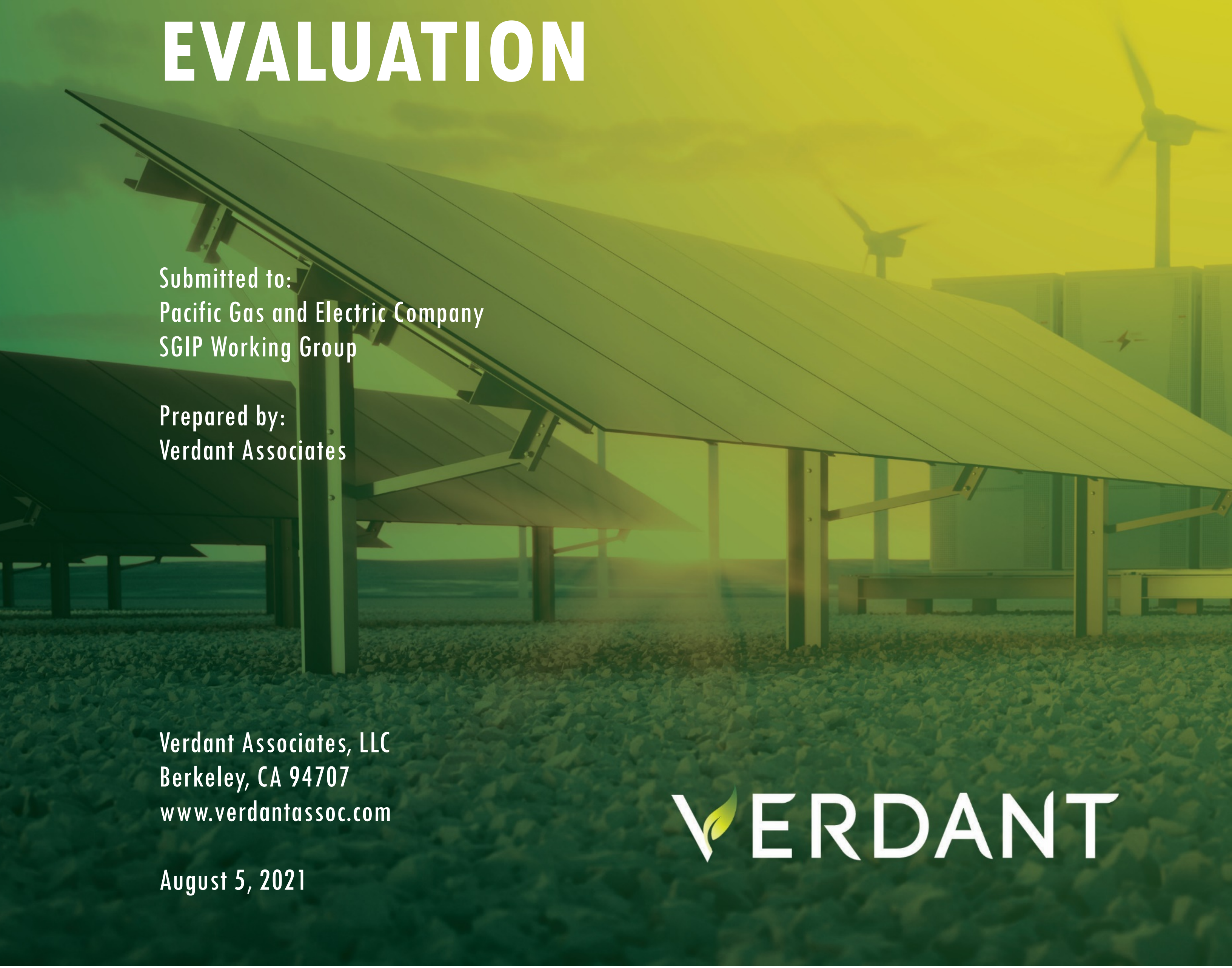
SELF-GENERATION INCENTIVE PROGRAM

2019 SGIP ENERGY STORAGE IMPACT EVALUATION



Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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TABLE OF CONTENTS

LIST OF FIGURES

VERDANT

VERDANT

VERDANT

LIST OF TABLES

1 EXECUTIVE SUMMARY

The Self-Generation Incentive Program (SGIP) was established in 2001 and provides financial incentives for the installation of energy storage and distributed generation (DG) technologies at customer homes and businesses. The SGIP is funded by California's electricity ratepayers and 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.

The SGIP was originally designed to help reduce energy demand at IOU customer locations to address peak electricity problems in California.[1] The program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time in response to California's evolving energy landscape. One key evolution is the contribution of energy storage technologies within the SGIP. Through the end of 2019, the SGIP had an incentive budget of over $500 million, with 80 percent of funds allocated to energy storage technologies. Furthermore, beginning in program year (PY) 2017, a first-come, first-served incentive system was supplemented with a lottery.[2] When the lottery is triggered, priority is given to storage systems paired with on-site renewable generation technologies like solar PV.

In 2019, the SGIP adopted greenhouse gas (GHG) emission reduction requirements brought forth by CPUC decision.[3] This requires the SGIP PAs to provide an accessible GHG emissions signal to storage developers so they have an opportunity to optimize storage performance to deliver customer bill savings *and* reduce emissions. In 2019, the CPUC also established an SGIP equity resiliency budget.[4] This decision helps set aside a budget for vulnerable households located in high fire threat districts, critical services facilities serving those districts, and customers located in those districts who participate in low-income/disadvantaged solar generation programs. These decisions were adopted in 2019, but were not implemented until PY 2020, so their impacts will not be captured until next year's evaluation.

1 CPUC Decision D. 01-03-073. March 27, 2001. https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/6083.PDF

2 CPUC Decision D. 16-06-055. June 23, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

3 CPUC Decision D. 19-08-001. August 9, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=310260347

4 CPUC Decision D. 19-09-027. September 18, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481

1.1 REPORT PURPOSE

The CPUC has developed a Measurement & Evaluation (M&E) plan, in consultation with the PAs, which calls for a series of annual impact evaluations focused on energy storage technologies.[5] This plan covers 2016 – 2020 and calls for several metrics to be reported for SGIP energy storage systems, including but not limited to:

- GHG emissions differentiated between residential and nonresidential systems, and between systems paired with renewable generation and non-paired systems.
- Timing and duration of charge and discharge on an average basis, and identification of groups of storage systems exhibiting certain trends in the timing of charge and discharge.
- Quantification of any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

The purpose of this study is to satisfy the requirements of the M&E plan for 2019 and assess the ability of storage technologies to meet SGIP objectives to provide environmental benefits, improve operations of the grid, and achieve market transformation for distributed energy resource technologies. As the M&E plan calls for annual impact evaluations, this study is a continuation of the work performed in the *2018 SGIP Energy Storage Impact Evaluation Report*.[6] All systems that were included in the 2018 evaluation are included in this study, in addition to systems receiving incentive payments during 2019.

1.2 SCOPE OF REPORT

This evaluation is an assessment of energy storage systems that received an SGIP incentive on or before December 31, 2019. Figure 1-1 shows growth in SGIP energy storage rebated capacity[7] over time. By the end of 2019, the SGIP had provided incentives to 8,875 energy storage systems representing almost 187 megawatts (MW) of rebated capacity. SGIP incentives are available for electrochemical, mechanical and thermal energy storage. As of December 31, 2019, all but one SGIP rebated storage system were electrochemical (battery) energy storage technologies.[8]

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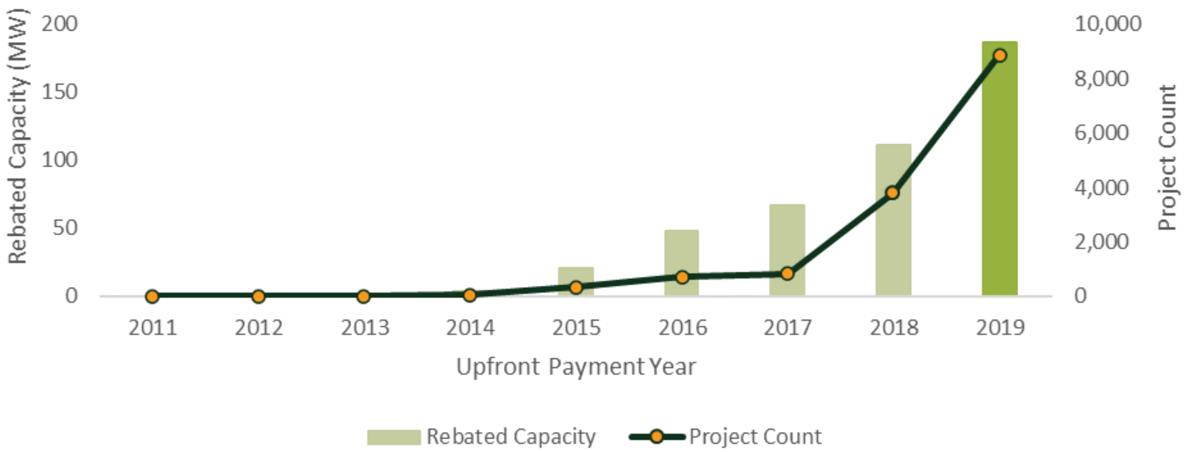
5 SGIP Measurement and Evaluation Plan for Programs Years 2016 – 2020. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/demand_side_management/customer_gen_and_storage/att-a-clean-revised-sgip-me-plan-2016-2020.pdf

6 *2018 SGIP Advanced Energy Storage Impact Evaluation*. https://www.cpuc.ca.gov/General.aspx?id=7890

7 Rebated capacity is defined as the average discharge power rating over a two-hour period.

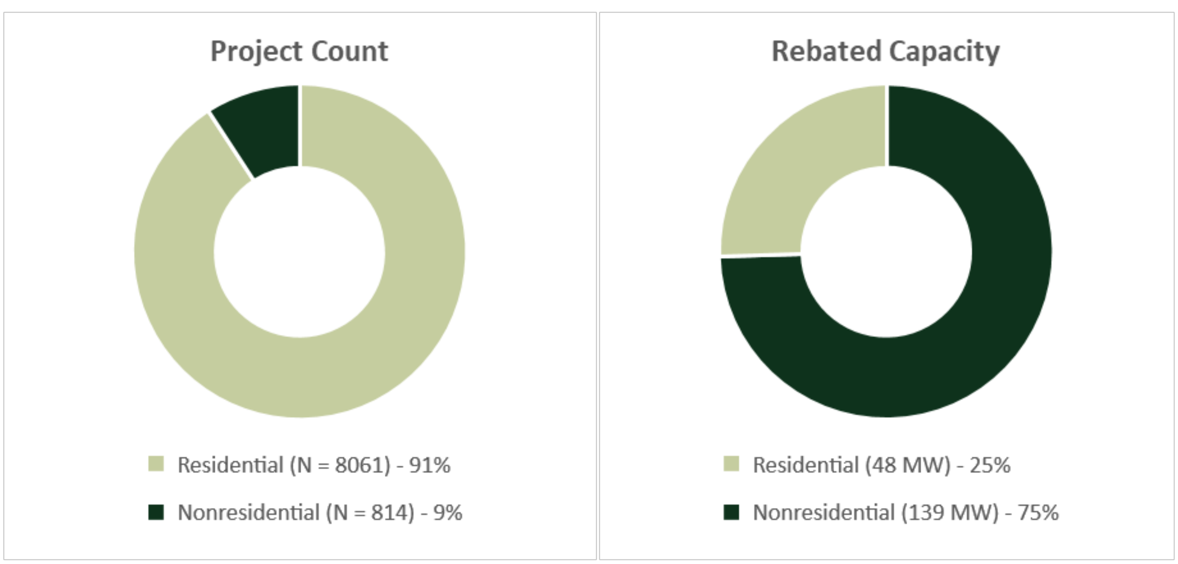
8 The first thermal energy storage system received upfront payment in 2019.

FIGURE 1-1: SGIP STORAGE CUMULATIVE GROWTH BY UPFRONT PAYMENT YEAR



The number of residential storage systems subject to evaluation in 2019 has increased roughly 20-fold since the 2017 evaluation. The count of nonresidential systems subject to evaluation has roughly doubled since 2017. Figure 1-2 shows the breakdown in sector by project count and rebated capacity in 2019. While the number of residential systems subject to evaluation in 2019 represents the vast majority by project count (91 percent), the majority of the SGIP storage rebated capacity (75 percent) are installed at nonresidential customer sites.

FIGURE 1-2: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR



1.3 EVALUATION APPROACH

This evaluation study examines the performance of energy storage systems by quantifying the observed impacts of systems throughout 2019. The Verdant team collected metered storage charge and discharge data and customer electric load profiles from residential and nonresidential SGIP participants. Our approach involves quantifying how installation of the storage system influenced the customer load compared to what the load would have been in the absence of the storage system. If a storage system was discharging to service load at a home, it was reducing the power needed from the grid at that moment. A customer could realize bill savings if discharging occurred during high-priced hours and charging occurred during lower-priced hours.[9] Furthermore, if that discharge also coincided with a period when marginal emissions are high – on a hot summer day when everyone is running their air conditioning – that load shift could provide a benefit to the utility and reduce GHG emissions.

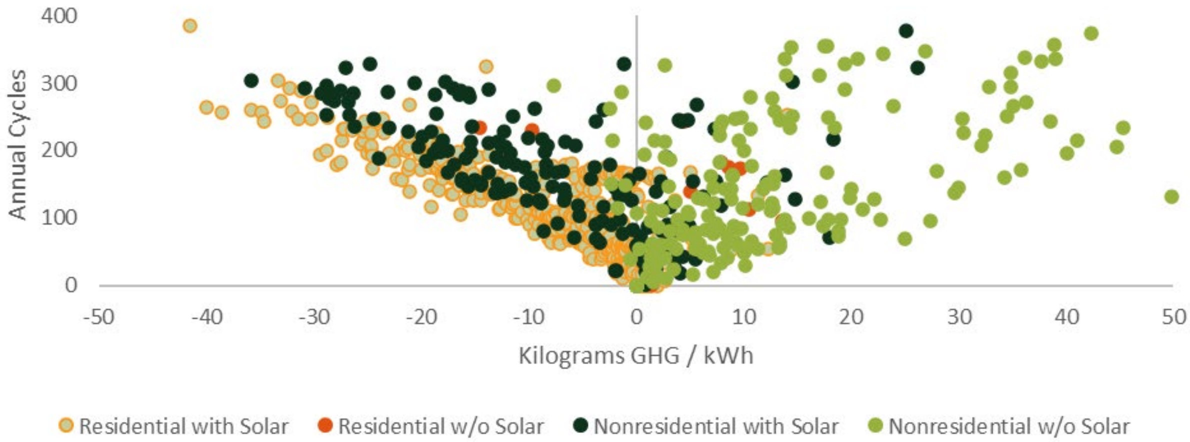
1.4 EVALUATION FINDINGS

Below we present key findings from the evaluation. These findings were developed based on metered data collected from a representative sample of residential and nonresidential customers (this is discussed in more detail in Section 3). Many of these findings reveal how storage behavior in 2019 was meeting or falling short of SGIP goals and objectives. In-depth findings and analyses can be found in Section 4 of this report.

1) Nonresidential systems contributed to a net increase in GHG even though residential systems reduced GHG emissions during 2019. For storage systems to reduce GHG emissions, the GHGs avoided during storage discharge must be greater than the GHG increase during storage charging. Batteries lose energy when converting electricity from one form into another. Since they inherently consume more energy during charging relative to energy discharged, the marginal emissions rate must be lower during charging hours relative to discharge hours. Figure 1-3 plots the decrease (-) or increase (+) in emissions for each system (horizontal axis) against the utilization of the system (vertical axis). Energy storage systems paired or co-located with on-site solar generation contribute to a net decrease in GHG emissions far more often than standalone systems.

[9] This is referred to as 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 roundtrip efficiency.

FIGURE 1-3: OBSERVED GHG EMISSIONS AND DISCHARGE FREQUENCY BY CUSTOMER SECTOR



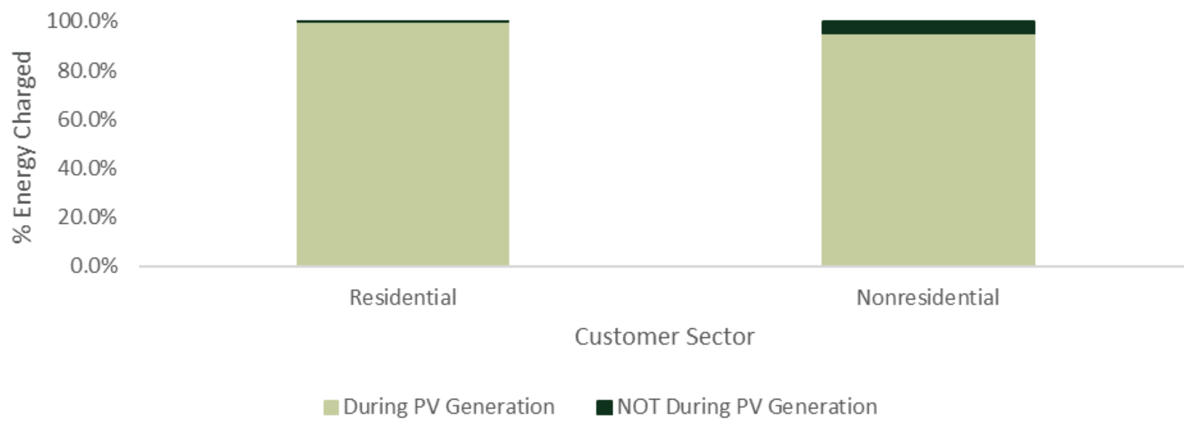
During 2019, residential systems decreased GHG emissions by 8.1 kilograms for each kWh of capacity and nonresidential systems increased emissions by roughly 3.9 kilograms for each kWh of capacity. Based on our approach, these estimates represent the emissions avoided or incurred relative to what they would have been in the absence of the storage system. In the 2018 evaluation, we found residential systems decreased emissions by roughly 3.6 kg CO_2/kWh and nonresidential systems increased emissions by roughly 16 kg CO_2/kWh. Both sectors realized a significant improvement from the 2018 evaluation, even though the nonresidential systems still increased net emissions overall. In total, residential systems reduced GHG emissions by almost 800 metric tonnes (MT) and nonresidential systems increased emissions by over 1,300 MT for a net increase of 559 MT in 2019.

2) The timing, magnitude and duration of residential storage charge and discharge behavior provided an avoided cost benefit to all utilities and nonresidential systems provided an avoided cost benefit to Southern California Edison (SCE) in 2019. The evaluation found that, overall, SGIP storage systems were charging during lower marginal cost periods and discharging during higher cost periods. Marginal costs are highest when energy prices are high and the electric system load is peaking. Nonresidential and residential systems were discharging throughout these highly constrained hours. On average, nonresidential systems provided an avoided cost benefit of roughly $4 per capacity kWh, and residential systems provided a benefit of $13 per capacity kWh across IOUs. Overall, the patterns of storage charge and discharge throughout 2019 resulted in a roughly $2.4 million benefit in avoided costs across utilities. These results are comparable to 2018 where the overall avoided cost benefit was roughly $2.2 million. However, the normalized benefits for nonresidential systems dropped from $10/kWh. Residential system benefits increased from $9/kWh in 2018.

3) Residential and nonresidential storage systems paired with on-site solar generation are charging almost exclusively from on-site solar generation. Residential customers who claim the Investment Tax

Credit (ITC) for solar and storage are required to charge their system exclusively from solar generation. Nonresidential customers are required to charge at least 75 percent from solar. We observed residential systems charging from solar 99.8 percent of the time and nonresidential systems at 95.0 percent of the time (Figure 1-4). Morning PV generating hours also align well with periods of low marginal emissions, so charging during this period provides systems a greater opportunity to reduce overall emissions throughout the year.

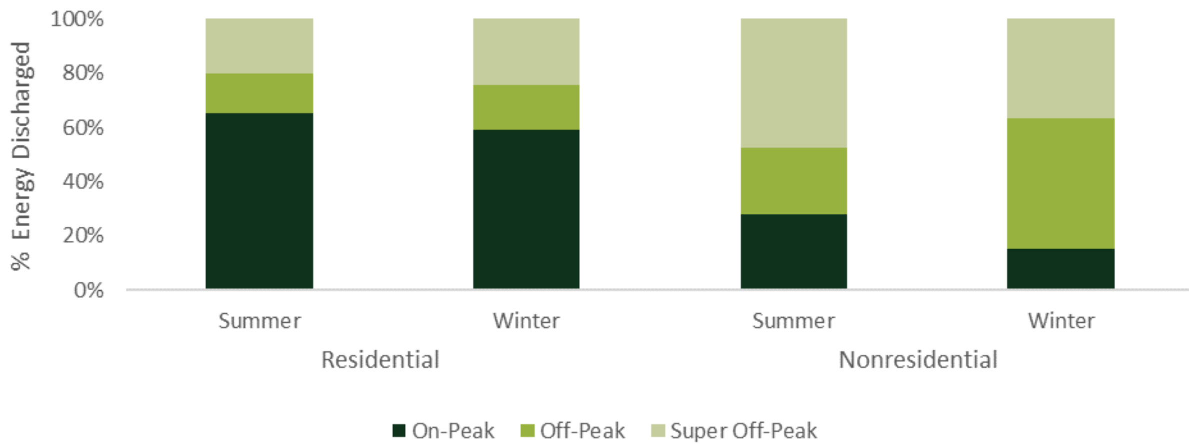
FIGURE 1-4: OBSERVED PERCENT CHARGE KWH DURING PV GENERATION BY CUSTOMER SECTOR



4) Customers located in Public Safety Power Shutoff (PSPS) areas utilized their storage systems to provide relief during outages stemming from wildfire threat in 2019. We observed, from a small sample of roughly 20 customers in PG&E territory, storage systems that were satisfying overall household demand or were connected to a critical household circuit like a refrigerator during long duration outages. Systems paired with on-site solar were capable of riding out longer duration utility power shutoffs (sometimes for 3 days) because the system could charge directly from solar. A larger study is required to better understand how systems are performing during these events, but anecdotally, it appears storage is providing customer relief.

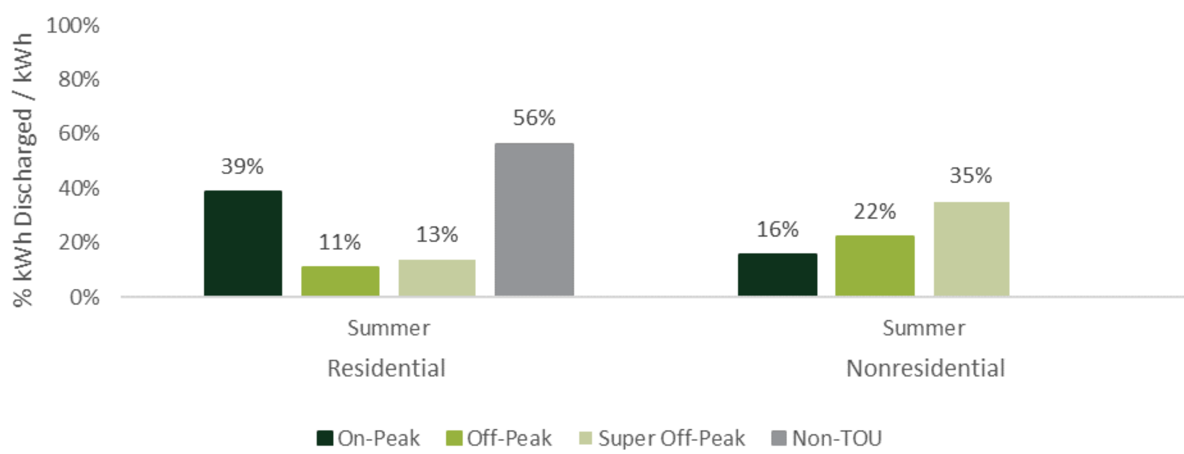
5) Residential storage systems are discharging a greater percentage of energy – but not all energy – throughout on-peak bill periods and nonresidential systems are discharging a greater percentage of energy outside the on-peak period. We observe residential systems discharging 65 percent of energy and nonresidential systems discharging 28 percent of energy throughout summer on-peak hours when customers are charged more for electricity (Figure 1-5). 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 outside this period. The data suggest that reducing the energy portion of bills may not be the key driver of storage behavior, especially for nonresidential customers who are utilizing their storage systems for demand charge reductions. Facility peak demand may not coincide with utility on-peak periods, so a customer may prioritize demand charge reduction at the expense of time-of-use (TOU) energy arbitrage.

FIGURE 1-5: OBSERVED PERCENT DISCHARGE KWH BY TOU PERIOD AND CUSTOMER SECTOR



6) Residential and nonresidential systems are not depleting their storage capacity and are discharging less energy than available within the system. We examined the total energy discharged throughout different periods as the percentage of energy capacity within the system. During on-peak periods, residential systems are utilizing roughly 39 percent of available energy, while nonresidential systems are using 16 percent. Customers not on a TOU rate (Non-TOU) are discharging, on average, 56 percent of available energy throughout the day (Figure 1-6).

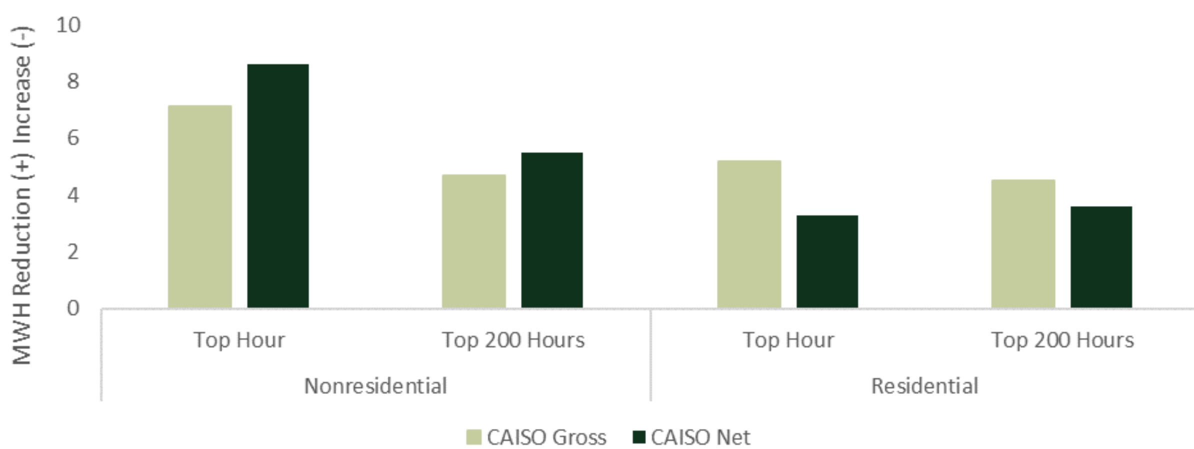
FIGURE 1-6: OBSERVED HOURLY NET DISCHARGE KWH PER CAPACITY KWH BY SUMMER TOU PERIOD



7a) Both customer sectors are providing a benefit to the electricity system during the CAISO peak hour and maintain that benefit across the top 200 peak system hours. The timing and duration of storage charge and discharge throughout the year is also important from the perspective of the CAISO system. Peak periods, in this context, coincide with periods when demand on the electricity grid is greatest and most congested and would benefit from reductions in demand. Figure 1-7 presents how each customer sector provides a benefit to the CAISO system during its peak hour in 2019 by discharging more energy throughout that hour than they were charging. Systems are discharging for long durations and, as a result, capturing reductions, on average, throughout the top 200 peak hours as well.

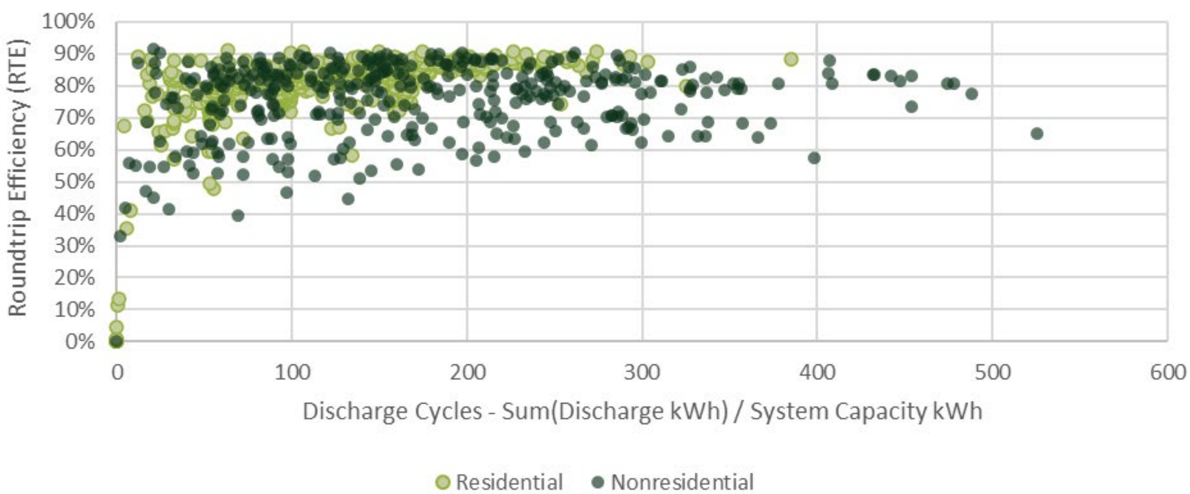
7b) Residential storage systems discharge a greater magnitude of energy during CAISO gross peak hours, while nonresidential systems are generally discharging at a greater magnitude a couple hours later, which coincides more with CAISO net peak hours. Utility planners are concerned about two peak periods; 1) the gross peak – when overall demand is at its highest and all available electricity supply sources reach their maximum generation (MW) and 2) the net peak – when overall demand minus renewable supply sources are reaching their peak generation. Residential customers are discharging at greater magnitude during the 4 – 5 pm hours, which are coincident to the gross peak. Nonresidential customers are discharging at greatest magnitude during the 6 – 8 pm hours, which are coincident to net peak hours (Figure 1-7).

FIGURE 1-7: OBSERVED NET DISCHARGE (MWH) DURING CAISO SYSTEM PEAK HOURS BY CUSTOMER SECTOR



8) There is a strong relationship between storage system utilization and system efficiency. Two important energy storage performance metrics are roundtrip efficiency (RTE) and discharge frequency. 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 consuming. The discharge frequency is a measure of utilization – how often is the system 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. This relationship is evident in Figure 1-8.

FIGURE 1-8: OBSERVED ROUNDTRIP EFFICIENCY VERSUS DISCHARGE FREQUENCY BY CUSTOMER SECTOR



In 2019, the average RTE for nonresidential systems was 80 percent, and 83 percent for residential systems. The average discharge frequency for nonresidential and residential systems was 157 cycles and 117 cycles, respectively.

9) Energy storage systems deliver bill savings. One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Customer objectives are based on a range of factors including:

- the amount of energy the home or facility uses and at what time of day and year they use it
- what rate schedule the customer is on and how their bill impacts are assessed
- whether they generate their own electricity from on-site generation, such as a fuel cell or solar

Nonresidential customers, on average, realized bill savings exceeding $50 per system capacity kWh. Forty percent of nonresidential customers realized bill savings greater than or equal to the $50/kWh. Residential customers realized bill savings of roughly $1.60 per system capacity kWh. However, the range of bill savings and bill increases is substantial with bill savings as high as $166 per rebated capacity kWh to as low as -$136 per rebated capacity kWh (a bill increase).

The range of use cases for storage in the SGIP will impact how the system is utilized throughout the year and the timing and duration of charge and discharge. Below we present the average hourly net charge (red) or discharge (green) for each month and hour throughout the year for both customer sectors. Nonresidential systems are further split between those with and without on-site solar generation.

Standalone nonresidential systems – those without on-site solar – are discharging throughout on-peak and off-peak TOU periods, charging more prominently overnight and customers are saving money on their electricity bill. Nonresidential storage systems not co-located with solar are discharging most prominently in the early/later afternoon hours. While they are often discharging energy outside of their on-peak bill period (when retail electricity rates are highest), they are consistently reducing their peak demand. While they incur costs for the increase in energy usage (kWh), they are saving significantly more on the demand charge (kW) portion of their bill.

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-3%	-4%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-3%
1	-2%	-3%	-1%	-1%	-2%	-2%	-1%	0%	0%	-1%	-3%	-3%
2	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%
3	-2%	-2%	-2%	-1%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-2%
4	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%
5	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
6	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	1%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-2%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-2%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
11	0%	0%	0%	0%	0%	1%	1%	1%	0%	1%	0%	0%
12	0%	0%	0%	0%	1%	0%	1%	1%	0%	1%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
14	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	1%	1%	2%	3%	3%	2%	2%	3%	0%	0%
16	1%	1%	1%	0%	1%	2%	1%	1%	1%	2%	3%	2%
17	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%
18	1%	1%	2%	1%	1%	0%	0%	0%	0%	1%	3%	2%
19	1%	1%	2%	1%	1%	1%	0%	0%	0%	2%	3%	2%
20	2%	2%	1%	0%	-1%	-2%	-2%	-2%	-2%	-3%	2%	4%
21	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-2%	-5%	-4%	-2%
22	-2%	-2%	-4%	-4%	-4%	-2%	-3%	-3%	-2%	-3%	-5%	-5%
23	-4%	-3%	-4%	-4%	-4%	-4%	-3%	-2%	-2%	-2%	-3%	-2%

Nonresidential systems paired with on-site solar are charging from on-site solar generation, are discharging later in the early evening when solar generation wanes and are saving customers money on their electricity bill. Nonresidential systems with solar exhibit a different pattern of charge/discharge behavior. These systems are discharging in the early morning, then charge the system from solar generation later in the morning. They discharge during on-peak TOU periods, in the early evening. Like the standalone systems, they increase the energy portion of the bill (kWh), but they are reducing overall demand (kW) and saving money on the demand portion of the bill. These paired systems are also commonly installed in primary and secondary schools.

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-1%	-1%	-1%	-1%	0%	-1%	0%	0%	0%	0%	-1%	0%
1	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	-1%	0%
2	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	1%	1%	2%	0%	0%	0%	0%	0%
4	0%	0%	0%	1%	2%	2%	3%	1%	0%	0%	0%	0%
5	1%	0%	2%	3%	3%	3%	4%	3%	2%	2%	0%	1%
6	2%	2%	2%	0%	0%	1%	0%	0%	0%	1%	1%	2%
7	2%	0%	-4%	-6%	-4%	-3%	-6%	-5%	-4%	-4%	-2%	1%
8	-3%	-5%	-9%	-10%	-8%	-8%	-12%	-10%	-7%	-8%	-6%	-4%
9	-8%	-10%	-12%	-12%	-10%	-12%	-14%	-11%	-9%	-10%	-9%	-9%
10	-9%	-11%	-11%	-9%	-8%	-11%	-10%	-9%	-8%	-8%	-9%	-10%
11	-8%	-8%	-7%	-5%	-6%	-7%	-5%	-4%	-4%	-5%	-7%	-8%
12	-5%	-4%	-3%	-3%	-3%	-4%	-3%	-1%	-2%	-1%	-4%	-6%
13	-3%	-2%	-2%	-2%	-2%	-2%	-1%	0%	0%	0%	-1%	-2%
14	-1%	-1%	-1%	-1%	-3%	-2%	-1%	0%	0%	0%	0%	-1%
15	0%	-1%	0%	0%	-2%	-1%	-1%	-1%	0%	0%	1%	0%
16	1%	1%	1%	2%	0%	1%	1%	2%	3%	3%	2%	1%
17	4%	3%	4%	4%	3%	2%	2%	2%	3%	4%	4%	4%
18	4%	5%	7%	8%	7%	7%	7%	6%	5%	5%	5%	5%
19	4%	5%	7%	8%	8%	9%	9%	7%	5%	5%	5%	5%
20	4%	5%	5%	5%	5%	6%	6%	4%	3%	4%	4%	4%
21	4%	5%	1%	0%	1%	3%	2%	1%	1%	1%	3%	3%
22	0%	0%	2%	3%	3%	3%	2%	2%	2%	3%	1%	0%
23	1%	2%	-1%	-1%	-1%	-1%	0%	-1%	-2%	-1%	2%	2%

Residential storage systems that are charging exclusively from on-site solar production are discharging during on-peak and off-peak TOU periods and are saving customers money on their electricity bill. Residential storage systems are often paired with on-site solar, so the storage system can bypass charging directly from the grid and utilize solar power to charge the system. Charging throughout the summer and latter part of the year comes almost exclusively in the morning hours when solar production is ramping up. Residential customers are not subject to demand charges (kW) and most customers are on a time-of-use (TOU) schedule. While we observe bill savings throughout summer months, residential customers are typically incurring bill increases throughout winter months because, on average, they are discharging their storage systems less often.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
1	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%
2	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
5	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-3%	-3%	-2%	-2%	-1%	0%	0%
7	-1%	-2%	-4%	-5%	-5%	-8%	-9%	-8%	-7%	-5%	-1%	-1%
8	-4%	-6%	-8%	-9%	-8%	-12%	-14%	-15%	-12%	-10%	-5%	-4%
9	-7%	-9%	-10%	-10%	-8%	-12%	-13%	-15%	-14%	-11%	-7%	-6%
10	-8%	-9%	-9%	-7%	-7%	-9%	-8%	-10%	-10%	-7%	-8%	-7%
11	-7%	-7%	-6%	-5%	-5%	-6%	-5%	-6%	-6%	-5%	-6%	-6%
12	-5%	-4%	-4%	-3%	-3%	-3%	-2%	-3%	-3%	-2%	-4%	-4%
13	-3%	-2%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-2%	-2%
14	7%	8%	1%	0%	0%	1%	1%	2%	2%	0%	0%	0%
15	1%	2%	8%	10%	10%	20%	20%	22%	22%	14%	2%	2%
16	3%	2%	5%	3%	3%	5%	6%	6%	5%	4%	10%	10%
17	4%	4%	3%	3%	3%	3%	4%	4%	4%	3%	4%	4%
18	4%	4%	4%	4%	3%	3%	4%	4%	4%	3%	3%	3%
19	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	3%	2%
20	2%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	1%
21	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%
22	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%
23	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%	0%

1.5 CONCLUSIONS AND RECOMMENDATIONS

The nonresidential results of this evaluation are largely consistent with observations from the 2018 SGIP energy storage evaluation. However, a new fleet of nonresidential systems paired with solar PV generators are providing benefits which had been unrealized in previous evaluations. Trends that were evident with residential systems in 2018 have continued into 2019, and with a much larger fleet of residential systems in the SGIP population, the overall impacts have increased substantially. Below we present key takeaways and conclusions from this evaluation. Where possible, we also provide considerations and recommendations.

The timing and duration of charge and discharge patterns is far more important from a GHG reduction or avoided cost perspective than simply increasing storage utilization and roundtrip efficiency. There is a strong relationship between utilization and RTE. However, increasing utilization for the sake of increasing RTE alone will likely not turn SGIP nonresidential systems into net GHG reducers. A GHG signal like the one being implemented through the SGIP GHG working group can help storage systems improve the timing and duration of charge/discharge. Our analysis shows that such a signal can be implemented to significantly reduce GHG emissions without a material impact on customer bills.

The federal Investment Tax Credit (ITC) is an effective mechanism for aligning storage system charging with periods of lower marginal emissions. Charging from on-site solar generation is critically important from an avoided cost and GHG emissions reduction perspective. The evaluation team observed an overall decrease in GHG emissions from residential projects and nonresidential systems paired with on-site solar. These systems were almost exclusively charging during solar generation hours early in the morning – when marginal emissions are low. Customers should continue to be motivated to charge their storage systems during early PV generation hours.

Large nonresidential systems without on-site solar consistently provide benefits to customers in the form of billed demand (kW) savings, are discharging throughout CAISO top hours, but increase GHG emissions. These results demonstrate that, under current retail rates, the incentives for nonresidential customers to dispatch energy to minimize bills are not well aligned with the goals of minimizing GHG emissions. More dynamic rates and a GHG signal that better align customer and grid benefits, could provide substantial ratepayer and environmental benefits that are currently unrealized. No projects operational during 2019 were required to follow the recently created GHG signal.

Residential systems with on-site solar consistently provide benefits to customers in the form of billed energy savings during the summer, are discharging throughout IOU and CAISO top hours and decrease GHG emissions while utilizing only 60 percent of available capacity. These results demonstrate that the combination of charging from on-site PV generation and discharging throughout on-peak TOU periods, and after PV generation has waned, provides customer, utility and environmental benefits. These benefits can be further optimized with a GHG signal.

2 INTRODUCTION AND OBJECTIVES

The Self-Generation Incentive Program (SGIP) was established legislatively in 2001 to help address peak electricity problems in California.[10] The SGIP is funded by California's electricity ratepayers and 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 and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

Since its inception in 2001, the SGIP has provided incentives to a wide variety of distributed energy technologies including combined heat and power (CHP), fuel cells, solar photovoltaic (PV) and wind turbine systems. The program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time in response to California's evolving energy landscape. One key evolution is the contribution of energy storage technologies within the SGIP.

2.1 HISTORY OF ENERGY STORAGE IN THE SGIP

Beginning in Program Year (PY) 2009, advanced energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies (wind turbines and fuel cells) were eligible for incentives.[11] Eligibility requirements changed during subsequent years. In PY 2011, standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives.[12]

In 2016, the CPUC issued Decision (D.) 16-06-055, which, among other changes, revised how the SGIP is administered.[13] Beginning with PY 2017, the SGIP is now administered on a continuous basis. This change was made largely to curb potential issues with incentives being depleted during program opening, as the

10 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

11 CPUC Decision D.08-11-044. November 21, 2008. http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/94272.htm

12 CPUC Decision D.10-02-017. February 25, 2010. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114312.PDF

13 CPUC Decision D.16-06-055. June 23, 2016. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163928075

program is typically oversubscribed. D. 16-06-055 also supplemented the first-come, first-served reservation system with a lottery. Priority in the SGIP lottery process is given to:

- Energy storage projects located in the Los Angeles Department of Water and Power (LADWP) service territory
- Energy storage projects located in Southern California Edison's West LA Local Capacity Area
- Energy storage projects paired with on-site renewable generation that are claiming the Investment Tax Credit (ITC) or charging at least 75 percent from the on-site renewable generator

Most recently, the CPUC has issued several Decisions that, while not applicable to this current evaluation, will shape the program in years to come. In August of 2019 the CPUC issued D. 19-08-001 approving greenhouse gas emission reduction requirements for the SGIP storage budget.[14] This decision requires SGIP PAs to provide a digitally accessible greenhouse gas (GHG) signal that provides marginal GHG emissions factors (kilograms CO_2/kWh) 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.

On September 12, 2019, the CPUC issued D. 19-09-027 that established an SGIP equity resiliency budget, modified existing equity budget incentives, approved the transfer of unspent funds to the budget, and approved funding to support the San Joaquin Valley Disadvantaged Community Pilot Projects.[15] 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-income/disadvantaged solar generation programs.

The SGIP had authorized incentive collections totaling $501,735,000 through the end of 2019 and 80 percent of funds were allocated to energy storage technologies. Figure 2-1 summarizes those authorized allocations by PA. The original incentive rate for storage systems was set at $2.00 / Watt in PY 2009. By PY 2019, the incentive levels for energy storage had changed and were predicated on system characteristics – large storage (>10 kW), large storage claiming ITC and residential storage (<= 10 kW) – and were divided across five steps. Incentives are now calculated on a watt-hour rather than watt basis and ranged from as high as $0.50/Watt-hour to $0.18/Watt-hour, depending on a variety of conditions in each Program Administrator territory.

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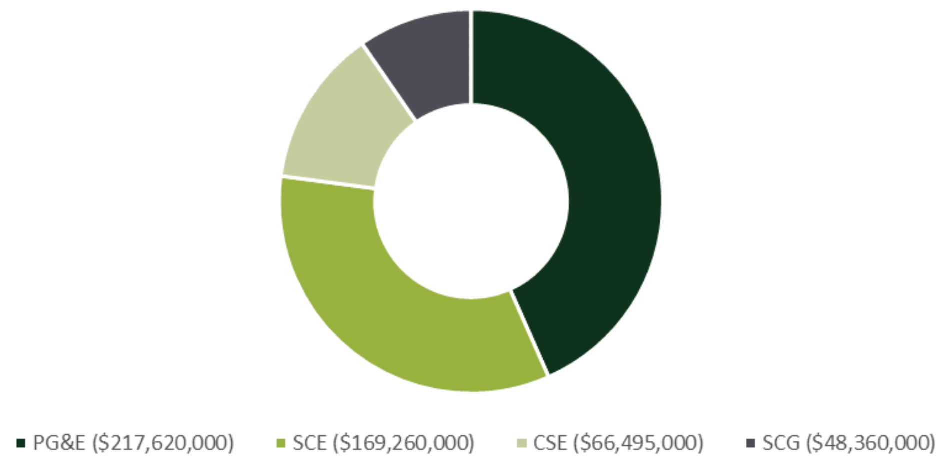
14 CPUC Decision D. 19-08-001. August 9, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=310260347

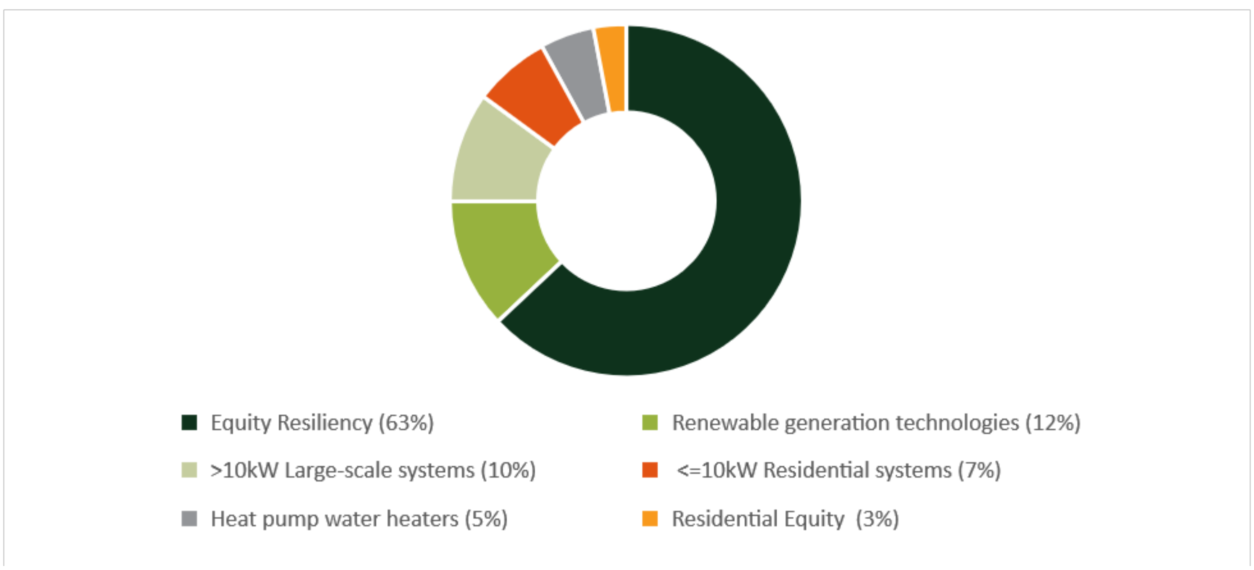
15 CPUC Decision D. 19-09-027. September 18, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481

FIGURE 2-1: STATEWIDE PROGRAM BUDGET AND ADMINISTRATOR ALLOCATIONS (THROUGH 2019)



In January of 2020, the CPUC issued D. 20-01-021.[16] The decision authorized the collection of ratepayer funds totaling $166 million dollars per year from 2020 to 2024. This decision increased the financial incentive budget for energy storage technologies to 85% of total SGIP funding. This decision also authorized the introduction of heat pump water heaters and changed incentives and rules for renewable generation. Figure 2-2 presents the overall distribution of SGIP allocation for 2020 to 2024.

FIGURE 2-2: DISTRIBUTION OF SGIP ALLOCATION FUNDING FROM 2020 TO 2024



[16] CPUC Decision D. 20-01-021. January 27, 2020. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF

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2.2 REPORT PURPOSE AND PROGRAM STATUS

SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Annual impact evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. As discussed above, the SGIP was originally designed to reduce energy use and demand at IOU customer locations. By 2007, growing concerns with potential air quality impacts prompted changes to the SGIP's eligibility rules. Approval of AB 2778[17] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Passage of SB 412[18] refocused the SGIP toward GHG emission reductions.

D. 16-06-055 states that an SGIP M&E Plan should be developed by CPUC Energy Division (ED) staff in consultation with Program Administrators. On January 13, 2017, the CPUC ED submitted its plan to measure and evaluate the progress and impacts of the SGIP for Program Years 2016 – 2020. The CPUC M&E plan calls for the creation of a series of annual impact evaluations that are focused on energy storage. The plan calls for several metrics to be reported for SGIP energy storage systems, including:

- Net GHG emissions of energy storage systems as a class (i.e., all systems combined) and net GHG emissions differentiated between residential and nonresidential systems, and between systems paired with renewable generation and non-paired systems.
- Timing and duration of charge and discharge on an average basis and identification of groups of storage systems exhibiting certain trends in the timing of charge and discharge.
- In accord with Public Utilities Code § 379.6(I)(6), quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

The purpose of this study is to satisfy the requirements of the M&E plan for 2019 and assess the ability of energy storage technologies to meet SGIP objectives. As the M&E plan calls for annual impact evaluations, this study is a continuation of the work performed in *2018 SGIP Energy Storage Impact Evaluation Report*.[19]

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17 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

18 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

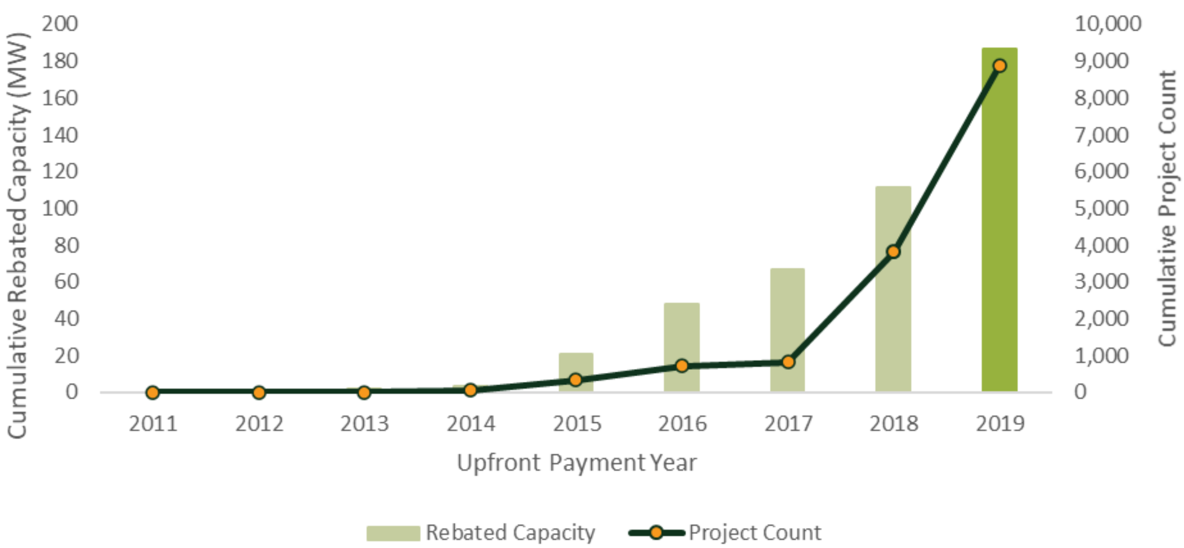
19 2018 SGIP Advanced Energy Storage Impact Evaluation. Submitted to Pacific Gas and Electric Company and SGIP Working. January 29, 2020. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf

All systems included in 2018 are included in this study, in addition to the systems that received incentive payments during 2019.

2.2.1 Scope

This evaluation is an assessment of energy storage systems receiving an SGIP incentive on or before December 31, 2019. Figure 2-3 shows growth in SGIP energy storage rebated capacity[20] over time. By the end of 2019, the SGIP had provided incentives to 8,875 systems representing almost 187 MW of rebated capacity. SGIP incentives are available for electrochemical, mechanical and thermal energy storage. As of December 31, 2019, all but one were electrochemical (battery) energy storage technologies.[21] The rebated capacity of the storage population increased by 68% from 2018 to 2019. The overall system count increased by 133%.

FIGURE 2-3: SGIP STORAGE CUMULATIVE GROWTH BY UPFRONT PAYMENT YEAR



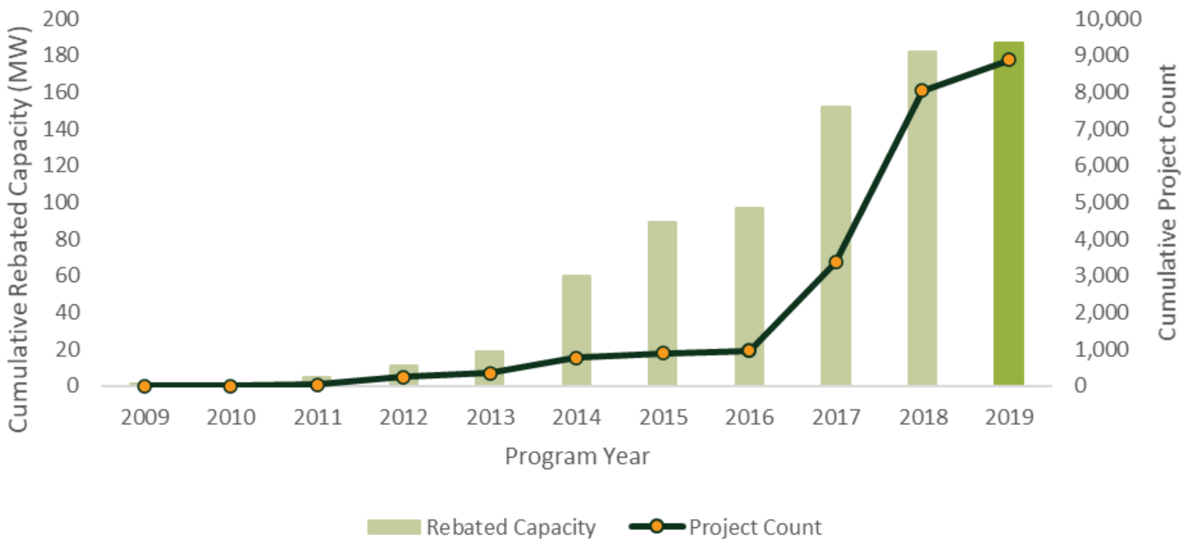
The evaluation team utilizes the upfront payment year to define the population frame and the scope of systems subject to evaluation for 2019. However, the upfront payment does not necessarily correspond to the program year in which the participant applied to the SGIP. A participant may apply to the SGIP in 2016, for example, but not receive their upfront payment until 2017. This is due to potential lag times between program application and the installation, interconnection and administrative timelines

[20] As of PY 2017, rebated capacity is defined as the average discharge power rating over a two-hour period. Throughout this report, we reference both a system's rebated capacity in kW as well as the energy capacity of the system in terms of kWh.

[21] The first thermal storage system in the SGIP received an upfront incentive in July of 2019.

associated with building energy storage systems. Figure 2-4 shows growth in storage rebated capacity by program year – the year a participant applied to the SGIP.

FIGURE 2-4: SGIP STORAGE CUMULATIVE GROWTH BY PROGRAM YEAR



The population subject to evaluation is based on the year the system received the upfront incentive payment. Throughout this report we describe the program population and population impacts by program year to provide additional insight into when customers applied to the program, which is relevant when thinking about the different program rules that apply to specific groups of projects (e.g., projects that applied prior to PY 2011 are not subject to performance-based incentive rules).

From the perspective of rebated capacity, the SGIP experienced the most significant growth in storage applications during PY 2012 – 2015. However, by project count, the program experienced the most extensive growth in storage applications during PY 2017 – 2018. The customer sector and policy timelines play a critical role in better understanding changes in the structure of the SGIP. Figure 2-5 and Figure 2-6 highlight these nuances where the growth in the SGIP storage program for nonresidential and residential participants is presented, by project count and rebated capacity.

The SGIP experienced significant growth in program applications during PY 2017 – 2018 because of the growth in residential participation. This dramatic increase is due, in part, to changing program eligibility requirements, administration and changing incentive levels. Other factors include declining energy storage costs, new residential storage product offerings and an increase in the number of distinct project developers offering residential energy storage products. Nonresidential systems experienced the most significant growth in applications during PY 2012 – 2015 after standalone energy storage became eligible for incentives. Nonresidential applications have leveled out since PY 2017, but the evaluated population (those receiving upfront payments) has continued to grow. Again, potential lag times between program application and actual installation and receipt of incentive payment explain this nuance (Figure 2-5 and Figure 2-6).

FIGURE 2-5: SGIP STORAGE CUMULATIVE PROJECT COUNT BY SECTOR AND PROGRAM YEAR

FIGURE 2-6: SGIP STORAGE CUMULATIVE REBATED CAPACITY BY SECTOR AND PROGRAM YEAR

Table 2-1 summarizes the total number of systems, rebated capacity and incentive amounts reserved[22] by PA. PG&E administers the most energy storage projects, followed by SCE and CSE. SCE has the greatest capacity, which is due, in part, to a significant increase in large nonresidential systems receiving incentives in 2019.

TABLE 2-1: ENERGY STORAGE PROJECT COUNT AND REBATED CAPACITY BY PA

Program Administrator	Number of Projects	Rebated Capacity (kW)	Incentive Amount Reserved
Pacific Gas and Electric Company	3,310	53,605	$73,939,808
Southern California Edison	3,124	87,320	$110,931,822
Southern California Gas Company	456	10,351	$9,746,381
Center for Sustainable Energy	1,985	35,469	$43,185,627
Total	***8,875***	***186,745***	***$237,803,638***

SGIP storage incentives are available to any California IOU customer. When the PA is a gas-only IOU the electric service may be provided by a municipal utility. Table 2-2 summarizes the number of projects and rebated capacity by PA and electric utility type. PG&E and Southern California Gas Company are the only PAs with energy storage systems installed at non-IOU electric customer locations.[23] Overall, SGIP energy storage systems installed at electric-IOU customer locations represent roughly 95 percent of all installations.

TABLE 2-2: ENERGY STORAGE PROJECT COUNT AND REBATED CAPACITY BY PA AND ELECTRIC UTILITY TYPE

Program Administrator	Number of Projects		Rebated Capacity (kW)	
	Electric IOU	Municipal	Electric IOU	Municipal
Pacific Gas and Electric	3,233	77	53,188	418
Southern California Edison	3,124	-	87,320	-
Southern California Gas Company	76	380	7,525	2,826
Center for Sustainable Energy	1,985	-	35,469	-
Total	**8,418**	**457**	**183,501**	**3,244**

22 The incentive amount reserved is defined as the sum of the upfront incentive and any potential performance-based incentives reserved for a project.

23 Municipal utilities include LADWP, Sacramento Municipal Utility District (SMUD), City of Glendale, and Anaheim Public Utility, among others.

2.2.2 Evaluation Period

This impact evaluation covers performance during the twelve-month period ending December 31, 2019. For systems that became operational during 2019, we estimate partial-year impacts based on the start of normal operations. Additional details on the evaluation methodology and approach are included in Section 4 and Appendix B.

2.3 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 (Section 3). Sources of data used in this evaluation include:

- The SGIP Statewide Project Database – contains project characterization information such as rebated 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 storage charge/discharge data
- Data for systems subject to PBI data collection rules were downloaded from the Statewide Project Database
- Data for a sample of all systems (regardless of size) were requested and received from project developers
- Metered customer interval load and tariff information were requested and received from the electric IOUs and project developers, where available
- Marginal emissions data were collected from the GHG signal provider, WattTime[24]
- Utility avoided cost information were collected from the CPUC 2019 Avoided Cost Calculator (ACC)

24 https://sgipsignal.com/

- Additional information such as paired generator (PV, fuel cell, etc.) characteristics and participation in demand response (DR) programs were received from project developers and electric utilities

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

2.4 REPORT ORGANIZATION

This report is organized into four sections and three 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 more granular characterization of the population and details the sampling approach used to develop population impacts
- Section 4 characterizes the metered sample and presents the observed and overall program impacts
- Appendix A describes how customer bill impacts were estimated
- Appendix B presents the sources of data used in this evaluation and the quality control exercises performed to verify storage data
- Appendix C provides additional figures and tables that were not included in the main body of the report

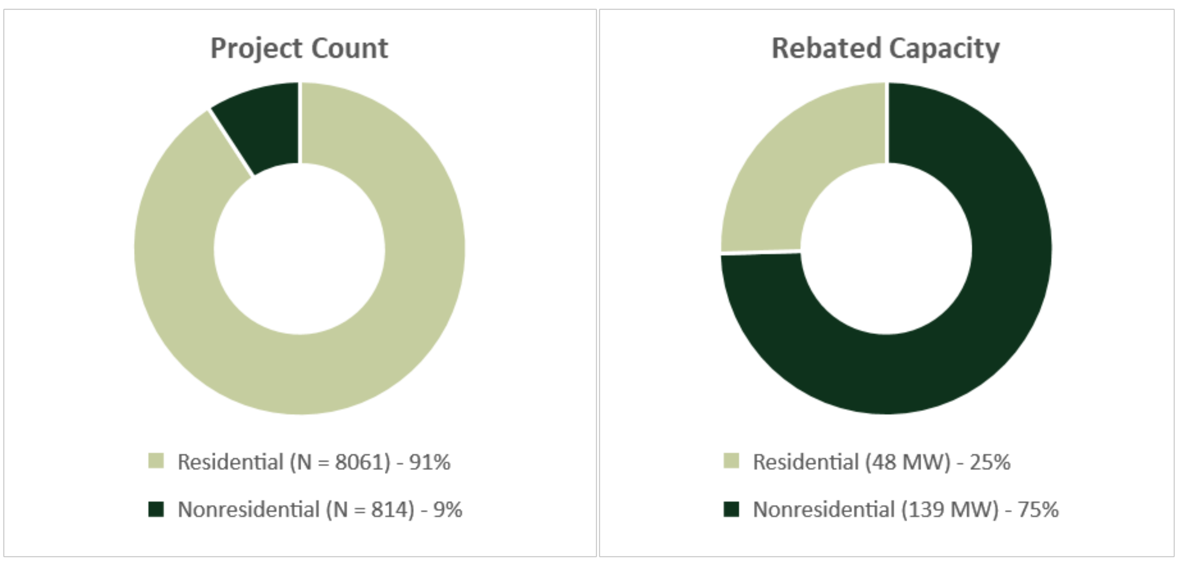
3 POPULATION AND SAMPLE CHARACTERIZATION

This section of the report presents the population of SGIP energy storage systems subject to evaluation in this study and describes the sample of projects the evaluation team analyzed to satisfy the impact evaluation objectives detailed in Section 2.

3.1 2019 SGIP ENERGY STORAGE POPULATION

As presented in Section 2, by the end of 2019, the SGIP provided incentives to 8,875 energy storage systems representing roughly 187 MW of rebated capacity. SGIP storage systems are installed at both residential and nonresidential customer sites. Figure 1-2 shows the breakdown in sector by project count and rebated capacity. While the number of residential systems subject to evaluation in 2019 represents the vast majority by project count (91 percent), the majority of the SGIP storage rebated capacity (75 percent) are installed at nonresidential customer sites.

FIGURE 3-1: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR



Nonresidential systems are almost always larger and therefore have a larger contribution to total program impacts. They range in size from roughly 5 kW to over 2,500 kW with an average capacity of 171 kW. Residential storage systems are generally in the 4.9 kW to 9.9 kW range with an average capacity of 6 kW. Figure 3-2 and Figure 3-3 provide the count of projects by rebated kW capacity bins for nonresidential and residential applications, respectively.

FIGURE 3-2: NONRESIDENTIAL POPULATION BY REBATED CAPACITY

FIGURE 3-3: RESIDENTIAL POPULATION BY REBATED CAPACITY

Systems are further split into two categories: 1) performance-based incentive (PBI) and 2) non-PBI. PBI systems are those with a rebated capacity equal to or greater than 30 kW that applied to the SGIP on or after PY 2011.[25] These systems receive 50% of their incentive upfront and receive the remaining 50% over the course of 5 successive years.

There are 456 PBI systems in the 2019 SGIP population, representing roughly 128 MW of the 187 MW total. This represents an increase of 97% in project count and 56% in capacity from 2018 to 2019. All PBI systems are installed at nonresidential customer locations. Residential systems comprise the majority of non-PBI systems, both in terms of project count and rebated capacity and, as discussed previously,

25 Beginning in PY 2020, all nonresidential storage systems will be classified as PBI, regardless of size.

experienced the most significant growth as a percentage of capacity from 2018 to 2019. Nonresidential systems less than 30 kW represent the remaining capacity of the program. They experienced modest growth from 2018 to 2019. Figure 3-4 and Figure 3-5 convey those changes for each customer sector and payment type.

FIGURE 3-4: SGIP STORAGE CHANGE IN KW CAPACITY FROM 2018 TO 2019 BY SECTOR AND PAYMENT TYPE

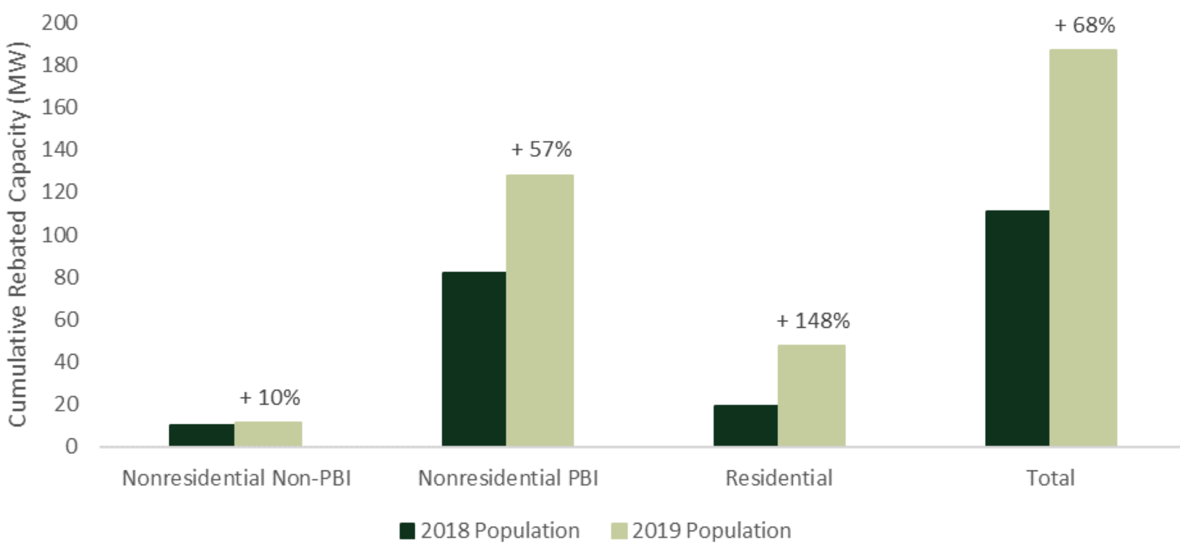
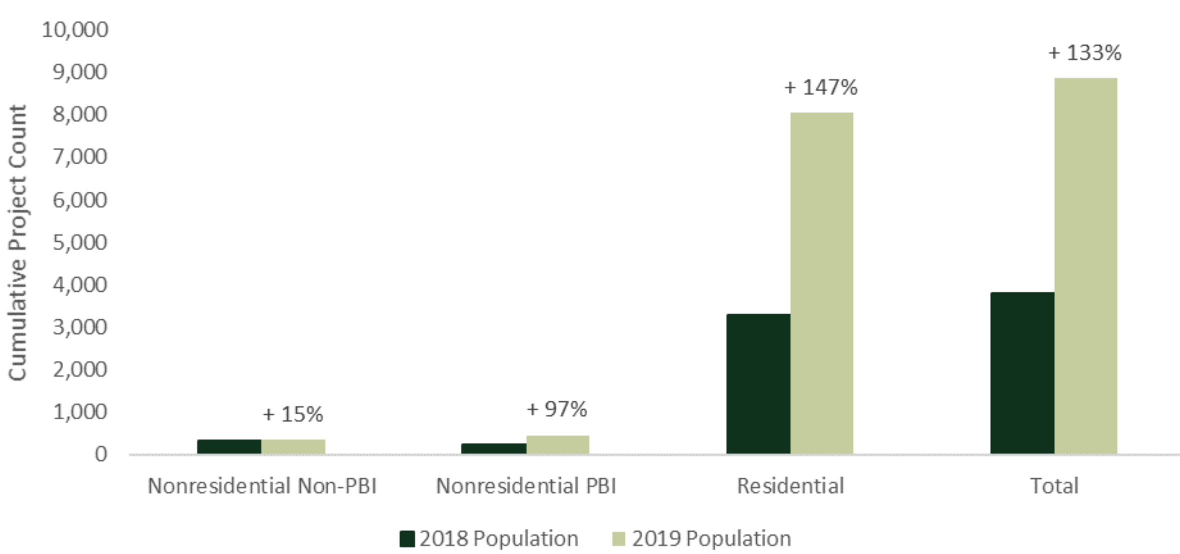


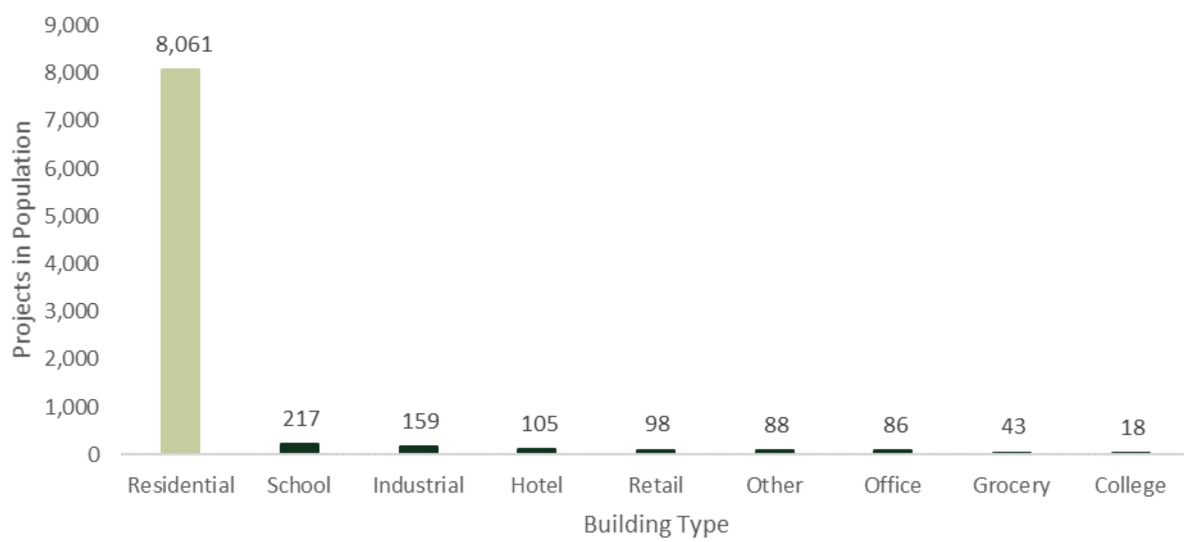
FIGURE 3-5: SGIP STORAGE CHANGE IN PROJECT COUNT FROM 2018 TO 2019 BY SECTOR AND PAYMENT TYPE



Energy storage systems are installed in a variety of building types. Customer segments potentially have different operating schedules throughout the year which can have a significant impact on the behavior of the system. For example, some facilities may experience peak demand periods that are non-coincident to CAISO or utility grid peak hours. Figure 3-6 and Figure 3-7 summarize the distribution of building types in the SGIP energy storage population subject to evaluation in 2019 by project count and capacity, respectively.

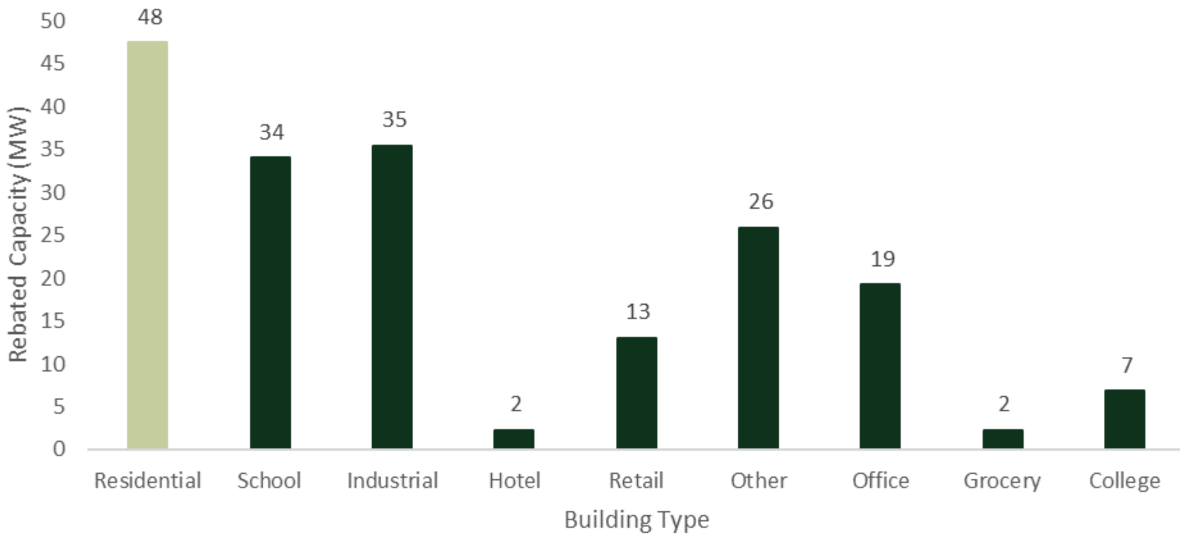
Most energy storage systems in the population are installed in residential settings (8,061 of 8,875 or slightly more than 90 percent), followed by a variety of nonresidential facilities.[26] However, residential energy storage systems are relatively small (approximately 6 kW, on average) compared to nonresidential energy storage systems (approximately 170 kW rebated capacity each, on average). Schools and industrial facilities comprise the most nonresidential systems by project count and rebated capacity. While there are 105 SGIP storage systems installed in hotels, the average capacity of these systems is smaller than systems installed in other facility types. The average capacity of systems installed in hotels is 22 kW, compared to 223 kW in industrial facilities, 157 kW in schools, and 224 kW in offices.

FIGURE 3-6: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY PROJECT COUNT



[26] The Other category consists of facility types with less than 15 represented in the population. This category includes assembly, warehouses, health care facilities, etc.

FIGURE 3-7: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY REBATED CAPACITY



Some nonresidential customer sectors have experienced more growth within the SGIP from the previous program year than others. The distribution of building types presented above are further disaggregated in Figure 3-8 and Figure 3-9 to highlight these changes. *Existing* projects are systems that were subject to evaluation in 2018 and *New* projects are those incremental systems receiving their upfront payment in 2019. The total 2019 evaluated population is the combination of the two.

FIGURE 3-8: NONRESIDENTIAL SYSTEMS BY BUILDING TYPE AND EVALUATION YEAR (PROJECT COUNT)

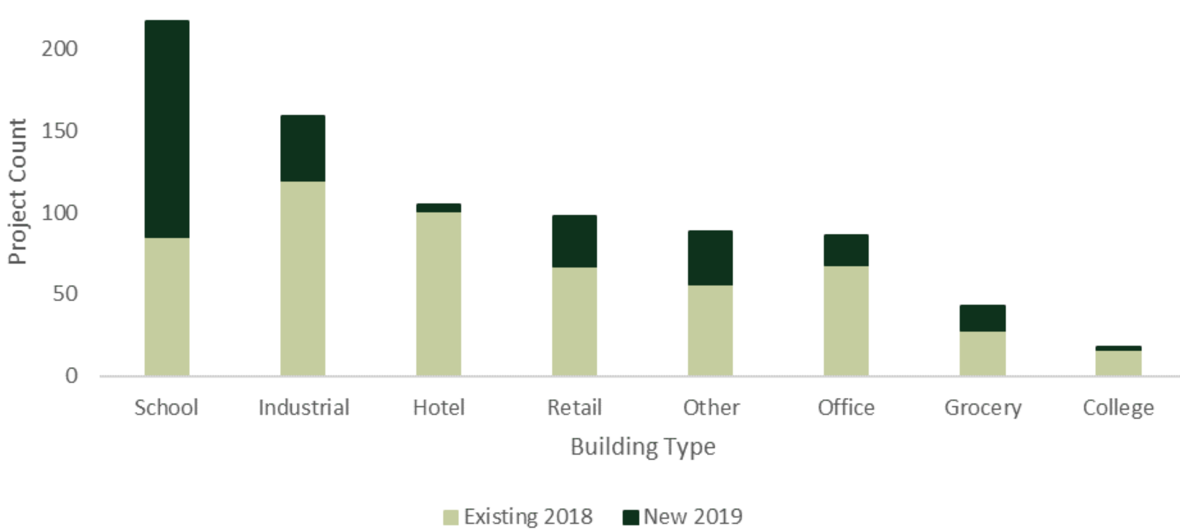
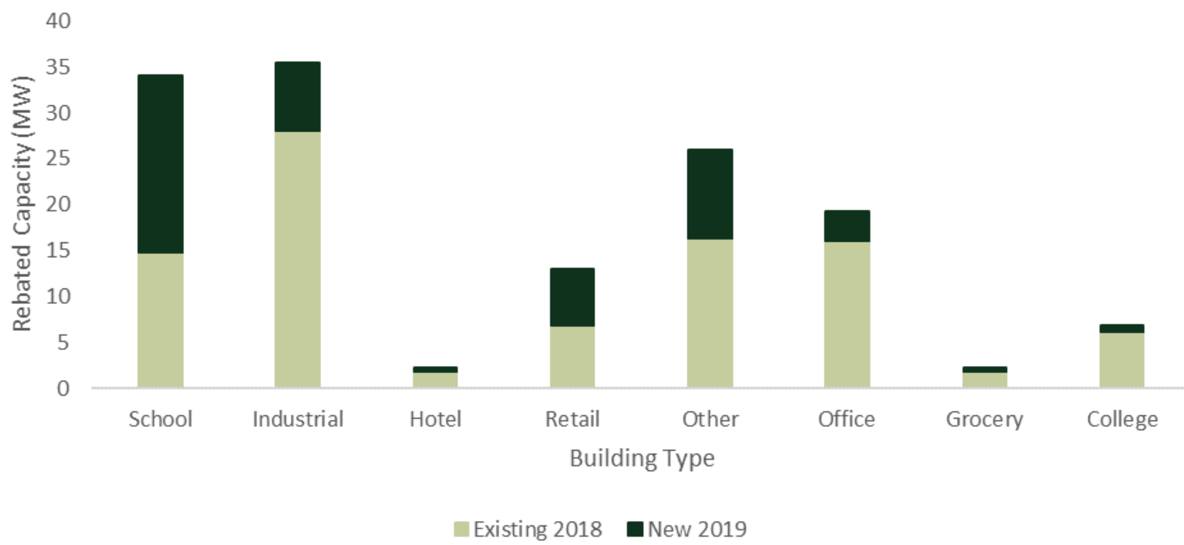


FIGURE 3-9: NONRESIDENTIAL SYSTEMS BY BUILDING TYPE AND EVALUATION YEAR (CAPACITY)

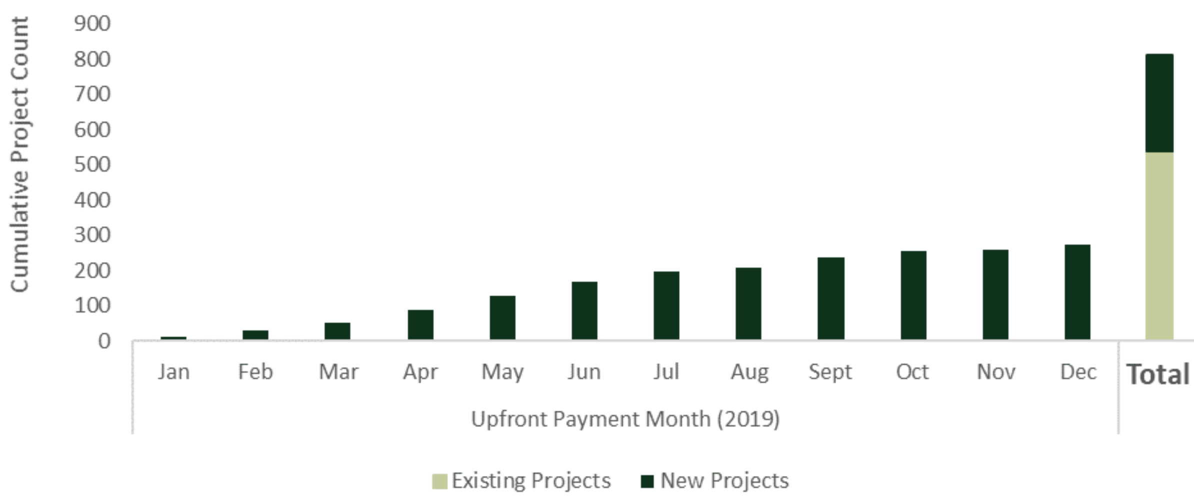


Each nonresidential building type contributed to growth in the program in 2019, however, schools more than doubled their contribution in 2019 alone – both in terms of project count and rebated capacity. For *New* projects that became operational during 2019, partial-year impacts have been developed based on the start of normal operations.[27] The evaluation team took this distinction into consideration when developing the sample design, which will be discussed in Section 3.2.

Systems that were evaluated in 2018 will have a full calendar year of storage data in 2019, while a system rebated in the late summer of 2019 will not have a full year of data. This is especially important for systems that began normal operations after the summer period, when utility marginal costs and environmental impacts are greatest. This nuance is highlighted below in Figure 3-10. Twenty-three percent of nonresidential customers received their upfront payment from September through December of 2019.

[27] The start of normal operations can be on or after the permission to operate (PTO) date, but no later than the upfront incentive payment date. The evaluation team reviews each customer's storage profile to determine the start of normal operations and to maximize the use of available metered data.

FIGURE 3-10: 2019 SGIP NONRESIDENTIAL POPULATION BY PROJECT COUNT



The roughly 147 percent increase in residential project count from 2018 to 2019 presents unique opportunities as well as unique challenges. As discussed previously, while a storage participant may apply to the SGIP during one calendar year, there is often a lag time between when that customer receives their permission-to-operate (PTO) and when the incentive is paid. Figure 3-11 presents the distribution of residential systems subject to evaluation for 2019 by upfront payment month. Upfront payments were distributed normally throughout the year with 30 percent receiving upfront incentives from September through December 2019. From the sample of systems that became operational during 2019, partial-year impacts were developed based on the start of normal operations.

FIGURE 3-11: 2019 SGIP RESIDENTIAL POPULATION BY PROJECT COUNT

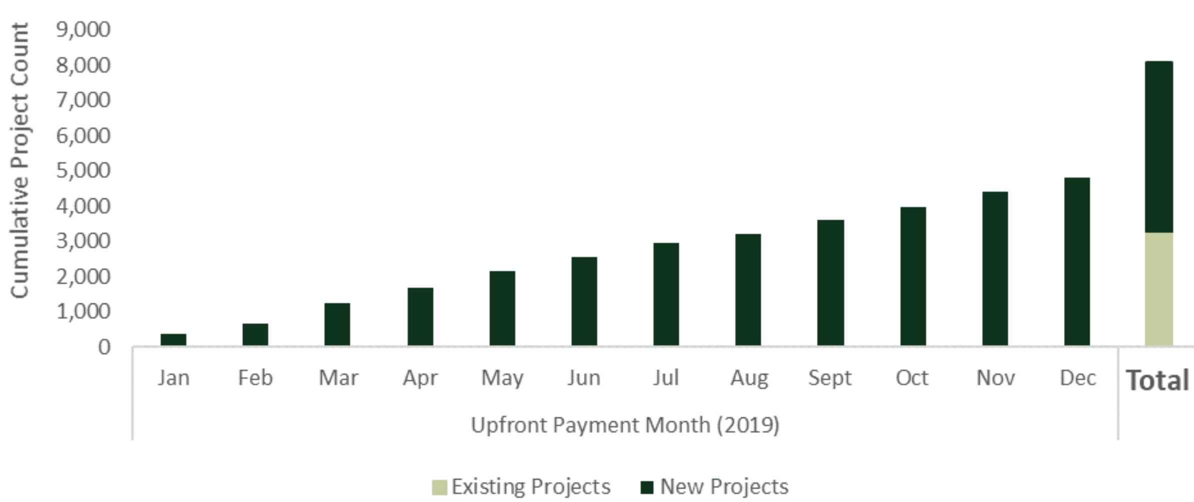


Table 3-1 presents the total number of systems in the 2019 population along with the total capacity for each customer sector and program administrator (PA). As discussed in Section 2, the 2019 population is comprised of 814 nonresidential and 8,061 residential projects (8,875 total). PG&E has provided the most incentives (3,310), followed by SCE (3,124), CSE (1,985) and SCG (456). SCE represents the most significant representation in rebated capacity, especially in the nonresidential space.

TABLE 3-1: 2019 SGIP POPULATION BY PA AND CUSTOMER SECTOR

PA	Customer Segment	Project Count	% Project Count	Rebated Capacity (kW)	% Rebated Capacity (kW)
CSE	Nonresidential	197	10%	25,497	72%
	Residential	1,788	90%	9,972	28%
	All	**1,985**		**35,469**	
PG&E	Nonresidential	219	7%	34,814	65%
	Residential	3,091	93%	18,792	35%
	All	**3,310**		**53,605**	
SCE	Nonresidential	362	12%	71,232	82%
	Residential	2,762	88%	16,088	18%
	All	**3,124**		**87,320**	
SCG	Nonresidential	36	8%	7,679	74%
	Residential	420	92%	2,672	26%
	All	**456**		**10,351**	
Total	**Nonresidential**	**814**	**9%**	**139,222**	**75%**
	Residential	**8,061**	**91%**	**47,524**	**25%**
	All	***8,875***		***186,745***	

3.2 2019 SGIP ENERGY STORAGE SAMPLE COMPOSITION

This section details the sampling plan for the 2019 energy storage impact evaluation. The sampling strategy is designed to provide statistically significant impact results for storage systems online in 2019 while maintaining evaluation delivery timelines and project budgets. The following sample design was developed from the 2019 population of SGIP storage projects. It is based on several factors:

- 2019 population of SGIP storage systems
- Availability of underlying data requirements
- An understanding of historical data limitations

- Results from the 2017 and 2018 impact evaluations
- Sampling requirements needed to develop population-level impact metrics with a high level of precision

3.2.1 Nonresidential Sample Composition

The nonresidential population comprises all storage systems with an SGIP rebated capacity less than 30 kW and PBI systems – those greater than or equal to 30 kW. These systems are installed in a variety of different facility types with potentially different operating schedules, load shapes and demand requirements, as discussed previously. Systems greater than or equal to 30 kW represent 93% of the total nonresidential capacity.

In previous storage impact studies, the evaluation team did not employ any sampling strategy to develop impacts for the larger systems, but rather attempted to evaluate all systems, where sufficient and verifiable storage discharge data was available. The evaluation team utilized the same approach for 2019, given the weight these projects represent in the SGIP storage population. As discussed in Appendix B, we downloaded all available data from the PBI web portal and placed separate data requests to individual project developers and host customers. We also requested and received metered load data from each of the IOUs.

Systems less than 30 kW represent the remaining 7% of the nonresidential population capacity. Given there are no PBI data delivery requirements for systems less than 30 kW, storage data supplied by the project developer is the only data source to measure and verify impacts from these systems. Given the increase in total projects, evaluation reporting deadlines, budgetary considerations, results garnered from the 2017 and 2018 impact evaluation, along with the understanding that there are far more PBI and residential systems subject to review (by count and rebated capacity) in 2019, we sampled fewer nonresidential systems with rebated capacity less than 30 kW than in 2018, while still providing statistically significant impact results.

The evaluation team uncovered some data limitations and data quality issues which precluded a rigorous evaluation of all sampled systems in 2019. If a system was missing long intervals of storage charge/discharge data or if the evaluation team determined that the storage dispatch behavior did not coincide with the metered load data at the same interval, those data were flagged for further quality control. If the issues could not be resolved, the system was removed from the analysis. Furthermore, the evaluation team encountered issues with missing data for systems receiving upfront payments late in 2019. Further discussion of the quality control exercises that were performed to verify storage data can be found in Appendix B.

Figure 3-12 presents the change in the SGIP nonresidential population from 2018 to 2019 by PA, as well as the statewide total. The 2018 evaluation year includes all systems in the SGIP population subject to evaluation in 2018 and those in the 2019 evaluation year represent the incremental systems receiving upfront payments in 2019 that were not subject to evaluation in 2018. Overall, the nonresidential population increased by roughly 50%.

FIGURE 3-12: CHANGE IN 2019 SGIP NONRESIDENTIAL POPULATION BY PA

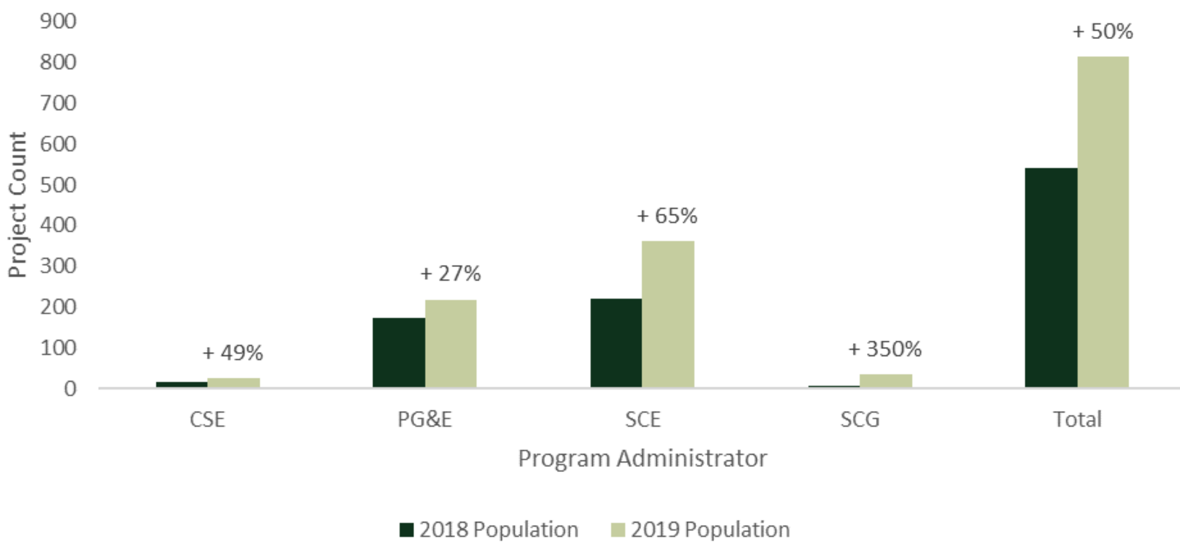
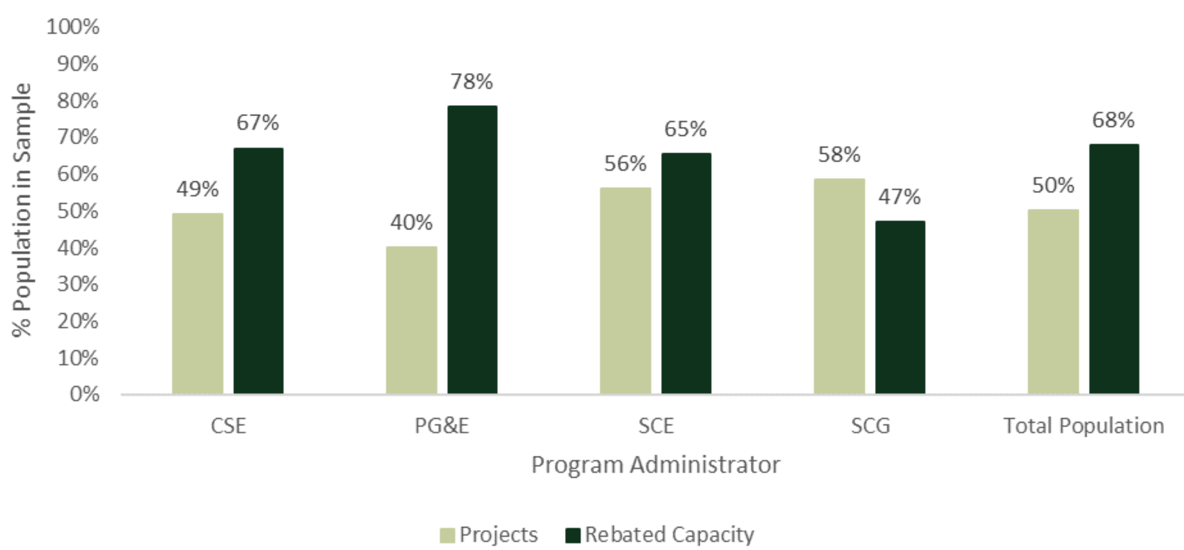


Table 3-2 presents the total number of systems in the population (shown as 'N') along with the total capacity of all nonresidential systems by PA, as well as the statewide total. Table 3-2 also presents the total number of systems represented in the analysis sample (shown as 'n'). Overall, the analysis sample represents 408 of the 814 systems subject to evaluation in 2019, which accounts for roughly 50 percent of all nonresidential systems by project count and, 68 percent by rebated capacity.

TABLE 3-2: 2019 SGIP NONRESIDENTIAL POPULATION AND SAMPLE COMPOSITION BY PA AND EVALUATION YEAR

PA	Year	Project Count			Rebated Capacity (kW)		
		N	Achieved n	% in Sample	N	Achieved n	% in Sample
CSE	2018	140	60	43%	17,131	10,340	60%
	2019	57	36	63%	8,366	6,720	80%
	Total	**197**	**96**	**49%**	**25,497**	**17,060**	**67%**
PG&E	2018	173	61	35%	27,602	22,925	83%
	2019	46	27	59%	7,211	4,387	61%
	Total	**219**	**88**	**40%**	**34,814**	**27,312**	**78%**
SCE	2018	220	119	54%	45,520	32,599	72%
	2019	142	84	59%	25,712	13,976	54%
	Total	**362**	**203**	**56%**	**71,232**	**46,575**	**65%**
SCG	2018	8	5	63%	1,739	1,449	83%
	2019	28	16	57%	5,940	2,163	36%
	Total	**36**	**21**	**58%**	**7,679**	**3,612**	**47%**
All Projects	2018	541	245	45%	91,992	67,315	73%
	2019	273	163	60%	47,229	27,246	58%
	Total	***814***	***408***	***50%***	***139,222***	***94,560***	***68%***

FIGURE 3-13: 2019 SGIP NONRESIDENTIAL POPULATION AND SAMPLE COMPOSITION BY PA



3.2.2 Residential Sample Composition

Residential systems represent roughly 48 MW of the total storage program capacity of 187 MW. The 48 MW represent a 147 percent increase in rebated capacity from 2018. There are 8,061 residential systems subject to measurement and verification which represents a 147 percent increase by project count from 2018. The storage systems range in size with roughly 80 percent less than 10 kW in capacity (see Figure 3-3).

The growth in residential storage receiving incentives in 2018 and 2019 includes newer and more sophisticated storage systems capable of operating under different modes and conditions. These systems also maintain more robust and reliable data acquisition systems which allow for a far more rigorous analysis of impacts. Our team requested and received storage, PV generation and customer load data from key storage developers and system manufacturers. Our sample was drawn from these projects. We also carefully reviewed the utility rate schedule each residential customer was on throughout 2019, to ensure that we were sampling from a representative mix of rate types, including existing TOU rates, more current TOU rates with different peak periods, electric vehicle (EV) rates, traditional volumetric tiered rates, etc.

Figure 3-14 presents the distribution of residential storage systems subject to evaluation in 2019 by PA and evaluation year. Again, customers in 2018 were part of the population frame in 2018, and 2019 represents those incremental customers receiving upfront payments in 2019. The number of residential systems receiving upfront payments in 2019 more than doubled for each of the PAs, with CSE and SCG experiencing the most significant growth in terms of percentage increase at 261% and 282%, respectively.

FIGURE 3-14: CHANGE IN 2019 SGIP RESIDENTIAL POPULATION BY PA

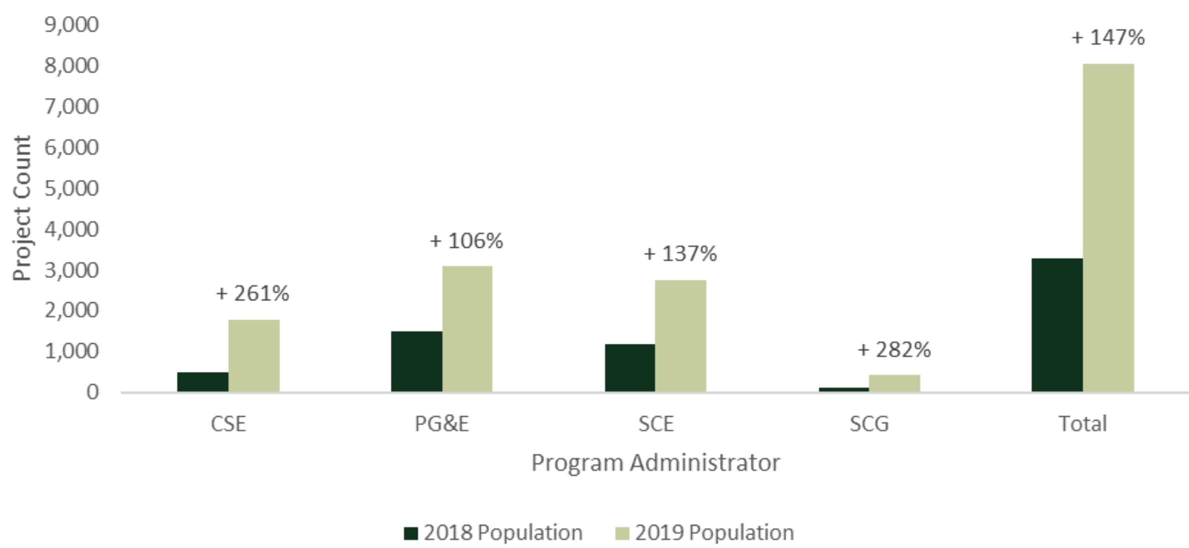


Table 3-3 presents the sample disposition for residential systems by PA and the customer program year. Overall, we evaluated 436 residential storage systems across the four PAs. These systems represent roughly 5% of the residential population by project count and 6% by rebated capacity.

TABLE 3-3: 2019 SGIP RESIDENTIAL POPULATION AND SAMPLE COMPOSITION BY PA AND EVALUATION YEAR

PA	Year	Project Count			Rebated Capacity (kW)		
		N	Achieved n	% in Sample	N	Achieved n	% in Sample
CSE	2018	495	38	8%	2,803	245	9%
	2019	1,293	56	4%	7,169	338	5%
	Total	**1,788**	**94**	**5%**	**9,972**	**583**	**6%**
PG&E	2018	1,498	60	4%	8,865	424	5%
	2019	1,593	89	6%	9,926	564	6%
	Total	**3,091**	**149**	**5%**	**18,792**	**988**	**5%**
SCE	2018	1,167	73	6%	6,830	459	7%
	2019	1,595	83	5%	9,258	523	6%
	Total	**2,762**	**156**	**6%**	**16,088**	**982**	**6%**
SCG	2018	110	14	13%	668	90	13%
	2019	310	23	7%	2,004	190	9%
	Total	**420**	**37**	**9%**	**2,672**	**280**	**10%**
All Projects	2018	3,270	185	6%	19,167	1,217	6%
	2019	4,791	251	5%	28,357	1,615	6%
	Total	***8,061***	***436***	***5%***	***47,524***	***2,833***	***6%***

3.3 SGIP POPULATION BEYOND 2019

The above sections detail the characterization of the SGIP energy storage population subject to evaluation in 2019 and provides a summary of how changes to the composition of that population from 2018 to 2019 dictated the evaluation approach. Residential systems constitute the most significant increase in the percentage of systems receiving upfront payments in 2019 when compared to 2018 and prior (both in terms of project count and rebated capacity). Likewise, large nonresidential systems subject to evaluation increased substantially. While the remainder of this report presents the results associated with systems subject to evaluation in 2019, here we provide a snapshot of how the composition of the population is changing from 2019 to 2020. Many of the conclusions and recommendations detailed in the Executive Summary are based on results garnered from this impact evaluation. Some, however, are forward looking and are predicated on an understanding of how the SGIP evolves from one year to the next.

Figure 3-15 and Figure 3-16 provide a snapshot of how the SGIP has evolved from 2018 to 2019 and what we expect the population to look like for the forthcoming 2020 evaluation year. The SGIP project list for 2020 was downloaded on August 20th, so the population will likely increase as more systems receive incentive payments through the latter months of the year. However, the trend is evident. The 2020 population will include many more residential systems, with modest growth from the nonresidential sector.

FIGURE 3-15: CHANGE IN SGIP STORAGE POPULATION 2018 – 2020 (BY CAPACITY)

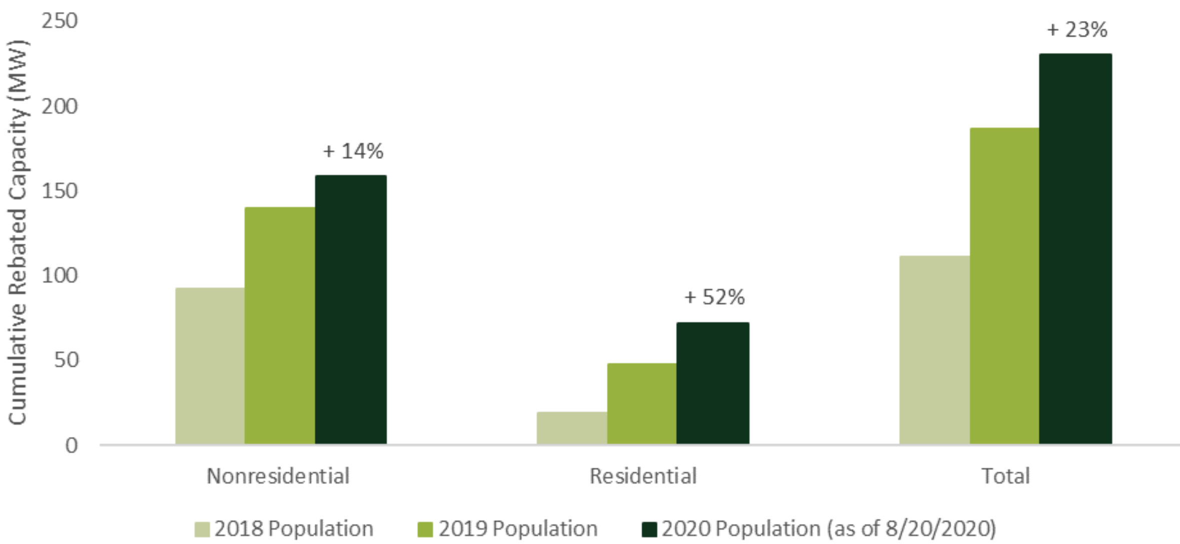
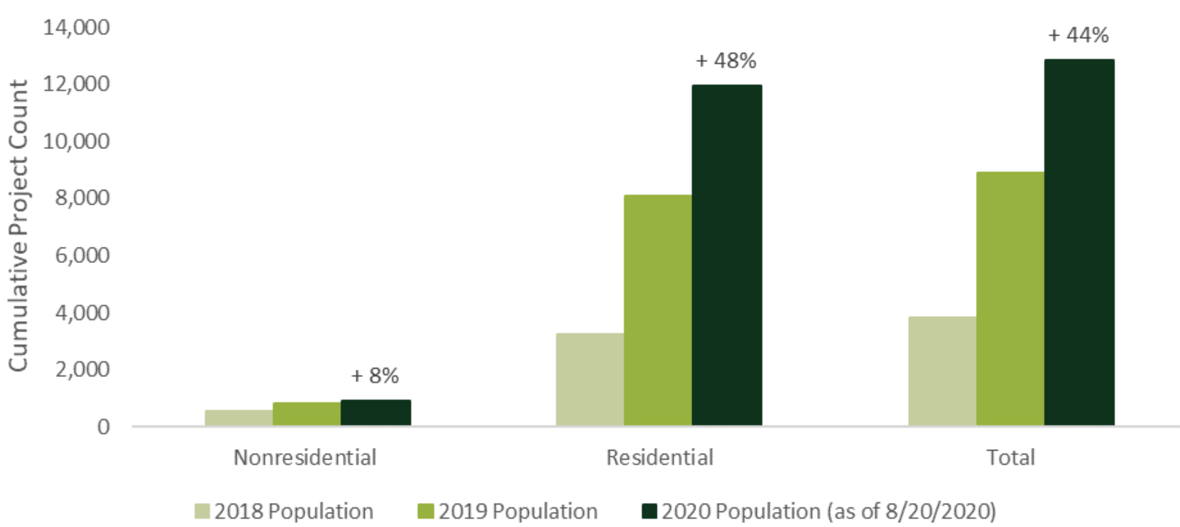


FIGURE 3-16: CHANGE IN SGIP STORAGE POPULATION 2018 – 2020 (BY PROJECT COUNT)



The 2020 evaluation year will also usher in some material changes to the program that will likely impact how we evaluate it moving forward. Beginning in 2020, systems will be required to meet specific GHG reduction targets and we anticipate the equity resiliency budget will foster a significant increase in applications for systems installed in high wildfire risk areas and vulnerable communities. The evaluation team will carefully take these changes into consideration when developing the research plan and sample design of the SGIP in 2020.

4 OBSERVED SGIP ENERGY STORAGE IMPACTS

The primary objective of this study is to evaluate the performance of energy storage systems rebated through the Self-Generation Incentive Program (SGIP) and operating during calendar year 2019. This section examines the performance of these systems and presents the observed impacts of SGIP energy storage throughout 2019. The evaluation team analyzed several different impact metrics to that end:

- **Observed Performance Impacts – Section 4.1**
  - Calculate roundtrip efficiencies (RTEs), capacity factors (CF), number of discharge cycles
  - Examine system power (kW), duration (hours) and energy (kWh)
  - Compare system performance in 2019 to performance in 2018
- **Observed Customer Impacts – Section 4.2**
  - Analyze and/or quantify charge/discharge behavior in relation to customer non-coincident peak demand, time-of-use (TOU) schedules and monthly bill savings
  - Analyze the behavior of storage systems paired or co-located with on-site generation technologies like solar photovoltaic systems (PV)
- **Observed CAISO and IOU System Impacts – Section 4.3**
  - Analyze and quantify charge/discharge behavior in relation to CAISO system load and utility coincident peak demand
- **Observed Environmental Impacts – Section 4.4**
  - Analyze and quantify charge/discharge behavior in relation to marginal greenhouse gas (GHG[28]) emissions
- **Observed Utility Marginal Cost Impacts – Section 4.5**
  - Analyze charge/discharge behavior in relation to utility marginal costs as quantified in the CPUC 2019 Avoided Cost Calculator
- **Observed System Behavior During Public Safety Power Shutoff (PSPS) Events – Section 4.6**
  - Analyze and quantity how storage systems are being utilized for customers affected by PSPS events during high wildfire risk periods
- **Energy Storage Program Level Impacts – Section 4.7**

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[28] This greenhouse gas emission impact analysis is limited to emissions from grid-scale gas power plants. Carbon Dioxide (CO_2) emissions were the only greenhouse gas modeled in this study. Throughout this report the terms "Greenhouse Gas" and "CO_2" are used interchangeably.

— Combine project-specific sample data from the objectives above to *quantify the magnitude* of total population level impacts for SGIP energy storage systems operating throughout 2019

4.1 PERFORMANCE METRICS

4.1.1 Capacity Factor, Roundtrip Efficiency and Discharge Cycles

Capacity factor is a measure of system utilization. It is defined as the sum of the storage discharge (in kWh) divided by the maximum possible discharge throughout a given period. This is based on the SGIP rebated capacity of the system (in kW) and the total hours of operation. When defining capacity factor, the SGIP handbook[29] assumes 5,200 maximum hours of operation in a year rather than the full 8,760 hours (60 percent).[30] For purposes of SGIP evaluation, the energy storage capacity factor is calculated as:

$$Capacity\ Factor = \frac{\sum kWh\ Discharge\ (kWh)}{Hours\ of\ Data\ Available \times\ Rebated\ Capacity\ (kW) \times\ 60\%}$$

Another key performance metric is roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP.[31] The RTE is defined as the total kWh discharge of the system divided by the total kWh charge. For SGIP evaluation purposes, this metric was calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

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

Finally, this evaluation examines another performance metric, “number of discharges (or cycles)”, which is a measure of system utilization like the CF. This metric 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.[32]

29 https://www.selfgenca.com/documents/handbook/2019

30 The SGIP Handbook requires performance-based incentive (PBI) projects that applied prior to 2017 to achieve a capacity factor of at least 10 percent per the above formula to receive full payment. Non-PBI systems are not required to meet that 10 percent CF to capture payment.

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

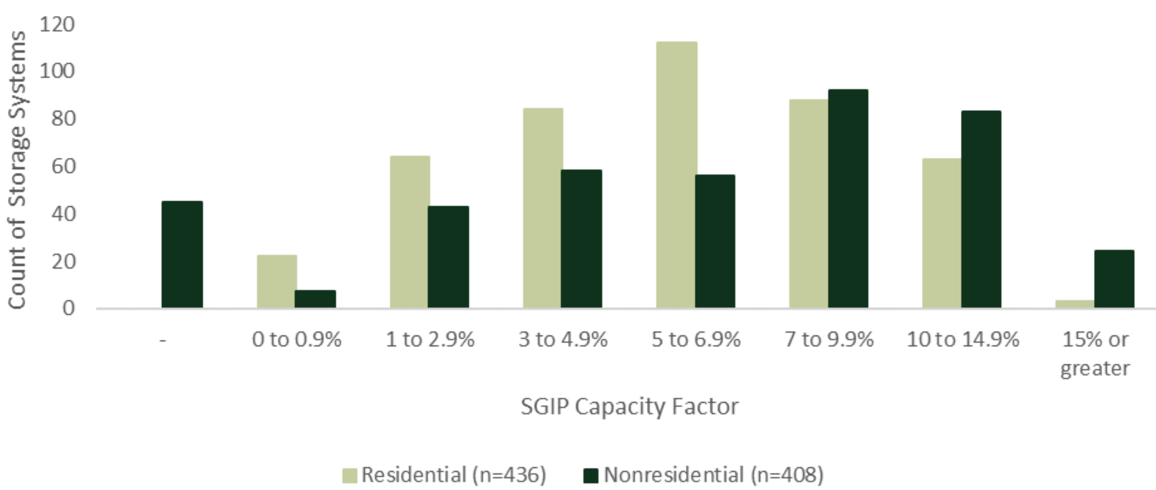
32 The 2019 SGIP Handbook requires commercial systems to discharge a minimum of 130 full discharges per year and residential systems to discharge a minimum of 52 full discharges per year. Each discharge does not have to

$$Discharge\ Frequency = \frac{\sum kWh\ Discharge\ (kWh)}{Rebated\ Capacity\ (kWh)}$$

Observed Performance Metrics

The capacity factors for the sample of nonresidential and residential energy storage systems are presented below in Figure 4-1. The results are binned to conveniently present the data. A total of 153 nonresidential systems of the 408 sampled (or 37.5 percent) and 170 residential systems of the 436 sampled (or 38.9 percent) have capacity factors less than 5 percent. We observed 148 nonresidential systems and 200 residential systems with a capacity factor between 5 and 10 percent. One hundred and seven nonresidential and 66 residential systems exhibited capacity factors of at least 10 percent. The mean capacity factor was roughly 7.0 percent for sampled nonresidential systems and the median value was 6.7 percent. The mean capacity factor for sampled residential systems during the evaluation period was 6.0% and the median value was 5.2%.

FIGURE 4-1: HISTOGRAM OF ANNUAL CAPACITY FACTOR BY CUSTOMER SECTOR



* Forty-five projects were offline throughout the entirety of 2019, had been decommissioned or received their upfront payment so late in the year that no impacts were measured. These projects are reported as “-” above.

Figure 4-2 presents the distribution of RTEs for both customer sectors. Besides offline and decommissioned systems, few projects exhibit an annual RTE of less than 50 percent. Most systems are within the 70 to 90 percent range. Sixty percent of residential systems exhibited an RTE in the 80 to 90 percent range alone. The average RTE was 81 percent for sampled nonresidential projects, and the median

be a discharge of 100% capacity. Rather, the full discharge definition equates to the aggregate amount of discharges over the year.

value was 79 percent. The average RTE was 83 percent for sampled residential systems over the entire evaluation period, and the median value was 82 percent.

FIGURE 4-2: HISTOGRAM OF ANNUAL ROUNDTRIP EFFICIENCY BY CUSTOMER SECTOR

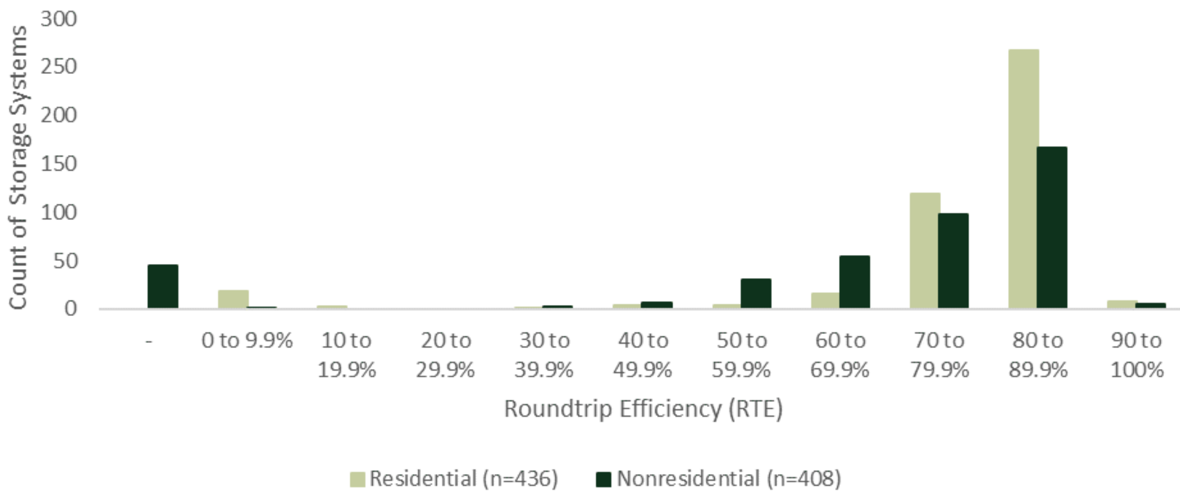
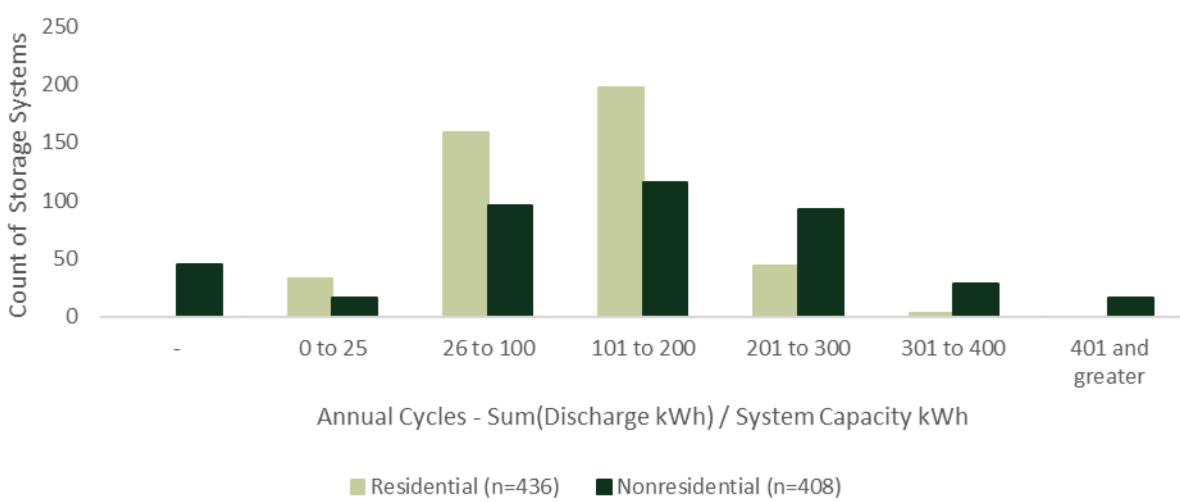


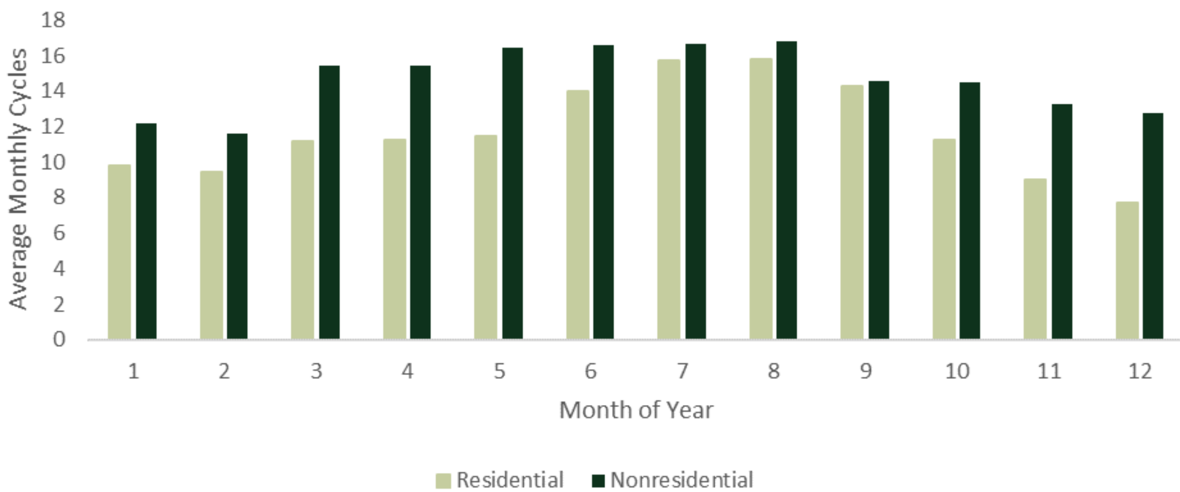
Figure 4-3 presents the number of discharge cycles performed by storage systems during 2019. Again, the results are binned to conveniently present the data. The distribution of discharge events for sampled nonresidential systems is rather normally distributed with an average of 157 cycles, and a median value of 144 cycles. The average for sampled residential systems was 117 cycles with a median value of 110 cycles. To make sense of this metric, if a 50 kWh system discharged 50 percent of capacity once a day, every day throughout the year, this would represent roughly 183 cycles ((50 kWh x 0.5 x 365) / 50 kWh).

FIGURE 4-3: HISTOGRAM OF ANNUAL DISCHARGE CYCLES BY CUSTOMER SECTOR



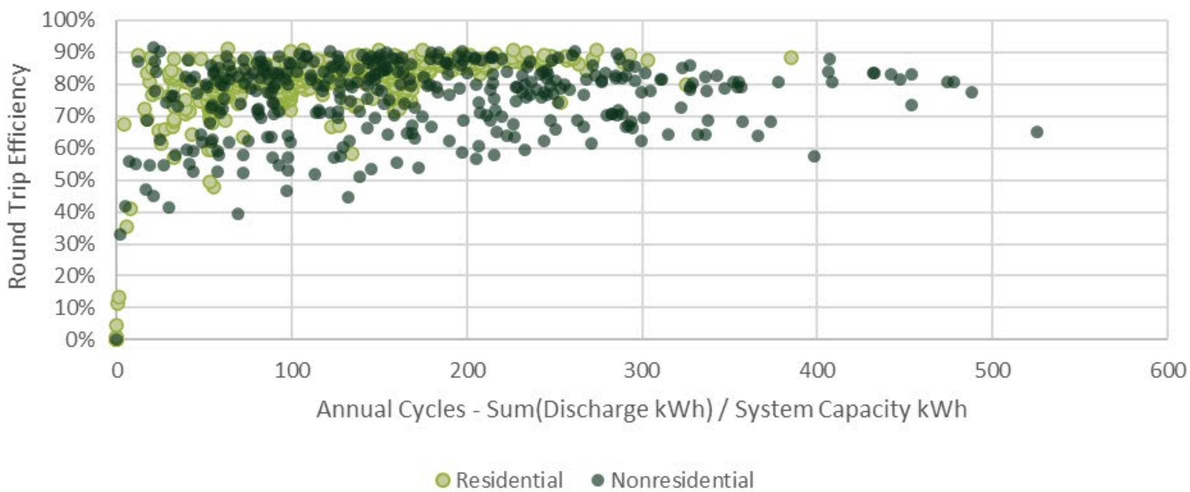
We also examined the distribution of discharge cycles for each month throughout the year. Both residential and nonresidential systems are being utilized more often in the summertime (Figure 4-4). Customer bill impacts ($/kWh and $/kW) and marginal emissions (kg CO_2/kWh) are also greatest throughout summer months.

FIGURE 4-4: HISTOGRAM OF MONTHLY DISCHARGE CYCLES BY CUSTOMER SECTOR



Note that by calculating the RTE over the course of several months, the metric not only captures the losses due to AC-DC power conversion but also the parasitic loads associated with system cooling, communications and other power electronic loads. Parasitic loads can represent a significant fraction of total charging energy, especially for systems that are idle for extended periods. This relationship is exhibited in Figure 4-5. When a system is utilized more often, it often has a greater RTE.

FIGURE 4-5: ANNUAL ROUNDTRIP EFFICIENCY VERSUS ANNUAL DISCHARGE CYCLES



4.1.2 Storage Power, Duration and Energy Capacity

Beginning in PY 2017, SGIP incentives are provided based on the energy capacity (kWh) of the system. The energy capacity is the product of the power (kW) and the duration (in hours) of the system. Since PY 2017, the SGIP program tracking database has collected the power, duration and energy of rebated systems as part of the incentive process. We compared the observed energy discharge of systems during 2019 to the rebated capacity of those systems. Some systems may maintain a certain minimum state of charge (SOC) throughout the year, so the system is never depleted, while other systems may fully discharge the system to keep load below a specific peak power threshold. Our analysis included estimating the longest duration discharge period throughout the year for each system, summing the total uninterrupted energy discharge kWh and comparing the observed estimate to the rebated system size. Those results are presented below in Figure 4-6 and Figure 4-7 for residential and nonresidential systems, respectively.

An observation on the dark green line would suggest that the maximum energy discharge of that system throughout 2019 was equal to the rebated capacity of the system. If an observation falls below the line, the observed energy is greater than the rebated capacity (and vice versa). As is evident in the figures below, most residential systems are utilizing less than the total available energy within the system[33], whereas the clustering along the line for nonresidential systems suggests these systems are utilizing a greater percentage of overall available energy.

[33] There are horizontal line clusters in the residential figure because there are far fewer capacity options for residential systems than the nonresidential sector. Twenty-five percent of systems are 26 kWh batteries, 37 percent are 13 kWh batteries and 33 percent are 8 kWh batteries.

FIGURE 4-6: ESTIMATED CAPACITY KWH TO REBATED CAPACITY KWH FOR RESIDENTIAL SYSTEMS

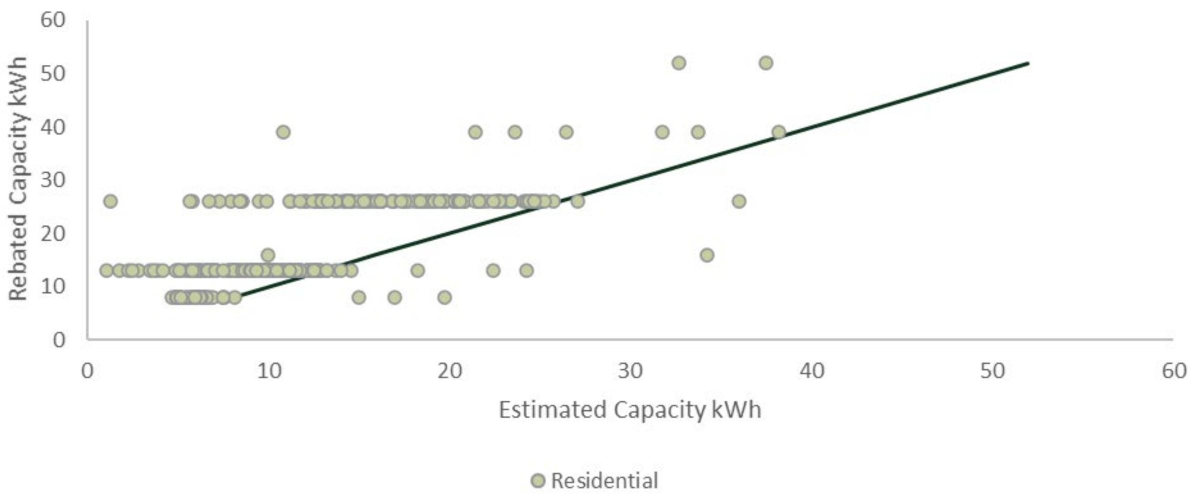
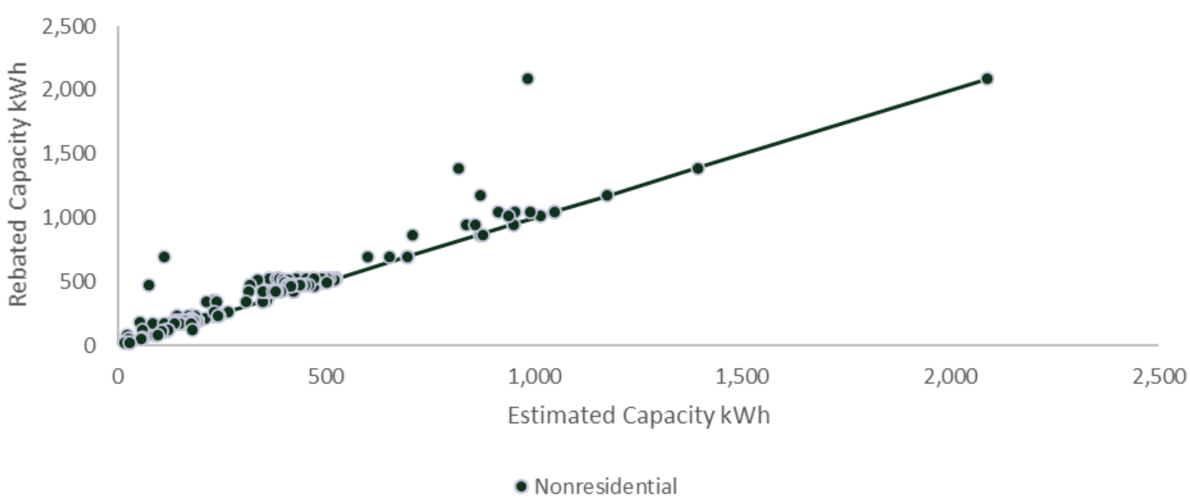


FIGURE 4-7: ESTIMATED CAPACITY KWH TO REBATED CAPACITY KWH FOR NONRESIDENTIAL SYSTEMS



4.1.3 Cross-Year Performance Impact Comparisons (2018 to 2019)

The evaluation team compared the performance metrics developed from the 2018 impact evaluation to those from this evaluation. These comparisons were made for system-level RTEs and utilization to highlight any potential changes in operation or utilization from one year to the next. Systems that came online during 2019 are not compared to projects in the 2018 population. Instead, the analysis is limited to the 36 residential systems and 218 nonresidential systems operational and sampled during both 2018 and 2019. It is important to note that many projects evaluated in 2018 received their upfront payments at different times throughout the year, so the performance metrics did not incorporate a full calendar year of impacts. All projects completed during 2018 were online and operating throughout the entirety of 2019, so any potential changes in performance from one year to the next may only reflect that difference.

Figure 4-8 and Figure 4-9 present those comparisons for RTEs and utilization. Any point on the figure above the green line represents a system with a greater RTE in 2019 than 2018. While thirty-six residential systems increased their utilization in 2019 – mostly because they were operational throughout the entirety of 2019 and only partially throughout 2018 – the efficiency of the systems was very similar across years. For nonresidential systems, we observe many systems with lower RTEs in 2018 (below 50%, for example) increasing their efficiency substantially in 2019. Systems with already high RTEs exhibited similar efficiencies across years. Nonresidential system discharge cycles also increased substantially.

FIGURE 4-8: CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2018 TO 2019)

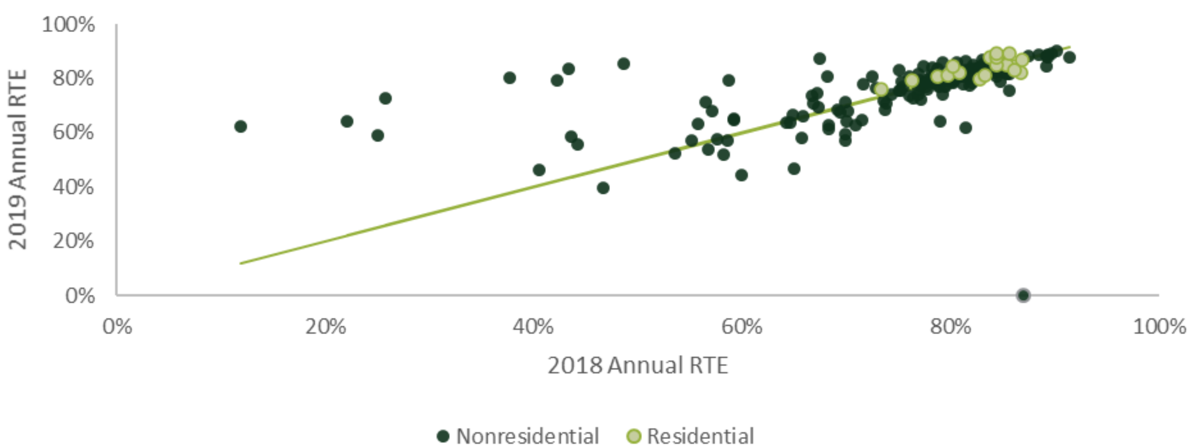
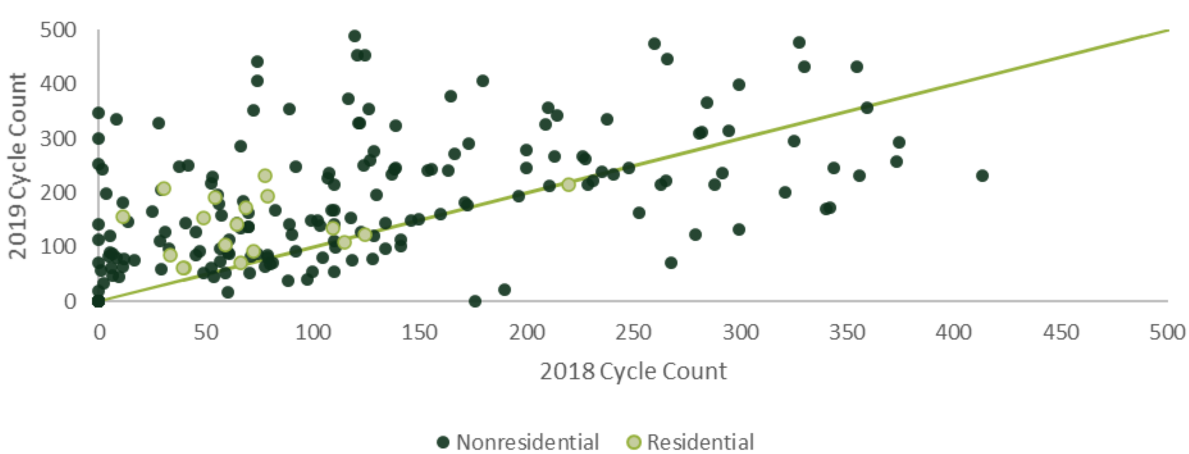


FIGURE 4-9: CROSS-YEAR DISCHARGE CYCLING COMPARISON (2018 TO 2019)



4.2 CUSTOMER IMPACTS

Storage systems can be utilized for a variety of use cases, and dispatch objectives are predicated on several different factors including facility 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, customers that are on a rate that assesses demand charges during peak demand periods and/or at the monthly billing level may prioritize peak demand reduction.

TOU periods are based on the electric utility and the customer's rate schedule. During winter months and summer months – which are defined by the specific IOU rate – customers pay a different rate and, within those seasons, pay different rates for each period (on-peak, off-peak and super off-peak[34]). The evaluation team conducted several different but concurrent analyses using the above TOU period descriptions along with customer rate schedules. The remainder of this section presents those results in more detail:

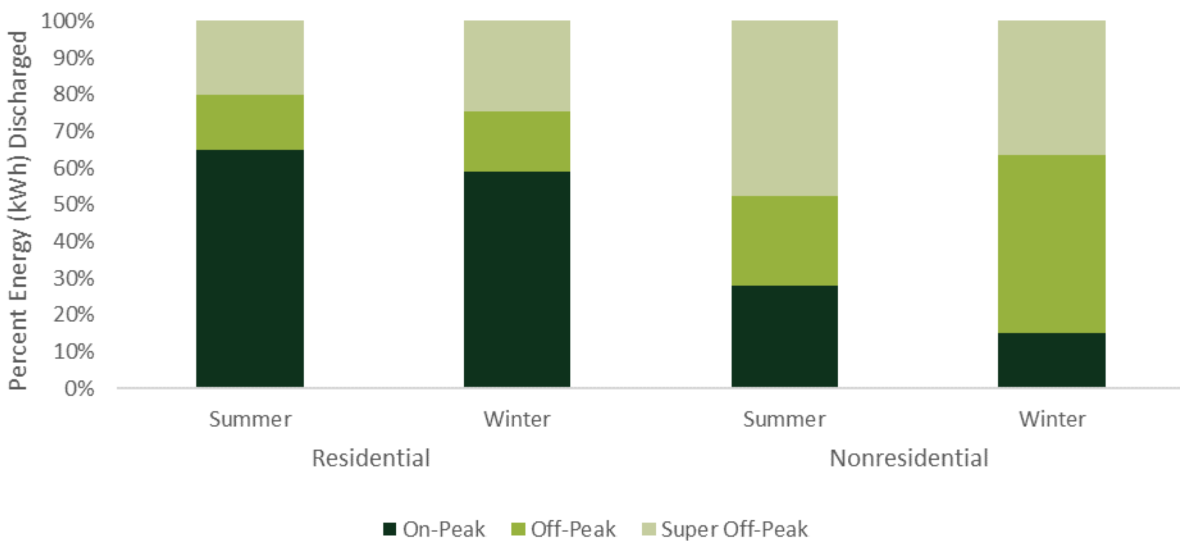
- Overall storage dispatch behavior based on TOU period and customer sector
- Overall storage dispatch behavior based on customer sector and presence of on-site generation
- Overall customer bill impacts ($/rebated kWh) by customer sector

4.2.1 Storage Dispatch Behavior by TOU Period and Customer Sector

The evaluation team analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage and peak demand reduction. We examined TOU energy dispatch by quantifying the magnitude of storage discharge by TOU period. Figure 4-10 presents the average percentage of energy discharged throughout each of the three TOU periods and two seasons for residential and nonresidential systems. This analysis only includes weekdays during each of the seasonal definitions.

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

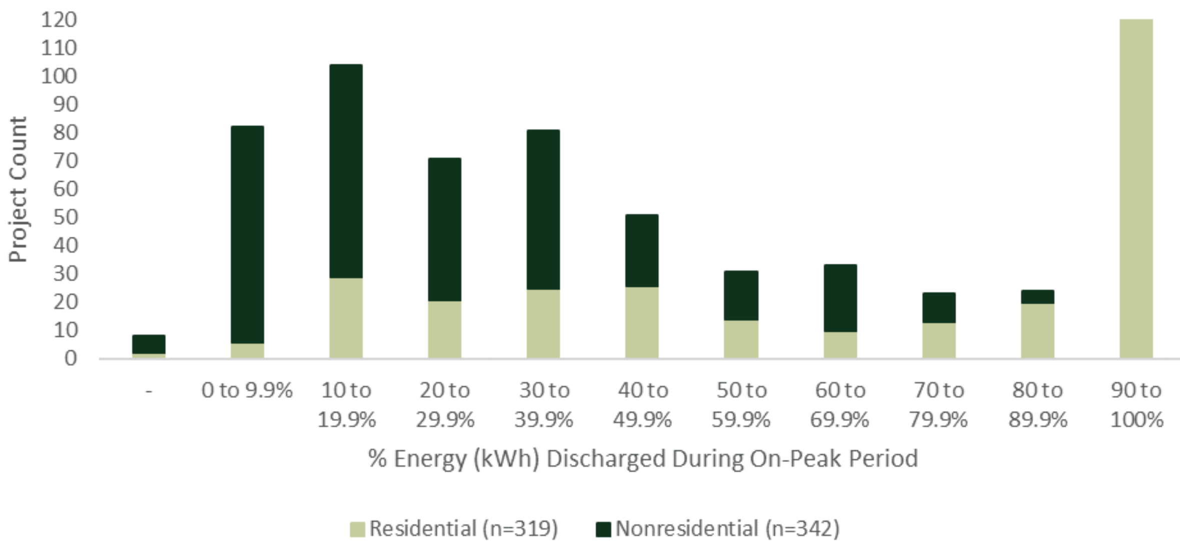
FIGURE 4-10: PERCENT DISCHARGE KWH BY TOU PERIOD AND CUSTOMER SECTOR



Residential systems are discharging energy more often throughout on-peak hours than off-peak and super off-peak periods, while nonresidential systems discharge far less often during the on-peak period. These on-peak hours, when retail energy rates are highest, provide the greatest opportunity for customers to realize billed energy savings. If a customer is discharging any percentage of energy outside this period, this suggests TOU arbitrage might not be the main causal mechanism of dispatch behavior. During both summer and winter periods, residential systems, on average, discharge greater than 60% of energy during on-peak, while nonresidential systems are discharging more often during off-peak and super off-peak hours.

Figure 4-11 provides the distribution of systems discharging energy throughout the on-peak period only. As evident from the far right of the figure, one hundred and sixty-three residential systems (or 50 percent of all residential customers on a TOU rate) are discharging greater than 90 percent of energy during on-peak, relative to all rate periods. No commercial systems are behaving that way.

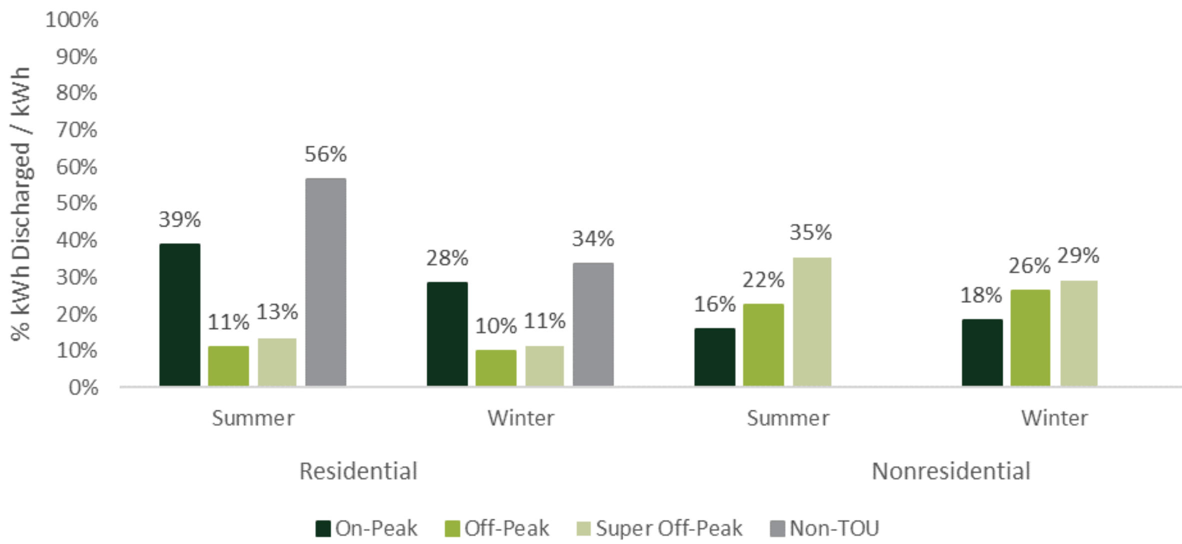
FIGURE 4-11: PERCENT KWH DISCHARGE DURING PEAK PERIOD BY CUSTOMER SECTOR



The previous exhibits provide evidence that most residential storage systems are discharging more often during on-peak periods relative to off- and super off-peak periods, and nonresidential systems are largely ignoring the energy price differential across periods and discharging more often outside on-peak periods. Next, we examine how much energy these systems are discharging throughout these TOU periods. Afterall, a system may discharge exclusively throughout an on-peak period, but if they are only discharging a small percentage of total capacity, the customer may not realize bill savings and the potential utilization of the system may be unrealized. Figure 4-12 presents the average magnitude of energy discharge during each season and period as a percentage of the total capacity of the system. It's important to note that this analysis sums the energy discharged across each customer's on-peak period, so the sum of energy discharged for a customer subject to a 5 hour on-peak period is treated the same as a customer subject to a 2 hour or 6 hour on-peak period.

On average, residential systems on a TOU rate are discharging 39% of system capacity during on-peak periods throughout the summer. They are also discharging during off- and super off-peak periods, but at much lower magnitudes of available capacity. Residential systems labeled "Non-TOU" are those still on a tiered volumetric rate during 2019. These rates do not contain any peak period definitions. Evident once again, is the lower magnitude of system discharge relative to capacity for nonresidential systems during on-peak periods. On average, these systems are discharging 16 percent of total available energy throughout summer on-peak periods.

FIGURE 4-12: HOURLY NET DISCHARGE KWH PER CAPACITY KWH BY SUMMER TOU PERIOD



Residential storage systems are discharging more often during on-peak periods than nonresidential systems and both customer sectors are utilizing less storage capacity during peak periods than available. Below we examine the timing of aggregated storage dispatch to further understand how storage systems are being utilized throughout the year. We performed this analysis by taking the average hourly charge and discharge kWh as a percentage of system kWh capacity for each month and hour within the year for residential and nonresidential systems. Figure 4-13 and Figure 4-14 present the findings for residential systems. The data are presented in hour beginning and Pacific Standard Time (PST).

These data follow the pattern presented above. Residential systems, on average, are discharging the most significant percentage of energy during the 3 pm PST hour (4 pm Pacific Daylight Time (PDT)). The magnitude of discharge drops off dramatically thereafter, but the pattern of less and less energy being discharged as customers transition to off-peak and super off-peak periods is evident in the data. Residential storage systems are almost exclusively charging during early morning hours, which coincides with early PV generation hours. This will be discussed in Section 4.2.2.

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FIGURE 4-13: AVERAGE HOURLY DISCHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
1	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
3	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
4	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
5	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
6	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
7	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%
11	0%	1%	1%	1%	1%	1%	1%	2%	1%	1%	0%	0%
12	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%
13	2%	2%	2%	2%	2%	3%	3%	3%	3%	2%	1%	1%
14	15%	15%	3%	2%	2%	3%	3%	4%	4%	2%	2%	2%
15	3%	4%	12%	15%	15%	28%	27%	29%	29%	20%	4%	3%
16	3%	3%	6%	4%	4%	7%	8%	8%	7%	5%	11%	12%
17	4%	4%	4%	4%	3%	4%	5%	5%	5%	4%	5%	6%
18	5%	5%	5%	4%	4%	4%	5%	5%	5%	4%	4%	4%
19	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%
20	3%	4%	4%	3%	3%	3%	3%	3%	3%	3%	3%	2%
21	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%
22	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%
23	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%

FIGURE 4-14: AVERAGE HOURLY CHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%
6	0%	0%	-1%	-2%	-2%	-4%	-4%	-3%	-2%	-1%	0%	0%
7	-1%	-2%	-4%	-6%	-6%	-8%	-9%	-8%	-7%	-5%	-2%	-1%
8	-4%	-6%	-8%	-9%	-8%	-12%	-14%	-14%	-12%	-10%	-5%	-4%
9	-7%	-9%	-10%	-10%	-8%	-12%	-13%	-15%	-14%	-11%	-7%	-6%
10	-8%	-9%	-9%	-7%	-7%	-9%	-9%	-10%	-10%	-8%	-8%	-7%
11	-7%	-7%	-7%	-5%	-5%	-6%	-5%	-6%	-6%	-5%	-6%	-6%
12	-6%	-5%	-4%	-3%	-4%	-4%	-3%	-3%	-4%	-3%	-4%	-4%
13	-4%	-3%	-3%	-2%	-2%	-3%	-2%	-2%	-2%	-1%	-2%	-3%
14	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	-1%	-1%	-1%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
23	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%

Nonresidential systems, conversely, exhibit more variability in charge and discharge behavior throughout the day. Figure 4-15 and Figure 4-16 convey these results. The magnitude of charge and discharge kWh within the same hours are similar throughout the hours of the day. The data provide evidence that nonresidential systems are discharging during peak periods, but also during off-peak and super off-peak periods. There appear to be no discernible reasons for this pattern of charge/discharge during the late evening and early morning hours from a bill savings perspective. However, this behavior does increase the utilization of the system. The charging behavior provides evidence of morning charging during early PV generation hours, as observed with residential systems.

FIGURE 4-15: AVERAGE HOURLY DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	1%	1%	2%	2%	2%	2%	2%	2%	2%	1%	2%	2%
1	2%	1%	2%	2%	2%	2%	3%	3%	3%	2%	1%	1%
2	2%	2%	2%	2%	2%	3%	3%	3%	2%	2%	1%	1%
3	1%	1%	2%	2%	2%	3%	3%	2%	2%	1%	1%	1%
4	1%	1%	2%	2%	2%	3%	3%	2%	2%	1%	1%	1%
5	1%	1%	2%	3%	3%	3%	3%	3%	2%	2%	1%	1%
6	2%	2%	3%	2%	2%	2%	2%	3%	2%	2%	1%	2%
7	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	3%
8	2%	2%	1%	1%	2%	1%	1%	1%	1%	1%	2%	2%
9	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%
10	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
11	1%	1%	1%	1%	2%	1%	2%	2%	2%	2%	1%	1%
12	1%	1%	1%	1%	2%	1%	2%	2%	2%	2%	1%	1%
13	1%	1%	1%	1%	2%	1%	2%	2%	2%	2%	1%	1%
14	1%	1%	1%	2%	2%	1%	2%	2%	2%	2%	2%	1%
15	1%	1%	2%	2%	2%	3%	3%	3%	3%	3%	2%	1%
16	2%	2%	2%	3%	2%	3%	3%	3%	4%	4%	4%	2%
17	3%	3%	3%	4%	3%	3%	3%	3%	3%	4%	4%	3%
18	3%	4%	5%	5%	5%	5%	5%	5%	4%	4%	5%	4%
19	4%	4%	5%	6%	6%	6%	6%	6%	4%	5%	5%	4%
20	4%	4%	5%	6%	5%	5%	5%	4%	4%	3%	4%	6%
21	4%	5%	4%	3%	3%	4%	3%	3%	3%	2%	3%	3%
22	2%	2%	3%	3%	3%	4%	4%	4%	4%	3%	2%	2%
23	2%	3%	2%	2%	2%	2%	2%	2%	2%	2%	3%	2%

FIGURE 4-16: AVERAGE HOURLY CHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-4%	-4%	-3%	-3%	-3%	-4%	-3%	-3%	-3%	-3%	-4%	-3%
1	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-2%	-3%	-3%
2	-3%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-2%
3	-3%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-2%
4	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-3%	-3%	-2%	-2%	-2%
5	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
6	-1%	-1%	-2%	-3%	-3%	-2%	-3%	-3%	-2%	-2%	-1%	-1%
7	-1%	-2%	-4%	-4%	-4%	-3%	-4%	-4%	-4%	-4%	-2%	-1%
8	-3%	-4%	-5%	-6%	-5%	-5%	-7%	-6%	-5%	-5%	-5%	-5%
9	-4%	-5%	-6%	-6%	-6%	-6%	-7%	-6%	-5%	-6%	-6%	-6%
10	-4%	-5%	-5%	-5%	-5%	-6%	-5%	-5%	-4%	-5%	-6%	-6%
11	-4%	-4%	-4%	-3%	-4%	-4%	-3%	-3%	-3%	-3%	-4%	-5%
12	-3%	-3%	-2%	-2%	-3%	-3%	-2%	-2%	-2%	-2%	-3%	-3%
13	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-2%
14	-1%	-1%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
15	-1%	-1%	-2%	-2%	-2%	-1%	-2%	-2%	-1%	-1%	-1%	-1%
16	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
17	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
18	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
19	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%
20	-1%	-1%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-1%	-1%
21	-3%	-3%	-4%	-4%	-4%	-4%	-3%	-4%	-3%	-4%	-3%	-3%
22	-3%	-3%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-3%	-5%	-4%
23	-4%	-4%	-5%	-5%	-4%	-5%	-4%	-3%	-3%	-3%	-3%	-3%

We then examined the impact of storage discharge on demand or power (kW). Hourly impacts provide insight into the performance of the system during TOU periods, but if the storage is optimized to reduce monthly demand charges, then examining peak demand over the course of the month provides additional insight into how storage is being utilized.

We analyzed the utilization of the system to execute customer peak demand benefits. We examined the monthly peak demand reductions relative to the rebated capacity of the system and the overall reduction in demand. The former analysis involved taking the difference of the highest 15-minute power (kW) reading in the absence of storage and the actual highest reading during each customer bill period. That measure was then normalized by the kW capacity of the system. A customer would presumably realize demand bill savings as the difference between the observed and counterfactual case.

Figure 4-17 conveys the results of that analysis. Throughout the year, nonresidential systems are reducing monthly demand as a percentage of rebated capacity more than residential systems. The average customer peak demand reduction is 18 percent of SGIP rebated capacity for nonresidential systems and 4 percent for residential systems. It’s important to note, residential systems are not subject to demand charges and exhibit longer low energy duration discharges than nonresidential systems.

FIGURE 4-17: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

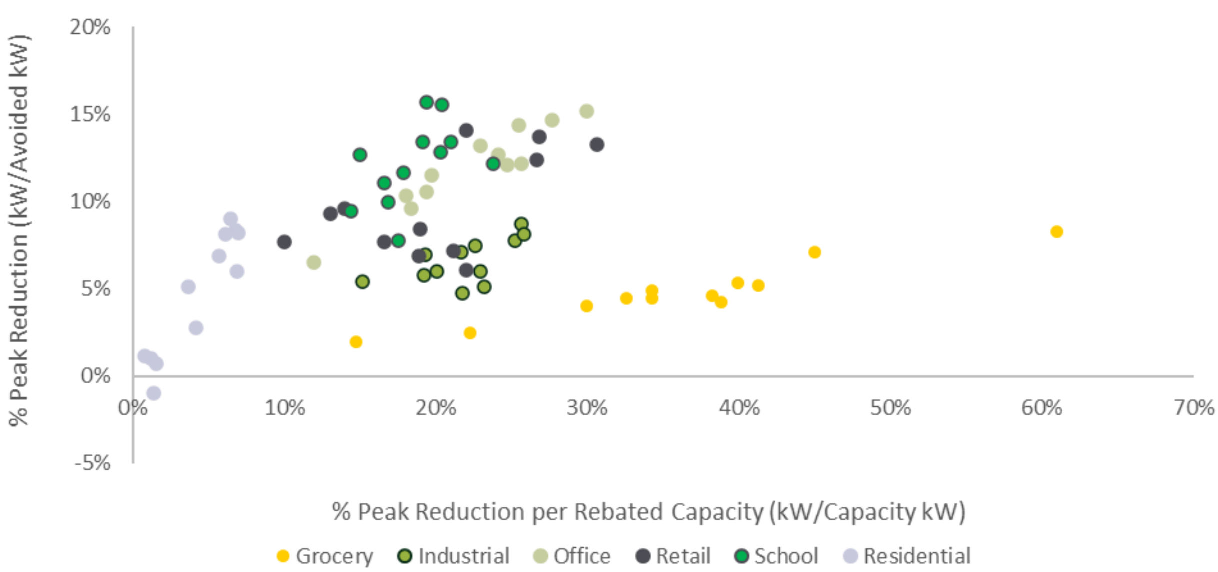
Figure 4-18 conveys the monthly average peak demand reduction as a percentage of the monthly avoided peak. In other words, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system – this value is calculated and not metered – and they reduced peak demand by 10 kW with storage, then the customer reduced their peak demand by 10 percent. On average, nonresidential customers are reducing their peak demand by 10 percent and residential customers are reducing their peak demand by 5 percent.

FIGURE 4-18: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

Figure 4-19 disaggregates the data provided in the above figures for each month and customer sector. The horizontal axis represents the monthly peak demand reduction, as a percentage of rebated capacity, for each system-month and the vertical axis represents the monthly peak demand reduction for each system relative to their avoided peak demand for that month.

While the average peak demand reduction is 18 percent of SGIP rebated capacity for nonresidential systems, the distribution by month ranges from as high as 60 percent for grocery stores in May of 2019 to as low as a 10 percent decrease for retail establishments in February of 2019.[35] Larger nonresidential systems are utilizing a small percentage of their storage capacity to reduce monthly peaks. However, given the size of the systems relative to the load they service, the average monthly peak demand reductions – as a function of peak facility load – are akin to residential systems. There is some inter-month variability, especially in facility types like grocery, retail and offices.

FIGURE 4-19: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY CUSTOMER TYPE



35 As of PY 2017, rebated capacity is defined as the average discharge power rating over a two-hour period. Throughout this report, we reference projects by their SGIP rebated capacity with an understanding that inverter sizes can be up to 2x greater than the SGIP rebated capacity value.

Figure 4-20 and Figure 4-21 present the rebated capacity for each system (residential and nonresidential, respectively) relative to the size of customer (vertical axis) and the maximum annual discharge 15-minute power relative to rebated capacity. Based on our methodology, if a storage system is sized at 50 kW (rebated capacity) and the maximum 15-minute load at that facility would have been 100 kW throughout the year in the absence of storage (the baseline assumption), the system size relative to load would be 50 percent. Similarly, if a system is rated at 10 kW and the maximum annual discharge power was 10 kW then the ratio is 100 percent. Each observation on the scatter plot represents an individual system and the nonresidential sector is further disaggregated by facility type.

Clustering near 1.0 on the horizontal axis, suggests that many systems – both residential and nonresidential – discharged their max power at least once throughout 2019. Observations above 1.0 suggest that some inverters are sized greater than the rebated capacity of the system. Observations below 1.0 suggest the system never fully discharged throughout one 15-minute interval throughout the year. This should be expected of residential systems, as these customers are not subject to demand charges and are more inclined to discharge a lesser percentage of energy over a longer period of time to realize energy bill savings or maintain zero net load at the home.

FIGURE 4-20: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR RESIDENTIAL SYSTEMS

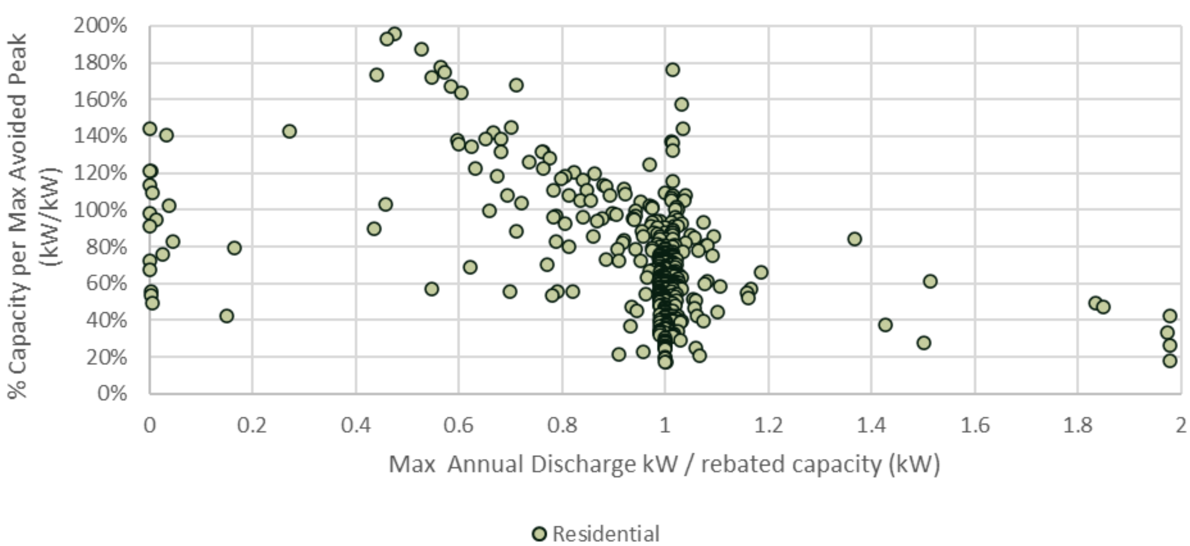
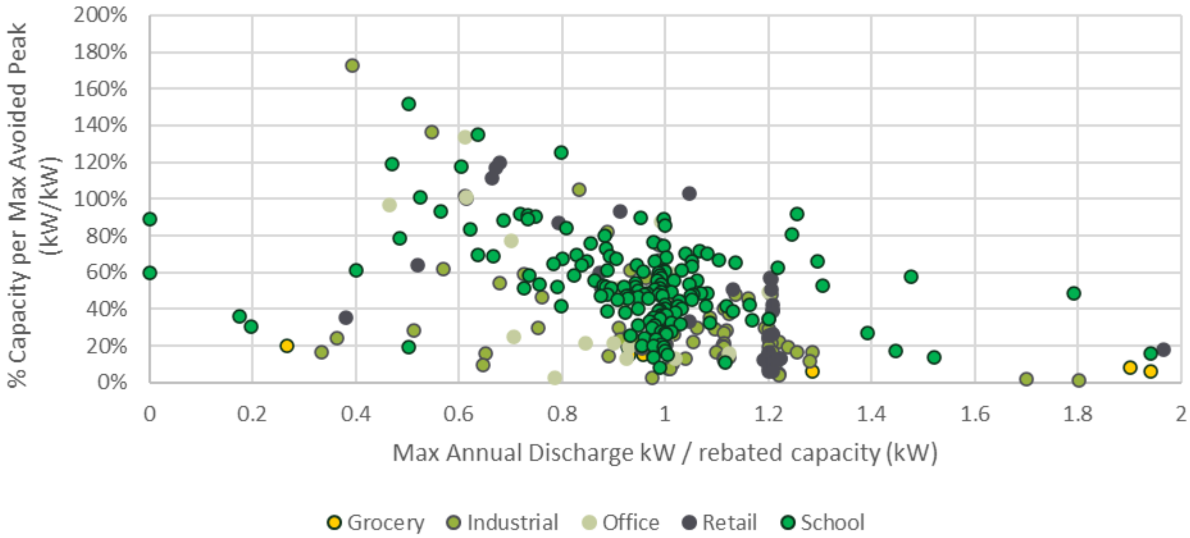


FIGURE 4-21: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR NONRESIDENTIAL SYSTEMS



4.2.2 Storage Dispatch Behavior with On-site Generation and EV Charging

The previous section provided evidence that residential storage systems are conducting some TOU arbitrage, while the discharge patterns outside IOU rate defined on-peak periods also suggests this is not the only motivation and use case for residential customers. Nonresidential system charge and discharge behavior suggests they are conducting non-coincident and coincident peak demand reduction at the expense of TOU arbitrage. However, each of these analyses focused almost exclusively on discharge.

Figure 4-15 and Figure 4-16 provided evidence that many storage systems are charging exclusively during early to late morning hours. This pattern of charging, which closely aligns with early PV generation hours, provides clear evidence that systems are performing PV self-consumption or, at least, charging coincident to PV generation. Figure 4-22 and Figure 4-23 summarize the total number of residential and nonresidential systems which are:

- Co-located or directly paired with solar PV
- Co-located or directly paired with solar PV and consumption patterns provide evidence of electric vehicle (EV) charging
- Not co-located or paired with solar PV, but consumption patterns provide evidence of EV charging
- No evidence of PV or EV charging

For residential systems, 98% of systems are paired or co-located with on-site PV. Further, 28 percent have PV and show evidence of EV charging. The split for nonresidential is more even, with 43 percent of systems paired with PV and 56 percent as standalone systems. The four EV only nonresidential systems are installed at dedicated EV charging stations.

FIGURE 4-22: DISTRIBUTION OF RESIDENTIAL SYSTEMS WITH AND WITHOUT ON-SITE PV AND EV CHARGING

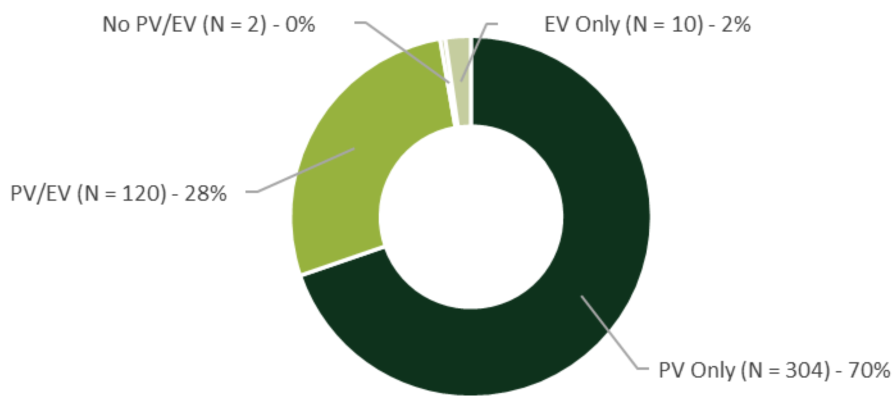
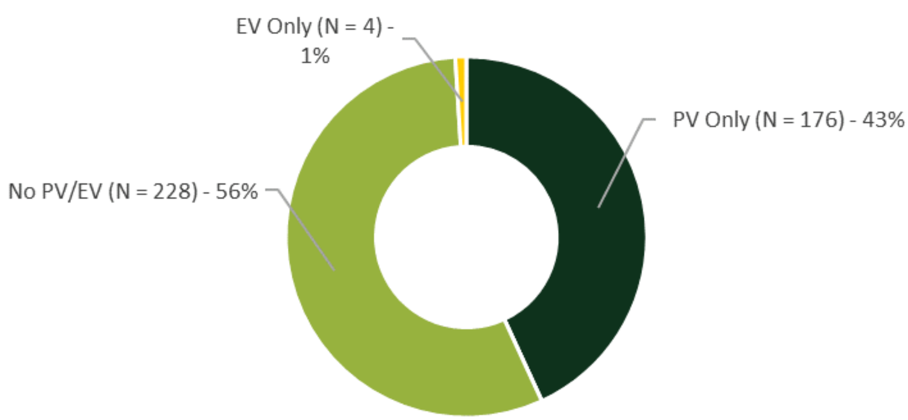


FIGURE 4-23: DISTRIBUTION OF NONRESIDENTIAL SYSTEMS WITH AND WITHOUT ON-SITE PV AND EV CHARGING



The federal solar tax credit, also known as the investment tax credit (ITC) provides financial incentives to install solar and solar plus storage. For residential customers, the ITC is available to customers installing storage if the storage system is only charged by on-site generation like solar. For nonresidential customers, the ITC is available if the storage system is charging from on-site generation more than 75 percent of the time. We reviewed the 15-minute kWh storage charge data for each system in the SGIP sample and compared that to 15-minute kWh PV generation data, where available. As noted above in Figure 4-22, 424 residential systems were operating alongside an on-site PV generator in 2019. However, our team did not receive PV generation data for all projects. We relied on reviewing the net load for customers to provide evidence of PV generation where actual PV generation data was missing. The same was done for nonresidential systems.

Figure 4-24 presents the percentage of energy charged from (or during) PV generation compared to the energy charged outside of PV generating hours. The number of systems used in this analysis is less than the total number of systems in our sample paired or co-located with PV. This analysis relied on data where we had PV generation data to compare against. Overall, residential systems in 2019 charged exclusively from/during PV generation (99.8%) and a similar pattern is evident for nonresidential systems (95.0%).

FIGURE 4-24: PERCENT CHARGE KWH DURING PV GENERATION BY CUSTOMER SECTOR

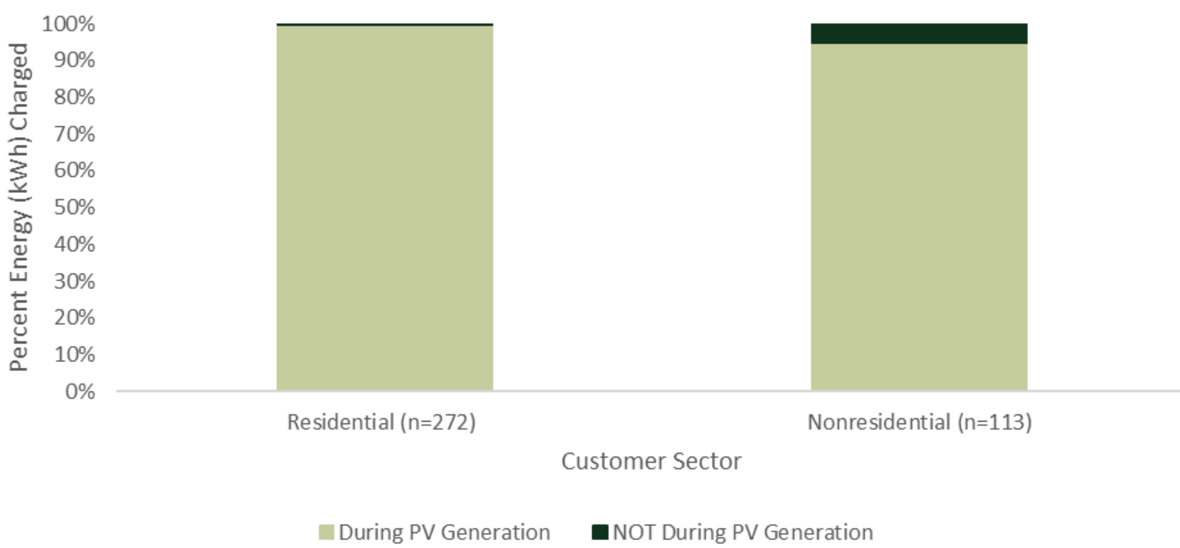


Figure 4-25 to Figure 4-28 present the average hourly net discharge kWh as a percentage of available system capacity kWh for each hour within the day and month throughout the year. Net discharge kWh for nonresidential and residential systems are provided, along with whether the systems were paired or co-located with on-site PV. Nonresidential systems without PV represent a variety of facility types, but the average net discharge is positive for a couple of early afternoon hours in the summer, and these systems are net charging more substantially after 7 pm PST and throughout early morning hours. Most nonresidential systems paired with PV are installed in primary and secondary schools. Systems are discharging during the early morning ramp, then charging from an on-site PV generator in the morning and discharging throughout the peak TOU periods, especially from 6 pm to 8 pm PST during the summer months. A similar pattern is evident with residential systems. Those systems without PV are discharging

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across a long duration of hours throughout the day and charging overnight. Systems paired with PV are charging during early PV generation hours and discharging beginning at the onset of the on-peak period.

FIGURE 4-25: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS (NO PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-3%	-4%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-3%
1	-2%	-3%	-1%	-1%	-2%	-2%	-1%	0%	0%	-1%	-3%	-3%
2	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%
3	-2%	-2%	-2%	-1%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-2%
4	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%
5	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
6	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	1%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-2%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-2%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
11	0%	0%	0%	0%	0%	1%	1%	1%	0%	1%	0%	0%
12	0%	0%	0%	0%	1%	0%	1%	1%	0%	1%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
14	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	1%	1%	2%	3%	3%	2%	2%	3%	0%	0%
16	1%	1%	1%	0%	1%	2%	1%	1%	1%	2%	3%	2%
17	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%
18	1%	1%	2%	1%	1%	0%	0%	0%	0%	1%	3%	2%
19	1%	1%	2%	1%	1%	1%	0%	0%	0%	2%	3%	2%
20	2%	2%	1%	0%	-1%	-2%	-2%	-2%	-2%	-3%	2%	4%
21	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-2%	-5%	-4%	-2%
22	-2%	-2%	-4%	-4%	-4%	-2%	-3%	-3%	-2%	-3%	-5%	-5%
23	-4%	-3%	-4%	-4%	-4%	-4%	-3%	-2%	-2%	-2%	-3%	-2%

FIGURE 4-26: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS (WITH PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-1%	-1%	-1%	-1%	0%	-1%	0%	0%	0%	0%	-1%	0%
1	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	-1%	0%
2	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	1%	1%	2%	0%	0%	0%	0%	0%
4	0%	0%	0%	1%	2%	2%	3%	1%	0%	0%	0%	0%
5	1%	0%	2%	3%	3%	3%	4%	3%	2%	2%	0%	1%
6	2%	2%	2%	0%	0%	1%	0%	0%	0%	1%	1%	2%
7	2%	0%	-4%	-6%	-4%	-3%	-6%	-5%	-4%	-4%	-2%	1%
8	-3%	-5%	-9%	-10%	-8%	-8%	-12%	-10%	-7%	-8%	-6%	-4%
9	-8%	-10%	-12%	-12%	-10%	-12%	-14%	-11%	-9%	-10%	-9%	-9%
10	-9%	-11%	-11%	-9%	-8%	-11%	-10%	-9%	-8%	-8%	-9%	-10%
11	-8%	-8%	-7%	-5%	-6%	-7%	-5%	-4%	-4%	-5%	-7%	-8%
12	-5%	-4%	-3%	-3%	-3%	-4%	-3%	-1%	-2%	-1%	-4%	-6%
13	-3%	-2%	-2%	-2%	-2%	-2%	-1%	0%	0%	0%	-1%	-2%
14	-1%	-1%	-1%	-1%	-3%	-2%	-1%	0%	0%	0%	0%	-1%
15	0%	-1%	0%	0%	-2%	-1%	-1%	-1%	0%	0%	1%	0%
16	1%	1%	1%	2%	0%	1%	1%	2%	3%	3%	2%	1%
17	4%	3%	4%	4%	3%	2%	2%	2%	3%	4%	4%	4%
18	4%	5%	7%	8%	7%	7%	7%	6%	5%	5%	5%	5%
19	4%	5%	7%	8%	8%	9%	9%	7%	5%	5%	5%	5%
20	4%	5%	5%	5%	5%	6%	6%	4%	3%	4%	4%	4%
21	4%	5%	1%	0%	1%	3%	2%	1%	1%	1%	3%	3%
22	0%	0%	2%	3%	3%	3%	2%	2%	2%	3%	1%	0%
23	1%	2%	-1%	-1%	-1%	-1%	0%	-1%	-2%	-1%	2%	2%

FIGURE 4-27: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS (NO PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-16%	-17%	-12%	-10%	-11%	-10%	-9%	-11%	-10%	-8%	-15%	-15%
1	-9%	-11%	-7%	-6%	-7%	-8%	-7%	-8%	-8%	-5%	-12%	-12%
2	-3%	-6%	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-3%	-7%	-8%
3	0%	-2%	-1%	0%	0%	0%	0%	0%	0%	0%	-3%	-4%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	2%	2%	2%	2%	2%	2%	1%	1%	0%	0%
7	2%	3%	3%	2%	2%	2%	2%	2%	2%	1%	1%	1%
8	3%	2%	2%	2%	2%	1%	2%	2%	2%	1%	1%	2%
9	3%	2%	2%	2%	1%	1%	2%	2%	2%	1%	1%	1%
10	3%	2%	2%	2%	2%	1%	2%	2%	2%	1%	1%	1%
11	3%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%
12	3%	2%	3%	3%	3%	3%	3%	2%	2%	1%	1%	1%
13	3%	3%	4%	4%	4%	5%	5%	6%	4%	2%	2%	1%
14	3%	4%	4%	3%	4%	5%	5%	6%	3%	1%	2%	2%
15	3%	4%	4%	4%	5%	7%	8%	8%	6%	3%	2%	2%
16	3%	4%	4%	5%	6%	7%	8%	8%	7%	4%	5%	6%
17	4%	5%	5%	5%	6%	7%	7%	5%	6%	5%	6%	6%
18	5%	6%	6%	6%	6%	6%	4%	4%	5%	4%	7%	7%
19	4%	6%	5%	6%	5%	4%	3%	2%	3%	3%	6%	6%
20	4%	5%	5%	4%	4%	3%	3%	3%	2%	2%	4%	4%
21	5%	4%	2%	0%	-2%	-3%	-3%	-2%	-1%	0%	3%	3%
22	0%	0%	-14%	-16%	-17%	-18%	-18%	-16%	-14%	-11%	0%	0%
23	-23%	-19%	-20%	-18%	-19%	-19%	-20%	-19%	-16%	-13%	-11%	-10%

FIGURE 4-28: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS (WITH PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
1	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%
2	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
5	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-3%	-3%	-2%	-2%	-1%	0%	0%
7	-1%	-2%	-4%	-5%	-5%	-8%	-9%	-8%	-7%	-5%	-1%	-1%
8	-4%	-6%	-8%	-9%	-8%	-12%	-14%	-15%	-12%	-10%	-5%	-4%
9	-7%	-9%	-10%	-10%	-8%	-12%	-13%	-15%	-14%	-11%	-7%	-6%
10	-8%	-9%	-9%	-7%	-7%	-9%	-8%	-10%	-10%	-7%	-8%	-7%
11	-7%	-7%	-6%	-5%	-5%	-6%	-5%	-6%	-6%	-5%	-6%	-6%
12	-5%	-4%	-4%	-3%	-3%	-3%	-2%	-3%	-3%	-2%	-4%	-4%
13	-3%	-2%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-2%	-2%
14	7%	8%	1%	0%	0%	1%	1%	2%	2%	0%	0%	0%
15	1%	2%	8%	10%	10%	20%	20%	22%	22%	14%	2%	2%
16	3%	2%	5%	3%	3%	5%	6%	6%	5%	4%	10%	10%
17	4%	4%	3%	3%	3%	3%	4%	4%	4%	3%	4%	4%
18	4%	4%	4%	4%	3%	3%	4%	4%	4%	3%	3%	3%
19	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	3%	2%
20	2%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	1%
21	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%
22	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%
23	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%	0%

4.2.3 Overall Storage Dispatch Behavior by Customer Rate Group

This section expands upon the analysis conducted in the prior section by introducing customer bill rate schedules. The evaluation team utilized the customer rate schedules to analyze how storage dispatch behavior is associated with different rates. There were almost 30 unique customer rates from the SGIP sample of nonresidential systems and all customers in the sample with a verified rate schedule were on some type of TOU schedule with demand charges:

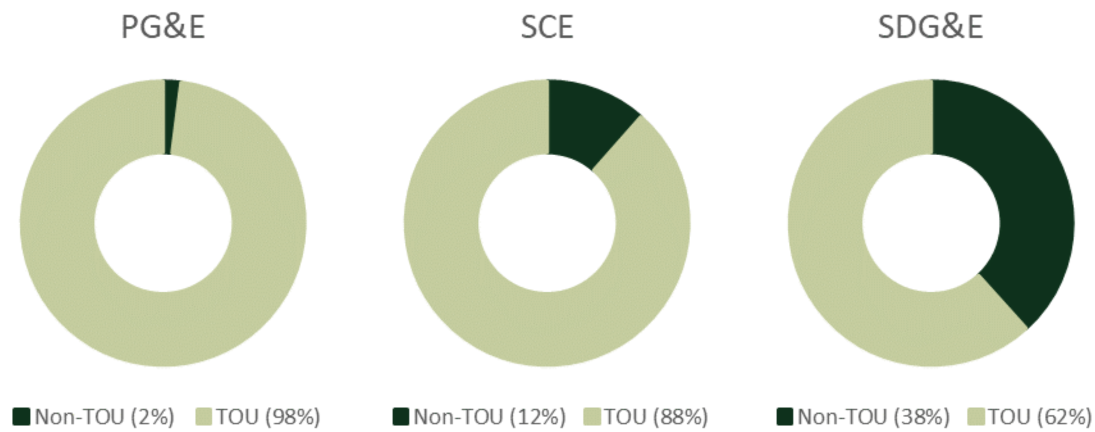
- TOU Energy with Demand Charge
  - This rate group includes customers on a TOU energy rate ($/kWh) as well as a monthly demand charge ($/kW). The monthly demand charge represents the highest rate of power (kW) during any 15-minute interval through each month in the year. This rate group may also contain customers with an additional demand charge incurred during a specific period (on-peak, off-peak and super off-peak) and season (winter or summer).

There were almost 25 unique customer rates from the sample of residential systems across IOUs. Residential customers with a verified rate schedule were on some type of volumetric or TOU energy rate in 2019:

- Tiered volumetric rate
  - This rate group includes customers on an energy only tariff. They are charged a certain energy rate ($/kWh) throughout a specific tier and rates increase when the customer exceeds the allowance within a tier and move into the next tier. Energy rates are not time-dependent like a TOU rate.
- TOU Energy Only Rate
  - This rate group includes customers on an energy only tariff. They were charged a different energy rate ($/kWh) depending on the period (on-peak, off-peak and super off-peak) and season (winter or summer). Some rates also have a tiered component along with the TOU charge. The on-peak periods vary by IOU and when the customer began on the rate. They include, among others:
    - 2pm to 7pm (PST) for customers on a TOU-A rate
    - 3pm to 8pm (PST) for customers on a TOU-B rate or TOU-D-4-9
    - 1pm to 8pm (PST) for customers on a traditional EV rate
    - 12pm to 6pm (PST) for customers on an E-6

Figure 4-29 presents the proportion of TOU rates versus non-TOU volumetric rates for each of the IOUs. It's important to note, these distributions represent all of the rates we analyzed throughout 2019 by month. A customer may have been on a volumetric rate early in 2019 and transitioned over to a TOU rate at some point throughout the year.

FIGURE 4-29: DISTRIBUTION OF TOU VS NON-TOU RATES FOR RESIDENTIAL CUSTOMERS (BY IOU)



Overall Customer Bill Savings ($/kWh) by Rate Group and Customer Sector

We combined the energy rates charged during each of the TOU periods and compared the observed energy consumption with storage to energy consumption without storage to develop bill impact estimates for customers. 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 specific customer rate schedule. The expectation is that customers on a TOU energy only rate are discharging during periods when energy rates are high and charging during periods of lower prices which would translate into bill savings. For customers with demand charges, the expectation is that they are optimizing either monthly facility demand charge reduction or peak period demand charge reduction, perhaps, at the expense of TOU energy arbitrage. Figure 4-30 presents the results for nonresidential customers by month. The vertical axis represents the average monthly savings (or increased cost) in dollars, normalized by the capacity kWh of the storage system.

Nonresidential customers incurred energy costs, on average, by utilizing their storage systems throughout 2019. However, they realized significant savings by utilizing their storage to reduce peak and/or monthly demand. This is especially true throughout summer months when both energy and demand charges are greatest.

FIGURE 4-30: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH

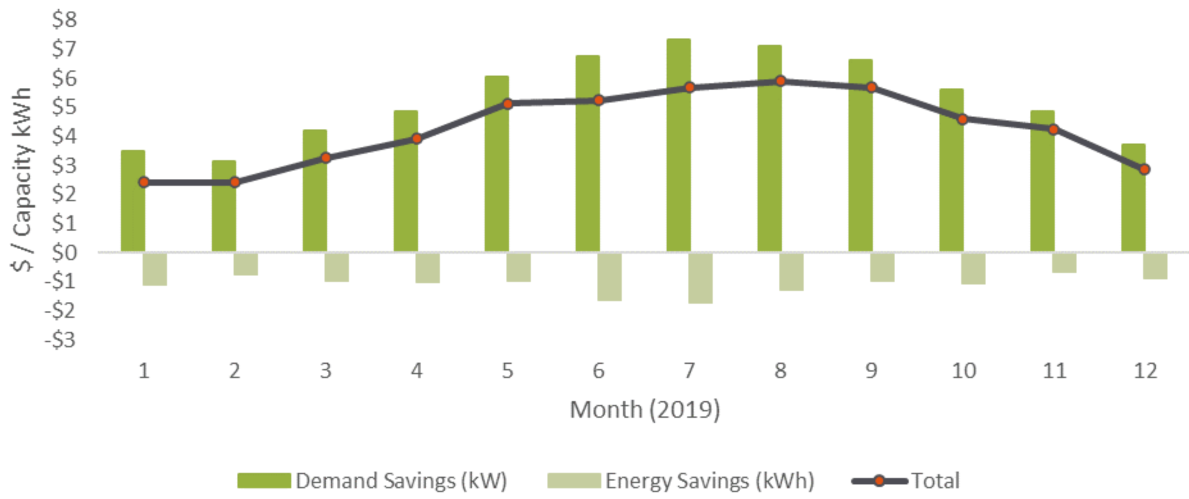
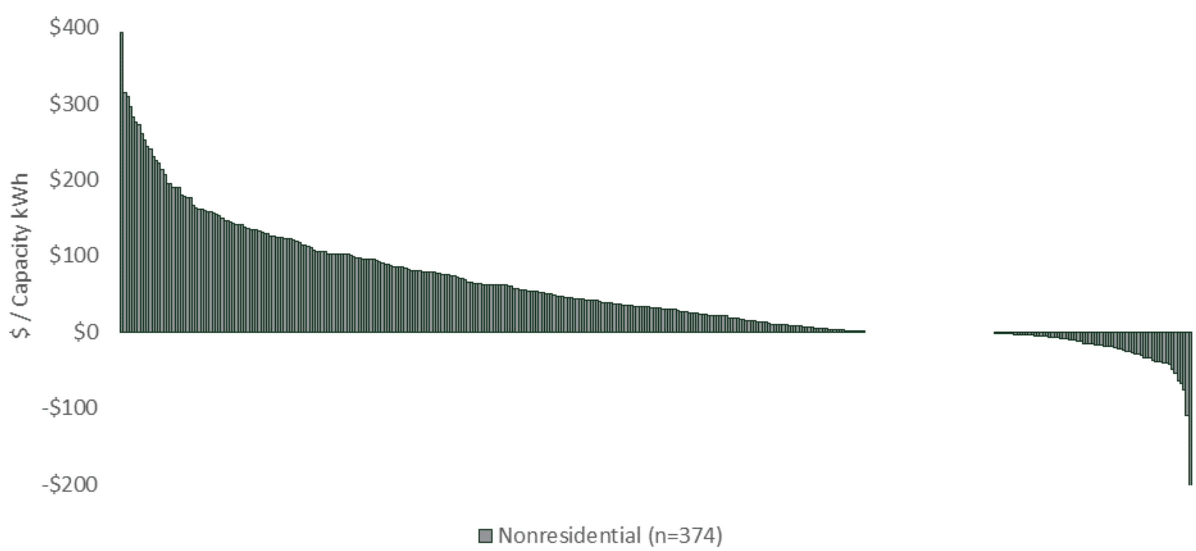


Figure 4-31 presents the distribution of total bill savings for each nonresidential storage participant, sorted by greatest savings to least savings (or an overall bill increase). Nonresidential customers, on average, realized bill savings exceeding $50 per system capacity kWh. Forty percent of nonresidential customers realized bill savings greater than or equal to the $50/kWh.

FIGURE 4-31: DISTRIBUTION OF NONRESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KWH)



Residential customers are not subject to demand charges, so charges accrue from customer energy consumption. Figure 4-32 presents the average monthly bill savings (or increased cost) for residential customers. As previously mentioned, residential customers are utilizing their storage systems much more during summer months, which coincides with periods of higher price per kWh. Residential customers incurred bill increases, on average, throughout winter months, but the bill savings during summer months were more substantial.

FIGURE 4-32: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH

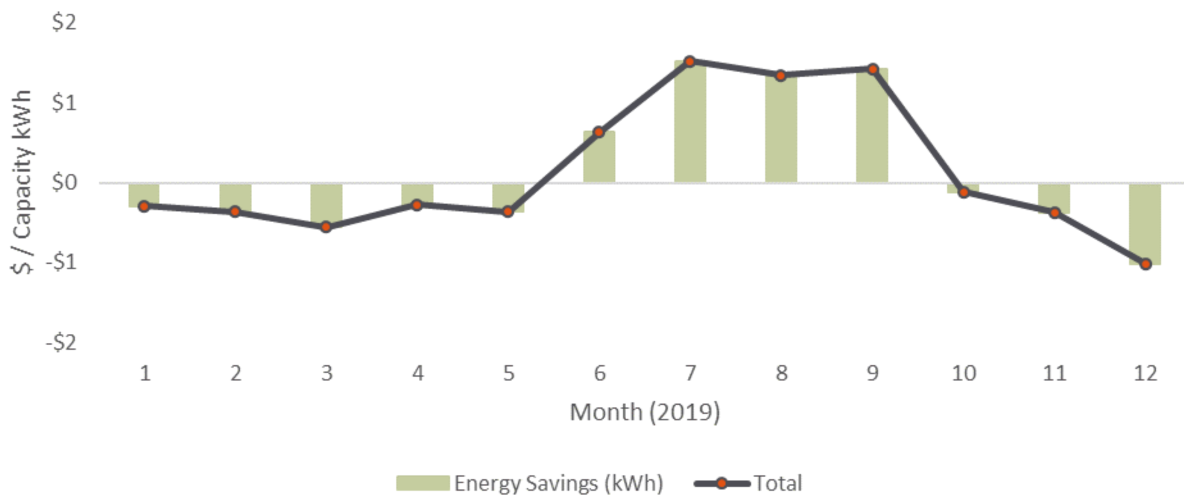
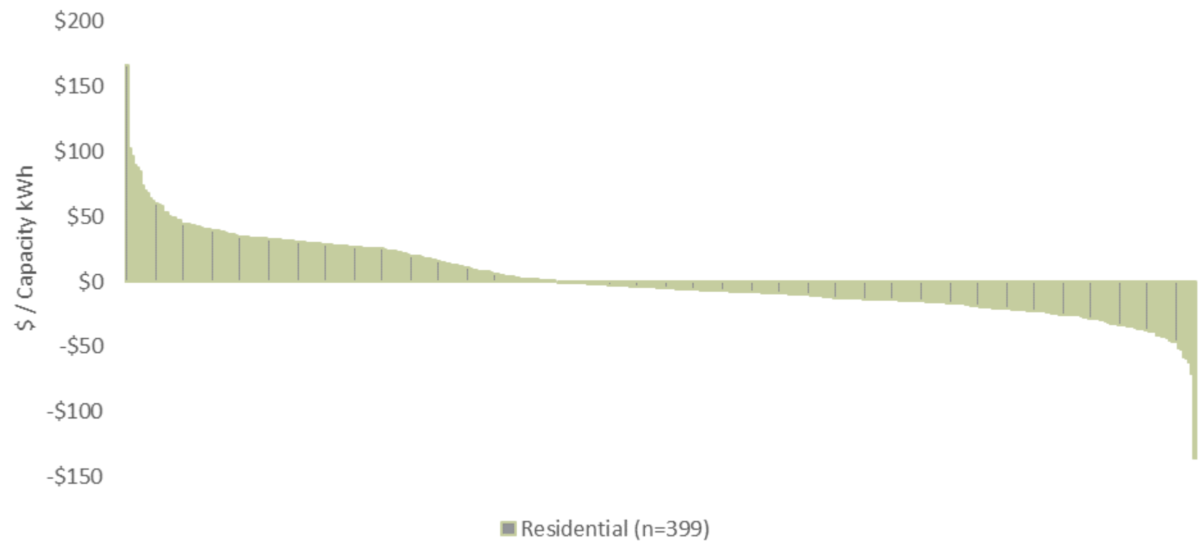


Figure 4-33 presents the distribution of total bill savings for residential customers, sorted by greatest savings to least savings (or an overall bill increase). Across the year, residential customers realized bill savings of roughly $1.60 per system capacity kWh. However, the range of bill savings and bill increases is substantial. Bill savings range from as high as $166 per rebated capacity kWh to as low as -$136 per rebated capacity kWh (a bill increase). All 57 customers on a non-TOU rate incurred bill increases in 2019.

FIGURE 4-33: DISTRIBUTION OF RESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KWH)



4.3 CAISO AND IOU SYSTEM IMPACTS

The timing and magnitude of storage dispatch throughout the year can also have an impact on the electricity grid. As detailed above, SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand and, to a much lesser extent, TOU energy arbitrage. They incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. Residential storage systems are being utilized for TOU arbitrage and to maintain zero net load throughout the day. 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. Both residential and nonresidential systems with on-site PV generators are charging exclusively during early PV generating hours and discharging later in the day.

The timing of charge and discharge not only directly impacts customer bills, but it can also have an impact on the CAISO or IOU systems. 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 include 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 with 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 throughout the top 200 gross and net peak demand hours in 2019 for the CAISO system[36] as well as the top gross peak hours for the three IOUs.

4.3.1 CAISO System Impacts

The evaluation team examined how SGIP storage systems were operating throughout 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 2019. 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 can be disruptive from a planning perspective.

The correct timing of energy storage discharge and charge can ease that transition and alleviate that disruption. Figure 4-34 and Figure 4-35 provide two example CAISO load days. Figure 4-34 represents a typical spring day where there is evidence of an early morning ramp, followed by a drop in net load throughout the day and an early evening ramp. Renewable generation (especially solar) hours align well with increases in demand, as demand for such energy-intensive on-site technologies like air conditioning are minimal.

[36] The top 200 CAISO gross peak hours all fall within summer months (June through September). The CAISO peaked in 2019 on August 15th during the 4 pm PST hour.

FIGURE 4-34: CAISO NET AND GROSS LOAD ON A TYPICAL EARLY SPRING DAY

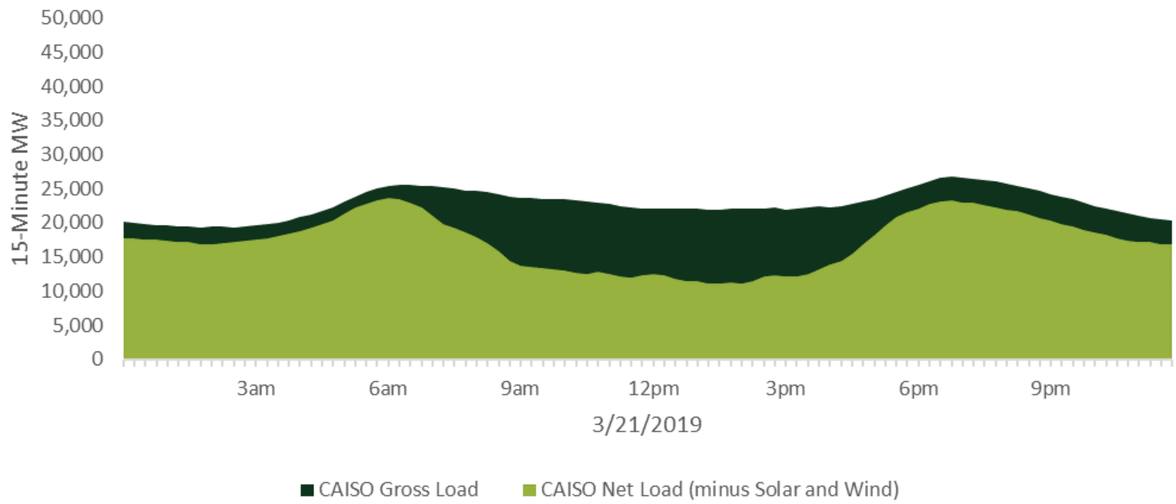
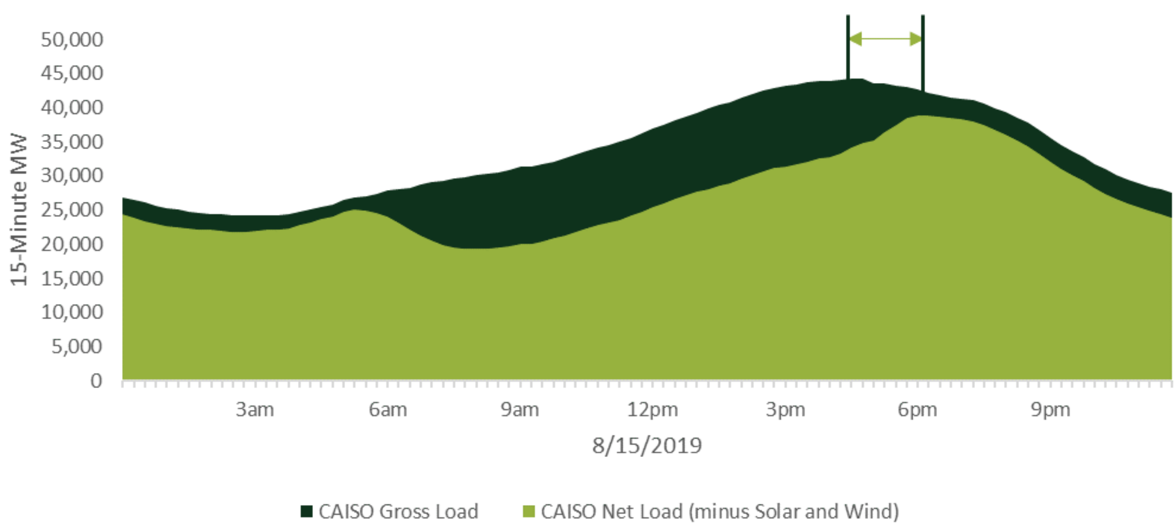


Figure 4-35 presents the CAISO net and gross load on August 15, 2019. During the 4 pm PST hour, CAISO gross load peaked. Longer days and more sunshine allow for more PV generation during daytime hours. However, as solar generation wanes in the early evening, demand is still building. As a result, the net peak occurs almost an hour and half after the gross peak. The net peak on this day was the 5th highest in 2019. The CAISO experienced the net peak a day prior on August 14th during the same hour (6 pm PST). When examining other days within the summer, a similar pattern is revealed. The net peak can occur 1 to 3 hours after the gross peak.

FIGURE 4-35: CAISO NET AND GROSS LOAD ON 8/15/2019 (TOP GROSS HOUR OCCURRED DURING 4 PM PST)



In the past, our evaluation team has only provided SGIP storage impacts during the top gross peak CAISO hours. Given the nuance in how these systems operate, at even an hourly level, we introduced an analysis of storage performance during net peak hours as well.

Figure 4-36 and Figure 4-37 below present the average kWh discharge per kWh capacity for nonresidential systems along with the gross and net peak MW for each of the top 200 CAISO hours, respectively. Both figures show nonresidential systems actively discharging, on average, throughout most gross and net peak hours. These peak hours generally occur in the summertime, however, the timing of when they occur helps explain why the magnitude of net discharge is different. The magnitude of net discharge throughout net peak hours is greater than the magnitude during gross peak hours. Net peak hours, on average, occur around 6 pm PST, while gross peak hours, on average, occur around 4 pm PST. Nonresidential storage systems, on average, are discharging a greater percentage of energy during the 6 – 8 pm PST hours, which aligns more with the net peak hours.

FIGURE 4-36: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP GROSS 200 HOURS FOR NONRESIDENTIAL

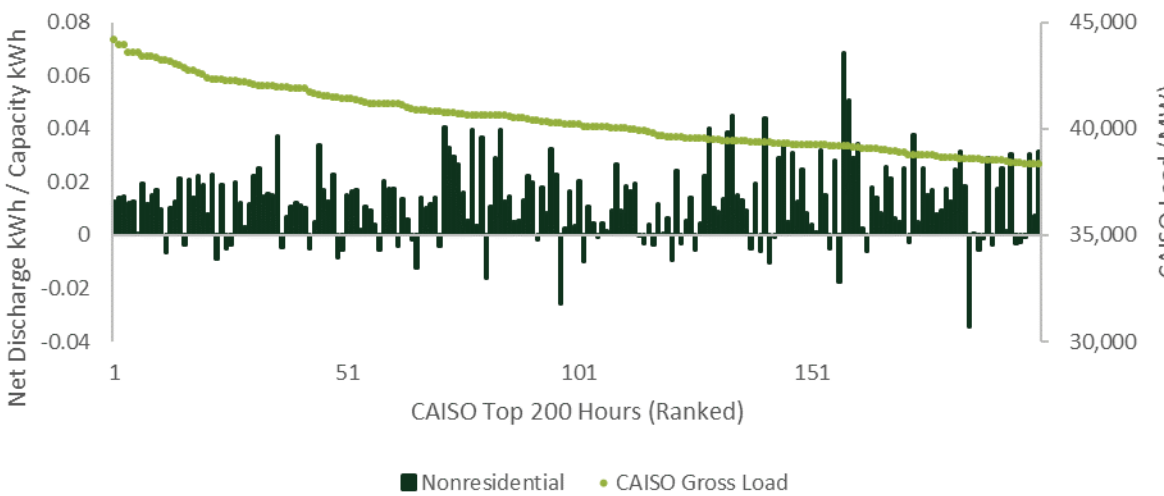


FIGURE 4-37: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP NET 200 HOURS FOR NONRESIDENTIAL

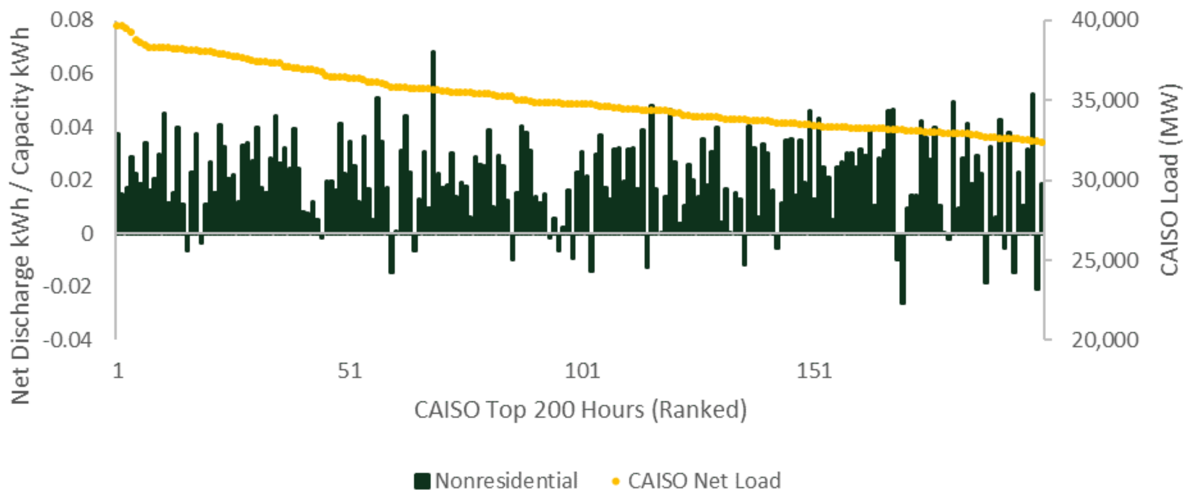


Figure 4-38 and Figure 4-39 below present the average kWh discharge per kWh capacity for residential systems along with the gross and net peak MW for each of the top 200 CAISO hours, respectively. Both figures show residential systems actively discharging throughout all but a few gross and net peak hours. While we observed a greater magnitude of net discharge for nonresidential systems as the CAISO transitioned from gross peak to net peak, we observed the opposite with residential systems. For many of the top gross peak hours, residential systems, on average, are discharging greater than 20% of available capacity throughout those hours. There are far fewer observances like this during net peak hours.

FIGURE 4-38: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP GROSS 200 HOURS FOR RESIDENTIAL

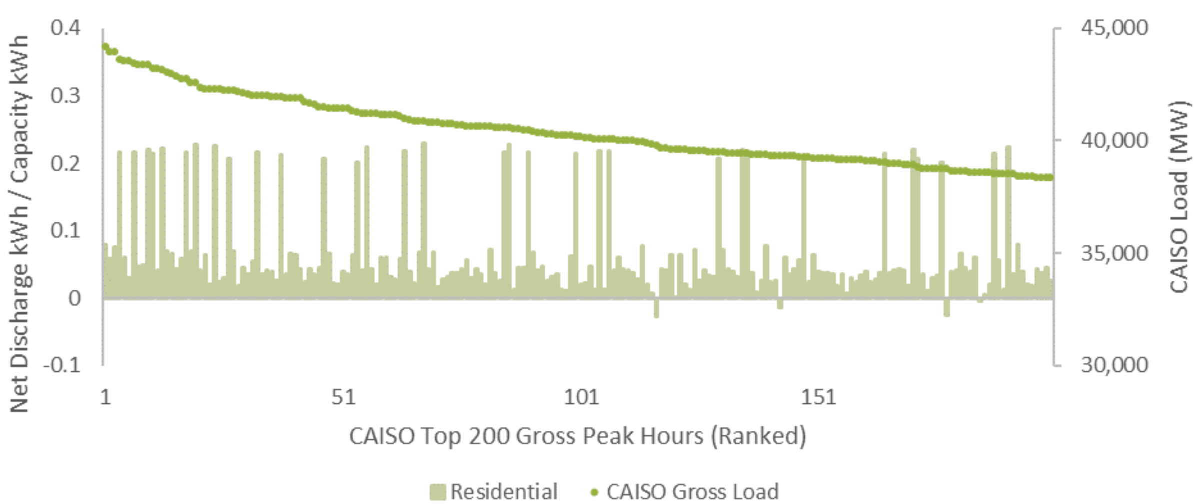
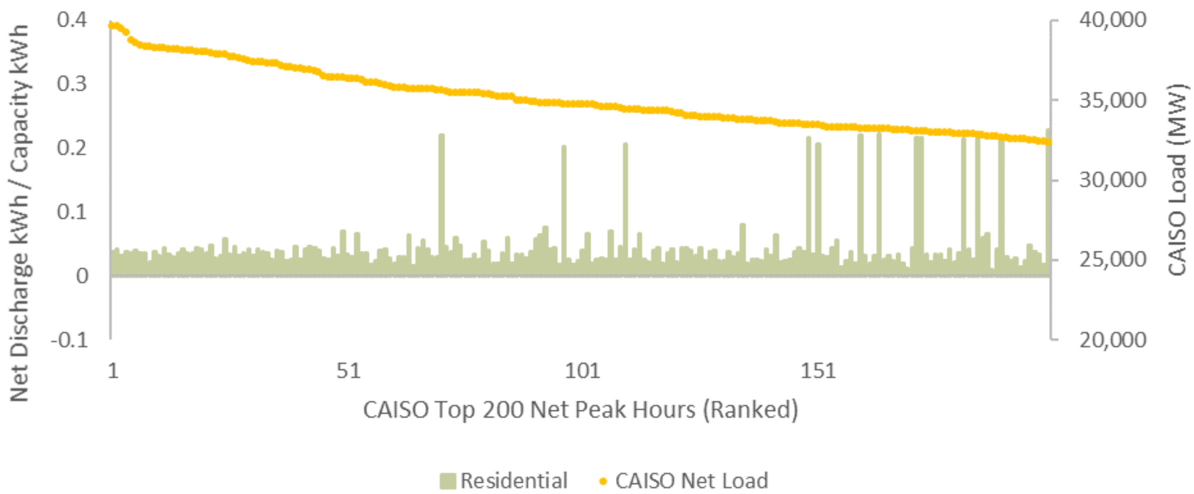


FIGURE 4-39: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP NET 200 HOURS FOR RESIDENTIAL



The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the underlying load shapes and use cases of customers. We examine this variability by providing a snapshot of how storage was being dispatched for nonresidential and residential customers during two of the more capacity constrained days in 2019 – August 14th and August 15th. These data are presented below in Figure 4-40 and Figure 4-41. In both figures, the CAISO gross and net loads are provided along with the average hourly net discharge of storage for the nonresidential and residential sector, respectively. The belly of the "duck curve" is clear throughout the morning and early afternoon as renewables (namely solar) are generating. The gross peak occurs around 4 pm PST, followed two hours later by the net peak around 6 pm PST, when grid-scale renewables begin to wane in generation. Storage net discharge (ordinarily in dark green) is highlighted in light green during the gross peak and orange during the net peak. Nonresidential systems, on average, are discharging a greater percentage of capacity during the net peak hour than the gross peak hour on both days. Residential systems are performing in a different manner. Furthermore, average net discharge for nonresidential systems is greatest throughout both days an hour after the net peak. Residential systems discharge the greatest percentage of energy during the hour prior to the gross peak on both days.

FIGURE 4-40: NONRESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAYS

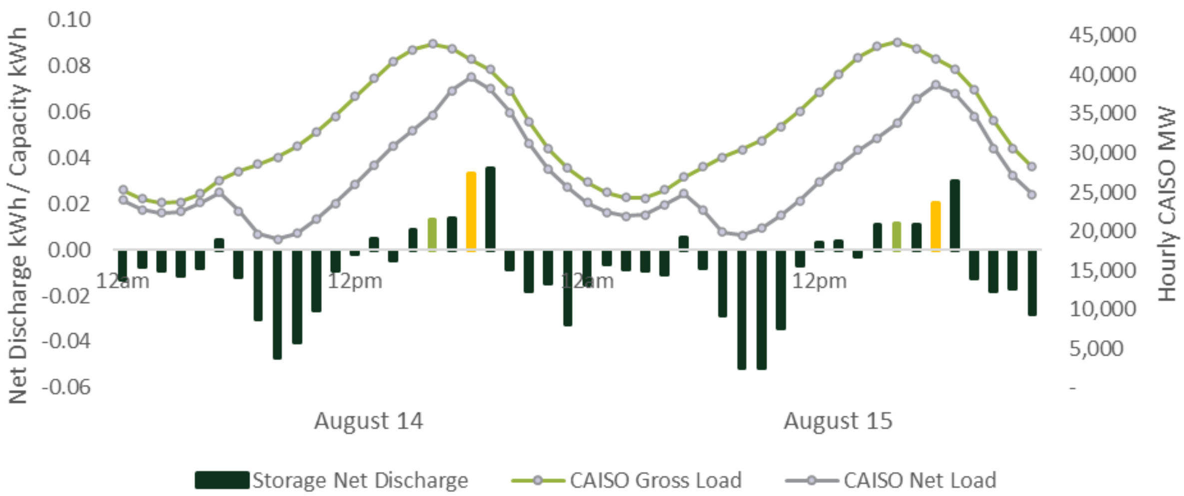
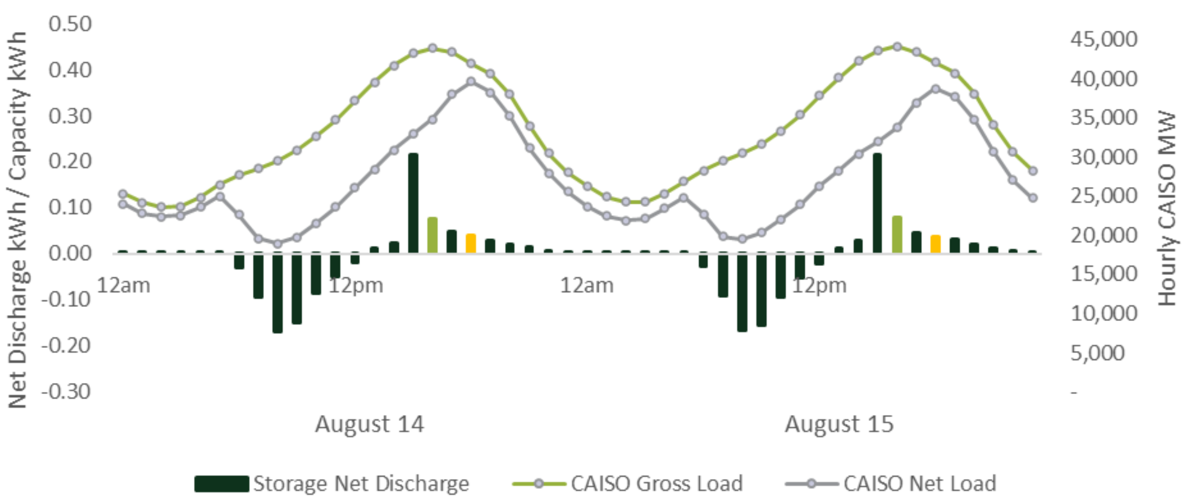


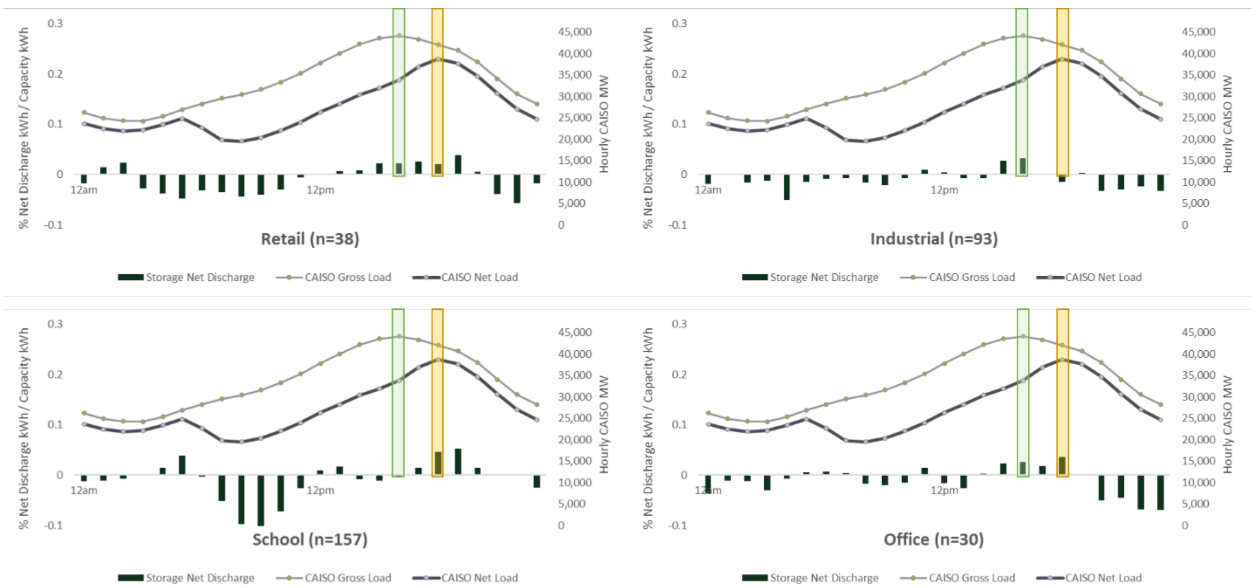
FIGURE 4-41: RESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAYS



The overall pattern of charge and discharge during top CAISO hours – and throughout the summer, in general – follows a similar pattern to what has been found in previous evaluations. However, the magnitude of impacts during top hours continues to change 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 program year to the next.

The magnitude and pattern of net discharge for different building types is presented below in Figure 4-42 for August 15th, 2019. The CAISO gross peak occurred during the 4pm PST hour on that day (highlighted in green in the figure) and the net peak occurred during the 6 pm PST hour (highlighted in orange). Again, discharging is positive, and charging is negative. The timing of discharge throughout the late afternoon and early evening for the facility types detailed below are different, along with their underlying load shapes and the impacts throughout those two hours.

FIGURE 4-42: NONRESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAY BY FACILITY TYPE



4.3.2 IOU System Impacts

We also examined the net discharge behavior of storage systems during the peak load hours for the three IOUs. The results for nonresidential systems and residential systems are presented in Figure 4-43 and Figure 4-44, respectively. The results are much like those for the CAISO peak hours. The magnitude of net discharge as a percentage of overall storage capacity kWh during top hours is greater for residential systems than nonresidential systems. However, both nonresidential and residential systems provided relief to the CAISO and utility systems across all top hour system peak bins. The magnitude of net discharge from nonresidential systems varies by IOU, while the impacts across IOU are similar for residential systems.

FIGURE 4-43: NET DISCHARGE KWH PER CAPACITY KWH DURING SYSTEM PEAK HOURS FOR NONRESIDENTIAL

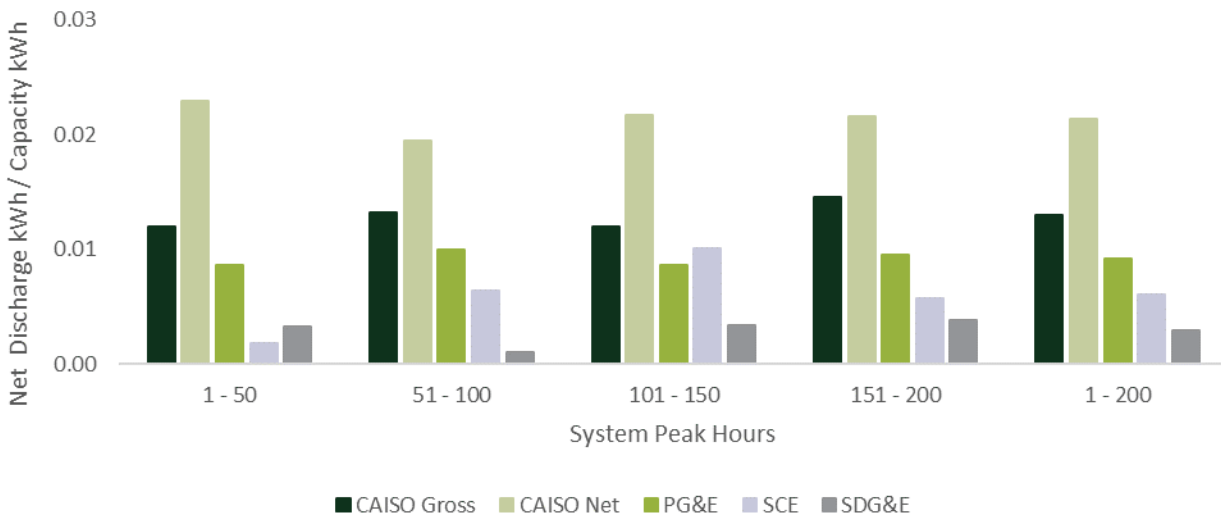
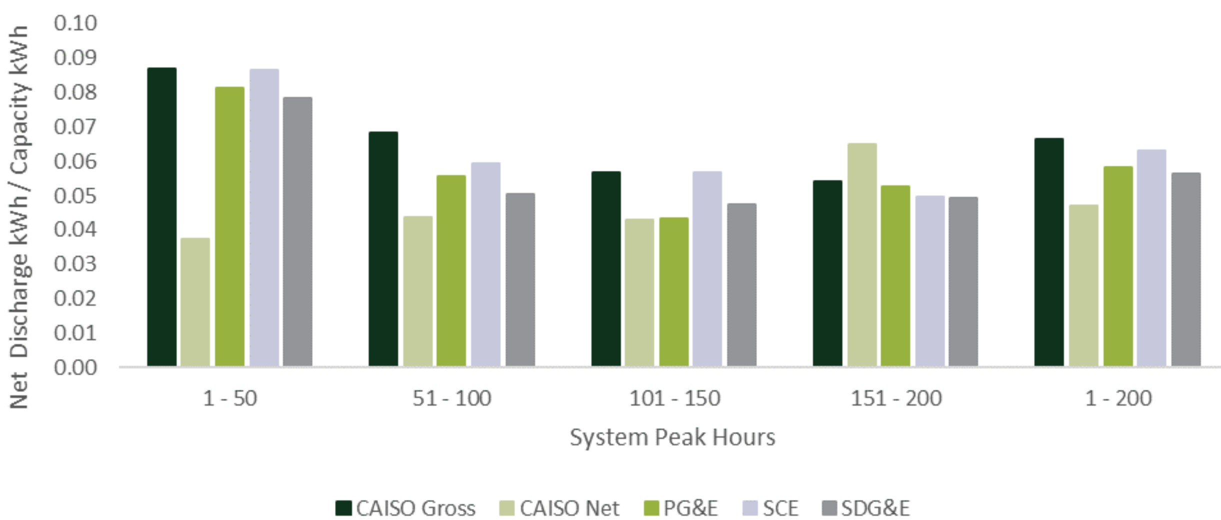


FIGURE 4-44: NET DISCHARGE KWH PER CAPACITY KWH DURING SYSTEM PEAK HOURS FOR RESIDENTIAL



4.4 ENVIRONMENTAL IMPACTS

This section summarizes the environment impacts associated with energy storage systems. We examine how the behavior of the systems led to an overall increase or decrease in greenhouse gas (GHG) emissions throughout 2019. The GHG considered in this analysis is CO_2, as this is the primary contributor to GHG emissions that is potentially affected by the operation of SGIP storage systems.[37]

Fifteen-minute 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 conditions. Baseline emissions are those that would have occurred in the absence of the storage system. Facility 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 facility loads and electrical supply in response to storage charging and discharging.

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. In other words, over the course of a year, these technologies will increase the energy consumption of a customer's home or facility relative to the baseline condition without the storage system.

The 15-minute energy impact of each system is equal to the charge or discharge that occurred during that interval. The energy impact during each 15-minute interval is then multiplied by the marginal emission rate for that interval (kilograms CO_2 / kWh) to arrive at a 15-minute emission impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the 15-minute emissions.

For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. Since energy storage technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate must be lower during charging hours relative to discharge hours. In other words, SGIP storage systems must charge during "cleaner" grid hours and discharge during "dirtier" grid hours to achieve GHG reductions. It is important to note that energy storage developers and customers are generally not aware of when marginal emissions rates are greater or less. The supply of energy, the sourcing of that energy, and marginal emissions associated with generation are generally not within their purview. Going forward, SGIP PAs have available a day-ahead marginal emissions signal that will provide storage systems and project developers with information on forecasted hourly emissions rates.[38]

Figure 4-45 and Figure 4-46 present the reduction (-) or increase (+) in GHG emissions for each system analyzed as part of the 2019 evaluation for residential and nonresidential, respectively. Both figures are sorted from greatest emissions reductions to greatest emissions incurred. Of the 436 residential systems,

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[37] 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/.

[38] These data can also be found at https://sgipsignal.com/

363 (83 percent) reduced emissions in 2019, and 216 (50 percent) reduced emissions by at least 5 kilograms per kWh capacity. Seventy-three (17 percent) residential systems increased emissions. Of the 408 nonresidential systems, 127 (31 percent) reduced emissions, and 97 (24 percent) reduced emissions by at least 5 kilograms per kWh capacity.[39] Two hundred and thirty-four (57 percent) nonresidential systems increased emissions.

FIGURE 4-45: NET CO2 EMISSIONS FOR RESIDENTIAL SYSTEMS (KILOGRAMS / KWH)

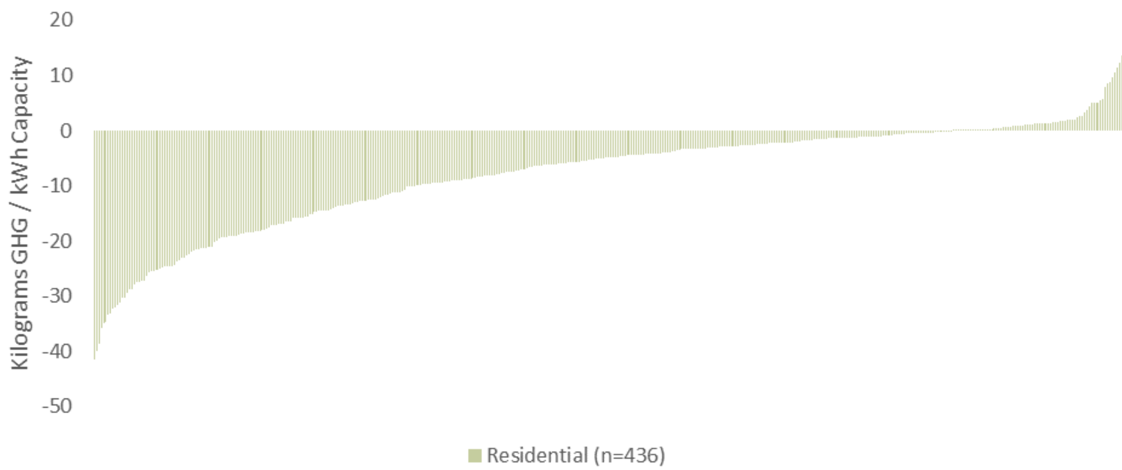
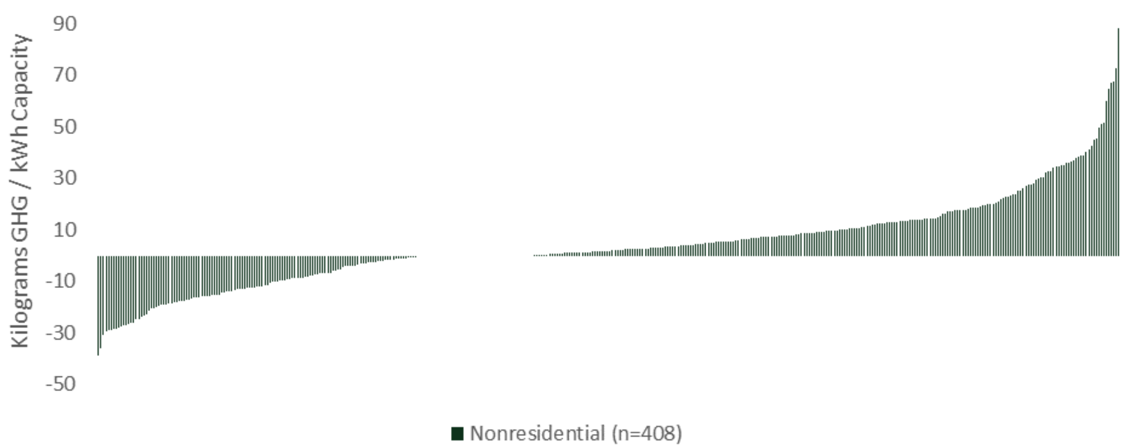


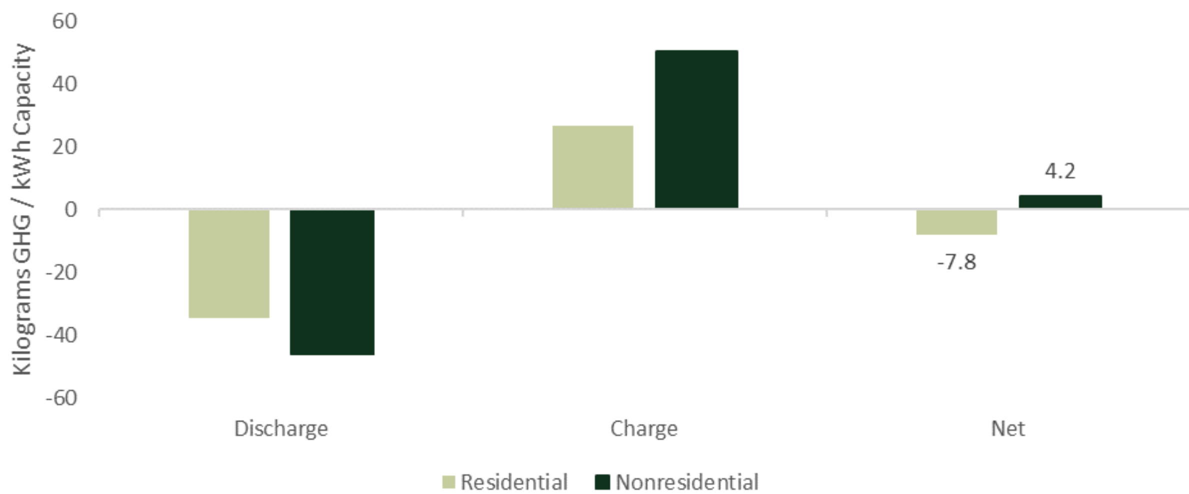
FIGURE 4-46: NET CO2 EMISSIONS FOR NONRESIDENTIAL SYSTEMS (KILOGRAMS / KWH)



39 Decision 19-08-001 requires new commercial projects to reduce GHG emissions by 5 kilograms per kilowatt hour (kg/kWh).

Figure 4-47 presents the overall GHG impacts for the sampled energy storage systems in 2019 by customer sector. The total kilograms of GHG avoided during discharge are presented with the total GHG emissions incurred during charge, along with the total net emissions. The sample of residential systems, on average, are reducing GHG emissions by roughly 7.8 kg CO_2/kWh, while nonresidential systems are contributing to an increase in emissions of roughly 4.2 kg CO_2/kWh over the course of 2019.

FIGURE 4-47: NET KILOGRAMS CO2 EMISSIONS PER CAPICITY KWH BY CUSTOMER SECTOR



As discussed in Section 4.4, the capacity of 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 natural gas generators, marginal emissions tend to increase. We observed the pattern of storage charge and discharge with systems paired with on-site solar generation often aligns well with marginal emissions periods. Storage systems with PV are charging during early morning solar generating hours and discharging later in the day as solar generation reduces and customer load ramps.

We captured these nuances in timing of charge and discharge as they relate to marginal emissions by examining the overall net emissions for systems paired with on-site solar generation and systems which are standalone. For residential systems, we also examined the magnitude of emissions for systems where evidence of electric vehicle charging was observed at the home.

Figure 4-48 and Figure 4-49 present those findings. For the residential sector, of the 424 systems paired with solar PV, 361 (85%) reduced emissions in 2019. This pattern is evident with nonresidential systems paired or co-located with solar PV as well. We also find a positive relationship between utilization (measured in annual cycles) and reductions in GHG. Systems that discharge more frequently and at a greater magnitude tend to lower emissions at a greater magnitude as well. Conversely, systems without on-site solar generation are not necessarily charging during early PV generating hours, when marginal emissions are lowest.

FIGURE 4-48: KILOGRAMS GHG / KWH INCREASE (+) DECREASE (-) FOR RESIDENTIAL SYSTEMS

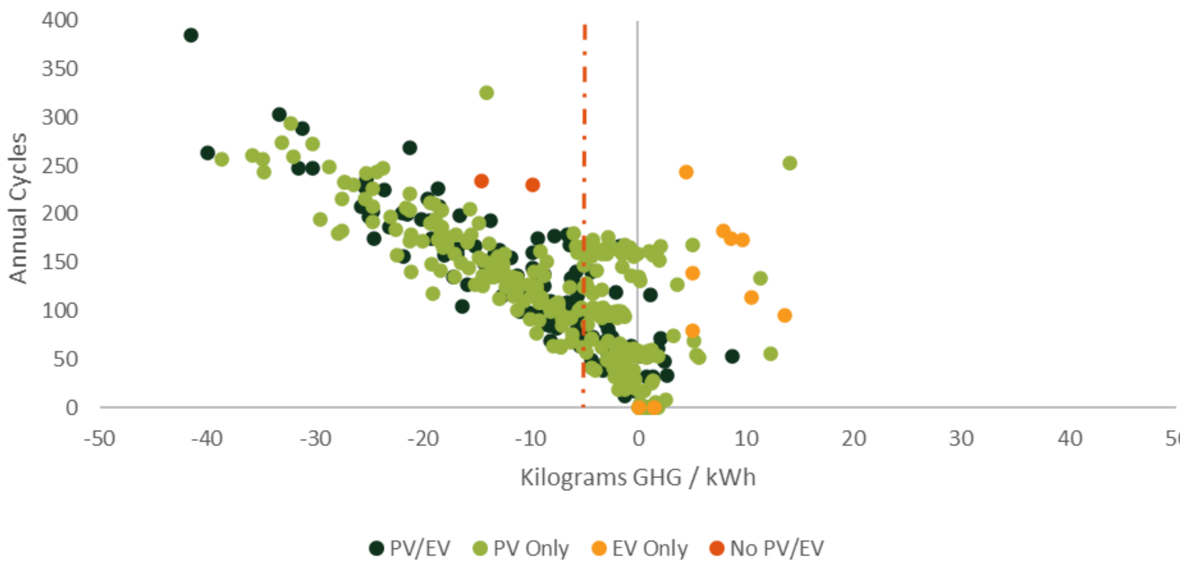
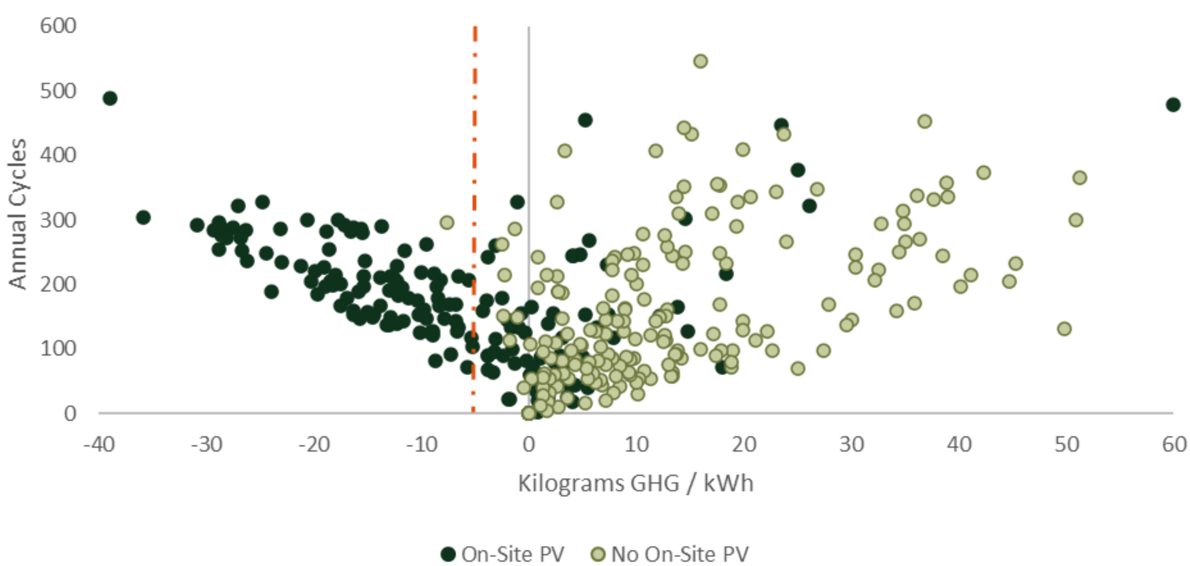
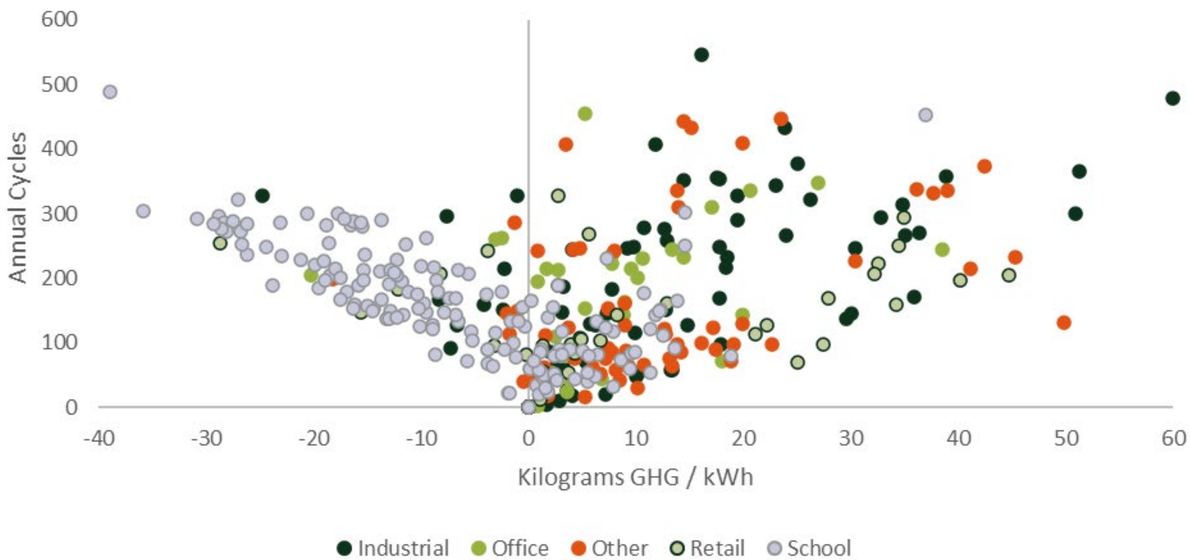


FIGURE 4-49: KILOGRAMS GHG / KWH INCREASE (+) DECREASE (-) FOR NONRESIDENTIAL SYSTEMS



We further disaggregated the nonresidential systems by facility type to better understand how underlying load shapes can have an impact on emissions. Most nonresidential facilities, excluding primary and secondary schools, contribute to an increase in marginal emissions. Schools are a unique case in that they generally have different operations based on their seasonal schedule. Many schools are not in session during peak summer months, so the systems are capable to arbitrage more during on-peak periods. Furthermore, almost all schools in the SGIP are paired directly with solar PV. While other facilities without solar PV may be discharging throughout on-peak periods, we observe they are often charging after on-peak periods when marginal emissions, while lower than on-peak periods, are higher than early morning PV generating hours (Figure 4-42).

FIGURE 4-50: KILOGRAMS GHG / KWH INCREASE (+) DECREASE (-) FOR NONRESIDENTIAL SYSTEMS (BY FACILITY)



From a GHG perspective, the value of charging during 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 emission 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.

Figure 4-51 and Figure 4-52 display the average daily net discharge for residential systems – for the summer and winter periods[40] – along with the average marginal CO_2 emissions shape, average net load and PV generation. In the summer, marginal emissions are highest during early morning and, most

40 Summer in this context is defined as June, July, August and September. All other months represent Winter.

significantly, throughout a few early evening hours as renewable generation ebbs and demand increases. As previously discussed, residential systems are charging in the morning from on-site PV generation and this time aligns well with lower marginal emissions. The peak magnitude of discharge occurs late in the afternoon, but still during PV generating hours. It's important to note, residential TOU on-peak periods generally run from 4 pm to 9 pm. If storage systems waited to discharge until 6 or 7 pm, when marginal emissions are greatest, they could achieve even greater GHG reductions while maintaining the bill savings benefits. In winter, storage systems are utilized less often and at a lower magnitude.

FIGURE 4-51: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR WINTER

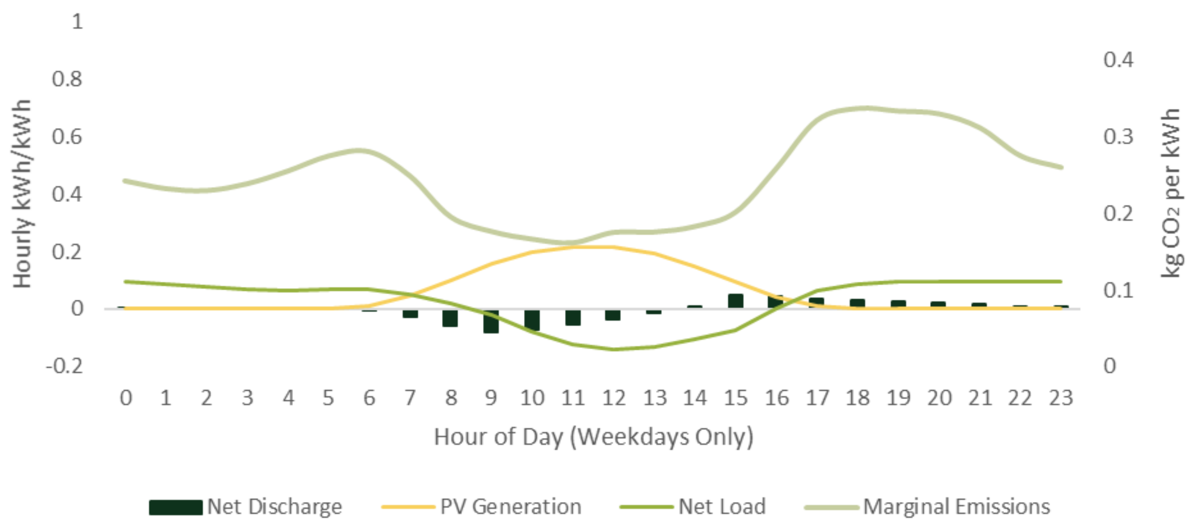


FIGURE 4-52: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR SUMMER

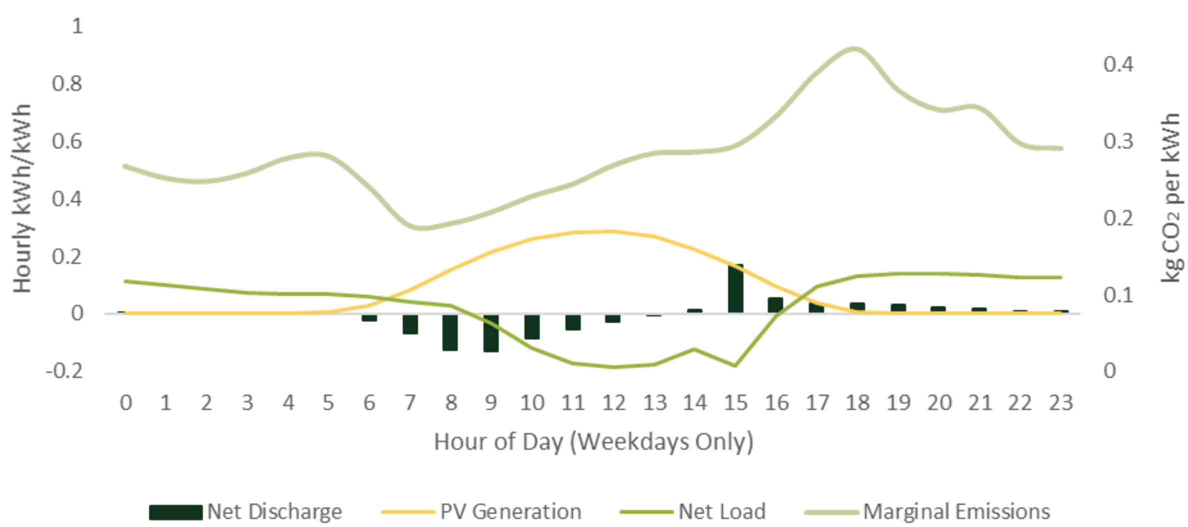


Figure 4-53 and Figure 4-54 display the average daily net discharge for nonresidential systems – for the summer and winter periods – along with the average marginal CO_2 emissions shape and PV generation. Nonresidential systems, on average, are discharging throughout higher marginal emissions periods, but we observe charging after the on-peak period and overnight. These periods also represent high marginal emissions periods, so the GHG benefit accrued during on-peak is eroded by the net charging over the remainder of the day. Residential systems (and nonresidential systems paired with PV) are only charging in the morning hours which are coincident to PV generation ramping and lower GHG marginal emissions.

FIGURE 4-53: NONRESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR WINTER

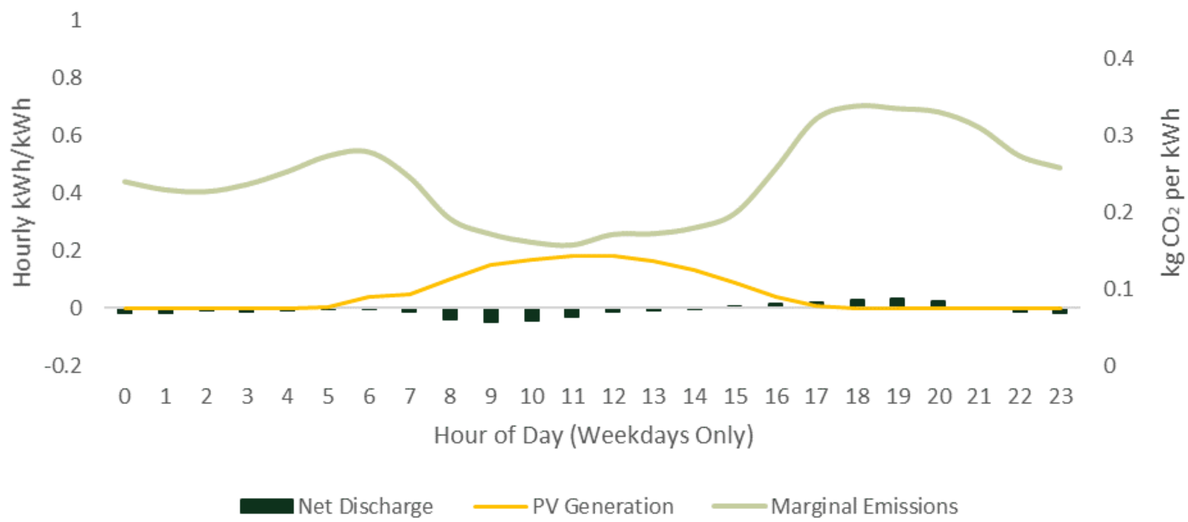
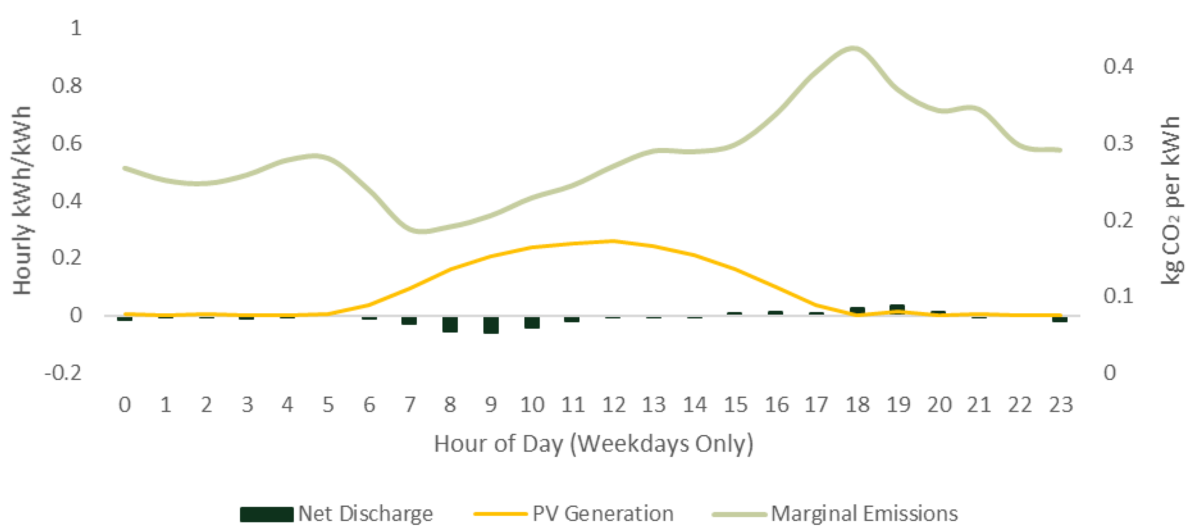


FIGURE 4-54: NONRESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR SUMMER



4.5 UTILITY MARGINAL COST IMPACTS

Utility marginal cost impacts were calculated for each IOU and each hourly time increment in 2019. This analysis was conducted using 2019 avoided costs from the CPUC-adopted 2019 avoided cost calculator. Storage system charging results in an increased load and therefore will generally increase cost to the utility. Discharging generally results in a benefit, or avoided cost, to the utility.

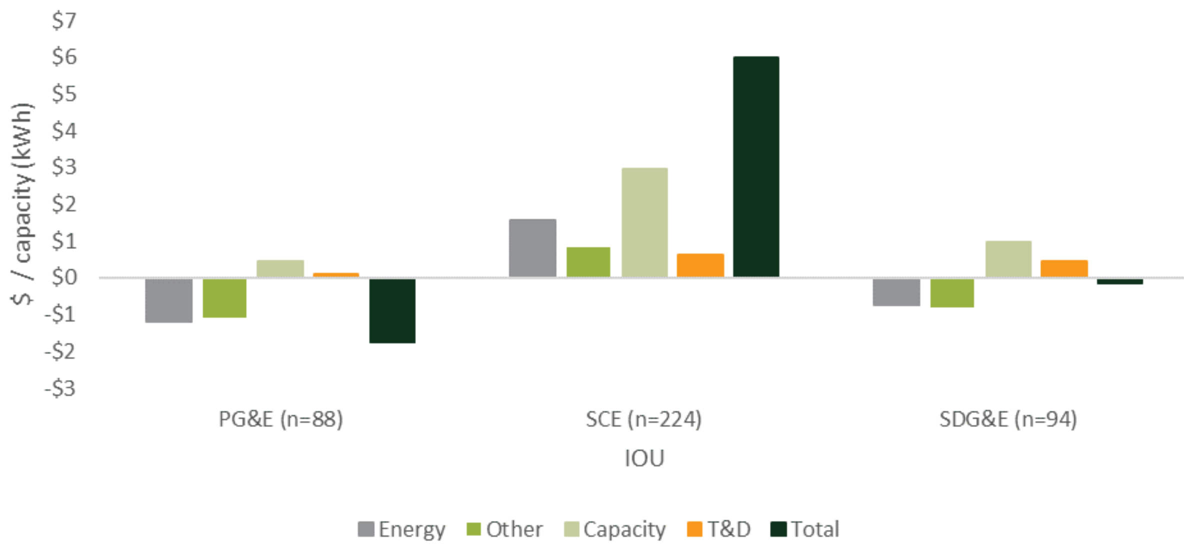
For energy storage systems to provide a benefit to the grid, the marginal costs *avoided* during storage discharge must be greater than the marginal cost increase during storage charging. Since storage technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate must be lower during charging hours relative to discharge hours. In other words, SGIP storage systems that charge during lower marginal cost periods and discharge during higher marginal cost periods will provide a net benefit to the system. The avoided costs that were included in this analysis include:

- Energy
- Losses
- Ancillary Services
- Cap and Trade
- Greenhouse gas (GHG) adder
- Generation Capacity
- Transmission Capacity
- Distribution Capacity

The normalized utility marginal costs are shown in Figure 4-55 by electric IOU for nonresidential energy storage systems.[41] Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). Overall, the average marginal *avoided* cost (+) for nonresidential systems in SCE territory is $6.00 per capacity (kWh) and the average marginal costs (-) from systems in PG&E and SDG&E territories are $1.75 and $0.13 per capacity (kWh), respectively.

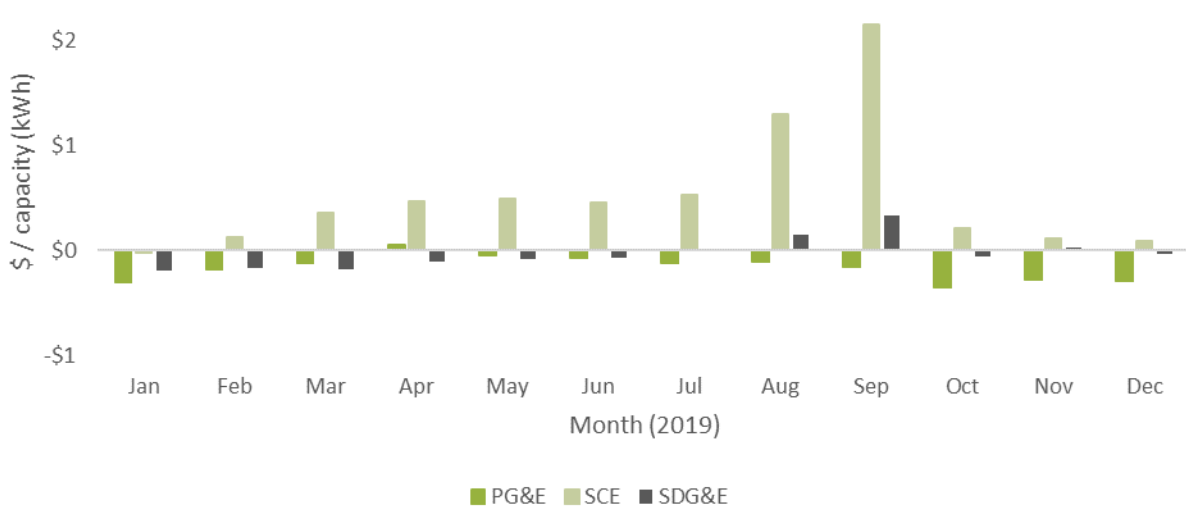
41 The levelized cost of ancillary services, cap and trade, losses and GHG adder have been combined into an "Other" category for presentation purposes.

FIGURE 4-55: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY IOU



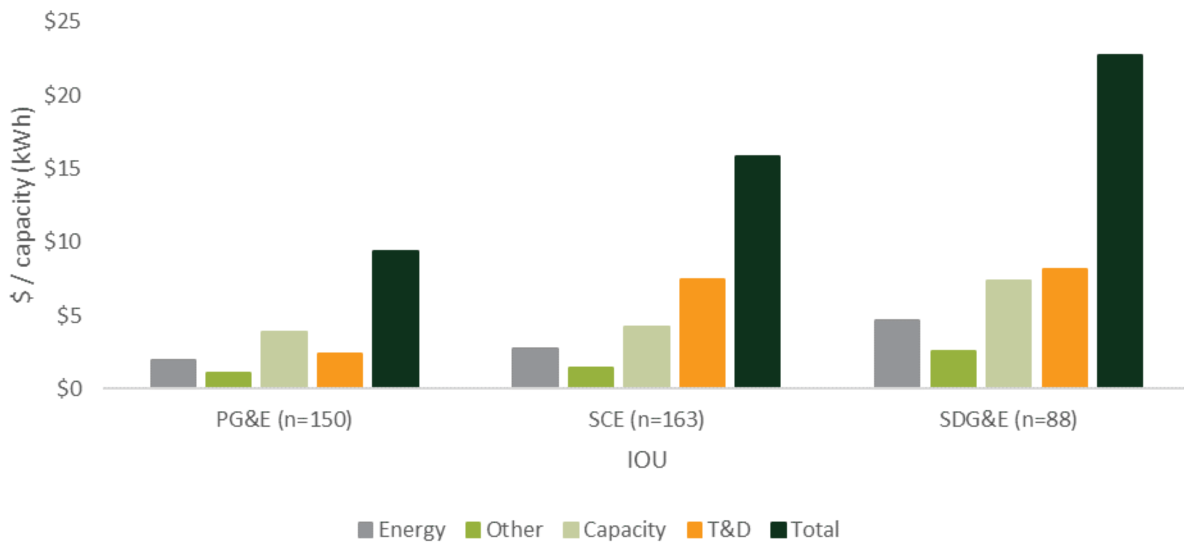
The marginal costs modeled in this study are highest when energy prices are high and the CAISO system load is peaking. Most of the system cost value is captured in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. These hours generally align with peak CAISO and IOU system hours. This is evident in Figure 4-56, where we examine the total avoided cost (+) or cost incurred (-) by utility and month. Most of the savings, especially for systems installed in SCE territory, are realized throughout summer months.

FIGURE 4-56: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



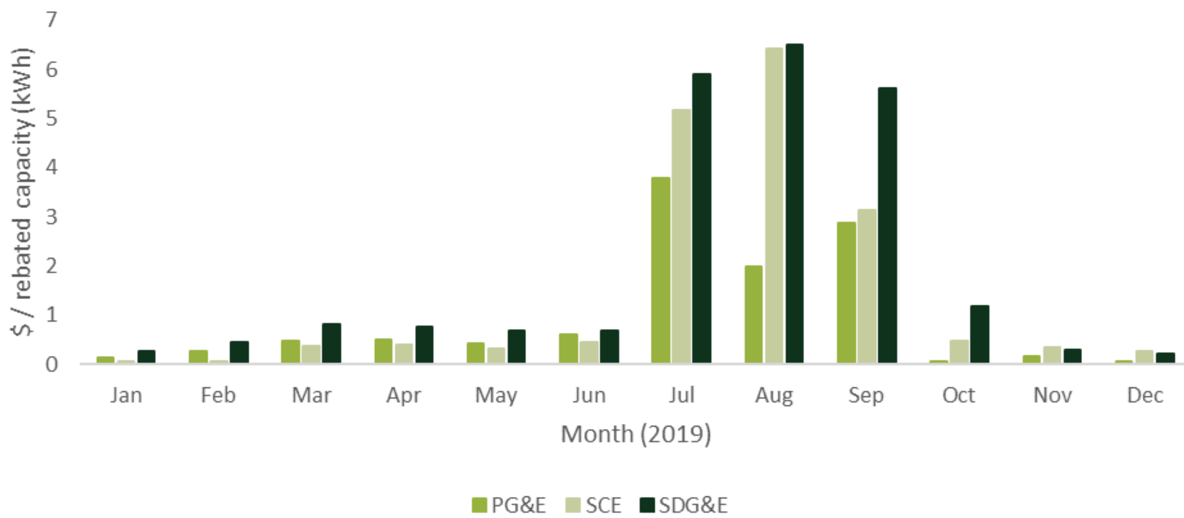
The normalized utility marginal costs are shown in Figure 4-57 for residential systems by electric IOU. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). Each of the three utilities realized total marginal cost savings throughout 2019. Furthermore, each component of the overall avoided cost total is positive within each IOU.

FIGURE 4-57: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY IOU



Residential storage behavior contributed to a net benefit to each of the three IOU systems. As discussed throughout this report, these systems were generally charging throughout low marginal cost periods and discharging in the early afternoon and evening during both high marginal cost and marginal emissions periods, especially throughout summer months. These higher costs also align with the new residential TOU periods and, as presented below in Figure 4-58, occur throughout the summer season when residential systems are being utilized more often.

FIGURE 4-58: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



4.6 STORAGE IMPACTS DURING PSPS EVENTS

Wildfire risk poses a unique 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 which identified 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 October and November of 2019, these threats were realized, leaving hundreds of thousands of electric customers without power – sometimes for days. This policy of de-energization has significant public policy and public health ramifications, especially for vulnerable individuals and communities, and the essential services they rely upon.

As discussed in Section 2, in September of 2019 the CPUC issued D. 19-09-027 establishing an SGIP equity resiliency budget.[42] To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 establishes a new equity resiliency budget set-aside for vulnerable households located in Tier 3 and Tier 2 high fire threat districts, critical services facilities serving those districts, and customers located in those districts that participate in low-income/disadvantaged solar generation programs.

42 CPUC Decision D. 19-09-027. September 18, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481

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This decision is forward looking in that SGIP participants within the context of this evaluation are not subject to any changes regarding how incentives are allocated across the equity resiliency budget. Nor were participants or project developers within this evaluation required to utilize SGIP storage systems in ways that would alleviate risk during Public Safety Power Shutoff (PSPS) events. However, given the real-world threats associated with wildfire risk and de-energization of the grid in response to PSPS events, we examined how SGIP participants located in PSPS planning areas utilized their storage systems throughout outages directly related to wildfire mitigation. The sample of storage systems for this 2019 evaluation were drawn to develop population impacts that satisfied the requirements of the SGIP M&E plan, so the forthcoming analysis includes systems as a sample of convenience. The sample was not designed to develop impacts associated with PSPS outages. However, the research planning and sample design of future evaluations will take this into account. Furthermore, the data we received regarding PSPS event outages only covers PG&E territory.

As discussed previously, by December 31st of 2019, the SGIP had provided incentives to 8,875 advanced energy storage systems, installed across multiple customer sectors. Of that total, 3,310 (37%) were installed in PG&E territory. We requested and received electric outage information for all 3,310 energy storage systems throughout 2019, along with the description of the outage cause. Of that total, 288 SGIP participants (9%) experienced at least one PSPS outage throughout October of 2019. We reviewed our sample of systems and determined that we had evaluated 24 of these participants for the 2019 impact evaluation – 14 residential customers and 10 nonresidential customers. The small sample size precludes a rigorous evaluation of PSPS customer impacts, but the data do provide some insights into how storage is being utilized to provide customer relief during long duration outage periods. At a high level, the data confirm:

- Customer electric load going to zero throughout multiple periods in October of 2019. The exact timing and duration of these PSPS outages is predicated on where these customers are located on the distribution system, but they occurred throughout three general time periods:
  - 10/9 through 10/11
  - 10/23 through 10/24
  - 10/26 through 10/31
- We observe no storage activity for the 10 nonresidential participants. During event periods, load goes to zero, but storage systems either remain idle or go offline throughout the event.
- We observe a wide variety of storage activity for residential customers
  - For those systems paired with solar PV, we observe the storage system satisfying consumption at the home. We observe consumption very similar to what it was prior to and after the PSPS events, and consumption that appears to be tied to only critical loads. Systems

are charging from on-site solar generation, so they can sustain their normal energy consumption behavior for long durations during shutdowns.

- For systems not paired with PV, we observe the storage system discharging, but only at low levels of magnitude – likely to maintain service on a few critical loads.

Given the small sample size and different outage periods, the evaluation team was limited in what conclusions could be made, but below we provide some anecdotal evidence that storage can and has provided relief to customers affected by PSPS outages in 2019. Figure 4-59 presents the storage behavior for a sample of customers who lost power during a PSPS event called from 10/26 through 10/28. We observe the net load, PV generation and storage charge (-) and discharge (+) throughout the 3 days. Customer load behaves normally throughout the first day until the power is shutoff in the early evening. The storage system then begins to discharge to satisfy consumption at the homes throughout the remainder of the evening and into the morning. PV generation allows the system to charge again and provide that benefit to the customers on the second day and into the third day. The power is restored in the late afternoon of 10/28.

FIGURE 4-59: OBSERVED RESIDENTIAL STORAGE BEHAVIOR DURING PSPS EVENTS (WITH SOLAR PV)

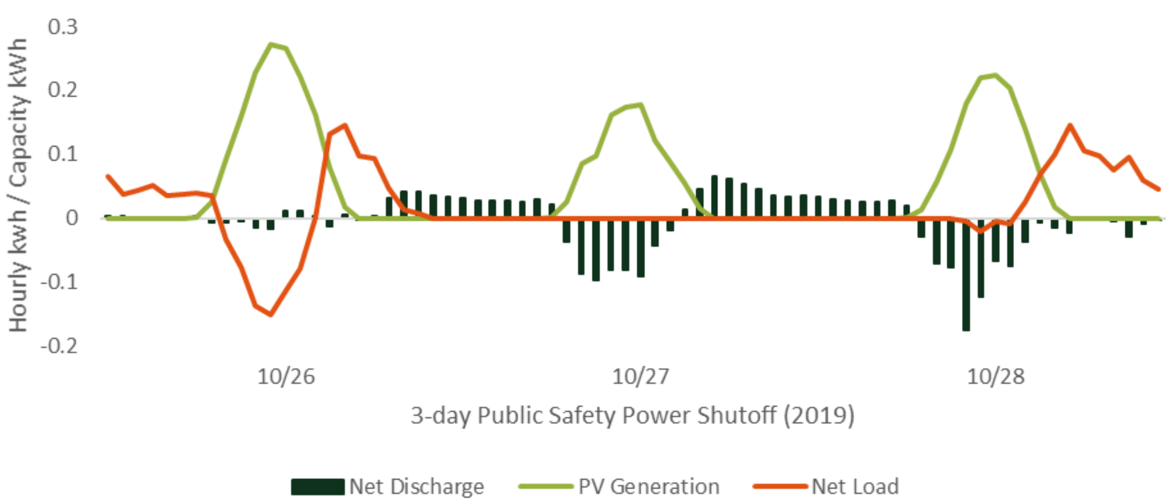
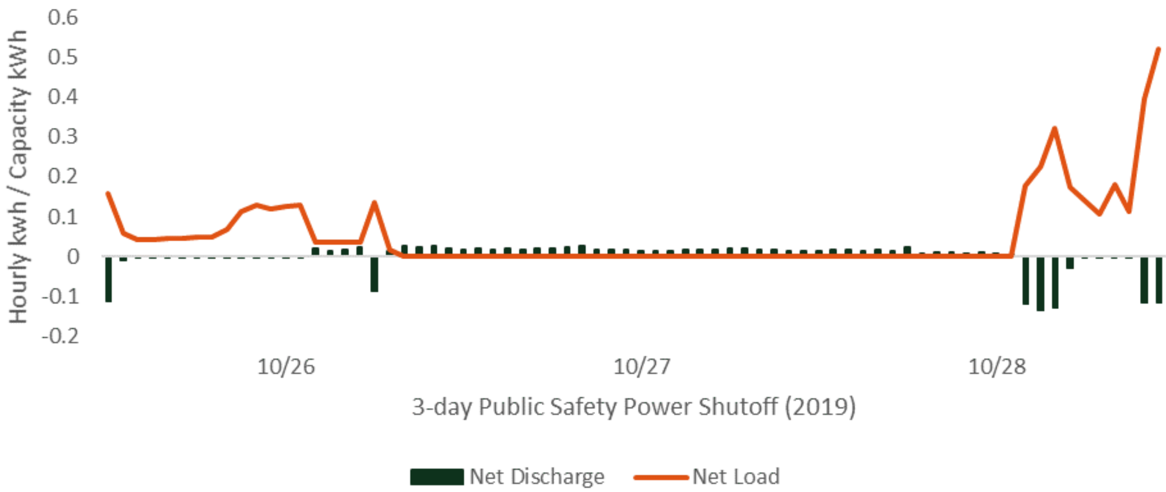


Figure 4-60 provides an example of a customer that does not have on-site PV generation, but experiences the same PSPS outage as the customers with PV. We observe the storage system charging right before the power is shut off. Then once the power is off, the system discharges a small magnitude of energy throughout the duration of the outage. This customer likely reduced consumption to an extremely low-level or the storage system was connected to a critical load that the customer did not want de-energized in the event of an outage.

FIGURE 4-60: OBSERVED RESIDENTIAL STORAGE BEHAVIOR DURING PSPS EVENTS (W/OUT SOLAR PV)



4.7 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of individual storage systems and samples of distinct customer segments – residential vs nonresidential and systems paired with solar PV vs standalone systems. These analyses were intended to highlight how SGIP storage systems were behaving in 2019 and how they were performing to meet program objectives. These analyses were all based on sampled systems from a larger population of SGIP storage systems. In this section, metered data from the sample of projects were used to estimate population total impacts for 2019.

Section 3 provides more detail into how each of these samples were developed, but they are summarized below in Table 4-1. Overall, our team evaluated 844 systems receiving upfront payments prior to December 31st of 2019 or 97.4 MW of total program capacity. The sample represents 10 percent of the total population by project count and 52 percent of the total population capacity. Again, large nonresidential systems and residential systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP population impacts.

TABLE 4-1: SAMPLE COMPOSITION OF SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MW)	Population Capacity (MW)	% of Capacity Sampled
Nonresidential	408	814	50%	94.6	139.2	68%
Residential	436	8,061	5%	2.8	47.5	6%
Total	**844**	**8,875**	**10%**	**97.4**	**186.7**	**52%**

Below we summarize the population estimates for several program impact metrics for each customer sector along with the program total. Population project counts[43] and relative precision levels are also reported in the tables and are based on a confidence level of 90 percent. The lower the relative precision, the more confident we are that the population estimate includes the true population value. Population estimates were calculated for the following in 2019:

- Electric energy – total energy charged, discharged and the overall roundtrip efficiency
- CAISO system peak demand – total CAISO top hour impacts and total top 200-hour impacts
- Environmental Impacts – total GHG impacts
- Utility Avoided Costs – total utility avoided costs

Total net discharge (i.e., the total energy impact that resulted from charging and discharging energy storage) during 2019 is summarized in Table 4-2. Electric energy impacts for all customer sectors are negative, reflecting increased energy consumption. As expected, storage systems inherently consume more energy than they discharge due to the combined effects of several factors, including standby loss rates, utilization levels and roundtrip efficiency. Nonresidential systems represent the most significant increase in total energy given their relative size. The total energy impact was an increase in electric energy consumption of 16,239 MWh during 2019.

[43] These population estimates exclude the impacts from 1 nonresidential system and 414 residential systems. The nonresidential system is a thermal storage system and the 414 residential systems represent those applying to the SGIP prior to 2016 and where data availability and integrity issues precluded an evaluation of these systems. However, these population impacts represent 99% of the energy capacity within the SGIP.

TABLE 4-2: ELECTRIC ENERGY IMPACTS

Customer Sector	N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE	Relative Precision
Nonresidential	813	56,059	70,075	-14,017	80%	4%
Residential	7,647	11,227	13,449	-2,222	83%	4%
Total	**8,460**	**67,286**	**83,524**	**-16,239**	**81%**	**4%**

CAISO system peak demand impacts are summarized in Table 4-3 and Table 4-4 for the gross and net top hours, respectively. In 2019 the CAISO statewide system gross load peaked at over 44,000 MW on August 15th during the 4 pm PST hour. The CAISO peaked, from a net load perspective, a day earlier on August 14th during the 6 pm PST hour. Both customer sectors provided a system benefit throughout those hours by net discharging a total of roughly 12.2 MWh throughout the gross peak hour and 11.9 MWh during the net peak hour. While the overall impacts across hours are almost identical, the nonresidential impact during the net peak is greater than during the gross peak. The opposite is true of residential systems (Section 4.4.1).

Note that the project count below is less than the total population (as indicated in the table above). This estimate is based on all systems that were conducting normal operations on August 14th and August 15th of 2019. Many residential and nonresidential SGIP participants received their upfront payment or began normal operations after these dates in 2019.

TABLE 4-3: CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS PEAK HOUR)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	748	7,062	21%
Residential	6,003	5,180	11%
Total	**6,751**	**12,242**	**13%**

TABLE 4-4: CAISO SYSTEM PEAK DEMAND IMPACTS (NET PEAK HOUR)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	748	8,608	18%
Residential	6,003	3,345	14%
Total	**6,751**	**11,953**	**13%**

The total impacts across the top 200 gross and net CAISO hours are presented below in Table 4-5 and Table 4-6. The system count is greater across the top 200 hours because some systems began normal operations and received their upfront payment during top CAISO load hours after August 15th.

TABLE 4-5: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 GROSS HOURS)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	778	940,805	8%
Residential	6,473	905,179	6%
Total	**7,251**	**1,845,983**	**5%**

TABLE 4-6: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 NET HOURS)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	778	1,108,194	12%
Residential	6,473	724,310	6%
Total	**7,251**	**1,832,504**	**8%**

Greenhouse gas impacts during 2019 are summarized in Table 4-7. Greenhouse gas impacts for nonresidential systems is positive, reflecting increased emissions. The magnitude and the sign of greenhouse gas impacts are dependent on the timing of storage charge and discharge. The residential sector, however, contributed to a decrease in GHG emissions throughout 2019. 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 4.5). 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 8.1 kg/kWh and nonresidential systems increased emissions by roughly 3.9 kg/kWh.

TABLE 4-7: GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Relative Precision
Nonresidential	813	1,358	18%
Residential	7,647	-799	9%
Total	**8,460**	**559**	**46%**

Utility marginal cost impacts during 2019 are summarized in Table 4-8. The evaluation found both customer sectors provided a utility-level population benefit of roughly $2.4 million in avoided costs. These results are consistent with the analyses presented in Section 4.6. Nonresidential and residential systems were generally discharging during hours that were capacity or distribution constrained, especially during the summertime. On average, nonresidential systems provided a benefit in avoided cost of roughly $4/kWh and residential systems provided a benefit of $13/kWh.

TABLE 4-8: UTILITY MARGINAL COST IMPACTS

Customer Sector	N	Population Impact (Avoided Cost $)	Relative Precision
Nonresidential	812	-$1,104,550	17%
Residential	7,648	-$1,289,685	6%
Total	**8,460**	**-$2,394,234**	**9%**

APPENDIX A BILL SAVINGS ANALYSIS

A.1 BILL SAVINGS ANALYSIS

The bill savings analysis done for the 2019 SGIP energy storage evaluation was performed by calculating the total annual bill using the net load from a given customer and comparing that to the annual bill of the same net load minus the storage dispatch. The net load used for this calculation consists of hourly kW and kWh inputs for one year. Each annual bill calculation is performed independently to assure both the correct rate and kWh baseline allowance is applied for each calculation.

Each annual bill is calculated by first summarizing the monthly kW and kWh by tier and 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 the following:

- Energy exported to the grid is reimbursed at the full retail rate
- The monthly billing cycles aligns with a calendar month
- No minimum bill is applied
- No California Climate Credit is applied
- No taxes are applied

Table A-1 and Table A-2 present the actual rate schedules used to develop bill impacts for residential and nonresidential SGIP participants in 2019, respectively. These are further disaggregated by IOU.

TABLE A-1: DISTRIBUTION OF RESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	Sample Count	Percent (%)
PG&E	E-TOU-A	95	64%
	EV-A	27	18%
	E-6	14	9%
	E-1	3	2%
	E-TOU-B	7	5%
	EM-TOU	1	1%
	EV2-A	2	1%
	Subtotal	**149**	**100%**
SCE	TOU-D-A	116	74%
	D	18	12%
	TOU-D-B	11	7%
	TOU-D-T	4	3%
	TOU-D_4_9	3	2%
	TOU-D_5_8	4	3%
	Subtotal	**156**	**100%**
SDG&E	GEVTOU2	4	4%
	EV-TOU-5	5	5%
	DR	32	34%
	GDRSES	15	16%
	EV-TOU	1	1%
	DRSES	28	30%
	DRLI	4	4%
	TOU-DR1	3	3%
	TOU-DR2	1	1%
	TOU-DR	1	1%
	Subtotal	**94**	**100%**
All	***Total***	***399***	

TABLE A-2: DISTRIBUTION OF NONRESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	Sample Count	Percent (%)
PG&E	E-20_1v	13	15%
	A10-X	10	11%
	A-6	6	7%
	E-19_2v	43	49%
	E-19_1v	7	8%
	E-20_transm	3	3%
	E-20_2v	4	5%
	AG-5-B	1	1%
	Subtotal	**87**	**100%**
SCE	TOU-8-D	38	19%
	TOU-8-B	9	5%
	TOU-GS2-D	15	8%
	TOU-GS2-B	3	2%
	TOU-GS3-D	27	14%
	TOU-8-R	8	4%
	TOU-GS3-R	46	23%
	TOU-GS2-E	4	2%
	TOU-GS2-R	23	12%
	TOU-8-RTP	4	2%
	TOU-GS1-D	1	1%
	TOU-EV-NR-8	1	1%
	TOU-8-S	4	2%
	TOU-8-E	3	2%
	TOU-GS3-E	5	3%
	TOU-GS3-B	6	3%
	Subtotal	**197**	**100%**
SDG&E	AL-TOU_<500kW_2v	54	60%
	GAL-TOU_<500kW_2v	22	24%
	AL-TOU2_<500kW_2v	4	4%
	GDG-R_2v	8	9%
	PA-T-1	2	2%
	Subtotal	**90**	**100%**
All	***Total***	***374***	

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 2019 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 data provided by project developers and Energy Solutions
- Interval load data provided by the electric utilities

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 including technology/fuel type, rebated capacity, 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 energy storage 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 includes descriptions of storage capacity and identification of existing metering equipment that can be used for impact evaluation purposes.

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

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Energy Solutions for projects that received a PBI incentive. 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 2019. 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 Developers	IOU
SGIP reservation number	X	X	X	
Storage system size (kW, duration, kWh)	X		X	
Program year (PY) of application and upfront payment date	X			
Customer sector	X			
Storage system payment type (PBI vs. Non-PBI)	X	X		
Storage system incentive	X			
Project developer	X		X	
Battery Manufacturer	X		X	
15-minute charge and discharge data (kWh)		X	X	
15-minute customer load data (kWh)			X	X
Renewable on-site generation (kWh)			X	X
Treatment of daylight savings		X	X	X
Data period beginning or ending		X	X	X
Unit of measure (kW, kWh, W, Wh, etc)		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

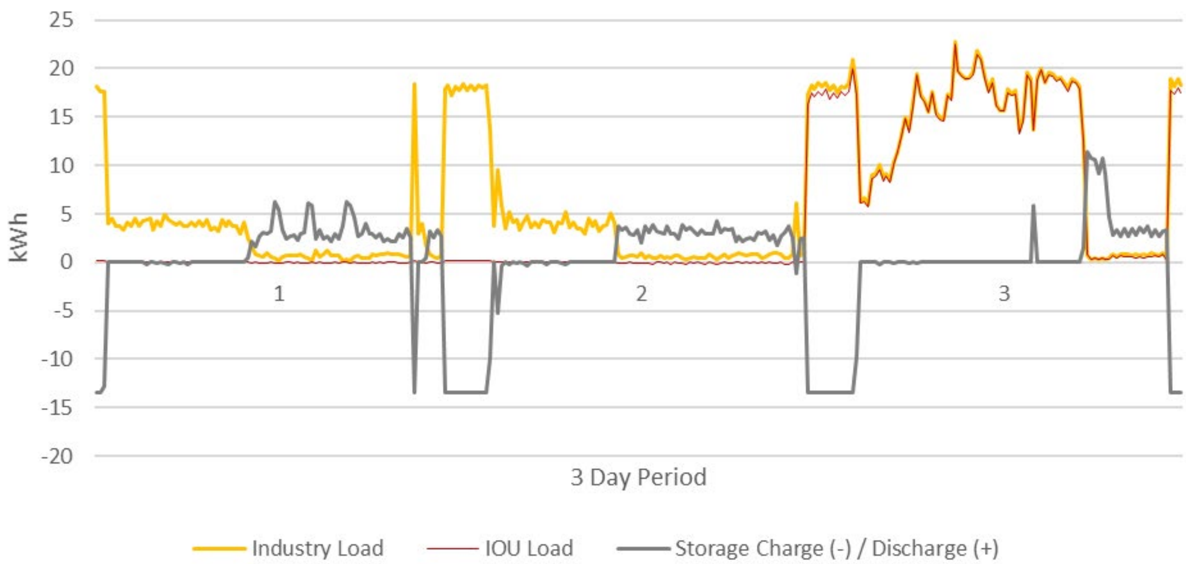
As discussed above, the storage analysis leveraged a variety of data sources including project developers, Energy Solutions (for projects that received a PBI incentive) and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were verifiable:

- Interval battery 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 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 time interval as the battery was charging (time syncing).
- 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 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.

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 are 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.

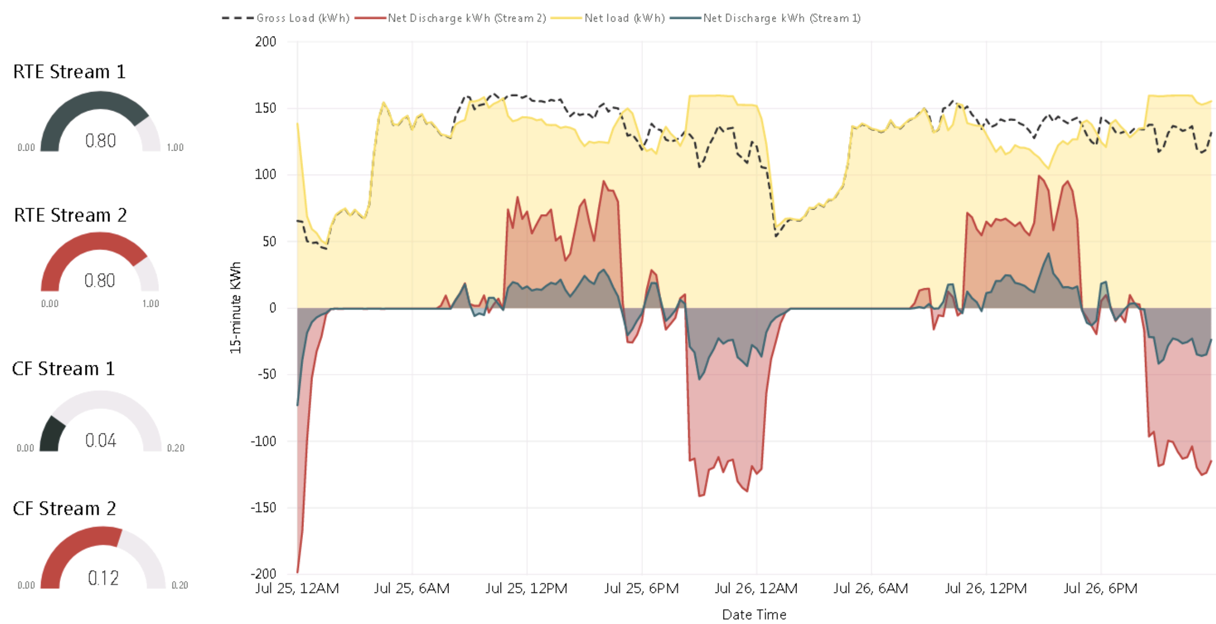
FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



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 were 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).

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 CF 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



APPENDIX C ADDITIONAL FIGURES

This appendix contains additional figures that may be of interest but were not included in the main body of this evaluation report.

Net Discharge kWh per kWh Rebated Capacity during CAISO Top 200 Gross and Net hours (by Facility Type)

FIGURE C-1: NET DISCHARGE KWH FOR GROCERY STORES DURING CAISO GROSS PEAKS

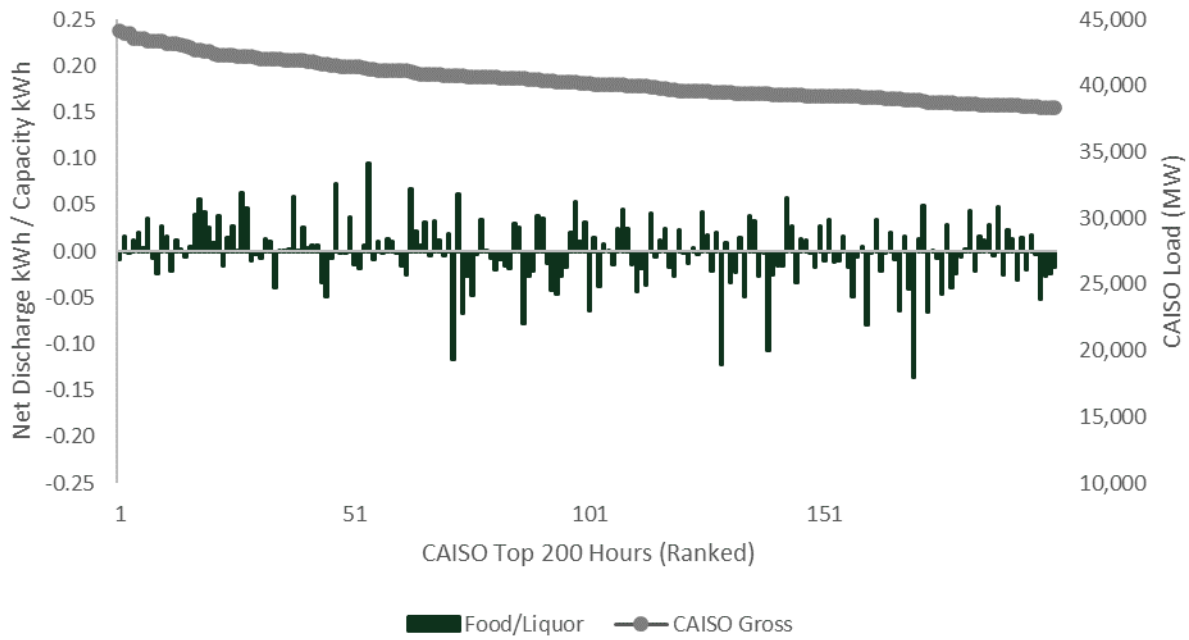


FIGURE C-2: NET DISCHARGE KWH FOR GROCERY STORES DURING CAISO NET PEAKS

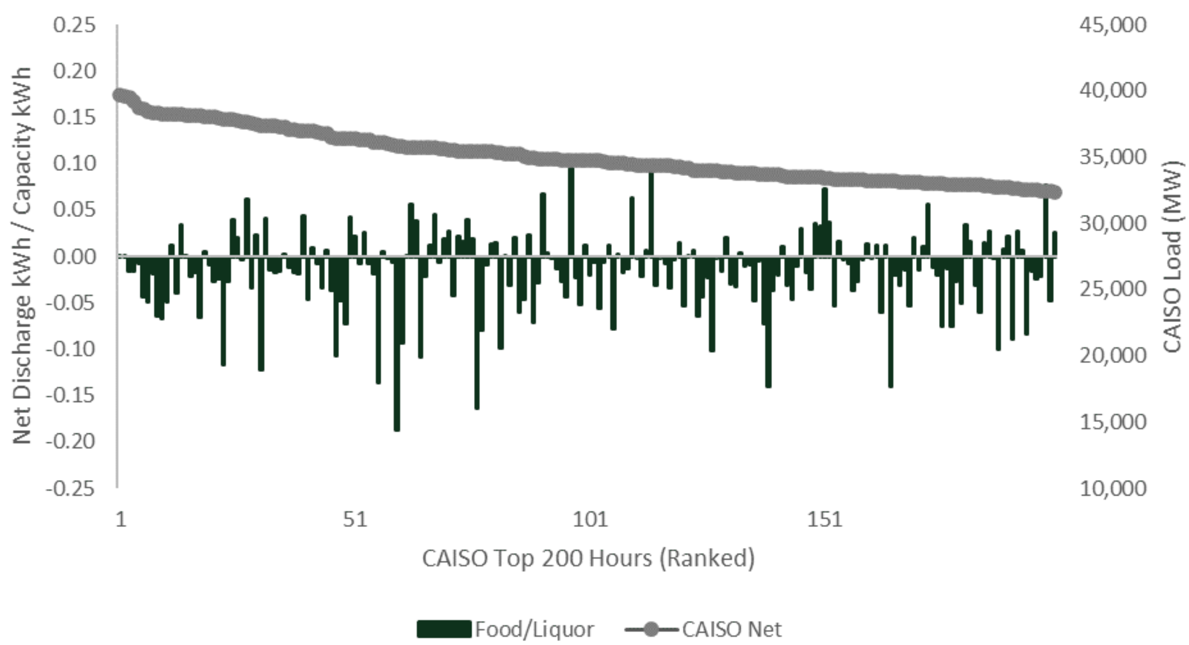


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FIGURE C-3: NET DISCHARGE KWH FOR HOTELS DURING CAISO GROSS PEAKS

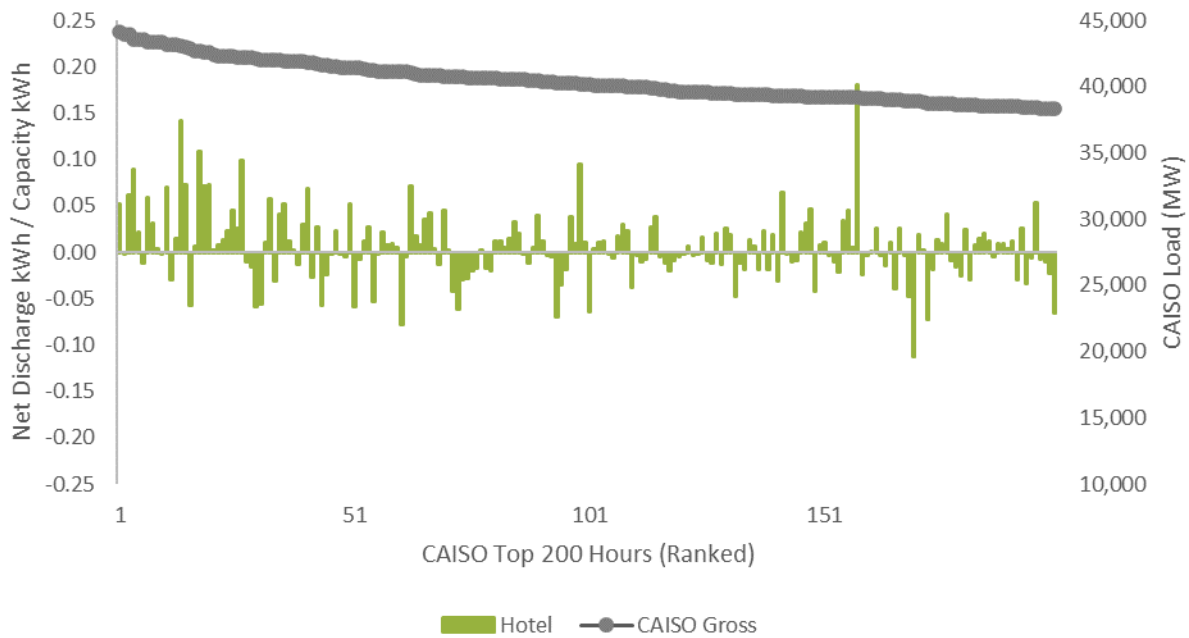


FIGURE C-4: NET DISCHARGE KWH FOR HOTELS DURING CAISO NET PEAKS

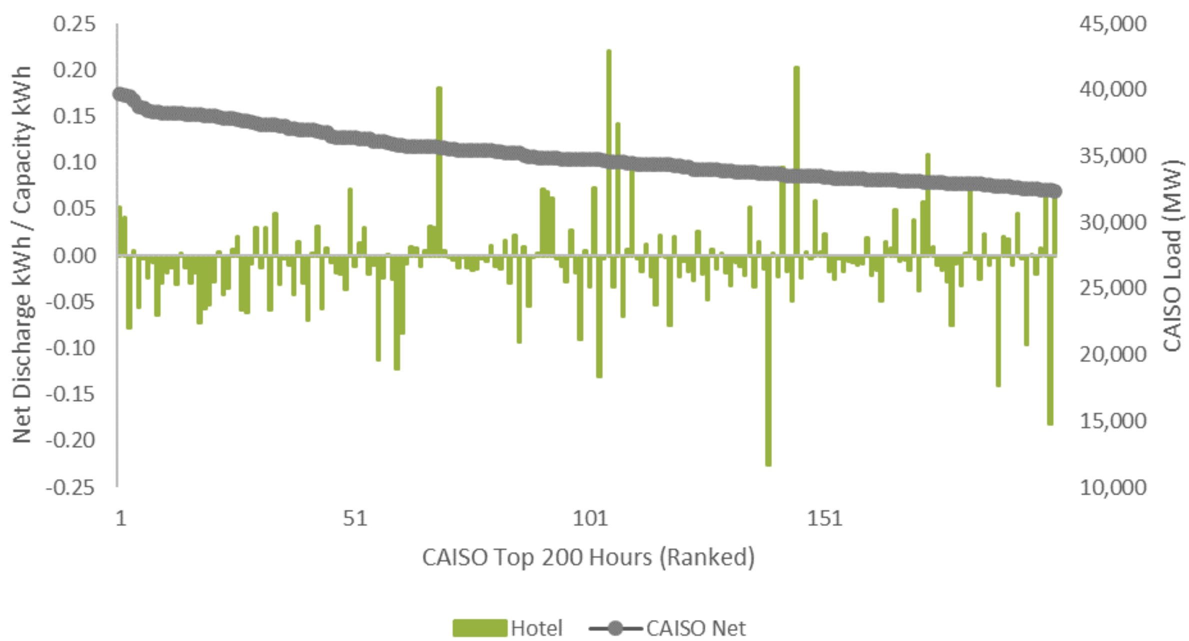


FIGURE C-5: NET DISCHARGE KWH FOR INDUSTRIAL FACILITIES DURING CAISO GROSS PEAKS

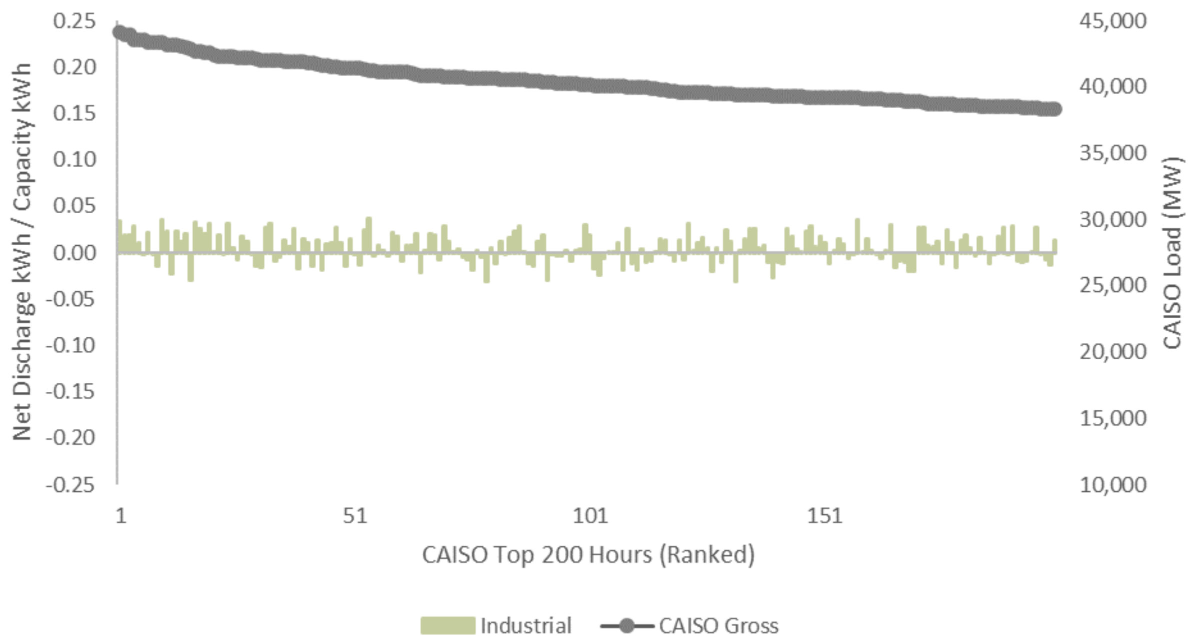


FIGURE C-6: NET DISCHARGE KWH FOR INDUSTRIAL FACILITIES DURING CAISO NET PEAKS

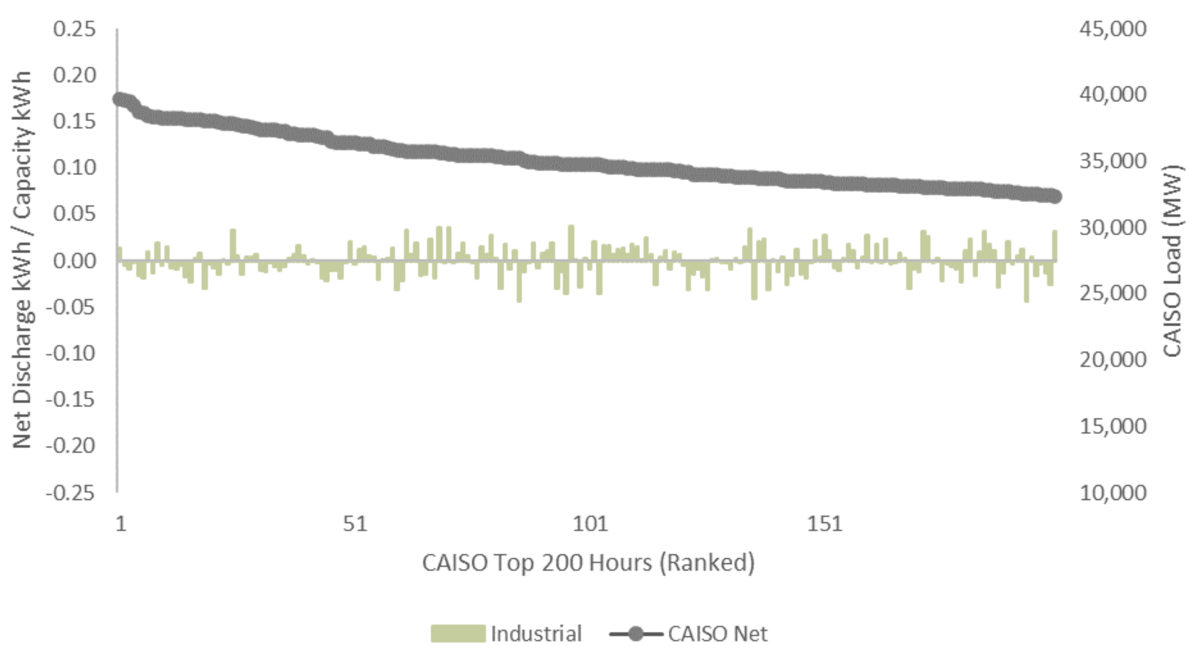


FIGURE C-7: NET DISCHARGE KWH FOR OFFICES DURING CAISO GROSS PEAKS

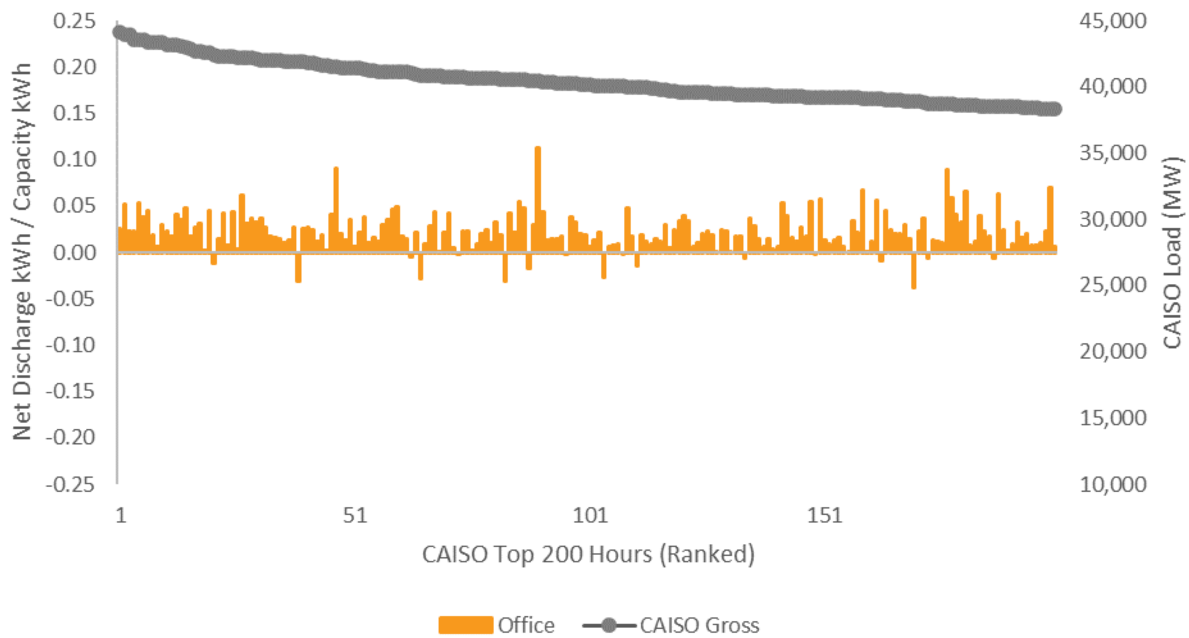


FIGURE C-8: NET DISCHARGE KWH FOR OFFICES DURING CAISO NET PEAKS

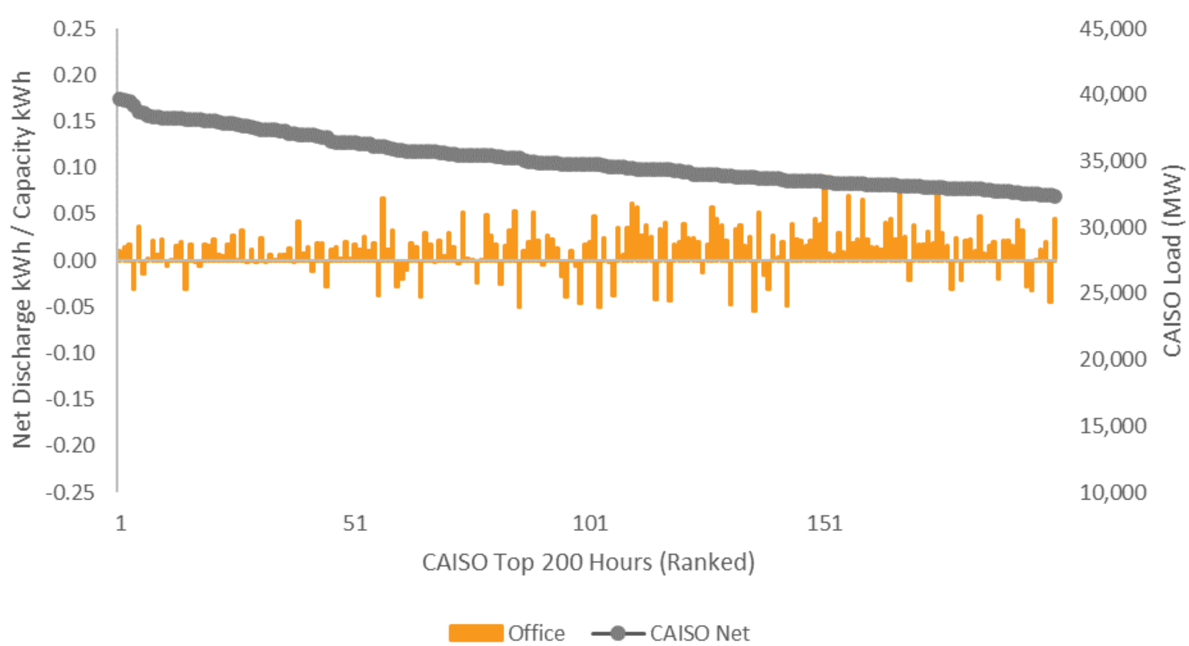


FIGURE C-9: NET DISCHARGE KWH FOR RETAIL STORES DURING CAISO GROSS PEAKS

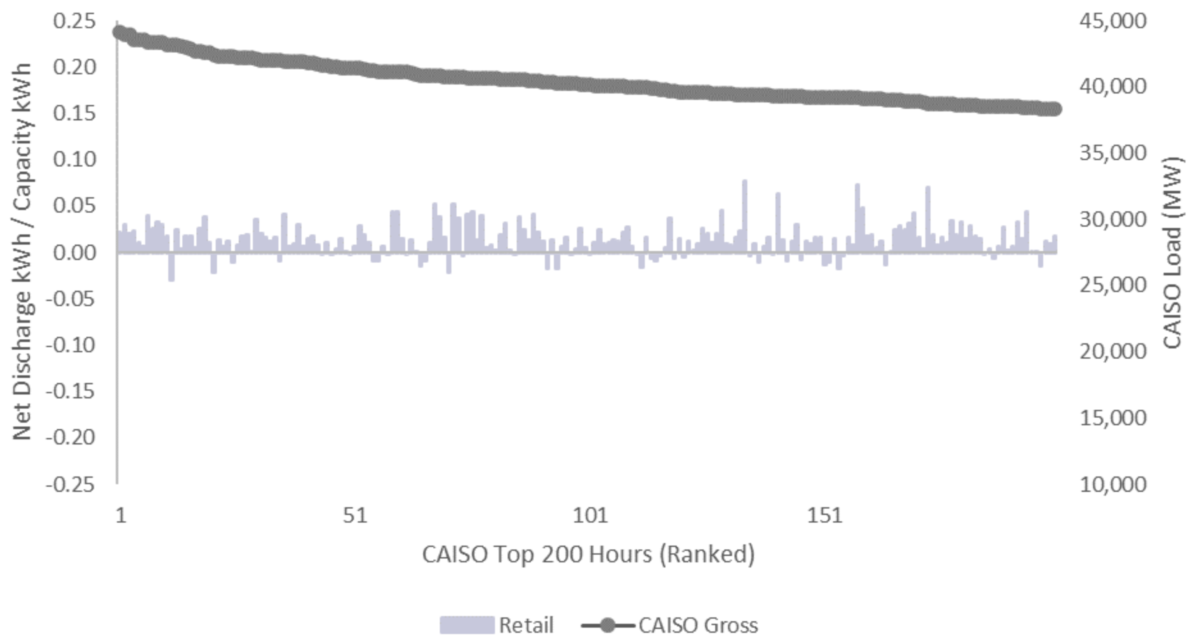


FIGURE C-10: NET DISCHARGE KWH FOR RETAIL STORES DURING CAISO NET PEAKS

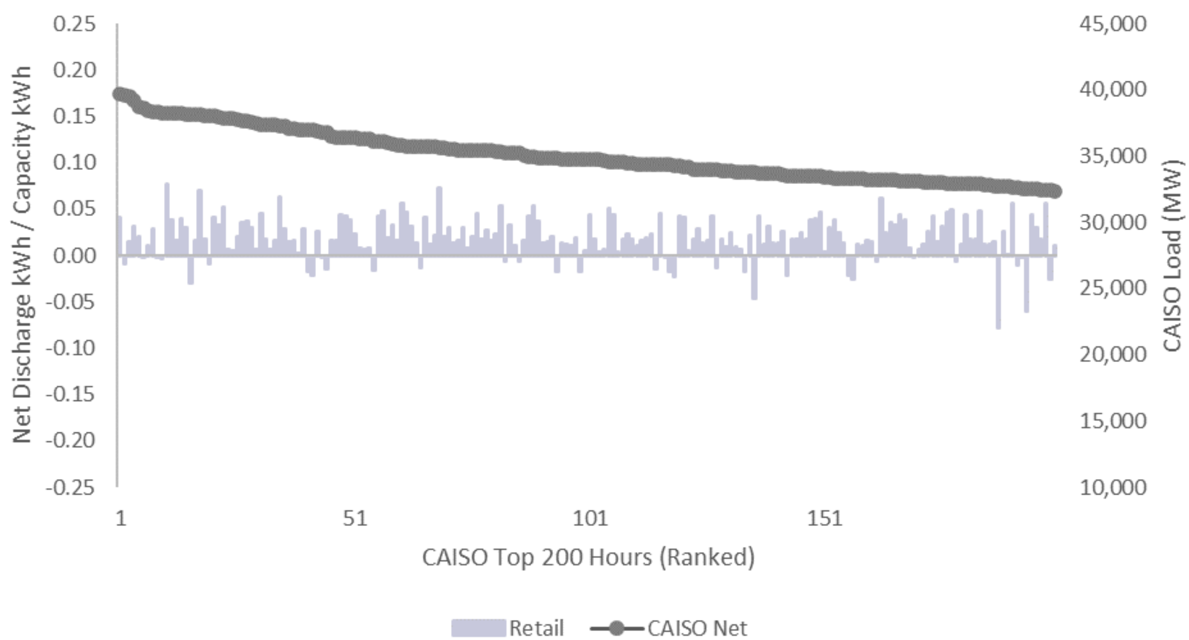


FIGURE C-11: NET DISCHARGE KWH FOR SCHOOLS DURING CAISO GROSS PEAKS

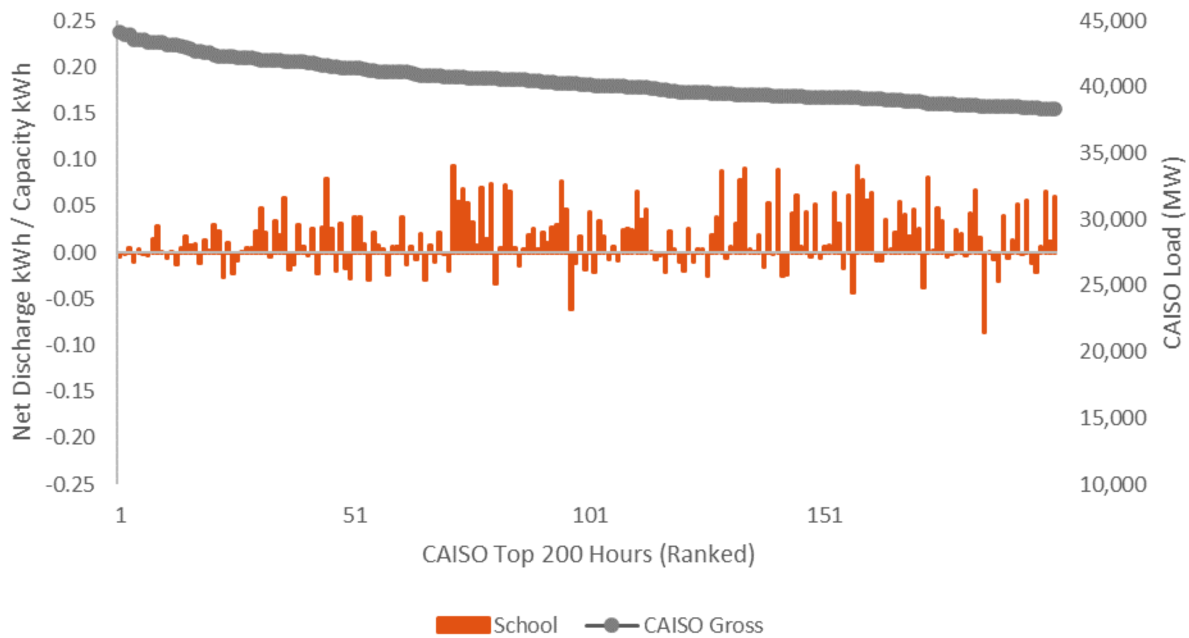
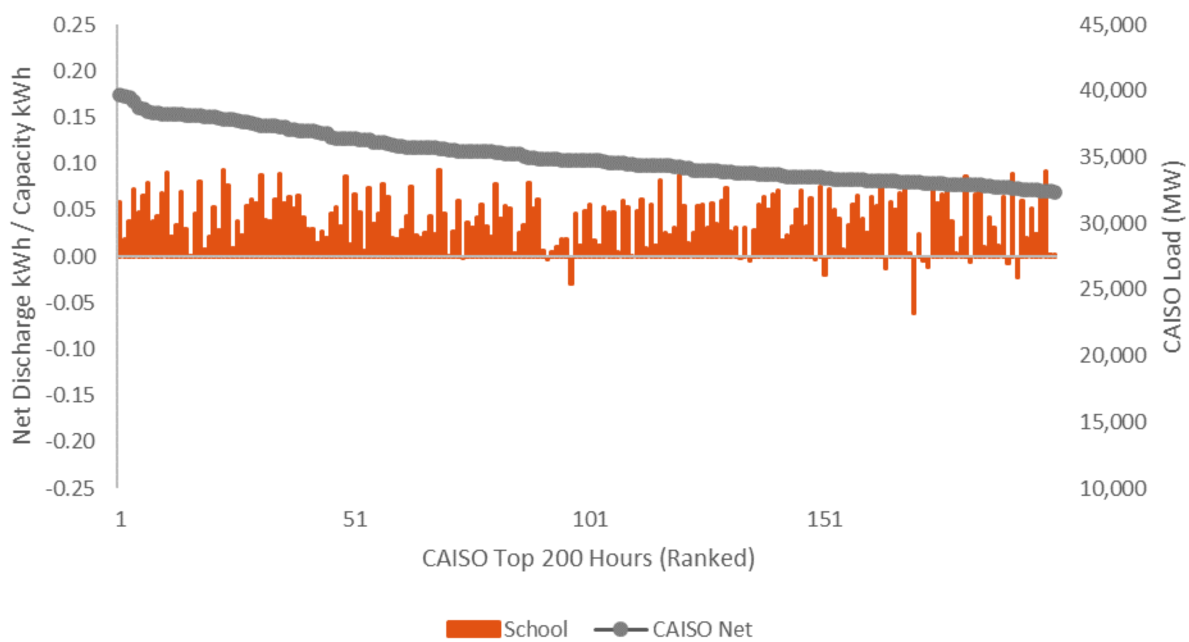


FIGURE C-12: NET DISCHARGE KWH FOR SCHOOLS DURING CAISO NET PEAKS



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Percent Discharge and Charge kWh per kWh Rebated Capacity Heat Maps (Average Hourly by Month)

FIGURE C-13: RESIDENTIAL SYSTEMS WITH SOLAR PV (CSE AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	3%	3%	3%	2%	2%	2%	2%	1%	1%	1%	1%	1%	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	5	0%	0%	0%	0%	0%	-1%	-1%	0%	0%	0%	0%	0%
6	1%	1%	1%	1%	1%	1%	0%	0%	0%	1%	1%	1%	6	0%	0%	-1%	-1%	-2%	-3%	-4%	-3%	-3%	-2%	0%	0%
7	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	7	-1%	-2%	-3%	-4%	-4%	-7%	-11%	-10%	-9%	-9%	-2%	-1%
8	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8	-5%	-7%	-8%	-8%	-7%	-13%	-19%	-19%	-17%	-17%	-5%	-4%
9	1%	1%	1%	0%	1%	0%	0%	0%	1%	1%	1%	0%	9	-10%	-11%	-12%	-9%	-8%	-14%	-16%	-19%	-17%	-17%	-7%	-6%
10	1%	1%	1%	0%	5%	4%	4%	4%	4%	4%	1%	1%	10	-11%	-12%	-11%	-8%	-8%	-11%	-10%	-11%	-11%	-10%	-8%	-7%
11	1%	1%	1%	1%	2%	2%	3%	3%	3%	2%	1%	1%	11	-10%	-9%	-9%	-5%	-6%	-8%	-6%	-7%	-6%	-5%	-6%	-6%
12	3%	3%	2%	1%	1%	1%	2%	1%	1%	0%	1%	1%	12	-8%	-6%	-6%	-3%	-4%	-5%	-3%	-3%	-4%	-3%	-4%	-4%
13	3%	3%	2%	1%	1%	1%	1%	2%	2%	1%	1%	1%	13	-5%	-4%	-3%	-2%	-3%	-3%	-1%	-2%	-3%	-1%	-2%	-2%
14	3%	3%	3%	1%	1%	1%	2%	2%	3%	2%	1%	1%	14	-2%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
15	3%	3%	4%	2%	3%	32%	31%	31%	31%	34%	3%	2%	15	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
16	6%	6%	4%	3%	2%	5%	7%	7%	6%	5%	4%	4%	16	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%
17	8%	7%	6%	4%	4%	4%	6%	7%	6%	6%	5%	6%	17	0%	0%	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
18	8%	8%	7%	6%	5%	5%	6%	6%	6%	5%	5%	5%	18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	7%	7%	6%	5%	5%	5%	5%	5%	5%	4%	4%	4%	19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	6%	6%	5%	4%	4%	4%	4%	4%	3%	3%	3%	3%	20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	2%	2%	21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	4%	4%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	1%	1%	23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

FIGURE C-14: RESIDENTIAL SYSTEMS WITH SOLAR PV (PG&E AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	2%	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	5	0%	0%	0%	0%	0%	-1%	-1%	0%	0%	0%	0%	0%
6	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	6	0%	0%	0%	-1%	-1%	-5%	-4%	-3%	-2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	7	0%	-1%	-1%	-3%	-3%	-10%	-8%	-7%	-6%	-1%	-2%	-1%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8	-1%	-2%	-3%	-5%	-6%	-14%	-13%	-13%	-11%	-4%	-5%	-4%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	9	-3%	-4%	-5%	-7%	-7%	-12%	-13%	-14%	-14%	-6%	-7%	-6%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	10	-4%	-5%	-6%	-6%	-6%	-8%	-9%	-10%	-11%	-6%	-8%	-7%
11	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	1%	1%	11	-5%	-5%	-6%	-5%	-5%	-5%	-6%	-7%	-7%	-5%	-6%	-6%
12	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	1%	12	-4%	-4%	-4%	-3%	-4%	-3%	-3%	-4%	-4%	-3%	-4%	-4%
13	1%	1%	1%	2%	2%	2%	2%	2%	2%	1%	1%	1%	13	-3%	-3%	-3%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%
14	2%	2%	2%	2%	2%	3%	3%	4%	4%	1%	1%	1%	14	-2%	-2%	-2%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	2%	2%	2%	2%	3%	31%	29%	33%	33%	2%	3%	2%	15	-1%	-1%	-1%	-1%	-1%	-1%	0%	-1%	-1%	0%	0%	0%
16	3%	3%	2%	2%	2%	7%	7%	7%	5%	2%	4%	4%	16	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	3%	4%	3%	3%	3%	4%	4%	4%	4%	3%	5%	6%	17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	5%	5%	18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	3%	4%	3%	4%	4%	4%	4%	4%	4%	3%	4%	4%	19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	3%	3%	20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	2%	2%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	1%	2%	2%	2%	3%	2%	3%	2%	2%	2%	2%	2%	22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	1%	1%	3%	3%	3%	3%	3%	2%	2%	2%	1%	1%	23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

VERDANT

FIGURE C-15: RESIDENTIAL SYSTEMS WITH SOLAR PV (SCE AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	5	0%	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%
6	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	6	0%	0%	-1%	-4%	-4%	-3%	-4%	-3%	-2%	-2%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	7	-1%	-3%	-6%	-9%	-9%	-7%	-9%	-9%	-7%	-7%	-2%	-1%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8	-5%	-8%	-12%	-14%	-12%	-11%	-14%	-14%	-12%	-12%	-5%	-4%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	9	-9%	-12%	-13%	-12%	-10%	-10%	-13%	-14%	-13%	-13%	-7%	-6%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	10	-10%	-11%	-10%	-8%	-7%	-9%	-9%	-10%	-10%	-8%	-8%	-7%
11	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	1%	1%	11	-8%	-7%	-6%	-5%	-5%	-6%	-5%	-6%	-6%	-5%	-6%	-6%
12	1%	0%	0%	1%	1%	1%	1%	1%	1%	0%	1%	1%	12	-6%	-4%	-4%	-3%	-3%	-4%	-3%	-3%	-3%	-2%	-4%	-4%
13	2%	1%	2%	2%	2%	3%	4%	4%	4%	2%	1%	1%	13	-3%	-3%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-1%	-2%	-2%
14	29%	30%	4%	2%	2%	3%	4%	5%	4%	3%	1%	1%	14	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
15	3%	5%	23%	32%	30%	29%	28%	29%	29%	32%	3%	2%	15	-1%	-1%	0%	0%	0%	-1%	-1%	0%	0%	0%	0%	0%
16	3%	2%	10%	5%	7%	9%	11%	10%	8%	8%	4%	4%	16	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	3%	3%	3%	3%	3%	3%	5%	5%	4%	4%	5%	6%	17	0%	0%	0%	-1%	0%	-1%	0%	0%	0%	0%	0%	0%
18	3%	3%	4%	3%	3%	3%	4%	4%	4%	4%	5%	5%	18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	4%	19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	2%	2%	3%	3%	2%	3%	3%	2%	2%	2%	3%	3%	20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	1%	2%	2%	2%	1%	2%	2%	1%	1%	1%	2%	2%	22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

FIGURE C-16: RESIDENTIAL SYSTEMS WITH SOLAR PV (SCG AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	2%	3%	3%	3%	3%	3%	3%	4%	3%	1%	1%	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	1%	1%	2%	2%	3%	2%	2%	2%	3%	3%	1%	1%	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	1%	1%	2%	2%	2%	2%	2%	2%	2%	3%	1%	1%	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	1%	1%	2%	1%	2%	2%	2%	2%	2%	2%	1%	1%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	1%	1%	2%	1%	1%	2%	1%	2%	2%	2%	1%	1%	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	1%	2%	1%	1%	1%	1%	1%	1%	2%	1%	1%	6	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
7	1%	1%	1%	0%	1%	1%	0%	0%	1%	1%	0%	0%	7	0%	-1%	-2%	-4%	-4%	-3%	-4%	-4%	-3%	-2%	-2%	-1%
8	1%	1%	1%	1%	1%	1%	0%	0%	1%	1%	0%	0%	8	-2%	-4%	-7%	-8%	-8%	-5%	-8%	-9%	-7%	-5%	-5%	-4%
9	1%	0%	1%	1%	2%	1%	1%	1%	1%	0%	1%	0%	9	-6%	-7%	-10%	-10%	-8%	-7%	-9%	-10%	-10%	-7%	-7%	-6%
10	1%	1%	1%	1%	1%	1%	1%	2%	1%	0%	1%	1%	10	-7%	-8%	-10%	-10%	-7%	-8%	-9%	-10%	-9%	-7%	-8%	-7%
11	1%	1%	1%	2%	2%	1%	2%	2%	3%	2%	1%	1%	11	-7%	-8%	-8%	-7%	-5%	-7%	-7%	-7%	-7%	-5%	-6%	-6%
12	1%	1%	4%	4%	4%	5%	6%	5%	5%	5%	1%	1%	12	-5%	-7%	-4%	-3%	-3%	-6%	-4%	-4%	-4%	-3%	-4%	-4%
13	4%	4%	4%	4%	4%	5%	4%	5%	5%	5%	1%	1%	13	-4%	-5%	-3%	-2%	-3%	-4%	-2%	-2%	-2%	-1%	-2%	-2%
14	3%	3%	3%	3%	3%	4%	4%	5%	5%	5%	1%	1%	14	-3%	-3%	-2%	-1%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%
15	3%	3%	3%	3%	3%	4%	4%	5%	5%	5%	3%	2%	15	-1%	-1%	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
16	3%	3%	3%	3%	2%	4%	4%	5%	4%	4%	4%	4%	16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	5%	6%	4%	4%	3%	4%	5%	6%	6%	6%	5%	6%	17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	5%	6%	5%	5%	5%	5%	7%	7%	7%	6%	5%	5%	18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	4%	5%	6%	6%	6%	7%	7%	7%	7%	6%	4%	4%	19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	5%	6%	6%	6%	6%	6%	6%	6%	6%	6%	3%	3%	20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	4%	6%	5%	5%	4%	5%	5%	5%	4%	4%	2%	2%	21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	3%	5%	4%	4%	3%	4%	4%	4%	4%	3%	2%	2%	22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	2%	3%	3%	3%	3%	3%	3%	3%	4%	4%	1%	1%	23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

VERDANT

FIGURE C-17: NONRESIDENTIAL SYSTEMS WITHOUT SOLAR PV (CSE AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	2%	3%	4%	4%	4%	4%	3%	3%	3%	3%	4%	3%	0	-5%	-6%	-5%	-5%	-5%	-5%	-4%	-4%	-3%	-5%	-11%	-9%
1	3%	2%	3%	4%	3%	3%	3%	4%	6%	4%	4%	2%	1	-4%	-5%	-5%	-5%	-6%	-5%	-4%	-3%	-3%	-3%	-8%	-7%
2	3%	3%	4%	5%	5%	5%	3%	6%	5%	5%	2%	1%	2	-4%	-3%	-5%	-5%	-5%	-5%	-4%	-4%	-4%	-4%	-4%	-4%
3	3%	2%	3%	4%	4%	3%	2%	3%	3%	2%	2%	1%	3	-4%	-3%	-4%	-5%	-5%	-5%	-4%	-5%	-5%	-4%	-4%	-3%
4	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	4	-4%	-3%	-4%	-5%	-5%	-4%	-3%	-4%	-4%	-4%	-3%	-3%
5	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	5	-4%	-2%	-4%	-5%	-5%	-4%	-4%	-5%	-5%	-3%	-2%	-1%
6	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	6	-3%	-2%	-3%	-3%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-1%
7	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	7	-1%	-1%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
8	1%	2%	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%	8	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
9	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	9	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
10	2%	2%	2%	3%	2%	3%	2%	2%	2%	2%	1%	1%	10	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
11	2%	2%	2%	3%	3%	3%	2%	3%	2%	3%	1%	1%	11	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%
12	2%	2%	2%	2%	2%	2%	2%	3%	2%	3%	2%	1%	12	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	1%	1%	2%	2%	2%	2%	2%	3%	2%	3%	2%	1%	13	-1%	-1%	-1%	-2%	-1%	-2%	-1%	-2%	-2%	-1%	-1%	-1%
14	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	14	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
15	1%	1%	6%	6%	5%	6%	6%	5%	5%	6%	1%	1%	15	-2%	-2%	-1%	-2%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
16	5%	5%	6%	5%	4%	4%	4%	4%	3%	4%	7%	4%	16	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
17	5%	5%	5%	4%	3%	3%	3%	3%	3%	4%	7%	5%	17	-1%	-1%	-2%	-2%	-2%	-3%	-2%	-4%	-3%	-2%	-1%	-1%
18	4%	5%	6%	5%	3%	4%	2%	3%	3%	4%	6%	4%	18	-1%	-1%	-2%	-3%	-2%	-3%	-3%	-4%	-3%	-2%	-1%	-1%
19	5%	5%	6%	4%	3%	5%	4%	4%	3%	5%	6%	5%	19	-1%	-2%	-2%	-3%	-2%	-2%	-2%	-3%	-3%	-2%	-2%	-1%
20	4%	5%	4%	3%	3%	3%	3%	3%	3%	2%	6%	9%	20	-2%	-2%	-7%	-8%	-7%	-8%	-6%	-7%	-6%	-6%	-3%	-2%
21	2%	3%	2%	2%	1%	3%	2%	2%	2%	1%	1%	1%	21	-8%	-9%	-11%	-9%	-7%	-9%	-8%	-7%	-6%	-7%	-7%	-5%
22	2%	2%	2%	3%	2%	2%	2%	2%	2%	1%	1%	1%	22	-7%	-7%	-7%	-6%	-5%	-6%	-5%	-5%	-3%	-5%	-7%	-6%
23	2%	3%	3%	5%	5%	5%	4%	4%	4%	4%	1%	1%	23	-6%	-6%	-7%	-6%	-6%	-6%	-5%	-4%	-4%	-7%	-5%	-4%

FIGURE C-18: NONRESIDENTIAL SYSTEMS WITH SOLAR PV (CSE AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	2%	1%	1%	0%	1%	1%	0	-1%	-1%	-1%	-1%	-1%	-3%	-1%	-1%	-1%	-1%	-4%	-3%
1	1%	1%	1%	1%	1%	1%	2%	1%	1%	0%	1%	1%	1	-1%	-1%	-1%	-2%	-2%	-3%	-1%	-1%	0%	-1%	-3%	-2%
2	1%	1%	1%	1%	1%	1%	2%	2%	1%	1%	0%	0%	2	-1%	-1%	-1%	-3%	-2%	-2%	-1%	0%	0%	0%	-2%	-1%
3	1%	1%	1%	1%	1%	1%	3%	2%	0%	0%	1%	1%	3	-1%	0%	-1%	-2%	-1%	-2%	0%	0%	0%	0%	-1%	-1%
4	1%	1%	1%	2%	2%	2%	4%	2%	1%	1%	0%	0%	4	0%	0%	-1%	-1%	0%	-1%	0%	0%	0%	0%	-1%	-1%
5	1%	1%	5%	4%	3%	3%	4%	6%	3%	2%	1%	1%	5	0%	0%	0%	0%	-1%	-1%	0%	0%	0%	0%	-1%	0%
6	4%	4%	6%	3%	3%	2%	2%	5%	3%	3%	1%	2%	6	0%	0%	-1%	-2%	-3%	-2%	-2%	-1%	-1%	-1%	0%	0%
7	3%	3%	4%	2%	3%	2%	1%	4%	3%	2%	1%	2%	7	-1%	-2%	-4%	-6%	-5%	-4%	-7%	-3%	-2%	-3%	-2%	-1%
8	2%	1%	2%	1%	2%	2%	1%	1%	1%	1%	1%	1%	8	-3%	-4%	-8%	-11%	-7%	-6%	-12%	-9%	-3%	-6%	-5%	-4%
9	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	9	-6%	-6%	-13%	-11%	-8%	-7%	-10%	-11%	-6%	-7%	-7%	-7%
10	1%	0%	1%	1%	1%	1%	0%	1%	1%	1%	0%	0%	10	-5%	-6%	-11%	-8%	-8%	-6%	-7%	-8%	-6%	-6%	-7%	-7%
11	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	11	-4%	-3%	-7%	-6%	-6%	-5%	-5%	-6%	-5%	-5%	-5%	-5%
12	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	12	-2%	-2%	-4%	-4%	-5%	-3%	-3%	-3%	-4%	-3%	-3%	-3%
13	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	1%	0%	13	-1%	-1%	-3%	-2%	-3%	-3%	-2%	-2%	-2%	-2%	-1%	-2%
14	1%	1%	2%	2%	1%	1%	1%	1%	2%	2%	2%	1%	14	-1%	-1%	-2%	-2%	-3%	-3%	-1%	-3%	-2%	-2%	-1%	-1%
15	0%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	1%	15	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-2%	-1%	0%
16	1%	1%	1%	2%	1%	1%	1%	4%	5%	5%	3%	2%	16	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	0%	0%	0%
17	3%	3%	5%	5%	4%	3%	2%	3%	3%	5%	8%	5%	17	0%	0%	0%	0%	-1%	-1%	0%	-1%	-1%	0%	0%	0%
18	2%	3%	7%	10%	8%	7%	6%	6%	4%	5%	9%	7%	18	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%
19	2%	3%	6%	9%	9%	8%	7%	6%	4%	5%	10%	8%	19	0%	0%	-1%	0%	0%	0%	0%	0%	-1%	0%	0%	0%
20	1%	2%	3%	4%	3%	3%	4%	3%	2%	2%	4%	3%	20	-1%	-1%	-1%	0%	0%	0%	0%	0%	-1%	-1%	0%	0%
21	0%	1%	1%	2%	3%	3%	3%	2%	1%	1%	2%	2%	21	-2%	-3%	-1%	0%	0%	0%	-1%	-2%	-4%	-2%	0%	0%
22	0%	1%	4%	5%	4%	4%	3%	2%	2%	2%	1%	1%	22	-1%	-2%	-1%	0%	0%	0%	-1%	-1%	-2%	-1%	-3%	-4%
23	0%	2%	2%	1%	1%	1%	2%	1%	0%	0%	1%	1%	23	-1%	-1%	-1%	-1%	-1%	-3%	-1%	-1%	-3%	-2%	-4%	-3%

FIGURE C-19: NONRESIDENTIAL SYSTEMS WITHOUT SOLAR PV (PG&E AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	5%	4%	7%	7%	7%	6%	5%	6%	6%	4%	4%	3%	**0**	-3%	-7%	-5%	-6%	-5%	-5%	-4%	-3%	-3%	-3%	-11%	-9%
1	5%	3%	8%	8%	7%	7%	7%	7%	7%	5%	4%	2%	**1**	-5%	-5%	-7%	-7%	-7%	-6%	-5%	-5%	-6%	-4%	-8%	-7%
2	4%	3%	6%	6%	6%	6%	5%	4%	4%	3%	2%	1%	**2**	-5%	-3%	-8%	-8%	-7%	-8%	-7%	-6%	-6%	-5%	-4%	-4%
3	2%	2%	5%	5%	4%	4%	4%	5%	4%	3%	2%	1%	**3**	-5%	-3%	-8%	-7%	-6%	-7%	-5%	-5%	-5%	-4%	-4%	-3%
4	2%	2%	4%	3%	3%	4%	4%	3%	2%	2%	1%	1%	**4**	-3%	-2%	-6%	-6%	-5%	-6%	-5%	-5%	-4%	-3%	-3%	-3%
5	1%	2%	3%	2%	2%	2%	2%	2%	2%	2%	1%	1%	**5**	-2%	-2%	-4%	-4%	-3%	-4%	-4%	-4%	-2%	-2%	-2%	-1%
6	1%	2%	2%	1%	2%	2%	2%	1%	2%	1%	1%	1%	**6**	-2%	-1%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-1%
7	2%	1%	1%	1%	2%	2%	2%	2%	2%	2%	1%	1%	**7**	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
8	1%	1%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%	**8**	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
9	1%	2%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%	**9**	-1%	-1%	-2%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-1%	-1%
10	1%	1%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	**10**	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%
11	1%	1%	1%	2%	2%	3%	4%	4%	4%	4%	1%	1%	**11**	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
12	1%	1%	2%	2%	2%	3%	3%	3%	3%	4%	2%	1%	**12**	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	1%	1%	2%	1%	2%	3%	3%	3%	3%	4%	2%	1%	**13**	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	1%	1%	1%	1%	3%	4%	3%	3%	3%	4%	2%	1%	**14**	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	1%	1%	1%	1%	4%	5%	3%	3%	3%	4%	1%	1%	**15**	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
16	1%	1%	1%	1%	4%	5%	3%	3%	4%	5%	7%	4%	**16**	-1%	-1%	-2%	-1%	-2%	-2%	-1%	-2%	-1%	-1%	-1%	-1%
17	1%	1%	1%	2%	2%	2%	2%	2%	3%	2%	7%	5%	**17**	-1%	-1%	-1%	-1%	-2%	-3%	-3%	-3%	-3%	-2%	-1%	-1%
18	1%	1%	4%	4%	2%	3%	2%	2%	3%	2%	6%	4%	**18**	-1%	-1%	-1%	-1%	-2%	-3%	-3%	-3%	-3%	-2%	-1%	-1%
19	1%	2%	4%	4%	3%	3%	3%	4%	4%	3%	6%	5%	**19**	-1%	-1%	-2%	-1%	-2%	-3%	-3%	-4%	-4%	-3%	-2%	-1%
20	2%	3%	5%	6%	5%	5%	4%	4%	4%	4%	6%	9%	**20**	-1%	-2%	-2%	-2%	-3%	-4%	-4%	-5%	-5%	-5%	-3%	-2%
21	2%	5%	6%	6%	6%	6%	6%	5%	6%	5%	1%	1%	**21**	-2%	-2%	-5%	-6%	-6%	-7%	-6%	-5%	-5%	-9%	-7%	-5%
22	2%	5%	5%	4%	4%	4%	4%	3%	4%	4%	1%	1%	**22**	-3%	-5%	-7%	-7%	-6%	-7%	-7%	-6%	-5%	-8%	-7%	-6%
23	2%	4%	4%	4%	3%	3%	3%	3%	3%	3%	1%	1%	**23**	-3%	-5%	-7%	-7%	-6%	-7%	-5%	-4%	-5%	-5%	-5%	-4%

FIGURE C-20: NONRESIDENTIAL SYSTEMS WITH SOLAR PV (PG&E AS PROGRAM ADMINISTRATOR)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	1%	1%	2%	2%	2%	2%	1%	2%	2%	2%	1%	1%	**0**	-2%	-2%	-2%	-3%	-3%	-3%	-2%	-3%	-3%	-2%	-4%	-3%
1	2%	1%	2%	1%	1%	2%	1%	2%	2%	1%	1%	1%	**1**	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-3%	-3%	-2%	-3%	-2%
2	1%	2%	2%	2%	2%	2%	1%	2%	2%	1%	0%	0%	**2**	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-3%	-3%	-2%	-2%	-1%
3	1%	1%	2%	3%	2%	2%	2%	2%	2%	2%	1%	1%	**3**	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-3%	-2%	-2%	-1%	-1%
4	2%	1%	2%	3%	2%	3%	3%	3%	3%	2%	0%	0%	**4**	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
5	2%	1%	4%	5%	4%	4%	5%	7%	4%	3%	1%	1%	**5**	-2%	-2%	-2%	-3%	-3%	-4%	-3%	-3%	-3%	-2%	-1%	0%
6	3%	3%	5%	4%	3%	3%	3%	5%	4%	3%	1%	2%	**6**	-1%	-2%	-3%	-6%	-8%	-8%	-7%	-7%	-4%	-3%	0%	0%
7	3%	3%	4%	3%	2%	2%	2%	4%	3%	3%	1%	2%	**7**	-2%	-3%	-7%	-10%	-10%	-12%	-10%	-10%	-8%	-5%	-2%	-1%
8	3%	3%	2%	2%	1%	1%	1%	3%	2%	2%	1%	1%	**8**	-6%	-7%	-11%	-11%	-10%	-12%	-13%	-12%	-10%	-8%	-5%	-4%
9	3%	2%	2%	2%	1%	1%	1%	2%	2%	1%	0%	1%	**9**	-8%	-9%	-12%	-11%	-10%	-10%	-12%	-13%	-10%	-10%	-7%	-7%
10	1%	1%	1%	1%	1%	0%	1%	1%	1%	1%	0%	0%	**10**	-9%	-10%	-10%	-8%	-7%	-6%	-7%	-10%	-8%	-8%	-7%	-7%
11	1%	1%	1%	2%	2%	2%	2%	4%	4%	2%	1%	0%	**11**	-9%	-8%	-6%	-5%	-4%	-3%	-3%	-3%	-3%	-4%	-5%	-5%
12	1%	1%	2%	1%	3%	2%	2%	3%	3%	2%	1%	0%	**12**	-6%	-4%	-3%	-3%	-2%	-1%	-1%	-1%	-1%	-2%	-3%	-3%
13	1%	1%	1%	1%	3%	2%	3%	3%	3%	2%	1%	0%	**13**	-4%	-3%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
14	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	1%	**14**	-3%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	1%	1%	1%	1%	1%	2%	2%	2%	3%	3%	3%	1%	**15**	-2%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	0%
16	2%	1%	1%	2%	2%	4%	4%	4%	5%	6%	3%	2%	**16**	-2%	-1%	-2%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	0%	0%
17	4%	3%	4%	5%	7%	6%	5%	6%	4%	5%	8%	5%	**17**	-1%	-1%	-1%	-2%	-2%	-3%	-4%	-6%	-4%	-2%	0%	0%
18	4%	4%	6%	8%	9%	10%	9%	11%	6%	4%	9%	7%	**18**	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-2%	-2%	0%	0%
19	3%	4%	7%	8%	10%	11%	10%	10%	5%	3%	10%	8%	**19**	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-3%	-2%	-2%	0%	0%
20	4%	5%	7%	7%	7%	8%	7%	6%	4%	3%	4%	3%	**20**	-1%	-1%	-2%	-2%	-3%	-2%	-2%	-3%	-2%	-2%	0%	0%
21	6%	6%	5%	4%	3%	3%	2%	2%	3%	3%	2%	2%	**21**	-2%	-2%	-3%	-4%	-4%	-4%	-3%	-3%	-4%	-4%	0%	0%
22	5%	5%	6%	8%	5%	6%	4%	5%	7%	6%	1%	1%	**22**	-2%	-3%	-3%	-4%	-3%	-4%	-3%	-3%	-3%	-3%	-3%	-4%
23	6%	8%	3%	2%	1%	2%	1%	2%	2%	2%	1%	1%	**23**	-2%	-2%	-3%	-5%	-4%	-5%	-3%	-3%	-3%	-3%	-4%	-3%

FIGURE C-21: NONRESIDENTIAL SYSTEMS WITHOUT SOLAR PV (SCE AS PROGRAM ADMINISTRATOR)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12	Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	1%	1%	1%	1%	1%	1%	1%	1%	2%	1%	4%	3%	0	-7%	-5%	-4%	-4%	-4%	-5%	-5%	-4%	-5%	-4%	-11%	-9%
1	1%	1%	1%	1%	1%	2%	2%	3%	3%	1%	4%	2%	1	-5%	-4%	-3%	-3%	-3%	-5%	-5%	-4%	-4%	-4%	-8%	-7%
2	2%	2%	1%	1%	2%	3%	2%	2%	2%	1%	2%	1%	2	-4%	-3%	-2%	-2%	-2%	-4%	-4%	-4%	-5%	-4%	-4%	-4%
3	1%	1%	1%	1%	1%	2%	2%	2%	2%	1%	2%	1%	3	-3%	-3%	-2%	-2%	-2%	-4%	-4%	-3%	-4%	-3%	-4%	-3%
4	1%	1%	1%	1%	1%	2%	2%	2%	2%	1%	1%	1%	4	-3%	-2%	-2%	-2%	-2%	-3%	-3%	-3%	-4%	-2%	-3%	-3%
5	1%	1%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	5	-2%	-2%	-1%	-1%	-1%	-3%	-3%	-2%	-2%	-1%	-2%	-1%
6	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	6	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-2%	-1%
7	2%	2%	2%	2%	2%	1%	1%	2%	2%	3%	1%	1%	7	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-2%	-2%	-4%	-1%	-1%
8	2%	2%	2%	2%	2%	1%	1%	2%	2%	2%	1%	1%	8	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-2%	-2%	-3%	-1%	-1%
9	2%	1%	2%	2%	2%	1%	2%	2%	2%	2%	1%	1%	9	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-2%	-1%	-2%	-1%	-1%
10	2%	1%	2%	2%	1%	1%	2%	2%	1%	2%	1%	1%	10	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%
11	2%	1%	2%	2%	2%	1%	2%	1%	1%	2%	1%	1%	11	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%
12	2%	1%	2%	2%	2%	1%	2%	1%	1%	2%	2%	1%	12	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	2%	1%	2%	2%	2%	1%	1%	1%	1%	2%	2%	1%	13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	2%	1%	14	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
15	1%	1%	1%	2%	3%	6%	5%	3%	3%	3%	1%	1%	15	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
16	1%	1%	1%	2%	3%	3%	3%	3%	3%	3%	7%	4%	16	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
17	1%	1%	1%	2%	2%	2%	3%	3%	2%	3%	7%	5%	17	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
18	1%	1%	2%	3%	3%	2%	2%	3%	2%	3%	6%	4%	18	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
19	3%	2%	2%	3%	3%	2%	2%	3%	2%	3%	6%	5%	19	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%
20	4%	3%	4%	5%	4%	3%	2%	2%	2%	1%	6%	9%	20	-1%	-1%	-2%	-2%	-3%	-3%	-4%	-5%	-4%	-4%	-3%	-2%
21	4%	3%	4%	4%	4%	4%	3%	3%	2%	1%	1%	1%	21	-2%	-2%	-2%	-3%	-3%	-4%	-3%	-4%	-4%	-4%	-7%	-5%
22	4%	2%	2%	2%	2%	4%	4%	3%	3%	2%	1%	1%	22	-3%	-3%	-6%	-8%	-7%	-5%	-5%	-5%	-5%	-4%	-7%	-6%
23	2%	2%	1%	1%	1%	1%	1%	2%	3%	3%	1%	1%	23	-7%	-5%	-7%	-7%	-7%	-7%	-6%	-5%	-5%	-3%	-5%	-4%

FIGURE C-22: NONRESIDENTIAL SYSTEMS WITH SOLAR PV (SCE AS PROGRAM ADMINISTRATOR)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12	Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	0%	0%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	0	-2%	-2%	-2%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-4%	-3%
1	1%	1%	1%	1%	1%	1%	2%	1%	0%	1%	1%	1%	1	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-3%	-2%
2	1%	0%	1%	1%	1%	2%	2%	1%	1%	1%	0%	0%	2	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%
3	1%	1%	1%	1%	2%	2%	3%	1%	1%	1%	1%	1%	3	-1%	-1%	-1%	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
4	1%	1%	1%	2%	3%	4%	4%	2%	1%	1%	0%	0%	4	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
5	2%	1%	3%	4%	4%	5%	6%	4%	2%	3%	1%	1%	5	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	-1%	0%
6	3%	3%	4%	4%	4%	4%	4%	4%	3%	3%	1%	2%	6	-1%	-1%	-2%	-4%	-3%	-3%	-3%	-4%	-3%	-2%	0%	0%
7	5%	3%	3%	2%	3%	3%	2%	2%	2%	2%	1%	2%	7	-2%	-4%	-7%	-8%	-7%	-5%	-8%	-7%	-6%	-6%	-2%	-1%
8	3%	2%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	8	-6%	-8%	-11%	-12%	-10%	-10%	-14%	-11%	-9%	-10%	-5%	-4%
9	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	1%	9	-9%	-11%	-13%	-13%	-12%	-14%	-16%	-12%	-10%	-11%	-7%	-7%
10	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	10	-11%	-12%	-12%	-11%	-10%	-14%	-12%	-9%	-8%	-9%	-7%	-7%
11	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	11	-10%	-9%	-8%	-7%	-8%	-9%	-6%	-5%	-5%	-6%	-5%	-5%
12	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	0%	12	-6%	-6%	-5%	-4%	-5%	-6%	-4%	-3%	-3%	-2%	-3%	-3%
13	1%	1%	1%	1%	2%	1%	1%	2%	2%	1%	1%	0%	13	-3%	-3%	-3%	-3%	-4%	-3%	-3%	-2%	-2%	-2%	-1%	-2%
14	1%	1%	1%	2%	1%	1%	1%	2%	2%	2%	2%	1%	14	-2%	-2%	-2%	-3%	-5%	-3%	-3%	-3%	-2%	-2%	-1%	-1%
15	1%	1%	2%	2%	1%	1%	1%	2%	2%	1%	3%	1%	15	-2%	-2%	-2%	-2%	-4%	-2%	-3%	-3%	-2%	-2%	-1%	0%
16	2%	2%	3%	3%	2%	2%	2%	3%	4%	2%	3%	2%	16	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-1%	-1%	0%	0%
17	4%	4%	5%	5%	3%	3%	3%	4%	4%	5%	8%	5%	17	-1%	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
18	5%	7%	8%	8%	7%	6%	7%	7%	6%	6%	9%	7%	18	-1%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%
19	5%	7%	8%	8%	9%	9%	9%	8%	6%	6%	10%	8%	19	-1%	-1%	0%	0%	0%	0%	0%	-1%	-1%	0%	0%	0%
20	5%	7%	7%	7%	6%	7%	7%	6%	5%	5%	4%	3%	20	-1%	0%	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-1%	0%	0%
21	5%	7%	3%	2%	2%	4%	4%	3%	3%	2%	2%	2%	21	-1%	-1%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	0%	0%
22	2%	2%	4%	4%	4%	4%	4%	4%	4%	4%	1%	1%	22	-1%	-1%	-2%	-2%	-1%	-2%	-2%	-3%	-3%	-1%	-3%	-4%
23	2%	3%	1%	1%	1%	1%	1%	1%	0%	1%	1%	1%	23	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-1%	-4%	-3%

FIGURE C-23: NONRESIDENTIAL SYSTEMS WITHOUT SOLAR PV (SCG AS PROGRAM ADMINISTRATOR)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12	Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	1%	1%	3%	1%	2%	3%	6%	7%	6%	3%	4%	3%	0	-1%	-2%	-1%	-1%	-1%	-6%	-5%	-7%	-6%	-2%	-11%	-9%
1	0%	1%	1%	2%	2%	7%	7%	10%	13%	4%	4%	2%	1	-1%	-1%	-2%	-2%	-1%	-3%	-4%	-6%	-5%	-2%	-8%	-7%
2	1%	0%	0%	3%	5%	10%	12%	12%	11%	6%	2%	1%	2	-1%	-1%	-2%	-1%	-1%	-4%	-5%	-9%	-9%	-3%	-4%	-4%
3	0%	0%	2%	3%	5%	9%	10%	11%	11%	4%	2%	1%	3	-1%	-1%	-1%	-2%	-3%	-7%	-7%	-10%	-9%	-4%	-4%	-3%
4	0%	0%	0%	2%	5%	6%	8%	8%	8%	3%	1%	1%	4	0%	-1%	-1%	-2%	-3%	-7%	-7%	-12%	-11%	-3%	-3%	-3%
5	0%	0%	0%	2%	5%	5%	5%	5%	5%	3%	1%	1%	5	0%	-1%	-1%	-3%	-5%	-7%	-8%	-9%	-11%	-3%	-2%	-1%
6	0%	0%	0%	1%	3%	4%	3%	5%	2%	3%	1%	1%	6	0%	-1%	-1%	-2%	-5%	-6%	-7%	-7%	-5%	-3%	-2%	-1%
7	0%	0%	1%	7%	9%	3%	3%	4%	1%	7%	1%	1%	7	0%	-1%	-1%	-2%	-4%	-5%	-4%	-4%	-3%	-7%	-1%	-1%
8	1%	1%	1%	3%	3%	3%	2%	3%	1%	4%	1%	1%	8	-1%	-1%	-1%	-4%	-6%	-3%	-3%	-4%	-2%	-8%	-1%	-1%
9	1%	1%	2%	2%	2%	3%	2%	2%	2%	4%	1%	1%	9	0%	-1%	-1%	-4%	-4%	-3%	-3%	-5%	-2%	-6%	-1%	-1%
10	2%	1%	1%	2%	3%	2%	2%	3%	2%	4%	1%	1%	10	0%	-1%	-1%	-2%	-3%	-2%	-1%	-2%	-2%	-5%	-1%	-1%
11	2%	1%	1%	2%	2%	2%	2%	3%	3%	3%	1%	1%	11	-1%	-1%	-1%	-2%	-3%	-2%	-1%	-2%	-2%	-4%	-1%	-1%
12	2%	1%	1%	2%	2%	2%	2%	2%	3%	4%	2%	1%	12	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-5%	-1%	-1%
13	2%	1%	1%	2%	3%	2%	1%	2%	1%	2%	2%	1%	13	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-4%	-2%	-5%	-1%	-1%
14	1%	1%	0%	1%	2%	2%	1%	2%	1%	3%	2%	1%	14	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-3%	-2%	-4%	-1%	-1%
15	1%	0%	2%	2%	4%	4%	4%	4%	4%	6%	1%	1%	15	-2%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-2%	-1%	-1%
16	0%	0%	1%	1%	2%	3%	3%	3%	2%	5%	7%	4%	16	-3%	-1%	-2%	-3%	-4%	-3%	-3%	-3%	-3%	-3%	-1%	-1%
17	0%	1%	1%	1%	2%	2%	2%	3%	2%	5%	7%	5%	17	-2%	-1%	-3%	-5%	-4%	-4%	-3%	-4%	-2%	-3%	-1%	-1%
18	0%	1%	0%	1%	2%	2%	3%	6%	2%	5%	6%	4%	18	-3%	-1%	-2%	-2%	-2%	-2%	-2%	-3%	-1%	-2%	-1%	-1%
19	1%	1%	1%	4%	7%	7%	5%	7%	5%	10%	6%	5%	19	-1%	-1%	-1%	-1%	-2%	-2%	-3%	-4%	-2%	-2%	-2%	-1%
20	1%	1%	1%	3%	5%	11%	14%	16%	19%	7%	6%	9%	20	-1%	-2%	-1%	-2%	-5%	-6%	-6%	-7%	-5%	-3%	-3%	-2%
21	0%	1%	0%	1%	3%	6%	6%	8%	6%	3%	1%	1%	21	-1%	-1%	-1%	-3%	-4%	-7%	-8%	-12%	-12%	-4%	-7%	-5%
22	1%	1%	0%	2%	4%	9%	7%	8%	9%	3%	1%	1%	22	-1%	-1%	-1%	-2%	-4%	-6%	-6%	-10%	-9%	-6%	-7%	-6%
23	0%	2%	0%	1%	2%	5%	5%	7%	7%	6%	1%	1%	23	-1%	-1%	-1%	-2%	-4%	-8%	-7%	-9%	-9%	-4%	-5%	-4%

FIGURE C-24: NONRESIDENTIAL SYSTEMS WITH SOLAR PV (SCG AS PROGRAM ADMINISTRATOR)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12	Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%	1%	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-4%	-3%
1	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%	1%	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-3%	-2%
2	0%	0%	0%	0%	1%	2%	2%	1%	0%	0%	0%	0%	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-2%	-1%
3	0%	0%	0%	1%	1%	4%	3%	1%	0%	0%	1%	1%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%
4	0%	0%	0%	1%	3%	5%	5%	2%	0%	1%	0%	0%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%
5	1%	1%	2%	2%	4%	5%	6%	5%	2%	3%	1%	1%	5	0%	0%	0%	-1%	-1%	0%	0%	-1%	0%	0%	-1%	0%
6	3%	3%	4%	4%	3%	5%	3%	3%	3%	3%	1%	2%	6	0%	0%	-2%	-5%	-4%	-1%	-2%	-7%	-4%	-3%	0%	0%
7	5%	5%	3%	1%	3%	4%	2%	1%	2%	1%	1%	2%	7	-2%	-5%	-11%	-13%	-9%	-5%	-9%	-15%	-13%	-11%	-2%	-1%
8	2%	2%	1%	1%	2%	2%	1%	0%	1%	1%	1%	1%	8	-10%	-13%	-19%	-17%	-15%	-16%	-20%	-18%	-18%	-18%	-5%	-4%
9	1%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	1%	9	-17%	-20%	-22%	-21%	-18%	-27%	-27%	-19%	-19%	-19%	-7%	-7%
10	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	10	-19%	-23%	-21%	-18%	-14%	-26%	-20%	-15%	-17%	-17%	-7%	-7%
11	0%	0%	1%	0%	1%	1%	1%	1%	0%	0%	1%	0%	11	-19%	-20%	-14%	-9%	-11%	-18%	-10%	-6%	-9%	-11%	-5%	-5%
12	0%	0%	0%	1%	2%	0%	1%	1%	1%	1%	1%	0%	12	-13%	-10%	-6%	-5%	-6%	-9%	-6%	-3%	-4%	-4%	-3%	-3%
13	0%	0%	1%	1%	2%	0%	1%	2%	1%	1%	1%	0%	13	-6%	-4%	-2%	-3%	-5%	-3%	-5%	-2%	-2%	-2%	-1%	-2%
14	1%	0%	2%	2%	2%	0%	1%	3%	1%	2%	2%	1%	14	-2%	-3%	-2%	-2%	-5%	-1%	-4%	-3%	-2%	-2%	-1%	-1%
15	1%	1%	3%	2%	1%	0%	0%	1%	1%	1%	3%	1%	15	-1%	-2%	-2%	-2%	-6%	-1%	-4%	-4%	-2%	-2%	-1%	0%
16	3%	3%	6%	6%	2%	1%	0%	2%	5%	4%	3%	2%	16	-1%	-2%	-2%	-2%	-3%	0%	-2%	-2%	-1%	-1%	0%	0%
17	10%	8%	9%	8%	4%	3%	4%	7%	8%	8%	8%	5%	17	0%	0%	-1%	-1%	-1%	0%	0%	-1%	-1%	0%	0%	0%
18	10%	12%	13%	12%	9%	11%	12%	10%	11%	11%	9%	7%	18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	10%	12%	13%	13%	12%	14%	15%	13%	11%	12%	10%	8%	19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	10%	13%	13%	12%	11%	13%	13%	11%	11%	12%	4%	3%	20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	10%	12%	4%	1%	3%	5%	5%	3%	5%	4%	2%	2%	21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	1%	4%	7%	6%	9%	8%	10%	10%	8%	1%	1%	22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-3%	-4%
23	2%	3%	1%	0%	0%	1%	2%	0%	0%	0%	1%	1%	23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-4%	-3%

FIGURE C-25: GROCERY STORES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0%	1%	2%	4%	5%	5%	3%	3%	3%	5%	6%	5%	0	-1%	-3%	-2%	-6%	-4%	-5%	-3%	-3%	-3%	-4%	-7%	-3%
1	2%	2%	1%	2%	1%	2%	3%	4%	4%	3%	5%	5%	1	-2%	-2%	-2%	-4%	-4%	-5%	-3%	-2%	-3%	-4%	-5%	-4%
2	5%	3%	0%	2%	2%	6%	6%	5%	4%	4%	3%	3%	2	-2%	-1%	-1%	-3%	-3%	-4%	-5%	-4%	-4%	-6%	-4%	-3%
3	2%	0%	0%	2%	1%	2%	3%	4%	3%	2%	3%	3%	3	-3%	-3%	-1%	-3%	-3%	-6%	-5%	-5%	-4%	-5%	-5%	-4%
4	2%	0%	0%	1%	1%	1%	2%	2%	1%	1%	2%	3%	4	-3%	-1%	-1%	-3%	-2%	-4%	-4%	-5%	-4%	-3%	-4%	-4%
5	1%	0%	1%	2%	2%	1%	2%	3%	2%	1%	1%	1%	5	-2%	0%	-1%	-2%	-2%	-2%	-4%	-2%	-1%	-2%	-3%	-3%
6	0%	0%	1%	1%	1%	0%	1%	3%	2%	2%	1%	1%	6	-2%	0%	-1%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%
7	0%	0%	3%	5%	4%	1%	1%	1%	2%	5%	1%	1%	7	0%	-1%	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-4%	-2%	-2%
8	1%	1%	2%	2%	1%	2%	2%	1%	1%	2%	3%	4%	8	-1%	0%	-3%	-3%	-3%	-1%	-1%	-2%	-2%	-3%	-3%	-3%
9	1%	1%	2%	3%	2%	2%	3%	3%	2%	2%	2%	3%	9	-1%	0%	-3%	-3%	-2%	-1%	-1%	-2%	-2%	-4%	-2%	-2%
10	1%	1%	1%	2%	2%	3%	4%	4%	3%	2%	2%	2%	10	-1%	-1%	-2%	-2%	-2%	-1%	-2%	-2%	-2%	-3%	-2%	-3%
11	1%	1%	1%	3%	2%	3%	4%	4%	3%	3%	2%	2%	11	-1%	-1%	-1%	-2%	-2%	-1%	-2%	-3%	-3%	-3%	-2%	-2%
12	1%	1%	2%	3%	2%	3%	4%	4%	2%	3%	2%	2%	12	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%
13	2%	1%	2%	3%	3%	3%	3%	3%	1%	2%	2%	2%	13	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-2%	-3%	-2%	-2%
14	2%	1%	2%	3%	3%	3%	3%	3%	1%	1%	3%	2%	14	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%
15	1%	1%	2%	3%	3%	6%	6%	4%	3%	4%	2%	1%	15	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-1%
16	2%	1%	2%	3%	3%	5%	4%	3%	3%	4%	6%	4%	16	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-1%	-2%	-2%	-2%
17	2%	1%	2%	3%	4%	2%	3%	3%	4%	3%	5%	4%	17	-1%	-1%	-2%	-3%	-2%	-3%	-3%	-4%	-2%	-3%	-1%	-1%
18	1%	1%	2%	5%	6%	3%	2%	4%	4%	3%	4%	3%	18	-1%	-1%	-3%	-3%	-3%	-3%	-5%	-5%	-2%	-2%	-1%	-2%
19	1%	1%	1%	5%	5%	1%	3%	7%	4%	4%	3%	3%	19	-2%	-1%	-3%	-4%	-3%	-5%	-5%	-5%	-3%	-2%	-2%	-2%
20	0%	1%	1%	3%	2%	5%	3%	2%	2%	4%	3%	5%	20	-2%	-2%	-3%	-6%	-6%	-7%	-8%	-7%	-5%	-4%	-3%	-2%
21	2%	4%	1%	3%	1%	3%	2%	0%	1%	2%	1%	3%	21	-3%	-3%	-4%	-9%	-8%	-9%	-8%	-7%	-6%	-5%	-7%	-6%
22	1%	2%	1%	2%	1%	2%	2%	0%	1%	1%	1%	1%	22	-3%	-5%	-2%	-6%	-4%	-7%	-5%	-4%	-4%	-5%	-7%	-9%
23	0%	2%	1%	3%	3%	1%	1%	0%	3%	7%	1%	2%	23	-2%	-3%	-3%	-7%	-6%	-6%	-4%	-3%	-3%	-5%	-5%	-5%

FIGURE C-26: HOTELS (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	14%	15%	10%	10%	11%	8%	8%	9%	8%	9%	2%	2%	0	-3%	-10%	-7%	-8%	-5%	-4%	-3%	-4%	-3%	-7%	-5%	-3%
1	17%	12%	21%	20%	18%	12%	18%	18%	17%	9%	0%	0%	1	-7%	-10%	-9%	-11%	-10%	-6%	-4%	-3%	-3%	-5%	-5%	-3%
2	10%	5%	7%	10%	13%	5%	11%	14%	13%	6%	0%	0%	2	-9%	-6%	-13%	-15%	-10%	-5%	-4%	-3%	-3%	-5%	-5%	-3%
3	8%	5%	9%	11%	9%	6%	10%	11%	10%	7%	0%	0%	3	-10%	-5%	-11%	-10%	-7%	-4%	-3%	-3%	-3%	-3%	-3%	-2%
4	8%	4%	6%	8%	8%	2%	3%	9%	9%	4%	0%	0%	4	-6%	-3%	-6%	-7%	-4%	-3%	-2%	-3%	-3%	-3%	-2%	-2%
5	3%	2%	2%	1%	1%	1%	1%	4%	5%	5%	0%	0%	5	-5%	-2%	-4%	-4%	-3%	-1%	-1%	-2%	-2%	-2%	-1%	-1%
6	1%	2%	2%	1%	1%	1%	1%	2%	1%	0%	0%	1%	6	-3%	-1%	-2%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	0%
7	3%	2%	2%	1%	1%	1%	2%	0%	1%	0%	0%	1%	7	-2%	-2%	-3%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%
8	1%	1%	1%	1%	1%	1%	2%	1%	2%	0%	3%	3%	8	-2%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
9	1%	1%	2%	1%	1%	1%	1%	0%	2%	0%	4%	4%	9	-2%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
10	1%	1%	1%	1%	1%	1%	1%	0%	1%	0%	2%	3%	10	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
11	0%	1%	1%	1%	1%	2%	1%	1%	1%	3%	2%	3%	11	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
12	1%	1%	1%	1%	1%	2%	2%	1%	1%	4%	2%	3%	12	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	0%	1%	1%	1%	1%	2%	3%	2%	2%	4%	2%	2%	13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	0%	1%	1%	2%	2%	4%	4%	2%	3%	3%	2%	2%	14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	-1%
15	0%	1%	1%	3%	3%	6%	4%	5%	5%	7%	2%	2%	15	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
16	1%	3%	1%	3%	4%	5%	5%	4%	3%	8%	7%	4%	16	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
17	2%	3%	1%	2%	1%	4%	2%	3%	3%	6%	7%	3%	17	-1%	-1%	-1%	-1%	-4%	-2%	-3%	-3%	-2%	-2%	0%	0%
18	4%	4%	5%	2%	2%	3%	2%	3%	3%	6%	8%	4%	18	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	0%	0%
19	3%	4%	4%	3%	3%	4%	3%	7%	6%	9%	9%	4%	19	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-2%	-1%	0%	0%
20	2%	4%	4%	3%	2%	2%	2%	3%	2%	1%	10%	12%	20	-1%	-2%	-3%	-3%	-3%	-4%	-5%	-5%	-3%	-4%	-1%	0%
21	2%	3%	11%	6%	10%	7%	7%	15%	3%	6%	1%	2%	21	-2%	-2%	-4%	-4%	-5%	-6%	-5%	-5%	-3%	-7%	-10%	-11%
22	6%	14%	10%	10%	5%	3%	4%	9%	6%	3%	0%	1%	22	-5%	-5%	-7%	-5%	-5%	-7%	-6%	-7%	-3%	-5%	-6%	-9%
23	2%	8%	14%	22%	17%	15%	12%	18%	15%	15%	0%	1%	23	-3%	-7%	-10%	-7%	-6%	-5%	-3%	-3%	-4%	-10%	-2%	-1%

VERDANT

FIGURE C-27: INDUSTRIAL FACILITIES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	4%	3%	6%	6%	5%	6%	5%	5%	5%	4%	4%	3%	0	-6%	-7%	-5%	-6%	-6%	-7%	-5%	-6%	-6%	-5%	-6%	-6%
1	4%	3%	5%	6%	5%	6%	7%	7%	8%	5%	3%	3%	1	-6%	-5%	-6%	-6%	-6%	-7%	-6%	-6%	-6%	-5%	-5%	-5%
2	6%	5%	6%	7%	7%	7%	6%	6%	6%	4%	3%	3%	2	-5%	-4%	-7%	-6%	-6%	-8%	-7%	-7%	-8%	-5%	-4%	-3%
3	3%	3%	5%	5%	5%	5%	5%	5%	5%	4%	3%	3%	3	-6%	-4%	-6%	-6%	-6%	-8%	-6%	-6%	-6%	-4%	-4%	-3%
4	3%	3%	4%	4%	4%	4%	4%	4%	5%	3%	3%	2%	4	-5%	-4%	-6%	-6%	-6%	-7%	-5%	-6%	-6%	-4%	-3%	-3%
5	3%	3%	3%	4%	3%	3%	3%	4%	5%	4%	3%	2%	5	-4%	-4%	-5%	-4%	-5%	-4%	-4%	-5%	-5%	-3%	-3%	-2%
6	3%	3%	3%	3%	2%	3%	2%	3%	4%	4%	3%	3%	6	-3%	-3%	-3%	-4%	-4%	-3%	-3%	-4%	-4%	-3%	-2%	-2%
7	3%	3%	3%	4%	3%	2%	3%	4%	4%	4%	2%	4%	7	-2%	-2%	-3%	-4%	-4%	-3%	-3%	-3%	-3%	-6%	-3%	-2%
8	3%	2%	2%	3%	3%	2%	2%	3%	3%	3%	4%	4%	8	-3%	-3%	-3%	-4%	-4%	-3%	-3%	-4%	-4%	-6%	-8%	-8%
9	3%	2%	2%	3%	2%	2%	3%	3%	3%	3%	4%	3%	9	-3%	-3%	-4%	-4%	-3%	-3%	-3%	-5%	-5%	-5%	-7%	-7%
10	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	3%	3%	10	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-5%	-5%	-5%
11	2%	2%	2%	3%	3%	4%	5%	4%	4%	4%	3%	2%	11	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-2%	-3%	-3%	-4%	-4%
12	2%	2%	2%	2%	4%	3%	4%	4%	4%	4%	3%	2%	12	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-3%
13	2%	2%	2%	2%	4%	3%	3%	3%	3%	3%	2%	2%	13	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-2%
14	1%	1%	2%	2%	4%	4%	3%	3%	3%	3%	2%	2%	14	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-2%
15	1%	1%	2%	2%	4%	6%	5%	5%	4%	6%	2%	2%	15	-2%	-2%	-2%	-3%	-3%	-2%	-2%	-2%	-2%	-1%	-3%	-2%
16	2%	2%	2%	2%	3%	6%	4%	5%	5%	6%	6%	4%	16	-2%	-2%	-2%	-2%	-3%	-3%	-2%	-2%	-2%	-1%	-2%	-1%
17	2%	2%	2%	3%	3%	4%	3%	4%	4%	5%	6%	4%	17	-2%	-2%	-2%	-2%	-2%	-4%	-4%	-5%	-4%	-3%	-2%	-1%
18	3%	2%	4%	5%	4%	5%	4%	5%	5%	5%	6%	4%	18	-2%	-2%	-2%	-2%	-2%	-3%	-4%	-4%	-3%	-3%	-2%	-2%
19	3%	3%	4%	5%	5%	5%	4%	5%	5%	6%	7%	6%	19	-2%	-2%	-2%	-2%	-3%	-3%	-4%	-4%	-3%	-3%	-2%	-1%
20	4%	4%	6%	8%	7%	7%	7%	7%	6%	4%	7%	10%	20	-2%	-2%	-3%	-4%	-4%	-6%	-5%	-6%	-6%	-5%	-3%	-2%
21	6%	8%	6%	6%	6%	7%	6%	6%	5%	3%	4%	5%	21	-3%	-3%	-6%	-7%	-6%	-7%	-6%	-8%	-7%	-8%	-6%	-5%
22	4%	5%	6%	6%	6%	7%	5%	5%	6%	4%	3%	3%	22	-6%	-7%	-6%	-7%	-7%	-8%	-7%	-7%	-7%	-6%	-8%	-7%
23	4%	5%	5%	4%	4%	5%	5%	5%	5%	4%	3%	3%	23	-5%	-6%	-7%	-8%	-7%	-10%	-7%	-7%	-8%	-7%	-5%	-4%

FIGURE C-28: OFFICES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	1%	2%	2%	2%	3%	1%	1%	1%	1%	1%	6%	3%	0	-18%	-13%	-10%	-10%	-10%	-8%	-9%	-5%	-7%	-7%	-7%	-8%
1	1%	1%	2%	2%	2%	1%	1%	2%	2%	1%	1%	2%	1	-12%	-11%	-6%	-6%	-7%	-8%	-8%	-4%	-6%	-6%	-8%	-8%
2	2%	2%	3%	3%	3%	3%	2%	3%	1%	1%	1%	1%	2	-8%	-7%	-5%	-4%	-5%	-6%	-7%	-4%	-6%	-6%	-5%	-6%
3	1%	1%	1%	2%	2%	2%	2%	2%	1%	1%	0%	2%	3	-5%	-6%	-4%	-4%	-4%	-6%	-6%	-4%	-5%	-5%	-5%	-5%
4	1%	1%	1%	1%	2%	3%	4%	2%	1%	1%	0%	2%	4	-3%	-4%	-3%	-3%	-3%	-5%	-4%	-2%	-4%	-3%	-3%	-4%
5	1%	2%	2%	2%	3%	2%	2%	2%	1%	1%	1%	3%	5	-2%	-3%	-2%	-2%	-2%	-4%	-2%	-1%	-2%	-1%	-2%	-3%
6	3%	3%	2%	2%	3%	2%	2%	2%	1%	1%	2%	5%	6	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-2%
7	3%	4%	2%	2%	3%	1%	1%	1%	1%	1%	2%	6%	7	0%	0%	-2%	-2%	-2%	-2%	-2%	-3%	-1%	0%	-1%	-1%
8	3%	4%	2%	2%	3%	1%	2%	1%	1%	2%	2%	3%	8	0%	0%	-2%	-2%	-2%	-2%	-2%	-3%	-1%	-1%	-1%	-1%
9	4%	3%	2%	2%	3%	2%	3%	2%	2%	2%	2%	2%	9	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-3%	-1%	-1%	-1%	-1%
10	3%	3%	2%	2%	3%	2%	3%	2%	2%	3%	2%	2%	10	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
11	3%	2%	3%	2%	3%	2%	3%	2%	3%	3%	3%	2%	11	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
12	4%	2%	4%	3%	4%	2%	3%	2%	2%	3%	3%	2%	12	0%	0%	-1%	-1%	-1%	0%	-1%	0%	0%	-1%	-1%	-1%
13	4%	3%	2%	2%	2%	2%	3%	2%	2%	3%	3%	2%	13	0%	-1%	-1%	-1%	-1%	0%	0%	-1%	0%	-1%	-1%	-1%
14	3%	2%	2%	2%	3%	2%	3%	2%	2%	3%	2%	1%	14	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%
15	3%	2%	3%	5%	7%	10%	7%	4%	3%	3%	2%	1%	15	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
16	5%	4%	4%	5%	7%	3%	4%	5%	3%	2%	3%	3%	16	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
17	4%	3%	4%	3%	3%	2%	3%	4%	3%	3%	3%	2%	17	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%	-1%	0%
18	3%	4%	5%	4%	4%	2%	3%	4%	3%	3%	2%	2%	18	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	0%	0%
19	3%	4%	5%	4%	4%	2%	3%	4%	3%	5%	2%	2%	19	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	0%
20	3%	4%	10%	11%	8%	3%	2%	2%	2%	1%	2%	3%	20	-1%	0%	-2%	-3%	-4%	-2%	-3%	-5%	-4%	-3%	-2%	-2%
21	7%	3%	11%	13%	8%	4%	3%	1%	1%	1%	1%	2%	21	-1%	-2%	-3%	-3%	-5%	-2%	-3%	-4%	-3%	-7%	-4%	-3%
22	9%	2%	3%	2%	2%	5%	4%	3%	1%	1%	1%	1%	22	-2%	-4%	-15%	-20%	-18%	-7%	-9%	-7%	-8%	-8%	-8%	-9%
23	1%	1%	2%	3%	3%	1%	1%	2%	4%	4%	1%	2%	23	-19%	-14%	-19%	-19%	-18%	-10%	-10%	-6%	-6%	-7%	-7%	-7%

FIGURE C-29: RETAIL STORES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	3%	2%	3%	2%	2%	2%	2%	2%	4%	5%	0	-4%	-4%	-4%	-4%	-5%	-5%	-3%	-3%	-2%	-2%	-5%	-5%
1	2%	2%	2%	2%	3%	3%	3%	5%	6%	4%	4%	3%	1	-3%	-4%	-3%	-3%	-4%	-3%	-3%	-3%	-4%	-3%	-4%	-4%
2	1%	2%	3%	2%	3%	4%	3%	6%	6%	6%	3%	2%	2	-3%	-3%	-3%	-3%	-4%	-4%	-3%	-4%	-4%	-3%	-4%	-3%
3	1%	2%	2%	1%	2%	3%	2%	3%	3%	2%	2%	2%	3	-3%	-3%	-3%	-3%	-4%	-4%	-3%	-5%	-6%	-5%	-3%	-3%
4	1%	1%	1%	1%	2%	2%	2%	3%	3%	2%	2%	2%	4	-2%	-2%	-3%	-2%	-3%	-4%	-3%	-5%	-4%	-4%	-3%	-3%
5	1%	1%	3%	1%	2%	2%	1%	1%	2%	2%	1%	2%	5	-2%	-1%	-1%	-2%	-4%	-5%	-4%	-5%	-5%	-3%	-2%	-2%
6	2%	3%	3%	1%	1%	1%	0%	0%	1%	1%	2%	2%	6	-1%	-1%	-2%	-2%	-3%	-4%	-4%	-3%	-3%	-3%	-2%	-2%
7	2%	2%	2%	1%	1%	2%	2%	1%	2%	2%	0%	1%	7	-1%	-2%	-2%	-4%	-4%	-4%	-4%	-5%	-3%	-4%	-2%	-2%
8	1%	1%	0%	1%	1%	1%	2%	2%	2%	2%	3%	2%	8	-2%	-3%	-4%	-5%	-4%	-4%	-5%	-5%	-4%	-4%	-2%	-3%
9	1%	0%	0%	1%	1%	2%	2%	2%	2%	2%	1%	1%	9	-3%	-3%	-5%	-5%	-4%	-4%	-5%	-5%	-4%	-4%	-3%	-4%
10	0%	1%	1%	1%	1%	1%	2%	2%	2%	1%	1%	1%	10	-3%	-3%	-4%	-4%	-3%	-3%	-5%	-4%	-4%	-4%	-3%	-3%
11	1%	1%	1%	1%	1%	2%	2%	2%	3%	2%	1%	1%	11	-2%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-2%	-3%	-2%
12	1%	1%	1%	1%	1%	2%	2%	2%	3%	2%	1%	1%	12	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-1%	-1%	-2%
13	1%	1%	1%	2%	1%	2%	2%	2%	2%	3%	2%	1%	13	-1%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-1%	-1%	-1%
14	2%	1%	1%	2%	2%	2%	1%	2%	2%	3%	2%	1%	14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-1%	-1%
15	1%	1%	1%	1%	3%	3%	3%	3%	3%	4%	2%	1%	15	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-1%	-1%
16	2%	1%	1%	2%	4%	5%	5%	4%	4%	4%	4%	2%	16	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-2%	-2%	-1%	-1%
17	5%	3%	3%	4%	4%	6%	6%	6%	5%	5%	7%	5%	17	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-2%	-1%	-1%
18	5%	6%	8%	9%	5%	5%	5%	6%	5%	5%	6%	5%	18	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
19	5%	6%	9%	11%	9%	9%	9%	7%	6%	6%	6%	5%	19	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-3%	-4%	-3%	-1%	-1%
20	4%	6%	8%	9%	7%	7%	7%	6%	5%	3%	6%	8%	20	-1%	-1%	-2%	-3%	-2%	-2%	-2%	-3%	-5%	-4%	-3%	-2%
21	2%	4%	2%	2%	2%	3%	3%	3%	2%	3%	2%	3%	21	-6%	-7%	-12%	-8%	-7%	-9%	-8%	-7%	-6%	-8%	-6%	-4%
22	1%	2%	1%	2%	2%	2%	2%	3%	4%	3%	2%	1%	22	-4%	-4%	-5%	-4%	-4%	-6%	-6%	-5%	-4%	-5%	-9%	-9%
23	1%	2%	1%	1%	2%	3%	3%	3%	3%	2%	2%	3%	23	-3%	-3%	-4%	-6%	-5%	-6%	-5%	-3%	-2%	-4%	-6%	-4%

FIGURE C-30: SCHOOLS (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	1%	0%	0	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%
1	1%	1%	1%	1%	1%	1%	2%	1%	0%	0%	0%	0%	1	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	-1%	-1%
2	1%	0%	0%	1%	1%	1%	2%	1%	0%	0%	0%	0%	2	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
3	1%	0%	1%	1%	1%	2%	2%	1%	0%	0%	0%	0%	3	-1%	-1%	-1%	-1%	0%	-1%	-1%	0%	0%	0%	0%	0%
4	1%	0%	1%	2%	2%	3%	4%	2%	1%	1%	1%	0%	4	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
5	1%	1%	3%	4%	4%	4%	5%	4%	2%	2%	1%	1%	5	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
6	3%	2%	4%	4%	4%	4%	3%	4%	2%	2%	2%	2%	6	0%	-1%	-2%	-3%	-3%	-3%	-3%	-3%	-2%	-1%	-1%	0%
7	4%	3%	3%	2%	3%	2%	2%	2%	2%	2%	1%	2%	7	-1%	-3%	-7%	-8%	-6%	-5%	-8%	-7%	-6%	-5%	-4%	-1%
8	3%	2%	2%	1%	2%	2%	1%	1%	1%	1%	1%	2%	8	-5%	-8%	-10%	-11%	-9%	-10%	-13%	-10%	-8%	-9%	-7%	-5%
9	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	9	-9%	-11%	-13%	-13%	-11%	-13%	-15%	-11%	-9%	-10%	-10%	-9%
10	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	10	-10%	-12%	-12%	-10%	-9%	-12%	-10%	-9%	-8%	-8%	-10%	-10%
11	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	11	-9%	-9%	-8%	-6%	-7%	-9%	-6%	-5%	-5%	-5%	-8%	-9%
12	1%	1%	1%	1%	2%	1%	1%	2%	1%	1%	1%	1%	12	-6%	-5%	-4%	-4%	-4%	-5%	-4%	-3%	-3%	-2%	-4%	-6%
13	1%	1%	1%	1%	2%	1%	1%	2%	2%	2%	1%	1%	13	-3%	-3%	-2%	-3%	-4%	-3%	-3%	-2%	-2%	-1%	-2%	-3%
14	1%	1%	1%	2%	1%	1%	1%	2%	2%	1%	2%	1%	14	-2%	-2%	-2%	-3%	-5%	-3%	-3%	-3%	-2%	-2%	-1%	-2%
15	1%	1%	3%	3%	2%	2%	2%	2%	3%	2%	2%	1%	15	-2%	-2%	-2%	-2%	-4%	-2%	-3%	-3%	-2%	-2%	-1%	-1%
16	3%	3%	4%	3%	2%	2%	2%	3%	4%	3%	3%	2%	16	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	0%
17	4%	4%	5%	5%	4%	3%	3%	4%	4%	5%	4%	4%	17	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	0%	0%
18	4%	6%	8%	8%	7%	7%	7%	7%	6%	5%	5%	5%	18	-1%	0%	0%	0%	-1%	0%	0%	-1%	-1%	0%	0%	0%
19	4%	6%	7%	8%	8%	9%	9%	7%	6%	5%	6%	6%	19	-1%	-1%	0%	0%	0%	0%	0%	-1%	-1%	-1%	0%	0%
20	4%	6%	6%	6%	6%	7%	7%	5%	4%	5%	5%	5%	20	-1%	-1%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	0%	0%
21	4%	6%	3%	2%	2%	4%	3%	3%	3%	2%	4%	4%	21	-2%	-2%	-3%	-2%	-2%	-1%	-1%	-2%	-2%	-1%	-2%	-1%
22	2%	2%	4%	5%	4%	5%	4%	4%	4%	4%	2%	2%	22	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-2%	-1%
23	3%	4%	1%	0%	1%	1%	1%	0%	0%	0%	3%	3%	23	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%