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Demand charge savings from solar PV and energy storage

Naïm R. Darghouth [a,*], Galen Barbose [a], Jarett Zuboy [b], Pieter J. Gagnon [c], Andrew D. Mills [a], Lori Bird [d]

[a] Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA, USA
[b] Independent Consultant, Golden, CO, USA
[c] National Renewable Energy Laboratory, Golden, CO, USA
[d] World Resources Institute, Washington, DC, USA

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ABSTRACT

With an increasing number of jurisdictions considering alternatives to net metering policies to financially compensate behind-the-meter solar photovoltaics (PV), customer economics will increasingly depend on its ability to reduce demand charges. Understanding these demand charge savings from PV—and how behind-the-meter storage can potentially enhance those savings—is essential to understand PV market dynamics and adoption in the coming years. This article explores how these demand charge savings vary with demand charge designs and customer load profiles, modeled for a variety of residential and commercial customers. Our findings indicate that demand charge savings are lowest under a basic, non-coincident demand charge design where the demand charge is based on the maximum demand level over the month, regardless of timing, resulting primarily from the temporal mismatch between the timing of the PV host's demand peak and PV generation. PV provides greater demand charge savings, for both commercial and residential customers, when demand charge designs are based on predefined, daytime peak periods or longer averaging intervals. Demand charge savings from PV combined with storage are almost always greater than the sum of the savings attained through either technology separately. We also explore how well demand charge savings from PV align with corresponding utility savings.

1. Introduction

Adoption of behind-the-meter (customer-sited) solar photovoltaics (PV) in the United States increased over fivefold from 2010 through 2018 (Wood Mackenzie and SEIA, 2019). In 2018, 10.6 GW of U.S. PV were installed: 22% residential, 19% non-residential, and 59% utility-scale (Wood Mackenzie and SEIA, 2019). Deployment has been fueled in part by steep declines in installed PV prices. The median price from 2009 through 2018 fell by 58% for residential PV and 56%–61% for non-residential PV, outpacing the reduction in state and local incentives and leading to net price reductions (Barbose and Darghouth, 2019). In addition to price reductions, the federal investment tax credit, and state and local incentives, PV deployment has been driven by state and local net-metering policies. Though net metering policies vary by jurisdiction, the most basic net metering policy allows customers to pay only for net monthly consumption, in kWh, regardless of the timing of their PV generation.

However, as behind-the-meter PV with net metering has proliferated, utilities, regulators, and ratepayer groups have expressed concerns about fixed-cost recovery, because PV customers whose rates are largely volumetric can greatly reduce their electricity bills. The under-recovery of fixed costs could lead to increased electricity rates for all ratepayers as utility sales decline (Darghouth et al., 2016; Hledik, 2014). This raises potential equity issues related to cost-shifting from PV customers to non-PV customers (Barbose et al., 2018; Lukanov and Krieger, 2019), although the extent of this cost shift is likely to be very limited where PV adoption is low (Barbose, 2017). The principal approach for addressing this issue is to reduce compensation for PV generation through changes to PV compensation mechanisms or retail rates or both. Some states are looking to move away from net metering (which in many cases effectively compensates all PV generation at the retail rate) toward alternative PV compensation mechanisms such as net billing (which compensates instantaneous exports to the grid, generally at a rate that is lower than the retail rate). Alternatively, or in some cases additionally, some utilities are exploring changes to retail electricity rate design for all residential or small commercial customers, or only for customers

* Corresponding author.
E-mail address: ndarghouth@lbl.gov (N.R. Darghouth).

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with on-site generation equipment—who previously mostly faced flat, volumetric rates. The purported reason for such changes is to better align bill savings from PV with utility cost reductions. These strategies variously include time-varying electricity rates, higher fixed monthly charges, and demand charges (NCCETC 2019).

This article focuses on the demand charge strategy. An electricity grid's generation, transmission, and distribution capacities must satisfy peak load, and demand charges are meant to allocate peak-load costs equitably by charging customers based on their contributions to that peak, in kW, rather than on the amount of energy they consume, in kWh (Simshauser, 2016; Stephen Henderson, 1983). Demand charges are already common among U.S. utilities for larger commercial and industrial customers, but the level and design of the charges vary significantly, without clear geographical patterns (McLaren et al., 2017). Demand charges are also offered by a few utilities to residential customers and, in at least two cases (Westar Energy in Kansas and Salt River Project), have been mandatory for residential customers with on-site PV generation. The most basic demand charge design is the non-coincident demand charge, which determines billing demand based on the customer's maximum demand (in kW) during a month, regardless of timing; a customer whose peak demand is during the hours of system peak pays the same demand charge as one whose peak demand is during off-peak hours. Other designs are meant to better align demand charges with utility costs. For example, billing demand can be set by a customer's peak demand during a utility-defined window meant to coincide with system peak demand. For demand charges with a seasonal element, the demand charge, in $/W, is higher in those months when loads tend to be higher. Another design element is the billing demand's averaging interval, with peak loads averaged over a prespecified period often ranging from 15 min to 1 h. Finally, demand charges can include a ratchet, where a given month's billing demand cannot be lower than a fixed percentage of the customer's peak billing demand in the last 12-month period. Utilities and their regulators look to balance cost-causality objectives with rate simplicity and available metering technologies when developing demand charge designs. Most demand charges implemented today tend to have basic, non-coincident designs, even for commercial and industrial customers (Ong and McKeel, 2012). Borenstein (2016) takes a critical view of these non-coincident demand charges and suggest that other pricing mechanisms to recover utility fixed costs may be more appropriate. Passey et al. (2017) find that more complex demand charge designs—such as coincident, seasonal, or location-specific demand charges—improve alignment between demand charges for customers and utility capacity costs.

Some studies have examined the interaction between PV and demand charges. Evidence suggests that introducing demand charges better aligns electricity bills with utility costs, and can thereby increase efficiency and reduce cross-subsidies from non-PV customers to PV (Brown and Sappington, 2018; Simshauser, 2016). McLaren et al. (2015) find that the total residential electricity bills of PV customers tend to increase when the customers switch from a standard rate to a demand charge rate. Conversely, to the extent that PV generation occurs during times that set billing demand levels, customers can potentially use PV to reduce their demand charges. The impact of PV on demand charges depends on the demand charge design and the customer's underlying load shape (Mills et al., 2008). A few studies have analyzed demand charge savings from PV with or without energy storage. For example, Glassmire et al. (2012) find that PV provides minimal demand charge savings for a university campus in Colorado, assuming a non-coincident demand charge. In a study of 54 PV + storage customers in Australia, Babacan et al. (2017) find that storage enhances demand charge savings compared with PV alone, considering only the non-coincident demand charge. Similar findings using a different dispatch strategy for a single customer load profile are presented in Hanna et al. (2014). Park and Lappas (2017) also find additional savings based on a customer's load profile when storage is coupled with PV, assuming a non-coincident demand charge. Young et al. (2019) highlight the importance of the network peak characteristics in determining the net financial impacts of PV + storage, as their findings indicate that rates with demand charges can lead to total bill savings that are commensurate with utility cost savings. Boampong and Brown (2020) explore the relationships between retail rate design, avoided utility costs, and cost-shifting (i.e. cross-subsidies) resulting from behind-the-meter PV + storage, and find that underlying retail rates drive the level of utility costs reductions from the addition of storage to PV systems; replacing non-coincident demand charges with peak demand charges (or coincident demand charges) can further reduce utility costs by incentivizing the dispatch of storage during times of system peak.

Our study builds on this literature by covering a much larger geographic scope for simulated load shapes representing customers with different usage patterns, based on models of 9 residential and 15 commercial customers. It also considers a more diverse set of demand charge designs. In addition, our storage analysis makes a novel contribution to the literature by focusing on the synergistic effects of PV and storage in reducing demand charges. Specifically, after we introduce our data and methods in Section 2, we analyze how demand charge savings from PV will vary based on differences in demand charge design (Section 3), customer load patterns and PV design characteristics (Section 4), and through the addition of electricity storage (Section 5). Section 6 discusses how well demand charge savings align with utility cost savings from PV. Finally, Section 7 presents conclusions and policy implications from this work.

Overall, our analysis contributes to building a nuanced understanding of demand charge savings from behind-the-meter PV and storage, which is essential for understanding PV market dynamics and adoption in the coming years. From the ratepayer and utility standpoints, the alignment between customer bill savings and utility cost savings will help determine the potential implications of PV on retail electricity rates and utility earned revenues.

2. Data and methods

Our analyses cover residential customers with standalone PV, commercial customers with standalone PV, and commercial customers with PV + storage. Fig. 1 illustrates our general method. We begin with 30 min data on insolation and other weather, spanning a 17-year period

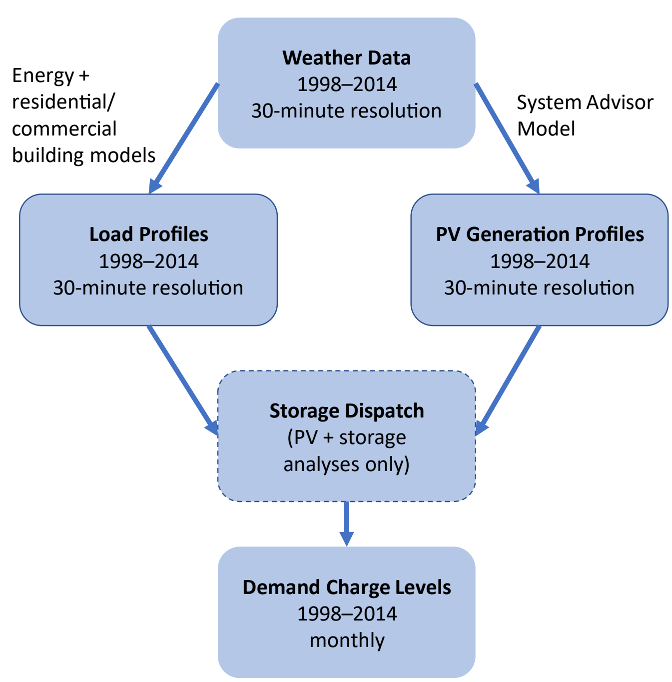


Fig. 1. Flow chart of analysis steps.

(1998–2014), sourced from the National Solar Radiation Database (Sengupta et al., 2018). We use those data to simulate loads for single-family homes with various characteristics in 15 cities via the U.S. Department of Energy's Energy + Residential Prototype Building Models (Mendon and Taylor, 2014), with 30 min resolution. We similarly use the weather data to simulate loads for 15 commercial building types (assuming new construction only) in 15 cities via the Energy + Commercial Reference Building Models (Field et al., 2010). A subset of the average daily load profiles used in the analysis are shown in Figs. 12 and 13 (Appendix A). We also use the weather data to simulate generation profiles—via the National Renewable Energy Laboratory's System Advisor Model—for PV installed on the various simulated residential and commercial buildings, for the 1998–2014 period at 30 min resolution. The simulated PV systems have a range of sizes and orientations. The commercial PV + storage analysis includes different/additional parameters, including a single PV orientation (south-facing[1]) and 10 storage system sizes. The result is 12,960 simulated combinations for residential buildings with standalone PV, 9000 for commercial buildings with standalone PV, and 22,500 for commercial buildings with PV + storage (which are compared with 2250 combinations of standalone PV and 2250 of standalone storage). Table 1 shows the assumptions used to create the building load profiles and PV/storage generation profiles. The ranges shown in each of the figures present the range of results for all residential or commercial buildings, unless otherwise indicated.

For the residential and commercial standalone PV simulations, we use the contemporaneous building load and PV generation profiles to estimate demand charge savings due to PV by comparing demand charges with and without PV under various demand charge designs, for each month over the 17-year (1998–2014) period.[2] For the commercial PV + storage simulations, we also include storage dispatch optimized solely for demand charge reduction (Fig. 2); that is, we do not consider other functions such as peak/off-peak arbitrage or participation in ancillary services markets or the value of resilience in the face of utility outages. We assume that the storage system can either be charged from the grid or from the PV system and is dispatched with perfect foresight, an 83% roundtrip efficiency, and batteries with a useable energy capacity (kWh) three times larger than their rated power (kW).[3] We then estimate demand charge savings (relative to no PV or storage) for standalone PV, standalone storage, and PV + storage under various demand charge designs. Table 2 shows the demand charge designs used for each analysis. We report results as demand charge savings (%), calculated as follows for each month and averaged for all months over the 17-year period:

$$\Delta D_b = \frac{D_{b,0} - D_{b,PV/storage}}{D_{b,0}}$$

D_b = billing demand, or the demand used to calculate a customer's monthly demand charge (kW)

$D_{b,0}$ = Billing demand without PV or storage (kW)

$D_{b,PV/storage}$ = Billing demand with PV or PV + storage (kW)

Our analysis has a number of boundaries and limitations:

[1] Optimizing orientation to maximize coincidence with a customer's peak load is less important with the presence of storage, since storage dispatch can be used to optimize timing of peak demand reduction.

[2] Calculations were performed using the Python programming language. We assume that the customer is on the same rate before and after installing a PV system; if the customer does not have a demand charge element to their rate prior to installing a PV system, then the customer's reduced volumetric energy charge should also be taken into account.

[3] Although the roundtrip efficiency and the capacity-to-power ratio are important design considerations that impact the financial performance of the system, they do not meaningfully influence the trends discussed in this research, which focuses on demand reduction and the synergies between PV and storage.

Table 1
Parameters varied to generate load and PV profiles.

	Residential	Commercial
Cities (15)[b]	Albuquerque (NM), Atlanta (GA), Baltimore (MD), Colorado Springs (CO), Duluth (MN), Helena (MT), Houston (TX), Las Vegas (NV), Los Angeles (CA), Miami (FL), Minneapolis (MN), Peoria (IL), Phoenix (AZ), San Francisco (CA), Seattle (WA)	Same as residential, except Boulder (CO) replaces Colorado Springs (CO), and Chicago (IL) replaces Peoria (IL)
Customer types (9 residential, 15 commercial)	4 heater types—electric resistance, electric heat pump, gas furnace, oil furnace 2 foundation types—slab-on-grade, crawlspace 3 vintages—2006 IECC, 2009 IECC, 2012 IECC	Super market, quick service restaurant, full service restaurant, primary school, secondary school, strip mall, standalone retail, small office, medium office, large office, hospital, midrise apartment, small hotel, large hotel, warehouse[a]
PV system sizes (9 residential, 10 commercial)[c]	Sized such that PV generates 20%–100% of annual customer load (in 10% increments)	Sized such that PV generates 10%–100% of annual customer load (in 10% increments)
PV orientations (4)	South-facing, southwest-facing, and west-facing @ 20°tilt Flat	Same as residential for standalone PV South-facing for PV + storage
Storage system sizes (10, for commercial PV + storage only)	N/A	Sized such that the battery's inverter capacity (in kW) is 10%–100% of the customer's lifetime peak load (in 10% increments), 3 h duration

[a] Based on U.S. Department of Energy Commercial Reference Buildings. IECC = International Energy Conservation Code.
[b] See Fig. 12 for a map of the continental United States showing the locations considered in the analysis.
[c] Residential customers tend to have larger PV-to-load ratios than commercial customers, in part a result of larger load levels and limited roof space for commercial PV systems. However, to enable direct comparisons of billing demand reductions between residential and commercial customers, for figures where PV system size is fixed, a single PV-to-load ratio of 50% is used for both customer types. In the commercial-only analysis, a smaller PV-to-load ratio of 20% is used when PV system size is fixed.

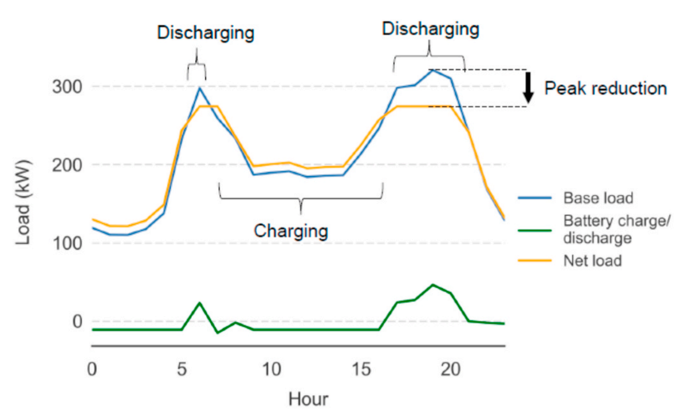


Fig. 2. Illustrative example of storage dispatch for peak demand (and thus demand charge) reduction.[a]
[a]This illustrative figure only shows the peak reduction within the day, but the day of the load peak could change as a result.

Table 2
Demand charge designs used in analyses.

Demand Charge Design	Analysis: Standalone PV (Residential and Commercial)[a]	Analysis: PV + Storage (Commercial)[b]
Basic (non-coincident)	Billing demand is determined by customer's monthly peak, regardless of timing. Customer load and PV generation use a default 30 min averaging interval.	Same, but uses a default 60 min averaging interval.
Seasonal	Similar to basic demand charge, but demand charges in summer (June–August) are 3 times higher than in non-summer months.	N/A
Ratchet	Billing demand set to at least 90% of maximum billing demand in previous 12 months, applied to the basic demand charge design.	N/A
Peak period	Billing demand is defined as the maximum demand in the following time windows: Early afternoon peak: 12–4 p.m. Afternoon peak: 12–6 p.m. Evening peak: 4–8 p.m.	Same, but only these windows considered: Afternoon peak: 12–5 p.m. Transition peak: 12–10 p.m. Evening peak: 5–10 p.m.
Averaging intervals	Averaging interval window set to 30 min, 1 h, 2 h, or 4 h, applied to the basic demand charge design.	Same

[a] These assumptions are used for all analyses in which standalone PV is the primary comparison configuration.
[b] These assumptions are used for all analyses in which PV + storage is the primary comparison configuration, including analyses with no PV or storage as well as the relevant subsets of analyses with standalone PV and standalone storage.

- Our simulated load and PV generation profiles reflect actual weather-related variations, but they do not reflect all sources of customer load variability. For example, the simulated load profiles do not reflect variations in occupancy patterns across customers within any given city or all possible differences in end-use equipment. This does not necessarily indicate systematic under- or over-estimation of average demand charge savings, although the estimated variability in demand charge savings is likely underestimated.
- Our smallest demand charge averaging interval is 30 min, whereas some demand charges use 15 min intervals. Because our results indicate that demand charge savings increase with the length of the averaging interval, 15 min intervals would likely yield lower demand charge savings than the estimates presented here.
- Our analysis does not consider demand management, the solar rebound effect (as described in Qiu et al., 2019), or customer demand elasticity, all of which would affect the customer's underlying load shapes and could affect PV's ability to reduce demand charges. The magnitude and direction of this impact would depend on the underlying load shape, PV system size, and retail rate. For most customers, there would be minimal effect as the load level is not a significant driver of demand charge savings from solar; rather, it's the load profile shape, as it compares with the PV generation profile shape, which drives the demand charge savings from solar.
- We model a limited number of demand charge designs. Other designs and combinations of features are possible, such as tiered demand charges, demand charges combined with time-varying rates for other approaches to defining coincident peak, and so forth.
- Although we consider PV-to-load ratios up to 100% for all building types, the roof space available on many commercial buildings types can tend to limit PV systems to much smaller sizes.
- Because the assumption of perfect foresight for storage dispatch is an idealization, the results are an upper bound to the performance of storage systems in minimizing demand charges. However, the impact of this idealization is partially mitigated by the fact that billing demand is typically based on average demand over an interval of time. For example, if a PV system's generation suddenly decreases because of a passing cloud, a co-located storage system would not need to have anticipated this; it would only need to dispatch a corresponding amount of energy within the averaging time interval.

3. Impacts of demand charge design on PV customer economics

The way in which demand charges are designed has significant effects on PV customer economics. We also examine the variability in results across the parameters noted in Table 1.

Fig. 3 (residential) and Fig. 4 (commercial) summarize the results, which are based on monthly demand charges averaged over the 17-year study period; unless otherwise noted, the demand averaging interval is 30 min. PV provides the least benefit under a basic, non-coincident demand charge design. For residential customers, the median reduction in billing demand is only 3%, and the reduction is below 8% in almost all cases. This is because most residential customers have late afternoon or evening peak loads, when PV generates little or no electricity. The benefits of PV under a basic design are larger and more variable in the commercial sector, yet the median reduction in billing demand is still only 7%, and the reduction is less than 15% in about 90% of all cases (for customers with PV systems that generate 50% of their annual load). Though many of the commercial load profiles are diurnal and hence generally align better than residential load profiles (see Fig. 12 in the Appendix), the net load quickly shifts to late afternoon when PV is not generating much, limiting demand charge savings (up to around 20%). The impact of customer load profiles on demand charge savings are explored in more detail in Section 4.

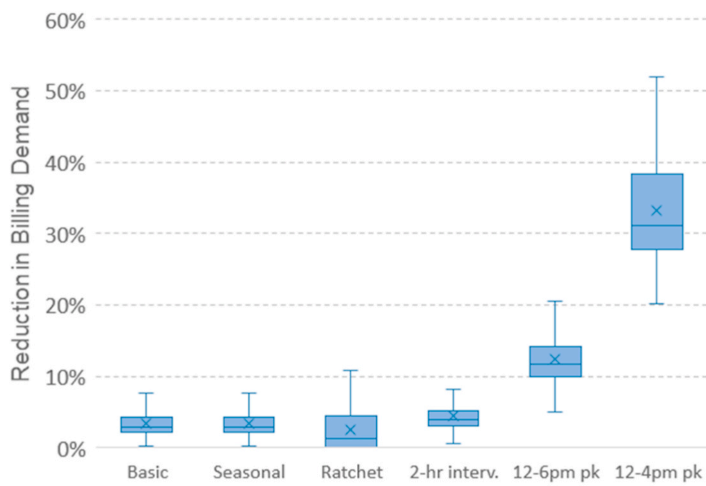
Basing demand charge designs on predefined, daytime peak periods increases the billing demand reduction substantially for residential and commercial customers. Fixing the PV size to 50% PV-to-load ratio to isolate variation in billing demand reduction from factors other than PV system size,[4] with a 12–4 p.m. peak period, the median residential reduction is 31% and the maximum exceeds 50%, while the median commercial reduction is 19% and the maximum exceeds 40%. However, the savings vary substantially owing to geographic location and building type (for commercial customers only, given the wider variation in load profile shapes). The benefit declines substantially for residential and commercial customers when late afternoon and early evening hours are included in the predefined peak period, because many customers experience peak demand during those low-PV-generation hours. The peak window definitions were chosen to be included in this analysis to illustrate these effects.

Increasing the averaging interval from 30 min to 2 h[5] under a basic demand charge design provides minimal benefits for residential customers, because the longer interval is insufficient to bridge the gap between times of PV generation and times of peak demand. For many commercial customers, however, a 2 h averaging interval is enough to capture higher-PV-generation periods under a basic design, in addition to dampening the effects of cloud events on PV generation. As a result, the median commercial demand reduction is about twice as high when using a 2 h interval rather than a 30 min interval. The impacts of demand charge designs with seasonal variation and ratchets are relatively minor for residential and commercial customers.

4. Impacts of customer characteristics and PV system design choices on customer economics

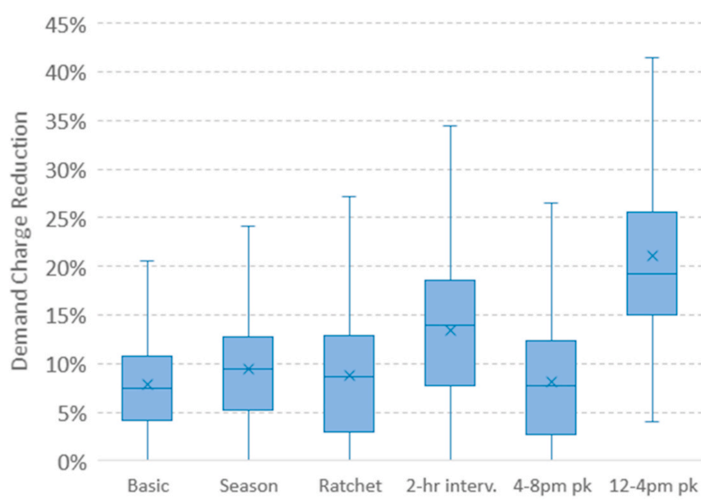
The characteristics of PV customers and their system choices also

[4] The impact of PV system size on demand charge savings is discussed in Section 4; see Figs. 7 and 8.
[5] We chose to model a 2 h averaging interval as we did not find any examples of US utilities that considered longer averaging time periods.



Each box-and-whiskers plot shows the distribution in the average monthly reduction in billing demand, across all 1,440 combinations of simulated load and PV generation profiles. PV generation profiles are for customers with PV systems that generate 50% of their annual load[7]. 'x' = mean; shaded box = 25th–75th percentile range; middle line = median; whiskers = maximum and minimum excluding outliers. 2-hr interv. = 2-hour interval averaging window; 12-6pm pk = 12–6 pm peak window; 12-4pm pk = 12–4 pm peak window.

Fig. 3. Residential results: distribution in average billing demand reduction across demand charge designs.



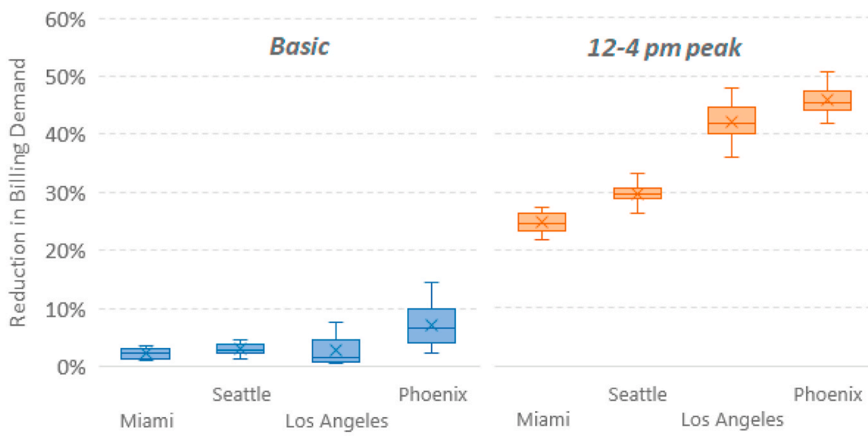
Each box-and-whiskers plot shows the distribution in the average monthly reduction in billing demand, across 900 combinations of simulated load generation. PV generation profiles are for customers with PV systems that generate 50% of their annual load. 'x' = mean; shaded box = 25th–75th percentile range; middle line = median; whiskers = maximum and minimum excluding outliers; 2-hr interv. = 2-hour interval averaging window; 4-8pm pk = 4–8 pm peak window; 12-4pm pk = 12–4 pm peak window.

Fig. 4. Commercial results: distribution in average billing demand reduction across demand charge designs.

have important impacts on PV customer economics under demand charges. Here we consider—for the residential and commercial sectors—the impacts of customer location, building type, PV system size, and PV panel orientation.

Residential and commercial savings are higher in sunny locations. As Fig. 5 shows for residential customers, although savings are minimal under a basic demand charge design across various locations, they are substantially higher in sunny locations under a 12–4 p.m. peak period design. In sunny locations such as Los Angeles and Phoenix, demand tends to be high—generally because of air conditioning—and PV generation is high during the afternoon window, which reduces demand charges by a median of 42% and 45%, respectively, for PV systems with a 50% PV-to-load ratio. In addition, in cities with fewer cloudy days, billing demand is more likely to be set on a sunny day when PV is reducing demand substantially, potentially due to higher cooling loads. Frequent partially cloudy conditions in otherwise-sunny cities, such as Miami, reduce savings considerably while increasing the month-to-month variability in savings as peak loads in some months occur during intermittently cloudy periods. Cloudy cities, such as Seattle, also yield lower demand charge savings. Longer averaging intervals can smooth out PV generation, making it less likely that billing demand is set during a cloud event, hence increasing demand charge savings from PV generation. A single cloud event can impact demand charges for the following twelve months, exacerbating the savings reductions in cloudy locations with demand charge designs that include ratchets.

Demand charge savings due to PV vary little across the limited sets of residential building characteristics that we analyze; only the use of electric rather than gas heating produces a noticeable effect, but that effect is still small as the load profiles do not diverge significantly. In contrast, among the wide range of commercial building types that we

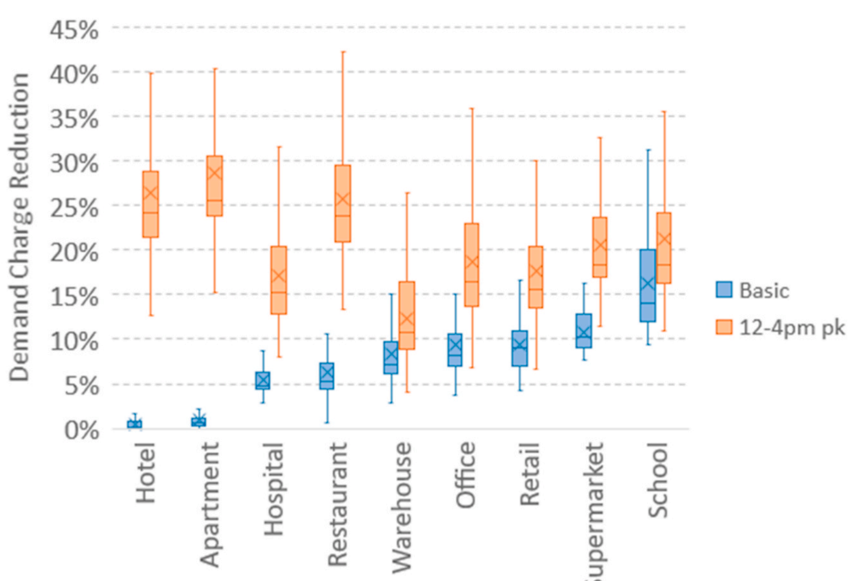


Each box-and-whiskers plot shows the distribution in the average monthly reduction in billing demand. PV generation profiles are for customers with PV systems that generate 50% of their annual load. 'x' = mean; shaded box = 25th–75th percentile range; middle line = median; whiskers = maximum and minimum excluding outliers.

Fig. 5. Residential results: distribution in average billing demand reduction by location.

analyze, demand charge savings vary more substantially and depend on the demand charge design. Fig. 6 shows variation in savings across nine commercial building types under basic and 12–4 p.m. peak period designs. The buildings whose loads coincide best with PV generation reap the largest savings under a basic design, particularly schools, which save a median of 14% when PV generates 50% of annual load. Most other building types average savings around 10% or less under a basic design owing to poor coincidence between load and PV generation as well as cloudiness. However, switching to a 12–4 p.m. peak period design increases savings for most building types substantially, especially for those with evening peaks such as hotels and apartments, whose average savings rise from around zero to almost 30%. Building types that have high demand early in the 12–4 p.m. period, such as restaurants and supermarkets, also realize savings from improved coincidence between their PV generation and loads. Conversely, the demand charge savings don't increase as much for building types that have relatively flat or increasing loads in the 12–4 p.m. period, such as schools or warehouses. Overall, demand charge savings due to PV tend to be lower for commercial customers that have a relatively high load factor (average load/maximum load over a given period) and higher for those that have more variable daily peak loads.

Thus far, we have presented results keeping PV system size fixed at 50% of PV-to-load ratio, to isolate the impacts of demand charge design, location, and building type from the PV system size. Larger PV systems can increase demand charge savings for residential and commercial customers, but with diminishing returns. Increasing PV size produces



The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e., 50% PV-to-load ratio), to eliminate variability due to PV system size. The range within each building type is due to location and orientation. 'x' = mean; shaded box = 25th–75th percentile range; middle line = median; whiskers = maximum and minimum excluding outliers; 12-4pm pk = 12–4 pm peak window.

Fig. 6. Commercial results: distribution in average billing demand reduction for various building types under basic and 12–4 p.m. peak period demand charge designs.

the smallest benefits under a basic demand charge design, as shown in Fig. 7 for several commercial building types in Phoenix and Miami.[6] For example, the median reduction for schools in Phoenix with PV sized to meet 20% of annual energy demand is 16%, but sizing PV to meet 100% of annual demand only increases the savings to 29%. The benefits of larger PV systems under a basic design are even smaller for restaurants and hotels. The diminishing returns occur because larger systems push peak demand to later in the day and/or to cloudy days when PV generation is lower. The diminishing returns to increasing PV system size are similar in other locations (e.g., Miami, as seen in the Figure). The benefits of a larger system are greater under a 12–4 p.m. peak period design, because PV cannot push the peak period out of that static window. However, even under such a design, larger PV systems can push peak demand to cloudy days when PV generation is lower. In addition, because relatively small PV systems can eliminate 12–4 p.m. demand charges completely in some months, further PV size increases provide no additional savings. The PV size trends for residential systems are broadly similar (Fig. 8). As with commercial customers, there is significant variation primarily due to different locations.

One strategy for reducing the impact of demand charges on PV's customer economics is to orient panels to the southwest or west so their generation peaks later in the day and coincides better with load, compared with generation from flat panels or those oriented to the south. However, we find that this approach generally produces modest demand charge savings, as observed in Fig. 14 in the Appendix. For example, for a school in Phoenix, the average demand charge reduction under a 12–4 p.m. peak period design is 31% for a south-facing system and 34% for southwest- and west-facing systems (assuming a constant system size set at a PV-to-load ratio of 50% for the south-facing system). Typical gains are similarly modest or nonexistent for other commercial building types and for homes, with some variation due to different demand charge designs.

5. Impacts of PV + storage systems on commercial demand charge savings

Energy storage is a commonly proposed approach to increase the bill savings driven by PV for customers on demand charges. Here we examine the impacts of PV + storage systems for commercial customers,[7] with a particular focus on their synergies in reducing the demand charge.

Across almost all results, PV + storage systems provide demand charge savings that are greater than the sum of the savings attained through either technology separately. For example, across all simulations with a basic non-coincident demand charge, the median reduction in demand charges is 8% for PV alone, 23% for storage alone, and 42% for PV + storage (i.e., an additional 11% reduction due to synergetic effects between PV generation and storage dispatch). Fig. 9 illustrates this effect. For a building with a broad peak load on a sunny day (Fig. 9, left), PV's predominantly midday generation does little to reduce peak demand, because it leaves narrow peaks in the early morning and evening (left, top). Storage alone also produces modest peak demand reductions as it is optimally discharged slowly over the broad peak (left, middle). However, with a PV + storage system, storage can clip the narrow morning and evening peaks left by PV, resulting in a greater billing demand reduction for a given quantity of energy discharged (left, bottom). PV + storage systems also can mitigate demand charges incurred owing to transient reductions in PV generation (e.g., from passing clouds), with storage acting as a buffer during these transient events and yielding greater demand charge savings than would be attainable using either PV or storage alone (Fig. 9, right).

Fig. 10 quantifies the synergies and shows their variation across commercial building types and locations. The left box shows demand charge savings for PV alone, storage alone, and PV + storage[8]. The right box shows the cooperation ratio—the main metric we use to quantify synergies—which is equal to the demand charge savings from PV + storage divided by the sum of the savings from PV alone and storage alone; a larger cooperation ratio means greater demand charge savings from combining PV with storage, rather than using the technologies separately. The synergies are larger for the building types and locations corresponding with the conditions illustrated in Fig. 9. For example, hospitals and large office buildings typically exhibit broad peaks (Fig. 9, left), so they have relatively high cooperation ratios (Fig. 10). Locations with frequent partially cloudy conditions, such as Miami, also have relatively high cooperation ratios owing to the dynamic illustrated in Fig. 9 (right). Miami-based hospitals and large offices are at the high end of the cooperation ratio ranges show in Fig. 10. However, building types with the greatest synergies do not necessarily have the highest demand charge savings, as Fig. 10 also shows.

The commercial building types that save the most with standalone PV under a basic demand charge design—those with distinct afternoon peak loads, such as schools and strip malls—generally save the most with PV + storage as well (Fig. 10). However, whereas some building types realize minimal benefit from standalone PV, all the types that we analyze reduce median demand charges by 20% or more using PV + storage. Apartments and hotels experience a particularly large rise in savings due to PV + storage, because their relatively narrow peak net loads are well suited for clipping by storage.

Similarly, the building locations that save the most with standalone PV—relatively cloudless cities with a strong solar resource like Phoenix and Albuquerque—typically save the most with PV + storage. In Fig. 10, the heights of the boxes and whiskers denote the location-based variability in savings for each building type, which is slightly less for PV + storage than for standalone PV.

The results shown above are based on a basic non-coincident demand charge design. Combined PV + storage systems provide larger demand charge savings under predefined peak period designs (Fig. 11). As with standalone PV, the benefits are greatest for an afternoon (12–5 p.m.) peak period that captures substantial PV generation, although the storage element of the system also provides benefits during an evening peak period (5–10 p.m.). The 12–10 p.m. period produces the smallest PV + storage savings among the peak-period designs analyzed because of the large window, which reduces storage's peak-clipping capabilities.

Because longer averaging intervals effectively perform the same function as storage by smoothing out short-duration peaks, demand reductions from PV + storage tend to be lower under demand charge designs with longer averaging intervals—which is opposite of the trend observed for standalone PV. Therefore, Figs. 10 and 11, which assume 1 h averaging intervals, may understate the demand charge savings from PV + storage, because most demand charge designs in the US currently use shorter averaging intervals such as 15 min (McLaren et al., 2017). When the ratio of PV size to storage size is high, the savings from PV + storage can more closely resemble those from standalone PV.

Finally, increasing the size of PV + storage systems results in

[6] These two cities were chosen as Phoenix has relatively few cloudy days whereas Miami has many more intermittent clouds, providing a range in solar generation profiles. Hotel, restaurant, and school were chosen as building types that span a wide range of load profiles and demand charge reduction levels.

[7] We focus on commercial customers for the PV + storage demand charge savings analysis, because, when storage is installed to reduce demand charges, it is almost exclusively for commercial customers, with few exceptions in areas where there are residential demand charges.

[8] Fig. 10 shows results for a fixed PV + storage size, to isolate the variation in billing demand reduction from other variables considered. The PV system is sized to meet 20% of annual demand and the storage system is sized to meet 20% of peak demand. Although smaller storage sizes may lead to greater demand savings per kW of storage capacity, as shown in Figs. 7 and 8, customers tend to install larger storage systems to achieve larger absolute demand savings.

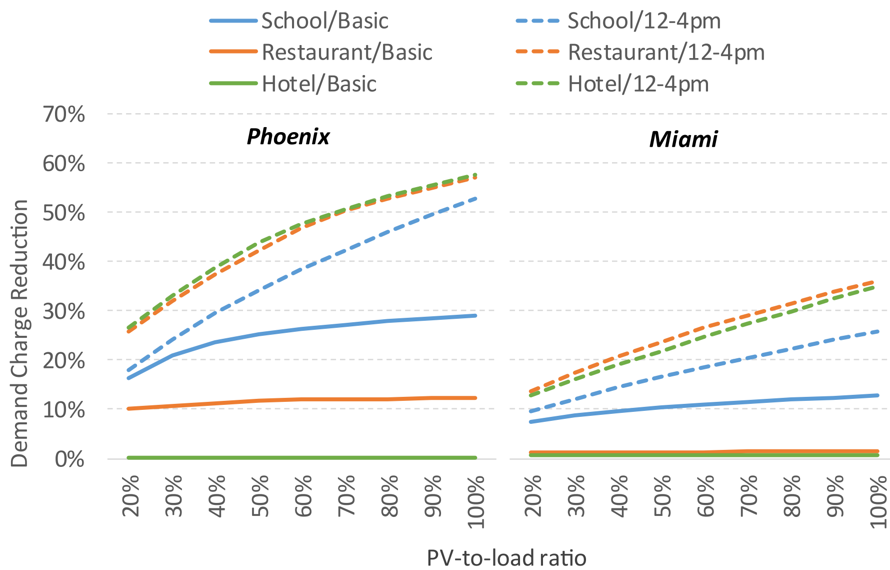


Fig. 7. Commercial results: median demand charge reductions with increasing PV system size for basic and 12–4 p.m. peak period demand charge designs, for three commercial building types in Phoenix and Miami.

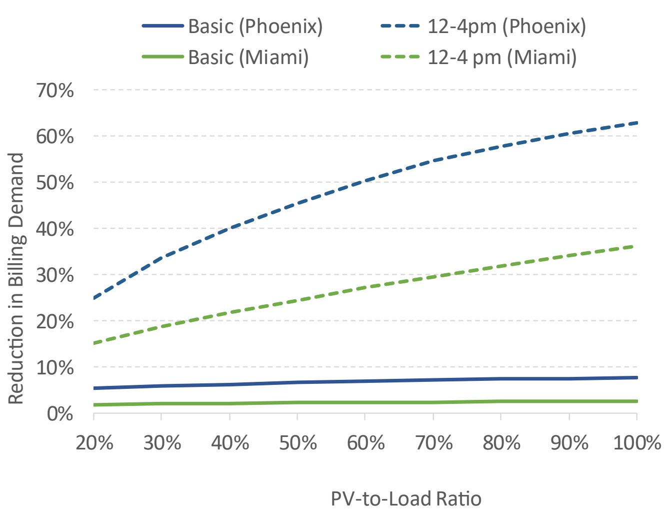


Fig. 8. Residential results: median demand charge reductions with increasing PV system size for basic and 12–4 p.m. peak period demand charge designs, in Phoenix and Miami.

diminishing returns. This also occurs with standalone PV as described previously, and it occurs with standalone storage, because larger system sizes produce progressively wider peak loads. However, the diminishing returns from PV + storage are mitigated by additional synergies, as larger PV systems create progressively narrower and taller peaks, which are progressively easier for storage systems to clip.

6. Alignment of demand charge savings from PV and corresponding utility cost savings

If rate design is used to maintain equity among electricity consumers by reducing cross-subsidies and providing consumers with "efficient," cost-reflective price signals, then the demand charge savings from PV should approximate the utility capacity cost reductions associated with the PV, potentially also reflecting recovery of sunk network costs.[9] When demand charge savings from PV are higher than utility capacity cost reductions, this implies a cross-subsidy from non-PV customers to PV customers (or reduced return to capital for the utility), and vice versa. The financial utility cost savings from PV that are not energy-related vary widely from one region to another, and quantifying capacity cost impacts from PV is beyond the scope of this analysis. However, some conclusions can be made with respect to the alignment of demand charge savings and utility cost savings.

First, the basic, non-coincident demand charge is a blunt tool to recover utility fixed charges associated with the transmission and distribution system. Two customers can have identical peak load levels—and hence demand charges—but have very different peak timings and cost implications to the grid; one customer's peak may coincide with the system peak, whereas the other's could contribute very little to the system peak (see, for example, Zethmayr and Makhija, 2019). Similarly, two PV customers with identical peak load levels but very different peak load timings (afternoon and evening, for example) would have different demand charge savings from PV, as observed in our results, whereas the capacity value of PV from the grid's perspective does not change. Indeed, the system-wide value of a PV system is largely independent of the host customer's load profile, so the widely varying basic, non-coincident demand charge reductions from PV suggest that these demand charges are not effectively communicating PV's system capacity value to customers.

Restricting the billing demand definition to a predefined peak

[9] Reducing cross-subsidies can be problematic in terms of equity in some cases and should not be seen as a universal policy objective. Increasing monthly fixed charges and decreasing volumetric charges reduces cross-subsidies from large consumers to small consumers, but can also disproportionately impact low-income consumers who may have lower monthly consumption levels. This is discussed in more detail in (Burger et al., 2020).

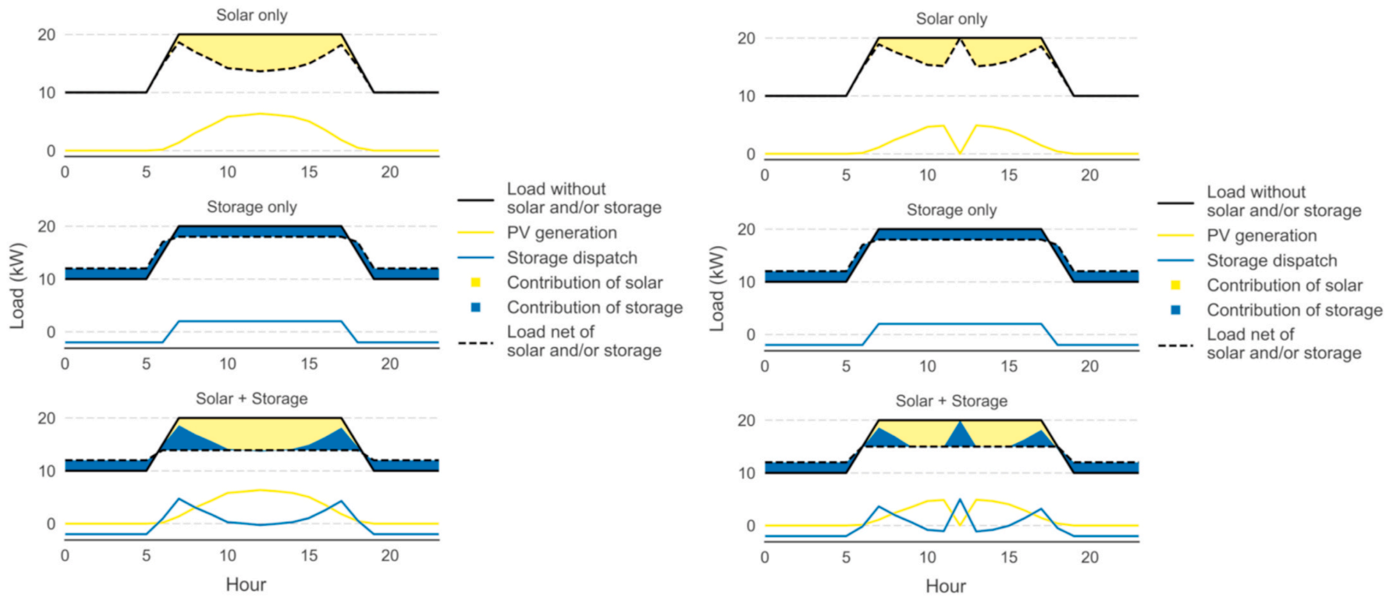
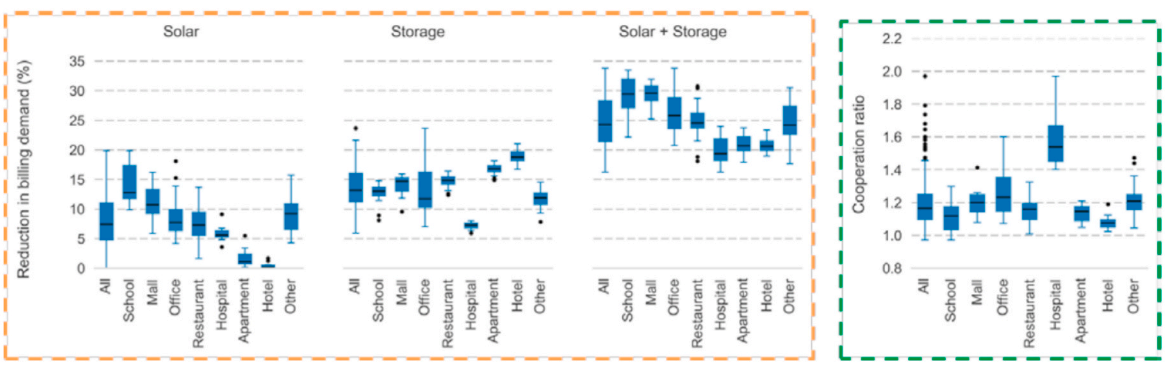


Fig. 9. Load-reduction synergies between PV and storage: PV creates narrow peak loads that storage clips (left), storage buffers transient dips in PV production (right).



The figure shows distributions in billing demand reductions for each building type (horizontal lines are median values; boxes are the first and third quartiles; whiskers are 1.5x the interquartile range). These results are based on a basic non-coincident demand charge with a 1-hour averaging interval, PV systems sized to meet 20% of each customer's annual load, and battery sized to equal 20% of the customer's annual peak demand.

Fig. 10. Demand reduction due to PV, storage, and PV + storage across commercial building types (left), and PV + storage cooperation ratio (right).

window generally increases the demand charge savings from PV if the window coincides with times of PV generation. On average, this may better match PV's capacity value to the utility, especially if considering demand charges that recover system peak utility costs, when the system peak is early afternoon to mid-afternoon. However, there is still a wide range in demand charge savings among customer types, again indicating a poor alignment in demand charge savings from PV and utility cost reductions for at least a subset of customers.

Another finding that indicates a mismatch in demand charge savings for customers and utility cost reduction from PV is the decreasing marginal demand charge savings with increasing PV system size observed in Figs. 7 and 8. There is little economic rationale for providing lower demand charge savings per kW for more capacity, because the system's cost savings per kW of individual behind-the-meter PV systems generally do not change with increasing size.[10]

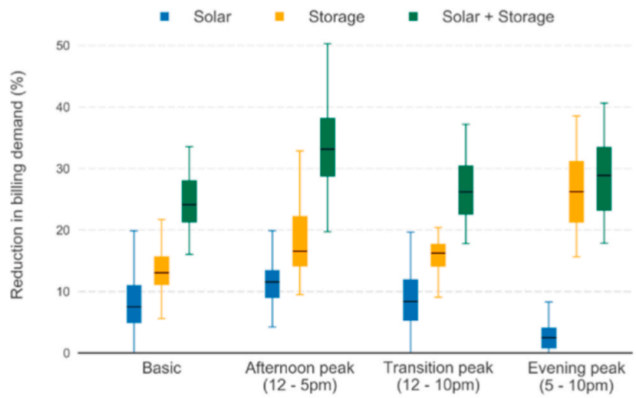
[10] The capacity value of PV decreases with increasing PV penetration levels, but this is unlikely to be noticeable at the kW or even MW scale of individual systems.

Although there may be specific scenarios for which demand charge savings from PV are commensurate to the resulting utility savings, there is no single demand charge design among those considered in this analysis that send cost-reflective price signals for all customer types and electricity market conditions.[11]

7. Conclusions and policy implications

Our results have several important policy implications related to behind-the-meter PV and demand charge design. Utility rate designs based on demand charges and lower net-metering compensation—including use of demand charges rather than volumetric charges to recover capacity costs—generally detract from the bill savings PV

[11] We would expect a cost-reflective rate design to have similar demand charge savings from PV regardless of the customer's underlying load profile and for larger PV systems to lead to proportionally larger demand charge savings (i.e. no diminishing returns with increasing size). None of the demand charge designs considered here meet these conditions.



The figure compares billing demand reductions between a basic non-coincident demand charge and several variants of a peak-period demand charge. The distributions reflect variation across building types and locations (horizontal lines are median values; boxes are the first and third quartiles; whiskers are 1.5x the interquartile range). All simulations used in this figure are based on PV systems sized to meet 20% of each customer's annual load and batteries equal to 20% of the customer's annual peak demand.

Fig. 11. Demand reductions under basic and peak period demand charge designs.

provides to residential and commercial customers. This reduced profitability of PV to customers has negative implications for behind-the-meter PV deployment, although not necessarily for overall PV deployment (Gagnon et al., 2017).

Some demand charge designs result in more customer bill savings than others. Basic, non-coincident demand charges diminish PV economics the most, because there is typically a mismatch between when a PV host's demand peaks and when PV is generating significant amounts of electricity for commercial and residential customers, to varying degrees. Demand charge savings under such a design are less than 10% for all the residential customers we analyzed, regardless of PV system size. Commercial customers with day-peaking loads in relatively high solar-resource areas (e.g., schools in Phoenix) can have demand charge reductions of up to one third, although most customers have substantially lower savings. Savings are larger under demand charges based on predefined afternoon peak periods that align with PV generation, reaching a median of 31% for residential customers and 19% for commercial customers when a 12–4 p.m. peak period is used, when PV is sized to generate 50% of annual load. Longer averaging intervals can also improve demand charge savings for residential and commercial PV customers, although the benefits depend on the underlying design. Designs with seasonal variation and ratchets have relatively minor effects.

Demand charge savings due to PV vary widely across customers, suggesting that utility rate designs based on demand charges direct PV deployment toward particular locations and building types. Customers in locations that have more intense insolation and fewer clouds realize higher demand charge savings, especially for afternoon peak period designs. Although savings vary little across the residential buildings that we analyze, savings vary substantially by commercial building type. For example, schools, which have load profiles that match relatively well with PV generation, benefit more than other building types under basic demand charge designs. In contrast, evening-peaking buildings like hotels and apartments receive almost no benefit under such a design. All commercial building types benefit more under a 12–4 p.m. peak period design, but substantial variability remains. Overall, savings tend to be lower for commercial customers that have a relatively high load factor and higher for those that have more variable daily peak loads.

Demand charges incentivize residential and commercial customers to install smaller PV systems, which would tend to reduce the total capacity of distributed renewable energy on the grid. The benefits of increasing PV system size are typically minimal under a basic demand charge design, and even with a 12–4 p.m. peak period there are diminishing returns. As a result, smaller systems reduce demand charges more effectively on a per-kW basis. Attempting to increase demand charge savings by orienting PV panels to the southwest or west results in modest gains at best.

In contrast, combining energy storage with commercial PV systems boosts demand charge savings considerably. Across almost all results, PV + storage systems provide savings that are greater than the sum of the savings attained through either technology separately. Still, the savings vary by building type, location, and system size, suggesting that PV + storage will be more attractive to some commercial customers than to others. The savings also vary by demand charge design. As with standalone PV, PV + storage provides the greatest benefit with an afternoon peak period design, although the storage element of the system also provides benefits during an evening peak period. In contrast to standalone PV, PV + storage systems produce greater demand charge savings when averaging intervals are shorter. Other impacts of PV + storage vary from those of standalone PV and storage as well, highlighting the need to understand the interactions among various technologies when designing demand charge rates. Demand charge reductions from PV may be higher with storage, as indicated by the PV + storage cooperation ratio being greater than one for the majority of customers, but the storage dispatch maximizes value to the grid only if a particular customer's net peak load coincides with the grid peak. Storage is dispatched to clip the net load peaks, which often occur in the mornings and late afternoon times for customers with business hour load patterns, such as schools, offices, or retail shops; for afternoon peaking systems, this storage dispatch pattern could be more favorable to reduce grid costs than a storage dispatch pattern for a customer without PV, leading to potentially improved customer bill and utility cost alignment—though the magnitude and direction of the alignment is dependent on the timing and shape of the customer load peaks. Our results support and builds on the conclusions in the existing literature (e.g. Young et al. (2019) and Boampong and Brown (2020), introduced in Section 2) by looking at a larger variety of customer types, locations, and demand charge designs but also provide additional insights on the alignment between customer bill and utility cost savings. Other load-management strategies and technologies should be considered as well to maximize demand charge savings and lead to better alignment between customer and utility savings.

This work informs rate-making priorities in a time of increasing interest in more cost-reflective—and often more complex—pricing strategies. Because basic, non-coincident demand charges do not necessarily signal PV's system value to customers, any billing demand reductions due to PV generation (or PV + storage) do not always align with the corresponding capacity cost reductions, with the exception of a few specific cases in which this alignment is better. This work corroborates arguments by Borenstein (2016), who posits that the basic, non-coincident demand charge is poor pricing tool to recover customer-specific fixed costs. Indeed, the impact of PV generation on utility fixed costs should be independent of the customer's underlying load profile, though we find a range in demand charge savings from PV even with the same PV generation profile, a finding that holds true for all demand charge designs considered. Of the many demand charge designs considered in this analysis, no single demand charge design sends cost-reflective price signals for all customer types and electricity market conditions. Demand charges may be better suited to recover local capacity costs rather than system-wide costs, because a customer's peak load is more likely to contribute to their distribution feeder capacity than to capacity over larger areas, especially if load profiles on the feeder are relatively homogeneous.

These findings could change in the future as electricity consumption patterns evolve, particularly with further electrification of appliances and new loads such as electric vehicles. Depending on the timing of these new loads, PV could provide greater demand charge savings, particularly if there was increased two-way communication between loads and PV generation. Depending on the charging patterns of electric vehicles for residential customers, electric vehicle charging could set peak demand levels; if the vehicle charger was able to react to changes in PV generation, potentially resulting from the passing of clouds, demand charge savings from PV could be optimized. Future research on demand charge savings could include interactions between new "smart" loads and PV generation and opportunities for novel rate designs that better align bill savings from PV with utility cost reductions.

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CRediT authorship contribution statement

Naïm R. Darghouth: Conceptualization, Software, Writing - original draft, Writing - review & editing, Visualization, Supervision, Project administration. **Galen Barbose:** Conceptualization, Writing - original draft, Supervision, Funding acquisition, Project administration. **Jarett Zuboy:** Writing - review & editing. **Pieter J. Gagnon:** Software, Conceptualization. **Andrew D. Mills:** Conceptualization. **Lori Bird:** Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix

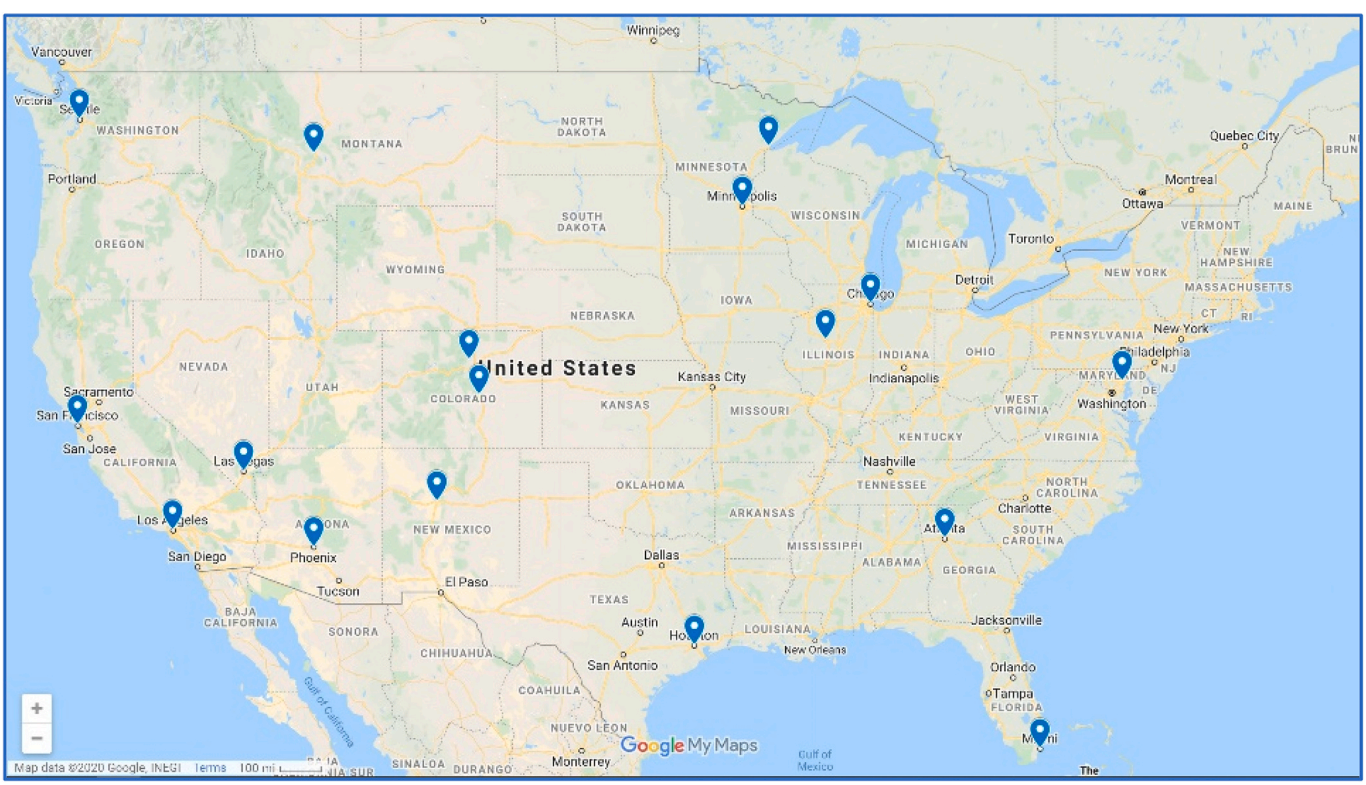

Fig. 12. Map showing all locations considered in the analysis.

See below for a selection of load profiles considered in this analysis. A small, representative set of daily average load profiles were chosen to be shown for two months, one in winter (January) and one in summer (July) for customers in Los Angeles. Though these do not capture the temporal and geographic variability in the large number of load profiles used in the analysis, it does provide some insights on the load shapes of each of the customer types, which can be useful in understanding some of the differences in demand charge savings from solar observed across customer types. The nine commercial profiles considered in Fig. 6 are shown in Fig. 13 below. Only one residential load profile is shown in Fig. 14, as there are no significant variations in the demand charge savings by residential customer type (see Section 4).

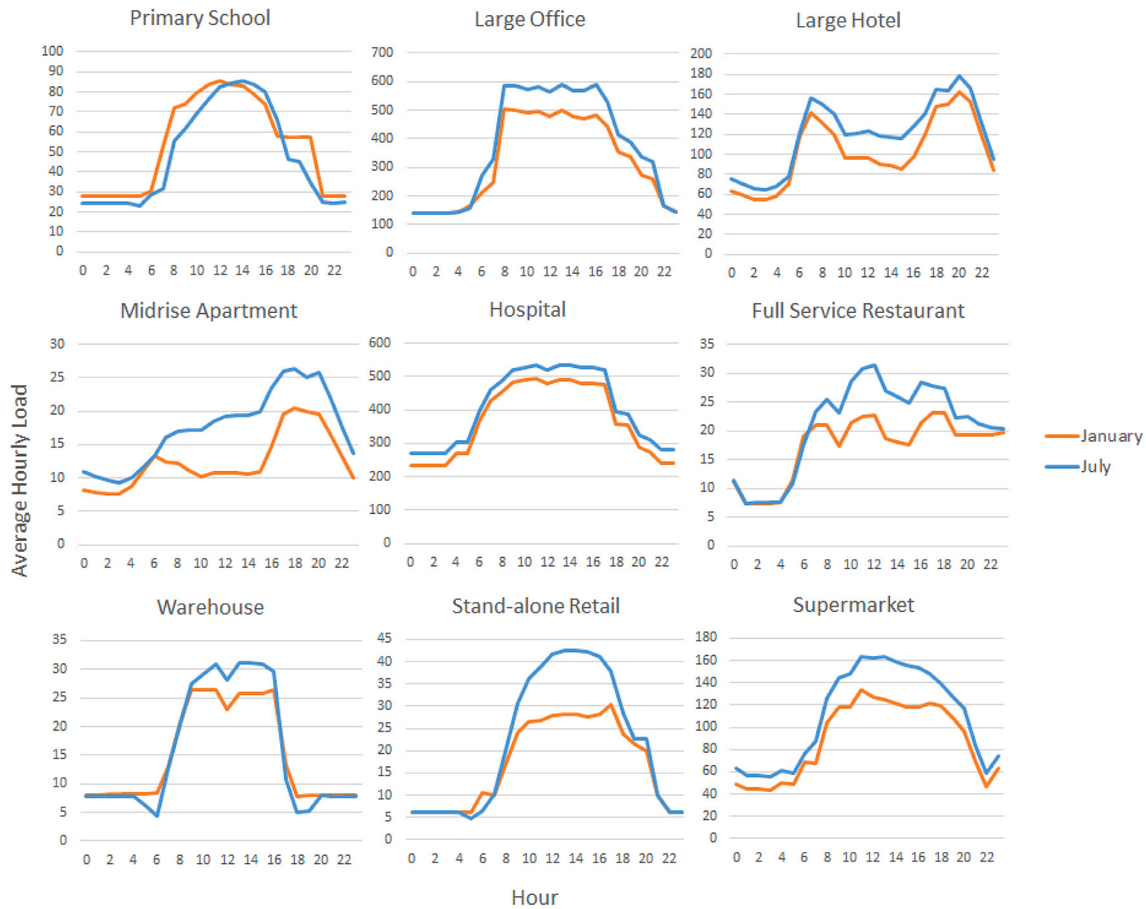

Fig. 13. Average daily load profiles for January and July for commercial customer types considered in this analysis, in Los Angeles.

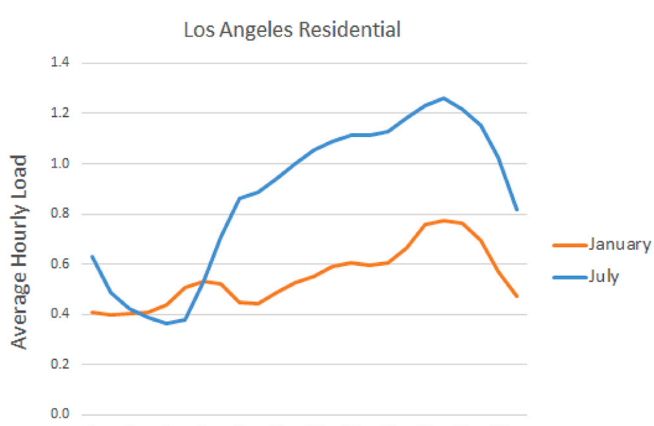

Fig. 14. Average daily load profiles for January and July for a residential customer in Los Angeles, with a gas furnace, with a crawlspace, and 2012 IECC vintage.

Mean demand charge reductions across PV panel orientations are shown in Fig. 15 for PV customers in Phoenix for a single PV system size kept constant for all orientations (50% PV-to-load ratio for a South facing system), to eliminate variability due to PV system size.

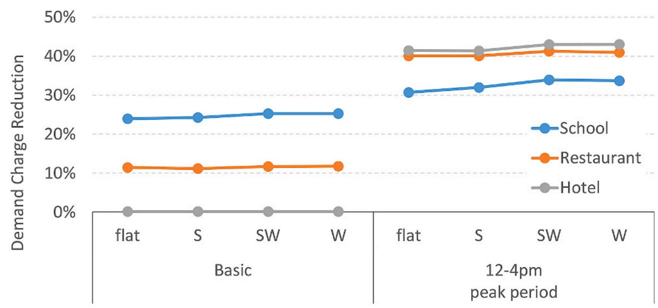

Fig. 15. Demand charge reductions across PV panel orientations for three commercial building types.

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