Batteries Unleashed: Supercharging Benefits Through Smarter Storage Programs

William Marin, Brian McAuley, Verdant Associates, Berkeley, CA

ABSTRACT

Battery storage systems can offer myriad benefits ranging from resiliency, peak demand reduction, and energy arbitrage (to name a few). Programs incentivizing adoption of energy storage technologies are proliferating throughout the country – California provides upfront incentives for the installation of battery storage systems that serve a customer's needs. In other states like Massachusetts, New York, and Vermont, different models are emerging ranging from utility ownership of batteries, utility/aggregator dispatch of batteries, and pay for performance programs. These programs are sometimes part of a utility's demand response (DR) portfolio, and other times storage programs are bespoke agreements with third parties in response to grid emergencies.

California currently finds itself at a crossroads regarding the future of battery storage. The State has provided incentives for tens of thousands of battery storage systems and produced tangible benefits to both participants and non-participants, providing resiliency during multi-day outages, generating greenhouse gas (GHG) emissions reductions, reducing system peak load, and delivering bill savings to customers. At the same time, impact evaluations have shown that residential batteries are only discharging roughly 45% of their kWh capacity on average on a daily basis and 16% of their kW capacity during the system peak hour.

As California looks to the future, should its battery program be considered a success given the benefits listed above, or are we only beginning to scratch the surface of potential benefits? What does success look like? Optimal dispatch modeling of rebated systems suggests that a battery optimized to provide grid benefits could provide 4x the societal benefits than systems are currently providing, and a system optimized for GHG emissions reductions could achieve 3x the reductions observed today.

Introduction

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 2023, Decision 24-03-071 implemented Assembly Bill (AB) 209 which allocated state funding from the Greenhouse Gas Reduction Fund (GGRF) to the SGIP. SGIP goals, eligibility requirements and incentive levels have changed in the past 20 years in alignment with California's evolving energy policies. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet those evolving goals.

Evaluation Population

The SGIP population subject to evaluation encompasses all cumulative projects since program inception receiving an upfront SGIP incentive through December 31, 2023, and remaining within their required permanency period as specified by the Program Handbook. The evaluation population includes 46,222 SGIP projects representing roughly 1,727 MWh of energy storage rebated capacity and 312 MW of generation equipment incentivized capacity. 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 565 kWh. Residential systems generally range from 10 kWh to 40 kWh, with an average capacity of 19 kWh.

Evaluation Approach

This evaluation examines the performance of SGIP systems by quantifying the observed impacts of systems during 2023. Verdant collected storage charge and discharge data and customer electric load profiles for SGIP participants. Some of the results discussed in this report are developed to better understand the efficiency or utilization of SGIP systems. Some impacts require additional assumptions about what a customer's electricity consumption would have been had they not installed the SGIP system. These assumptions describe an unobservable, counterfactual, non-SGIP baseline which we compare to observed electricity consumption to estimate impacts of the SGIP system at the utility meter.

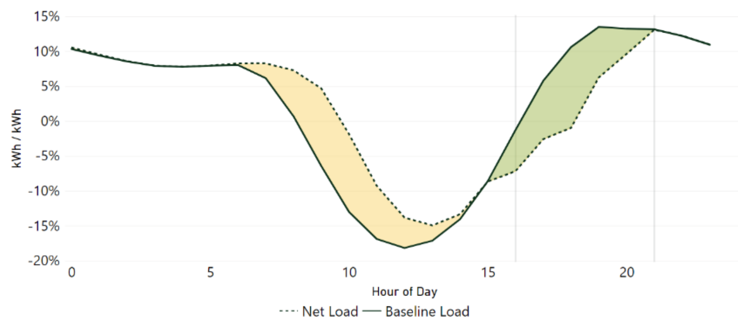

Figure 1. Comparing baseline load to observed load.

The calculation of energy storage impacts, for example, is illustrated in Figure 1 above depicting average hourly delivered load on summer weekdays, along with vertical lines depicting the 4pm – 9pm 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 (green 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 could realize bill savings relative to the counterfactual if discharge occurred during high-priced hours (4 pm – 9pm) and charging occurred during lower-priced hours. Furthermore, systems could provide greenhouse gas (GHG) emissions reductions if the emissions avoided during storage discharge are greater than the emissions increases during storage charging.

Evaluation Findings

This section presents key findings and conclusions from this evaluation based on metered data collected from a representative sample of residential and nonresidential customers. Where possible, we also provide recommendations that could inform future policy and program design. Many of these findings reveal how storage behavior during 2023 was meeting or falling short of SGIP goals and objectives.

Storage Dispatch Behavior

Verdant evaluated a sample of 2,077 residential energy storage systems (5% of the population). Solar PV-paired residential energy storage systems represented roughly 99% of those installations by the end of 2023. Solar PV-paired residential energy storage systems are generally conducting 1) solar self-consumption (64% of sampled projects), 2) TOU energy arbitrage (30%) without export or with export – either regularly or exclusively during specific times like a demand response event, 3) under-utilization or back-up – 6% of systems are in back-up mode and maintaining a full state-of-charge (SOC) in anticipation of an outage or are not being cycled often – both of which don't ascribe to program rules. We also observe some systems paired with PV conducting TOU arbitrage but not charging from solar (3% of PV Paired systems). These systems charge overnight, perhaps to take advantage of relatively lower off-peak electric vehicle (EV) billed rates. 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 results in GHG emissions increases.

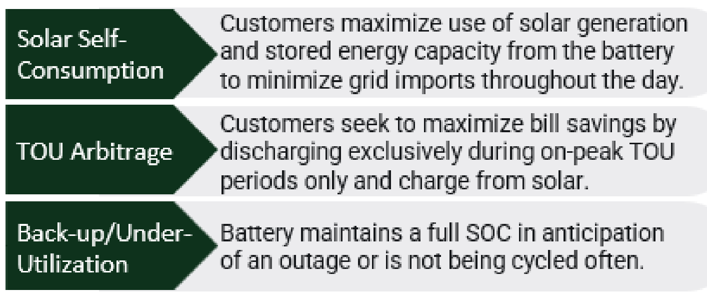

Figure 2. Typical residential operating modes.

Verdant evaluated 1,211 nonresidential energy storage systems (78% of the population). Systems co-located or paired with PV represented roughly 35% of those installations by the end of 2023. The remaining 65% represents standalone energy storage systems. Nonresidential storage performance is guided by similar principles and economics, but customer bill rate structure (monthly, on-peak, daily demands charges and TOU 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. Despite these differences, PV paired nonresidential systems are generally charging from on-site solar and both standalone and PV paired systems are discharging on-peak.

Greenhouse Gas Emissions

CPUC D. 19-09-001 guided the development of a GHG signal to assist SGIP technologies optimize performance and reduce 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. The signal calculates the marginal emissions per kWh of different generation sources (natural gas-fired power plant or renewable generation) using real-time CAISO Locational Marginal Prices (LMP) and other inputs. 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.

Residential and nonresidential energy storage systems, alone and combined, contributed to a net reduction in GHG emissions in 2023. The combined GHG reductions across sectors totaled 19,094 metric tons (MT). This follows a trend first observed in 2020 in the residential sector and at the program level, despite emissions increases from the nonresidential sector in that year. Figure 3 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 six Impact Evaluations (2018-2023). Residential fleet reductions were first observed in 2019 and have increased with each successive evaluation – from an average reduction of 4.3 kilograms (kg) for each kWh of capacity in 2019 to a reduction of 17.3 kg for each kWh of capacity in 2023.

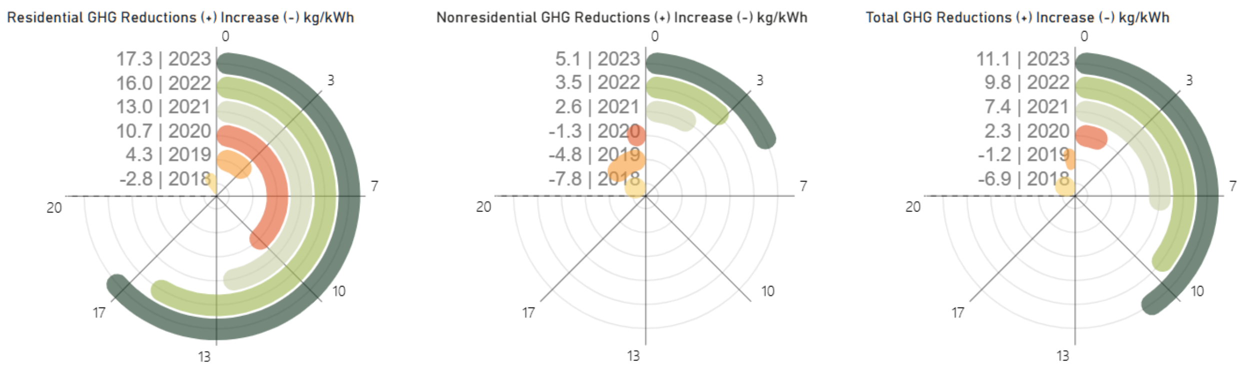

Figure 3. Storage GHG emissions impacts by year and sector (kg/kWh, reduction (+) increase (-))

GHG emissions reductions have also improved in the nonresidential sector during the past three evaluations – with emissions reductions of 2.6 and 3.5 kg for each kWh of capacity in 2021 and 2022, respectively, increasing to 5.1 kg per kWh of capacity in 2023. 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.

Sampled residential storage systems paired with on-site PV and charging from PV decreased emissions by over 19 kg per kWh of capacity, while standalone systems and PV-paired systems charging overnight increased emissions by 5 kg and 2 kg per kWh of capacity, respectively. While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – 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. From a GHG perspective, the value of charging during PV generating hours cannot be overstated. SGIP energy storage systems are discharged in late afternoon and early evening when retail electricity rates are higher and on-site generation and grid-level renewable generation wanes – times that coincide with high marginal emission periods and billed on-peak hours. 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. We recommend that the CPUC explore ways to ensure that standalone systems achieve GHG reductions, such as requiring that they follow the SGIP GHG signal or real-time pricing signals. Furthermore, policies and rate structures developed to promote EV home charging overnight should be considered alongside SGIP program goals of reducing GHG emissions to ensure the motivations of one policy don't adversely affect those of the other.

Sampled nonresidential systems paired with PV reduced emissions in 2023 by roughly 14 kg per kWh of capacity. Emissions reductions for PV paired systems were realized across all facility types. Standalone nonresidential systems reduced emissions in 2023 by 3 kg per kWh of capacity. More recent installations of longer duration batteries installed through the Equity Resiliency Budget (ERB) are conducting arbitrage and reducing emissions at the expense of the non-coincident peak demand reductions where we observe subsequent charging "snapback" associated with demand shaving. Furthermore, EV charging stations – which are standalone – are discharging roughly 65% of capacity daily during summer on-peak hours. Charging is reserved for morning hours, much like observed by systems paired with on-site PV.

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 (generally 4pm – 9pm). 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.

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. 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 a battery engineering, effective useful life, or warranty perspective. However, there is considerable untapped potential for Resource Adequacy (RA), Emergency Load Reduction Program (ELRP), and other grid benefits if additional battery capacity is deployed in response to grid needs and/or price signals.

Solar PV paired residential storage discharges roughly 42% of system kWh capacity daily throughout summer weekdays, and standalone systems discharge about 14% of available capacity (Section 4.2.1). Most of that discharge occurs during the 4pm – 9pm on-peak hours (60% for PV paired systems and 71% for standalone systems). 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.

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

BY MONTH, HOUR

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
January	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	5%	3%	3%	1%	1%	1%
February	1%	0%	0%	0%	0%	0%	0%	-0%	-3%	-6%	-7%	-7%	-5%	-3%	-2%	-0%	3%	5%	6%	4%	3%	2%	1%	1%
March	0%	0%	0%	0%	0%	0%	1%	-0%	-3%	-5%	-7%	-6%	-5%	-3%	-2%	-1%	2%	3%	5%	4%	3%	2%	2%	1%
April	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-9%	-8%	-5%	-3%	-1%	-0%	2%	3%	4%	5%	4%	3%	2%	2%
May	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-6%	-7%	-7%	-5%	-4%	-2%	-1%	2%	3%	4%	4%	4%	3%	2%	2%
June	1%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-8%	-7%	-6%	-4%	-2%	-0%	2%	3%	5%	4%	4%	3%	2%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-6%	-3%	-1%	0%	4%	5%	6%	6%	5%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-7%	-4%	-2%	-0%	4%	5%	6%	6%	5%	3%	2%	1%
September	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	5%	3%	2%	1%
October	0%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	4%	2%	2%	1%
November	0%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	3%	2%	1%	1%
December	-0%	-0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	5%	3%	2%	1%	1%	1%

Figure 4. Residential storage discharge and charge kWh per kWh capacity.

Residential and nonresidential storage systems are providing grid relief during CAISO peak hours; however, there is significant untapped potential to provide grid benefits. Utility planners are concerned about two peak periods; 1) the gross peak – when overall demand is at its highest and all available electricity supply sources reach their maximum generation and 2) the net peak – when overall demand minus renewable supply sources is reaching peak generation. The total program energy storage capacity in 2023 was over 1,700 MWh. Residential and nonresidential systems discharged roughly 96 MWh (about 6% of total program energy capacity) during the top gross peak hour, and 91 MWh (~5%) during the top net peak hour (which is when the greatest grid stress occurs, and when energy prices are the highest).

We observe differences in storage dispatch between sampled customers participating in ELRP on event days compared to control days. During event days, which in 2023 align with capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging more capacity than they ordinarily would. Peak event discharge reaches roughly 14% of system kWh capacity during the 7pm hour on event days. On non-event days, peak discharge reaches 6% of capacity during the 6pm hour (green bars).

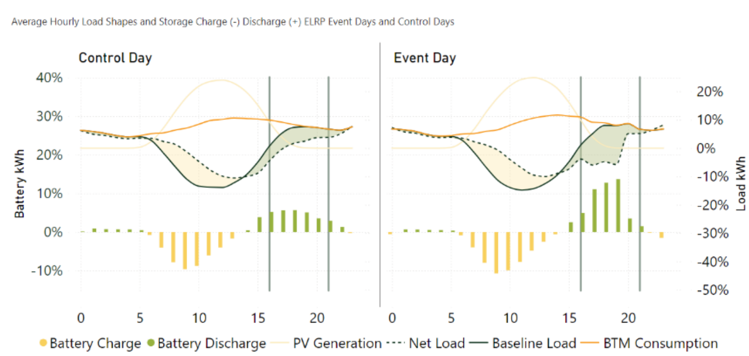

Figure 5. ELRP versus control day utilization.

Not only were ELRP participants discharging a greater magnitude of system capacity during events but discharge also extended beyond customer load requirements (shaded green area). For ELRP participants, we observe roughly, on average, 37% of kWh capacity discharged daily. However, on event days, utilization increases to 53% 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). We recommend that the CPUC and SGIP PAs continue to encourage participation in DR programs. Programs like the ELRP that compensate customers for export (rather than just reductions in consumption) should be prioritized as they represent an incremental load reduction relative to typical battery dispatch.

Customer Bill Impacts

One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Most nonresidential systems can realize bill savings on the energy and demand portion of their bill. Residential customers are not subject to demand charges, so bill savings result from energy arbitrage exclusively. 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.

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 increases on the energy component of their bill, but demand reduction savings lead to a net decrease 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 2023. Overall bill savings are greatest during summer months for both PV paired and standalone systems.

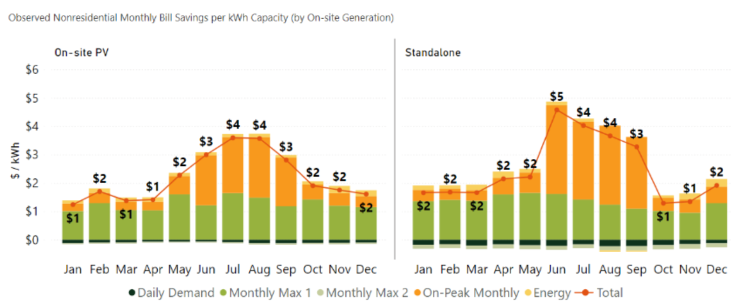

Figure 6. Nonresidential monthly bill savings.

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 producing savings on the energy component of bills, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often. Solar PV paired systems are generating annual savings of roughly $12 per kWh of capacity, and standalone system savings were roughly $2 for each kWh of capacity in 2023. Systems conducting TOU arbitrage are realizing roughly double the average savings than systems conducting self-consumption during summer months. However, under-utilized systems and those likely in backup-only mode are incurring bill increases of roughly $1 for each kWh of capacity.

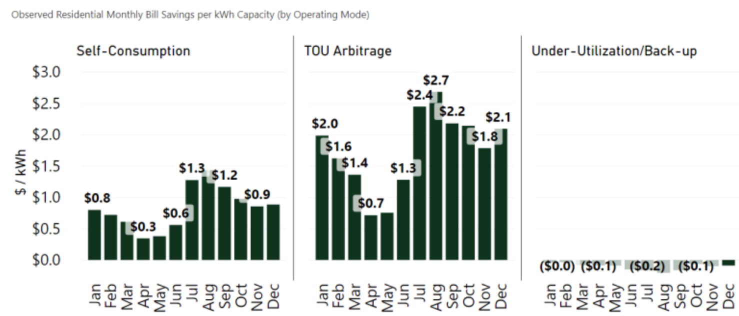

Figure 7. Residential monthly bill savings.

Utility Avoided Costs

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.

Observed storage behavior was advantageous from an avoided utility cost perspective in 2023. Overall, SGIP storage systems were charging during lower marginal cost periods and discharging during higher cost periods. Nonresidential and residential systems were discharging during constrained hours. This behavior resulted in a $22.7 million avoided cost benefit across utilities, which represents an increase from each previous impact evaluation – except for 2022. Avoided cost benefits – on average – equaled roughly $17 per kWh of capacity for the residential sector, and $10 per kWh for the nonresidential sector in 2023. While not directly comparable, 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.

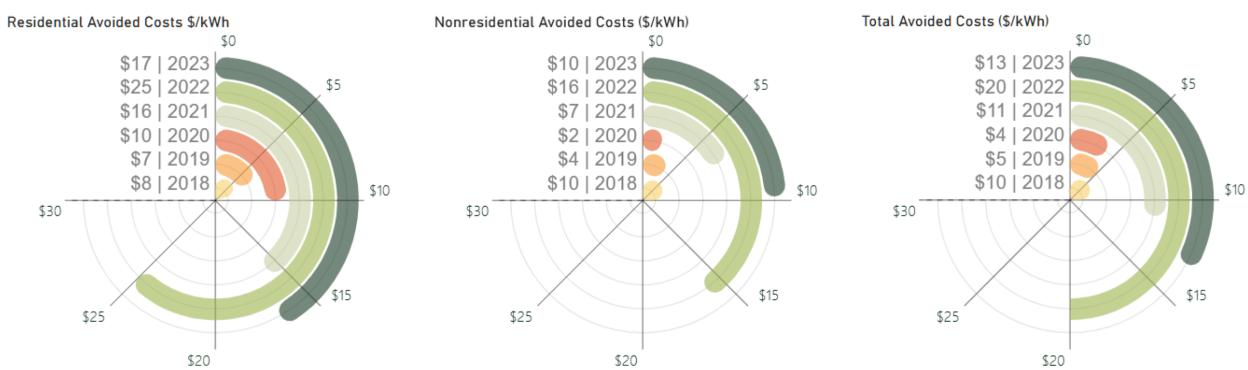

Figure 8. Energy storage utility avoided costs ($/kWh) by year and sector.

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. 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.

Optimization modeling revealed that the average actual avoided emissions of 17 kg of GHG per kWh of capacity would more than triple if optimized for GHG reductions or utility avoided costs. They would almost double if customer bill savings were optimized. Verdant compared observed storage performance to optimal performance following the hourly marginal emissions factor, utility avoided costs, and customer rate schedules. Observed GHG emissions reductions in 2023 and potential reductions achievable following these different signals are all significantly greater than zero.

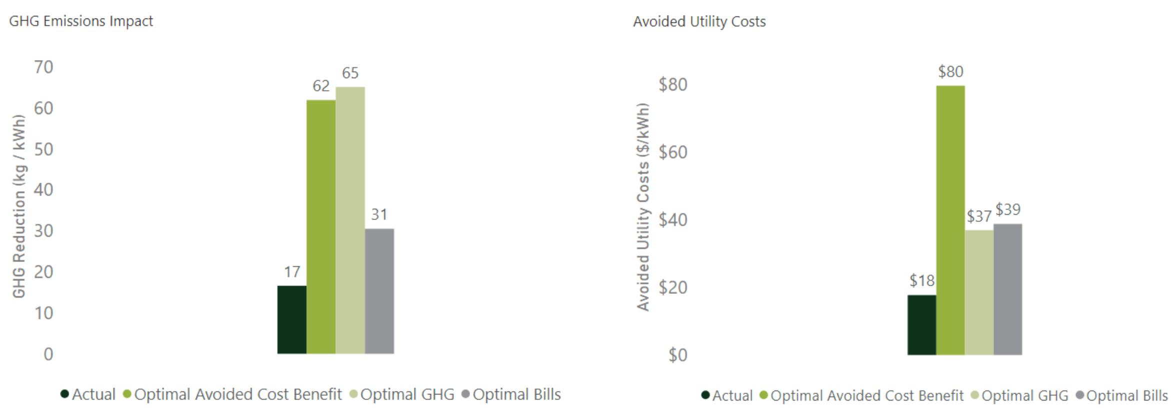

Figure 10. Residential GHG (left) and avoided cost (right) optimization results.

Optimizing residential charge and discharge for utility avoided cost benefits would result in a 4x improvement over actual avoided cost benefits in 2023. 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 $18 per kWh of capacity would increase to $80 if storage followed the avoided cost signal. Most of the incremental avoided cost benefits under this optimization scenario are realized during capacity constrained hours during on-peak summer hours, as well as during morning ramps. We recommend the CPUC continue to explore strategies to encourage SGIP participants to enroll in DR or real-time retail rates to encourage increased dispatch during high GHG/demand hours.

References

California Public Utilities Commission, Self-Generation Incentive Program Evaluation Reports. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program/self-generation-incentive-program-evaluation-reports

California Public Utilities Commission, Distributed Energy Resource Cost-Effectiveness. https://www.cpuc.ca.gov/dercosteffectiveness

California Self-Generation Incentive Program Greenhouse Gas Signal. https://content.sgipsignal.com/