

SELF-GENERATION INCENTIVE PROGRAM

2024 SGIP IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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Glossary

Abbreviation	Term
AB	Assembly Bill
ACC	Avoided Cost Calculator
AMI	Advanced Metering Infrastructure
BTM	Behind-the-meter
CAISO	California Independent System Operator
CF	Capacity Factor
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
CPUC	California Public Utility Commission
CSE	Center for Sustainable Energy
CY	Calendar Year
D.	Decision
DR	Demand Response
ED	Energy Division
ELRP	Emergency Load Reduction Program
ERB	Equity Resiliency Budget
EV	Electric Vehicle
GGRF	Greenhouse Gas Reduction Fund
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
HFTD	High Fire-Threat District
HPWH	Heat Pump Water Heater
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kg	kilogram
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LHV	Lower Heating Value
LMP	Locational Marginal Price
M&E	Measurement and Evaluation
MT	Metric Ton
MW	Megawatt
MWh	Megawatt hour
NBT	Net Billing Tariff

NCP	Non-coincident Peak
NEM	Net Energy Metering
OP	Ordering Paragraph
PA	Program Administrator
PBI	Performance Based Incentive
PDP	Peak Day Pricing
PG&E	Pacific Gas and Electric Company
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PSPS	Public Safety Power Shut off
PTO	Permission to Operate
PV	Photovoltaic
PY	Program Year
QC	Quality Control
RRF	Reservation Request Form
RSSE	Residential Solar and Storage Equity
RTE	Round-trip Efficiency
SB	Senate Bill
SCE	Southern California Edison
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program
SJV	San Joaquin Valley
SOC	State-of-Charge
T&D	Transmission and Distribution
TOU	Time-of-Use

1 EXECUTIVE SUMMARY

The Self-Generation Incentive Program (SGIP) was established in 2001 and provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer’s electricity needs. The program is managed by Program Administrators (PAs) representing California’s major investor-owned utilities (IOUs). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP. Historically, the SGIP has been solely funded by California’s ratepayers. However, in 2024, Decision 24-03-071 implemented Assembly Bill (AB) 209, which allocated state funding from the Greenhouse Gas Reduction Fund (GGRF) to low-income residential storage and solar customers. This Residential Solar and Storage Equity (RSSE) component of the program opened in 2025 and will be incorporated into future program evaluations.

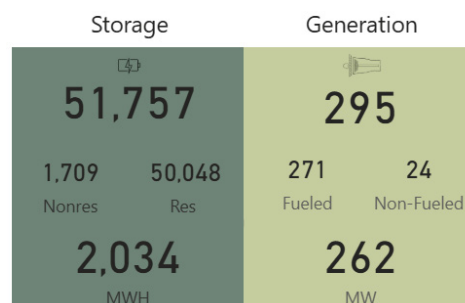
Measurement and Evaluation

CPUC Decision 19-09-027 required the SGIP PAs to develop a Measurement and Evaluation (M&E) Plan for the SGIP covering 2021-2025. That plan was approved in May 2022 and finalized in January 2023. The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP systems operating during calendar year (CY) 2024.

Evaluation Population

The SGIP population subject to evaluation encompasses all projects – since program inception – receiving an upfront SGIP incentive through December 31, 2024, and remaining within their required permanency period¹ as specified by the Program Handbook. While over 97% of the SGIP storage population are residential projects, the program capacity is roughly split between the residential and nonresidential sectors. Energy storage technologies are installed across multiple budget categories and facility types. Nonresidential systems range in size from roughly 10 kWh to over 5,000 kWh, with an average capacity of 625 kWh. Residential systems generally range from 10 kWh to 40 kWh, with an average capacity of 19 kWh. Electric-only fuel cell projects account for a third of the total rebated generation capacity.

FIGURE 1-1: SGIP 2024 POPULATION



¹ Permanency period refers to the length of time an SGIP incentivized technology is required to abide by program rules (usually 10 years for most technologies).

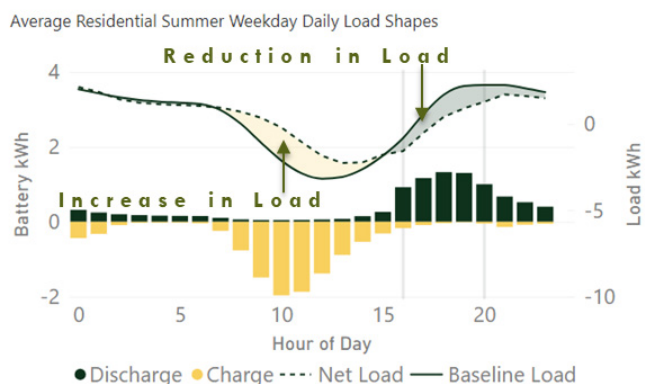
Evaluation Approach

This evaluation examines the performance of SGIP systems by quantifying the observed impacts of systems during 2024. Verdant collected metered generation data, storage charge and discharge data, and customer electric load profiles for SGIP participants. The calculation of energy storage impacts, for example, can be estimated by comparing observed customer load to a counterfactual (or baseline) of no storage.

The figure to the right depicts average hourly delivered load on summer weekdays, along with vertical lines depicting the 4 p.m. – 9 p.m. on-peak period. If a customer is discharging their battery, they are reducing the need to service load from the grid. So observed net load is lower than baseline net load (gray shaded area). When

a customer is charging the battery, they are increasing their load relative to a baseline of no storage (yellow shaded area). A customer may realize bill savings relative to the counterfactual if discharge occurred during high-priced hours (4 p.m. – 9 p.m.) and charging occurred during lower-priced hours.² Furthermore, systems may provide greenhouse gas (GHG) emissions reductions if the emissions *avoided* during storage discharge are greater than the emissions *increase* during storage charging.

FIGURE 1-2: EVALUATION APPROACH



Evaluation Findings, Conclusions, and Recommendations

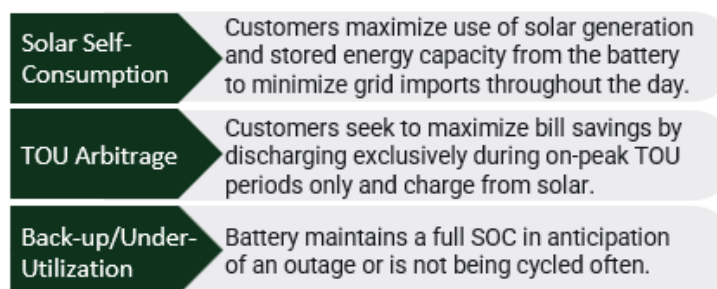
Following are key findings and conclusions from this evaluation based on metered data collected from a representative sample of residential storage and nonresidential storage and generation customers. These findings are guided by the research objectives specified in the M&E plan, along with results gained from past impact evaluations, and in consultation with the Program Administrators and the CPUC. Where possible, we also provide recommendations that could help inform program design improvements and future energy policies, in general. Many of these findings reveal how storage behavior during 2024 was meeting or falling short of SGIP goals and objectives. In-depth findings and analyses can be found in Section 4 and Section 5 of this report.

² This is referred to as time-of-use (TOU) energy arbitrage. Billed energy savings are realized when the total dollars saved from discharging exceeds the total dollars incurred from charging the system, along with any energy losses associated with round-trip efficiency.

Storage Dispatch Behavior

Verdant evaluated a sample of 2,006 residential energy storage systems (5% of the evaluation population). By the end of 2024, roughly 97% of those installations were energy storage systems paired with solar photovoltaic (PV) systems. Solar PV paired residential energy storage systems are generally conducting 1) solar self-consumption (62% of sampled projects), 2) time-of-use (TOU) energy arbitrage (25%) without export or with export – either regularly or exclusively during specific times like a demand response event, and 3) under-utilization or backup – 13% of systems are in backup mode and maintaining a full state-of-charge (SOC) in anticipation of an outage or are not being cycled often – which are not consistent with SGIP cycling requirements. The incidence of under-utilization³ has increased twofold since the 2023 evaluation – from 6% in 2023 to 13% in 2024.

FIGURE 1-3: TYPICAL RESIDENTIAL OPERATING MODES



We also observe some systems paired with PV conducting TOU arbitrage but not charging from solar⁴ (6% of PV paired systems). These systems charge overnight, perhaps to take advantage of relatively lower off-peak electric vehicle (EV) billed rates. This dispatch behavior has also increased twofold since the 2023 evaluation. Standalone systems are conducting TOU arbitrage – discharging the battery exclusively on peak and charging overnight. **Performance of under-utilized, standalone, and PV paired systems charging overnight all result in GHG emissions increases.**

Verdant evaluated 1,318 nonresidential energy storage systems (77% of the population). Systems co-located or paired with PV represented roughly 42% of those installations by the end of 2024. Nonresidential storage performance is guided by similar principles and economics as residential energy storage systems, but customer bill rate structure (monthly, on-peak, daily demands charges, and TOU

³ Under-utilization refers to residential systems that cycle less than 52 times during a calendar year.

⁴ The Federal Investment Tax Credit (ITC) was sunset in 2023, but battery storage systems were eligible for the ITC if they were paired with on-site generation like solar PV and charged from that renewable generation at least 75% of the time throughout the year. The SGIP also gives priority to projects charging a minimum of 75% from on-site renewables that don't claim the ITC. The Inflation Reduction Act (IRA) updated and expanded the tax credit for energy storage. However, minimum charging requirements from clean on-site renewable generation were removed. Furthermore, the IRA tax credit for host customer owned storage ended on 12/31/2025.

energy charges), site-specific power demands and differing load shapes create a more heterogeneous collection of dispatch profiles than the residential sector. Furthermore, nonresidential systems are also installed across a variety of building types – offices, retail, grocery stores, industrial facilities, electric vehicle (EV) charging stations, and public utilities like wastewater treatment plants.

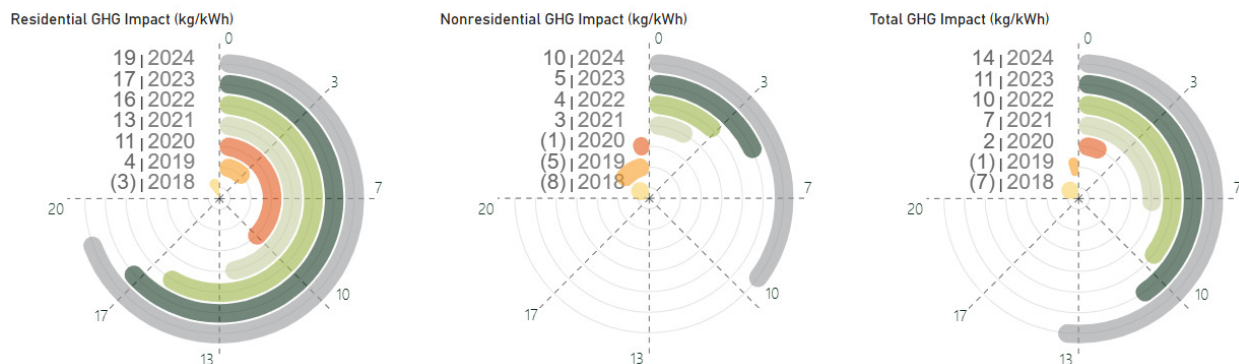
- » **Recommendation 1.** *An increased observance of under-utilized systems in 2024 should trigger program compliance review. While backup mode provides private benefits by way of resiliency in the event of an outage, these benefits are not shared by the ratepayer base that helps fund the program. Annual impact evaluations should continue to review project-specific performance and utilization metrics to help the CPUC and PAs identify compliance with cycling requirements.*

Greenhouse Gas Emissions

Residential and nonresidential energy storage systems contributed to a net reduction in GHG emissions in 2024 (Section 4.4.1 and 4.7). The combined GHG reductions across sectors totaled 28,433 metric tons (MT). Figure 1-4 plots the decrease (+), moving clockwise from zero, or increase (-), moving counterclockwise, in emissions for each customer sector – along with the total program impact – from the past seven Impact Evaluations (2018-2024). Residential fleet GHG emissions reductions were first observed in 2019 and have increased with each successive evaluation – from **an average reduction of 4 kilograms (kg) for each kWh of capacity in 2019 to a reduction of 19 kg for each kWh of capacity in 2024.**

GHG emissions reductions have also **improved in the nonresidential sector during the past four evaluations – with emissions reductions increasing twofold from 5 kg in 2023 to 10 kg per kWh of capacity in 2024.** An increasing share of PV paired systems charging from on-site solar and more focused on-peak discharging from more recently incentivized systems have contributed to that improvement. Some facility types like electric vehicle charging stations, schools, and critical facilities incentivized via the Equity Resiliency Budget (ERB) provide substantial emissions reductions, given the timing, magnitude, and duration of charge and discharge.

FIGURE 1-4: STORAGE GHG EMISSIONS IMPACTS BY YEAR AND SECTOR (KG/KWH, REDUCTION (+) INCREASE (-))



Sampled residential storage systems paired with on-site PV *and* charging from PV (the majority of systems) **decreased** emissions by over 22 kg per kWh of capacity, while standalone systems and PV paired systems charging overnight (a small subset of systems) **increased** emissions by 7 kg and 5 kg per kWh of capacity, respectively (Section 4.4.1). While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity – solar pairing plays an essential role in dictating when a system charges. Systems paired with on-site solar and charging from that solar provide benefits not realized by systems charging from the grid overnight, whether paired with solar or not. **From a GHG perspective, the value of charging during PV generating hours is important.** The emissions differentials between charging overnight and discharging on-peak are **not sufficient to realize emissions reductions like observed with PV paired systems** charging from on-site PV during much lower emissions hours.

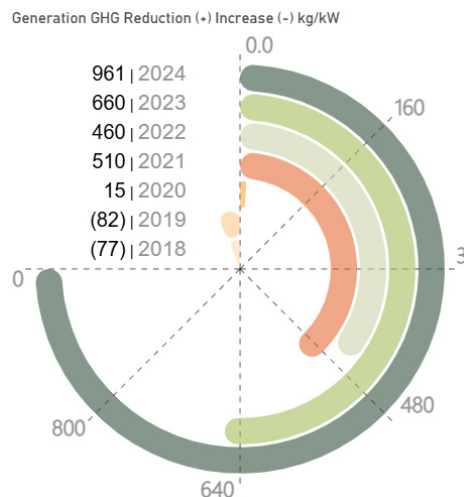
Sampled nonresidential systems paired with PV reduced emissions in 2024 by roughly 17 kg per kWh of capacity (Section 4.4.1). Emissions reductions for PV paired systems were realized across all facility types. Standalone nonresidential systems reduced emissions in 2024 by 6 kg per kWh of capacity.

» **Recommendation 2.** *We recommend that the CPUC explore ways to incentivize standalone systems to achieve GHG reductions, such as through GHG signals or real-time pricing signals*

Generation systems provided the vast majority of GHG emissions reductions in 2024 (Section 4.4.2).

Although generation systems comprise less than 1% of the systems installed in the SGIP, they reduced emissions by 961 kg per kW of rebated capacity throughout 2024. Renewable fueled systems capturing methane that would otherwise be vented into the atmosphere contributed to the greatest avoided GHG impact, followed by renewably fueled systems with a flared baseline and non-fueled systems. Non-renewable gas turbines also reduced emissions, due to their high rates of heat recovery. Figure 1-5 highlights annual impacts. **These reductions are highly dependent on marginal emissions rates built into the SGIP GHG signal⁵,** but there are several other drivers as well. Higher marginal emissions rates in 2024 from 2023 drove some increases in GHG reductions. Additionally,

FIGURE 1-5: GENERATION GHG IMPACTS



⁵ Additional details on these updates can be found in 'SGIP GHG Signal Update', WattTime. Self-Generation Incentive Program Fourth Quarterly Workshop, December 13, 2021. <https://www.selfgenca.com/documents/workshops/2021/q4>



many non-renewably fueled systems have completed their 10-year permanency period. The non-renewably fueled internal combustion engines that remain in the program exhibit higher heat-recovery rates than some of the older systems, which in turn increases per kW GHG reductions.

System Utilization and Grid Needs

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand while system charging is left to less critical times. Utility marginal costs and grid constraints are generally highest during on-peak hours, which are captured with TOU on-peak periods in California. Conversely, storage charging is most effective during off-peak and super off-peak periods, when retail rates, utility avoided costs, marginal emissions, and grid constraints are at their lowest.

Solar PV paired with residential storage discharges roughly 43% of system kWh capacity daily during summer weekdays, and standalone systems discharge about 20% of available capacity (Section 4.2.1).

Most of that discharge occurs during the 4 p.m. – 9 p.m. on-peak hours. On-peak hours, when retail energy rates are highest, provide the greatest opportunity for customers to realize billed energy savings. If a residential customer is discharging any percentage of energy outside this period, this suggests that bill reductions may not be the primary driver or system operating mode. In fact, we observe self-consumption as the most prominent operating mode for residential storage at a fleet level. Since systems in self-consumption mode are limited by underlying customer load, hourly discharge ranges from 1% to 6% of system kWh capacity depending on the month (Figure 1-6).

FIGURE 1-6: RESIDENTIAL STORAGE DISCHARGE AND CHARGE KWH PER KWH CAPACITY

Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from PV)

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-4%	-2%	0%	3%	4%	4%	3%	3%	1%	1%	1%
February	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-5%	-4%	-3%	-2%	-0%	2%	4%	4%	3%	3%	2%	1%	1%
March	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-5%	-7%	-7%	-5%	-4%	-2%	-1%	2%	3%	4%	4%	3%	2%	2%	2%
April	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-8%	-7%	-5%	-3%	-2%	-1%	2%	2%	4%	4%	4%	3%	2%	2%
May	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-8%	-8%	-5%	-3%	-2%	-1%	2%	2%	3%	4%	4%	3%	3%	2%
June	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-9%	-8%	-6%	-3%	-2%	-0%	2%	3%	4%	5%	4%	3%	2%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-7%	-9%	-8%	-6%	-4%	-2%	-0%	3%	4%	5%	6%	4%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-7%	-10%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	4%	3%	2%	2%
September	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-5%	-3%	-1%	3%	5%	6%	6%	4%	2%	2%	2%
October	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-5%	-7%	-8%	-7%	-5%	-3%	-1%	3%	4%	5%	5%	3%	2%	2%	1%
November	1%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-6%	-4%	-3%	-1%	1%	3%	4%	4%	3%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	4%	3%	2%	1%	1%	1%

Renewably fueled and non-fueled generation technologies provide consistent, low emission generation throughout the year, and have provided additional capacity during times of grid constraints. California

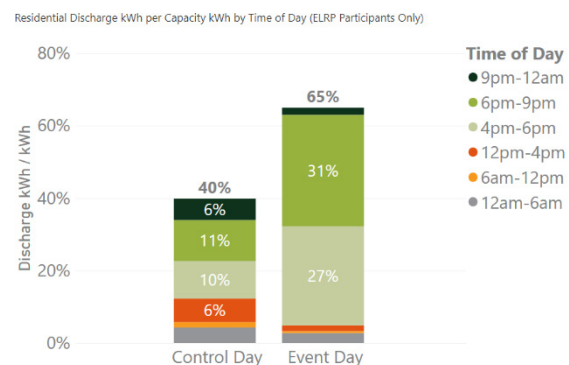
witnessed significant energy constraints during 2020, and in response, one fuel cell manufacturer, which has incentivized most of the all-electric fuel cell capacity in the SGIP, ran an initiative to **export significant energy to help relieve the strain on the grid** using combustion-free, fuel-flexible technologies. These changes still appear evident, with many of these systems exporting a large percentage of their load.

Residential and nonresidential battery systems are not discharging the total capacity of the system regularly, and many residential customers are limiting discharge to maintain net zero load rather than exporting (Section 4.2.1). This finding is intuitive – if customers are already abiding by SGIP rules for round-trip efficiency (RTE), utilization, and GHG reductions – they may also want to have reserve energy in the event of an outage. However, there are considerable untapped potential additional grid benefits including net-peak dispatch, load-flexibility support, and critical-hour response, if additional battery capacity is deployed in response to grid needs and/or price signals.

- » **Recommendation 3.** *We recommend that the CPUC explore strategies to encourage dispatch patterns that emphasize discharging batteries (and reducing load) on-peak periods, as opposed to defaulting to daily self-consumption.*

We observe significant differences in storage utilization for sampled customers participating in the Electric Load Reduction Program (ELRP) (Section 4.3.1). During event days, which in 2024 align with capacity constrained grid hours, systems that were ordinarily operating in solar self-consumption or arbitrage modes, but were enrolled in ELRP, discharged more capacity than they ordinarily would. Peak hourly discharge reached roughly 21% of system kWh capacity during the 6 p.m. hour on event days. On non-event days, peak discharge reached 5% capacity. Average daily utilization was 40% of kWh capacity. However, on event days, utilization increased to 65% of kWh capacity. During event days, excess discharge was being exported to the grid – a behavior from this cohort of systems that wasn’t observed ordinarily throughout the year. We also observe increased charging on and after event days because greater discharge utilization resulted in lower end-of-day state-of-charge (SOC).

FIGURE 1-7: ELRP PARTICIPANT UTILIZATION



- » **Recommendation 4.** *We recommend that the CPUC and SGIP PAs encourage participation in real-time rates to provide an even more granular signal to customers. In lieu of real-time rates, the CPUC and SGIP PAs should continue to encourage participation in demand response programs.*

Residential and nonresidential storage systems provide grid relief during CAISO peak hours and there is opportunity for further grid benefits (Section 4.3.1). The total program energy storage capacity in 2024 was over 2,000 MWh. Residential and nonresidential systems discharged roughly 156 MWh (~8% of available capacity) during the top net peak hour (which is when the greatest grid stress occurs, and when energy prices are the highest) and each sector averaged roughly 45 MWh of discharge across the Top 100 net peak hours in 2024.

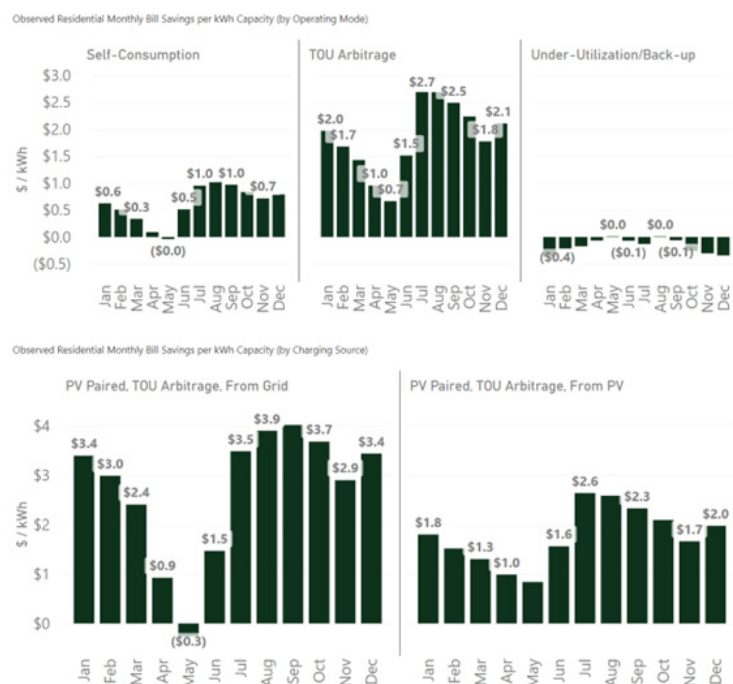
- » **Recommendation 5.** *The CPUC is currently exploring ways to encourage additional battery utilization through participation in real-time rates or other mechanisms that encourage demand flexibility and grid support while also safeguarding private resiliency benefits. We recommend that these mechanisms be considered and leveraged where appropriate.*

Customer Bill Impacts

Residential storage systems are primarily being utilized for TOU arbitrage and solar self-consumption, and customers realize bill savings as systems arbitrage energy across higher and lower priced hours. Savings are generally greatest during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often. Given the more focused discharge during on-peak hours, systems conducting **TOU arbitrage provide annual bill savings of roughly \$22 per kWh of capacity**, and those in **solar self-consumption mode generate about \$7 per kWh of capacity** in billed savings. While we observe similar daily utilization for systems in each operating mode, focusing utilization and discharge during on-peak hours exclusively generates three times more in bill savings for systems conducting arbitrage. Unsurprisingly, **under-utilized systems or those in backup mode result in slight bill increases** (\$2 per kWh of capacity).

We also observe **differences in billed savings by system configuration and storage charging source.** Systems paired with PV and conducting arbitrage but charging overnight realize \$33 per kWh of capacity

FIGURE 1-8: RESIDENTIAL MONTHLY BILL SAVINGS



in billed savings, compared to paired systems conducting arbitrage, but charging from solar (\$21/kWh). **Greater utilization and more focused discharging on peak provide that increased bill savings opportunity.** Furthermore, since solar self-consumption is the prominent observed operating mode in the SGIP, bill savings for PV paired systems charging from solar align with savings in that operating mode.

Generation customers, whose systems provide a baseload or minimum level of power to meet regular facility demands, generally see higher bill-savings the more energy they produce, even accounting for the added fuel costs. All-electric fuel cells saw monthly bill savings averaging around \$80-\$160 per kW of capacity per month, while internal combustion engines saw bill savings around \$40-\$110 per kW of capacity per month.

SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand and on-peak demand and/or daily demand charges, as well as TOU energy arbitrage (Section 4.2.1). Systems designed for demand charge reductions may incur billed increases on the energy component of their bill, but demand reduction savings led to a net reduction in bills overall. Some nonresidential systems perform TOU arbitrage exclusively, and subsequent charging may lead to increased non-coincident peak demand. On average, nonresidential storage dispatch behavior allowed customers to realize overall bill savings for each month of 2024. Bill savings opportunities are greatest during summer months and annual savings range from \$31 per kWh of capacity for PV paired systems and \$34 per kWh of capacity for standalone systems.

- » **Recommendation 6.** While PV paired storage charging from grid resources provides 1) private benefits by way of customer-billed energy savings and 2) grid benefits by virtue of on-peak discharge, GHG emissions differentials between charging overnight and discharging on-peak are not sufficient to realize emissions reductions as observed with PV paired systems charging from on-site PV. The SGIP PAs and CPUC should develop communication strategies or enforce program rules to both project developers and host customers to ensure paired systems are charging exclusively from solar, where applicable. This will help the program realize GHG emissions reductions goals. Furthermore, policies and rate structures developed to promote EV home charging overnight should consider impacts of GHG emissions and PV paired storage.

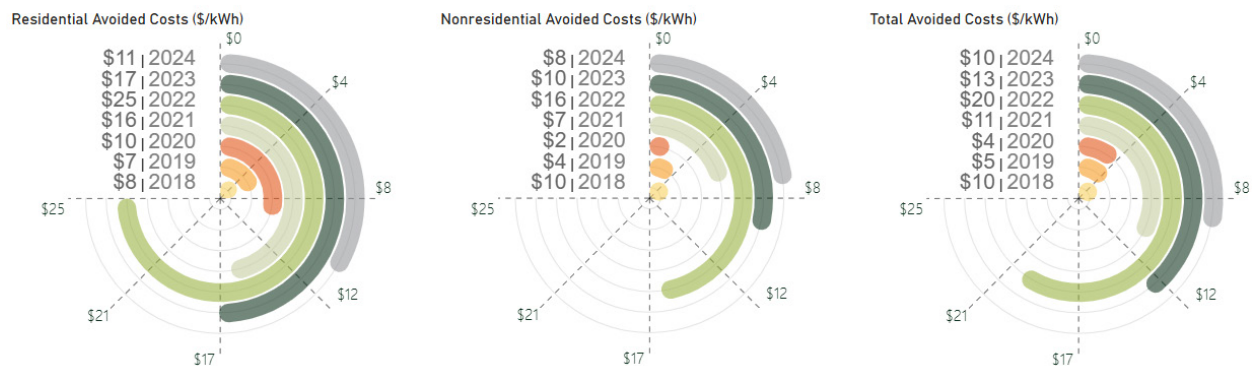
Utility Avoided Costs⁶

Energy storage utilization provided utility avoided cost benefits in 2024 (Section 4.5.1). Overall, SGIP storage systems were charging during lower marginal cost periods and discharging during higher cost

⁶ The 2024 Avoided Cost Calculator was used as the basis for this analysis along with updated cost values to align with actual weather and locational marginal prices (LMP) observed in 2024 (Appendix E).

periods. This behavior resulted in a \$19.2 million avoided cost benefit across utilities. Avoided cost benefits – on average – equaled roughly \$11 per kWh of capacity for the residential sector and \$8 per kWh for the nonresidential sector in 2024.⁷ During the first full week in September 2022, protracted high temperatures throughout the state generated critical stress and well-above normal demands on the CAISO and utility systems. This resulted in some very high-cost hours – relative to 2023 and 2024 – which is one reason why avoided cost benefits were much greater that year. Furthermore, the 2024 ACC employed a new analytic methodology to calculate estimates of marginal generation capacity cost. As a result of this change, estimated marginal generation capacity costs used to calculate 2024 SGIP impacts were lower than those used previously to calculate impacts.⁸

FIGURE 1-9: ENERGY STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY YEAR AND SECTOR



Generation systems provided significant electric utility avoided costs in 2024 (Section 4.5.2). As most generation technologies provide baseload generation across the course of the year, the total electric avoided costs for generation technologies are generally proportional to the amount of energy generated by the system. However, on a normalized, per kW-basis, the electric utility avoided costs correspond to operation during times when avoided costs are the highest. All-electric fuel cells exhibited capacity factors over 90%, meaning they were operating during most hours of the year, and they provided electric utility avoided costs averaging \$450/kW. These were followed by gas turbines averaging \$404/kW. The total

⁷ It's important to note that ratepayer incentives for SGIP storage technologies range from \$180 per kWh of capacity to \$1,000 per kWh depending on the budget category and time of program participation. While systems are providing utility avoided cost benefits, these benefits – even when calculated over the 10-year permanency period – are far less than the ratepayer incentives issued to participating customers.

⁸ 2024 Distributed Energy Resources Avoided Cost Calculator Documentation, for the CPUC, October 2, 2024, Version 1b, at 37-38. Available at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

electric avoided costs for 2024 generation systems totaled \$61.4 million, averaging about \$311 per kW of generation capacity.

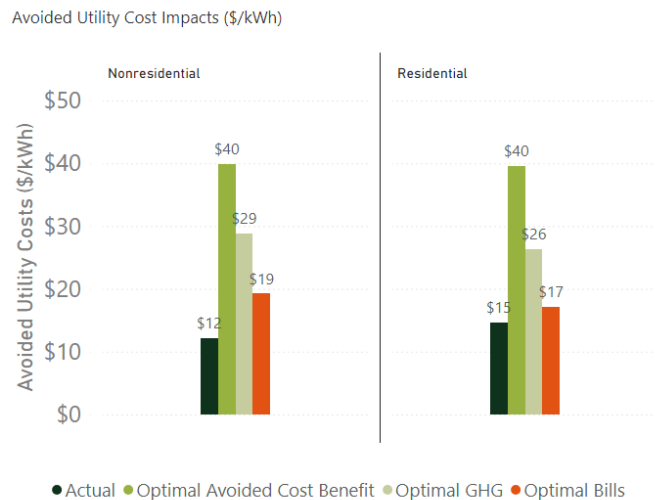
Storage Optimization

A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge during higher emissions and price hours (Section 5). Obviously, storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or incentive) encourages shifting or reducing demand at specific times. Customers have access to their bill rate structure, but grid-level demand may not be in their purview. On-peak TOU periods provide a broad signal to arbitrage energy over a five-hour period, but emissions vary considerably during this period, narrowing the window for achievement of maximum emissions reductions or utility avoided costs.

Optimizing storage charge and discharge for utility avoided cost benefits would result in a threefold improvement over actual avoided cost benefits in 2024. Avoided cost benefits would also increase if GHG emissions or bill savings were optimized, but at lower magnitudes (Section 5). Optimization

modeling revealed that the average actual avoided cost benefit of \$12 and \$15 per kWh of capacity would increase to \$40 if storage followed the avoided cost signal for both nonresidential and residential sectors. Most of the incremental avoided cost benefits under this optimization scenario are realized during capacity-constrained, on-peak, summer hours, as well as during morning ramps.

FIGURE 1-10: RESIDENTIAL AVOIDED COST OPTIMIZATION



- » **Recommendation 7.** *We recommend the CPUC continue to explore strategies to encourage SGIP participants to dispatch during high GHG/demand hours and encourage demand flexibility and grid support while also safeguarding resiliency benefits.*

2 INTRODUCTION AND OBJECTIVES

California’s Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer’s electricity needs. The SGIP is funded by both California’s ratepayer collections and by state monies through the Greenhouse Gas Reduction Fund (GGRF). The SGIP is managed by Program Administrators (PAs) representing California’s major investor-owned utilities (IOUs). These PAs include Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E), and Los Angeles Department of Water and Power (LADWP), which participates in SGIP through distinct administrative arrangements. The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP. This evaluation report is only applicable to the ratepayer-funded portion of SGIP as the state-funded portion did not open to applications until 2025.

2.1 HISTORY OF THE SGIP

Since its inception in 2001, the SGIP has provided incentives for a wide variety of distributed energy technologies including combined heat and power (CHP), fuel cells, solar photovoltaic (PV), and wind turbine systems. While the program was initially designed to help address peak electricity problems in California,⁹ the program has evolved, with eligibility requirements and incentive levels changing over time.

Approval of Assembly Bill (AB) 2778¹⁰ in September 2006 limited SGIP project eligibility to “ultraclean and low-emission distributed generation” technologies. By 2007, growing concerns with potential air quality impacts prompted changes to the SGIP’s eligibility rules, and passage of Senate Bill (SB) 412¹¹ shifted the program’s focus from peak-load reduction to greenhouse gas (GHG) emissions reductions. Beginning in 2009, energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies – wind turbines and fuel cells – were eligible for incentives.¹² In 2011, standalone storage

⁹ California Assembly Bill 970, Ducheny. September 6, 2000.
http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

¹⁰ California Assembly Bill 2778, Lieber. September 29, 2006.
http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

¹¹ California Senate Bill 412, Kehoe. October 11, 2009.
http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

¹² CPUC Decision D.08-11-044. November 21, 2008.
https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/94272.pdf

systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives.¹³ In 2011, the CPUC issued Decision (D.) 11-09-015, which added SGIP eligibility requirements based upon GHG reductions.¹⁴ This was followed by D. 16-06-055 in 2016, which, among other changes, revised how the SGIP is administered.¹⁵ Beginning in 2017, the SGIP was administered on a continuous basis. This change was made largely to curb potential issues with incentives being depleted during program opening, as the program is typically oversubscribed. D. 16-06-055 also supplemented the first-come, first-served reservation system with a lottery. In 2017, D. 17-10-004 established the SGIP Equity Budget, where 25% of SGIP funds collected for energy storage projects were reserved for single-family and multi-family low-income housing, including disadvantaged communities.¹⁶

In August 2019, the CPUC issued D. 19-08-001 approving GHG emission reduction requirements for the SGIP storage budget.¹⁷ This decision requires SGIP PAs to provide a digitally accessible GHG signal that provides marginal GHG emissions factors and directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets as part of annual SGIP storage evaluations. This decision also defined compliance pathways and operational requirements for residential and nonresidential SGIP energy storage projects based on whether a project was “legacy” or “new.”¹⁸

On September 12, 2019, the CPUC issued D. 19-09-027 that established an SGIP equity resiliency budget, modified existing equity budget incentives, and approved the transfer of unspent funds to the equity resiliency budget.¹⁹ To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 set aside a budget for vulnerable households located in Tier 2 and Tier 3 High Fire-Threat Districts, critical services facilities serving those districts, and customers located in those districts that participate in low-

¹³ CPUC Decision D.10-02-017. February 25, 2010.

http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114312.PDF

¹⁴ CPUC Decision D.11-09-015. September 16, 2011.

https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/143459.pdf

¹⁵ CPUC Decision D.16-06-055. June 23, 2016.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF>

¹⁶ CPUC Decision D. 17-10-004. October 12, 2017.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M197/K215/197215993.PDF>

¹⁷ CPUC Decision D. 19-08-001. August 9, 2019.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K260/310260347.PDF>

¹⁸ “New” projects are those submitting completed applications on or after 4/1/2020. “Legacy” projects are all others completing applications prior to that date.

¹⁹ CPUC Decision D. 19-09-027. September 18, 2019.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M313/K975/313975481.PDF>

income/disadvantaged solar generation programs. In January 2020, the CPUC issued D. 20-01-021.²⁰ The decision authorized the collection of ratepayer funds totaling \$166 million per year from 2020 to 2024 across the four program administrators. This decision also increased the financial incentive budget for energy storage technologies to 88% of total SGIP funding.

Passage of AB 209 in 2022 secured funding for combined solar and storage incentives to California residential customers.²¹ Initially, the bill included \$900 million for the SGIP, which would be allocated across three fiscal budget years. The funding was reserved mostly for eligible low-income residential customers (70%), with the remaining budget reserved for general market customers. This was followed by AB 102²² in 2023, which amended the original budget act and allocated \$280 million of the original funding to the CPUC in 2023-2024, with the remaining original budget allocations dependent on future budget bill negotiations. The \$280 million was appropriated from the Greenhouse Gas Reduction Fund (GGRF), which is derived from funding in the state's Cap-and-Invest Program proceeds. SGIP had previously been funded exclusively from ratepayer collections since its inception in 2001. The bill focused on incentive allocations to eligible low-income residential customers only, standalone storage, or storage paired with solar PV, and extended incentives to customers who receive electricity service from Public Owned Utilities (POU). Those changes to program administration, funding, and incentives were implemented in D. 24-03-071.²³ Table 2-1 summarizes the timelines and key provisions from each of those decisions since 2008.

The Residential Solar and Storage Equity (RSSE) budget category opened for reservations beginning in June 2025 for eligible low-income residential customers receiving electric service from entities administered by PG&E, SCE, SCG and CSE and was followed by Los Angeles Department of Water and Power (LADWP) in September. Impacts from RSSE systems are not included in this report.²⁴ However, they will be included in future evaluations as storage systems are built out, paid incentives, and begin to operate under new SGIP rules, eligibility, and program administration.

²⁰ CPUC Decision D. 20-01-021. January 27, 2020.

<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF>

²¹ California Assembly Bill 209, Committee on Budget. September 6, 2022.

https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209

²² California Assembly Bill 102, Ting. July 10, 2023.

https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB102

²³ CPUC Decision D. 24-03-071. March 21, 2024.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K963/527963349.pdf>

²⁴ More information on RSSE incentives can be found here: <https://www.cpuc.ca.gov/sgip>

TABLE 2-1: CPUC DECISIONS INFLUENCING THE SGIP

CPUC Decision	Decision Date	Key Provisions
D. 08-11-044	11/2008	Energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies (wind turbines and fuel cells) were eligible for incentives
D. 10-02-017	02/2010	Standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives
D. 11-09-015	09/2011	Modified program to include eligible technologies that achieve GHG emission reductions
D. 16-06-055	06/2016	- SGIP administered on a continuous basis - Supplemented the first-come, first-served reservation system with a lottery - Energy storage allocated 75% of program funds - Required minimum biogas blending requirements, up to 100% biogas requirement starting in 2020.
D. 17-10-004	10/2017	25% of funds collected for energy storage projects are reserved for the SGIP Equity Budget
D. 19-08-001	08/2019	- Requires SGIP PAs to provide a digitally accessible GHG signal - Defines compliance pathways and operational requirements for "new" and "legacy" projects and "developer fleets" - Provided GHG enforcement standards for electrochemical and thermal energy storage systems - Directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets
D. 19-09-027	09/2019	- Established the equity resiliency budget - Modified existing equity budget incentives
D. 20-01-021	01/2020	- Authorized ratepayer collections of \$166 million per year during 2020-2024 to fund the SGIP 88% of incentive budget is reserved for energy storage technologies - Implemented program revisions pursuant to Senate Bill 700 and other program changes
D. 21-06-005	06/2021	Revised program requirements for renewable generation projects
D. 24-03-071	03/2024	- Established and allocated \$280 Million from the Greenhouse Gas Reduction Fund (GGRF) to the Residential Solar and Storage Equity (RSSE) budget category - Modified SGIP eligibility requirements and program administration including: - Changes to upfront incentive payments to RSSE customers - Increased maximum incentive levels for RSSE and SJV budgets - Transition of NEM customers who apply for SGIP incentives to NBT for general market budget categories (beginning June 2024). Based on the timing of this decision, very few SGIP participants were on NBT in this study. However, future studies will track those transitions from NEM to NBT. - Required all new SGIP participants to enroll in an SGIP approved qualified Demand Response (DR) program.

2.2 REPORT PURPOSE

SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. Decision (D.) 16-06-055 initially stated that an SGIP Measurement and Evaluation (M&E) Plan should be developed by CPUC Energy Division (ED) staff in consultation with Program Administrators. The subsequent passage of SB 700²⁵ extended annual collections of ratepayer funds for the SGIP through 2024 and extended administration of the program through 2025. SB 700 also required the CPUC to adopt new program rules regarding GHG emissions impacts and restricted all SGIP generation technologies to 100% renewable fuel by 2020. Furthermore, Ordering Paragraph (OP) 7(h) of D.19-09-027 required the SGIP program administrators to develop an M&E Plan for 2021-2025, which was ultimately approved in May 2022, and finalized in January 2023.

2.3 GOALS AND OBJECTIVES

The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP energy storage and generation technologies operating during CY 2024. Verdant analyzed several different observed performance metrics and impacts and compared them to expectations and program requirements. Verdant also took those observed impacts for energy storage systems and compared them to optimal performance, where the systems have perfect foresight, and respond to different signals (price, GHG, utility costs). The observed performance is compared to the optimal performance under those different scenarios to better gauge whether additional value can be extracted from these BTM resources. The research objectives and methods summarized in Table 2-2 are guided by the M&E Plan, along with results gained from past impact evaluations, and in consultation with Program Administrators and CPUC.

²⁵ California Senate Bill 700, Wiener. September 27, 2018.
https://leginfo.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB700

TABLE 2-2: OVERVIEW OF RESEARCH OBJECTIVES AND METHODS

Quantitative Research Objectives	Methods
Observed Performance Metrics	
• Are projects maintaining minimum capacity factors, RTEs and cycling requirements? • How have project efficiencies and utilization changed over the years? • How do utilization and system efficiencies (electrical, thermal, and total) differ based on different segmentation – facility type, operating mode, TOU period, season, presence of on-site generation, capacity constrained hours, fuel type? • To what extent do SGIP technologies employ renewable fuel and how does their performance compare to non-renewable and blended projects? • Quantification of electricity generated, fuel consumed (both renewable and non-renewable), and useful heat recovered? • Non-coincident peak demand impacts?	Analysis of metered data for energy storage system charge and discharge, generation system output, and facility load at the utility meter. Optimal dispatch modeling.
Grid Impacts and Utility Marginal Costs	
• How do systems currently operate throughout grid constrained hours (CAISO net peak and gross peak hours) and utility coincident peak? What are the key differences between groups based on different segmentation? • How are resources that charge from renewable generation exporting to the grid? How often? At what times? At what capacities? • How do systems affect utility and grid costs? • Are storage systems exporting and, if so, is export energy renewable based? • Quantification of impacts from systems participating in wholesale markets and demand response?	Comparing CAISO and IOU load data to the metered storage and generation data throughout specific hours throughout the year. Quantification of dispatch behavior throughout demand response and wholesale market participation. Quantification of grid benefits using the Avoided Cost Calculator (ACC) and locational marginal energy prices. Optimal dispatch modeling.
Environmental Impacts	
• Are projects reducing GHG emissions? Have emissions changed over time? • Do emissions vary by key segmentation – facility type, developer/manufacture, presence of on-site solar, rate schedule, legacy status, etc? • What are developer fleet emissions? • How does optimal GHG emissions reductions compare to observed emissions and how can changes to operation lead to increased GHG emissions reductions? • Quantification of emissions impacts based on the various emissions components – generation technology by fuel type, electric power plant, heating and cooling, biogas treatment?	Analysis of emissions avoided during storage discharge and emissions increases during storage charging. Comparison of emissions impacts by component for differing technologies, fuels, and baseline types; impact of electric power plant, heating and cooling loads, and biogas treatment. Optimal dispatch modeling.
Integration of On-site Solar PV	
• How does storage interact with systems paired with PV? Does behavior differ for standalone systems and by different segmentation? Do discharge patterns differ by TOU periods? • What is the relationship between storage sizing and PV sizing? How does that relationship correlate to customer, grid, and environmental impacts?	Analyze and quantify storage performance throughout PV generating hours – percentage of energy charged, magnitude of charge relative to size of PV generator (kW, kWh)
Customer Resiliency	
• How does storage behave during outages? • Quantification of BTM consumption during PSPS events compared to similar non-PSPS days? Changes in utilization, consumption, PV generation? • How are critical needs facilities being utilized to provide community support during utility outages?	Analysis of storage, load, and PV data during PSPS and other outage events compared to like days. Review of outage data provided by utilities. Review of program tracking.
Customer Bill Impacts	
• Are SGIP participants realizing bill savings from storage and generation utilization? • Are nonresidential customers realizing demand charge savings? TOU energy savings? • How do customer bill impacts differ by rate schedule, month? • How does optimal bill savings compare to observed customer bill savings? • Co-optimization with GHG reductions or utility avoided costs?	Analysis of changes to a customer's bill from a baseline where no storage exists using Verdant's Bill Calculator and Cost-Effectiveness Tool. Optimal dispatch modeling.
Storage Costs	
• Quantification of self-reported storage costs? What comprises storage eligible costs – capital expenditure, labor, interconnection, permitting? • How have these costs changed over time? Do costs differ by component or by developer/manufacture?	Analysis of disaggregated eligible costs from program tracking data. Analysis of trends based on developer/manufacture, size of system, program year of application.
Population Impacts	
• Quantification of storage and generation impacts to the population of the SGIP?	Ratio estimation. Extrapolation of sample-level impacts to the population of projects.

2.4 METHODOLOGY OVERVIEW AND SOURCES OF DATA

The empirically observed impacts reported in this evaluation are based directly on metered performance data collected from a sample of SGIP projects. The evaluation team used sampling methods and estimated population-level impacts using statistical approaches that conform to industry standards for impact evaluations. Sources of data used in this evaluation include:

- The SGIP Statewide Project Database – contains project characterization information such as incentivized capacity, host customer address, electric utility, project developer, and upfront payment date
- Installation Verification Inspection Reports – used to supplement the Statewide Project Database with additional details such as inverter size (kW), battery size (kWh), and storage system type
- Metered generation, charge, and discharge data
 - Data for generation and energy storage systems subject to Performance-Based Incentive (PBI) data collection rules were downloaded from the Statewide Project Database
 - Data for a sample of all energy storage systems (regardless of size) were requested and received from project developers
 - Data for generation systems came from both customers and performance data providers
- Metered customer interval load and tariff information (energy storage) were requested and received from the electric IOUs and project developers, where available
- Marginal emissions data were collected from the GHG signal provider, WattTime²⁶
- Utility avoided cost information was developed using locational marginal price and GHG Allowance price data from CAISO, as well as marginal cost data from the CPUC 2024 Avoided Cost Calculator (ACC)
- Additional information such as electric outage information, paired generator (PV, fuel cell, etc.) characteristics, and participation in demand response (DR) programs, where applicable, were received from project developers and electric utilities

The data was reviewed to ensure data integrity and quality. Characterization of the sample including performance metrics and program impact estimates by various categorical variables is included in Section 4. Details on the data integrity and quality control (QC) methods are provided in Appendix B.

²⁶ <https://sgipsignal.com/>

2.5 REPORT ORGANIZATION

This report is organized into five sections and five appendices as described below.

- Section 1 provides an executive summary of the key findings and recommendations from this evaluation
- Section 2 summarizes the purpose, scope, methodology, and organization of the report
- Section 3 provides a detailed description of the SGIP population
- Section 4 presents performance metrics and observed impacts for sampled projects, as well as estimated total impacts for the overall population
- Section 5 presents observed energy storage performance to optimal dispatch
- Appendix A describes how customer bill impacts were estimated
- Appendix B presents the sources of data used in this evaluation and the quality control procedures used to verify storage data
- Appendix C characterizes the metered sample
- Appendix D provides methodologies related to greenhouse gas calculations
- Appendix E provides methodologies related to utility avoided costs

3 STUDIED POPULATION

The 2024 SGIP energy storage and generation population is collected from the most recent version of the statewide project database and downloaded at www.selfgenca.com.²⁷ This dataset provides the current listing of all projects that have applied to the program and contains individual project data, including incentive status, project developer name, system size, system location, electric utility name, and whether a project is paired with a renewable generator (among other fields).

The energy storage population subject to evaluation is defined as all projects: 1) receiving an upfront SGIP incentive on or before December 31, 2024, and 2) having status of “Payment Completed” or “Payment PBI in Process”, and 3) where equipment type is electrochemical, mechanical, or thermal storage, and 4) still within their permanency period as specified by the Program Handbook.

The generation population subject to evaluation is defined as all projects: 1) receiving an upfront SGIP incentive on or before December 31, 2024, and 2) having status of “Payment Completed” or “Payment PBI in Process” and 3) where equipment type is gas turbine, fuel cell, microturbine, wind turbine, waste heat to power, pressure reduction turbine, or internal combustion engine, and 4) still within their permanency period as specified by the Program Handbook.

FIGURE 3-1: SGIP 2024 EVALUATION POPULATION

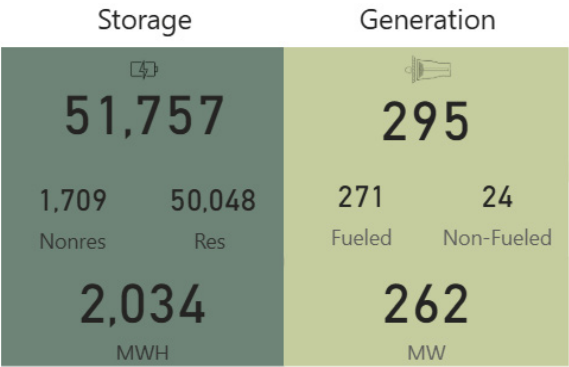


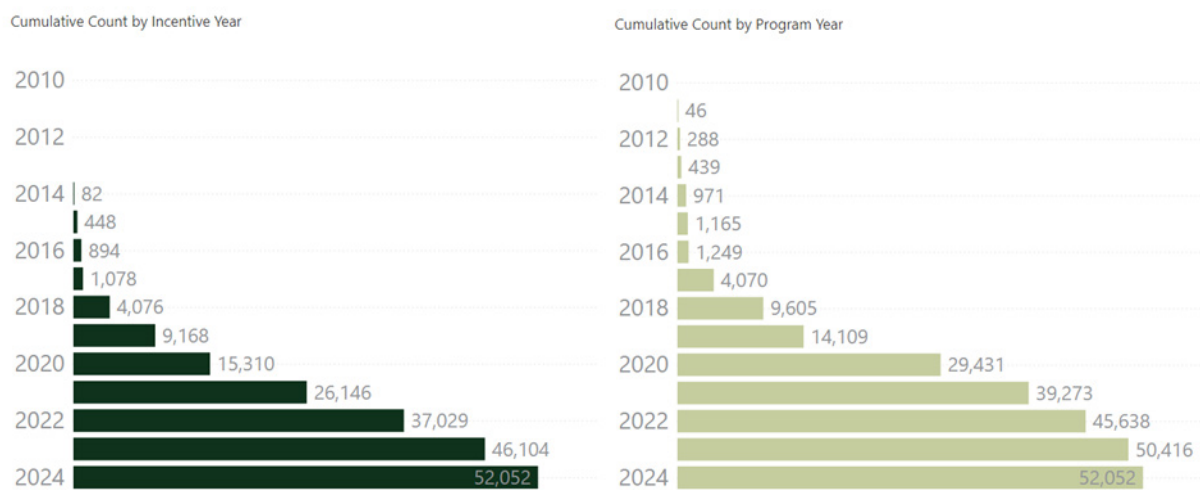
Figure 3-1 summarizes the cumulative storage and generation evaluation population for 2024. During 2024, there were almost 52,000 storage projects in the population, with over 50,000 of them being residential systems. On the other hand, only 295 generation systems were within the SGIP population, still being within their permanency period, 271 of which were fueled systems running on either natural gas, renewable fuel, or a blend of both. The program has incentivized over 2,000 MWh of storage capacity, and 262 MW of capacity of generation projects still within their permanency period.

Figure 3-2 presents the growth in SGIP population over time by program year (PY) and upfront payment (or incentive) year for projects within their permanency period. The program year represents the year a project applied to the SGIP, and the incentive year corresponds to when the participating customer

²⁷ The population data informing this study was downloaded on 01/23/2025.

ultimately received their incentive payment. Given potential lag times due to interconnection and administrative requirements, projects may receive their incentive (or upfront payment) a year or two after initially applying to the program. This is evident in the figure below, where the total number of projects applying within a given year is greater than the number of projects subject to evaluation for that year. Since the program application process can extend beyond one calendar year, our team defines the population of SGIP systems subject to evaluation for a given year based on when the customer received their upfront payment, rather than when they initially applied to the program.²⁸

FIGURE 3-2: SGIP CUMULATIVE PROJECT COUNT GROWTH OVER TIME



3.1 COMPOSITION OF SGIP ENERGY STORAGE POPULATION

The first step in the evaluation design process was to define the energy storage population subject to evaluation for this 2024 study. Host customers and project applicants are at different stages of the application process at any given time, so initial cut points were created to frame the population and were based on four categories collected from the statewide project database. These categories include 1) all projects that received an upfront SGIP incentive on or before December 31, 2024, *and* 2) have fully qualified state of “Payment Completed” or “Payment PBI in Process”, 3) where equipment type is electrochemical, mechanical, or thermal storage, *and* 4) still within their permanency period as specified by the Program Handbook. While this impact evaluation covers storage performance in 2024, the

²⁸ For example, a participant may apply to the SGIP in 2023 but not receive their incentive payment until 2025. This customer would NOT be part of the population frame for 2024.

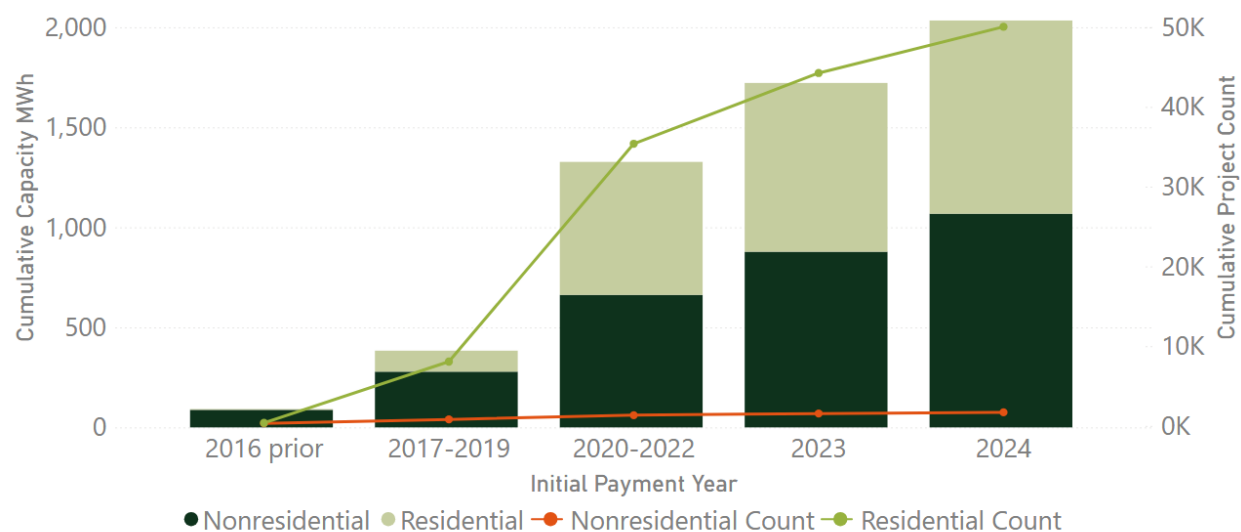
population considers cumulative growth, in that every project receiving an incentive from program inception through the end of 2024 is subject to evaluation.

Storage Composition by Customer Sector

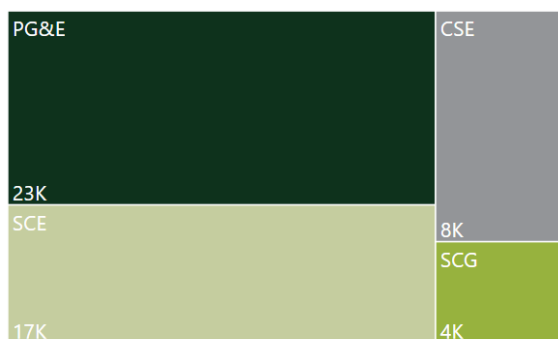
Figure 3-3 presents the cumulative growth of SGIP incentivized energy storage from 2014 – when the first nonresidential systems received incentives – to the end of 2024. By the end of 2024, the SGIP provided incentives for **50,048 residential** and **1,709 nonresidential** projects representing roughly **966 MWh** and **1,068 MWh of incentivized capacity** for each sector, respectively. As of December 31, 2024, all but eight projects were electrochemical (battery) energy storage technologies.

FIGURE 3-3: SGIP STORAGE CUMULATIVE GROWTH BY CUSTOMER SECTOR AND INCENTIVE PAYMENT YEAR

Cumulative Storage Growth by Sector and Payment Year



Program Count Share by PA

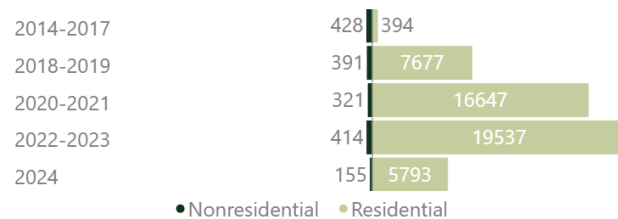


Program Capacity Share by PA

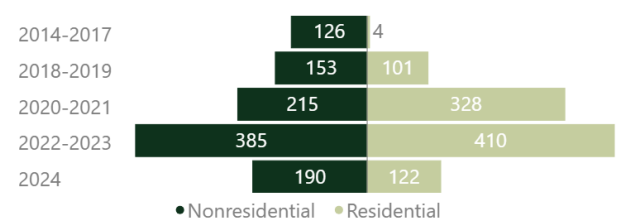


Standalone nonresidential energy storage was the predominant technology in earlier years, but new program funding and budget categories with differing incentive levels allowed newer, more sophisticated energy storage configurations access into the program. In 2016, 75% of the SGIP budget was allocated to energy storage and the program began experiencing a significant increase in participation. The overall share of the SGIP budget reserved for storage technologies increased from 75% to 88% in 2020. These program changes ultimately explain the significant growth in residential program participation, with over 50,000 systems receiving incentives by the end of 2024. New project applications in the nonresidential sector have slowed, except for in the Equity Resiliency Budget (ERB) category. While over 97% of the SGIP storage population are residential projects, the program capacity is roughly split between the residential and nonresidential sectors. PG&E and SCE constitute a greater share of projects and capacity, followed by CSE and SCG.

Projects Paid by Sector and Payment Year Grouping



MWh Paid by Sector and Payment Year Grouping



The program has continued to pay out incentives since the most recent impact evaluation was completed for CY 2023. This growth is represented by the almost 6,000 residential and nonresidential projects receiving SGIP incentives between January 1, 2024, and December 31, 2024, and the 312 MWh of capacity added in the figure above. This coincides with several changes made to the SGIP budget allocation process and program eligibility requirements in 2020. In previous program years, the Small Residential Storage budget category, which was open to any residential IOU electric or gas customer, represented over 90% of all SGIP applications. Starting in 2020, the program shifted focus toward equity projects and customer resiliency, which is primarily captured in the Equity Resiliency Budget category.

Storage Composition by Budget Category

The SGIP energy storage budget is broken out into seven categories: Large-Scale, Small Residential, Residential Equity, Equity Resiliency, Nonresidential Equity, San Joaquin Valley Pilot (SJV Pilot), and Heat Pump Water Heaters. The SGIP energy storage budget is 88% of the overall 2020-2024 budget, and the remaining 12% of the budget is reserved for renewable generation technologies. Most of the energy storage budget (63% of the overall 2020-2024 budget) is allocated to the Equity Resiliency budget category with the remaining 25% of the energy storage budget split between the remaining categories. Table 3-1 presents the overall distribution of budget allocation along with a brief description of the budget categories.

TABLE 3-1: DESCRIPTION OF SGIP PY 2020-2024 BUDGET CATEGORIES²⁹

Budget Category	Budget Allocation	Brief Budget Category Description
Equity Resiliency (Residential and Nonresidential)	63%	Intended for vulnerable households located in Tier 2 and Tier 3 High Fire-Threat Districts (HFTDs) or customers who have been subjected to two or more Public Safety Power Shutoff (PSPS) events.
Renewable Generation	12%	Open to generation technologies. All new generation projects must be 100% fueled with renewable fuel.
Large-Scale Storage	10%	Open to nonresidential projects or residential projects greater than 10 kW.
Small Residential Storage	7%	Open to residential projects less than or equal to 10 kW.
Residential Equity	3%	Open to single-family low-income housing or multi-family low-income housing, regardless of project size.
Nonresidential Equity	n/a	No additional collections authorized. Received funding until exhaustion of previous budget carryover.
San Joaquin Valley Pilot	n/a	No additional collections authorized. Received funding from SCE and PG&E's unused nonresidential equity budget.

Current budget category designations were not created until PY 2017, so projects applying to the program before then were subject to different eligibility and compliance requirements. Furthermore, the incentive structure changed in PY 2017 from a power output (kW) basis to an energy storage (kWh) basis. Verdant has considered many of the programmatic changes that have shaped the program over the years as we reviewed the statewide program database and designed this study.

Below we highlight the program participant count and system capacity contributions for each budget category throughout the years – Figure 3-4 presents growth in project count and Figure 3-5 presents growth in MWh capacity. Payment years have been combined for ease of presentation, but they generally align with significant changes to incentive and program structure over time. Projects identified as “2017 Prior” represent those receiving incentives prior to the creation of the current budget categories (systems applying to the program prior to 2017). Budget categories like Small Residential and Equity Resiliency (ERB), which was created in PY 2020, account for a significant increase in total projects beginning in 2021-2022. Currently, incentives received through the Small Residential budget category represent the largest

²⁹ D.20-01-021 included a 5% budget allocation for heat pump water heaters (HPWH). The budget for HPWH incentives has since increased. However, the HPWH element of the SGIP is largely independent of the energy storage and generation elements from an administration and evaluation standpoint. As such, changes to the HPWH program are not documented in this report.

share of projects, followed by ERB. Measured in program capacity, the Large-Scale Storage category represents the greatest share because this category is open to both residential and nonresidential systems – the latter of which are generally much larger in size. The Equity categories have experienced the lowest participation in the program with 268 projects and 55 MWh of capacity receiving incentives. By the end of 2024, Small Residential, ERB, and Large-Scale Storage represented 97% of all energy storage incentives received within the SGIP since program inception.

FIGURE 3-4: SGIP STORAGE PROJECT COUNT GROWTH BY BUDGET CATEGORY AND PAYMENT YEAR

Cumulative Storage Growth by Sector and Payment Year

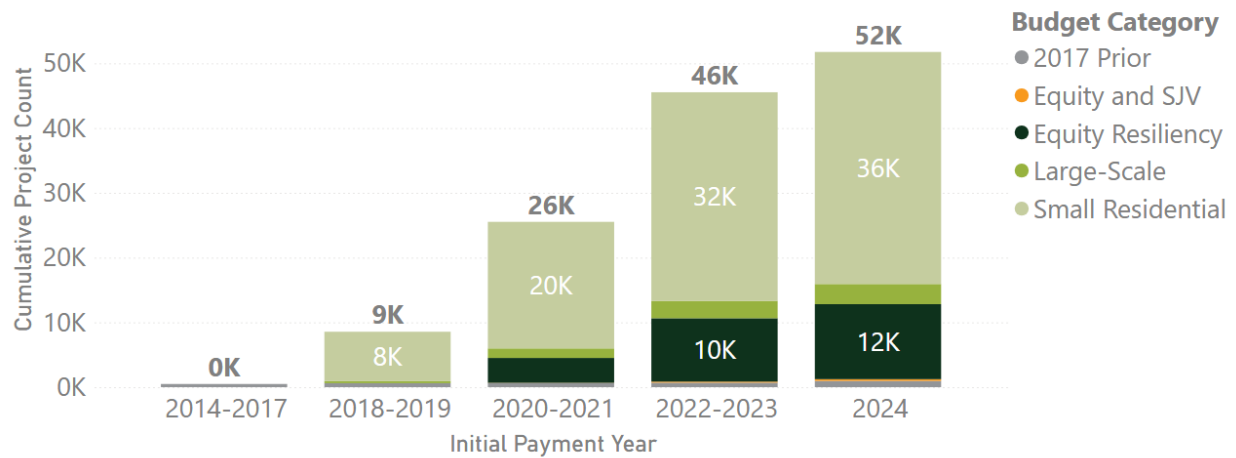
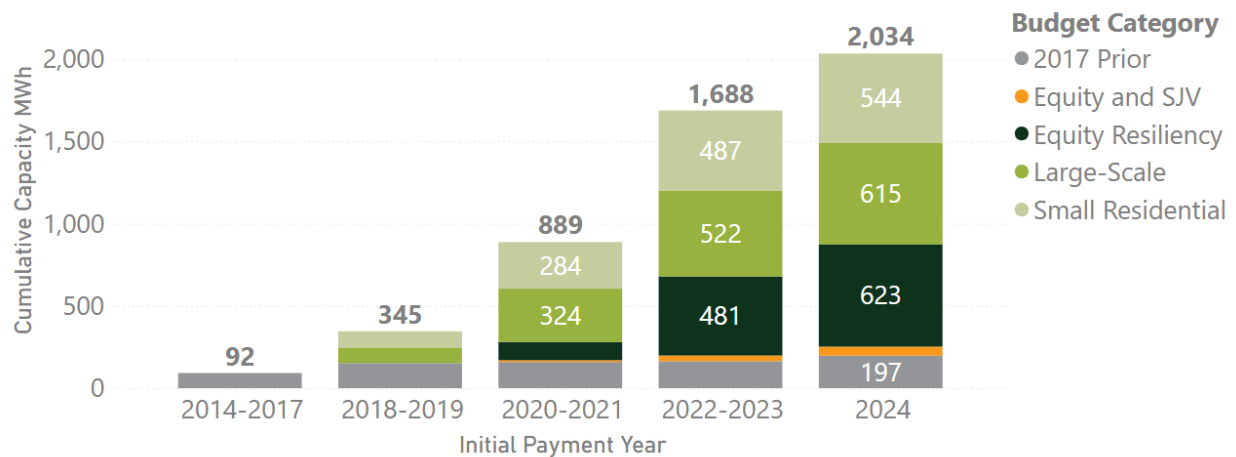


FIGURE 3-5: SGIP STORAGE CAPACITY GROWTH (MWH) BY BUDGET CATEGORY AND PAYMENT YEAR

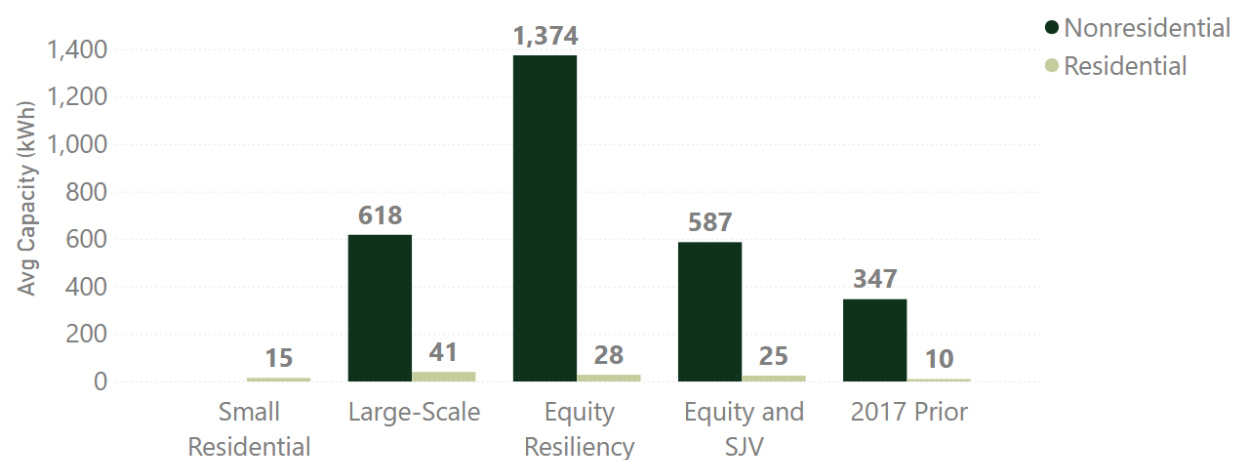
Cumulative Storage Growth by Budget Category and Payment Year



Nonresidential systems are almost always larger and therefore represent a greater contribution to total program impacts. They range in size from roughly 10 kWh to over 5,000 kWh, with an average capacity of almost 625 kWh. Residential systems generally range from 10 kWh to 52 kWh, with an average capacity of 19 kWh. We also observe significant variation in installed capacities across budget categories for a given sector. Nonresidential installations in the ERB are, on average, two times larger than nonresidential installations in other budget categories. The ERB installations are installed at critical services facilities, which in the event of an outage, could require larger and longer duration batteries to provide community resiliency. The same is true in the residential sector. Storage systems installed in ERB are, on average, twice the size of Small Residential systems (28 kWh compared to 15 kWh). Customers experiencing PSPS outages and needing to service critical loads like medical devices may require a larger system to provide lifesaving support throughout a multi-day outage. Furthermore, residential customers receiving incentives in Large-Scale Storage might have much greater underlying load requirements than customers in the Small Residential category – which may explain why systems installed in that category are, on average, three times larger than those in the Small Residential budget category.

FIGURE 3-6: AVERAGE INCENTIVIZED CAPACITY (KWH) BY BUDGET CATEGORY AND CUSTOMER SECTOR

Average Storage Capacity kWh by Sector and Budget Category



Participation within specific budget categories is also influenced by budget allocation (as discussed previously) and upfront incentive levels. The ERB and Equity budget incentives can reach up to \$1.00 and \$0.85 per watt hour, respectively, while Large-Scale and Small Residential incentives are allocated through a stepdown process – where initial incentives were provided at \$0.50 per watt hour, and the incentive is reduced (to as low as \$0.15 per watt hour) as stepped participation targets are met and closed, and new steps open.

Figure 3-7 and Figure 3-8 presents how residential and nonresidential incentive levels differ by budget category. The reference line for median incentive is also provided. The size of points is proportional to the total count of projects that have received incentives within a budget category. While the nonresidential ERB incentive is also \$1.00 per watt hour, this figure presents upfront incentive payments. Nonresidential systems are subject to Performance-Based Incentive (PBI) requirements where 50% of the incentive is paid upfront and the remaining 50% is paid out over the next five years, based on project performance. These projects began receiving their upfront incentive between 2021-2024, so they haven't received their full incentive by the end of 2024.

FIGURE 3-7: RESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

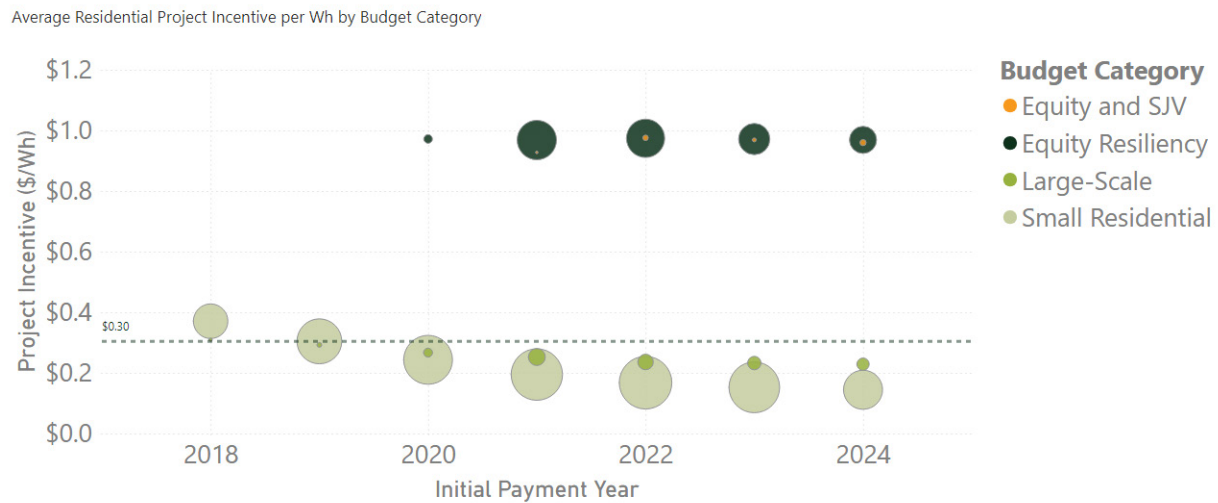


FIGURE 3-8: NONRESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

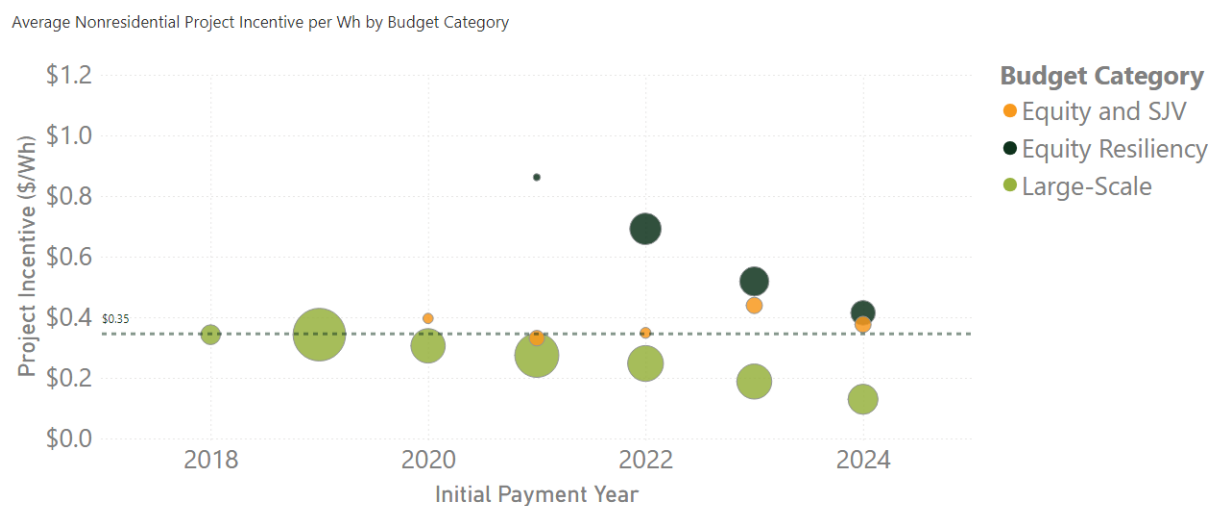


Figure 3-9 and Figure 3-10 convey how, over time, those self-reported eligible costs vary based on customer sector and budget category. Unlike incentive levels, which have either remained constant in categories like the ERB, SJV, and Equity budgets, or have declined like in the Small Residential and Large-Scale Storage categories, total eligible costs have all increased over time. The average self-reported total eligible cost in the Small Residential category increased from \$0.81 per watt hour in 2018 to \$1.17 per watt hour in 2024.

FIGURE 3-9: RESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY

Average Residential Project Cost per Wh by Budget Category

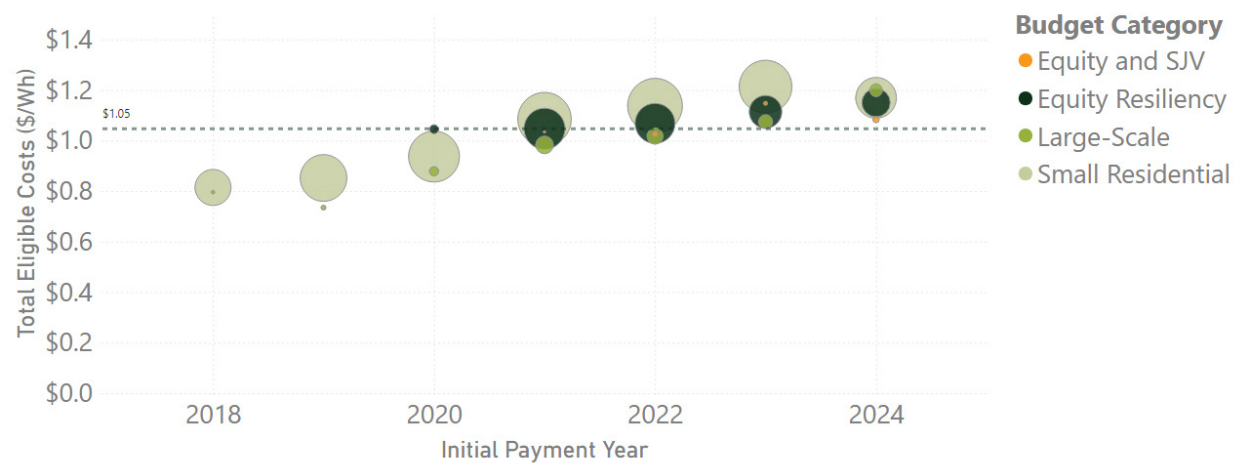
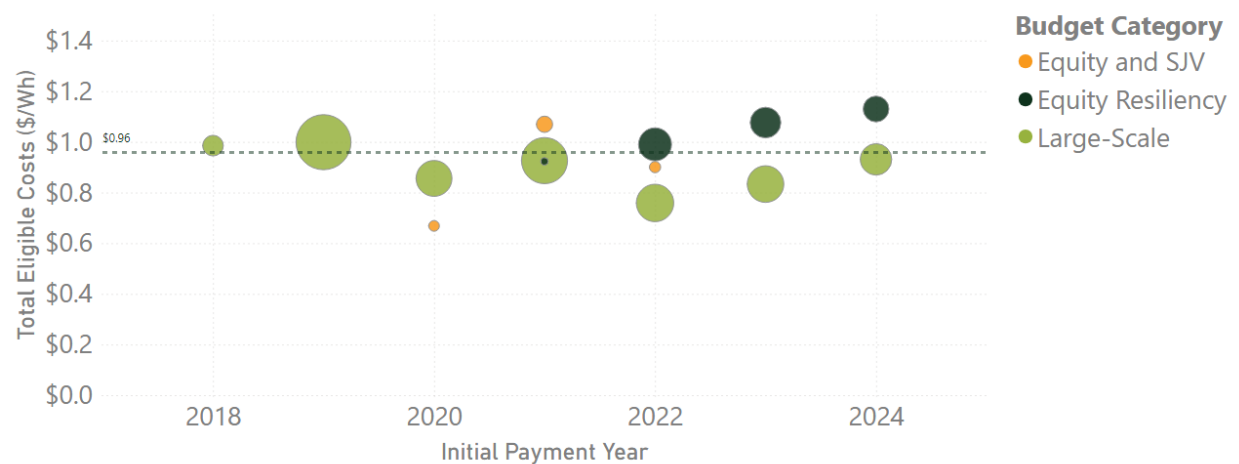


FIGURE 3-10: NONRESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY

Average Nonresidential Project Cost per Wh by Budget Category



Steady cost increases and static (or declining) incentives have increased the share of costs borne by participating customers. General market participation has been largely unaffected by these increased out-of-pocket expenses, and the ERB has afforded participating customers with a large enough incentive to cover all or most of the system and installation costs. Figure 3-11 presents the relationship between total eligible costs and residential customer incentives. The median incentive across all budget categories – \$16,866 – is also provided as the horizontal dark dashed line. The median total eligible costs – \$28,580 – are provided as the vertical dashed line. Results for the nonresidential sector follow in Figure 3-12.

FIGURE 3-11: RESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

Average Residential Project Cost and Incentive by Budget Category

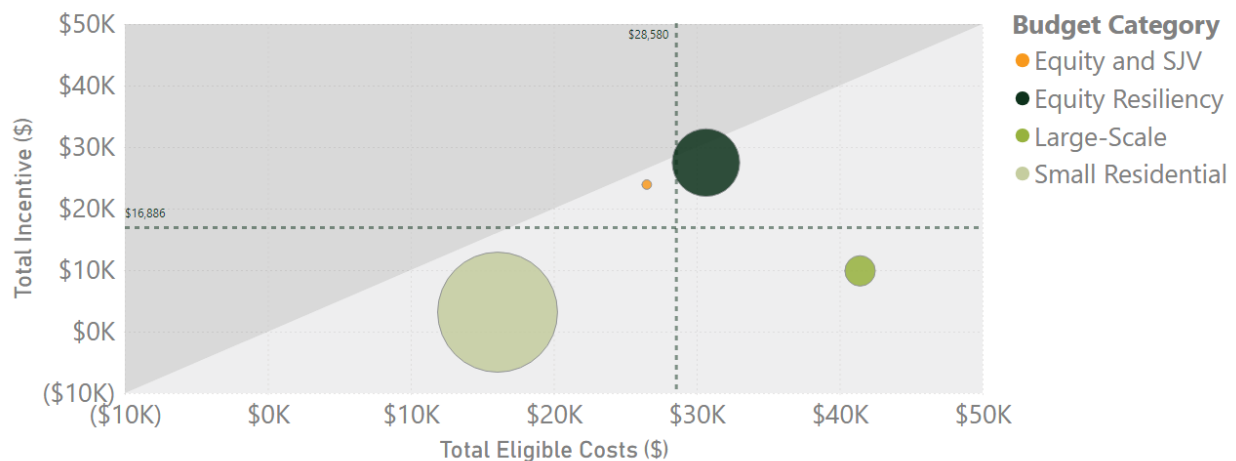


FIGURE 3-12: NONRESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

Average Nonresidential Project Cost and Incentive by Budget Category

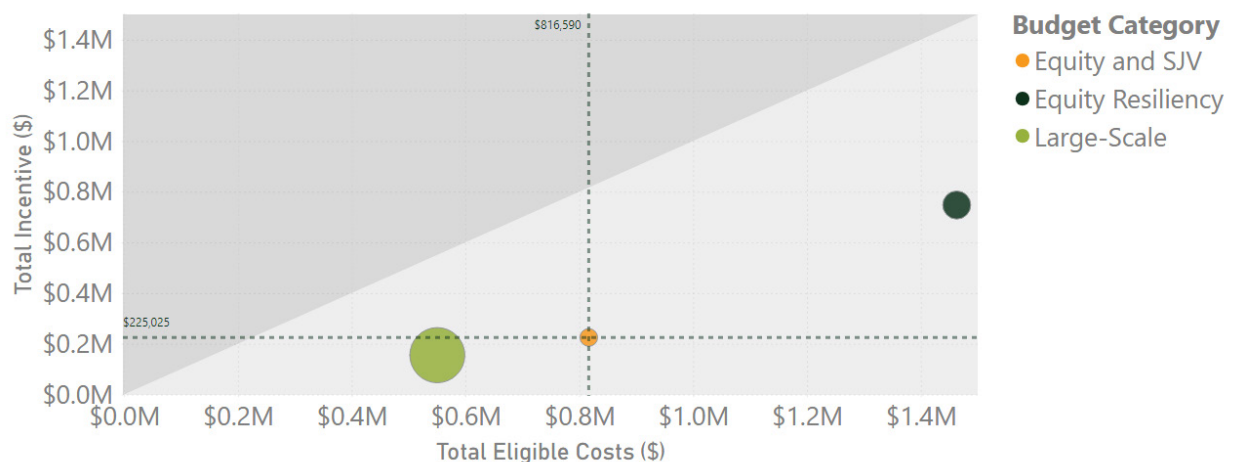


Table 3-2 summarizes the above information and includes, for each budget category and payment year grouping (the years in which the incentive was actually paid out): 1) total project counts, 2) average system sizes (kW and kWh), and 3) average eligible costs, incentives, and out-of-pocket expenses per watt hour of capacity. For residential ERB participants in 2024, the SGIP incentive covered all but \$6,000 (\$0.21 per watt hour of capacity) of the roughly \$34,000 average total eligible costs. In 2018-2019, the incentive covered roughly 37% of the total eligible costs for Small Residential participants. In 2024 the incentive covered roughly 12% of the total eligible costs.

TABLE 3-2: AVERAGE RESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

n Prj, kW, kWh, Incentive/Wh, Out-of-Pocket/Wh, Eligible Cost/Wh
BY BUDGET CATEGORY, PAYMENT YEAR

Budget Category	Payment Year	n Prj	kW	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2020-2021	7	7	18	\$1.04	\$0.89	\$0.15
Equity and SJV	2022-2023	92	9	25	\$1.09	\$0.96	\$0.13
Equity and SJV	2024	83	10	25	\$1.14	\$0.95	\$0.18
Equity Resiliency	2020-2021	3837	10	28	\$1.08	\$0.97	\$0.10
Equity Resiliency	2022-2023	5785	11	28	\$1.12	\$0.98	\$0.14
Equity Resiliency	2024	1740	11	29	\$1.18	\$0.97	\$0.21
Large-Scale	2018-2019	63	16	42	\$0.81	\$0.30	\$0.51
Large-Scale	2020-2021	862	16	42	\$0.98	\$0.26	\$0.72
Large-Scale	2022-2023	988	15	40	\$1.07	\$0.24	\$0.83
Large-Scale	2024	354	16	36	\$1.22	\$0.23	\$0.98
Small Residential	2018-2019	7601	6	13	\$0.89	\$0.33	\$0.56
Small Residential	2020-2021	11937	6	16	\$1.06	\$0.22	\$0.84
Small Residential	2022-2023	12672	6	16	\$1.23	\$0.16	\$1.07
Small Residential	2024	3616	6	16	\$1.24	\$0.15	\$1.10

Summaries from the nonresidential sector are presented below in Table 3-3.³⁰ Incentive estimates represent upfront payment amounts, and nonresidential customers are subject to PBI requirements where 50% of the incentive is paid upfront. Most of these customers have or will recover the subsequent 50% of the incentive over five years from the time of the upfront payment (depending on performance and program compliance).

³⁰ Prior to 2018, incentives were paid on \$ per Watt rather than Wh basis.

TABLE 3-3: AVERAGE NONRESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

n Prj, kW, kWh, Incentive/Wh, Out-of-Pocket/Wh, Eligible Cost/Wh
BY BUDGET CATEGORY, PAYMENT YEAR

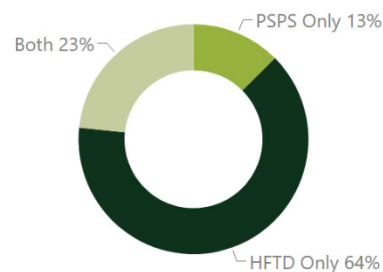
Budget Category	Payment Year	n Prj	kW	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2020-2021	30	161	366	\$1.24	\$0.42	\$0.82
Equity and SJV	2022-2023	33	257	651	\$2.59	\$0.48	\$2.11
Equity and SJV	2024	23	297	784	\$2.10	\$0.41	\$1.68
Equity Resiliency	2020-2021	4	254	1,131	\$0.96	\$0.87	\$0.09
Equity Resiliency	2022-2023	162	256	1,268	\$1.08	\$0.62	\$0.46
Equity Resiliency	2024	53	370	1,718	\$1.21	\$0.46	\$0.75
Large-Scale	2018-2019	276	161	335	\$1.15	\$0.34	\$0.82
Large-Scale	2020-2021	273	336	705	\$1.11	\$0.30	\$0.81
Large-Scale	2022-2023	219	320	720	\$0.95	\$0.24	\$0.71
Large-Scale	2024	79	385	1,025	\$1.19	\$0.14	\$1.05

Storage Composition by Eligibility Criteria

Budget categories have different criteria which guide the types of installations eligible for a given incentive. Some are exclusively predicated on the size of the system like in the Small Residential or Large-Scale Storage budgets, and some have strict income qualification minimums or a requirement to be installed in a disadvantaged community like in the Equity budget. The ERB is unique in that it has two eligibility criteria. The first mandatory criterion is that the system must be installed within a Tier 2 or Tier 3 HFTD, or the host customer must have recently experienced at least two PSPS events. As of the end of 2024, most installations – 87% of ERB participants – were in HFTDs, with 13% qualifying for this eligibility requirement based on PSPS history alone.

FIGURE 3-13: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 1

Equity Resiliency Eligibility Pathways 1



The second eligibility criterion considers other demographic, property, and participant information. Evident in the inset figure, most participants secured eligibility through having a medical baseline (71%) or an electric well pump installed at the property (24%). Very few low-income participants (4% of all ERB installations) garnered incentives within the ERB category or used that eligibility pathway. The remaining 2% either provided critical services or the installation occurred in conjunction with a low-income solar program like SASH.

FIGURE 3-14: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 2

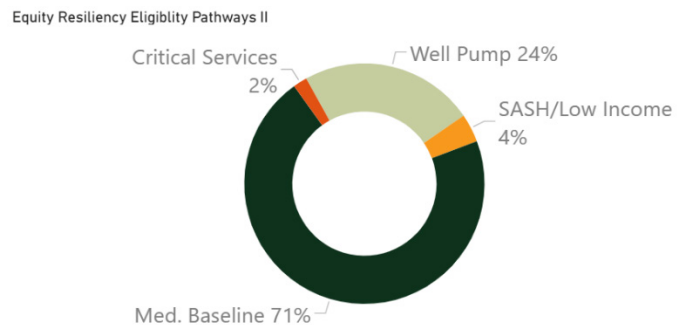
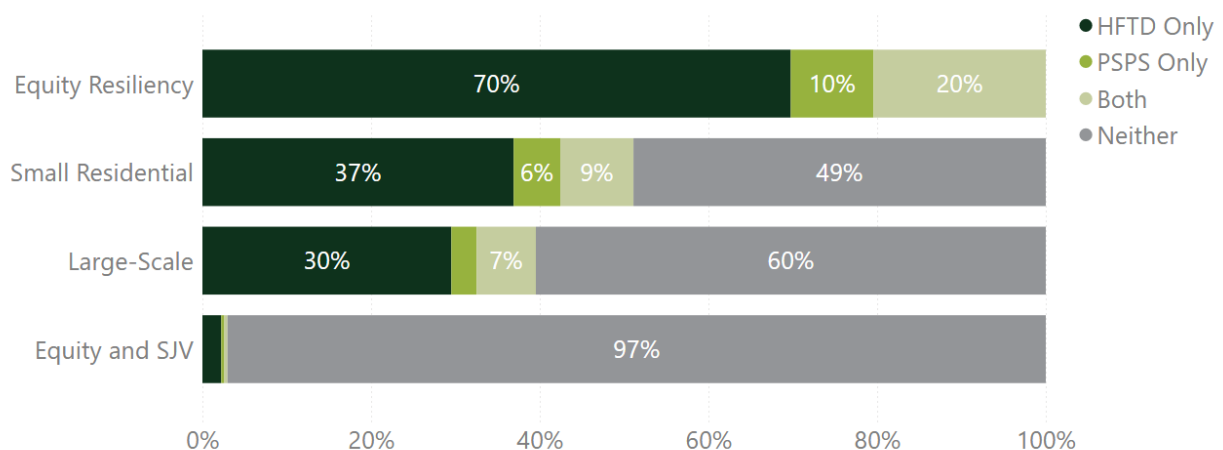


Figure 3-15 also presents the first eligibility criterion for ERB participants along with where and if participants from other budget categories installed systems in HFTDs and/or experienced PSPS events. These other budget categories don't have the same eligibility requirements (or the up to \$1.00 per watt hour incentive), so they were likely to install energy storage for personal resiliency without qualifying for the ERB incentive or they participated in the program prior to the creation of the ERB. Roughly half (51%) of Small Residential and nearly 40% of Large-Scale Storage installations have occurred in HFTDs, PSPS areas, or both.

FIGURE 3-15: DISTRIBUTION OF HFTD AND PSPS INSTALLATIONS BY BUDGET CATEGORY

Distribution of HFTD and PSPS Installations by Budget Category

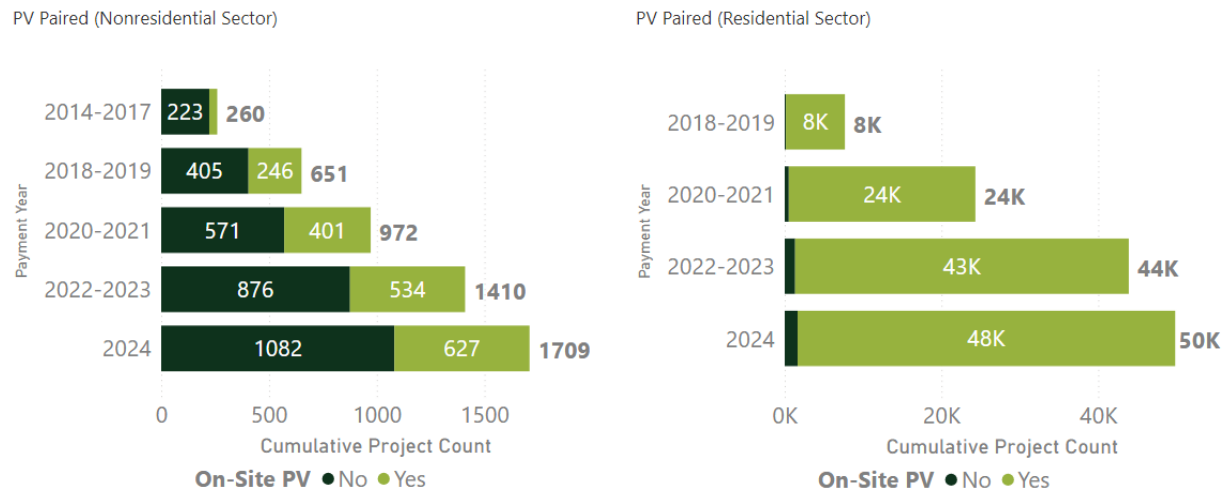


Storage Composition by On-Site Solar Generation

While D. 10-02-017 made standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – eligible for incentives, solar PV attachment rates within the SGIP didn't really tick up

in the nonresidential sector until 2019 when a large fleet of solar plus storage paired systems began receiving incentives. Early residential storage installations were standalone, but when the program began allocating sufficient resources and funding to residential customers in 2017, the program saw a significant increase in solar plus storage installations, along with storage installations retrofit onto existing solar PV.

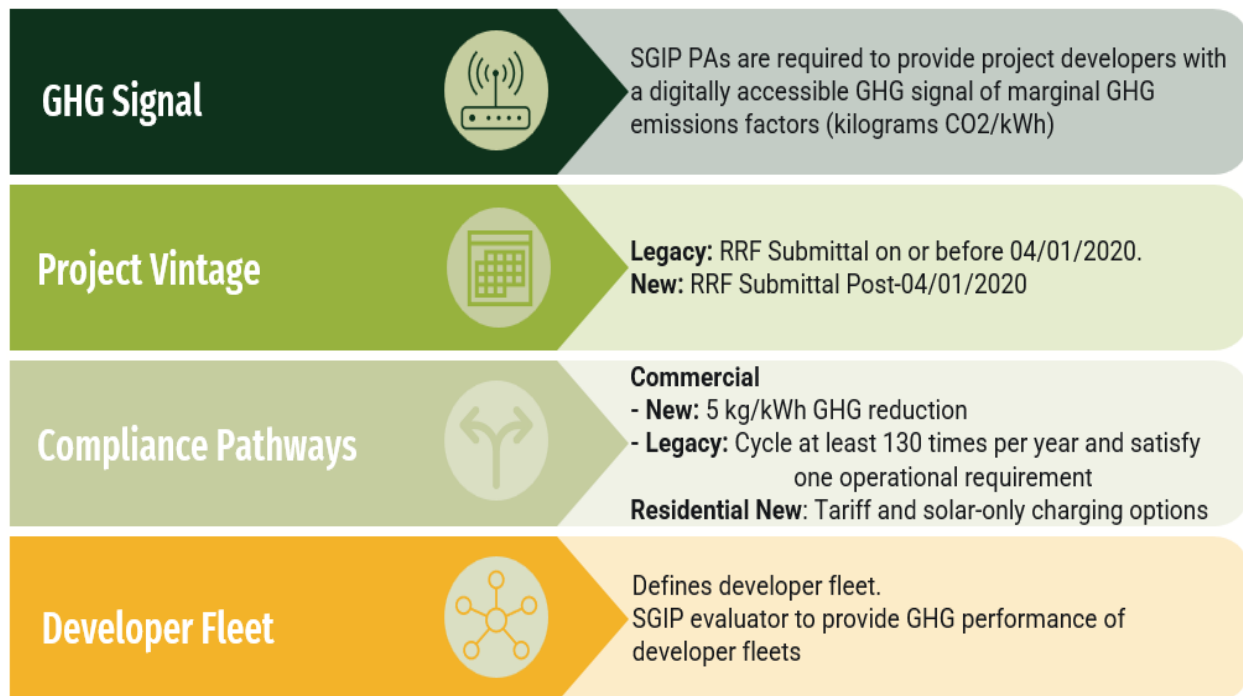
FIGURE 3-16: STORAGE COMPOSITION BY PRESENCE OF ON-SITE SOLAR GENERATION



Storage Composition by Developer Legacy Status

Decision 19-08-001 approved the greenhouse gas emission reduction requirements for the SGIP storage budget. Impact evaluation results from 2018 revealed that storage performance and utilization were leading to increases in GHG emissions – which deviated significantly from one of the core goals and objectives of the program. As a result, a working group was convened to better steer system performance in a direction that would improve the timing and magnitude of system charge and discharge to help facilitate future GHG emissions reductions. Project developers were provided with a digitally accessible GHG signal to help guide more granular and beneficial system performance and the CPUC developed compliance protocols to better track and hold developers accountable for project performance. Figure 3-17 highlights the key provisions set forth in the decision.

FIGURE 3-17: GREENHOUSE GAS EMISSIONS REDUCTION REQUIREMENTS FROM D.19-08-001



This decision was approved in 2019 and was instituted in PY 2020, so the GHG emission reporting for this impact evaluation is limited to legacy nonresidential and residential developer fleets. New nonresidential and residential projects are ALL within their third or fourth year of permanency in 2024, so GHG reporting is NOT required for this evaluation, per the decision. However, the M&E plan calls for an impact evaluation of the program, so new residential and nonresidential systems need to be included in the context of program impacts – the evaluator is just not required to include these systems in the fleet level GHG emissions reporting.

Figure 3-18 presents the over 50,000 residential systems subject to evaluation for this 2024 study by payment year and vintage. With the significant influx of new funding and completed applications after April 1, 2020, there are now over 34,000 new systems requiring evaluation, along with 15,000 legacy systems. Developer GHG impacts are required for the 15,000 projects, if they constitute a developer fleet, and while there is no developer specific GHG reporting requirement for the 34,000 new systems until year five of permanency, Verdant developed impacts for them to meet overall program impact evaluation goals.

FIGURE 3-18: NEW VERSUS LEGACY RESIDENTIAL SGIP PROJECTS

Residential Cumulative Storage Growth by Legacy Status and Payment Year

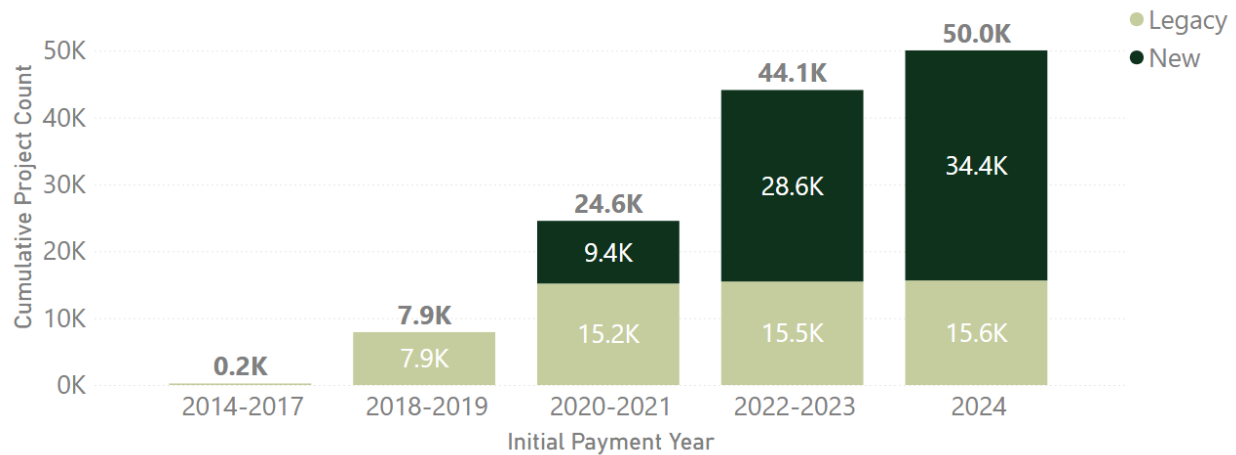
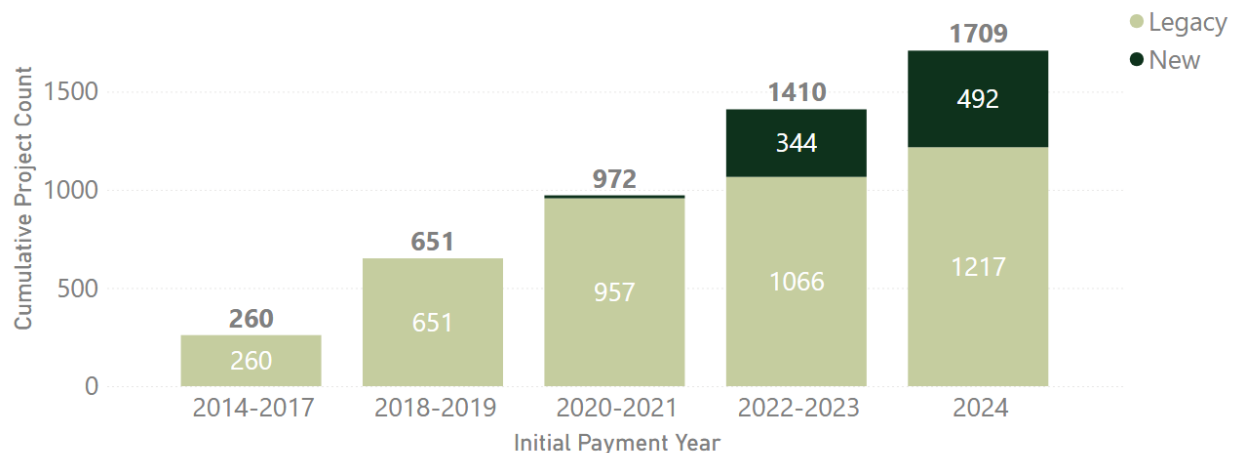


Figure 3-19 presents the new versus legacy status for the nonresidential sector. Given the greater average lag times between the program initial reservation request forms (RRF) program application submittal to eventual upfront incentive payment, and the recent slowing of nonresidential application submissions, 71% of nonresidential projects subject to evaluation in this study are legacy. There are 1,709 nonresidential systems subject to evaluation in 2024, with 1,217 of those defined as legacy systems. Only 492 projects in this sector completed their application on or after April 1, 2020, *and* received their upfront incentive payment prior to the end of 2024.

FIGURE 3-19: NEW VERSUS LEGACY NONRESIDENTIAL SGIP PROJECTS

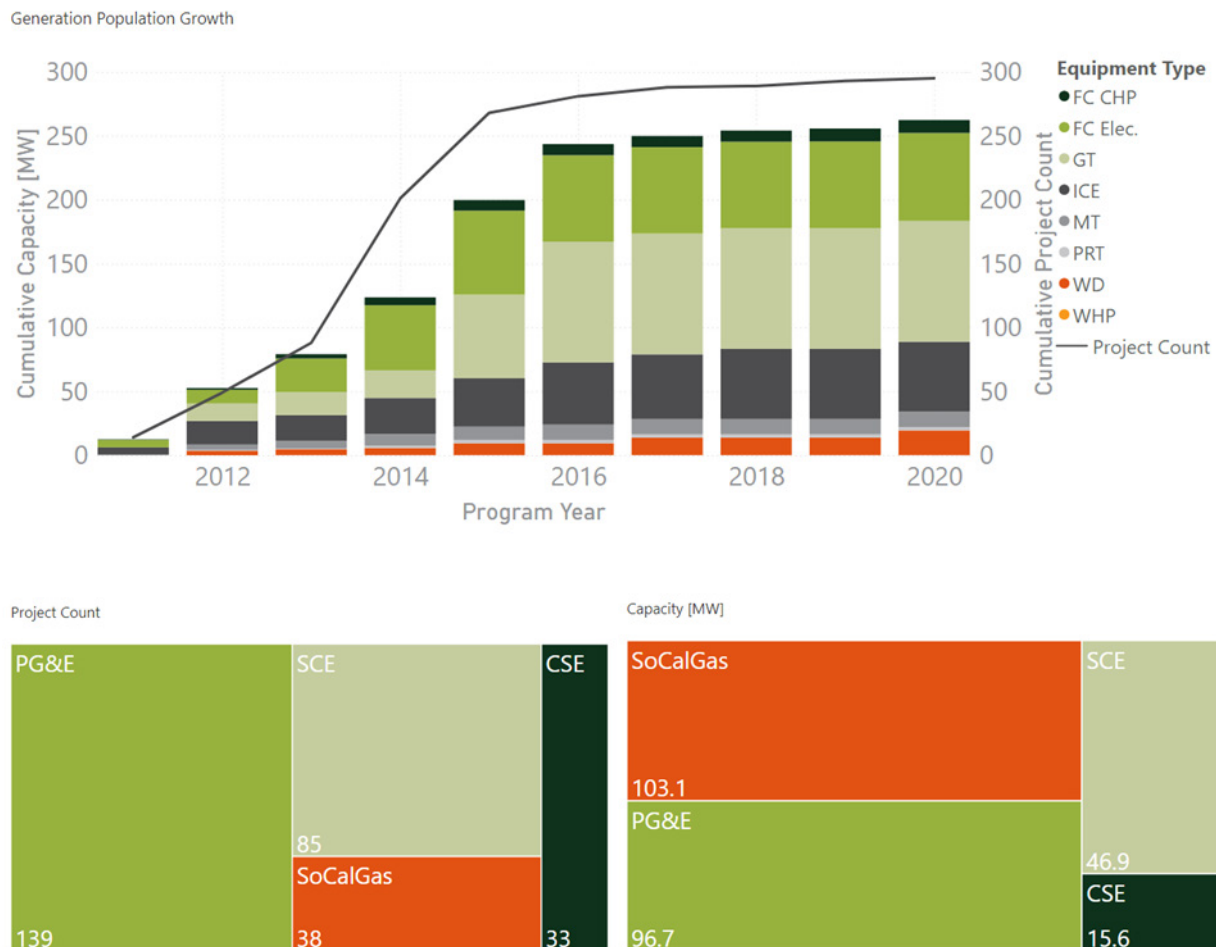
Nonresidential Cumulative Storage Growth by Legacy Status and Payment Year



3.2 COMPOSITION OF SGIP GENERATION POPULATION

Figure 3-20 highlights the growth in SGIP incentivized generation capacity since program inception through 2024, for projects still within their permanency period. The program year (PY) on the horizontal axis represents the year a project applied to the SGIP. By the end of 2024, the SGIP provided incentives for 295 generation projects still within their permanency period, representing 262 MW of incentivized capacity. Due to changes in the SGIP for generation technologies, since 2017, the number of project applications resulting in incentive payments has dropped off significantly. This dramatic decrease in projects shows the impact changes in program fuel requirements have had on participation levels. As can be seen below, since 2020, no new projects have been incentivized.

FIGURE 3-20: SGIP GENERATION CUMULATIVE GROWTH BY EQUIPMENT TYPE AND PROGRAM YEAR



Note: **FC CHP**: CHP Fuel Cell, **FC Elec.**: All-Electric Fuel Cell, **GT**: Gas Turbine, **ICE**: Internal Combustion Engine, **MT**: Microturbine, **PRT**: Pressure Reduction Turbine, **WD**: Wind Turbine, **WHP**: Waste Heat to Power

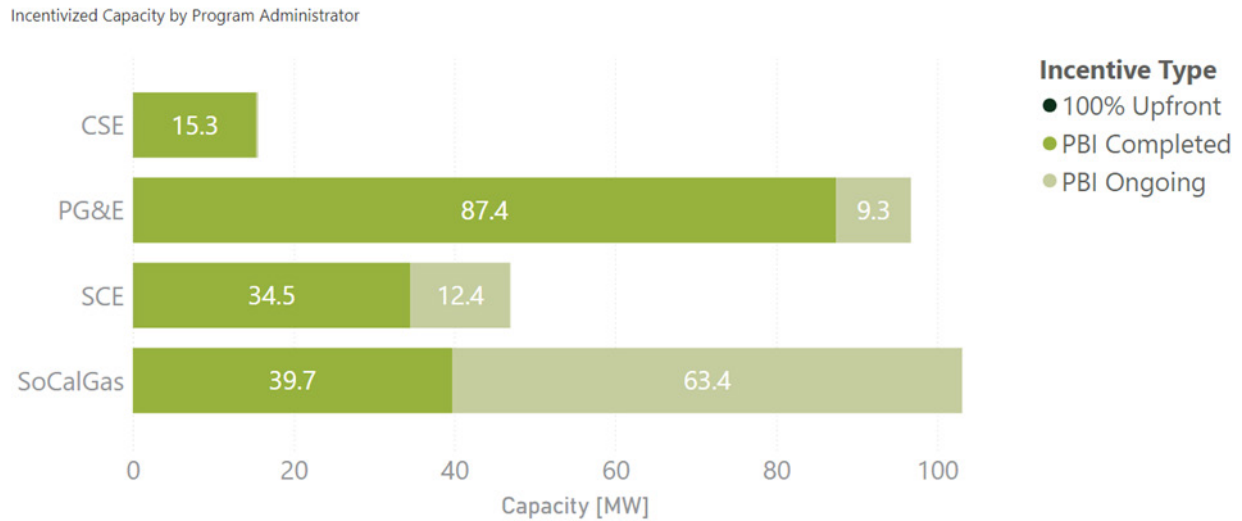
PG&E accounted for most of the generation projects in the population, with a total of 139 projects. Table 3-4 displays both the project count and the rebated capacity by technology. Over 60% of these, by project count, were fuel cell electric equipment. While SCE made up the next largest share of projects, at 85, SoCalGas made up the largest share of rebated capacity due to the large gas turbine projects they incentivized.

TABLE 3-4: PROJECT COUNT AND INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR

Equipment Type	CSE		PG&E		SCE		SoCalGas	
	Count	MW	Count	MW	Count	MW	Count	MW
Fuel Cell Electric	21 (64%)	5.9 (38%)	84 (60%)	33.8 (35%)	62 (73%)	18.5 (39%)	21 (55%)	10.7 (10%)
Fuel Cell CHP	5 (15%)	1.7 (11%)	3 (2%)	3.4 (4%)	1 (1%)	0.4 (1%)	4 (11%)	4.6 (4%)
Gas Turbine	1 (3%)	4.4 (28%)	1 (1%)	9.6 (10%)	--	--	5 (13%)	80.5 (78%)
Internal Combustion Engine	4 (12%)	2.0 (13%)	31 (22%)	28.2 (29%)	10 (12%)	21.3 (45%)	4 (11%)	3.4 (3%)
Microturbine	--	--	7 (5%)	4.6 (5%)	3 (4%)	3.6 (8%)	4 (11%)	3.9 (4%)
Wind	1 (3%)	1.0 (6%)	10 (7%)	16.5 (17%)	4 (5%)	1.9 (4%)	--	--
Pressure Reduction Turbine	1 (3%)	1.0 (3%)	2 (1%)	0.7 (1%)	5 (6%)	1.3 (3%)	--	--
Waste Heat to Power	--	--	1 (1%)	0.1 (0%)	--	--	--	--
Total	33 (100%)	22.5 (100%)	139 (100%)	96.7 (100%)	85 (100%)	46.9 (100%)	38 (100%)	103.1 (100%)

All generation projects greater than 30 kW are required to take performance-based incentives, meaning that 50% of the incentive is paid up front, and the remaining 50% is paid over five years, depending on how the system is performing. However, prior to PY 2011, all projects received the entire incentive up front upon project completion. Figure 3-21 highlights the incentivized capacity by Program Administrator and by incentive type. Most of the projects in the generation population were PBI projects that have now expired and are past their 5-year reporting requirements and have had all incentives paid out. Only 8 projects remain that received upfront, capacity-based incentives. Three of these eight projects are small, decommissioned CHP fuel cells (15 kW each). One project is a small 30 kW microturbine. The remaining 4 projects are small wind turbines, 12kW or less. The majority of the projects have completed their PBI compliance periods, but SoCalGas has almost two-thirds of their incentivized capacity that is still within their PBI period, due to some large-capacity gas turbines.

FIGURE 3-21: INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR AND INCENTIVE TYPE



Note: There are 2 PG&E, 3 SCE, and 3 CSE projects still within their permanency period that received 100% upfront, capacity-based incentives. The rebated capacity for these projects is 0.03 MW for PG&E, 0.04 MW for SCE, and 0.05 MW for CSE, and therefore too small to be seen on the graph.

4 SGIP PERFORMANCE METRICS AND IMPACTS

The primary objective of this study is to evaluate energy, environmental, and financial impacts of generation systems and energy storage systems incentivized through the Self-Generation Incentive Program (SGIP) and operating during CY 2024. Results of analysis of metered data only are presented in Sections 4.1 through 4.6.

Table 4-1 and Table 4-2 summarize the energy storage and generation population subject to evaluation, along with the number of sampled projects. We summarize population and samples by sector, payment year, and project status. Energy storage decommissioned projects were identified by project developers and provided to the evaluation team, while the generation decommissioned projects were identified during discussions with the PAs or with customers or performance data providers. These systems provide no tangible benefits to the program and are not included in the subsequent sample impacts developed in this section. However, their non-performance (or zero impacts) is included in the population impacts of the program for 2024 because they are still within their 10-year permanency. There are also five nonresidential storage projects that fall outside their 10-year permanency period and are not included in either the sample or the population impacts of the program.

TABLE 4-1: 2024 SGIP ENERGY STORAGE POPULATION AND SAMPLE OF PROJECTS

SGIP Energy Storage Population and Sample by Sector, Payment Year and Project Status

Sector	Payment Yr	Status	Pop	Smp	% Prj Smp	Pop MWh	Smp MWh	% MWh Smp	In Smp Impacts	In Pop Impacts
Nonresidential	2017 Prior	Decommissioned	212	212	100%	10	10	100%	No	Yes
Nonresidential	2017 Prior	Operable	216	84	39%	116	53	46%	Yes	Yes
Nonresidential	2017 Prior	Outside Permanency	5	-	0%	4	-	0%	No	No
Nonresidential	2018-2022	Decommissioned	31	31	100%	7	7	100%	No	Yes
Nonresidential	2018-2022	Operable	890	686	77%	529	408	77%	Yes	Yes
Nonresidential	2023-2024	Operable	360	305	85%	406	363	90%	Yes	Yes
Nonresidential	Total		1,714	1,318	77%	1,072	841	79%		
Residential	2017 Prior	Unknown	411	-	-	4	-	-	No	No
Residential	2018-2022	Operable	34,974	1,543	4%	661	35	5%	Yes	Yes
Residential	2023-2024	Operable	14,663	463	3%	301	10	3%	Yes	Yes
Residential	Total		50,048	2,006	4%	966	45	5%		
Total	Total		51,762	3,324	6%	2,037	886	44%		

TABLE 4-2: 2024 SGIP GENERATION POPULATION AND SAMPLE OF PROJECTS

SGIP Generation Population and Sample by Sector, Payment Year, and Project Status

Sector	Payment Yr	Status	Pop	Smp	% Prj Smp	Pop MW	Smp MW	% MW Smp	In Smp Impacts	In Pop Impacts
Generation	Pre 2017	Decommissioned	18	18	100%	10	10	100%	No	Yes
Generation	Pre 2017	Operable	168	146	87%	91	59	66%	Yes	Yes
Generation	2017-2019	Decommissioned	2	2	100%	1	1	100%	No	Yes
Generation	2017-2019	Operable	90	61	68%	76	37	48%	Yes	Yes
Generation	2020 & Later	Decommissioned	1	1	100%	0	0	100%	No	Yes
Generation	2020 & Later	Operable	16	11	69%	85	79	93%	Yes	Yes
Total			295	239	81%	262	186	71%		

The metered sample of projects informs the impact analyses and optimization modeling conducted for this study. Decommissioned projects are of particular importance when examining the program impacts and results from the metered sample of projects. As previously mentioned, our team has identified, from past and current evaluation activities, systems that are offline or have been decommissioned. The forthcoming analyses on observed system performance exclude the impacts from these projects. These systems are no longer installed and operable, so their non-performance is known and would misrepresent the impacts generated from SGIP storage systems that are currently installed and operable. However, given the cumulative nature of these evaluations, their non-performance is captured when developing program population impacts because these systems are still within their 10-year permanency period.

Another important consideration, as highlighted in the following sidebar, is to calculate impacts by classifying and quantifying the counterfactual baselines.

Counterfactual Baselines: Calculation of impacts, such as change in coincident peak electricity demand measured at the utility meter, requires assumptions about what a customer's electricity consumption at the meter would have been had they *not* installed the SGIP system. These assumptions describe an unobservable, counterfactual, non-SGIP baseline that is compared to electricity consumption observed to estimate impacts of the SGIP system at the utility meter.

$$Impacts = UtilityMeterLoad_{with\ SGIP\ system} - UtilityMeterLoad_{counterfactual}$$

For this impacts evaluation, the key assumption underlying the impacts analytic methodology is that participation in the SGIP was not responsible for any changes in the quantity or timing of electricity loads for end uses or **LoadsEndUses** (e.g., lighting, HVAC) that might have occurred after installation of the SGIP system, or for any changes in the quantity or timing of electricity production (**PV**) of any photovoltaic system capacity that might be present. The values of **LoadsEndUses** and **PV** are thus identical for the counterfactual and for the observed conditions (with SGIP system). That is:

$$UtilityMeterLoad_{counterfactual} = LoadsEndUses - PV$$

$$UtilityMeterLoad_{with\ SGIP\ system} = LoadsEndUses - PV - SGIP_{engo}$$

$$Impacts = (LoadsEndUses - PV - SGIP_{engo}) - (LoadsEndUses - PV) = -SGIP_{engo}$$

The impacts of the SGIP system on coincident peak electricity consumption measured at the utility meter are simply equal to the negative of SGIP system output. This is an intuitive result describing the situation where SGIP system power output serves to decrease the amount of utility power required to satisfy end use loads. Where **SGIP_{engo}** is defined as SGIP system power output, as it is above, battery energy storage systems would have negative **SGIP_{engo}** values while charging, resulting in positive impacts (i.e., increased load at the utility meter) when charging.

4.1 OBSERVED PERFORMANCE METRICS

The effectiveness of energy storage systems and generation systems in producing impacts depends largely on energy conversion efficiencies and operational choices governing equipment utilization. Metered data were analyzed to develop measures of efficiency and utilization of SGIP systems operating during 2024. Overall system efficiencies depend on the combined effects of efficiencies of many subsystems. For example, gas turbine generator system efficiency depends on fuel combustion efficiency, electric generator efficiency, and numerous other component efficiencies. Battery energy storage efficiency depends on electro-chemical efficiencies associated with charge/discharge cycles, voltage transformation efficiencies, and numerous other component efficiencies. However, overall system efficiencies are of interest to end users and are the efficiencies we present results for in this section.

The general term “utilization” summarizes the combined effects of various factors governing how much an SGIP system is used, which is closely related to the impacts it can produce. Utilization may encompass matters of choice (e.g., operating hours, operating mode selection), as well as resource availability in the case of wind turbine systems. Capacity factor is one performance metric customarily used to measure

utilization. Capacity factors are calculated as the ratio of system energy output during any particular period of time to the maximum possible quantity of energy the system could have output during that period. Following are capacity factors for generation systems and energy storage systems. A second utilization metric is used for battery energy storage: charge/discharge cycle rate, with the total number of cycles per year being of most interest.

4.1.1 Energy Storage Performance Metrics

Verdant reviewed three performance metrics within the SGIP – roundtrip efficiency (RTE), capacity factor (CF), and annual energy storage cycling – to better quantify the efficiency and utilization of energy storage technologies during 2024. Furthermore, we present if and how efficiencies and utilization differ based on the age of the system, system capacity, budget category, facility type (for nonresidential installations), and presence of on-site solar PV generation.

Energy Storage Roundtrip Efficiency

RTE is measured as the total kWh discharge of the system divided by the total kWh charge and is an eligibility requirement for the SGIP.³¹ The RTE can be calculated as a single-cycle RTE, which captures the energy losses associated with AC-DC power conversion, and over a given time to also capture operational parasitic loads. This evaluation quantifies the latter, where efficiency is calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

EQUATION 4-1

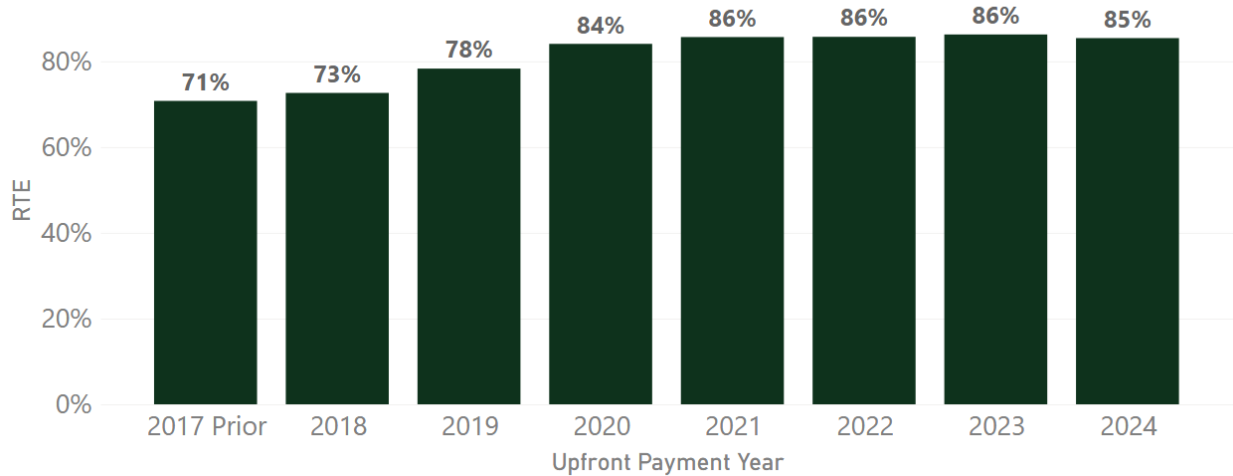
$$\text{Roundtrip Efficiency} = \frac{\sum \text{kWh Discharge (kWh)}}{\sum \text{kWh Charge (kWh)}}$$

Figure 4-1 presents the average RTE for installed and operable nonresidential systems in 2024 by upfront payment year. We observe an average RTE of 71% and 73% in 2024 for projects receiving their upfront incentive payment 2017 prior and 2018, respectively. We observe a trend in increased efficiency for systems rebated more recently – with systems receiving incentives in 2020 onward exhibiting an RTE of 86% on average.

³¹ Energy storage systems must maintain a round-trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round-trip efficiency of 66.5 percent, assuming a 1% annual degradation rate (Appendix E of the aforementioned SGIP Handbook).

FIGURE 4-1: AVERAGE 2024 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

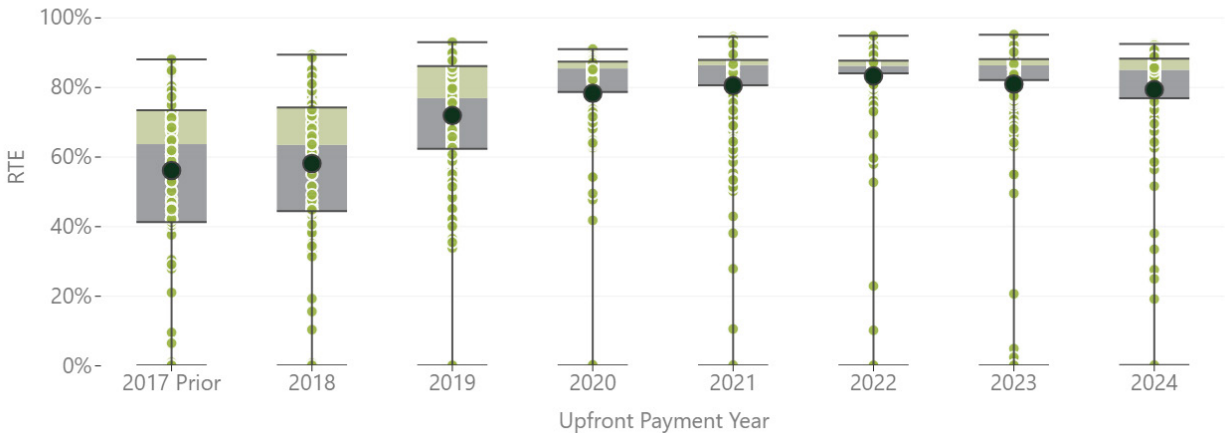
Nonresidential Average RTE by Upfront Payment Year



We also examined the distribution of project-specific RTEs across incentive payment year (Figure 4-2). These boxplots present the mean RTE (black circle) along with the minimum, maximum, quartile, and median values. We observe not only increases in average and median RTE values with more recently incentivized projects, but less variation in project RTEs as well. An RTE of 0% signifies that the system was non-operational and the total 2024 discharge was 0 kWh (40 projects or 4% of projects). Verdant verified the performance of each project as part of the QA/QC process, and the metered data for systems exhibiting low or zero RTE confirm this non-performance. Most of these non-operational systems applied to the program in earlier years (2012-2016) and represent a developer experiencing more recent decommissioning. Verdant will continue to track these projects in future evaluations to determine if systems were offline or non-operational just for a given time, or if the non-performance is a harbinger for future decommissioning.

FIGURE 4-2: DISTRIBUTION OF 2024 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Distribution of Project RTE



Residential RTEs exhibit similar average RTEs across payment year to the nonresidential sector, but less variability across project and payment year. Average efficiencies are all above 80% (Figure 4-3). Unlike the nonresidential sector, all sampled residential projects applied to the program in 2017 or after and received their upfront payments in 2018 or thereafter.

Verdant did observe some low and non-operational systems within the sample of projects. This non-performance suggests these systems were being under-utilized or were operating in exclusive backup mode. Roughly 13% of sampled residential systems were found to be under-utilized or in backup-only mode during 2024.³² The incidence of underutilization or backup has increased compared to the 2023 evaluation by roughly twofold. Lower utilization leads to reductions in system efficiencies and results in 1) increases in GHG emissions, 2) utility costs, and 3) customer bills – each of which will be discussed in further detail in Sections 4.2 – 4.5.

³² Underutilization/backup refers to a system which is cycled less than 52 times in 2024.

FIGURE 4-3: AVERAGE 2024 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Residential Average RTE by Upfront Payment Year

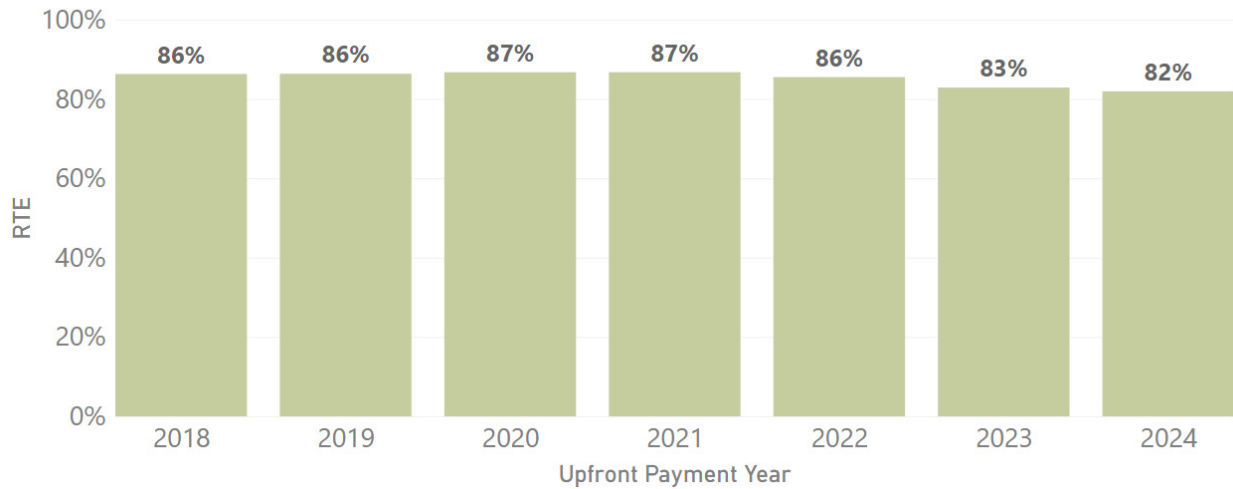
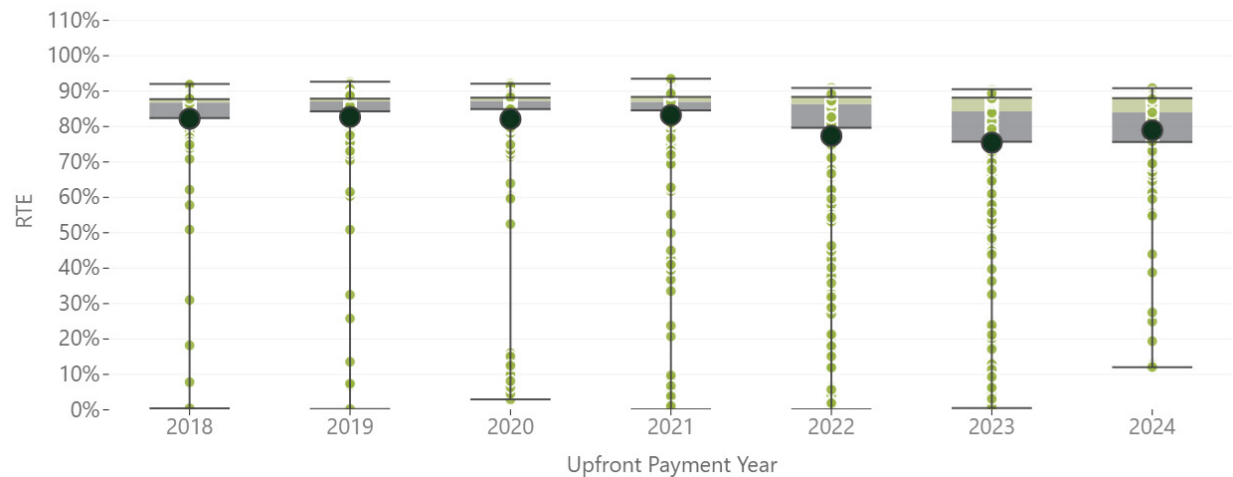


FIGURE 4-4: DISTRIBUTION OF 2024 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Distribution of Project RTE





Energy Storage Utilization

Unlike generating technologies, like a fuel cell that can operate at or near full capacity nearly continuously, energy storage discharge is limited by the size of the inverter and the kWh capacity of the battery along with the battery state-of-charge (SOC). Example capacity factors are provided in the figure to the right to better understand utilization as a function of discharge capacity – in percent power discharge over the course of an hour – and battery duration. In practice, a five-hour battery discharging at 100% discharge capacity once a day would have a 21% capacity factor.

Capacity Factor by System Duration and % kW Hourly Discharge

kW Discharge ▲	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	0%	1%	1%	2%	2%
20%	1%	2%	3%	3%	4%
40%	2%	3%	5%	7%	8%
60%	3%	5%	8%	10%	13%
80%	3%	7%	10%	13%	17%
100%	4%	8%	13%	17%	21%

Hourly discharge capacity is also predicated on the underlying storage operating mode – TOU arbitrage (with or without export), demand charge reduction, or (solar) self-consumption. If a battery is programmed for self-consumption – zeroing out imported load as much as possible – battery discharge is limited to underlying BTM consumption and may represent only a fraction of system capacity within a given hour. On the other hand, TOU arbitrage may result in daily cycling during the four summer months (June-September) but none during the other eight months of the year, due to low peak to off-peak rate differentials.

The capacity factors for the sample of nonresidential storage systems are presented below in Figure 4-5 by upfront payment year. To better understand the range in system utilization during the year, project distributions follow in Figure 4-6. Capacity factors are positively correlated to RTEs – an under-utilized storage system (or system with a low-capacity factor) will generally exhibit a low RTE and greater utilization (i.e., higher capacity factor) indicates greater system efficiency (i.e., a high RTE). Capacity factors range from as low as 0% (indicating non-performance) to as high as 18%. The greater capacity factor for projects paid in 2022 reflects a large fleet of longer duration batteries installed in the Equity Resiliency Budget (ERB) category.

FIGURE 4-5: AVERAGE 2024 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR

Nonresidential Average CF by Upfront Payment Year

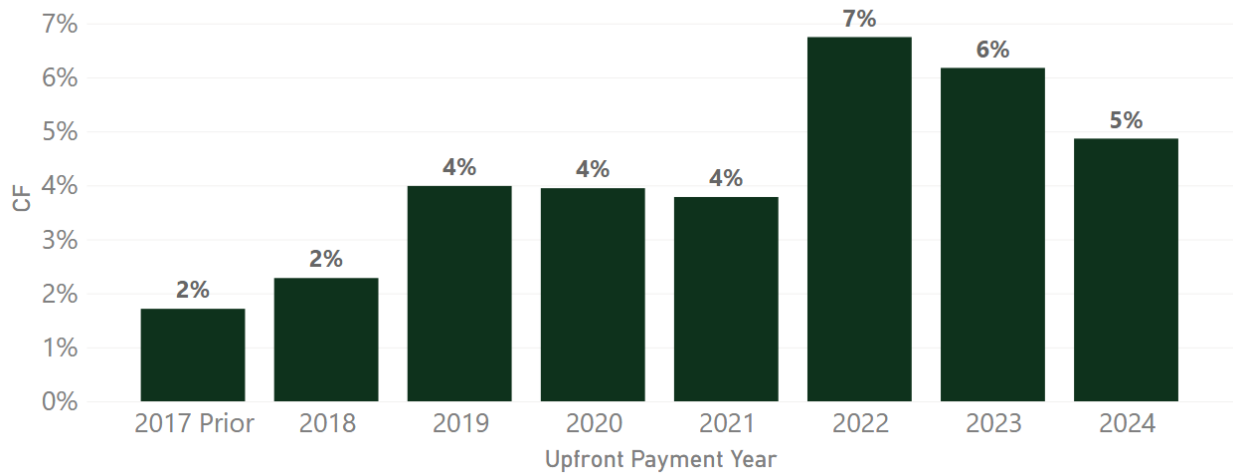
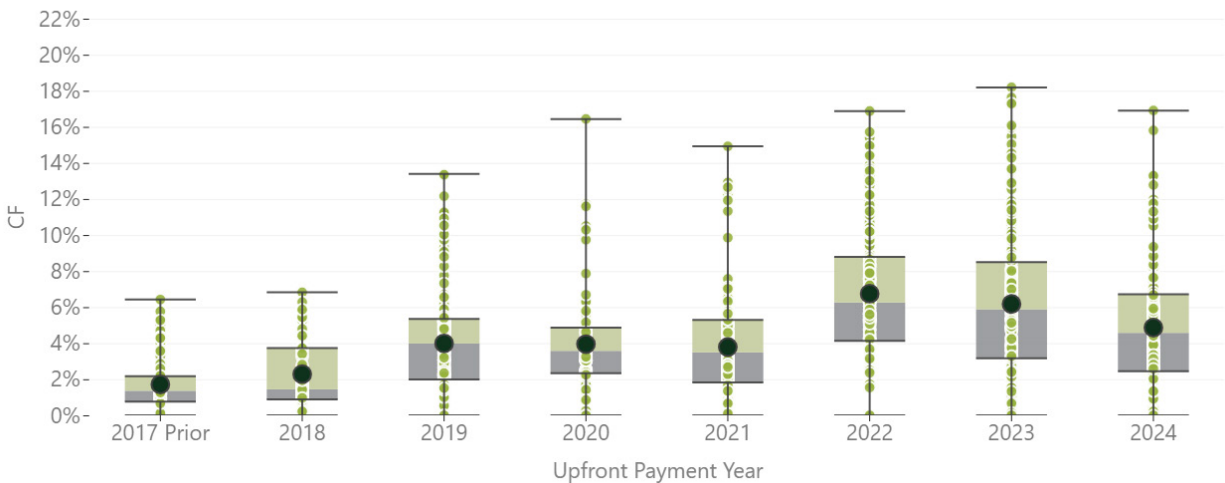


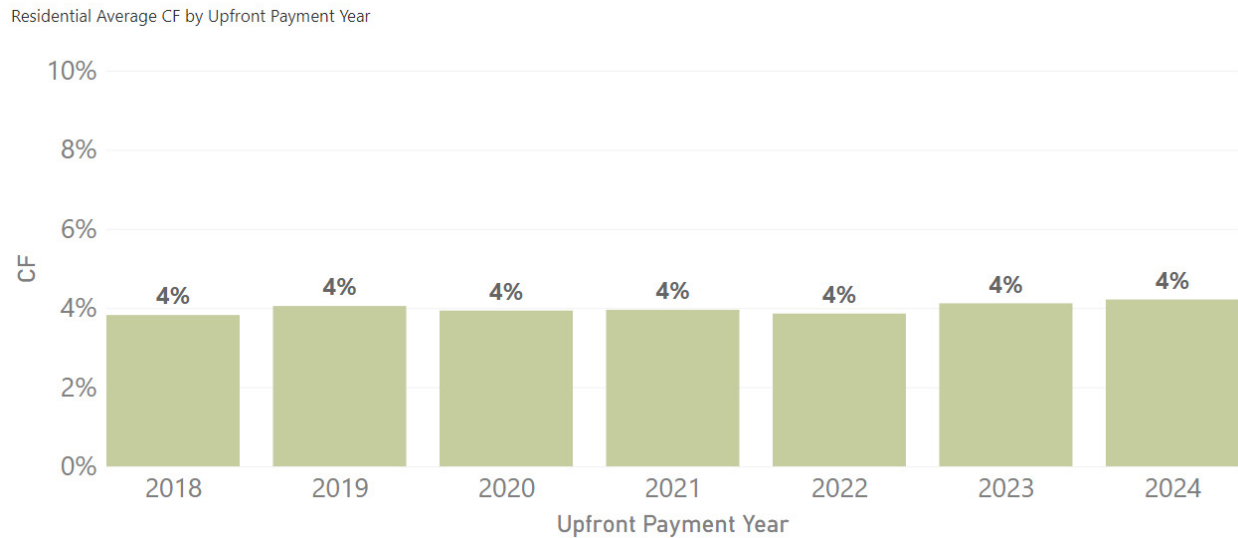
FIGURE 4-6: DISTRIBUTION OF 2024 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR

Distribution of Project CF



Average capacity factors and capacity factor distributions in the residential sector are presented in Figure 4-7 and Figure 4-8. Residential capacity factors don't exhibit much variability across payment year, but we do observe inter-project variability.

FIGURE 4-7: 2024 AVERAGE CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

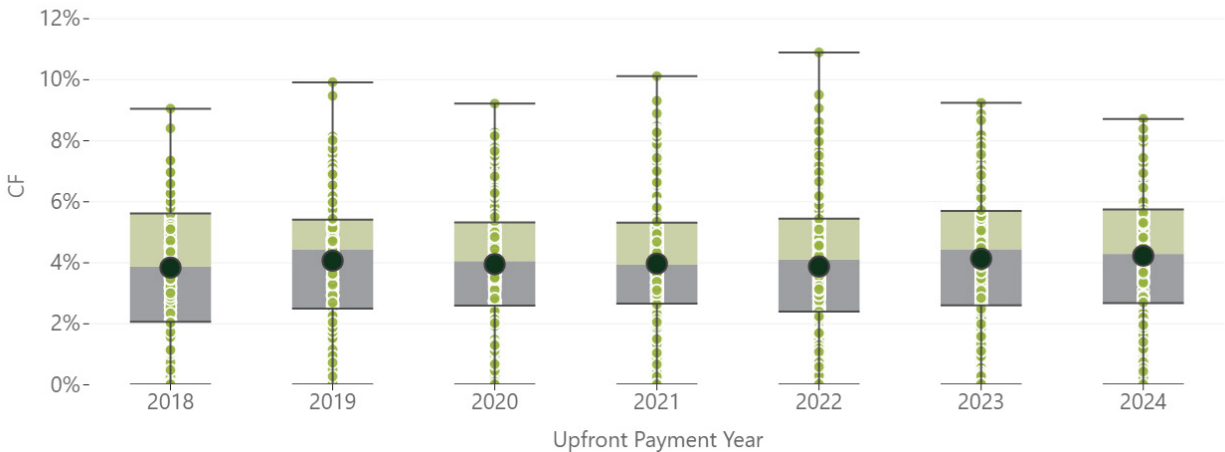


Residential systems are generally operating in one of two modes – TOU arbitrage or self-consumption. For systems operating in either mode – and not exporting – discharge is limited to underlying customer load. For TOU arbitrage, the battery will generally discharge only during the customer on-bill peak period to zero out utility imports. Once the battery reaches a minimum state-of-charge (SOC) the battery will stop discharging. Self-consumption is a similar operation, but discharge may extend outside of on-peak billed periods. Either way, utilization is limited to the size of the battery relative to customer BTM consumption.

However, utilization tends to increase for systems conducting arbitrage and exporting additional capacity not being used to service load. In these circumstances, the discharge is not limited to customer load, so additional capacity can be utilized and returned to the grid much like excess solar generation.

FIGURE 4-8: DISTRIBUTION OF 2024 CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Distribution of Project CF



The second utilization metric tracked within the SGIP is cycling or “number of discharges” and is defined as the total kWh discharge of the system divided by the energy (kWh) capacity of the system. It represents a proxy for total number of discharge cycles throughout the year for a given system.³³ If a two-hour, 50-kW system (100 kWh) discharged 60% of capacity once a day, every day throughout the year, this would represent roughly 219 cycles – $(50 \text{ kW} \times 2 \text{ hr} \times 0.6 \times 365) / 100 \text{ kWh}$. While capacity factors are generally greater for longer duration batteries (all else being equal), the cycling metric is proportional to the size of the battery – a two-hour battery fully discharging once a day will cycle the same amount as a 5-hour battery discharging fully once a day. With similar utilization, a storage system can exhibit an 80% RTE during one month of activity or throughout a full year of operation. The same is true for a system capacity factor. A system can exhibit a 10% capacity factor during one peak hour, or throughout a month or year because it’s based on

Cycles by System Duration and % kW Hourly Discharge

kW Discharge	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	37	37	37	37	37
20%	73	73	73	73	73
40%	146	146	146	146	146
60%	219	219	219	219	219
80%	292	292	292	292	292
100%	365	365	365	365	365

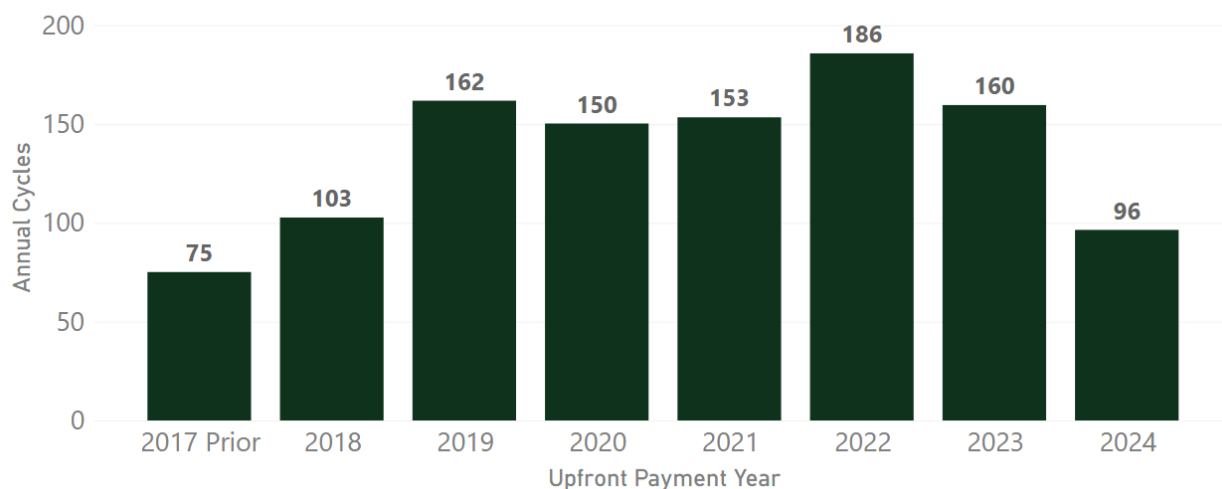
³³ The 2021 SGIP Handbook requires commercial systems to discharge a minimum of 130 full discharges per year and residential systems to discharge a minimum of 52 full discharges per year. Each time a system discharges it does not have to be a discharge of 100% capacity. Rather, the full discharge definition equates to the aggregate amount of discharges over the year (Sections 5.2.3 and 5.2.9).

operational periods. Cycling is predicated on the magnitude of hourly discharge, but also the length of time in which the system has been operating.

This latter point is evident in Figure 4-9 below, which summarizes annual cycling in the nonresidential sector by payment year. We observe an increase in annual utilization, from an average of 75 cycles for projects paid in 2017 or earlier to 186 cycles for projects paid in 2022. However, utilization drops again for 2024 projects. The reason we observe a reduction in cycles for projects incentivized in 2024 is the reduced length of time in which a system may have been operating. Verdant develops partial year impacts for systems receiving incentives midway through a calendar year. We do not extrapolate one full year of data from partial year impacts. So, while a system may receive its incentive and begin normal operations in August 2024 and exhibit an 80% RTE and 8% CF during that operational period, the annual cycles are calculated off four or five months of metered data, rather than a full calendar year. These systems will have a full calendar year of metered data in 2025, so we'd expect utilization of those projects to increase in the next report.

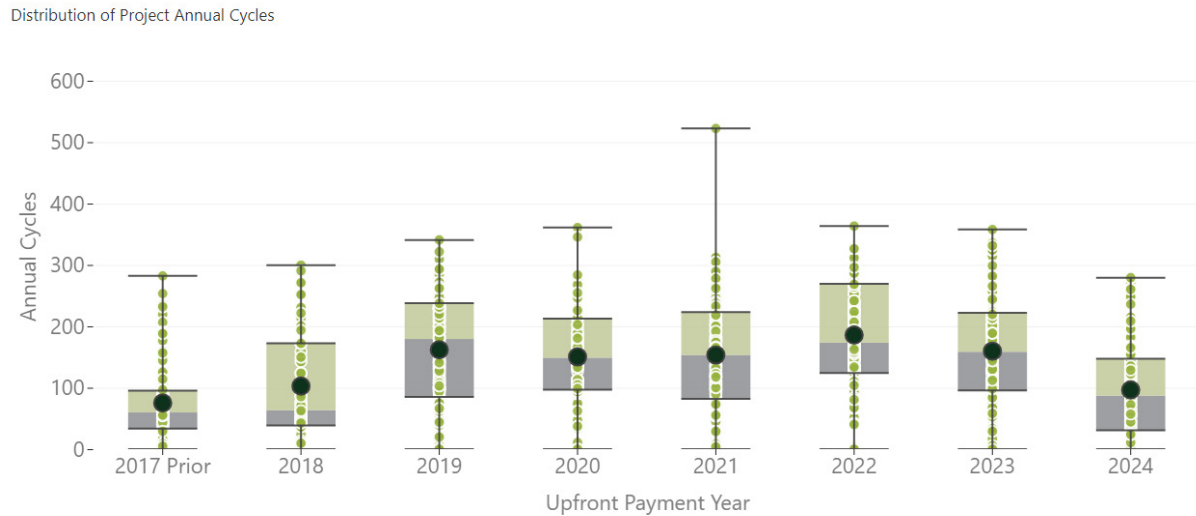
FIGURE 4-9: 2024 AVERAGE ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Nonresidential Average Cycles by Upfront Payment Year



Project distributions in Figure 4-10 also reveal the minimum, maximum, and median values of project utilization in 2024. Of note are projects at or near the top of each whisker with utilization greater than 365. This signifies, on average, a system fully discharging more than once per day throughout the year. Metered storage data confirms this. Some systems are actively cycling during the day without any clear intended purpose, while others are more nuanced and sophisticated – discharging to reduce customer noncoincident peak demand. We observe some systems discharging to keep load below a certain threshold, then charging immediately thereafter, and continuing this pattern during the day.

FIGURE 4-10: DISTRIBUTION OF 2024 CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



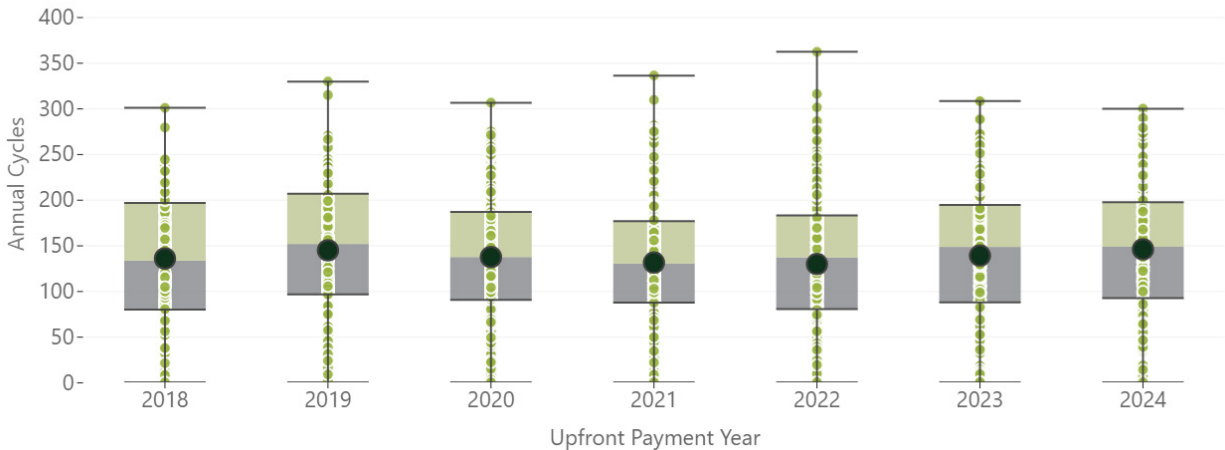
Residential systems cycle more than the program minimum of 52 cycles (Figure 4-11). We observe roughly 97% of residential projects paired with on-site solar PV, with most charging the battery exclusively from solar. The battery will only charge during PV generating hours, so we don't observe the constant daily charge and discharge cycling observed with some nonresidential systems conducting peak shaving. Systems paired with solar are also utilized more than standalone systems, where we observe a much smaller percentage of battery capacity discharged on-peak. Project distributions in Figure 4-12 also reveal the minimum, maximum, and median values of project utilization in 2024.

FIGURE 4-11: 2024 AVERAGE ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



FIGURE 4-12: DISTRIBUTION OF 2024 CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Distribution of Project Annual Cycles



As noted previously, the RTE is a measure of the efficiency of the system – how much energy the system is discharging relative to the amount of energy the system is charging. The discharge frequency is a measure of utilization – how often the system is being discharged to perform different objectives or the total discharge kWh of the system divided by the total capacity kWh of the system. The two are related – if a system is not being utilized then it remains idle and consumes energy without providing any benefits. Depending on its size and location, an idle system is like the equivalent of a large flat screen TV being left on all day. The energy consumption can seem small, but over time, those losses add up and reduce the RTE and any potential environmental benefits of the system. Efficiency is impacted, not only by any battery losses due to AC-DC power conversion but also the parasitic loads associated with system cooling, communications, and other power electronic loads.

When a system is utilized more often, it often has a greater RTE. This relationship is evident in Figure 4-13 and Figure 4-14 where the total number of discharge cycles for each project are plotted against the efficiency or RTE of the system for the nonresidential and residential sectors, respectively. We observe a general increase in RTE (vertical axis) as a system is being utilized more often (i.e., undergoing a higher volume of cycles) (horizontal axis). These figures also highlight the more prevalent inter-project variability in the nonresidential sector compared to residential. The nonresidential sector exhibits a much greater range in storage system capacity than residential systems and are installed in a variety of facility types with differing load shapes and demand requirements.

FIGURE 4-13: RTE VERSUS DISCHARGE CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE

Nonresidential Efficiency and Utilization Correlation

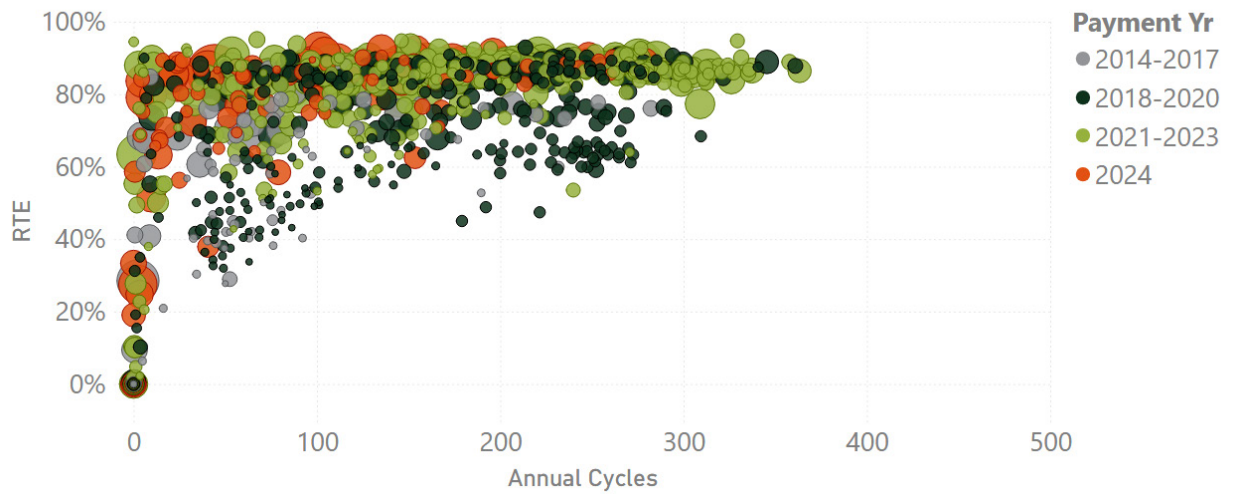
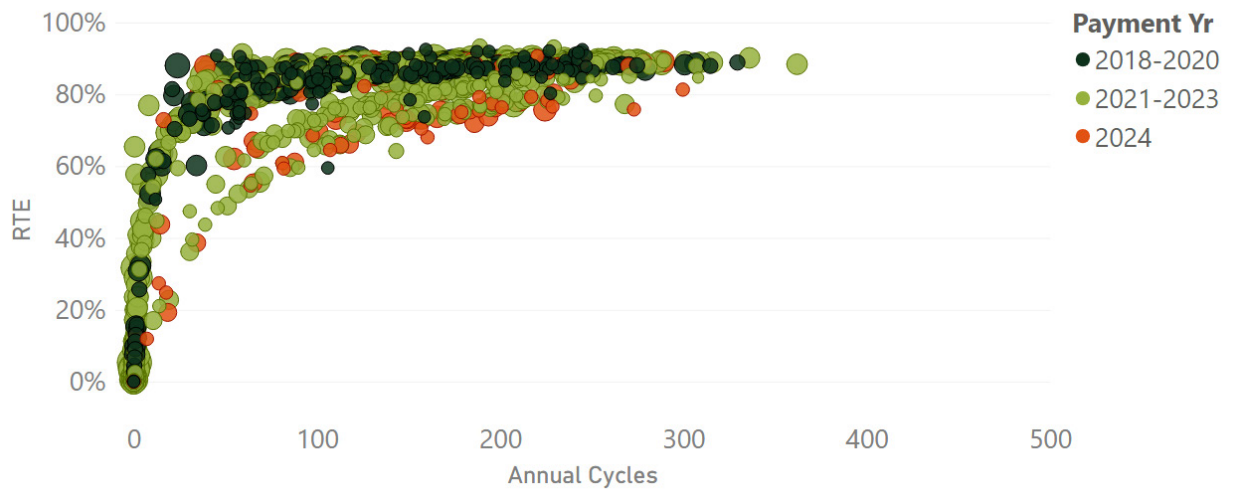


FIGURE 4-14: RTE VERSUS DISCHARGE CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE

Residential Efficiency and Utilization Correlation



Energy Storage Performance Summaries³⁴

Metrics like utilization and efficiencies play a key role in determining how storage is providing customer, utility, and environmental benefits within the SGIP. We observe changes in these performance metrics from one evaluation year to the next as program requirements and objectives evolve and energy storage systems become more sophisticated and capable of operating in different modes.³⁵ Figures 4-15 – 4-27 summarize the performance metrics discussed above for both the nonresidential and residential sectors, respectively.

FIGURE 4-15: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY PA

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
CSE	188	230	578	2.5	85%	4%	126
PG&E	372	297	805	2.7	85%	5%	159
SCE	451	286	761	2.7	83%	4%	143
SCG	64	403	1,154	2.9	85%	5%	149
Overall	1075	287	767	2.7	84%	5%	146

FIGURE 4-16: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY PA

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
CSE	285	9	24	2.6	87%	5%	156
PG&E	1035	9	23	2.6	85%	4%	121
SCE	590	8	21	2.6	86%	4%	153
SCG	96	9	24	2.7	86%	4%	117
Overall	2006	9	22	2.6	85%	4%	135

³⁴ The forthcoming performance summaries represent sampled impacts, not those extrapolated to the population like those found in Section 4.6.

³⁵ One important consideration is program year versus payment year. A customer may apply to the program in 2017 but not receive their incentive until 2019. Project design, permitting, system build-out, inspection, etc. take time, especially for larger nonresidential projects. In other words, a project program year may be different than the project upfront (or initial) payment year.

FIGURE 4-17: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY PAYMENT YEAR

Payment Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2014	1	27	54	2.0	38%	2%	76
2015	11	613	1,227	2.0	72%	3%	137
2016	39	306	612	2.0	69%	2%	66
2017	33	240	480	2.0	73%	1%	66
2018	64	138	272	2.0	73%	2%	103
2019	208	169	351	2.1	78%	4%	162
2020	83	323	675	2.1	84%	4%	150
2021	145	364	762	2.1	86%	4%	153
2022	186	261	814	3.1	86%	7%	186
2023	182	342	1,137	3.3	86%	6%	160
2024	123	387	1,271	3.3	85%	5%	96
Overall	1075	287	767	2.7	84%	5%	146

FIGURE 4-18: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY PAYMENT YEAR

Payment Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2018	120	7	18	2.5	86%	4%	136
2019	165	7	17	2.5	86%	4%	145
2020	259	8	20	2.6	87%	4%	137
2021	576	10	25	2.6	87%	4%	131
2022	423	9	25	2.6	86%	4%	129
2023	309	8	21	2.6	83%	4%	139
2024	154	9	21	2.5	82%	4%	146
Overall	2006	9	22	2.6	85%	4%	135

FIGURE 4-19: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2017 Prior	151	254	508	2.0	72%	2%	74
Equity Resiliency	199	287	1,395	4.9	87%	9%	147
Large-Scale Storage	659	298	649	2.2	84%	4%	166
Non-Residential Storage Equity	66	253	653	2.6	84%	4%	109
Overall	<u>1075</u>	<u>287</u>	<u>767</u>	<u>2.7</u>	<u>84%</u>	<u>5%</u>	<u>146</u>

FIGURE 4-20: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
Equity Resiliency	607	11	28	2.6	86%	4%	126
Large-Scale Storage	122	16	40	2.6	84%	3%	115
Residential Equity	2	8	20	2.6	89%	6%	185
SVJ	44	10	26	2.6	85%	2%	65
Small Residential	1231	7	18	2.6	85%	4%	144
Overall	<u>2006</u>	<u>9</u>	<u>22</u>	<u>2.6</u>	<u>85%</u>	<u>4%</u>	<u>135</u>

FIGURE 4-21: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2012	4	407	814	2.0	74%	3%	126
2013	1	9	18	2.0	28%	1%	50
2014	45	365	729	2.0	69%	2%	80
2015	49	282	564	2.0	75%	1%	60
2016	52	125	250	2.0	72%	2%	77
2017	297	199	414	2.1	80%	4%	159
2018	54	426	861	2.0	86%	3%	129
2019	71	440	912	2.1	85%	4%	164
2020	372	307	972	3.2	86%	6%	175
2021	94	351	1,373	3.9	86%	6%	120
2022	31	284	618	2.2	82%	4%	105
2023	4	141	509	3.6	71%	4%	43
2024	1	448	2,261	5.0	86%	5%	22
Overall	1075	287	767	2.7	84%	5%	146

FIGURE 4-22: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles

BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2017	110	8	20	2.6	86%	4%	138
2018	185	7	17	2.5	86%	4%	142
2019	183	8	21	2.6	87%	4%	136
2020	778	10	25	2.6	87%	4%	130
2021	310	9	25	2.6	86%	4%	132
2022	205	8	21	2.6	83%	4%	139
2023	180	7	19	2.6	81%	4%	150
2024	55	9	21	2.3	82%	4%	138
Overall	2006	9	22	2.6	85%	4%	135

FIGURE 4-23: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY PV PAIRING

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY ON-SITE GENERATION

On-site Generation	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
On-site PV	455	268	669	2.5	83%	5%	151
Standalone	620	301	840	2.8	85%	5%	142
Overall	1075	287	767	2.7	84%	5%	146

FIGURE 4-24: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY PV PAIRING

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY ON-SITE GENERATION

On-site Generation	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
On-site PV	1953	9	22	2.6	85%	4%	137
Standalone	53	10	26	2.6	83%	2%	60
Overall	2006	9	22	2.6	85%	4%	135

FIGURE 4-25: SUMMARY OF 2024 NONRESIDENTIAL PERFORMANCE METRICS BY BUILDING TYPE

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY BLDG TYPE

Bldg Type	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
All Others	187	368	1,021	2.8	85%	5%	121
EV Station	118	292	598	2.0	86%	6%	250
Grocery	55	117	523	4.5	85%	7%	148
Industrial	167	401	854	2.1	83%	3%	122
Office	71	334	719	2.2	85%	3%	123
Retail	76	207	442	2.1	81%	3%	114
School	279	187	479	2.6	80%	4%	151
Utility	122	332	1,424	4.3	87%	7%	136
Overall	1075	287	767	2.7	84%	5%	146

FIGURE 4-26: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY OPERATING MODE

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY OPERATING MODE

Operating Mode	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
Nothing	251	10	25	2.6	61%	0%	14
Self-Consumption	1248	9	23	2.6	86%	5%	154
TOU	496	8	21	2.5	86%	4%	149
Unknown	11	8	19	2.4	85%	3%	122
Overall	<u>2006</u>	<u>9</u>	<u>22</u>	<u>2.6</u>	<u>85%</u>	<u>4%</u>	<u>135</u>

FIGURE 4-27: SUMMARY OF 2024 RESIDENTIAL PERFORMANCE METRICS BY TARIFF TYPE

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY TARIFF TYPE

Tariff Type	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
NBT	31	9	23	2.6	87%	4%	130
NEM	1670	9	22	2.6	86%	4%	138
Overall	<u>1701</u>	<u>9</u>	<u>22</u>	<u>2.6</u>	<u>86%</u>	<u>4%</u>	<u>138</u>

4.1.2 Generation Performance Metrics

Verdant reviewed several performance metrics for SGIP generation participants – capacity factor (CF), electrical, thermal and system efficiency, and useful heat recovery – to better quantify the efficiency and utilization of generation technologies throughout 2024. We also reviewed if systems increased or decreased their utilization and efficiency over time by examining how performance changed for projects operating in 2024. Furthermore, we present if and how efficiency and utilization differ based on the type of generation equipment. The metrics were calculated based on observed meter data collected for a sample of projects. Metering rates vary by technology and whether a system uses fuel or recovers heat, and whether electricity, fuel, or heat data were collected. These rates are presented in Appendix C, but electricity generation and fuel consumption rates vary between 17% for internal combustion engines and 85% for all-electric fuel cells, and heat recovery rates between 12% for engines and 35% for CHP fuel cells.

Capacity Factor

Energy impacts are a function of generating capacity. Capacity factor (CF) is a metric of system utilization. For generation technologies, the CF is defined as the amount of energy generated during a given period

divided by the maximum possible amount of energy that could have been generated during that period. A CF closer to one indicates that the system is being utilized to its maximum potential.

For the majority of SGIP generation projects, systems are intended as baseload resources, meaning they are operated to generate enough electricity to cover the base load needs of a customer. However, host customers often utilize their systems at CFs according to their individual needs. Some facilities only need full capacity during weekday afternoons, and some might need full capacity 24/7. Annual CFs are useful when comparing utilization between or across varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (regarding greenhouse gases) than the grid energy they displace, high annual CFs are desirable. A CF of 1.0 is full utilization regardless of a project’s generating capacity.

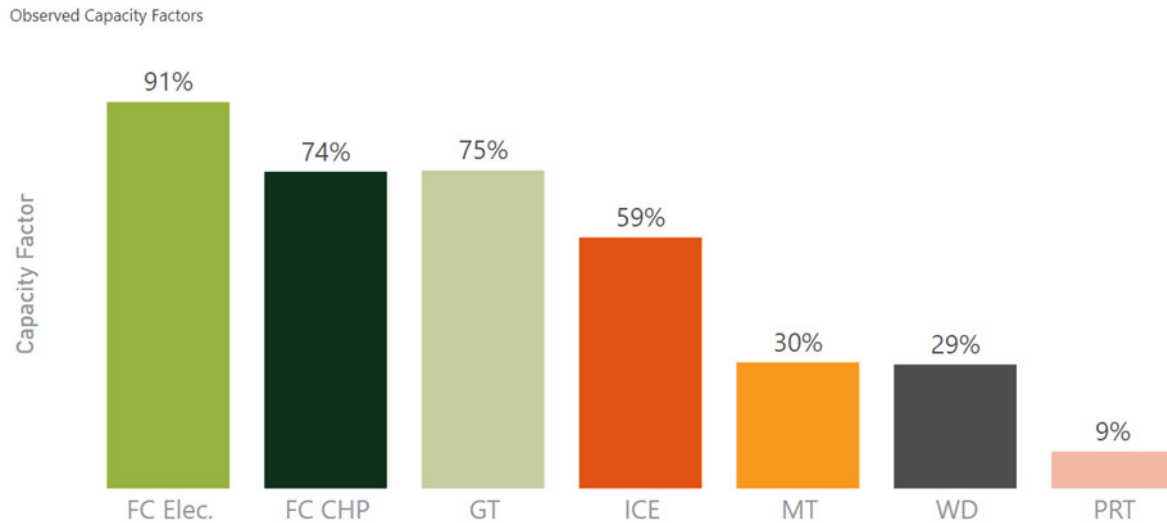
The annual capacity factor of a generation project, CF_a , is defined in Equation 4-2 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project’s capacity and 8,760 hours. If a project was completed midyear, then the annual capacity factor is evaluated from the completion date through the end of the year.

$$CF_a = \frac{\sum ENGO_h [kWh]}{Capacity [kW] \times Hours of Data Available [hr]} \quad \text{EQUATION 4-2}$$

Figure 4-28 shows the observed average 2024 capacity factors of the program’s incentivized generation technologies. Gas turbines and all-electric fuel cells showed the highest capacity factors, followed by CHP fuel cells and microturbines. Other technologies showed much lower capacity factors. Wind turbines are not expected to meet the same capacity factor as other technologies due to the availability of wind in some areas. The expected capacity factor for wind turbines is 25%, whereas the expected capacity factor for baseload technologies is 80%.³⁶

³⁶ The SGIP also has a category labeled “dispatchable resource,” for those systems operation intended to firm on-site intermittent renewables, provide peak load shaving, or support flexible loads. The required capacity factor for these systems is 15%, but there are currently no systems incentivized under the SGIP which meet these criteria.

FIGURE 4-28: 2024 OBSERVED AVERAGE CAPACITY FACTOR BY GENERATION TECHNOLOGY

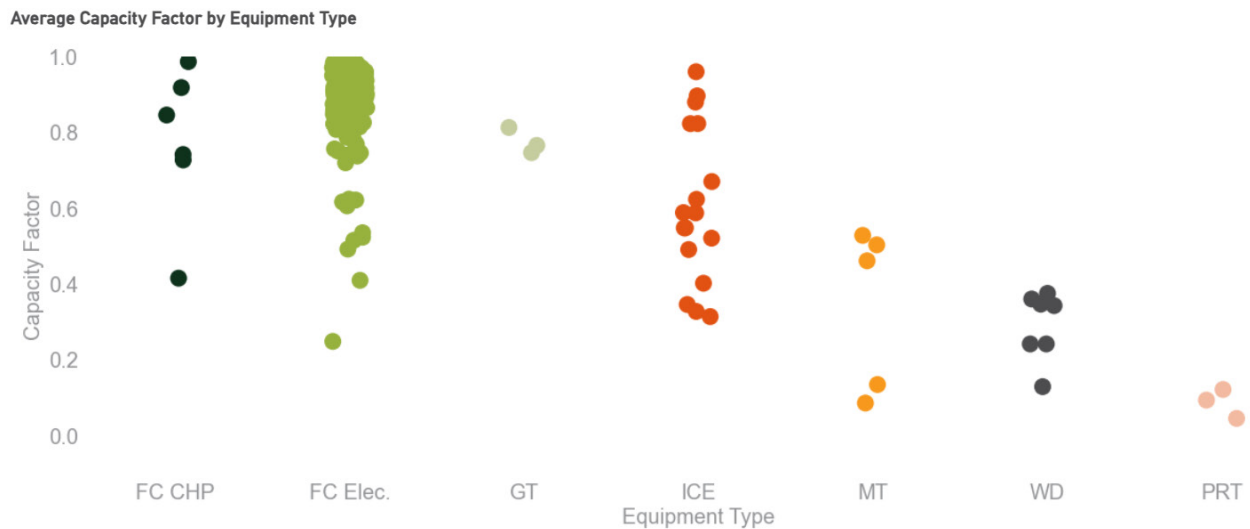


Note: **FC CHP**: CHP Fuel Cell, **FC Elec.**: All-Electric Fuel Cell, **GT**: Gas Turbine, **ICE**: Internal Combustion Engine, **MT**: Microturbine, **PRT**: Pressure Reduction Turbine, **WD**: Wind Turbine, **WHP**: Waste Heat to Power

The distribution of project-specific CFs, for those projects that were operational (non-decommissioned),³⁷ are shown in Figure 4-29. The few gas turbines all displayed capacity factors that were quite consistent, while all other technologies exhibited substantial site-to-site variation even across their technology. While all-electric fuel cell technologies generally saw higher CFs than other technologies, there was a large spread in the project-specific findings for this equipment.

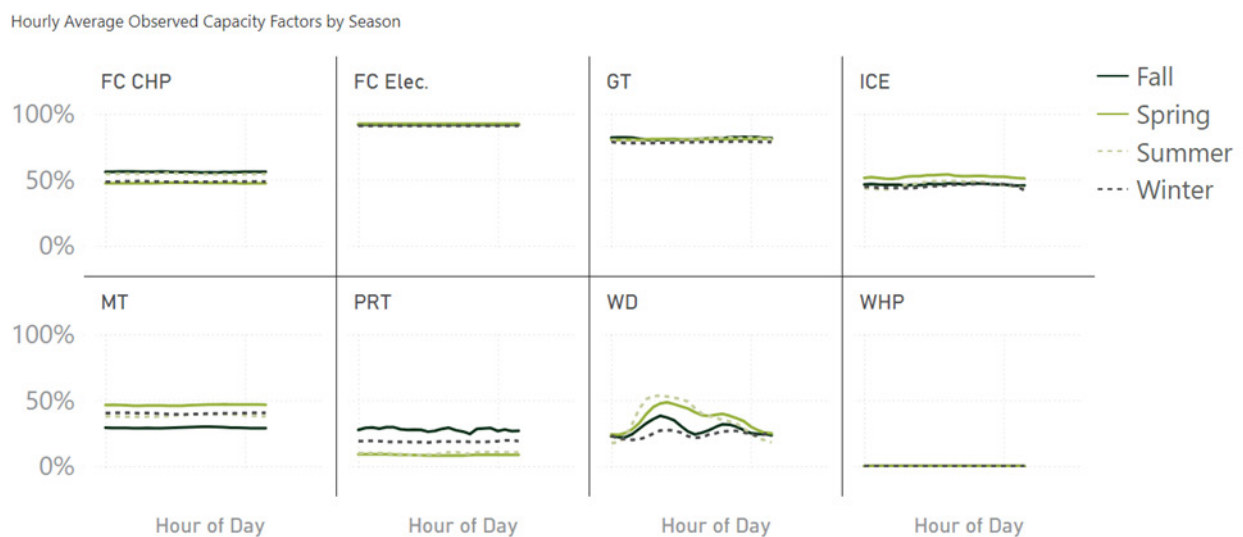
³⁷ While this does not include decommissioned projects, there were some projects that had near-zero generation in 2024 that were not confirmed to be decommissioned.

FIGURE 4-29: DISTRIBUTION OF OBSERVED 2024 CAPACITY FACTORS BY GENERATION TECHNOLOGY



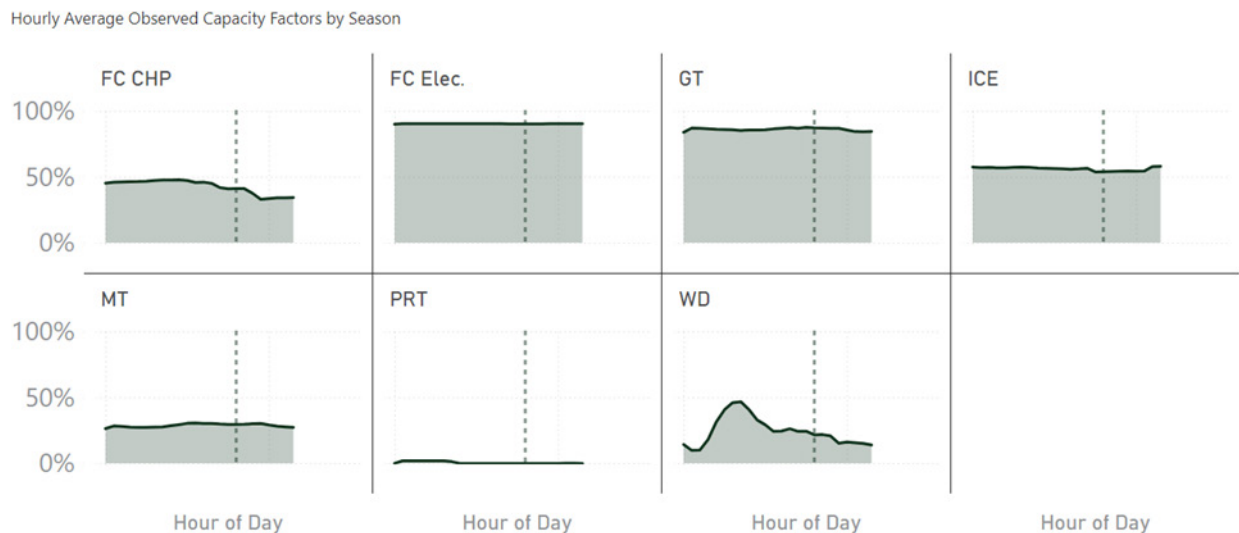
Historically, SGIP generation projects have not been designed to be ramped up and down quickly and are typically intended to satisfy a portion of the facility’s base load. As such, except for wind turbines which rely on availability of wind, the CFs are typically quite consistent throughout the day. This is also evident in the SGIP requirements, which specifies that most generation technologies are to meet an 80% annual capacity factor to realize their full PBI payment. Figure 4-30 presents hourly capacity factor generation profiles across different seasons for non-decommissioned generation systems. The data reiterates that systems are typically designed to handle a facility’s base load, and the results do not vary much by season.

FIGURE 4-30: AVERAGE 2024 GENERATION PROFILES BY EQUIPMENT TYPE AND SEASON



Higher utilization coincident with CAISO and IOU peak hours yields greater benefits to the grid than during other hours. The CF generation profiles for each technology during the 2024 CAISO peak day are shown in Figure 4-31, and the peak hour of the year is also highlighted with the grey dashed line. Across the CAISO peak hour, all-electric fuel cells and gas turbines were found to have the highest capacity factors at around 90% (compared to their summer average of about 90% and 80%), respectively, while CHP fuel cells and internal combustion engines hovered around 50% (in alignment with their summer averages of around 50%). As noted previously, generation technologies are generally designed to satisfy facility base load, so there is little variation in their utilization during the peak day or peak hours versus non-peak times.

FIGURE 4-31: 2024 OBSERVED CAISO PEAK DAY GENERATION PROFILES BY EQUIPMENT TYPE



Electrical, Thermal, and System Efficiency

The ability to convert fuel into useful electrical and thermal energy is measured by the system's combined efficiency in doing both. The combined or overall system efficiency is defined in Equation 4-3 as the ratio of the sum of electrical generation and useful recovered heat³⁸ to the fuel energy input.

³⁸ In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat.

$$C\eta_{system} = \frac{ENGO_{kWh} \times 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,LHV}}$$

EQUATION 4-3

The higher the system’s overall efficiency the less fuel input is required to produce the sum of electricity and useful recovered heat. Electric-only fuel cells do not require useful heat recovery capabilities; therefore, their system overall efficiency has only an electrical component. Technologies that recover useful heat have electrical and thermal component efficiencies. All efficiencies are reported on a lower heating value (LHV) basis.³⁹

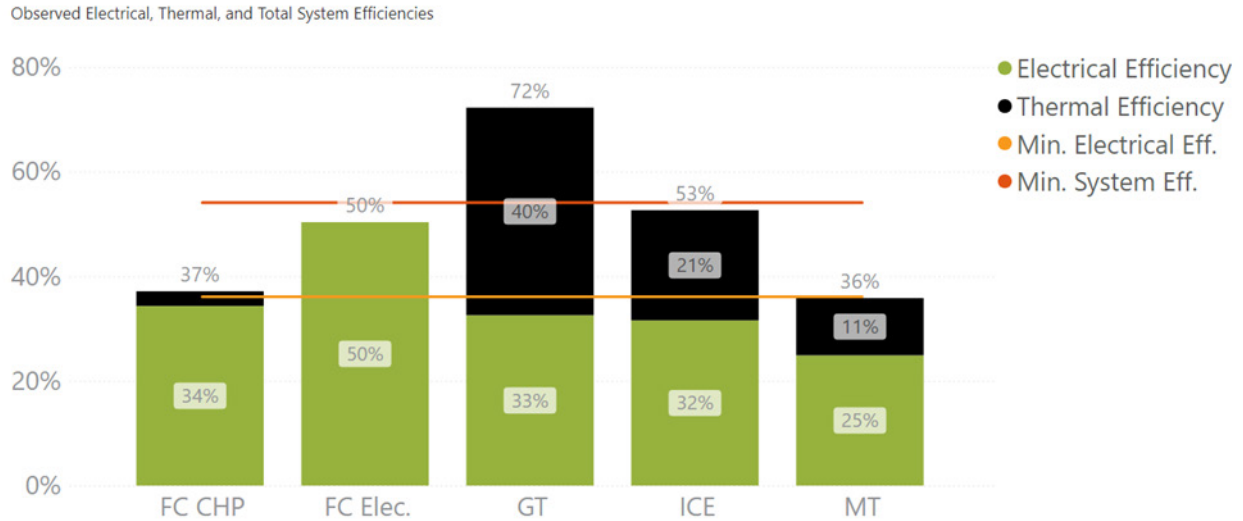
The observed overall system and component efficiencies are shown in Figure 4-32. The electrical conversion efficiency is shown in light green while the thermal efficiency is in dark green. The figure also displays red and orange horizontal lines that represent the program minimum system efficiency targets of 54.1% LHV (or 60% HHV) for CHP and 36.1% LHV (or 40% HHV) for electric-only fuel cells. On average, all-electric fuel cells and gas turbines met their efficiency targets. CHP fuel cells met their electrical efficiency requirements but not their system efficiency requirements, and internal combustion engines and microturbines, on average, didn’t meet either one.

Heat recovery is the most complicated engineering challenge when implementing CHP. If the CHP generator is not appropriately sized to the annual heating and cooling loads of a building, then much of the excess heat must be dumped into the atmosphere through a radiator. Useful heat recovery loops may also be temporarily shut down due to maintenance issues. These types of events can cause this technology to have a low useful heat recovery rate and therefore an observed system efficiency that falls short of design specifications.

In this evaluation, like the prior 2023 evaluation, the observed, project-level thermal efficiencies range between almost 0% up to about 45% for internal combustion engines, and between 6% to 15% for microturbines.

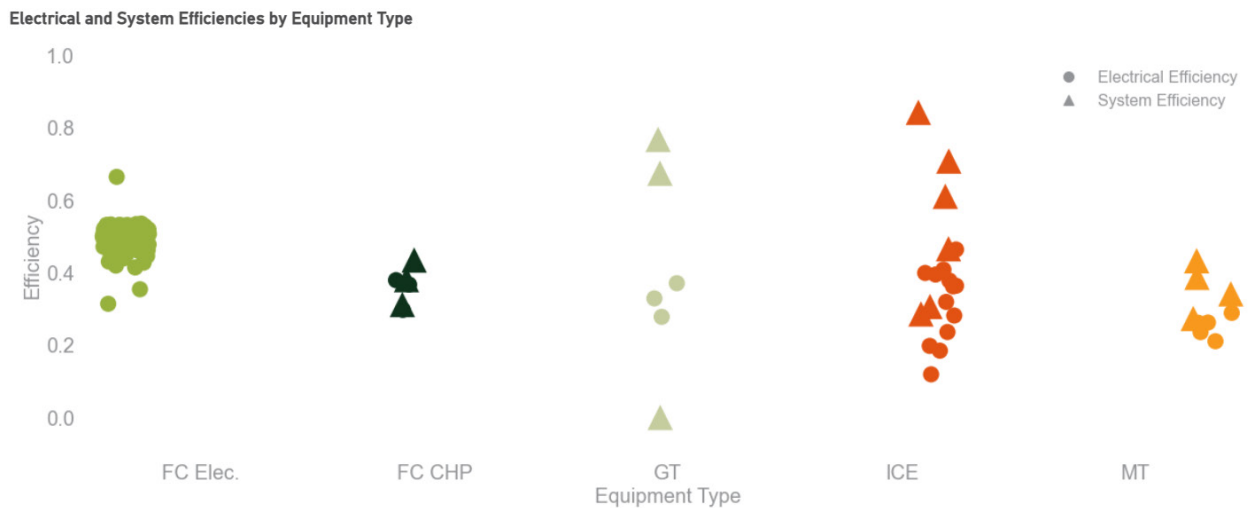
³⁹ This evaluation report assumes a natural gas lower heating value energy content of 934.9 Btu/SCF and higher heating content of 1036.6 Btu/SCF for an LHV/HHV ratio of 0.9019 (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

FIGURE 4-32: 2024 OBSERVED WEIGHTED AVERAGE ELECTRICAL, THERMAL, AND SYSTEM EFFICIENCIES BY TECHNOLOGY TYPE



* The total system efficiency displayed above the chart reflects the sum of the average electrical efficiency and the average thermal efficiency. However, it should be noted that the projects that go into a calculated weighted average electrical efficiency are not always the same projects that go into a calculated weighted average thermal efficiency, due to the availability of metered data, so these overall system efficiencies do not match the system efficiencies highlighted below in Figure 4-35.

FIGURE 4-33: DISTRIBUTION OF OBSERVED 2024 ELECTRICAL AND SYSTEM EFFICIENCIES BY GENERATION TECHNOLOGY



Useful Heat Recovery

Fuel energy that enters SGIP systems is converted into electricity and heat. Certain SGIP technologies can capture this heat to usefully serve on-site end uses instead of dissipating it to the atmosphere. Except for electric-only fuel cells that achieve high fuel-to-electric conversion efficiencies, the SGIP requires useful heat recovery where natural gas is the predominant fuel. Where the predominant fuel is renewable biogas, the SGIP system is exempt from the heat recovery requirement. The biogas exemption from heat recovery was introduced in the program's first year. The end uses served by heat recovery for heating and cooling have important implications for net greenhouse gas emissions. The comparable baseline measures for heating and cooling are a natural gas boiler and a grid-served electric chiller, respectively. Useful heat recovery that displaces a baseline boiler will reduce emissions more than if it displaces a baseline electric chiller. The distribution of end uses served by useful heat recovery from SGIP systems is summarized in Table 4-3. The incentivized capacity of projects utilizing heat recovery has steadily declined over the last few evaluation cycles. There were 63 projects in 2024 that still recovered heat. This is due in part to projects dropping out of the population due to completing their permanency periods, as well as projects within their permanency period being decommissioned.

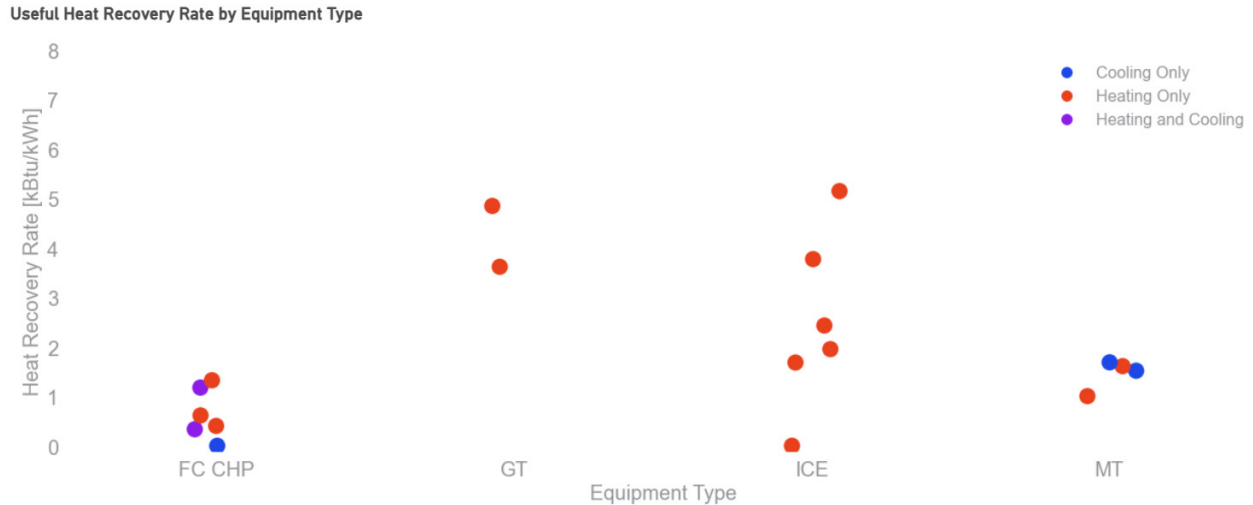
TABLE 4-3: END USES SERVED BY USEFUL RECOVERED HEAT

End Use	Project Count	Rated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	6	7	4%
Heating and Cooling	6	12	8%
Heating Only	51	141	88%

Heat recovery rates during 2024 for metered CHP systems are depicted graphically in Figure 4-34. The range of values is large, from 0 to almost 6 kBtu/kWh. As noted previously, like the 2023 impact evaluation, rates of heat recovery are lower than was seen in prior reporting cycles, which has driven the overall average system efficiencies lower this evaluation year. One factor influencing heat recovery rates is electric efficiency. The higher the electrical efficiency, the less energy remains to be captured after generation of electricity. The presence of a thermal load coincident with demand for electricity generation is a second critical factor influencing average heat recovery rates.

Additionally, accurate heat recovery data was less available than in prior impact evaluations. Of the over 50 non-PBIPBI projects recovering heat, only 19 projects provided us with data that was complete enough to process.

FIGURE 4-34: DISTRIBUTION OF OBSERVED 2024 HEAT RECOVERY RATES BY GENERATION TECHNOLOGY AND END USE SERVED



Performance Summaries

Metrics like capacity factors and efficiencies play a key role in determining how generation technologies provide benefits within the SGIP. These performance metrics are generally technology specific. Figure 4-35 summarizes the performance metrics discussed. Also included are observed project counts and total system capacities (in MW), and average system generation (GWh).

FIGURE 4-35: SUMMARY OF 2024 GENERATION PERFORMANCE METRICS BY EQUIPMENT TYPE

2024 Observed Generation Performance Metrics

Equipment Type	Project Count	Rated Capacity [MW]	Electrical Generation [GWh]	Capacity Factor	Electrical Efficiency	System Efficiency
FC CHP	13	10	2.06	77%	34%	37%
FC Elec.	188	69	2.27	92%	50%	
GT	7	94	73.49	78%	33%	48%
ICE	49	55	1.53	61%	32%	54%
MT	14	12	1.74	50%	25%	36%
PRT	8	3	0.14	9%		
WD	15	19	2.35	29%		
WHP	1	0	0.00			
Total	295	262	3.74	85%	48%	45%

4.2 CUSTOMER IMPACTS

Customers choosing to participate in the SGIP do so expecting their generation or energy storage system to deliver a variety of impacts to their energy services and bottom lines. Financial impacts are of particular importance to most participants. Electricity tariffs have a temporal dimension: the quantity and timing of use of electricity from the grid influence bills. As such, by operating at certain times, SGIP participants may be able to reduce the billed demand charges and/or the energy charges on their electricity bills. Findings of analysis related to customer impacts are presented below for energy storage and generation technologies.

4.2.1 Energy Storage

Storage systems dispatch objectives are predicated on several different factors including facility and household load profiles, rate structures, other market-based mechanisms, and reliability in the event of an outage. Customers on TOU rates may be incentivized to discharge energy during on-peak hours (when retail energy rates are higher) and avoid charging until off-peak hours when rates are lower. Furthermore, customer rates that assess demand charges during peak demand periods and/or at the monthly billing level may prioritize peak demand reduction. Finally, systems co-located or paired with an on-site generator like solar PV can also exhibit substantially different behavior than a standalone system.

Figure 4-36 demonstrates how residential load shapes are impacted by energy storage system charge and discharge and how those load shapes differ by season⁴⁰ and the presence of on-site PV generation. Average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage – are presented along with the season and whether the energy storage system is paired with on-site PV. Also included are vertical light gray lines representing the 4 p.m. – 9 p.m. on-peak period. Furthermore, the vertical axis corresponds to the average hourly baseline and net load normalized by the average capacity of the energy storage system and the horizontal axis corresponds to the hour of the day for each weekday (Monday – Friday). The figure highlights the following:

- The presence of on-site solar is evident in the first two graphics with a drop in load – to export – during late morning and early afternoon hours for both the baseline and net load shapes. This corresponds to excess PV generation being exported back to the grid.

⁴⁰ Summer represents June through September inclusive. Winter months are all others.

- The shaded area in yellow represents an increase in customer load relative to a baseline of no storage (battery charging). The gray area represents a decrease in customer load (battery discharging).
- These two load shapes and shaded areas correspond to average energy storage discharge (positive and black) and charge (negative and yellow).
- PV paired systems are charging almost exclusively from on-site solar power, so less PV is being exported than in the baseline. Storage system charging, during morning hours, absorbs PV generation that otherwise would have been exported.
- PV paired systems are discharging almost exclusively on peak with some discharge occurring thereafter and into the morning hours. Storage discharging replaces grid energy that otherwise would satisfy customer consumption.
- Standalone systems are discharging exclusively during the on-peak and begin charging thereafter, with the greater magnitude of charge occurring after midnight.

FIGURE 4-36: AVERAGE RESIDENTIAL DAILY WEEKDAY LOAD SHAPES (PV PAIRED AND STANDALONE)

Average Residential Summer Weekday Daily Load Shapes

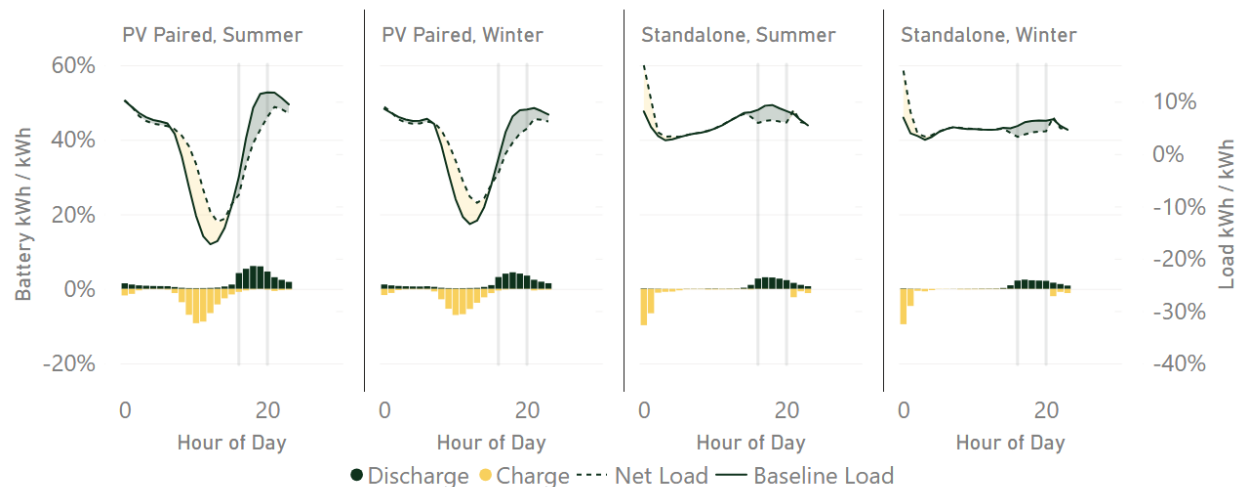


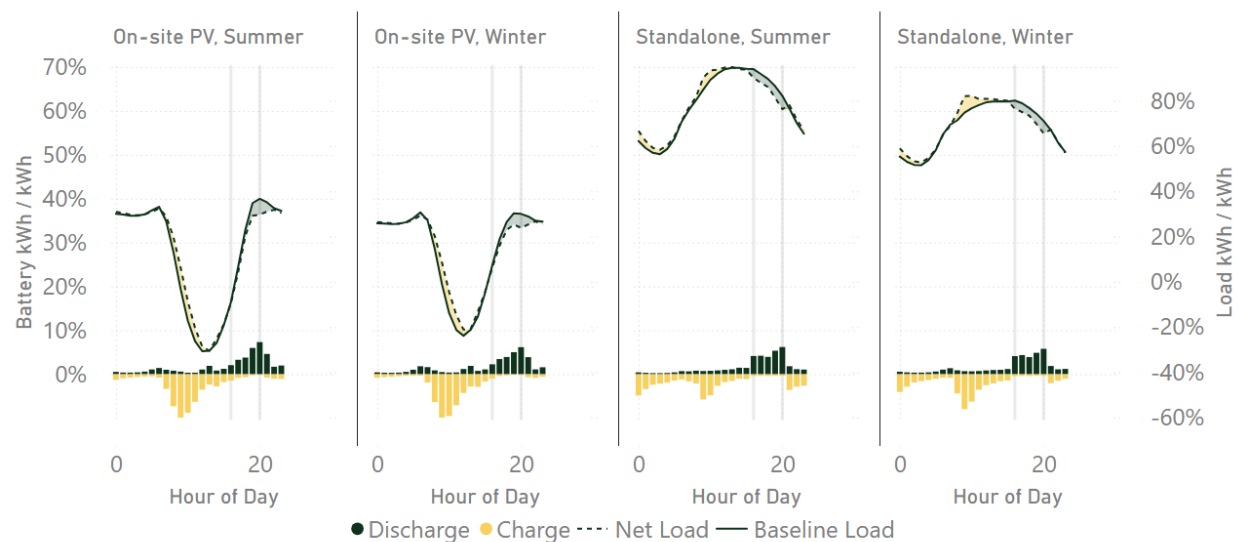
Figure 4-37 demonstrates how nonresidential load shapes are impacted by energy storage system charge and discharge and how those load shapes differ by season and the presence of on-site PV generation. Nonresidential load shapes are far more heterogeneous than residential ones given the variety of facility types, underlying load requirements, and customer bill rate structure. However, some similar patterns can be gleaned from average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage. The 4 p.m. – 9 p.m. on-peak period is also highlighted, and average hourly baseline and net load are

normalized by the average capacity of the energy storage system for each hour of the weekday. The figure conveys similar information to the residential ones, along with:

- While PV paired systems are charging from on-site solar and discharging on peak, we also observe discharge during early morning hours when consumption ramps prior to PV generation.
- Facilities with standalone systems, on average, are much larger – relative to the size of the storage system – than facilities with on-site solar. Most discharge occurs during the on-peak and charging occurs thereafter. However, systems are also discharging during noncoincident peak hours.
- We also observe system charging during early morning solar generating hours for systems not paired or co-located with on-site solar PV. This will be explored later in this section and is attributed to the time of charge for specific facility types – namely electric vehicle (EV) charging stations.

FIGURE 4-37: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES (PV PAIRED AND STANDALONE)

Average Nonresidential Weekday Daily Load Shapes



While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – solar pairing plays a significant role in dictating when a system charges. Solar PV pairing is a critical source of reduced greenhouse gas emissions and utility avoided costs, because BTM storage charging from on-site solar aligns well with grid-scale renewable production and lower marginal emissions and utility energy costs.

Energy arbitrage opportunities are guided by TOU periods that are based on the electric utility and the customer’s rate schedule. During winter and summer months, customers pay different rates and, within those seasons, pay different rates for each period (on-peak, off-peak, and super off-peak⁴¹).

Figure 4-38 demonstrates how residential load shapes are impacted by energy storage system charge and discharge and how those load shapes differ by prevalent energy storage operating modes. Average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage – are presented for systems paired with on-site PV. Also included are vertical light gray lines signifying the 4 p.m. – 9 p.m. on-peak period and bars indicating the average battery charge (negative and yellow) and discharge (positive and green) kWh normalized by the system energy capacity. The figure highlights the following:

- **Self-consumption.** This mode represents the majority of residential SGIP dispatch behavior (~62%) and includes discharging during the on-peak period and thereafter until the battery SOC reaches a pre-defined minimum. This mode enables customers to maximize their PV generation and minimize delivered load from the utility. Storage capacity is never exported to the grid under this mode unless a customer participates in a demand response program.
- **TOU Arbitrage.** The middle figure represents the average load shapes for sampled residential customers conducting TOU arbitrage (~25% of sampled projects) and charging their battery from on-site solar or from grid resources. Discharging occurs only during the customer’s on-peak period (generally 4 p.m. – 9 p.m.) to maximize bill savings opportunities. Some systems regularly discharge excess capacity to the grid, while others only export during demand response events.
- **Under-Utilization/Backup.** The rightmost figure represents the sample of systems that are idle or under-utilized during the metering period (~13%). Systems here are likely in backup-only mode and maintaining a full SOC in anticipation of an outage or are not being cycled often – both of which don’t ascribe to program rules. As a result, baseline and observed net loads are almost identical. We have observed a twofold increase in under-utilized system performance (measured as less than 52 annual cycles) in 2024 compared to the previous evaluation year.

⁴¹ These rate periods are presented across utility definition and naming convention. For this analysis, On-Peak/Off-Peak/Super Off-Peak is equivalent to Peak/Partial-Peak/Off-Peak. The definitions are the same. Rate period naming conventions have been combined for presentation purposes.

FIGURE 4-38: AVERAGE RESIDENTIAL SUMMER WEEKDAY LOAD SHAPES BY OPERATING MODE (PV PAIRED)

Average Residential Summer Weekday Daily Load Shapes

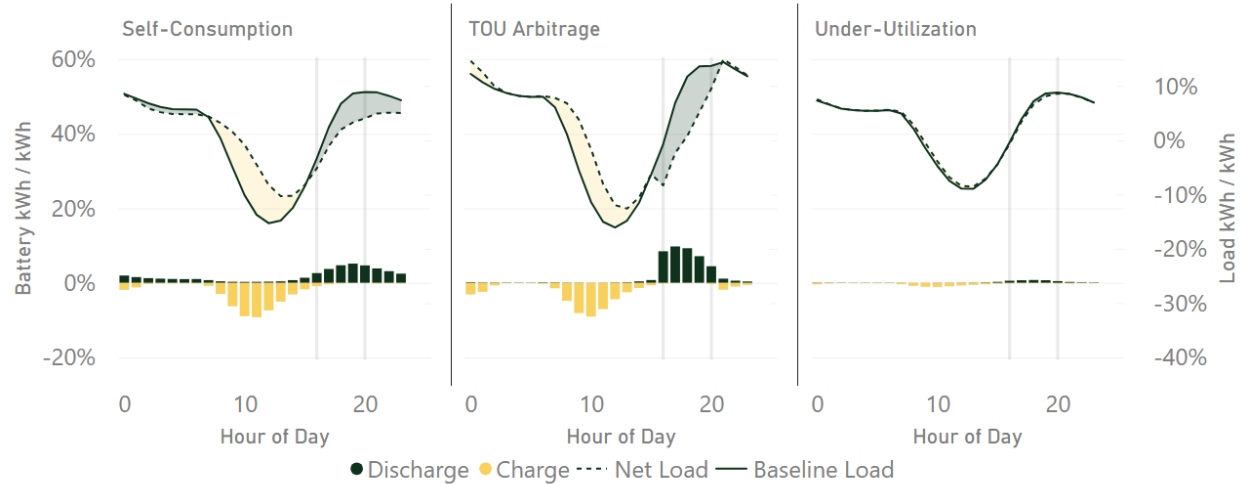
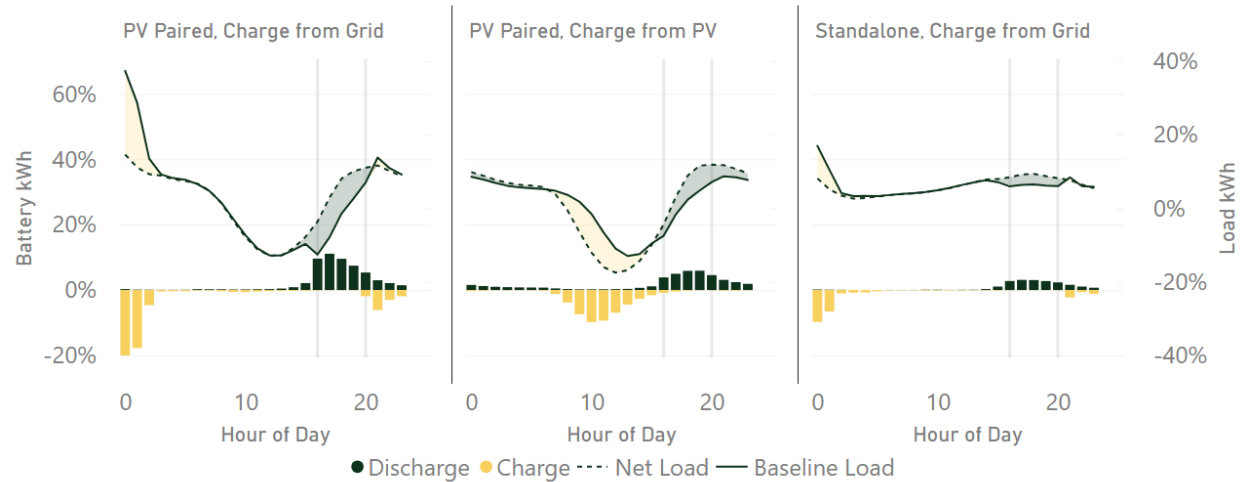


Figure 4-39 presents how baseline and metered summer weekday load shapes differ by how and when the energy storage system is charging. The leftmost and middle graphic represent systems paired with on-site PV. While there are similarities in when systems discharge (positive black bars), systems on the left are not charging from on-site solar PV. Rather, they begin charging after 9 p.m., with the greatest magnitude of charge occurring from 12 a.m. through 1 a.m. Standalone energy storage systems (the rightmost graphic) exhibit similar timing of charge and discharge to paired systems charging from grid resources; however, the magnitude of dispatch and utilization are much less.

FIGURE 4-39: AVERAGE RESIDENTIAL SUMMER WEEKDAY LOAD SHAPES BY CHARGING SOURCE

Average Residential Summer Weekday Daily Load Shapes



Some products meter charge/discharge at the inverter, but also meter PV production and customer net load. These metering techniques allow the battery to recognize when net load goes positive or negative and provide an opportunity for a customer to conduct self-consumption. These modes provide differing arbitrage opportunities and discharge patterns based on how the battery is built and how it interacts with customer load and on-site generation.

Nonresidential storage performance is guided by similar economics, but customer bill rate structure (monthly, on-peak, daily demand charges, and TOU energy charges), site-specific power demands, and load shapes guide dispatch. Figure 4-40 presents the average baseline and observed metered load for systems paired or co-located with on-site PV by building type. Average load shapes are similar across building type with on-site solar charging prevalent in the morning and early afternoon, and storage discharge occurring during on-peak hours. It's important to note that, while the load shapes are similar, average demand varies by building type. This is indicated by the different secondary vertical axis scaling for each load shape.

FIGURE 4-40: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY BUILDING TYPE (ON-SITE PV)

Average Nonresidential Weekday Daily Load Shapes (On-site PV and Building Type)

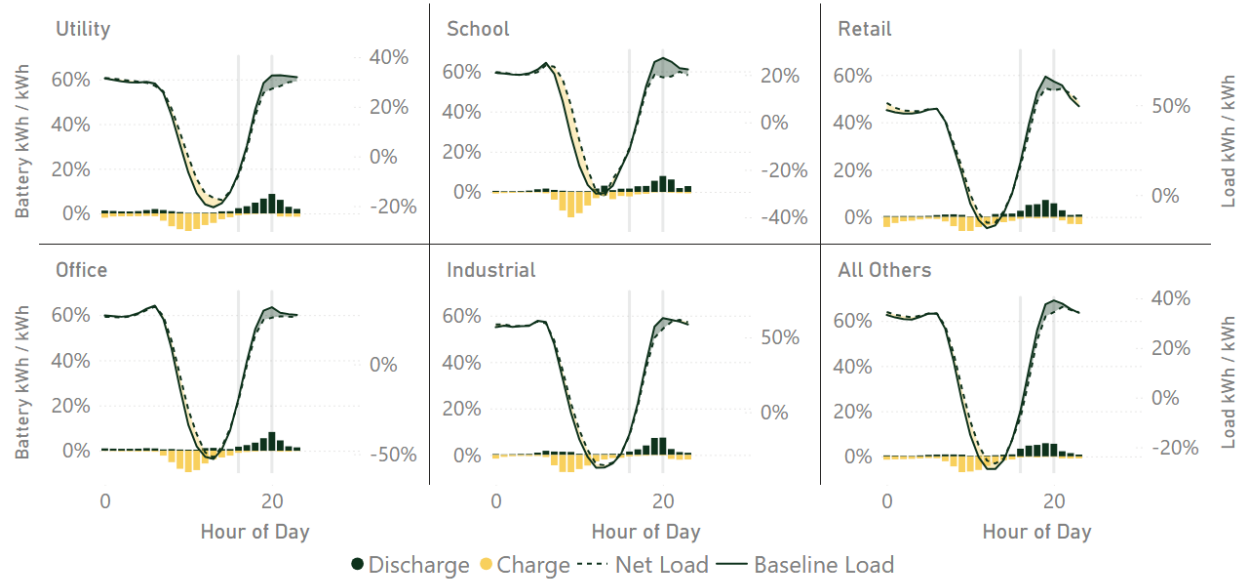
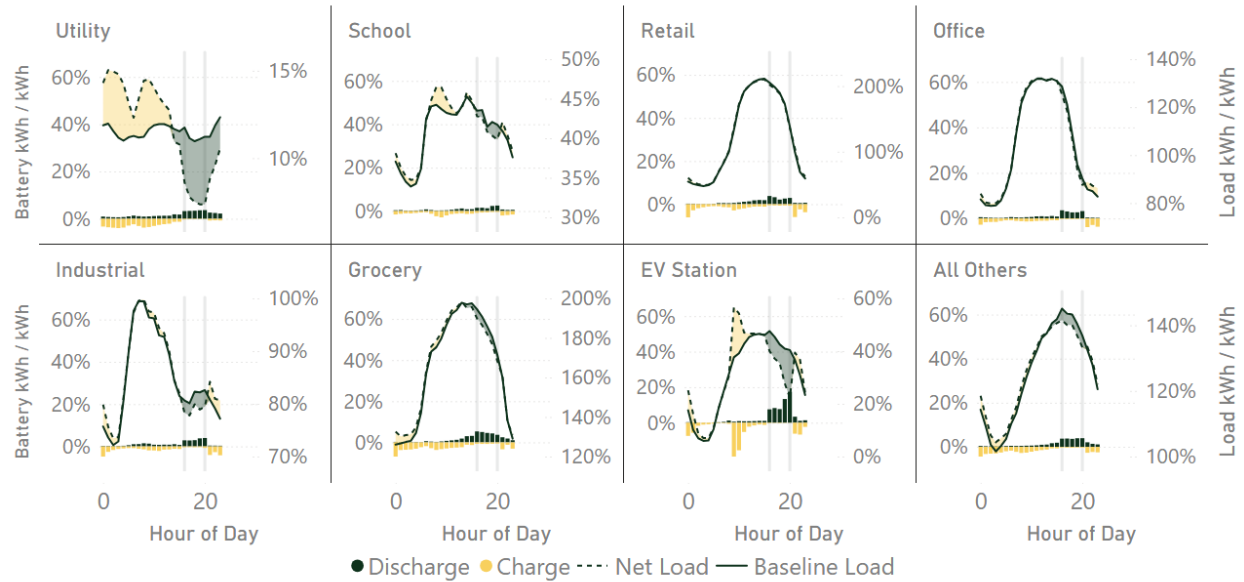


Figure 4-41 highlights the different facility load shapes without on-site PV generation and how storage charge and discharge influence facility load. Without on-site solar generation, variations in the timing and magnitude of average facility peak demand are more prevalent. Retail establishments, on average, tend to have later noncoincident peak periods than schools or industrial facilities. Load shapes for utility (mostly for wastewater treatment plants and public works facilities incentivized under the Equity Resiliency Budget [ERB]) are much flatter and less peaky than other building types. These facilities, along with EV charging stations, exhibit the most pronounced storage charge and discharge.

FIGURE 4-41: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY BUILDING TYPE (STANDALONE)

Average Nonresidential Weekday Daily Load Shapes (Standalone and Building Type)



Storage Dispatch Behavior

Verdant analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage, self-consumption, and peak demand reduction. We observed a variety of storage use cases in 2024 which dictate the charge and discharge behaviors during the year. Verdant characterized TOU energy dispatch by quantifying the magnitude of storage discharge by time of day. Retail electricity rates are higher during on-peak hours compared to off-peak and super off-peak hours, so an individual attempting to maximize the energy savings on their bill would be less incentivized to discharge their system outside on-peak hours. Furthermore, utility marginal costs and grid constraints are generally highest during on-peak hours, with on-peak periods shifting to 4 p.m. – 9 p.m. Conversely, storage charging is best left to off-peak and super off-peak time periods when retail rates are lower, as are utility avoided costs, marginal emissions, and grid constraints.

Solar PV pairing guides charging during early PV generating hours. However, an increasing percentage of PV paired systems are bypassing charging from only solar and charging from grid resources after midnight, much like standalone residential systems.

The timing and magnitude of storage charge and discharge is influenced by several factors already discussed: 1) underlying customer load shapes, 2) storage system mode of operation, 3) customer rate schedule, 4) on-site solar PV presence, and 5) storage system sizing relative to customer load. The following bar charts present the average daily weekday percentage of energy discharged and charged

during different hours of the day for residential and nonresidential systems. The exhibits also differentiate by season and presence of on-site solar. While a system may discharge exclusively during a billed on-peak period, it may only be discharging a small percentage of total capacity, in which case a customer may not realize bill savings and the potential utilization of the system may go unrealized. Figure 4-42 presents the magnitude of average daily discharge – as a percentage of energy storage kWh capacity – for the residential sector. Utilization is further broken down by PV paired versus standalone systems, the season, and the time of day of discharge. The figure highlights the following:

- On average, residential systems are discharging roughly 43% of available kWh capacity during summer weekdays. Most of that discharge occurs during the 4 p.m. – 9 p.m. period (9% from 4 p.m. – 6 p.m. and 16% during 6 p.m. – 9 p.m.). The remaining capacity is discharged outside the on-peak period – indicating the presence of systems conducting self-consumption in the average.
- On average, standalone systems (~3% of systems) are discharging much less capacity daily (20%) than PV paired systems. Almost all discharge occurs during the 4 p.m. – 9 p.m. hours.
- Utilization for PV paired and standalone systems is less in winter than in summer months. Summer months carry higher on-peak price differentials than winter months, making energy arbitrage less attractive. Customers also generally have lower electric demand during winter months, so less energy capacity is required to meet household consumption.

FIGURE 4-42: RESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

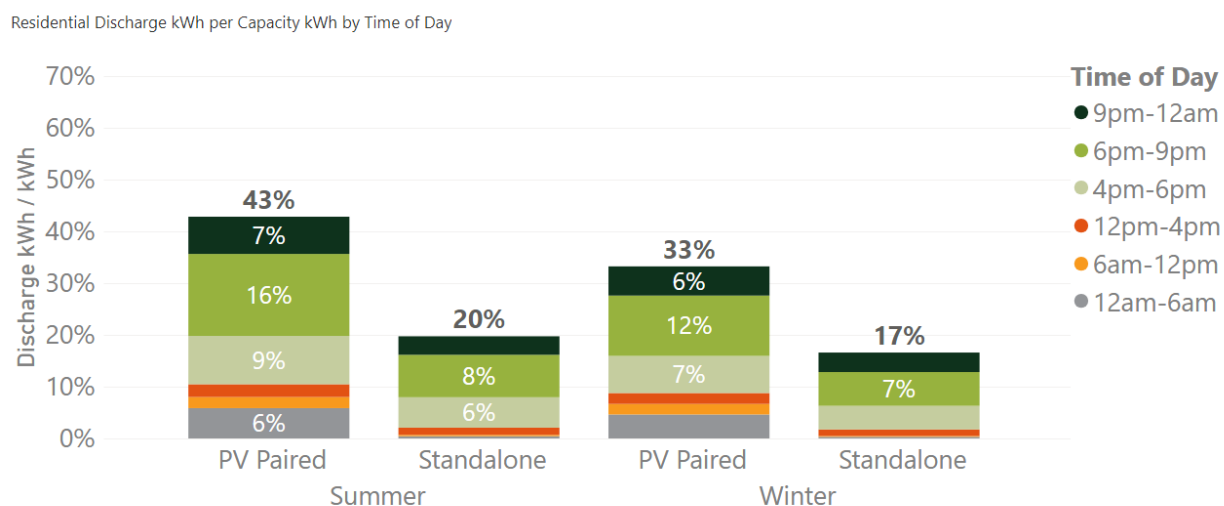


Figure 4-43 presents the magnitude of average daily discharge in the nonresidential sector. We observe 44% of available capacity discharged daily for systems co-located or paired with solar PV. Standalone

systems exhibit similar utilization, and overall winter utilization is greater.

FIGURE 4-43: NONRESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

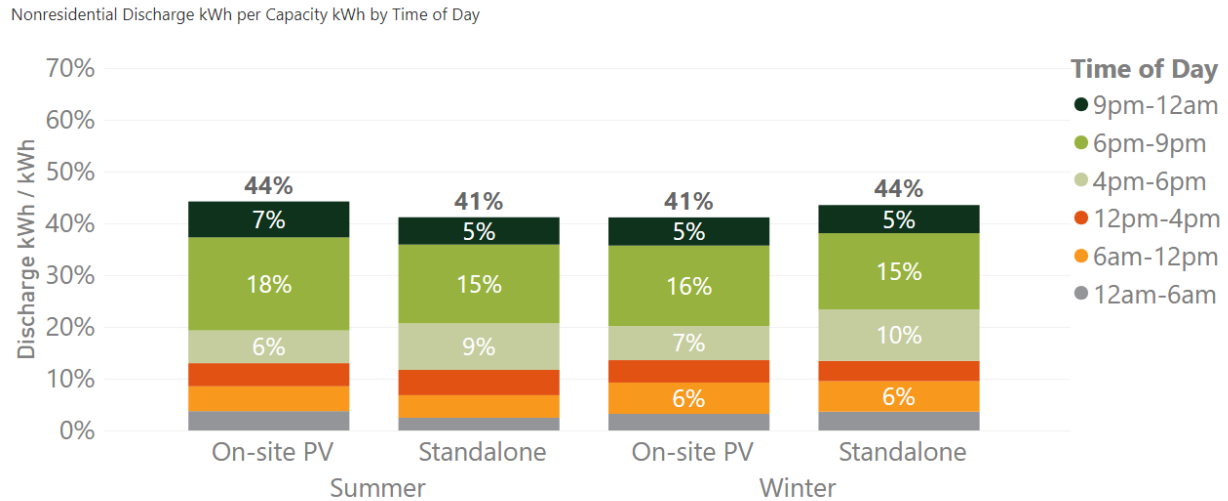


Figure 4-44 and Figure 4-45 present average daily charging magnitudes in the residential and nonresidential sectors, respectively. We observe PV paired systems charging almost exclusively during 6 a.m. – 4 p.m. when on-site PV is generating. Standalone residential systems charge exclusively after 9 p.m. and through the midnight hours.

FIGURE 4-44: RESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY

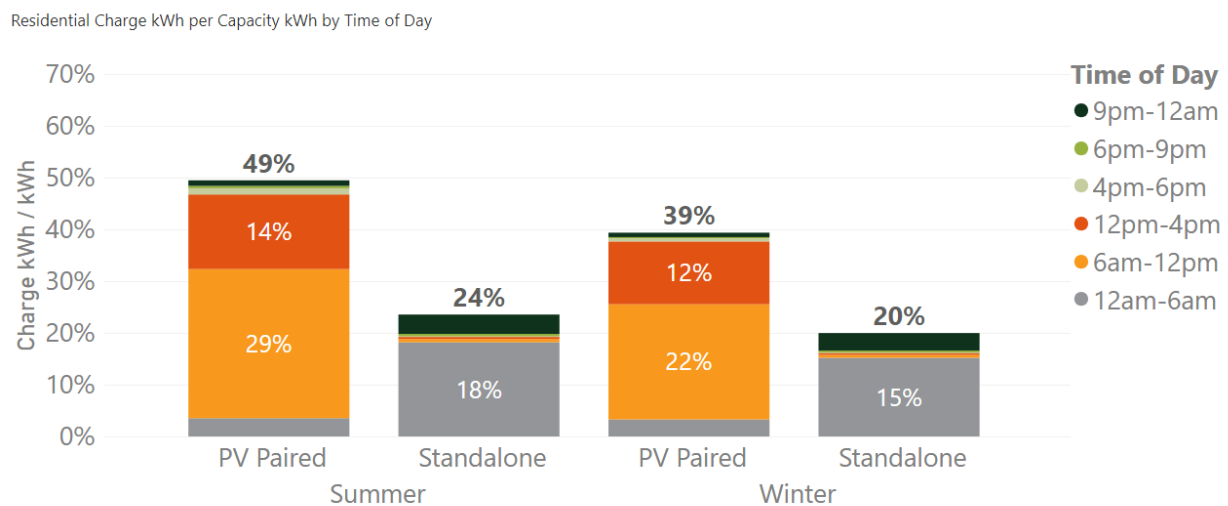
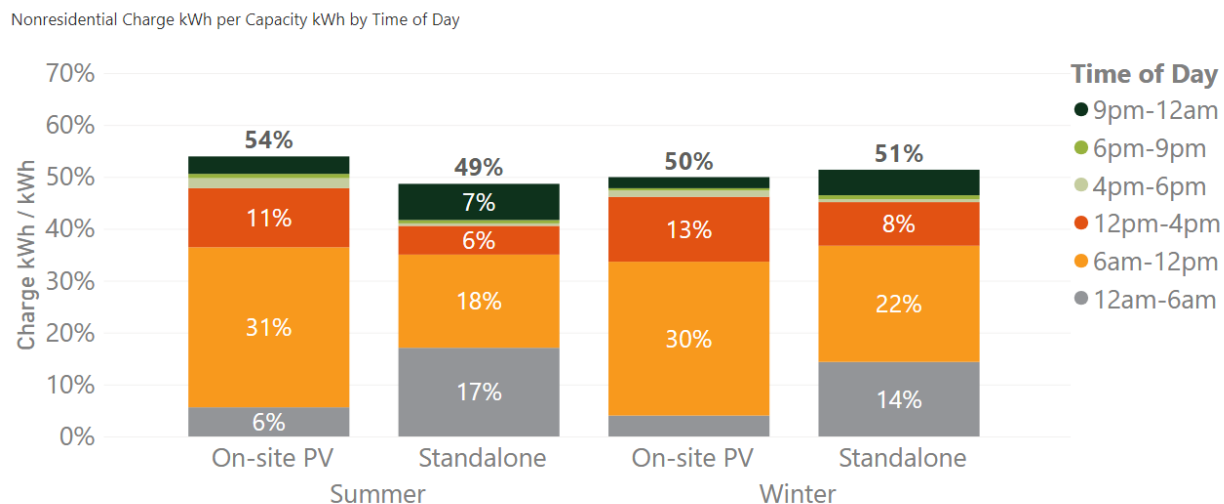


FIGURE 4-45: NONRESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY



As presented in Figure 4-38 previously, average daily residential load shapes can differ substantially from baseline to retrofit based on the dispatch patterns and operating modes of the energy storage system. This is evident in Figure 4-46 where we summarize utilization by time of day for each of three prevalent residential operating modes. As expected, systems operating in self-consumption limit imported load by discharging the battery, even outside of on-peak hours. TOU arbitrage aims to maximize bill savings, so discharge is reserved for on-peak billed periods only. However, there is little difference in the overall daily utilization. Under-utilized systems maintain a much higher daily state of charge (SOC).

FIGURE 4-46: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND OPERATING MODE

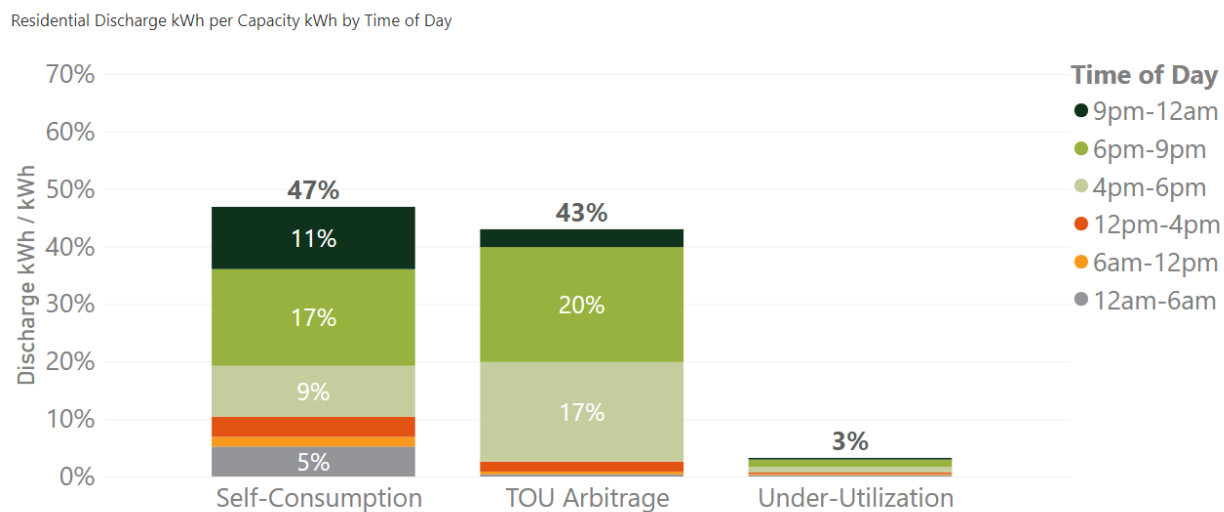
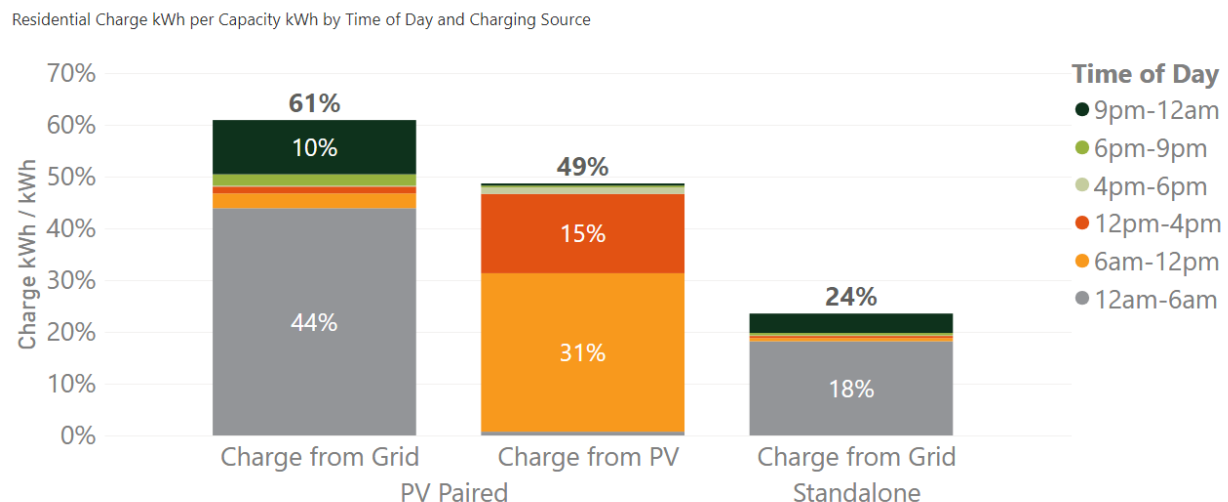


Figure 4-47 presents the average daily charge during summer weekdays as a percentage of kWh capacity for 1) paired PV systems charging from grid resources, 2) paired PV systems charging from solar, and 3) standalone residential systems evaluated in this study. We observed the greatest utilization from PV paired systems charging from the grid (and overnight), followed by those paired with on-site PV and charging from that early morning generation. Evident in both the left and rightmost graphics are greater magnitudes of system charge occurring overnight (the dark gray bars in the graphics). The consequences of charging overnight will be explored in more detail in Section 4.4 where we present the GHG emissions impacts associated with energy storage utilization in 2024.

FIGURE 4-47: RESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND CHARGING SOURCE



We also reviewed how and if SGIP participants on the Net Billing Tariff (NBT) utilized their energy storage systems differently than Net Energy Metering (NEM) customers. The NBT replaced the previous NEM tariff for new solar interconnection applications after 4/14/2023. While the NBT structure is like NEM – where customers receive credits for excess solar generated and exported back to the grid – the export compensation is much less for NBT customers. Further, as of June 2024, all general market SGIP applicants installing new storage paired with existing solar are required to enroll in the NBT.⁴²

Given the lag time between interconnection applications filed before 4/15/2023 and subsequent solar installations and permission to operate (PTO), along with the June 2024 SGIP requirement, we did not

⁴² Residential Solar and Storage Equity, low-income qualified Equity Resiliency residential, and San Joaquin Valley Residential (SJV) are exempt from the requirement.



expect to observe a significant number of SGIP participants enrolled on the NBT tariff for the entirety of 2024. Utility rate and tariff data for 2024 confirmed a substantial increase in NBT enrollment for the population of 2024 SGIP customers, but the majority transitioned over late in 2024 once customers had their reservation request forms (RRF) submitted and their incentive paid out. However, our 2024 sample captured 31 SGIP customers on NBT throughout 2024 (roughly 1.5% of sampled projects).

Given the significantly lower export compensation associated with NBT, one would expect customers on NBT to utilize their energy storage system differently than a NEM customer. From a purely economic perspective, one would expect energy storage systems to absorb more excess solar generation under NBT. An increase in on-site solar generation charging would then translate over to greater energy storage system utilization as a lower end of day state of charge (SOC) would allow for greater solar charging (and less export).

Figure 4-48 and Figure 4-49 present the average daily discharge and charge utilization for each tariff by season. It's important to note that the NBT sample size of 31 is far less than that of NEM customers (~1,700), but we do observe similar utilization across customer groups – roughly 41% and 43% of energy storage capacity was utilized on summer weekdays for NBT and NEM customers, respectively. Solar self-consumption is the predominant operating mode for both customer classes, so storage utilization is limited to minimum SOC thresholds and underlying customer load and solar generation relative to battery capacity.

FIGURE 4-48: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND NBT/NEM DESIGNATION

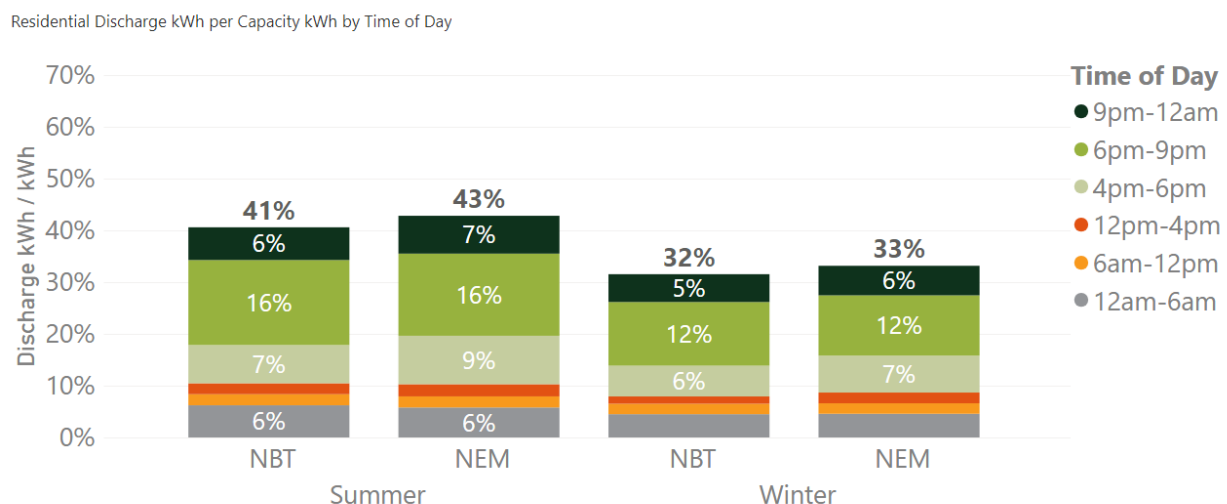
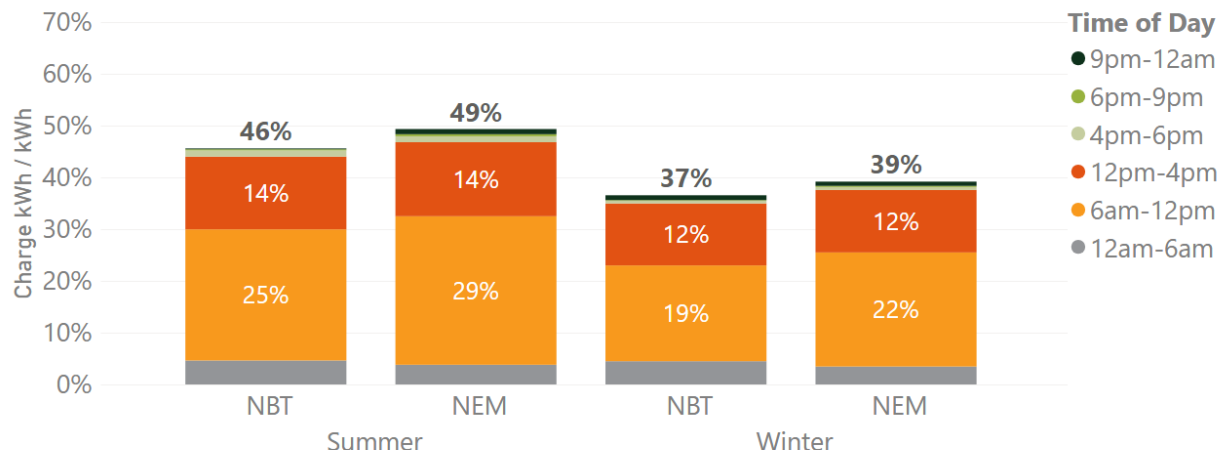


FIGURE 4-49: RESIDENTIAL CHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND NBT/NEM DESIGNATION

Residential Charge kWh per Capacity kWh by Time of Day



Average daily discharge magnitudes for nonresidential systems by building type and presence of on-site PV generation are also presented in Figure 4-50. Public utility facilities like wastewater treatment plants and primary/secondary schools with on-site PV are utilized more during summer weekdays than other facility types. However, across facility types paired with solar PV, most discharge occurs during the on-peak period (4 p.m. – 9 p.m.). Discharging outside the on-peak periods represent either 1) systems conducting self-consumption, 2) systems conducting noncoincident demand charge reduction, 3) systems arbitraging or conducting demand charge reduction on an older rate without a 4 p.m. – 9 p.m. on-peak, or 4) systems discharging until a minimum SOC is reached or on-site PV begins generating.

FIGURE 4-50: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND BUILDING TYPE (PV PAIRED)

Nonresidential Discharge kWh per Capacity kWh by Time of Day and Building Type (PV Paired during Summer Months)

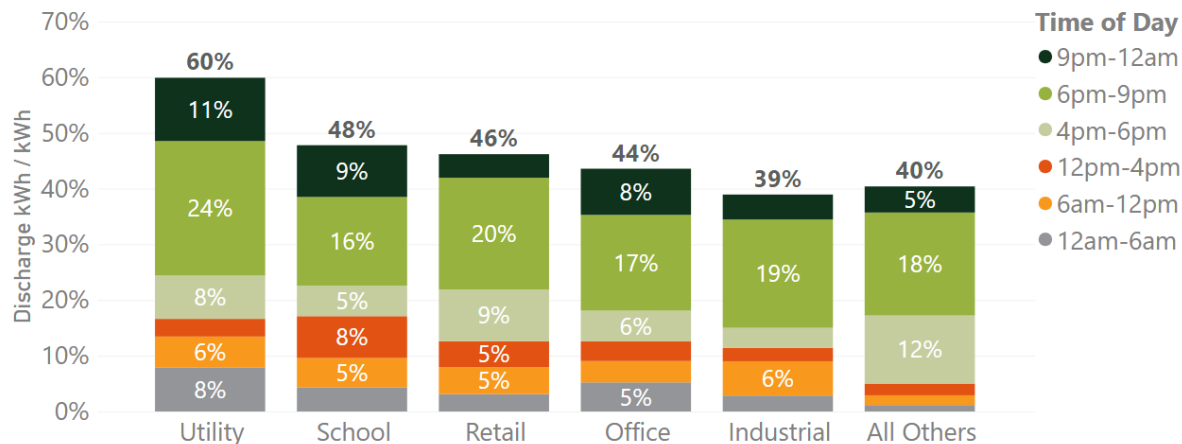
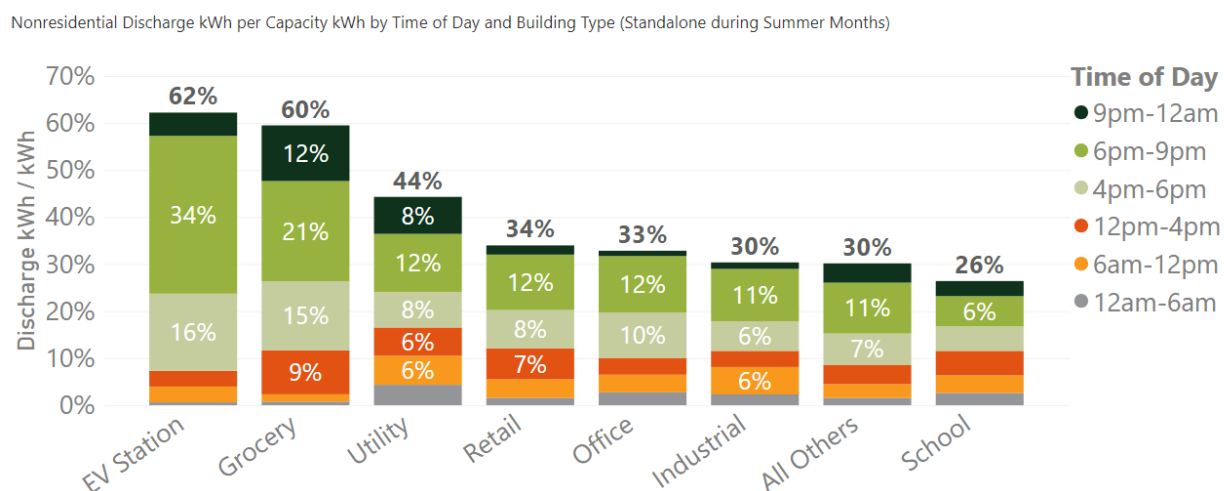


Figure 4-51 presents average daily discharge magnitudes for standalone nonresidential systems. EV charging stations exhibit the greatest utilization during summer weekdays as well as the most focused discharge on-peak, followed by grocery stores. Again, longer duration systems installed at public utility facilities exhibit lower utilization rates. However, standalone systems at schools and industrial facilities exhibit the lowest utilization rates across building types.

FIGURE 4-51: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND BUILDING TYPE (STANDALONE)



Residential storage systems and nonresidential systems utilize less storage capacity, on average, daily than available. The following discussion reveals the more granular timing of dispatch behavior to further understand how storage systems are being utilized throughout the year. This was done by developing the average hourly charge and discharge kWh as a percentage of system kWh capacity for each month and weekday hour throughout the year. These summaries are further separated into percentage of discharge (+) and charge (-) only and whether a storage system is paired with on-site PV or not. Times represent weekdays only (Monday-Friday) and are all presented as hour beginning and in Pacific Local Time. Furthermore, months are displayed on the vertical axis, and the hour of the day is exhibited across the top horizontal axis. Finally, the heat map color gradient goes from dark green – signifying the hours of greatest utilization or discharge – to red – which captures the greatest magnitude of system charging.

Figure 4-52 through Figure 4-54 present these results for residential systems: 1) paired with on-site PV and charging from on-site solar (97% of solar paired systems), 2) paired with on-site PV, but charging from grid energy (3%), and 3) standalone (1% of overall sample). As is evident above in the daily summaries, the greatest magnitude of discharge, on average, occurs during the 4 p.m. to 9 p.m. hours (16 through 20 in the exhibits below).



Residential storage systems paired with PV are almost exclusively charging during early to mid-morning hours, which coincides with early PV generation hours, and charging generally tails off after 12 noon when the battery reaches a maximum SOC.

FIGURE 4-52: RESIDENTIAL HOURLY NET DISCHARGE (KWH)/CAPACITY (KWH) PV PAIRED CHARGING FROM PV

Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from PV)

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-4%	-2%	0%	3%	4%	4%	3%	3%	1%	1%	1%
February	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-5%	-4%	-3%	-2%	-0%	2%	4%	4%	3%	3%	2%	1%	1%
March	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-5%	-7%	-7%	-5%	-4%	-2%	-1%	2%	3%	4%	4%	3%	2%	2%	2%
April	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-8%	-7%	-5%	-3%	-2%	-1%	2%	2%	4%	4%	4%	3%	2%	2%
May	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-8%	-8%	-5%	-3%	-2%	-1%	2%	2%	3%	4%	4%	3%	3%	2%
June	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-9%	-8%	-6%	-3%	-2%	-0%	2%	3%	4%	5%	4%	3%	2%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-7%	-9%	-8%	-6%	-4%	-2%	-0%	3%	4%	5%	6%	4%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-7%	-10%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	4%	3%	2%	2%
September	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-5%	-3%	-1%	3%	5%	6%	6%	4%	2%	2%	2%
October	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-5%	-7%	-8%	-7%	-5%	-3%	-1%	3%	4%	5%	5%	3%	2%	2%	1%
November	1%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-6%	-4%	-3%	-1%	1%	3%	4%	4%	3%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	4%	3%	2%	1%	1%	1%

Charging behavior for PV paired systems charging from grid energy and standalone systems are similar (Figure 4-53 and Figure 4-54). Both begin charging after 9 p.m., with the greatest magnitude of charging beginning at midnight. For PV paired systems charging from grid resources overnight, greater overall utilization results in much greater magnitudes of charge, which is confined to the midnight and 1 a.m. hours. Verdant has observed more systems choosing to forego charging from solar (~6%) than previous evaluation years. Most of these customers are enrolled in an electric vehicle rate which charges customers much lower energy prices during super off-peak hours to encourage EV charging during these times. Customers on the EV2-A in PG&E service territory, for example, pay 50% less per kWh during the super off-peaks hours of 12 a.m. – 3 p.m. It’s unclear why the battery would forego charging from solar if the customer is paying the same \$/kWh at midnight as they would at 10 a.m. when on-site solar is generating. Whatever the reason, this behavior impacts greenhouse gas emissions – something that is discussed in further detail in Section 4.4.

While grid-scale emissions and system capacity constraints are lower at midnight or 1 a.m. than during the summer on-peak hours of 4 p.m. to 9 p.m. – and EV rates were designed to motivate EV charging to less critical grid constrained hours with a super off-peak period beginning at 12 a.m. – they are still much higher than during morning hours when on-site and grid-scale solar PV are generating. As a result, storage charging overnight leads to increases in GHG emissions as currently observed in the SGIP.

FIGURE 4-53: RESIDENTIAL HOURLY NET DISCHARGE (KWH)/CAPACITY (KWH) PV PAIRED CHARGING FROM GRID

Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from Grid)

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-17%	-12%	-2%	-0%	-0%	-0%	-0%	-0%	-1%	-1%	-1%	-1%	-1%	-0%	0%	2%	7%	8%	6%	5%	4%	-1%	1%	-0%
February	-17%	-11%	-2%	-0%	-0%	-0%	0%	-0%	-1%	-1%	-1%	-1%	-1%	-0%	0%	2%	6%	7%	6%	5%	4%	-0%	1%	0%
March	-17%	-10%	-2%	-0%	-0%	0%	1%	1%	-1%	-1%	-3%	-2%	-1%	-0%	0%	1%	6%	6%	6%	5%	4%	-0%	1%	0%
April	-16%	-10%	-2%	0%	0%	0%	1%	1%	-1%	-1%	-3%	-2%	-1%	-1%	0%	1%	6%	7%	6%	4%	4%	-0%	1%	0%
May	-17%	-11%	-2%	0%	0%	0%	0%	0%	-2%	-1%	-1%	-1%	-1%	-0%	0%	2%	6%	7%	6%	4%	4%	-1%	1%	0%
June	-21%	-16%	-4%	-0%	-0%	-0%	0%	-0%	-0%	-1%	-1%	-1%	-0%	0%	1%	2%	8%	10%	8%	6%	4%	-3%	-0%	0%
July	-21%	-17%	-4%	-0%	-0%	-0%	0%	0%	-0%	-1%	-1%	-0%	-0%	-0%	1%	2%	10%	11%	9%	7%	3%	-3%	-1%	-0%
August	-21%	-16%	-4%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-1%	-0%	-0%	0%	1%	2%	10%	11%	9%	6%	3%	-3%	-1%	-0%
September	-22%	-16%	-4%	-0%	-0%	-0%	0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	2%	9%	11%	9%	7%	3%	-3%	-1%	0%
October	-21%	-16%	-4%	-0%	-0%	-0%	0%	0%	-2%	-1%	-1%	-0%	-0%	0%	1%	2%	9%	10%	7%	6%	4%	-1%	1%	0%
November	-18%	-12%	-3%	-0%	-0%	-0%	0%	0%	-2%	-1%	-1%	-0%	-0%	-0%	0%	2%	7%	8%	6%	5%	4%	-1%	1%	0%
December	-18%	-13%	-3%	-0%	-0%	-0%	0%	0%	-1%	-1%	-0%	-0%	-0%	-0%	0%	2%	7%	8%	6%	5%	4%	-1%	1%	1%

FIGURE 4-54: RESIDENTIAL HOURLY NET DISCHARGE (KWH)/CAPACITY (KWH) STANDALONE SYSTEMS

Average Hourly Residential Standalone Net Discharge kWh / kWh Capacity

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-10%	-6%	-1%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	1%	2%	3%	3%	3%	3%	0%	0%	0%
February	-10%	-4%	-0%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	2%	2%	2%	2%	2%	0%	1%	-0%
March	-9%	-3%	-0%	-1%	-0%	-0%	-0%	-0%	-0%	-1%	-0%	-0%	-0%	-0%	0%	1%	2%	2%	2%	2%	2%	-0%	0%	-0%
April	-8%	-3%	-0%	-1%	-0%	-0%	-0%	0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	1%	2%	2%	2%	2%	2%	-1%	0%	-0%
May	-9%	-4%	-0%	-1%	-0%	-0%	-0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	2%	0%	1%	-0%
June	-9%	-6%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	0%	0%	0%	0%	0%	1%	3%	3%	3%	2%	2%	-0%	1%	-0%
July	-9%	-6%	-1%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	3%	3%	3%	3%	2%	-1%	0%	-0%
August	-9%	-5%	-1%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	2%	3%	3%	2%	2%	-1%	0%	-0%
September	-9%	-5%	-1%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	2%	3%	3%	2%	2%	-0%	1%	0%
October	-9%	-5%	-0%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	0%	0%	1%	2%	2%	2%	2%	2%	-0%	1%	0%
November	-8%	-4%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	0%	1%	2%	2%	2%	2%	2%	-0%	1%	-0%
December	-9%	-5%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	2%	3%	2%	2%	2%	0%	1%	0%

Figure 4-55 and Figure 4-56 summarize the hourly discharge and charge of standalone nonresidential systems and those paired with or co-located with on-site PV, respectively. Darker green coloring within the 4 p.m. – 9 p.m. period suggests TOU arbitrage as a prominent use case. Facilities with peak loads coincident to on-peak, customers on rates with on-peak daily demand charges, and systems following the GHG signal may also prioritize discharge during these hours. Standalone systems begin charging after 9 p.m. local time and continue throughout the evening. Again, these hourly net discharge values represent a variety of different facility types, energy storage capacities, underlying facility loads, and rate structures.

With on-site solar, monthly noncoincident peaks might occur during non-generating hours. Also, solar generation may not always meet or exceed customer BTM consumption, so the battery may be dispatched to make up the difference. The first point is evident during 6 a.m. – 7 a.m. We observe nonresidential

discharge during early morning facility load ramps, but prior to PV generation. The second point is evident during 12 p.m. – 2 p.m. with reduced net charging. Facility load may exceed on-site generation during those hours, so the battery is discharged to make up the difference.

FIGURE 4-55: NONRESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) STANDALONE

Average Nonresidential Standalone Net Discharge kWh / kWh Capacity

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-3%	-3%	-2%	-2%	-1%	-0%	0%	1%	-2%	-5%	-4%	-2%	-1%	-1%	-1%	-1%	3%	4%	4%	4%	5%	-0%	-0%	0%
February	-3%	-3%	-2%	-2%	-1%	-0%	1%	1%	-3%	-5%	-4%	-3%	-2%	-1%	-1%	-1%	3%	4%	4%	5%	5%	-0%	-0%	0%
March	-2%	-2%	-2%	-1%	-1%	-0%	1%	2%	-3%	-6%	-5%	-4%	-3%	-2%	-1%	-1%	3%	4%	4%	5%	5%	1%	-0%	0%
April	-2%	-2%	-1%	-1%	-1%	-0%	1%	1%	-3%	-7%	-5%	-3%	-2%	-2%	-1%	-1%	3%	4%	4%	4%	5%	1%	0%	1%
May	-2%	-2%	-2%	-1%	-1%	-0%	0%	0%	-3%	-7%	-5%	-3%	-2%	-1%	-0%	-0%	4%	4%	4%	4%	5%	1%	0%	1%
June	-3%	-3%	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-4%	-3%	-2%	-1%	-1%	1%	0%	4%	5%	4%	5%	5%	-1%	-1%	-1%
July	-3%	-3%	-3%	-2%	-2%	-1%	-1%	-1%	-2%	-4%	-3%	-2%	-1%	-1%	0%	0%	4%	4%	4%	5%	6%	-0%	-1%	-1%
August	-4%	-3%	-3%	-3%	-2%	-1%	-0%	-1%	-2%	-4%	-4%	-2%	-1%	-1%	1%	1%	4%	4%	4%	5%	5%	-0%	-1%	-1%
September	-3%	-3%	-3%	-3%	-2%	-1%	-0%	1%	-2%	-4%	-4%	-2%	-1%	-1%	1%	1%	4%	4%	4%	5%	5%	-0%	-0%	-0%
October	-2%	-2%	-2%	-2%	-2%	-1%	0%	1%	-3%	-6%	-5%	-3%	-2%	-1%	-1%	-1%	4%	5%	4%	4%	5%	1%	0%	1%
November	-3%	-3%	-3%	-2%	-1%	-1%	0%	0%	-5%	-7%	-6%	-4%	-3%	-2%	-1%	1%	7%	7%	6%	5%	5%	-0%	-1%	-0%
December	-3%	-3%	-3%	-2%	-2%	-1%	0%	1%	-4%	-7%	-5%	-3%	-2%	-2%	-1%	1%	7%	7%	5%	5%	4%	-0%	-1%	-0%

FIGURE 4-56: NONRESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) WITH ON-SITE PV

Average Nonresidential with On-site PV Net Discharge kWh / kWh Capacity

Month/Hr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-1%	-0%	-0%	-0%	-0%	0%	1%	1%	-3%	-6%	-7%	-6%	-4%	-2%	-2%	-1%	2%	4%	4%	4%	5%	2%	0%	1%
February	-1%	-1%	-0%	-0%	-0%	1%	2%	0%	-5%	-7%	-7%	-5%	-3%	-2%	-2%	-1%	1%	4%	5%	5%	5%	2%	0%	1%
March	-0%	-0%	-0%	-0%	0%	1%	2%	1%	-3%	-8%	-8%	-7%	-4%	-2%	-2%	-1%	1%	3%	4%	6%	6%	2%	0%	1%
April	-0%	-0%	-0%	0%	0%	1%	2%	0%	-5%	-8%	-8%	-6%	-4%	-2%	-2%	-1%	0%	2%	4%	6%	6%	3%	1%	1%
May	-0%	-0%	-0%	0%	0%	1%	1%	1%	-1%	-4%	-7%	-7%	-6%	-4%	-2%	-2%	-1%	0%	2%	3%	6%	6%	3%	1%
June	-1%	-0%	-0%	-0%	0%	1%	0%	0%	-3%	-6%	-7%	-7%	-5%	-3%	-2%	-2%	-1%	1%	3%	4%	6%	7%	3%	1%
July	-1%	-1%	-0%	-0%	-0%	1%	1%	0%	-2%	-5%	-7%	-7%	-5%	-3%	-1%	-2%	-1%	1%	3%	4%	6%	7%	3%	1%
August	-1%	-1%	-1%	-0%	-0%	0%	1%	0%	-1%	-5%	-7%	-7%	-5%	-3%	-2%	-1%	0%	1%	3%	4%	6%	6%	2%	0%
September	-1%	-1%	-1%	-1%	-0%	0%	1%	0%	-4%	-7%	-7%	-6%	-4%	-2%	-1%	-0%	2%	4%	5%	6%	6%	2%	0%	0%
October	-1%	-1%	-1%	-0%	-0%	0%	1%	1%	-3%	-7%	-8%	-6%	-4%	-2%	-2%	-1%	1%	4%	5%	5%	6%	2%	0%	1%
November	-0%	-0%	-0%	-0%	-0%	0%	1%	0%	-1%	-6%	-9%	-7%	-5%	-3%	-1%	-1%	0%	4%	5%	4%	5%	2%	0%	1%
December	-1%	-0%	-0%	-0%	-0%	0%	1%	1%	-4%	-7%	-7%	-6%	-4%	-2%	-2%	0%	3%	4%	4%	4%	5%	2%	0%	1%

Metered data collected from systems operating in 2024 confirm the prevalence of energy arbitrage and self-consumption as primary operating modes within the residential sector. Self-consumption is observed only with PV paired systems, but TOU arbitrage is observed across paired and standalone systems. The big difference in the residential sector is the timing of charge. Operating modes within the nonresidential sector are more nuanced given the significant heterogeneity of facility types and load profiles, along with how the demand charge component impacts a customer's bill. We examined the monthly impact of storage discharge on facility demand or power (kW) within the nonresidential sector. If storage is

discharged to minimize or reduce monthly demand charges, then examining the change in peak demand over the month from a baseline of no storage may reveal that economic prioritization.

Figure 4-57 exhibits the percentage of sampled nonresidential customers who either 1) reduced their monthly peak demand (Reduced Peak), 2) experienced no demand increase (No Change), or 3) added to their monthly peak with how they utilized their energy storage system (Added to Peak). The distributions are categorized by presence of on-site PV generation or not and summer versus winter months for each nonresidential budget category. Demand charges are a significant component of nonresidential customer bills, so utilizing the storage system to reduce monthly demand and coincident peak demand are meaningful ways to realize bill savings.

The percentage of projects reducing monthly peaks during the year differs little by season, but markedly by budget category. A greater percentage of projects reducing monthly peaks makes sense – if facility peak 15-minute power at a facility was reduced 50 kW by battery discharge in July for example, the customer will realize demand charge savings compared to baseline of no storage. We observe a significant percentage of idle systems in some budget categories (in particular, older vintage systems) that contribute to no change in monthly facility maximum load, as well as systems that increase their monthly peak demand. The latter behavior would suggest a customer realized an increase on the on-bill demand portion of their bill. This behavior is more common with standalone systems, and later in the calendar year as well.

FIGURE 4-57: DISTRIBUTION OF MONTHLY NONRESIDENTIAL PEAK DEMAND IMPACTS

Nonresidential Monthly Peak Demand Impacts by Season

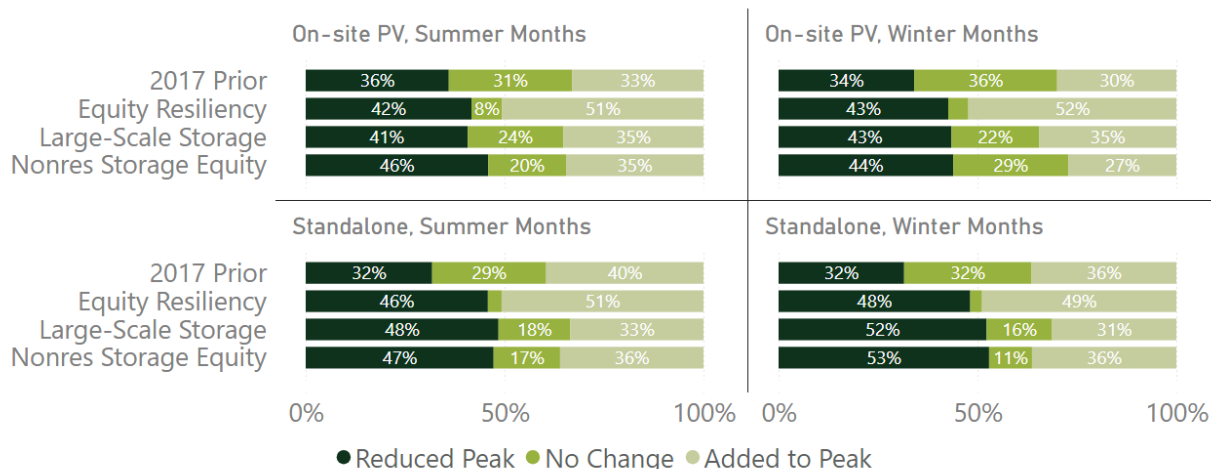
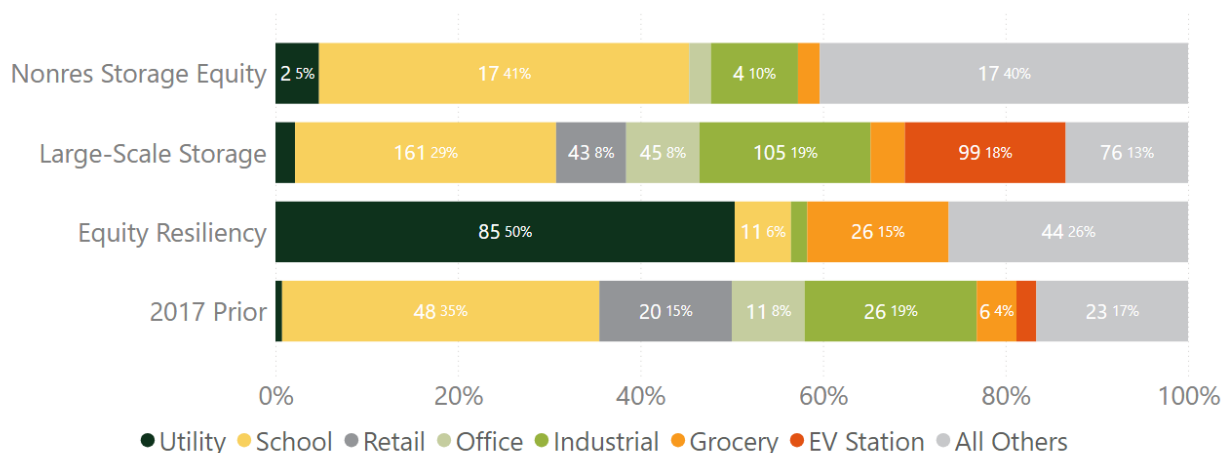


Figure 4-58 highlights the distribution of energy storage installations by building type. Energy storage installed and operable in primary and secondary schools – paired with PV or standalone – are regularly

reducing noncoincident peak. As evident in Figure 4-41 above, public utility facilities like wastewater treatment plants regularly increase their load relative to a baseline of no storage.

FIGURE 4-58: DISTRIBUTION OF NONRESIDENTIAL BUILDING TYPES BY BUDGET CATEGORY

Distribution of Building Types by Budget Category



We also examined monthly peak demand reductions relative to system capacity by calculating the difference between the highest 15-minute demand (kW) in the absence of storage – the counterfactual baseline – and the highest metered 15-minute demand during each customer’s billing period. Verdant then normalized that difference by the kW capacity of the system. A customer would realize billed demand savings if the difference between the observed and baseline was positive. It also signals the maximum system capacity used for noncoincident demand reduction. For example, where monthly baseline load would have been 100 kW in the absence of storage and the peak observed load was 80, that delta represents the change in billed demand of 20 kW. If this demand reduction was serviced by a 20-kW system – which would be discharging at full capacity in this example – the reduction would represent 100% of capacity. With a 100-kW system, utilization would be at 20% of capacity.

Figure 4-59 conveys those results for the nonresidential sector by month and budget category. We observe variability in average customer peak demand reductions (and increases) across budget category and throughout the year. Storage equity projects realize the greatest monthly demand reductions as a percentage of system kW capacity, ranging from 8% of rebated capacity to 15%. Older systems (labeled 2017 Prior) exhibit much lower monthly demand reductions – ranging from 4% of kW capacity to 7%. Equity Resiliency projects increase load, on average. This is consistent with the more prevalent increase in load during those months presented.

FIGURE 4-59: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

Nonresidential Monthly Peak Demand Reductions (+) Increases (-) per kW Capacity

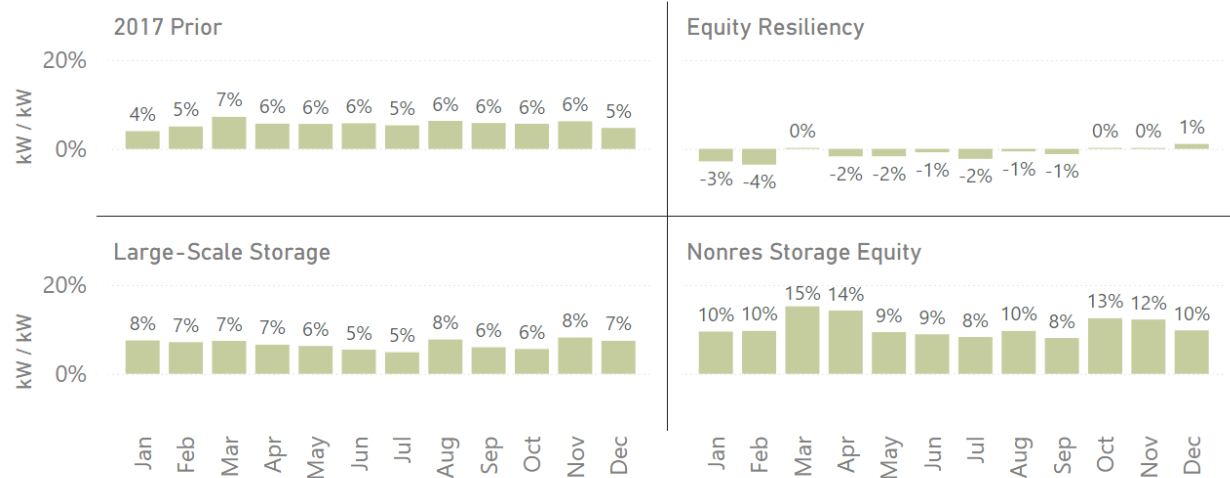
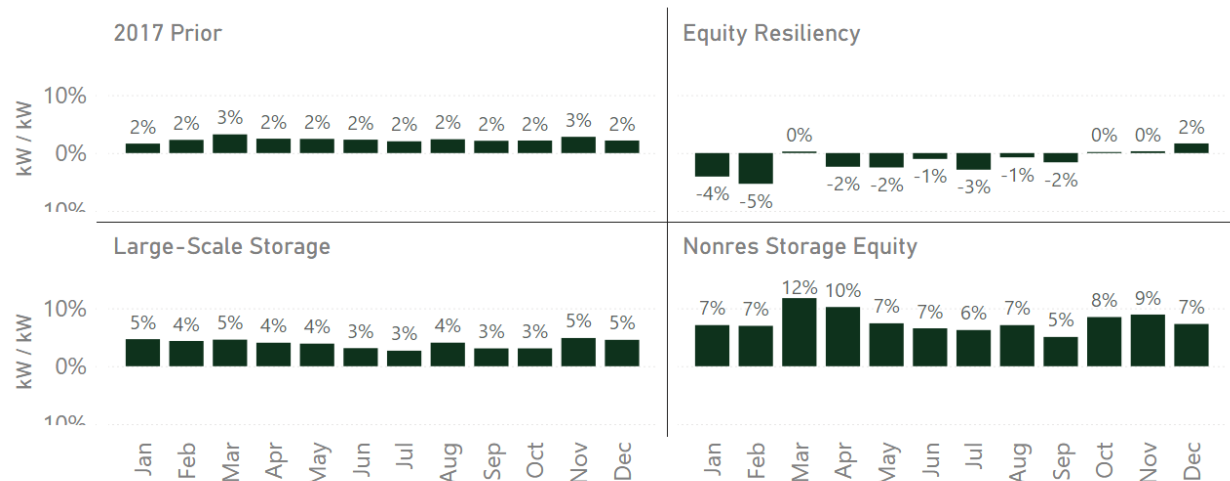


Figure 4-60 conveys the monthly average peak demand reduction as a percentage of a customer's monthly avoided peak. An example case is, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system and they reduced peak demand by 10 kW with storage discharge, then the customer reduced their peak demand by 10%. Greater percentages would indicate an energy storage system that is sized closer to facility peak loads.

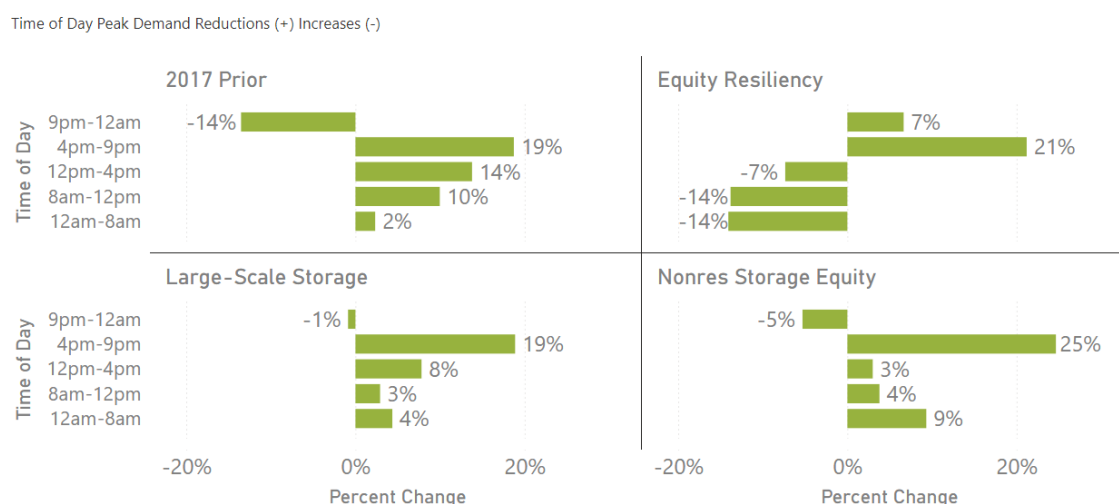
FIGURE 4-60: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

Nonresidential Monthly Peak Demand Reductions (+) Increases (-) per Avoided Peak (kW)



Verdant also reviewed changes in monthly demand by time of day. While older vintage projects (2017 Prior) and systems installed via the equity or large-scale storage budget category reduced monthly demand, on average, we do observe variations in summer peak demand by time of day. For example, equity projects reduced demand during most hours of the day, but a 5% increase in demand was observed during the 9 p.m. – 12 a.m. hours. This is true for older vintage systems and large-scale storage projects. This reflects customers charging the system just after the on-peak period. Equity Resiliency projects – which are medium duration systems – discharge on-peak, but that discharge extends beyond that period through to midnight.

FIGURE 4-61: SUMMER PEAK DEMAND REDUCTIONS BY TIME OF DAY



Residential Bill Savings (\$/kWh)

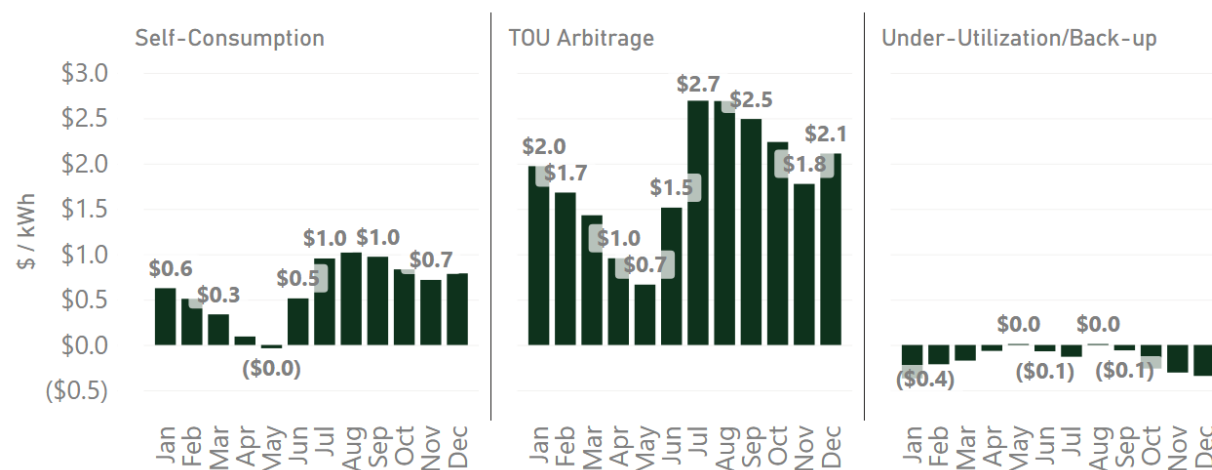
Self-consumption provides less of an economic benefit to customers than systems specifically operating to generate bill savings for customers. This is evident in Figure 4-62. Furthermore, idle and under-utilized systems unsurprisingly incur small bill increases due to under-utilization and round-trip efficiency (RTE) losses. TOU arbitrage and self-consumption provide billed savings across each month of 2024, but systems performing arbitrage realize the greatest savings, particularly during July through September, when savings exceed \$2.70/kWh.

Spring months like April and May exhibit the least savings on average. During those months, many customers have not transitioned to higher on-peak energy rates, and greater on-/off-peak price differentials. Billed rates, combined with significant on-site solar generation with temperatures that preclude A/C and other high demand end uses, allow customers to arbitrage or self-consume at lower utilization. If the system is zeroing out delivered load, and is not exporting, billed savings for these months could be less relative to a baseline (or counterfactual) of no storage. On average, residential systems

performing solar self-consumption are providing customers with \$7/kWh capacity of bill savings (roughly \$160 annually), while systems conducting arbitrage provide customer bill savings of more than \$22/kWh or \$440 annually. Customers with under-utilized systems or those in backup mode realize modest bill increases of roughly \$2/kWh or \$50 annually.

FIGURE 4-62: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND OPERATING MODE

Observed Residential Monthly Bill Savings per kWh Capacity (by Operating Mode)



Monthly residential bill impacts are also summarized in Figure 4-63 for standalone systems and those paired with PV. PV paired systems are further disaggregated by source of battery charging (from solar or from grid). We observe monthly bill savings for residential customers ranging from as high as \$3.40/kWh in September 2024 to as low as no bill savings in May 2024 for paired systems charging from grid. These systems generate the greatest bill savings for customers with greater utilization and focused discharging during on-peak hours only (Figure 4-47 and Figure 4-53 above). Average annual bill savings are roughly \$26/kWh of capacity (or \$676, assuming an average capacity of 26 kWh). PV paired systems charging from solar realize bill savings as well but given the lower average utilization and reduced bill credits associated with charging from solar that otherwise could be exported, annual savings are less than systems foregoing charging from PV to charge overnight from grid resources.

As discussed above, self-consumption is the most prominent operating mode in the residential sector, so discharge outside of on-peak hours doesn't provide the same savings as arbitraging over the highest priced hours exclusively. Standalone systems are generally under-utilized compared to PV paired systems and provide the least bill savings.

FIGURE 4-63: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND PV PAIRING

Observed Residential Monthly Bill Savings per kWh Capacity (by Charging Source)

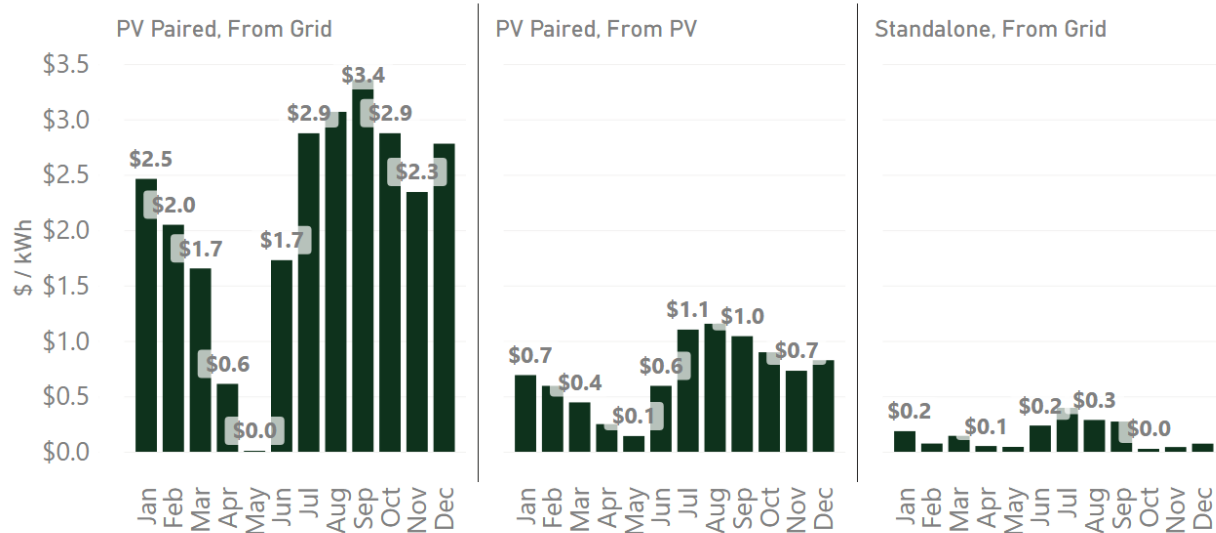


Figure 4-64 exhibits average monthly bill savings by IOU. For systems receiving electric service from each IOU, bill savings are generally greater in summer months, but we observe differences across IOUs. Systems receiving electric service from PG&E realize lesser savings, overall, with most bill savings realized by customers on the EV-2A rate (roughly \$12/kwh annually). Most savings for SDG&E systems are realized from July to October inclusive with the greatest magnitude of savings realized by customers on DR-SES (roughly \$8/kWh annually) and EV-TOU-5 (roughly \$21/kWh annually). Higher on-/off peak differentials in SCE, especially with the TOU-D-Prime rate (\$23/kWh average annual savings), might explain the more consistent bill savings for SCE customers during the year. Average bill savings by rate schedule and IOU are summarized below in Figure 4-78.

Average bill savings by budget category are also provided in Figure 4-65. Almost 80% of San Joaquin Valley budget installations were standalone – a significant departure from the standalone system percentage in other budget categories (~3%). As noted previously, standalone systems were utilizing roughly 20% of available capacity daily during summer months, which corresponds to the reduced bill savings observed compared to other budget categories.

FIGURE 4-64: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND IOU

Observed Residential Monthly Bill Savings per kWh Capacity (by IOU)

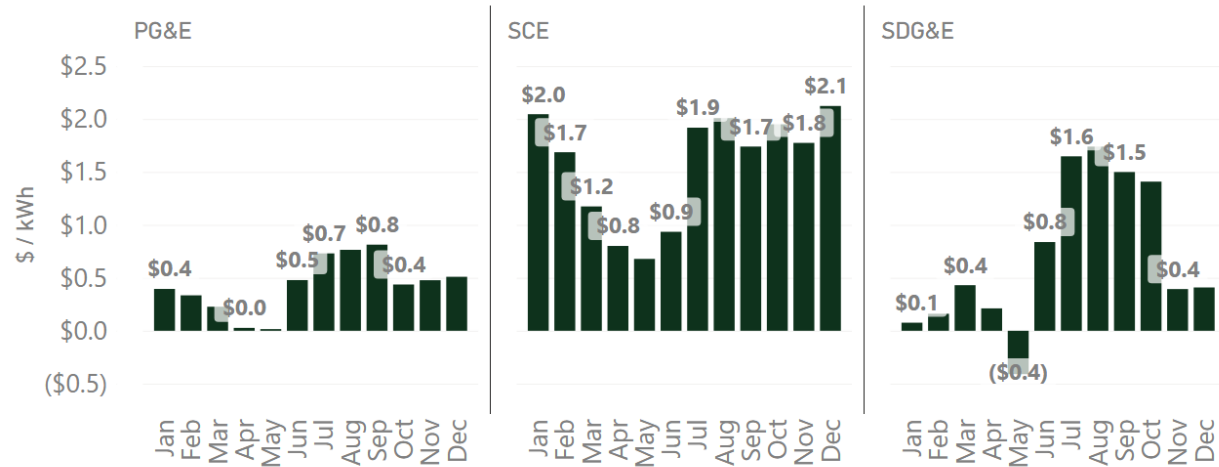
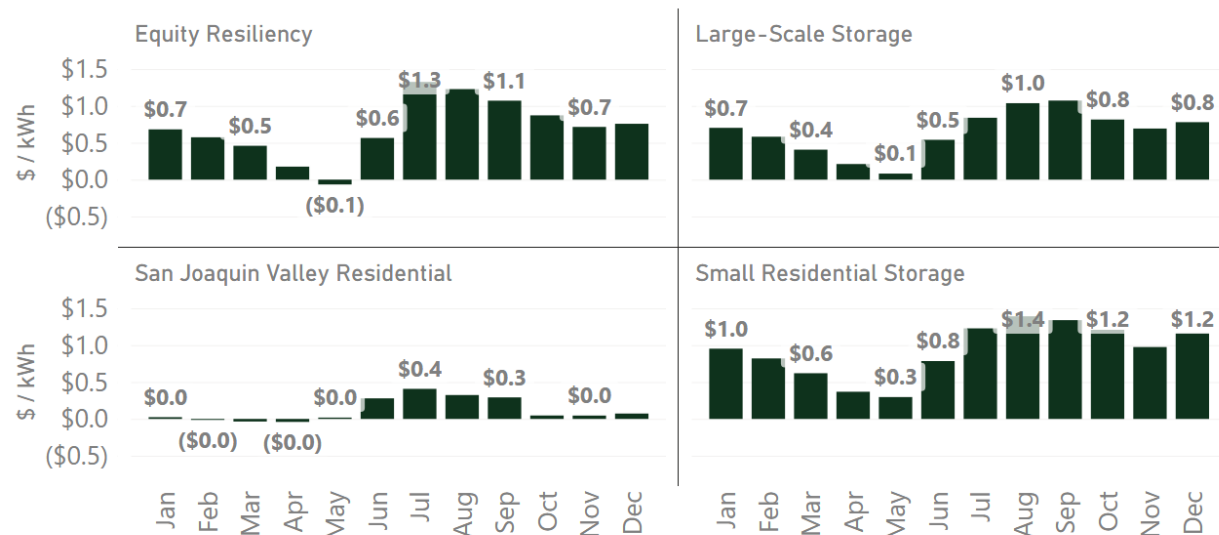


FIGURE 4-65: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND BUDGET CATEGORY

Observed Residential Monthly Bill Savings per kWh Capacity (by Budget Category)

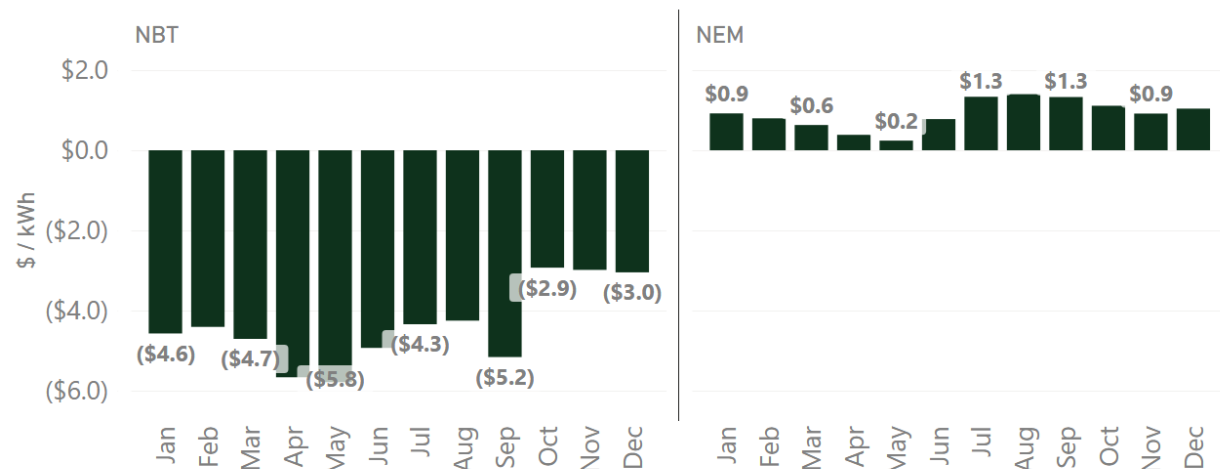


Average monthly bill impacts have also been summarized based on customer tariff (Figure 4-66). The Net Billing Tariff (NBT) replaced the previous Net Energy Metering (NEM) tariff for new solar interconnection applications after 4/14/2023. While the NBT structure is like NEM – where customers receive credits for excess solar generated and exported back to the grid – the export compensation is much less for NBT customers. Furthermore, beginning in June 2024, all general market SGIP applicants installing new storage

paired with existing solar are required to enroll in the NBT. Given the significantly lower export compensation associated with NBT, one would expect customers on NBT to utilize their energy storage system differently than a NEM customer. From a purely economic perspective, one would expect energy storage systems to absorb more excess solar generation under NBT. An increase in on-site solar generation charging would then translate over to greater utilization as a lower end of day state of charge (SOC) would allow for greater solar charging (and less export). However, a majority of SGIP participants (including both NEM and NBT) are conducting solar self-consumption already, so we don't observe significant differences in daily storage charge/discharge timing and magnitudes for customers on NBT relative to NEM customers. As a result, SGIP participants transitioning from NEM 1.0 or 2.0 to NBT realize billed energy increases, given the lower export compensation – and independent of the energy storage system performance or utilization.⁴³

FIGURE 4-66: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND TARIFF TYPE

Observed Residential Monthly Bill Savings per kWh Capacity (by Tariff Type)



From a customer sector perspective, residential energy storage dispatch provided roughly \$9/kWh of capacity in annual savings in 2024, on average. However, as mentioned previously, those bill impacts vary considerably by system operating mode and utilization, customer pre-and post-rate, NEM vs NBT, and budget category. To highlight that variability, project-specific bill impacts are provided in Figure 4-67 through Figure 4-70 for each of the scenarios presented. The scatter plots communicate the distribution

⁴³ While the NBT bill increases are expected compared to the more favorable export compensation (credit) under NEM, the NBT sample size was much smaller in 2024 given the timing of the statewide roll-out and the SGIP requirement in June 2024 (31 of the total 1,756 systems evaluated in the bill impact analysis).

of those impacts across different cohorts of customer classes, along with how those bills are correlated with system utilization. The horizontal axis represents the bill savings (+) normalized by system kWh capacity, and the vertical axis highlights the utilization – measured in annual cycles – for each project. Bill savings, for the most part, are positively correlated with increased utilization – especially during summer months, when higher on- to off-peak price differentials allow for greater arbitrage opportunities. The size of each project circle also corresponds to the relative size of the energy storage systems measured.

FIGURE 4-67: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY OPERATING MODE

Bill Savings \$/kWh (+) and Utilization by Operating Mode

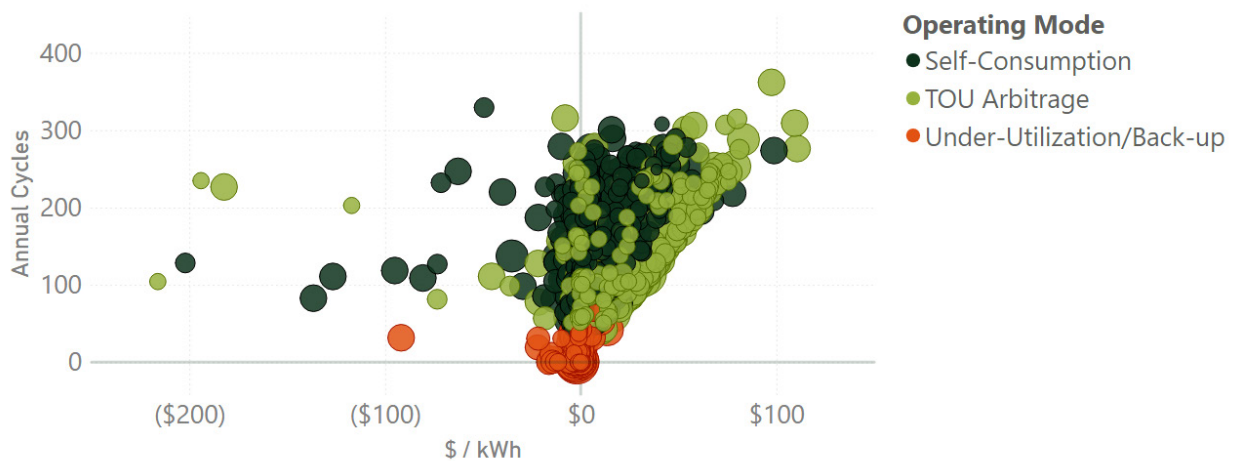


FIGURE 4-68: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY IOU

Bill Savings \$/kWh (+) and Utilization by IOU

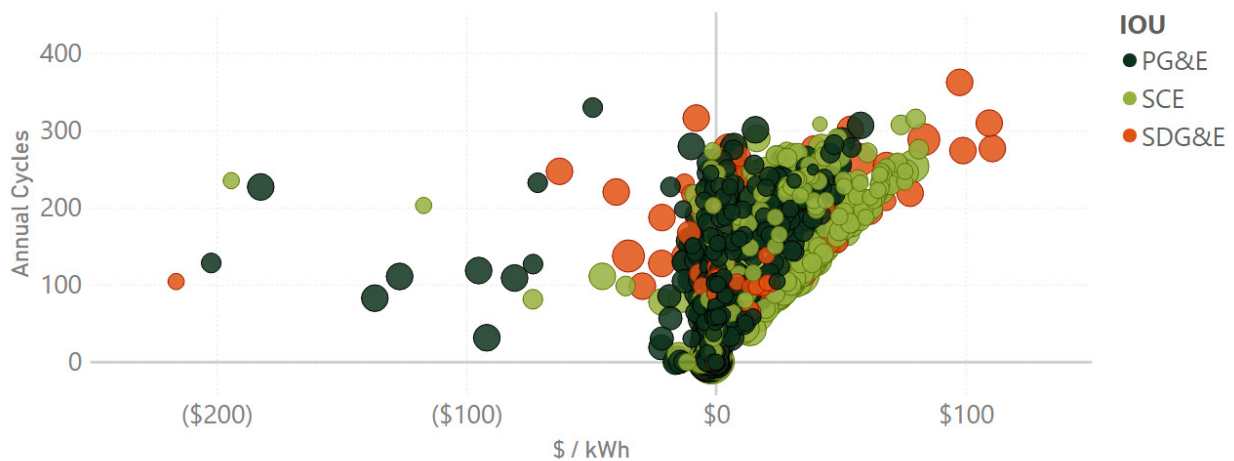


FIGURE 4-69: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY BUDGET CATEGORY

Bill Savings \$/kWh (+) and Utilization by Budget Category

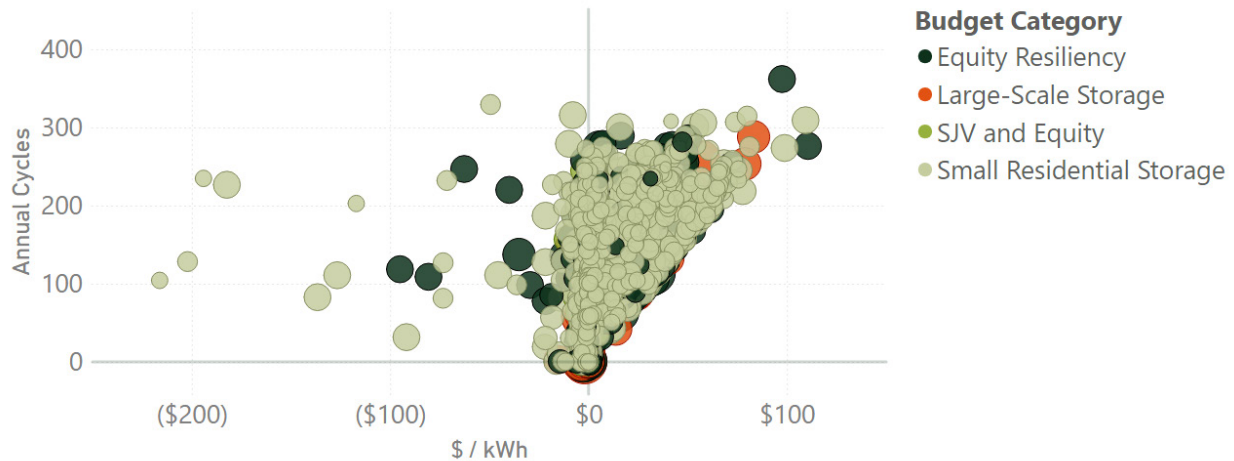
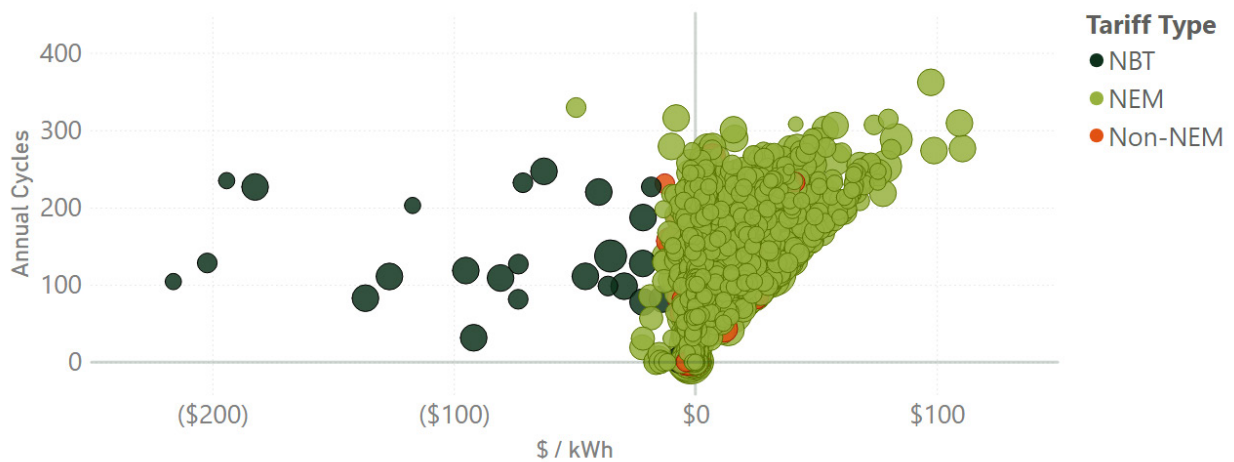


FIGURE 4-70: RESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY TARIFF TYPE

Bill Savings \$/kWh (+) and Utilization by Tariff Type



Nonresidential Bill Savings (\$/kWh)

Verdant compared the observed billed energy for each TOU period to baseline billed energy impacts. For customers with demand charges, we further estimated the reduction (or increase) in peak demand at a monthly level and during specific TOU periods to calculate demand savings (or increased cost) based on the customer rate schedule. A customer could realize bill savings if they are arbitraging – discharging during on-peak TOU and charging during periods of lower prices – and the price differential between on-



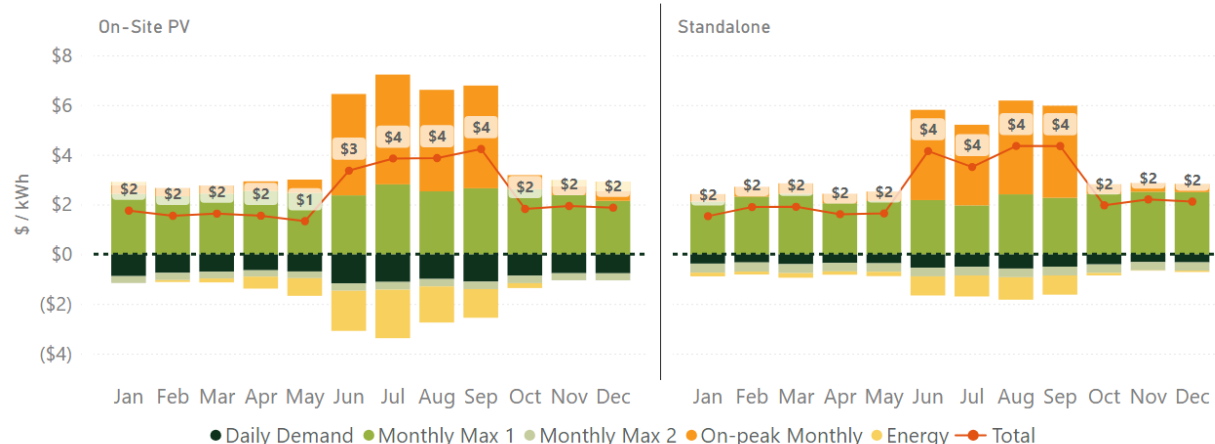
and off-peak is sufficient to negate RTE losses. Demand charge savings are realized at the monthly, on-peak, or daily period and may be prioritized at the expense of TOU energy arbitrage. Nonresidential bill components modeled in this study include:

- **Daily demand** – a daily on-peak and partial-peak demand charge assessed to medium and large nonresidential PG&E customers with energy storage (Option S). The daily demand charge replaces the per month peak and off-peak demand charge
- **Monthly Max 1** – the standard maximum monthly non-coincident demand charge. For Option S customers, this demand charge is reduced dramatically compared to an equivalent non-Option S rate in PG&E
- **Monthly Max 2** – a monthly demand charge assessed to PG&E Option S customers only (but excludes hours between 9 a.m. – 2 p.m.)
- **On-Peak Monthly** – a monthly maximum demand charge assessed during on-peak and partial-peak (where applicable) periods as defined by the customer rate
- **Energy** – the total energy component billed during the month
- **Total** – the sum of the bill parts.

Figure 4-71 presents the results for nonresidential customers by month and presence of on-site PV generation. The vertical axis represents the average monthly savings (+) or bill increases (-) in dollars, normalized by the capacity kWh of the storage system. On average, nonresidential storage dispatch behavior allowed customers to realize overall bill savings for each month of 2024. Bill savings are greatest during summer months for both PV paired and standalone systems, with overall savings of roughly \$4/kWh of capacity during each of those months. Most of those bill savings are realized on the on-peak and monthly demand charge components of the bill (orange and green bars). Negative bill components represent bill increases. These bill increases generally impact customers on the daily demand charge rate (Option S in PG&E service territory). The modeling for customers enrolled on Option S assumes a similar non-Option S rate in the baseline, because the Option S rate requires storage. The baseline or counterfactual for bill impacts assumes no storage – so bill savings for these customers combine the impacts from both the rate change and the energy storage utilization in the post-period. The non-Option S rates don't have a daily demand or the Monthly Max 2 demand charge, so those charges are assessed only on the post-retrofit bill for Option S customers. Furthermore, daily volumetric energy charges are greater on Option S, compared to an equivalent non-Option S rate, which is why energy costs (or yellow bars) are negative. However, despite those additional bill components, customers realize billed savings from the greatly reduced on-peak and monthly demand charge reductions.

FIGURE 4-71: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND PV PAIRING

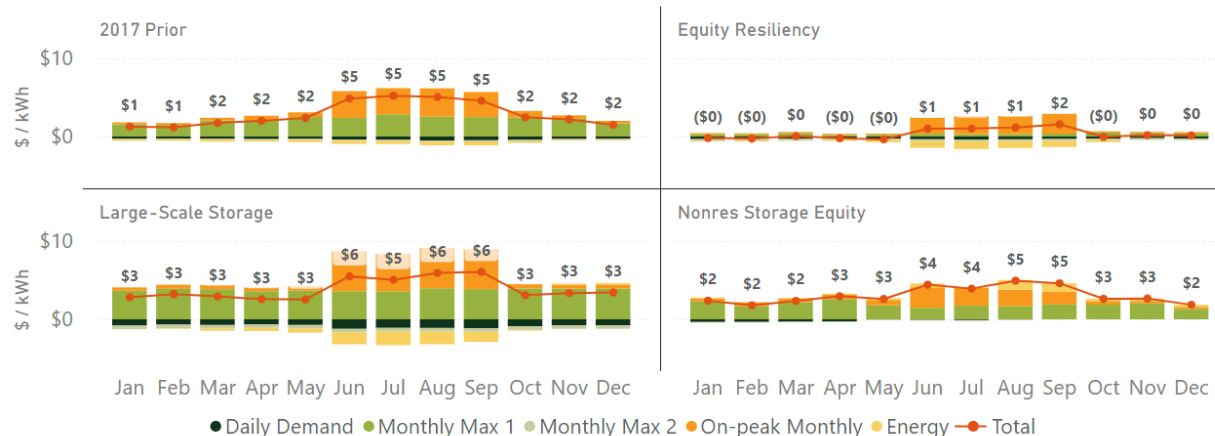
Observed Nonresidential Monthly Bill Savings per kWh Capacity (by On-site Generation)



Average monthly bill impacts were also developed by budget (Figure 4-72). We observe many customers increase their non-coincident monthly peak demand in the ERB – with medium duration energy storage systems discharging from 1 p.m. to 12 a.m. during summer months. Discharging exclusively during that period also leads to reductions in peak and partial-peak demand (orange bars above). While other budget categories realize maximum monthly demand reductions (non-coincident demand), ERB projects incur increases on that component of the bill. Charging overnight typically leads to a new maximum, which translates over to the observed bill increase on the maximum/non-coincident peak (non-coincident demand and the green bar).

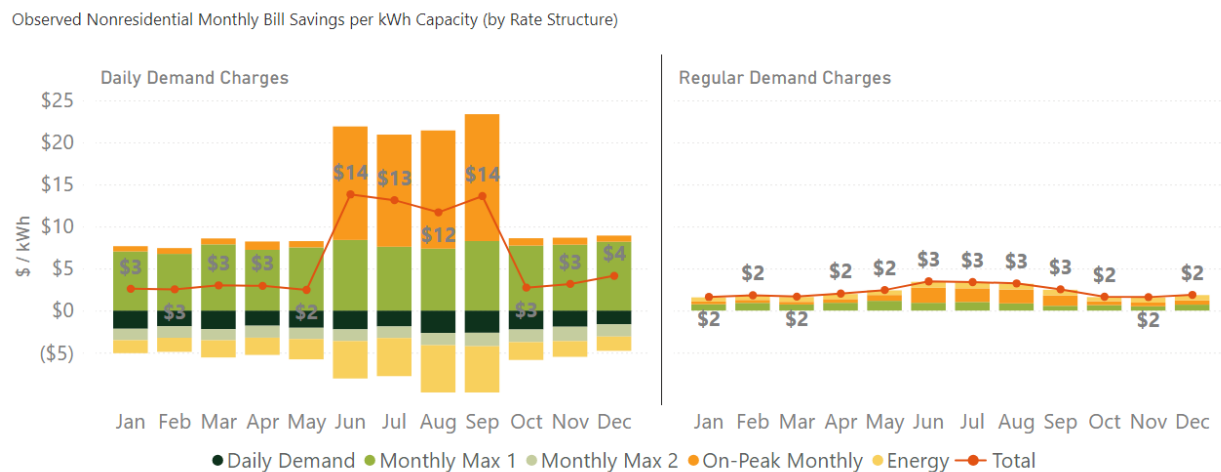
FIGURE 4-72: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND BUDGET CATEGORY

Observed Nonresidential Monthly Bill Savings per kWh Capacity (by Budget Category)



We also differentiate bill impacts by those assessed daily demand charges compared to those assessed regular per month demand charges only (Figure 4-73). Both rate groups contribute to a reduction in customer bills based on the magnitude and timing of energy storage charge and discharge behavior, along with the charges associated with the pre- and post-bills. Customers with daily demand charges realized far more significant bill savings, which may be driven by the more forgiving rate structure compared to the base schedule as well as the impacts from storage charge and discharge performance in the post-bill.

FIGURE 4-73: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY MONTH AND PV PAIRING



Overall, nonresidential energy storage dispatch provided roughly \$33/kWh of capacity in annual savings in 2024, on average. However, as mentioned previously, those bill impacts vary considerably by system operating mode and utilization, customer pre-and post-rate, budget category, and system size.

To highlight that variability, project-specific bill impacts are provided for each of the scenarios in Figure 4-74 through Figure 4-76. The scatter plots communicate the distribution of those impacts across different cohorts of customer classes, along with how those bills are correlated with system utilization. The horizontal axis represents the bill savings (+) normalized by system kWh capacity, and the vertical axis highlights the utilization – measured in annual cycles – for each project.

Bill savings, for the most part, are positively correlated with increased utilization – especially during summer months, when higher demand charges provide opportunities to discharge the battery more strategically. The size of each project circle also corresponds to the relative size of the energy storage systems measured in kWh capacity. These differences are more discernible in the nonresidential sector than in the residential sector, given the more significant range in capacities. Also, it's important to note the minor differences in bill savings for standalone systems compared to those paired or co-located with

PV. This is a very different outcome compared to the residential sector where lower utilization and RTE losses contributed to lower bill savings from standalone systems.

FIGURE 4-74: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY ON-SITE GENERATION

Bill Savings \$/kWh (+) and Utilization by Presence of On-Site Generation

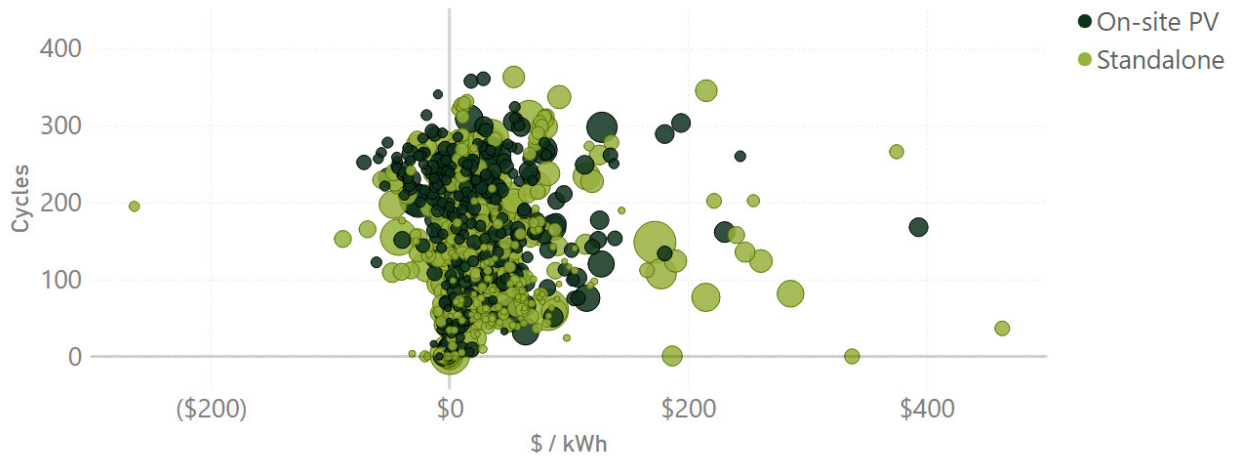


FIGURE 4-75: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY BUDGET CATEGORY

Bill Savings \$/kWh (+) and Utilization by Budget Category

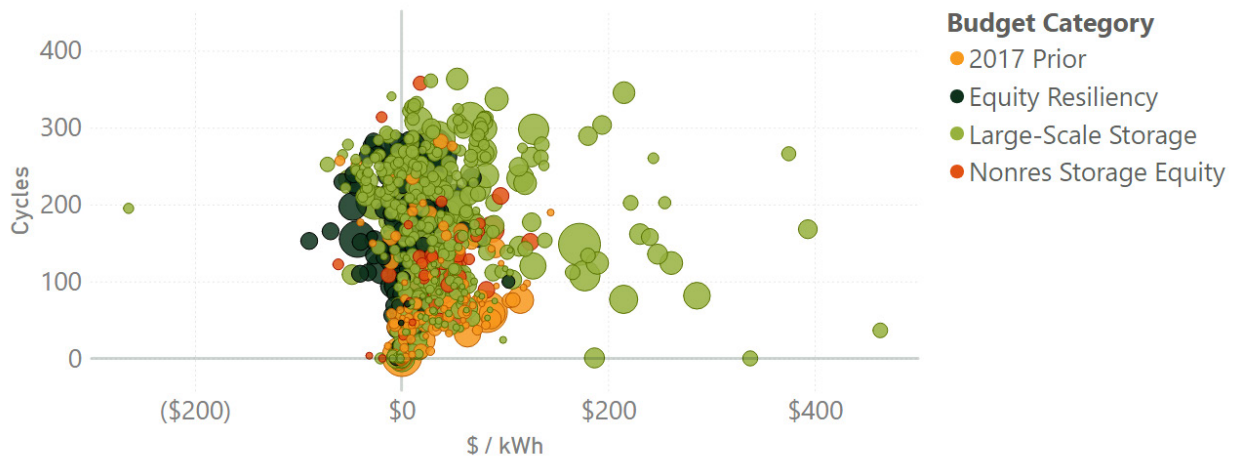
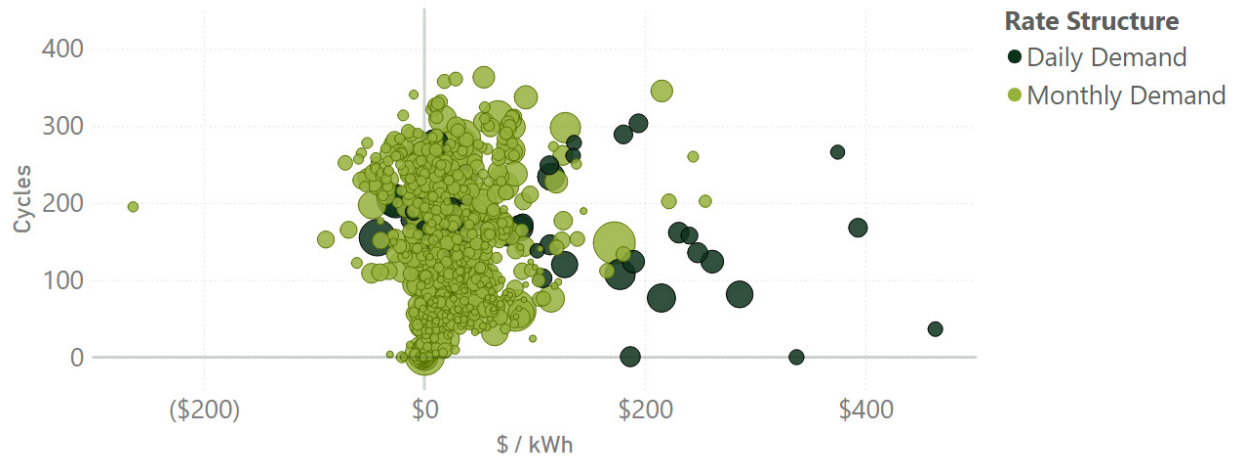


FIGURE 4-76: NONRESIDENTIAL CUSTOMER BILL SAVINGS (\$/KWH) BY RATE STRUCTURE

Bill Savings \$/kWh (+) and Utilization by Rate Structure



Energy Storage Bill Impact Summaries

The following figures summarize bill impacts for 2024 by different groupings for the sampled residential and nonresidential sectors. Also included are the total count of projects modeled for the bill impacts. These counts may be different than ones presented in other sections of the report, given the fact that we might not have known the customer rate or the customer may have received electricity service from a non-IOU. Furthermore, all bill impacts are presented in dollars per kWh of energy storage capacity to provide normalized results across different system sizes and configurations.

FIGURE 4-77: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY IOU

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs
BY IOU

IOU	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
PG&E	974	\$78	\$73	\$5
SCE	515	\$99	\$80	\$19
SDG&E	267	\$59	\$51	\$9
Overall	1756	\$80	\$71	\$9

FIGURE 4-78: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY IOU AND RATE

n Prjs, Pre-Bill, Post-Bill, Total Bill Impact

BY IOU, RATE GROUP

IOU	Rate Group	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
PG&E	All Others	28	\$46	\$82	(\$35)
PG&E	E-1	20	\$133	\$137	(\$4)
PG&E	E-TOU-C	332	\$75	\$75	(\$1)
PG&E	E-TOU-D	36	\$143	\$144	(\$2)
PG&E	EV-2A	539	\$75	\$63	\$12
PG&E	EV-A	19	\$62	\$55	\$7
SCE	D	15	\$41	\$43	(\$2)
SCE	TOU-D (4-9)	86	\$108	\$98	\$10
SCE	TOU-D (5-8)	65	\$76	\$64	\$13
SCE	TOU-D-PRIME	349	\$104	\$81	\$23
SDG&E	All Others	28	\$41	\$41	\$1
SDG&E	DRSES	65	\$54	\$46	\$8
SDG&E	EV-TOU-2	16	\$54	\$42	\$12
SDG&E	EV-TOU-5	48	\$62	\$41	\$21
SDG&E	TOU-DR1	110	\$64	\$60	\$4
Overall		1756	\$80	\$71	\$9

FIGURE 4-79: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY ON-SITE GENERATION

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY ON-SITE GENERATION

On-site Generation	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
PV Paired	1704	\$78	\$68	\$10
Standalone	52	\$153	\$151	\$2
Overall	1756	\$80	\$71	\$9

FIGURE 4-80: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY TARIFF TYPE

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY TARIFF TYPE

Tariff Type	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
NBT	31	\$78	\$131	(\$53)
NEM	1669	\$78	\$67	\$11
Non-NEM	56	\$144	\$142	\$3
Overall	1756	\$80	\$71	\$9

FIGURE 4-81: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY PAYMENT YEAR

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY PAYMENT YEAR

Payment Year	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
2018	112	\$137	\$127	\$10
2019	145	\$97	\$87	\$9
2020	229	\$97	\$85	\$12
2021	544	\$80	\$69	\$10
2022	396	\$74	\$66	\$8
2023	294	\$60	\$50	\$10
2024	36	\$50	\$51	(\$1)
Overall	1756	\$80	\$71	\$9

FIGURE 4-82: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY BUDGET CATEGORY

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY BUDGET CATEGORY

Budget Category	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
Equity Resiliency	542	\$68	\$60	\$8
Large-Scale Storage	92	\$70	\$62	\$8
SVJ and Equity	46	\$111	\$108	\$2
Small Residential Storage	1076	\$91	\$80	\$11
Overall	1756	\$80	\$71	\$9

FIGURE 4-83: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY CHARGING SOURCE

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY ON-SITE GENERATION, CHARGING SOURCE

On-site Generation	Charging Source	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
PV Paired	From Grid	105	\$119	\$94	\$26
PV Paired	From PV	1599	\$75	\$66	\$8
Standalone	From Grid	52	\$153	\$151	\$2
Overall		1756	\$80	\$71	\$9

FIGURE 4-84: SUMMARY OF 2024 RESIDENTIAL BILL IMPACTS BY OPERATING MODE

Post-Bill, Pre-Bill, Total Bill Impact, n Prjs

BY OPERATING MODE

Operating Mode	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
Other/Unknown	8	\$126	\$129	(\$4)
Self-Consumption	1100	\$62	\$55	\$7
TOU Arbitrage	437	\$115	\$93	\$22
Under-Utilization/Back-up	211	\$107	\$109	(\$2)
Overall	1756	\$80	\$71	\$9

FIGURE 4-85: SUMMARY OF 2024 NONRESIDENTIAL BILL IMPACTS BY IOU AND RATE STRUCTURE

n Prj, Monthly, Daily, Non-Coincident, Peak, Energy, Total Bill

BY IOU, RATE GROUP

IOU	Rate Group	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill	
PG&E	Daily Demand	59	(\$27)	(\$49)		\$129	\$78	(\$61)	\$70
PG&E	Monthly Demand	278	\$0	\$0		\$4	\$8	\$0	\$11
SCE	Monthly Demand	391	\$0	\$0		\$17	\$10	\$6	\$33
SDG&E	Monthly Demand	139	\$0	\$0		\$8	\$7	\$10	\$25
Overall		867	(\$4)	(\$8)		\$31	\$20	(\$6)	\$33

FIGURE 4-86: SUMMARY OF 2024 NONRESIDENTIAL BILL IMPACTS BY ON-SITE GENERATION

n Prj, Monthly, Daily, Non-Coincident, Peak, Energy, Total Bill
BY ON-SITE GENERATION

On-site Generation	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
On-site PV	354	(\$4)	(\$11)		\$32	\$22	(\$8) \$31
Standalone	514	(\$5)	(\$5)		\$30	\$19	(\$5) \$34
Overall	868	(\$4)	(\$8)		\$31	\$20	(\$6) \$33

FIGURE 4-87: SUMMARY OF 2024 NONRESIDENTIAL BILL IMPACTS BY BUDGET CATEGORY

n Prj, Monthly, Daily, Non-Coincident, Peak, Energy, Total Bill
BY BUDGET CATEGORY

Budget Category	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
2017 Prior	124	(\$2)	(\$4)		\$27	\$18	(\$3) \$36
Equity Resiliency	154	(\$3)	(\$4)		\$5	\$12	(\$5) \$5
Large-Scale Storage	540	(\$6)	(\$11)		\$49	\$27	(\$8) \$51
Nonres Storage Equity	50	(\$1)	(\$1)		\$23	\$13	\$5 \$38
Overall	868	(\$4)	(\$8)		\$31	\$20	(\$6) \$33

4.2.2 Generation

The operational characteristics of several generation technologies influence their impact on customer operations and energy bills. Wind turbines and pressure reduction turbines differ from the others due to the nature of their energy inputs. The supply of wind energy varies with weather, while the supply of steam may vary with facility production levels. Generation technologies relying on gaseous fuels are designed to operate with higher capacity factors and thus offer more potential for consistently impacting noncoincident facility peak demand levels that factor into the calculation of billed demand charges on electricity bills. The following section presents the impacts of generation systems on customer noncoincident peak demand and electricity exports.

Customer Noncoincident Peak Demand

SGIP projects impact customer demand in addition to the system (IOU or CAISO) coincident peak demand. It is not always the case that a customer's peak demand falls on the CAISO or IOU peak load hour. The peak customer demand during any stated period is called the customer noncoincident peak (NCP) demand. The impact on a customer's annual peak demand is an important element of the total impact an



SGIP system has on a customer's load throughout the year. The demand portion of customer bills is based on the monthly peak kW. Thus, in addition to the reduction in annual peak demand, the monthly demand reduction illustrates how SGIP impacts customer electricity costs.

Approach for Customer Noncoincident Peak Demand Impacts

To analyze the impact of SGIP on customer NCP demand, the available utility Advanced Metering Infrastructure (AMI) load data and the generation data are aligned on an hourly basis. The gross demand without the presence of the SGIP generation is then calculated as:⁴⁴

$$\text{Gross Load } (\overline{kW}) = \text{Metered Load} + \text{Generation} - \text{Exported} \quad \text{EQUATION 4-4}$$

$$\text{Net Load } (\overline{kW}) = \text{Metered Load} \quad \text{EQUATION 4-5}$$

The potential impact of SGIP generators on gross and net load can be seen graphically in the following figures. Figure 4-88 shows an example of how metered NCP customer demand, represented by net load, is reduced by SGIP generation. During 2024, the maximum electrical generation brought the maximum gross peak down, on average, by as much as 87% of rebated capacity. Figure 4-89 illustrates the impact an SGIP generator outage has on NCP customer demand. Depending on the customer load profile, net load during a generator outage or period of reduced electrical production may set the monthly or annual peak demand.

⁴⁴ For this analysis, demand is calculated as the average power draw within a one-hour period. This is an approximate calculation, as demand is measured in 15-minute intervals and may differ from the hourly average.

FIGURE 4-88: EXAMPLE DEMAND IMPACTS FROM GENERATOR

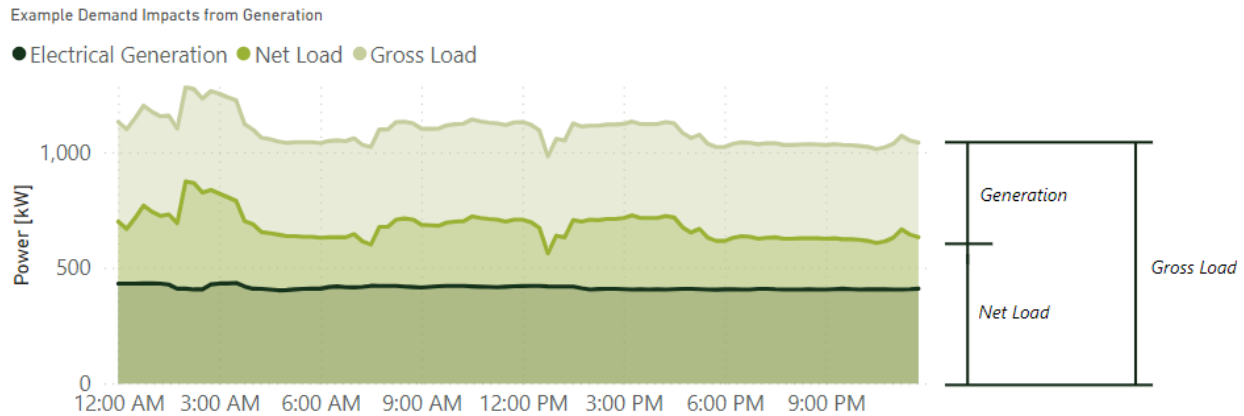
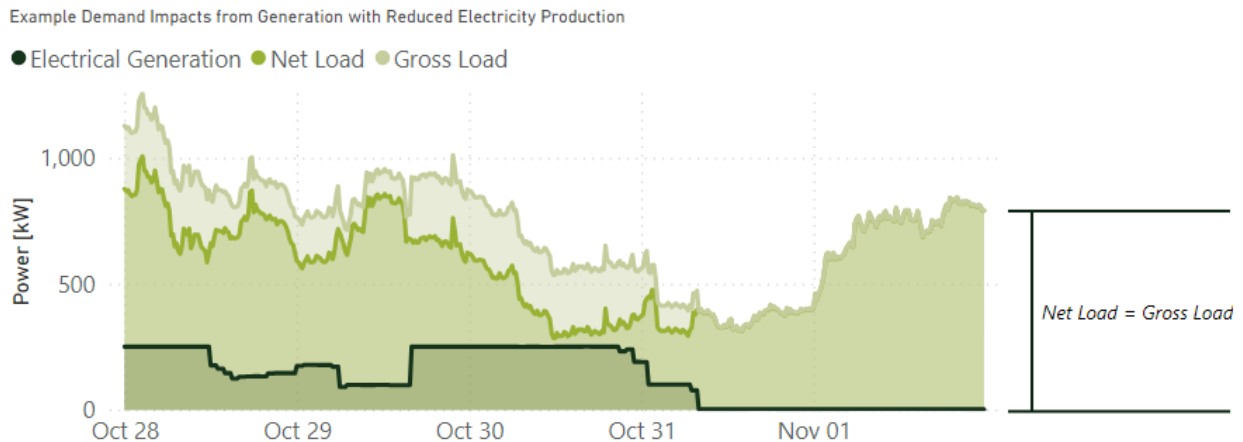


FIGURE 4-89: EXAMPLE DEMAND IMPACTS FROM GENERATOR WITH REDUCED ELECTRICITY PRODUCTION



Average NCP Customer Demand Impacts

The weighted average impacts of generation technologies on NCP customer monthly maximum demand are shown in Figure 4-90 as a proportion of rebated capacity. Electric fuel cell projects, on average, provided customer monthly peak demand savings equal to 88% of rebated capacity, a significant increase from the last evaluation that only saw an observed monthly peak reduction of 41% per rebated capacity. In other words, a customer with a -100-kW fuel cell would see a reduction of their net load of about 88 kW during their monthly peak load hours. Internal combustion engines and microturbines, on average, saw similar results to last year's evaluation, with 73% and 53% customer peak load reduction per rebated capacity. There was insufficient data for wind and gas turbines to be able to provide a noncoincident demand analysis for these technologies.

Figure 4-91 shows the same information at the monthly level. Microturbines and internal combustion engines show the greatest monthly variations. While it's difficult to tell the exact reason for variations in operation, many of these variations appear to be due more to differences in site-specific operation than technology-specific use cases. Although generation systems generally provide a baseload, technologies like microturbines and internal combustion engines are easier to ramp up and down than fuel cells and therefore do have the ability to be shut down or run at a reduced capacity when not needed. Seasonal variations could also be due to unexpected disruptions in facility or SGIP system operations.

FIGURE 4-90: OBSERVED AVERAGE MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY

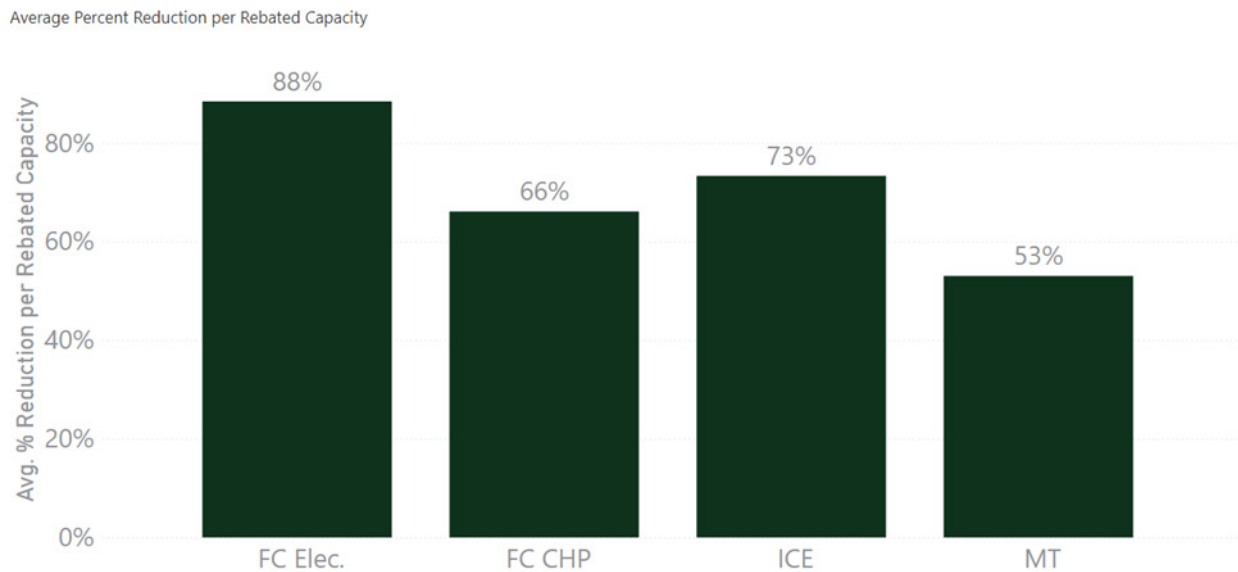
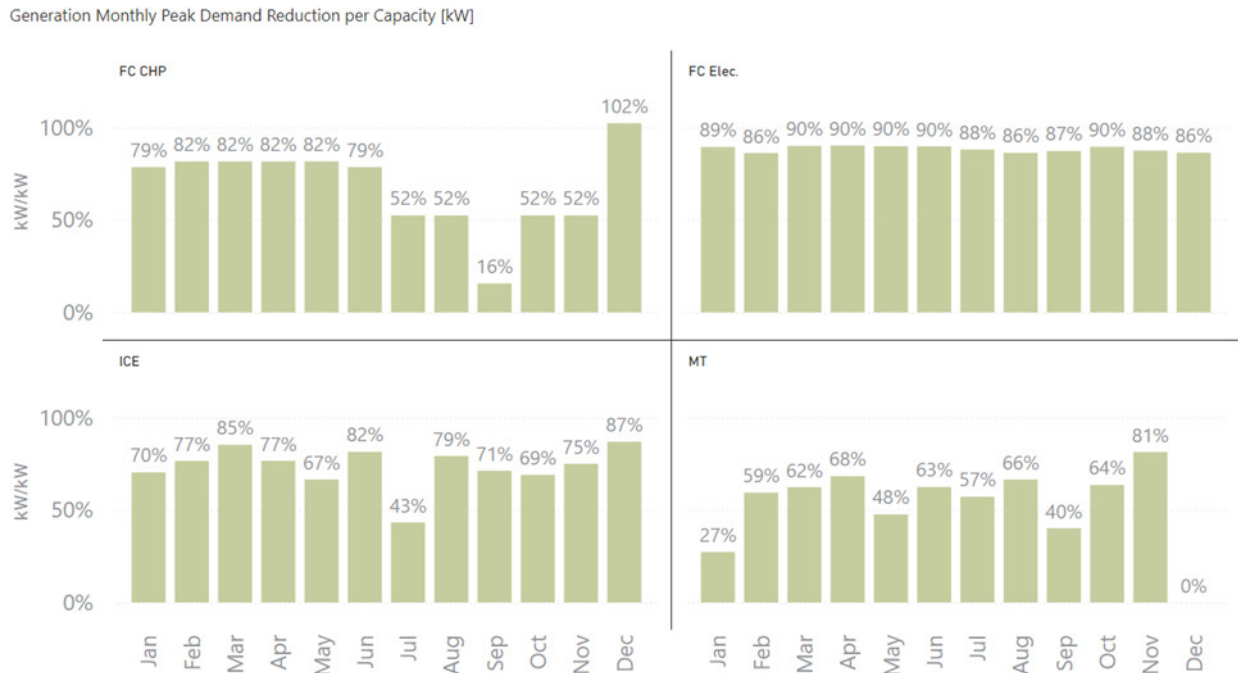


FIGURE 4-91: OBSERVED MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY



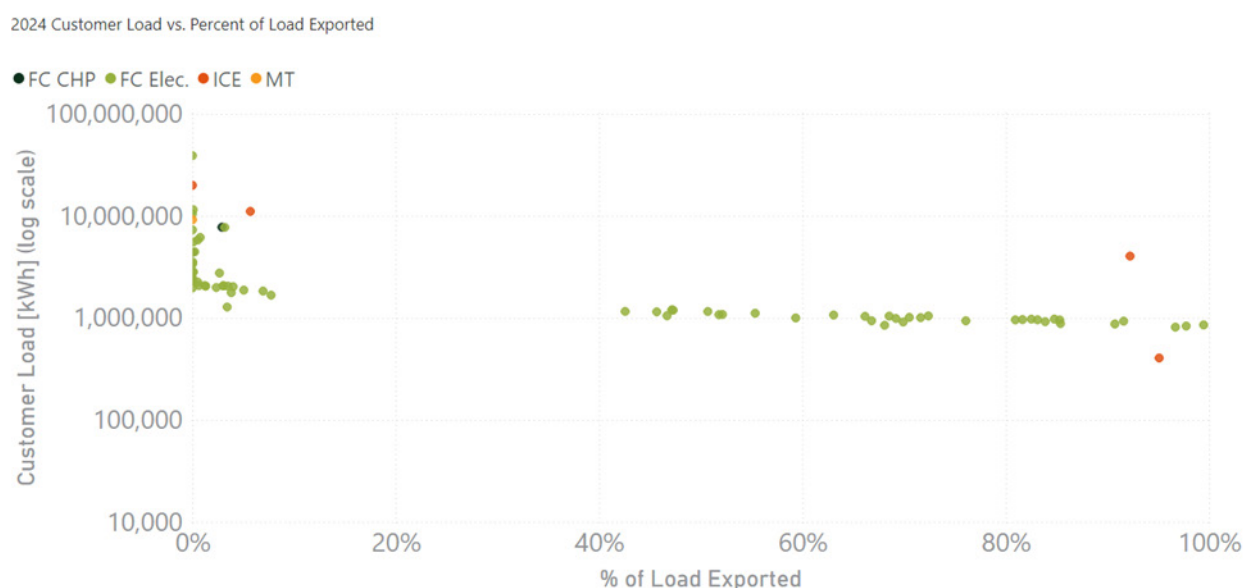
Generation Export

Electricity generation systems are generally designed to be base loaded, meaning they are operated to generate enough electricity to cover the base load needs of a customer. Since at least PY 2011, the SGIP Program Handbook allows SGIP incentivized systems to export a maximum of 25% of their on-site consumption to the grid, on an annual basis. The SGIP handbook clarifies that the PBI payment is calculated based on the generated electricity consumed on-site, and that proof of export documentation may be required prior to payment. However, the handbook doesn't specifically call out projects that have completed their PBI requirements. Twenty-six percent of the observed sites in 2024 were exporting over 25% of their energy generated, down from 45% in 2023, but still up from about 15% in 2018.

Figure 4-92 highlights the percent of load exported during 2024. Of note, many all-electric fuel cells appear to be exporting a large percentage of energy. As we noted in the last report, many of the customers installing all-electric fuel cells appear to be on power purchase agreement (PPA) contracts, requiring them to purchase 100% of the electricity generated from the systems, even if they are not utilizing all the

energy.⁴⁵ California saw significant energy constraints during 2020, and in response, Bloom Energy, the sole manufacturer the all-electric fuel cells currently participating in the SGIP, ran an initiative to export significant energy to help relieve the strain on the grid using combustion-free, fuel flexible technologies.⁴⁶ It is possible that since this initiative, many Bloom customers have continued to export all unused excess energy. However, there were also two projects with internal combustion engines that were exporting over 90% of the energy produced by the generators.

FIGURE 4-92: CUSTOMER LOAD VS PERCENT OF LOAD EXPORTED ACROSS 2024



Natural Gas Impacts

The use of natural gas fuel by early SGIP systems results in increased pipeline transport of natural gas in California. However, the useful recovery of heat that displaces natural gas boilers reduces the pipeline transport of natural gas. Figure 4-93 below summarizes the project-level observed net impacts on natural

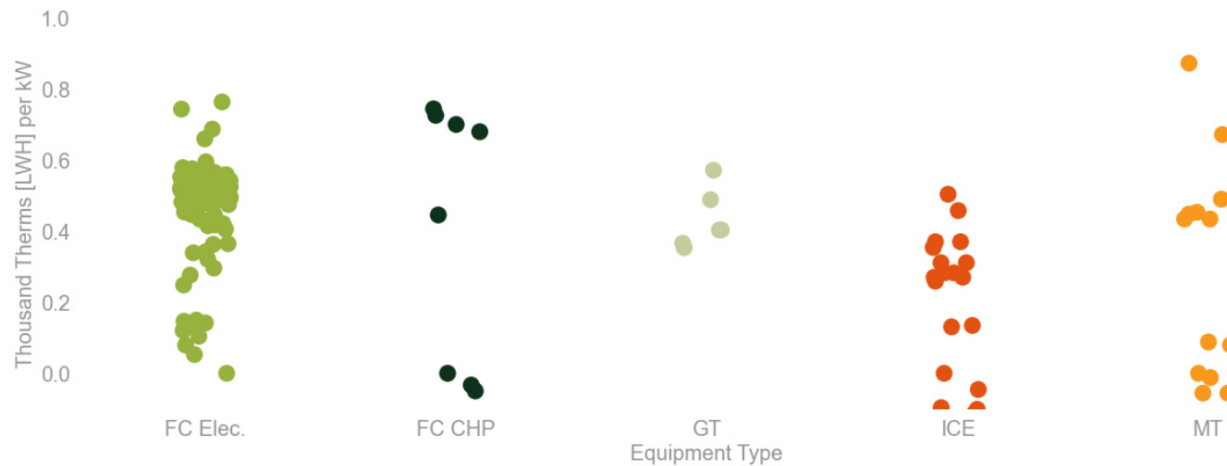
⁴⁵ Bloom Energy's 2018 July S-1 Statement states "... The end-customer is required to purchase all of the electricity generated by the Energy Servers for the duration of the offtake agreement..." Page 89. <https://d18rn0p25nwr6d.cloudfront.net/CIK-0001664703/f332ae61-2c3b-4eff-92b4-8565d1ea9781.pdf>. Accessed 10/24/2023.

⁴⁶ *Local Ordinances Exceeding the 2019 Energy Code. San Jose – 2019 2 Public Comments 3*. Docket Number 19-BSTD-06. Docket Date: 02/12/2021. Page 4. <https://efiling.energy.ca.gov/GetDocument.aspx?tn=236754-10&DocumentContentId=69797>. Accessed 03/20/2024.

gas, displayed as thousand therms per rebated kW. Based on the metered data, these projects result in a natural gas increase of around 390 therms per rebated kW, so a 500-kW generation system would increase natural gas usage by 195 thousand therms. Microturbines, gas turbines, and all-electric fuel cells have a higher natural gas impact, whereas CHP fuel cells and internal combustion engines were more likely to recover heat, leading to a lower natural gas impact and reduced GHG emissions.

FIGURE 4-93: 2024 OBSERVED NATURAL GAS IMPACTS

Observed Natural Gas Net Impacts (Thousand Therms per Rebated kW)



Generation Customer Bill Savings (\$/kW) by Technology

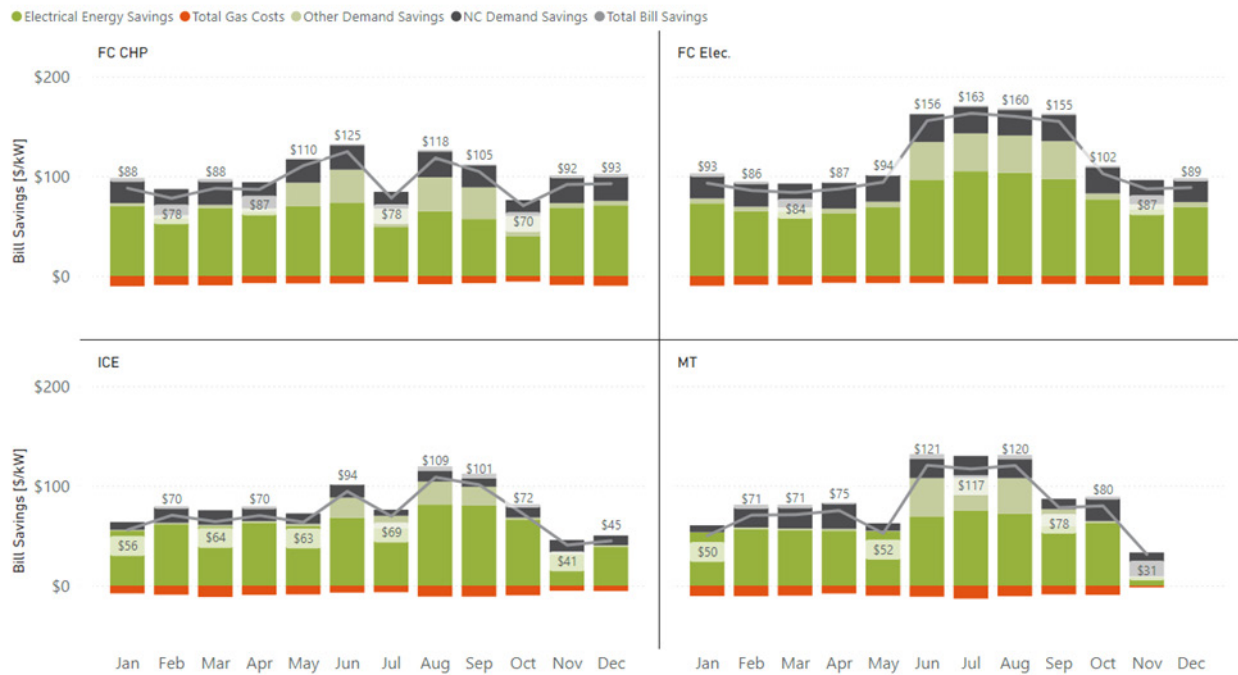
Verdant compared the observed billed energy for each period to baseline billed energy impacts. For customers with demand charges, we further estimated the reduction (or increase) in peak demand at a monthly level and during specific TOU periods to calculate demand savings (or increased cost) based on the customer rate schedule. Additionally, Verdant accounted for the cost of the natural gas consumed, and for the projects where heat was recovered, the offset of natural gas from heat recovered feeding into the boiler.

Figure 4-94 presents the results for generation customers by month separated out by technology types. Similar to the storage analysis, the bars correspond to the components of the bill: 1) non-coincident demand represents the maximum monthly demand in \$/kW, 2) other demand represents the maximum peak and partial-peak (where applicable) demand in \$/kW, 3) electrical energy represents the electrical component of the bill in \$/kW, 4) total gas costs are the associated increases in bills due to the additional gas usage, as well as the reduction in boiler fuel usage due to any heat recovery, and 5) the total is the sum of bill parts. The vertical axis represents the average monthly savings (or increased cost) in dollars, normalized by the capacity kW of the generation equipment.

All-electric fuel cells saw the largest maximum bill savings. As previously noted, a large share of all-electric fuel cells were exporting a portion of their energy generation, and not importing any energy, significantly reducing their bills.

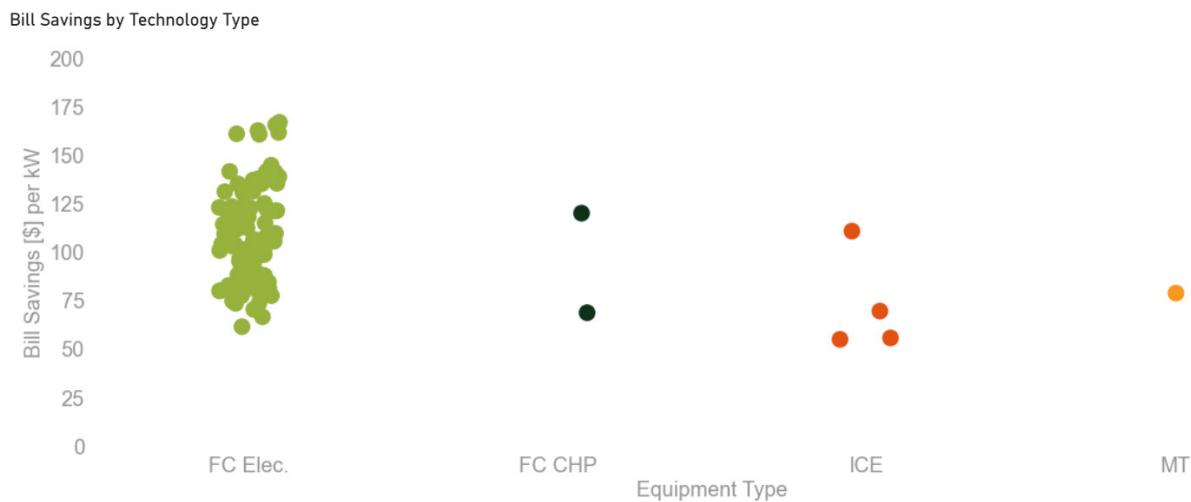
FIGURE 4-94: MONTHLY BILL SAVINGS PER KW BY TECHNOLOGY TYPE

Average Bill Savings by Technology Type



While Figure 4-94 highlights the average monthly bill savings, Figure 4-95 displays the distribution of annual 2024 project bill impacts, along with the variance, by technology type. Average monthly savings for fuel cells, internal combustion engines, and microturbines hover around \$100/kW. However, as can be seen in the figure, project-level bill savings varied significantly, project by project. We should note that these savings are calculated only for periods of time when a project is within its permanency period, so if a project ended its 10-year permanency period during 2024, or was decommissioned part way through 2024, the results will not reflect a full year of bill impacts.

FIGURE 4-95: DISTRIBUTION OF 2024 BILL SAVINGS PER KW BY TECHNOLOGY TYPE



4.3 CAISO AND IOU SYSTEM IMPACTS

By generating or discharging during CAISO and IOU peak hours, SGIP project hosts allow their electric utility to avoid the purchase of high-cost wholesale energy. At the same time, the electric utility reduces its transmission and distribution losses during hours of high system congestion. During extreme events, generating/discharging can even help avoid rolling blackouts. Ideally, SGIP system hosts are generating at full capacity and avoiding system maintenance during peak hours and thus contributing the greatest possible demand impacts. However, these CAISO or IOU peak hours do not necessarily occur when an SGIP system host may want to be generating, therefore a host may not always operate their SGIP system optimally during the grid peak hours.

This section examines generation during CAISO and IOU annual peak “gross” load and “net” load hours as well as their top 100 hours. Table 4-4 lists hours and magnitudes of CAISO and IOU peak demands during 2024. The gross peak CAISO hour occurred September 5th, during the 5 p.m. hour (local time), while the net peak hour occurred an hour later the same day. We show impacts related to both gross and net peak hours.⁴⁷

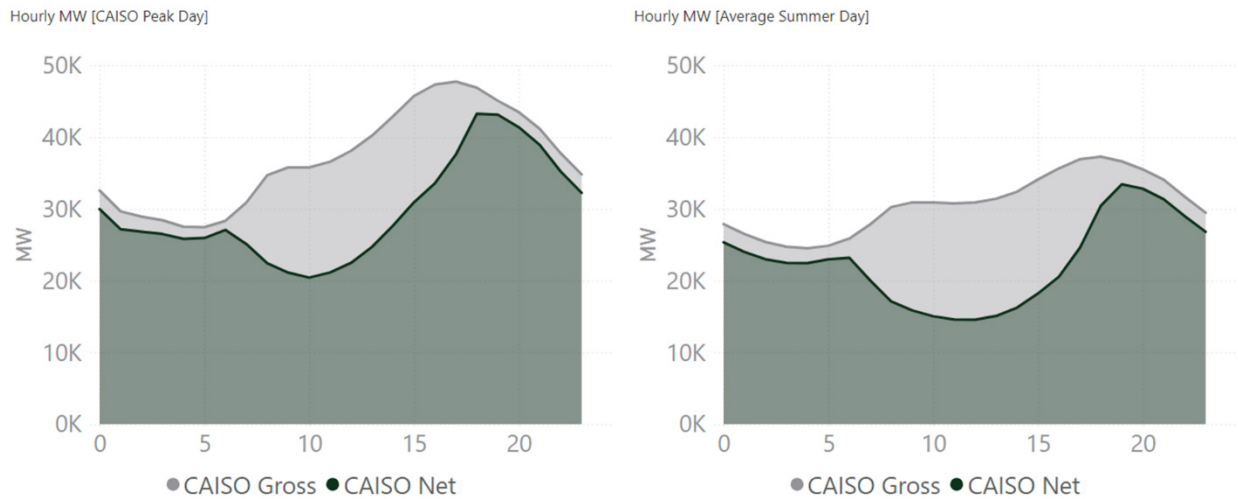
⁴⁷ The gross load is equal to total load at the transmission level and is equal to (net) customer meter data plus losses. Gross load therefore includes the impact of customer-sited generation and batteries; it comprises the back of the duck in CAISO’s famous duck curve. Net load subtracts grid-scale solar and wind generation and comprises the belly of the duck. While gross load is the amount that must be generated or imported to meet customer demand, the net load is a better indicator of both energy prices and grid stress than gross load.

TABLE 4-4: 2024 CAISO AND IOU PEAK HOURS AND DEMAND [MW]

Peak Period	Peak Demand [MW]	Date	Hour [Local Time]
CAISO - Gross	47,759	September 5 th	5 p.m.-6 p.m.
CAISO – Net	43,276	September 5 th	6 p.m.-7 p.m.
PG&E	21,159	July 11 th	6 p.m.-7 p.m.
SCE	25,394	September 6 th	4 p.m.-5 p.m.
SDG&E	4,861	September 8 th	5 p.m.-6 p.m.

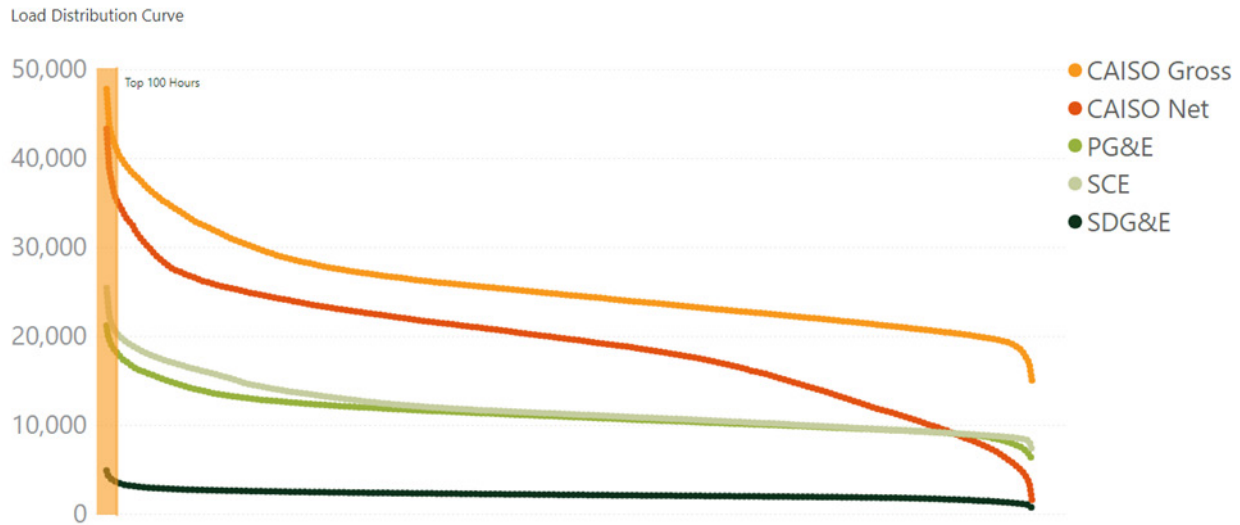
Figure 4-96 highlights the differences between the CAISO gross and CAISO net loads. The right figure represents an average summer day where there is a slight early morning ramp, followed by a drop in net load throughout the day and an early evening ramp. The graphic also shows the CAISO gross and net load on the gross peak day in 2024. On that day, as solar generation waned in the late afternoon, demand was only slowly declining. As a result, the net peak occurred one hour after the gross peak. The net peak on this day was also the highest during 2024. When examining other days within the summer, a similar pattern is revealed. The net peak often occurs one to three hours after the gross peak.

FIGURE 4-96: CAISO GROSS AND NET LOAD FOR AVERAGE SUMMER DAY VS CAISO PEAK DAY (09/05/2024)



CAISO and IOU annual peak and net peak hour coincident generation is a snapshot of beneficial program impacts. Analyzing the top 100 peak hours results in a more robust measure of impacts during CAISO and IOU peak grid loads. Representing just 1.1% of all the hours in a year, the top 100 peak hours capture the steepest part of load distribution curves. Figure 4-97 shows the 2024 CAISO and IOU load distribution curves and indicates the 100-hour mark as the solid orange bar on the left side.

FIGURE 4-97: LOAD DISTRIBUTION CURVES



The distributions of the top 100 hours over a year differ between CAISO and the three IOUs, and from year to year. While generally mid-to-late summer afternoon occurrences, a top 100 hour can occur as early as June, but during 2024, most of these hours occurred during July and September. Figure 4-98 displays the distribution of the top 100 peak hours by month. Like the prior year, PG&E saw the earliest 2024 peak hours occurring in June.

FIGURE 4-98: TOP 100 HOUR DISTRIBUTIONS BY MONTH

Top 100 Hour Distributions by Month

Territory	June	July	August	September	October
CAISO Gross		50	9	40	1
PG&E	3	80	4	2	11
SCE		20	19	61	
SDG&E		7	27	66	

4.3.1 Energy Storage

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand and system charging is left to less critical times. As detailed, SGIP nonresidential storage systems are generally being utilized to reduce noncoincident monthly peak demand, but also TOU energy arbitrage. Systems designed for demand



charge reductions may incur increases in the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. We also observe nonresidential systems performing TOU arbitrage exclusively, and subsequent charging leads to increases in noncoincident peak demand.

Residential storage systems are being utilized for TOU arbitrage and self-consumption – where the battery is discharged to minimize grid imports during the on-peak period as well as after. Residential systems are realizing savings on the energy component of their bill, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often.

The timing of charge and discharge not only impacts customer bills, but it can also have an impact on grid services. Benefits to these systems are potentially due to participation in demand response programs (both system-level/localized and real-time/day-ahead), enrollment in IOU tariffs with TOU rates or peak energy pricing like Critical Peak Pricing (CPP) or Peak Day Pricing (PDP). Some benefits may just be coincidental. Storage project operators and host customers may not be aware of system or utility level peak hours unless they are enrolled in a demand response program or retail rate where a price signal (or incentive) is generated to shift or reduce demand. Customers understand their facility operations and bill rate structure, but grid level demand may not be in their purview.

Storage discharge behavior that is coincident to critical system hours can provide additional benefits beyond customer-specific ones. These benefits include avoided generation capacity costs and transmission and distribution costs. The evaluation team assessed this potential benefit by quantifying the storage dispatch from the sample of nonresidential and residential systems during the top 100 gross and net peak demand hours in 2024 for the CAISO system, along with IOU-specific peaks.

CAISO System Impacts

Verdant examined how SGIP storage systems were operating during periods when the grid may be capacity constrained. We analyzed the magnitude of residential and nonresidential storage system charge and discharge during some of the peak system-level hours. To evaluate CAISO system-level impacts, we reviewed both the top gross and net load hours in 2024. On any given day, CAISO load is comprised of a variety of energy supply sources, including natural gas power plants, large hydro, imported power, and grid-level renewables like wind and solar. The availability of renewable energy throughout the day allows grid operators to use less fossil fuel-based sources. However, the intermittent nature of these renewables is disruptive.

Intermittency is particularly troublesome with grid-scale solar PV which, like on-site rooftop solar, generates only when the sun is shining. Billed on-peak periods, like from 4 p.m. – 9 p.m., provide price signals to customers to reduce, avoid, or shift their consumption during those periods, but that five-hour period is still broad. Most residential systems are two-to-three-hour batteries, so if a system fully

discharges during the early on-peak period (4 p.m. to 6 p.m.), state-of-charge will be insufficient to continue discharging throughout the latter hours of the on-peak period. Discharging a few hours later at full capacity or over a longer duration could provide more utility benefits and GHG reductions – as grid-level net load ramps – with bill savings largely unchanged. CAISO gross load (including renewables) peaked on 9/5/2024 between the 5 p.m. and 6 p.m. hour, while the net peak occurred an hour later. As a result, we examined storage performance at two peak periods: the gross peak, when overall demand is at its highest and all available electricity supply sources reach their maximum generation (MW), and the net peak, when overall demand minus renewable supply sources is reaching peak generation.

For each customer sector, we evaluated the average kWh discharge per kW capacity during all CAISO gross and net hours in 2024. Figure 4-99 and Figure 4-100 present those results for the nonresidential sector. On the vertical axis is the average discharge (+) and charge (-) kWh normalized by kW capacity. The secondary vertical axis provides the average hourly CAISO MW load, and the horizontal axis ranks the gross and net CAISO hours from highest to lowest throughout the year. While it's difficult to tease out individual hourly impacts from a figure exhibiting 8,760 of them, general patterns are observable. Greater average hourly discharge occurs during higher ranked CAISO gross and net hours compared to lower load hours. This behavior supports the distributions of discharge by time of day presented in Section 4.2.1 where a combination of TOU arbitrage and demand charge reductions were observed across the fleet of nonresidential storage systems. Greater magnitudes of charging occur during the lowest net CAISO peak hours because that load represents hours when grid-scale renewables like solar PV are generating a significant mix of California's energy portfolio – times when nonresidential systems paired with on-site PV are also charging.

FIGURE 4-99: HOURLY STORAGE KWH PER KW – 2024 CAISO GROSS LOAD HOURS FOR NONRESIDENTIAL

Nonresidential Charge, Discharge and CAISO Gross Load

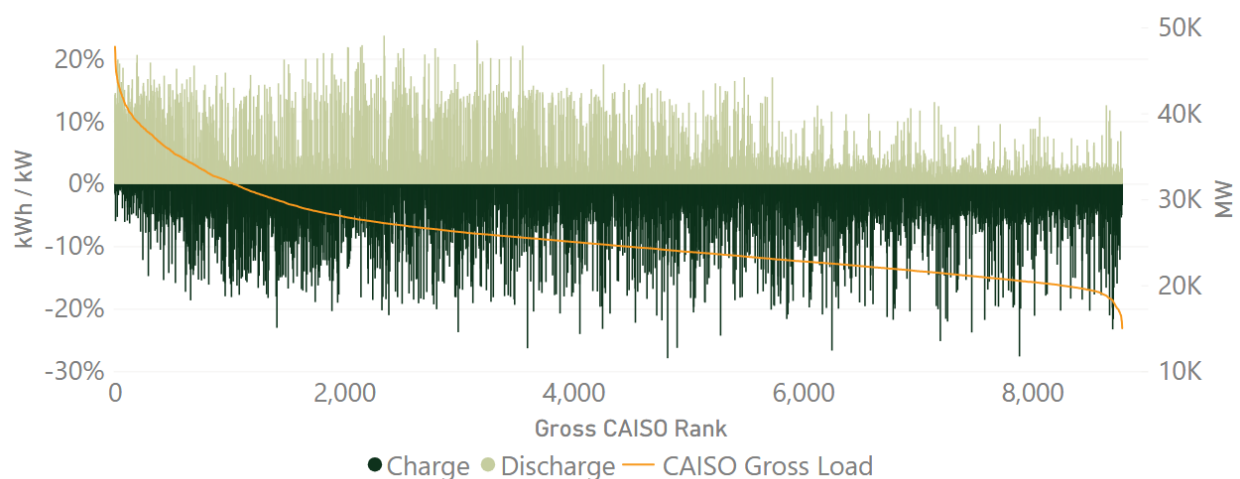
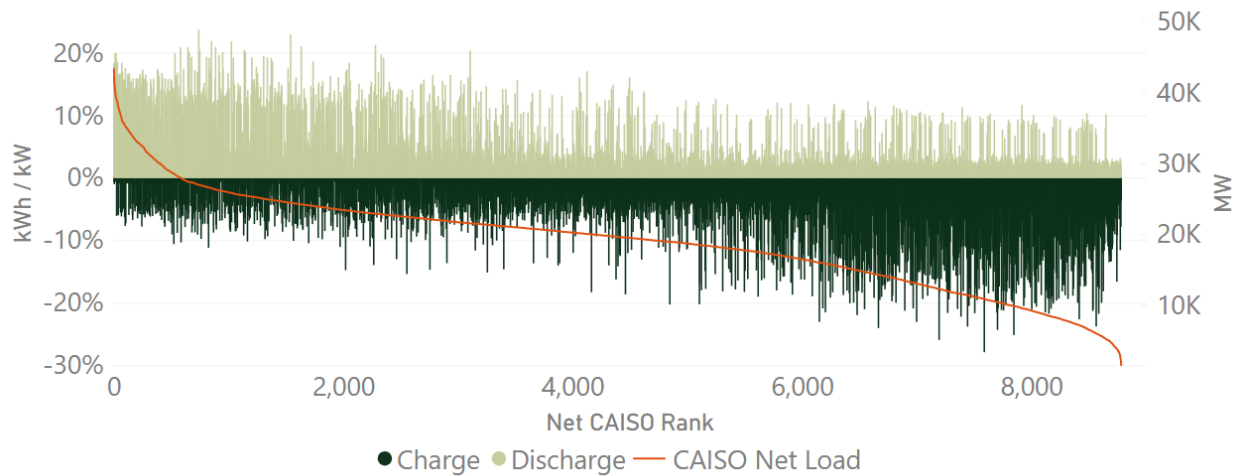


FIGURE 4-100: HOURLY STORAGE KWH PER KW – 2024 CAISO NET HOURS FOR NONRESIDENTIAL

Nonresidential Charge, Discharge and CAISO Net Load



Residential systems exhibit a similar trend in average hourly charge and discharge during ranked gross CAISO hours – greater discharge magnitudes during peak hours relative to lower demand hours, but still significant inter-hour charging and discharging during the year (Figure 4-101). More evident is the negative correlation between discharge and charge magnitudes when compared to net CAISO hours (Figure 4-102). We observe greater magnitudes of inter-hour discharge than charge during peak net CAISO hours – when residential systems are almost exclusively discharging for self-consumption or arbitrage – and greater inter-hour charging when CAISO net loads are lower – when residential systems are charging systems from on-site PV.

FIGURE 4-101: HOURLY STORAGE KWH PER KW – 2024 CAISO GROSS LOAD HOURS FOR RESIDENTIAL

Residential Charge, Discharge and CAISO Gross Load

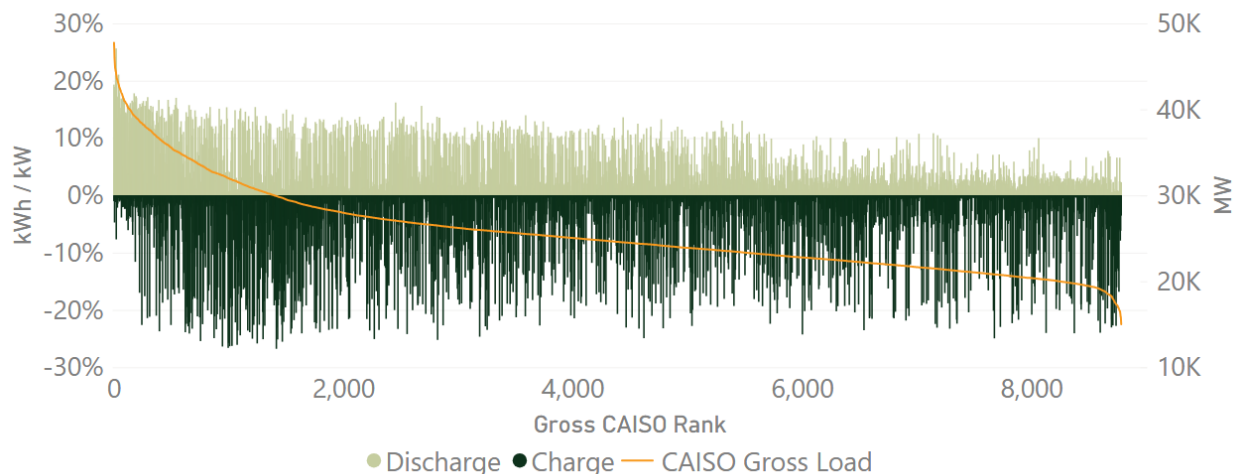


FIGURE 4-102: HOURLY STORAGE KWH PER KW – 2024 CAISO NET HOURS FOR RESIDENTIAL

Residential Charge, Discharge and CAISO Net Load

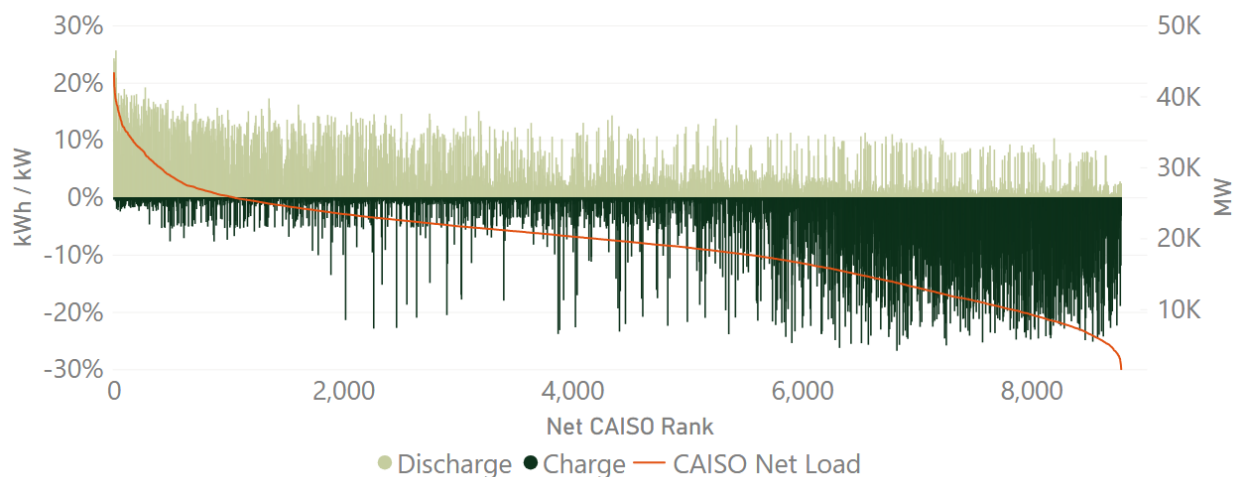


Figure 4-103 and Figure 4-104 present the average kWh discharge and charge per kW capacity for nonresidential systems during each of the top 100 CAISO gross and net hours in 2024, respectively. Given some of the observed performance differences for standalone and PV paired systems, figures have been further segmented by that classification. Both figures show nonresidential systems actively discharging or charging during all gross and net peak hours at differing magnitudes. As mentioned previously, net peak

hours occur later in the day than top gross peak hours during summer months. Some of those later hours correspond to periods when nonresidential systems have already charged from paired PV earlier in the day and are discharging exclusively on peak. This is one of the reasons why charging magnitudes are much lower across top net peak hours for systems paired with PV. Also evident is the greater discharge observed with standalone nonresidential systems, relative to charge during the same hours.

FIGURE 4-103: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR NONRESIDENTIAL

Nonresidential Charge and Discharge by Top 100 CAISO Gross Load Hours

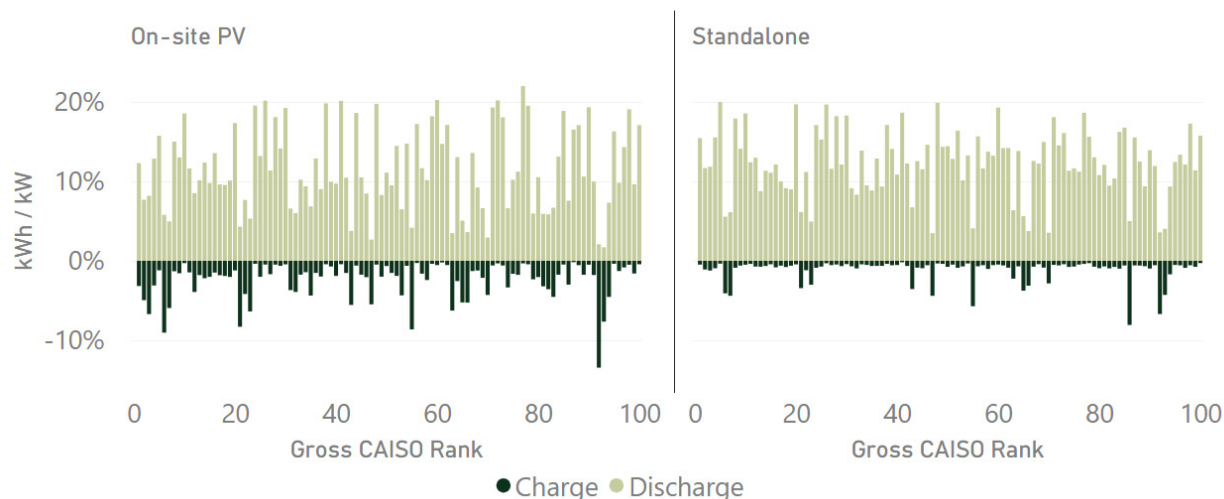


FIGURE 4-104: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR NONRESIDENTIAL

Nonresidential Charge and Discharge by Top 100 CAISO Net Load Hours

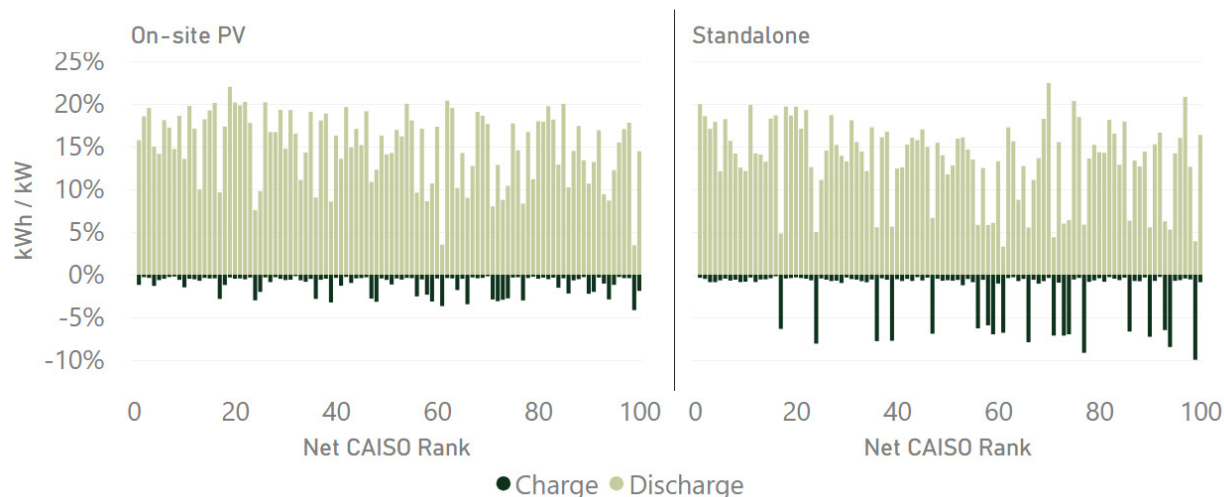


Figure 4-105 and Figure 4-106 present average hourly charge and discharge during peak hours for the residential sector, across all sampled projects. Standalone residential systems are conducting energy arbitrage, so we expect to observe discharging during on-peak net and gross CAISO hours. Standalone system charging occurs almost exclusively after 9 p.m. and overnight. Some CAISO gross peak hours occur early enough in the day when on-site PV is still generating. Net peaks occur later, when both grid-scale and on-site PV generation diminish, and systems begin discharging more regularly to lower on-peak loads.

FIGURE 4-105: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR RESIDENTIAL

Residential Charge, Discharge and CAISO Gross Load

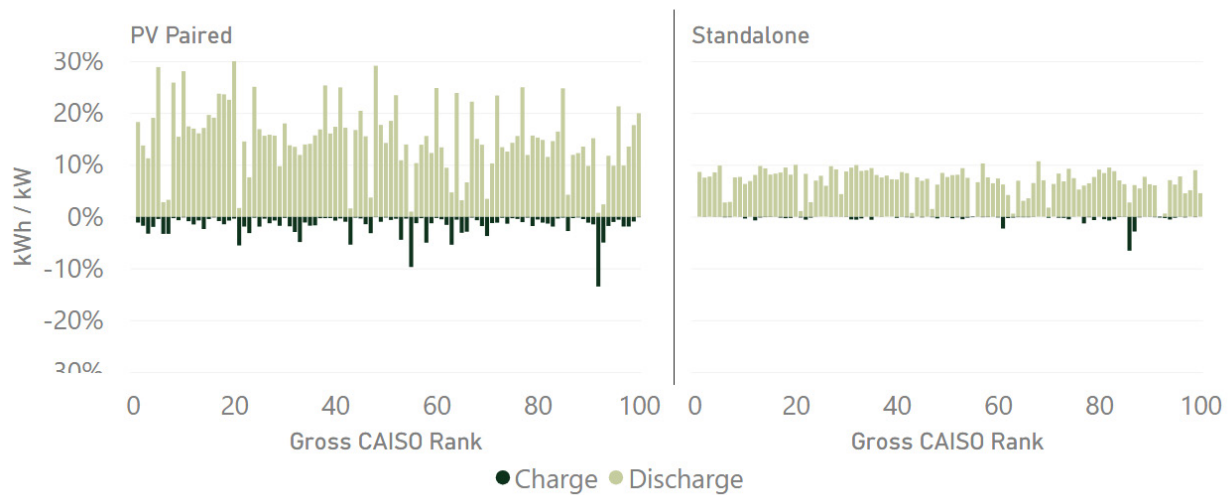
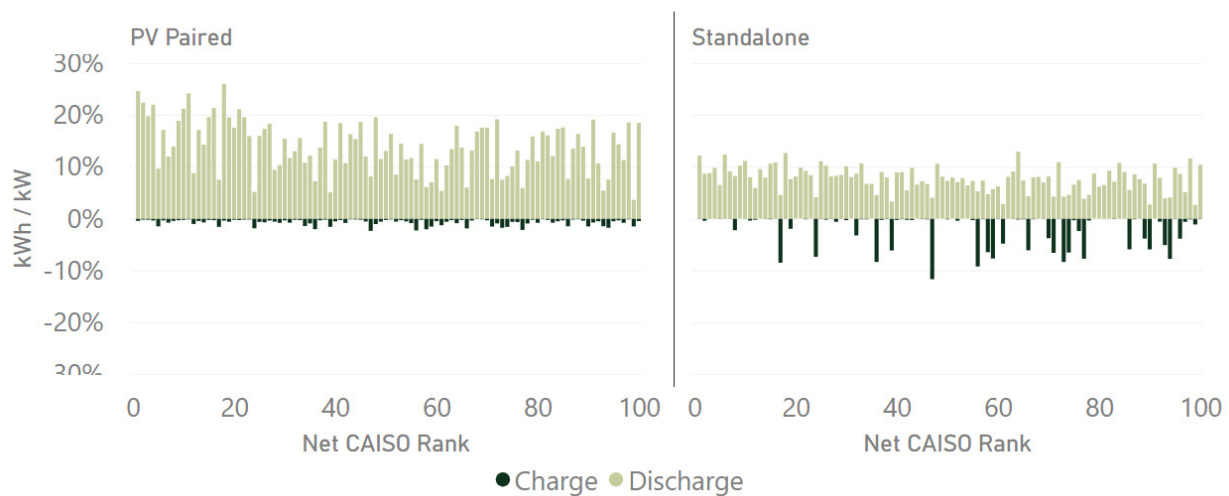


FIGURE 4-106: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR RESIDENTIAL

Residential Charge, Discharge and CAISO Net Load



The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the presence of on-site solar generation, underlying load shapes, battery operating modes, and general system utilization. The overall pattern of charge and discharge during top CAISO hours – and during the summer, in general – follows a similar pattern to what has been observed in previous evaluations. However, the magnitude of impacts during top hours continues to evolve from one evaluation to the next. This is due, in part, to peak CAISO hours differing from year to year as well as the underlying load shapes and use cases of customers in SGIP changing from one year to the next. Two of the more critical recent changes are 1) more focused nonresidential discharging during on-peak hours – particularly with medium duration batteries installed via the Equity Resiliency Budget (ERB) category, and 2) residential systems discharging a greater percentage of capacity during the latter half of the on-peak period. Increased price differential between billed on and off-peak, demand response participation like ELRP, and developer fleet dispatch modifications⁴⁸ have contributed to more tangible benefits realized from the grid perspective.

The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the presence of on-site solar generation, underlying load shapes, battery operating modes, and general system utilization.

We also explore how storage was being dispatched for nonresidential and residential customers on 9/5/2024, the day CAISO peaked. These data are presented below in Figure 4-107 and Figure 4-108. For all figures, the CAISO gross peak hour is highlighted by the leftmost vertical line, and the net peak hour follows one hour later (the red vertical line). Baseline and observed net loads are provided, along with the average hourly charge (yellow bars) and discharge (dark green bars) in kWh normalized by system capacity. The figures also differentiate energy storage system performance by prominent building types and presence of on-site PV or standalone, respectively. Evident for most building types is the greater magnitude of discharge around and within those peak hours (the gray shaded area represents a reduction in load compared to the baseline of no storage), despite differences in underlying customer load shapes and magnitudes of peak load. The yellow shaded area represents an increase in load, which corresponds to storage charging.

⁴⁸ In previous evaluations, Verdant observed the fleet of systems for one developer discharging consistently at 4 p.m.-5 p.m. during the summer on-peak period. Beginning in the late summer of 2021 they changed the algorithm of discharge and withheld dispatch from the first two hours of the on-peak period and began discharging during 6 p.m.-7 p.m. This grid-friendly behavior was observed during 2024 as well.

FIGURE 4-107: NONRESIDENTIAL STORAGE WITH PV UTILIZATION DURING PEAK DAY (BY BUILDING TYPE)

Baseline and Metered Net Load with Battery Charge (-) and Discharge (+) 9/5/2024 (CAISO Peak Day)

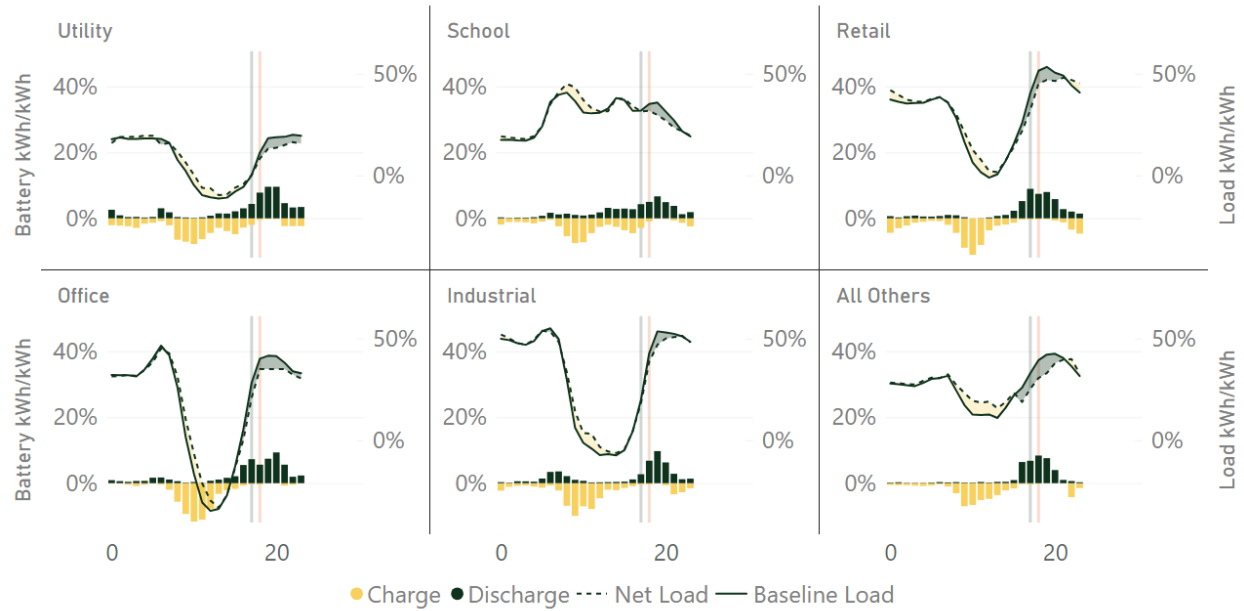
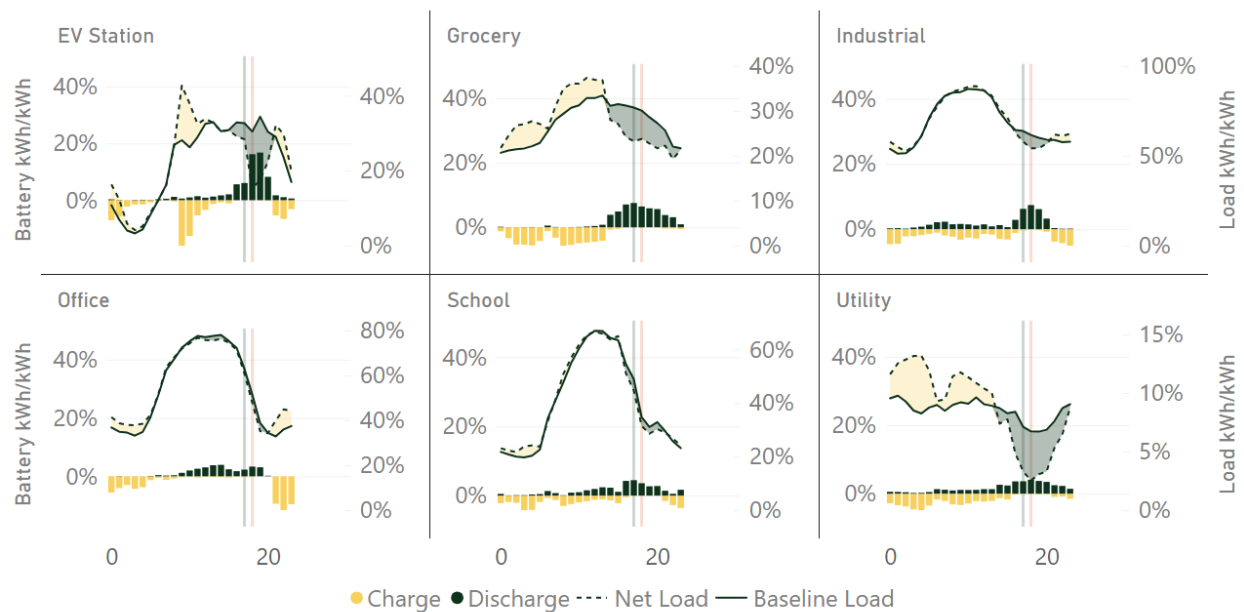


FIGURE 4-108: NONRESIDENTIAL STANDALONE STORAGE UTILIZATION DURING PEAK DAY (BY BUILDING TYPE)

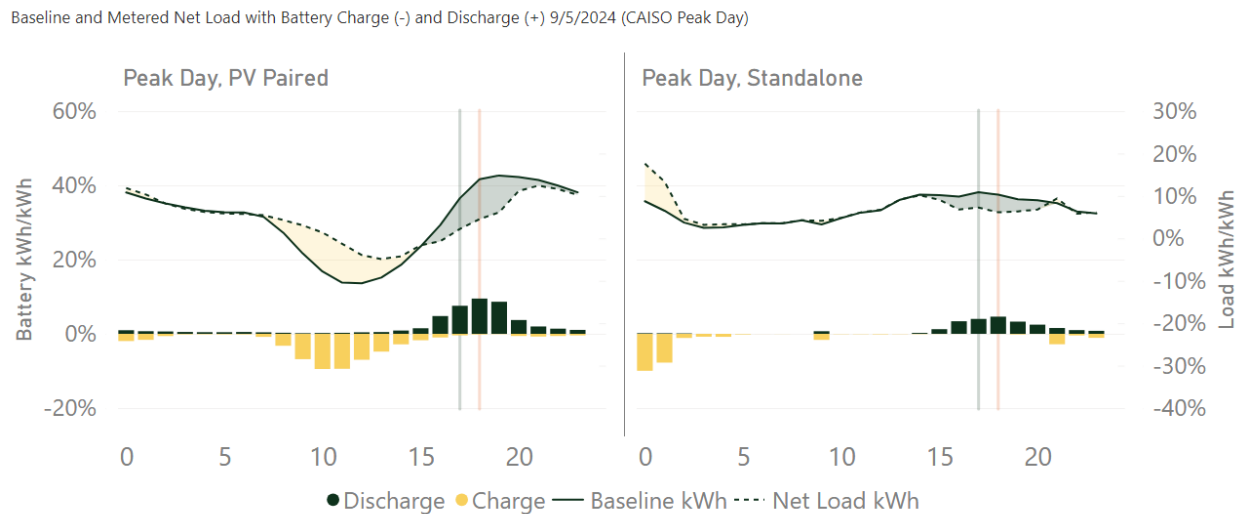
Baseline and Metered Net Load with Battery Charge (-) and Discharge (+) 9/5/2024 (CAISO Peak Day)



Residential systems paired with PV and standalone systems are discharging during and between gross and net peak hours, with the greatest magnitude of discharge occurring between 5 p.m. and 8 p.m. Charging occurs almost exclusively during solar generating hours for PV paired systems. Figure 4-109 illustrates how customer load is impacted by energy storage dispatch on the peak day for PV paired systems and standalone systems. The broad 5-hour on-peak period corresponds to grid constrained hours, so higher on-peak rates provide customers with a price signal to arbitrage energy and reduce delivered load during these critical periods.

Figure 4-110 presents storage dispatch and load shapes for each of the prevalent operating modes (along with an overall average daily shape in the top right quadrant). Discharge patterns are similar for each of the operating modes, but certainly, the magnitude of discharge is different based on the composition of customers conducting each mode of operation. Customers conducting TOU arbitrage combine customers netting out delivered load, along with customers either 1) discharging to export regularly or 2) discharging to export only during specified demand response (DR) events.⁴⁹

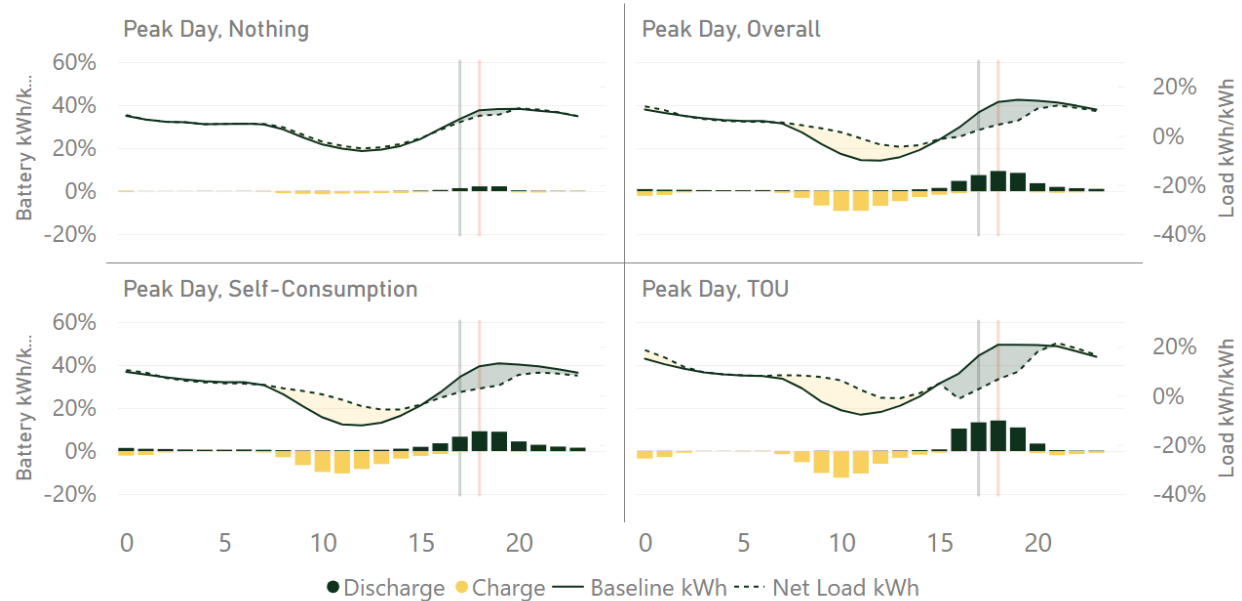
FIGURE 4-109: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO DAY



⁴⁹ This latter behavior will be explored in more detail in the next section.

FIGURE 4-110: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO NET DAY

Baseline and Metered Net Load with Battery Charge (-) and Discharge (+) 9/5/2024 (CAISO Peak Day)



Residential Storage Utilization during Demand Response Events

The previous section highlighted SGIP energy storage performance during CAISO peak hours. However, the operating modes guiding that performance during critical hours – self-consumption, arbitrage, arbitrage with export – were observed outside these peak hours in 2024. PV paired systems were generally charging during lower grid constrained hours, and both paired and standalone systems were discharging in the early afternoon and evening during high utility cost hours and system peaks, particularly in summer months. In other words, on average SGIP energy storage systems were not performing very differently during capacity constrained hours than they were ordinarily in 2024. However, when looking at a subset of Emergency Load Reduction Program⁵⁰ (ELRP)

In other words, on average, SGIP residential energy storage systems were not performing much differently during capacity constrained hours than they were ordinarily in 2024.

⁵⁰ More information about ELRP can be found here:

<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program-data-and-information>



participants on event days, we do see some differences in battery discharge during capacity constrained hours.

Verdant compared average daily residential energy storage performance to system utilization during ELRP events for customers participating in the program. Storage systems are generally self-consuming or following a price signal built into a customer billed on- and off-peak rate schedule, so behavioral changes from typical summer weekdays and event days would be either wholly coincidental or predicated on additional signals customers are exposed to – flex alert notifications and/or demand response participation where, in the case of ELRP, load reductions can be compensated at up to \$2.00 per kWh.

We do observe some incremental utilization and differing performance from systems enrolled in demand response programs like ELRP. During event days, which in 2024 align with capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging more capacity during event windows than usual. In fact, systems were discharging beyond customer load needs and exporting excess capacity to the grid during events. To better understand and quantify any potential incremental performance benefits ascribed to storage during demand response events relative to normal observed dispatch, Verdant compared event utilization to like-day utilization.

The methods used to classify similar days included mapping weekday weather station information – like minimum/maximum temperature, mean temperature, and temperature during peak hours – to SGIP storage systems by premise-level ZIP codes. Comparison or control days were then selected using Mahalanobis distance matching, based on a combination of metrics. After reviewing outputs for each set of selected metrics, Verdant chose the smallest Mahalanobis distance using maximum temperature. This method selected the best fitting temperature shape during the peak hours. Occasionally, the selected day was missing system discharge, load, or PV data, and the second closest Mahalanobis distance was selected. If that day contained missing data, the project was removed from the analysis dataset.

It's important to note that this exercise was not intended to replicate a load impact study. The research question stems from what potential demand reductions a BTM distributed energy resource like energy storage can reasonably provide for quickly dispatchable grid support (there are over 2,000 MWh of installed capacity within the SGIP alone). The question is what percentage of that capacity is already being dispatched for customer TOU arbitrage or self-consumption versus what incremental capacity can be expected from these systems in response to ELRP events. The analysis compared 1) energy storage utilization – charge (-) and discharge (+), 2) customer net load, 3) on-site PV generation, and 4) BTM household consumption on ELRP event days to control days.

ELRP participants discharged a greater magnitude of system capacity during events. Moreover, discharge extended beyond customer load requirements, with excess capacity being exported to the grid.



Verdant received 2024 residential ELRP participant lists from PG&E and SDG&E. Residential ELRP participation is less than 1% of PG&E and SDG&E SGIP participants and was 9% of the PG&E and SDG&E SGIP sample. The analysis summarizes 124 PG&E and SDG&E residential ELRP participants that were in the 2024 SGIP sample. There were six ELRP events in 2024 between July 10th and September 9th. These events lasted, on average, three hours and ranged between two and five hours. ELRP events in 2024 started between 4 p.m. and 8 p.m. and always ended at 9 p.m.

Figure 4-111 compares average hourly charge and discharge during ELRP events for customers participating in the program, along with how those systems were operating on similar non-event days. Load shapes – like PV generation, baseline load, and behind-the-meter consumption – are all similar across days. However, the dashed line, which represents the metered customer load, is visibly different. More targeted and greater energy storage discharge utilization on event days decrease load to export (green shaded area). Peak event discharge reaches nearly 21% of system kWh capacity during the 6 p.m. hour on event days. On non-event days, peak discharge reaches almost 5% of capacity during the 6 p.m. hour.

FIGURE 4-111: AVERAGE HOURLY LOAD SHAPES DURING ELRP EVENTS AND CONTROL DAYS (2024)

Average Hourly Load Shapes and Storage Charge (-) Discharge (+) ELRP Event Days and Control Days

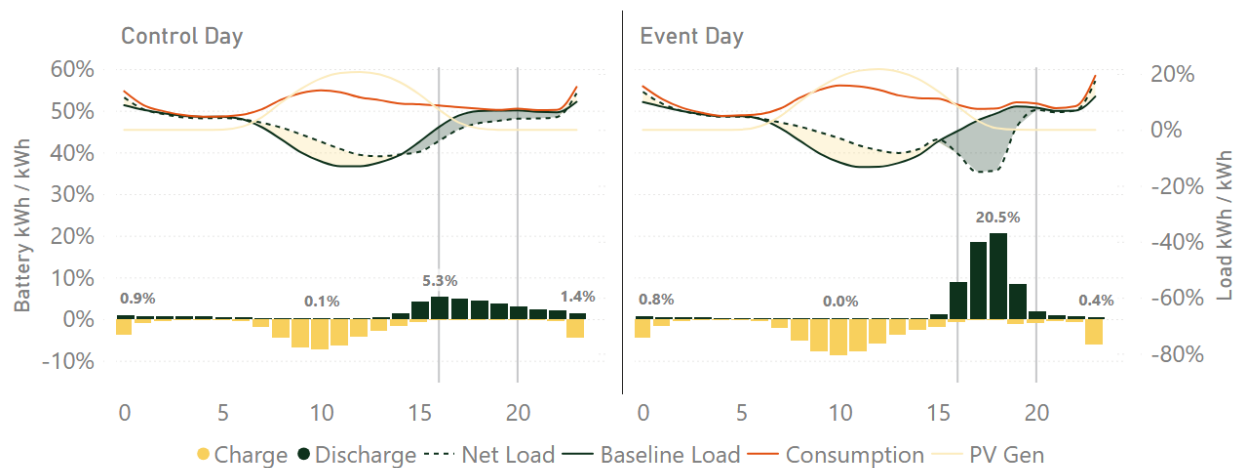


Figure 4-112 summarizes the average daily discharge for systems participating in ELRP. Control day utilization averages 43% of kWh capacity with a majority being dispatched between 4 p.m. and 9 p.m. On event days, daily utilization increases to roughly 68% of capacity. Discharge magnitudes during the 4 – 9 p.m. peak almost double on these days. Not only were ELRP participants discharging a greater magnitude of system capacity during events, but discharge also extended beyond customer load requirements, with excess capacity being exported to the grid.

FIGURE 4-112: AVERAGE DAILY RESIDENTIAL DISCHARGE PER KWH CAPACITY (ELRP VERSUS CONTROL DAYS)

Residential Discharge kWh per Capacity kWh by Time of Day (ELRP Participants Only)

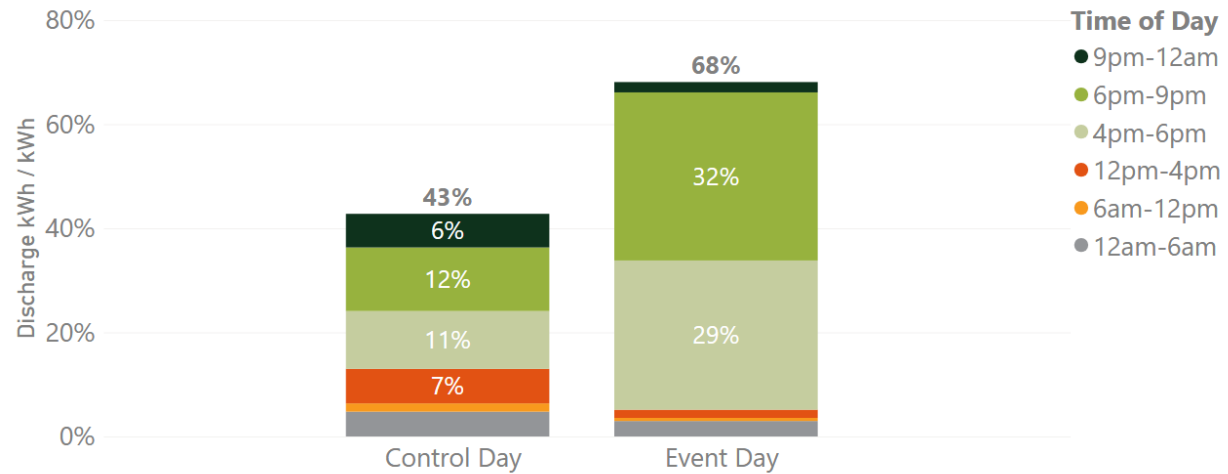
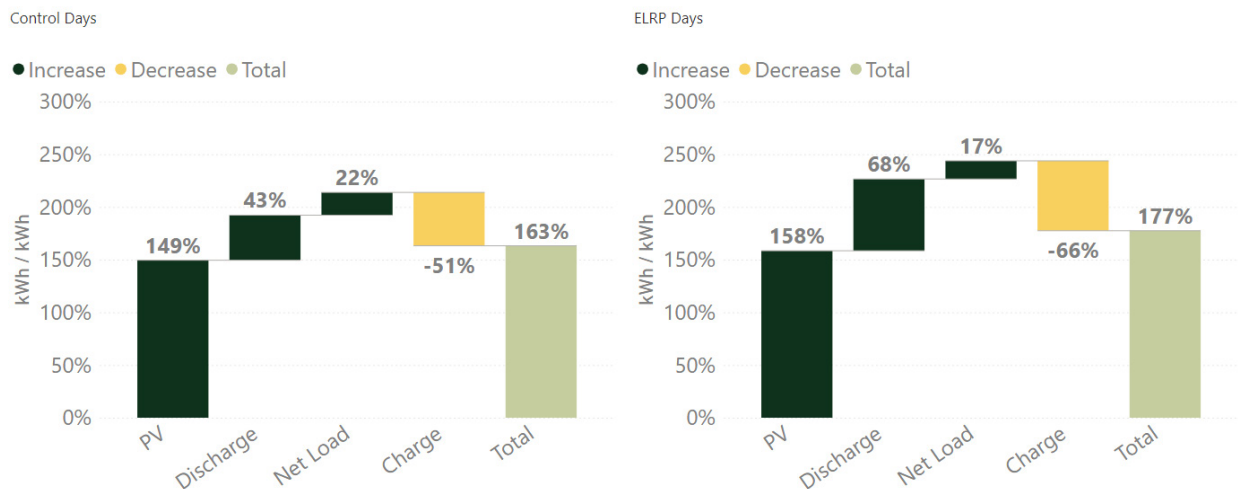


Figure 4-113 presents average PV generation, delivered/received load, storage charge/discharge, and BTM consumption during control days and ELRP events in 2024, normalized by energy storage kWh capacity. The increase in utilization (discharge) presented above is evident in the graphic below. PV generation is slightly higher, on average, during ELRP days than on control days, and BTM consumption ranges from 163% per kWh capacity on control days to 177% per kWh capacity on event days.

FIGURE 4-113: AVERAGE DAILY LOAD AND UTILIZATION PER KWH CAPACITY WATERFALL (ELRP)



4.3.2 Generation

Unlike energy storage, generation technologies are not typically used for load shifting or TOU arbitrage but are mostly used to satisfy a customer’s base load. Therefore, while they can provide peak hour benefits, these benefits are not typically greater than will be seen the rest of the year. Generation coincident with the gross and net CAISO annual peak hours during 2024 (i.e., the impact in terms of reducing the gross or net load peak) is shown by PA in Table 4-5. PG&E projects contributed the largest portions of the gross CAISO peak hour generation, making up over 40% of the total generation during the CAISO gross and CAISO net peak hours of 2024.

TABLE 4-5: ANNUAL OBSERVED CAISO GROSS AND NET PEAK DEMAND IMPACT BY PROGRAM ADMINISTRATOR

CAISO	PA	Peak Hour Generation [MW]	Percent of Total
Gross	CSE	10.05	8.2%
	PG&E	52.59	43.0%
	SCE	27.42	22.4%
	SoCalGas	32.37	26.4%
	Total	122.42	100%
Net	CSE	10.06	8.2%
	PG&E	53.00	43.1%
	SCE	27.47	22.34%
	SoCalGas	32.41	26.4%
	Total	122.93	100%

Figure 4-114 and Figure 4-115 show the CAISO gross peak demand impact per rebated capacity kW, by technology type total, as well as broken out by PA. Gas turbines and all-electric fuel cells generated the highest peak demand impact per rebated kW during 2024 during the statewide gross peak, followed by internal combustion engines and then CHP fuel cells. When compared by PA, gas turbines, fuel cells, and internal combustion engines typically saw the highest peak demand impact per rebated kW.

FIGURE 4-114: 2024 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE

Observed Statewide Gross Peak Demand Impact per Rebated kW

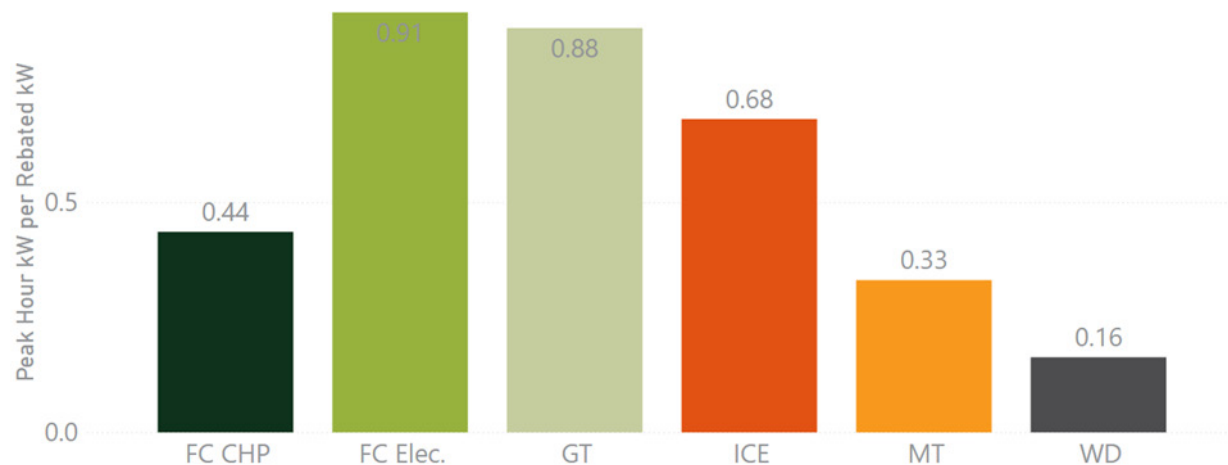
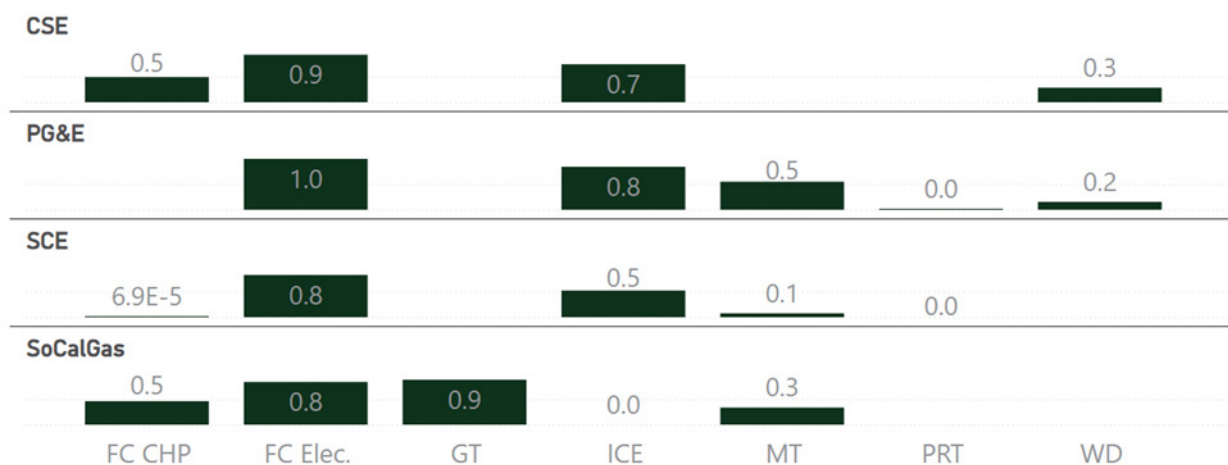


FIGURE 4-115: 2024 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND PA

Observed PA Gross Peak Demand Impact per Rebated kW

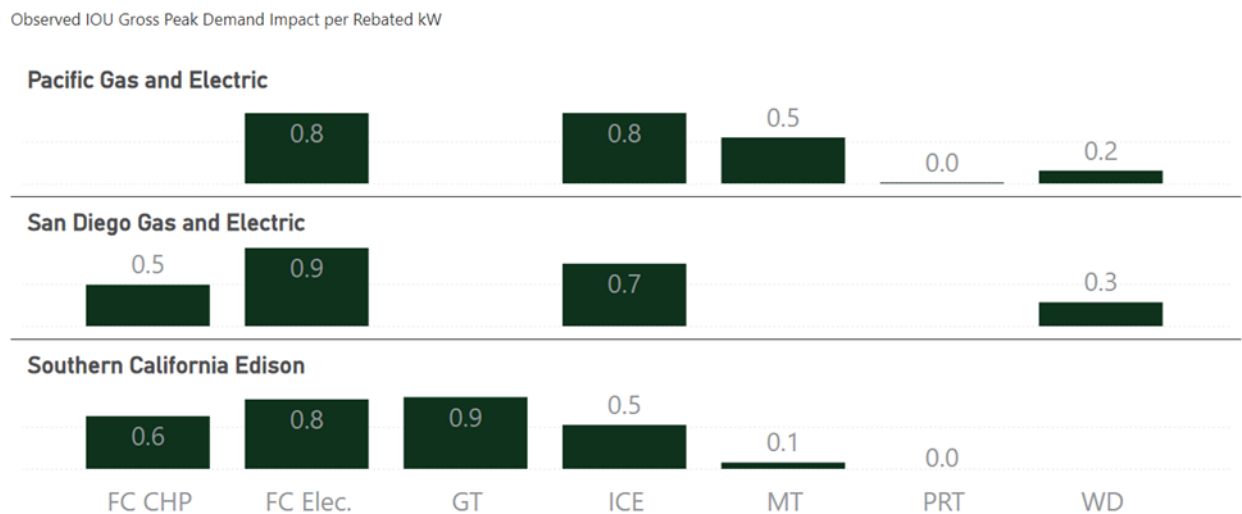


Note: Where data is missing, no generation data was collected or the PA did not have any projects of that technology type.

Gross peak IOU impacts were also analyzed, as displayed in Figure 4-116. These peak hour impacts from SGIP systems are assigned to the IOU providing the electrical service, which is not necessarily the same as the PA. For example, SoCalGas projects may be electrically interconnected to a municipal utility rather than an IOU.

The 2024 PG&E gross peak hour generation occurred on July 11th, between 6 p.m. and 7 p.m. local time. During this hour, observed projects electrically interconnected to PG&E’s system generated 0.6 kW per rebated kW. SCE’s 2024 gross peak hour was on September 6th between 4 p.m. and 5 p.m. where coincident generation from observed projects was 0.8 kW per rebated kW. Observed projects interconnected to SDG&E’s electrical system reached 0.7 MW per rebated kW during the 2024 gross peak hour on September 8th between the hours of 5 p.m. and 6 p.m.⁵¹ Similar to the CAISO findings, on a per rebated kW basis, observed CAISO peak hour generation per kW was generally led by fuel cells, gas turbines, and internal combustion engines.

FIGURE 4-116: ANNUAL IOU GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND ELECTRIC UTILITY

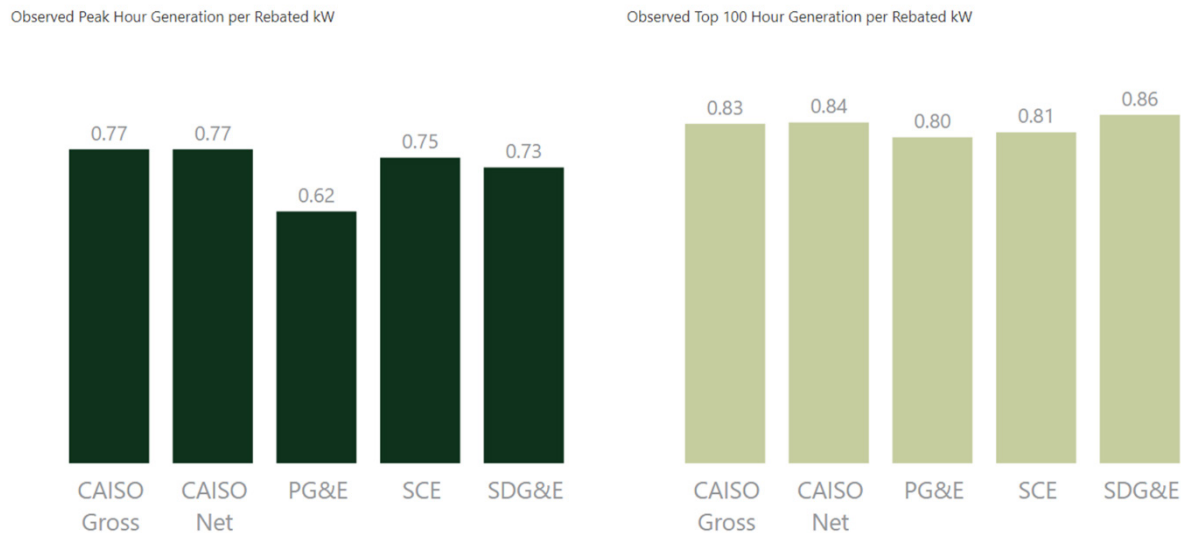


Note: Where data is missing, no generation data was collected or the PA did not have any projects of that technology type.

Figure 4-117 shows observed project generation per rebated kW coincident with the three IOU and CAISO gross and net peak hours, alongside average project generation per rebated kW coincident with the top 100 peak hour. On a per-rebated kW basis, peak hour generation and top 100-hour average generation were very close in all cases.

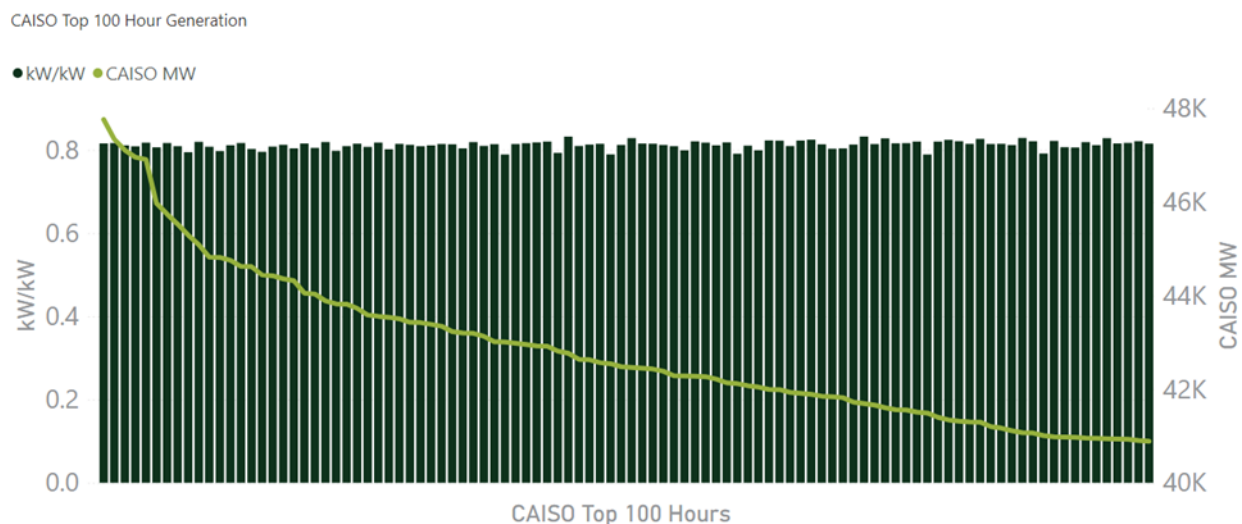
⁵¹ The defined peak hours are all in local time.

FIGURE 4-117: OBSERVED PEAK HOUR GENERATION COMPARED TO AVERAGE TOP 100 HOUR GENERATION [PER KW]



As discussed above, generation systems typically provide a baseload, rather than providing peak hour benefits. Figure 4-118 below highlights the observed generation per rebated kW over the CAISO top 100 hours, showing that the generation per rebated kW generally stays steady across the top 100 hours.

FIGURE 4-118: OBSERVED CAISO GROSS TOP 100 HOUR GENERATION PER REBATED CAPACITY KW

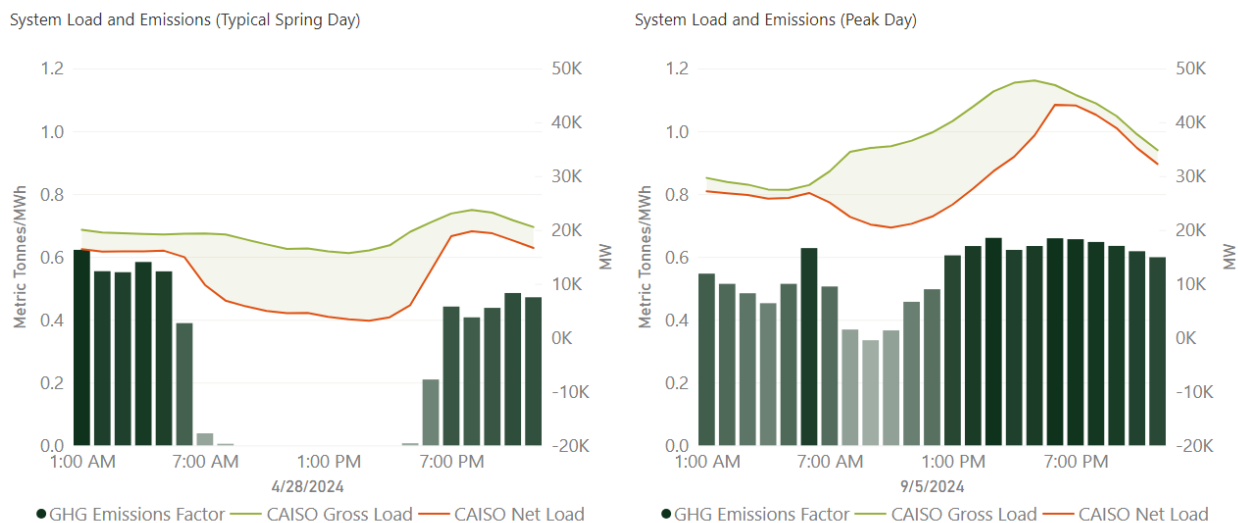


4.4 ENVIRONMENTAL IMPACTS

The environmental impact considered in this analysis is change in emissions of CO₂, as it is the GHG most affected by the operation of SGIP systems.⁵² Environmental impacts are calculated as the difference between the CO₂ emissions associated with SGIP system operations and those associated with counterfactual baseline system operations. In the case of generation systems, numerous possible baseline conditions are possible depending on the type of fuel being utilized by the SGIP system. When the baseline entails venting of methane directly to the atmosphere, the GHG impact is expressed in terms of equivalent CO₂ (CO₂eq). Details of GHG impact calculations for generation systems are provided as Appendix D. Generation systems and energy storage systems both change the timing and magnitude of CO₂ emissions of electric utilities. This aspect of the environmental impacts analysis is described and discussed.

The relationship between electric grid load and marginal CO₂ emissions is depicted graphically in Figure 4-119. Two days in 2024 are presented: 4/28/2024 – a sunny, Sunday in late April on the left, and 9/5/2024 – on the right, where CAISO gross and net load reached peaked during the 5 p.m. and 6 p.m. hours local time, respectively. The green and red lines represent hourly CAISO gross and net load, respectively, and the dark bars represent average marginal emissions during that hour.

FIGURE 4-119: CAISO LOAD AND MARGINAL EMISSIONS ON SPRING DAY VERSUS PEAK DAY



⁵² The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: <https://sgipsignal.com/>.



System load and corresponding marginal emissions on the left are typical of a spring day. For many hours during the day when marginal emissions are zero, ample sunshine, long daylight hours, and low demand for energy-intensive end uses like air conditioning (A/C) allow utility-scale solar generation to meet nearly all system demand aside from base load. Even after exports to other states, some renewable generation must be curtailed to maintain grid stability, resulting in zero – or even negative – prices in CAISO. Marginal emissions are zero when renewables are being curtailed, because more load will be met by reducing curtailment rather than by increasing GHG-producing generation. During the 4 p.m. and 5 p.m. hours, renewable generation continues to decrease from its midday maximum and is displaced by more carbon-intensive generators.

System load on the peak day (right pane of Figure 4-119) is much greater and marginal emissions don't hit zero at any point during the day (although we observe a drop between 7 a.m. – 11 a.m. when grid-scale renewables begin to ramp, and underlying system demand is still low). At the net peak (6 p.m.) emissions remain stable when the upper bound of power plant heat rate is reached, indicating the most carbon-intensive generator is on the margin during those hours. A perfectly designed energy storage system optimized to reduce GHG emissions would charge only during the lowest marginal emissions periods and discharge during (net) peak hours only.

Generation systems, on the other hand, generally provide a baseload to the facility, and don't have significant variation hour to hour or season to season and are therefore not optimized to maximum GHG emissions reductions during peak hours. Renewably fueled systems with vented baselines saw the highest GHG emissions reductions, but non-renewable fueled systems with high heat recovery rates also reduced GHG emissions.

The marginal grid GHG emissions values used to calculate environmental impacts were prepared by WattTime. The data sources and analytic methodology used by WattTime are consistent with the Avoided Cost Calculator (ACC) and are approved by the CPUC. Assumptions in the ACC are updated periodically. Updated assumptions in the 2020 ACC and the 2021 ACC provided motivation for an update to the SGIP GHG Signal calculations. That update resulted in WattTime releasing a new version of the SGIP GHG Signal starting February 1, 2022: Version 2.⁵³

⁵³ Presentation: 'SGIP GHG Signal Update', WattTime. Self-Generation Incentive Program Fourth Quarterly Workshop, December 13, 2021. <https://www.selfgenca.com/documents/workshops/2021/q4>

4.4.1 Energy Storage

Hourly GHG impacts were calculated for each SGIP system as the difference between the grid power plant emissions for observed system operations and the emissions for the baseline condition or the counterfactual. Baseline emissions are those that would have occurred in the absence of the storage system. Facility and household loads are identical for baseline and SGIP conditions. What varies is the timing and quantity of grid power plant electricity required to maintain balance between loads and electrical supply in response to storage charging and discharging.

Hourly storage performance is equal to the charge or discharge that occurred during that interval. The energy impact during that interval is then multiplied by the marginal emissions rate for that interval (kilograms CO₂ / kWh) to arrive at an hourly emissions impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the total emissions.

Energy storage technologies are not perfectly efficient. Consequently, the amount of energy they discharge over any given period is always less than the amount of energy required to charge the system. Roundtrip efficiency (RTE) losses from AC/DC power conversion and parasitic loads – particularly with under-utilized systems – will always result in increased energy consumption at a customer's home or facility relative to the baseline condition without storage. For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. In other words, SGIP storage systems must charge during “cleaner” grid hours and discharge during “dirtier” grid hours to achieve GHG reductions. Grid-level renewable generation during morning and early afternoon hours helps satisfy system-level demand throughout those hours. During periods when more renewables are on the grid, marginal GHG emissions tend to reduce as well. As renewable generation wanes in the late afternoon and demand ramps are satisfied on the margin with more imports and natural gas peak generators, marginal emissions tend to increase.

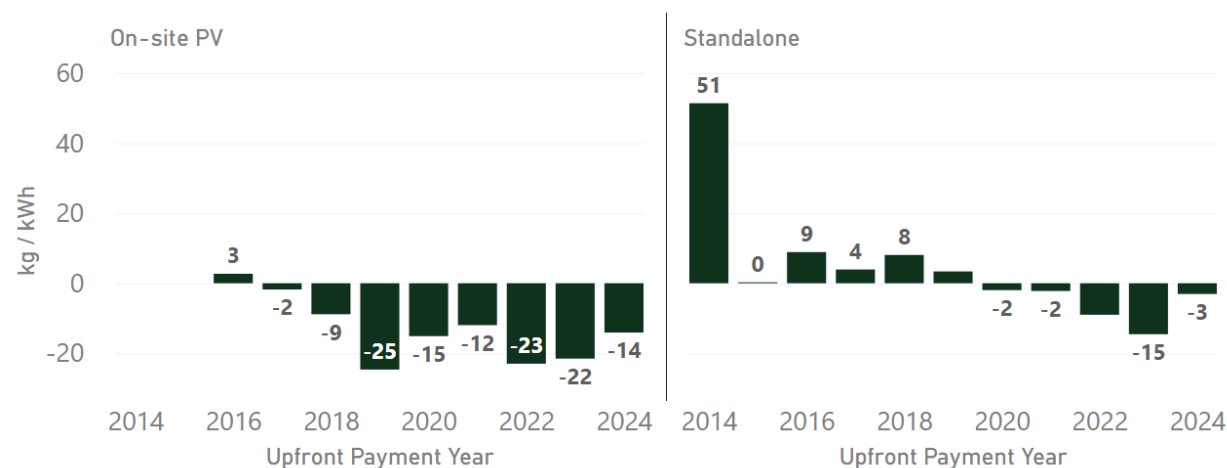
Nonresidential Storage

Figure 4-120 presents the range in GHG emissions reductions (-) or increases (+) for the sample of nonresidential projects analyzed as part of the 2024 Impact Evaluation. The bar chart provides the year in which an SGIP energy storage project received their upfront incentive payment, along with if the systems are paired or co-located with on-site PV (left pane) or are standalone (right pane). We observe an overall increase in system efficiency and utilization from systems installed more recently, and this behavior helps contribute to many more realized GHG emission benefits in 2024 compared to some previous years.

Except for some earlier vintage projects,⁵⁴ systems paired with PV – independent of payment year – reduced emissions in 2024, with average reductions (-) ranging from 2 kg/kWh for systems paid in 2016 to as high as 23 kg/kWh for systems paid in 2022. More recent standalone system installations are reducing emissions as well.

FIGURE 4-120: EMISSIONS (KG GHG/KWH) FOR NONRESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

Nonresidential GHG Emissions By Upfront Payment Year and On-site Generation



Recent reductions in GHG emissions in the nonresidential sector are largely attributable to PV paired storage performance, more targeted on-peak discharge from standalone systems, and more recent installations of longer duration batteries in the ERB conducting arbitrage at the expense of noncoincident peak demand reductions (and subsequent charging “snapback” associated with demand shaving). Figure 4-121 presents average energy storage charge (-) and discharge (+) kWh/kWh capacity along with the average marginal emissions shapes by PV paired or co-located systems operating in summer months of 2024 and standalone systems operating during the same time. The marginal emissions curve (with units displayed on the secondary vertical axis) conveys the hour-by-hour variability in emissions magnitudes. Emissions exhibit a morning ramp when system demand begins, but prior to grid-scale renewable generation. The subsequent dip in emissions thereafter is caused by renewable generation ramping. Summer months are laden with high cooling loads later in the day – represented by the peak from 7 p.m. to 9 p.m.

⁵⁴ The 51 kg/kwh increase in GHG emissions in 2014 represents only one standalone energy storage project.

More important than highlighting marginal emissions in isolation is the corresponding energy storage performance during those hours. Yellow bars represent charging, and we observe much greater charging from on-site solar for paired systems, which is also coincident to lower marginal emissions periods. Discharging (dark bars) is observed during on-peak hours and coincident to high marginal emissions. Standalone systems also discharge during the peak and are “net” charging in all other hours.

FIGURE 4-121: NONRESIDENTIAL SUMMER STORAGE DISPATCH AND EMISSIONS BY ON-SITE GENERATION

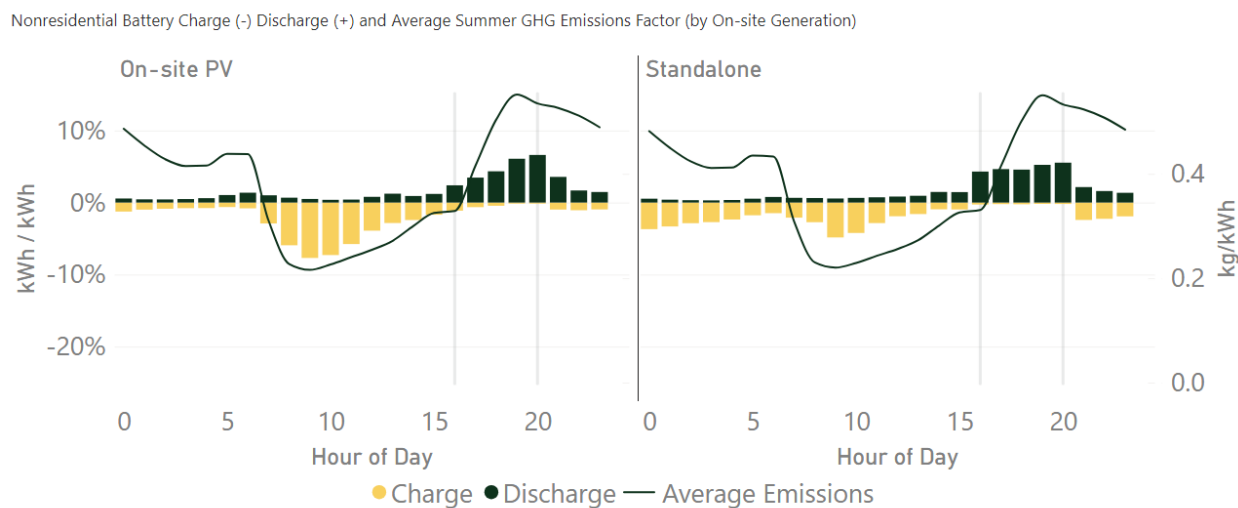


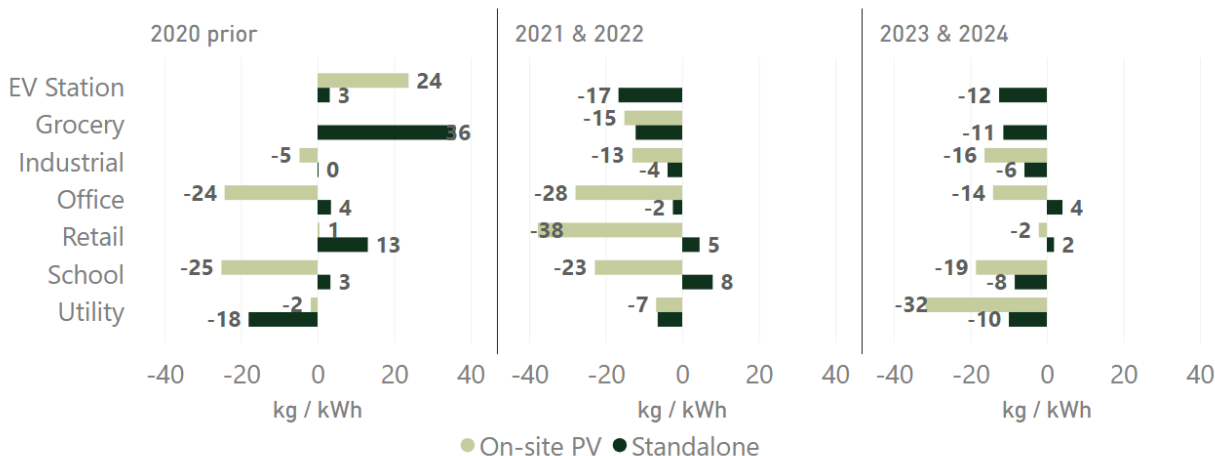
Figure 4-121 is an average across the fleet of nonresidential systems and belies some of the more nuanced performance by budget category, facility type, and battery size. In Figure 4-122, Verdant has combined systems paid in 2020 and prior (left) and compared those against systems paid in 2021-2022 and those paid in 2023 and 2024. Comparisons for each period are made by facility type and presence of on-site PV. Bars moving left from zero represent average reductions in emissions (kg /kWh) for each of the facility types on the left. Bars moving right from the reference line signal increases in emissions. Standalone systems are dark bars, and PV paired systems are presented in light green. For many of the reasons discussed, PV paired systems are reducing emissions – independent of facility type – with magnitudes of reductions similar across project vintage. The more surprising detail is the standalone emissions reductions – particularly for EV stations, grocery, and utility classifications. Systems installed at dedicated EV charging stations are themselves charging exclusively during morning off-peak hours and discharging on peak, potentially due to high peak to off-peak differentials in EV rates, or driver behavior favoring EV charging (and thus SGIP battery discharging) late in the day. Utility classification represents mostly critical facilities incentivized through the ERB. The most common installations are medium duration (4-6 hour)

Overall, improved performance from legacy systems and favorable behavior from more recent installations have improved nonresidential GHG performance in 2024.

batteries installed at wastewater treatment plants servicing a low-income community. As already discussed, these systems regularly discharge throughout peak hours and charge overnight (often creating a new facility peak as a result).

FIGURE 4-122: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY PAYMENT YEAR AND PV

Average GHG Reductions (-) or Increases (+) by Building Type, Payment Year Grouping, and PV Presence



Overall, improved performance from legacy systems and favorable behavior from more recent installations continued to improve nonresidential GHG performance in 2024, relative to past evaluation years, excluding the 2023 study. Verdant also re-created average summer weekday marginal emissions and average charge (yellow) and discharge (green) as percentage of system kWh capacity (Figure 4-123 and Figure 4-124 below). Again, standalone system discharge is focused during the summer on-peak period, which is coincident to greater marginal system emissions. PV paired systems exhibit similar discharge profiles, but the greater magnitude of charging from solar and during lower grid-scale marginal emissions leads to greater overall emissions reductions.

FIGURE 4-123: NONRESIDENTIAL SHAPES AND EMISSIONS BY BUILDING TYPE (STANDALONE SYSTEMS)

Nonresidential Battery Charge (-) Discharge (+) and Average Summer GHG Emissions Factor by Building Type and On-site Generation

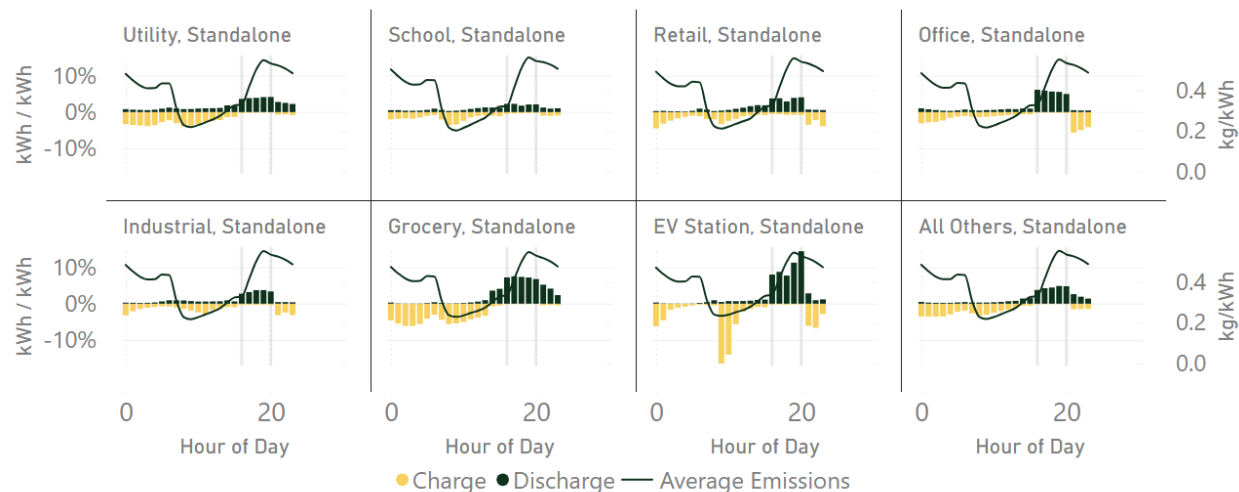


FIGURE 4-124: NONRESIDENTIAL SHAPES AND EMISSIONS BY BUILDING TYPE (ON-SITE PV)

Nonresidential Battery Charge (-) Discharge (+) and Average Summer GHG Emissions Factor by Building Type and On-site Generation

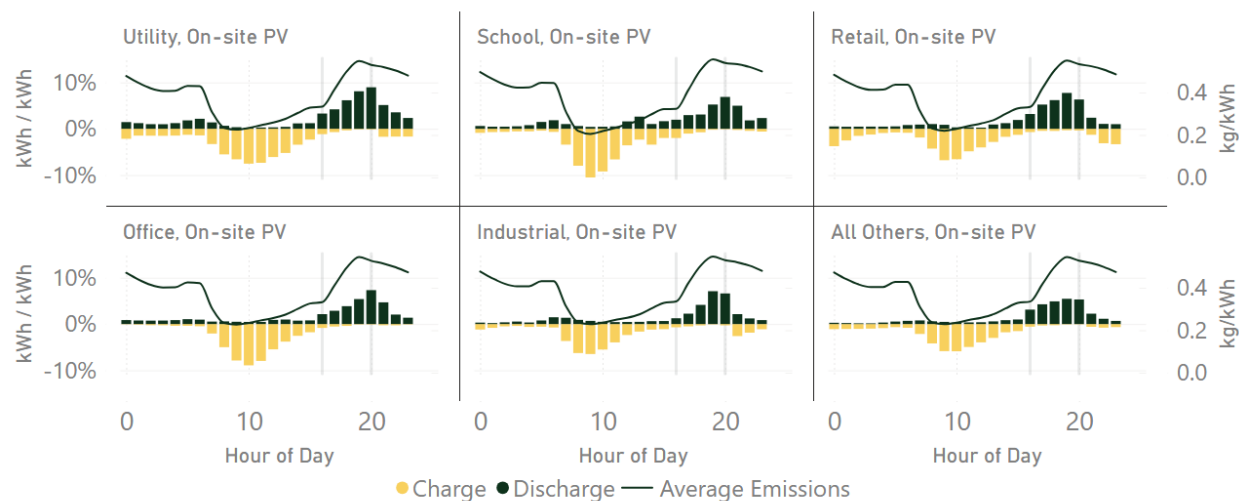


Figure 4-125 through Figure 4-127 present project-specific scatter plots of average emissions increases (+) or reductions (-) and utilization in 2024 for paired versus standalone systems, by budget category and by building type, respectively. Greater utilization generally leads to increases in GHG emissions reductions if the timing of charge and discharge align with emissions. This is especially true for storage systems paired with on-site solar and charging from that early morning generation. Most of the standalone systems

realizing GHG reductions are longer duration ERB installations or systems installed at EV charging stations.

FIGURE 4-125: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY ON-SITE GENERATION

Nonresidential Project GHG Emissions and Utilization by PV Pairing

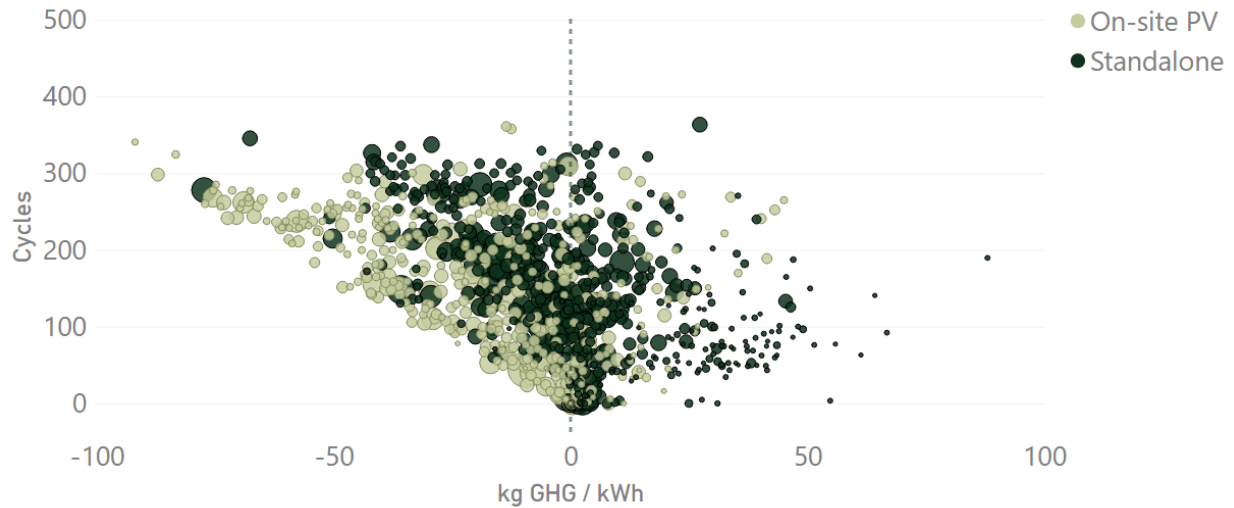


FIGURE 4-126: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY BUDGET CATEGORY

Nonresidential Project GHG Emissions and Utilization by Budget Category

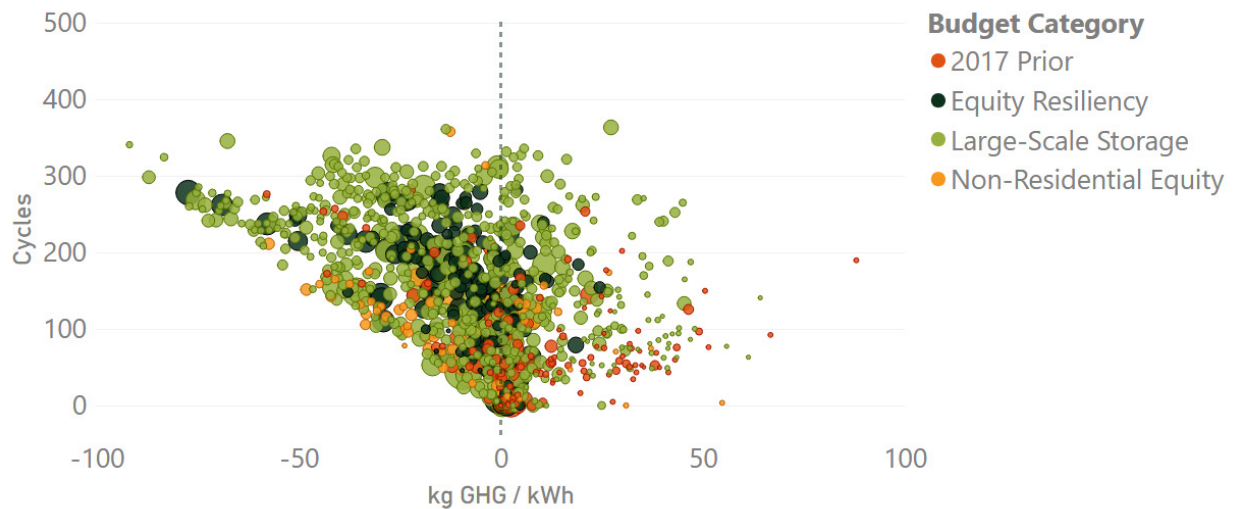


FIGURE 4-127: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY BUILDING TYPE



Residential

Figure 4-128 presents the range in GHG emission reductions (-) or increases (+) for the sample of residential projects analyzed as part of the 2024 impact evaluation by upfront payment date. We observe significant GHG emissions reductions across the residential sector, independent of the length of time the system has been installed and operable – with average emissions reductions ranging from 18 kg/kWh to 22 kg/kWh. Distributions of emissions reveal some variability. The upper quartile for each payment year grouping is negative, signaling 75% or more projects were reducing emissions in 2024 (Figure 4-129).

FIGURE 4-128: EMISSIONS (KILOGRAMS GHG/KWH) FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

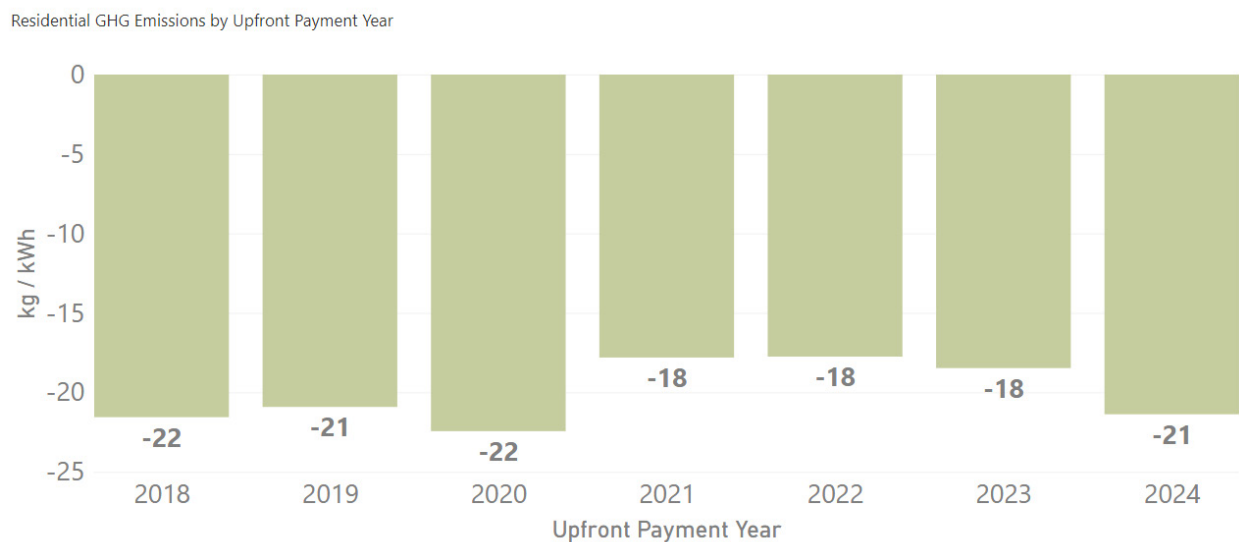
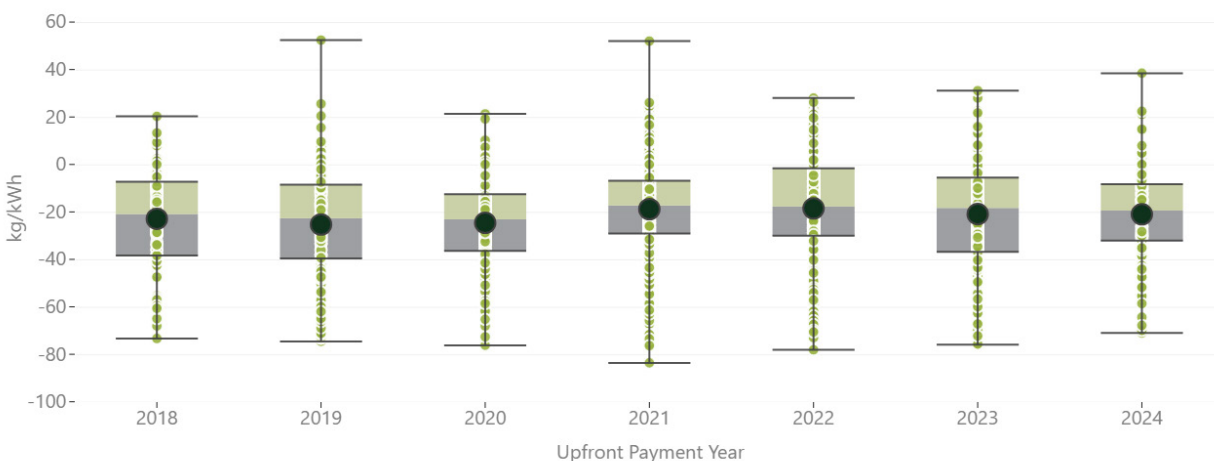


FIGURE 4-129: DISTRIBUTION OF EMISSIONS FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

Distribution of Residential Project GHG Emissions per kWh Capacity (by Payment Year)



From a GHG perspective, the value of charging during on-site PV generating hours cannot be overstated. Furthermore, discharging in late afternoon and early evening, when on-site generation and grid-level renewable generation wanes, provides systems with an opportunity to reduce emissions during high marginal emission periods. These high marginal emissions periods also generally fall within newer on-peak TOU periods, so customers also have an opportunity to realize bill savings if discharging is coincident with high marginal emissions periods. In winter months, marginal emissions are lowest during daylight hours when grid-scale renewables are generating and demand for A/C loads is far less than in summer months. In the summer, marginal emissions are highest during the early morning and, most significantly, during early evening hours on most days.

Well-utilized PV paired residential systems are generally conducting 1) TOU arbitrage without export, 2) TOU arbitrage with export – either regularly or exclusively during specific times like an ELRP event, 3) self-consumption, or 4) some combination of all. We also observe under-utilization – not at a fleet or sector level – but from project to project. Idle, under-utilized systems are likely servicing a load much less than the capacity of the system or are in exclusive backup mode, which is not allowed within the SGIP. We also observe some systems paired with PV that were charging from solar in 2021-2023, but begin charging the battery overnight in 2024, perhaps to take advantage of extremely low off-peak EV billed rates. This latter behavior is far more infrequent and is like that of standalone systems, but the change in charge timing has a dramatic effect on system emissions.

The prevalent residential operating modes are presented in Figure 4-130 and Figure 4-131. Self-consumption is the most frequently observed dispatch behavior in the sample of residential PV paired systems (64%), followed by TOU arbitrage (30%). The mode referred to as “Utilization” combines systems

that are under-utilized or remained idle throughout the entirety of the metering period (roughly 6% of the sample). These figures show how PV-paired systems charging from on-site PV conducting TOU arbitrage are discharging the system on-peak only, where discharge from PV-paired systems conducting self-consumption extends outside the on-peak period and throughout the night. Systems paired with PV, but charging from grid energy (roughly 6% of PV paired projects) have a similar discharge pattern to standalone systems (3% of all projects).

FIGURE 4-130: RESIDENTIAL DISPATCH AND EMISSIONS PV PAIRED SYSTEMS CHARGING FROM PV

Residential PV Paired Battery Charge (-) Discharge (+) and Average Summer GHG Emissions Factor by Operating Mode

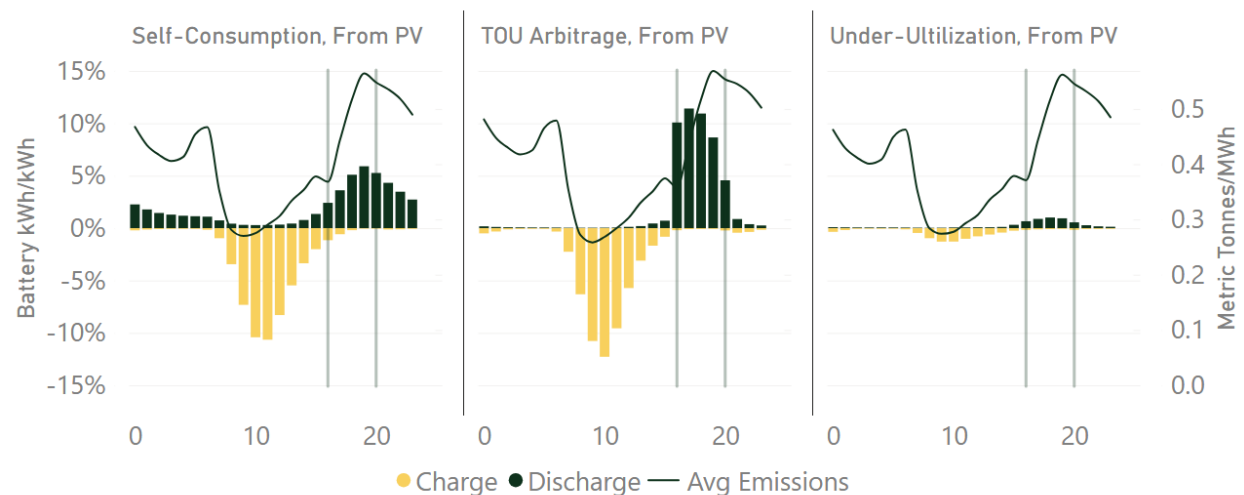
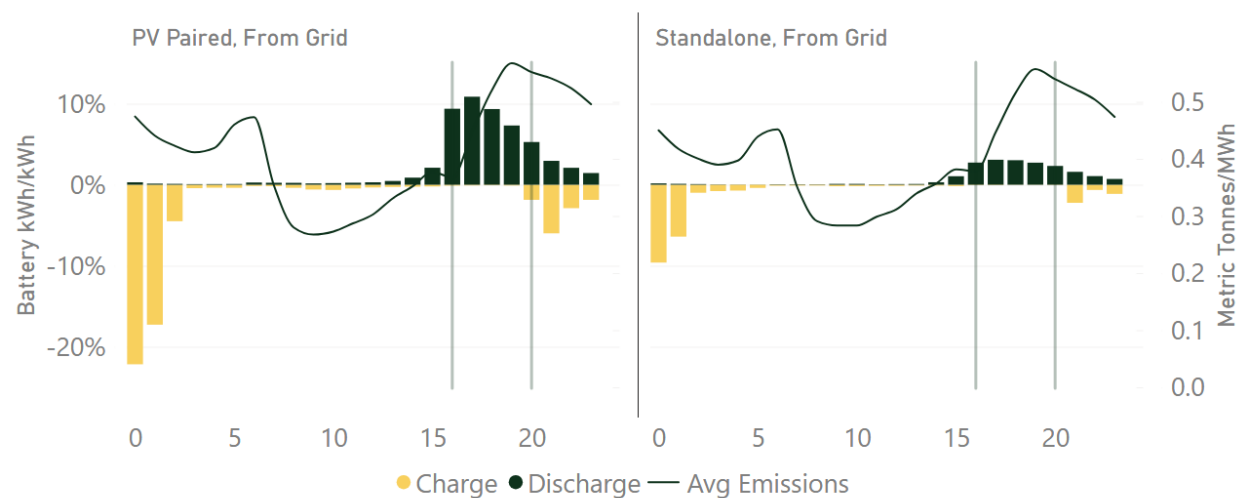


FIGURE 4-131: RESIDENTIAL DISPATCH AND EMISSIONS PV PAIRED AND STANDALONE CHARGING FROM GRID

Residential PV Paired and Standalone Battery Charge (-) Discharge (+) and Average Summer GHG Emissions Factor Charging from Grid

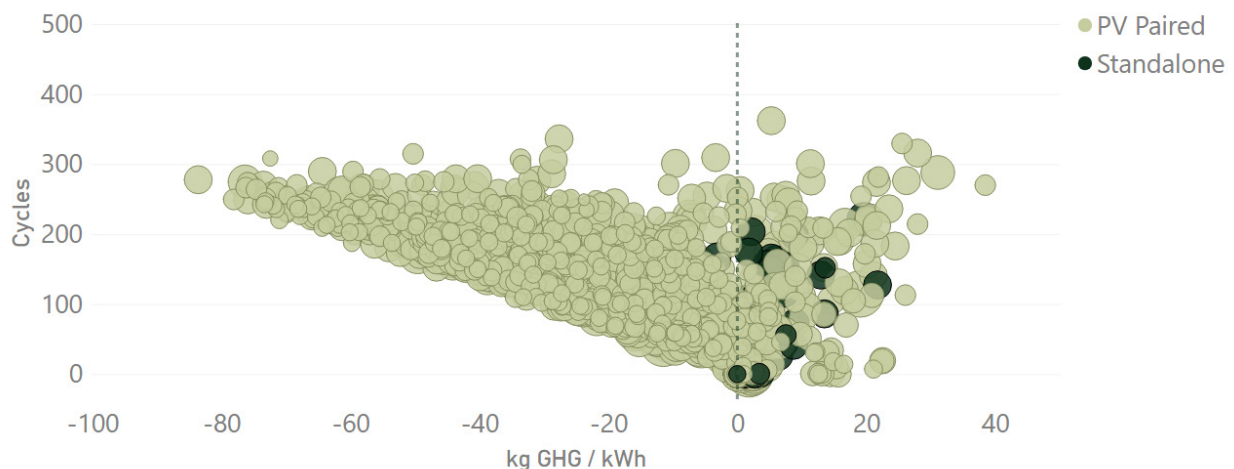


As noted previously, TOU on-peak periods generally run from 4 p.m. to 9 p.m. Marginal emissions are highest during only a portion of that on-peak period on most days, so optimizing for the greatest emissions reductions can be achieved while maintaining bill savings benefits. Most residential systems are two- or three-hour batteries, so a system might be discharged beginning at 4 p.m. to reduce billed energy imports. If discharged at full capacity, the battery would be exhausted before 7 p.m. and likely sooner if the SOC threshold is 20%-30%. If marginal emissions peak during 7 p.m. or 8 p.m., the system has lost the opportunity to maximize emissions reductions. If discharge was held to 7 p.m. or 8 p.m. the customer could realize virtually identical bill savings, with the added benefit of discharging during a period of greater grid stress and emissions.

Figure 4-132 presents the project-specific annual GHG emissions impacts for each residential project in 2024 by PV pairing. Emissions in kg GHG/kWh of capacity are represented on the horizontal axis with emissions reductions (negative) on the left of the vertical axis and increases (positive) on the right of the vertical axis. Annual cycles, a proxy for system utilization, are also plotted on the vertical axis to highlight the correlation between greater utilization and emissions magnitudes. PV paired systems are almost invariably reducing emissions (if well utilized) and standalone systems are all increasing emissions. The emissions differentials between charging overnight and discharging on peak are not sufficient for standalone systems to realize emissions reductions like observed with PV paired systems charging from on-site PV during much lower emissions hours.

FIGURE 4-132: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY PV PAIRING

Residential Project GHG Emissions and Utilization by PV Pairing



Project emissions for PV paired systems conducting arbitrage, self-consumption, or doing nothing (a proxy for under-utilization or backup) are presented in Figure 4-133. Idle systems generally lead to small increases in emissions as system parasitic loads accumulate over the course of the year.

FIGURE 4-133: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY OPERATING MODE

Residential Project GHG Emissions and Utilization by Operating Mode

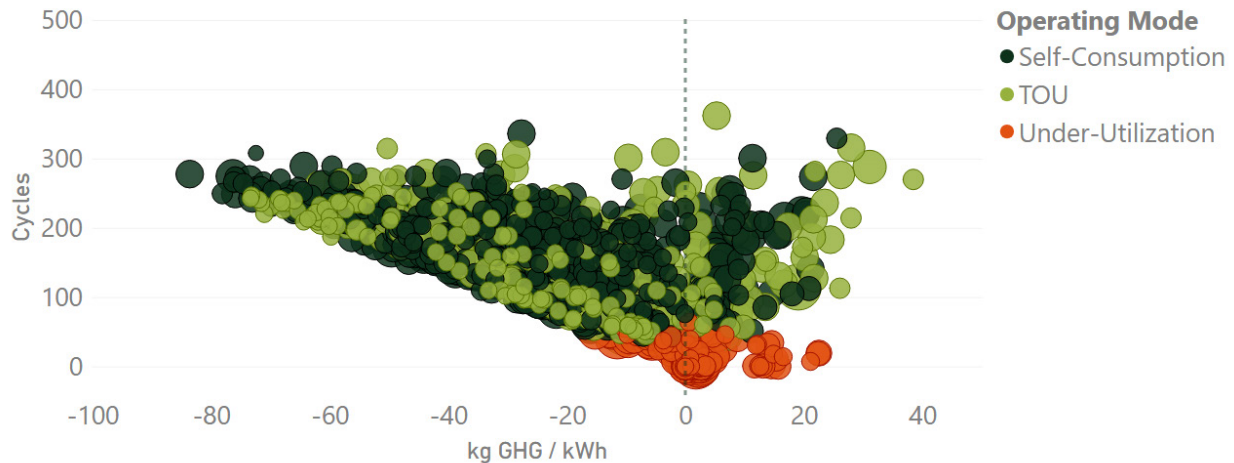
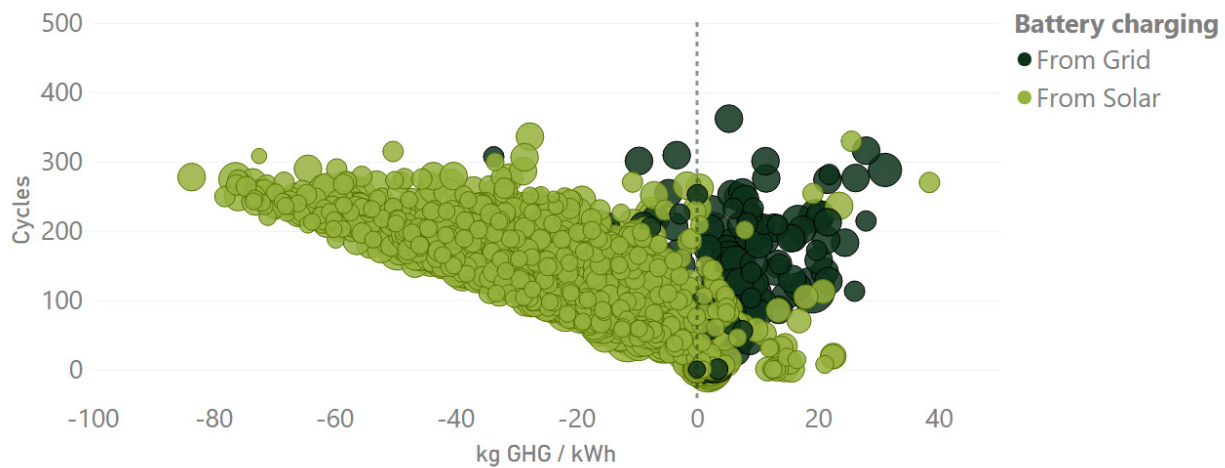


Figure 4-134 presents emissions based on the source of energy storage charging. Systems paired with PV, but charging from grid energy after the on-peak or overnight are increasing emissions, much like standalone systems are doing. Again, the emissions differentials between charging overnight and discharging on peak are not sufficient for these systems to realize the same degree of emissions reductions we would expect to observe if these systems charged from on-site PV instead.

FIGURE 4-134: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY CHARGING SOURCE

Residential Project GHG Emissions and Utilization by Charging Source



Overall GHG Impact Summaries

The following figures summarize the GHG impacts discussed for both the nonresidential and residential sectors, respectively. Comparisons are provided by different domains of interest, including by PA, PV pairing, legacy status, and upfront payment year.

FIGURE 4-135: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PA

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh
BY PROGRAM ADMINISTRATOR

Program Administrator	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
CSE	188	230	578	981	973	-1%	-10
PG&E	372	297	805	1,128	1,119	-1%	-9
SCE	451	286	761	840	830	-1%	-11
SCG	64	403	1,154	408	394	-4%	-14
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-136: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY ON-SITE GENERATION

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh
BY ON-SITE GENERATION

On-site Generation	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
On-site PV	455	268	669	646	630	-3%	-17
Standalone	620	301	840	1,084	1,078	-1%	-6
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-137: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PROGRAM YEAR

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh
BY PROGRAM YEAR

Program Year	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2012-2014	50	361	722	3,620	3,623	0%	3
2015	49	282	564	1,603	1,605	0%	2
2016	52	125	250	1,880	1,883	0%	1
2017	297	199	414	1,472	1,461	-1%	-10
2018	54	426	861	1,091	1,087	-0%	-6
2019	71	440	912	1,435	1,430	-0%	-7
2020	372	307	972	489	477	-2%	-13
2021	94	351	1,373	342	323	-5%	-15
2022-2024	36	273	651	311	302	-3%	-9
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-138: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY BUDGET CATEGORY

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh

BY BUDGET CATEGORY

Budget Category	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2017 Prior	151	254	508	2,530	2,533	0%	2
Equity Resiliency	199	287	1,395	190	177	-7%	-12
Large-Scale Storage	659	298	649	1,104	1,094	-1%	-12
Non-Residential Equity	66	253	653	1,026	1,014	-1%	-11
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-139: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh

BY PAYMENT YEAR

Payment Year	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2017 Prior	84	317	634	2,966	2,970	0%	4
2018	64	138	272	1,641	1,640	-0%	-1
2019	208	169	351	1,414	1,399	-1%	-15
2020	83	323	675	1,695	1,690	-0%	-6
2021	145	364	762	1,374	1,369	-0%	-6
2022	186	261	814	442	430	-3%	-12
2023	182	342	1,137	458	442	-4%	-17
2024	123	387	1,271	410	401	-2%	-8
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-140: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY BUILDING TYPE

n prjs, kW, kWh, Post GHG, Baseline GHG, % Reduction, GHG kg/kWh

BY BUILDING TYPE

Building Type	n prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
All Others	187	368	1,021	1,483	1,476	-0%	-9
EV Station	118	292	598	748	734	-2%	-13
Grocery	55	117	523	697	687	-1%	-11
Industrial	167	401	854	1,420	1,417	-0%	-6
Office	71	334	719	1,157	1,151	-1%	-7
Retail	76	207	442	1,351	1,350	-0%	-1
School	279	187	479	473	455	-4%	-17
Utility	122	332	1,424	273	260	-5%	-12
Overall	1075	287	767	934	924	-1%	-10

FIGURE 4-141: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
CSE	285	9	24	142	113	-20%	-28
PG&E	1035	9	23	113	101	-10%	-11
SCE	590	8	21	178	149	-16%	-29
SCG	96	9	24	140	109	-22%	-30
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-142: SUMMARY OF RESIDENTIAL GHG IMPACTS BY ON-SITE GENERATION

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY ON-SITE PV

On-site PV	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
PV Paired	1953	9	22	134	114	-15%	-20
Standalone	53	10	26	182	186	3%	5
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-143: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PAYMENT YEAR

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY PAYMENT YEAR

Payment Year	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2018	120	7	18	220	198	-10%	-22
2019	165	7	17	180	159	-12%	-21
2020	259	8	20	162	139	-14%	-22
2021	576	10	25	126	108	-14%	-18
2022	423	9	25	122	105	-14%	-18
2023	309	8	21	114	95	-16%	-18
2024	154	9	21	133	111	-16%	-21
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-144: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA BY BUDGET CATEGORY

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY BUDGET CATEGORY

Budget Category	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
Equity Resiliency	607	11	28	114	96	-16%	-18
Large-Scale Storage	122	16	40	107	92	-14%	-15
SJV	44	10	26	160	162	1%	2
Small Storage	1231	7	18	157	135	-14%	-22
Storage Equity	2	8	20	279	233	-17%	-46
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-145: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA BY PROGRAM YEAR

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY PROGRAM YEAR

Program Year	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2017	110	8	20	171	151	-11%	-20
2018	185	7	17	204	182	-11%	-22
2019	183	8	21	153	131	-14%	-21
2020	778	10	25	128	109	-15%	-19
2021	310	9	25	130	113	-13%	-17
2022	205	8	21	117	99	-15%	-18
2023	180	7	19	115	94	-18%	-21
2024	55	9	21	136	116	-14%	-20
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-146: SUMMARY OF RESIDENTIAL GHG IMPACTS BY OPERATING MODE

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh

BY OPERATING MODE

Operating Mode	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
Self-Consumption	1248	9	23	113	89	-21%	-23
TOU Arbitrage	496	8	21	196	177	-10%	-19
Under-Utilization	251	10	25	142	142	1%	1
Unknown	11	8	19	175	176	0%	1
Overall	2006	9	22	135	116	-14%	-19

FIGURE 4-147: SUMMARY OF RESIDENTIAL GHG IMPACTS BY CHARGING SOURCE

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY ON-SITE PV CHARGING

On-site PV	Charging	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
PV Paired	From Grid	111	10	26	194	201	3%	7
PV Paired	From Solar	1842	9	22	130	108	-17%	-22
Standalone	From Grid	53	10	26	182	186	3%	5
Overall		2006	9	22	135	116	-14%	-19

4.4.2 Generation

Passage of SB 412 in 2009 required the CPUC to establish GHG goals for the SGIP. Therefore, most of the generation projects in the population today are designed with GHG goals in mind. Non-renewable projects, in general, were found to increase emissions during 2024, however; there were a few non-renewable projects with high rates of heat recovery that decreased emissions during 2024. Renewably fueled projects reduced emissions, with systems with vented baselines contributing to the highest reductions in emissions. Non-fueled technologies like wind and pressure reduction turbines also reduced emissions.

The projects impacts observed in this section include all projects with metered data for all applicable streams of data. For example, wind turbine projects only require energy generation data. Combustion technologies without heat recovery would only require energy generation and fuel consumption data. However, combustion technologies with heat recovery would require energy generation, fuel consumption, and heat recovery data. Heat recovery is notoriously difficult to meter. The limited quantity of metered heat recovery data is used in the calculation of population-level GHG estimates for CHP systems using methods discussed in Appendix E.

The GHG impact analysis is limited to carbon dioxide (CO₂) and CO₂ equivalent (CO₂eq) emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

- Methodology Overview and Summary of Environmental Impacts
- Non-Renewable Generation Project Impacts
- Renewable Biogas Generation Project Impacts
- Waste Gas and Non-Fueled Project Impacts

The scope of this analysis is further limited to the operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and

construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix D.

Background and Baseline Discussion

Emission impacts are calculated as the difference between the emissions generated by SGIP projects and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat may avoid emissions associated with displacing boiler use.

Grid Electricity Baseline

The passage of SB 412 established a maximum GHG emissions rate for SGIP generation technologies. Beginning in 2011, eligibility for SGIP generation projects was limited to projects that did not exceed an emissions rate of 379 kg CO₂/MWh over 10 years. Later, the CPUC revised the maximum GHG emissions rate for eligibility to 350 kg CO₂/MWh over 10 years for projects applying to the SGIP in 2016. During 2024, only one microturbine project was observed to have a GHG rate over this threshold, seeing a GHG impact rate of 441 kg CO₂/MWh.

When developing these emission factors for eligibility, the CPUC and the SGIP PAs must look forward and forecast what baseline grid conditions will look like during an SGIP project's service life. These forecasts must make assumptions about power plant efficiencies and the useful life of SGIP projects. By contrast, an impact evaluation has the benefit of being backward-looking and can leverage historical data to quantify the grid electricity baseline. Consequently, the avoided grid emissions rates used in this impact evaluation report to assess project performance are different than the avoided grid emissions factors used to screen SGIP applications for program eligibility requirements. This evaluation relies on avoided grid emissions rates developed by WattTime as part of the SGIP GHG Signal efforts.⁵⁵

Non-Renewable Generation Project Greenhouse Gas Impacts

SGIP non-renewable generation projects include fuel cells (CHP and electric-only), gas turbines, internal combustion engines, and microturbines. These include those directed biogas projects that have met their contractual procurement requirements and are assumed to no longer procure renewable fuel. These projects are powered by natural gas and are used to generate electricity to serve a customer's load. These projects produce emissions that are proportional to the amount of fuel they consume. In the absence of

⁵⁵ The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: <https://sgipsignal.com/>.

the program, the customer’s electrical load would have been served by the electricity distribution company. If SGIP projects only served electrical loads, they would need to generate electricity more cleanly than the avoided marginal grid generator to achieve GHG emission reductions.

CHP projects recover waste heat and use it to serve on-site thermal loads, like a customer’s heating or cooling needs. In the absence of the SGIP, a heating end-use is assumed to be met by a natural gas boiler, and the cooling end-use met with an electric chiller. Natural gas boilers generate emissions associated with the combustion of gas to heat water. The emissions associated with electric chillers are due to the central station plant that would have generated the electricity to run the chiller. Emissions impacts are the difference between the SGIP emissions and those avoided emissions. As shown below in Figure 4-148, observed non-renewable gas turbines and internal combustion engines were found to reduce emissions due to their high rates of heat recovery, however, other non-renewably fueled generators were observed to increase emissions.

FIGURE 4-148: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACTS RATES BY TECHNOLOGY TYPE

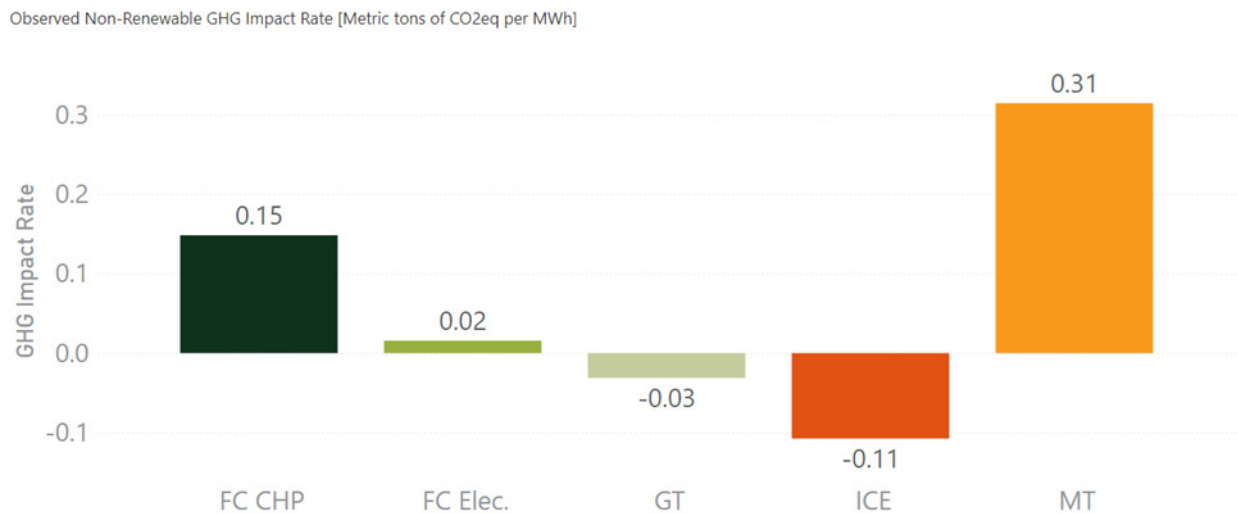


Table 4-6 shows the impact rates of the individual contributors to the GHG impact calculations. Non-renewable technologies have a higher emissions rate than the electrical power plants that they avoid ($A > B$). Even when accounting for the heating and cooling services avoided, the emissions impact (F) is generally higher, relative to the conventional energy services baseline.

TABLE 4-6: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE
[METRIC TONS OF CO₂EQ PER MWH]

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Cooling Services [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell CHP	0.56	0.37	0.05	0.00	0.42	0.15
Fuel Cell Electric	0.39	0.37	0.00	0.00	0.37	0.02
Gas Turbine	0.60	0.36	0.27	0.00	0.63	-0.03
Internal Combustion Engine	0.48	0.35	0.24	0.00	0.59	-0.11
Microturbine	0.74	0.36	0.05	0.01	0.42	0.31
Total	0.55	0.36	0.12	0.00	0.49	0.07

Figure 4-149 shows the 2024 range of GHG impact rates for each project by equipment type. Microturbines and CHP fuel cells all increased emissions, while impact rates for other technologies varied, with most systems increasing emissions and a few decreasing emissions.

FIGURE 4-149: OBSERVED NON-RENEWABLE PROJECT-LEVEL GREENHOUSE GAS IMPACTS TECHNOLOGY TYPE



Renewable Biogas Project Impacts

SGIP renewable biogas projects include CHP fuel cells, internal combustion engines, microturbines, and gas turbines. About 15% of the total SGIP generation is fueled, at least partially, by renewable biogas. Sources of biogas include landfills, water resource and recovery (WRRF), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due, in part, to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. Also, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix E.

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO₂ equivalent (CO₂eq) so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH₄ is 25 times that of CO₂. The biogas baseline estimates of vented emissions (CH₄ emissions from renewable SGIP facilities) are converted to CO₂eq by multiplying the metric tons of CH₄ by 25. In this section, CO₂eq emissions are reported if projects with a biogas venting baseline are included. Otherwise, CO₂ emissions are reported.

The 2024 GHG performance of renewably fueled biogas SGIP projects is summarized in Figure 4-150 by technology type and biogas baseline. Only all-renewable fueled projects where metered data was available are shown. Almost all renewable fueled projects were found to decrease GHG impacts, and on average, technologies at least partially fueled by renewable fuel were found to reduce GHG emissions.

FIGURE 4-150: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

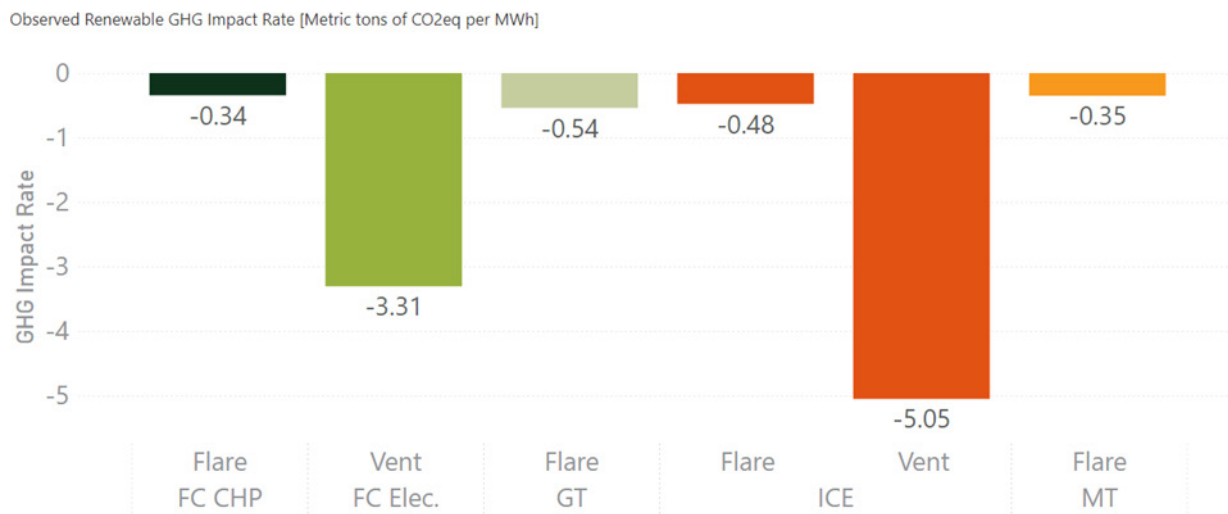


Table 4-7 highlights the impact rates for renewably fueled technologies, separated by biogas baseline type. Technologies with flaring biogas achieved reductions between 0.34 and 0.54 metric tons of CO₂ per MWh. All-electric fuel cells with vented biogas baselines achieved GHG reductions that were an order of magnitude greater, over 3 metric tons of CO₂eq per MWh, while vented internal combustion engines achieved emissions reductions of over 5 metric tons of CO₂eq per MWh due to their heat recovery.

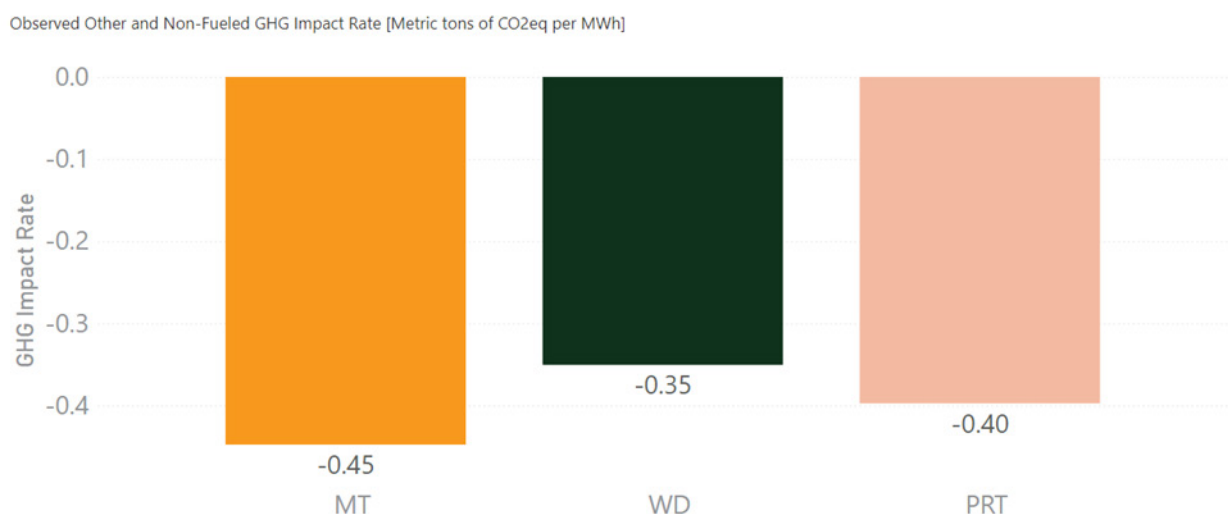
TABLE 4-7: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE [METRIC TONS OF CO₂EQ PER MWH]

Equipment Type (Baseline Type)	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell CHP (Flare)	0.59	0.41	0.03	0.50	0.93	-0.34
Fuel Cell Electric (Vent)	0.36	0.38	0.00	3.29	3.67	-3.31
Gas Turbine (Flare)	0.58	0.36	0.27	0.50	1.13	-0.54
ICE (Flare)	0.63	0.37	0.18	0.56	1.11	-0.48
ICE (Vent)	0.56	0.37	0.13	5.11	5.62	-5.05
Microturbine (Flare)	0.81	0.39	0.09	0.69	1.16	-0.35
Total	0.59	0.38	0.11	1.77	2.27	-1.68

Other-Fueled and Non-Fueled Projects Impacts

Wind and pressure reduction turbine projects do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates are equal to the emissions rate of the grid, as described in Appendix D. Figure 4-151 summarizes the impact rate and overall GHG impact from these projects. A single microturbine was also fueled by waste gas from oil and gas drilling processes. All other non-fueled projects were found to decrease emissions.

FIGURE 4-151: OBSERVED OTHER AND NON-FUELED GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE



The individual impacts are shown in Table 4-8. There are no baseline emissions for non-fueled technologies, so the emissions impact is the inverse of the electric power plant emissions for the same amount of electrical generation.

TABLE 4-8: OBSERVED NON-FUELED PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E=B + C + D]	Emissions Impact [F=A-E]
Microturbine	0.91	0.38	0.06	0.91	1.36	-0.45
Wind	0	0.35	0	0	0.35	-0.35
Pressure Reduction Turbine	0	0.40	0	0	0.40	-0.40
Total	0.30	0.38	0.02	0.30	0.70	-0.40

GHG Impact Summaries

The following figures summarize the observed GHG impacts discussed by technology type and fuel type.

FIGURE 4-152: SUMMARY OF NON-RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation [GWh]	GHG [MT/MWh]
Fuel Cell CHP	4	4.43	0.17
Fuel Cell Electric	176	2.38	0.01
Gas Turbine	2	219.63	-0.03
Internal Combustion Engine	2	10.19	-0.05
Microturbine	4	5.45	0.32
Total	188	4.89	0.02

FIGURE 4-153: SUMMARY OF RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation [GWh]	GHG [MT/MWh]
Fuel Cell CHP	2	4.52	-0.34
Fuel Cell Electric	1	7.02	-3.31
Gas Turbine	1	75.20	-0.54
Internal Combustion Engine	15	3.64	-1.95
Microturbine	1	0.72	-0.35
Total	20	7.33	-1.70

FIGURE 4-154: SUMMARY OF OTHER-FUELED AND NON-FUELED GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation [GWh]	GHG [MT/MWh]
Microturbine	1	1.87	-0.45
Wind	7	5.04	-0.36
Pressure Reduction Turbine	3	0.37	-0.39
Total	11	3.48	-0.38

4.5 UTILITY MARGINAL COST IMPACTS

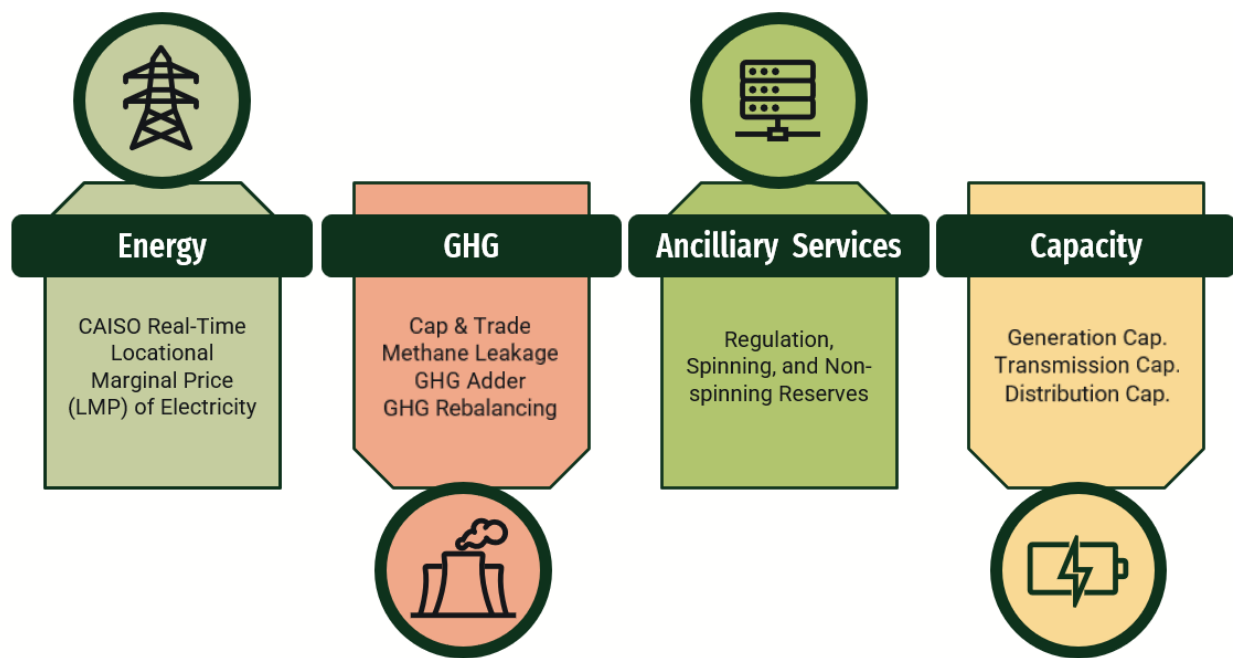
Utility marginal cost impacts for each IOU were calculated for each hour in 2024. These costs correspond to transactions in several types of markets, and market type dictates selection of data sources and analytic methods used to estimate marginal costs. The CAISO markets were the source of data for several utility costs, most notably, real-time energy price.

Entirely different types of markets influence marginal capacity costs incurred by utilities. As such, the 2024

Avoided Cost Calculator (ACC) served as the source of marginal utility costs for generation capacity, distribution capacity, and transmission capacity. Estimated costs for these capacity elements reflect underlying assumptions used in the ACC. Of note this year is the fact that the 2024 ACC employed a new analytic methodology to calculate estimates of marginal generation capacity cost. As a result of this change, estimated marginal generation capacity costs used to calculate 2024 SGIP impacts are lower than those used previously to calculate 2023 SGIP impacts.⁵⁶

The marginal GHG emissions rates introduced in the previous section were calculated by WattTime using marginal electricity, natural gas, and carbon price data. The same marginal electricity and carbon price data were used to calculate utility marginal cost impacts as were used to calculate GHG impacts. The data and assumptions used for each utility cost component are described in detail in Appendix E. The electric utility costs that were included in this analysis are shown below in Figure 4-155.

FIGURE 4-155: ELECTRIC AVOIDED UTILITY COSTS

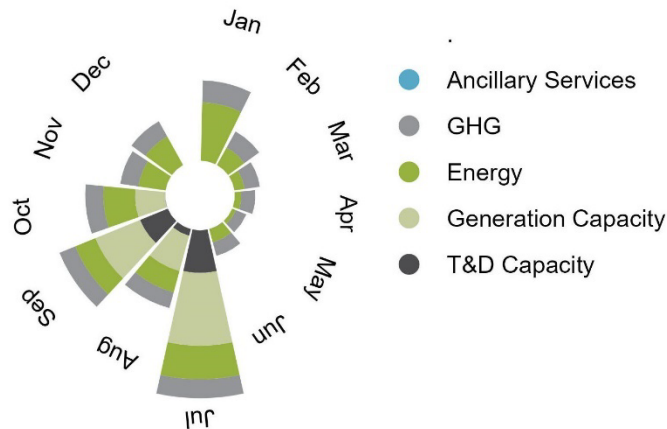


Energy costs, GHG adders, and cap and trade costs represent the most consistent share of avoided costs throughout the year. A high-level summary of these patterns is shown in Figure 4-156, where the values

⁵⁶ 2024 Distributed Energy Resources Avoided Cost Calculator Documentation, for the California Public Utilities Commission, October 2, 2024, Version 1b, at 37-38. Available at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

represent averages across the three electric IOUs.⁵⁷ During April and May, when there are longer days and plentiful grid-scale renewable generation without the A/C demand of summer months, these costs generally are lower. However, during summer months – June through September – there are some significantly capacity-constrained hours. (Ancillary services are included in the chart for the sake of completeness, however those values are so small that they are indistinguishable in the chart.)

FIGURE 4-156: AVERAGE 2024 MARGINAL ELECTRIC UTILITY COSTS BY MONTH AND COST CATEGORY



Sources: CAISO and 2024 Avoided Cost Calculator

4.5.1 Energy Storage

Previous sections have detailed the nuanced observed behavior of nonresidential and residential energy storage systems within the SGIP. When the timing and magnitude of charge and discharge follow the price signal of a customer tariff or a marginal emissions signal, storage performance can lead to customer bill savings and avoided GHG emissions. The same is true for utility costs.

For energy storage systems to reduce utility costs, the marginal costs *avoided* during storage discharge must be greater than the marginal cost increase during storage charging. Since storage technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate must be lower during charging hours relative to discharge hours if utility cost savings are to be realized. In other words, SGIP storage systems that charge during lower marginal cost periods and discharge during

⁵⁷ In this exhibit, losses are included with 'Energy' and methane leakage is included with 'GHG.'

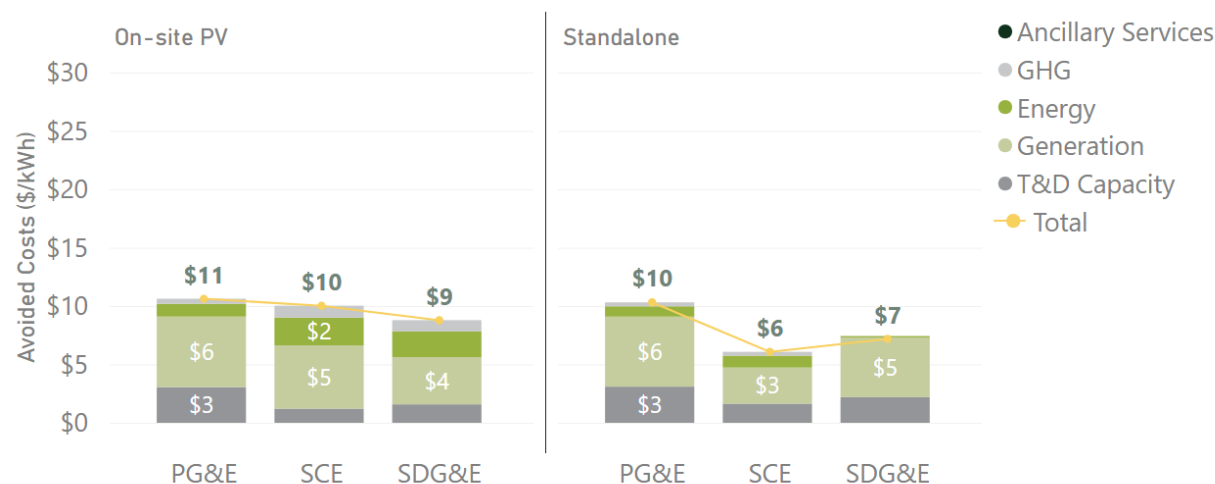
higher marginal cost periods will provide a net benefit to utility systems.

Nonresidential Utility Avoided Costs

The normalized utility marginal avoided costs in 2024 are shown in Figure 4-157 by electric IOU for standalone nonresidential energy storage systems and those paired or co-located with on-site PV. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The timing, magnitude and duration of nonresidential storage charge and discharge behavior provided an avoided cost benefit to all electric utilities in 2024. SGIP storage systems were charging during lower marginal cost periods – particularly systems paired with on-site PV – and discharging during higher cost periods, which also coincide with billed on-peak hours and times of greater marginal emissions. Marginal costs are highest when energy prices are high, and generation capacity and transmission and distribution (T&D) systems are constrained. On average, energy storage systems are discharging during the most constrained hours (and not charging). The average marginal *avoided* cost (+) for standalone systems and those co-located or paired with on-site PV are similar for each of the IOUs, with marginally greater benefits being realized, on average, for systems paired or co-located with solar PV.

FIGURE 4-157: NONRESIDENTIAL AVOIDED COST \$ PER CAPACITY KWH BY IOU

Observed Nonresidential Utility Avoided Costs per kWh Capacity by IOU and On-site Generation



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Figure 4-158 and Figure 4-159 provide the distribution of nonresidential project avoided costs for 2024. Moving right along the horizontal axis from zero signals avoided cost benefits to the utility. The vertical axis ties the utilization of the system in annual cycles to the utility costs, where a correlation between greater utilization and increased utility avoided cost benefit is evident. The size of the bubble corresponds to the relative kWh size of the system, with many of the smaller systems exhibiting lower utilization and

small utility cost increases from performance in 2024. Distributions are presented in Figure 4-160.

FIGURE 4-158: NONRESIDENTIAL PROJECT AVOIDED COST \$ PER CAPACITY KWH BY IOU

Nonresidential Project Utility Avoided Costs and Utilization by IOU

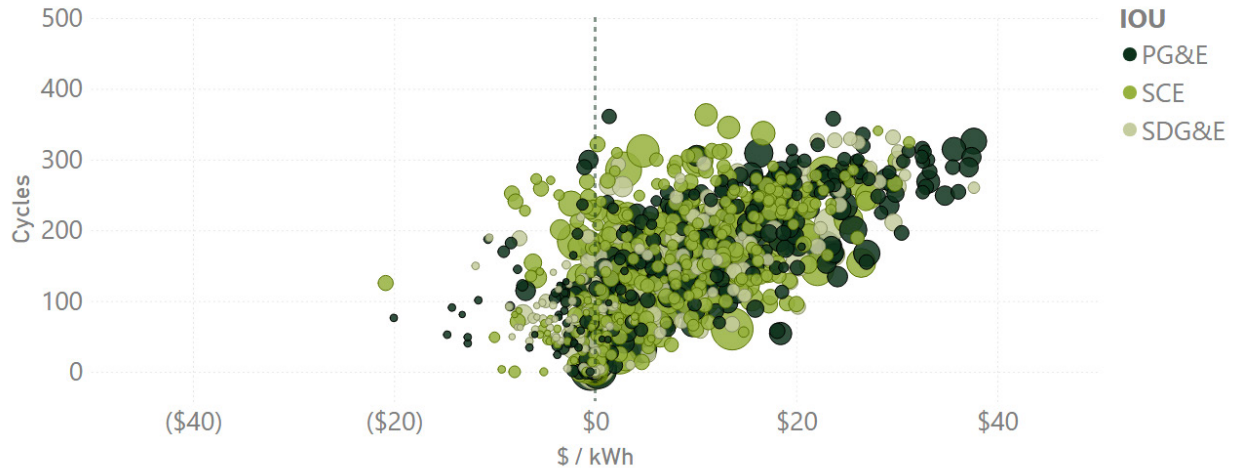


FIGURE 4-159: NONRESIDENTIAL PROJECT AVOIDED COST \$ PER CAPACITY KWH BY ON-SITE GENERATION

Nonresidential Project Utility Avoided Costs and Utilization by On-site Generation

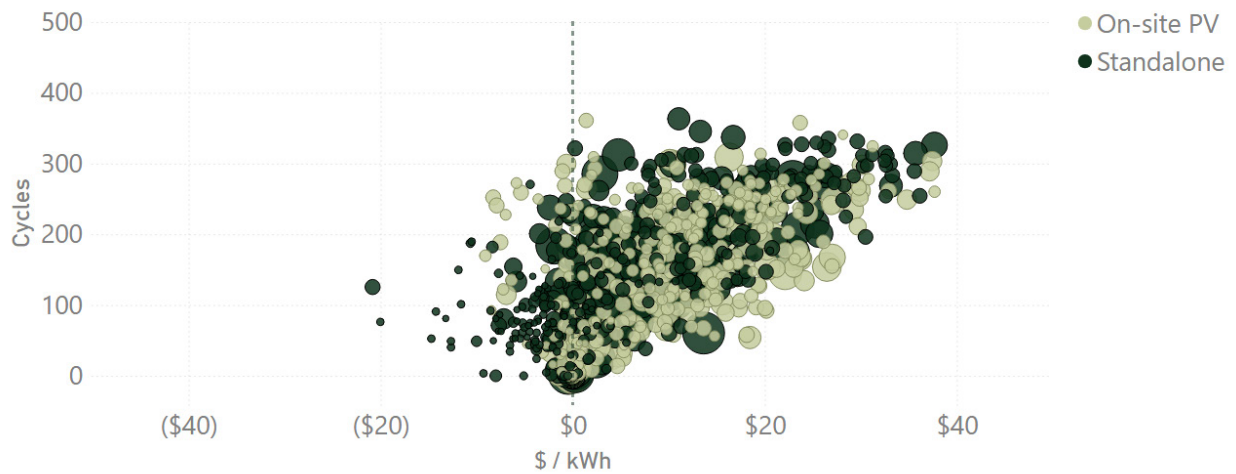
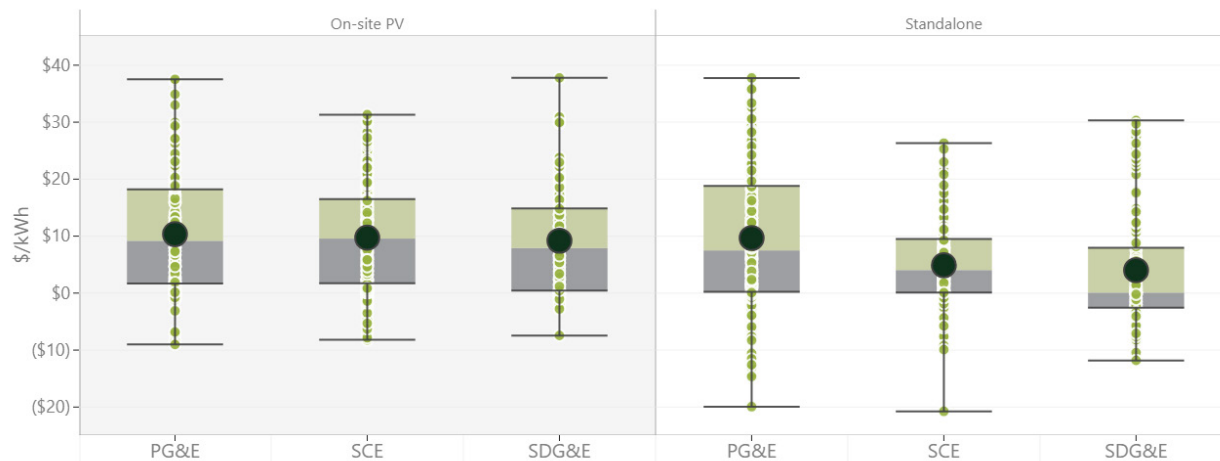


FIGURE 4-160: DISTRIBUTION OF NONRESIDENTIAL AVOIDED COSTS \$ /KWH BY IOU AND ON-SITE GENERATION

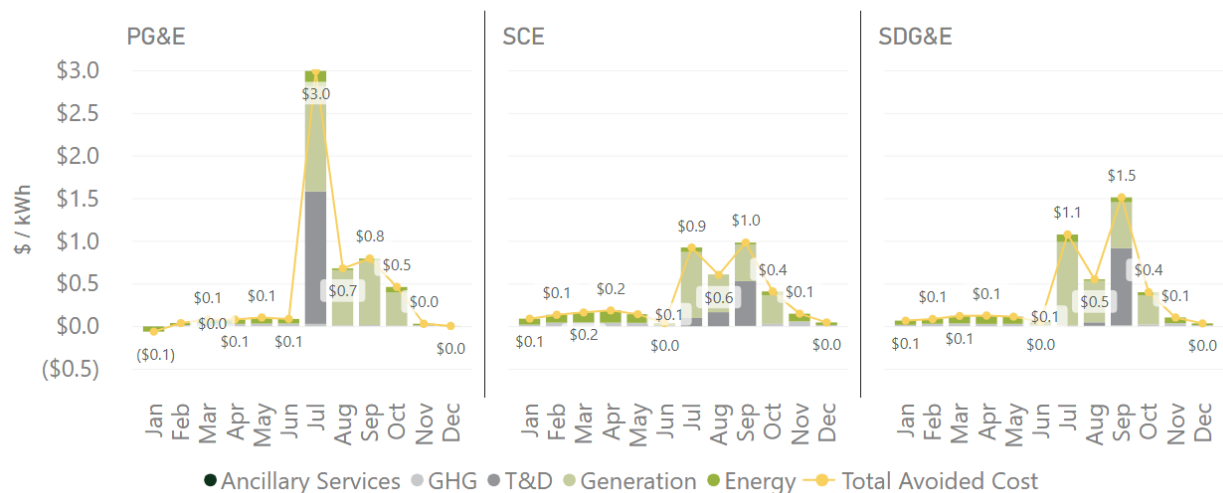
Avoided Cost \$ per kWh Capacity



The timing of utility avoided cost benefit is evident in Figure 4-161, which presents how those avoided cost benefits are allocated across months during 2024 for each IOU. Again, the marginal costs modeled in this study are highest when energy prices are high, and the CAISO system load is peaking. Most of the system cost value is captured in a small number of high-cost hours that are generation capacity constrained. These hours generally align with net peak CAISO hours, which is evident with the magnitude of savings in July and September compared to other months throughout the year.

FIGURE 4-161: NONRESIDENTIAL MARGINAL AVOIDED COST \$ PER CAPACITY KW BY MONTH AND IOU

Observed Nonresidential Monthly Utility Avoided Costs per kWh Capacity (by IOU)

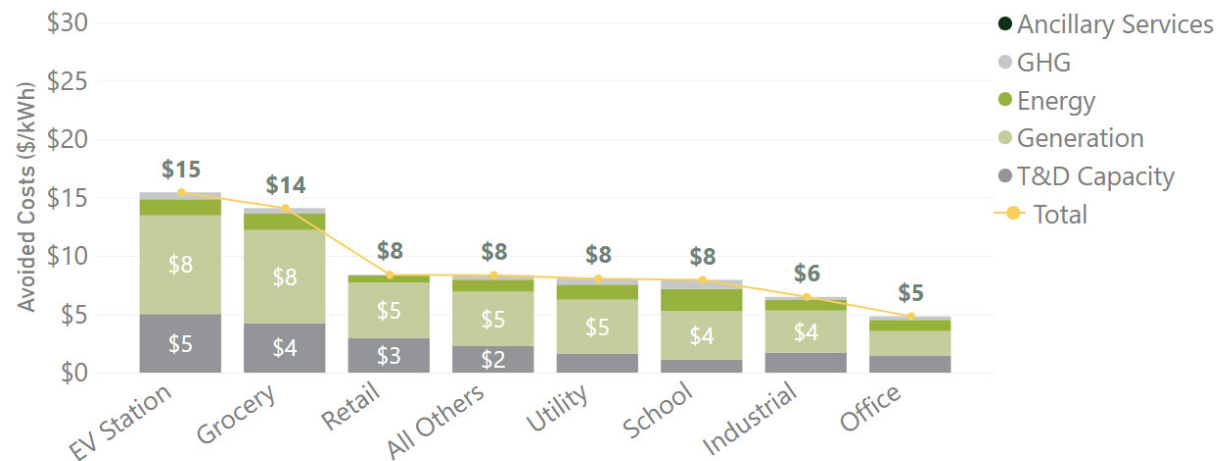


Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Figure 4-162 presents the average utility avoided cost benefits in \$/kWh capacity by nonresidential facility type. We observed targeted discharge and greater utilization of systems installed at EV stations during on-peak hours. This discharge behavior allows for greater realized utility avoided cost benefits.

FIGURE 4-162: NONRESIDENTIAL MARGINAL AVOIDED COST \$ PER CAPACITY KWH BY BUILDING TYPE

Observed Nonresidential Utility Avoided Costs per kWh Capacity by Building Type



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Residential Utility Avoided Costs

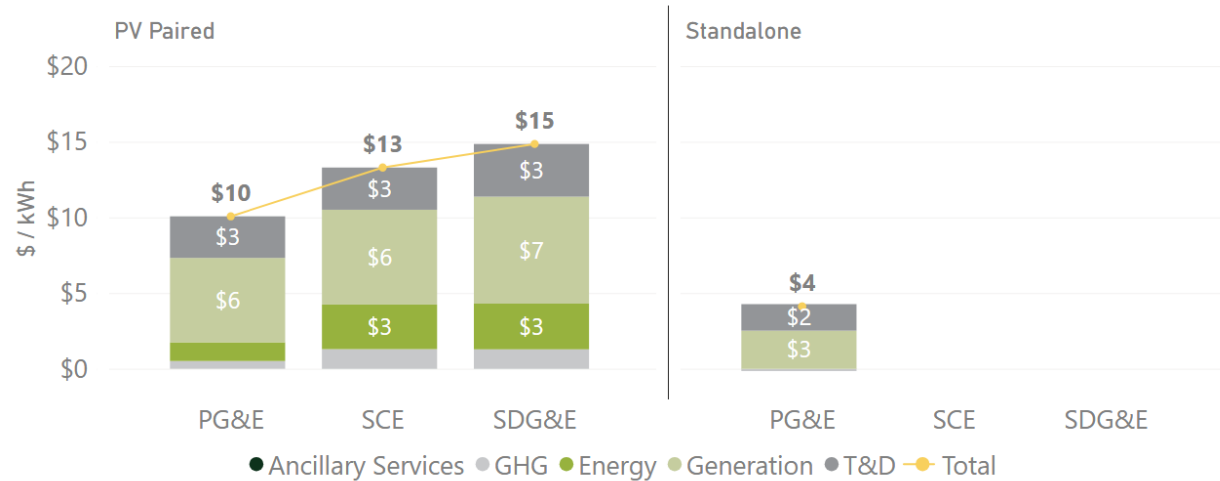
Prior sections of the evaluation have detailed how residential systems are being utilized for TOU arbitrage and self-consumption. When paired with on-site PV, systems are discharging exclusively on-peak or on-peak *and* to zero out delivered load. Furthermore, some systems are discharging beyond BTM consumption and exporting excess battery kWh capacity to the grid during on-peak hours. Export is standard daily practice for some groups of systems and wholly event based (ELRP, for example) for other groups.

Either way, these behaviors are advantageous from a customer bill, a system load, and GHG perspective. Given the correlation between billed on-peak hours of 4 p.m. – 9 p.m., CAISO net loading, and marginal grid generator emissions to utility costs, observed residential system behavior in 2024 would be advantageous from an avoided utility cost perspective as well. The normalized utility marginal costs for residential systems by electric IOU are shown in Figure 4-163. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). PV paired systems for all three utilities realized total marginal avoided cost savings during 2024 at a greater overall magnitude than standalone storage systems, when normalized by kWh capacity. Overall, the average marginal *avoided* cost (+) for PV paired residential

systems in PG&E territory is \$10 per capacity (kWh), for SCE they were \$13, and for SDG&E they were \$15 per capacity (kWh). Again, most of those cost savings come from energy, T&D, and generation capacity. Since systems operating in self-consumption and TOU arbitrage modes are discharging on-peak, reductions in household consumption during those hours translate to avoided cost savings for each utility. Under-utilized systems provide minimal benefits (Figure 4-164).

FIGURE 4-163: RESIDENTIAL MARGINAL AVOIDED COST \$ PER KWH CAPACITY BY IOU

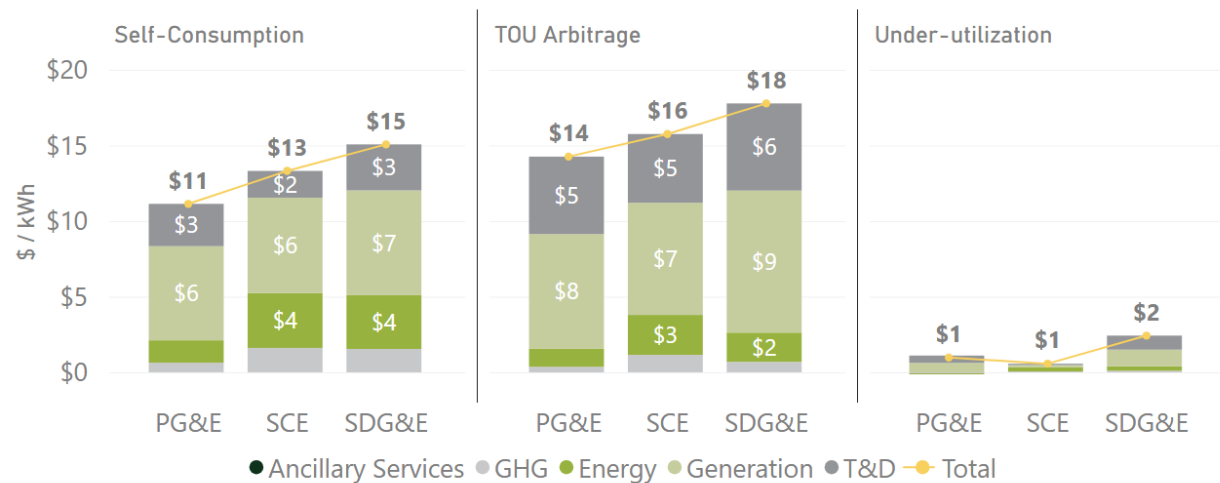
Observed Residential Utility Avoided Costs per kWh Capacity by IOU and PV Pairing



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

FIGURE 4-164: RESIDENTIAL MARGINAL AVOIDED COST \$ PER KWH CAPACITY BY IOU AND OPERATING MODE

Observed Residential Utility Avoided Costs per kWh Capacity by IOU and Use Case

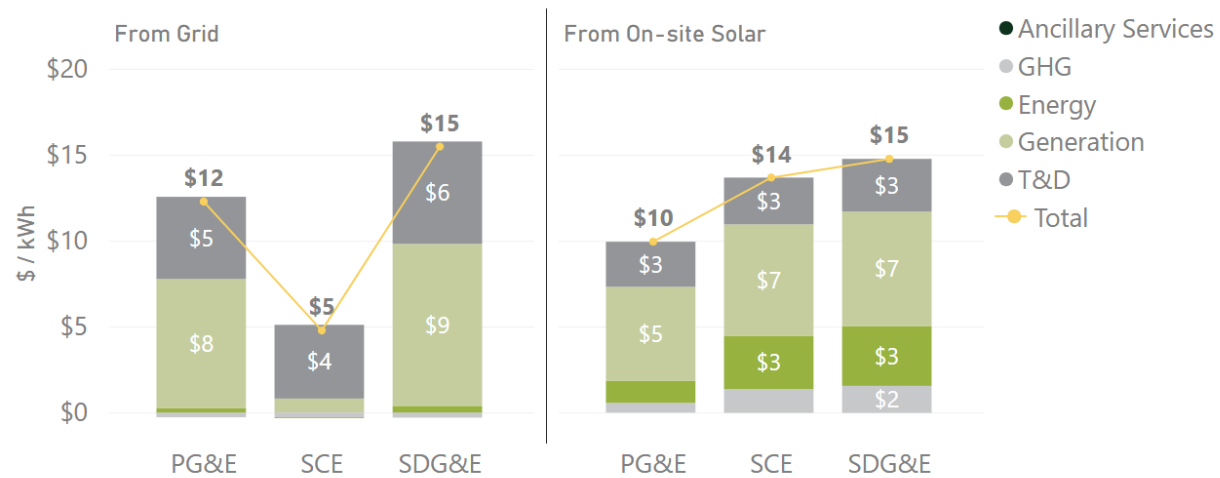


Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Greater benefits are also realized for PV paired systems charging from on-site solar than similar paired systems charging from grid energy. We observed an increased benefit from the energy component of the utility avoided cost for paired systems (Figure 4-165). The correlation between greater utilization and utility avoided cost benefits is presented for the residential sector in the scatter plots in Figure 4-166 and Figure 4-167. Almost all residential systems provided an avoided cost benefit in 2024 – independent of PV pairing or not – but the magnitude of benefit is aligned with greater system utilization.

FIGURE 4-165: RESIDENTIAL MARGINAL AVOIDED COST \$ PER KWH CAPACITY BY IOU AND CHARGING SOURCE

Observed Residential Utility Avoided Costs per kWh Capacity by IOU and Charging Source



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

FIGURE 4-166: RESIDENTIAL PROJECT AVOIDED COST \$ PER CAPACITY KWH BY ON-SITE GENERATION

Residential Project Utility Avoided Costs and Utilization by On-site Generation

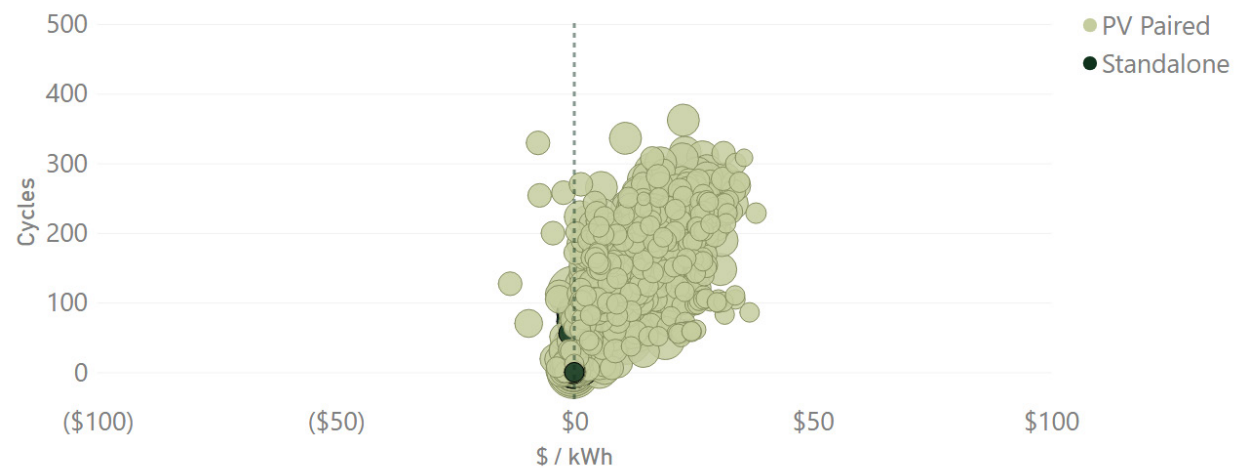
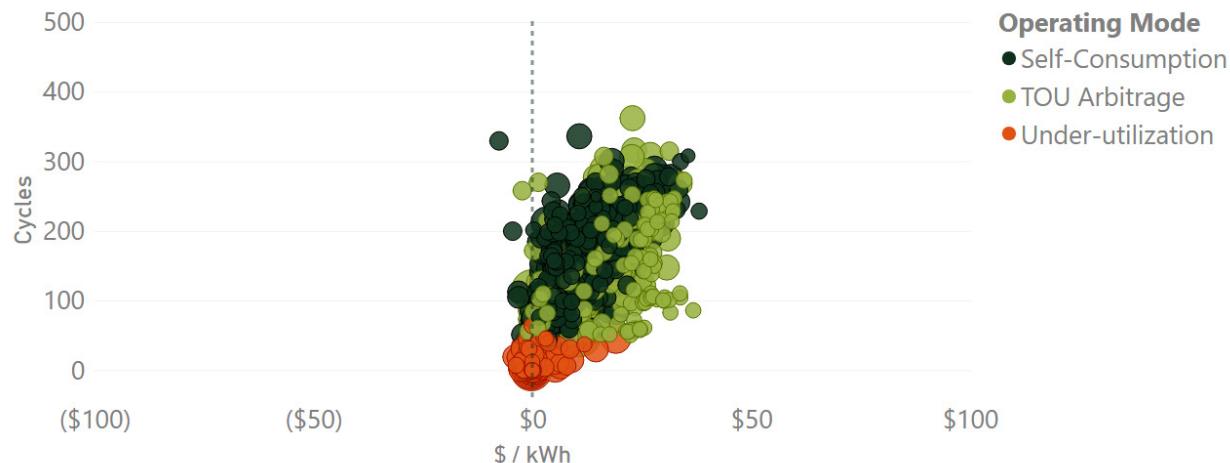


FIGURE 4-167: RESIDENTIAL PROJECT AVOIDED COST \$ PER CAPACITY KWH BY OPERATING MODE

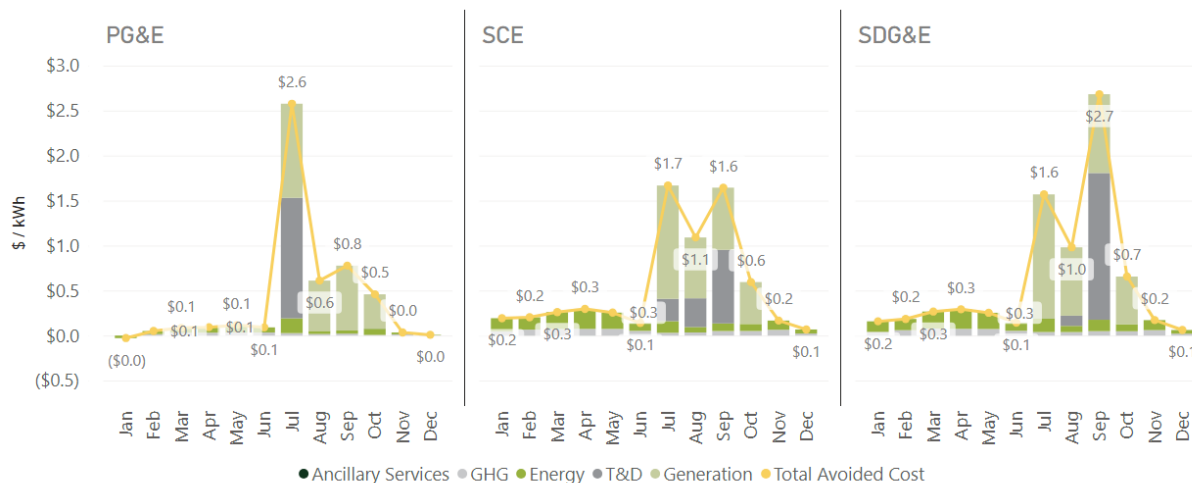
Residential Project Utility Avoided Costs and Utilization by Operating Mode



Like the nonresidential sector, utility cost benefits are really driven by storage performance during some specific costly hours. As discussed throughout this report, these systems were generally charging during low marginal cost periods and discharging in the early afternoon and evening during high utility cost and emissions periods, especially during summer months. These higher costs also align with on-peak TOU periods and, as presented in Figure 4-168, occur throughout the year, but like nonresidential systems, the benefits accrued over capacity-constrained hours in July and September.

FIGURE 4-168: RESIDENTIAL MARGINAL AVOIDED COST \$ PER CAPACITY KWH BY MONTH AND IOU

Observed Residential Monthly Utility Avoided Costs per kWh Capacity



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Overall Utility Avoided Cost Summaries

In Figure 4-169 through Figure 4-181, we summarize the total avoided cost benefits (+) or incurred (-) during 2024 for each of the three IOUs and two customer sectors – nonresidential and residential. Average impacts by avoided cost component are also detailed along with the total. The utilization, timing, and efficiency of storage charge and discharge during 2024 provided an avoided cost benefit to all three IOUs. Residential projects provided a greater benefit than nonresidential systems, on average, as a percentage of capacity kWh. We also observe some differences within each sector and across utility as well.

FIGURE 4-169: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY IOU

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ELECTRIC IOU

Electric IOU	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PG&E	368	\$0	\$1	\$0	\$3	\$6	\$10
SCE	504	\$0	\$1	\$1	\$2	\$4	\$7
SDG&E	188	\$0	\$1	\$0	\$2	\$4	\$8
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-170: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY ON-SITE GENERATION

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ON-SITE GENERATION

On-site Generation	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
On-site PV	446	\$0	\$2	\$1	\$2	\$5	\$10
Standalone	614	\$0	\$1	\$0	\$2	\$4	\$8
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-171: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY BUDGET CATEGORY

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY BUDGET CATEGORY

Budget Category	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2017 Prior	146	\$0	\$0	(\$0)	\$1	\$2	\$3
Equity Resiliency	199	\$0	\$1	\$1	\$2	\$5	\$9
Large-Scale Storage	651	\$0	\$1	\$1	\$2	\$5	\$9
Non-Residential Storage Equity	64	\$0	\$1	\$0	\$2	\$6	\$10
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-172: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY PAYMENT YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY UPFRONT PAYMENT YEAR

Upfront Payment Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2014-2016	50	\$0	\$0	(\$0)	\$1	\$3	\$4
2017	32	\$0	\$0	(\$0)	\$1	\$1	\$2
2018	63	\$0	\$1	\$0	\$1	\$2	\$3
2019	207	\$0	\$2	\$1	\$1	\$4	\$7
2020	82	\$0	\$1	\$0	\$2	\$3	\$5
2021	141	\$0	\$1	\$0	\$2	\$3	\$7
2022	185	\$0	\$1	\$1	\$3	\$6	\$12
2023	180	\$0	\$2	\$1	\$3	\$6	\$11
2024	120	\$0	\$1	\$0	\$2	\$5	\$8
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-173: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY BUILDING TYPE

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY BUILDING TYPE

Building Type	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
All Others	185	\$0	\$1	\$0	\$2	\$5	\$8
EV Station	118	\$0	\$1	\$1	\$5	\$8	\$15
Grocery	54	\$0	\$1	\$0	\$4	\$8	\$14
Industrial	164	\$0	\$1	\$0	\$2	\$4	\$6
Office	67	\$0	\$1	\$0	\$1	\$2	\$5
Retail	75	\$0	\$1	\$0	\$3	\$5	\$8
School	277	\$0	\$2	\$1	\$1	\$4	\$8
Utility	120	\$0	\$1	\$1	\$2	\$5	\$8
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-174: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY PROGRAM YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY PROGRAM YEAR

Program Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2012-2014	49	\$0	\$0	(\$0)	\$2	\$3	\$4
2015	48	\$0	\$0	(\$0)	\$0	\$1	\$1
2016	49	\$0	\$0	(\$0)	\$1	\$1	\$2
2017	293	\$0	\$1	\$0	\$1	\$4	\$7
2018	54	\$0	\$1	\$0	\$2	\$3	\$6
2019	71	\$0	\$1	\$0	\$3	\$3	\$8
2020	370	\$0	\$1	\$1	\$3	\$6	\$11
2021	92	\$0	\$2	\$1	\$1	\$5	\$8
2022-2024	34	\$0	\$1	\$0	\$1	\$3	\$6
Overall	1060	\$0	\$1	\$0	\$2	\$5	\$9

FIGURE 4-175: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY IOU

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY ELECTRIC IOU

Electric IOU	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PG&E	1030	\$0	\$1	\$0	\$3	\$5	\$10
SCE	614	\$0	\$3	\$1	\$3	\$6	\$13
SDG&E	285	\$0	\$3	\$1	\$3	\$7	\$15
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-176: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY ON-SITE GENERATION

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY ON-SITE PV

On-Site PV	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PV Paired	1876	\$0	\$2	\$1	\$3	\$6	\$12
Standalone	53	(\$0)	(\$0)	(\$0)	\$2	\$3	\$4
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-177: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY PAYMENT YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY PAYMENT YEAR

Payment Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2018	115	\$0	\$2	\$1	\$3	\$7	\$14
2019	156	\$0	\$2	\$1	\$3	\$7	\$13
2020	240	\$0	\$2	\$1	\$3	\$6	\$13
2021	560	\$0	\$2	\$1	\$3	\$6	\$11
2022	409	\$0	\$2	\$1	\$2	\$5	\$10
2023	299	\$0	\$2	\$1	\$3	\$6	\$11
2024	150	\$0	\$2	\$1	\$3	\$7	\$13
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-178: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY BUDGET CATEGORY

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY BUDGET CATEGORY

Budget Category	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
Equity and SJV	46	\$0	\$0	(\$0)	\$2	\$3	\$6
Equity Resiliency	596	\$0	\$2	\$1	\$3	\$5	\$11
Large-Scale Storage	115	\$0	\$2	\$1	\$3	\$5	\$10
Small Residential Storage	1172	\$0	\$2	\$1	\$3	\$6	\$13
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-179: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY PROGRAM YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total

BY PROGRAM YEAR

Program Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2017	103	\$0	\$2	\$1	\$3	\$7	\$13
2018	178	\$0	\$2	\$1	\$3	\$7	\$14
2019	165	\$0	\$2	\$1	\$3	\$6	\$12
2020	754	\$0	\$2	\$1	\$3	\$6	\$11
2021	302	\$0	\$2	\$1	\$3	\$5	\$11
2022	196	\$0	\$2	\$1	\$3	\$6	\$11
2023	178	\$0	\$2	\$1	\$3	\$6	\$12
2024	53	\$0	\$2	\$1	\$3	\$7	\$13
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-180: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY OPERATING MODE

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY OPERATING MODE

Operating Mode	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
Self-Consumption	1205	\$0	\$2	\$1	\$3	\$6	\$12
TOU Arbitrage	488	\$0	\$2	\$1	\$5	\$8	\$16
Under-utilization	228	\$0	\$0	(\$0)	\$0	\$1	\$1
Unknown	8	(\$0)	(\$0)	(\$0)	\$0	(\$1)	(\$1)
Overall	1929	\$0	\$2	\$1	\$3	\$6	\$11

FIGURE 4-181: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS (\$/KWH) BY CHARGING SOURCE

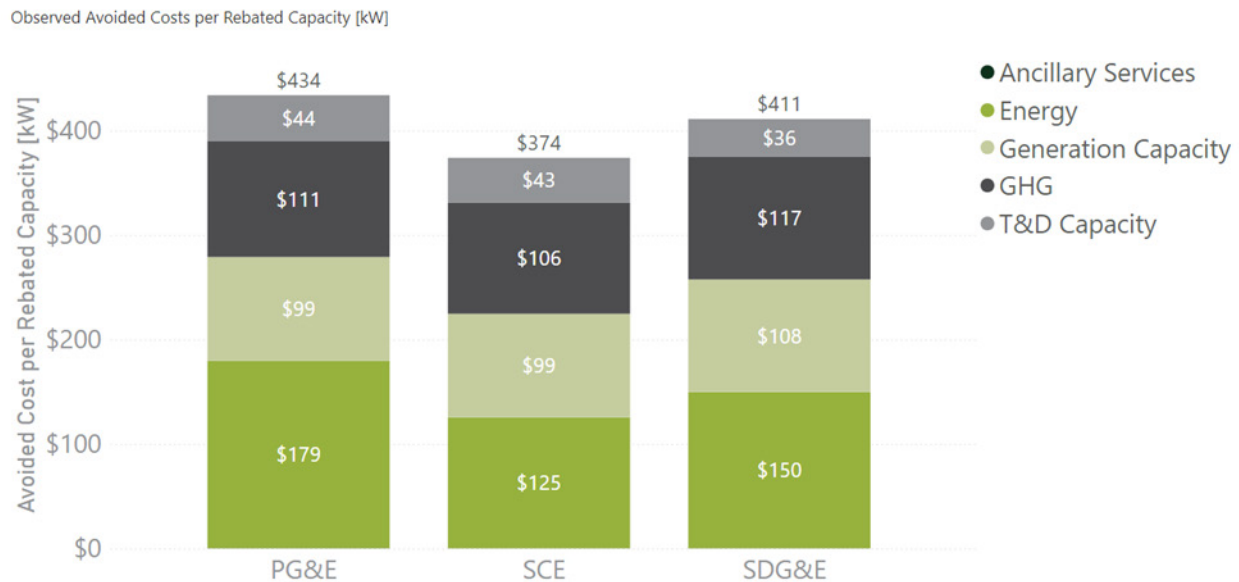
n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ON-SITE PV, BATTERY CHARGING

On-Site PV	Battery Charging	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PV Paired	From Grid	109	\$0	\$0	(\$0)	\$5	\$7	\$12
PV Paired	From On-site Solar	1767	\$0	\$2	\$1	\$3	\$6	\$12
Standalone	From Grid	53	(\$0)	(\$0)	(\$0)	\$2	\$3	\$4
Overall		1929	\$0	\$2	\$1	\$3	\$6	\$11

4.5.2 Generation

Marginal utility cost rates (\$/kWh) described previously were combined with observed hourly electricity generation profiles in calculations of avoided costs for generation systems. Results are shown in Figure 4-182 by IOU, on an avoided cost per incentivized kW basis. PG&E realized the highest avoided costs per incentivized kW, achieving \$434 per incentivized kW. SDG&E saw avoided costs of \$411 per incentivized kW, and SCE saw \$374 per incentivized kW in 2024. SDG&E GHG costs were higher than other utilities, while PG&E energy costs were higher than the other utilities. Avoided costs are higher for generation technologies than for storage projects in part because these are electric utility avoided costs only. For generation projects, a complete benefit-cost analysis would be required to account for changes in gas utility costs. Higher capacity factors of generation projects also contribute to differences in avoided costs per unit of capacity.

FIGURE 4-182: OBSERVED GENERATION SYSTEM 2024 UTILITY AVOIDED COSTS BY IOU (\$ PER REBATED KW)



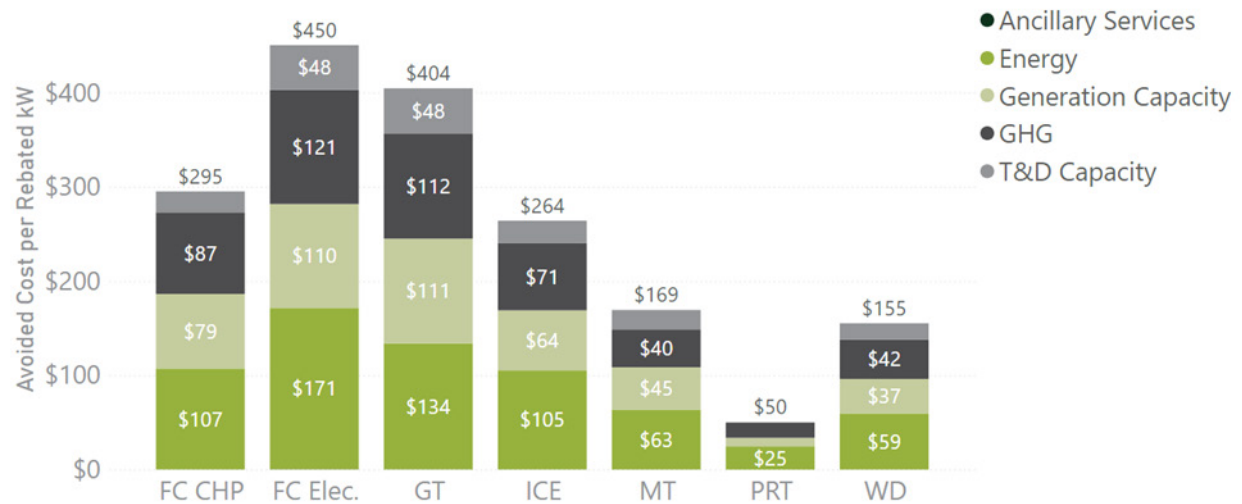
Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.
 * Differences in total versus component level costs have to do with rounding between the components.

When reviewing the observed utility marginal avoided costs by technology type, as shown in Figure 4-183, the all-electric fuel cells avoid the highest total marginal avoided costs per capacity, at \$450/kW. Pressure reduction turbines operated very inconsistently throughout the year and spent much of the year drawing parasitic loads but not generating electricity. Therefore, on average, these systems avoided the fewest marginal costs. Differences in utilization are the most important factors explaining differences in these avoided costs. The distribution of projects across electric utility service areas is another factor. Lastly, avoided electric utility costs are reported only for PG&E, SCE, and SDG&E. Avoided electric utility costs are not reported for projects installed by SGIP participants receiving electric service from some other provider (e.g., LADWP). Consequently, different groups of projects may contribute to calculation of avoided cost results and observed capacity factors.

Figure 4-184 shows the avoided cost rate per incentivized capacity by month during 2024. July saw some of the highest avoided cost rates, especially for PG&E, topping \$178 per incentivized kW, while the rates for the spring months were mostly under \$40/kW and the rates during the last half of the year were closer to \$70/kW.

FIGURE 4-183: OBSERVED GENERATION SYSTEM 2024 UTILITY AVOIDED COSTS BY TECHNOLOGY TYPE (\$ PER REBATED KW)

Observed Avoided Costs per Rebated Capacity [kW]

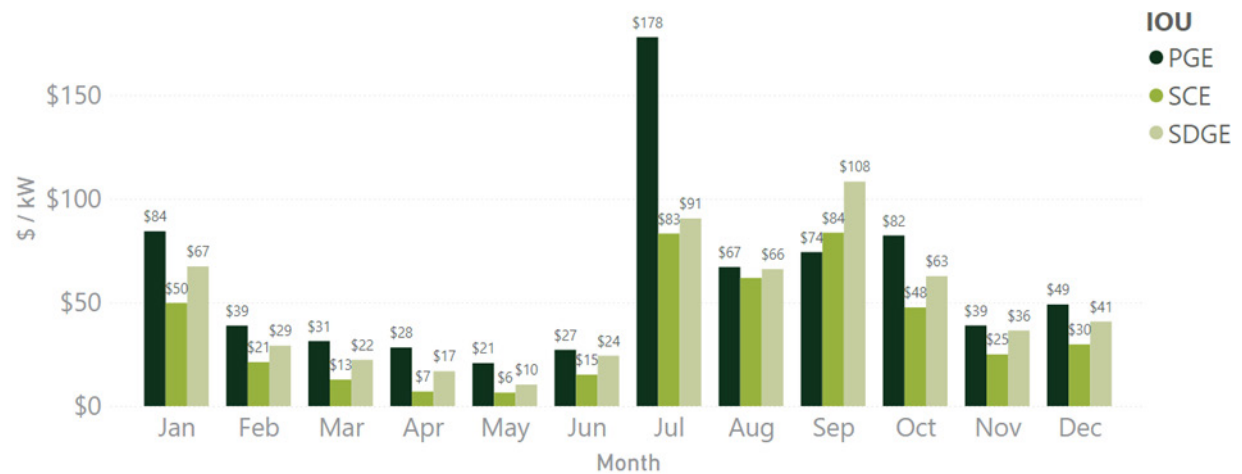


Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

* Differences in total versus component level costs have to do with rounding between the components.

FIGURE 4-184: OBSERVED GENERATION SYSTEM 2024 UTILITY AVOIDED BY IOU AND MONTH

Observed Avoided Cost per Rebated Capacity [kW]



Utility Avoided Cost Summaries

Figure 4-185 through Figure 4-187 summarize the total observed avoided cost benefits throughout 2024 for each of the three IOUs by equipment type and by fuel type. All generation systems were found to produce avoided cost benefits. Average impacts by avoided cost component are also detailed along with the total. All-electric fuel cells showed the greatest avoided costs, driven by the generation and T&D Cost components. Non-renewably fueled systems also saw higher avoided costs than renewable systems due to the large amount of generation from these systems compared with other fuel types.

FIGURE 4-185: SUMMARY OF OBSERVED 2024 GENERATION UTILITY AVOIDED COSTS IMPACTS BY ELECTRIC UTILITY (\$/KW)

Utility	n Prj	Ancillary Services	Energy	Generation Cost	GHG	T&D Cost	Total
PG&E	96	\$0	\$179	\$99	\$111	\$44	\$434
SCE	71	\$0	\$125	\$99	\$106	\$43	\$374
SDG&E	24	\$0	\$150	\$108	\$117	\$36	\$411

* Differences in total versus component level costs have to do with rounding between the components.

FIGURE 4-186: SUMMARY OF OBSERVED 2024 GENERATION UTILITY AVOIDED COSTS IMPACTS BY TECHNOLOGY TYPE (\$/KW)

Equipment Type	n Prj	Ancillary Services	Energy	Generation Cost	GHG	T&D Cost	Total
Fuel Cell CHP	6	\$0	\$107	\$79	\$87	\$22	\$295
Fuel Cell Electric	177	\$0	\$171	\$110	\$121	\$48	\$450
Gas Turbine	3	\$0	\$134	\$111	\$112	\$48	\$404
Internal Combustion Engine	17	\$0	\$105	\$64	\$71	\$24	\$264
Microturbine	6	\$0	\$63	\$45	\$40	\$21	\$169
Wind	7	\$0	\$59	\$37	\$42	\$17	\$155
Pressure Reduction Turbine	3	\$0	\$25	\$9	\$16	\$1	\$50

* Differences in total versus component level costs have to do with rounding between the components.

FIGURE 4-187: SUMMARY OF OBSERVED 2024 GENERATION UTILITY AVOIDED COSTS BY FUEL TYPE (\$/KW)

Fuel Type	n Prj	Ancillary Services	Energy	Generation Cost	GHG	T&D Cost	Total
Non-Renewable Gas	188	\$0	\$168	\$109	\$119	\$47	\$442
Other	11	\$0	\$47	\$27	\$33	\$12	\$119
Renewable Gas	20	\$0	\$107	\$65	\$72	\$23	\$267

* Differences in total versus component level costs have to do with rounding between the components.

4.6 ENERGY STORAGE IMPACTS DURING PSPS EVENTS

Wildfire risk poses a challenge in California, especially during the long duration periods of high temperature, low humidity, and gusting winds in the late summer and fall. These severe weather events can threaten portions of the electricity transmission and distribution system and, more importantly, vulnerable communities and populations. In 2018, the CPUC, working alongside CAL FIRE and other public safety officials, developed a high fire-threat map that identifies areas that are at extreme risk or elevated risk for wildfires. Furthermore, the CPUC built upon earlier rules providing authority to electric utility companies to shut down portions of the electric grid in response to wildfire threat.

In September through December 2020 these threats were realized, leaving hundreds of thousands of electric customers without power – sometimes for days. The 2020 SGIP Energy Storage Impact Evaluation first examined how SGIP residential customers experiencing Public Safety Power Shutoffs (PSPS) utilized their storage systems to provide resiliency during outages stemming from wildfire threat in 2020. Systems paired with on-site solar could ride out longer duration utility power shutoffs – sometimes for three days – because the system could charge directly from solar, and the solar energy could be used to partially power the home during the day.

In 2024, PG&E had 35 (0.2%) of their total 23,155 storage projects experience a PSPS event in 2024. SCE had 469 projects (3%) of their total 16,559 projects experiencing a PSPS event in 2024. There were no reported PSPS events in SDG&E service territory in 2024. While PSPS outages were limited in 2024, Verdant still reviewed the metered storage, PV, and load data for each sampled project to garner more information about the resiliency afforded by SGIP incentivized storage to customers experiencing grid de-energization. We first reviewed the frequency and timing of events, which are presented by the heat map in Figure 4-188. The data Verdant received from PG&E and SCE provided PSPS outage information affecting a significant number of customers during the following time periods:

- PG&E: November 5th – 7th and October 17th – 19th
- SCE: November 6th – 8th and December 9th – 11th

FIGURE 4-188: 2024 PSPS EVENT DAYS BY IOU

IOU - Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
PG&E - August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PG&E - December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PG&E - July	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PG&E - November	0	0	0	0	12	26	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PG&E - October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18	21	16	1	0	0	0	0	0	0	0	0	0	0	0
PG&E - September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	
SCE - August	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCE - December	0	0	0	0	0	0	0	0	58	253	231	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0
SCE - July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCE - November	0	0	0	0	0	355	355	88	0	0	0	0	2	0	0	0	0	0	0	0	1	1	5	5	0	0	0	0	0	0	0
SCE - October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	35	35	0	0	0	0	0	0	0	0	1	1	1	0
SCE - September	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The preceding information represents population summaries for 2024 PSPS outage events. Verdant developed a stratified random sample to estimate program-level impacts, so the total number of projects we sampled and received data for are less than the population totals. Overall, our analysis includes 28 systems in PG&E territory, or 2% of the PG&E SGIP analysis sample and 33 systems in SCE territory, or 3% of the SCE SGIP analysis sample. The sample for PG&E includes 27 residential and one nonresidential system. For SCE, the outage analysis sample contains 27 residential and six nonresidential systems. On average, PG&E customers experienced longer PSPS outage durations at around 32 hours compared to 30 hours in SCE. The longest event in PG&E service territory lasted over 66 hours, while the longest event in SCE lasted 55 hours.

Figure 4-189 displays the average hourly net discharge, consumption, load, and PV generation as a percentage of system kWh capacity for PG&E SGIP customers who experienced a PSPS outage in 2024. The figure compares PSPS outage performance on the left to non-PSPS performance throughout weekdays of the same season. Each stream is discussed in more detail.

Net Discharge. This represents the hourly charge (-) or discharge (+) utilization of the energy storage system during outages (left) and throughout similar days with full grid connectivity (right). On non-PSPS days, storage systems are performing normal operations – charging from on-site solar and discharging during the on-peak period and after to reduce delivered load from the utility. During PSPS days, storage discharge and solar generation are the only means by which a customer can still service plug loads and critical circuits, so storage discharges a much greater magnitude of energy, particularly during non-PV generating hours in the evening and overnight.

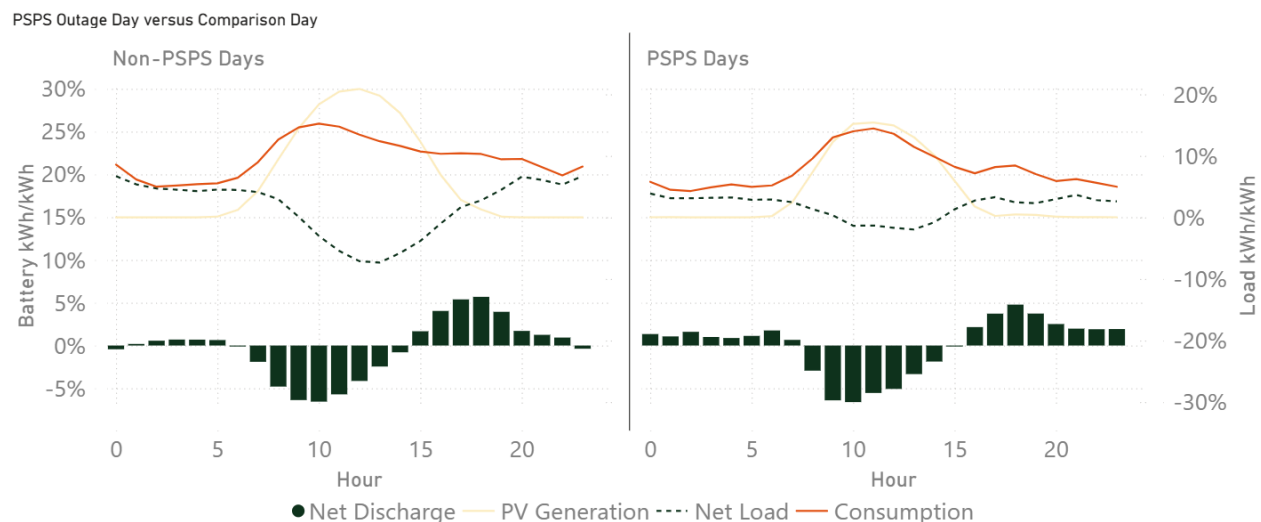
PV Generation. Differences in solar generation are more pronounced across days, with typical solar generation evident on the right, and significantly reduced output observed on outage days. Peak and overall solar PV generation throughout the PSPS events and while islanding is scaled back as solar output

is curtailed. Excess PV generation cannot be exported to the grid throughout an outage, so systems are likely configured to curtail solar output to balance supply and demand behind the meter – either energy storage charging or backed up critical circuits.

Net Load. The obvious difference in delivered and received utility load on PSPS event days is the complete absence of it. Metered load during the outage is zero, whereas normal load shapes of excess PV export and import when storage is not discharging are evident on the right.

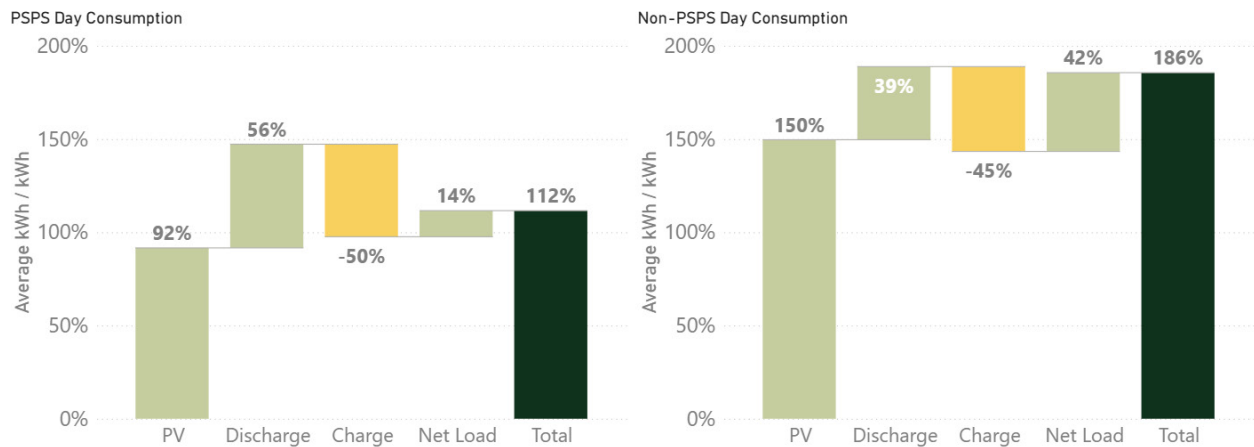
Consumption. Consumption represents the BTM metered customer load and includes – in the case of PSPS days – all circuits backed up and providing resiliency throughout the outage. The main takeaway here is that even though customers are disconnected from the grid during outages, a combination of solar generation and energy storage utilization provides customers with personal resiliency.

FIGURE 4-189: AVERAGE HOURLY LOAD SHAPES DURING PSPS EVENTS VS. NON-PSPS EVENTS



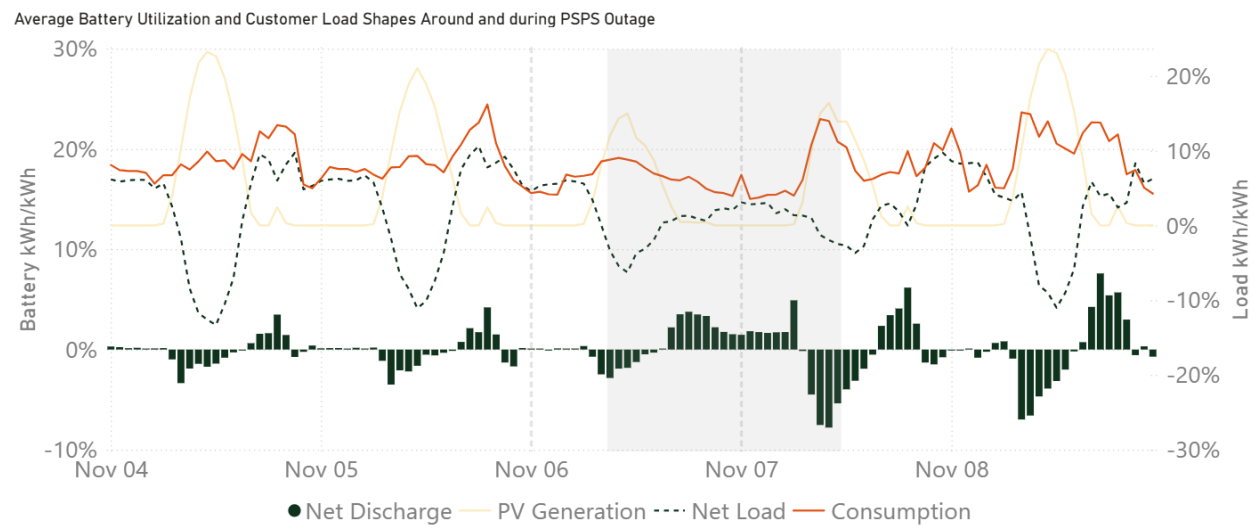
The load shapes above have been summed below in Figure 4-190 to the daily level to better compare overall differences between the streams. Green bars represent PV generation or energy storage discharge, and charge is represented by the yellow bar. In this example, overall BTM consumption is represented by the dark bar. We observe greater storage discharge utilization on outage days as more of the capacity is used for customer resiliency and greater PV generation on non-outage days as curtailment is not limiting solar output. While customers are consuming more on non-event days, non-zero consumption on outage days highlights the benefits afforded from a paired solar plus storage system to utility customers.

FIGURE 4-190: AVERAGE DAILY IMPACTS DURING PSPS EVENTS VS. NON-PSPS EVENTS



Finally, Figure 4-191 provides a time series of normal SGIP system performance punctuated by a planned PSPS outage in SCE service territory. System performance and load shapes after the outage are also presented. The outage itself is highlighted from roughly 9 a.m. on November 6th through 10 a.m. on November 7th.

FIGURE 4-191: NET DISCHARGE, LOAD, PV, AND CONSUMPTION OVER 5-DAY PERIOD WITH A PSPS OUTAGE



This five-day example reveals much of the same information as prior exhibits regarding storage system utilization, PV generation, customer load, and BTM consumption. Prior to the event, battery charging was provided by excess solar generation and system discharge occurs mostly during the 4 p.m. and 9 p.m. on peak (this load shape represents an average across multiple systems, so a combination of TOU arbitrage and self-consumption is evident). The gray box aligns with the outage, where the system continues to

charge from solar, but discharge extends exclusively from 4 p.m. on November 6th *throughout* the night and into the next morning, when on-site PV begins generating again. Reductions in solar generation during the event are evident as solar generation is curtailed to maintain supply and demand behind the meter. The system prioritizes recovery with a deep charge in the morning before gradually resuming normal arbitrage operations.

4.7 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of sampled generation and energy storage systems. These analyses were intended to highlight how SGIP systems were behaving in 2024 and how they were performing to meet program objectives. These analyses were all based on sampled systems from a larger population of SGIP systems. In this section, metered data from the sample of projects were used to estimate population total impacts for 2024.

Appendix C provides more detail into how each of these samples were developed, but they are summarized in Table 4-9 and Table 4-10. Overall, our team evaluated 3,325 energy storage systems (842 MWh of total energy storage capacity) and 239 generation systems (186 MW of total program generation capacity) receiving upfront payments prior to January 1, 2025. The energy storage sample represents 5% of the total population by project count and 44% of the total population capacity, with the generation sample representing 81% of project count and 71% of the rebated capacity. Large nonresidential storage systems and residential storage systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP storage population impacts, whereas all-electric fuel cells and gas turbines represent the greatest influence on generation population impacts.

TABLE 4-9: SAMPLE COMPOSITION OF 2024 SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MWh)	Population Capacity (MWh)	% of Capacity Sampled
Nonresidential	1,318	1,709	77%	842	1,068	79%
Residential	2,007	50,048	4%	45	966	5%
Total	3,325	51,757	6%	887	2,034	44%

*Sampled projects include decommissioned projects

TABLE 4-10: SAMPLE COMPOSITION OF 2024 SGIP GENERATION POPULATION BY TECHNOLOGY TYPE

Technology Type	Sample n	Population N	% of Projects Sampled	Sample Capacity [MW]	Population Capacity [MW]	% of Capacity Sampled
Fuel Cell CHP	12	13	92%	9	10	86%
Fuel Cell Electric	181	188	96%	61	69	89%
Gas Turbine	3	7	43%	73	94	77%
Internal Combustion Engine	25	49	51%	21	55	38%
Microturbine	7	14	50%	8	12	67%
Wind	7	15	47%	13	19	67%
Pressure Reduction Turbine	3	8	38%	1	3	41%
Waste Heat to Power	1	1	100%	0	0	100%
Total	239	295	81%	186	262	71%

*Sampled projects include decommissioned projects

The following tables summarize the population estimates for several program impact metrics. Population project counts are also reported in the tables. Population estimates were calculated for the following in 2024:

- Electric energy – total energy generated or charged & discharged, capacity factors, and electrical and system efficiencies or overall roundtrip efficiency
- CAISO system peak demand – total CAISO top hour impacts and total top 100-hour impacts
- Environmental Impacts – total GHG impacts
- Utility Avoided Costs – total utility avoided costs

TABLE 4-11: 2024 STORAGE POPULATION ELECTRIC ENERGY IMPACTS

Customer Sector	Population N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE
Nonresidential	1,709	118,598	140,898	-22,300	84%
Residential	50,048	5,783	6,769	-986	85%
Total	51,757	124,381	147,667	-23,285	84%

TABLE 4-12: 2024 GENERATION POPULATION ELECTRIC ENERGY IMPACTS

Technology Type	Population N	Population Generation [GWh]	Population CF	Population Electrical Efficiency	Population System Efficiency
Fuel Cell CHP	13	48	43.8%	34.2%	40.7%
Fuel Cell Electric	188	516	90.6%	50.3%	--
Gas Turbine	7	660	74.7%	32.6%	72.8%
Internal Combustion Engine	49	242	46.6%	34.6%	65.7%
Microturbine	14	34	41.3%	25.0%	35.4%
Wind	15	4	13.6%	--	--
Pressure Reduction Turbine	8	0	0%	--	--
Waste Heat to Power	1	55	30.1%	--	--
Total	295	1,558	73.1%	45.5%	57.5%

CAISO system peak demand impacts are summarized in Table 4-13 and Table 4-14 for the gross and net top hours. In 2024 the CAISO statewide system gross load peaked at almost 48,000 MW during the 5 p.m. hour on September 5th. The CAISO peaked, from a net load perspective, an hour later at almost 43,300 MW. SGIP generation projects provided a peak hour benefit by generating 137 MW of power during the CAISO gross peak hour, and 124 MW of power during the CAISO net peak hour. The total impacts across the top 100 gross and net CAISO hours follow in Table 4-15 and Table 4-16.

TABLE 4-13: 2024 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Customer Sector	Population N	Population Gross Peak Hour Net Discharge [MWh]	Population Net Peak Hour Net Discharge [MWh]
Nonresidential	1,709	46.5	64.3
Residential	50,048	64.5	91.4
Total	51,757	111.0	155.7

TABLE 4-14: 2024 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Technology Type	Population N	Population Gross Peak Hour Generation [MW]	Population Net Peak Hour Generation [MW]
Fuel Cell CHP	13	8.38	8.65
Fuel Cell Electric	188	155.39	155.42
Gas Turbine	7	205.99	205.46
Internal Combustion Engine	49	99.95	100.15
Microturbine	14	8.46	8.51
Wind	15	9.48	10.69
Pressure Reduction Turbine	8	0	0
Waste Heat to Power	1	0	0
Total	295	487.64	488.87

TABLE 4-15: 2024 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Customer Sector	Population N	Population Gross Top 100 Hour Net Discharge [MWh]	Population Net Top 100 Hour Net Discharge [MWh]
Nonresidential	1,709	38	46
Residential	50,048	40	43
Total	51,757	78	88

TABLE 4-16: 2024 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Technology Type	Population N	Population Average Gross Top 100 Hour Generation [MWh]	Population Average Net Top 100 Hour Generation [MWh]
Fuel Cell CHP	13	4.40	4.55
Fuel Cell Electric	188	56.12	56.37
Gas Turbine	7	77.89	78.16
Internal Combustion Engine	49	27.15	27.48
Microturbine	14	4.04	3.96
Wind	15	3.68	3.40
Pressure Reduction Turbine	8	0.02	0.15
Waste Heat to Power	1	0	0
Total	295	173.29	174.07

Greenhouse gas impacts during 2024 are summarized in Table 4-17 and Table 4-18. Positive greenhouse

gas impacts reflect increased emissions. The magnitude and sign of greenhouse gas impacts are dependent on the timing of charge and discharge for storage systems. For generation systems, the magnitude and sign of impacts have more to do with the fuel type and baseline type, as renewably fueled systems tend to reduce emissions, and systems with vented baselines reduce emissions significantly more than flared baselines.

Both the residential and nonresidential energy storage sectors contributed to a decrease in GHG emissions in 2024. This was largely an effect of charging systems from on-site PV generation in morning hours when marginal emissions were lower than afternoon and evening hours (Section 4.4.1). Systems were either trying to maintain zero net load during these higher marginal emission hours or responding to TOU price signals. On average, residential systems decreased GHG emissions by roughly 18.8 kg/kWh and nonresidential systems decreased emissions by roughly 9.6 kg/kWh (an almost twofold improvement compared to CY 2023).

TABLE 4-17: 2024 ENERGY STORAGE POPULATION GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO ₂)	Capacity MWh	MT / Capacity MWh
Nonresidential	1,709	-10,293	1,068	-9.6
Residential	50,048	-18,141	966	-18.8
Total	51,757	-28,433	2,034	-14.0

TABLE 4-18: 2024 GENERATION POPULATION GREENHOUSE GAS IMPACTS

Technology Type	Fuel Type	Baseline Type	Population N	Population GHG Impact [MT CO _{2eq}]	GHG Impact Rate [MT CO _{2eq} /MWh]
Fuel Cell CHP	Non-Renewable Gas	N/A	11	4,143	0.15
	Renewable Gas	Flare	2	-5,926	-0.30
Fuel Cell Electric	Non-Renewable Gas	N/A	183	7,147	0.01
	Renewable Gas	Flare	1	0	0
		Vent	1	-24,345	-3.32
Gas Turbine	Non-Renewable Gas	N/A	6	-18,335	-0.02
	Renewable Gas	Flare	1	-40,719	-0.54
Internal Combustion Engine	Renewable Gas	Flare	25	-55,867	-0.47
		Vent	7	-106,533	-5.86
	Non-Renewable Gas	N/A	17	-691	0.00
Microturbine	Renewable Gas	Flare	4	-336	-0.35
	Non-Renewable Gas	N/A	9	10,393	0.32
	Other	Flare	1	-838	-0.45
Wind	Other	N/A	15	-19,129	-0.35
Pressure Reduction Turbine	Other	N/A	8	-1,363	-0.39
Waste Heat to Power	Other	N/A	1	0	0
Total	--	--	295	-252,399	-0.19

Utility marginal cost impacts during 2024 are summarized in Table 4-19 and Table 4-20. The evaluation found SGIP incentivized energy storage systems provided a utility-level population benefit of over \$19 million in avoided costs across both storage sectors, while generation systems provided utility-level population benefits of over \$61 million. These results are consistent with the analyses presented in Section 4.5.1. Nonresidential and residential storage systems were generally discharging during hours that were capacity or distribution constrained, especially during the summertime, while generation systems typically provided a baseload that didn't vary much throughout the day or year. On average, nonresidential storage systems provided a benefit in avoided cost of roughly \$8/kWh and residential storage systems provided a benefit of \$11/kWh, while generation systems provided a benefit in avoided cost between \$49 per rebated kW capacity for pressure reduction turbines to \$407 per rebated capacity for gas turbines.

TABLE 4-19: 2024 ENERGY STORAGE UTILITY MARGINAL COST IMPACTS

Customer Sector	Population N	Population Impact (Avoided Cost \$)	Population Impact (Avoided Cost \$) / kWh Capacity
Nonresidential	1,709	\$8,312,908	\$7.78
Residential	50,048	\$10,930,248	\$11.32
Total	51,757	\$19,243,157	\$9.46

TABLE 4-20: 2024 GENERATION UTILITY MARGINAL COST IMPACTS

Technology Type	Population N	Population Impact (Avoided Cost \$)	Population Impact (Avoided Cost \$) / kW Capacity
Fuel Cell CHP	13	\$1,889,699	\$128.47
Fuel Cell Electric	188	\$24,207,632	\$406.48
Gas Turbine	7	\$18,950,642	\$325.23
Internal Combustion Engine	49	\$12,083,613	\$180.92
Microturbine	14	\$1,506,232	\$139.79
Wind	15	\$2,616,338	\$133.01
Pressure Reduction Turbine	8	\$184,443	\$49.21
Waste Heat to Power	1	\$0	\$0
Total	295	\$61,438,598	\$311.18

5 STORAGE OPTIMIZATION

The previous section revealed how the performance and utilization of energy storage systems contributed to decreases in greenhouse gas (GHG) emissions and utility costs, while providing bill savings to host customers in 2024. Residential energy storage systems are generally conducting 1) self-consumption, 2) TOU arbitrage without export, 3) TOU arbitrage with export – either regularly or exclusively throughout specific times like a demand response event, or 4) some combination of all. Nonresidential energy storage systems typically focus on reducing billed demand charges, as that objective most often offers the highest marginal potential for bill savings.

We observe residential and nonresidential PV paired systems discharging, on average, 43% or 44% of system capacity daily during summer months and many residential customers are limiting discharge to maintain net zero load rather than exporting. This finding is intuitive – if customers are already abiding by SGIP rules for round-trip efficiency, utilization, and GHG reductions – they may also want to have reserve energy in the event of an outage. Furthermore, frequent full discharge cycling may not be advantageous from battery engineering, effective useful life, or warranty perspective. Storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or incentive) encourages shifting or reducing demand. Customers understand their BTM consumption and bill rate structure, but grid-level demand may not be in their purview. The 4 p.m. – 9 p.m. on-peak TOU hours provide a broad signal to arbitrage energy over a five-hour period, but emissions and utility costs vary considerably during this period, narrowing the window for achievement of maximum emissions reductions.

A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge only when marginal emissions or utility costs are at their maximum. The motivation behind this optimization analysis is to quantify the considerable untapped potential of battery capacity if deployed in response to grid needs.

Verdant has developed a simulation tool that can dispatch storage systems for optimal timing and magnitude in response to specified signals and other conditions. This tool can estimate benefits of optimized dispatch based on selected objectives, including 1) to minimize the customer's bill, 2) to minimize greenhouse gas emissions, or 3) to minimize utility costs. In this section we explore how the observed real-world performance of SGIP storage systems compares to simulated optimal performance for these dispatch scenarios.



Data and Methods

Verdant's optimization tool uses mixed-integer linear programming to optimally charge and discharge storage under actual load and PV conditions. Battery configuration information is required for the model, including the system's total energy capacity (kWh) and its charge/discharge power capacity (kW). This information is collected from the SGIP statewide project list. The model also requires input that specifies the RTE of the battery as well as the minimum state of charge (SOC) allowable for the battery. For these optimized simulation runs we assumed RTEs of 90% and 85% for residential and nonresidential systems, respectively.

The 90% RTE value assumed for residential systems is at the high end of measured residential RTEs and is indicative of the energy losses associated with a single duty cycle. Observed residential system efficiencies range considerably based on the equipment type and overall utilization. Under-utilization can result in the accumulation of parasitic losses that can further erode the actual efficiency of the system over time. The lower RTE value of 85% assumed for nonresidential systems reflects their higher average cycling frequency.

Another important modeling constraint is not to allow the battery to discharge beyond a predetermined minimum SOC. Verdant modeled optimized dispatch to maintain a minimum SOC of 35% of its total capacity for residential applications and 20% for nonresidential. The assumptions were based on observed behavior and discussions with OEMs, and – just like the RTE – can vary based on system operating mode and technology type.

The model requires information on the customer's hourly interval gross consumption and PV data (if present). The customer's gross consumption was calculated from the IOU-provided Advanced Metering Infrastructure (AMI) data or developer metered load and the metered storage charge and discharge data collected for this evaluation. The customer's gross consumption (i.e., their consumption if they didn't have a battery installed) was calculated as their net load with the battery charge and discharge activity backed out. For customers with PV onsite, the hourly metered interval PV generation data provided by project developers and manufacturers was also backed out of the AMI data to determine the customer's gross consumption. Both the gross consumption and the PV generation interval data are used as inputs in the optimization model.

The final input required for the optimization is information related to the model's objective, (i.e., the cost against which the model is minimizing). We simulated optimal dispatch against three different representations of cost; 1) the customer's bill, 2) greenhouse gas emissions (GHG), and 3) utility costs. For simulations minimizing the customer's bill, we reviewed the historical rate selection of each customer (provided by the IOUs) and noted their selected rate on or near July 2024. Simulations that minimized greenhouse gas emissions utilized the WattTime SGIP signal marginal emissions rate for the customer's

associated grid region. To minimize utility costs, we used hourly utility avoided cost values for the customer's associated utility and climate zone, this model simulates a customer being on a real-time rate.

A mixed-integer linear program was used for our simulations. The simulations assume "perfect knowledge," meaning that decisions are made about the optimal dispatch over the entire optimization horizon with full knowledge of the actual load and PV generation over the entire horizon. In our simulations, we limited the battery so that it could only charge from energy generated by the on-site PV. In cases with no PV on-site, the battery was allowed to charge directly from the grid; however, exports were not allowed.

Results

Throughout this section, we will present comparisons of optimal and actual observed battery dispatch. Note that the observed dispatch results presented will differ from the avoided utility costs, avoided GHG emissions, and customer bill savings presented in previous sections of this report. The results shown are exclusive to projects included in our optimization modeling. Projects were dropped from the optimization modeling sample for several reasons, including lack of information on the customer's rate along with quality control of the simulation results. The results presented in this section are meant to be used for directional purposes and are not intended to be taken as a final reporting of avoided utility costs, reduced GHG emissions, or customer bill savings.

Figure 5-1 through Figure 5-3 show the average avoided utility costs, reduced GHG emissions, and customer bill savings of the three optimal scenario types (Optimal Avoided Utility Cost, Optimal GHG, and Optimal Bills) compared with actual dispatch for each customer sector. The bars on each chart represent actual dispatch or the three optimal scenarios.

Figure 5-1 shows that optimizing dispatch for utility costs has the potential to reduce utility costs by three or four times the reductions achieved by the actual dispatch (\$40 versus \$12 per kWh of battery capacity for nonresidential projects and \$40 versus \$15 per kWh of battery capacity for residential projects). Interestingly, we also find that optimizing GHG reduction and customer bill savings could reduce utility costs further than actual dispatch with optimal reductions slightly different for each customer sector.

FIGURE 5-1: 2024 AVOIDED UTILITY COSTS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS (\$ PER KWH)

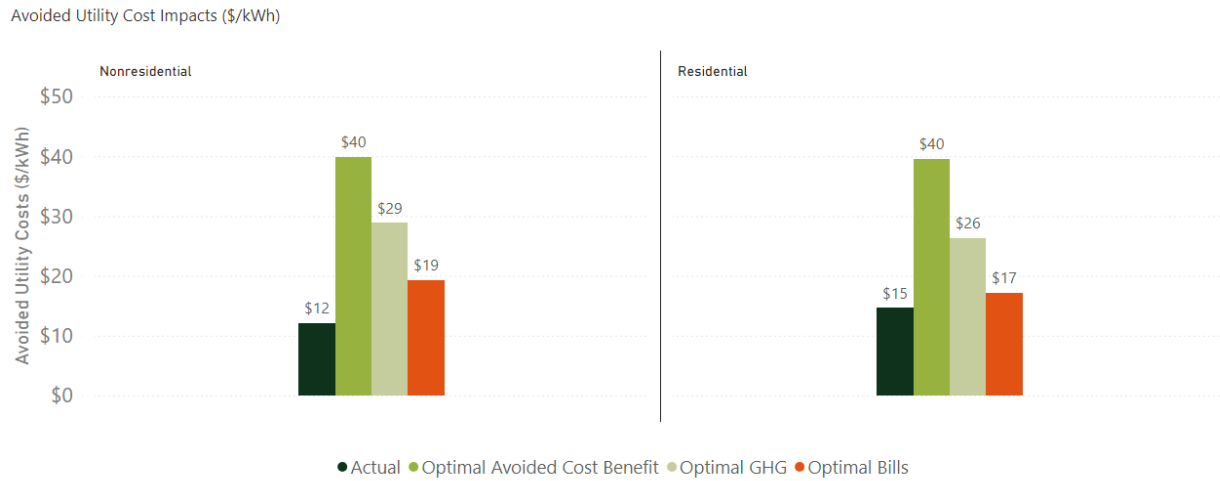


Figure 5-2 shows that optimizing for GHG emissions has the potential to reduce GHG emissions by a significant percentage for nonresidential projects modelled in this exercise – a 2 kg/kWh observed reductions, to well over 100 kg/kWh. Modelled residential projects could realize 92 kg per kWh of capacity reduction (roughly 3 times the reduction achieved by actual dispatch). Notably, optimizing for utility costs achieves nearly the same amount of GHG reduction as the optimal GHG scenario for each sector. The scenario that optimizes customer bills also achieves higher GHG emission reductions than actual dispatch (31 kg/kWh and 35 kg/kWh, respectively).

FIGURE 5-2: 2024 EMISSIONS REDUCTION FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS (KG CO2 PER KWH)

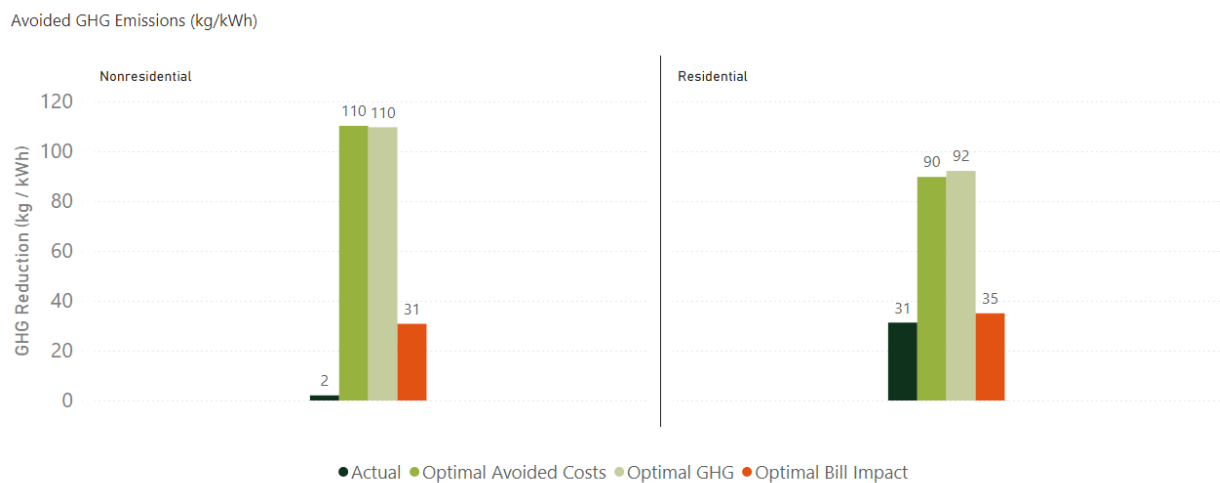


Figure 5-3 shows that bill optimization can reduce customer bills further than observed operations in 2024. Incremental bill savings from observed to optimal are less in the nonresidential sector than residential projects. This is an expected result, given SGIP nonresidential customers are far more economically driven to reduce bills than residential customers (many of which are conducting solar self-consumption). Furthermore, both the optimal utility avoided cost and optimal GHG scenarios deliver reduced customer bill savings compared to the actual dispatch for the residential sector.

FIGURE 5-3: 2024 CUSTOMER BILL SAVINGS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS (\$ PER KWH)

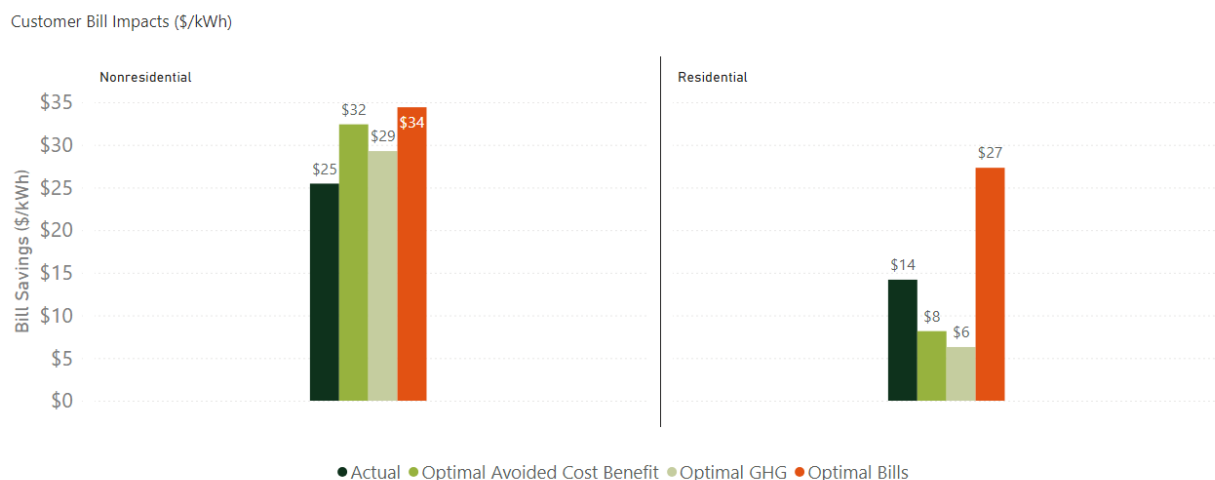


Figure 5-4 presents heat maps of the average hourly charge and discharge for each hour of the day by month for residential projects. The figure shows battery dispatch activity for the actual dispatch, followed by the dispatch activity for the optimal utility avoided cost scenario, the optimal GHG scenario, and finally the optimal customer bill scenario. These figures highlight that each optimal scenario charges and discharges more completely than the actual dispatch during charging and discharging hours. In addition, charging profiles are virtually identical between utility cost and GHG-optimized scenarios.

On average, actual system discharge never exceeds 7% of capacity in any given month-hour, while the optimal scenarios discharge up to 27% of capacity in peak discharge hours. Similarly, the actual dispatch never charges more than 10% of capacity in any given month-hour, while the optimal scenarios charge up to 16% of capacity in a single month-hour. When comparing the hours of the day that the battery typically discharges, the optimal customer bill scenario is most like actual, with most of the discharge activity occurring between 4 p.m. and 9 p.m. Both the optimal customer bill scenario and the actual dispatch also maintain relatively uniform hourly dispatch patterns during the year. In contrast, the optimal avoided cost and optimal GHG scenarios vary their discharge patterns significantly from month to month (following the heterogeneous nature of the avoided cost and GHG cost signals).

FIGURE 5-4: RESIDENTIAL HRLY DISPATCH BY MONTH (ACTUAL, OPTIMAL UTILITY COSTS, GHG AND BILLS)

Actual Hourly Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-7%	-9%	-6%	-3%	-1%	0%	5%	6%	7%	6%	3%	1%	1%	0%
2	-0%	-0%	0%	0%	0%	0%	0%	-0%	-3%	-5%	-7%	-6%	-3%	-2%	1%	-0%	4%	4%	5%	4%	3%	1%	1%	0%
3	-0%	0%	1%	0%	0%	0%	0%	-0%	-3%	-5%	-8%	-8%	-2%	-1%	-1%	-0%	3%	4%	4%	4%	3%	1%	1%	1%
4	0%	0%	0%	0%	0%	0%	1%	2%	-2%	-6%	-7%	-4%	-4%	-2%	-1%	-0%	2%	3%	3%	4%	3%	1%	2%	1%
5	0%	1%	0%	1%	1%	0%	1%	-1%	-3%	-5%	-7%	-6%	-3%	-2%	-1%	-1%	3%	3%	5%	4%	3%	2%	1%	2%
6	0%	-0%	0%	1%	0%	0%	0%	-1%	-3%	-5%	-8%	-7%	-3%	-3%	-2%	-0%	3%	4%	4%	5%	4%	2%	1%	1%
7	-0%	-0%	0%	0%	0%	0%	0%	-1%	-1%	-4%	-5%	-4%	-3%	-2%	-1%	-0%	2%	4%	4%	4%	3%	1%	1%	1%
8	-0%	-0%	0%	0%	0%	0%	1%	-1%	-2%	-4%	-6%	-5%	-4%	-2%	-1%	-1%	3%	4%	4%	4%	3%	1%	1%	1%
9	-0%	-0%	1%	0%	0%	0%	0%	-0%	-2%	-3%	-6%	-7%	-6%	-2%	-1%	-1%	4%	4%	5%	4%	2%	1%	3%	1%
10	-0%	-0%	0%	2%	0%	0%	0%	0%	-1%	-3%	-5%	-4%	-3%	-2%	-2%	-1%	2%	3%	3%	4%	4%	1%	1%	2%
11	-0%	-0%	0%	0%	0%	0%	0%	-1%	-3%	-5%	-7%	-9%	-4%	-1%	-2%	0%	4%	5%	6%	6%	4%	1%	1%	1%
12	-0%	-0%	0%	0%	0%	0%	0%	-1%	-3%	-5%	-8%	-9%	-7%	-2%	-1%	0%	5%	7%	7%	6%	4%	1%	0%	0%

Utility Avoided Cost Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	-0%	-0%	-0%	1%	2%	9%	4%	5%	1%	-6%	-13%	-13%	-10%	-8%	-1%	2%	10%	4%	1%	3%	5%	0%	-0%
2	0%	-0%	-0%	-0%	0%	0%	9%	2%	4%	-2%	-7%	-5%	-13%	-7%	-5%	-2%	-0%	8%	9%	6%	8%	2%	0%	0%
3	4%	-0%	-0%	-0%	0%	3%	12%	10%	-1%	-2%	-6%	-5%	-6%	-7%	-13%	-9%	-4%	1%	6%	5%	3%	8%	6%	2%
4	2%	0%	2%	1%	0%	3%	15%	3%	-3%	-2%	-7%	-7%	-0%	-6%	-14%	-4%	-10%	0%	0%	9%	9%	10%	2%	3%
5	6%	1%	-0%	-0%	0%	3%	5%	0%	-3%	-4%	-4%	-4%	-6%	-10%	-13%	-6%	-8%	-0%	3%	17%	14%	2%	2%	6%
6	4%	1%	-0%	-0%	-0%	1%	2%	-2%	-6%	-9%	-6%	-6%	-11%	0%	-7%	-4%	-7%	-3%	3%	26%	22%	3%	3%	0%
7	1%	-0%	-0%	-0%	-0%	4%	4%	-1%	-5%	-11%	-16%	-14%	-10%	-1%	-4%	1%	-4%	4%	10%	26%	15%	5%	4%	0%
8	0%	-0%	-0%	-0%	-0%	3%	6%	-1%	-5%	-10%	-13%	-10%	-11%	-6%	-3%	-3%	-4%	5%	10%	24%	11%	5%	2%	1%
9	4%	0%	-0%	-0%	-0%	2%	16%	1%	-3%	-9%	-13%	-10%	-9%	-11%	-3%	-4%	-2%	11%	13%	6%	4%	3%	1%	1%
10	0%	0%	-0%	-0%	-0%	10%	11%	0%	-7%	-11%	-12%	-8%	-6%	-7%	-8%	-4%	12%	5%	6%	8%	6%	2%	0%	0%
11	0%	-0%	-0%	1%	0%	3%	17%	2%	-1%	-8%	-7%	-11%	-13%	-11%	-8%	-0%	10%	1%	5%	3%	5%	5%	6%	4%
12	2%	2%	-0%	-0%	-0%	0%	9%	8%	2%	-4%	-5%	-7%	-16%	-15%	-11%	-2%	6%	15%	3%	3%	3%	3%	2%	2%

GHG Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	1%	1%	1%	3%	5%	1%	2%	0%	-6%	-12%	-13%	-11%	-8%	-0%	1%	9%	6%	3%	3%	7%	0%	-0%
2	0%	-0%	-0%	-0%	0%	0%	9%	2%	3%	-3%	-6%	-9%	-11%	-10%	-6%	-2%	-0%	7%	9%	7%	7%	3%	0%	-0%
3	4%	2%	0%	0%	0%	4%	11%	10%	0%	-3%	-4%	-7%	-6%	-6%	-10%	-6%	-5%	1%	6%	6%	5%	8%	2%	2%
4	2%	0%	2%	2%	0%	3%	12%	3%	-0%	-2%	-3%	-3%	-7%	-5%	-10%	-8%	-8%	-4%	0%	13%	10%	9%	3%	3%
5	6%	1%	-0%	-0%	0%	3%	5%	-0%	-4%	-2%	-1%	-2%	-10%	-9%	-10%	-5%	-7%	-3%	2%	17%	14%	2%	1%	5%
6	4%	1%	-0%	-0%	-0%	1%	-0%	-2%	-6%	-9%	-9%	-8%	-7%	-3%	-4%	-2%	-10%	-3%	4%	27%	20%	4%	2%	0%
7	1%	-0%	-0%	-0%	-0%	3%	1%	-1%	-5%	-10%	-15%	-14%	-11%	-0%	-2%	4%	-5%	2%	4%	22%	12%	8%	4%	1%
8	0%	-0%	-0%	-0%	-0%	4%	9%	-0%	-4%	-9%	-11%	-8%	-8%	-5%	-4%	0%	-6%	-0%	4%	18%	4%	7%	5%	2%
9	3%	0%	-0%	-0%	-0%	2%	17%	2%	-4%	-7%	-10%	-11%	-11%	-10%	-2%	-1%	-5%	2%	12%	6%	0%	5%	5%	1%
10	0%	0%	-0%	-0%	-0%	8%	10%	-0%	-7%	-11%	-12%	-9%	-7%	-8%	-6%	-2%	13%	9%	2%	2%	7%	5%	1%	1%
11	1%	0%	-0%	0%	0%	2%	11%	1%	-2%	-7%	-8%	-11%	-14%	-11%	-9%	-0%	11%	3%	4%	5%	7%	6%	6%	3%
12	0%	2%	1%	-0%	-0%	0%	8%	8%	1%	-3%	-7%	-7%	-16%	-15%	-11%	-2%	7%	13%	5%	4%	5%	4%	1%	2%

Bill Impact Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	0%	0%	0%	0%	0%	-0%	-1%	-2%	-4%	-10%	-13%	-14%	-12%	-6%	10%	16%	12%	12%	7%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	-0%	-1%	-2%	-3%	-7%	-13%	-13%	-12%	-8%	14%	13%	11%	10%	7%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	-0%	-0%	-1%	-4%	-8%	-13%	-16%	-13%	-11%	23%	14%	9%	7%	6%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	-0%	-0%	-1%	-4%	-6%	-10%	-15%	-16%	-15%	26%	18%	5%	7%	4%	0%	0%	0%
5	0%	0%	0%	0%	-0%	0%	0%	-0%	-0%	-1%	-2%	-3%	-8%	-16%	-18%	-17%	26%	21%	10%	1%	3%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	-0%	-0%	-1%	-2%	-6%	-12%	-15%	-17%	-16%	25%	23%	10%	1%	2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	-0%	-0%	-1%	-2%	-6%	-10%	-15%	-18%	-17%	25%	22%	10%	2%	4%	0%	0%	0%
8	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-2%	-4%	-7%	-17%	-20%	-18%	25%	19%	7%	5%	6%	0%	0%	-0%
9	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-2%	-5%	-10%	-17%	-18%	-15%	23%	17%	9%	9%	5%	-0%	-0%	-0%
10	0%	0%	0%	0%	0%	0%	0%	-0%	-0%	-1%	-3%	-8%	-13%	-15%	-15%	-11%	19%	13%	11%	9%	7%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	-0%	-1%	-4%	-9%	-12%	-13%	-12%	-9%	-4%	15%	15%	11%	10%	9%	0%	0%	0%
12	0%	0%	0%	-0%	0%	-0%	0%	-0%	-2%	-5%	-8%	-10%	-12%	-12%	-9%	-4%	12%	15%	10%	10%	8%	0%	0%	0%

Figure 5-5 displays the average weekday battery dispatch pattern for the three optimization scenarios (solid dark lines) alongside the actual dispatch pattern during the same period (dashed dark lines) for residential projects during summer months (June-September, inclusively). The shaded yellow areas represent times when more charging occurs than actual, and the light gray shaded area signifies more discharge than actual from optimal dispatch. The vertical lines highlight the typical peak pricing period of 4 p.m. – 9 p.m.

FIGURE 5-5: RESIDENTIAL AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS SUMMER MONTHS

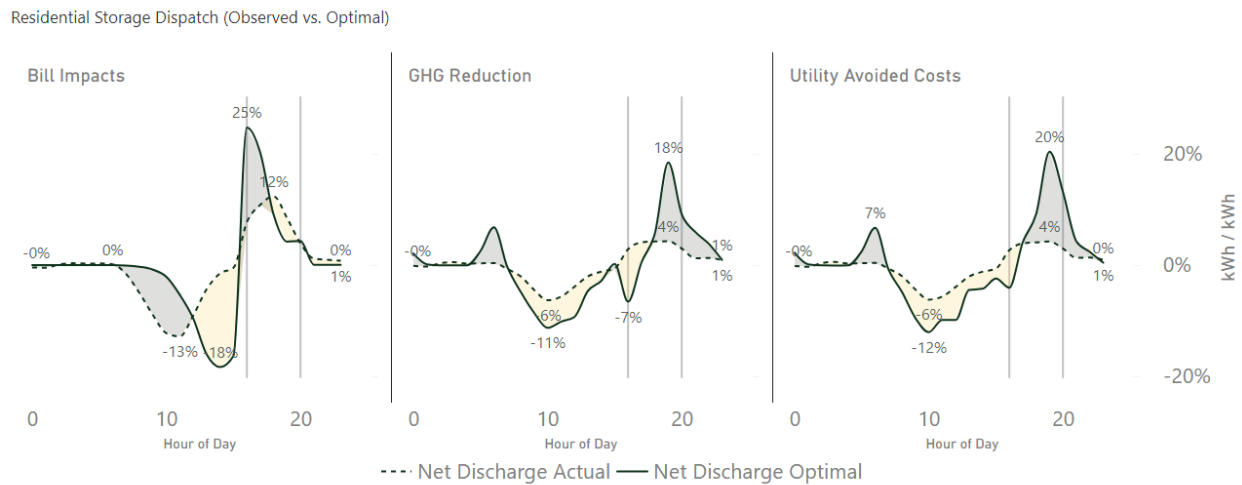


Figure 5-6 presents heat maps of the average hourly charge and discharge for each hour of the day and month for nonresidential projects. The figure shows battery dispatch activity for the actual dispatch, followed by the dispatch activity for the optimal utility avoided cost scenario, the optimal GHG scenario, and finally the optimal customer bill scenario. These figures highlight that each optimal scenario charges and discharges more completely than the actual dispatch during charging and discharging hours. Again, charging profiles are virtually identical between utility cost and GHG-optimized scenarios.

On average, actual system discharge never exceeds 8% of capacity in any given month-hour, while the optimal scenarios discharge up to 21% of capacity in peak discharge hours. Similarly, the actual dispatch never charges more than 5% of capacity in any given month-hour, while the optimal scenarios charge up to 18% of capacity in a single month-hour. The nonresidential sector has a much more even distribution between standalone and solar paired systems. When comparing the hours of the day that the battery typically discharges, the optimal customer bill scenario is most like actual, with most of the discharge activity occurring between 4 p.m. and 9 p.m. The optimal avoided cost and optimal GHG scenarios vary their discharge patterns significantly from month to month (following the heterogenous nature of the avoided cost and GHG cost signals).

FIGURE 5-6: NONRESIDENTIAL HRLY DISPATCH BY MONTH (ACTUAL, OPTIMAL UTILITY COSTS, GHG AND BILLS)

Actual Hourly Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-4%	-2%	-2%	-1%	-1%	-0%	0%	1%	-1%	-3%	-3%	-3%	-2%	-1%	-1%	0%	3%	4%	3%	4%	4%	-1%	-1%	-0%
2	-4%	-3%	-2%	-1%	-1%	-1%	0%	0%	-2%	-3%	-3%	-2%	-2%	-1%	-1%	-0%	2%	3%	3%	4%	4%	-0%	-1%	-0%
3	-3%	-2%	-2%	-1%	-1%	-0%	1%	1%	-2%	-4%	-5%	-4%	-3%	-2%	-1%	-0%	2%	3%	3%	4%	4%	2%	-1%	-0%
4	-2%	-2%	-1%	-1%	-1%	-0%	1%	1%	-2%	-4%	-5%	-4%	-3%	-2%	-1%	-1%	3%	3%	4%	4%	5%	1%	-0%	0%
5	-3%	-1%	-1%	-1%	-1%	-0%	1%	-0%	-2%	-5%	-4%	-3%	-3%	-2%	-1%	-0%	3%	3%	3%	4%	5%	0%	-1%	0%
6	-4%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-3%	-3%	-2%	-2%	-1%	-0%	0%	4%	4%	4%	4%	5%	-1%	-1%	-1%
7	-4%	-3%	-2%	-2%	-1%	-1%	-0%	-1%	-2%	-3%	-3%	-2%	-2%	-1%	-0%	0%	3%	4%	4%	5%	5%	0%	-1%	-2%
8	-3%	-2%	-2%	-2%	-2%	-1%	-0%	-1%	-2%	-3%	-3%	-2%	-2%	-1%	-0%	-0%	3%	4%	4%	4%	4%	-0%	-1%	-1%
9	-3%	-2%	-2%	-2%	-1%	-1%	-0%	-0%	-2%	-3%	-3%	-3%	-2%	-1%	-0%	0%	3%	4%	4%	4%	4%	-0%	-1%	-1%
10	-3%	-2%	-2%	-2%	-1%	-1%	-0%	0%	-2%	-3%	-3%	-2%	-2%	-1%	-1%	-1%	3%	5%	4%	4%	4%	0%	-1%	-0%
11	-4%	-4%	-3%	-2%	-1%	-1%	-0%	-0%	-3%	-4%	-4%	-3%	-2%	-1%	-0%	3%	8%	8%	6%	4%	4%	-1%	-2%	-2%
12	-4%	-3%	-3%	-2%	-2%	-1%	0%	0%	-2%	-4%	-3%	-3%	-2%	-1%	-0%	4%	7%	7%	5%	3%	3%	-1%	-2%	-2%

Utility Avoided Cost Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-1%	-5%	-7%	-6%	-0%	3%	12%	10%	3%	3%	-2%	-11%	-14%	-10%	-10%	-3%	5%	13%	6%	5%	5%	7%	-0%	-4%
2	-2%	-7%	-6%	-5%	-1%	5%	16%	5%	2%	-2%	-9%	-6%	-13%	-7%	-5%	-5%	1%	10%	11%	8%	9%	6%	1%	-6%
3	3%	-2%	-8%	-6%	-1%	7%	16%	10%	2%	-1%	-5%	-8%	-5%	-8%	-15%	-8%	-6%	2%	8%	8%	9%	9%	4%	1%
4	2%	-2%	-4%	-1%	2%	6%	16%	5%	-5%	-2%	-3%	-7%	-2%	-5%	-14%	-5%	-13%	-3%	3%	13%	10%	10%	4%	4%
5	6%	1%	-6%	-4%	1%	8%	11%	-2%	-4%	-10%	-1%	-1%	-6%	-6%	-14%	-11%	-11%	-4%	4%	17%	14%	5%	4%	4%
6	4%	1%	-0%	0%	1%	5%	2%	-13%	-14%	-13%	-5%	-3%	-6%	2%	-6%	-1%	-8%	-2%	5%	20%	18%	7%	5%	1%
7	2%	-1%	-5%	-4%	-3%	7%	9%	-5%	-14%	-17%	-18%	-11%	-5%	1%	-2%	3%	-0%	6%	9%	19%	14%	8%	6%	1%
8	2%	-1%	-2%	-9%	-5%	6%	15%	1%	-14%	-16%	-16%	-6%	-6%	-5%	-2%	-1%	-2%	5%	10%	18%	12%	6%	4%	2%
9	6%	1%	-5%	-5%	-3%	5%	19%	3%	-12%	-16%	-12%	-8%	-7%	-7%	-1%	-2%	-3%	11%	13%	7%	6%	4%	3%	2%
10	2%	-1%	-5%	-11%	-9%	-1%	15%	16%	-2%	-14%	-12%	-6%	-1%	-3%	-8%	-14%	-5%	15%	8%	6%	7%	8%	5%	1%
11	1%	-2%	-9%	-6%	-2%	7%	16%	6%	-2%	-8%	-6%	-7%	-11%	-12%	-11%	3%	12%	6%	4%	4%	6%	8%	6%	2%
12	-0%	-1%	-6%	-9%	-3%	2%	13%	11%	3%	-2%	-4%	-6%	-13%	-17%	-19%	-0%	8%	10%	4%	5%	6%	5%	5%	2%

GHG Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	-3%	-7%	-6%	-1%	4%	10%	9%	2%	2%	-2%	-11%	-14%	-11%	-10%	-2%	5%	13%	6%	5%	4%	7%	-0%	-2%
2	-1%	-8%	-6%	-5%	-0%	5%	16%	4%	1%	-2%	-6%	-9%	-11%	-8%	-6%	-6%	1%	10%	11%	8%	9%	5%	1%	-5%
3	4%	-2%	-7%	-6%	-1%	7%	16%	10%	2%	-1%	-3%	-5%	-6%	-5%	-13%	-11%	-9%	2%	8%	9%	9%	8%	3%	1%
4	2%	-2%	-4%	-1%	2%	6%	15%	4%	1%	-1%	-1%	-2%	-6%	-4%	-8%	-14%	-15%	-3%	2%	14%	11%	10%	5%	3%
5	6%	1%	-6%	-4%	1%	8%	11%	-1%	-4%	-4%	-2%	1%	-5%	-5%	-9%	-8%	-12%	-7%	4%	16%	15%	5%	4%	4%
6	4%	1%	-1%	0%	1%	5%	2%	-12%	-13%	-12%	-6%	-5%	-3%	0%	-2%	1%	-11%	-2%	5%	21%	18%	8%	4%	1%
7	2%	-1%	-5%	-3%	-2%	6%	8%	-5%	-13%	-17%	-19%	-11%	-5%	3%	1%	6%	-4%	2%	3%	17%	12%	9%	6%	4%
8	2%	0%	-1%	-8%	-5%	5%	15%	0%	-11%	-15%	-13%	-6%	-5%	-3%	-3%	0%	-6%	1%	6%	16%	6%	8%	6%	3%
9	5%	1%	-1%	-5%	-3%	4%	19%	4%	-12%	-14%	-13%	-9%	-9%	-6%	1%	-1%	-8%	4%	13%	8%	3%	5%	6%	3%
10	2%	-0%	-3%	-10%	-9%	-1%	15%	15%	-0%	-14%	-12%	-5%	-3%	-3%	-7%	-11%	-7%	14%	11%	4%	3%	7%	6%	2%
11	2%	-2%	-8%	-7%	-3%	4%	15%	6%	-1%	-7%	-7%	-7%	-10%	-12%	-11%	2%	11%	8%	4%	6%	6%	8%	6%	3%
12	-1%	-1%	-4%	-8%	-3%	2%	12%	12%	4%	-1%	-5%	-6%	-11%	-18%	-20%	-1%	11%	10%	4%	5%	5%	4%	5%	2%

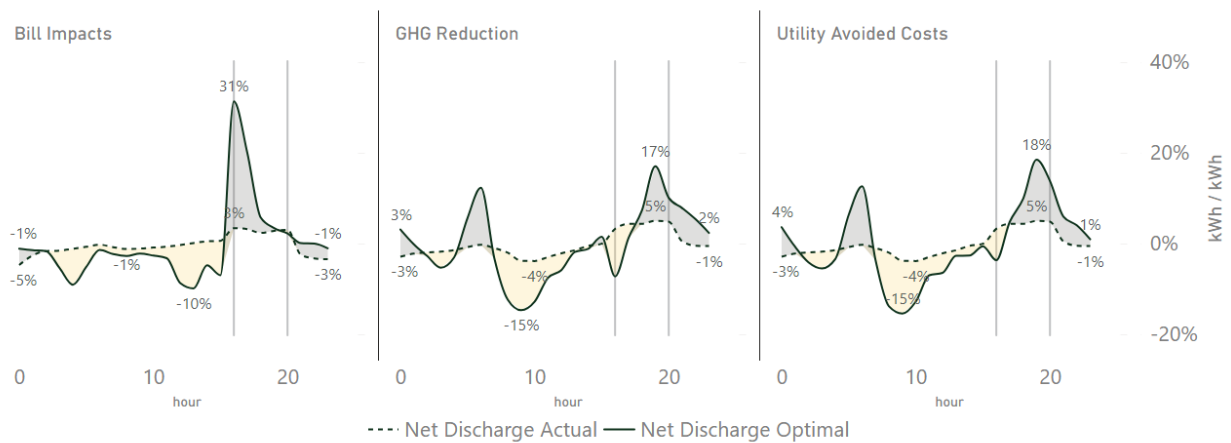
Bill Impact Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-1%	-1%	-1%	-2%	-3%	-3%	-4%	-3%	2%	0%	-2%	-2%	-2%	-4%	-12%	-14%	23%	16%	5%	3%	1%	-0%	-1%	-1%
2	-0%	-1%	-2%	-2%	-3%	-3%	-4%	-4%	1%	0%	-1%	-2%	-2%	-4%	-12%	-15%	24%	16%	6%	3%	2%	-0%	-0%	-0%
3	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	2%	0%	-2%	-2%	-5%	-7%	-7%	-10%	24%	16%	5%	3%	2%	-1%	-1%	-1%
4	-0%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	1%	-1%	-2%	-3%	-6%	-7%	-7%	-10%	24%	16%	5%	3%	2%	-0%	-1%	-1%
5	-0%	-0%	-1%	-2%	-3%	-3%	-4%	-4%	2%	0%	-2%	-3%	-5%	-7%	-8%	-10%	25%	16%	4%	2%	2%	-0%	-1%	-1%
6	-1%	-2%	-2%	-3%	-3%	-3%	-2%	-2%	3%	-3%	-4%	-4%	-8%	-9%	-9%	-14%	30%	21%	8%	5%	4%	0%	-0%	-1%
7	-1%	-2%	-2%	-3%	-4%	-3%	-3%	-4%	-3%	-3%	-4%	-4%	-7%	-8%	-9%	-13%	31%	22%	7%	5%	3%	0%	0%	-1%
8	-1%	-1%	-1%	-3%	-3%	-3%	-2%	-3%	-4%	-3%	-4%	-4%	-8%	-9%	-8%	-11%	30%	20%	8%	5%	3%	-0%	-0%	-1%
9	-1%	-2%	-2%	-3%	-4%	-3%	-2%	-3%	-2%	-2%	-3%	-3%	-6%	-9%	-9%	-13%	30%	21%	8%	4%	2%	0%	0%	-2%
10	-0%	-1%	-1%	-2%	-3%	-2%	-3%	-3%	2%	0%	-1%	-1%	-2%	-3%	-14%	-17%	25%	16%	5%	2%	1%	-0%	-1%	-1%
11	-0%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	1%	0%	-1%	-1%	-2%	-4%	-12%	-14%	24%	15%	4%	2%	1%	-0%	-1%	-1%
12	0%	-0%	-1%	-2%	-2%	-2%	-3%	-3%	1%	0%	-1%	-1%	-1%	-2%	-12%	-14%	23%	15%	4%	2%	1%	-0%	-1%	-1%

Figure 5-7 displays the average weekday battery dispatch pattern for the three optimization scenarios (solid dark lines) alongside the actual dispatch pattern during the same period (dashed dark lines) for nonresidential projects during summer months (June-September, inclusively). The shaded yellow areas represent times where more charging occurs than actual, and the light gray shaded area signifies more discharge than actual from optimal dispatch. The vertical lines highlight the typical peak pricing period of 4 p.m. – 9 p.m.

FIGURE 5-7: NONRESIDENTIAL AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS SUMMER MONTHS

Nonresidential Storage Dispatch (Observed vs. Optimal)





APPENDIX A BILL SAVINGS ANALYSIS

We estimated bill savings for the 2024 SGIP energy storage evaluation through use of Verdant’s distributed energy resource cost effectiveness analysis tool (DER CAT). Monthly and annual bills were estimated using the tool’s bill calculation module. To estimate bill savings, we calculated a customer’s bill using their historical hourly net load and an estimated baseline load. The baseline load was defined as the net load minus the hourly storage dispatch activity. Bill savings were calculated as the difference between the actual and baseline bills. Table A-1 and Table A-2 present the actual rate schedules used to develop 2024 bill impacts for residential and nonresidential SGIP participants, respectively. These are further disaggregated by IOU.

TABLE A-1: DISTRIBUTION OF RESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	2023	
		Sample Count	Percent (%)
PG&E	B-6	1	<1%
	E-1	13	1%
	E-1-CARE	7	<1%
	E-ELEC	10	1%
	E-ELEC-CARE	2	<1%
	E-TOU-B	13	1%
	E-TOU-C	302	31%
	E-TOU-C-CARE	28	3%
	E-TOU-C-FERA	2	<1%
	E-TOU-D	34	3%
	E-TOU-D-CARE	2	<1%
	EM	1	<1%
	EM-TOU	1	<1%
	EV-A	19	2%
	EV-B	1	<1%
	EV2-A	505	52%
	EV2-A-CARE	34	3%
	Subtotal	975	100%
SCE	D	15	3%
	TOU-D_4_9	80	15%
	TOU-D_4_9-CARE	6	1%
	TOU-D_5_8	55	10%

SDG&E	TOU-D_5_8-CARE	10	2%
	TOU-D-PRIME	334	64%
	TOU-D-PRIME-CARE	17	3%
	TOU-GS1-E	5	<1%
	TOU-GS2-D	1	<1%
	TOU-GS3-D	1	<1%
	Subtotal	524	100%
	DR	10	4%
	DRSES	64	24%
	DRSESLI	1	<1%
	EV-TOU-2	16	6%
	EV-TOU-5	46	17%
	EV-TOU-5-CARE	2	<1%
	Subtotal	267	100%
All	Total	1,766	

TABLE A-2: DISTRIBUTION OF NONRESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	2024	
		Sample Count	Percent (%)
PG&E	A10-X	5	1%
	AG-5-C	1	<1%
	AG-A1	1	<1%
	AG-B	1	<1%
	AG-C	2	<1%
	B-1	7	2%
	B-6	7	2%
	B-10	28	8%
	B-19	145	43%
	B-19_1v	9	3%

SCE	B-19_1v-Option-S	2	<1%
	B-19-Option-S	43	13%
	B-20_1v	17	5%
	B-20_1v-Option-S	10	3%
	B-20_2v	5	1%
	B-20_2v-Option-S	2	<1%
	B-20_t	4	1%
	B-20_t-Option-S	2	<1%
	E-19	25	7%
	E-19_1v	13	4%
	E-20_1v	9	3%
	Subtotal	338	100%
	TOU-8-R	14	3%
	TOU-GS1-D	2	<1%
	TOU-GS2-B	4	<1%
	TOU-GS3-R	23	6%
	TOU-PA2-D	4	<1%
	TOU-GS3-E	23	6%
	TOU-GS1-E	2	<1%
	TOU-GS2-E	41	10%
	TOU-GS2-D	39	9%
	TOU-8-E	17	4%
	TOU-PA2-E	10	2%
	TOU-PA3-D	8	2%
	TOU-EV-9-2kv	23	6%
	TOU-PA3-B	1	<1%
	TOU-8-D	66	16%
	TOU-PA3-A	1	<1%
	TOU-PA3-E	11	3%
	TOU-GS2-R	54	13%
	TOU-8-B	6	1%
	TOU-GS3-B	7	2%
	TOU-EV-NR-8	2	<1%
	TOU-GS3-D	54	13%
	Subtotal	412	100%

SDG&E	AL-TOU_<500kW_1v	2	1%
	AL-TOU_<500kW_2v	66	44%
	AL-TOU_>500kW_1v	4	3%
	AL-TOU_>500kW_2v	8	5%
	AL-TOU2_<500kW_2v	11	7%
	AL-TOU2_>500kW_2v	6	4%
	DG-R_<500kW_2v	32	21%
	DG-R_>500kW_1v	1	<1%
	DG-R_>500kW_2v	1	<1%
	EV-HP	15	10%
	TOU-M	1	<1%
	TOU-PA2_2v	1	<1%
	TOU-PA3_2v	3	2%
	Subtotal	151	100%
All	Total	901	

Updating the Model

The DER CAT contains detailed IOU tariff information that is used to calculate customer bills. For this analysis, we entered rate information for tariffs as of July 2024. The tool captures full information about TOU periods, tiered rates, and demand charges. Figure A-1 shows an example of how the TOU periods are captured inside the model.

FIGURE A-1: DER CAT HOURLY TIME-OF-USE INPUT SHEET

RateName	Season	WeekEndHoliday	H00	H01	H02	H03	H04	H05	H06	H07	H08	H09	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23
TOU-DR1	Summer	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off

All sub-components of an individual tariff are captured for energy and demand charges. Figure A-2 shows an example of the rate components that are recorded in the tool. The rate's subcomponents are tracked separately so that non-bypassable charges are handled appropriately in bill calculations. Demand charges are also recorded in the tool, separating out peak, non-coincident, and TOU charges for transmission and distribution.



FIGURE A-2: DER CAT RATE INPUT SHEET

Season	TOU	Tier	Transm	Distr	PPP	ND	CTC	LGC	RS	TRAC	CostRe	PUCRF	BaselineDis	UDC	DWRBond	EECCDWR	TotalNBP	TotalRate
Summer	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.43976	0.0262	0.69702
Summer	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.19788	0.0262	0.45514
Summer	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.07083	0.0262	0.32809
Winter	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.14857	0.0262	0.54517
Winter	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.08335	0.0262	0.47995
Winter	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.06442	0.0262	0.46102
Summer	_ALL_												-0.10159	-0.10159			0	-0.10159
Winter	_ALL_												-0.10159	-0.10159			0	-0.10159

Bill Calculation

Each annual bill is calculated by first summarizing the monthly kW and kWh by tier and/or TOU period. These monthly totals are then multiplied by the applicable \$/kW or \$/kWh provided in the given utility rate sheet. This process allows many different rate structures to be utilized in the same calculator. The annual bill is then calculated by summing each of the monthly kW and kWh components. The bill calculations assume that the monthly billing cycles align with calendar months. Exports were reimbursed at the full retail rate (NEM 2.0). The billing analysis for this project involves estimating bills for each customer under two scenarios: actual customer usage with a battery, and customer usage if their system was not paired with battery storage. The bill calculation tool is run over the usage from both scenarios, creating annual bills for both scenarios. The difference between these bills is the bill savings we report.

APPENDIX B DATA SOURCES AND QUALITY CONTROL

This appendix provides an overview of the primary sources of data used to quantify the energy and peak demand impacts of the 2024 Self-Generation Incentive Program (SGIP) and the data quality and validation process.

B.1 DATA SOURCES

The primary sources of data include:

- The statewide project list managed by the Program Administrators (PAs),
- Site inspection and verification reports completed by the PAs or their consultants,
- Metered storage and generation data provided by project developers, the SGIP Data Portal, directly from customers, or from performance data providers,
- Metered load and PV generation data from project developers, and
- Utility provided data:
 - Metered utility 15 minute or hourly load data
 - SGIP customer rate schedules
 - SGIP customer demand response participation and event times
 - SGIP customer outage information and outage times, including Public Safety Power Shutoffs (PSPS) events

B.1.1 Statewide Project List and Site Inspection Verification Reports

The statewide project list contains information on all projects that have applied to the SGIP. Critical fields from the statewide project list include:

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and eligible/ineligible cost information, and
- Project characteristics include technology/fuel type, rebated capacity, fuel types, and equipment manufacturer/model.

Data obtained from the statewide project list are verified and supplemented by information from site inspection verification reports. The PAs or their consultants perform site inspections to verify that installed SGIP projects match the application data and to ensure they meet minimum requirements for



program eligibility. Our team reviews the inspection verification reports to verify and supplement the information in the statewide project list. Additional information in verification reports include descriptions of storage and generation capacity, differences between incentivized and nameplate capacities, and identification of existing metering equipment that can be used for impact evaluation purposes, fuel descriptions and percentage of biogas, and details surrounding heat recovery.

B.1.2 Interval Load Data and Metered Data

Metered energy storage charge and discharge data are requested and collected from system manufacturers and developers for performance-based incentive (PBI) and non-PBI projects, and from Energy Solutions for projects that received a PBI incentive. Metered energy generation, fuel consumption, and heat recovery data were requested directly from customers and performance data providers, as well as downloaded from the Energy Solutions data portal for those projects still within their PBI period.

Interval load data for each project were requested from Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2024. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze energy storage dispatch. Due to the confidential nature of customer load data, we signed nondisclosure agreements (NDAs) with each of the utilities to obtain the load data. Once load data were received and processed, we matched them to available charge/discharge data to allow project-by-project analysis of the customer demand impacts of SGIP. Table B-1 provides a summary of the types of data requested and used in the analysis as well as the data source(s).

TABLE B-1: DATA REQUESTED AND DATA SOURCES

Types of Data Requested/Used/Received	SGIP Project Database	Energy Solutions	Project Developer	Customers	PDPs	IOU
SGIP reservation number	X	X	X			
Capacity (kW, duration, kWh for Storage), kW for generation	X		X			
Program year (PY) of application and upfront payment date	X					
Customer sector	X					
Payment type (PBI vs. Non-PBI)	X	X				
Incentive	X					
Project developer	X		X			
Battery manufacturer	X		X			
Interval Charge and discharge data (kWh)		X	X			
Interval electrical generation, fuel consumption, and heat recovery		X	X	X	X	
15-minute customer load data (kWh)			X			X
Renewable on-site generation (kWh)			X			X
Treatment of daylight savings		X	X	X	X	X
Data period beginning or ending		X	X	X	X	X
Unit of measure (kW, kWh, W, Wh, etc)		X	X	X	X	X
Status of storage system (operational/off-line)			X			
Storage system use case – TOU bill arbitrage, coincident/non-coincident demand charge reduction, PV self-consumption, backup, demand response/wholesale market participation			X			
How system interacts with on-site renewable			X			
Customer utility tariff			X			X
Flow Direction (delivered vs. received) for bi-directional meters						X
Dates and times of any DR, capacity or other program participation			X			X
Dates and times of planned/unplanned outages (PSPS, etc)			X			X
SubLAP associated with the geographic location of customer						X

B.2 DATA CLEANING

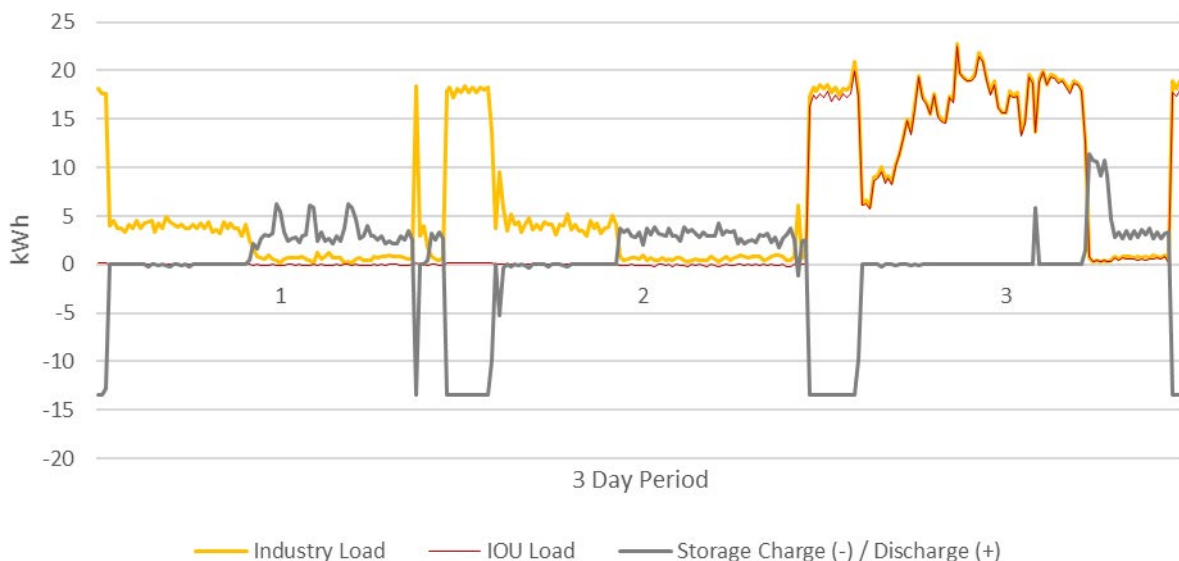
As discussed above, the analysis leveraged a variety of data sources from project developers, Energy Solutions (for projects that received a PBI incentive), directly from customers and performance data providers, and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were verifiable:

- Interval battery, electrical generation, fuel consumption, heat recovery, and load data were aligned to Pacific Standard Time (PST). Data for each time interval were set to the beginning of the time interval.
- Visual inspections of storage dispatch, generator, and load data were conducted for all projects where we received data. This allowed the evaluation team to verify if, for example, metered load data increased at the same interval as the battery was charging (time syncing), or if both fuel consumption and electrical generation showed consistencies. This step also identified sites with differing or inconsistent timestamps, and load data with the wrong sign (i.e. negative when it should be positive and positive when it should be negative).
- When battery data were provided by the project developer and the PBI database, we conducted quality control (QC) on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- When load data were provided by the project developer and the IOU, we conducted QC on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- We reviewed hourly, daily and monthly performance metrics to determine whether the data were accurate.
- We reviewed battery capacities and generation capacities in the program tracking database to verify they were accurate.
- We reviewed the battery storage data usage to identify the start date of valid data.
- We identified outliers in battery data by setting any 15-minute charge and discharge power that is above the rated capacity of the battery times four as abnormal spikes. Outliers were also identified in electrical output and fuel generation data.
- We identified battery storage data that signified possible data quality issues:
 - Round trip efficiency over 92.5 percent
 - Maximum battery discharge as a percentage of kW capacity greater than 3
 - The 99th percentile of battery storage discharge as a percentage of kWh capacity greater than 1, indicating the possibility of a second battery installed that was not installed through SGIP

Figure B-1 conveys a visualization of the data cleaning process. This is a three-day example that was mocked up to represent one of the storage projects. The yellow line represents the load data that would have been provided by the project developer. The red line represents the IOU load, and the gray line represents the storage dispatch behavior. This example illustrates a couple of data cleaning exercises we performed:

- We can confirm the sync between the battery and load data. When the battery is charging (-) the load increases on the same time stamp.
- The IOU load data in this representative example is missing throughout the first day and halfway through the second day. The IOU data does not match with the project developer data until midnight on the third day (see between 2 and 3 below). We could stitch the two load streams and not lose the first two days.

FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



We received battery storage data that sometimes started before the interconnected date, but still appeared to be valid, usable data. To retain the most amount of valid data, we reviewed the data received to determine an analysis start date. For most of the sites, this was not an issue, as they were interconnected prior to 2021. However, for the ones that were interconnected in 2023, we determined the start date as follows:

- If the upfront payment date came before the date that the battery first cycled then the start date used was the most recent of either the upfront payment date or the first date of any data,
- Else if there was no battery cycling in the winter then the start date used was the first date of any data,

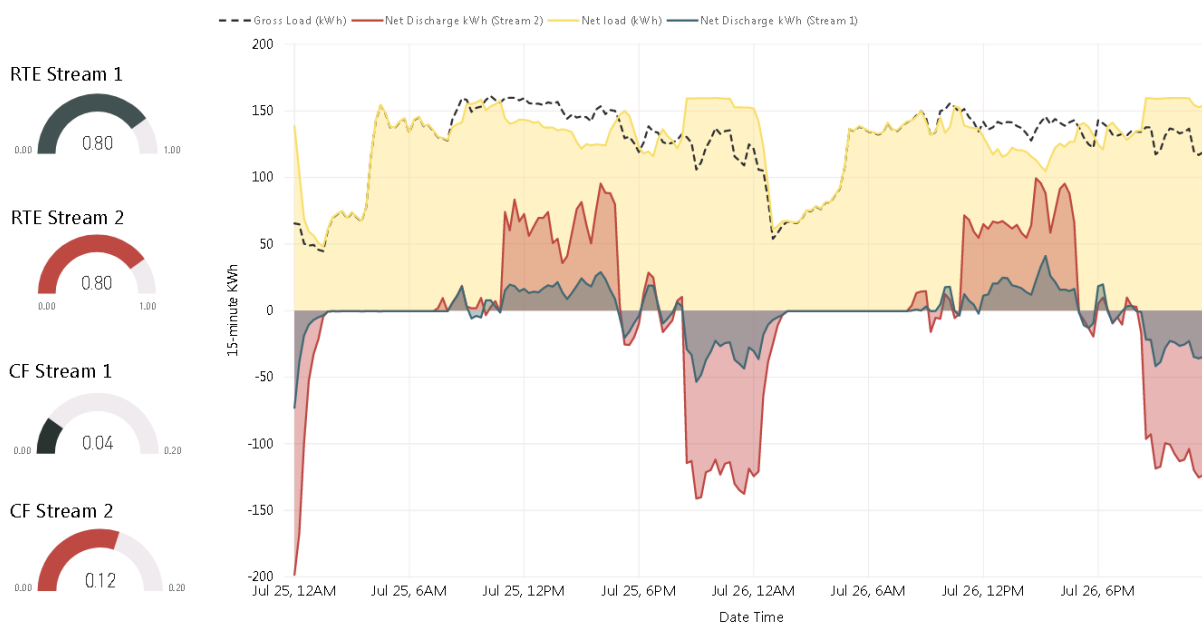
- Else the start date used was the first date the battery started cycling.

Storage systems inherently increase energy consumption. Because of losses in the battery, less energy can be discharged than is stored in the battery. This fact provided an additional QC benefit. After we removed data that was completely missing or clearly corrupt, we examined the roundtrip efficiency (RTE) – which is the ratio of total discharge to total charge energy – for each project by hour, day, and month. Since energy discharged cannot be greater than energy stored, we identified potential data issues by reviewing projects that exhibited RTEs greater than one at the monthly level (Section 4 discusses this performance metric in detail).

For the residential projects, looking for the appearance of a second battery addition was an additional QC step that was implemented in this evaluation. The data goes through a series of checks, beginning with incorporating the identified second battery additions from the previous evaluation years. The next step is identifying when the 99th percentile of consecutive battery storage charge or discharge exceeds the kWh capacity of the battery. Finally, maximum charge and discharge over a single time interval are compared to the system's rated kW capacity, and systems with a value significantly greater than their capacity are flagged. The time series data was manually reviewed to assess the date of when the additional battery appears, and the storage data was pro-rated after that point so that the savings will only reflect that of the battery installed through the program.

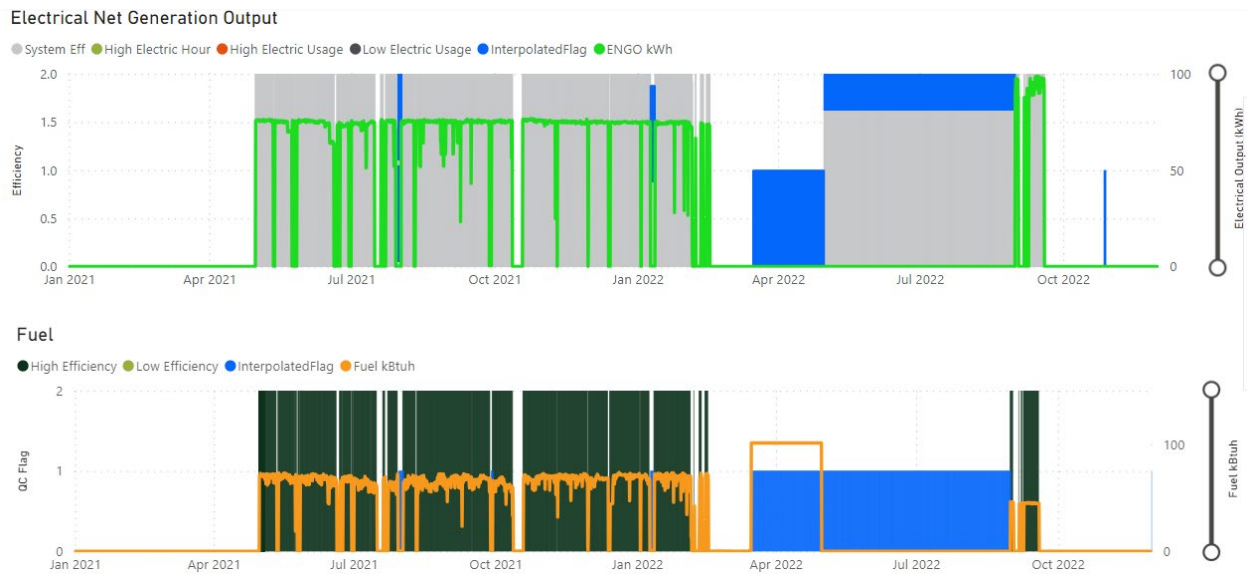
Another QC check was also conducted where the evaluation team received multiple streams of data. Capacity factors and RTEs have expected ranges, therefore observations that fall outside of these ranges are flagged for further review. Figure B-2 illustrates this initial data cleaning step – where we compare the RTE and CF from two distinct data streams. While the RTE for both streams are identical (and within an expected range) the CFs for both streams are different. These data are flagged for further analysis. This analysis would reveal that “Stream 1” is the appropriate storage net discharge profile for this project. The magnitude of net discharge for “Stream 2” is too great, given the metered load profile for this facility.

FIGURE B-2: EXAMPLE 2 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



On the generation side, dashboards were developed which included hourly electrical, fuel, and heat data, as well as a calculation of efficiency, and flags indicating whether the electric output appeared too high. An example is shown below in Figure B-3. For this project, the calculated efficiency of the system was between 200-300%, indicating that the fuel data may not be complete, or the electrical output may include output for another generator. In this case, the electrical output seemed reasonable, within the reasonable range based on the size of the generator, but the fuel data could not be validated, so we dropped the fuel data from the analysis, but kept the electrical generation data.

FIGURE B-3: EXAMPLE 3 OF DATA CLEANING AND QC PROCESS FOR A GENERATION PROJECT



One final QC check was implemented to ensure the quality of data was within expected ranges for billing calculation. All of the solar generation data was stratified by meter and hour and normalized by assigning a z-score to each datapoint. Any data points with a z-score greater than 7.5 or less than -7.5 were removed from the final dataset. This retains more than 99.999% of the data, while removing the occasional extremely anomalous value. This process was followed up with manual verification to ensure that the data points being removed were in fact anomalous.

To accurately estimate billing impacts, there can be no missing values in the netload dataset for a given household. If data was missing, or removed in the step previous anomaly detection step, it was replaced with interpolated data from the same meter. In the case of data gaps spanning less than two hours, data was interpolated linearly between the nearest known datapoints.

APPENDIX C SAMPLING PLANS AND DATA COLLECTION OUTCOMES

This section details the sampling approach used for the 2024 SGIP impact evaluation. The sampling strategy was designed to provide statistically significant impacts while maintaining evaluation delivery timelines and project budgets. The sample design was informed by many of the program attributes discussed above in previous sections, and how they have changed and evolved over time. Sampling plans for energy storage and generation are described below. Different approaches were used for these two program elements due to material differences in their population sizes.

FIGURE C-1: SAMPLE DESIGN CONSIDERATIONS

Program Understanding	Design Considerations
Composition of the SGIP storage and generation projects Data for key segmentation variables will be obtained from the program tracking database and summarized in the research planning phase.	• Customer sector, PBI designation, budget category, program year • Project developer, technology type and manufacturer • Permanency or legacy status • System capacity, presence of on-site generation • PSPS outage and high fire threat district (HFTD) designation
Availability of underlying data requirements and historical data limitations Our extensive experience evaluating the SGIP, and our knowledge of the program, provide us with a unique understanding of what data is realistically available to collect for M&E purposes.	• Decommissioned generation and storage projects • Residential storage systems with ineffective data collection systems • Operational status research (OSR)
Reporting requirements stemming from passage of D.19-08-001 This decision developed GHG emissions requirements and compliance pathways for developer "fleets". It directs the impact evaluator to provide summarized GHG performance of developer fleets as part of the annual SGIP impact evaluations.	• Different compliance pathways for "new" vs. "legacy" projects • Defines project developer fleets • Differs by legacy status, customer sector, permanency period • Increased sample sizes required
Previous evaluation experience and lessons learned Our team understands the drivers of uncertainty surrounding key reporting metrics from past impact evaluation work.	• Development of coefficients of variation based on design variables • Optimal sample design which achieves desired levels of precision without excessive data collection

C.1 ENERGY STORAGE

For the energy storage population, the sample design was based on several factors: 1) the composition of the 2024 population of SGIP storage projects, including budget category, payment year, service territory installation, project developer, equipment manufacturer, 2) availability of underlying data requirements, 3) understanding of historical data limitations, 4) results from the 2023 impact evaluation, 5) sampling requirements needed to develop population-level metrics with a high level of precision and 6) Decision 19-08-001 approved greenhouse gas emission reduction requirements. Our sample design for this study follows an approach consistent with previous evaluations. We developed a stratified random sampling



approach, with an attempted census for some sectors for 2024, given evaluation reporting deadlines, budgetary considerations, and results garnered from previous impact evaluations.

Our nonresidential sample design accounts for 1) project legacy status, 2) developer fleet designation, and 3) PBI status. We planned to evaluate all PBI projects, regardless of legacy status, and a sample of non-PBI legacy project. The nonresidential sample design was developed to:

- Develop legacy developer fleet GHG performance impacts at 90/30 or better. Given the high inter-project variability, we attempted a census for all developer PBI projects and sampled from a small subset of non-PBI projects.
- Develop population-level GHG performance impacts at the overall nonresidential sector level – along with other impact metrics like total avoided utility costs, coincident peak demand and roundtrip efficiency (RTE) – at 90/10 or better

With over 50,000 residential projects subject to evaluation, represented by over 500 unique project developers, the residential sample design requires a far more robust stratified random sampling approach than the nonresidential sector. Our proposed design accounts for many of the program summaries presented in Section 2 and includes stratification by 1) two upfront payment year categories (2018-2022 and 2023-2024), 2) equipment manufacturers, 3) program budget category, and 4) program administrator.

Data processing and validation steps were performed on all metered data Verdant received as part of this impact evaluation. Sample sizes were developed to ensure SGIP population impacts were estimated at high levels of confidence and precision, and with an understanding that metering data acquisition systems are not perfect. Data attrition occurs when Verdant receives unverifiable metered data – either from partial or wholly missing metered values or data anomalies that one would not expect from energy storage performance (an example of this is a project roundtrip efficiency of greater than 100%). This section summarizes the sample design discussed previously and presents the final achieved sample for each of the energy storage customer sectors after a rigorous QA/QC process was completed.

Table C-1 presents the population and achieved sample design for the nonresidential and residential storage sectors. Each is presented by payment year grouping, fully qualified state (or status). While there is inter-segment variability, sample sizes achieved in the nonresidential sector range from 39% to 100% by project count. Overall, data were collected and analyzed for 1,318 nonresidential projects (77% of all nonresidential projects in the population). The sample achieved is slightly greater as a percentage of program capacity. Achieved sample sizes range from 46% to 100% by program capacity – with 79% of the MWh of the nonresidential program represented. We evaluated roughly 4% of all residential projects subject to evaluation in 2024 – representing 5% of total sector-level capacity in MWh.

TABLE C-1: 2024 SGIP ENERGY STORAGE POPULATION AND SAMPLE OF PROJECTS

SGIP Energy Storage Population and Sample by Sector, Payment Year and Project Status

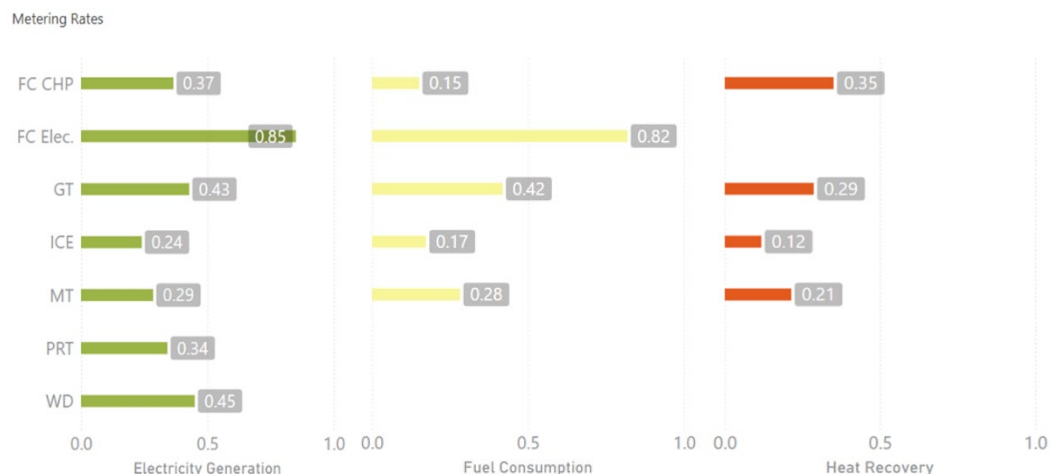
Sector	Payment Yr	Status	Pop	Smp	% Prj Smp	Pop MWh	Smp MWh	% MWh Smp	In Smp Impacts	In Pop Impacts
Nonresidential	2017 Prior	Decommissioned	212	212	100%	10	10	100%	No	Yes
Nonresidential	2017 Prior	Operable	216	84	39%	116	53	46%	Yes	Yes
Nonresidential	2017 Prior	Outside Permanency	5	-	0%	4	-	0%	No	No
Nonresidential	2018-2022	Decommissioned	31	31	100%	7	7	100%	No	Yes
Nonresidential	2018-2022	Operable	890	686	77%	529	408	77%	Yes	Yes
Nonresidential	2023-2024	Operable	360	305	85%	406	363	90%	Yes	Yes
Nonresidential	Total		1,714	1,318	77%	1,072	841	79%		
Residential	2017 Prior	Unknown	411	-	-	4	-	-	No	No
Residential	2018-2022	Operable	34,974	1,543	4%	661	35	5%	Yes	Yes
Residential	2023-2024	Operable	14,663	463	3%	301	10	3%	Yes	Yes
Residential	Total		50,048	2,006	4%	966	45	5%		
Total	Total		51,762	3,324	6%	2,037	886	44%		

C.2 GENERATION

For the generation population, the approach was simple; due to the small size of the generation population in comparison to the overall program, the evaluation team attempted a census of the generation population. The first step was to download metered data for all projects still receiving PBI payment, from the Energy Solutions portal. For the remaining projects with no PBI data, the team reached out to every customer or project developer to request either metered performance data during 2024, or in the absence of the data, to attempt to understand whether the system was performing normally, had major downtimes, was offline completely, or was decommissioned and removed from the facility. We were able to collect data from 239 out of the 295 total generation projects within the 2024 population.

Metering rates for generation equipment, for each of the different data types (electrical generation, fuel consumption, and heat recovery) are provided below in Figure C-2. The metering rate is defined as the number of hours for each project during the year with metered data divided by the total number of hours per year that the equipment is within its permanency period. For example, if a project exited its permanency period halfway through the year, the total number of hours for that project would reflect the date it was no longer within its permanency period. These metering rates are unweighted and do not reflect the relative importance of metering large projects. They are based only on projects that are still operational.

FIGURE C-2: GENERATION METERING RATES



For generation projects, missing values (either due to gaps in metered data or unavailable project data) are estimated using the findings from previous operations status surveys and ratio estimation. Ratio estimation was used to calculate estimates of hourly performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects (projects outside the sample or projects in the sample with gaps in metered data) can be estimated from projects with metered data using a ratio estimator and an auxiliary variable. The ratio estimator is calculated from the metered sample, and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. Table C-3 summarizes the characteristics of the ratio estimation.

TABLE C-2: RATIO ESTIMATION PARAMETERS

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation [kWh]	Capacity Factor [kWh/kW·hr]	Rebated Capacity [kW]	Hourly, by tech. type, incentive, size category, fuel type, and PA.
Fuel Consumption [MBtu]	Electrical Conversion Efficiency [unitless]	Electricity Generation [kWh]	Annual, by technology
Useful Heat Recovered [MBtu]	Useful Heat Recovery Rate [MBtu/kWh]	Electricity Generation [kWh]	Annual, by technology

The outcome of the ratio estimation process is a complete hourly impacts time series for 2024 where meter data gaps are filled with estimates of electricity generation, fuel consumption, and useful heat recovery.

APPENDIX D GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY

This section describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) projects. The GHGs considered in this analysis are limited to carbon dioxide (CO₂) and methane (CH₄), as these are the two primary pollutants that are potentially affected by the operation of SGIP projects.

Hourly GHG impacts are calculated for each SGIP project as the difference between the GHG emissions under observed conditions and assumed counterfactual baseline conditions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP storage projects change the timing of demand for electricity from power plants. Because GHG emission rates from power plants vary, this shifting of electricity demand by storage projects changes the total quantity of emissions. SGIP generation projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases. SGIP generation projects fueled with biogas may reduce emissions of CH₄ in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

The calculation of GHG impacts in terms of CO₂ equivalent (CO₂eq)¹ by date and time (hereafter referred to as “hour”) is summarized by Equation D-1.

$$\Delta GHG_{i,h} = sgipGHG_{ih} - enoPP_{ih} - basePPchlr_{ih} - baseBlr_{ih} - baseBio_{ih} \quad \text{EQUATION D-1}$$

Negative GHG impacts (ΔGHG) indicate reduction in GHG emissions. Other terms in the equation represent SGIP system emissions ($sgipGHG$), power plant emissions ($enoPP$), baseline emissions associated with operations of heating and cooling equipment ($basePPchlr$, $baseBlr$), and baseline emissions associated with biogas ($baseBio$). Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP distributed generation technology and fuel type. For energy storage systems the equation simplifies to Equation D-2.

$$\Delta GHG_{i,h} = -enoPP_{ih} \quad \text{EQUATION D-2}$$

¹ Carbon dioxide equivalency describes, for a given mixture and amount of greenhouse gas, the amount of CO₂ that would have the same global warming potential (GWP), when measured over a specific time period (100 years). This approach must be used to accommodate cases where the assumed baseline is venting of CH₄ to the atmosphere directly.

Detailed explanations of each of the equation terms are provided below.

SGIP Generation System GHG Emissions (*sgipGHG*)

For generation projects utilizing natural gas or renewable biogas fuel, GHGs are released by the SGIP system.

SGIP emission rates for SGIP projects that use natural gas fuel were calculated as:

$$sgipGHG_{ih} = Fuel_{ih} \times \frac{1ft^3CH_4}{935Btu} \times \frac{1lbmoleCH_4}{379ft^3} \times \frac{1lbmoleCO_2}{1lbmoleCH_4} \times \frac{44lbsCO_2}{1lbmoleCO_2} \times \frac{1metrictonCO_2}{2,205lbsCO_2} \quad \text{EQUATION D-3}$$

SGIP emission rates for SGIP projects that use renewable biogas fuel were calculated as:

$$sgipGHG_{ih} = eno_{ih} \times \frac{3412Btu}{kWh} \times \left(\frac{1}{EFF_T} \right) \times \frac{1lbmoleCH_4}{379ft^3} \times \frac{1lbmoleCO_2}{1lbmoleCH_4} \times \frac{44lbsCO_2}{1lbmoleCO_2} \times \frac{1metrictonCO_2}{2,205lbsCO_2} \quad \text{EQUATION D-4}$$

Where:

<i>sgipGHG_{ih}</i>	=	CO ₂ emitted by SGIP project <i>i</i> during hour <i>h</i> [Metric ton/hr]
<i>Fuel_{ih}</i>	=	fuel consumption of SGIP project <i>i</i> during hour <i>h</i> [Btu]
<i>eno_{ih}</i>	=	electrical net output of SGIP project <i>i</i> during hour <i>h</i> [kWh]
<i>EFF_T</i>	=	measured electrical efficiency of technology T (see Table D-1). [Dimensionless fractional efficiency, lower heating value (LHV)]

TABLE D-1: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR GHG EMISSIONS CALCULATION

	Electrical Efficiency [Eff_T]
Fuel Cell Electric	0.52
Fuel Cell CHP	0.29
Internal Combustion Engine	0.34
Microturbine	0.28
Gas Turbine	0.36

* Based on metered electricity generation and fuel consumption (LHV) data collected from SGIP projects

Central Station Electric Power Plant GHG Emissions (*enoPP*)

This section describes the methodology used to calculate impacts on CO₂ emissions from electric power plants. The methodology involves combining emission rates (in metric tons of CO₂ per kWh of electricity



generated) that are service territory- and hour-specific with information about the magnitude and timing of SGIP system operation.

The service territory of the SGIP project is considered in the development of emission rates by accounting for whether the site is located in Pacific Gas and Electric's (PG&E's) territory (northern California) or in Southern California Edison's (SCE's) or Center for Sustainable Energy's (CSE's) territory (southern California). Variations in climate and electricity market conditions have an effect on the demand for electricity. This in turn affects the emission rates used to estimate the avoided CO₂ release by central station power plants. Lastly, timing of electricity generation affects the emission rates because the mix of high and low efficiency plants differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO₂ emission rate.

The GHG Signal calculated by WattTime is used for estimating GHG impacts of SGIP systems. The CPUC-approved methodology that WattTime uses to calculate the GHG Signal assumes:

- The emissions of CO₂ from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and
- The mix of high and low efficiency plants in operation is reflected in the price and demand for electricity at that time.

The premise for hourly CO₂ emission rates calculated by WattTime is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of electricity reflect the market demand for electricity. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO₂. In other words, one can expect an emission rate representing the release of CO₂ associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours. Similarly, when prices are very low or negative, the CO₂ emission rate is assumed to be zero and implies renewable curtailment on the margin. Power plant emissions are calculated according to Equation D-5.

$$enoPP_{ih} = CO_2EF_{ih} \times eno_{ih} \times \frac{1 \text{ MWh}}{1000 \text{ kWh}} \quad \text{EQUATION D-5}$$

Where:

$enoPP_{ih}$ = power plant GHG emissions impact for SGIP project i for hour h [Metric Ton CO₂/hr]

CO_2EF_{ih}	=	power plant GHG emissions per unit of electric energy for SGIP project i for hour h [Metric Ton CO ₂ /MWh]. Value from WattTime SGIP GHG Signal. https://sgipsignal.com/sgipmoer/ Version 2
eno_{ih}	=	electrical net output of SGIP project i during hour h [kWh/hr] For battery storage systems, negative while charging, positive while discharging. For generation systems, positive while generating electricity.

The equations used by WattTime to calculate values of CO_2EF are presented below for the sake of completeness and to provide context for the approaches used for some of the marginal costs (e.g., marginal wholesale electricity cost) discussed in Appendix F. For the impact evaluation, the CO_2EF values resulting from these equations were downloaded from an API maintained by WattTime.

First solve for Heat Rate HR :

$$HR \frac{\text{Btu}}{\text{kWh}} = \frac{\left(LMP \frac{\$}{\text{MWh}} - VOM \frac{\$}{\text{MWh}} \right) \frac{1\text{MWh}}{1000\text{kWh}}}{\left(GasP \frac{\$}{\text{MMBtu}} + GasTransP \frac{\$}{\text{MMBtu}} + EF \frac{\text{MT CO}_2}{\text{MMBtu}} CapTradeP \frac{\$}{\text{MT CO}_2} \right) \frac{1\text{MMBtu}}{1,000,000\text{Btu}}} \quad \text{EQUATION D-6}$$

Where:

HR	Implied heat rate of marginal generator (electrical conversion efficiency of a power plant consuming natural gas) Units: Btu / kWh
LMP	Price for electricity in the wholesale real-time market Interval: 5 minutes Units: \$ / MWh Source: CAISO OASIS real-time 5-minute locational marginal price for utility DLAPs. From menu at: Prices—Energy Prices — Interval Locational Marginal Prices DLAPs as 'NODE_ID' values: — DLAP_PGAE-APND — DLAP_SCE-APND — DLAP_SDGE-APND
VOM	Variable Operating and Maintenance Costs of a natural gas plant Units: \$ / MWh Source: 2021 Avoided Cost Calculator

<i>GasP</i>	Price for commodity gas Interval: Daily Units: \$ / MMBtu HHV Source: Natural Gas Intelligence (NGI)
<i>GasTransP</i>	Price to transport natural gas Units: \$ / MMBtu HHV Source: 2021 Avoided Cost Calculator
<i>EF</i>	Emissions Factor for natural gas Value: 0.0530703704 Units: MT CO ₂ / MMBtu HHV Source: 2024 Avoided Cost Calculator
<i>CapTradeP</i>	Price associated with cap and trade compliance Units: \$ / MT CO ₂ Source: CAISO OASIS Green House Gas Allowance Price (published daily).

Emissions are directly proportional to Heat Rate *HR* and calculated as:

$$CO_2 EF \frac{MT\ CO_2}{MWh} = HR \frac{Btu}{kWh} \frac{1MMBtu}{1,000,000Btu} \frac{1000kWh}{1MWh} EF \frac{MT\ CO_2}{MMBtu} \quad \text{EQUATION D-7}$$

Electric Power Plant Operations Corresponding to Electric Chiller Operation (*basePPchlr*)

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. As absorption chillers are assumed to replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO₂ emissions associated with these cogeneration facilities. The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{ih} = Chiller_i \times heat_{ih} \times COP \times effElecChlr \times \left(\frac{1tonhrCooling}{12Mbtu} \right) \quad \text{EQUATION D-8}$$

Where:

<i>chlrElec_{ih}</i>	=	the electricity of a power plant that would be needed to provide baseline electric chiller for SGIP CHP project <i>i</i> for hour <i>h</i> [kWh]
<i>Chiller_i</i>	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspection reports (see Table D-2).

$heat_{ih}$	=	quantity of useful heat recovered for SGIP CHP project i for hour h from metering or ratio analysis [MBtu]
COP	=	0.6 – assumed efficiency of the absorption chiller using heat from SGIP CHP project [Mbtu _{out} /Mbtu _{in}]
$effElecChlr$	=	0.634 - assumed efficiency of the baseline new standard efficiency electric chiller [kWh/tonhr·Cooling]

TABLE D-2: ASSIGNMENT OF CHILLER ALLOCATION FACTOR

Project Design	Chiller _i
Heating and Cooling	0.5
Cooling Only	1
Heating Only	0

Baseline GHG Emissions from Power Plant Operations for chiller operations

The location- and hour-specific CO₂ emissions rate, when multiplied by the electricity requirements of a baseline chiller, estimates the hourly emissions avoided.

$$basePpChiller_{ih} = CO_2EF_{ih} \times chlrElec_{ih}$$

EQUATION D-9

Where:

$basePpChiller_{ih}$ = the baseline power plant GHG emissions avoided due to SGIP CHP project i delivery of cooling services for hour h [Metric Ton CO₂/hr]

Boiler GHG Emissions ($baseBlr$)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building or process heating loads. Using recovered heat in lieu of natural gas in this manner helps reduce CO₂ emissions. The equation below describes impacts of SGIP CHP projects providing heating services.

$$baseBlr_{ih} =$$

$$Boiler_i \times heat_{ih} \times effHx \times \frac{1}{effBlr} \times \frac{1ft^3CH_4}{935Btu} \times \frac{1,000Btu}{1Mbtu} \times \frac{1lbmoleCO_2}{1lbmoleCH_4} \times \frac{44lbsCO_2}{1lbmoleCO_2} \times \frac{1metrictonCO_2}{2,205lbsCO_2}$$

EQUATION D-10

Where:

$baseBlr_{ih}$	=	CO ₂ emissions of the baseline natural gas boiler for SGIP CHP project i for hour h [Metric tons CO ₂ /hr]
$effBlr$	=	0.8 - assumed efficiency of the baseline natural boiler, based on previous cost effectiveness evaluations [Mbtu _{out} /Mbtu _{in}]
$Boiler_i$	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspections report (see Table D-3).

$heat_{ih}$	=	the quantity of useful heat recovered for SGIP CHP project i for hour h from metering or ratio analysis [MBtu]
eff_{HX}	=	0.9 – assumed efficiency of the SGIP CHP project’s primary heat exchanger

TABLE D-3: ASSIGNMENT OF BOILER ALLOCATION FACTOR

Project Design	Boiler _i
Heating and Cooling	0.5
Cooling Only	0
Heating Only	1

Biogas GHG Emissions (*baseBio*)

Distributed generation projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

There are two common sources of biogas found within the SGIP: landfills and digesters. Digesters in the SGIP to date have been associated with water resource recovery facilities (WRRF), food processing facilities, and dairies. Because of the importance of the baseline treatment of biogas in the GHG analysis, these facilities were contacted in 2009 to more accurately estimate baseline treatment. This resulted in the determination that venting is the customary baseline treatment of biogas for dairy digesters, and flaring is the customary baseline for all other renewable fuel sites. Baseline treatments of biogas for different biogas sources and facility types are described below.

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies² has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO₂ and CH₄. These lagoons are typically uncovered, so all CH₄ generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for

² Most dairies manage their waste via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in CH₄ being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas projects).

volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WRRFs and food processing facilities, the baseline is not quite as straightforward. There are almost 250 WRRFs in California, and the larger facilities (i.e., those that could generate 1 MW or more of electricity) are typically required to capture and destroy methane; therefore, flaring is used as the biogas baseline.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. California law requires most landfills with at least 450,000 tons of waste in place to collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled distributed generation landfill site contacts verified that they would have flared their CH₄ in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the CH₄.

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include “directed biogas” projects. Deemed renewable fuel use projects, directed biogas projects were eligible for higher incentives under the SGIP. Directed biogas projects purchased biogas fuel that is produced at another location. The procured biogas was processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased gas was not likely to be delivered and used at the SGIP renewable fuel use project, directed biogas projects were treated as renewable fuel use projects for GHG impacts purposes. However, no more directed biogas projects are within their permanency period.

GHG Emissions of Flared Biogas

Methane is naturally created in landfills, wastewater treatment plants, and dairies. If not captured, the CH₄ escapes into the atmosphere contributing to GHG emissions. Capturing the CH₄ provides an opportunity to use it as a fuel. When captured CH₄ is not used to generate electricity or satisfy heating or cooling loads, it is burned in a flare.

In situations where flaring occurs, baseline GHG emissions comprise CO₂ only. The flaring baseline was assumed for the following types of biogas projects:

- Facilities using digester gas (with the exception of dairies),
- Landfill gas facilities, and

The assumption is that the flaring of CH₄ would have resulted in the same amount of CO₂ emissions as occurred when the CH₄ was captured and used in the SGIP project to produce electricity.

$$baseBio_{ih} = sgipGHG_{ih}$$

EQUATION D-11

GHG Emissions of Vented Biogas

Methane capture and use at renewable fuel use facilities where the biogas baseline is venting avoids release of CH₄ directly into the atmosphere. The venting baseline was assumed for all dairy digester SGIP projects. Biogas consumption is typically not metered at SGIP projects. Therefore, CO₂eq emission rates were calculated by assuming an electrical efficiency.

$$eno_{ih} \times \frac{3412 \text{ Btu}}{kWh} \times \frac{1}{EFF_T} \times \frac{1 \text{ ft}^3 \text{ CH}_4}{935 \text{ Btu}} \times \frac{1 \text{ lbmole CH}_4}{379 \text{ ft}^3 \text{ CH}_4} \times \frac{16 \text{ lbs CH}_4}{1 \text{ lbmole CH}_4} \times \frac{1 \text{ metric ton}}{2,205 \text{ lbs}} \times \frac{21 \text{ metric tons CO}_2}{1 \text{ metric ton CH}_4} = baseBio_{ih}$$

EQUATION D-12

Where:

$baseBio_{ih}$	=	CO ₂ eq emissions of the baseline methane emissions for SGIP CHP project <i>i</i> for hour <i>h</i> [Metric tons CO ₂ /hr]
EFF_T	=	electrical efficiency of technology T (see Table D-1)

APPENDIX E ELECTRIC UTILITY AVOIDED COSTS

Evaluation of SGIP impacts includes impacts on electric utility costs. These impacts are not measured directly. Information from secondary sources is incorporated to estimate these impacts. The approach used to estimate electric utility avoided costs is described in this appendix. Key data sources are summarized below.

E3 Avoided Cost Calculator (ACC). ACC forecasts of distribution capacity costs, transmission capacity costs, and generation capacity costs were included in the impacts evaluation. The ACC is primarily used as a planning tool rather than for impacts evaluation, as it contains 31-year forecasts (2022-2052) for costs and emissions. The forecasts are based on assumed, typical weather and market conditions. However, these forecasts are suitable for estimating marginal avoided costs of the three capacity costs due to the long-term nature of capacity expansion. Additionally, assumptions from the ACC are incorporated into calculation of the GHG Signal (see Appendix D), as well as into several cost components as described below.

CAISO Real-Time Locational Marginal Price Data (RT-LMP). Real-time LMPs serve as the measure of marginal electric energy prices in the impacts evaluation in order to maintain consistency with the GHG Signal and estimates of GHG impacts. In the RT-LMP data, Energy costs and GHG Cap & Trade costs are bundled together and reported as the ‘Energy’ price. To maintain consistency with ACC methods, the RT-LMP values are separated into Energy and GHG components.

SGIP GHG Signal. Values of the GHG Signal are used to estimate Cap & Trade costs. Data sources for the GHG signal include the ACC and CAISO data (see Appendix D for detailed description of GHG Signal).

Each of the components of electric utility marginal costs is described below.

E.1 ENERGY

$$Energy \frac{\$}{MWh} = LMP - CO_2EF \times CapTradeP$$

EQUATION E-1

Where:

Energy Portion of marginal total electricity price *LMP* (including GHG cap & trade) attributable to power plant fuel and operations, and not attributable to cap & trade costs

Units: \$ / MWh

LMP Real-time locational marginal price of electricity

Units: \$ / MWh

Source: CAISO OASIS

CO₂EF Marginal power plant GHG emissions factor

Units: \$ / MWh

Source: <https://sgipsignal.com/sgipmoer/> Version 2

CapTradeP Marginal cost of compliance with the California Air Resources Board's cap-and-trade system.

Units: \$ / MT CO₂

Source: CAISO OASIS GHG allowance daily price

E.2 GHG CAP & TRADE

$$GHGcapTrade \frac{\$}{MWh} = CO_2EF \frac{MT\ CO_2}{MWh} \times CapTradeP \frac{\$}{MT\ CO_2} \times LossRate \quad \text{EQUATION E-2}$$

Where:

GHGcapTrade Portion of total CAISO locational marginal energy price (including GHG) attributable to GHG Cap & Trade

Units: \$ / MWh

LossRate Electricity distribution loss factor

Value: 1.0724

Units: Dimensionless

Source: 2024 ACC, Sheet 'Losses', Cells R7:R8766

E.3 LOSSES

$$Losses \frac{\$}{MWh} = Energy \times (LossRate - 1) \quad \text{EQUATION E-3}$$

Where:

Losses Electrical losses

Units: \$ / MWh

E.4 GHG ADDER

$$GHG_{adder} \frac{\$}{MWh} = CO_2EF \frac{MT\ CO_2}{MWh} \times GHG_{adder_fc} \frac{\$}{MT\ CO_2} \times LossRate \quad \text{EQUATION E-4}$$

Where:

GHG_{adder} The non-monetized carbon price beyond the cost of cap-and-trade allowances, reflecting the cost of further reducing carbon emissions

Units: \$ / MWh

GHG_{adder_fc} GHG Adder Price Forecast

Value: 2024 = 0.00

Units: \$ / MT CO₂

Source: 2024 ACC, Sheet 'Emissions', Cells T15:T16

E.5 GHG PORTFOLIO REBALANCING

$$GHG_{rebalancing} \frac{\$}{MWh} = -CI \frac{MT\ CO_2}{MWh} \times GHG_{adderP} \frac{\$}{MT} \times LossRate \quad \text{EQUATION E-5}$$

Where:

GHG_{rebalancing} Result of utility resource plan adjustments for added distributed energy resources and achievement of annual emissions intensity targets

Units: \$ / MWh

CI Allowable carbon intensity

Value: 2024 = 0.19405

Units: MT CO₂ / MWh

Basis: Nominal \$US

Source: 2024 ACC, Sheet 'Emissions', Cell T41

E.6 ANCILLARY SERVICES

$$AncillarySrvcs \frac{\$}{MWh} = Energy \times ASfactor \quad \text{EQUATION E-6}$$

Where:

AncillarySrvcs Ancillary services costs

Units: \$ / MWh

ASfactor Ancillary services factor (as fraction of Wholesale Energy)

Value: 2024 = 0.0020833

Units: Dimensionless

Source: 2024 ACC, Sheet 'AS Procurement', Cell E3

E.7 METHANE LEAKAGE

$$MethaneLeakage = (CO_2EF \times GHG_{total} - CI \times GHG_{adder}) \times UpInLeak \times LossRate \quad \text{EQUATION E-7}$$

Where:

MethaneLeakage Cost of methane leakage

Units: \$ / MWh

UpInLeak Upstream in-state methane leakage factor (as fraction of Wholesale Energy)

Value: 0.0557

Units: Dimensionless

Basis: 100-year active GWP time horizon

Source: 2024 ACC, Sheet 'Methane Leakage', Cell D4

And:

$$GHG_{total} \frac{\$}{MT} = CapTradeP + GHG_{adder_fc} \quad \text{EQUATION E-8}$$

Where:

GHG_{total} New Total GHG Value

Units: \$ / MT

E.8 GENERATION, DISTRIBUTION, AND TRANSMISSION CAPACITY

The estimation of marginal costs of generation, distribution, and transmission capacity is a long-term planning undertaking that is fundamentally different from estimation of marginal costs such as Energy or Cap & Trade, for which transparent and immediate markets exist to satisfy real-time demands. As no alternatives to the ACC are readily available, values from the ACC are used for SGIP impacts evaluation. They are not used directly however, because the values in the ACC are based on typical meteorological year weather. To align the cost values with weather actually observed during 2024 the values from the



ACC were rank ordered prior to merging into the SGIP data. In the resulting data set, the highest capacity costs from the ACC are assigned to the hours when actual 2024 grid loads were highest.

E.9 SUMMARY

Final sources of data for evaluation of SGIP 2024 electric utility marginal cost impacts are summarized in the table below.

Cost Element	Data Sources for SGIP Impacts Evaluation
Energy	CAISO for Energy (with GHG)
GHG Cap & Trade	CAISO GHG Allowance
GHG Adder	ACC for GHG Adder Factor
GHG Rebalancing	ACC for Carbon Intensity Factor
Ancillary Services	ACC for constants, CAISO for Energy (with GHG), SGIP GHG Signal for emissions
Losses	
Methane Leakage	ACC for constants, SGIP GHG Signal for emissions
Generation Capacity	2024 ACC Data for 2024 Rank-ordered based on CAISO DLAP grid loads
Transmission Capacity	
Distribution Capacity	