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Optimizing solar capacity for commercial-scale PV systems: An empirical cost-benefit framework for all stakeholders

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ABSTRACT

The conventional approach to developing commercial behind-the-meter solar discounts peak demand savings and focuses on maximizing the number of installed panels with little consideration for optimizing economic benefits to solar customers, much less for utility ratepayers. While a select number of studies similarly point to the peak demand reduction benefits of distributed solar, they typically rely on simulations and theoretical models to support their conclusions. In contrast, this study draws on a wealth of empirical data from a commercial solar development company, demonstrating consistent peak demand savings for various solar customers as well as grid-scale benefits to utilities and their ratepayers. Using 5- to 30-minute interval data from solar arrays and utility meters, we analyze the impact of solar PV on operational energy demand for nine commercial facilities in Virginia, USA. All facilities analyzed exhibited a mid-day- and summer-peaking demand profile, making them ideal for solar integration. Through analyzing both sets of interval data, we find that solar reduced monthly peak demand by an average of 22.9%, consistently shifted peak load towards off-peak hours, and reduced demand during coincident peak periods for utilities in PJM, the mid-Atlantic regional transmission organization, by an average of 42.3%. In addition to demonstrating substantial peak demand reduction, these findings emphasize the importance of systematically optimizing system capacity according to facility-level energy consumption and utility rate tariffs. This paper debunks conventional dogma that distributed solar burdens non-participants with cross-subsidization, rather highlighting the need for policies which promote distributed solar access and more equitable energy grids.

1. Introduction

Our research on commercial solar arrays builds on a rich multi-year data repository retained by Secure Solar Futures, a leading Virginia-based solar development company that finances, designs, owns, and operates over 36 MW of solar and ground-mounted arrays for numerous commercial customers including public school districts, universities, colleges, hospitals, and businesses. The findings build on the author's prior research (Smith, 2015) that showcased the benefits of solar for a university and its local utility, based on a cost-benefit methodology agreed upon with the utility, which demonstrated that net metered solar projects in fact benefit all ratepayers. This study expands on those findings to include nine facilities over multiple years, arriving at similar conclusions with farther-reaching implications. It challenges the notion that behind-the-meter (BTM) photovoltaic (PV) solar energy only benefits solar customers at the expense of other ratepayers, a claim commonly referred to as "cost-shifting" or a "cross-subsidy" [1–3]. This narrative encompasses two main aspects: the integration of solar generation within the energy grid and the financial implications of widespread adoption of distributed solar, the latter of which are particularly influenced by intentional policy choices. These components are interconnected with our existing energy system, including generation, ownership, regulation, and the industry's ability to address pressing societal challenges. Our study provides empirical insights based on detailed real-world performance data from commercial-scale PV systems, shedding light on crucial factors to consider when strategically designing solar arrays.

1.1. Narratives around solar's structural role in the grid

The claim that solar energy burdens ratepayers is based on the assertion that it is an intermittent resource and requires full backup from non-renewable sources due to passing cloud cover [1,4–7]. However,

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Nomenclature

DG	Distributed generation
PV	Photovoltaic
kW	Kilowatt
kWp	Nameplate capacity (array DC or inverter AC)
AC	Alternating current (grid-side demand and metered solar generation)
DC	Direct current (solar array generation)
IOU	Investor-owned utility
5CP	Five coincident peak (high load periods determined annually by PJM)
PS	Public school
CS	Cold storage
H	Hospital
U	University
PPA	Power Purchase Agreement
SDP	Summer- and daytime-peaking (or summer-daytime-peaking)
kWG	Demand on the grid given reduction by solar
kWT	Total facility demand between grid demand and solar generation
RMP	Reduction in monthly peak demand (kW) by billing period
RCP	Reduction in coincident peak demand (kW) during 5CP periods
P	Time at which peak demand occurs, either kWG, kWT, or a derivation as specified
S	Span between or shift among peak times as specified

this disregards the lowering costs and increasingly diverse applicability of renewables over the past decade, as well as the high costs of natural gas peaker plants [8–15].

Furthermore, the “duck curve” is commonly used to invalidate solar adoption, but this ignores numerous geographic and seasonal dynamics at play. In regions with significant summer cooling load, demand peaks shift closer to mid-day when solar production is highest. For example, in Virginia, as well as on average in PJM, the regional transmission organization (RTO) PJM in which the state falls, the grid load exhibits a duck curve only in winter. Fall and spring (“shoulder months”) have lower, relatively flat daytime peak load, while summer experiences a prominent mid-afternoon peak, surpassing other months by 20–30 % [16].

This compatibility with seasonal grid load generally holds true throughout much of the United States, with some colder regions exhibiting faint duck curves during shoulder months, while warmer and southerly regions experience not only peaks of greater magnitude in summer months, but also more prominent mid-afternoon peaks during shoulder months (based on data from 2015 to 2019) [17]. Given this critical niche solar can fill, our study focuses on the effectiveness of solar PV in offsetting daytime and summer peaks, both for individual customers and the grid. We analyze commercial PV arrays, demonstrating the capability and reliability of distributed solar as a sustainable alternative to fossil fuel generation.

1.2. *Economic and policy structures surrounding solar*

Extending from physical infrastructure and technological advancements, the financial incentives and policies surrounding solar energy play a crucial role in its competitiveness and growth in the energy market. Fossil fuel proponents and investor-owned utilities often argue against policies such as net metering and federal tax incentives, effectively claiming that they unfairly subsidize wealthy households and businesses at the expense of low-income households [18,19,2]. However, our research provides evidence to the contrary due to reduced need for expensive generation as well as transmission and distribution (T&D) strain incurred by utilities during peak load periods. Implementing regulations that require utilities to pass on these financial savings and promote decentralized renewable energy generation could benefit all ratepayers.

A kernel of truth does exist surrounding the potential for solar incentives to widen economic inequality. This, however, is a product of broader systems encompassing the consolidation of ownership, rate structures, and active deregulation in the energy industry, which are frequently perpetuated by investor-owned energy utilities through tight control over renewable generation expansion [20–22]. Disproportionate economic benefits to already affluent solar customers will not begin or end with distributed solar, and discouraging the adoption of distributed solar will not serve to mitigate cost-shifting.

Furthermore, investor-owned utilities, which are heavily reliant on fossil fuels and exercise monopolistic control over energy markets, frequently impose significant rate hikes on customers [21,23,24]. Utilities such as Dominion Energy and Appalachian Power Company in Virginia have implemented substantial rate increases exceeding 10 % annually in response to economic and geopolitical events between 2020 and 2022 [25–27].

By eroding regulatory standards and prioritizing projects that yield high returns for shareholders, such practices by investor-owned utilities prioritize short-term gains over customer savings [24,28–31]. They also retain tight control over the expansion of renewable generation by writing state legislation and by imposing interconnection barriers, standby charges, and minimum bills to create barriers to entry [32–34]. These measures perpetuate market share and avoid the short-term costs of transitioning to renewable infrastructure [20–22]. Utility-owned solar initiatives enjoy a guaranteed rate of return on generation assets, while meeting regulations such as renewable portfolio standards (RPS) [29–33,35,36]. This reinforces an inequitable and centralized economic structure in energy generation, favoring utility-scale solar projects while undermining distributed generation (DG) and net metering [37–40].

Our research provides concrete examples demonstrating the reliable applicability of distributed solar in reducing peak demand across various commercial facilities. Along with other DG technologies, this has the potential to subvert the paradigm of centralized, monopolistic ownership of energy grids, highlighting a clash of interests among individual, corporate, and regulatory stakeholders in the energy industry [41–43].

1.3. *Scope and relevance within current research*

Our analysis focuses on commercial-scale solar photovoltaic (PV) systems for customers with summer-daytime-peaking (SDP) demand and an electric demand tariff. This represents a subset of the 17.4 % of total energy consumption in the United States attributed to commercial buildings in 2022 [44]. In this study, summer-peaking is defined as having the highest monthly peak demand (before solar) between May and August, while daytime-peaking refers to regular demand peaks occurring between 11:00 AM and 4:00 PM with minimal spikes during off-production hours. All facilities included in our analysis meet these criteria.

The scope of our empirical data, the performance insights they provide, and our methodology for optimizing solar array capacity represent a unique addition to prior work in the field. As further detailed in Sections 2.1 and 2.2.1, we apply a combination of detailed electric meter and billing data from utilities, solar generation interval data from owned arrays, and historical records of coincident peak periods from the regional transmission organization PJM.

Our empirical analysis demonstrates conclusively that commercial behind-the-meter (BTM) distributed solar consistently offsets various types of grid demand. We define demand reduction as the decrease in peak billed kilowatts (kW) resulting from solar generation during monthly billing periods, 12-month periods (if an 11-month demand ratchet is in place), and/or coincident peak periods. While solar energy is intermittent, its predictability allows for reliable demand offset in many scenarios. We recommend using the term “variable” rather than “intermittent” to describe solar PV, particularly when comparing it to other variable renewable energy sources.

While annual and daily demand profiles of commercial facilities vary based on local climates, previous research, supplemented by our own findings, shows that facilities such as schools, hospitals, retail stores, supermarkets, and warehouses (including cold storage) in temperate or warm climates are often the most suitable for daytime peak load reduction [45,46]. Our research utilizes real historical interval data from commercial facilities with solar PV to compare their demand profiles on the grid with and without solar. Additionally, we examine coincident peak (CP) data published by PJM, the regional transmission organization covering Virginia and the Mid-Atlantic region, to assess the alignment of solar generation with these periods. This analysis reveals an additional benefit where utilities and all ratepayers can consistently gain from commercial solar PV.

Existing published research, based on simulations, mathematical modeling, and limited field data, largely aligns with our findings regarding the ability of commercial solar PV to reduce both grid load and customer peak demand, benefiting all ratepayers; however, this is a relatively small body of research with impacts on coincident peak demand largely unexplored [47–50]. Moreover, commercial-scale solar customers experience significant cost savings, particularly when a substantial portion of demand charges stem from mid-day load, and further savings can be achieved with time-of-use and/or coincident peak tariffs [45,47,50,51]. However, our study contributes to a narrower subset of research by conducting highly granular performance data analyses on a wide range of commercial-scale facilities while quantifying the peak demand savings impact of solar for individual commercial customers and for the grid.

We propose that facilities with an SDP load profile, which many commercial-scale facilities exhibit, can effectively benefit from solar PV without the need for extensive backup battery storage. Furthermore, with sufficient market penetration, these savings can extend to entire energy grids and be passed on to all ratepayers through utilities, facilitating a faster, less resource-intensive, and more cost-effective transition away from fossil fuels.

2. Methodology

2.1. Optimizing system capacity in commercial-scale solar development

Our systems approach for optimizing solar capacity begins with designing and appropriately sizing the nameplate capacity of commercial-scale solar arrays. This process is informed by more concrete findings from the peak demand reduction analysis as well as financial modeling, in-person site inspections, and theoretical applications used to simulate predicted solar performance.

Before undertaking the detailed design process, we use 12 months of customer utility bills and more granular interval data to model the electricity consumption profile of a prospective facility to better understand the potential impacts of solar. Key factors to consider include the prominence of daily and seasonal total demand peaks (particularly if the facility is SDP),overall annual kWh consumption, and a spreadsheet model of the utility rate tariff associated with the particular facility. Identifying this profile can elucidate the relationship between a facility’s typical peak demand and overall kWh usage, including the typical utility charges associated with each, which can ultimately serve to establish an upper bound and/or target for optimizing solar capacity. These parameters should be further refined based on the guidance in the Results (Section 3.4) and Discussion (Section 4.3), as well as the steps below regarding the project design and planning process.

The following design steps, which draw on our analysis and development process, primarily consider financial, siting, and energy profile constraints. Note that this process is iterative and may involve circling back between steps to increasingly refine specifications and expected outcomes. They ultimately serve to derive an appropriate nameplate capacity based on system specifications, progressing as follows:

A. Develop the Customer Electricity Usage (kW and kWh) Model.

Establish a baseline understanding of the existing facility’s peak demand and energy usage patterns through a combination of:

12 or more months of electricity bills from the host customer of each facility which detail not only electricity kWh usage charges, but also kW demand charges, demand- and usage-based charges and riders, as well as other taxes and fees;

Granular utility meter readings in the form of interval data (preferably in 30-minute intervals or smaller) as detailed in Section 2.2.1, and.

Utility rate tariff analysis to reconstruct the energy bill line by line in spreadsheet form, which can then be combined with projected electricity consumption offsets by solar.

Further details regarding the typical composition of commercial electric bills and expected scenarios depending on the breakdown of charges can be found in the Results (Section 3.4) and the Discussion (Section 4.3).

B. Site-specific Solar Array Design and Field Inspections.

Site assessment: Conduct a detailed assessment of the rooftop or ground mount site, considering key factors such as orientation (i.e., solar azimuth), tilt, shading, and available space. This involves understanding the physical characteristics of the site to optimize solar exposure.

System configuration: Using the commercially available HelioScope software, input relevant system configuration parameters, including the type and efficiency of solar panels, inverter specifications, and other system components. These settings can be customized to match the specific requirements and characteristics of the solar project.

Shading analysis: Utilize HelioScope’s shading analysis tools to assess potential obstructions that could impact solar panel exposure and efficiency. This involves inputting nearby objects such as buildings or vegetation to optimize panel placement.

Solar panel layout: Working around shaded zones and other unsuitable installation areas, use the platform’s design tools to create an optimized solar panel layout on the rooftop or site. HelioScope allows users to experiment with different configurations and orientations to maximize energy production while maintaining placement constraints.

Performance simulation: Helioscope simulates the solar system’s performance based on the configured parameters and the designed layout. The platform uses local weather data, shading analysis, and other factors to estimate energy production over time. This simulates key outputs for a year, also broken down into hourly and monthly intervals.

Energy yield estimates: Review the energy yield estimates provided by HelioScope, which indicate the expected amount of electricity the solar array will generate over different time periods. This information is crucial for understanding the system’s potential impact on energy needs.

System optimization: Return to HelioScope to fine-tune the solar array design and configuration based on the results of the simulation. HelioScope allows users to make adjustments and optimize the system for maximum energy production given design constraints.

Report generation: Generate detailed reports that summarize the system specification and layout, performance estimates, and other information relevant to the customer. These reports can be used for project documentation, stakeholder communication, and decision-making.

Project documentation and export: Document the finalized solar array design within HelioScope and export relevant data for further integration with other tools or sharing with project stakeholders. Also note that the financial analysis tools offered by Helioscope are not used for optimizing solar capacity, as the financial analysis is independently performed in steps C and D described below.

C. Pre- and Post-solar Project Financing Analysis.

Merge and analyze solar capacity datasets: Input HelioScope solar generation data from step B into the customer electricity consumption model described in step A to evaluate the predicted solar generation in reducing metered kW demand and kWh usage over an annual period.

Optimize solar capacity based on energy savings to the customer: Apply a marginal cost-benefit analysis to determine the optimized solar capacity which will ultimately maximize the realized energy savings for the customer in terms of overall energy costs ($/kWh) and demand savings ($/kW). As explored in Section 4.3, an optimal strategy may entail maximizing either peak demand reduction, annual kWh consumption, or a balance of both. As discussed in Step D below and in the Section 3 in the Results, the maximum available rooftop (or ground-mount) footprint for a solar array often does not equate to the maximum economic benefit for the customer.

D. Long-term Modeling to Optimize Solar Capacity and Financial Returns.

Finally, using assumptions and inputs from the previous steps, model cashflow projections to show customer savings during year one after the project is placed in service, as well as total net savings (after deducting PPA fees) over the 20- to 25-year term of the contract and the projected return on capital investment based on debt financing costs and/or financing hurdle rates.

Estimate system development costs: Obtain engineering, procurement, and construction costs for installing the project.

Calculate financing outcomes: Model the costs of total project development, installation, and maintenance against assumptions about ideal monetization of tax benefits, power purchase agreement (PPA) revenue, and annual escalators among utility rates and developer costs.

Create an integrated financial model based on stakeholder returns: Integrate Steps A-C and D 1 and 2 into a dynamic XIRR financial model that responds dynamically to capital and operating system expenses for the life of the PPA terms. Key inputs include terms of any debt financing and investor hurdle rates; PPA fee and any PPA escalators; electric utility costs and assumed escalators based on historical utility rate data; Engineering, Procurement and Contracting (EPC) costs and estimated dates for capital expenditures and milestone completion dates; and a Solar Value Analysis that provide the Customer with a cost-benefit cashflow model for the PPA term, taking into account PPA fees, solar generation, and net savings in a 20 to 25 year cashflow.

Marginal utility bill analysis: Evaluate the costs-benefits for each additional increase in the solar capacity against the actual savings to the customer per installed kW of solar array, to optimize solar capacity to maximize actual savings in terms of peak demand kW and electric usage in kWh. Put in other terms, seek to minimize the diminishing marginal utility of over-sizing the solar capacity to achieve the "sweet spot" for peak demand shaving at the lowest solar capacity.

Ongoing model refinement: Optimize solar financial model based on real-time changes in supply-chain constraints, inflation rates, utility interconnection requirements, permitting requirements, and changes to solar array capacity based on engineering.

2.2. Peak demand reduction analysis

The first and largest portion of the methodology outlines the empirical process by which we combine real historical interval data of solar generation and each facility's corresponding demand on the grid to measure solar demand reduction on various temporal scales. This involves analyzing the real historical demand profiles across a diverse set of nine commercial facilities.

2.2.1. Data Sources, research Area, and sampled projects

The data repository retained by Secure Solar Futures primarily includes 5-minute interval data generated from the data acquisition system (DAS) for each facility's solar array, recording data on the following metrics in a cloud-based storage system:

- kW production
- Cell temperature
- Air temperature
- Irradiation at the plane of array

Additionally, we accessed the following data to model solar's interactions with the grid:

- Interval data of kW demand measured by the customer's meter from the utility, confidentially acquired from each utility via the customer. Utilities provided these data in intervals of 30 min or less with records spanning one to three years, all depending on the utility's recording and handling of data.
- Dates and times of the five summertime coincident peak periods ("5CP") for each year published by PJM, the regional transmission organization, indicating hours at which the regional grid experienced its annual peak load.

Our analysis encompasses a diverse range of commercial customers with summer-daytime-peaking (SDP) demand and utility demand tariffs, highlighting those who can benefit significantly from solar-induced demand reduction. The sample includes three public school facilities (two of which are actually pairs of schools metered jointly as a single facility), three cold storage facilities, one hospital, and two university facilities. This sample was narrowed from a larger body of potential facilities primarily due to data quality and access considerations as well as a necessity for arrays exceeding a year in service. These facilities are served by four different utilities and five rate tariffs in Virginia: Dominion Energy (Schedules 100 and GS-2), Appalachian Power Company (306), Shenandoah Valley Electric Cooperative (B-13), and Rappahannock Electric Cooperative (LP-1). The first two utilities are large investor-owned companies, while the latter two are member cooperatives.

2.2.2. Data organization

For each facility, we aligned 12 or more months (some facilities had multiple years) of utility interval data (post-solar installation) with solar production data, all of which represented average kW readings over a specified interval. To match the solar and grid interval data accurately, we adapted to the interval duration used by each utility for grid demand data, which was either 5, 15, or 30 min. This alignment allowed us to reconstruct the demand profile for each facility, combining solar generation and grid demand at any given time. Our method of reconstructing "total" demand closely follows previous studies, with data resolution equal to or greater than comparable examples, thanks to the availability of solar production data in 5-minute intervals [47,49–55]. In cases where solar generation data needed to match the grid load readings from the metered data, some solar generation values were averaged over 15- or 30-minute intervals. Additionally, we derived kilowatt-hour (kWh) values from the interval data for grid load (kWG) and total demand (kWT) by summing 5-minute kW values and dividing by 12, allowing us to quantify kWh usage and corresponding kWh offsets during different time periods as indicated.

2.2.3. Calculating peak demand reduction and shifting

Initially, we determined the grid peak demand (based on the highest interval kW data from the grid) and total peak demand (combining the highest of grid and solar interval kW data) for each monthly billing period analyzed at each facility. In this study, grid demand is denoted as "kWG" and total demand is denoted as "kWT," These terms specifically

Table 1
List of analyzed facilities and key solar generation and billing information corresponding to each. *Note: For more background into the variability of array nameplate capacity relative to average annual kWh offset, see Section 3.3.*

Facility Name	Facility Type	Facility Code	Range of Available Data	Array kWp	Array Avg. Annual kWh Offset	Utility	Utility Rate Tariff	Data Interval
Wilson Elementary School	Public School	PS-1	Dec. 2020 – Nov. 2021 (12 mos.)	351.5 DC (276.0 AC)	35.3 %	Dominion Energy	100	30 min.
Stuarts Draft Elementary & High School	Public School	PS-2	Jan. 2021 – Dec. 2021 (12 mos.)	620.2 DC (470.0 AC)	23.7 %	Shenandoah Valley Electric Cooperative	B-13	5 min.
Fort Defiance High School & Clymore Elementary School	Public School	PS-3	Jan. 2021 – Dec. 2021 (12 mos.)	642.7 DC (570.0 AC)	36.0 %	Shenandoah Valley Electric Cooperative	B-13	5 min.
InterChange – Port Services	Cold Storage	CS-1	Jan. 2018 – Oct. 2022 (46 mos.)	277.2 DC (230.0 AC)	16.2 %	Rappahannock Electric Cooperative	LP-1	15 min.
InterChange – cPad2	Cold Storage	CS-2	Mar. 2020 – Feb. 2021 (12 mos.)	96.6 DC (89.1 AC)	82.2 %	Dominion Energy	GS-2	30 min.
InterChange – Blue Stripe	Cold Storage	CS-3	May 2019 – Sep. 2022 (41 mos.)	591.0 DC (480.0 AC)	137.5 %	Shenandoah Valley Electric Cooperative	B-13	5 min.
Carilion New River Valley Medical Center	Hospital	H-1	Jan. 2018 – Dec. 2020 (36 mos.)	1,379.7 DC (1,206.0 AC)	14.3 %	Appalachian Power Company	306	15 min.
Shenandoah University – Wilkins Athletics & Events Center	University	U-1	Feb. 2021 – Jan. 2022 (12 mos.)	363.3 DC (295.0 AC)	36.9 %	Shenandoah Valley Electric Cooperative	B-13	5 min.
Shenandoah University – Smith Library	University	U-2	Feb. 2021 – Jan. 2022 (12 mos.)	46.6 DC (36.0 AC)	4.7 %	Shenandoah Valley Electric Cooperative	B-13	5 min.

refer to monthly peak demand periods or demand during any other specified period. The total demand represents an estimation of the customer's demand profile without solar, allowing us to derive the actual demand reduction by solar during each period. For this purpose, we use "RMP" to indicate Reduction in Monthly Peak demand. The calculation for monthly peak demand reduction is as follows:

$$RMP = KWT_{all} - KWG_{all}$$

where subscript $_{all}$ denotes the maximum among all kW values in a given month.

Calculated average RMP values are shown in Fig. 1a, while variance among kWG and kWT values for each facility are shown using a grouped boxplot (Fig. 1b). Additionally, the distribution of RMP values by time of day is plotted in Figs. 3a and 3b. Figs. 1b, 3a, and 3b were generated using the R statistical language (ver. 4.2.2) and RStudio (ver. 2022.12.0 + 353) with the ggplot2 package (ver. 3.4.1), while Microsoft Excel was used for all underlying data preparation and to generate all remaining figures.

In addition to illustrating the level of peak demand reduction, our analysis revealed the extent of temporal peak shifting from higher midday demand peaks to lower peaks occurring in the morning and evening due to solar generation. We determined the degree of shifting by calculating the time of the total peak within each monthly billing period and averaging these times across all available months ("P_{TA}" - usually falling in the early afternoon). This established an annualized baseline to generalize the facility's total consumption patterns, against which solar's monthly contribution to grid peak shifting towards or away from the average total peak time, or net peak shift ("ΔS"), could be evaluated. To determine net peak shift for each month, we calculated the time of day at which the grid peak ("P_{GM}") and total peak ("P_{TM}") occurred within the month's billing period, the time spans between each peak time and the average annualized total peak time, which are denoted respectively as "S_{GM}" and "S_{TM}", and finally the difference among the absolute values for each span. These net peak shift values are comparable between facilities and can be aggregated across months. Note that we used an "HH:MM" format to encode time in Microsoft Excel when calculating ΔS, but this principle applies to any method of encoding time. For each facility in a given month, the net peak shift is calculated as follows:

$$S_{GM} = P_{TA} - P_{GM}$$

$$S_{TM} = P_{TA} - P_{TM}$$

$$\Delta S = |S_{GM}| - |S_{TM}|$$

Finally, we generated time-of-day graphs to show the net impact solar peak demand reduction and shifting across annual and seasonal periods. For Figs. 4a-4d, we calculated the maximum kWT and kWG values for each 15-minute interval across all years of available data as indicated, averaging all values within each preceding 15-minute period if necessary. To plot expected net demand reduction for the hospital in Fig. 4e, we identified single months (January, April, July, and October averaged across both years of available data) to represent each season, averaging kWT and kWG along the same 15-minute intervals. We chose single months as an approximate middle of each season rather than averaging across three months at a time to avoid transitional periods between each season, which would dilute average calculations and diminish the difference between peaks, shoulders, and minima among inter-seasonal kWT and solar generation trends.Fig. 5

2.2.4. Calculating coincident peak demand reduction

We applied a similar method to the previous section to estimate the potential solar peak demand reduction during the five summertime coincident peak (5CP) times identified by PJM. These 5CP periods represent the periods at which the regional grid experiences its highest load, resulting in increased costs for utilities and ratepayers due to the increased reliance of natural gas peaker plants and elevated transmission and distribution (T&D) strain. Typically, the 5CP times occur on summer weekdays in the mid to late afternoon due to substantial cooling load. By calculating the difference between the average grid demand and total demand during these hour-long periods, we approximate solar's capacity to reduce coincident peak demand ("RCP"). Similar to RMP, RCP is calculated as follows:

$$RCP = KWT_{CP} - KWG_{CP}$$

where subscript $_{CP}$ denotes the maximum among values kW within each coincident peak period as listed in Table 2.

2.2.5. Aggregation of results

After applying this process to all facilities that met the criteria for summer-daytime-peaking (SDP) load profiles, the analyzed data on peak demand and 5CP offset were aggregated to evaluate solar performance both at the individual facility level and overall. Key metrics used to

Table 2
Historical PJM 5CP periods over the five years analyzed (2018–2022). Times listed represent the end of each period, with the preceding hour encompassing the entire coincident peak period (e.g., 17:00 includes all data points with timestamps > 16:00 and ≤ 17:00).

2018	2019	2020	2021	2022
6/18/2018 17:00	7/10/2019 18:00	7/6/2020 15:00	6/29/2021 17:00	7/20/2022 18:00
8/27/2018 17:00	7/17/2019 17:00	7/9/2020 18:00	7/6/2021 17:00	7/21/2022 17:00
8/28/2018 17:00	7/19/2019 18:00	7/20/2020 17:00	8/12/2021 17:00	7/22/2022 18:00
9/4/2018 17:00	7/29/2019 17:00	7/27/2020 17:00	8/24/2021 18:00	8/3/2022 18:00
9/5/2018 17:00	8/19/2019 17:00	7/29/2020 18:00	8/26/2021 16:00	8/8/2022 16:00

assess solar performance, both for each facility and across all facilities, included the following:

- average reduction in monthly peak demand (RMP) as a percent of average total peak demand (kWT),
- the degree to which load shifted away from the average total peak time across all months (i.e., the proportion of months in which ΔS was positive),
- average reduction in coincident peak demand (RCP) as a percent of average total peak demand during coincident peak periods (kWT_{CP}), and
- the magnitude of RMP and RCP relative to the total DC power rating of each facility's solar array.

These metrics provide valuable insights into the effectiveness of solar in reducing peak demand and its impact in relation to the capacity of each facility's solar installation.

2.2.6. *Validation and further applications of methodology*

Other studies have conducted interval data analyses, utilizing real or simulated data on grid demand and solar generation. Some have also employed similar approaches to model battery storage optimization strategies or estimate future peak demand reduction by solar [47–49,51–57]. However, our research stands out due to its comprehensive scope and scale, combining empirical retroactive and future-looking analyses to systematically refine capacity and evaluate customer- and grid-level benefits. We have examined a wide range of commercial facility types and utilized real historical data to reconstruct highly detailed evaluations of solar performance and customer load profiles. This approach is relatively unique in the field. Additionally, our analysis incorporates more recent advancements in technology and financial modeling for solar projects, building upon previous groundbreaking research on solar's capacity for peak demand reduction [48,49]. An additional advantage of our findings is that they can be used to generate precise historical financial savings figures for solar customers when applied to rate tariff models, primarily in terms of kWh and peak kW savings per billing period.

Commercial customers often have demand-based tariffs, where a significant portion (often around 30 % or more) of their electricity bill is determined by their peak kilowatt (KW) demand, regardless of the energy consumed (kWh). In some cases, demand-based tariffs are calculated based on a ratchet system, in which a customer's billed demand is constrained by metered demand during the previous 11 months. This can further increase the necessity for solar to provide consistent RMP throughout the year, since billed demand may differ substantially in some (lower kWG) months relative to metered demand, even if it is reduced by solar generation.

For commercial-scale customers such as public schools, universities, and cold storage facilities with peak demand occurring during daytime summer hours (SDP customers), evaluating the load profile is essential not only for optimizing solar capacity, but also determining the optimal azimuth and tilt angle. For instance, if the peak load typically occurs in the afternoon, an azimuth of 190 degrees (south-southwest) may yield better results than a true south azimuth. Additionally, analyzing the load profile can help identify opportunities for demand-side management through behavioral or operational changes at the facility.

3. Results

These findings offer distinct benefits to two groups: commercial solar customers and utilities, which should ultimately include all ratepayers, including non-solar customers in particular. Commercial solar customers benefit from reduced peak demand charges on their monthly utility bills, as well as potential savings during coincident peak demand periods if they are on a 5CP tariff. Non-solar participants, on the other hand, could by rights save money due to reduced generation and transmission costs incurred by utilities during periods of high grid load, especially 5CP periods. Therefore, if regulations were to require such benefits to be distributed to ratepayers, the consistency and reliability of such demand reductions would be advantageous for all stakeholders.

Furthermore, it is worth noting that while this analysis focuses exclusively on commercial facilities, the principles can extend to other solar applications such as residential, community, and utility-scale solar. In theory, these segments could also generate net benefits for non-solar customers on the grid. This is possible because the overall temporal patterns of solar generation and grid load considered in this study can be translated to these segments if there is proper interconnection and/or net metering with the grid. Conversely, the demand savings for individual solar customers in other market segments will depend on factors such as array capacity, usage patterns, and the structure of the demand tariff, if applicable.

3.1. *Customer peak demand reduction*

Peak demand reduction by solar varied depending on the capacity of the array at each facility. Nameplate capacities ranged between 46.6 and 1,379.7 kW (DC). The average summer (May-August) reduction in monthly peak demand (RMP) by solar ranged from 16.9 to 626.6 kW (AC), while average annualized RMP ranged from 14.6 to 517.5 kW (AC). The systems analyzed varied significantly not only in raw capacity, but also the relative sizing of their capacity compared to facility energy consumption. Therefore, they represent a range of expected performance outcomes under SDP conditions. Considering this, the average RMP offsets were 26.1 % during the summer months and 22.9 % annually across all facilities. Figs. 1a and 1b illustrate the raw (kW) peak demand reduction by while Figs. 2a and 2b depict the percentage of peak demand reduction by facility for both summer and all months.

Fig. 1b displays the distributions of monthly kWG and kWT peaks separately. By presenting these quartile boxplots, we not only show the overall reductions in peak demand but also demonstrate the consistency, wide variability, and/or potential skewness within each kWG and kWT distribution. This visual representation provides a comprehensive understanding of the peak demand profiles and their variations across different months and facilities.

For seven out of the nine facilities, solar PV achieved higher percentage RMP during the summer months compared to the average across all months as shown in Figs. 2a and 2b. In certain individual months, the percent RMP even surpassed the 50 % mark. This indicates that solar generation exhibits more significant variations throughout the year, with prominent peaks, particularly in summer-peaking facilities, compared to the overall variations in total demand (kWT). These figures provide insights into the seasonal dynamics of solar generation and its impact on peak demand reduction, emphasizing the potential for higher percentage RMP during the summer months, which aligns with the load profiles of facilities that peak during this period.

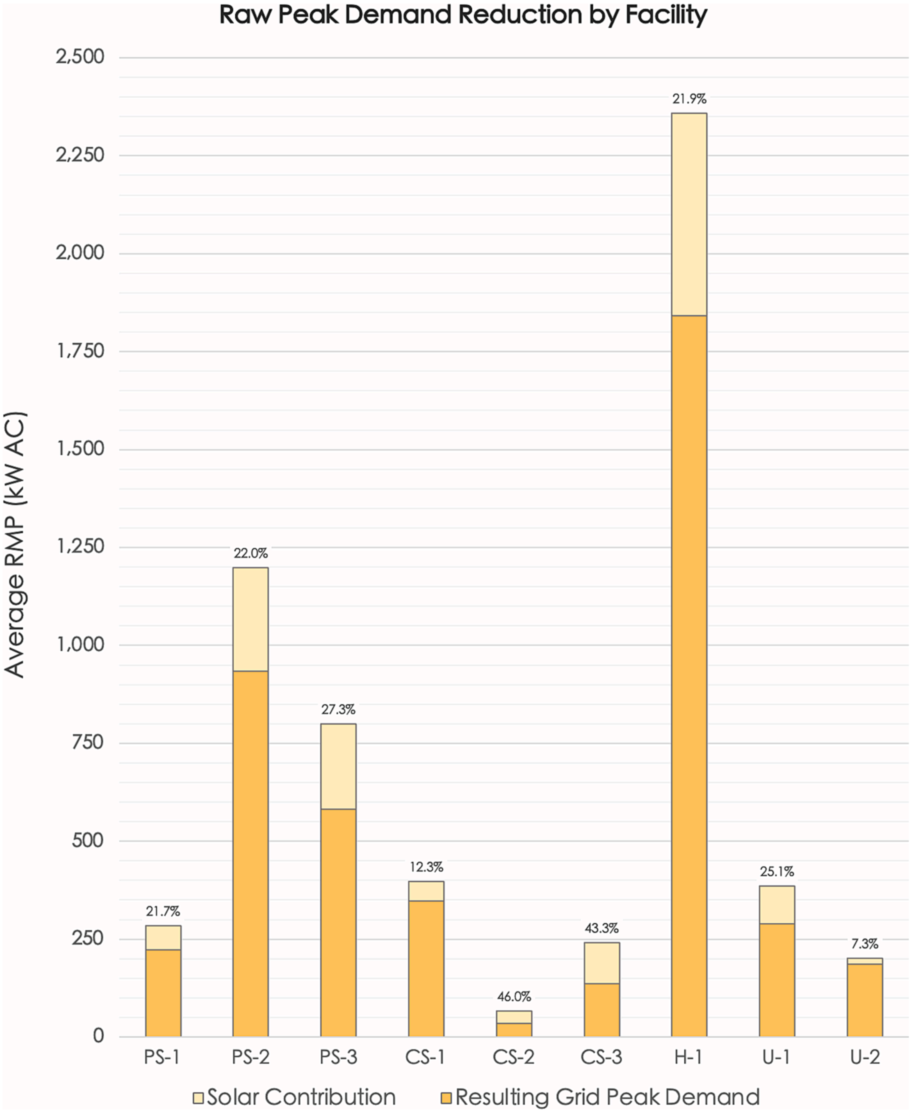

Fig. 1a. Average raw monthly peak demand reduction by solar in terms of kW (AC) at each of nine facilities (equivalent to comparing average kWG and kWT). All available data are aggregated into each customer's historical monthly billing periods, and the reductions during each period were averaged together. This chart demonstrates the difference in magnitude between all system capacities, each facility's kWG, and the resulting RMP by solar.

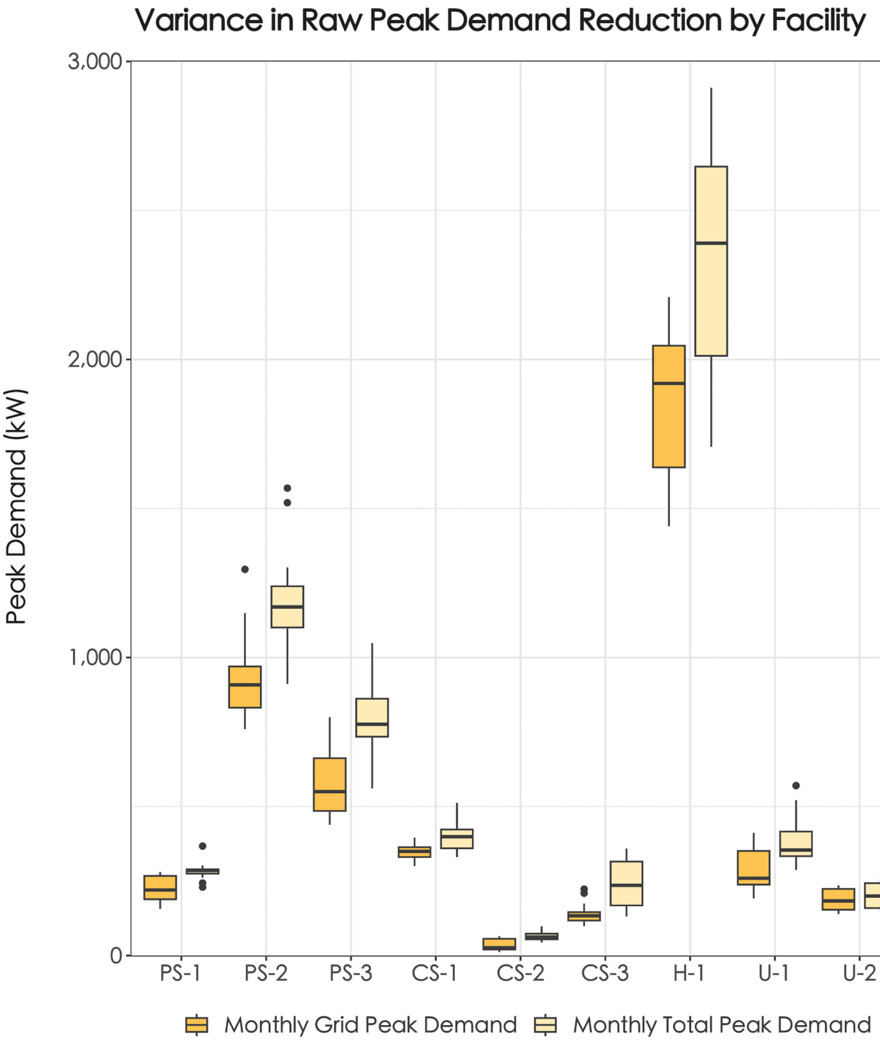

Fig. 1b. Distribution of raw monthly values for peak kWG and kWT in quartile boxplot format to display both magnitude and variance among all months of available data for each facility. The centerline represents the median, while the boxes represent the 25th and 75th percentiles, spanning the interquartile range (IQR). The whiskers extend up to 1.5 times the IQR, capturing the majority of the data, and outliers are displayed individually.

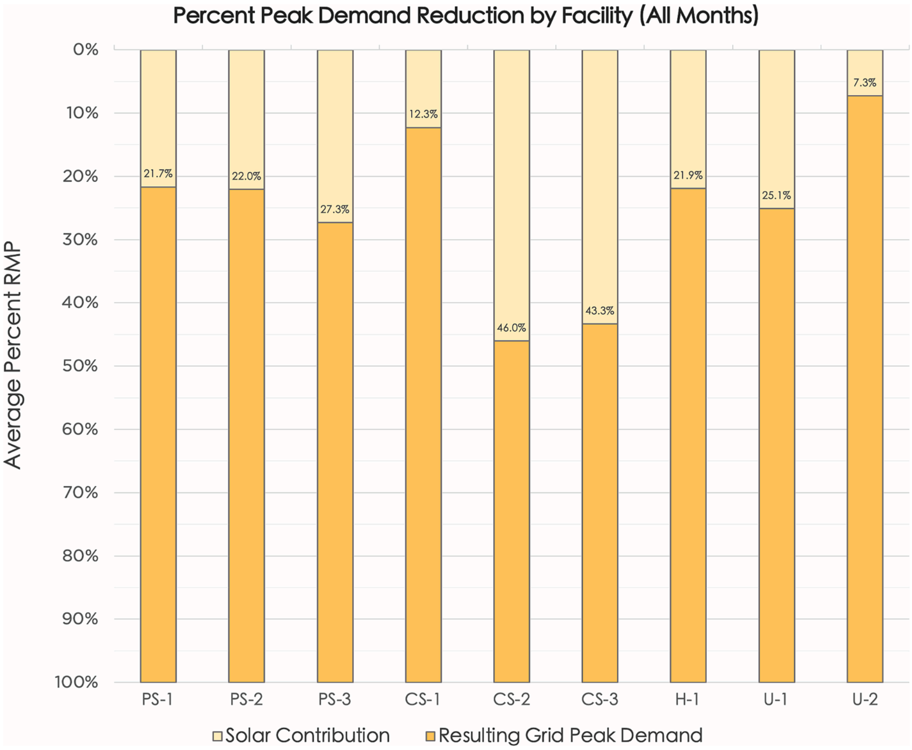

Fig. 2a. Average percentage of monthly peak demand reduction (RMP) achieved by solar at each of the nine facilities across all months of available data.

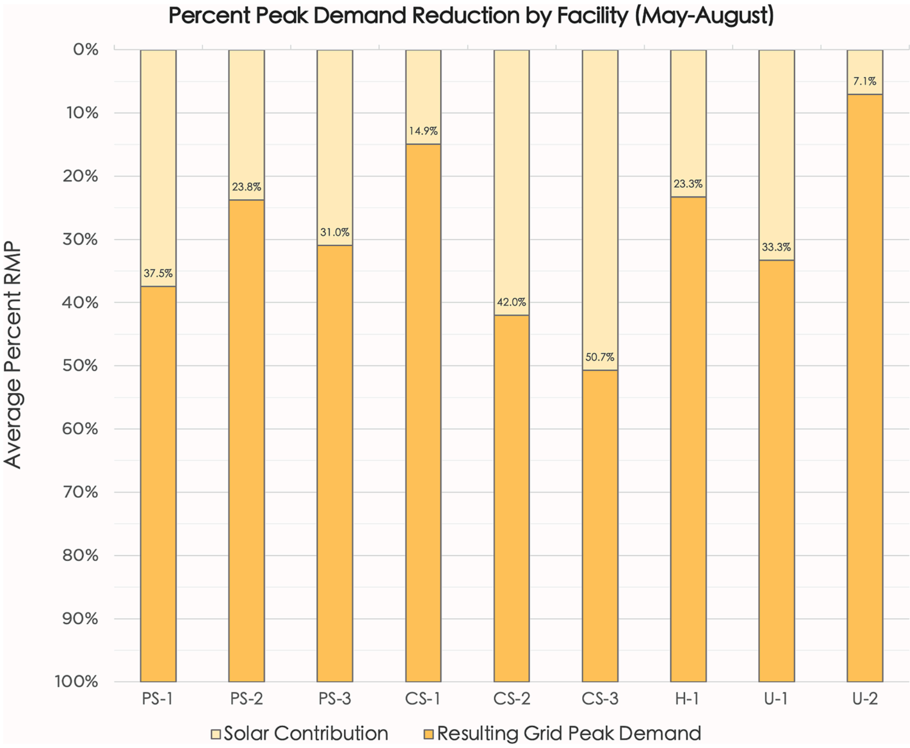

Fig. 2b. Average percentage of monthly peak demand reduction (RMP) achieved by solar at each of the nine facilities across all summer months (in this case, May through August).

3.2. Customer peak load shifting

In addition to reducing peak demand, the solar facilities we examined demonstrated a significant decrease in the number of grid demand peaks during mid-day hours due to the temporal shifting of peak load. While the magnitude of this shift can vary depending on factors such as system capacity and demand-side consumption patterns, our analysis found that 165 out of 195 months (equivalent to 84.6 % of the analyzed period) exhibited a positive net peak shift (ΔS) in peak occurrence away from the afternoon.

This indicates that in the vast majority of cases, SDP commercial customers experienced their peak demand on the grid occurring much later in the day or earlier in the morning compared to when it would have occurred without solar. Figs. 3a and 3b depict this shifting pattern

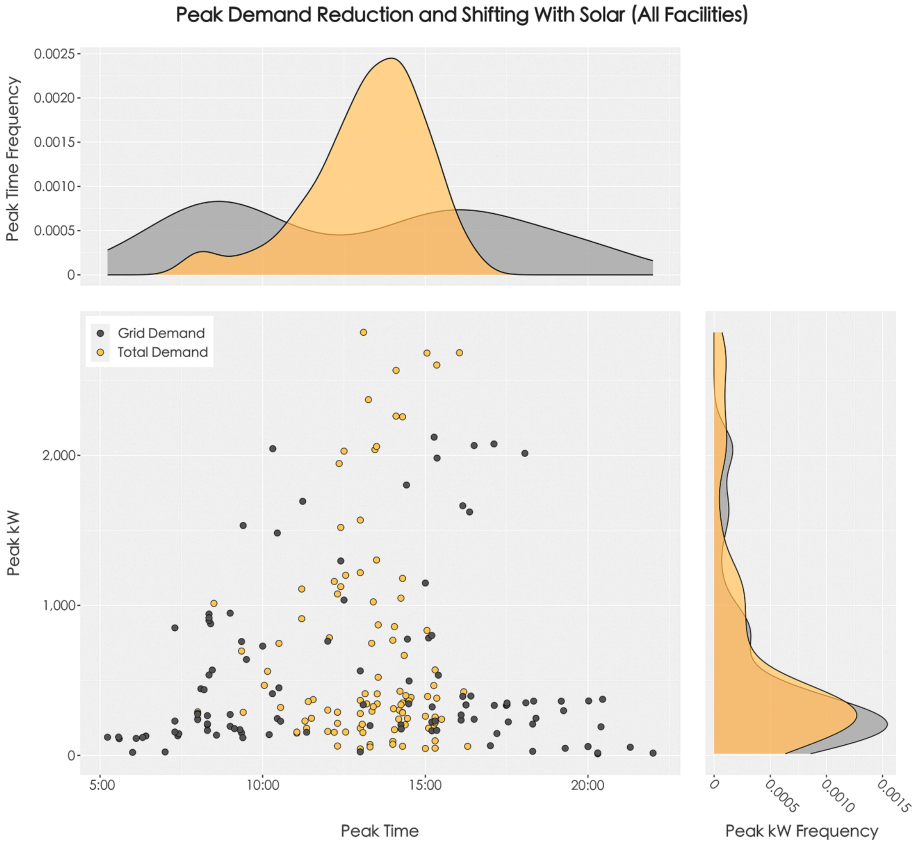

Fig. 3a. Marginal distribution plot illustrating the relationship between peak times (P_{GM} and P_{TM}) against the magnitude of grid peak demand (kWG) and peak total demand (kWT) analyzed year-round by month, encompassing the wide range of demand profiles across all nine analyzed facilities. Facilities with multiple years of data were averaged together for corresponding months, ensuring equal weighting of all facilities.

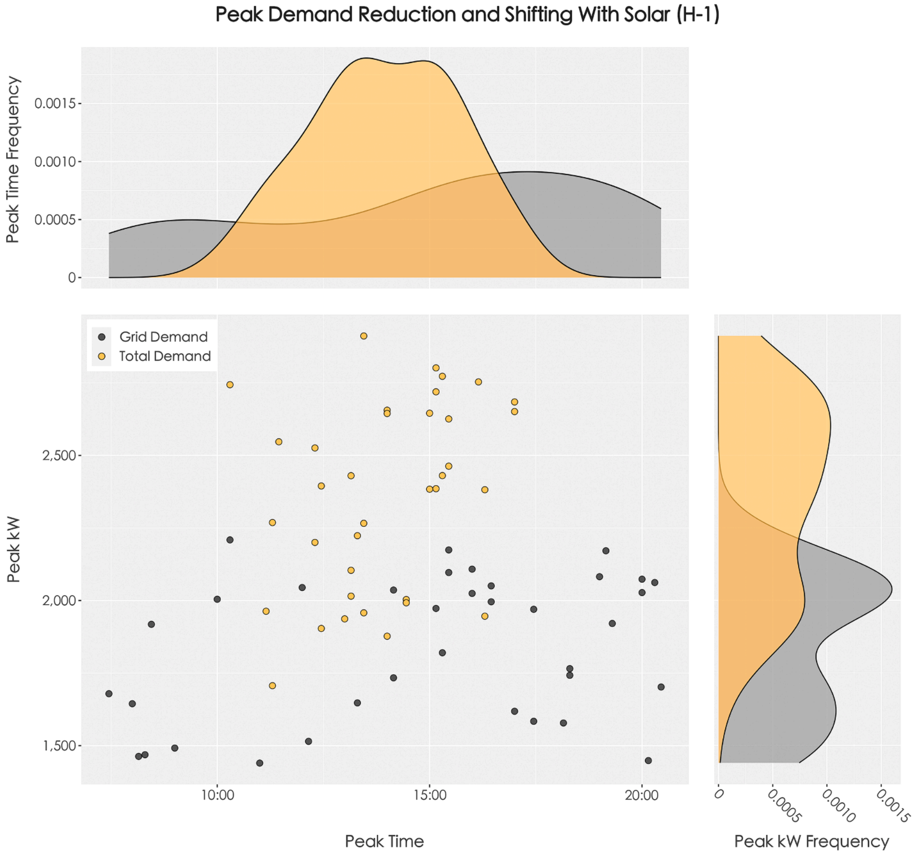

Fig. 3b. Marginal distribution plot of peak times (P_{GM} and P_{TM}) against the magnitude of grid peak demand (kWG) and peak total demand (kWT) analyzed year-round by month, using a hospital (H-1) as a representative model of peak load shifting.

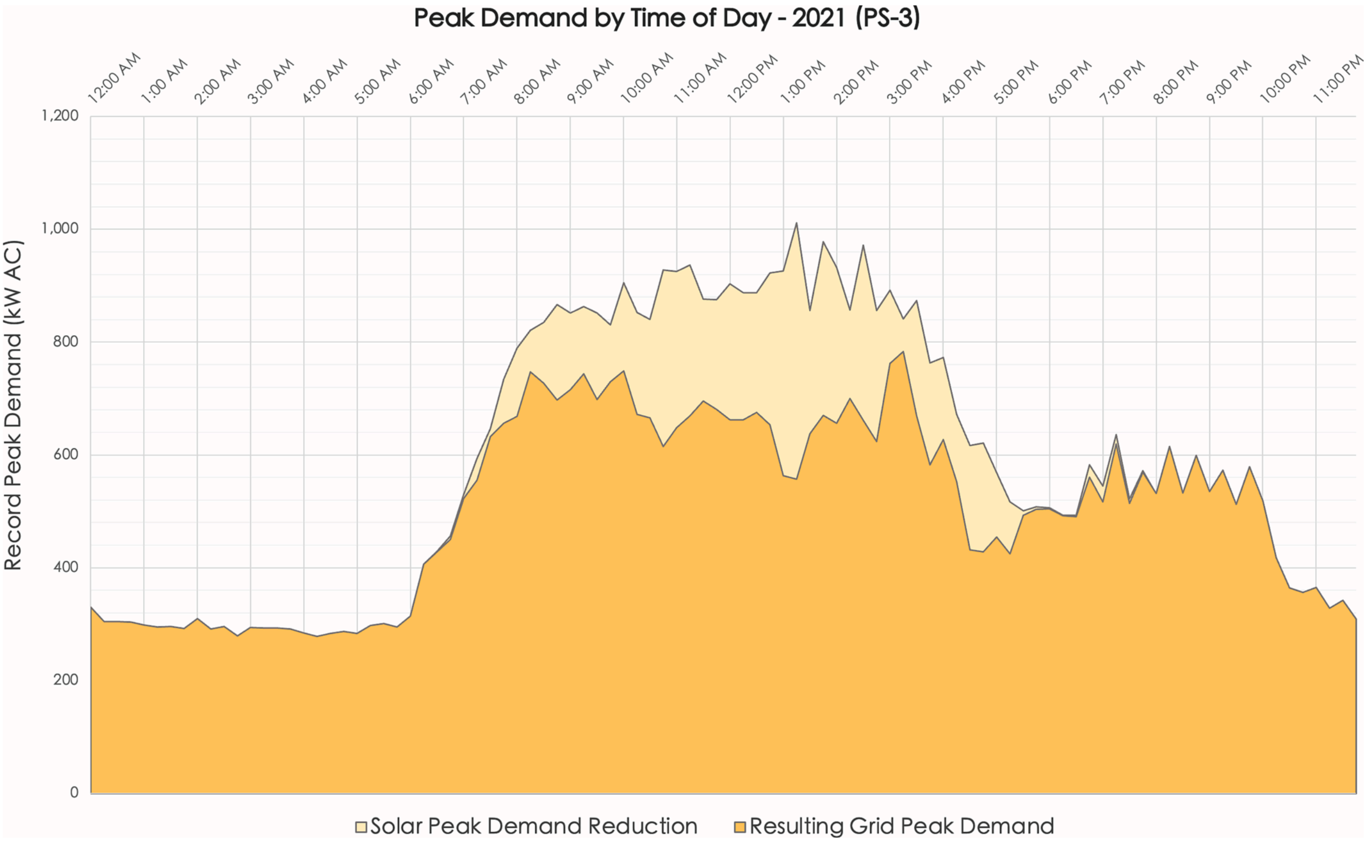

Fig. 4a. Peak demand reduction by time of day at a public school facility (combined elementary and high school).

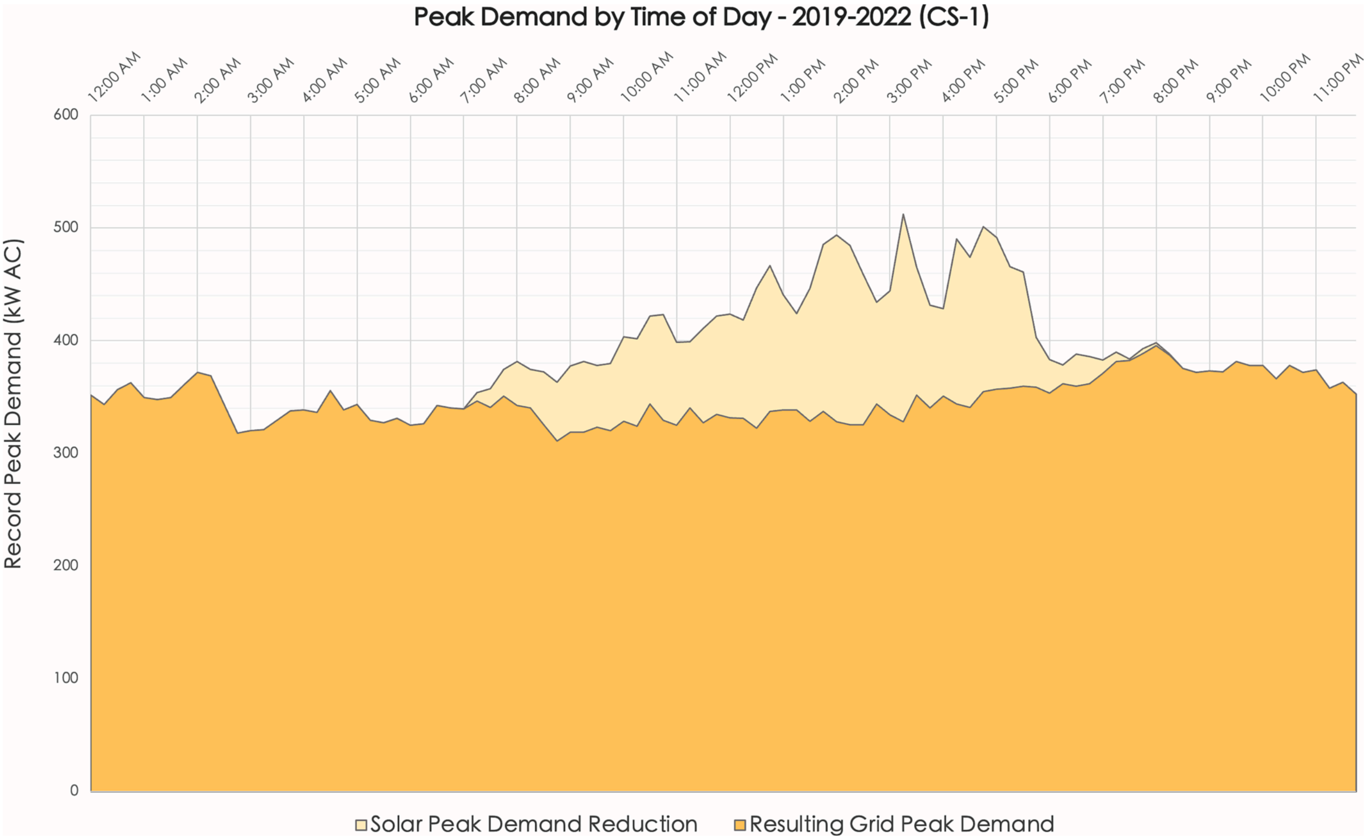

Fig. 4b. Peak demand reduction by time of day at a cold storage facility.

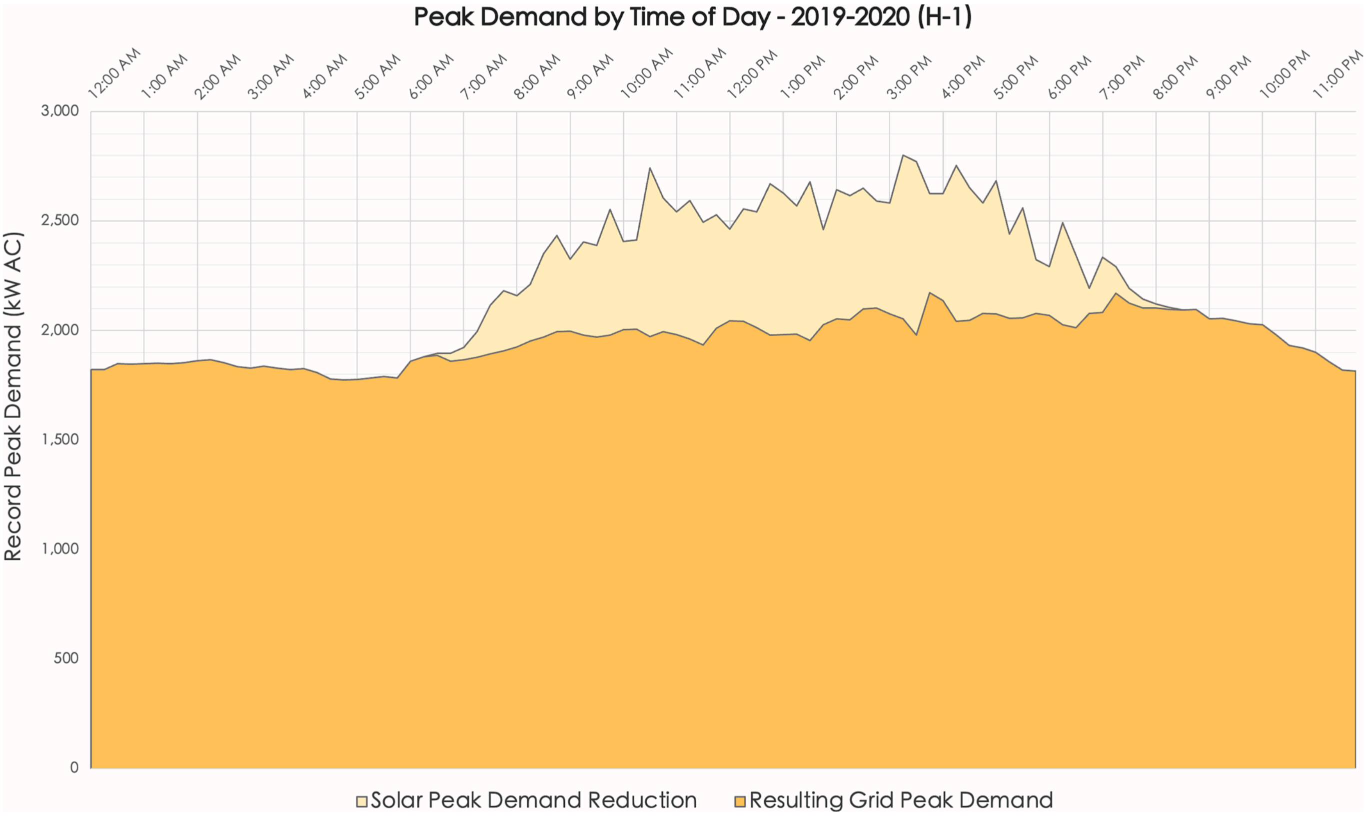

Fig. 4c. Peak demand reduction by time of day at a hospital.

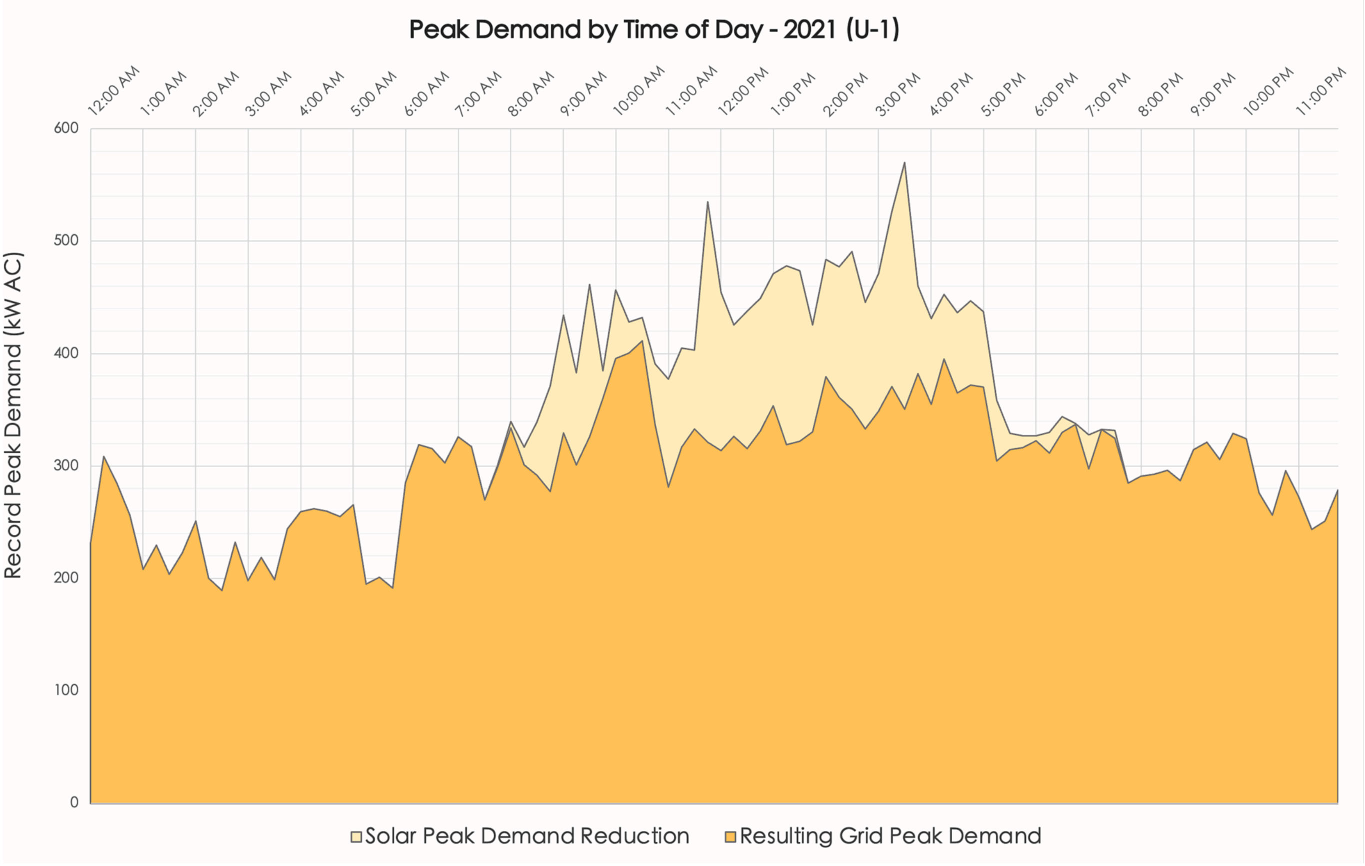

Fig. 4d. Peak demand reduction by time of day at a university athletic facility.

for all facilities and at one model facility, respectively. Additionally, Figs. 4a-4d present example profiles illustrating the reduction in peak demand by time of day for different facility types. These figures showcase the noticeable effect of solar generation on shifting the timing of peak demand, resulting in a lower, smoother, and more distributed demand profile throughout the day.

Across all examples, these findings reveal a consistent pattern of solar PV contributing to the shifting of peak load from mid-day to mornings and evenings, thus flattening or shaving peak demand. Peak demand shaving through energy efficiency and other demand reduction measures is a well understood management term for facilities managers. Shaving peak demand with distributed solar, however, represents yet another arrow in the quiver for facilities managers. This shift is particularly pronounced during summer days and weekdays, aligning with increased commercial energy consumption during daytime hours.

As an alternative visualization of this phenomenon, Figs. 4a-4e visualize peak demand reduction throughout the day using examples from four different facility types across annual or multi-year time periods, as specified. Each point represents the highest kW demand value per 15-minute interval for both kWG and kWT across all days analyzed, indicating the actual load on the grid with solar compared to what it would have been without solar. The difference between the two values signifies the net demand reduction achieved through solar generation by time of day. While the results varied among facility types, the presence of solar PV consistently resulted in smoother and relatively level peak demand profiles throughout the day compared to scenarios without solar. The analyzed facility types include a public school (4a), a cold storage facility (4b), a hospital (4c), and a university athletics building (4d).

Fig. 4e visualizes a similar profile for a hospital as shown in 4a-4d, except net kW demand values for each time of day are averaged together instead of only showing the difference among peaks, additionally broken down by season (within each indicated month). This shows that kWT and kWG were by far highest in the summer, but RMP was fairly consistent in terms of raw kW in the spring, summer, and fall, ranging between an approximately 250 to 300 kW (AC) net reduction and shifting P_{GM} from mid-day to the evening (as well as morning to a lesser extent).

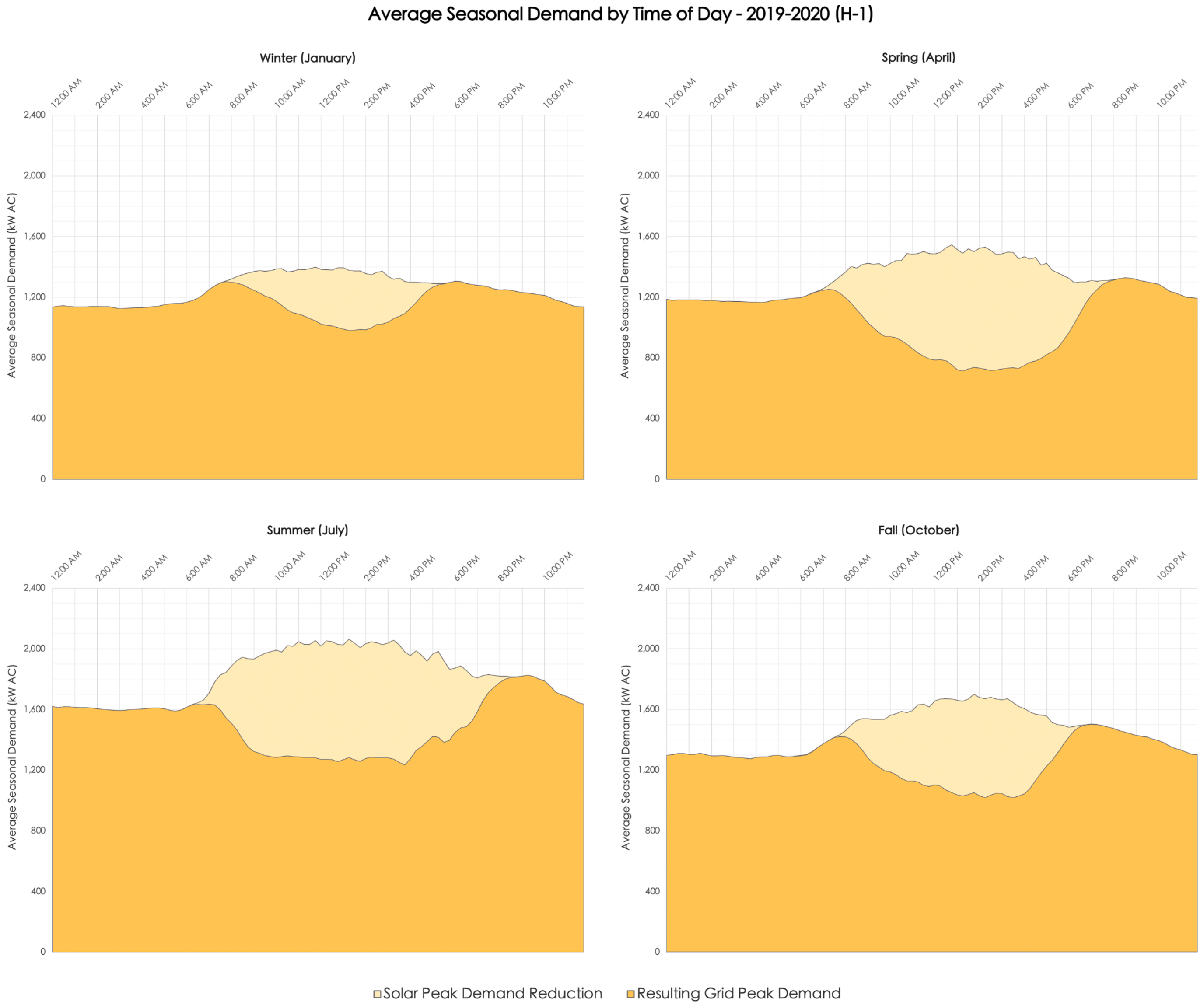

Fig. 4e. Average demand reduction by time of day for each season using a hospital (H-1) as a representative model of expected peak demand reduction and shifting throughout the year. Plots are combined into a single figure for inter-seasonal comparison along a common scale.

3.3. Customer peak demand reduction as a percentage of solar nameplate capacity

Nameplate capacity (kWp DC) serves as the standard metric for quantifying the size or maximum output potential of a solar array, playing a central role in quantifying the performance and efficiency of an array. While customers typically gauge the effectiveness of their solar PV system by directly evaluating the kWh reduction it achieves, they may be less familiar with its potential for peak demand (kW) shaving. This approach does not consider limitations on system capacity due to external factors such as available roof area, interconnection caps, and other physical, financial, and policy constraints (as illustrated by the variation in annual customer kWh offsets in Table 1).

To account for these differences, we can divide the reduction in monthly peak demand (RMP) by the nameplate capacity of the array, enabling a more standardized evaluation of system performance and capacity optimization. This assessment, denoted as "RMP/kWp," allows for meaningful comparisons between systems regardless of scale.

In the summer months, the RMP/kWp was higher (averaging 39.7 %) across all facilities compared to the overall average for the year (31.0 %). This observation is logical considering the anticipated higher solar output during the summer months relative to the constant value represented by the system's nameplate capacity. These findings indicate that achieving a high RMP/kWp does not necessarily require a particularly large system. Instead, this metric is influenced by the system's performance relative to expected output, compatibility with the customer's load profile, and the optimal capacity chosen to meet the desired project outcomes.

For instance, CS-3 serves as an example of the impact of proper capacity optimization on RMP/kWp. Despite being significantly oversized (offsetting 137.5 % of annual kWh usage) due to a change in occupancy after installation resulting in reduced facility energy consumption, it achieved a RMP exceeding 60 % during certain months. However, a smaller system (~85 % of the maximum RMP with ~ 70 % of the kWp DC) could have achieved only marginally lower RMP. This highlights the interesting scenario where the system was sized far beyond what was necessary to achieve optimal RMP/kWp, leading to diminishing returns in terms of both energy and financial savings. It also emphasizes the importance of allowing some margin in the optimal system capacity to favor higher unitized savings (e.g., sizing the system capacity to offset 95–98 % of annual kWh instead of 100 %) when energy consumption levels may fluctuate or change completely from year to year.

In contrast, many other systems, while relatively smaller in terms of percent kWh offset and RMP, achieved similar or even higher RMP/kWp as determined through the Financial Modeling described in Section 2.1. D. This was primarily due to more moderate capacity sizing (fewer diminishing marginal utility returns in RMP) and ideal compatibility with the demand-side load profile. An example can be seen in H-1 depicted in Fig. 4c, where the array only offset 14.3 % of annual kWh usage, yet it significantly flattens the facility's overall peak kWG profile and achieves more than double the average RMP/kWp due to solar PV's excellent compatibility with the facility's demand profile.

3.4. Billing considerations and financial savings optimization

The above findings consistently demonstrate that increasing system capacity leads to diminishing returns in RMP, particularly beyond achieving 100 % kWh offset, indicating a soft upper limit for optimizing nameplate capacity. However, the significance of this relationship depends on how demand charges are weighted in a customer's bill. Therefore, conducting a financial analysis that considers projected savings in billed demand and kWh usage is crucial for fine-tuning system capacity.

For our study area, a median case of commercial rate tariffs is represented by an SDP customer on Dominion's GS-2 Intermediate General Service rate tariff. While charges can vary based on the customer's kWh/kW load ratio, this tariff includes approximately 32.3 % demand charges, with the remainder based on kWh usage, which is typical for commercial rate tariffs. In this scenario, an SDP customer can expect to achieve an average RMP of around 50 % per year by sizing the system capacity to offset 98 % of annual kWh usage, effectively reducing both demand and usage charges.

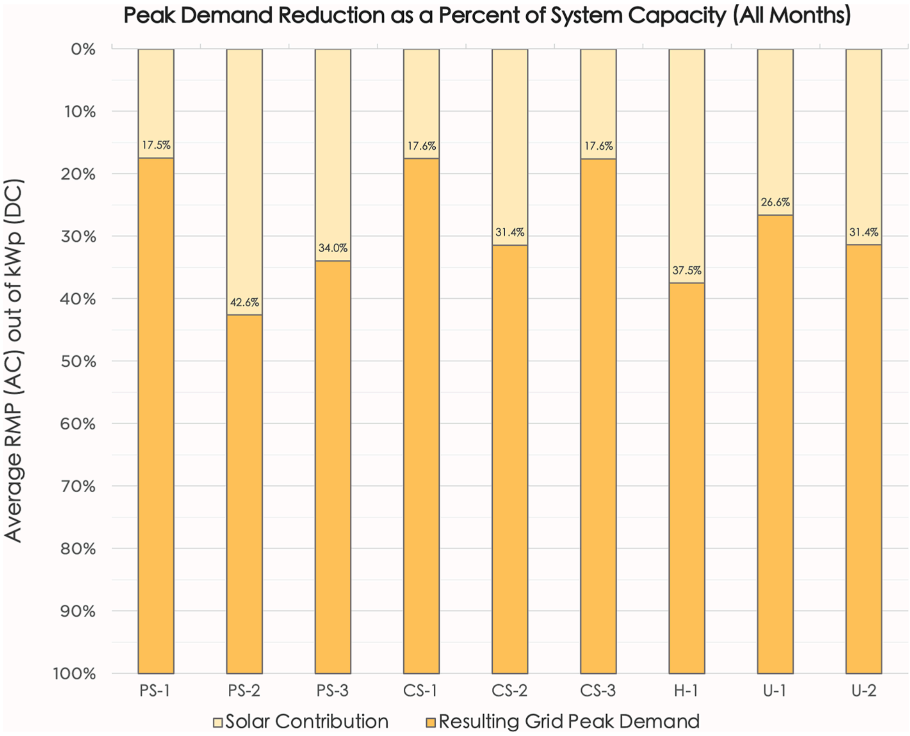

Fig. 5. RMP/kWp for all nine analyzed facilities across all analyzed months. This provides an indication of how effectively solar PV contributes to reducing peak demand each month relative to the system's capacity.

Various factors can, however, influence financial outcomes between projects. For similar SDP facilities with demand charges representing a smaller portion than 30 % of the bill, maximizing system capacity to fully offset billed kWh usage is likely an optimal strategy. On the other hand, customers with a larger proportion of demand charges may aim to maximize peak demand reduction per unit of installed capacity, leading to a more moderately sized system capacity (i.e., less than 98 % kWh offset and perhaps as low as 40–50 %). Both strategies are derived from the understanding that savings from kWh reduction scale linearly with kWp DC, while peak demand reduction yields diminishing returns. Further discussion and visualization of these scenarios is included in Section 4.3. Ultimately, using these guidelines, systems should be designed in a manner that offsets the greatest volume of utility charges.

It is worth noting that utilities employ different methods for calculating peak demand based on metered kW interval data, which, all else being equal, may affect monthly peaks derived from this data. Darghouth et al. found that longer grid demand intervals (30–60 min) allow solar to more effectively reduce peak demand compared to shorter intervals (5–15 min), although our results did not consistently confirm this finding [47]. Theoretically, longer intervals smooth out demand spikes and reduce the customer's billed peak demand. However, in our analysis of the relationship between demand interval length and RMP/kWp, we did not find any significant correlation. This could be attributed to the limited sample size, variation in system capacity relative to total kWh usage, and the fact that Darghouth et al. analyzed both residential and commercial customers.

Ideally, to compare demand interval length to RMP/kWp, the capacity of all analyzed systems would be standardized to offset close to 100 % of annual customer kWh usage, as RMP does not scale linearly with kWp DC. However, given the constraints of system capacity sizing and the continuous advancement of industry knowledge in system design, achieving this goal remains a suggestion for future studies.

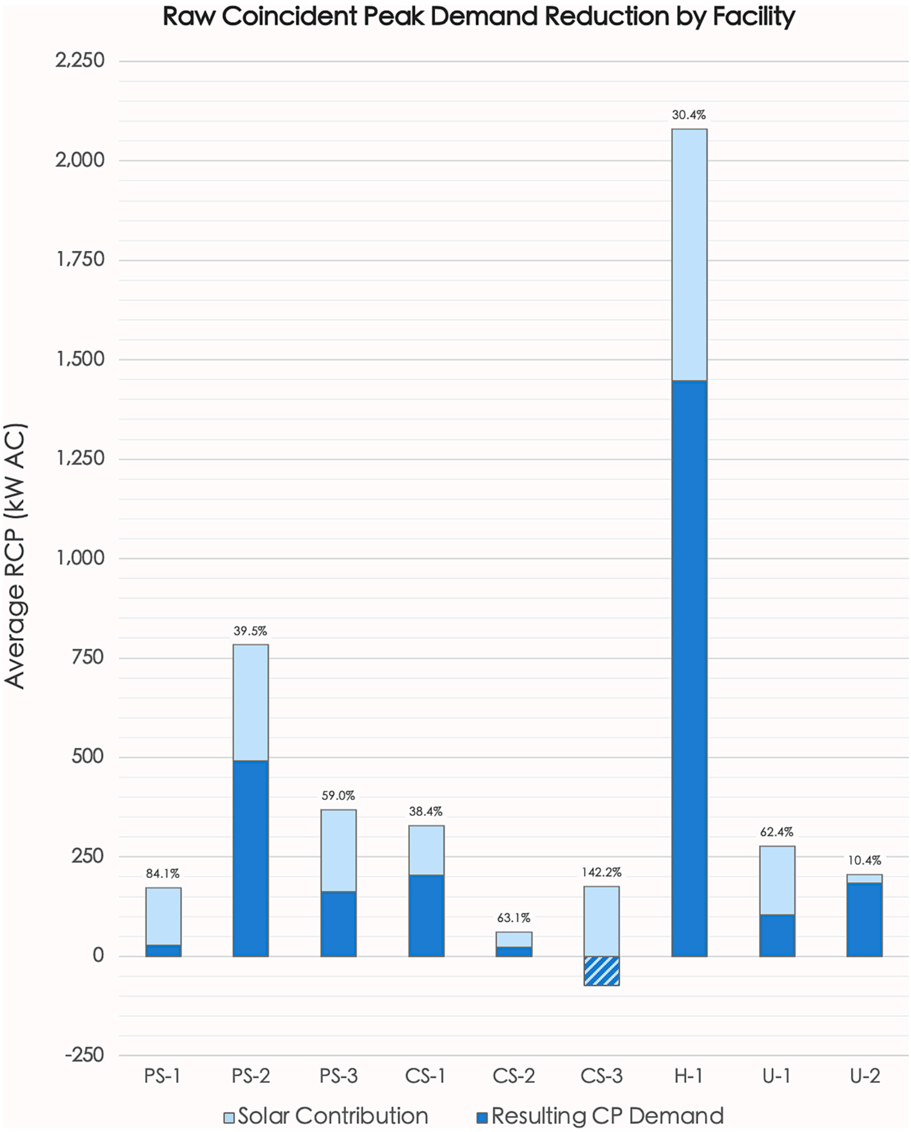

Fig. 6. Average raw coincident peak demand reduction (RCP) by solar, measured in kW (AC), for each of the nine facilities. All available data from historical PJM 5CP periods are aggregated, and the reductions across all periods are averaged by facility. This effectively illustrates the varying magnitudes of system capacities, kWG values for each facility, and the resulting RCP achieved by solar PV. *Note: Striped areas below 0 kW indicate instances where the system produced an average excess during the analyzed 5CP periods due to a drastic reduction in the cold storage facility occupancy patterns during the study period. In such cases, kWG is negative on average due to surplus solar generation, while kWT is represented by the corresponding positive area.*

3.5. Utility coincident peak demand reduction

The average PJM coincident peak demand reduction during the 5CP periods varied among facilities based on system capacity and demand-side consumption patterns, similar to customer peak demand reduction. However, the average 5CP offset consistently exceeded the average monthly customer peak demand reduction. For reference, the 5CP periods during which RCP was analyzed are shown by year in Table 2 (Section 2.2.4).

Reduction in coincident peak demand during 5CP periods (RCP) ranged from 10.4 % to 142.2 %, while the average monthly customer peak demand reduction (RCP) ranged from 7.3 % to 46.0 %. As a result, average RCP was 42.3 %, almost double that of the average annual RMP (22.9 %). This difference can be attributed to the fact that 5CP periods predominantly occur in the late afternoons during summer when solar production is relatively high. In contrast, monthly peak demand can occur during winter months and outside of peak solar production hours due to any number of facility-specific patterns, such as use of electricity for heating. For comparison, Fig. 2b provides selected summer months, highlighting that summer RMP is still considerably lower on average compared to RCP. The overall pattern of raw (kW) RCP by facility is displayed in Fig. 6 below, while Fig. 7 depicts the percentage in RCP by facility.

3.6. Utility coincident peak demand reduction as a percentage of solar nameplate capacity

Similar to quantifying RMP, the reliability of solar PV in terms of RCP, which offers the potential for utilities to benefit from reduced summertime peak loads, can be standardized as a percentage of the system's nameplate capacity. The 5CP demand reduction, expressed as a percentage of kWp DC and denoted as RCP/kWp, ranged between 32.1 % and 47.7 % (with an average of 43.1 %). This variation in percent offset is generally higher and more consistent compared to RMP/kWp. Given that 5CP periods occurred exclusively during summer months in recent years, it is understandable that RCP/kWp is similar in magnitude to RMP/kWp from May through August, averaging at 39.7 %. However, the latter metric displayed a wider range of values across different facilities. Fig. 8 provides an overview of RCP/kWp values for each facility.

These findings demonstrate that when solar PV achieves sufficient market saturation and interconnection with the grid, it can consistently reduce coincident peak demand for energy utilities and effectively alleviate strain on grid infrastructure. Under these favorable conditions, all ratepayers can potentially benefit from solar energy, as utilities save on peak generation costs and grid maintenance expenses. This holds true regardless of whether individual customers have solar panels installed on their rooftops.

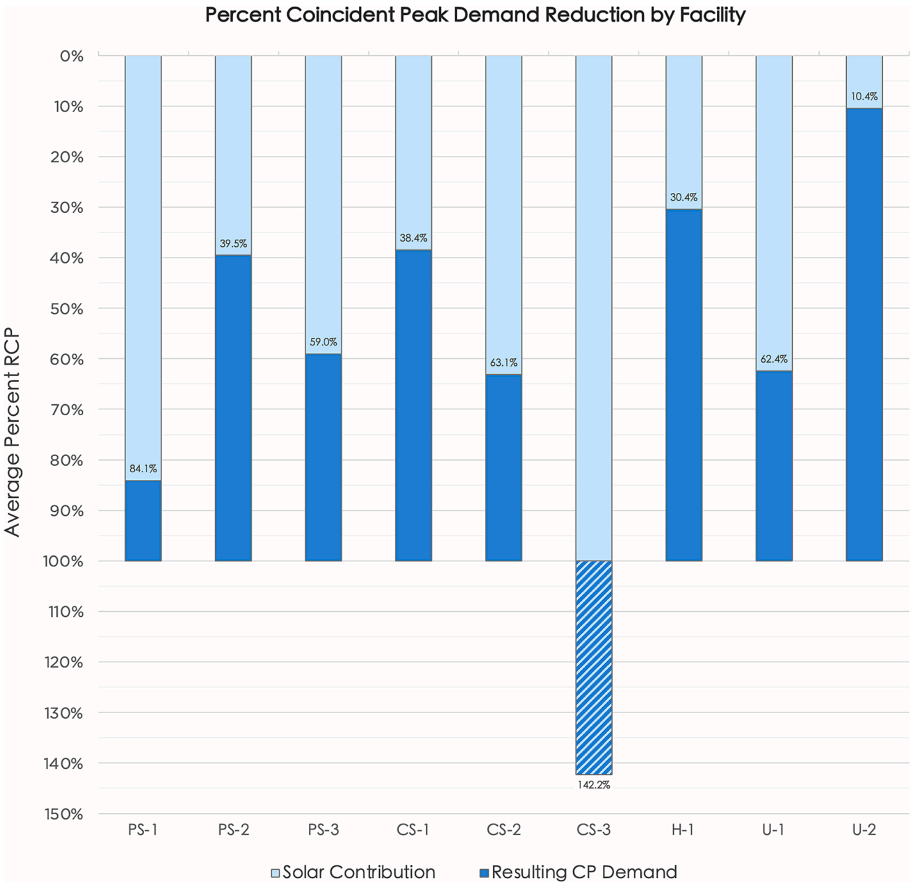

Fig. 7. Average percentage of coincident peak demand reduction (RCP) achieved by solar at each of the nine facilities. These percentages are derived from the averaged kW reduction values across all available 5CP periods, as depicted in Fig. 6. above. *Note: Striped area for CS-3 (the cold storage facility that experienced a dramatic reduction in occupancy patterns during the study period) exceeds 100% and indicates instances where the system, on average, produced an excess during the analyzed 5CP periods.*

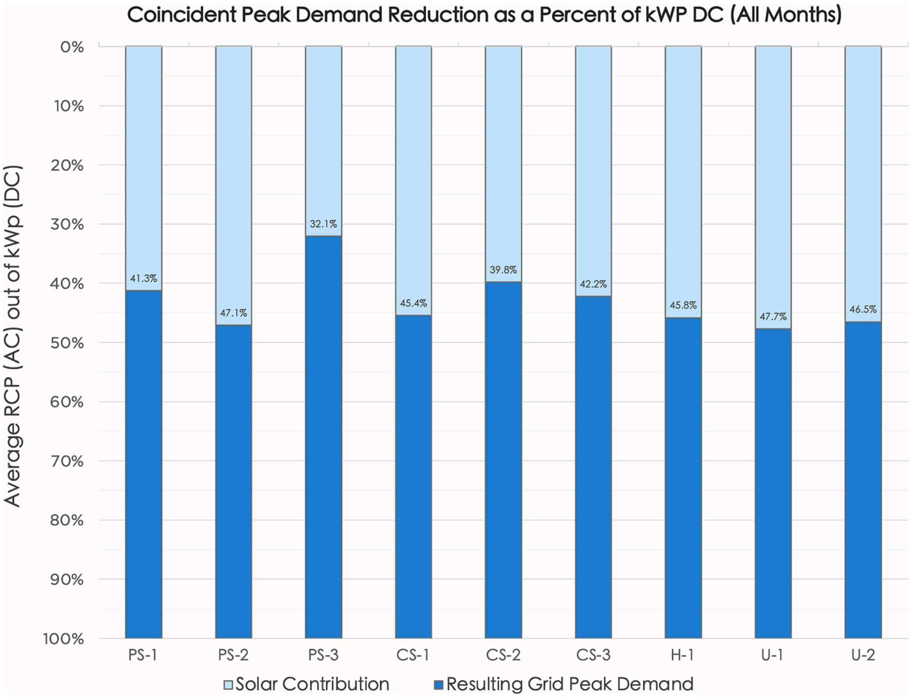

Fig. 8. Average coincident peak demand reduction by solar (kW AC), expressed as a percentage of the solar array's nameplate capacity (kWp DC), calculated for each of the nine facilities.

4. Discussion

4.1. Deconstructing dogma on solar reliability and cross-subsidization

Assertions that solar is ineffective at reducing peak demand have been widely proclaimed, even within the solar industry, perpetuating the belief that solar is niche and limited in scalability. This study refutes these claims and challenges misinformation used by the fossil fuel industry and utilities to maintain status quo energy policies. Additionally, it provides an upper bound on common solar capacity optimization practices which often seek to use all available roof space in large part to maximize solar market penetration [58,59].

Our findings bolster existing research on solar capacity to consistently reduce billed peak demand for solar customers, additionally providing guidance on how to optimize solar capacity for facilities with summer-daytime-peaking (SDP) total demand profiles. Solar can provide tremendous peak demand savings even with relatively undersized systems, although larger systems can more effectively smooth SDP load profiles and maximize savings for customers whose bills are comprised in large part by kWh charges (especially > 70 %). Along with consistent RMP for solar customers, those on coincident peak tariffs can realize even greater savings on CP charges on top of benefits realized by demand-side management alone.

In addition to benefiting solar customers, our findings highlight the positive impact of distributed commercial-scale solar on the energy grids as a whole, particularly in regions where grid load exhibits an SDP profile, as is the case throughout much of the U.S. [17]. It can smooth load profiles for regions with SDP grid load patterns, reducing utility peaker plant generation and grid strain. The impact of distributed solar during coincident peak periods offers significant cost relief for utilities and demonstrates the potential benefits of distributed solar and net metering to all ratepayers should such cost savings be redistributed to non-solar customers.

While narratives of high cost and ineffective peak demand reduction are deeply ingrained, public awareness and regulatory policy are very recently starting to turn, with even some of the most coal-dependent utilities and states starting to acknowledge the economic (not to mention the obvious environmental) benefits which solar PV in its various forms can provide. In an ongoing case (as of 2022 and 2023) before the Kentucky Public Service Commission, Louisville Gas and Electric Company and Kentucky Utilities Company (jointly LG&E/KU), upon requesting approval to construct a 120 MW utility-scale solar PV plus battery storage facility and purchase another 120 MW solar facility, outlined numerous wide-reaching benefits which it contends the facility will provide [60]. These notably include that:

"… the proposed Mercer Solar Facility and Marion Solar Facility would result in savings in three of the six fuel price scenarios studied even without considering a cost of Greenhouse Gas regulation compliance or income from the sale of RECs [renewable energy credits] and indicated that it planned to add those facilities as a hedge against market uncertainties concerning the solar industry, gas prices, and future environmental regulations." (p. 78) and,

"… their proposed portfolio 'will not harm customers; rather, including all known direct and indirect costs that affect revenue requirements (and therefore customers' bills), it will likely result in substantial PVRR [present value revenue requirement] benefits to customers.'" (pp. 18–19).

This case is not without its drawbacks, notably that the proposed solar facilities accompany proposals for two natural gas combined cycle units, and that it only invokes benefits from utility-scale solar, over which LG&E/KU retains control and ownership, rather than similar (even additional) benefits which can be realized from distributed solar. Still, it signifies substantial progress and a slowly shifting landscape in the energy industry.

4.2. Policy and regulatory implications

The current global energy transition is driven in large part by record adoption of solar and other distributed renewables. This necessitates proactive efforts to develop smarter and more responsive energy grids, as well as bidirectional metering to accommodate rooftop solar, all of which can foster greater democratization and resilience in these systems. Demand response programs and strategic deployment of battery storage can also optimize renewable generation and phase out fossil-fuel-based peaker plants.

Strong financial regulations and incentives can limit rate hikes and encourage utilities to prioritize the deployment of renewables and corresponding infrastructure. However, long-term solutions should address the challenges posed by investor-owned utilities retaining monopolies on infrastructure which should serve the public benefit. Addressing financial barriers and ensuring equitable redistribution of savings from demand reduction by distributed solar are crucial steps in dispelling the myth that non-solar ratepayers subsidize solar customers [56]. Moreover, solutions which support economic and environmental equity align with the precautionary principle, first laid out in this context in Principle 15 of the United Nations 1992 Rio Declaration on Environment and Development: "In order to protect the environment, the precautionary approach shall be widely applied by States according to their capabilities. Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation." [61].

4.3. Implications for optimizing solar nameplate capacity

For optimal peak demand reduction through solar, commercial facilities should exhibit a summer-daytime-peaking (SDP) total demand profile. Given this, it is then crucial to understand the upper limits that may influence the optimal solar capacity sizing process. Assuming sufficient roof or land space and interconnection capacity, systems should be designed to offset at most 100 % of the customer's annual billed kWh usage (ideally between 95 and 98 % to account for fluctuations year-over-year), as utilities generally do not compensate for excess net metered usage at a one-to-one rate.

Based on the bills of the facilities analyzed (and simplifying charges into only kWh usage and kW demand categories), most commercial customers can expect their demand charges to account for between 20 % and 40 % of their overall bill as a product of their electricity consumption habits and utility rate tariff. Depending on this composition, different strategies for refining system capacity may be optimal as shown in Fig. 9 and discussed below.

System nameplate capacity (kWp DC) scales linearly with grid kWh usage offset, such that additional capacity for tariffs with little to no peak demand charges will not exhibit a significant diminishing marginal return in kWh offset up to 100 % of annual usage. As such, if the vast majority of a customer's bill (approximately $>$ 70 %) consists of kWh charges, it may be beneficial to maximize kWh reduction.

Conversely, kWp DC does not scale linearly with realized peak demand reduction, as solar is able to offset increasingly smaller portions of grid demand that falls outside of solar production hours as kWp increases with a given commercial facility. In our analyses of SDP facilities, RMP can be expected to reach approximately 50 % in peak performing months with a system offsetting 98 % of annual kWh usage. If kW demand costs represent a sizable portion (30–40 %) of a commercial customer's electric bill, as is often the case, any additional solar generation that does not substantially reduce peak demand can represent a diminishing marginal return in overall financial savings compared to the cost of additional installed solar capacity. In this case, a small or moderately-sized system (often well below 100 % annual kWh offset) may be optimal to take advantage of more valuable peak demand reduction (i.e., greater RMP can be expected from the first 500 kWp installed than the next 500 kWp).

The presence of a demand ratchet in a customer's bill may also raise the minimum PV capacity needed to realize consistent demand savings, but the challenge this poses will depend on the strength of the ratchet (e.g., 11-month 50 % vs. 90 %) and the customer's underlying peak demand profile from month to month. By establishing upper and lower limits to optimal capacity and considering projected utility savings, the ideal system capacity range can be determined based the specifications which will maximum financial savings. Despite fluctuations in facility usage patterns and weather conditions, our results demonstrate that properly designed systems can reliably reduce peak demand. However, we also advise maintaining a buffer around installed capacity, within which system performance will still be acceptable given potential year-to-year fluctuations in the facility's usage profile.

4.4. Areas for future research

One crucial area for future research involves exploring the medium- to long-term implications of increased solar development and its impact on grid-scale load shifting. Although the duck curve is not currently as

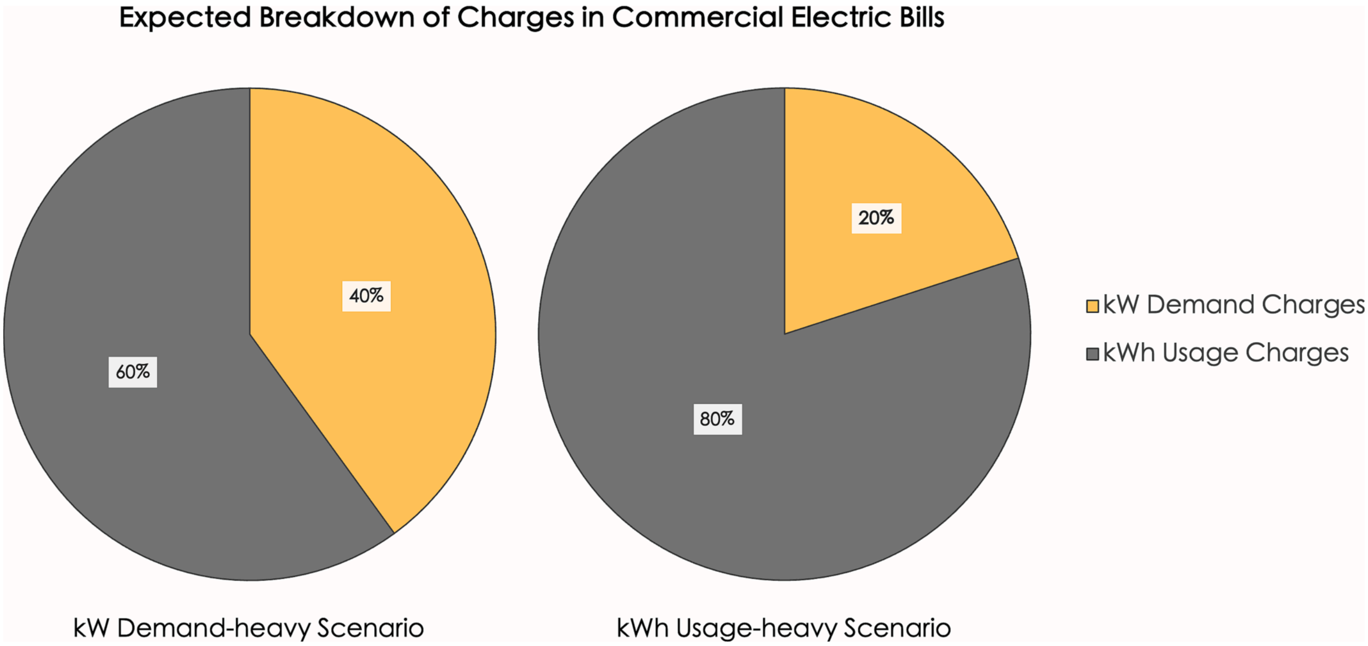

Fig. 9. Approximate upper and lower ranges of expected commercial electricity bill charges, broken down between kWh usage and kW demand charges. Charts visualize a kW demand-heavy scenario (demand charges approach ~ 40 %) and a kWh usage-heavy scenario (demand charges account for as little as ~ 20 %), which correspond to solar capacity optimization strategies that prioritize offsetting one category of charges over the other (or both equally).

pressing of an issue as commonly perceived, solar's day-peaking nature does have capacity limitations on the grid [57]. This may also become additionally important to understand as additional clean technologies such as electric vehicles, smart and demand-responsive grids, and even other renewables such as wind come online and further disrupt grid load patterns. In the worst case, additional load due to EV charging could increase peak demand, even if solar has the same output. In a situation with incentives such as variable metering and other smart grid applications which can optimize the timing of EV charging, this can (and should) match solar output and grid on– and off-peak dynamics much less impactfully. It is important to investigate whether there is a saturation point for solar's market share and how it may vary based on localized conditions such as other generation and storage sources, transmission and distribution infrastructure, and seasonal grid load patterns. How can optimized solar capacity principles be applied to infrastructure transition planning on the regional transmission organization (RTO) level? What does it look like for solar to fully realize its niche on the grid level?

Additionally, further research efforts could more substantially address the financial implications of stranding fossil fuel assets such as coal plants to adopt a more diversified grid comprised of solar among other renewables. Considering the externalities associated with the environmental degradation and privatized ownership of fossil fuels, it is quite possible that transitioning to renewables before fossil fuel assets have completed their life cycle could still be more economically beneficial overall. Similarly, further research should be conducted to quantify the exact costs posed by fossil fuel baseload and peaker plants (perhaps as a cross-regional comparison) and how the costs of stranded generation assets could be offset by transitioning the use of baseload and dispatchable peak generation to lower cost renewable sources. With the acknowledgement that economic implications are not and should not always serve as the focus when addressing societal issues in line with the precautionary principle, it is often necessary in modern economic and political landscapes to quantify major decisions in economic terms.

5. Conclusions

In summary, our research challenges prevailing narratives surrounding solar PV system performance, debunking misconceptions perpetuated by the fossil fuel and energy utility industries. Despite claims of solar viability issues, our findings affirm its cost-effectiveness, sustainability, and compatibility with grid patterns. We reject the notion of solar-induced cost-shifting, emphasizing the externalization of costs by utilities and fossil fuel industries. The current paradigm prevents savings distribution, hindering legislation that could promote equitable distributed generation implementation and renewable grid development.

Our analysis recommends a systems approach to optimizing solar capacity, emphasizing optimization for energy and financial savings. Empirical evidence shows that properly scaled solar PV systems consistently reduce peak demand, benefiting both individual customers and the grid. To accelerate widespread adoption, we propose policy changes, including universal net metering, support for electric vehicle-to-building energy storage, increased grid interconnection capacity, and modernization of distribution and transmission systems.

Moreover, we advocate for reshaping economic and political landscapes to dismantle the regulatory systems in which cost-shifting is even possible. Key policy recommendations include financial reimbursement for solar customers, incentives for renewable energy, reduced utility rates reflecting solar savings, increased regulation on utility lobbying, phasing out fossil fuel subsidies, and transitioning toward public ownership of utilities and extraction industries for the benefit of the public rather than shareholder profit.

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.

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