEPR.

II. 2013 IEPR UNDERSTIMATES DEMAND REDUCING FACTORS

The 2013 underestimates several factors that significantly reduce demand: energy efficiency, photovoltaics, demand response, and combined heat and power.

A. <u>Additional Achievable Energy Efficiency</u>

The high Additional Achievable Energy Efficiency ("AAEE") forecast should be the Base Case 2024 EE assumption, should be the high AAEE value, not the mid-case. The California Energy Efficiency Strategic Plan (2008, 2011) is California Public Utilities Commission (Commission) regulatory policy. The 2013 IEPR cannot presume EE forecasts that are substantially below the EE targets described in the California Energy Efficiency Strategic Plan. Recommendation: the 2013 IEPR should be amended to adopt the *high* AAEE forecast.

B. Photovoltaics

The self-generation PV peak reduction assumed in the 2013 IEPR in 2024, as detailed in the *CED 2014-2024 Final Report*, is approximately the self-generation PV peak reduction that will occur by no later than mid-2017 as a result of AB 327 caps. Assuming peak reduction is 50 percent of nameplate PV rating, by 2017 the expected minimum amount of self-generation PV will be: PG&E = 1,205 MW; SCE = 1,120 MW; SDG&E = 304 MW. In contrast, the CEC projects the following self-generation PV peak reduction in 2024: PG&E = 1,000 to 1,314 MW; SCE = 638 and 850 MW; SDG&E = 367 and 435 MW. CEC staff apparently ignored the targets specified in AB327, passed into law in September 2013, as there is little difference in the CEC self-generation PV forecasts in the May 2013 draft CED and the December 2013 final CED.

AB 327 provides these minimum net metering allocations, by no later than mid-2017, for each IOU:[7] SDG&E, 607 MW; SCE, 2,240 MW; and PG&E, 2,409 MW. After the NEM cap is reached, the IOU compensation is supposed to be modified with no further cap on self-generation PV capacity: "There shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017." It is reasonable to assume that the rate of PV self-generation will continue beyond the July 1, 2017 termination date for the net-metering targets at or above

[7] http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.htm

the rates achieved prior to that date. A reasonable conservative assumption would be that the amount of self-generation PV installed between mid-2017 and the end of 2024 will at least replicate the amount of self-generation PV installed by mid-2017. Recommendation: amend the PV projection to reflect reasonable growth between 2017 and 2024.

C. Demand Response

The 2013 IEPR is in error to place DR in two separate categories, “Fast Effective DR” and “Other DR.” As identified in Table 10 of the 2013 IEPR, only a small subset of total DR is identified as “Fast Effective DR.” “Fast Effective DR” refers to the expectation that fast-response DR would be able to respond in sufficiently less time than 30 minutes from the time of CAISO dispatch, to allow CAISO operators enough time to detect a non-response and dispatch an alternative resource if needed to mitigate a contingency. This assumption is incorrect. All DR can be dispatched a day-ahead consistent with the current alert timeline utilized in the CAISO “Flex Alert” program. All “Other DR” should be assumed to be proactively dispatched day-ahead to meet predicted high demand events the following day, supplemented by 30-minutes ahead “Fast Effective DR” as needed. All DR, both “Other DR” and “Fast Effective DR” should count fully for meeting local capacity requirements. IOU customers are already paying for the DR resource and it is not being dispatched to its potential on high demand days.[8] All DR resources should be counted as available and deployed to meet predicted peak demand events, not just “fast response” DR resources. Recommendation: DR resource capacity should be assumed to grow at the same annual rate in 2025-2034 as it does in 2014-2024.

D. Combined Heat and Power

[8] CPUC, *Lessons Learned From Summer 2012 Southern California Investor Owned Utilities’ Demand Response Programs – Commission Staff Report*, May 1, 2013.

The 2013 IEPR forecast of new CHP in 2024 is substantially lower than state targets and CHP market potential. The ICF International CHP consultant report referenced in the 2013 IEPR[9] description shows a range of new CHP additions from approximately 2,000 MW (Base Case) to 6,000 MW (High Case) in 2025 as shown in Figure 2. Almost no CHP growth is projected beyond 2025 by ICF International.

Figure 2. Cumulative New CHP Market Penetration, MW[10]

2011 Scenarios	Cumulative New CHP Market Penetration, MW				
	2011	2015	2020	2025	2030
Base Case	123	617	1,499	1,817	1,888
Medium Case	233	1,165	3,013	3,533	3,629
High Case	340	1,700	4,865	5,894	6,108
2009 Scenarios	**Cumulative New CHP Market Penetration, MW**				
	2009	**2014**	**2019**	**2024**	**2029**
Base Case	136	680	2,096	2,816	2,998
High Case (All-in)	442	2,209	5,338	6,306	6,519

Source: ICF International, Inc.

This potential is almost equally split between onsite self-generation CHP and export CHP, as shown in Figure 3.

Figure 3. Cumulative Market Penetration by Market for Large and Small Systems[11]

Scenario	Base		Medium		High	
Size	< 20 MW	> 20 MW	< 20 MW	> 20 MW	< 20 MW	> 20 MW
On-site	1,269	246	1,519	263	2,901	388
Avoided Air Conditioning	130	30	155	32	316	45
Export	91	122	93	1,568	295	2,162
Total	**1,489**	**399**	**1,766**	**1,863**	**3,513**	**2,595**

Source: ICF International, Inc.

9 At p. 183

10 ICF International, Inc., *Consultant Report - Combined Heat and Power: Policy Analysis and 2011 – 2030 Market Assessment*, June 2012, prepared for California Energy Commission, Table ES-2.

11 Ibid, Table ES-3.

However, The CED 2014-2024 Final Report shows almost no growth of "non-photovoltaic self-generation" in the 2014-2024 timeframe for any of the utilities included in the document. This despite the state's clear commitment to rapid expansion of CHP as underscored in the 2013 IEPR:

> p. 182: "The California Air Resources Board's AB 32 Climate Change Scoping Plan includes a target of 6.7 million metric tons of carbon dioxide equivalent (CO2e) reductions from new and existing CHP resources, and Governor Brown's Clean Energy Jobs Plan sets a goal of 6,500 MW of new CHP capacity by 2030."
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> p. 183: "In 2011 the Energy Commission contracted with ICF Consulting to identify existing CHP capacity and quantify the long-term market potential for CHP in California and the degree to which CHP can reduce potential GHG emissions over the next 20 years. The resulting Combined Heat and Power: 2011-2030 Market Assessment identified 8,518 MW of installed CHP at the end of 2011 and indicated that cumulative market penetration for new CHP in 2030 varies between 1,888 MW and 6,108 MW"

<u>Recommendation</u>: The IEPR should adopt the Medium Case identified in the ICF International June 2012 report, both for onsite self-generation CHP and export CHP.

IV. 2013 IEPR DOES NOT ADEQUATELY ADDRESS ALTERNATIVE SUPPLY MODELS SUCH AS CCA

Choice Aggregation (CCA) has now been established in Marin County and Sonoma County. Every indication points to CCA development being an accelerating trend, and CCA's have been investigated planned, or proposed in many more California communities.

As CCA's grow, their share of retail energy load will increase, reducing IOU procurement needs. The need to account for this has previously been recognized by Pacific Gas and Electric, which, in its 2006 LTPP, modeled a scenario where CCA would increase to account for 10% of retail load. PG&E noted:

> Several entities have expressed desire to take advantage of the CCA to receive commodity service outside of the utility bundled service… if and when it happens, CCA will reduce PG&E's procurement needs.[12]

In order to be factually accurate, any scenario considered in this proceeding must account for the existence and accelerating growth of CCA's by reducing retail load accordingly. Given the upward trend in CCA adoption, the 10% figure used by PG&E in 2006 is appropriate for all scenarios in this proceeding. <u>Recommendation:</u> Amend the 2013 IEPR to fully account for CCA, using the 10% figure originally proposed by PG&E.

VI. CONCLUSION

As discussed above, POC recommends that the 2013 IEPR be amended as follows:

- The "CED 2013 Final Low" peak demand growth scenario best reflects actual trends and should be considered the Base Case demand forecast in the 2013 IEPR.
- The *high* AAEE forecast should be adopted in place of the mid forecast.
- Amend the PV projection to reflect reasonable growth between 2017 and 2024.
- DR resource capacity should be assumed to grow at the same annual rate in 2025-2034 as it does in 2014-2024
- The IEPR should adopt the Medium Case identified in the ICF International June 2012 report, both for onsite self-generation CHP and export CHP.
- Fully account for CCA, using the 10% figure originally proposed by PG&E.

[12] PG&E 2006 Long Term Procurement Plan Volume 1, at p. IV-52

Respectfully Submitted,

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