Exploring Demand Charge Savings from Residential Solar

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Overview

This analysis estimates demand charge savings from residential solar across a range of 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, various building characteristics, 9 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

Upcoming work will expand upon the scope of this study:

- This study focuses on demand charge savings from solar, alone, without storage or load management; upcoming work will examine demand charge savings from solar plus storage
- This study focuses on residential customers; upcoming work will focus on commercial 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

Key Findings (1)

How effective is solar at reducing residential demand charges?

- **The potential demand charge savings depends, first and foremost, on demand charge design**
  - Demand charge savings are generally negligible if based on peak demand at any time of day, as residential loads typically peak in early evening hours.
  - Solar can yield more significant demand charge savings if based, instead, on peak demand during a designated daytime peak period (e.g., maximum demand during the 12-4 pm window).
  - Other demand charge design features, such as averaging interval, may also be important.

Which PV characteristics are most important to determining the demand charge savings?

- **PV system size** has a significant impact on how effective a PV system is at reducing a demand charge. Smaller systems are more effective at reducing billing demand than larger ones, on a per-kW basis.
- **Panel orientation** impacts demand charge savings under limited conditions and only to a limited degree: Southwest- and West-facing panels can be marginally more effective at reducing demand charges, depending on PV system size and peak demand definition.

Key Findings (2)

How do location and building type impact residential demand charge savings?

- **Location significantly impacts potential demand charge savings from solar.** Customers in sunnier, warmer regions can generate greater demand charge savings from solar due to greater coincidence between solar generation and loads, and higher loads.
- **Building characteristics can have modest impacts on the potential demand charge savings from solar.**
  - Demand charge savings from solar are somewhat smaller for more-recent building vintages, as a result of greater energy efficiency and lower underlying peak demand.
  - Homes with electric space heating offer marginally greater demand charge savings potential from solar.

How variable from month-to-month are the demand charge savings from residential solar?

- **Monthly variability in demand charge savings depends mostly on the demand charge design.** Demand charge designs based on maximum demand during a designated peak period window (e.g., 12-4 pm) tend to have less variability than when based on maximum demand during any time of day.

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Residential Demand Charges Have Received Increased Consideration in Recent Years

- Demand charges are based on the customer's peak demand and are notionally intended to recover utility capacity costs driven by peak load
- Demand charges have long been used for commercial and industrial customers, often comprising 50% or more of the customer bill
- Demand charges for residential customers are being increasingly considered in many states, often within the context of broader discussions about retail rate reforms
  - Residential demand charges have historically been offered only on a voluntary basis
  - Recent discussions have considered mandatory demand charges for residential customers (either for those with solar, specifically, or for residential customers as a whole)

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

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)
  - Often monthly 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 changes with increasing billing demand.
  - For example, first 5 kW billed at one price, next 5 kW billed at a different price, and any demand greater than 10 kW billed at yet another price
- Tiering is not considered in current analysis

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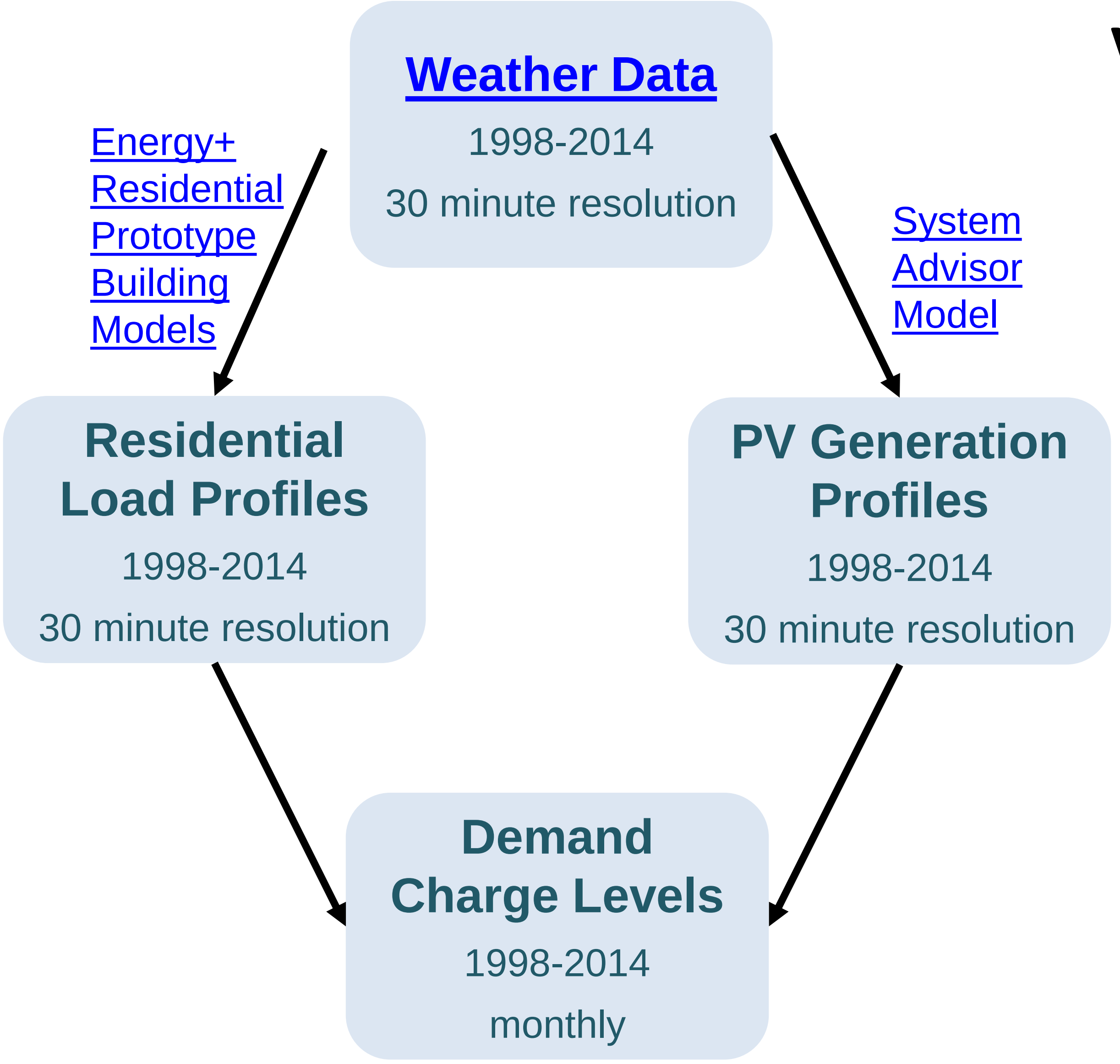
Methodology



Variables considered for generating load/PV profiles

Customer Characteristics	**15 Cities**	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
	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
PV System attributes	**9 PV System Sizes**	Sized such that PV generates 20%-100% of annual customer load (in 10% increments)
	4 PV Orientations	South-facing, Southwest-facing, West-facing → all 20° tilt; flat

→ **12,960 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**. E.g. if maximum demand in last year is 10 kW, minimum billing demand is
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
  - For example, the simulated load profiles do not reflect variations across customers within any given city in occupancy patterns or all possible differences in end-use equipment
  - 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
- 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 charges, other approaches to defining coincident peak, etc.)

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Two Demand Charge Savings Metrics

Both are percentages, but serve different purposes

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

- Provides a point of comparison to bill savings that can be achieved through volumetric rates

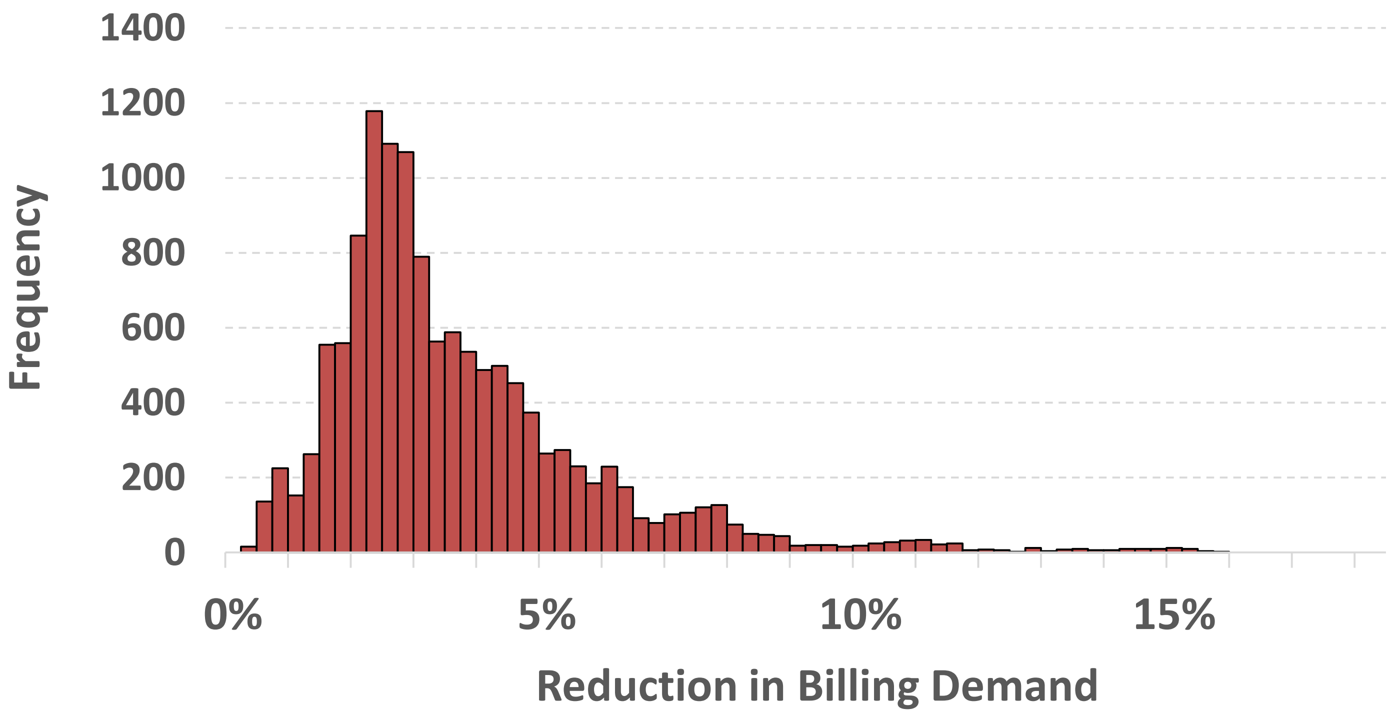
We first present results in terms of this metric

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

- For example: If a 10 kW system reduces billing demand by 4 kW, the demand charge capacity credit = 40%
- Provides a point of comparison to bulk power capacity credit (capacity that can be avoided per kW of PV)

Under the "Basic" Demand Charge Design, Solar Is Not Effective at Reducing Demand Charges

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

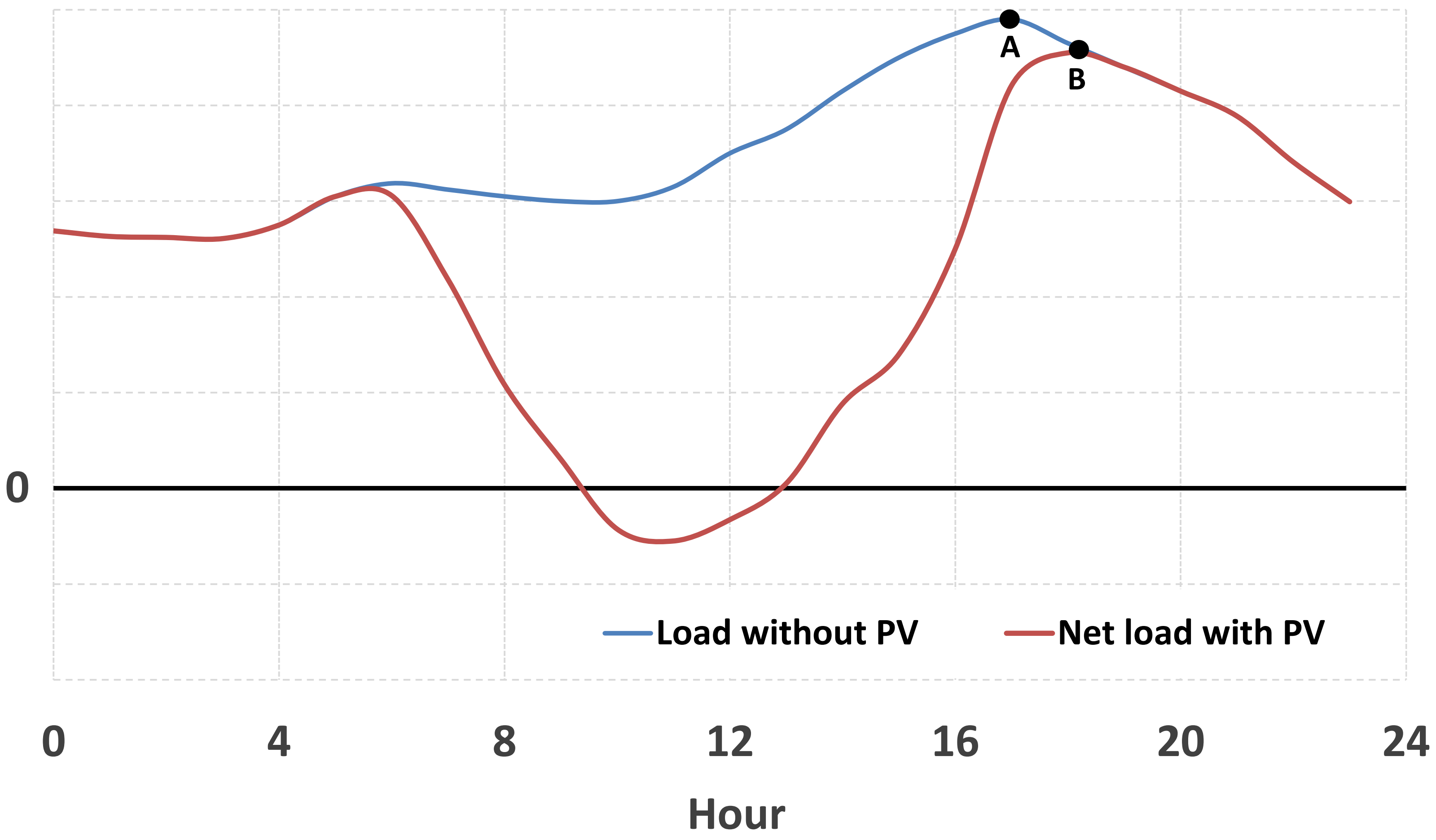


The figure shows the distribution in billing demand reduction across all 12,960 combinations of simulated load and PV generation profiles. Each data point is the average percentage reduction, for a single load/PV combination, across all months of the 17-year historical weather period.

- 3% reduction in billing demand in the median case
- Relatively narrow distribution: < 8% reduction in 95% of all cases
- Demand charge reductions under this design are small, because residential customer loads tend to peak in evening hours (or if electric heating is present, in early morning peaks)
  - See appendix for further information on the hour of peak demand for each city modeled

Graphical Example Illustrating Impact of Solar on Demand Charges Under the “Basic” Demand Charge Design

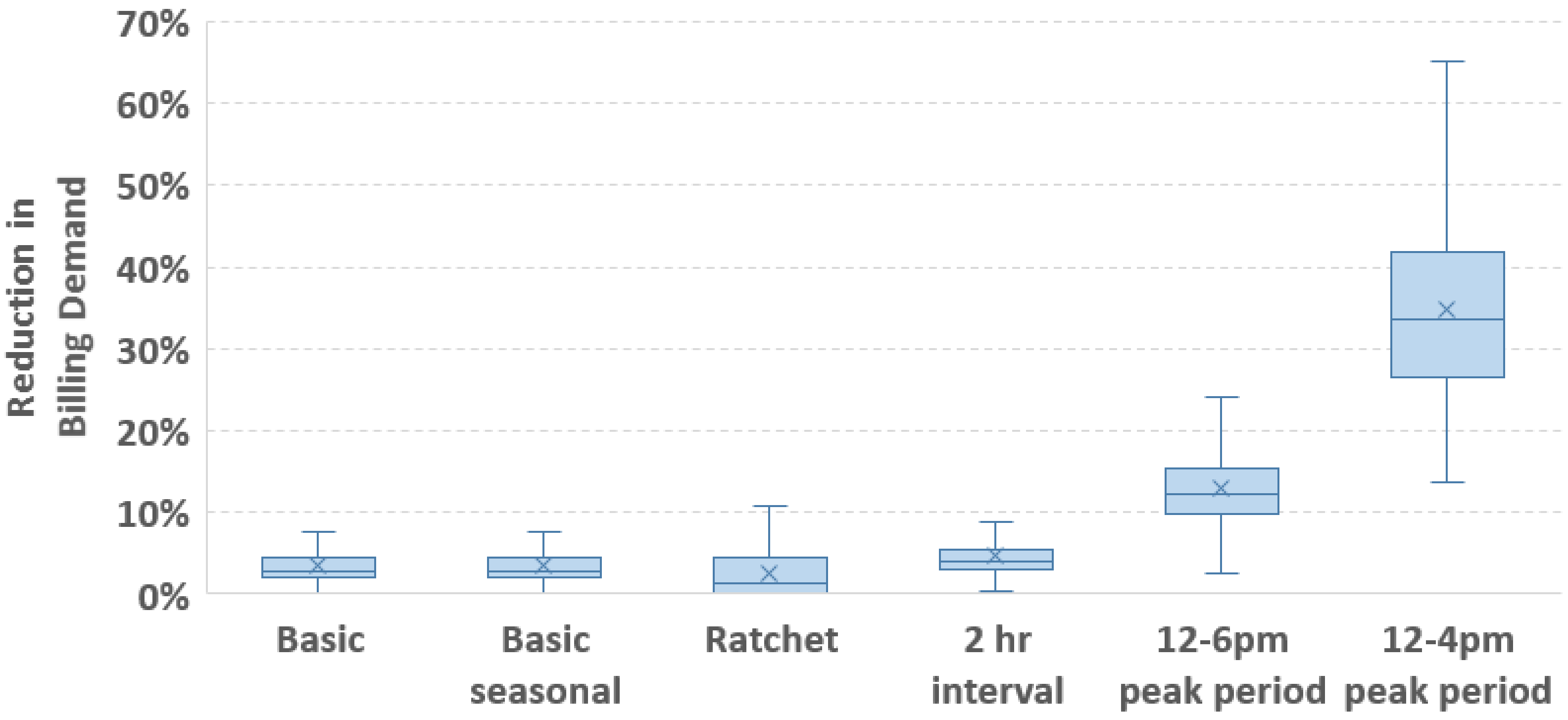
Hourly load profiles with PV (red line) and without PV (blue line) for a hypothetical customer



- Demand charge savings from solar depend on **the hours in which billing demand is set**
- When billing demand is set during the day, solar has the potential to reduce billing demand and hence demand charges (e.g. points A → B)
  - Billing demand reduction is limited by customer’s maximum monthly demand level in evening times

Demand Charge Savings Can Be More Significant when Based on Pre-Defined Peak Periods

Distribution of percentage billing demand reductions for various demand charge designs

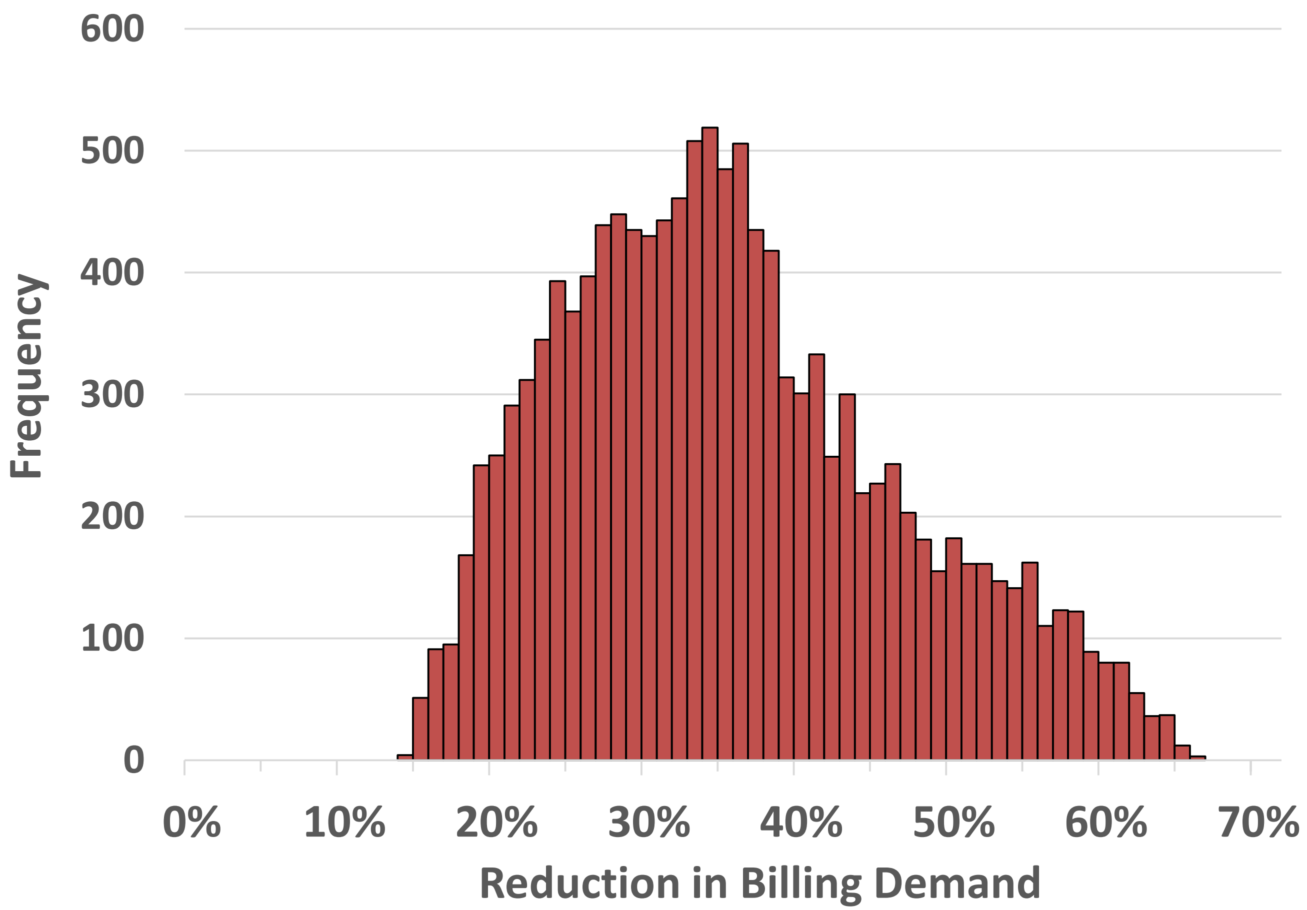


*Note: 'x' = mean; shaded box = 25th-75th percentile range; middle line = median; whiskers exclude outliers (quartile ± 1.5*IQR); IQR = inter-quartile range*

- For demand charges based on a 12-4 pm peak period, median reduction in billing demand = 34% (compared to 3% for basic demand charge design)
- Negligible differences in demand charge savings associated with seasonal demand charges, ratchets, or longer averaging intervals (2 hr. vs. 30 min.)
- Further exploration of these design features are provided later in this presentation

Demand Charge Savings under Peak Period Demand Charge Designs Vary Widely Across Customers

Distribution of billing demand reduction:
Demand charge based on 12-4 pm peak period



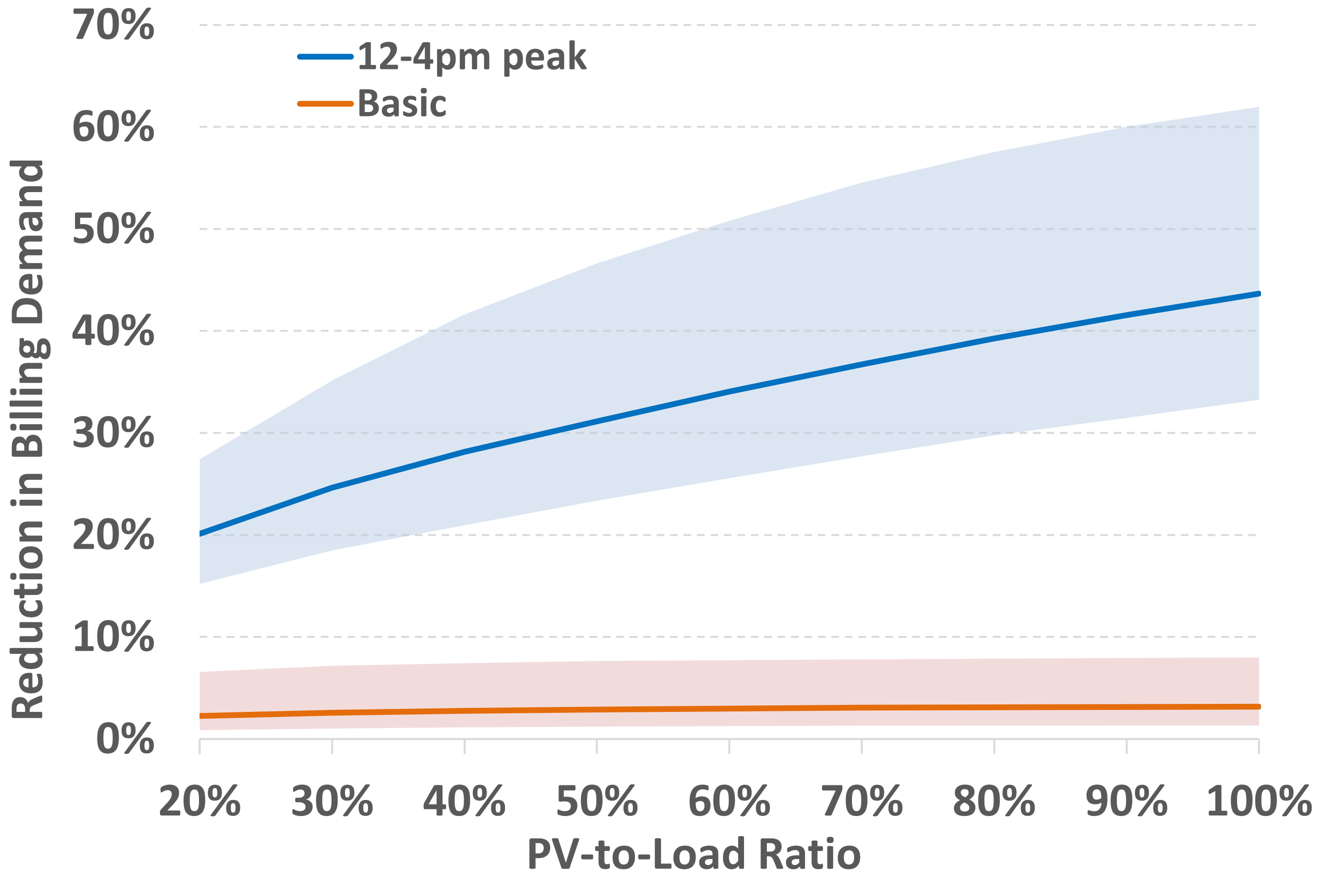
For demand charges based on a 12-4 pm peak period window:

- Relatively wide distribution, with a quarter of all cases yielding >42% reduction in average demand charges
- Wide distribution primarily reflects variation in PV system sizes and locations

As previously noted, the simulated load profiles used in this analysis do not capture all sources of variability; thus actual customers may exhibit an even wider range of demand charge savings than shown here

Demand Charge Reductions Increase with PV System Size, but with Diminishing Returns

Demand charge reductions with increasing PV system size



Note: Solid lines are median values and shadings indicate 5th to 95th percentile range.

- PV systems sized to meet 20% of annual usage reduce demand charges by 2% and 20%, in the median case for the basic and 12-4 pm peak DC design, respectively
- But increases in system size do not yield proportionately greater demand charge savings
- Drivers for diminishing returns
  - Demand charge in some months can be eliminated with relatively small PV systems
  - With larger systems, peak demand is more likely to be set on a cloudy day
  - Larger systems push peak demand to evening hours
- Contrasts with volumetric energy rates, where savings scale roughly in proportion to PV system size

Two Demand Charge Savings Metrics

Both are percentages, but serve different purposes

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

- Provides a point of comparison to bill savings that can be achieved through volumetric rates

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

- For example: If a 10 kW system reduces billing demand by 4 kW, the demand charge capacity credit = 40%
- Provides a point of comparison to bulk power capacity credit (capacity that can be avoided per kW of PV)

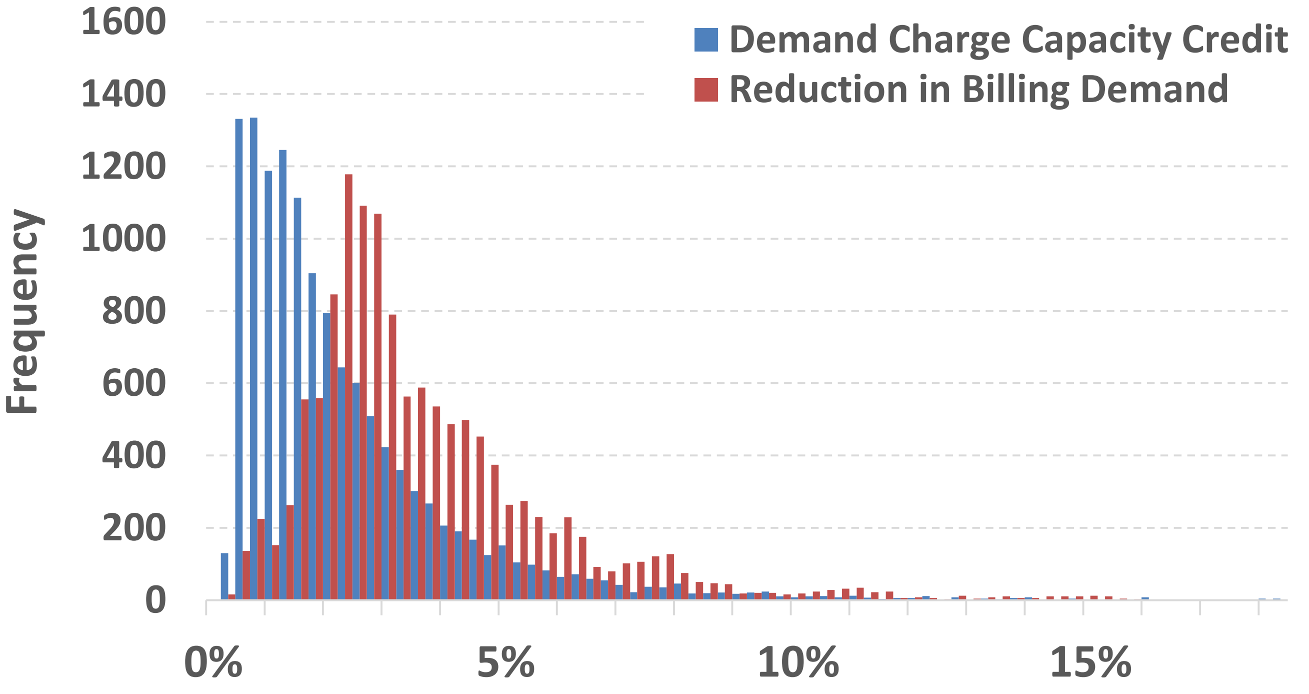
The remainder of the results are presented in terms of this metric

Why Describe Demand Charge Savings in Terms of "Capacity Credit"?

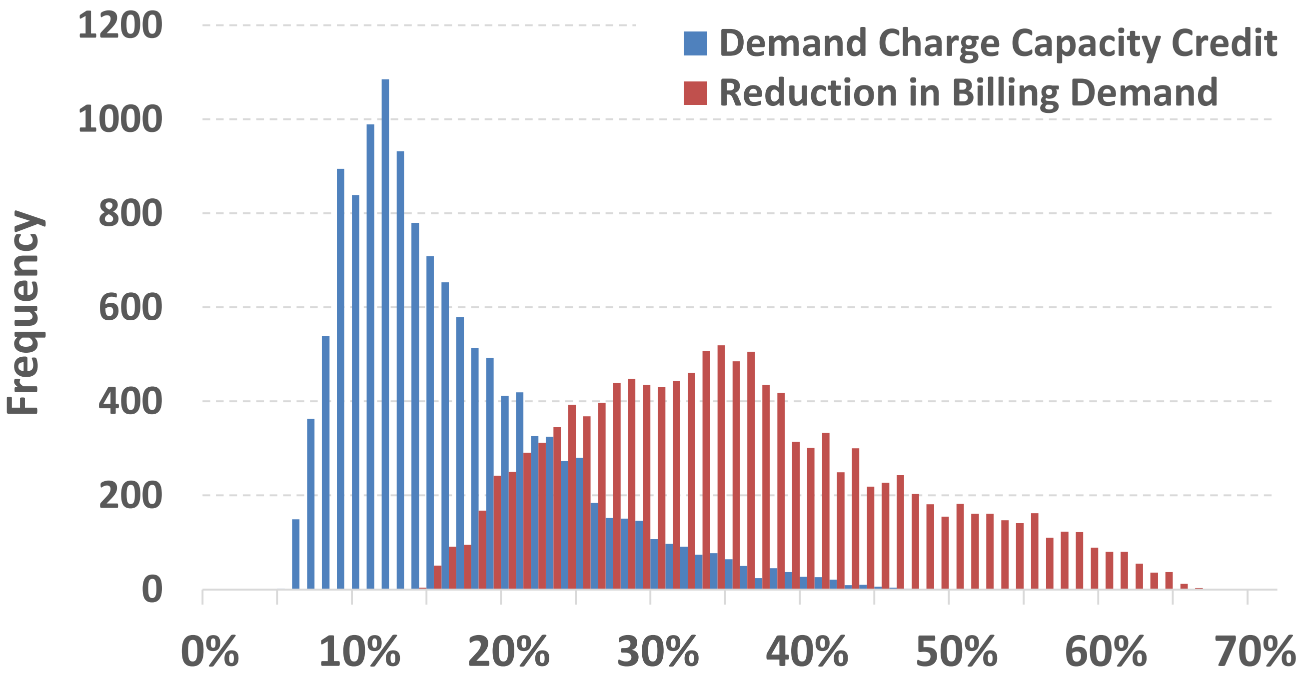
- Capacity credit is often used to describe the capacity value of intermittent resources to the electric system
  - Denotes the quantity of infrastructure capacity (generation, transmission, distribution) that can be avoided per kW of intermittent capacity added
- Expressing demand charge savings in terms of the demand charge capacity credit allows for comparison between the capacity value provided to the *customer* and to the *electric system*
  - The present analysis focuses on the first aspect of this comparison (the capacity value to the customer)
  - Subsequent analysis will assess alignment with capacity value to the electric system

Comparison of Demand Charge Savings Metrics

Distributions of demand charge savings metrics:
Basic demand charge design



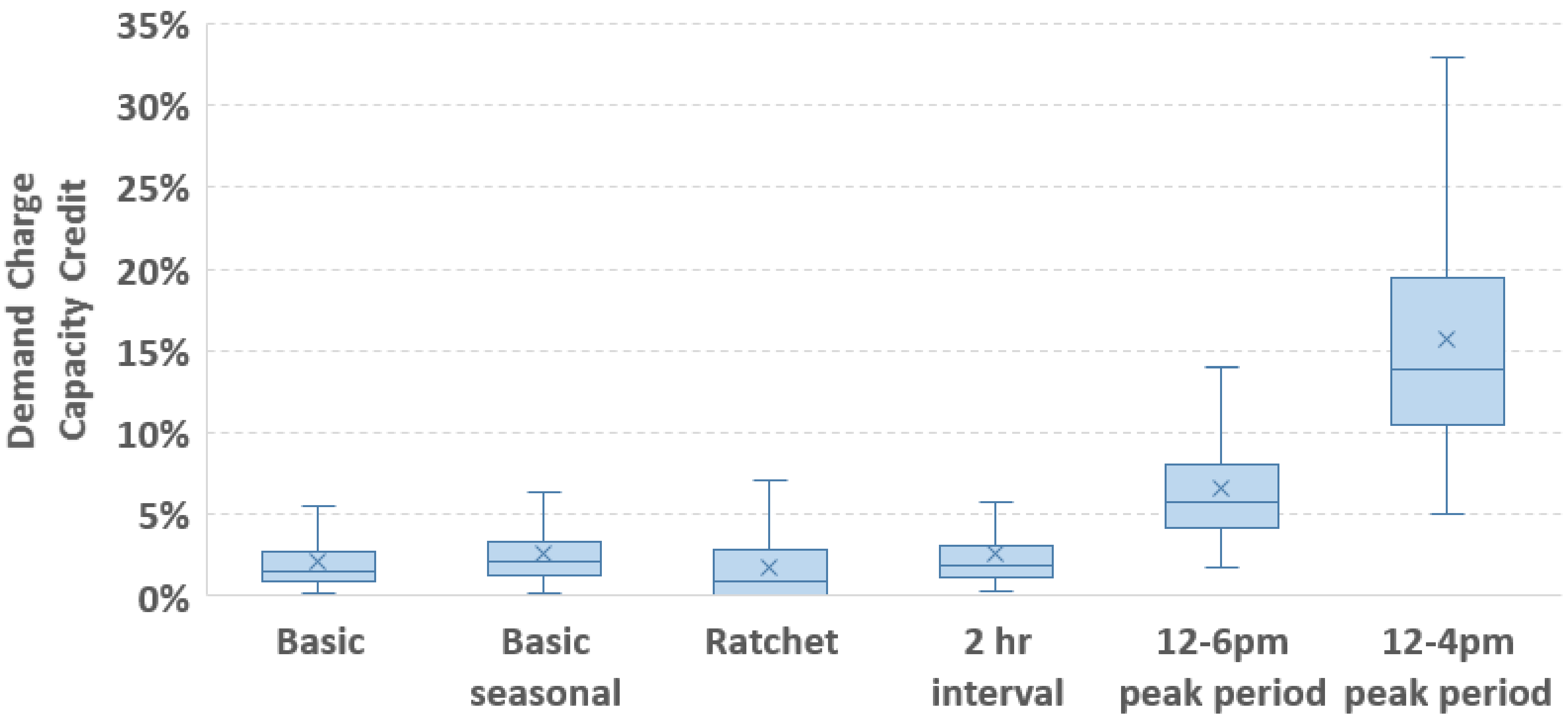
Distributions of demand charge savings metrics:
Demand charge based on 12-4 pm peak period



- DCCC is generally smaller in magnitude than percentage reductions in billing demand, but reveals similar trends
- The remainder of the analysis is presented in terms of DCCC to provide the foundation for comparison (in future planned analyses) of customer demand charge savings to utility cost savings

DCCC Varies Across Demand Charge Designs

Distribution of demand charge capacity credits for various demand charge designs

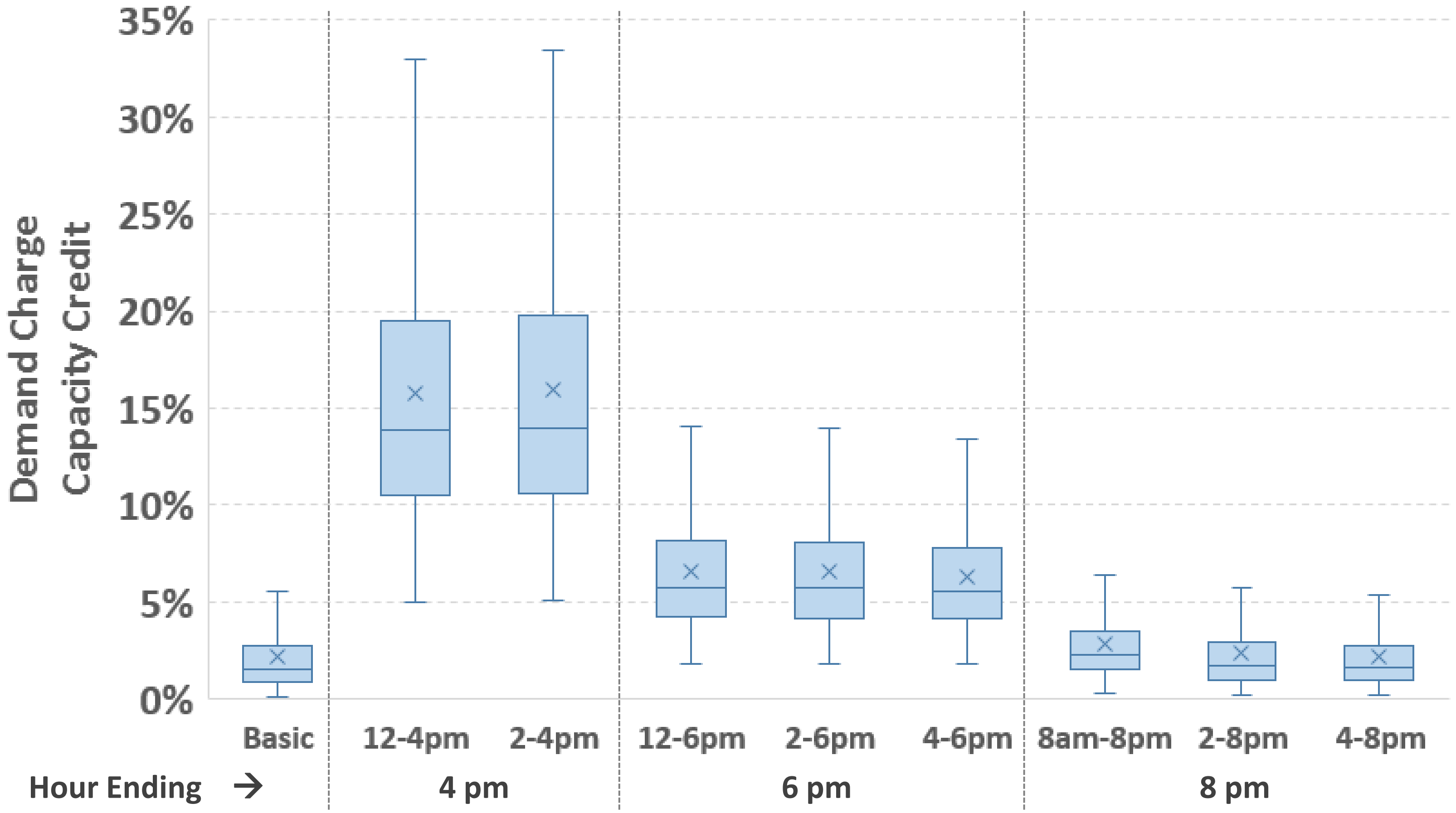


*Note: 'x' = mean; shaded box = 25th-75th percentile range; middle line = median; whiskers exclude outliers (quartile ± 1.5*IQR); IQR = inter-quartile range*

- DCCC distribution for the various demand charge designs are similar than those for demand charge reductions from PV
- Much of the range across customers due to variation in PV system size
  - However, contrary to reduction in billing demand, smaller PV systems lead to largest DCCC levels
- Capacity credits are larger if using "peak period" demand charges
  - Clear differences depending on how peak period is defined
- Figure is based on monthly average DCCC over 17 year period for each
  - month-to-month variability in the DCCC for each customer, quantified later in this presentation

Demand Charge Savings Are Greater When Peak Periods End Earlier in the Day

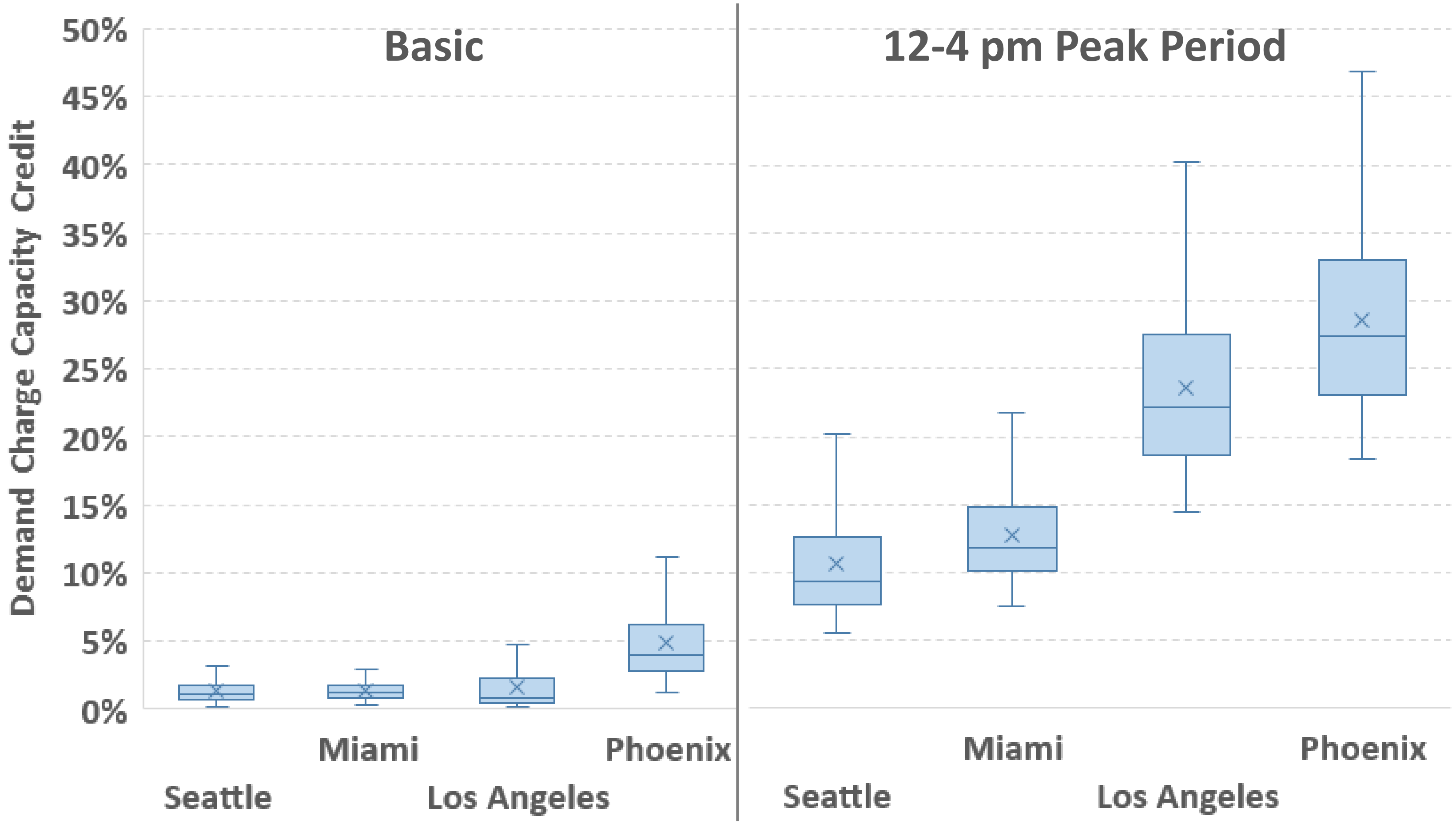
Distribution of DCCC for demand charge designs with varying peak period definitions



- Residential loads tend to have higher consumption levels in mornings and early evenings, though daily peaks are typically in the evenings
- Demand charge is typically set based on demand at the end of the peak period window; consequently:
  - Peak period windows that end later tend to have lower DCCC
  - Start times have less impact on DCCC

Demand Charge Savings Can Vary Significantly Depending on Location

Distribution of DCCC across a representative set of cities



- Much greater differences across cities for peak period demand charge design than for basic demand charge
- Two principal drivers for variability in demand charge savings by city:
  - **“Peakiness” of load shapes:** Higher loads during peak demand windows—generally associated with A/C—allow for deeper demand charge savings
  - **Cloudiness:** In cities with many cloudy days, billing demand is more likely to be set on a cloudy day, leading to lower average capacity credits
- Intra-city DCCC range due in large measure to varying PV system size

Weather Patterns Impact Demand Charge Savings from Solar

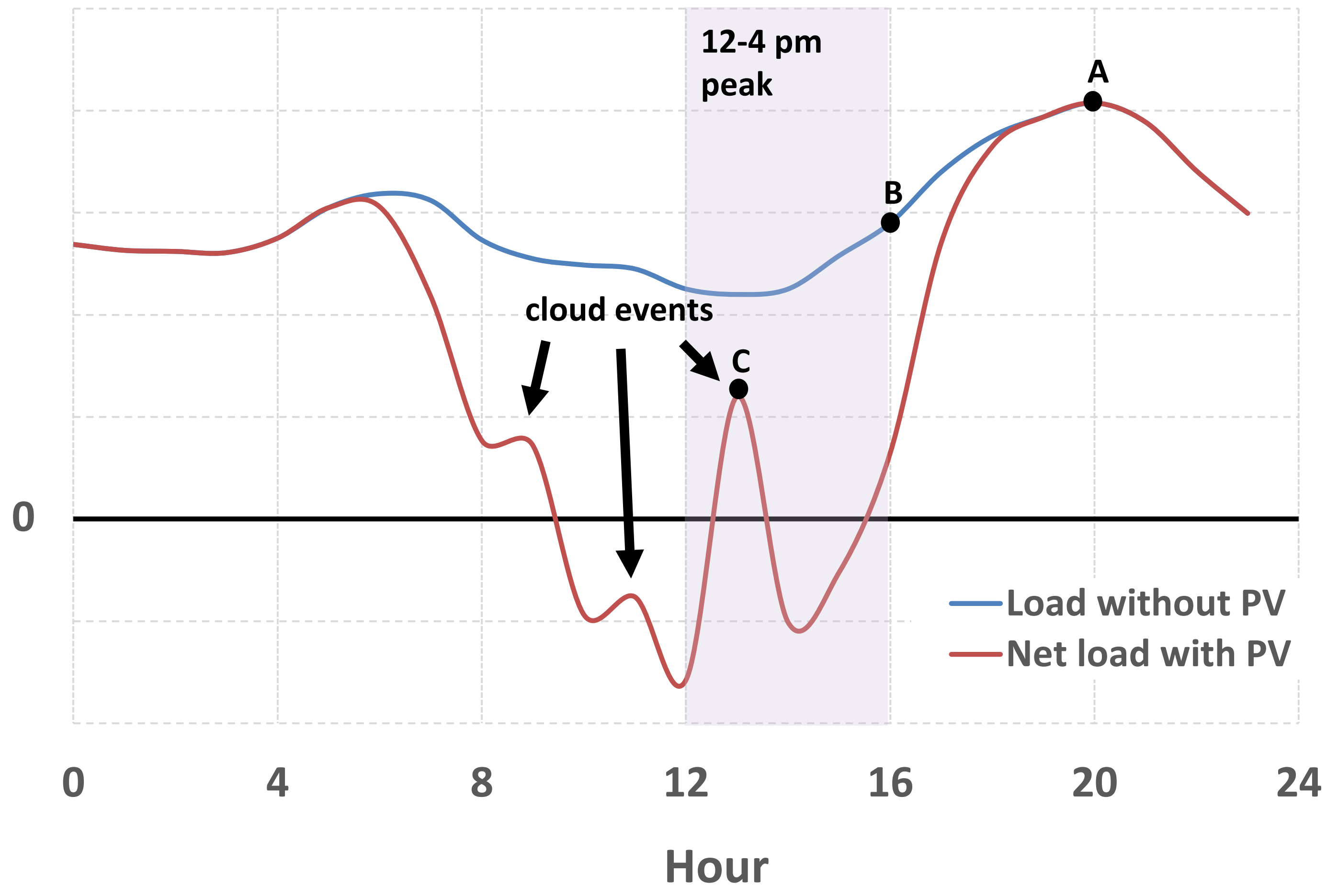
Demand charge savings from solar also depend on:

- **How sunny it is *on average***
  - Customers in sunny locations generally have higher peak demands, and thus more peak demand to potentially reduce
  - Customer load profiles in sunny locations tend to coincide better with the timing of PV generation
- **How *variable* the cloudiness is**
  - Locations with prone to intermittent cloudiness (even if sunny, on average) will have greater month-to-month variability in demand charge savings, as there will be some months where the customer’s peak load occurs during times of passing clouds

→ These explain some of the differences in DCCC across cities

Solar Can Potentially Reduce Billing Demand but Only as Well as on the Cloudiest Days

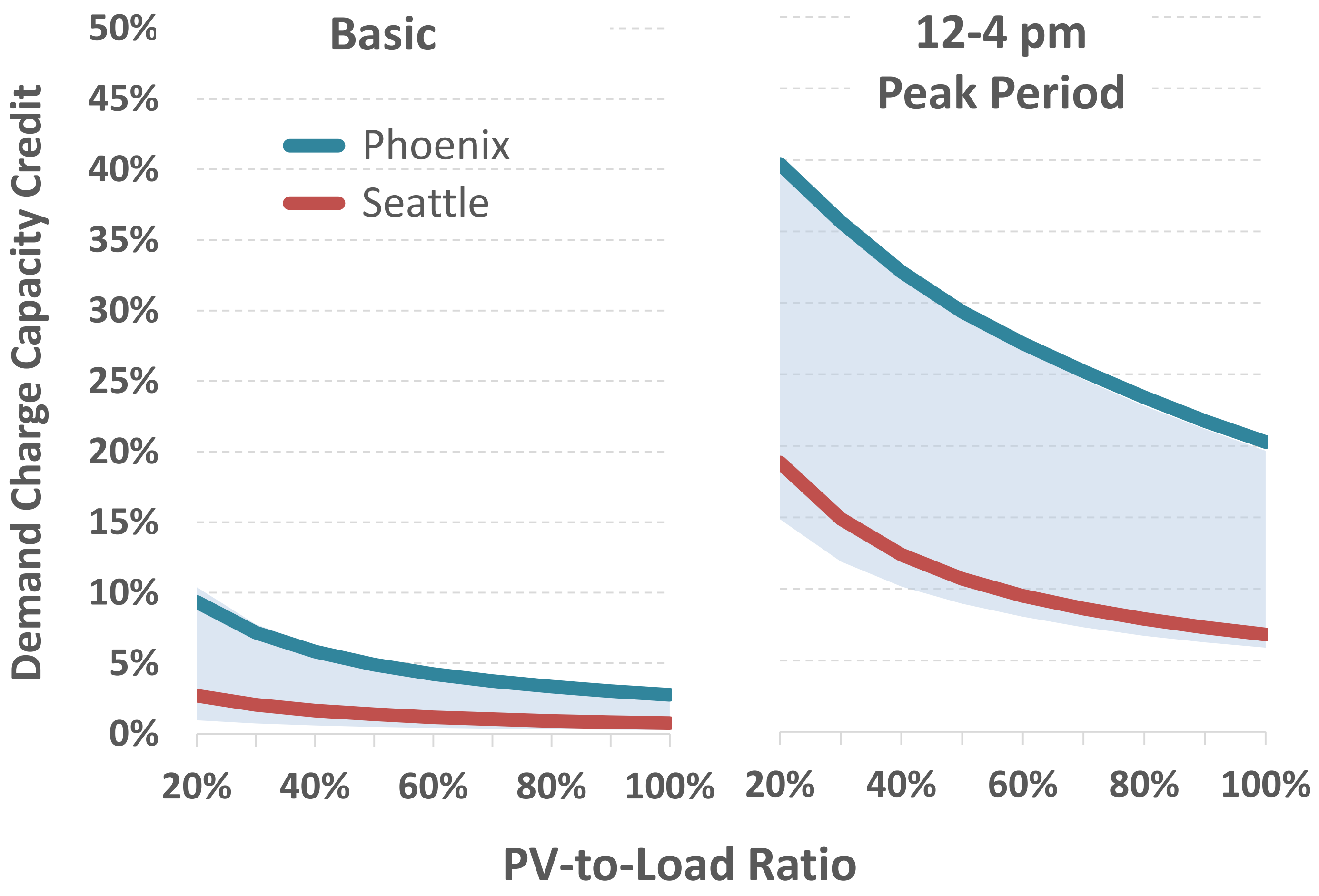
Hourly load profiles with PV (red line) and without PV (blue line)



- When billing demand is set during daylight hours, as is the case with this customer under a 12-4 pm peak demand charge design with short averaging time intervals, the customer can reduce their billing demand (e.g. from point **B** to **C**)
- Note, however, that the reduction in billing demand is limited by the cloudiest hour, which reduces PV generation (e.g. cloudy hour **C** has reduced PV generation and sets the billing demand)

DCCC Declines with PV System Size

Average DCCC with increasing PV-to-load ratio

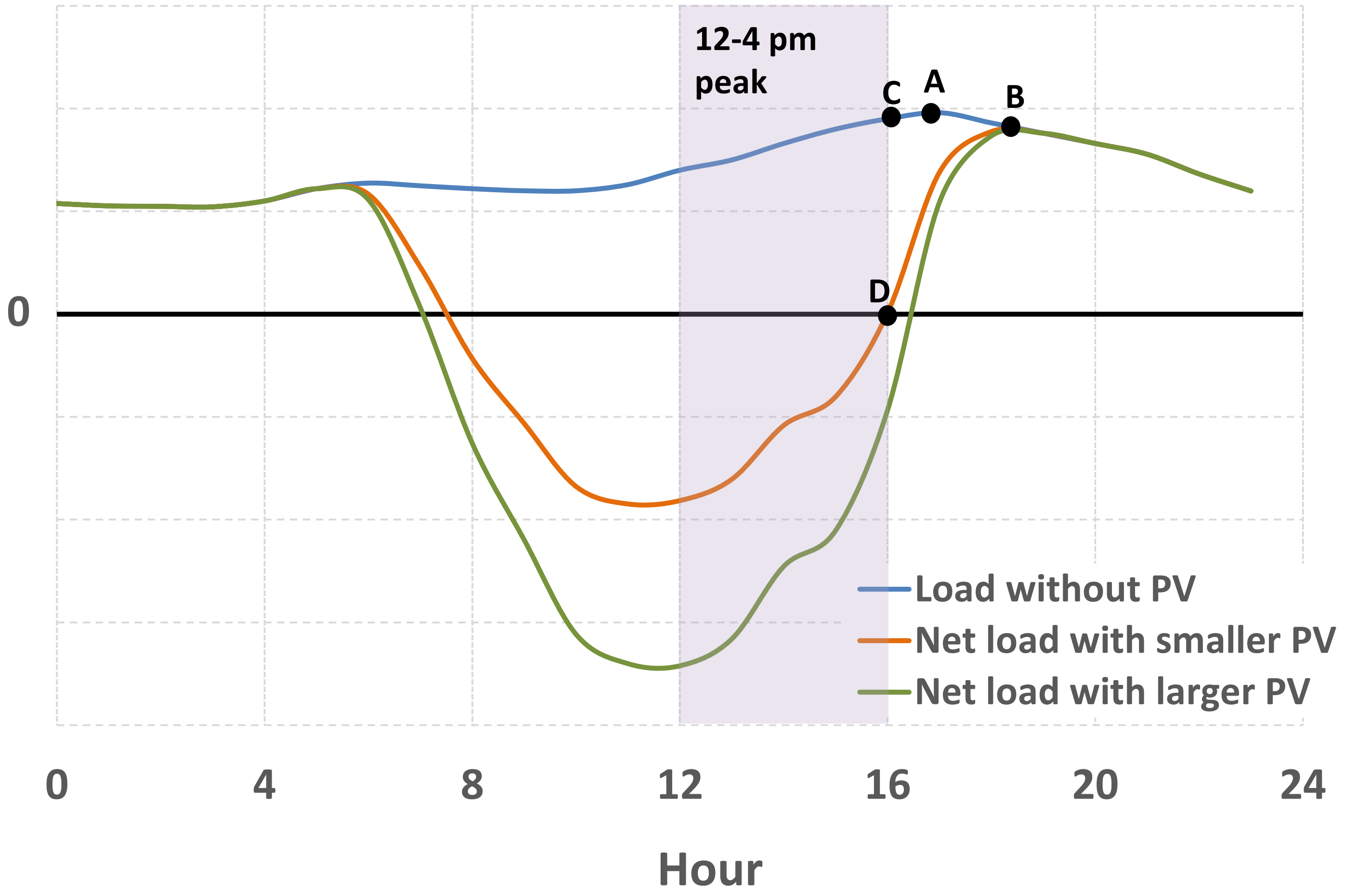


Note: Solid lines represent average values; shaded areas represent 5th and 95th percentile values.

- 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
- Ranges at each PV-to-load ratio reflect differing locations (load/PV generation profiles)

Larger PV Systems May Reduce Billing Demand but with Diminishing Returns

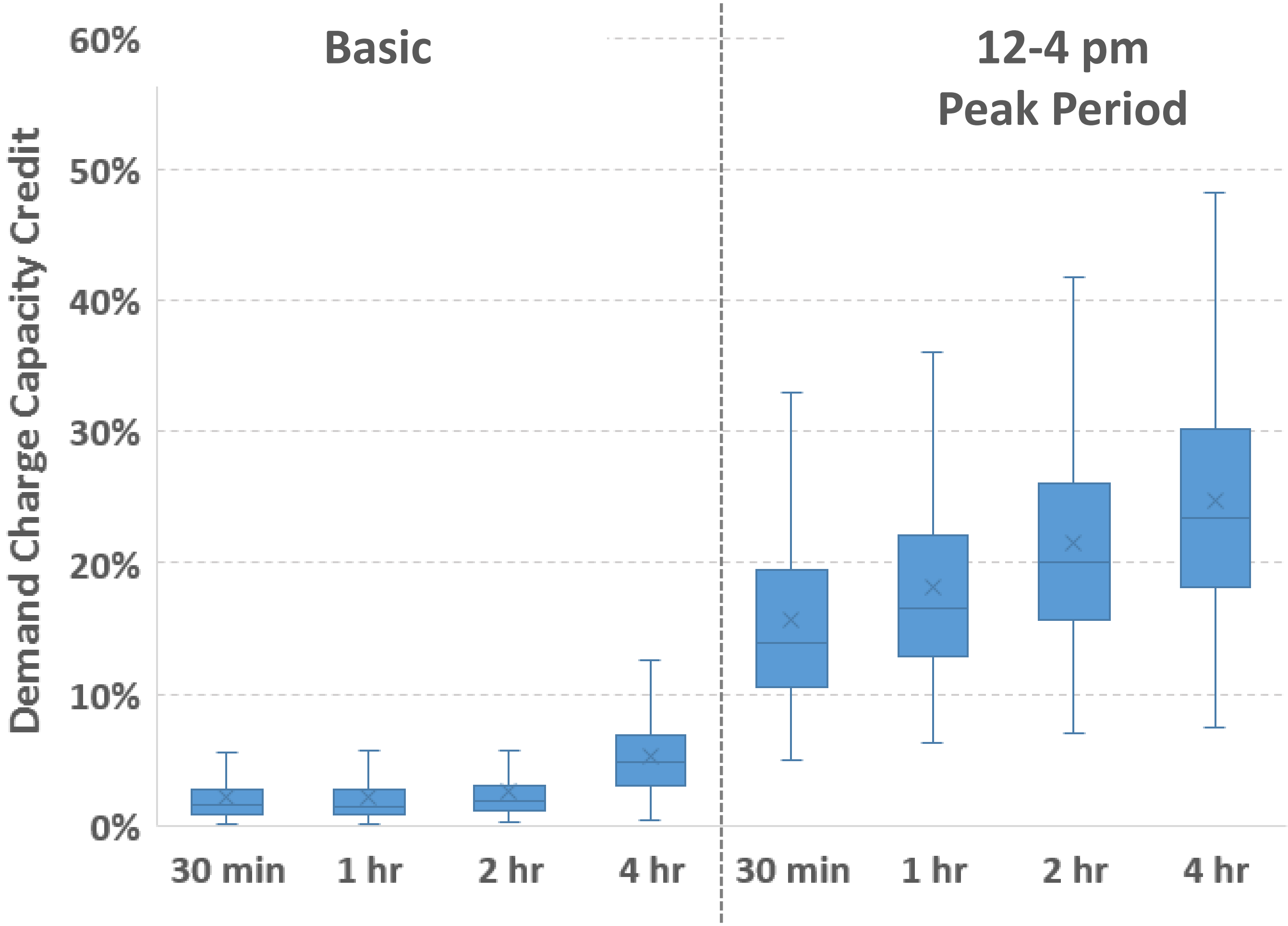
Hourly load profiles without PV (blue) and with two PV system sizes (orange and green)



- With basic demand charge design (i.e. billing demand can be set any hour), PV pushes the hour setting the billing demand later in the evening, and larger PV systems are not more effective at reducing billing demand (e.g. points **A → B**)
  - When net load is zero during the entirety of the peak demand charge window, a larger PV system doesn't reduce the demand charge any further
- In the figure, billing demand is zeroed out with the small PV system with a 12-4 pm peak demand charge with a short averaging interval in a sunny location, so a larger PV system has no incremental effect on demand charge savings (e.g. points **C → D**)
- Finally, if billing demand without PV is set on a sunny day, smaller PV systems may reduce billing demand, but larger PV systems may not be able to if the next highest demand hour is on a cloudy day, leading to diminishing returns with increasing PV system size

Demand Charge Savings Are Greater with Longer Averaging Intervals

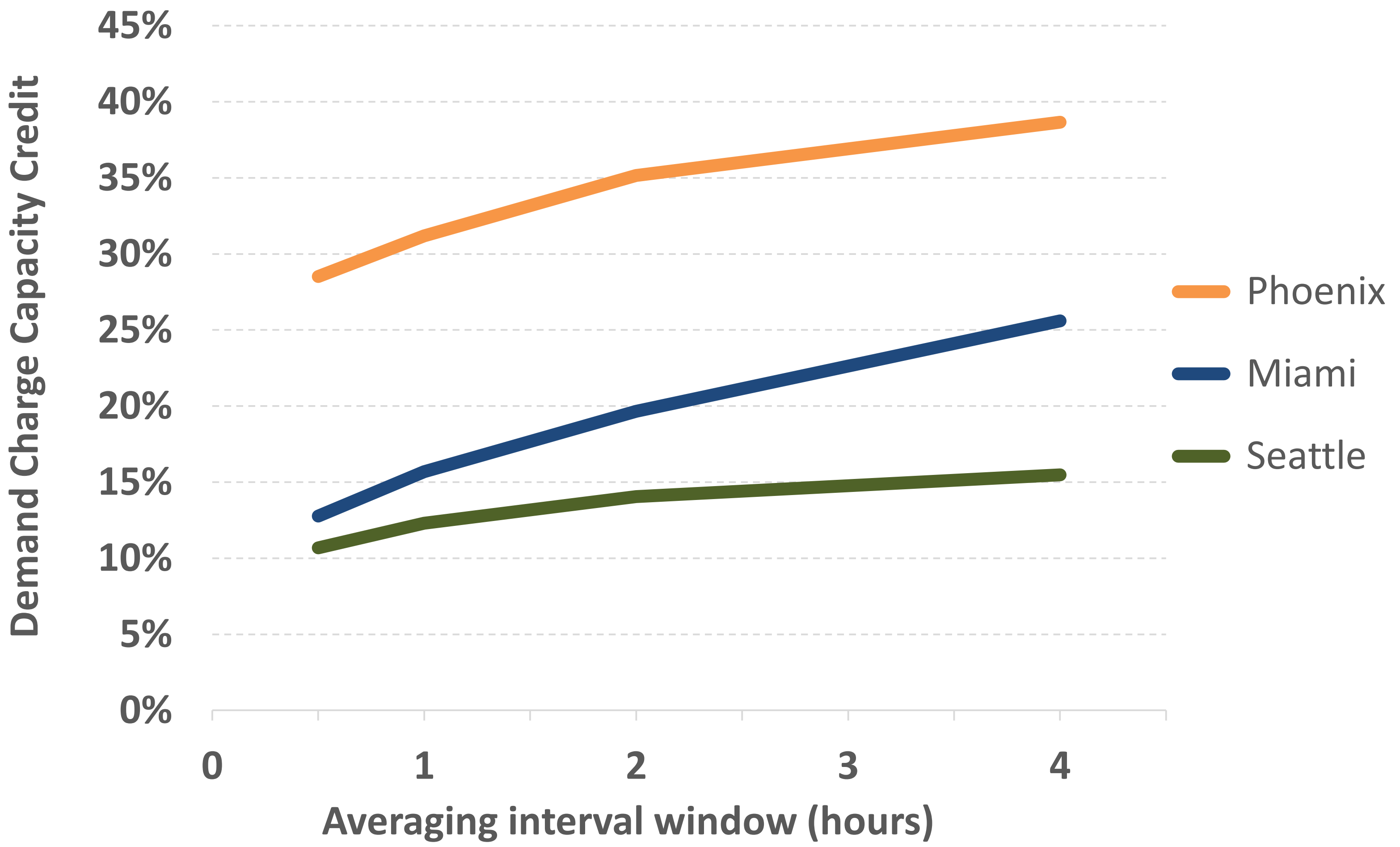
Distribution of DCCC across varying averaging intervals



- 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)
- Under the basic demand charge, the effect is relatively minor and most evident at a 4-hour averaging interval (which captures solar generation in hours prior to 4 pm)
- Under the peak period demand charge, the length of the averaging interval has a more pronounced effect
  - 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)

Effect of Averaging Interval Is Most Pronounced for Regions with Intermittent Cloudiness

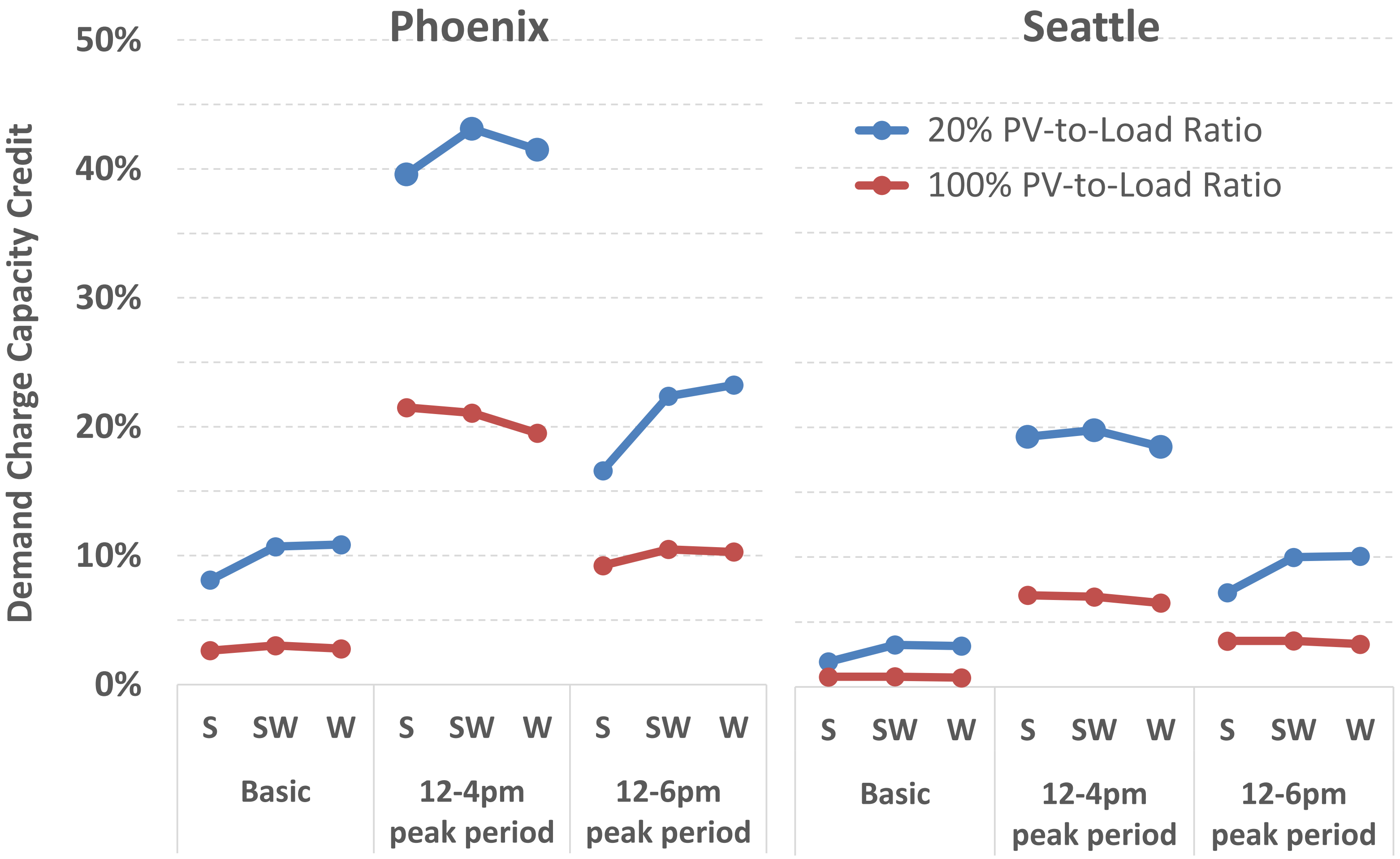
Change in DCCC with increasing averaging interval:
Demand charge based on 12-4 pm peak period



- Though DCCC increases with averaging interval for all locations, it has more of an impact in some cities
- Specifically, effects are most pronounced in cities with intermittent (short-duration) cloudiness
  - This can be seen for Miami (and to a lesser extent Phoenix), where cloud cover tends to be of relatively short duration
  - Contrasts with Seattle, where cloudiness tends to span long durations, thus little effect from “smoothing” out multi-hour periods

Impact of Panel Orientation on Demand Charge Savings Not Significant, Depends on its Design and PV System Size

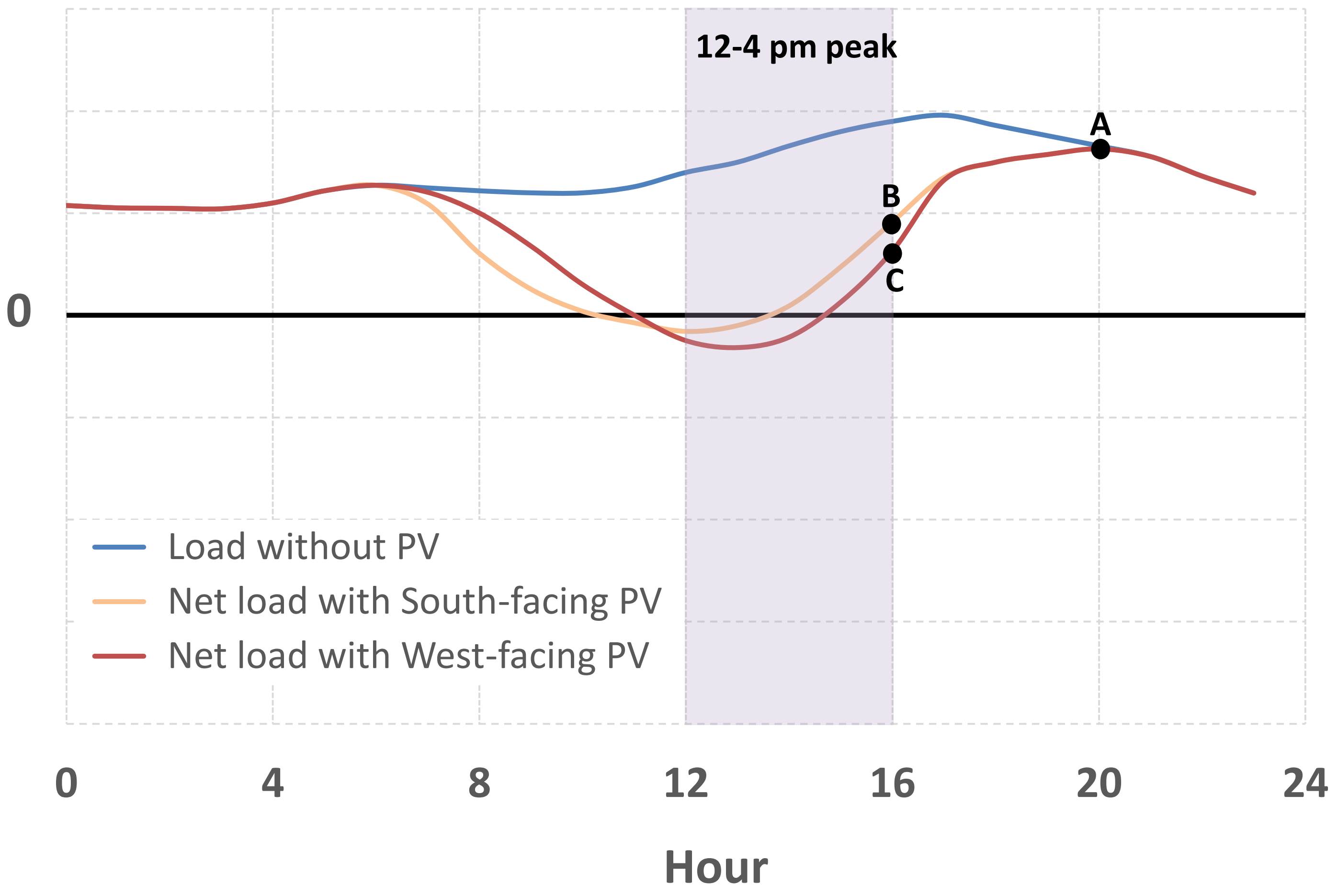
Change in DCCC across PV panel orientations:
System installed in select cities



- Southwest- and West-facing panels peak later in day, coinciding better with load than do South-facing panels
- For small systems: leads to slightly higher DCCC
- For large systems: less customer-benefit to Southwest- or West-facing panels
  - If demand charge already eliminated with South-facing system, no gain from optimizing orientation
- Orienting panels away from South also reduces total PV generation (kWh), requiring larger system size to maintain the same PV-to-load ratio
  - Mathematically, this tends to reduce DCCC

West-facing PV can Reduce Billing Demand More Than South-facing PV for Some Designs

Hourly residential load profile without PV (blue) and with PV for South- and West-facing PV systems



- With a basic demand charge design, the billing demand (point **A**) and demand charge savings do not change with orientation
- West-facing panels peak later in the day, hence are more likely to reduce afternoon peak load (e.g. points **B → C**)
- However, West-facing PV systems generate fewer kWh per kW and hence require larger nameplate capacity for the same PV-to-load ratio

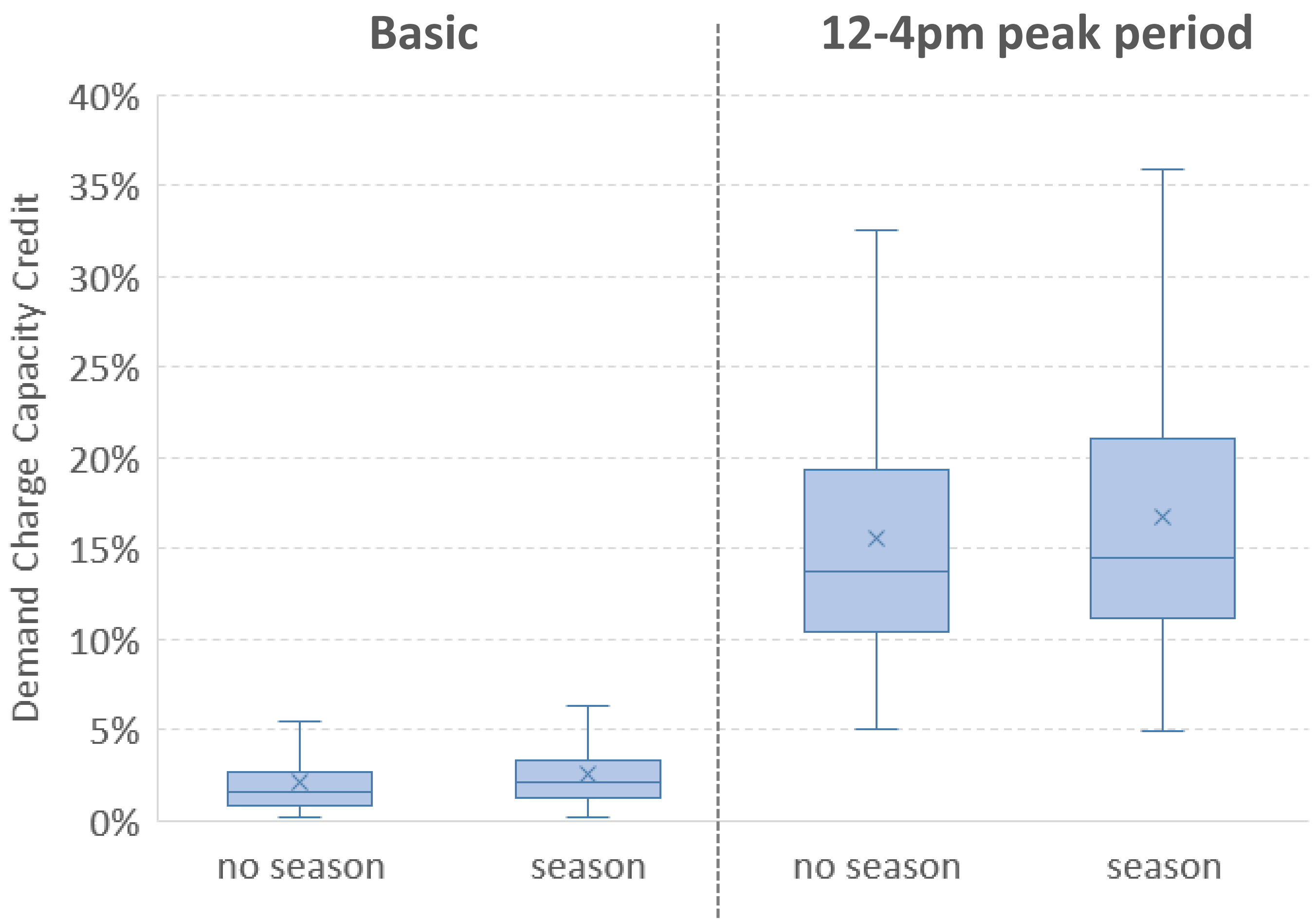
→Partially offsets the greater billing demand reduction when calculating capacity credit; an example with a 30% PV-to-load ratio:

	Billing Demand Reduction (A)	System Size (B)	Capacity Credit (A/B)
South-facing	4 kW	20 kW	20 %
West-facing	5 kW	23 kW	22%

- For larger PV-to-load ratios, when billing demand is zeroed out, capacity credit is larger for South-facing as PV system size is smaller than for West-facing

Seasonal Demand Charges Only Provide a Small Boost to Capacity Credit Levels

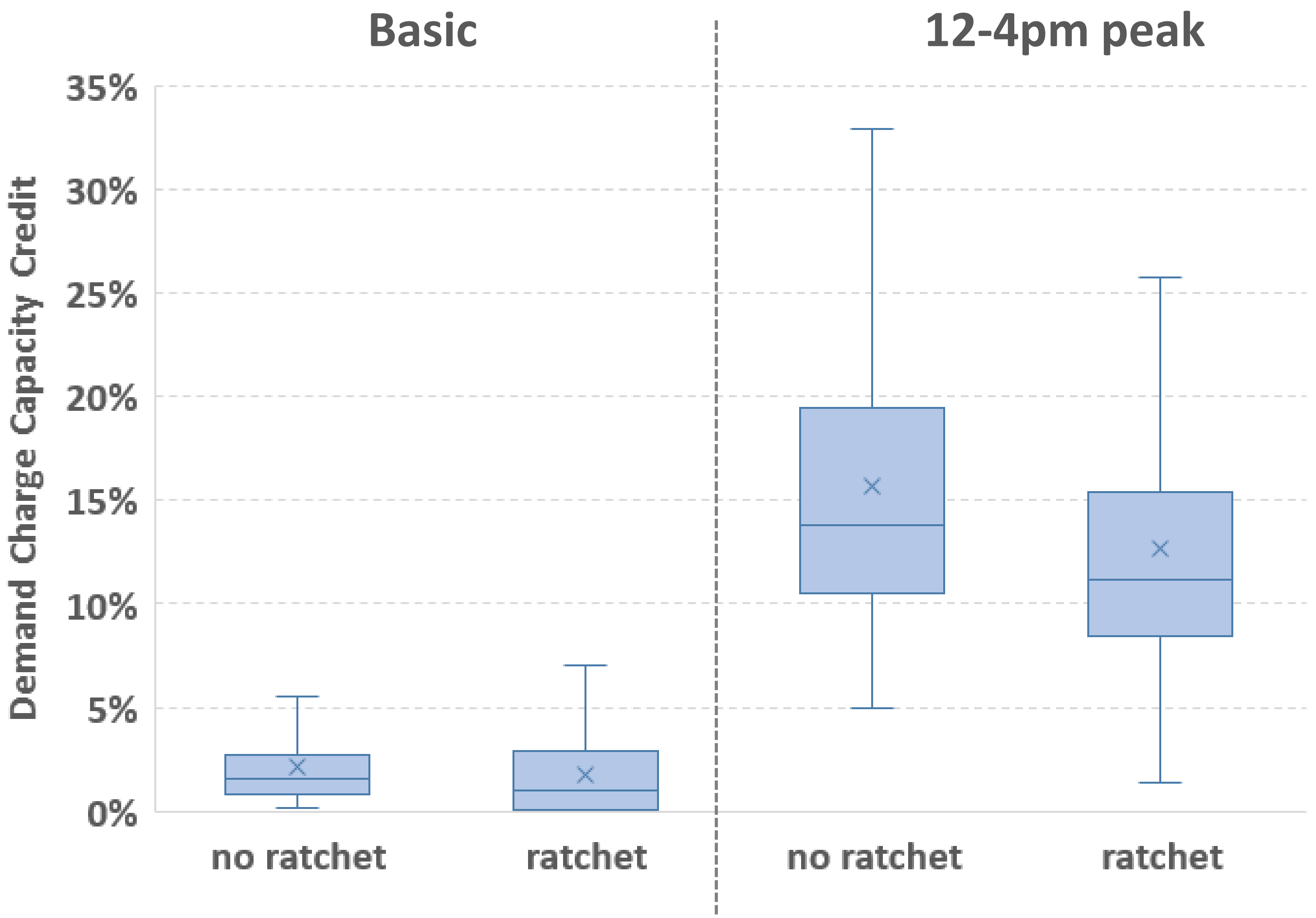
Distribution of DCCC for demand charge designs with and without seasonal differentiation



- 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 Can Reduce the Demand Charge Savings

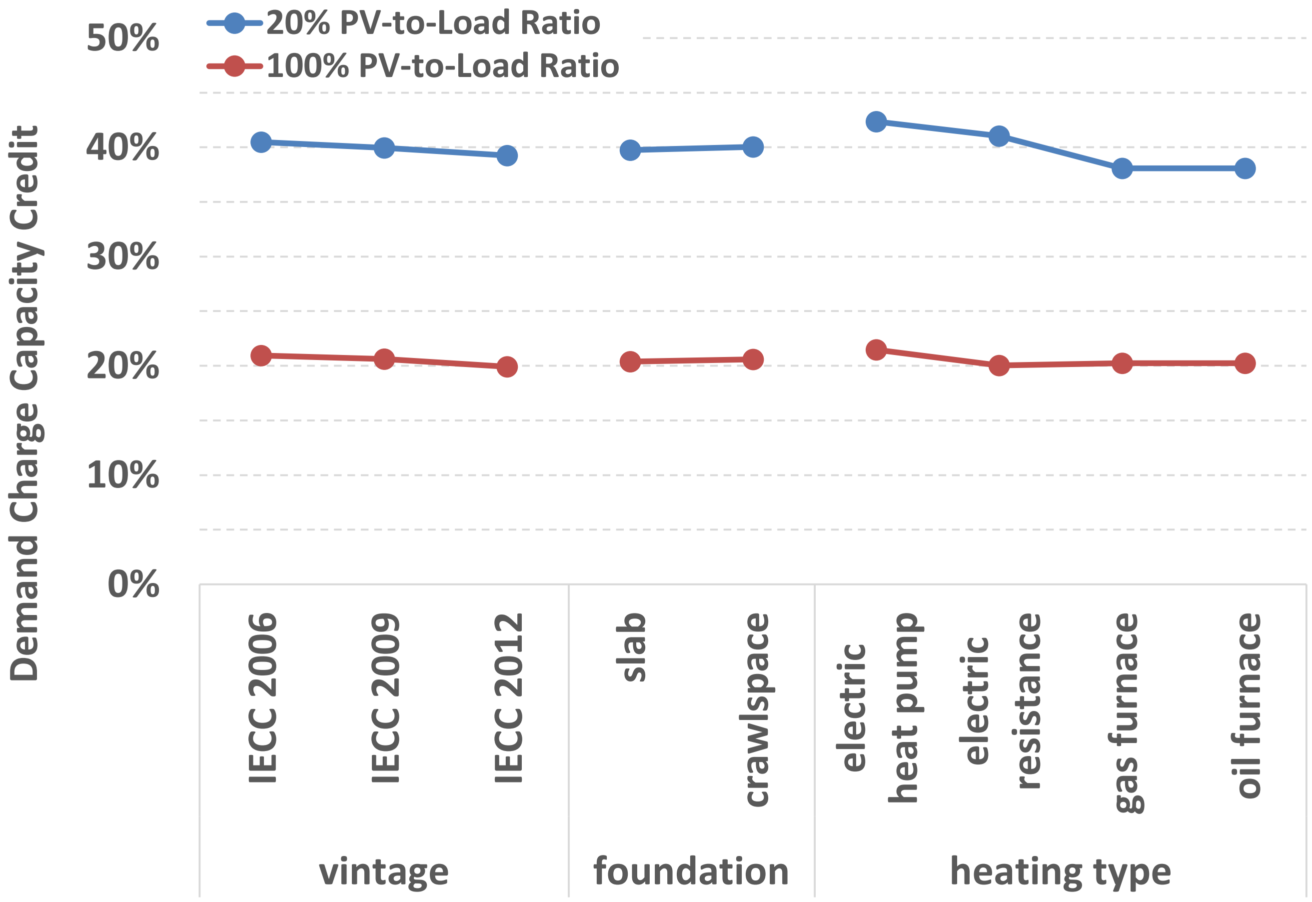
Distribution of DCCC for demand charges with and without a ratchet (set at 90% of rolling 12-month peak)



- Ratchets have little discernible effect when combined with the “basic” non-coincident demand charge
  - Demand charge savings are already low/zero
- Effects of ratchet are more pronounced for demand charge design based on 12-4 pm peak period
  - Months when PV does not reduce billing demand are likely to set the ratchet, limiting the ability of PV to reduce demand charges in subsequent months
  - Further investigation of the simulation results show that impacts are especially pronounced in cloudy cities

Building Characteristics Generally Have Small Impacts on Demand Charge Savings

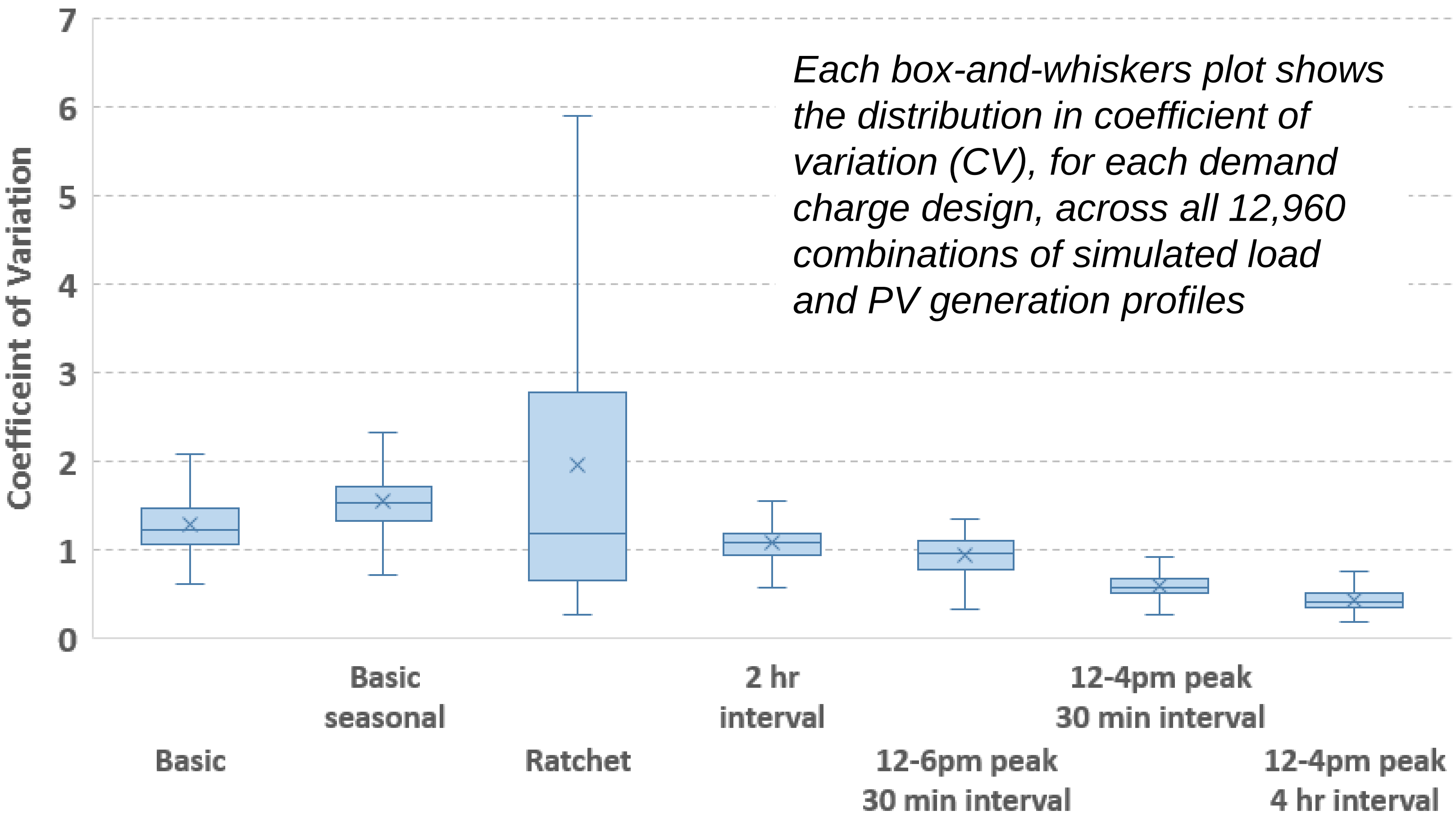
DCCC across building vintages, foundation types, and space heating types: For system installed in Phoenix and a demand charge based on 12-4 pm peak period



- **Building Vintage:** Slight reduction in capacity credit with newer, more energy efficient building vintages
- **Foundation Type:** Negligible differences between slab and crawl space
- **Heating Type:** Electric heating has slightly higher capacity credit levels; this is due to increased heating load during the peak period, allowing PV a deeper reduction in the demand charge in some months

Monthly Variation in Demand Charge Savings Is Lowest for Demand Charges Based on Peak Periods and Long Averaging Intervals

$$\text{Coefficient of Variation} = \frac{\text{Standard deviation in monthly } DCCC}{\text{Mean DCCC over 17 year analysis period}}$$



- Demand charge savings vary significantly from month-to-month, as measured in terms of the coefficient of variation (CV)
  - Demand charges with ratchets have the greatest monthly variability, as demand charge savings in some months are limited by the ratchet
  - Demand charges based on peak periods have relatively low month-to-month variation (though still have CVs up to 50%)
  - Longer averaging intervals reduce variability
- Variation shown here is based primarily on weather variability
  - Use of simulated loads likely understates actual month-to-month variability

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Conclusions (1)

- Solar is not efficient at reducing residential demand charges when billing demand is set by the monthly customer peak
- Some demand charge designs allow solar to reduce billing demand more effectively, such as daytime peak demand charges, when higher demand levels can be displaced by solar generation
- Much of the range in capacity credit levels for a given simulated demand charge design are a result of differences in PV system size and customer's location
- Each incremental kW of PV installed becomes less effective at reducing demand charges, for most demand charge designs considered
- Southwest- and West-facing panels tend to have higher capacity credits than South-facing panels for demand charge designs with peak windows in the afternoon and small PV-to-load ratios

Conclusions (2)

- Demand charge savings are higher in sunny locations
- Longer time averaging interval windows lead to higher capacity credit levels
- Demand charge designs with a seasonal element can increase average capacity credits if capacity credit levels are higher in the high season months
- Ratcheting tends to decrease demand charge savings, as ratchets are often set during cloudy months which limits the ability for PV to reduce the demand charge in other months
- There are substantial month-to-month variations in residential demand charge savings

Policy Implications

- Moving away from fully volumetric electricity rates to demand charges + lower volumetric rates will generally reduce bill savings from residential solar with net metering
  - Load management or storage, though not considered in this analysis, could mitigate this to some extent
  - Orienting PV panels to the Southwest or West has limited value in mitigating reduced bill savings
  - Use of demand charges would likely encourage smaller PV systems
- Though this study does not directly compare demand charge savings to utility cost savings, the results suggest that demand charges may, in some cases, under-compensate solar customers for savings to the electric system
  - In many cases, demand charge capacity credit is close to zero, which may not realistically reflect solar capacity value across the entirety of the electric system (generation, transmission, and distribution)
  - Little economic rationale for providing lower demand charge savings per kW to larger systems
- Demand charge savings from solar also tend to be quite volatile from month to month, which can also impact financial viability of new projects
- Some demand charge designs—specifically, those based on peak demand during afternoon peak periods, and with relatively long averaging intervals—retain greater potential bill savings from solar

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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

- Residential Prototype Building Models (https://www.energycodes.gov/development/residential/iecc_models), developed by the Pacific Northwest National Laboratory, were selected for the 15 cities considered in the analysis.
- Only single-family homes with either a slab or crawlspace foundation and either a electric resistance, heat-pump, natural gas furnace or oil furnace for heating 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 output 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 Capacity Credits

Heat maps show DCCCs for various peak demand charge definitions with a 30 minute averaging interval window

Seattle

	ending hour										
beginning Hour	10	11	12	13	14	15	16	17	18	19	20
8	5	5	6	6	7	7	7	6	5	3	2
9	-	7	8	8	9	9	8	7	5	2	1
10	-	-	9	9	9	9	9	7	4	2	1
11	-	-	-	10	10	10	9	7	4	2	1
12	-	-	-	-	10	10	9	6	4	2	1
13	-	-	-	-	-	10	8	6	4	2	1
14	-	-	-	-	-	-	9	6	4	2	1
15	-	-	-	-	-	-	-	6	4	2	1
16	-	-	-	-	-	-	-	-	4	2	1
17	-	-	-	-	-	-	-	-	-	2	1
18	-	-	-	-	-	-	-	-	-	-	1

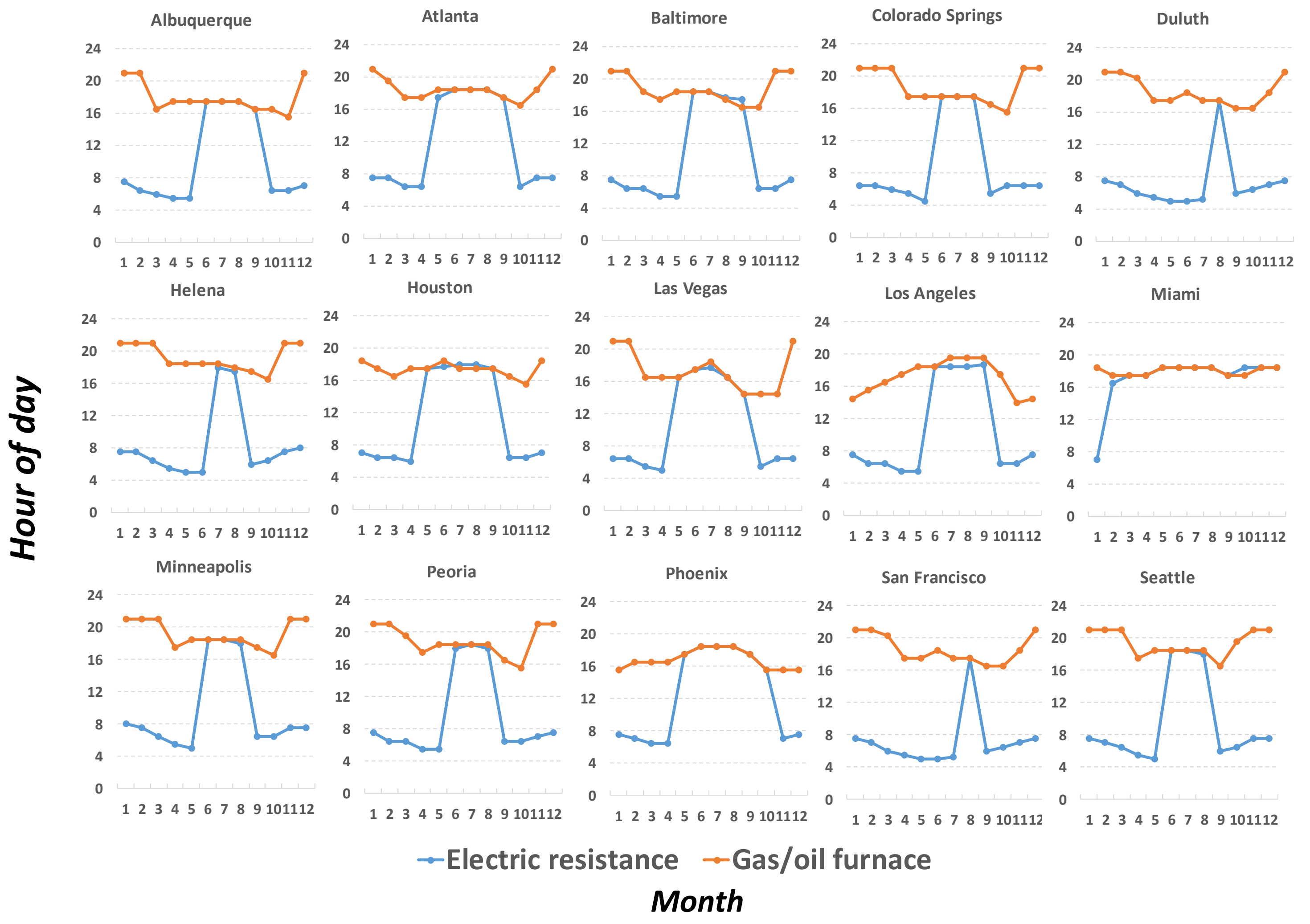
Phoenix

	ending hour										
beginning Hour	10	11	12	13	14	15	16	17	18	19	20
8	13	15	17	19	20	20	19	16	11	6	5
9	-	21	23	25	26	25	23	18	12	7	5
10	-	-	27	28	28	27	24	19	12	6	4
11	-	-	-	30	30	28	25	19	12	6	4
12	-	-	-	-	31	29	25	19	12	6	4
13	-	-	-	-	-	30	26	19	12	6	4
14	-	-	-	-	-	-	27	19	12	6	4
15	-	-	-	-	-	-	-	20	12	6	4
16	-	-	-	-	-	-	-	-	11	6	4
17	-	-	-	-	-	-	-	-	-	5	3
18	-	-	-	-	-	-	-	-	-	-	2

- Capacity credits are relatively high over a large range of TOU definitions.
- As ending hours advance into the evening hours, beginning hour has little effect on the capacity credit level.
- Though the capacity credit levels can vary significantly by location, the peak definitions that lead to highest capacity credits are similar.

Hour of Customer Peak Demand Is Often Outside the Period When PV Generates Electricity

Median peak hour by month for all cities simulated



- Summer residential peaks are often between 5 pm and 8 pm for most cities simulated
- Non-electric heating has earlier peaks in summer (due to AC load)
- Electric heating leads to early morning peaks (5-7 am)
- Nationwide, 63% of households use oil or natural gas as their main heating fuel and 29% use electricity*
  - Regional trends can vary significantly however

* from Residential Energy Consumption Survey 2009

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