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Pacific Gas and Electric Company
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Incremental Demand-Side Program Methodology
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Efficiency Program Impacts – Form 3.2

Energy Efficiency Probabilistic Forecast

1 Introduction

The PG&E Energy Efficiency (EE) savings forecasts for energy (GWh), peak (MW), and gas (Therms) currently leverage the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) mid case[1] and Additional Achievable Energy Efficiency (AAEE) studies, and the CPUC-funded Navigant Potential and Goals model.[2] For the peak (MW) and gas (Therms) forecasts, PG&E extrapolates to future years using a compound average growth rate. However, for energy savings (GWh), PG&E then develops a probabilistic distribution around the uncertain portions of the given forecast.

2 Approach

PG&E Energy Efficiency (EE) forecasts leverage the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) mid case and Additional Achievable Energy Efficiency (AAEE) studies, and the CPUC-funded Navigant Potential and Goals model. Combined, these provide committed and uncommitted energy efficiency savings from programs and codes and standards (C&S).

[1] http://www.energy.ca.gov/2016_energypolicy/index.html
[2] http://www.cpuc.ca.gov/General.aspx?id=2013

The committed C&S and committed program savings come from the CEC IEPR forecast, and are based on measures and C&S already in place. The uncommitted C&S and uncommitted (incremental) program savings are outputs of the Navigant Potential and Goals model. In aggregate, this is the best deterministic point estimate of future EE savings in PG&E service territory at the time it is produced. Figure 1 shows the aggregate incremental savings expected from each of these streams.

This underlying deterministic forecast is a combination of the CEC and CPUC models, which represents the mid or base forecast. PG&E's probabilistic EE forecast uses this as a starting point, and then incorporates stochastic modeling to understand how likely PG&E is to achieve, exceed, or miss these savings levels based on the uncertainties in the underlying assumptions. This does not require PG&E to build a stand-alone forecast model, but to estimate a probabilistic distribution around the uncertain part of the CEC + CPUC forecast. In addition, PG&E's probabilistic forecast incorporates new information that hadn't been incorporated into the IEPR or AAEE (e.g., SB350, AB802, updated avoided cost model) or occurred after the latest CEC and CPUC forecasts.

Parts of the underlying deterministic forecast are considered relatively certain, such as the committed C&S. However the uncommitted streams are quite uncertain, as they depend on future economics, changing policies, avoided costs, etc. The lower portions of the chart in Figure 1 are the uncommitted savings streams, which represent the uncertain portion of the forecast. The probabilistic analysis applies to this uncertain portion.

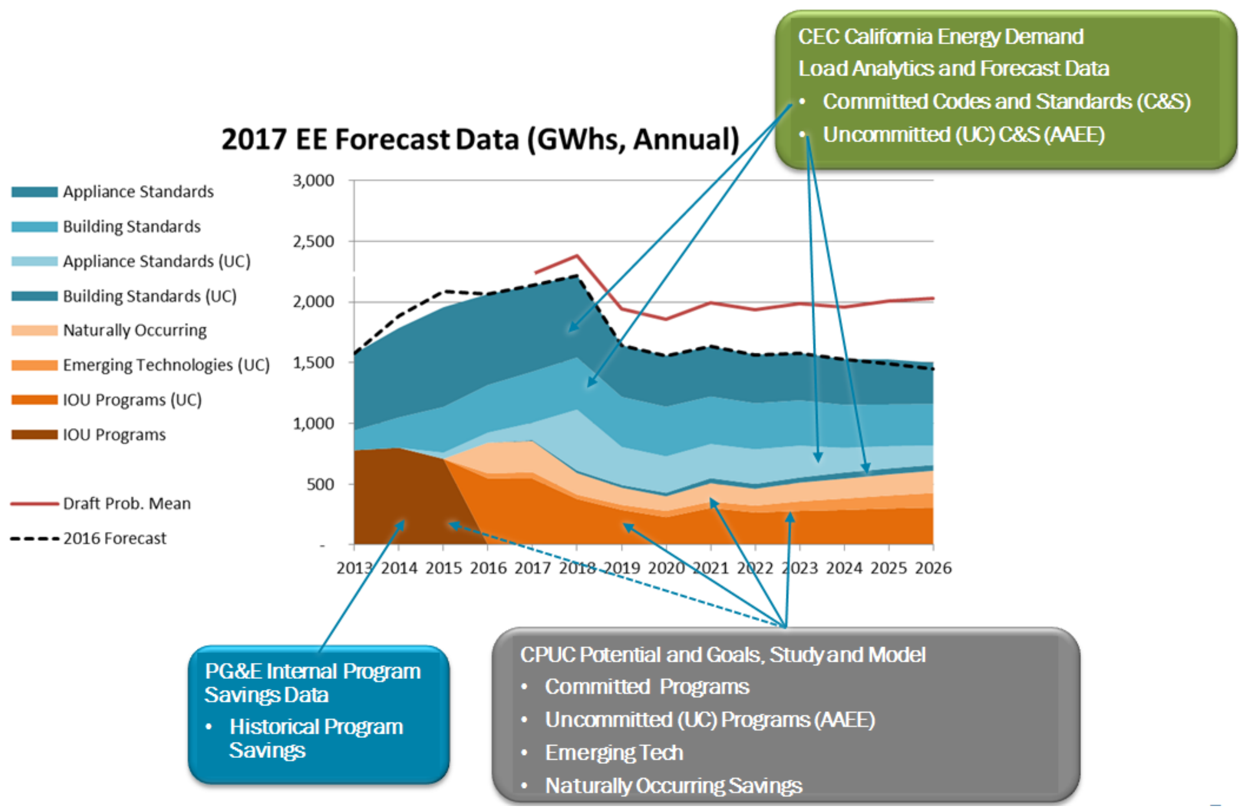

Figure 1) Public model results from the CEC and CPUC which, in aggregate, become the PG&E EE forecast

3 Methods/Assumptions

There are three steps to developing the probabilistic forecast:

- Identifying the key drivers on future EE savings and determining their sensitivity
- Assigning uncertainty around each driver
- Evaluating the outcomes and likelihoods of each

3.1 Identifying key drivers and sensitivities

The objective is to assess the sensitivity to different variables to determine the key drivers of efficiency and then estimate probabilities for each driver. Since the majority of the uncertain portion of the deterministic forecast is from the Navigant Potential and Goals model, we use this model to evaluate sensitivities. Fortunately, the CEC has published a sensitivity chart of the key EE drivers in their model. The CEC worked with Navigant, who produced these sensitivities by altering each driver in the model (one at a time) to high and low values. The high and low values are unique to each variable, based on logical extreme (not maximum) values. The drivers and settings from the CEC/Navigant are shown in Table 1.

Table 1) Drivers and Potential model sensitivity settings from CEC/Navigant

Demand Case	High	Mid	Mid	Mid	Low
Savings Scenario	Low (Scenario 1)	Low (Scenario 2)	Mid (Scenario 3)	High (Scenario 4)	High (Scenario 5)
Building Stock	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
Retail Prices	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
Avoided Costs	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
UES	Best Estimate UES	Best Estimate UES	Best Estimate UES	Best Estimate UES	Best Estimate UES
Incremental Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs
Measure Densities	Best Estimate	Best Estimate	Best Estimate	Best Estimate	Best Estimate
ET's	50% of model Results	50% of model Results	100% of model results	150% of model results	150% of model results
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Word of Mouth Effect	Mid	Mid	Mid	Mid	Mid
Marketing Effect	Mid	Mid	Mid	High	High
Implied Discount Rate	Best Estimate	Best Estimate	Best Estimate	Estimate minus 20%	Estimate minus 20%
Compliance Reduction	20% Compliance Rate Reduction	20% Compliance Rate Reduction	No Compliance Reduction	No Compliance Reduction	No Compliance Reduction
Standards Compliance	No Compliance Enhancements	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements	Compliance Enhancements
Title 24	2016	2016	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20	2016	2016	2016, 2018-2022	2016, 2018-2022	2016, 2018-2022
Federal Standards	On-the-books	On-the-books	On-the-books, Expected	On-the-books, Expected, Possible	On-the-books, Expected, Possible

Source: Table 12: "IOU AAEE Savings Scenarios;" Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. California Energy Demand 2016-2026, Revised Electricity Forecast. California Energy Commission. Publication Number: CEC-200-2016-001-V1.

We start by evaluating the individual drivers of potential EE from the model. The sensitivity study from the CEC/Navigant may not reflect new information about EE (e.g., updated avoid cost model impacts). Working with PG&E's subject matter experts (SME) on their respective topics, we adjust the sensitivities to better reflect current and updated information. The underlying deterministic CEC and CPUC inputs are pre-SB350 guidance, so we allow these sensitivities to reflect a low-SB350 scenario. This reflects a world where the State does not aggressively track toward meeting SB350, which could arise for a number of economic, cost effectiveness, or policy reasons.

With PG&E's SMEs, we also create a similar sensitivity table assuming an aggressive track toward achieving SB350's targets. This High-SB350 scenario reflects a world where the State is aggressively seeking to achieve SB350 targets. Reaching these targets will require some structural changes, such as using a modified cost test (or a version of a societal cost test), or considering what threshold determines program portfolio cost effectiveness. Reaching these targets will also focus attention on other parameters to ensure or accelerate EE savings, such as increased compliance enhancement, more aggressive C&S updates, more/better marketing and targeting, increase outreach, faster technology development and distribution (leading to higher UES), and more. This focus is captured with scale factors applied to both GWh impact and likelihoods.

3.2 Assigning uncertainties

Next we seek expert opinion on the likelihood of achieving each outcome of the sensitivities for each variable, and build a probability tree to assess the joint probabilities and impacts. To minimize the number of levels in the probability tree, we aggregate all of the drivers into two classes: behavior/economic and regulatory/programmatic. To do this, we sum the sensitivities and weight the driver probabilities. We do this for the Low SB350 scenario and the High SB350 scenario such that we arrive at a tree that combines these two scenarios.

3.3 Evaluating the outcomes and likelihoods

Now we can assess the conditional probabilities of each outcome. Branches two and three of the tree are conditional on which SB350 scenario; however, we considered them independent to each other (we lack supporting research to do otherwise). This generally has a tendency to understate the extreme ends (high-high and low-low).

Ranking the conditional probabilities and impacts produces a relatively coarse cumulative density function (CDF). The CDF represents what is not likely (0% probability), and what is nearly certain (100% probability), and everything in between. For now, PG&E assumes the CDF is constant over time.

4 Results and Summary

The CDF is used to produce a probability spread and percentile bands. This is accomplished by first fitting a spline to the piecewise linear CDF from our model and then using a Monte Carlo simulation to pull 250,000 random draws from the spline to determine the percentile spread.

While PG&E starts with the CEC forecast, PG&E then makes adjustments based on results from the stochastic modeling process. The stochastic modeling allows PG&E to understand the distribution of potential EE future results around the uncertain pieces of the CEC forecast. It also allows for incorporation of new information in assessing the likelihood of various outcomes. Hence, this modeling results in a probabilistic mean that can reflect higher or lower levels of savings, relative to the CEC's original deterministic forecast.

Renewables and Distributed Generation Program Impacts – Form 3.3

1 Introduction and Scope

Form 3.3 presents PG&E's 2017-2026 forecast for behind the meter (BTM) Distributed Generation (DG) adoption and generation within its service area. For the purposes of this form, we define BTM DG as any generation technology sized less than 20 MW, located at the customer's site, and designed to offset on-site customer load. BTM storage technologies are not included in this forecast. Historical installed capacity reported in Form 3.3 is from PG&E's interconnection database.

PG&E forecasted DG adoption and generation by the following technology categories:

- Solar Photovoltaic
- Combustion and Heat to Power Technologies
- Fuel Cells
- Wind

The category "Solar Photovoltaic" refers to electricity-generating solar technologies.[3] The technology category "Combustion and Heat to Power technologies" includes combustion turbines and internal combustion (IC) engines fueled by the combustion of gaseous or liquid fuels, as well as steam turbines that run on waste heat. The category "Fuel Cells" refers to technologies that generate electricity through a chemical reaction, generally using a gaseous fuel. The category "Wind" refers to distributed electricity-generating wind turbines designed to offset customer load that can range in size from a few kilowatts to several megawatts.

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. Distributed generation reflected in Form 3.3 may run on renewable or non-renewable fuels, depending on the applicable requirements of the incentive program and/or tariff or interconnection agreement used by the customer.

Instructions for Form 3.3 ask for adoption associated with DG programs. Customers who adopt DG technologies have historically received support from a number of direct incentive programs including the Self Generation Incentive Program (SGIP), which provides incentives for non-solar DG generation technologies, as well as the California Solar Initiative (CSI) program designed to promote BTM solar PV

[3] Adoption of solar water heating technologies in PG&E's service area has been limited and has primarily offset gas usage – impact is not considered material for system- level electric load forecasting purposes.

and thermal technologies. California Assembly Bill 1637 (2016) authorized additional funding for the SGIP program which will be available through 2020 per CPUC Decision-06-06-055[4].

The CSI program authorized by California Senate Bill 1 (2006) included a "General Market" program available to all customers of California's Investor Owned Utilities (IOUs) as well as the Multifamily Affordable Solar Homes (MASH) and Single Family Affordable Solar Homes (SASH) programs which targeted incentives for low income customers. Funding for the CSI General Market program in PG&E's service area has been exhausted since 2014. BTM PV and other DG adoption in PG&E's service area continues to be supported through tariffs that provide credits to customers for electricity exported to the grid – primarily Net Energy Metering (NEM) tariffs – and also includes DG that is interconnected under a Non-Export interconnection agreement.[5] PG&E reached the NEM capacity limit set by SB 1 (2006) on Dec 15, 2017, and the NEM tariff authorized by SB 1 has been replaced by the NEM Successor Tariff as authorized by AB 327 (2014) and CPUC Decision 16-01-044.

California AB 693 (2015) authorized additional funding for the CSI MASH and SASH programs which is considered in PG&E's BTM PV forecast, along with anticipated funding targeted at promoting solar PV adoption in "Disadvantaged Communities". PG&E also considers solar adoption on new construction driven by the California Energy Commission's New Solar Homes Partnership (NSHP) program and solar on new homes associated with Title 24 requirements to meet California's Zero Net Energy Goals.

The subsequent sections describe PG&E's approach to forecasting behind the meter solar and Non-PV distributed generation technology adoption and generation.

2 Behind-the-Meter Distributed Solar PV Forecast

PG&E projected customer adoption of behind the meter solar and estimated hourly generation associated with historical and forecasted installed MWs. To forecast PV adoption, PG&E used two separate approaches: (1) a Bass[6] Diffusion modeling framework, and (2) a policy goals model. The Bass Diffusion model attempts to capture future customers' decision-making regarding whether to adopt PV based on PV cost-effectiveness and constraints on adoption. In addition to forecasting economically-driven customer PV adoption using the Bass diffusion modeling approach, PG&E forecasted adoption driven by policy mandates such as Zero Net Energy (ZNE) goals, and low-income programs based on anticipated program funding.

[4] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

[5] Under a Non-Export interconnection agreement, customers are able to offset onsite load but are limited in the amount of electricity exported to the grid.

[6] Bass, F. 1969, Bass, F. 1969, "A new product growth model for consumer durables, A new product growth model for consumer durables," Management Science, Management Science, Vol. 15, no. 4, pp. 215-227

2.1 Bass Diffusion Modeling Approach

In the Bass Diffusion modeling approach, adoption is projected by assessing market size and modeling how a technology is likely to spread within that market. In the modeling framework used by PG&E, adoption in a given year n (t) in the formula below is a function of:

- The "market potential" $\overline{N_t}$, or the pool of customers who are able to adopt given conditions in a given year *(t)*
- The level of adoption that has already occurred as of the preceding time period (N_{t-1})
- Parameters that determine the rate of adoption within the market potential:
  - The diffusion parameter *(p)* which is commonly referred to as the "coefficient of innovation" or the "advertising effect" and captures the effect of advertising or the technologies' inherent attractiveness to customers
  - The parameter *(q)* which is commonly referred to as the "coefficient of imitation" or the "word-of-mouth effect" and is designed to capture increasing levels of consumer confidence and interest in a technology as the technology is more widely adopted

Discretized Bass Diffusion Model: $$\boldsymbol{n(t) = \left[p + \frac{q}{\overline{N}_t} N_{t-1}\right] [\overline{N}_t - N_{t-1}]}$$

PG&E estimates the market potential for BTM solar in a given year by customer sector, and models the rate of diffusion within that sector using diffusion parameters (p and q) that are referenced to available literature[7] and calibrated based on historical adoption.[8] In a given year, market potential is estimated by first identifying the percent of customers who are able to adopt, meaning that they are not constrained from adopting by technical barriers such as a lack of suitable roof space or by other market barriers such as not owning their homes or properties. This set of customers is identified in PG&E's modeling framework as the "addressable market". For customers in the addressable market, PV cost-effectiveness is then estimated based on forecasted solar costs and bill savings. The portion of the addressable market that would be willing to adopt at a given level of cost-effectiveness is defined by a "market share curve". This curve estimates customer demand for BTM solar at varying levels of cost-effectiveness. The market potential in a given year is thus the subset of customers who are not constrained from adopting by technical or market barriers and for whom solar is a cost-effective investment decision. The following sections further describe these components in PG&E's PV adoption modeling framework.

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[7] a) Sultan, Farley, and Lehmann (1990), "A Meta-Analysis of Applications of Diffusion Models." *J. Marketing Research* 27(1). https://www0.gsb.columbia.edu/mygsb/faculty/research/pubfiles/909/909.pdf
b)Van den Bulte and Stremersch (2004), "Social Contagion and Income Heterogeneity in New Product Diffusion: A Meta-Analytic Test." *Marketing Science* 23(4).
c) Meade and Islam (2006), "Modelling and forecasting the diffusion of innovation – A 25-year review." *International Journal of Forecasting* 22.

[8] PG&E estimated the Coefficient of Innovation (p) at 0.03 for Residential customers and 0.0225 for Non Residential Customers. The coefficient of imitation (q) was estimated at 0.3 and 0.25 for Res and Non Res customer respectively.

2.1.1 Estimating the Addressable Market

The addressable market of customers who can adopt in a given year is estimated by accounting for factors that are likely to constrain customers' ability to adopt, including access to space for PV (technical potential), owner-occupancy, credit-worthiness, and transaction costs relative to potential savings (higher transaction costs relative to potential savings is likely to constrain adoption among lower usage customers).

BTM PV technical potential by sector was estimated based on reports and data from the National Renewable Energy Laboratory[9] and by work done by Navigant for PG&E which builds on a study performed for NREL in 2008.[10] Owner-occupancy estimates were based on Experian data for residential customers, Commercial Building Energy Consumption Survey data for Commercial and Industrial customers, and USDA Census data for Agricultural customers.[11] Experian data was used to estimate the percent of residential customers with adequate credit. The impact of high fixed transaction costs on constraining PV adoption among lower-usage residential and small commercial customers was estimated using billing data and by calibrating to historical adoption trends.

2.1.2 Cost-Effectiveness

PG&E estimated the cost-effectiveness of Behind-the-Meter (BTM) solar based on forecasted solar costs compared to bill savings under Net Energy Metering. PG&E forecasted the cost of BTM solar based on market analyst projections.[12] Bill savings were estimated using rates and TOU periods proposed in PG&E's General Rate Case Phase 2 September 2016 filing.

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[9] Feldman, David et. al., 2015. Shared Solar: Current Landscape Market Potential and the Impact of Federal securities regulations. NREL Technical Report 6A20-63892 (Chapter 4) http://www.nrel.gov/docs/fy15osti/63892.pdf pp. 22-24 which references work later documented in: Gagnon et al., 2016. Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. Technical Report NREL/TP-6A20-65298. http://www.nrel.gov/docs/fy16osti/65298.pdf.

[10] Paidipati et.al., 2008. Rooftop Photovoltaics Market Penetration Scenarios http://www.nrel.gov/docs/fy08osti/42306.pdf

[11] a) Commercial Building Energy Consumption Survey (CBECS) Table B17. Occupancy of nongovernment-owned and government-owned buildings, number of buildings, 2012

b) United States Department of Agriculture 2012 Census of Agriculture. California Data.

https://www.agcensus.usda.gov/Publications/2012/Full_Report/Volume_1,_Chapter_1_State_Level/California/cav1.pdf

Table 70. Summary by Tenure of Principal Operator and by Operators on Farm

https://www.agcensus.usda.gov/Publications/2012/Full_Report/Volume_1,_Chapter_1_State_Level/California/st06_1_070_070.pdf

[12] The following analyst reports and forecasts were considered:

a) NREL: *US Solar Photovoltaic System Cost Benchmark: Q1 2016.* Published September 2016
b) IHS Global Insights: *US Solar PV Energy Price and Capital Cost Outlook, 2016-2040.* Published June 2016; cost per Watt through 2040
c) Bloomberg New Energy Finance (BNEF): *H1 2016 PV Market Outlook*. Published June 2016; cost per Watt through 2030.
d) GTM Research: *PV Systems Pricing Forecast with Breakdown.* Published June 2016; cost per Watt through 2022
e) GTM Research: *US Solar PV Price Brief H1 2016: System Pricing, Breakdowns and Forecasts.* Published June 2016

2.1.3 Estimating a Market Share Curve

The relationship between cost-effectiveness and demand for solar was modeled based on a survey of potential and actual solar adopters conducted in 2013 by US National Renewable Energy Lab researchers that evaluated the percent of customers who would be willing to adopt at a given level of bill savings.[13]

2.1.4 Solar Mandates and Low Income Programs

In addition to customer-driven adoption modeled using a Bass Diffusion modeling framework, PG&E models PV adoption associated with requirements for solar on new residential construction as well PV adoption driven by incentive programs targeted to low-income communities.

Solar on New Construction

PG&E forecasts BTM PV on new homes per California's Zero Net Energy goals. Those goals, as outlined in California's Long Term Energy Efficiency Plan[14], set a target that all new residential construction in California will be Zero Net Energy (ZNE) by 2020 and that all new commercial construction in California will be ZNE by 2030. PG&E did not incorporate estimates for solar from ZNE requirements on new non-residential construction as that requirement is set to begin outside of the 10-year forecast horizon.

Solar requirements on new residential construction are still being established through the 2019 Title 24 update and significant uncertainty remains as to what requirements will be in place. Local ordinances or additional statewide legislation may also play a role in requiring solar on new construction. For new construction occurring prior to enactment of ZNE Title 24 requirements in 2020, PG&E considers solar adoption on new construction driven by the California Energy Commission's New Solar Homes Partnership (NSHP) program. For solar on new residential construction starting in 2020, PG&E forecasts the percent of new homes anticipated to have PV as a result of Title 24 ZNE requirements and applies that percentage to housing start projections for PG&E's service area developed by Moody's analytics (2016).

Solar from Low Income Programs

PG&E projects PV installs associated with low-income targeted programs over the forecast horizon. These installs are estimated based on funding levels associated with the Multi-Family Solar Homes program (MASH), the Single Family Solar Homes program (SASH), and potential funding authorized by AB 693 which established funding for solar in Disadvantaged Communities.[15]

2.2 BTM Solar Generation

To estimate generation from BTM solar PV, PG&E modeled hourly generation by CEC climate zone using NREL's PV Watts model based on typical system configurations in PG&E's service area for the residential and non-residential sectors. These profiles were then weighted by the installed capacity in a given CEC

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[13] Sigrin, B, and Drury, E., 2014. 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

[14] California's Long Term Energy Efficiency Plan - 2011 update http://www.cpuc.ca.gov/general.aspx?id=4125. CEC's 2011 Integrated Energy Policy Report created parallel Zero Net Energy new construction goals that were reaffirmed in the 2013 and 2015 Integrated Energy Policy Reports.

[15] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

climate zone by sector to generate a system-level hourly load profile. The system-level profile was used to model BTM PV's impact on hourly load as described in Form 4. Generation estimates were adjusted using an annual degradation rate of 0.5% per year.[16]

3 Non-PV Distributed Generation Forecast

PG&E's Non-PV DG forecasts reported in Form 3.3 consist of non-solar distributed generation technologies less than 20 MW in size, designed to offset on-site customer load, and in the following technology categories:

- Combustion and Heat to Power Technologies
- Fuel Cells
- Wind

PG&E's forecast for these technologies was developed using a Bass Diffusion modeling approach similar to that used for the solar PV forecast. Cost-effectiveness and market potential estimates for Non PV DG technologies used in the this framework were informed by Self Generation Incentive Program Measurement and Evaluation reports[17], and were adjusted for anticipated SGIP, GHG policy, and market developments.

3.1 GHG Policy and Non PV DG

A key consideration that informed the forecast is a policy shift away from encouraging natural-gas fueled distributed generation technologies as California seeks to meet aggressive Greenhouse Gas Emission reduction goals per California Senate Bill 350 (2015). In consideration of promoting GHG emission reductions, the SGIP program now requires that systems installed through the program be fueled in part by biogas, with the requirement increasing to 100 percent biogas-fueled by the end of the current funding cycle.[18] While estimates of biogas potential are still being refined[19], biogas resources are more limited than natural gas, and PG&E expects that GHG emissions regulations will constrain adoption of gas-fueled technologies.

3.2 Non PV DG Generation

Generation from Non PV technologies was estimated using annual capacity factors by technology reported by Itron in the 2015 Self Generation Incentive Program Impact Report.[20] The capacity factors were developed using incentive program measured generation data. PG&E does not currently have

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[16] Jordan, D et. al. 2016 Compendium of Photovoltaic Degradation Rates. Progress in Photovoltaics. 10.1002/pip.2744 http://onlinelibrary.wiley.com/doi/10.1002/pip.2744/abstract

[17] a) Itron, Nov 2015. SGIP Market Transformation Final Report, submitted to PG&E and the SGIP Working Group
b)Itron, Nov 2016. 2014/2015 SGIP Impact Evaluation, submitted to PG&E and the SGIP Working Group
c) Itron, Oct 2015. 2015 SGIP Cost Effectiveness Study ,submitted to PG&E and the SGIP Working Group

[18] Per CPUC Decision 16-06-055. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

[19] Itron in Ibid (a) at table 6-17 estimates technical potential in PG&E's service area for on-site biogas generation at 360 MW. Directed biogas could increase the potential for biogas-fueled DG but the physical and legal infrastructure to make directed biogas feasible is still under development.

[20] Itron, Nov 2016. 2014/2015 SGIP Impact Evaluation, submitted to PG&E and the SGIP Working Group. Figure 1-3

robust hourly generation profiles for Non-PV technologies, so annual capacity factors were used as a proxy for generation at system peak.

4 Limitations and Caveats

While the forecast developed for Form 3.3 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 must be considered for planning purposes. Key factors that lend uncertainty to future DG adoption include the following:

- Consumer appetite for DG technology adoption is uncertain, and PG&E's estimates of the addressable market and the demand for a given technology may over or understate the DG market opportunity.
- Future cost-effectiveness of DG technologies depends on rate design as well as the structure of Net Energy Metering or other mechanisms for customers to receive credits when offsetting on-site energy and when exporting to the grid. There is uncertainty as to the structure of Distributed Energy Resources (DER) compensation mechanisms in California that will be informed by on-going regulatory initiatives related to Net Energy Metering, Integrated Resource Planning (IRP), and the Integrated Distributed Energy Resources (IDER) proceeding, among other initiatives.
- As storage technologies evolve and achieve wider deployment and cost reductions, they may change the value proposition of DG technologies, giving customers' more flexibility in managing on-site load and generation.
- Potential changes to funding and the structure of the Self Generation Incentive Program once the currently allocated funding is exhausted lend uncertainty to adoption of Non PV DG technologies.
- Future Greenhouse Gas Emissions reduction policies and regulations contribute uncertainty to the viability of DG technologies that have historically run on natural gas. Greenhouse gas emissions limits for fuel cells eligible for a fuel-cell specific Net Energy Metering tariff (NEMFC) are under development per direction from CA Assembly Bill 1637 (2016), and there is uncertainty in how GHG emission limits will affect future fuel cell adoption.

Demand Response Program Impacts – Form 3.4

Demand Response Program Costs and Impacts

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 Portfolio with the CPUC on April 1st of each year. The DR program impacts included in Form 3.4 for years 2017 to 2027 are based on PG&E's load impact filings on April 3, 2017.

Pursuant with D.08-04-050, as modified by CPUC Decision 10-04-006, PG&E must also file an Executive Summary that provides a ten year overview of the company's DR Portfolio on April 1st 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=406805