Exploring Demand Charge Savings from Commercial Solar

Naïm Darghouth, Galen Barbose, Andrew Mills, Ryan Wiser
Lawrence Berkeley National Laboratory

Pieter Gagnon and Lori Bird
National Renewable Energy Laboratory

July 2017

This analysis was funded by the Solar Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Overview

This analysis estimates demand charge savings from commercial solar across a range of customer types, US locations, PV system characteristics, and demand charge designs

- We use simulated load and PV generation profiles, based on 17 years of weather data for 15 cities, 15 customer types, 10 PV system sizes, and 4 panel orientations
- Demand charge savings are calculated for demand charge designs with and without seasonally varying prices and ratchets, and for various peak period definitions and averaging intervals

This work is part of a series of analyses exploring PV and demand charges:

- This study focuses on demand charge savings from solar, alone, without storage or load management; upcoming work will examine commercial demand charge savings from solar plus storage
- This study focuses on commercial customers; past work has focused on residential customers
- This study focuses on implications of demand charges for solar customers; upcoming work will consider how customer bill savings align with utility cost savings from distributed solar

This analysis is *not* intended to advocate for or against demand charges, but rather to help identify opportunities to align bill savings from solar with utility cost savings

Table of contents

Commercial demand charges have traditionally been a core component of electricity rate design

- Demand charges are based on the customer's peak demand and are notionally intended to recover utility capacity costs driven by peak load
- Most electric utilities offer commercial and industrial electricity rates with demand charges, often mandatory for larger customers
  - Demand charges often comprise 50% or more of the customer bill
- Commercial PV adoption has historically lagged other sectors, partly due to challenges associated with evaluating potential demand charge savings
- Regulators and utilities are continuing to refine rate designs, including for C&I customers, in order to better reflect cost causation and to provide efficient price signals to electricity consumers
- Given that context, regulators, utilities, consumers, and solar developers are all seeking to better understand how solar impacts commercial demand charges

Demand charges come in a variety of designs

Seasonal differentiation

- Some months have a higher demand charge level (in $/kW) than others
- Summer / non-summer is a common seasonal distinction

Frequency of billing demand measurement and ratchets

- Billing demand is determined on a monthly or annual basis (the latter not considered here)
  - A monthly basis is more common so that single event doesn’t determine annual bill
- Demand ratchets set billing demand as a fixed percentage of the maximum demand in the previous year, at minimum

Averaging interval

- Billing demand is measured as an average load over a predefined time interval
- From 15 minutes to an hour or more

Timing of billing demand measurement

- Most common: Maximum customer demand during the billing cycle
- Alternative: Maximum customer demand during predefined peak period window
- Alternative: Customer load at the actual time of system peak (i.e., coincident)

Peak period window definition

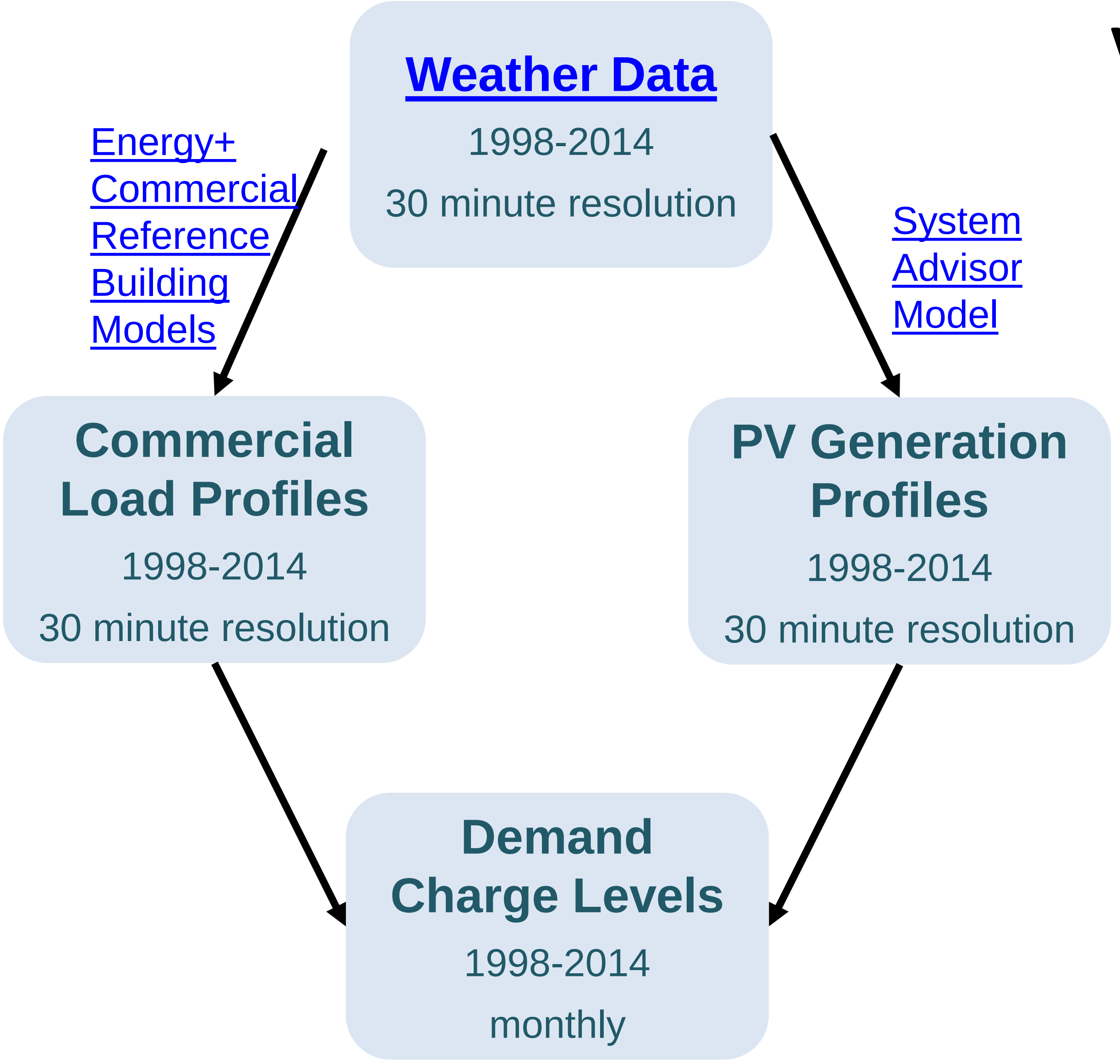
- Predefined peak period window definitions can vary to cover a range of hours in the day
- This analysis includes a large range of peak period definitions with the earliest start time of 8 am and the latest end time of 8 pm

Tiering

- Demand charge may change with increasing billing demand
  - For example, first 100 kW billed at one price, next 100 kW billed at a different price, and any demand greater than 200 kW billed at yet another price
- Tiering is not considered in current analysis

Table of contents

Methodology



Variables considered for generating load/PV profiles

Customer Characteristics	**15 Cities**	Albuquerque, NM; Atlanta, GA; Baltimore, MD; Boulder, CO; Duluth, MN; Helena, MT; Houston, TX; Las Vegas, NV; Los Angeles, CA; Miami, FL; Minneapolis, MN; Chicago, IL; Phoenix, AZ; San Francisco, CA; Seattle, WA
	15 Customer Types	Super Market, Quick Service Restaurant, Full Service Restaurant, Primary School, Secondary School, Strip Mall, Stand-alone Retail, Small Office, Medium Office, Large Office, Hospital, Midrise Apartment, Small Hotel, Large Hotel, Warehouse
PV System Attributes	**10 PV System Sizes**	Sized such that PV generates 10%-100% of annual customer load (in 10% increments)
	4 PV Orientations	South-facing, Southwest-facing, West-facing → all 20° tilt; flat

→ **9,000 combinations** simulated

Note: more details on the methodology are provided in Appendix

Simulated demand charge designs

Demand Charge Design	Description
Basic	Simplest demand charge design considered: billing demand is determined by the **customer's monthly peak**, regardless of timing. Customer load and PV generation uses a **30 minute averaging interval window.**
Seasonal	Similar to basic demand charge. Demand charges in **summer months** (June, July, August) are **3 times higher** than non-summer months.
Ratchet	Billing demand is set to at least **90% of maximum billing demand in previous 12 months**.
Averaging intervals	Averaging interval window is set to **30 minutes, 1 hour, 2 hours, or 4 hours**.
Peak period demand charge	Billing demand is defined as the maximum demand in the following time windows: Starting times: 8 AM – 6 PM Ending times: 10 AM – 8 PM 2 hour window minimum → 66 peak window definitions *E.g. 12-4 pm peak demand charge, billing demand is set as monthly maximum demand during those hours*

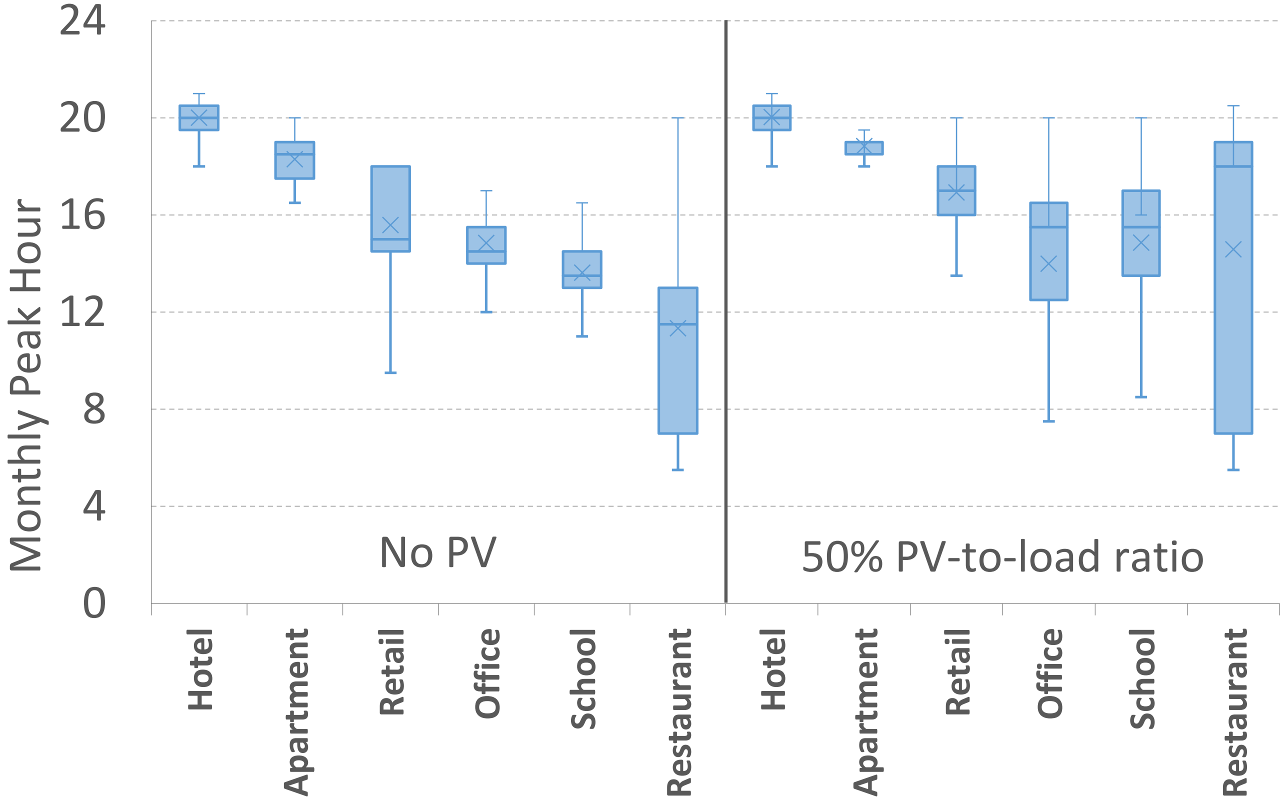
Analysis boundaries and limitations

- The load profiles and PV generation profiles used in this analysis are simulated and reflect actual weather-related variations, but they do not reflect <u>all</u> sources of customer load variability
  - This does not necessarily indicate a systematic under- or over-estimation of average demand charge savings, though the estimated *variability* in demand charge savings is likely underestimated
- The smallest demand charge averaging interval considered in our analysis is 30 minutes, whereas some demand charges use 15-minute averaging intervals
  - Our results indicate that demand charge savings increase with the length of the averaging interval, hence 15-minute average intervals would likely yield lower demand charge savings than the estimates presented here
- The analysis considers percentage reduction in demand charges but abstracts from demand charge savings (in $). Hence, comparing percentage demand charge reductions from various demand charge designs does not allow for a direct comparison of the level of demand charge savings
- This analysis doesn’t consider storage or demand management, which would impact the ability for PV to reduce demand charges, though later analysis will include storage
- This analysis models only a limited number of demand charge designs; certainly other designs and combinations of features are possible (e.g., tiered demand charges)
- Although we consider PV-to-load ratios up to 100% for each building type, available roof-space for many commercial building types will tend to limit PV system size to much smaller sizes

Table of contents

Commercial building load profiles vary considerably across building types

Distribution of monthly peak hours for a selection of commercial customer types



*'x' = mean; shaded box = 25th-75th percentile range; middle line = median; whiskers exclude outliers (quartile ± 1.5*IQR); IQR = inter-quartile range. Range within each building type is mostly due to variability of monthly load shapes and location.*

- Demand charges can only be reduced if PV generation can reduce monthly peak demand
  - This depends in part on the hour of the day in which the monthly peak occurs
- Monthly peak hour fluctuates widely depending on building type
- With PV, peaks can be pushed to later in the day (e.g. apartment, retail) but can also be pushed to earlier in the day (e.g. office, school)
- Load factors and daily variability in load also differ greatly across building types

PV sizing is expressed as **PV-to-load ratio**, the proportion of annual load generated by the PV system

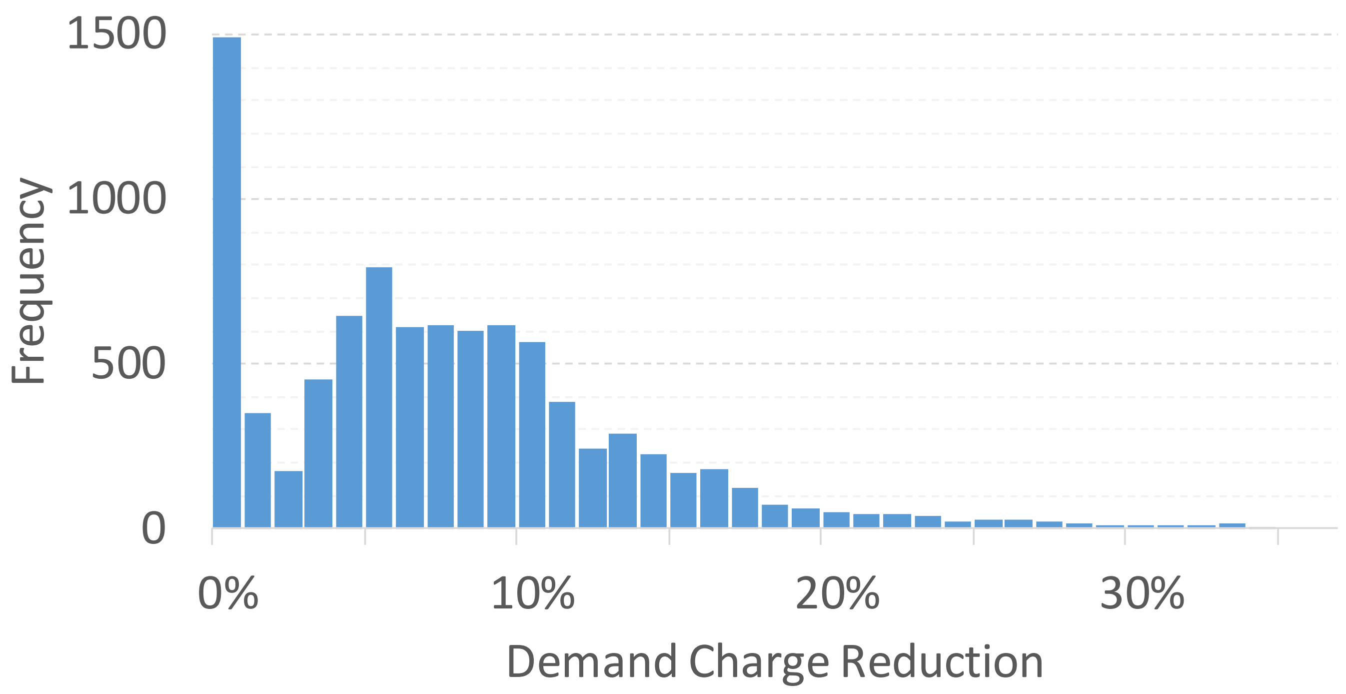
Demand charge savings metric

$$\textbf{Reduction in Billing Demand} = \frac{\text{Billing Demand Reduction (kW)}}{\text{Billing Demand without PV (kW)}}$$

- Provides a point of comparison to bill savings that can be achieved through volumetric rates
- Simple to translate into actual bill savings, but abstracts from demand charge level
  - Results not in $ terms as demand charge level varies widely from one utility to the next
- Does not provide a point of comparison to bulk power capacity credit (capacity that can be avoided per kW of PV)
  - Separate metric used for this (demand charge capacity credit) is presented in appendix

Under the basic demand charge design, PV does not reduce demand charges significantly for most customers

Distribution of percentage billing demand reduction: *Basic demand charge design*

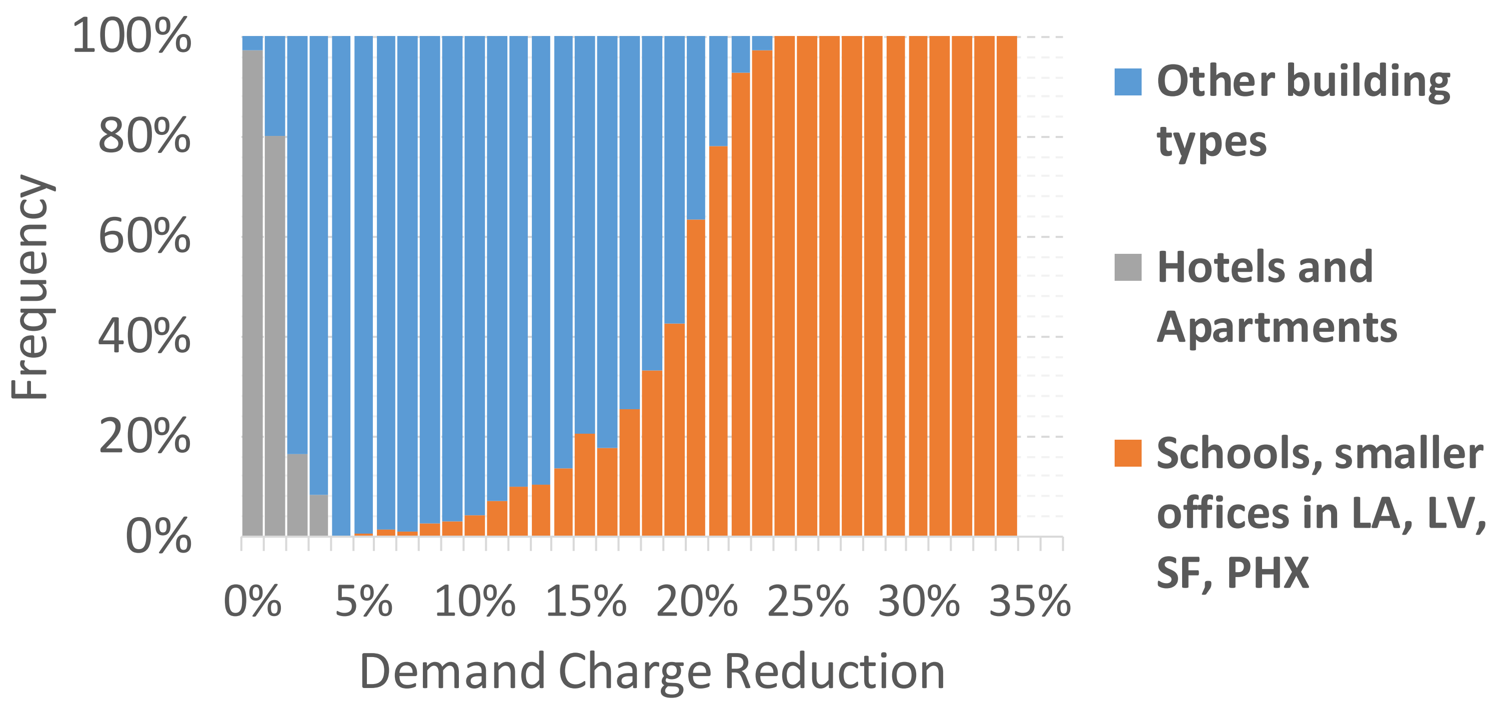


The figure shows the distribution in billing demand reduction across all 9,000 combinations of simulated load and PV generation profiles. Each data point is the average percentage reduction, for a single load/PV combination, across all months of the 17-year historical weather period. PV system sizes range from generating 10%-100% of annual customer load.

- 7% DC reduction in the median case
- Uneven distribution:
  - ~20% of customers simulated have DC reduction < 2%
  - ~10% have DC reduction >15%
- DC reduction is relatively small – but nonetheless nonzero – for most simulations regardless of PV system size
  - Load profiles tend to peak at hours that do not align with PV production peak

Highest/lowest non-coincident demand charge reductions are dominated by select building types and locations

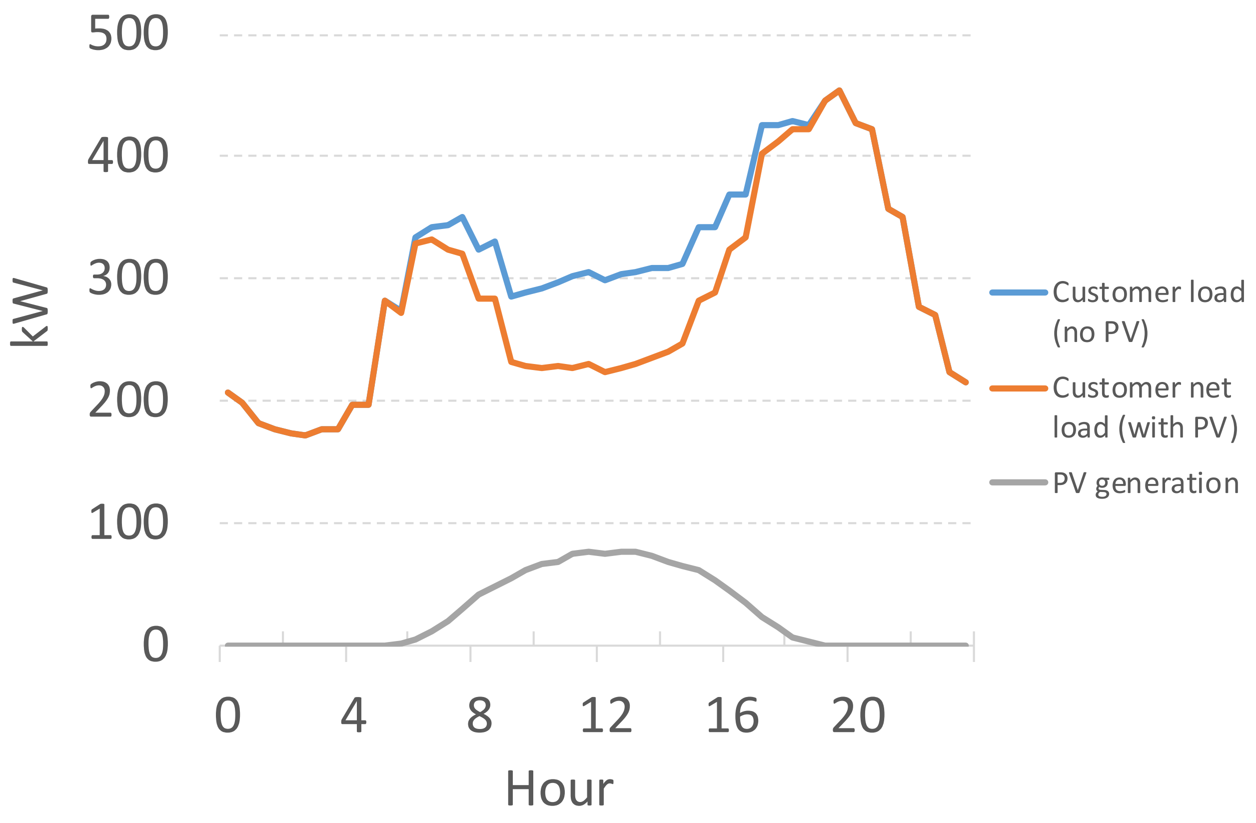
Distribution of simulations in each non-coincident demand charge reduction bin



- The tail ends of the distributions are dominated by 25% of simulations
- Hotels and apartments, regardless of location, have lowest demand charge reduction
  - Median demand charge reduction for hotels and apartments is zero
- Schools and small/medium offices in Los Angeles, Las Vegas, San Francisco, and Phoenix have highest demand charge reductions
  - Median demand charge reduction for these buildings is 18%

When customer load peaks in evening hours, solar does not reduce non-coincident demand charge

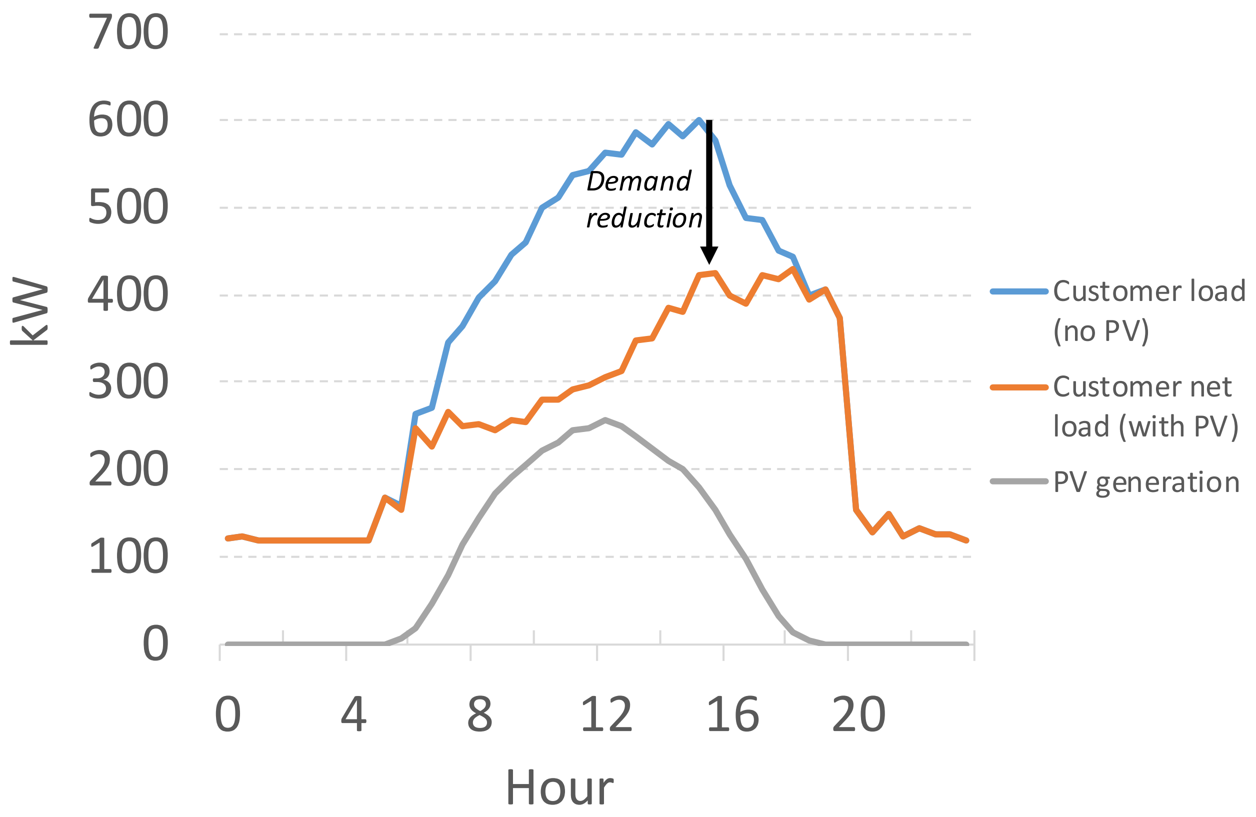
Example customer load and PV generation profile for a hotel in Phoenix



- Hotels and apartment buildings have lowest demand charge reduction as loads often peak in evening times
  - When solar generation does not impact the net demand peak, the demand charge reduction is zero
- Demand charge can only be reduced if billing demand is defined over predetermined set of daytime hours
  - Different definitions of demand charge designs explored later in presentation

Solar can reduce demand charges effectively when customer load profile aligns with PV generation profile

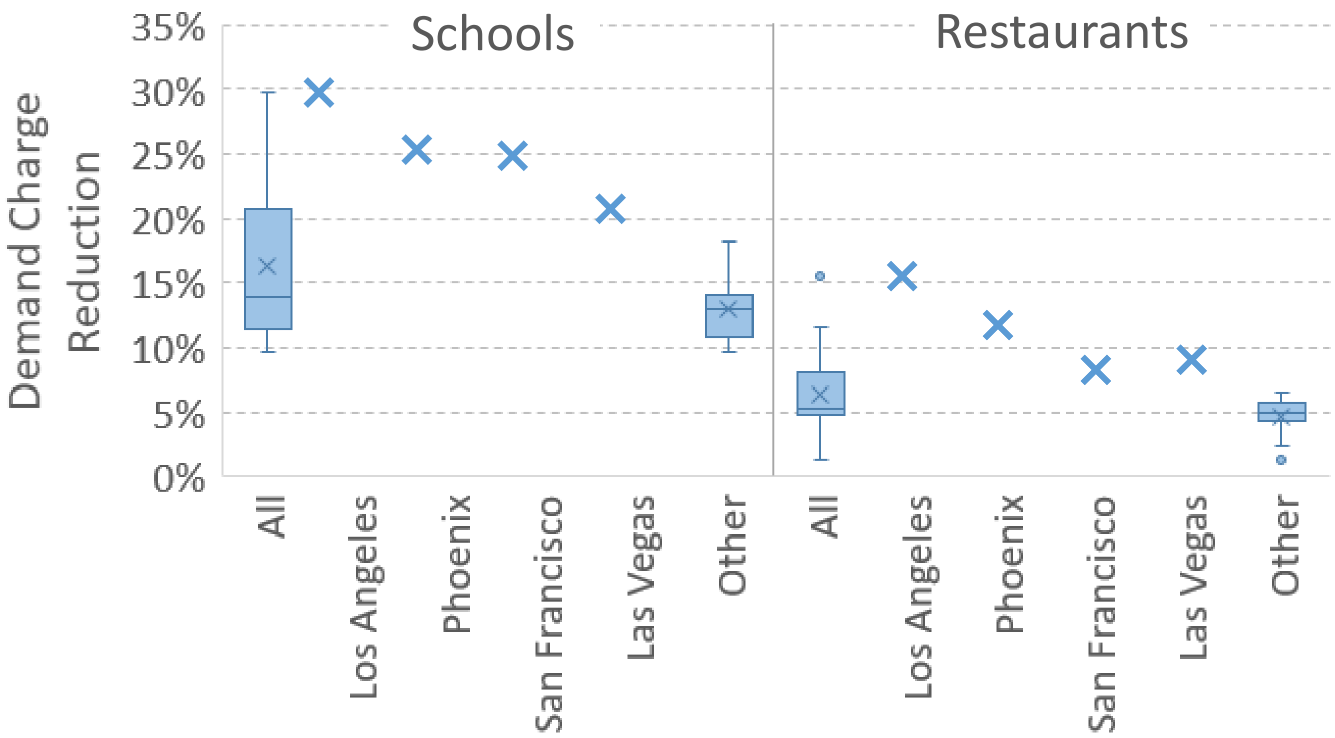
Example customer load and PV generation profile for a school in Phoenix



- When customer load coincides well with PV generation profile, demand reduction is highest
  - When customer's daily peak load does not vary significantly within the month, demand reduction is limited by cloudiest day
- Demand reduction for schools and offices is highest in sunny regions
  - Schools and offices in regions with intermittent or continuous cloudy days have lower demand charge reduction

Much of the variation in non-coincident demand charge reduction for a given building type is driven by location

Percentage non-coincident demand charge reduction for schools (left) and restaurants (right) in various locations

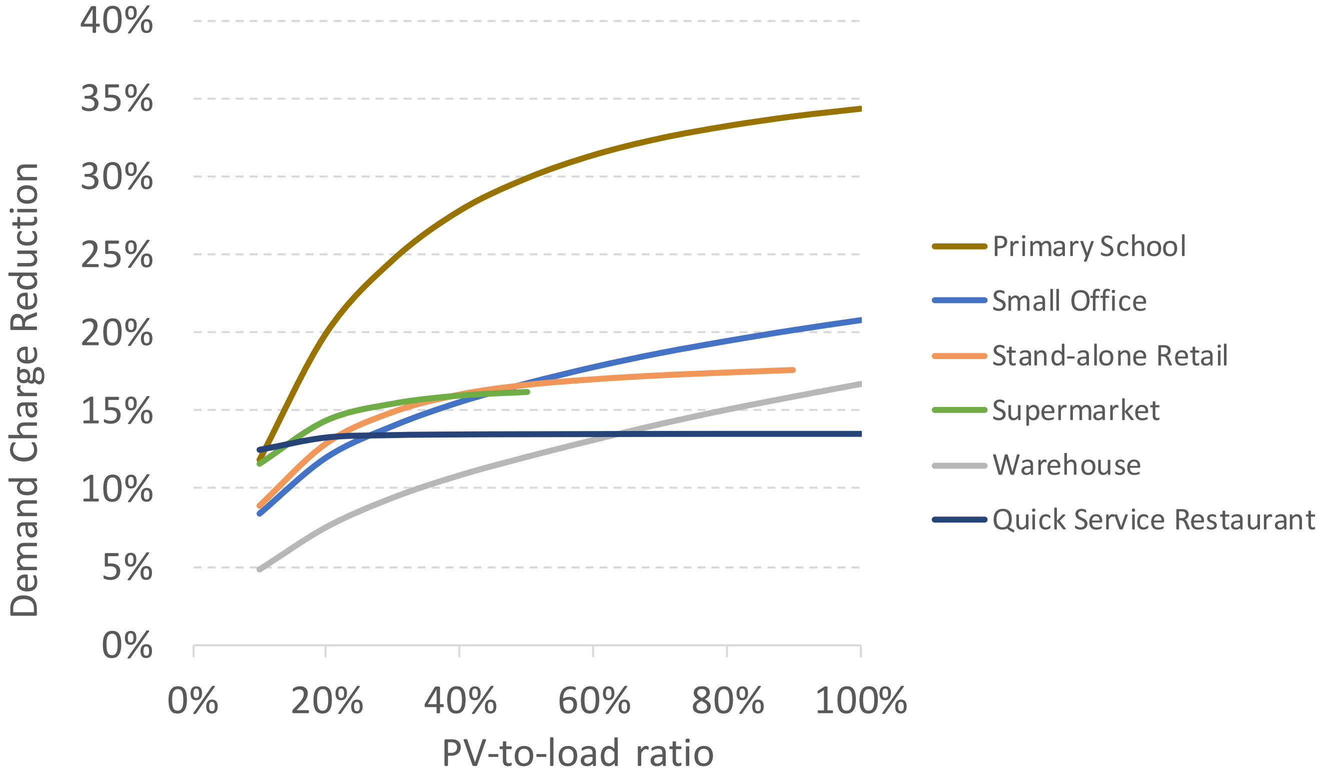


Values are average demand charge reduction for PV-to-load ratios of 50% across all orientations. Range within each bar due to location only.

- Locations in California and the Southwest have highest demand charge reductions
  - These are all relatively sunny locations and hence solar generation is more likely to reduce peak demand
- Locational differences largely hold across PV system sizes and building types

PV system size drives non-coincident demand charge reduction but with diminishing returns

Figure shows how PV system size impacts median percentage demand charge reduction for various building types in Los Angeles

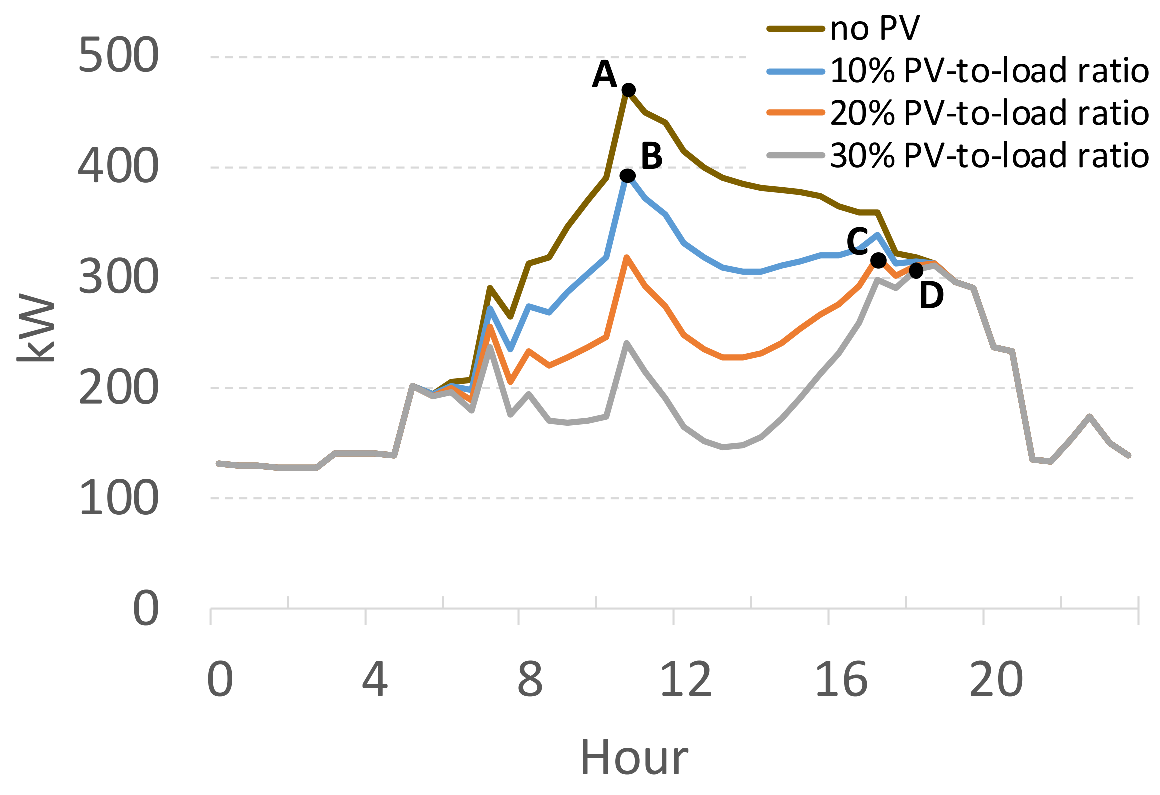


The lines in the chart end at a PV system size that corresponds to twice the maximum available roof space for each building type, as modeled, to account for differing building configurations and availability of non-roof space (e.g. parking structures). Points represent median value across orientations.

- Demand charge reductions increase non-linearly with increasing PV system size
  - Indicates a limit on demand charge reduction regardless of PV system size
  - As net load peak shifts to non-daytime hours, additional PV is not able to further reduce billing demand
- The shape and slope of the demand charge reduction curves with increasing PV size vary for different building types
  - Demand charge reductions for supermarkets, retail shops, and restaurants taper off relatively quickly
  - PV in schools, offices, and warehouses continue to decrease the demand charge as PV system sizes increase
  - For example, a restaurant’s peak demand may shift to dinner time with a relatively small PV system whereas for warehouses, peak hours continue to be moderately aligned with PV generation as PV system sizes continue to increase
- Other locations considered have similar demand charge reduction curve shapes, though levels vary

Graphical example illustrating impact of PV system size on demand charge savings

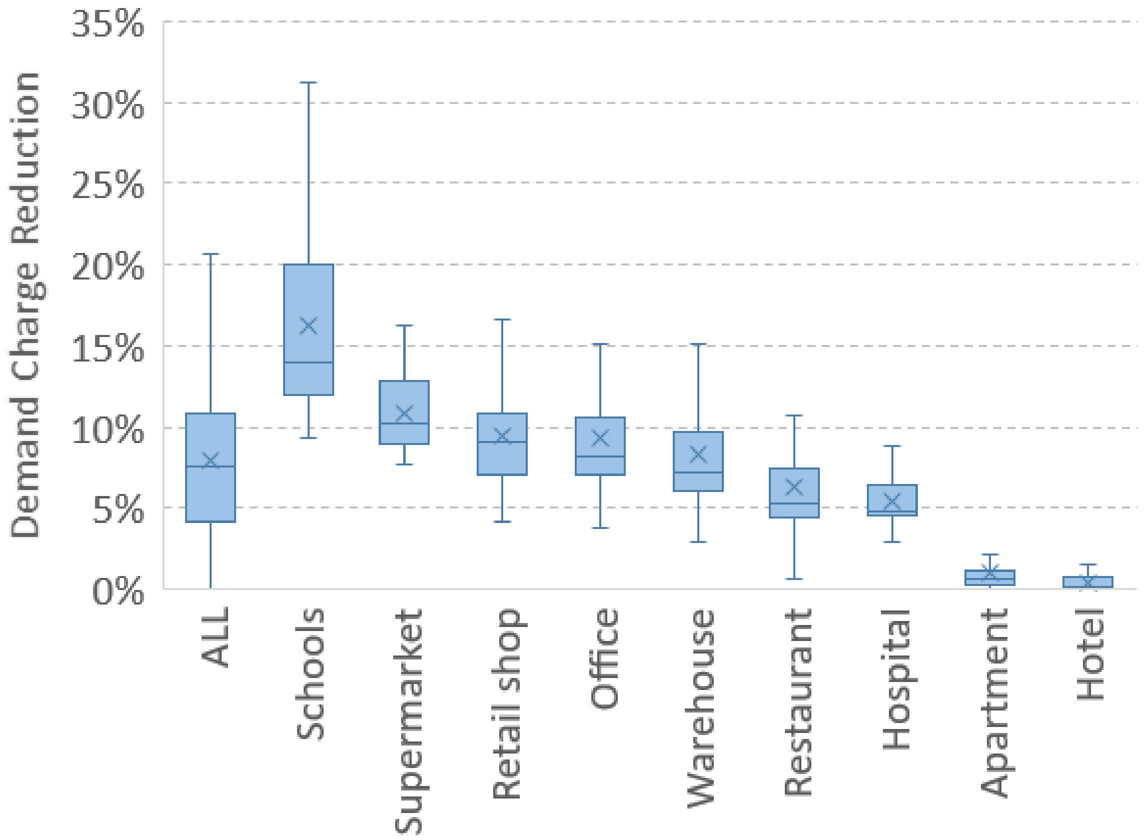
Example customer load and PV generation profile for a supermarket with increasing PV system size



- Small PV systems can be effective at reducing the peak demand (e.g. A→B)
  - When a PV system shifts the peak demand to late afternoon, any larger PV system will not be able to further reduce the demand level (e.g. C→D)

There is a large range in non-coincident demand charge reductions by building type

Distribution of demand charge reductions by building type for 50% PV-to-load ratio

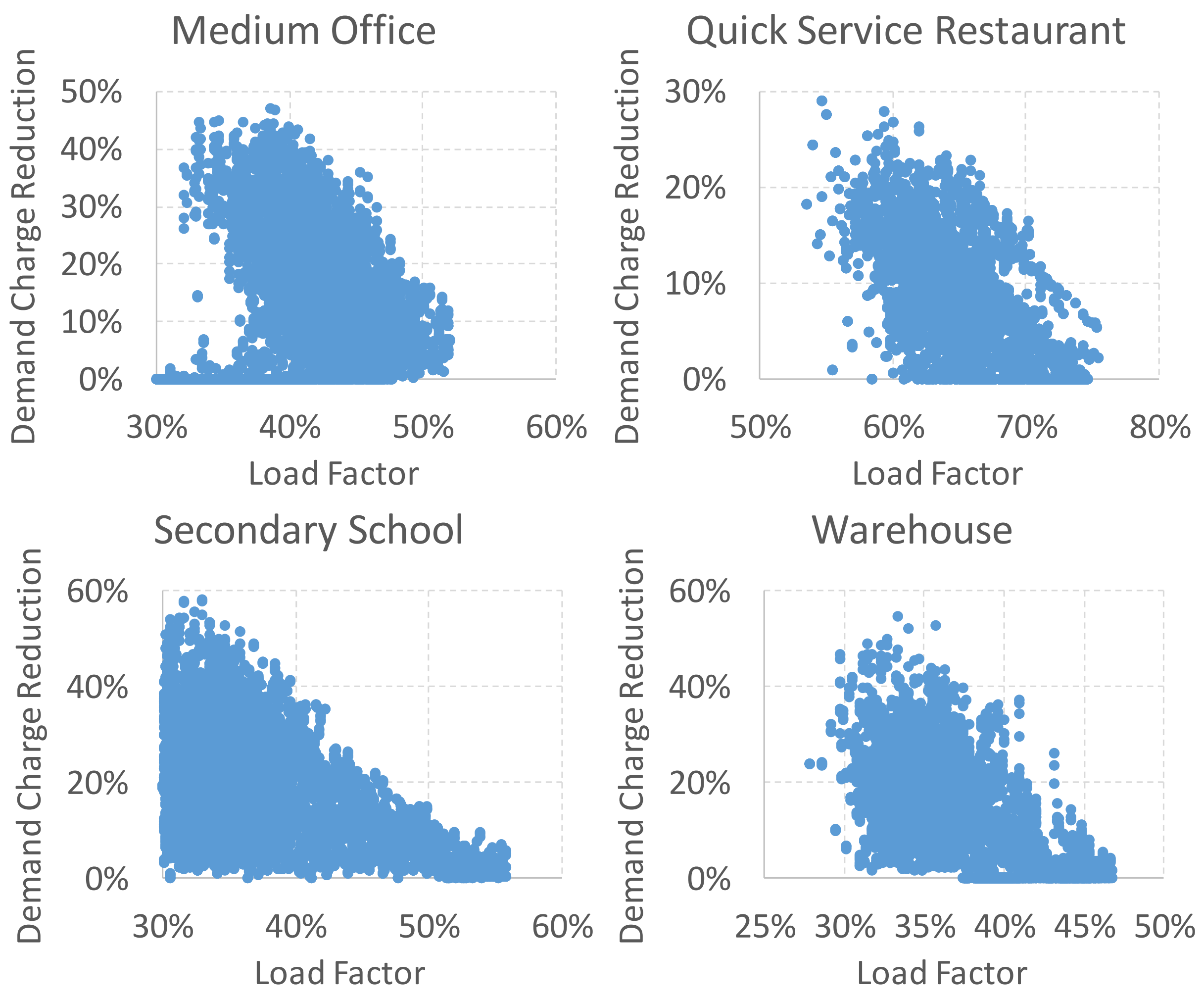


Range within each building type due to location and orientation.

- Even when peak load occurs in daytime, demand charge reductions stay low for most building types
  - For PV systems that generate half of annual load, demand charges are only reduced by 5-10% in most cases
- Demand charge reductions are limited by poor coincidence between load and PV generation profiles, as well as variable cloudiness
  - Both of these limit the ability for PV to reduce billing demand

Higher load factors limit the non-coincident demand charge savings

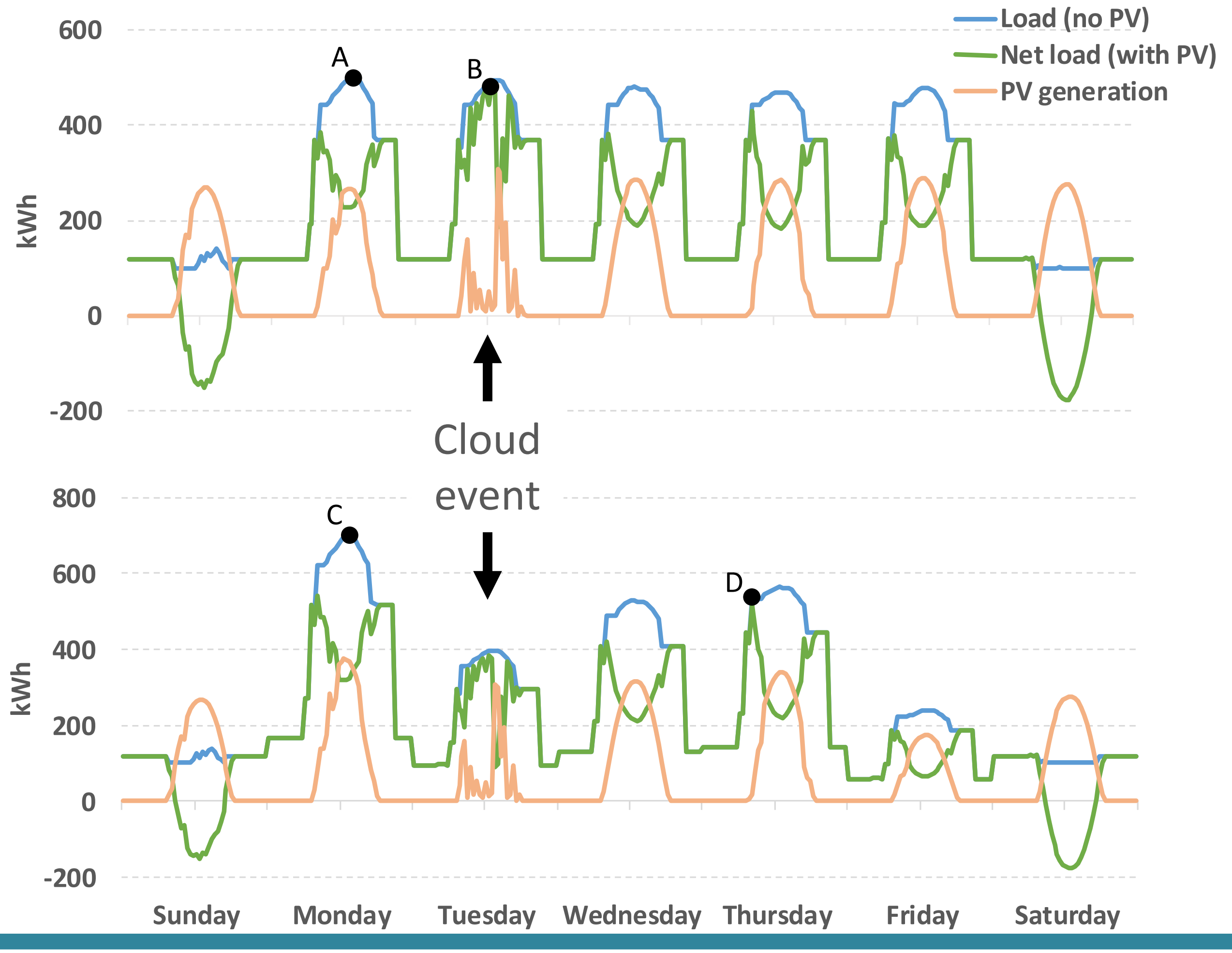
Monthly demand charge reduction vs. monthly load factor for a 50% PV-to-load ratio under a basic demand charge design



- Regardless of the building type, higher load factors lead to lower demand charge reductions
  - Load factors, however, are not good predictors of demand charge reductions as low load factors do not always lead to higher demand charge reductions
- Higher load factors imply "flatter" load profiles and hence PV generation can more readily shift peak demand to evening times

Cloudy days are more likely to impact demand charge reduction for loads with consistent daily peak levels

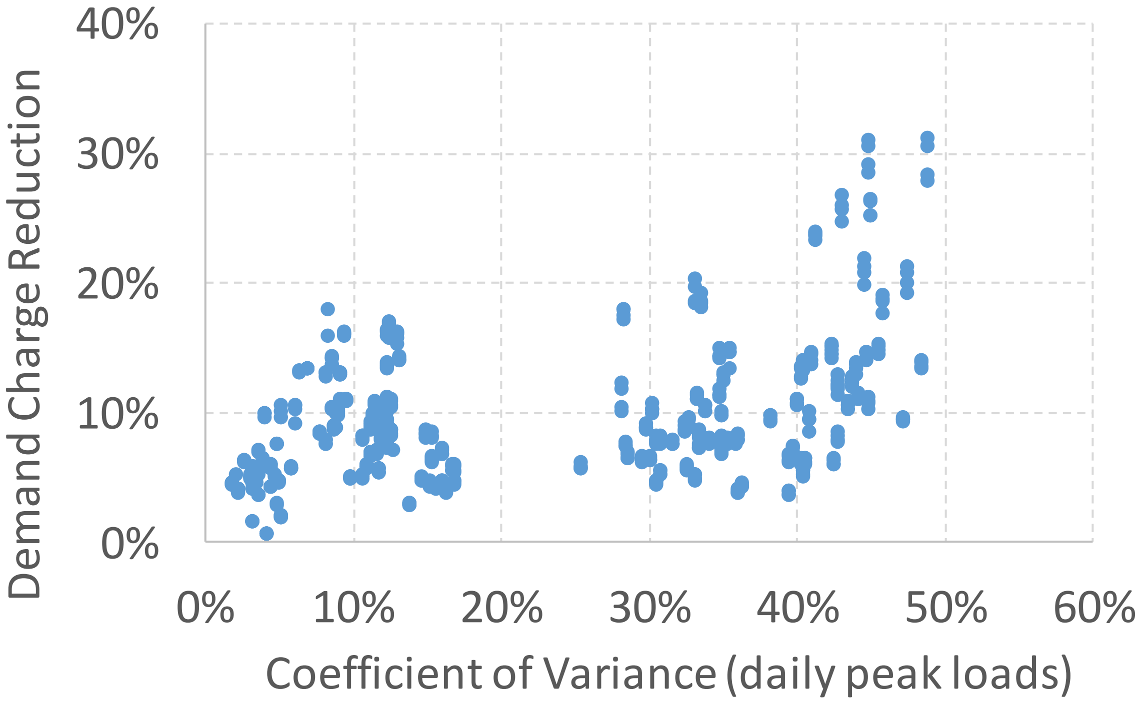
Example load and PV profiles: low variability (top) and high variability (bottom) in peak load levels



- The peak load with PV occurs during a cloudy day when the customer's daily load profile is very regular
  - In the top figure, PV does not impact peak load level (A→B) as net load peak occurs during cloudy day
- When the daily load profile is more variable throughout the billing period, a cloud event may not impact peak load with PV
  - In the bottom figure, peak demand with PV is set on a non-cloudy day and hence PV is more effective in reducing demand charges (C→D)
  - If loads driven by AC usage, loads are more likely to be lower on cloudy days

Less variable daily peak loads often lead to lower average non-coincident demand charge savings

Mean demand charge reduction under the basic demand charge design vs. mean coefficient of variance (CV) of daily peak load



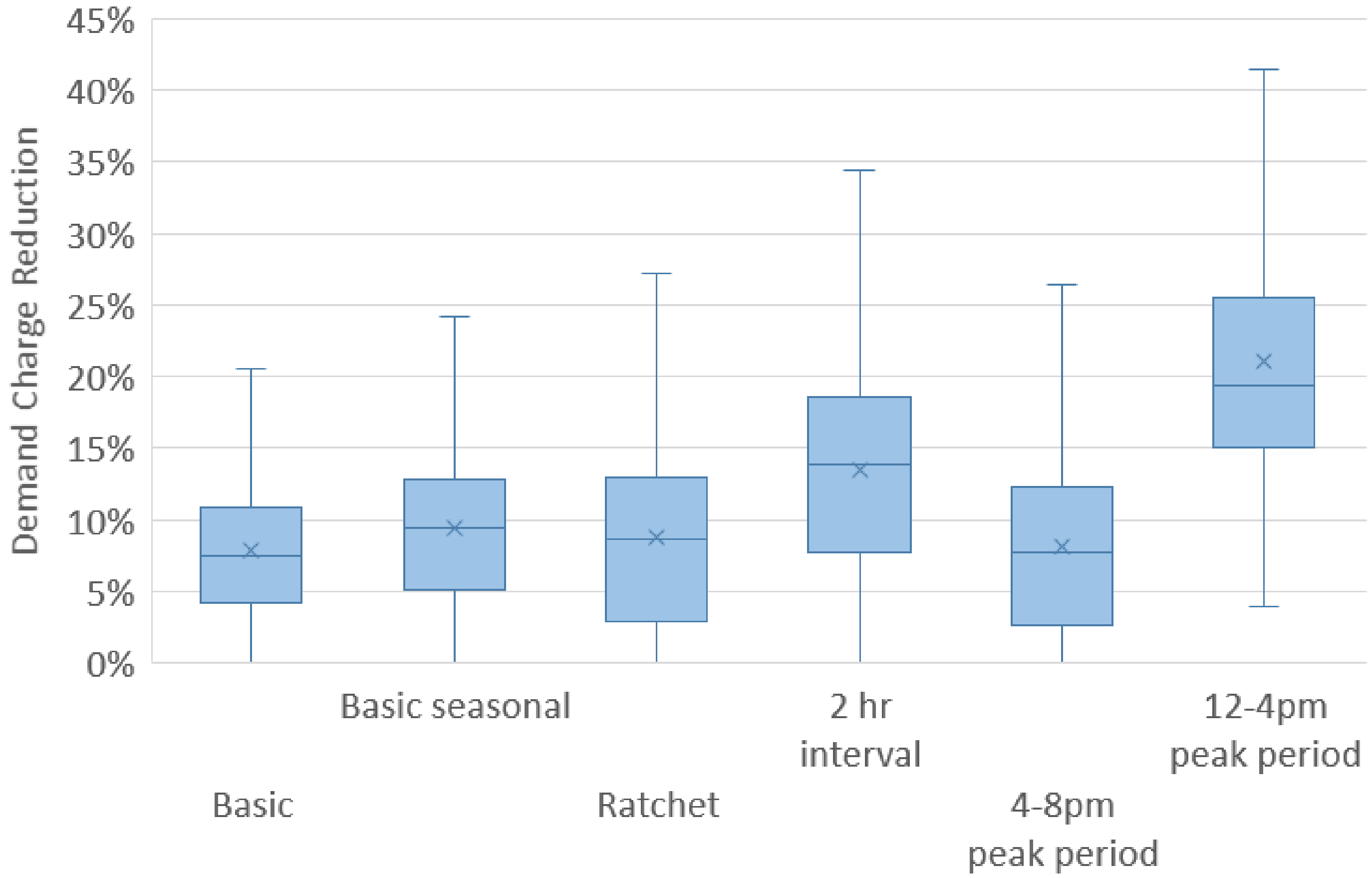
The figure shows results for all building types and locations for PV-to-load ratios of 50% excluding hotels and apartment buildings as these have late afternoon and evening peaks (900 combinations total). Each data point is the average percentage reduction and CV, for a single load/PV combination, across all months of the 17-year historical weather period.

$$CV_{month} = \frac{variance\ of\ daily\ peak\ load}{mean\ of\ daily\ peak\ load}$$

- Loads that are driven by weather tend to have higher CV_{month}
- Customers with lower CV_{month} tend to be more susceptible to demand reductions being set on cloudy days
  - A random cloud event will impact billing demand for customers whose daily peak loads are always the same, whereas there is a lower probability that it impacts billing demand for loads with varying daily peak loads (as shown in graphical example in previous slide)
- Higher CV_{month} alone does not imply high demand charge reductions, as it is one of many factors impacting billing demand

Demand charge design can greatly impact demand charge reductions

Distribution of demand charge reductions for various demand charge designs

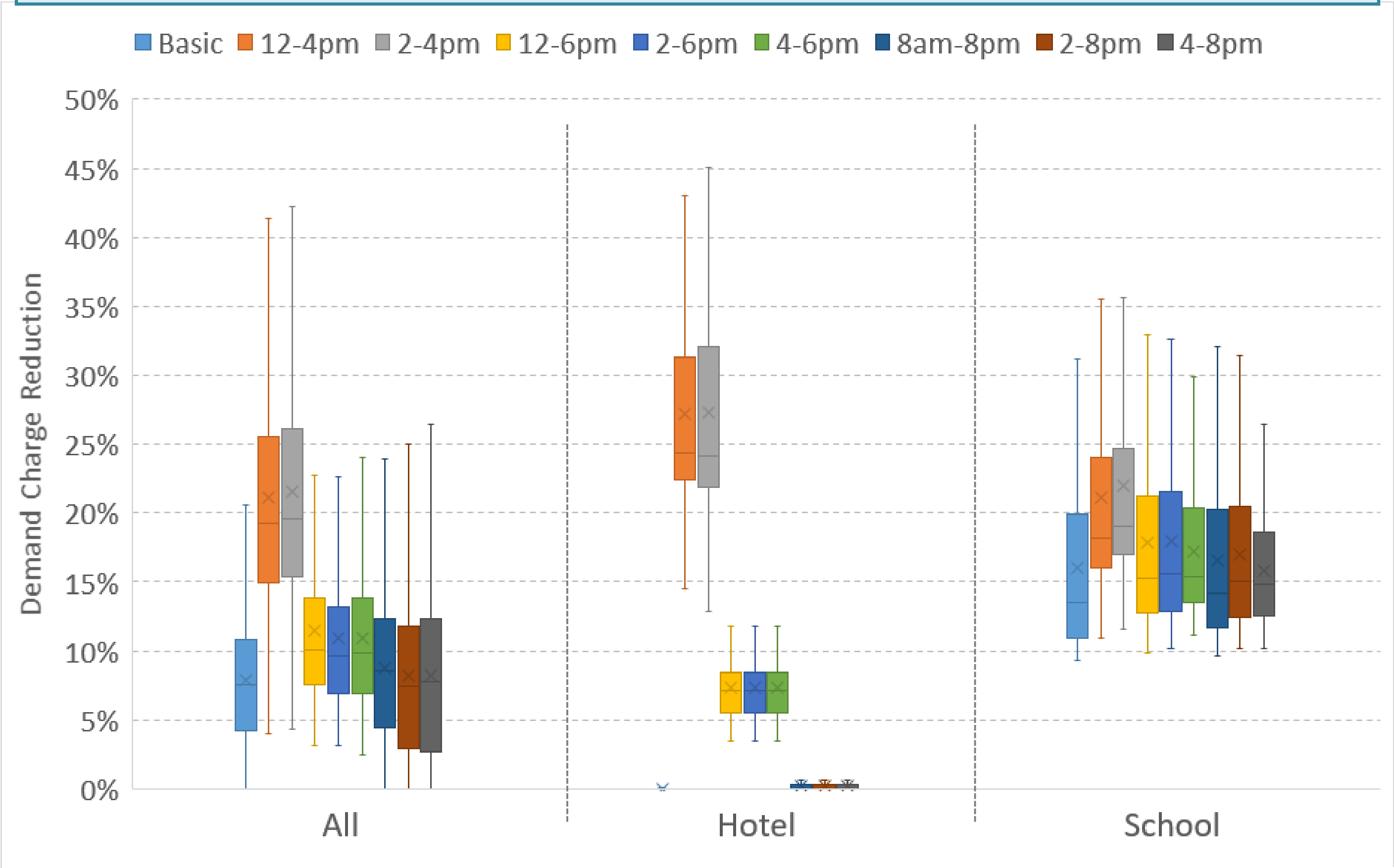


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each demand charge design is due to building type, location, and orientation.

- For demand charges based on a 12-4 pm peak period, the median reduction in billing demand is 19% (compared to 7% for basic demand charge design)
- Negligible differences in demand charge savings associated with seasonal demand charges or ratchets
- Averaging over longer time period provides higher demand charge reductions
- Demand charge reductions are larger if using "peak period" demand charges
  - Clear differences depending on how peak period is defined
- Figure is based on monthly average demand charge reductions over 17 year period for each customer
  - It does not include month-to-month variability in the demand charge reduction for each customer, though this is quantified in a later slide

Peak period definitions impact demand charge reductions to a varying degree, depending on building type

Distribution of demand charge reductions for designs with varying peak period definitions

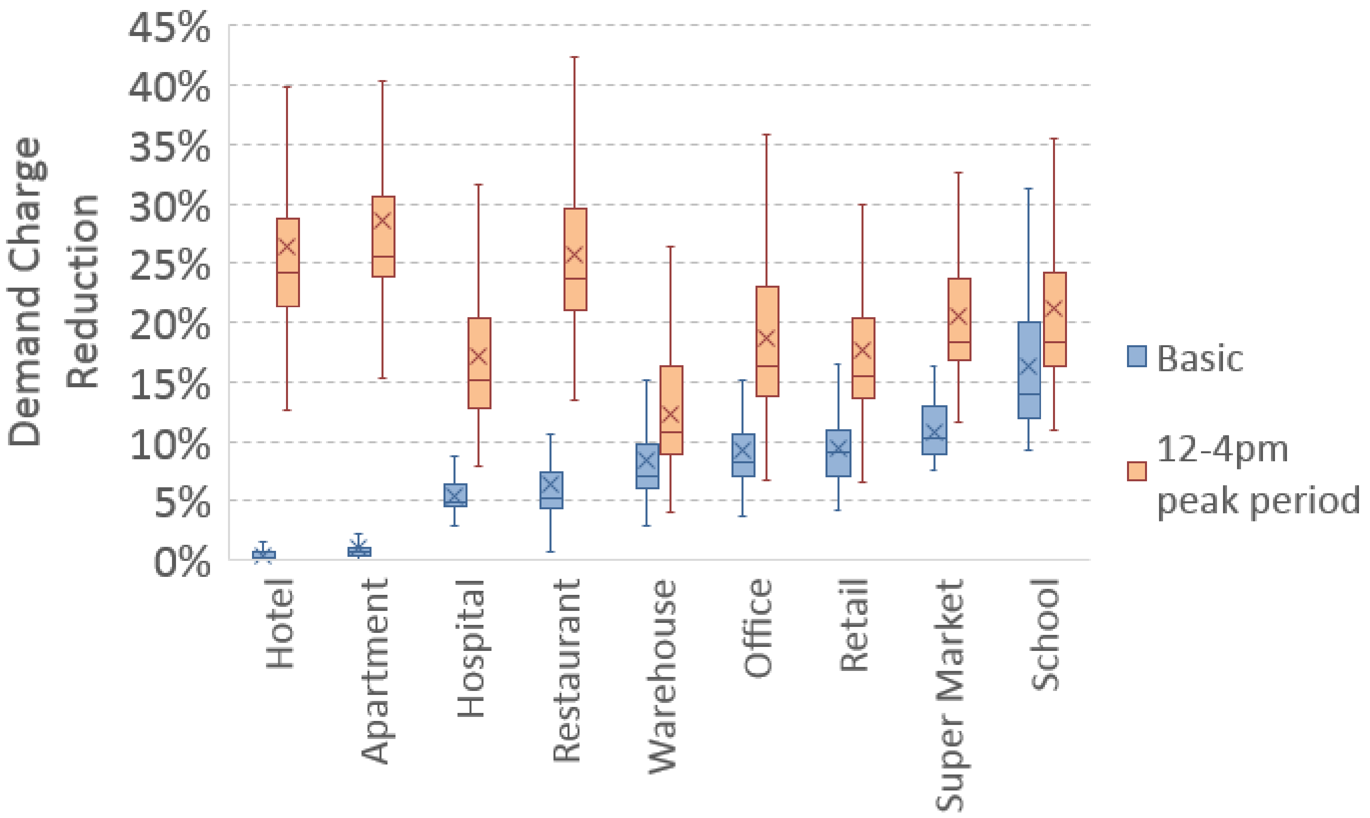


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each demand charge design is due to location and orientation.

- Peak period windows that end later tend to have lower demand charge reductions from PV
  - Start times also have impact on demand charge reductions, though to a lesser extent
- Building types with load profiles which coincide well with PV generation profiles are less impacted by peak period definition (e.g. schools)
  - Conversely, TOU definitions can greatly impact savings for evening-peaking loads (e.g. hotels)
- Upcoming slides exploring peak period demand charges focus on the 12-4 pm peak period
  - To provide a bookend of a peak period demand charge in terms of demand charge savings from solar

Shifting to peak period demand charge designs increases savings for all building types, but to different degrees

Distribution of demand charge reductions by building type for the basic and the 12-4 pm peak period demand charge

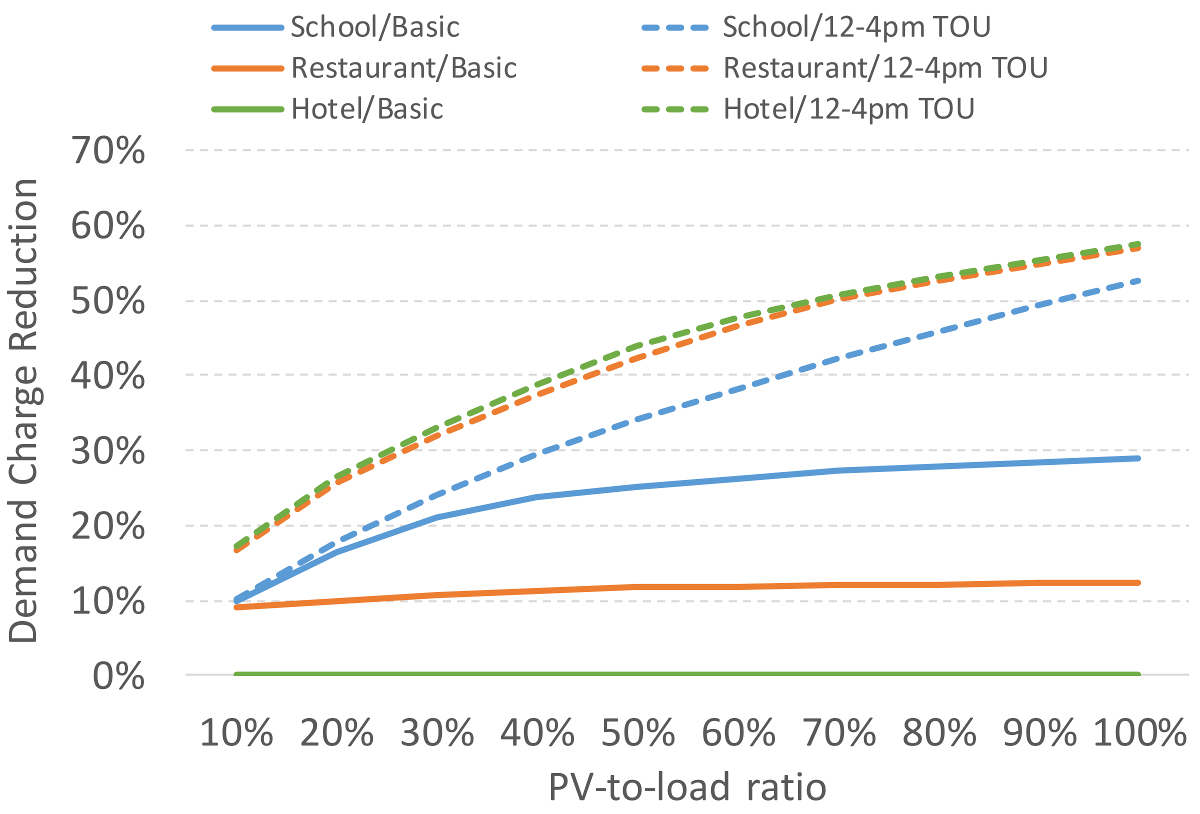


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each building type is due to location and orientation.

- Buildings whose loads coincide well with PV generation profiles (such as schools) don't benefit much from changing from the basic to the peak period demand charge
  - Evening peaking buildings (such as hotels and apartment buildings) gain most from peak period demand charges
- Buildings whose loads peak earlier in the demand window have greater savings from peak period demand charges
  - This leads to a better coincidence between load profiles and PV generation within the peak demand window, as is the case with restaurants and supermarkets which peak earlier in the 12-4 pm window

Peak demand charge designs have diminishing returns with increasing PV system size, but less than for basic design

Comparison of demand charge reductions with increasing PV system size for basic and 12-4 pm peak demand charge designs

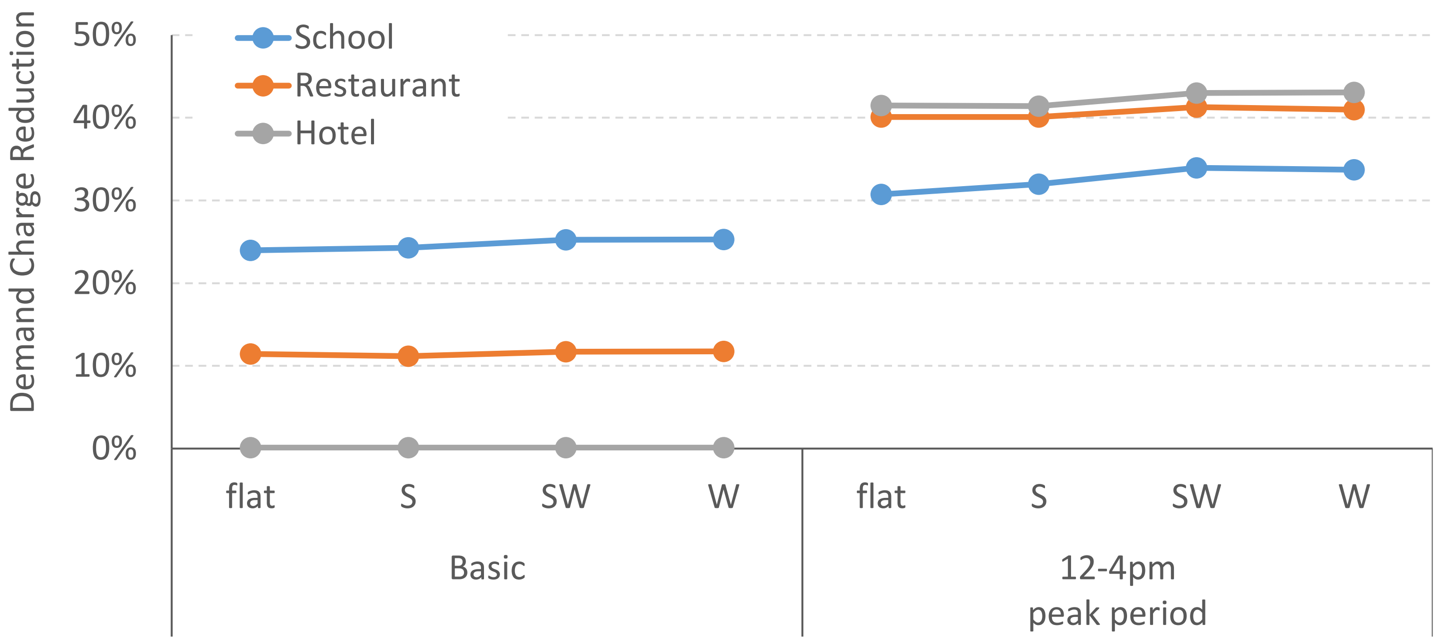


The figure shows the demand charge reductions for PV systems in Phoenix. Similar trends are observed for simulated load and PV generation profiles in other locations. Hotel, restaurant, and school were chosen as building types that span a wide range of load profiles and demand charge reduction levels.

- Degree to which there are diminishing returns varies by customer type
  - Restaurants reach their maximum demand charge reductions with smaller PV system sizes than schools, for example
- Demand charge reductions continuously increase with increasing PV system size for demand charges with peak period definitions
  - In contrast with the basic non-coincident demand charge, peak load cannot be driven into early morning or evening hours
  - However, there are still diminishing returns with increasing PV system size as peak demand can still be pushed to cloudy hours

West-facing panels lead to slightly greater demand charge savings for afternoon peak periods

Demand charge reductions across PV panel orientations: *System installed on select building types*

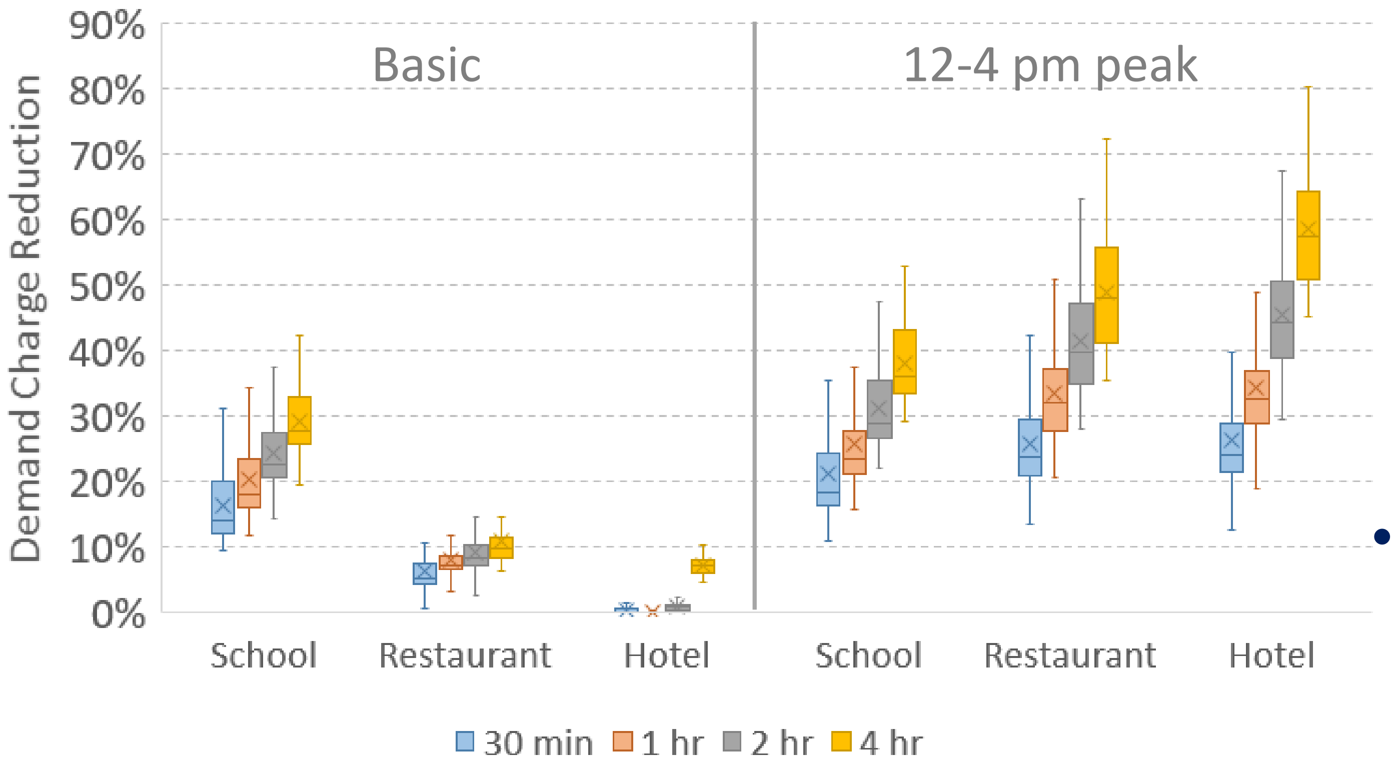


The figure shows the mean demand charge reductions for PV customers in Phoenix for a single PV system size kept constant for all orientations (50% PV-to-load ratio for a South facing system), to eliminate variability due to PV system size.

- Southwest- and West-facing panels peak later in day, coinciding better with load than do South-facing panels
  - Moving from South to West-facing panels increases the demand charge reduction by at most 3%
- Similar trends for all building types, locations, and PV system sizes considered
  - Not shown in this figure
- Orienting panels away from South also reduces total PV generation (kWh)
  - The increase in demand charge savings associated with Southwest- or West-facing panels is likely to be lower than the reduced bill savings from lower PV generation for most customers

Demand charge savings are greater with longer averaging intervals

Distribution of demand charge reduction across varying averaging intervals

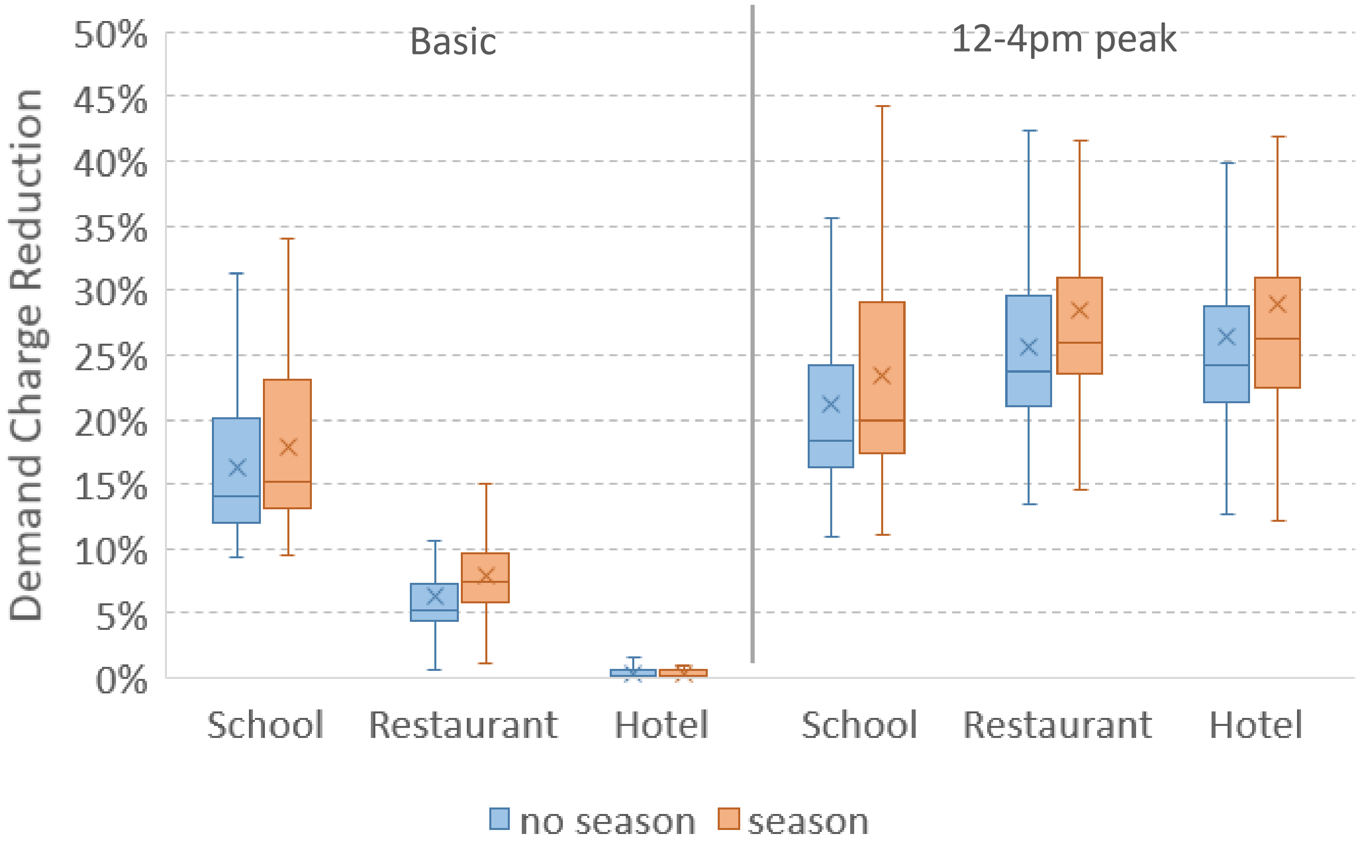


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each building type is due to location and orientation

- Longer averaging intervals dampen the effects of cloud events and tend to capture PV generation during earlier times of the day (when generation is higher)
  - For example, a 4-hour interval captures the impact of PV generation on average load over the entire 12-4 pm period (as opposed to just the last 30-minutes of that period)
  - Valid for load profiles from most building types
- Effect particularly salient for demand charge designs with afternoon peaks

Seasonal demand charges only provide a small boost to demand charge reduction levels

Distribution of demand charge reduction with and without seasonal differentiation

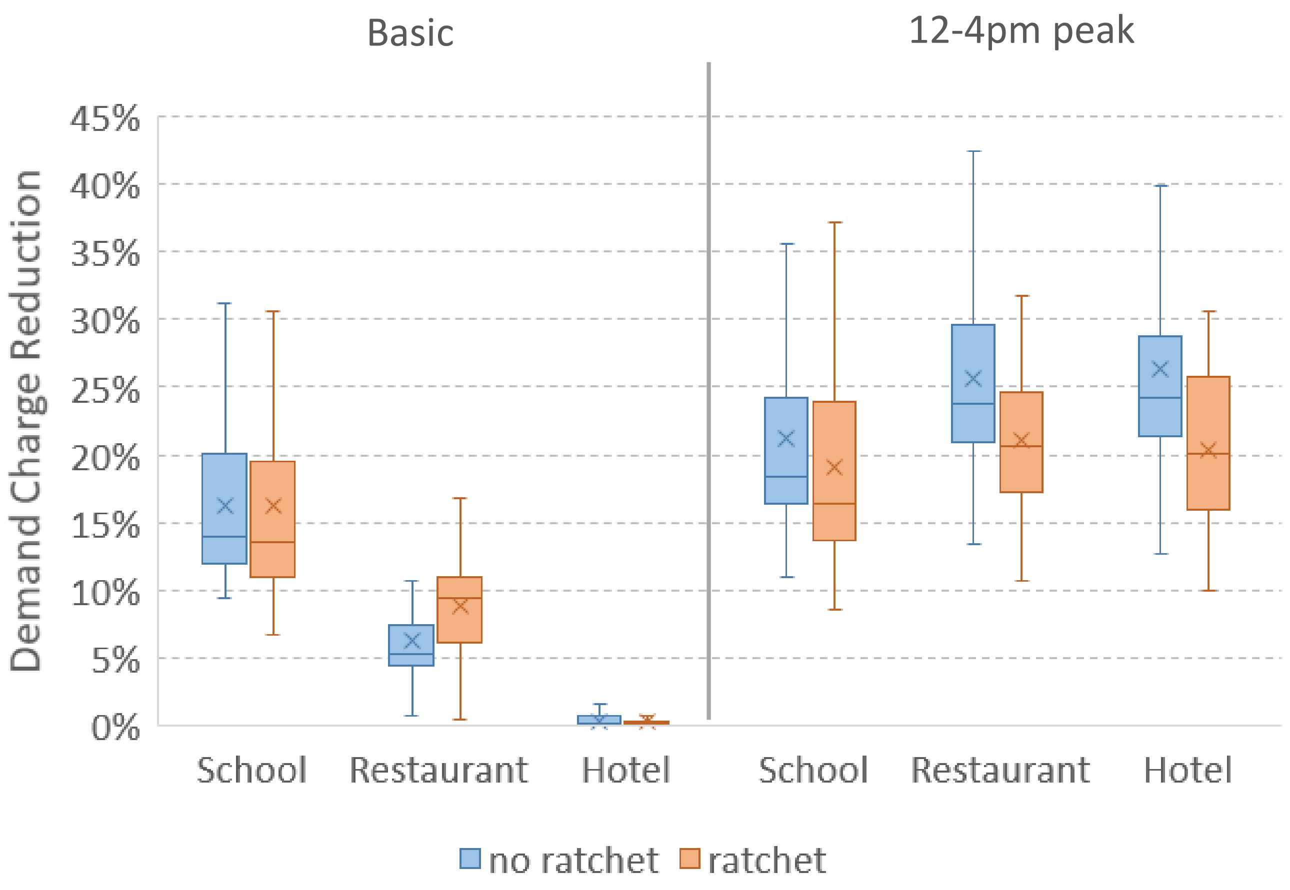


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each building type is due to location and orientation.

- With the simulated seasonal demand charge, the demand charge level is three times higher from June to August than for other months
- The impact of a seasonal demand charge on demand charge savings from solar is not significant for most customers, as their summer savings are not significantly higher than in winter months
  - Cloudy cities tend to have very little difference in the demand charge savings by month, resulting in negligible differences in savings with and without the seasonal element
- The relative effect of the seasonal element on the demand charge is similar for the basic demand charge design and that with a 12-4 pm peak

Ratchets have a small effect on demand charge reductions

Distribution of demand charge reduction for demand charges with and without a ratchet (set at 90% of rolling 12-month peak)

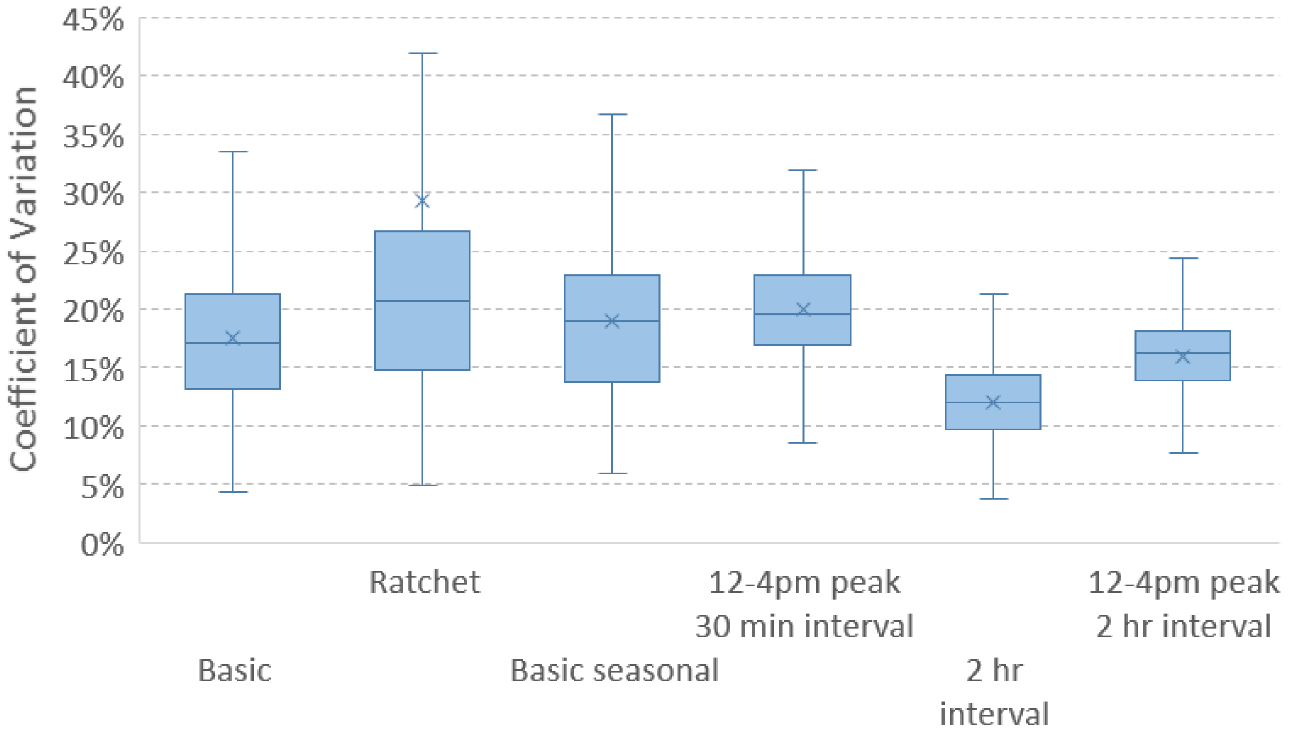


The figure shows the demand charge reductions for PV systems that generate half of the customer's annual load (i.e. 50% PV-to-load ratio), to eliminate variability due to PV system size. Range within each building type is due to location and orientation.

- Ratchets increase the demand charge reductions in the months with lower peak billing demand
  - The highest demand months, often during the summer, set the ratchet
  - As these are also the highest PV generation months, the ratchet extends summer demand charge reductions to months with lower peak demand
- Ratchets decrease the demand charge reductions in the months with highest peak billing demand
  - Previous months when PV does not reduce billing demand are likely to set the ratchet during these high peak demand months
- Further investigation of results show that the net effect often depends on location and variability in peak load

Variations in year-to-year demand charge reductions are similar for various demand charge designs

$$\text{Coefficient of Variation} = \frac{\text{Standard deviation in annual demand charge reduction}}{\text{Mean in annual demand charge reduction over 17 year analysis period}}$$



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 figure also excludes data from hotels and apartment buildings, as mean demand reduction values are very small, leading to disproportionately large coefficients of variation.

- Demand charge reductions do not vary significantly from year-to-year, as measured in terms of the coefficient of variation (CV)
  - Intra-year, monthly variations can be much larger
  - Not a large difference in range depending on demand charge design
- Variation shown here is based primarily on weather variability
  - Use of simulated loads likely understates actual month-to-month variability

Table of contents

Conclusions (1)

- Under a basic, non-coincident demand charge design, commercial customers generally achieve low reductions in demand charges from solar
  - Rooftop solar reduces demand charges by just 7% in the median case and by less than 15% in about 90% of all cases when based on a basic non-coincident demand charge, for customers with PV systems that generate 50% of their annual load
  - Demand charge reductions for most commercial customer types considered in this analysis are higher than for residential customers under the basic non-coincident demand charge
- Demand charge savings may be significantly greater when based on pre-defined peak periods and on longer time averaging intervals
  - If based on the customer’s maximum demand during a 12-4 pm peak period, commercial solar reduces demand charges by 19% in the median case, and by 40% or more in some cases
  - Averaging load over longer periods of time can smooth out variability in PV generation due to intermittent cloud cover, as well as better align load and PV generation when peak load occurs later in the daytime

Conclusions (2)

- Other demand charge design elements generally have less significance for bill savings from solar
  - Seasonally varying demand charges and ratchets do not significantly impact demand charge reductions from solar, when applied to a basic non-coincident peak demand charge
- Demand charge reductions from solar are heavily dependent on building type
  - Building types which have loads that better coincide with PV generation have higher demand reductions (e.g. 18% for 50% PV-to-load ratio for schools) and vice versa
  - For most building types, non-coincident demand reductions are low (5-10% for 50% PV-to-load ratio)
  - For the peak period demand charge designs, differences in demand charge reductions among commercial building types are less significant than for the non-coincident demand reductions, given the lower variability in load profiles during the peak window

Conclusions (3)

- Demand charge savings increase with PV system size, but with diminishing returns
  - Demand charge savings do not scale directly in proportion to PV system size
  - Main reasons: (a) larger systems push peak demand to later in the day; (b) larger systems push peak demand to cloudy days; (c) under peak period demand charge designs, demand charges in some months can be eliminated, in which case further increases in system size yield no additional savings
- Orienting PV panels westward yields, at most, only slight increases demand charge savings
  - The increase in the demand charge reduction moving from flat to southwest and west-facing PV panels is roughly similar across customer types and never more than 3%

Policy implications (1)

- The widespread use of demand charges for commercial customers may tend to direct solar deployment towards particular business types and likely constrains overall growth
  - Non-coincident demand charges could have a limiting effect on commercial deployment overall, given that most commercial customers can generally expect small demand charge reductions from PV systems
  - Differences in demand charge reductions by customer type may lead to uneven deployment patterns, directing commercial PV deployment to customers with highest demand savings (e.g. schools and supermarkets)
- Some demand charge designs are clearly better than others for solar customers
  - A few customer types can have higher demand charge savings from solar under the basic, non-coincident demand charge design, but *all* customers have higher demand charge savings from solar under other designs such as the 12-4 pm peak window demand charge design
  - Peak window demand charge designs make demand charge savings more predictable for potential commercial customers as savings are less variable across customer types
- Demand charges incentivize commercial customers to install smaller PV systems
  - This effect is starkest with the basic, non-coincident demand charge, but is also observed with peak window demand charge designs
  - This suggests that smaller PV systems are more effective at reducing demand charges in terms of bill savings per kW

Policy implications (2)

- Demand charges may not always align well with utility cost savings from solar
  - Given that the system-wide value of a PV system is largely constant regardless of its host building, the wide variation in demand charge reductions from solar suggests that demand charges are not effective at communicating the capacity-value of PV to commercial customers
  - There may be a mismatch in the demand charge savings for customers (less than 10% for most commercial customers) and the capacity value of solar to the utility (can be 30-70% for electric systems with low PV penetrations)
  - There is a diminishing return to scale for the customer whereas the capacity value of PV to the utility is the same regardless of an individual customer's PV system size
- In other scenarios, demand charges align better with utility savings from solar
  - Alignment may be good for a subset of customers with peak loads that match the timing of bulk power system or distribution system peaks, under a basic, non-coincident demand charge design
  - Alternatively, there would be proper alignment for demand charges defined with a peak period that mirrors that of the bulk power system or the distribution system peak

Table of contents

Methodology – Further details

Solar insolation and weather data
- Solar insolation data and other weather data were downloaded from the National Solar Research Database, managed by the National Renewable Energy Lab (https://maps.nrel.gov/nsrdb-viewer/) for each location on a one half hour timescale for years 1998 through 2014

Energy Plus building load simulations
- Commercial Reference Building Models (https://energy.gov/eere/buildings/commercial-reference-buildings), developed by the National Renewable Energy Laboratory for the US Department of Energy, were selected for the 15 cities considered in the analysis.
- Only new construction category models were used
- The weather data files from the NSRDB were converted to Energy Plus weather files and used as an input into the Energy Plus simulation platform, developed by Lawrence Berkeley National Laboratory and managed by the National Renewable Energy Laboratory
- The outputted files were annual load profiles for each customer type and location by 30 minute increments

PV generation profiles
- The same weather data files were converted into a file format to be read by the System Advisor Model, developed by the National Renewable Energy Laboratory
- PV generation profiles were generated for each location for the four orientations considered in this analysis

Demand charge savings calculations
- Billing demand was calculated for each customer type and location for each month in the 17 years of cotemporaneous simulated load without PV and with PV for various PV system sizes that generate specified percentages of the customer’s final year of load for all demand charge designs considered in the analysis
- Calculations were performed using the Python programming language

Impacts of timing of demand charge peak window on demand charge reduction

- Demand charge reductions are relatively high over a large range of TOU definitions
- Though the demand charge reduction levels can vary significantly by building type and location, the peak definitions that lead to highest reductions are similar
- For customer load profiles which peak during daytime, TOU definition has less impact on demand charge savings (e.g. schools), whereas TOU definitions can greatly impact savings for evening-peaking loads (e.g. hotels)

Heat maps show mean demand charge reductions for various peak demand charge definitions with a 30 minute averaging interval window and PV systems sized to generate half their annual load

Schools Seattle

beginning Hour \ ending hour	10	12	14	16	18	20
8	14%	20%	21%	20%	19%	18%
10	-	23%	23%	21%	20%	19%
12	-	-	26%	22%	20%	19%
14	-	-	-	22%	20%	19%
16	-	-	-	-	20%	18%
18	-	-	-	-	-	5%

Hotels Seattle

beginning Hour \ ending hour	10	12	14	16	18	20
8	11%	11%	11%	11%	8%	1%
10	-	28%	26%	22%	8%	1%
12	-	-	30%	22%	8%	1%
14	-	-	-	22%	8%	1%
16	-	-	-	-	8%	1%
18	-	-	-	-	-	1%

Schools Phoenix

beginning Hour \ ending hour	10	12	14	16	18	20
8	26%	36%	37%	32%	28%	27%
10	-	42%	40%	33%	28%	27%
12	-	-	44%	34%	29%	27%
14	-	-	-	36%	29%	27%
16	-	-	-	-	28%	26%
18	-	-	-	-	-	6%

Hotels Phoenix

beginning Hour \ ending hour	10	12	14	16	18	20
8	18%	18%	17%	17%	13%	1%
10	-	52%	49%	42%	16%	0%
12	-	-	59%	44%	14%	0%
14	-	-	-	47%	14%	0%
16	-	-	-	-	14%	0%
18	-	-	-	-	-	0%

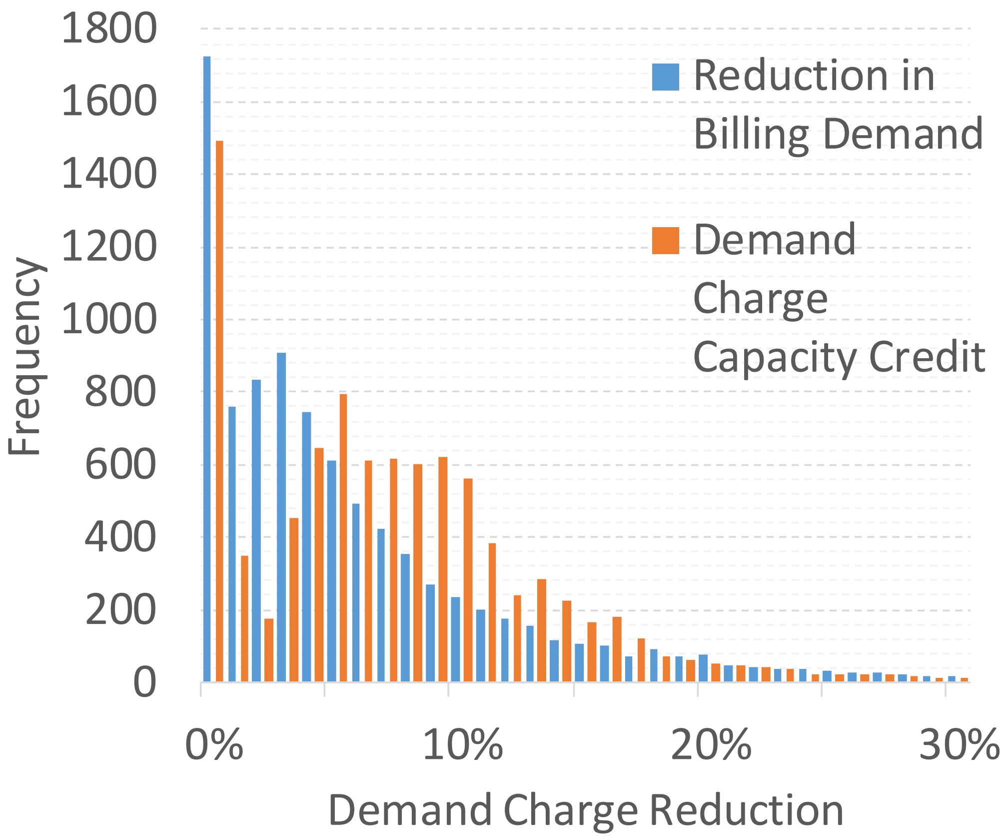
Alternative demand charge savings metric

$$\textbf{Demand Charge Capacity Credit (DCCC)} = \frac{\text{Billing Demand Reduction (kW)}}{\text{PV System Size (kW)}}$$

- For example: If a 100 kW system reduces billing demand by 40 kW, the demand charge capacity credit = 40%
- Measures efficacy of solar to reduce demand charge and allows direct comparison of PV systems of various sizes
- Provides a point of comparison to bulk power capacity credit (capacity that can be avoided per kW of PV)
  - Capacity credit is often used to describe the capacity value of intermittent resources to the electric system

Comparison of demand charge savings metrics

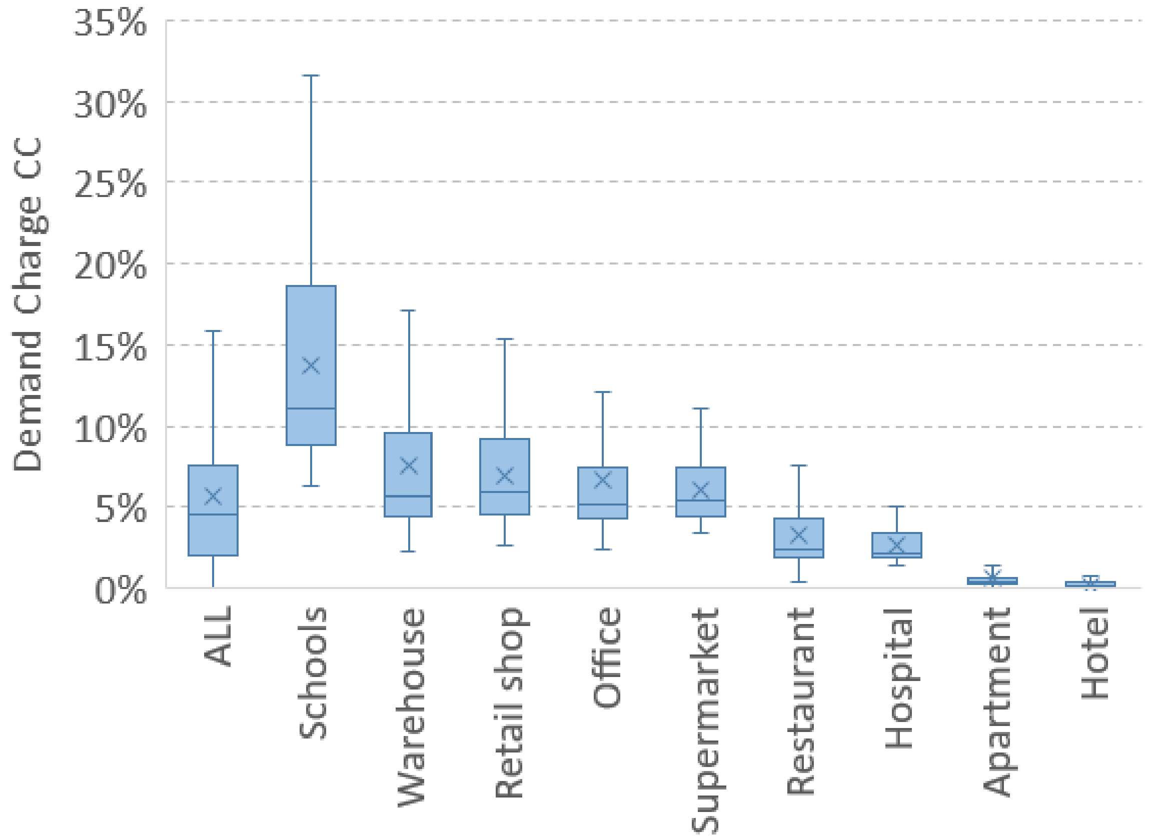
Distributions of demand charge savings metrics: *Basic demand charge design*



- DCCC is generally smaller in magnitude than percentage reductions in billing demand, but reveals similar trends
- Under the basic demand charge design:
  - 4% DCCC in the median case
  - 90% of simulations have a DCCC <90%

DCCC varies significantly by building type

Distribution of DCCC by building type for 50% PV-to-load ratio

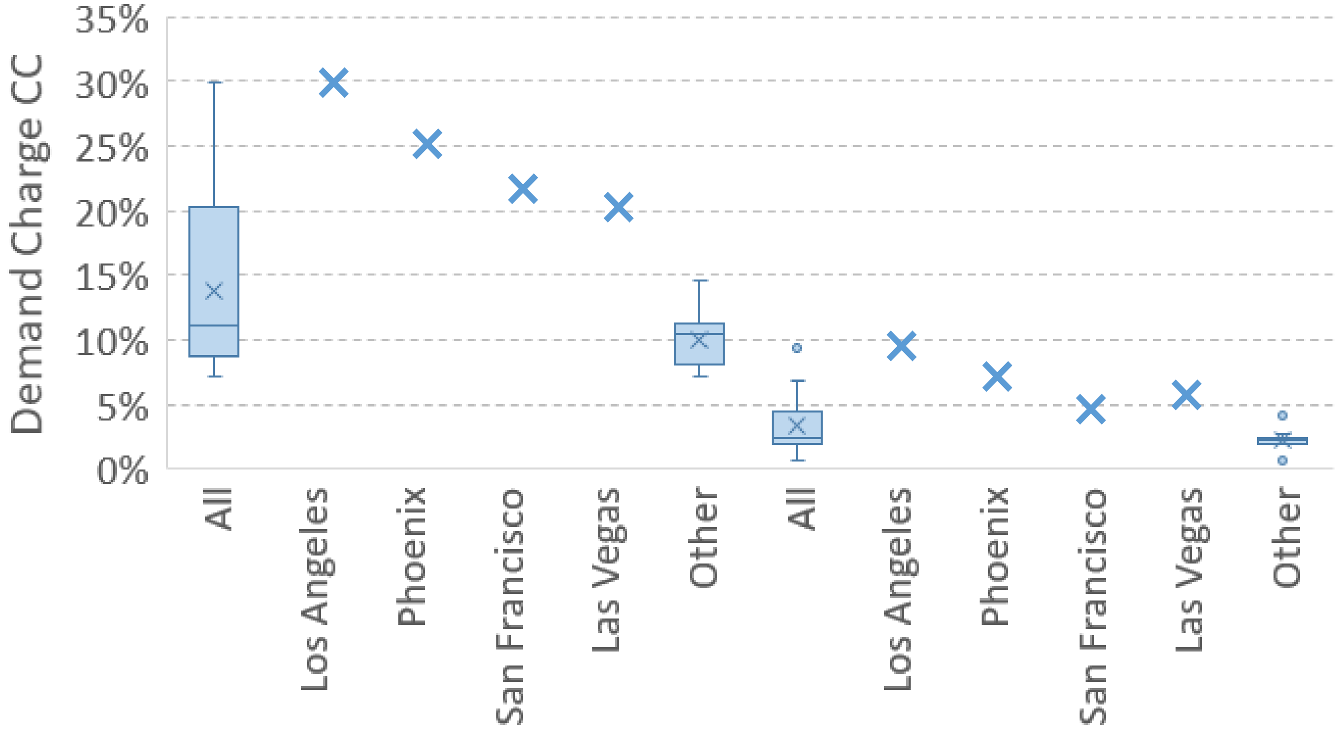


Range within each building type due to location and orientation.

- Similar trends than for demand charge reduction figure, presented earlier in this briefing
  - Schools, which have afternoon load peaks, have the highest demand charge capacity credits
  - Late afternoon and evening-peaking load profiles, as for apartment buildings and hotels, have lowest demand charge capacity credits

Much of the range in DCCC for a given building type is driven by location

Demand charge capacity credit for schools (left) and restaurants (right) in various locations

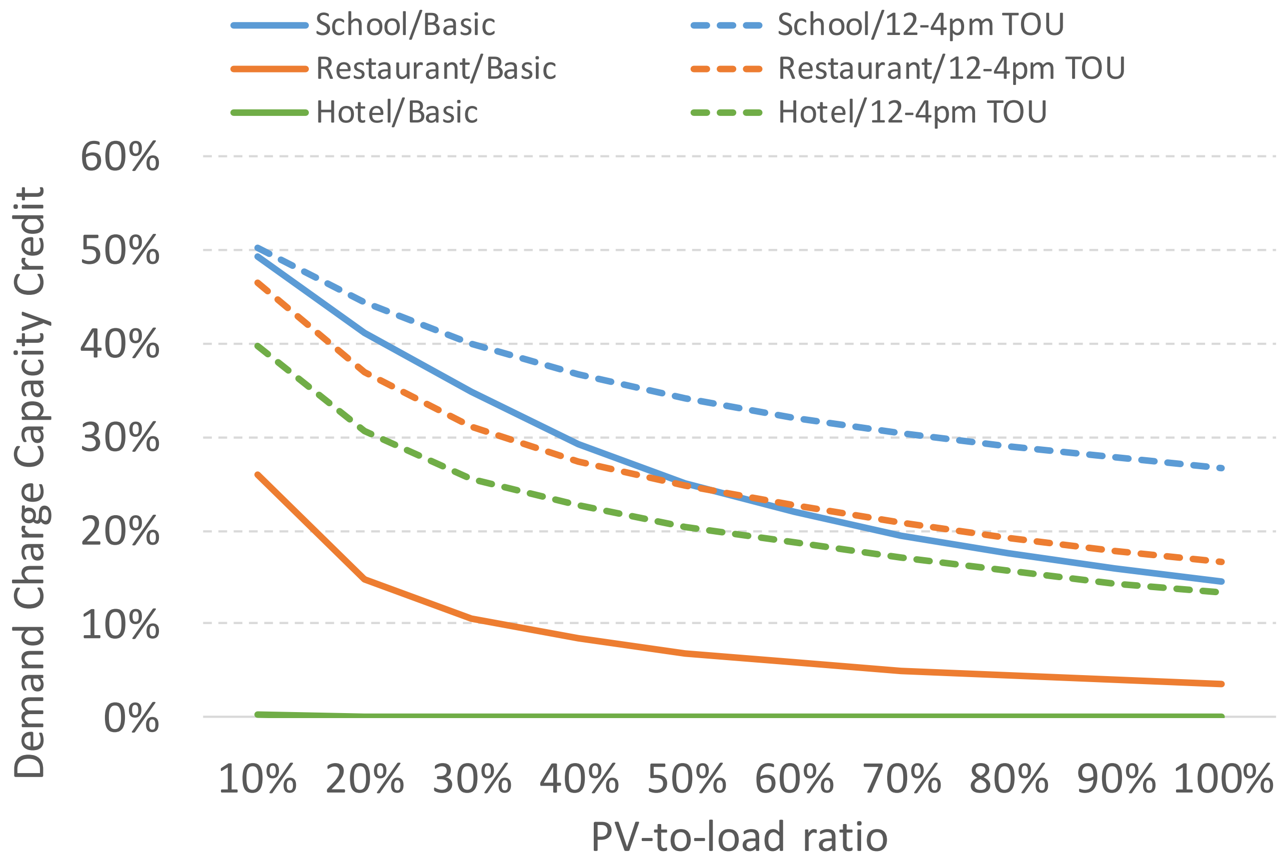


Values are average DCCC for PV-to-load ratios of 50% across all orientations. Range within each bar is due to location only.

- As in the demand charge reduction figure presented earlier, locations in California and the Southwest tend to have higher DCCC than other locations considered

Reduction in DCCC with increasing PV size indicates diminishing returns

Comparison of DCCC with increasing PV system size for the basic and the 12-4 pm peak demand charge designs



The figure shows the demand charge reductions for PV systems in Phoenix. Similar trends are observed for simulated load and PV generation profiles in other locations.

- Mirrors earlier trend showing diminishing returns to billing demand reductions with increasing PV generation
- Declining DCCC means that each incremental kW of PV is progressively less effective at reducing billing demand
  - Under "basic" demand charge design, no further reduction in demand charges once customer peak has been pushed to evening hours
  - Under "peak period" demand charge design, demand charge in some months can be completely eliminated with relatively small PV systems
- The diminishing returns effect is stronger for the basic demand charge design than for the peak demand designs

For Further Information

Download the executive summary

https://emp.lbl.gov/publications/exploring-demand-charge-savings-0

Contact the authors:

Naïm Darghouth, ndarghouth@lbl.gov, 510-486-4570

Galen Barbose, *glbarbose@lbl.gov*, 510-495-2593

Sign up for our email list

https://emp.lbl.gov/join-our-mailing-list

Follow us on Twitter

@BerkeleyLabEMP

Acknowledgments

We thank Elaine Ulrich, Odette Mucha, Daniel Boff, and Ammar Qusaibaty of the U.S. Department of Energy's Solar Energy Technologies Office for their support of this work.

We would like to thank members of our advisory group: Ryan Hledik (Brattle Group), Jim Lazar (Regulatory Assistance Project), Tom Stanton (National Regulatory Research Institute), Jeff Bailey (Duke Energy), Robert Levin (California Public Utilities Commission), James Sherwood (Rocky Mountain Institute), Chris Villareal (Minnesota Public Utilities Commission), and Casimir Bielski (Edison Electric Institute).

Of course, the authors are solely responsible for any omissions or errors.

This analysis was funded by the Solar Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.