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Abstract

The economic value of distributed photovoltaic (PV) electricity is affected both by its correlation with transmission level energy prices and by a host of effects it may have on distribution systems. In this study we combine detailed physical simulation of distribution circuits with budgetary information provided by Pacific Gas & Electric (PG&E) to estimate PV's value with respect avoided transmission-level energy expenditures, avoided distribution system capacity upgrades, and increased expenditures to manage voltage magnitudes. We find that favorable timing of generation and the potential to defer capacity investments both increase PV's value on average by a small amount. We use circuit-level loading and load growth data to show that distribution circuit capacity value is very heterogeneous: PV shows very little capacity value on most circuits but substantial (over \$60/kW-yr, nearly half of the near-term targets for the cost of distributed PV) on a limited number of circuits. We examine some other distribution system impacts of PV, including voltage regulator operations and voltage quality, and find that they are also likely to be very small on average, with the caveat that there are some impacts (such as the effect of reverse power flow on protection equipment) that we have insufficient data to assess. In much the same way that dynamic pricing tariffs capture PV's value in time, our results point toward the importance of tariffs that recognize the heterogeneity of PV's impacts on distribution systems across different locations.

Keywords: electric distribution, photovoltaic generation, valuation

1. Introduction

Distribution systems were designed to deliver power from high voltage transmission networks to customers. When photovoltaics (PV) are embedded in distribution systems, they fundamentally change power flow conditions: power transfer could go from one customer to another, or from customers back to the transmission system. This has created concern among distribution engineers, regulators and researchers as to whether distribution systems will be able to accommodate very high penetrations of PV – and if so, what the associated costs will be. There are a number of areas where PV could have important impacts, including: resistive losses, peak load (which impacts capacity investments), and voltage levels

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at the point of utilization, transformer aging, voltage regulator mechanical wear, and the ability of protection systems to properly identify fault conditions.

A number of studies quantify various engineering impacts of PV in distribution systems, e.g. Quezada et al. (2006); Shugar (1990); Woyte et al. (2006); Thomson and Infield (2007); Navarro et al. (2013); Widén et al. (2010); Paatero and Lund (2007); Hoke et al. (2013); Cohen and Callaway (2013), but relatively little research has been done to translate the full range of engineering impacts into economic values. Indeed, the California Public Utilities Commission (CPUC) rejected the possibility of valuing PV's non-energy economic impacts, especially its possible deferral of generation, transmission and distribution capacity, on the basis of limited evidence (California Public Utilities Commission, 2011, p. 34). This paper aims to address this gap with new estimates of the economic impacts that PV could have on distribution systems, with a focus on conditions in California.

The contribution we make in this paper is to apply previously reported physical results from Cohen and Callaway (2013, 2015) to an economic framework that quantifies distributed PV's impact on distribution system operation and maintenance costs. We do this with a combination of (1) assumptions about growth in demand and PV capacity, and their interactions with one another, (2) a model of how PV capacity defers investment in distribution capacity infrastructure and (3) a unique set of data on distribution capacity expenditures and feeder-level growth rates from Pacific Gas and Electric.

Our key findings are as follows: First, PV provides distribution circuit capacity deferral value of up to $6/kW-yr when averaged across the potential impact on *all* feeders in PG&E's service territory. This is a very small fraction of the installed cost of PV (approximately $380/kW-yr using historical cost estimates, or $110/kW-yr if near-term DOE projections are met). However roughly 90% of these feeders receive no capacity benefit from PV because their peak load is much less than their peak capacity or their load growth is low – therefore those feeders do not require capacity upgrades over the horizon we investigate. We find that PV's capacity value on the 10% of feeders that would otherwise require capacity upgrades ranges from $10/kW-yr to more than $60/kW-yr at very low penetrations. This range suggests that the value on some circuits could be a significant fraction of the installed cost of PV. We also find that these benefits decline relatively quickly as additional PV is installed on each circuit; at 50% penetration capacity value is half of its value at low penetrations.

Second, based on our engineering simulations of PV impacts on distribution circuits, we find PV's impacts on voltage magnitudes and voltage regulator operations are relatively small (Cohen and Callaway, 2013, 2015). If we assume that voltage regulator maintenance scales linearly with the frequency of operation, results in this paper indicate that distributed PV would increase PG&E's annual costs by $442,000 if *all* circuits in PG&E territory had 100% PV penetration – an extremely small amount of PG&E's roughly $6 billion operations and maintenance budget. Because we do not have circuit-level data from PG&E on voltage maintenance, we are not able to accurately quantify the heterogeneity of PV's impacts on the cost to address voltage issues. However our earlier engineering simulations showed feeder location and design can significantly impact the likelihood that PV will create voltage problems, suggesting that proactive distribution planning may serve to avoid these voltage problems altogether at relatively low cost.

1.1. Overview of PV economics

Distributed PV's value has three main components. The first, and simplest, is avoided cost of energy. Distributed PV offsets electricity purchases that the supplying utility would otherwise make. The second component has to do with PV's impact on the performance and requirements of generation, transmission and distribution infrastructure. At the distribution level these impacts can be both positive and negative, including reducing line losses, avoiding the need to build distribution system capacity and also increasing voltage regulation problems. Third, PV reduces pollution and possibly other negative externalities associated with conventional generation. We also note that incentives for PV capacity may have *positive* externalities; incentivizing deployment might lead to otherwise unattainable economies of scale and technology learning.

Ideally, the price paid to PV owners would include accurate assessments of all of the above components of PV's value. Unfortunately, the second and third components are difficult to measure or estimate, and this uncertainty leads to controversy over the appropriate magnitude of incentives. This paper addresses these uncertainties by providing new estimates of the value of PV's energy and its effects on distribution systems.

Our analysis relies on simulated distribution system impacts. This approach has advantages and limitations. On the positive side, our detailed physical simulation allows us to study high levels of PV penetration while taking into account important factors such as the smoothing of aggregate generation profiles due to small-scale geographic diversity of PV production. It also allows us to examine effects that cannot be addressed without a detailed physical model, such as voltage quality. On the other hand, the detailed nature of the simulations limits our scope – in this case to one utility's territory, to a small but representative set of engineering models of distribution systems, and to one year of PV production and weather data. We note, however, that by using locational marginal prices for electricity, we implicitly capture both the energy and transmission value of PV.

1.2. Prior studies on system-level economics of PV

Three recent studies examined the how PV capacity might affect distribution capacity upgrades in California: Darghouth et al. (2010); Energy and Environmental Economics (2013); Beach and McGuire (2013). Darghouth et al. (2010) used existing estimates of PV's transmission and distribution capacity value but noted that capacity value is highly uncertain (ranging between \$0.001/kWh to \$0.10/kWh). They also noted that accounting for avoided line losses increases the value of PV above wholesale generation costs, though not by a significant amount (Darghouth et al., 2010, pp. 40-42). The Crossborder Energy study (Beach and McGuire, 2013) allocates capacity value to distributed PV by examining its output during the hottest hours of the year, which generally correspond roughly to the hours with the most energy usage. These capacity savings are multiplied by an estimated marginal cost of T&D capacity from utility rate cases to find a total capacity value (Beach and McGuire, 2013, pp. 23-28 of appendix B-2). E3 Energy and Environmental Economics (2013) uses a more granular method that estimates distribution capacity upgrade costs from specific projects forecasted by PG&E. They estimate the present value of PV for deferring those capacity projects by crediting PV production in any hour that a generic substation load profile is within one standard deviation of its peak (Energy and Environmental Economics,

2013, pp. C-40–C-44). None of these studies investigate the distribution capacity value of PV at the circuit level and for different quantities of PV installed on each circuit.

In addition to these California-based studies, we are aware of a several other studies that address the economic impacts of distributed PV on distribution systems. These address the value of deferred capacity upgrades and to a lesser degree avoided energy purchases: Woo et al. (1994); Gil and Joos (2006, 2008); Piccolo and Siano (2009).

This paper builds on prior work in several important ways. First, by working with circuit-level load growth assessments for each of PG&E's 3,000 feeders, we are able investigate the full range of capacity benefits on a feeder-by-feeder basis. Second, because we build our economic assessments up from a distribution power flow model that uses real PV production data as inputs, we are able to assess the economics of other engineering impacts of PV in distribution systems (most notably voltage impacts). Third, we investigate the impacts of PV on distribution circuits at a large range of penetrations (PV capacity ranging from 7.5% to 100% of feeder peak demand); this allows us to quantify the declining distribution capacity benefits of PV as circuit-level net load peaks get pushed later in the day when PV production is low.

2. Simulation and utility data inputs

Our study focuses on climate, photovoltaic production and infrastructure representative of PG&E's territory (Northern California). We chose this region in part for the prominence of distributed photovoltaics there and its and ongoing policy debates on issues of net metering and retail tariff design. We also chose this region due to our ability to access unique information (in particular, feeder-level load growth rates) under the terms of a non-disclosure agreement. For reference, in 2012 PG&E accounted for 38.3% of California's total energy consumption (California Energy Commission, 2013).

GridLAB-D models. We generated simulation results – summarized in the next section and described in detail in other papers (Cohen and Callaway, 2013, 2015) – with GridLAB-D, developed by Pacific Northwest National Laboratory (PNNL). GridLAB-D simulates distribution system operation over time and captures load variation due to varying building occupancy patterns and ambient conditions. It models major distribution system equipment including capacitors, voltage regulators, on-load tap changing transformers, and secondary distribution transformers. We used GridLAB-D version 2.3 with the forward-backward sweep power flow solver.

Table 1 summarizes the feeders we studied. These come from a set of "taxonomy" models provided by PNNL. PNNL assembled the taxonomy set by first collecting 575 distribution feeder models from 151 separate substations from a range of investor- and municipally-owned utilities and rural cooperatives in the United States (Schneider et al., 2008). The taxonomy feeders are the result of a systematic clustering analysis that identified 23 representative models from the set of 575. We simulated taxonomy feeders associated with California climate zones. This left us with five feeders in region 1 (R1, temperate west coast) and three in region 3 (R3, desert southwest). Though the original PNNL sample was neither random nor exhaustive, with these feeders we can explore a broad range of PV's impacts on representative distribution systems. Note that we did not study PV on General Industrial Case (GC)

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feeders (9-20% of feeders, according to PNNL) because they consist essentially of one large industrial or commercial load and we did not have available an appropriately representative set of commercial and industrial load shapes. The feeder taxonomy also does not include networked urban cores, which represent 5-10% of the distribution system (Schneider et al., 2008). Frequencies for the remaining feeders, taken from Schneider et al. (2008), are listed in Table 2.

Locations and Timeframe. We simulated each of the eight feeders in two locations – Berkeley and Sacramento – during the 366 days between September 25, 2011 and September 24, 2012, inclusive. We chose these locations and time span due to the availability of high-resolution PV and weather data and because Berkeley and Sacramento are representative of PG&E's two major climate regions (coastal and interior, respectively). These data and the feeder placement process are described later in this section. California peak demand during the selected year was fairly typical relative to the past decade, with a peak load of 46,846 MW in 2012 versus a high of 50,270 MW in 2006 (CAISO, 2013b).

PV Generation Data and Assignment to Feeder Locations. The PV integrator SolarCity provided a database of instantaneous power at each inverter they monitor (roughly 7,000 systems, mostly in California) under the terms of a non-disclosure agreement. The majority of inverters provide data on the quarter hour; some have one-minute data. 325 systems in the vicinity of Berkeley and 308 systems in the vicinity of Sacramento passed our data quality checks, with minimal gaps in recording and very few anomalous readings.

We associated PV profiles with GridLAB-D houses to capture diversity in output driven by differences in cloud cover, array orientation, technology and shading. We constructed geographic layouts of the taxonomy models (Cohen and Callaway, 2013; Cohen, 2013), and then used ArcGIS to superimpose the locations of the SolarCity PV systems on the feeder layouts; we ran a "nearest neighbor" query to associate each GridLAB-D distribution transformer with the closest SolarCity profile with acceptable data quality. Roughly 100 PV systems were matched with a GridLAB-D transformer in each location. The matched systems had ratings between 1.6 kW and 13.2 kW. If necessary we reduced the capacity of the assigned PV system on simulated buildings to ensure the array size did not exceed available roof area.

Penetration Levels and PV Placement. We define PV "penetration" relative to a baseline (no PV) loading for each feeder as:

$$\text{PV penetration} = \frac{\sum (\text{PV system ratings})}{\text{Peak feeder load from baseline run}}$$

We populated as many houses with PV as necessary to vary penetration from zero to 100 percent. We placed PV randomly across the available house models. We used the same random number seed in each scenario to ensure that houses populated with PV in the lower penetration scenarios were a strict subset of those populated in the higher penetration scenarios, in order to isolate the effect of penetration from the effect of placement. We used the same random ordering of houses for PV placement in each test location, and modeled PV as a unity power factor "negative load".

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Deployment Timelines and Financial Discounting. In our economic calculations we compute the net present cost or value of PV over a ten year horizon using 2012 dollars. In most cases we discount with PG&E's weighted average cost of capital (WACC) of 7.6% less a combined inflation plus project escalation rate of 2.5% (PG&E, 2013a) – yielding a net discount rate of $r = 5.1\%$.

We define penetration scenarios by a function that specifies the amount of PV penetration achieved in a given year:

$$p(t) = \frac{e^{\alpha t} - 1}{e^{\alpha T} - 1} X$$

where $0 < p(t) < 1$ is the penetration in year t, X is the final penetration, T is the year in which to reach the target penetration (ten, in our case) and α is a shape parameter. Figure 1 illustrates how the shape of $p(t)$ changes with varying α. α values above zero and less than 0.4 are likely most reasonable (with installations spread out over ten years), but we present results for several α values for comparison.

Most values of $p(t)$ did not correspond exactly to penetration levels that we modeled; e.g. on the way to 15% penetration in year ten the function passes through 0.7% in year one, 1.5% in year two, and so on. In these cases, we interpolated linearly between the the two nearest penetrations that we had modeled.

Weather Data. We used one-minute temperature, humidity, and solar irradiance data obtained for Berkeley from Lawrence Berkeley National Laboratoray (Fernandes, 2012) and for Sacramento from SOLRMAP at the Sacramento Municipal Utility District(National Renewable Energy Laboratory, 2012). The weather data determined HVAC load in GridLAB-D. Using SolarCity generation data sources near to the weather stations preserved the correlation between air conditioning load and PV generation.

PG&E Feeder Data. We obtained feeder-level capacity and peak loading data (in MW) from 2012 and projected annual load growth percentages for 2013-2017 for 2,987 feeders in the PG&E service territory, provided under the terms of a non-disclosure agreement by PG&E (PG&E, 2013a). 36.3% of these feeders are located in PG&E's coastal region, and we mapped the data from those to temperate west coast taxonomy feeders (region R1). The remaining 63.7% of feeders are located in PG&E's interior region, which we mapped to the desert southwest climate taxonomy feeders (region R3). We used peak demand projections based on one-year-in-two weather data.

3. Summary of Simulation Engineering Results

System Losses. By serving loads locally, system losses decrease with PV penetration. As with prior studies (Quezada et al., 2006; Widén et al., 2010; Navarro et al., 2013; Thomson and Infield, 2007) we found that on some feeders losses begin to increase at very high penetrations due to heavy reverse flow conditions. However on most feeders, losses continued to decrease to the maximum penetration level we studied (100%). In general, feeder type had a stronger influence on the total magnitude of losses than did climate.

Peak Loading. PV reduced peak load by 6-35% (at 100% penetration) over the period we studied. Demand reductions are well below the penetration level because peak demand

occurs in late afternoon or early evening, later in the day than peak PV production. In general we found that location (which drove load and PV production profiles) had a stronger influence on peak load reduction than feeder type.

Transformer aging. Transformer aging is driven by thermal degradation; higher loading results in greater losses and accelerated insulation aging. In general, we observed minimal aging in all scenarios and penetration levels, with a mean equivalent aging of up to 0.29 y in one scenario (R3-12.47-3, Sac.) and all other scenarios having mean aging less than 0.001 y. We sized transformers at or just above their baseline peak load (Cohen and Callaway, 2013); aging would have been faster if the transformers were undersized.

Voltage regulators. Voltage magnitude on a conductor typically declines in the direction of power flow, and as power flow increases, voltage declines further. There are three basic types of equipment that maintain voltage within prescribed bounds in a distribution circuit: on-load tap changers (LTC) located at distribution substations, capacitor banks and voltage regulators. LTCs and voltage regulators automatically adjust voltage by changing the "turns ratio" on an in-line transformer to maintain voltage within a prescribed range. We only studied voltage regulator impacts. We neglected LTC impacts because their operation is a strong function of transmission level voltage and because GridLAB-D does not model transmission impedance (meaning LTC output voltage is minimally affected by PV variability); we neglected capacitor bank switching because, to the extent it occurs, is often scheduled (rather than based on a voltage measurement). See (Cohen and Callaway, 2013) for more discussion. Overall we found that the change in the number of tap changes on the regulators ranged from negative 10 percent to positive 30 percent.

Voltage quality. In general, across all penetrations and feeders, we found voltages to be relatively well-controlled, with most runs having less than 0.002% of readings out of the ANSI standard range (virtually unchanged from the base case), and the worst case (R3-12.47-3, Sac.) having 0.32% of readings out of range at 100% penetration. This is consistent with prior work suggesting that many feeders can support high penetrations of PV without voltage violations (Hoke et al., 2013). Across the scenarios we investigated, the propensity for voltage excursions to occur was most strongly driven by location, with the most occurring in Sacramento.

Reverse power flow. We studied the incidence of negative real power flow ("backflow") through the substation, which can be a proxy for protection equipment problems and higher interconnection costs. At 50% penetration, 8 of the 16 scenarios exhibited occasional backflow, but no more than 1% of the time in any one scenario. At 100% penetration, all scenarios experienced backflow at least 4% of the time.

4. Economic Results

4.1. Energy and Transmission Value of PV

PV's energy and transmission value is increased by PV production's positive correlation with electricity prices, and its tendency to reduce system losses.[1] In this paper we will inves-

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[1]Note that PV may *increase* end-use demand slightly by causing voltage-dependent loads to consume more power in high voltage conditions. GridLAB-D captures this effect, though we did not disaggregate it from other effects that tend to reduce net load.

tigate this value using locational marginal prices from the study area; because these prices include energy, transmission congestion and transmission loss components they implicitly capture both the energy and transmission value of PV at specific locations. However given the "lumpy" nature of transmission investments, the LMP is only a rough proxy for the value of deferred transmission infrastructure upgrades.

We calculated the net LMP benefit for each feeder as the difference between the cost to supply energy at the substation at 0% PV penetration and the cost to serve the substation at the given PV penetration:

$$
\begin{aligned}
C_j(X) =& (\text{feeder } j \text{ energy cost without PV}) \\
& - (\text{feeder } j \text{ energy cost with X\% PV}) \\
=& \sum_t \lambda_{j,t} D_{j,t}(0) - \lambda_{j,t} D_{j,t}(X)
\end{aligned}
\tag{1}
$$

where j indexes the taxonomy feeder, D is simulated hourly demand at the feeder head, and $\lambda_{j,t}$ is the hourly locational marginal price (LMP) for the feeder's location.[2] We obtained hourly LMPs from the California Independent System Operator's (CAISO) day-ahead market for nodes CLARMNT_1_N001 (Berkeley locations) and WSCRMNO_1_N004 (Sacramento locations) (CAISO, 2013a).[3]

We calculated a weighted average energy benefit within and across regions as follows:

$$
C_{\text{av}}(X) \;=\; p_{\text{R1}} \sum_{j \in R1} f_j C_j(X) + p_{\text{R3}} \sum_{j \in R3} f_j C_j(X),
\tag{2}
$$

where X denotes the penetration level, R denotes region (R1, coastal; R3, interior), j indexes the taxonomy feeders, f_j denotes the frequency of feeders within each region (see Table 2), and we used $p_{\text{R1}} = 0.363$ and $p_{\text{R3}} = 0.637$ to define the frequency of feeders in PG&E's coastal and interior zones, respectively (see Section 2). This provides a representative estimate of the energy benefit across all penetration levels. We computed PV energy for the representative sample, $E_{\text{PV,av}}(X)$ in the same way.

For each feeder, we calculated end-use consumption by subtracting system losses from substation energy at 0% PV penetration and we then computed a weighted average end-use consumption for the sample using the same weighted average approach as in Eq.(2).

We factored in future load growth by scaling consumption to the 2012-2022 projections for PG&E published by the California Energy Comission (CEC) (California Energy Commission, 2012, p. 6, California Energy Commission, 2013, pp. 36-40). These projections include net load reductions due to customer sited PV, since the CEC assumes that a higher percentage of generation will come from this source over time. The CEC provides high and low estimates of customer PV generation, with a midrange of 1% of PG&E's consumption in 2012 and 2%

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[2]LMP patterns will very likely change over ten years, depending on fuel and carbon prices and generation infrastructure. A thorough investigation of these future scenarios is very important, but outside the scope of this paper, whose key focus is distribution systems.

[3]We compared several nodes in the general area of Berkeley and Sacramento and chose these two arbitrarily after confirming that differences in price relative to neighboring nodes were very small.

in 2022 (California Energy Commission, 2012, p. 6, 28). To convert the CEC consumption figures to end-use consumption, we multiplied the CEC's "CED 2011 Revised-Mid" forecasts by one plus the solar generation ratio, scaled linearly from 1-2% over the 10 year period.

Next, we calculated the ratio of PG&E consumption to that in our sample, denoted s_y with y indexing years. The ratio ranged from $s_1 = 5{,}720$ to $s_{10} = 6{,}453$. We multiplied the representative feeder energy benefit by s_y to scale it to the PG&E system.[4] Then, using the same method as PG&E (2011), we levelized the energy benefits by dividing the net present value of C_{av} by the sum of discounted PV generation, $E_{\mathrm{PV,av}}$:

$$\text{levelized energy value} = \frac{\sum_{y=1}^{10} \frac{s_y C_{\mathrm{av}}(X_y)}{(1+r)^y}}{\sum_{y=1}^{10} \frac{s_y E_{\mathrm{PV,av}}(X_y)}{(1+r)^y}}. \tag{3}$$

In all scenarios we found the average levelized energy value to be between \$0.0349/kWh and \$0.0351/kWh. The weighted average LMP between Berkeley and Sacramento during our test year was \$0.0297/kWh[5] , meaning PV was about 18% more valuable than a resource with constant production and no effect on losses or voltage-dependent loads. This percentage is consistent with prior work, e.g. Borenstein (2008). The relative insensitivity of the average value to penetration occurs because cost and energy benefits are roughly linear functions of penetration. The small variation across scenarios was due to random variations in which PV generation profiles were chosen and where they were placed on the feeders (see Section 2).

4.2. Distribution Capacity Value of PV

Growth in distribution feeder peak load creates a need for investment in higher capacity distribution equipment such as transformer banks and conductors. To the extent PV reduces peak net load, it can defer these investments. In this section we combine our simulation results with PG&E distribution system data to estimate the system-wide distribution capacity benefit of distributed PV.

4.2.1. Projects and Feeder Data

Figure 2 illustrates how we calculate the capacity benefit of distributed PV. The approach, similar to Gil and Joos (2006); Piccolo and Siano (2009); Energy and Environmental Economics (2013); Woo et al. (1994), involves first establishing a baseline estimate of the year in which distribution capacity projects would occur in the next ten years. Then, based on peak load reduction simulation results, we compute the year in which the same project would occur in the presence of PV. Though we limited the pool of initial projects to a ten

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[4]While the calculated multiplier was on the order of 6,000, there are approximately 3,000 feeders in PG&E's system. This implies that the average PG&E feeder uses about twice as much energy annually as our weighted average simulated feeder. Since the sample is being scaled to the full system size this discrepancy does not affect the overall magnitude of the results.

[5]\$0.0297/kWh is roughly half the levelized cost of energy from combined cycle gas fired generators (U.S. Energy Information Administration, 2014), suggesting that the market is not in long-run equilibrium. This is likely because natural gas prices in the the U.S. in late 2011 and 2012 were extremely low. But it may also reflect the fact that a portion of generators' levelized costs are paid for via resource adequacy capacity contracts. This highlights the fact that both the basic energy value and the size of the PV "premium" depend on energy market conditions; they may be larger or smaller in future years.

year horizon, we continued to account for the cost of deferred projects for 25 years. We considered projects deferred beyond 25 years to be completely avoided.[6]

We used feeder-level capacity and peak loading data for 2012-2017 described in Section 2, and carried the 2017 growth rates forward for a rough prediction of future trends. We assumed that each feeder project occurs in the year that its peak load reaches 100% of rated capacity.[7]

Before running the PG&E feeders through the model, we eliminated the following categories:

- Feeders operating at or below 4.16 kV (2.4% of PG&E capacity). These are smaller, older, idiosyncratic parts of the distribution system that PG&E engineers felt would not be appropriate to include in a general analysis of this kind (PG&E, 2013a).

- Feeders already having greater than 10% PV penetration (7.6% of PG&E capacity). Because peak load growth forecasts for these feeders are likely affected by existing PV, their forecasted growth rates do not provide a good "control" against which to apply further peak load reductions due to PV. These feeders are relatively similar to the population (2012 peak demand average of 7.0 MW versus 7.7 MW for the population; average voltage of 14.5 kV versus 14.1 kV for the population; and 31.4% coastal / 68.6% interior versus 36.3% / 63.7% for the population).

- Feeders already loaded over their rated capacity (1.7% of total capacity).

We used demand growth data to estimate which of the remaining feeders would require a capacity project in the next ten years. This left us with 296 feeders totalling 4,143 MVA (roughly 10% of the 2,987 feeders, and 20% of the total 20,600 MVA of capacity, for which we received data). This equates to roughly 30 distribution projects per year, which is approximately the number of PG&E feeders that actually reach capacity in a given year (PG&E, 2013a).

4.2.2. Applying Model Runs to PG&E Feeders

We permuted each R1 result that was simulated with Berkeley weather data with the loading and load growth data for each feeder in PG&E's "coastal" service territory, and each R3 result that was simulated with Sacramento weather data with each feeder in PG&E's "interior" service territory. For each combination of taxonomy feeder and PG&E feeder that would require a capacity project within ten years, we computed savings in net present value as a ratio (ρ) between the savings and the original project cost:

$$
\begin{aligned}
\rho_{i,j}(X, \alpha) &= \frac{\text{(present value of original project)} - \text{(present value of deferred project)}}{\text{present value of original project}} \\
&= \frac{\text{(real project cost)}(1+r)^{-y_{i,j}^0} - \text{(real project cost)}(1+r)^{-y_{i,j}^d(X,\alpha)}}{\text{(real project cost)}(1+r)^{-y_{i,j}^0}} \qquad (4) \\
&= 1 - (1+r)^{(y_{i,j}^0 - y_{i,j}^d(X,\alpha))}
\end{aligned}
$$

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[6]Using a WACC of 7.6% (our nominal case), a project deferred from year 1 to year 25 would decrease in present cost by 71%.

[7]In practice, other factors can affect project timing; see section 4.2.6 for further discussion.

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where i indexes the PG&E feeder and j indexes the simulation results of each GridLAB-D taxonomy feeder (in the appropriate climate), r is the discount rate, and $y_{i,j}^0$ is the originally estimated year of the capacity project. $y_{i,j}^d(X, \alpha)$, the deferred year, depends on the year ten penetration level X and deployment scenario α.[8]

We then calculated $\rho_{\text{aggregate}}$, the total weighted average normalized savings in net present value across all GridLAB-D taxonomy feeders in the coastal and interior zones:

$$\rho_{\text{aggregate}} = \frac{\sum_{i \in \text{R1}, j \in \text{R1}} f_j \rho_{i,j} + \sum_{i \in \text{R3}, j \in \text{R3}} f_j \rho_{i,j}}{N}, \tag{5}$$

where $N = 296$ is the total number of feeders we estimate will require a capacity project in the next ten years, R denotes region (R1 / coastal; R3 / interior), f_j is the regional taxonomy feeder frequency from Table 2, and N is the total number of feeders across all regions.

4.2.3. Scaling to PG&E's Distribution Capacity Budget

We calculated the system-wide financial benefit of project deferral by multiplying $\rho_{\text{aggregate}}$ by the fraction of PG&E's distribution budget that could reasonably be affected by PV. PG&E records and forecasts all line and substation capacity upgrade expenditures in major work categories (MWC) 06 and 46, respectively (PG&E, 2012, Workpaper Table 12-5). In consultation with PG&E (PG&E, 2013a), we assumed the following MWC subcategories would be influenced by PV's contribution to peak loading: MWC 06A (Feeder Projects Associated with Substation Work), MWC 06D (Circuits Reinforcements (DE Managed)), MWC 06E (Circuits Reinforcements (PS Managed)) and MWC 46A (all projects). We excluded some smaller distribution expenses that would not likely be influenced by PV's peak load reduction: 06B (Overloaded Transformers), 06E (Reinforce Circuit > 6000 customers per feeder), 06E (Complete Mainline Loops per Standard), 06G (Voltage Complaints (Includes PEV)), and Line Voltage Regulator Revolving Stock.

In total, the categories deemed sensitive to PV impacts on peak loading constitute 93% of PG&E's 2012 distribution capacity budget in MWC 06 and 46, or approximately $133 million. For 2013-2016 we used nominal budget projections directly from PG&E (2012, Workpaper Table 12-5) and found that 83–89% of the budget in those years is projected to be sensitive to PV peak load reduction[9]. For 2017-2022 we used the average PV-sensitive budget for 2013-2016. The total net present cost of the budget that we deemed PV-sensitive is $1.2 billion (using $r = 5.1\%$).

Note that we did not explicitly model all measures that can be implemented to deal with a capacity shortfall. Instead, by normalizing the model's results and applying them to the entire distribution budget, the approach we use implicitly captures all measures in the historical budget and forecasts. That is, the distribution budget may include shortfalls that were solved through less expensive means than full replacement of equipment, such as switching loads to different feeders. In other words, this analysis assumes that while the *number* of capacity shortfalls may change with increasing PV penetration, the distribution of actions taken in response will not change.

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[8]Note that the real project cost, assumed to be independent of time, cancels from the ratio.

[9]The percentages are lower than in 2012 because the excluded work categories are projected to grow somewhat more quickly than the included categories.

4.2.4. Value of Capacity Deferral

Figure 3 displays the net present value of distribution capacity project deferral, computed by multiplying $\rho_{\text{aggregate}}$ by the estimated peak-load-sensitive PG&E distribution budget, for a range of penetration levels and deployment ramps. The total value of deferral increases at a decreasing rate, because as PV capacity is added the feeder peak gets pushed later in the day, when PV production is lower. One can also see that the value increases with the rate of deployment, but there is relatively little difference between immediate deployment of PV and intermediate deployment rates. The total NPV of deferral is substantial, up to half of the estimated 10 year distribution capacity budget. Note also that if the large industrial ("GC") feeders accrue PV-related capacity benefits similarly to the weighted average of the feeders we modeled, the total benefit across all penetration levels and deployment trajectories would be about 19% higher (see Section 2 for discussion of the treatment of GC feeders).

Energy-levelized capacity benefit. To put the overall capacity benefit into perspective, we can levelize the capacity benefit across the kWh of PV generated throughout the ten year horizon. As with other levelized statistics we discount future energy production in addition to costs:

$$\text{Energy-levelized capacity benefit} = \frac{\text{net present value of deferral}}{\sum_{y=1}^{10} \frac{s_y E_{\text{PV,av}}(X_y)}{(1+r)^y}}, \tag{6}$$

where we compute energy production in year y as the *total* PG&E-wide PV production associated with each particular deployment and final penetration scenario.

Figure 4 shows the result of this calculation. As with the total benefit, capacity benefit rises with PV penetration but with diminishing returns. Overall the range of levelized benefits is between 0.05¢/kWh and 0.7¢/kWh; this is roughly 0.3% to 5% of the average retail tariff in PG&E. These numbers are similar to the range reported by Darghouth et al. (2010) (0.1¢/kWh – 10¢/kWh).

Recall, however, that we evaluated the present value of capacity deferral only on those feeders identified as having a capacity project in the first ten years of analysis. This subset of feeders is 10% of the number of feeders, and 20% of total capacity, in PG&E. Therefore if one assigned the capacity value only to those PV systems on feeders with deferred projects, the levelized value of those systems would be roughly five times greater (1/0.2) than the numbers reported in Figure 4, or 0.25¢/kWh to 3.5¢/kWh (roughly 1.8% to 25% of the average retail tariff).

Though earlier deployment always improves the NPV of the capacity benefit, the effect on the energy-levelized benefit is slightly different. As one might expect, levelized benefit is greatest with intermediate rates of deployment, where solar deployment (and energy production) roughly follows the feeder load growth trajectories.

Annualized capacity benefit. An alternative way to put the capacity benefit in context is to normalize per kW of installed PV. We computed the following metric for each target penetration and ramp rate:

$$CV_{\text{av}} = \frac{\text{annualized capacity benefit}}{\text{(per unit of PV capacity)}} = \frac{\frac{\text{net present value of deferral}}{\text{target PV penetration on all feeders}}}{\text{annuity factor}}, \tag{7}$$

where we annualize in order to facilitate comparisons with annual distribution fixed charges as well as generation capacity costs at the conclusion of this section. To compute the annuity

factor we used the same discount rate as before ($r = 5.1\%$), and we assumed benefits accrue over $n = 25$ years. We made the second assumption because, although we only compute deferral benefits on feeders that would have projects in the first ten years in the absence of PV, we count the cost of the deferred project for up to as much as 25 years. In this case, with $r = 5.1\%$, the annuity factor is $\frac{1-(1+r)^{-n}}{r} = 13.95$ years.

Figure 5 shows the result, with values ranging from nearly zero to more than \$6/kW-yr As one would expect, the value declines with increasing penetration and increases with the rate of deployment. By comparison, at \$5.30/W (the 2012 average price for residential systems (Barbose et al., 2013), the annualized *cost* of PV was on the order of \$380/kW-yr in 2012. Moreover, if DOE's SunShot 2020 goal of \$1.50/W for residential solar is met (U.S. DOE, 2012), the annualized cost would be roughly \$110/kW-yr, still much greater than the annualized benefit.

However, as mentioned in Section 4.2, we found that only 10 percent of feeders would require a project within ten years. Therefore dividing by PV capacity on *all* feeders dilutes the value of PV on feeders that *would* have projects. We computed the following metric to capture the capacity value on feeders with deferred projects:

$$CV_\text{deferred} = \text{deferred feeder annualized capacity benefit}$$
$$= \frac{\frac{\text{present value of capacity deferral}}{\text{target PV penetration on } \textit{deferred} \text{ feeders}}}{\text{annuity factor}}. \tag{8}$$

We then estimated feeder-specific capacity value as follows, where i and j denote deferred PG&E feeders and GridLAB-D taxonomy feeders, respectively:

$$CV_i = CV_\text{deferred} \frac{\sum_{j \in R_i} f_j \rho_{i,j}}{\rho_\text{aggregate}} \tag{9}$$

where the normalized NPV of deferral, $\rho_{i,j}$, is defined in Eq. (4), f_j is the regional taxonomy feeder frequency from Table 2, R_i is the subset of taxonomy feeders with the same regional designation (either interior or coastal) as PG&E feeder i, and $\rho_\text{aggregate}$ is defined in Eq. (5). This metric weights the average deferral value by the ratio of each feeder's normalized NPV of capacity deferral to the normalized average NPV of capacity deferral – in effect this gives the feeder-specific deferral value. Figure 6 shows percentiles of capacity benefit on the subset of feeders with projects in the first ten years for the fast ramp scenario ($\alpha = -50$). Because we find that roughly 10% of PG&E feeders would require capacity projects within ten years, the percentiles in this figure are roughly ten times larger than they would be if computed across all feeders in PG&E. These numbers compare more favorably to current and and projected annualized costs of PV, though on most feeders (and all in the percentiles we show) the benefits remain well below the cost of PV.

We can also compare these annualized numbers to the size of a possible fixed charge on customer bills. In 2013 California's AB327 authorized its Public Utility Commission to approve up to \$120 per year, in partial recognition of the fact that owners of PV use less energy but still place burdens on infrastructure. However these results suggest that PV systems on deferred feeders could have benefits of the same order as the fixed charge. For example, at a low feeder PV penetration (7.5 percent) a 5 kW system would create \$50

to over \$300 per year benefit in terms of avoided capacity upgrades; even at 100 percent penetration the benefit could be as high as \$100 per year.

Though earlier studies suggested a large range of PV capacity values depending on model assumptions (e.g. Darghouth et al. (2010)), in this case the input data themselves (circuit loading and peak load growth statistics) produce a large range of values, holding model assumptions constant. As we will discuss in the conclusions, this suggests that location-specific compensation for PV capacity benefits may be an effective strategy to minimize utility-wide capacity upgrade costs. Implementing this type of tariff could be challenging from a regulatory and process perspective, though we note that Minnesota's recently approved "Value of Solar Tariff" methodology includes a location-specific capacity value, and it has received both positive (e.g. Draxten, 2013) and negative (e.g. Podratz, 2013) comments from utilities.

4.2.5. Discount Sensitivity Analysis

Because capacity value benefits depend on events that occur in the future, the magnitude of the benefit depends on the assumed WACC (or discount rate). Therefore we ran the model for different values of α (PV deployment rates) and using a WACC of 5.0% and 10.0% (less and greater than the originally assumed WACC of 7.6%). Figure 7 shows the result. As expected, higher discount rates make deferral more desirable. Though immediate deployment (fast ramp) has the highest sensitivity in absolute terms, sensitivities in percent terms (e.g. the percent change in benefit due to increasing or decreasing WACC) are comparable for all WACC / ramp combinations.

4.2.6. Caveats

From a utility perspective, uncertainty in the reliability of distributed solar may prevent some or all of the capacity benefit we measured from being realized during the investment planning process; for instance, utilities may conservatively prefer to provide distribution capacity that would normally not be needed due to PV's reduction of peak load, in order to be prepared for an emergency that temporarily takes PV offline. We also note that in practice capacity projects may be initiated sooner than absolutely necessary to economize on personnel and equipment in the area for other work. To the extent that these phenomena affect distribution capacity costs, they would reduce the capacity value of PV somewhat; we view characterizing this effect as an opportunity for future research. For further discussion of these issues from a utility perspective see PG&E (2013b).

A related concern is that all results are based one year of simulation. We did not directly analyze the impact of cloudy or partly cloudy days (or a lack thereof) on peak feeder loading. However in PG&E's climate zones – especially in the interior region – clouds are infrequent in hours when peak loading occurs. Therefore we believe it is unlikely that other years would have significantly different peak net loading resulting from cloud cover. This may not be the case in other climates.

Finally, we were not able to validate the peak load shapes produced by GridLAB-D against actual feeder-level load shapes in the PG&E service territory. Our analysis in Cohen and Callaway (2015) compares GridLAB-D load shapes against load data from all of PG&E, all of CAISO, and a few isolated substations provided by PG&E under a non-disclosure agreement. Those results suggest that some circuits peak earlier and some peak later than

the GridLAB-D load shapes, but that GridLAB-D load shapes are roughly in the middle of the distribution of typical feeder load shapes.

4.3. Voltage Regulators and Voltage Quality

As we indicated in Section 3, PV can impact voltage regulator operation patterns by influencing distribution circuit flow. To the extent this increases or decreases voltage regulator switching, PV could change the maintenance requirements (and therefore cost to distribution companies) for voltage regulators. Using our physical results for voltage regulators (Section 3 and Cohen and Callaway (2013, 2015)) we can make some very general estimates as to how regulator maintenance expenses might change if the trends observed in the simulated taxonomy feeders scaled up to the system.

There are several PG&E major work categories (MWC) related to voltage regulators. MWC BK (Distribution Line Equipment Overhauls) is a category that includes needed overhauls for line reclosers and regulators; in 2012 expenses of $2,645,000 were forecast for this purpose (PG&E, 2012, p. 5-34). Regulators constitute about 41% of the total units of line equipment (regulators + reclosers) PG&E (2013a). Under the coarse assumption that the unit cost to overhaul a regulator is the same as the unit cost for a recloser, regulator overhaul expenses are roughly $1,085,000. MWC 48 (Replace Substation Equipment) includes several "Subprograms < $1M", including a line item for regulator replacements projected to be $297,000 in 2012 (PG&E, 2012, Workpaper Table 13-16). Some LTC replacement work also takes place under MWC 54 (Distribution Transformer Replacements) which had an overall forecasted value of $61,005,000 in 2012 (PG&E, 2012, p. 13-14). However, most of this expense is for general substation transformers not LTCs, and projects are usually triggered by factors unrelated to the LTC such as dissolved gas analysis of the transformer oil; in these cases the LTC is replaced in the course of a larger project rather than due to wear on the LTC itself (PG&E, 2013a). Therefore we conclude that MWC 54 expenses are unlikely to be affected by changes in LTC operation triggered by PV. This leaves us with a total projected 2012 regulator budget of $1,382,000 from MWC BK and 48 that could be affected by changes in tap-change activity.

If we assume that substation LTCs will respond similarly to line regulators (this is a strong assumption because LTCs will respond more to transmission level variation in voltage), we can extrapolate our earlier regulator results (Cohen and Callaway, 2013) to the system and estimate how much PV might affect overall regulator expenses. At the high end (100% penetration), PV increased regulator operations by 32%. Assuming line regulator and LTC maintenance requirements increase linearly with the number of tap changes, then maintenance expenses would also increase by 32%, or roughly $442,000 in 2012. In a more optimistic scenario where regulator operations decreased by 8% due to the presence of PV (in line with our "best case" simulation results) across the system, regulator maintenance expenses might decrease by $111,000. In reality both of these scenarios might exist somewhere in the system, in addition to many intermediate cases and a few more extreme ones, likely resulting in an overall expense change somewhere between these bookend values. The overall impact will be more favorable if the reduced current duty brought about by PV also extends regulator lifetime, but the sensitivity of regulator lifetime to reductions in current is heavily dependent on the regulator model and its pre-PV current duty, so we lack the

data to estimate the magnitude of this effect. In any case, the clear conclusion of the budgetary analysis is that any regulator maintenance cost changes – whether they are positive or negative – will be very small in comparison to the energy cost and capacity cost effects of PV.

For comparison, PG&E's budget for addressing Voltage Complaint Projects Involving Secondary Distribution (MWC 06G) was forecast to be $2,800,000 in 2012; some fraction of MWC 06E (Circuits Reinforcement – Project Services Managed, forecast at $36,941,000 in 2012) is also dedicated to "primary distribution voltage correction work" (PG&E, 2012, p. 12-20). As noted in Cohen and Callaway (2013, 2015), voltage quality on our simulated feeders was only mildly affected by PV, although we expect that in the field there will be some feeders where it will be a significant issue. Though our data are not sufficient to make a conclusive estimate of how frequently PV will actually trigger complaints or create serious enough problems to require additional work in the above mentioned MWCs, they suggest that the costs will be relatively small.

4.4. Transformer Aging and Backflow/Protection

As noted in Cohen and Callaway (2013, 2015) we observed minimal transformer aging across all of our simulated scenarios, with little change due to PV except with one particular feeder/climate combination. We attribute the lack of aging mainly to conservative sizing of the distribution transformers relative to the loads served. We attempted to locate a data set of distribution transformer loading to ascertain how well this assumption matched California's actual distribution transformers, but utilities do not track the loading of these transformers closely.

We do expect that PV will have some effect on transformer lifetimes in areas where transformers are loaded at or above capacity. In most cases, lifetime is likely to be extended as daytime transformer loading is reduced by generation on the secondary side. In some cases where the installed PV power is much greater than the previous daytime load, transformer lifetime may be decreased by large reverse power flows. Given the uncertainty about existing transformer load shapes and ages it is difficult to estimate the size of the benefit (or cost) that PV could provide.

Similarly, we refrain from drawing any conclusions about the economic effect of backflow caused by high PV penetrations (see Section 3 for physical results). The main concern regarding backflow is that it may require modifications to protection systems that were designed with only one-way power flow in mind. Determining whether such corrections are necessary on any given feeder requires a specialized protection analysis which is beyond the scope of this study.

5. Conclusions and Policy Implications

We found that PV provides a capacity deferral value of up to $6/kW-yr when averaged across the potential impact on all feeders in PG&E's service territory. However, when we disaggregate the result by feeder – some of which are much closer to requiring a capacity upgrade project and have load shapes that are better correlated with PV production – the capacity value can be as much as $60/kW-yr on a small subset of feeders. When viewed

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against a possible connection fixed charge (proposed to be on the order of \$120/yr in California's AB327), the capacity deferral value of PV could be significant in some cases and inconsequential in others. Also when viewed against the cost to install PV (\$380/kW-yr at the end of our study period Barbose et al. (2013), but possibly as low as \$110/kW-yr if the DOE's SunShot goal of \$1.50/W is met), the capacity deferral value of PV could be a significant incentive for some customers to install PV. There is some precedent for recognizing the capacity value of distributed PV (for example Minnesota's "value of solar" tariff), but our findings suggest that the range of distribution capacity benefits is significant enough that a location-specific credit should be considered. Much as the time-value of PV is recognized in time-of-use pricing tariffs, we propose that this spatially heterogeneous value of PV should be recognized in the structure of retail fixed charges. This process could be streamlined with substation-level loading, load growth and capacity data, though a full analysis of equity implications and administrative costs would be needed to determine if locational credits are, on the whole, desirable.

Our earlier results indicate that voltage regulator operations could increase by as much as 32% at high PV penetrations. If voltage regulator maintenance scales linearly with the amount of operation, our results in this paper indicate that distributed PV would increase annual costs by \$442,000 – an extremely small amount of PG&E's roughly \$6 billion operations and maintenance budget in 2012, and much smaller than the roughly \$30-\$40 million annual capacity benefit we estimate that PV would provide at the same penetration. Though we do not have sufficient data to assess the heterogeneity of these voltage impacts across PG&E's feeders, our earlier engineering simulations suggest feeder location and design can significantly impact the likelihood that PV will create voltage problems, suggesting that proactive distribution planning may serve to avoid these voltage problems altogether at relatively low cost.

Overall our results suggest that the distribution-level economic impacts we measure are on average very small, and slightly positive. A large part of those positive impacts seem to be concentrated in a small number of circuits. Therefore to the extent these benefits *could* be reflected in incentives to customer-sited PV, we do not anticipate that they would support a significant expansion in total PV capacity in our study region. This suggests that significant PV penetration in distribution systems will be economically justified only when the *energy value* – ideally including environmental externalities such as CO_2 – reaches parity with the levelized cost of PV.

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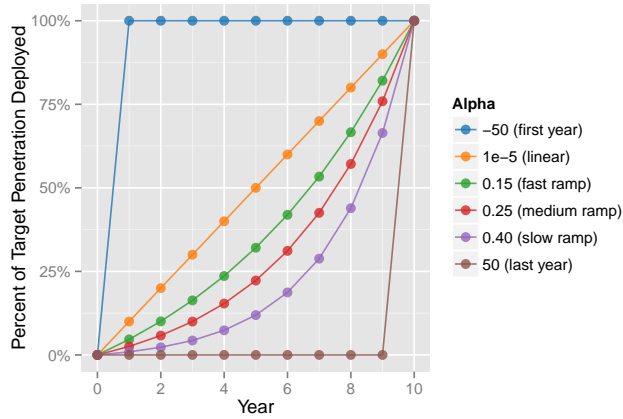
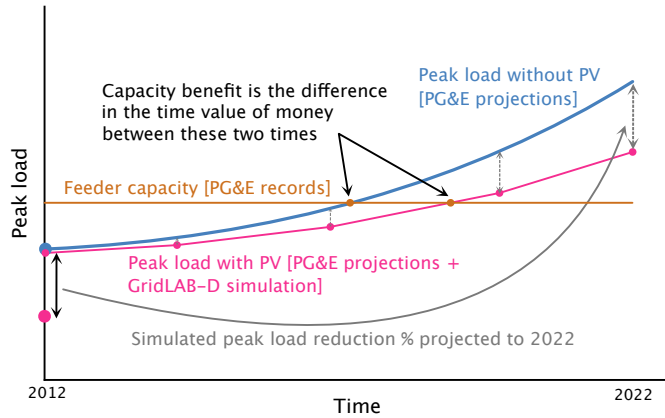Figure 1: Representative realizations of our deployment ramp up function $p(t)$ for varying α.

Figure 2: Schematic showing how the value of capacity investement deferral is calculated for an individual feeder at a given PV penetration.
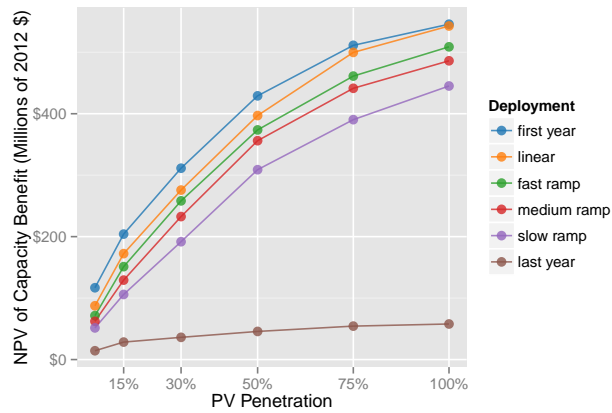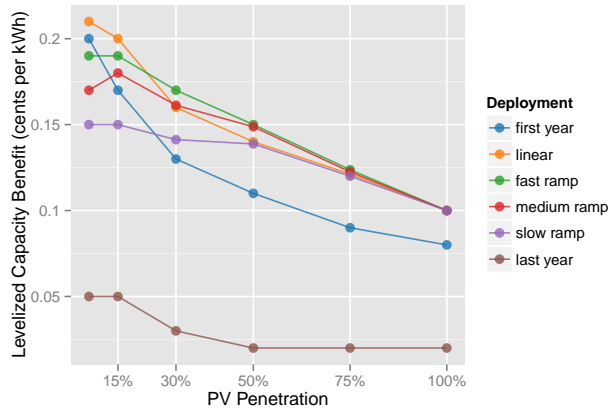

Figure 3: PG&E system-wide capacity benefit.

Figure 4: Energy-levelized capacity benefit, computed with Eq. (6) and $r = 5.1\%$.
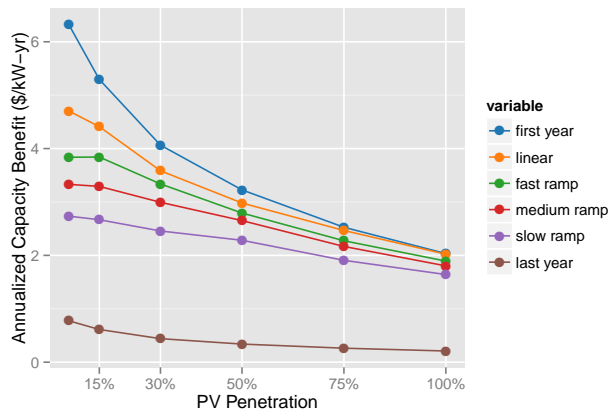

Figure 5: Average annualized capacity benefit, computed using Eq. 7. Note that the benefit is normalized by total PV capacity, rather than PV capacity on only the deferred feeders.
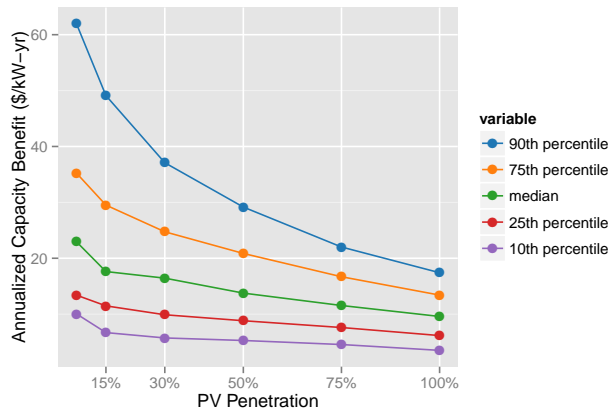

Figure 6: Capacity benefit percentiles on deferred feeders. Because we find that roughly 10% of PG&E feeders would require capacity projects within ten years, the percentiles in this figure are roughly ten times larger than they would be if computed across all feeders in PG&E.
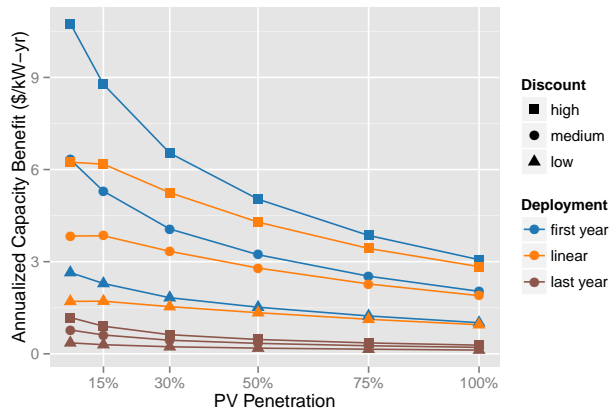
Figure 7: Sensitivity of capacity benefit to discount rate.

Table 1: Summary of Simulated Feeder Characteristics and Figure Legend

Name*	Serves[1]	Nominal Peak Load (MW)[1]	Dist. Transformers	Avg House (kW)[2]	Approx Length (km)	Baseline Peak Load (MW)		PV Profiles Selected for Use	
						Berk.	Sac.	Berk.	Sac.
R1-12.47-1	mod. suburban & rural	7.15	618	4.0	5.5	5.56	7.59	21	26
R1-12.47-2	mod. suburban & lt. rural	2.83	264	4.5	10.3	2.00	2.82	30	30
R1-12.47-3	moderate urban	1.35	22	8.0	1.9	1.27	1.60	10	8
R1-12.47-4	heavy suburban	5.30	50	4.0	2.3	4.31	5.65	12	12
R1-25.00-1	light rural	2.10	115	6.0	52.5	2.35	3.00	28	30
R3-12.47-1	heavy urban	8.40	472	12.0	4.0	6.64	8.70	20	25
R3-12.47-2	moderate urban	4.30	62	14.0	5.7	3.45	4.40	13	18
R3-12.47-3	heavy suburban	7.80	1,733	4.0†	10.4	7.54	9.67	56	55

[1] Schneider et al. (2008)

[2] Pacific Northwest National Laboratory (2012)

* Climate region of origin is indicated by R1 (temperate west coast) or R3 (arid southwest).

Nominal voltage is designated by 12.47 or 25.00 (kV).

† Changed from default of 7.0 kW due to an excess of streetlighting.

See Schneider et al. (2008); Pacific Northwest National Laboratory (2012)

for the relationship between avg. house size and street lighting.

Table 2: Assumed frequency of R1 and R3 feeders, adapted from Schneider et al. (2008)

Feeder	Assumed frequency, f_j
R1-12.47-1	23%
R1-12.47-2	26%
R1-12.47-3	21%
R1-12.47-4	19%
R1-25.00-1	12%
R3-12.47-1	38%
R3-12.47-2	38%
R3-12.47-3	25%