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Pacific Gas and Electric Company

2015 IEPR Form 6 – Incremental Demand-Side Program Methodology

Efficiency Program Impacts – Form 3.2

Energy Efficiency (EE) savings are estimated on a gross basis for programs, gross (excluding NOMAD) for codes and standards (C&S). Reported program results, C&S impacts in the base California Energy Demand (CED) forecast, and savings from the Additional Achievable Energy Efficiency (AAEE) report are used in generating the EE forecast.

Data from the CED and AAEE are based on an extensive body of research, which includes the CPUC Potential and Goals Studies/Model, DEER and IOU workpaper savings parameters, Saturation Surveys, Cost Studies, and a variety of other EM&V research. Due to limitations on data availability through 2026, estimates for years 2025 and 2026 are based on the compound annual growth rate of savings in the last years of the existing forecast data (through 2024).

Cumulative savings are estimated using annual incremental estimates, without adjustments for decay. The CPUC Potential Model shows unrealistically high levels of savings decay, mostly due to CFL replacements, which will be captured once the second phase of the Title 20 lighting standard takes effect in 2018. As a result of these unrealistic decay assumptions, the CPUC discontinued cumulative goals in 2013.

Renewables and Distributed Generation Program Impacts – Form 3.3

1. Introduction

Form 3.3 shows PG&E's forecast for retail Distributed Generation (DG) adoption within its service area. For the purposes of this form, we define retail DG as any generation technology sized less than 20 MW, located at or near the customer's site of load, and designed to offset on-site customer load.

PG&E forecasted DG adoption by the following technology groupings:

- Solar Photovoltaic
- Combustion Turbines (Including Microturbines) and Internal Combustion (IC) Engines[1]
- Fuel Cells
- Wind

[1] Combustion turbines and IC engines, as well as fuel cells, may be configured in a "combined heat and power" (CHP) or an electric only application, and may run on renewable or non-renewable fuel.

As explained in subsequent sections, PG&E forecasts customer adoption of each DG technology using the most appropriate and relevant methodology, including trend analysis and benchmarking to market monitoring services. PG&E also adjusts its quantitative modeling to account for the impact of key policies on DG markets in its forecast.

The market for DG technologies has historically received strong support by a number of state and federal policies and incentives, including but not limited to the Self Generation Incentive Program (SGIP), the California Solar Initiative (CSI), Net Energy Metering (NEM) and the federal Investment Tax Credit (ITC). Some of these policies are sun setting or being reformed and as such are expected to reduce the incentives in alignment with technology maturity. Changes such as the 2017 ITC reduction and NEM successor tariff implementation are likely to accelerate near-term adoption of eligible DG technologies, bringing forward some of the market that would otherwise have adopted at later dates.

The CSI General Market program, which provided direct incentives for retail PV installations, became fully subscribed in PG&E's service in 2014 and no longer offers incentives. The CEC's New Solar Homes Partnership (NSHP), the CSI Multifamily Affordable Solar Housing, (MASH) and Single Family Affordable Solar Housing (SASH) support PV adoption in new and low-income housing. The Self Generation Incentive Program (SGIP) continued to provide incentives for adoption of non-PV self-generation technologies including fuel cells, wind, gas turbines, and internal combustion engines.

In addition to direct incentive programs, the Net Energy Metering (NEM) tariff offered by Investor Owner Utilities (IOUs) has been an important policy tool that has bolstered broad solar and other DG adoption through a rate-embedded incentive. Under NEM, customers receive bill credits at full retail rates for electricity exported to the grid which offsets the cost of electricity consumed on-site. The amount of generation capacity that can be installed under the NEM program in PG&E's territory is capped at 2,409 MW, and PG&E expects to reach our Net Energy Metering cap within the year 2016. A NEM successor tariff is currently under development and scheduled to be established by the end of 2015 per Assembly Bill 327. In addition to the inherent challenge in predicting technology diffusion, uncertainty in the outcome of the NEM successor tariff, as well as potential future changes in retail rate structures contribute uncertainty to DG adoption forecasts.

DG technology adoption is also driven by a number of technology and market factors such as technology cost reductions, vendor growth strategies, zero-down financing options and customer market size. To the extent that lower technology costs result in lower prices to customers, then adoption would be expected to continue to increase despite reductions in incentives. As an example, the CSI General Market program which provided direct incentives for retail PV installations became fully subscribed in PG&E's service area, yet solar PV adoption is increasing rapidly even without the CSI incentives. Also, aggressive vendor marketing to take advantage of lucrative state and federal incentives is expected to result in strong growth of NEM- and ITC-eligible technologies between 2015 and 2017 before changes to these policies take effect. Further, the emergence of innovative, zero-down loan and lease financing structures has removed a key adoption barrier for solar customers. Finally, the growth trajectory and ultimate market size for any DG technology will be a function of the number of customers for whom technical, economic and other considerations of adopting DG align to make investment in the technology an attractive proposition.

2. PG&E's Retail DG Forecast Summary

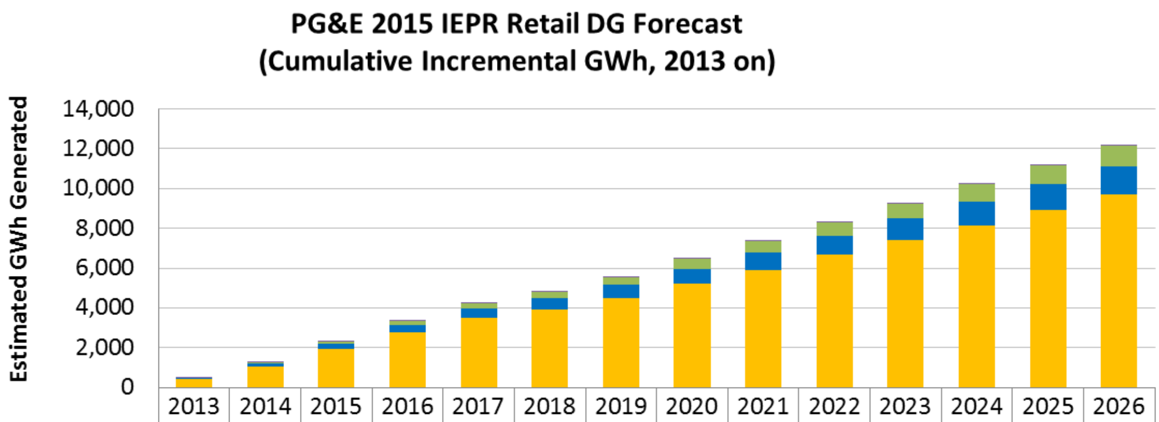
For the 2015 IEPR process, PG&E has developed a forecast for planning purposes that is independent of the CEC forecast in order to more accurately reflect its expectation of market and policy dynamics that drive DG adoption. For the 2013 IEPR process, PG&E submitted the CEC's high adoption case to represent our mid/expected case DG forecast. As DG adoption (mostly residential PV) has increased rapidly in recent years due to a number of market innovations, we have reassessed the CEC's forecast, and determined that the CEC forecast has historically significantly under-predicted likely DG adoption, and we believe this to be the case going forward unless changes are made to the methodology To enable better long-term planning, PG&E has thus developed its own forecast for future DG adoption than that reflected in the mid and high California Energy Commission's (CEC) 2013 California Energy Demand (CED) forecasts and 2014 updates that were submitted as part of the IEPR process. The most dramatic differences between PG&E and CEC forecasts pertain to distributed PV.

CEC's IEPR Form 3.3 requires the user provide "cumulative incremental impacts" for DG starting in 2013. Thus, PG&E presents its forecast in terms of incremental estimated generation capacity and energy after 2012.

In its "Expected Case" by 2025, PG&E estimates approximately 11,000 GWh of generation from retail distributed generation (DG) facilities will be added from 2013-2025, with solar PV comprising the majority of retail DG generation (Figure 1). This compares to about 4,000 GWh of generation from self-generation facilities forecasted in the CEC's 2014 IEPR update for the years 2015-2025 (Table 1).

PG&E's forecast for DG additions is higher than the CEC's 2014 IEPR Updated self-generation forecast primarily due to differing approaches to modeling PV adoption. Also contributing to this difference in forecast values is the fact that PG&E accounted for PV additions associated with ZNE policy compliance in its forecast, while the CEC did not.

Figure 1. PG&E's Retail DG "Expected Case" IEPR Forecast, Estimated Incremental Energy Generated 2013-2025



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Wind	2	5	9	13	18	22	26	30	35	39	43	48	52	56
Fuel Cells	34	73	128	188	253	324	401	483	570	663	761	864	968	1,071
Comb. Turb/IC Engine	26	132	238	344	450	556	662	768	874	980	1,086	1,192	1,298	1,404
PV	435	1,058	1,957	2,789	3,510	3,906	4,490	5,197	5,921	6,656	7,401	8,155	8,917	9,686
Total DG	497	1,268	2,331	3,334	4,230	4,808	5,579	6,478	7,399	8,338	9,291	10,259	11,235	12,218

Table 1. PG&E's Retail DG Forecast compared to the CEC's 2014 IEPR self-generation forecast update. Incremental GWh 2013-2025.

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	PV	295	639	874	1,073	1,167	1,280	1,415	1,583	1,799	2,066	2,384	2,743	3,103
CEC	Non-PV	(68)	87	423	548	601	652	701	743	782	814	839	858	877
	Total DG	**227**	**725**	**1,297**	**1,621**	**1,768**	**1,931**	**2,115**	**2,326**	**2,581**	**2,880**	**3,222**	**3,601**	**3,979**
	PV	435	1,058	1,957	2,789	3,510	3,906	4,490	5,197	5,921	6,656	7,401	8,155	8,917
PG&E	Non-PV	62	210	375	545	721	902	1,089	1,281	1,479	1,682	1,890	2,104	2,318
	Total DG	**497**	**1,268**	**2,331**	**3,334**	**4,230**	**4,808**	**5,579**	**6,478**	**7,399**	**8,338**	**9,291**	**10,259**	**11,235**

3. DG Growth Primarily Driven by Residential Solar PV

A growing number of PG&E's customers are choosing to install solar photovoltaic (PV) electric generating technologies to offset on-site usage. From 2010-2014, the compound annual growth rate (CAGR) of interconnected retail solar capacity in PG&E's service territory was about 30 percent. In recent years, growth has been driven primarily by the residential sector (Figure 2) which has seen YOY growth rates of approximately 70 percent from 2012-2014 (Figure 3).

Decreasing PV costs and increased availability of little or no-money-down financing arrangements, such as solar leases, PPAs and loan products, have driven increasing adoption in the residential sector. This growth has also been bolstered by aggressive marketing by retail solar providers in advance of policy changes that are likely to reduce the financial incentives associated with NEM and the ITC. Finally, the PV sector's growth has also been accelerated by access to abundant and low cost capital and greater standardization of residential PV contracts which has reduced transaction costs.

Figure 2. Historical Annual Adoption (MW CEC-AC) by Sector

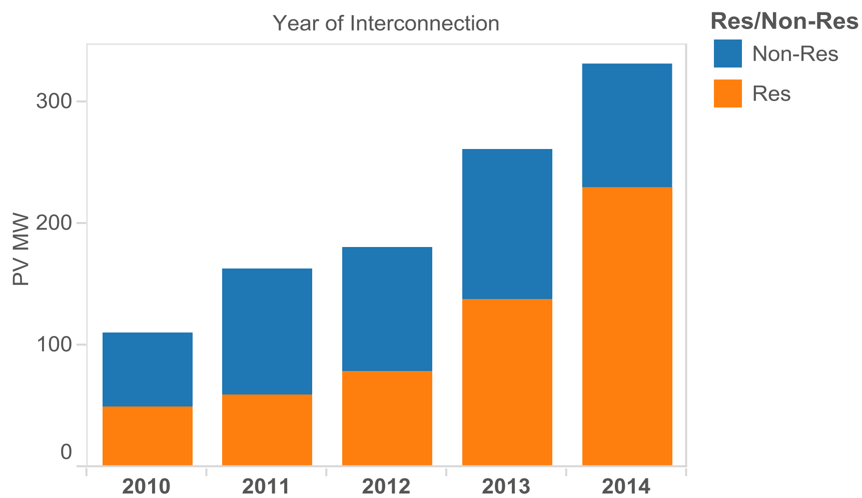
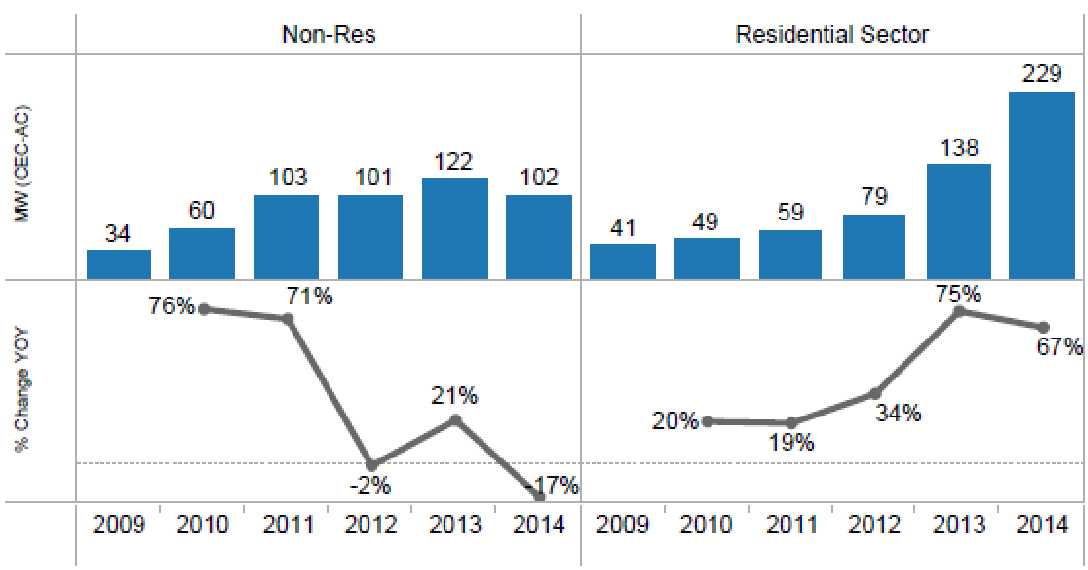


Figure 3. Growth Rates by Sector

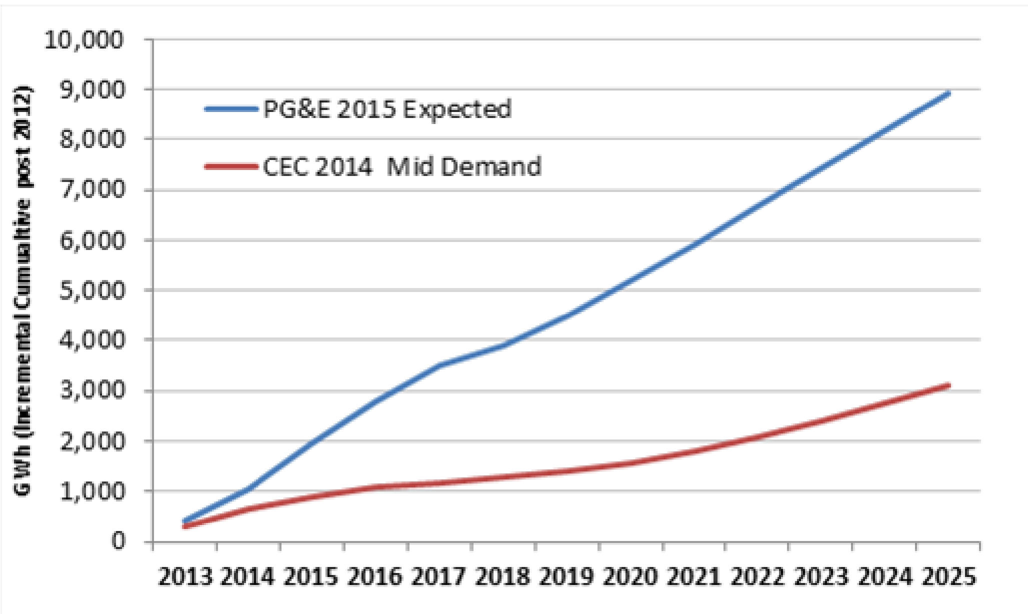


4. PG&E's PV Forecast

To forecast retail PV adoption, PG&E's general approach is to examine historical PV adoption rates, adjusted market growth projections based on anticipated policy developments, and referenced our forecast to near-term growth rates and long term cost reduction predicted in a study by market research firm, Bloomberg New Energy Finance (BNEF, Jan 2015). The BNEF study forecasted retail solar PV adoption in CA, and our forecast assumed that PV adoption growth rates in PG&E's territory will be similar to growth in the State.

PG&E projects that by 2025, incremental added retail distributed PV in our territory (post 2012) will produce about 9,000 GWh (Figure 1) of energy at the point of generation, compared to about 3,000 GWh from retail PV in 2025 in the CEC's mid demand 2014 CED update, and about 3,900 GWh in the CEC's low demand (high solar adoption) case.[2]

Figure 4. Generation From Incremental Retail PV Capacity Installed After 2012 in PG&E's Service Area, PG&E's 2015 Expected Case IEPR Submission Versus CEC's 2014 IEPR Update



PG&E anticipates a "gold rush" in annual installations from 2014 to the end of 2016, as vendors install systems before reduction of the federal ITC and changes to Net Energy Metering (NEM) tariffs are enacted. For 2015 and 2016, PG&E matched the growth in annual installed capacity (MW-AC) to BNEF's projections for California. The year-over-year (YOY) growth rate for annual retail solar PV MW installed for the Residential sector is projected to be 50 percent in 2015, and 30 percent in 2016. For the Non Residential sector, the YOY growth rate in annual MWs installed is projected to be 35 percent in 2015, and 10 percent in 2016. These YOY growth rates are less aggressive than those presented in a more recent forecast presented by GTM Research[3] in their 2014 Solar Market Insight report. Our forecast predicts that PG&E will meet its NEM cap (2,409 MW) in 2016 due to this "gold rush" effect.

[2] Workshops and Documents - 2014 Integrated Energy Policy Report Update, PG&E Forms 1.2. http://www.energy.ca.gov/2014_energypolicy/documents/index.html#adoptedforecast. Accessed April 10, 2015.

[3] GTM Research, 2015. U.S. Solar Market Insight Report, 2014 Year in Review.

2015	2016
57%	65%
42%	61%

In 2017, BNEF projects that in California, residential sector YOY growth in annual PV MWs will continue to increase at 10 percent and the YOY growth in the non-residential sector will be flat. Because we believe that PG&E will hit the Net Energy Metering cap in 2016, and that there will be a rush to get in under the cap, PG&E anticipates a reduction in annual incremental PV adoption in 2017 and 2018 of 25 percent for the Res sector and 10 percent for the Non Res sector.

From 2019 to 2026, PG&E projects that annual PV MWs installed in the residential sector will be comparable to 2014 levels at 250 MW per year. In addition to this added capacity on existing buildings, we project that Zero Net Energy (ZNE) requirements will add about 70 MW of PV per year from 2020-2026. This estimate is based on housing start projections by Moody's analytics, assuming that 50 percent of new single family homes install solar. During this period (2019-2026) in the non-residential sector, PG&E projects that annual installations of PV will grow proportionate to the reduction in the levelized cost of energy (LCOE) of PV projected by BNEF, at 3.5 percent per year.

Comparison of PG&E and CEC's PV Forecasts

The major sources of discrepancy between the CEC and PG&E forecast for retail PV appears to be explained primarily by two factors: (1) A different approach to modeling customer adoption behavior; and (2) the incorporation of additional adoption post 2020 from ZNE in PG&E's forecast, with no ZNE adoption assumed in the CEC forecast.

A significant portion of the discrepancy between CEC and PG&E forecasts is likely explained by different modeling approaches used by the CEC and Bloomberg New Energy Finance (BNEF), whose forecast informed PG&E's projection. The CEC uses a modeling approach that is based on the US Energy Information Administration's NEMS model and the National Renewable Energy Laboratory's Solar DS model. The CEC model predicts adoption based on consumer response to cost-effectiveness as measured by a payback calculation.[4] This approach was developed when most PV systems were owned by host customers, and is likely to under predict how cost effective PV is for consumers now that third party owned (TPO) solar financing models are widely available. Under a TPO financing structure, consumers assess cost-effectiveness by comparing IOU retail energy rates with energy prices that a third party solar provider can offer given its PV system costs and profit margins.

BNEF uses an adoption model that reflects the above-mentioned measure of cost effectiveness by comparing levelized bill savings against the levelized cost of solar. PG&E believes the approach used by Bloomberg better captures consumer decision-making under the current residential retail PV market environment in which third party financing models predominate. With TPO financing, the customer has an economic

[4] California Energy Demand 2014-2024 Final Forecast Volume 1 Appendix B (Jan 2014) page B-6.

incentive to install solar if bill savings are greater than the financing payment. Given that zero-down financing mechanisms now dominate the retail PV market place, payback is not the most applicable metric in this context, and use of this metric can lead to significant under-prediction of adoption.

A recent NREL study provides further evidence that payback period is not the most appropriate measure to assess solar cost effectiveness. The NREL report evaluated what financial metrics solar customers used to assess the economics of their solar investment.[5] The 2014 study was based on a survey administered to over 790 non-solar and 1,200 solar customers in San Diego, CA. The NREL study concludes that "monthly bill savings" was the primary economic measure used by all customers, even those who owned their own systems. For those who leased their solar system, 60 percent used monthly bill savings to evaluate their solar investment while only 16 percent used payback time.[6]

The NREL researchers also suggest that payback may not be an appropriate measure for understanding solar consumers' economic decision making:

> *Previously, the consumer behavior literature has suggested that residential customers primarily use a simple payback time to evaluate a new technology (Rai and Sigrin 2013; Camerer et al. 2004; Kempton & Montgomery 1982; Kirchler et al. 2008). However, with the strong growth of third-party owned systems, we expect that leasing customers are frequently being pitched PV systems based on the monthly bill savings rather than a payback time.*[7]

The NREL researchers also suggest that this finding has implications for defining adoption patterns and market potential:

> *By framing the proposition for adopting solar as a series of monthly savings—as opposed to a large upfront payment, greater portions of the general population could be enticed than if projects' returns were expressed in terms of the payback time.*[8]

[5] Sigrin, B, and Drury, E., Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics http://www.aaai.org/ocs/index.php/FSS/FSS14/paper/view/9222 Accessed Jan 17, 2015.

[6]/ Id., Table 3, page 41.

[7]/ Id., p. 41.

[8]/ Id., p. 42.

5. Non-PV Distributed Generation Forecast

For the purposes of forecasting non-PV DG, we examined historical adoption by three technology categories:

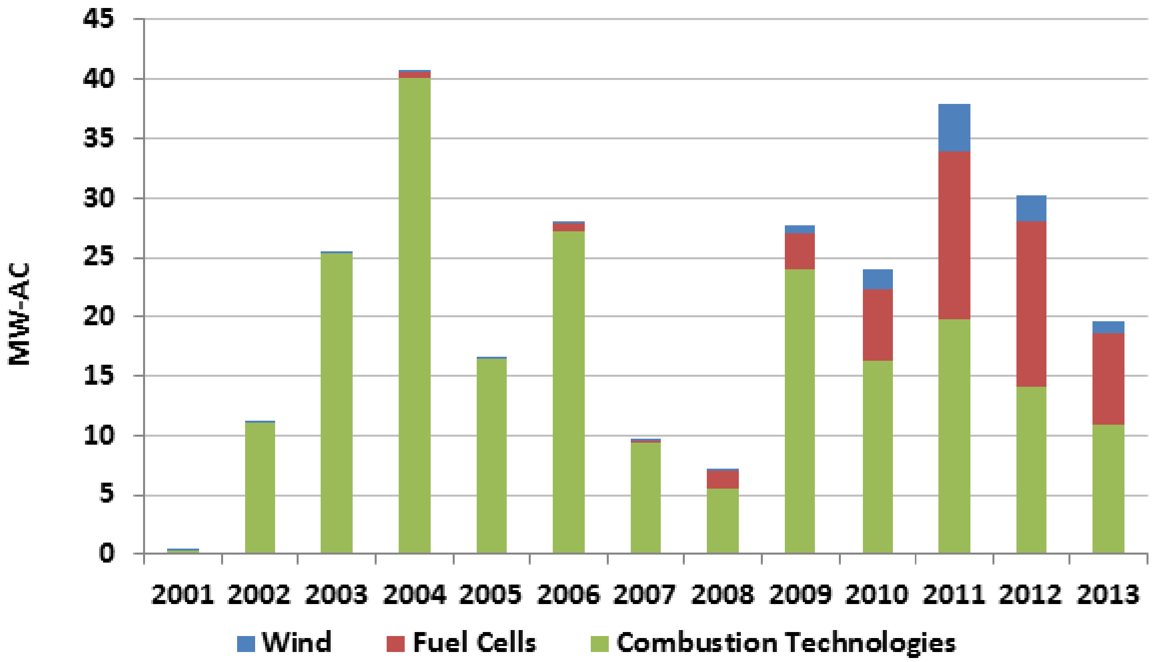
- Combustion Technologies
- Fuel Cells
- Wind

The technology category "combustion technologies" includes gas turbines, microturbines and internal combustion engines, most of which are configured in a combined heat and power application. Available historical data may not capture which combustion technologies are used in a combined heat and power configuration, so that distinction is not captured in our forecast. Combustion technologies for on-site energy generation are well developed and have been in use by commercial and industrial customers for decades. Technological advancements, policy initiatives, and electric rate structures that impact adoption are not expected to change substantially over the forecast period. For this reason, PG&E's combustion technologies forecast was developed using an historic 10-year average adoption rate over the period 2004-2013 of about 20 MW per year. Due to limited availability of information on historic adoption prior to 2001, we only forecast incremental adoption using a historical baseline of 2001.

Fuel cells and wind are supported through the Self-Generation Incentive Program (SGIP). Fuel cell adoption has accelerated in recent years (Figure 5). Incentives available through the Self-Generation Incentive Program, declining system and install costs, and rising system efficiencies (particularly from all-electric systems) are improving the economics of fuel cells. As a result, a linear trend function based on historical adoption in PG&E's service area from 2005-2014, showing increasing rates of capacity addition, is used to develop the fuel cell forecast, increasing to 25 MW annual capacity installed by 2025.

Distributed wind technologies have not been widely adopted due to siting constraints and other factors. For wind, a five year (2009-2013) adoption rate of 2 MW per year was used for the forecast.

Figure 5. Historical Annual Adoption – Non PV DG Technologies



6. Annual Generation and Capacity at Peak

Assumptions for converting installed capacity to energy and peak reductions were based on CSI and SGIP impact evaluation reports, United States Energy Information Administration (US EIA) information, and expert judgment where references were lacking. Annual capacity factors and assumed capacity available coincident with system peak (Aug 4-5 pm) are summarized in Table 2.

Table 2. Capacity Factors (Percent)

	PV	CHP	Fuel Cell	Wind
Annual Capacity Factor	17-20[9]	60[10]	50	25[11]
Capacity At Peak	33[12]	60	60[13]	10

[9] Capacity factors estimates from CSI Measurement &Evaluation Reports and PG&E analysis of CSI Performance Based Incentive (PBI) data. Degradation of 0.05% per year assumed and applied to PV fleet based on year of interconnection.

[10] US Energy Information Administration (US EIA). http://www.eia.gov/todayinenergy/detail.cfm?id=8250. Accessed Dec 15, 2014.

[11] US Energy Information Administration (US EIA). http://www.eia.gov/todayinenergy/detail.cfm?id=14611. Accessed Dec 15, 2014.

[12] 2010 CSI Impact Evaluation Report. See Figure 6-3, page 6-13, http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

[13] 2013 SGIP Impact Evaluation Report Figure 6-7.

7. Limitations and Caveats

While the forecast presented in this report is based on PG&E's best estimate of future patterns of DG adoption, as with any technology diffusion forecast, there are a number of sources of uncertainty that should be considered for planning purposes. Key factors that lend uncertainty into future DG adoption include the following:

- Limitations in understanding future DG technology adoption behavior based on historical patterns which may not apply to later adopters.
- Potential disruptive technologies could change customers' options in terms of energy choices.
- Distributed storage may impact DG adoption as storage technologies evolve and achieve wider deployment.
- ZNE policy, which increases the outlook for solar PV after 2020.
- Specific NEM reform proposals are uncertain. The next generation of NEM tariffs and policies will not be established until January of 2016.
- Because non-PV systems are often only cost-effective when supported by an incentive program such as the Self-Generation Incentive Program (SGIP) or the former Emerging Renewables Program, adoption is highly dependent on the continuation of such programs.
- Changes to federal incentives, such as the production and investment tax credits, could impact adoption trends of DG technologies.

Demand Response Program Impacts – Form 3.4

Pursuant with Ordering Paragraph 5 of the Load Impact Protocols adopted in CPUC Decision 08-04-050, PG&E files load impact reports for its Demand Response (DR) Portfolio with the CPUC on April 1 of each year. The DR program impacts included in Form 3.4 for years 2015 to 2025 are based on PG&E's load impact filings on April 1, 2015. PG&E's 2012-2014 Demand Response programs are funded through CPUC Decision (D.) 12-04-045, and the 2015-2016 DR programs are funded through D.14-05-025.

Pursuant with D.08-04-050, as modified by CPUC D.10-04-006, PG&E must also file an Executive Summary that provides a 10-year overview of the company's DR Portfolio on April 1 of each year. This document contains a discussion of the methodologies, assumptions, statistical models and other information relevant to how PG&E calculates its load impacts and enrollment forecasts. Along with the Load Impact Reports, the Executive Summary can be downloaded here: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=330612.