CALIFORNIA SOLAR INITIATIVE (CSI) FINAL IMPACT EVALUATION

Final Report to CPUC

Submitted to:

California Public Utilities Commissions (CPUC)
Pacific Gas and Electric Company
CSI Working Group

Prepared by:

Itron

1111 Broadway
Suite 1800
Oakland, CA 94607
www.itron.com/strategicanalytics

VERDANT

Verdant Associates, LLC.

Berkeley, CA 94707
www.verdantassoc.com

January 28, 2021

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 EXECUTIVE SUMMARY

The California Solar Initiative (CSI) was established legislatively by Senate Bill (SB) 1 (Murray, 2006) as a key part of the Go Solar California campaign to increase the adoption of solar energy systems. The CSI was a solar rebate program for California customers in Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) territories. The program was funded by California's electricity ratepayers and managed by Program Administrators (PAs) representing California's three major electric investor-owned utilities (IOUs). The California Public Utilities Commission (CPUC) provided oversight and guidance on the CSI program. The CSI program had a total budget of $2.167 billion between 2007 and 2016 with the goals to install approximately 1,940 MW_{AC} of new solar generation capacity and establish a robust, self-sustaining industry for customer solar photovoltaic (PV) in California. One year after the end of the program, at the end of 2017, 724,816 behind-the-meter (BTM) solar PV systems with 5,885 MW_{AC} of capacity had been installed in California's three IOU territories.

1.1 PURPOSE AND SCOPE OF REPORT

The purpose of this Final Impact Evaluation is to provide the CPUC staff and the California public with important insight into the value and efficacy achieved by the CSI program, including value from the statewide BTM PV population. These insights should serve as a guide for future program design and policymaking initiatives to support the state's renewable energy and greenhouse gas (GHG) emissions reduction targets. This evaluation broadened the scope beyond the CSI to encompass all BTM PV systems installed in the three IOU territories.

Previous CSI Impact Evaluation studies provided important information on impacts of customer solar installed through the program from 2007 through 2010. The Final Impact Evaluation investigates how all customer solar PV installed in California has affected the electricity system and the environment through December 31, 2017. The evaluation also investigates how solar PV impacts the electrical load observed by the utilities (net load) and the quantity of electricity consumed by California customers with BTM solar.

A key goal of the CSI program was to establish a self-sustaining customer solar market – a goal that has largely been achieved – as approximately 80 percent of the installed customer solar systems in California have been installed without the CSI program rebates.[1] The Final Impact Evaluation describes CSI program

[1] Based on approximately 149,000 CSI systems out of a total of 733,000 BTM solar PV systems installed by the end of 2017.

participation and customer PV market trends, describing who installed BTM solar and where installations are concentrated within the IOU territories.

Where possible, this evaluation's focus extended beyond the CSI, encompassing BTM PV systems installed with and without CSI incentives. The broader focus allowed the evaluation to develop a more complete picture of the impact of BTM PV on customers, the market, the environment, and the grid. The expanded focus, however, required the evaluation team to synthesize data from multiple sources covering different years, geographies, and customers. The different data sources and their advantages and limitations are described in each section, as are the different analytical approaches.

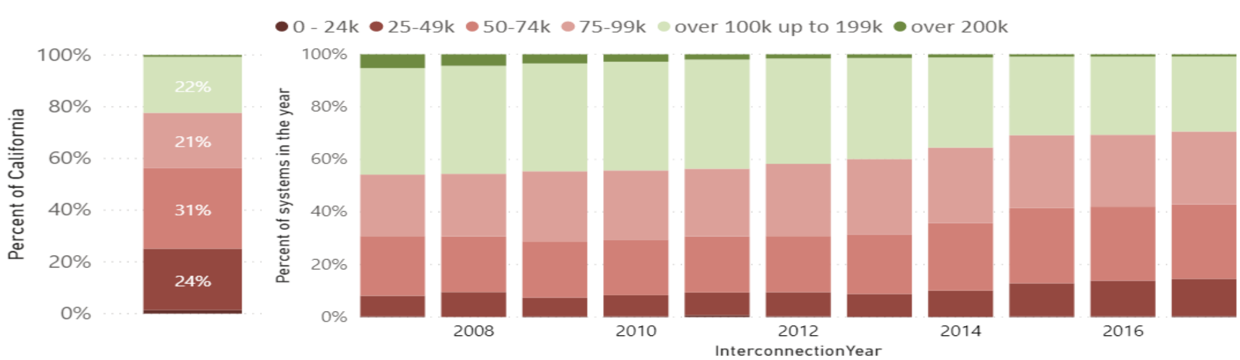
1.2 EVALUATION FINDINGS

The evaluation team's findings were developed based on observed and, as appropriate, simulated analyses for a wide range of impacts. These impacts reveal how BTM PV impacted the electricity consumption, emissions, customer load, and load on some distribution feeders. High-level findings from this impact evaluation are presented below, and in-depth findings and analyses can be found in *Section 3 through Section 7* of the report. The demographics and changing trends of residential solar PV adoption are also analyzed in *Section 3.*

1.2.1 Demographic Adoption Trends

The primary goal of the CSI was to create a self-sustaining solar industry in California. A key aspect of that goal includes broad adoption of solar across different household economics and demographics to ensure that the benefits from solar adoption are available to all Californians, not just those with higher incomes. Figure 1-1 shows total solar adoption by census tract median income in 2017 and the trend in this over time. California's overall population is shown on the left and illustrates that more solar tends to be installed in more affluent areas and less frequently in less affluent areas. But in later years there is an increase in solar adoption in neighborhoods with lower median incomes.

FIGURE 1-1: ADOPTION OF SOLAR BY MEDIAN HOUSEHOLD INCOME (2017$) AND INTERCONNECTION YEAR

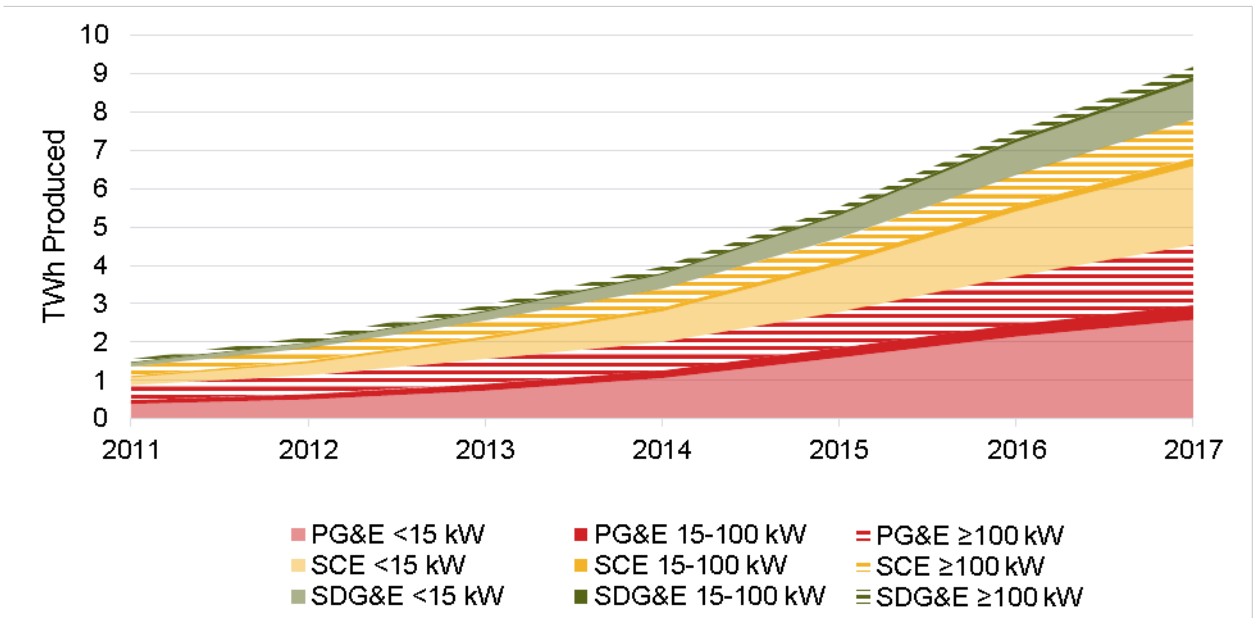


Some neighborhoods show significant adoption of solar, with over half the homes having solar for many census tracts. Many of the high adoption areas align with new solar subdivisions that received New Solar Homes Partnership (NSHP) incentives.[2] The trend of new subdivisions driving higher residential solar density is likely to expand as Title 24 building codes for 2020 mandate solar for most new homes in California.

1.2.2 PV Generation and its Benefits

Solar generation is a growing part of California's energy mix. Figure 1-2 shows the annual generation from BTM solar PV by utility customer and PV size category. In *Section 4*, the evaluation team presents PV generation results and impacts on system (utility) load and emissions. By 2017, BTM solar generated over 9 terawatt-hours (TWh) of electricity. This represents approximately 5 percent of the total system electric consumption for PG&E, SCE and SDG&E for 2017.[3] In later years, smaller systems (those less than 15 kilowatts (kW) and largely residential) are the largest part of capacity and generation. For reference, the average size of a single-family residential system is ~5 kW_{AC}, commercial systems ~90 kW_{AC} and Industrial systems ~402 kW_{AC}.

FIGURE 1-2: ANNUAL GENERATION BY YEAR, UTILITY CUSTOMER, AND SOLAR PV SYSTEM SIZE RANGE

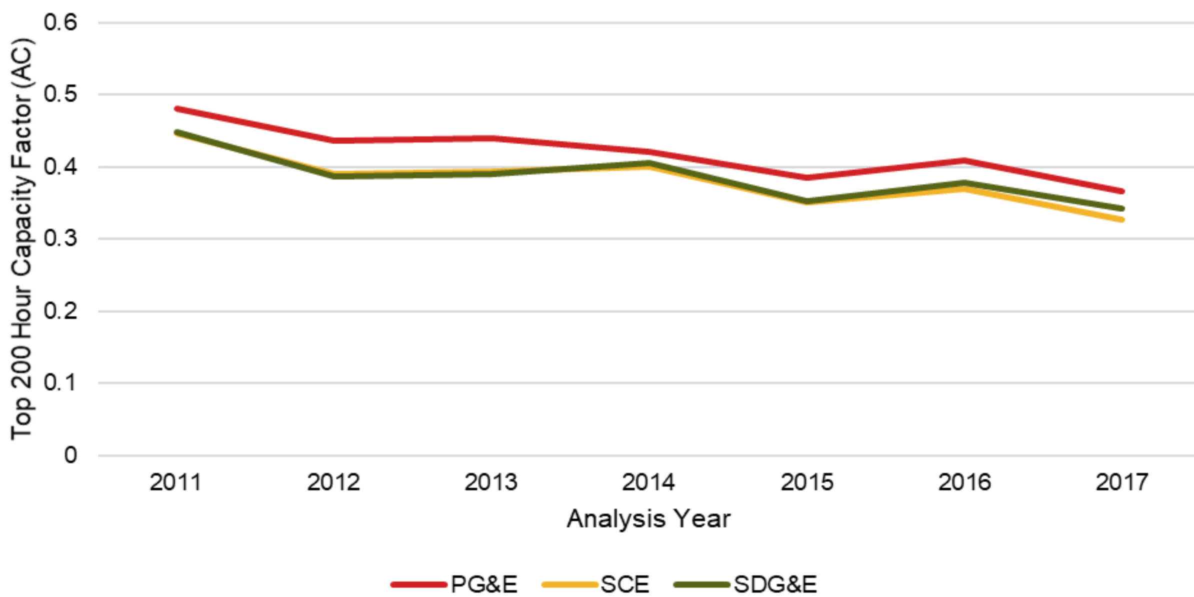


[2] https://www.energy.ca.gov/programs-and-topics/programs/new-solar-homes-partnership-program-nshp

[3] Consumption in 2017 was 81,945 gigawatt-hours (GWh) in PG&E territory, 85,602 GWh in SCE territory, and 19,017 GWh in SDG&E territory, for a total of 186,564 GWh. http://www.ecdms.energy.ca.gov/elecbyutil.aspx

Annual generation is only one metric of how solar provides for California's electricity needs. Another metric is how well solar generation is matched to electricity demand. Excess energy that cannot be used is not very valuable unless it can be stored cost-effectively for later use. Solar's ability to reduce peak electricity demand is one metric that provides some insight into how well solar serves customers' electricity needs during higher stress hours for the grid. Capacity Factor (CF) is the fraction of the installed capacity that is producing energy during any given time period; a 1 kW system with a capacity factor of 1 over a year would produce 8,760 (365*24) kWh. Figure 1-3 below shows the average CF during the top 200 hours of net load by IOU and calendar year. Each line represents the contributions of PV systems within each IOU's service territory towards the California Independent System Operator (CAISO) peak load. In general, CFs during the top 200 CAISO load hours range from 0.35 to 0.50.

FIGURE 1-3: ESTIMATED IMPACT (CAPACITY FACTOR) DURING CAISO TOP 200 GROSS LOAD HOURS[4]



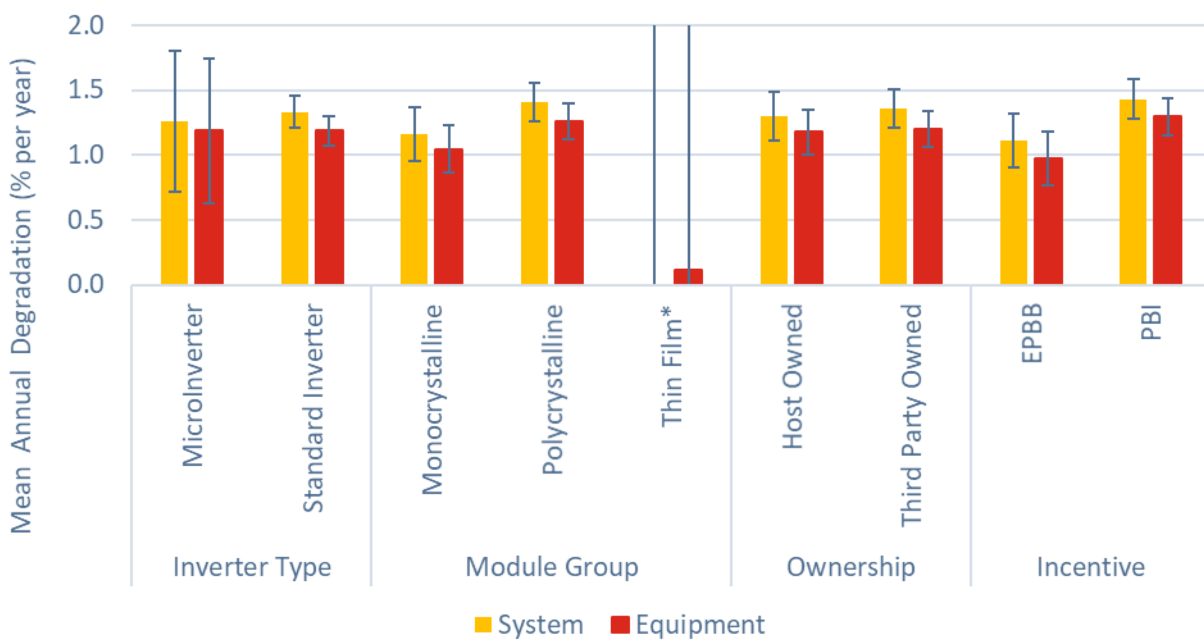
Systems in PG&E territory show somewhat higher CFs during the top 200 hours of load statewide because of longer summer days and, therefore, more late-afternoon sunlight in more northern latitudes and western longitudes. The decline in average CF over time is due to the peak CAISO load hours moving to later in the summer/fall and the slowly increasing age of the fleet of BTM solar PV systems in California.

4 The top 200 CAISO hours can be found in Appendix A, Table A-7.

During 2017, the evaluation team estimates that California BTM PV systems reduced GHG emissions by nearly 3.5 million metric tons of CO_2, which is equivalent to removing over 700,000 passenger cars from the road.[5]

Solar PV systems tend to produce less energy, or degrade, as the systems and components age.[6] Figure 1-4 shows the mean annual year-over-year degradation rates and error bars at the 90 percent confidence level by different groupings such as inverter type, module group, ownership, and incentive. Data is available for only a handful of thin film systems, so although the mean degradation for thin film appears lower than other technologies, the uncertainty associated with this mean is substantial, as evidenced by error bars that exceed the range of the graph.

FIGURE 1-4: ANNUAL DEGRADATION RESULTS BY GROUP



5 https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

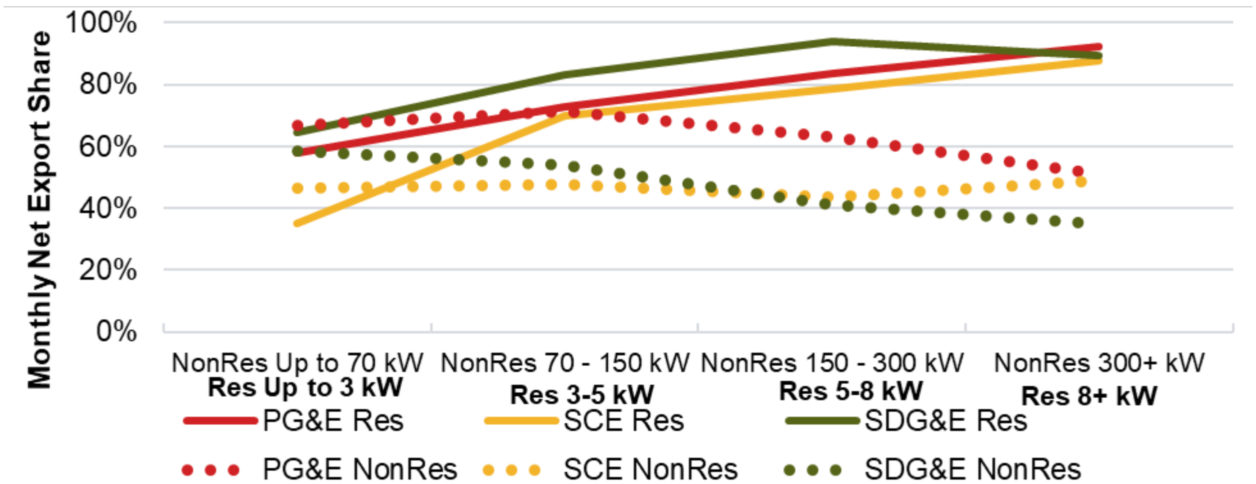
6 Life cycle costs that include solar PV manufacturing and disposal are not included in this analysis. NREL analysis has found that the energy payback for a PV panel to replace the energy required to create the panel is one to four years. With life expectancies of 30 years, 87 to 97 percent of the energy that PV systems generate will not be plagued by pollution, GHG, and depletion of resources. From *PV FAQS:* https://www.nrel.gov/docs/fy04osti/35489.pdf

The overall mean performance degradation rate was 1.35 percent, developed using the RdTools software created by NREL.[7] This rate is similar to the 1.5 percent default assumption built into NREL's PVWatts simulator and the 2 percent rate estimated by the annual regression model. *Section 4* of this report presents the evaluation team's analysis of PV generation, emissions impacts, and PV performance degradation.

1.2.3 Customer Load Impacts

"Net energy export", or net export, is a consequence of PV production exceeding a site's electricity consumption. The analysis in *Section 5* and *Appendix B* of this report explores several factors influencing net export, including customer segment, coastal and inland geography, system size, and seasonality. The evaluation team found that the likelihood of residential monthly net export (when total monthly generation exceeds total monthly consumption) averaged 83 percent for SDG&E PV households, 73 percent for PG&E, and 67 percent for SCE. A substantially smaller share of residential customers with PV are annual net exporters: 38 percent in SDG&E, 19 percent for PG&E, and 18 percent for SCE. Note that the likelihood of commercial net export is lower than for residential PV customers. Figure 1-5 shows the share of sites with at least a month of net export by system size. Larger residential systems are more likely to be net exporters than smaller residential systems, while smaller non-residential systems are more likely to have monthly net export than larger non-residential systems.

FIGURE 1-5: MONTHLY NET EXPORT SHARE BY SECTOR, IOU, AND PV SYSTEM SIZE



PV generation has a dramatic impact on customers' consumption of utility electricity and their export of electricity to their utility, or their net load shape. The cumulative impact of increasing BTM generation

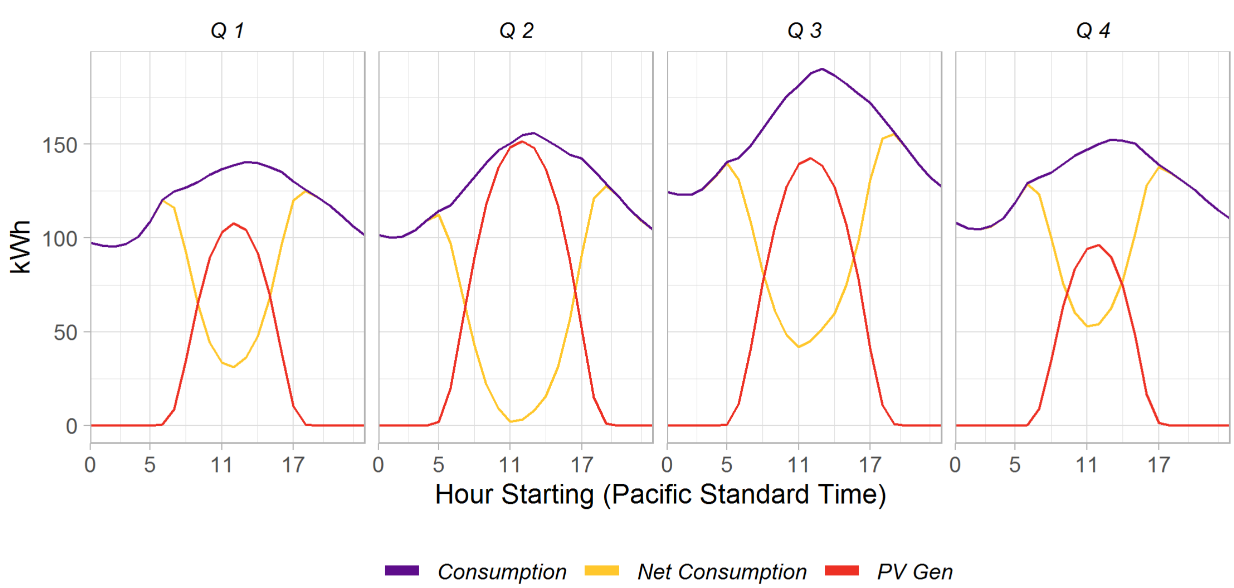
7 National Renewable Energy Lab (NREL) RdTools is a Python-based open source tool developed by a collaboration of NREL and the solar industry to analyze the degradation rate of PV generation.

contributes to the "duck curve" with lower net daytime loads and a steeper afternoon ramp. In *Section 6* and *Appendix C*, the evaluation team presents findings of how PV generation changes customer net load.

The average residential PV system in the team's sample[8] produces 63 percent of household electricity consumption in PG&E and SCE's territories and 69 percent in SDG&E's. However, the California Energy Commission (CEC) recently assumed that residential PV systems produce 90 percent of a customer's electricity needs over a year—and this potential overestimation could lead to under procurement of generation to meet California's energy needs.[9] The recent NEM 2.0 Lookback study has additional data on newer systems that shows that newer systems tend to be sized for a much larger fraction of annual consumption and the 90 percent assumption may underestimate the generation from newer systems.

Customer consumption, PV production, and net load are seasonal. Figure 1-6 shows the average quarterly variation for SCE's residential PV customers. Average PV generation peaks and net consumption reaches a minimum during the second quarter when California skies are clear, and temperatures are low. Average consumption peaks in the summer months (the third quarter), likely driven by higher summer AC usage. The combination of higher PV production and lower electricity consumption drives the ratio of PV generation/consumption to be highest in the spring, falling in the summer.

FIGURE 1-6: SCE AVERAGE RESIDENTIAL CSI CUSTOMER CONSUMPTION, LOAD, AND PV PRODUCTION BY QUARTER



[8] See Sections 4 and 5 for details on available data.

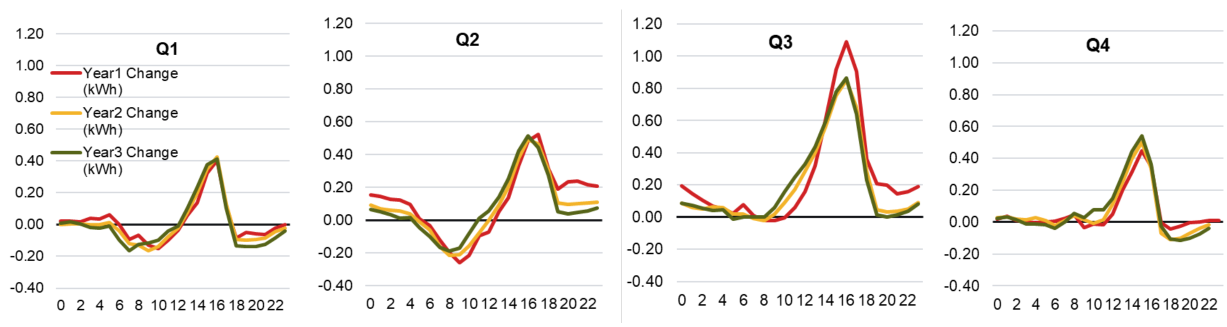
[9] California Energy Demand 2018-2030 Revised Forecast, accessed on 12/23/2019 at https://efiling.energy.ca.gov/getdocument.aspx?tn=223244, page A-9.

Average residential consumption of electricity peaks during the late afternoon hours, typically from 4 to 5 PM. With PV, the utilities observe the net load (with peaks typically from 7 to 8 PM) as PV production declines. Average commercial consumption peaks from 2 to 3 PM. With BTM PV, the commercial net load also peaks from 7 to 8 PM. For residential and commercial customers with BTM PV, the evening decline in PV production results in a close alignment of these customers' net peaks as observed by the utilities.

In *Section 7* and *Appendix D*, the evaluation team presents its investigation into how customer consumption changes after the installation of solar PV. The objective of the consumption change analysis is to determine the impact of PV generation on total electricity consumption. Consumption could increase, decrease, or stay the same following the installation of a BTM PV system.

This analysis required a year of pre-installation hourly load data, a year of post-installation hourly load data, and a year of hourly PV production data. Given the significant data requirements, data were only available for the residential sector in PG&E's territory and PG&E and SCE's non-residential sector. PG&E residential sites averaged a 7.1 percent increase in consumption the year following the installation of PV. The change in consumption varied over the course of the day and by season as shown in Figure 1-7, with the largest hourly increase in the late afternoon (during peak hours) in the third quarter.

FIGURE 1-7: RESIDENTIAL CHANGE IN CONSUMPTION (KWH) BY QUARTER (PG&E) FOLLOWING PV INSTALLATION

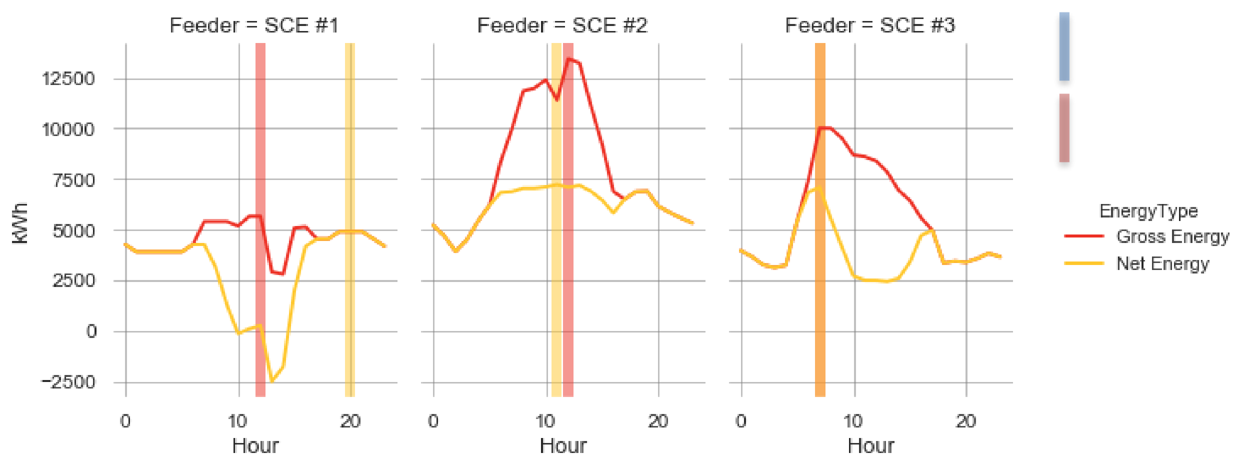


The non-residential data were divided into small and large systems because of the larger variation in non-residential PV system sizes. Small non-residential sites with PV increased consumption by 7.1 percent in the first year following the addition of solar, and 4.4 percent in PG&E and SCE territories, respectively. Large non-residential sites were observed to decrease consumption slightly in the first year after the installation of PV, averaging a 0.4 percent decrease in monthly consumption in PG&E territory and 1.8 percent in SCE territory.

1.2.4 Distribution Feeder Impacts

PV systems can provide distribution system benefits by producing electricity during the top hours of a feeder's load to potentially defer maintenance or equipment upgrades due to lower loads. However, excess PV generation during a feeder's (the wiring that connects electrical substations to customers) lower load hours can lead to reverse power flow to the substation and create potential issues related to voltage regulation, protection, and reliability. Feeders with midday load peaks that coincide with PV generation are most likely to see significant reductions in peak load. Figure 1-8 shows how PV generation changes the feeder load shapes on (gross) peak demand days in SCE territory. In general, PV generation lowers the feeder peak and moves the peak load later in the day. *Section 8* of this report presents more analysis of how PV impacts feeder load. Note that these feeders were selected as examples and should not be taken to be representative.

FIGURE 1-8: EXAMPLE FEEDER GROSS AND NET LOAD SHAPES FOR PEAK SYSTEM LOAD DAYS - SCE[10]



1.2.5 Conclusions and Recommendations

CREATED A SELF-SUSTAINING MARKET: California's solar market has continued to grow after the end of the CSI program. This growth has included increased adoption in middle- and lower-income neighborhoods in recent years. Some neighborhoods show significant adoption of solar, with over half the homes installing solar. Many of the high adoption areas align with new solar subdivisions that received NSHP incentives. The trend of new subdivisions driving higher residential solar density is likely to expand as Title 24 building codes for 2020 mandate solar for most new homes in California. A more in-depth analysis may be useful to determine what drivers and trends might be expected in the future solar PV market.

GROWING BUT AGING GENERATION: The BTM solar fleet generated over 9 TWh to offset nearly 3.5 million tons of CO_2 in 2017. As the fleet continues to grow, the total generation and emissions offsets will grow. The average age of the installed BTM solar PV fleet is increasing in California as the market matures. Although technology has improved over the years, PV systems produce less energy over time due to panel

[10] Net and Gross load peak timing is identical for Feeder SCE #3, demonstrating that for some feeders PV does not impact peak load

degradation, increased outages, and potentially more shading as trees grow. This aging fleet is leading to a slight decline in average performance, with systems degrading at slightly less than 1.5 percent/year.

Different net export trends by sector: Larger-sized residential systems are more likely to show net energy export (where PV generation exceeds site consumption) over a month or a year. Non-residential systems show the opposite trend, with larger systems less likely to show net export over any given time. These trends should be kept in mind as utility planners adapt to growing PV installations and changes in the average sizing of systems.

Potential need to adjust PV sizing assumptions: The average residential PV system in the analysis sample offset approximately 63 percent of site load. However, the California Energy Commission (CEC) recently assumed that residential PV systems produce 90 percent of a customer's electricity needs over a year. The NEM 2.0 Lookback Study currently underway will develop updated estimates of the share of electricity consumption offset by PV production. Recent changes in NEM policies and other factors may also lead to changes in the configuration of residential systems.

Solar homeowners and smaller businesses are increasing their consumption: Residential and small commercial sites with solar PV were found to increase their consumption of electricity after solar installation. Increases in electricity usage by PV customers may impact the accuracy of electricity forecasts if these changes are not incorporated. More analysis that includes sites without solar PV is needed to assess if the observed increase in electricity consumption is unique to PV customers (reflecting behavior changes and/or additions in technologies) or consistent with a population-level increase in average consumption.

Solar PV is lowering feeder peak loads and moving these peaks later in the day: For the distribution feeders included in this analysis, PV largely lowered the feeder peak loads and moved those peaks later in the day. How PV generation impacted feeder load was highly dependent on feeder load shape and the quantity of PV generation on a feeder. These changes in load may have impacts on equipment reliability and voltage regulation.

More work is needed to determine if these results reflect the future state of PV in California: The findings presented in this report are based on systems installed through the end of 2017. Since that time, NEM rules have changed, all Californians will be required to move to a Time of Use rate, and the price of solar has continued to fall. All these factors could significantly change how new PV systems are sized and designed as well as the timing and quantity of electricity used by customers. Future analyses are needed to better understand the relationship between PV system design, customer consumption and net load, and utility system impacts for assisting planners and other stakeholders with adapting to a growing, greener generation landscape.

2 INTRODUCTION AND OBJECTIVES

The California Solar Initiative (CSI) was established legislatively by Senate Bill (SB) 1 (Murray, 2006) as a key component of the Go Solar California campaign to increase the adoption of solar energy systems.[11] The CSI was a solar rebate program for California customers in Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) service territories.[12] The program was 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) provided oversight of and guidance on the CSI program.

The CSI provided financial incentives for solar energy systems for existing homes, as well as existing and new commercial, industrial, government, non-profit, and agricultural properties—within the service territories of the three above-listed IOUs.[13] The CSI had a budget of $2,167 million between 2007 and 2016, and its goal was to reach 1,940 megawatts (MW) of installed solar capacity by 2016. This goal included 1,750 MW from the general market (GM) CSI program, which provided incentives for photovoltaic (PV) and other solar electric generating technologies. The goal also included 190 MW from the two low-income residential incentive programs, the Multifamily Affordable Solar Housing (MASH) Program and the Single-family Affordable Solar Homes (SASH) Program.[14]

2.1 THE CALIFORNIA SOLAR INITIATIVE AND CALIFORNIA SOLAR PROGRAMS

The CSI program built on nearly 10 years of state solar rebates offered to customers in California IOU territories. Following deregulation of the electric utilities in 1998, the California Energy Commission (CEC) was placed in charge of a new renewable energy program to help increase total renewable electricity production statewide. This followed decades of bipartisan legislative and gubernatorial support for renewable energy, helping to make California a recognized leader in the field.[15] From 1998 to December 31, 2006, the CEC's Emerging Renewables Program (ERP) provided financial incentives for grid-connected solar PV systems under 30 kilowatts (kW) on homes and businesses in the IOUs' service territories. The Self-Generation Incentive Program (SGIP) was established legislatively in 2001 to help address peak

[11] http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0001-0050/sb_1_bill_20060821_chaptered.html

[12] The Center for Sustainable Energy (CSE) administered the program in SDG&E's service territory.

[13] Customers of municipal utilities may also qualify for similar incentives through their municipal service provider.

[14] https://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF

[15] https://ww2.energy.ca.gov/renewables/

electricity problems in California.[16] Beginning in the summer of 2001, the SGIP issued financial incentives for the installation of solar PV systems installed to meet all or a portion of the electric energy needs of a facility. The SGIP complemented the CEC's ERP, which provided incentive funding to smaller PV systems (less than 30 kW), by adding incentive funding to larger units up to 1 MW in size.

In August 2004, Governor Schwarzenegger widened state support for solar generation technologies and announced the Million Solar Roofs program. In 2006, the CPUC collaborated with the CEC to develop the framework of the CSI program. In August 2006, Governor Schwarzenegger signed SB 1, which authorized the CPUC's CSI program. On January 1, 2007, the CSI program launched and began operating. The CEC separately administers the New Solar Homes Partnership (NSHP) Program for residential new construction. California's publicly owned utilities administer solar programs in their respective territories.

The total CSI program budget was $2,167 million: $1,950 million for the GM CSI program, $108.3 million for the MASH Program, and $108.3 million for the SASH Program. Table 2-1 shows the CSI program budget as authorized by the CPUC for each PA.

TABLE 2-1: CSI PROGRAM BUDGET BY PROGRAM ADMINISTRATOR, 2007–2016 ($ MILLIONS)

Program Administrator	Percent of Total Budget	Budget ($ Millions)
PG&E	43.7%	$946
SCE	46.0%	$996
CSE	10.3%	$223

Adapted from the California Solar Initiative Program Handbook; rounding may impact total amount

Both residential and non-residential customers were eligible for the CSI program. Table 2-2 shows the planned capacity by customer class in the GM CSI program. An additional 190 MW were expected from the residential MASH and SASH Programs, for a total of 1,940 MW of installed solar capacity by 2016.

[16] Assembly Bill 970, California Energy Security and Reliability Act of 2000 (Ducheny, September 6, 2000). The SGIP was established the following year as one of several programs to help address peak electricity problems.

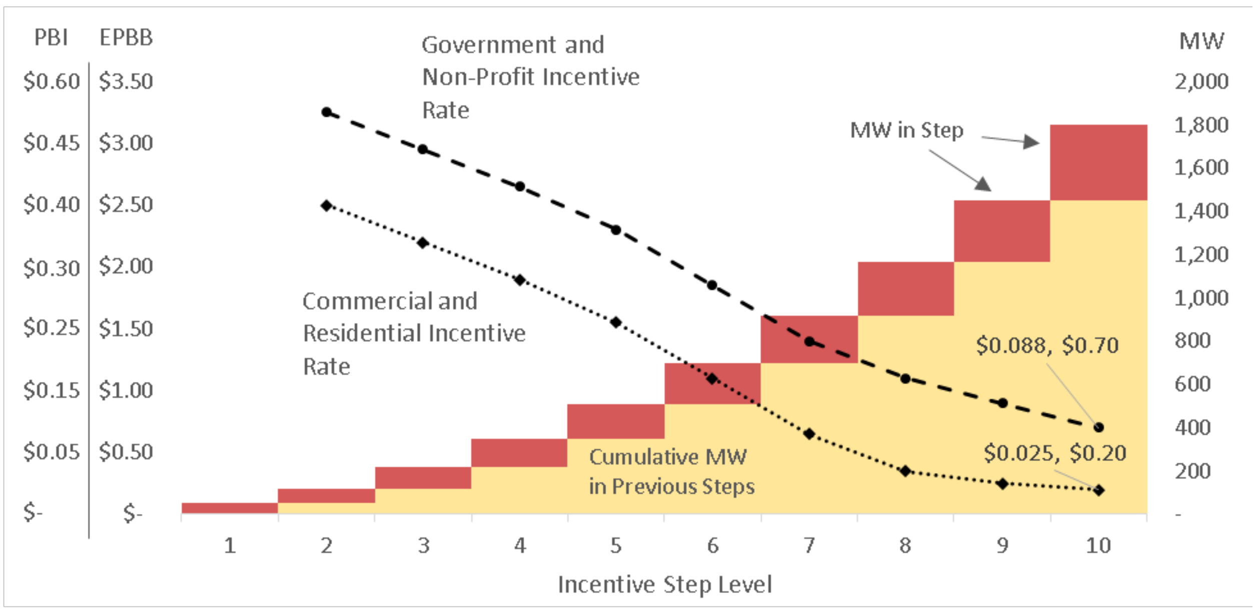
TABLE 2-2: GENERAL MARKET CSI CAPACITY ALLOCATIONS BY CUSTOMER CLASS

Customer Sector	Capacity (MW)	Percent of Capacity
Residential	578	33%
Non-residential	1,173	67%
Total	***1,750***	***100%***

Adapted from the California Solar Initiative Program Handbook

GM CSI rebates varied according to utility territory, system size, customer class, and performance and installation factors. The rebates automatically declined in "steps" based on the volume of solar capacity confirmed within each utility service territory. Figure 2-1 shows the expected schedule for rebate decline over time. There were two incentive paths available to consumers: Expected Performance Based Buydown (EPBB) and Performance Based Incentive (PBI).

FIGURE 2-1: GENERAL MARKET CSI CAPACITY TARGETS AND INCENTIVE RATES BY CUSTOMER CLASS



Adapted from https://www.gosolarcalifornia.ca.gov/csi/rebates.php

The CSI program paid solar consumers an incentive based on system performance. The incentives were either an upfront lump-sum payment based on expected performance, or a monthly payment based on actual performance over five years. The EPBB was the upfront incentive available only for smaller systems. The EPBB incentive was a capacity-based incentive that was adjusted based on expected system performance calculated using an EPBB calculator that considered major design characteristics of the system, such as panel type, installation tilt, shading, orientation, and solar insolation available by location.[17]

The PBI was paid based on actual performance over the course of five years. The PBI was paid on a fixed dollar per kilowatt-hour ($/kWh) of generation basis and was the required incentive type for systems greater than 30 kW in size, although smaller systems could also opt to be paid based on PBI. The larger PBI systems were installed almost entirely at commercial and industrial sites with larger loads and rooftops than single family homes. In the beginning of the CSI program, all systems 100 kW and greater were required to take the PBI incentive. In January 2008, all systems 50 kW and greater were required to take the PBI incentive. As of January 2010, all systems 30 kW and greater were required to take the PBI incentive.

After operating for 10 years, the GM CSI program has exhausted all incentive funds and is closed for new applicants.

2.1.1 California Net Energy Metering Policy Context

The CSI program operated in the context of an evolving landscape of retail rate reform and net energy metering (NEM) policy changes. California SB 656 (Alquist, 1995) required every electric utility in the state (including a privately owned or publicly owned public utility, municipally owned utility, and electrical cooperative that offers residential electrical service—whether or not the entity is subject to the jurisdiction of the CPUC) to develop a standard contract or tariff providing for NEM. SB 656 defined NEM as "using a single, non-demand, non-time-differentiated meter to measure the difference between the electricity supplied by a utility and the electricity generated by an eligible customer-generator and fed back to the utility over an entire billing period." SB 656 required California utilities to make this NEM tariff available to eligible customers on a first-come, first-served basis until the time that the total rated generating capacity in each utility's service area equaled 0.1 percent of the utility's peak electricity demand forecast for 1996.[18] NEM tariffs are a sizeable benefit to solar PV customers and NEM credits are generally considered a critical driver of PV adoption.

Since SB 656 in 1996, California's NEM policies have undergone several changes. Assembly Bill (AB) 1755 (Keeley, Olberg, and Takasugi, 1998) required utilities to provide a standard NEM contract for all eligible NEM customer generators.[19] Several other bills expanded the NEM cap (originally set to 0.1 percent of the 1996 peak electricity demand forecast) and modified the maximum allowable PV system size. On

---

[17] http://www.csi-epbb.com/

[18] http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

[19] http://www.leginfo.ca.gov/pub/97-98/bill/asm/ab_1751-1800/ab_1755_bill_19980925_chaptered.html

January 28, 2016, the CPUC issued Decision (D.) 16-01-044, which created the NEM successor tariff.[20] The current NEM program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017. The program provides customer-generators full retail rate credits for energy exported to the grid and requires them to pay a few charges intended to align NEM customer costs more closely with non-NEM customer costs. Any customer-generator applying for NEM will:

- **Pay a one-time interconnection fee.** Customer-generators with facilities under 1 MW must pay a pre-approved, one-time interconnection fee based on each IOU's historic interconnection costs. (PG&E's fee is $145, SCE's is $75, and SDG&E's is $132.) Customer-generators with systems over 1 MW must pay an $800 interconnection fee and pay for all transmission/distribution system upgrades.
- **Pay non-bypassable charges.** Customer-generators pay small charges on each kWh of electricity they consume from the grid. These charges fund programs such as low-income and energy efficiency programs.
- **Transfer to a time-of-use (TOU) rate.** If a customer-generator is not already operating at a TOU rate, they will be required to move to TOU rates to participate in NEM.

At the end of a customer's 12-month billing period, any balance of surplus electricity is trued-up at a separate fair market value, known as net surplus compensation (NSC). The NSC rate is based on a 12-month rolling average of the market rate for energy. That rate is currently approximately $0.02 to $0.03 per kWh.

2.2 PURPOSE AND SCOPE OF REPORT

The purpose of CSI impact evaluation reports has been to quantify the energy, demand, and environmental impacts of solar PV systems rebated by the CSI. The most recent CSI impact evaluation was published in June 2011 for calendar year 2010.[21] Prior to that, impact evaluations covering 2007–2008 (combined) and 2009 were also completed.[22] The primary purpose of this report is to complete a multi-year impact assessment of CSI program for calendar years 2011 through 2017. Given that the GM CSI

---

[20] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

[21] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/EE_and_Energy_Savings_Assist/CSI_2010_Impact_Eval_RevisedFinal.pdf

[22] https://www.cpuc.ca.gov/General.aspx?id=7623

program is winding down, this final CSI impacts evaluation looks at the CSI within the context of the broader California solar PV market.

By the end of 2017, the CSI program had issued incentives to nearly 149,000 projects[23] representing more than 1.9 GW_{AC} of capacity.[24] To put this number in perspective, approximately 724,000 solar PV systems were interconnected by the California IOUs by the end of 2017, representing almost 5.8 GW_{AC} of capacity. In this context, it is of limited value to quantify the impacts of CSI-rebated PV systems, which by the end of 2017 represented less than one-third of all California PV interconnections. For this reason, this research considers the impacts of not only the subset of PV systems rebated by the CSI, but also all PV systems interconnected by the IOUs through December 31, 2017.

Focus on Metered Data

Previous impact evaluation reports have relied exclusively on metered PV generation data to quantify solar impacts. The rationale for this reliance on metered data is straightforward: the evaluation team believes that an impact evaluation must leverage actual metered observations to ground its assessments. The team recognizes that considerable improvements have been made to solar PV modeling tools and access to satellite-based irradiance estimates is constantly improving. However, in the team's opinion, relying exclusively on satellite-based simulations is not appropriate for an impact evaluation. PV models are useful to estimate expected impacts or to quantify PV potential. However, these models often fail to properly account for the effects of shading, soiling, degradation, and real-world equipment malfunctions. In fact, the team believes that timeseries analyses based on metered PV generation data—such as this research—help to provide feedback to PV model developers and ultimately improve their simulation tools.

2.2.2 Evaluation Objectives

The purpose of this CSI Program Final Impact Evaluation is to provide the CPUC, the CSI PAs, and the California public with important insight into the achieved CSI program value and impacts resulting from the statewide behind-the-meter (BTM) PV population. These insights serve as a guide for future program design and policymaking initiatives to support the state's renewable energy and greenhouse gas (GHG) emissions reduction targets. Specific evaluation objectives of this research include:

- An assessment of demographic adoption trends of solar PV in California, including:
  - Total number and capacity of systems installed

[23] Based on the December 31, 2017 CSI Working Dataset from https://www.californiadgstats.ca.gov/.

[24] Based on CEC AC rating.

  - Physical orientation and incidence of tracking systems
  - Customer demographics, including household income and education level
  - Degree to which systems are located in CalEnviroScreen-designated disadvantaged communities[25]
- Quantifying the energy and demand impacts of all California BTM PV systems
  - Impacts are evaluated for each calendar year from 2011 through 2017
  - Relevant energy metrics include annual capacity factor and total energy generated during the calendar year
  - Relevant demand metrics include CAISO peak hour capacity factor and IOU peak hour capacity factor
- Calculating the observed degradation rate of BTM PV systems in California
- Exploring the relationship between BTM PV generation and customer load, such as the fraction of PV energy consumed on-site versus exported to the grid
- Evaluating the extent to which installation of BTM PV systems is influencing the underlying energy consumption patterns of residential and non-residential customers
- Reporting the total GHG emissions reductions associated with BTM PV generation
- Assessing the load impacts of BTM generation on local distribution feeder loads such as peak demand changes and backfeed, as well as other locational impacts, including ramp rates

To the extent possible, metrics are reported by geography, climate zone, and electric IOU.

2.2.3 Data Sources

This evaluation report relies primarily on four distinct data types: 1) Incentive program and utility interconnection data with PV system characteristics, 2) Interval PV generation data, 3) Interval customer load data, and 4) IOU distribution feeder data.

PV System Characteristic Data

The first step in estimating the impacts of California BTM PV systems is to define the population of systems interconnected on or before December 31, 2017. The evaluation team relied on three sources of data:

25 https://oehha.ca.gov/calenviroscreen

- IOU-specific datasets listing all PV projects interconnected behind the meter (both NEM and Rule 21)
- IOU program (e.g., CSI PowerClerk, SGIP statewide database) datasets
  - These datasets usually include information above and beyond what is included in interconnection datasets, such as incentive payment amounts and detailed system characteristics
- The statewide NEM interconnection dataset[26]

These datasets were merged and combined to develop a comprehensive picture of all California BTM PV systems, including PV system characteristics (e.g., size, tilt, azimuth, tracking type) and customer information (e.g., location, customer class). Section 3 provides a detailed analysis of the evaluated population and customer demographics.

Interval PV Generation Data

Fifteen-minute interval data were collected from a sample of California BTM PV systems. The metered sample consisted of thousands of residential and non-residential projects receiving either an EPBB or PBI incentive from the CSI program.[27] Performance data were collected for 2011 through 2017. For the degradation analysis, the evaluation team also expanded the metered sample to include 2008–2010 performance data collected for prior impact evaluation reports. These data were subjected to thorough quality control and data cleaning steps, including timestamp standardization and eliminating erroneous observations. Appendix A summarizes the data quality control steps employed before using the data for impacts analysis. Section 4 describes the PV generation data sample design.

Interval Customer Load Data and Distribution Feeder Data

Fifteen-minute interval customer load data were collected for a sample of customers in the evaluation team's PV generation sample. These data were quality controlled and aligned with the PV generation data to quantify impacts of PV generation on usage and export statistics. Load data were collected for one year prior to PV system interconnection through 2017 to quantify the potential behavioral effects of BTM PV on customer usage. Fifteen-minute distribution feeder data were also requested for customers in the team's metered PV sample to evaluate the feeder-level impacts of BTM PV. Appendix A summarizes the

[26] https://www.californiadgstats.ca.gov/download/interconnection_nem_pv_projects/

[27] Our sample is limited to PV generation data from CSI participants due to data access and confidentiality constraints. Project developers were receptive to providing CSI project performance data but cited legal constraints to providing performance data from non-CSI solar customers.

data quality control steps employed before using the customer load data for impacts analysis. Section 5 describes the customer load data sample design.

2.3 REPORT ORGANIZATION

The report is organized into eight sections and four appendices, as described below.

- Section 1 is the Executive Summary of the key findings from this evaluation
- Section 2 is the report introduction that summarizes the purpose, scope, methodology, and organization of the report
- Section 3 describes the California BTM PV population, including key summary statistics and geospatial analyses
- Section 4 presents the PV generation data sample design and quantifies the energy, demand, and environmental impacts of California BTM PV
- Section 5 presents the net export analysis, summarizing the fraction of PV customers and the size of net export for monthly, annual, and 12 consecutive month net exporters
- Section 6 describes the energy consumption, PV energy production, and net energy load shapes by customer class, geography, system size, and season
- Section 7 presents the electricity consumption change analysis, using econometric methods to quantify the long-term change in customer usage after the installation of PV
- Section 8 quantifies the impacts of PV on the load shapes of distribution feeders
- Appendix A presents the regression models used to estimate the impacts in Section 4 and provides the statewide (CAISO) top 200 gross load hours and IOU top 200 gross load hours
- Appendix B contains additional details of the net export in Section 5 for each utility, along with an Excel workbook with results for each utility
- Appendix C presents additional results for the load shape analysis in Section 6, accompanied by an Excel workbook with an 8760 of average consumption, PV production and net load
- Appendix D includes additional results for the hourly consumption change analysis in Section 7 and describes the findings for the monthly consumption change billing analysis

3 POPULATION AND DEMOGRAPHIC CHARACTERISTICS

This section presents the results of the evaluation team's work combining various interconnection, demographic, and program application datasets to create a single population dataset of BTM PV systems classified as residential and installed in years 2007 to 2017. Throughout this section, the evaluation team discusses the data sources and methods used to generate the population dataset and provide overall characteristics and demographic trends of California's BTM residential solar PV population installed between January 1, 2007 and December 31, 2017.

This section focuses on the demographics and trends for the residential sector and does not present total BTM solar installs or costs. Those data and graphics are already publicly available at the California Distributed Generation Statistics website.[28]

3.1 DATA SOURCES AND METHODOLOGY

Solar Population Interconnection Dataset

The population dataset developed for this study was used in several aspects of the evaluation, including identifying demographic characteristics and trends in PV adoption described in this section. The population subject to evaluation includes all BTM PV systems subject to Rule 21[29] interconnected in any of the three IOU service territories between January 1, 2007 and December 31, 2017. For the analysis presented in this section, only systems in the residential customer rate class were used. Interconnection data were requested and collected directly from each IOU and then combined and organized for consistency. Some of the key fields utilized from this dataset include:

- System interconnection application number
- Electric utility service territory
- Customer rate class[30]

---

28 https://www.californiadgstats.ca.gov/

29 Rule 21 is a tariff that describes interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system. https://www.cpuc.ca.gov/Rule21/

30 Customer sector (e.g., residential, commercial, agricultural) was not well defined across all IOU interconnection datasets. For consistency across interconnection datasets, customer rate class was used as a proxy for customer sector.

- Interconnection year[31]
- Net Energy Metering (NEM) tariff (NA, 1.0 or 2.0)[32]
- System characteristics, including: System capacity, including both system capacity (kW_{AC}) and nameplate rating (kW_{DC}); Azimuth; Tilt; Tracking type (e.g., fixed, single-axis, dual-axis)
- Equipment characteristics, including: Inverter manufacturer; Module manufacturer; Installer company; Third party ownership
- Location: Climate zone (e.g., coastal, inland)[33]; Street address; City; County; Zip Code; Latitude; Longitude

The individual IOU interconnection datasets were quality controlled and standardized before combining into a single statewide interconnection dataset. This dataset is similar to the information available on the California Distributed Generation Statistics website, the main difference being that this analysis required identifying the specific location of each PV system in order to determine customer demographic trends and to perform the impact evaluation tasks described later in this report. The location of each BTM PV system was established by geocoding the street address or latitude and longitude information included in the interconnection dataset. This information was then used to spatially merge the interconnection dataset to other datasets for analysis (e.g., American Community Survey and CalEnviroScreen 3.0).

Incentive Program Data

Utility interconnection datasets contain the most comprehensive listing of BTM PV systems in each IOU service territory. However, the evaluation team found that in many cases the system characteristic data (e.g., system tilt, azimuth) or other attributes are not consistently defined. For example, PV system orientation variables were either blank or listed as "multiple" for over 45 percent of records across all IOUs. On the other hand, incentive program application datasets like the CSI PowerClerk database are more rigorous and contain consistent and verified system characteristics, albeit for a subset of the overall California BTM PV population. The evaluation team incorporated various incentive program application datasets from the California Distributed Generation Statistics website to supplement the IOU interconnection information. Note that in most cases, the team was unable to establish a perfect one-to-one relationship between the IOU interconnection datasets and the program application data. Not all

31 Interconnection date information was not consistently populated across all IOUs. In many cases, the evaluation team derived the year of interconnection from several date fields related to application and installation milestones unless the interconnection date was specified definitively.

32 NA indicates a BTM PV system is Rule 21 but not on a NEM tariff. This field sometimes contained non-intuitive values such as systems being identified as NEM 2.0 well after an IOU reached its NEM 1.0 cap. In these cases, the evaluation team adjusted the NEM flag based on the team's best understanding of when each IOU transitioned from NEM 1.0 to NEM 2.0.

33 For this analysis, the evaluation team designated California Building Climate Zones 1-7 as coastal and 8-16 as inland. https://ww2.energy.ca.gov/maps/renewable/building_climate_zones.html

IOUs include incentive application numbers in their interconnection datasets, meaning that the relationship must be established using customer name, address, or account numbers. This linking was especially challenging for SDG&E customers, whose CSI incentive applications are processed by CSE.

The specific program datasets used were:

- The CSI PowerClerk dataset, which contains CSI incentive applications from PG&E, SCE, and SDG&E service territories
- Low-Income Solar PV data, which include all applications through the Single-family Affordable Solar Homes (SASH) and Multi-family Affordable Solar Homes (MASH) programs
- New Solar Homes Partnership (NSHP) application data

CSI application data, including customer identifying information such as address, were received directly from the Program Administrators. NSHP and Low-Income Solar PV datasets were downloaded from the California Distributed Generation Statistics website,[34] which includes program-level datasets without any personally identifiable information (PII). The absence of PII means that there is no location information, which prevents any geocoding and, therefore, spatial mapping to demographic data. Hence, the program affiliation is very limited in the demographic analysis, so data are not presented by incentive program. The years included in the timeframe (2007 through 2017) imply the beginning of the SB1 programs collectively, although SASH and MASH had later start dates.

Demographic Data and Census Tract

The United States Census Bureau produces data on the American population and economy such as population count, age, race, income, and home values.[35] This information is reported by census tract, a subdivision of a county with between 1,500 and 10,000 people and an average population of around 4,000. Census tracts are preferable to counties or Zip Code boundaries for identifying demographic and economic trends as populations within a Zip Code can range widely from a few people to over 100,000. Census tract boundaries are designed with the intention of being maintained over many decades so that statistical comparisons can be made from census to census. Figure 3-1 shows the 8,057 census tracts in California and the population each represents. The census tracts, along with the data from the 2013-2017 American Community Survey (ACS) five-year estimates were used for this analysis. The ACS is an ongoing survey that provides vital information on a yearly basis about the United States and its population. Every year, the Census Bureau contacts over 3.5 million households across the country to participate in the ACS.

---

34 https://www.californiadgstats.ca.gov/

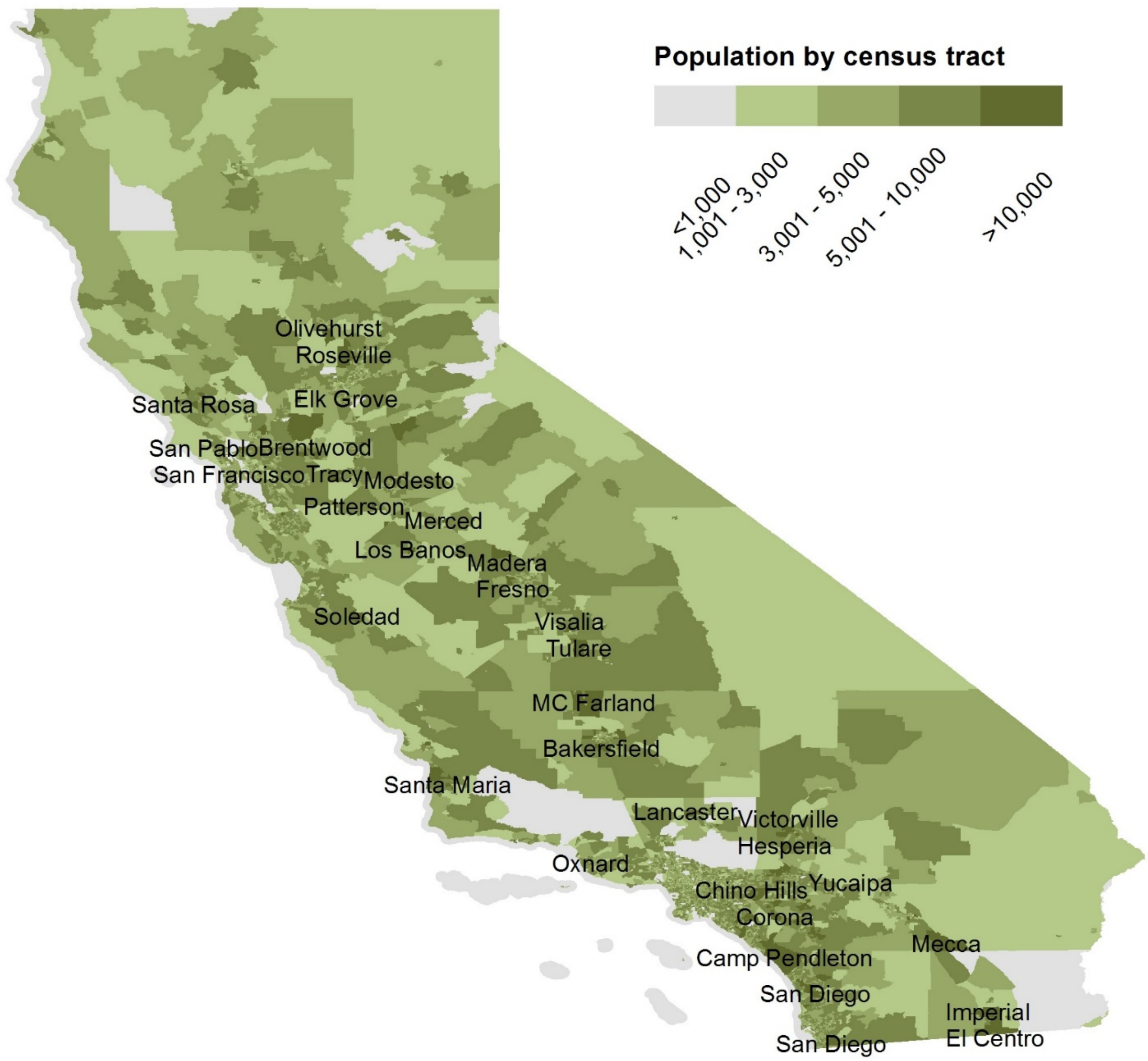
35 https://data.census.gov

It is a useful mechanism to fill in the information in the years between each census. The ACS data is developed through surveys of sample populations to represent the whole.

These data were spatially merged with the IOU interconnection datasets and the characteristics of each census tract were assigned to each system. The key demographic indicators used to correlate adoption trends include:

- Median household income (in 2017 dollars)
- Median home value (in 2017 dollars)
- Home ownership (as percent of owner-occupied units)
- Education (as percent of population over 25 years) with high school or higher and bachelors and professional degrees
- Median age

FIGURE 3-1: CALIFORNIA CENSUS TRACTS AND POPULATION REPRESENTED

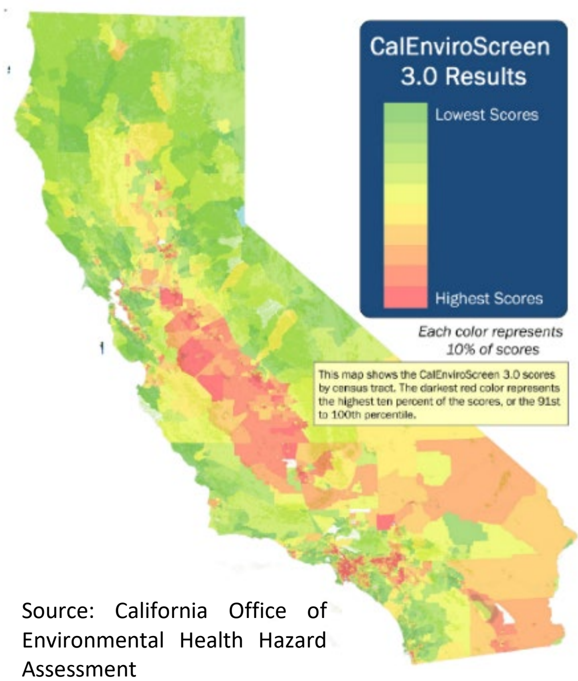


The ACS data are also available at a block group level, which is a finer resolution than the census tract. For perspective, there are approximately 24,000 block groups in California versus 8,000 census tracts. However, the block group level, while finer, also needs the precise location of systems to map them effectively. Because the interconnection data had several gaps in geolocation or street address data, the evaluation team had to approximate the cross mapping to census tracts based on Zip Codes, which would have been more challenging for block groups and lost or misrepresented the information. Also, the

CalEnviroScreen data is available at the census tract level. In order to stay consistent, the team chose to keep all the analysis in this section at the census tract level.

Disadvantaged Community Data

CalEnviroScreen is a mapping tool that helps identify California communities that are most affected by various sources of pollution and where people are often especially vulnerable to pollution's effects.[36] CalEnviroScreen uses environmental, health, and socioeconomic information to produce scores for every census tract in the state, allowing metrics within each community to be compared. An area with a high score is one that experiences a much higher pollution burden than areas with low scores. CalEnviroScreen ranks communities based on data that are available from state and federal government sources.



Source: California Office of Environmental Health Hazard Assessment

CalEnviroScreen 3.0, initially released in January 2017 and updated in June 2018, provides a score for each census tract using 20 different indicators of pollution and population burden. This score is relative among the California census tracts and ranges from 0–100, with higher scores representing the more vulnerable populations. The analysis compared the deployment of solar in the high CalEnviroScreen score census tracts. The SB 535 designation of disadvantaged communities was used as factor to assess the levels of solar adoption, along with population and poverty levels.[37] Disadvantaged communities are defined as the top 25 percent of scoring areas from CalEnviroScreen, along with other areas with high amounts of pollution and low populations.

Analysis Methodology

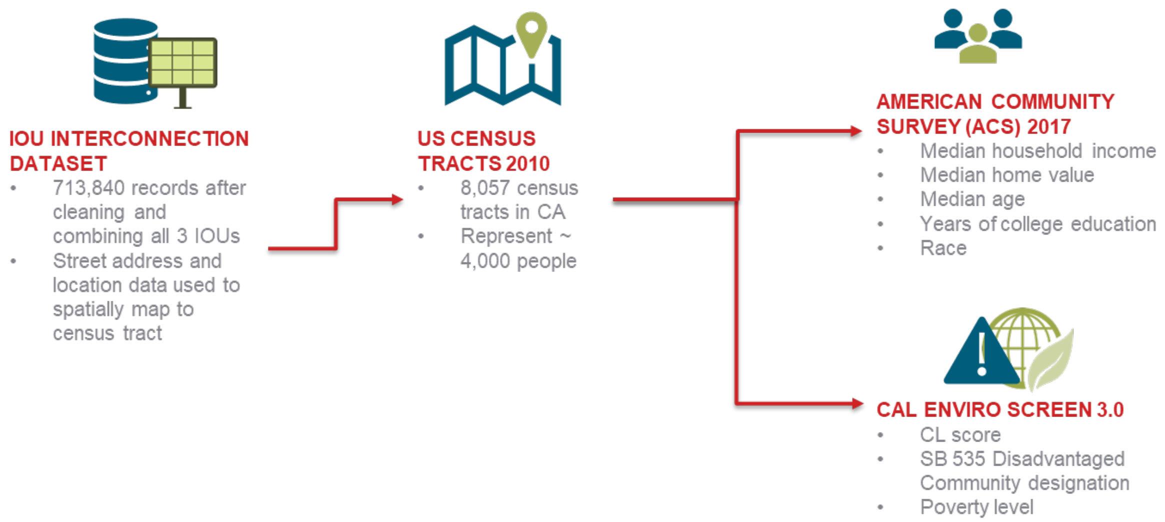
The initial task in this analysis was to perform quality control and merge all the IOU interconnection datasets, creating a single combined statewide IOU interconnection dataset with consistent variable definitions. This dataset was augmented, to the extent possible, with information from the incentive program application datasets. Next, each of the observations in the combined statewide IOU interconnection dataset was geocoded using geographic information system (GIS) mapping software

36 https://oehha.ca.gov/calenviroscreen

37 https://oehha.ca.gov/calenviroscreen/sb535

(ArcMaps) and spatially joined to the census tract boundaries to associate each project with a census tract.[38] The census tract designation for each system was then used to join the data further to the information available in the ACS dataset for demographic indicators and the CalEnviroScreen data for disadvantaged communities.

FIGURE 3-2: DATASETS AND CROSS MAPPING FOR THE ANALYSIS



As described earlier, it was not always possible to establish a one-to-one relationship between incentive program application data and IOU interconnection data. Incentive program application data are useful because they contain considerable detail that was not provided in all IOU interconnection datasets, such as system ownership (e.g., third party) and component-level manufacturer/model information (e.g., module and inverter manufacturer/model). This information is often verified by on-site inspections prior to incentive payment, whereas utility interconnection data are self-reported and, to the evaluation team's knowledge, these data are not verified. To maximize the value of incentive program application data, the evaluation team built two separate application datasets. The primary dataset, which is the foundation for most analyses, is based on the IOU interconnection datasets and supplemented where possible by the incentive program application datasets. A separate dataset based exclusively on incentive program application datasets was built to report on metrics that were not available from the interconnection datasets.

38 http://desktop.arcgis.com/en/arcmap/

3.2 BEHIND THE METER (BTM) RESIDENTIAL SOLAR POPULATION

As stated previously, this section focuses on trends in BTM solar PV installations. From January 1, 2007 through December 31, 2017, the California IOUs had interconnected 677,996 BTM residential PV systems, representing 3,605 MW_{AC} of capacity. Table 3-1 presents the number of BTM residential PV systems in the population by IOU.

TABLE 3-1: CALIFORNIA BTM RESIDENTIAL PV POPULATION (2007-2017) BY IOU

IOU	Total Number of BTM residential PV Systems	PV System Capacity (MW_{AC})
Pacific Gas and Electric	325,613	1,715
Southern California Edison	242,984	1,303
San Diego Gas and Electric	109,399	587
Total	***677,996***	***3,605***

The number and capacity of BTM residential PV systems by IOU are shown in Figure 3-3 below. PG&E has interconnected the largest share of BTM PV systems, both in terms of count and capacity, at about 50 percent, with SCE at 35 percent and SDG&E closer to 15 percent. These counts and capacities are somewhat proportional to the footprints of the territories in terms of the load and customers they serve.

FIGURE 3-3: 2017 CALIFORNIA BTM POPULATION, PROJECT COUNT, AND CAPACITY BY IOU

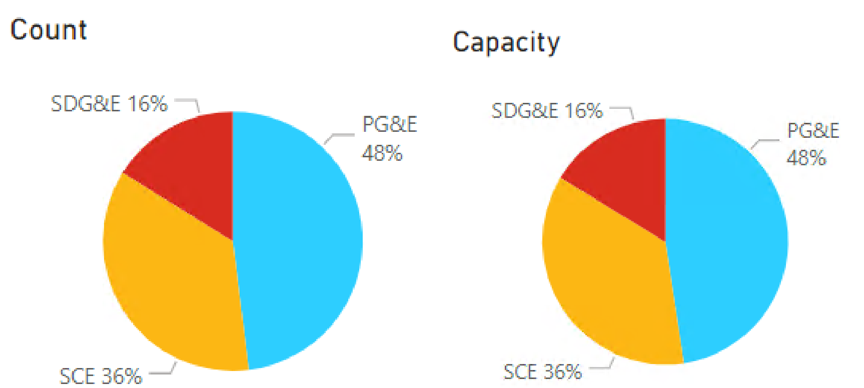


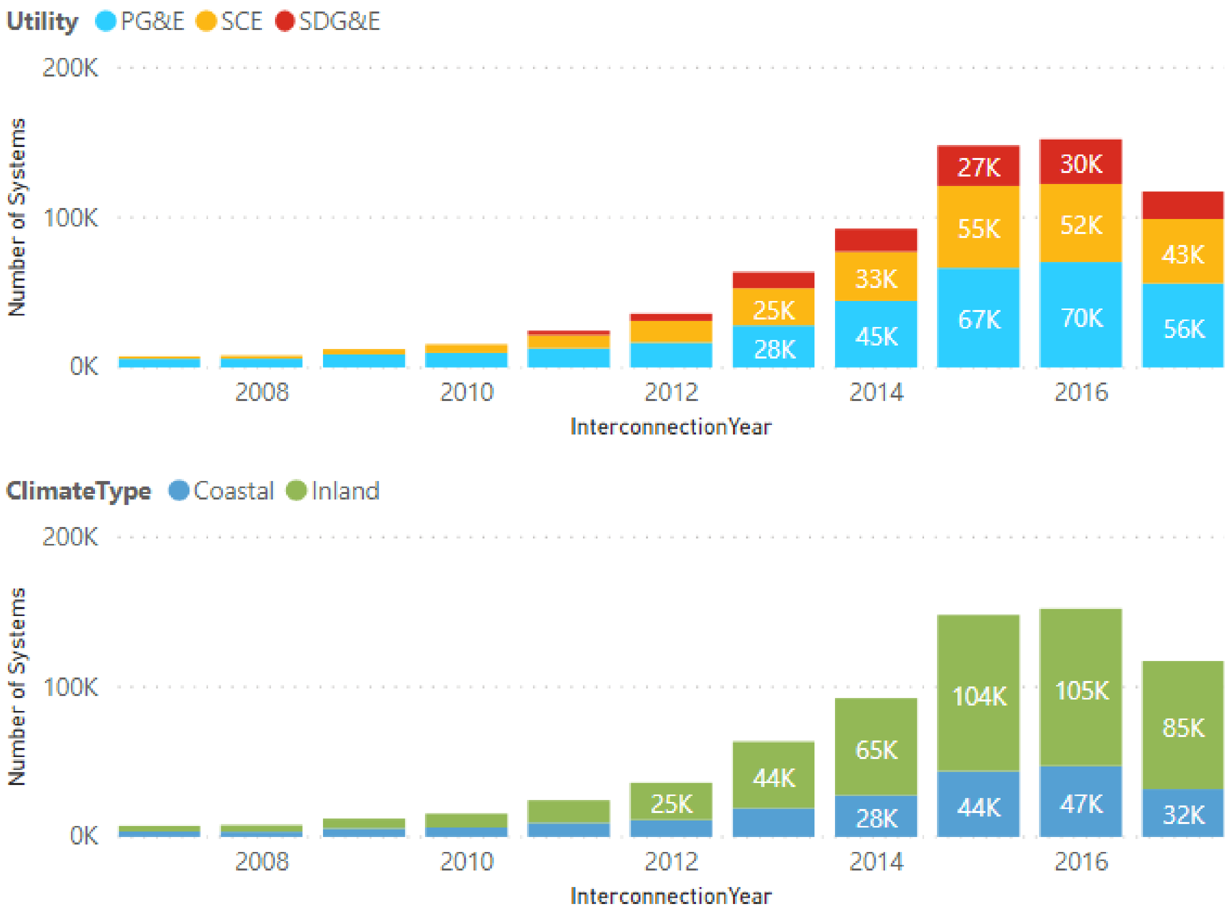
Figure 3-4 shows interconnection trends over time by IOU and climate zone. In all cases, the evaluation team observed that the rate of interconnections accelerate in 2007 and begin to slow down in 2016. 2017 was the first year where the total number of interconnections during the year decreased relative to the previous year. This drop may be related to three factors that drove installers and customers to complete installations before the end of 2016 and not later:

- The CSI program incentives started to run out in 2015 and the program ended incentives at the end of 2016.

- NEM 1.0 to NEM 2.0: Customers with BTM PV are mostly eligible for NEM and, therefore, get credited for any energy exported to the grid. The rules for NEM have changed over time as utilities reached their capacity-based caps for NEM systems. Per the CPUC:[39] "The current NEM program (often called NEM 2.0) was adopted by the CPUC in Decision (D.)16-01-044 on January 28, 2016 and is available to customers of PG&E, SCE and SDG&E. The current NEM program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017. Any customer-generator applying for NEM under the current rules will have to do the following (under NEM 1.0 non-bypassable charges were not paid on exported energy and the transition to TOU rates was slower):
  - Pay a one-time interconnection fee. Customer-generators with facilities under 1 MW must pay a pre-approved one-time interconnection fee based on each IOU's historic interconnection costs. PG&E fee is $145; SCE $75; and SDG&E $132. Customer-generators with systems over 1 MW must pay $800 interconnection fee and pay for all transmission/distribution system upgrades.
  - Pay non-bypassable charges. Customer-generators, similar to other utility customers, will pay small charges on each kilowatt-hour (kWh) of electricity they consume from the grid. These charges fund important programs such as low-income and energy efficiency programs.
  - Transfer to a time-of-use (TOU) rate. If a customer-generator is not already on one, they will be required to take service on a TOU rate to participate in NEM. "
- The federal Investment Tax Credit (ITC) was originally planned to expire on December 31, 2016 but was extended in 2015. Some customers may have planned to have solar installed before the original expiration date of December 31, 2016.

[39] https://www.cpuc.ca.gov/General.aspx?id=3800

FIGURE 3-4: NUMBER OF BTM RESIDENTIAL PV SYSTEMS INTERCONNECTED BY IOU & CLIMATE ZONE 2007-2017

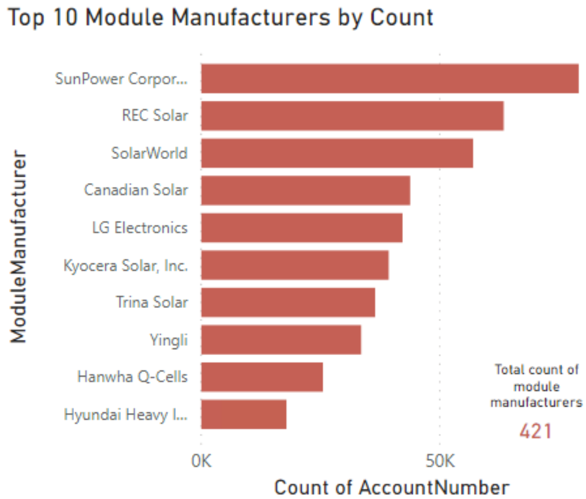


EQUIPMENT AND INSTALLERS

The interconnection data sets do not always capture equipment manufacturer and vendor information on all systems, but they do showcase a large representation of systems. Of the systems for which the data were available, the top 10 most prolific module manufacturers and inverter manufactures by count are shown in Figure 3-5 below. SunPower modules and Enphase inverters have the largest share by count. The next nine manufacturers are represented by count below.

The top installer vendors by count are led by SolarCity (now Tesla), with approximately three times the number of installs as the next closest installer. The other nine vendors are shown in descending order of install count in Figure 3-6. These vendors represent the most prolific vendors in the residential market sector.

FIGURE 3-5: MOST PROLIFIC MODULE AND INVERTER MANUFACTURES REPRESENTED IN THE BTM POPULATION



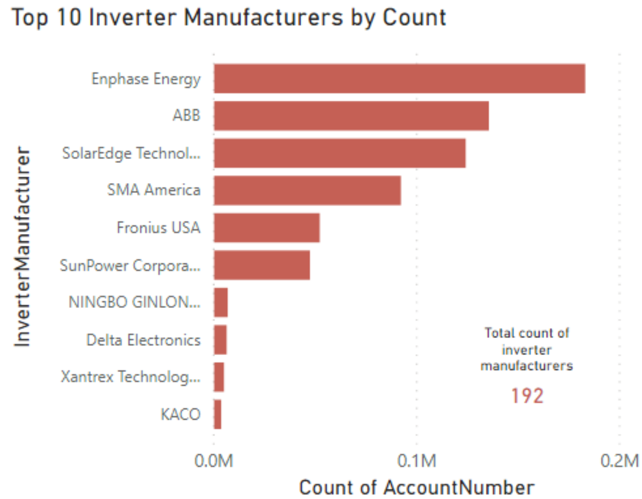
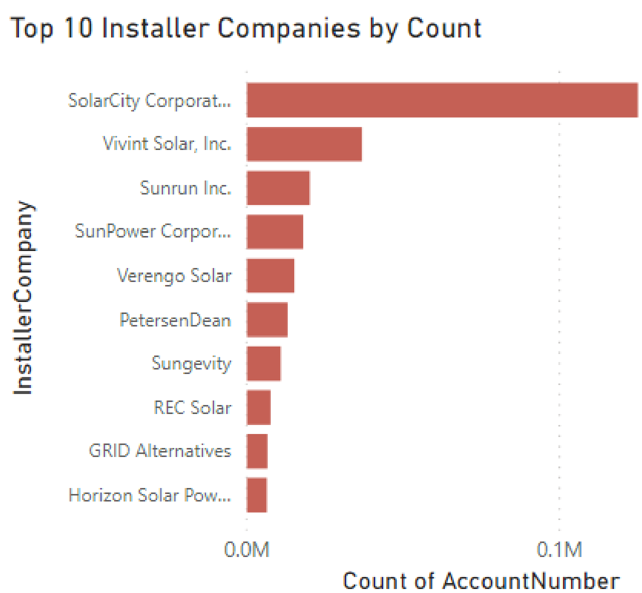
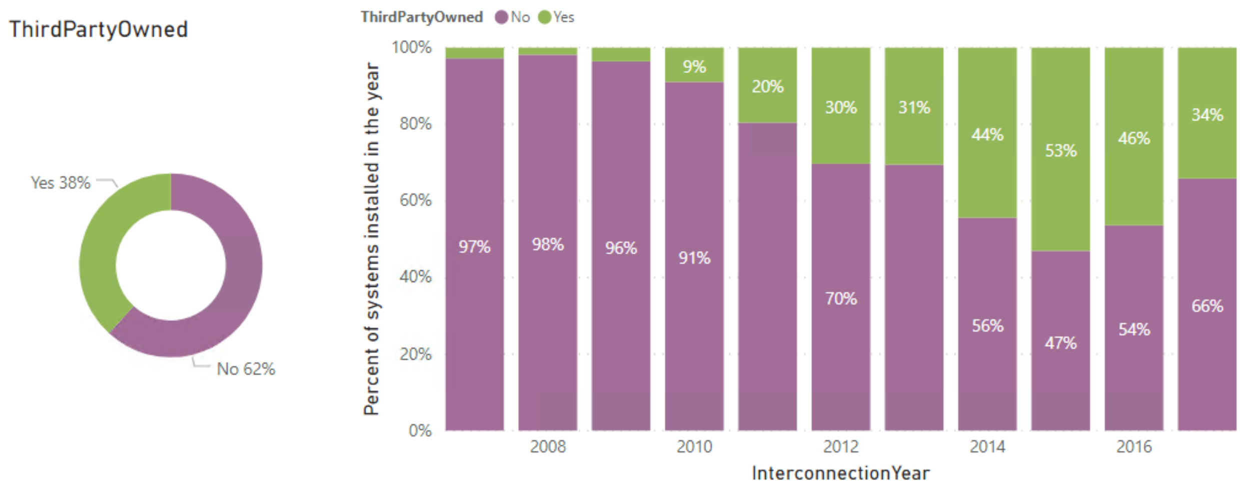


FIGURE 3-6: MOST PROLIFIC INSTALLERS



Installations have seen a significant trend towards third-party ownership over the years. 2007 saw the emergence of business models for third party ownership as leased systems and power purchase agreements became available on residential-scale systems, and the trend since then has been an ever-increasing market share of this ownership type (as seen in Figure 3-7 below). The trend in third-party ownership steadily increased from 2007 through 2015 where it represented more than 50 percent of the residential market by count, but the trend appears to have scaled back more recently with slightly lower proportions in 2016 and 2017. Part of this could be attributed to changes in the tax equity market that had allowed third party owners to easily monetize the ITC. This drop may also be related to falling solar prices and/or historically low interest rates leading to less need for third party ownership.

FIGURE 3-7: THIRD PARTY OWNERSHIP OVERALL AND BY YEAR

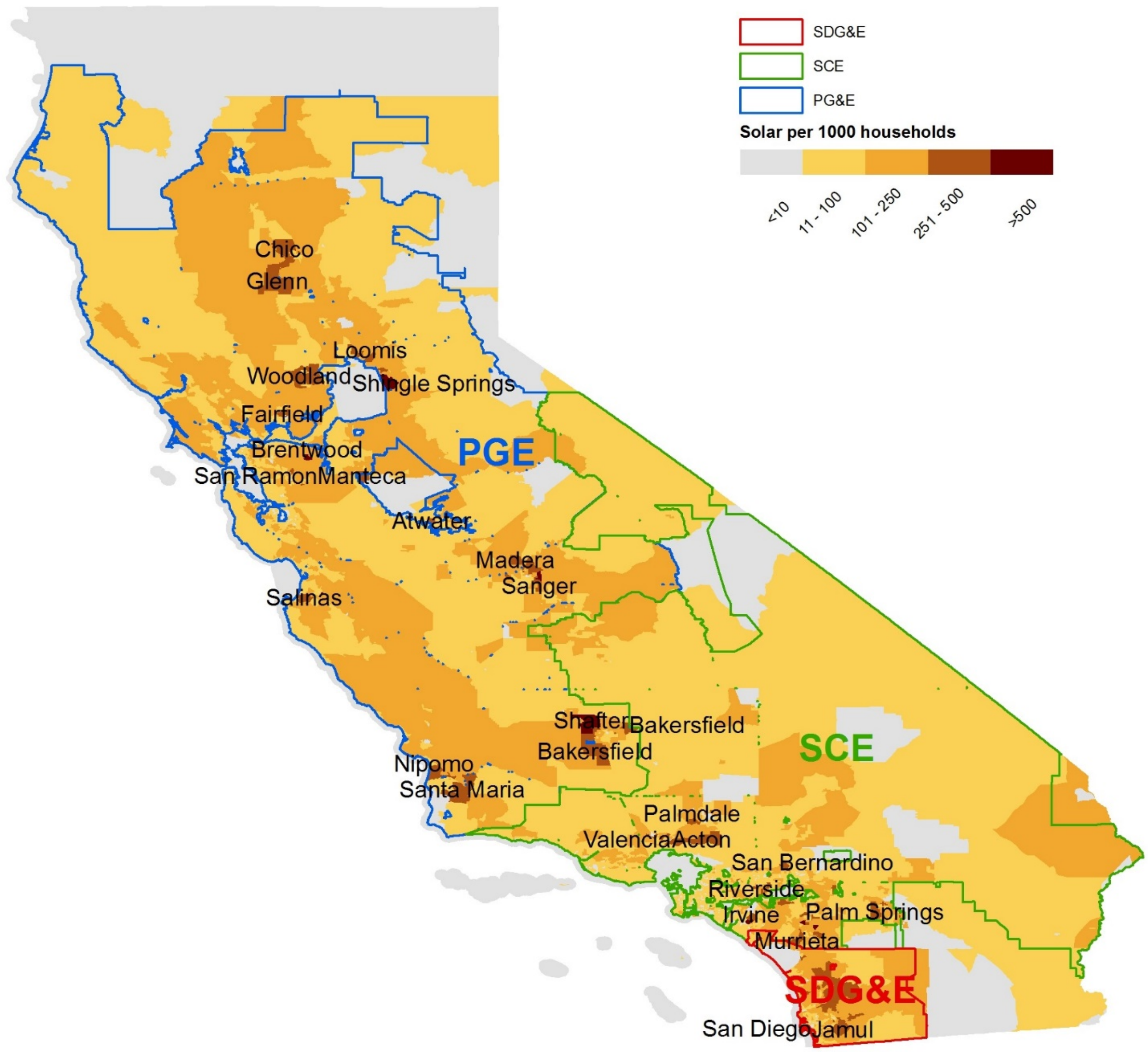


3.3 DEMOGRAPHIC TRENDS

The demographic trends in solar adoption described in the following narrative are based on the ACS 2017 five-year rolling survey.[40] These data were used at the census tract level to join with the interconnection dataset provided by the IOUs. The analysis results use capacity and counts only for systems classified as residential. That was done to avoid any skew from larger commercial and industrial systems that may impact the tallies for census tracts not aligned with representing the actual household population of the area. Figure 3-8 shows a map of California with the census tract boundaries and the color scale represents the number of solar installations in the census tract per 1,000 households. This number represents the scale of adoption based on the number of households in the census tracts and helps convey the strength of adoption in a census tract. The cities labeled in the map represent the closest city centers associated with areas where the adoption of solar is at or above 500 per 1,000 households: in other words, a 50 percent adoption rate. These areas do not always correspond to high population or density regions at large, but to specific regions that have adopted solar more aggressively. In most cases, the high solar adoption census tracts correlate to the location of subdivisions that adopted solar with NSHP incentives.

40 https://www.census.gov/programs-surveys/acs
https://www.census.gov/programs-surveys/acs/data/summary-file.html

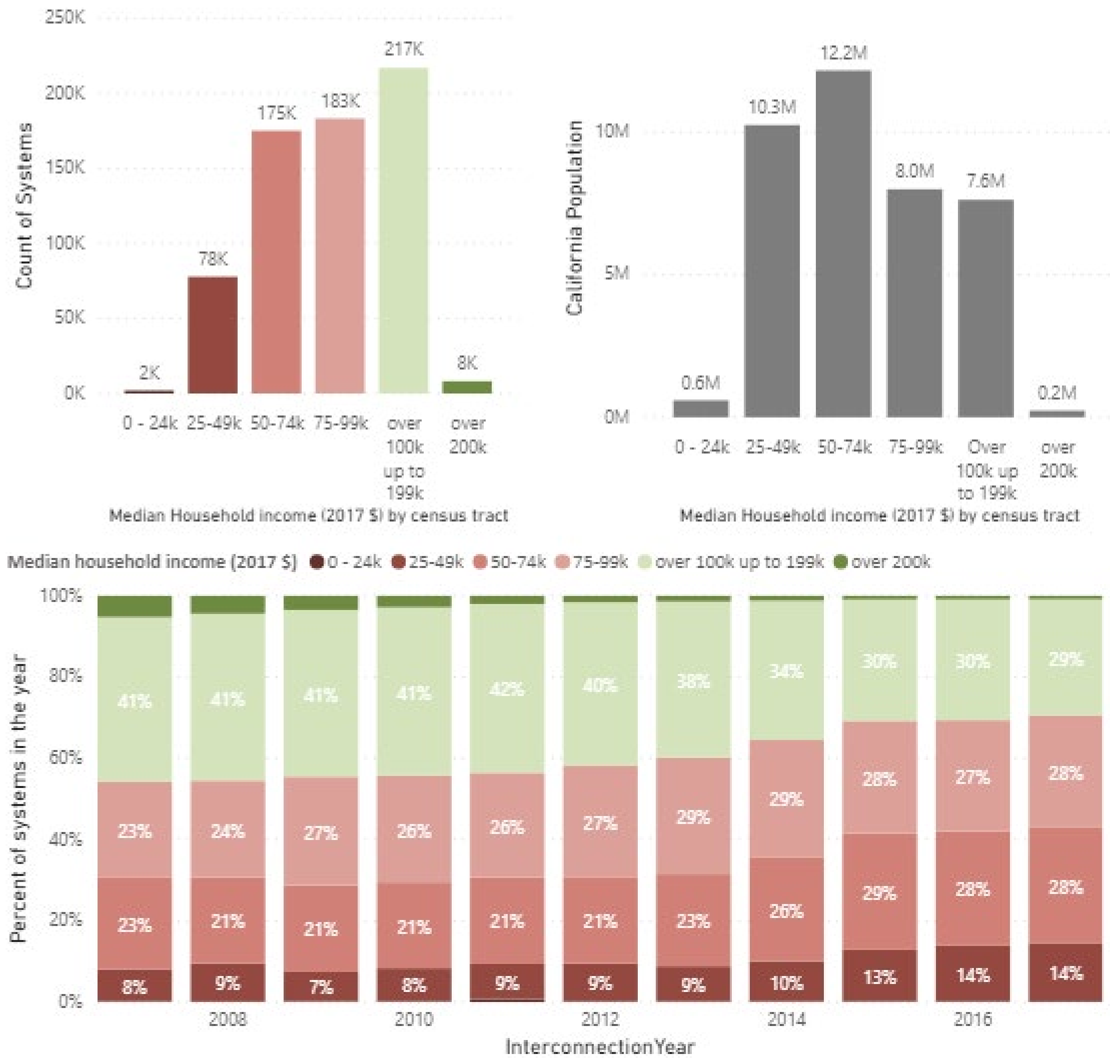
FIGURE 3-8: SOLAR ADOPTION PER 1,000 HOUSEHOLDS BY CENSUS TRACT



Household Income

Solar adoption trends were analyzed compared to neighborhood median household income, reported in 2017 dollars in Figure **3-9**. The highest adoption rate by install count is in census tracts with median incomes over $100,000. Also shown in gray are the statewide median incomes by census tract and comparing the two top graphs it is readily apparent that solar is being installed more often in higher income census tracts (with median incomes above $100k) than census tracts with lower incomes.

FIGURE 3-9: ADOPTION OF SOLAR BY MEDIAN HOUSEHOLD INCOME (BY CENSUS TRACT) AND INTERCONNECTION YEAR*



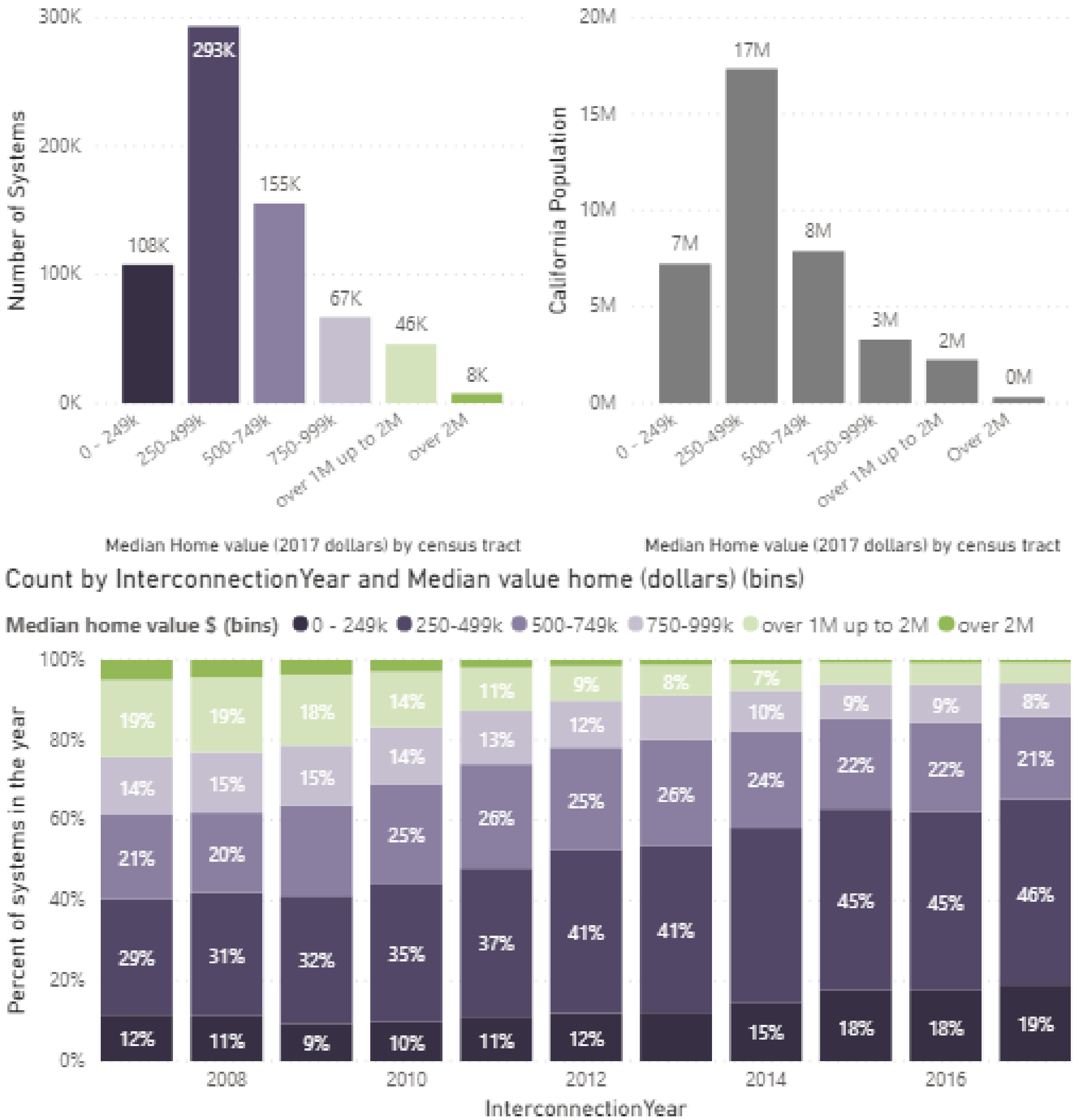
*Median household statewide income in California in 2017 was $73,555 in (2017 $).[41]

However, lower income brackets have seen an increase in the proportion of installs in recent years. This is shown in the histogram chart at the bottom of Figure **3**-**9**, where the proportion of installs in upper income brackets (green) decreases while the relatively lower median income neighborhoods (paler reds) increase starting in 2007. This leads to the observation that solar adoption is slowly increasing outside of the highest income bracket neighborhoods, though not by leaps and bounds. The very high-income bracket (darkest green, $200,000 and over) has seen proportionally fewer installations in recent years.

HOME VALUE

The median home value in a neighborhood or census tract was another measure of the demographics that was analyzed for solar adoption trends, both as overall distribution as well as time trends. The main observation was that the highest adoptions by count were in neighborhoods or census tracts where the median home value was in the $250,000 to $500,000 range. This is not surprising since the population distribution (shown again in gray) also has the most population in those census tracts but solar appears slightly more prolific in areas with higher home values. However, similar to income, the trend of solar adoption has shown a movement towards more installations in neighborhoods or census tracts with lower median home values. As observed in the histogram chart below, from 2007 onwards there is a similar trend towards median household income in the increased proportion of lower median home value neighborhoods or census tracts and a declining trend for the very high home value brackets ($2 million and higher, shown in dark green). The reduction in the higher home value brackets could be attributed partly to the saturation in those areas with early adoption or could be due to higher growth in other areas. However, the increased proportion of lower home value neighborhoods or census tracts could be seen as a positive trend towards getting solar to census tract regions where the median home value is lowest.

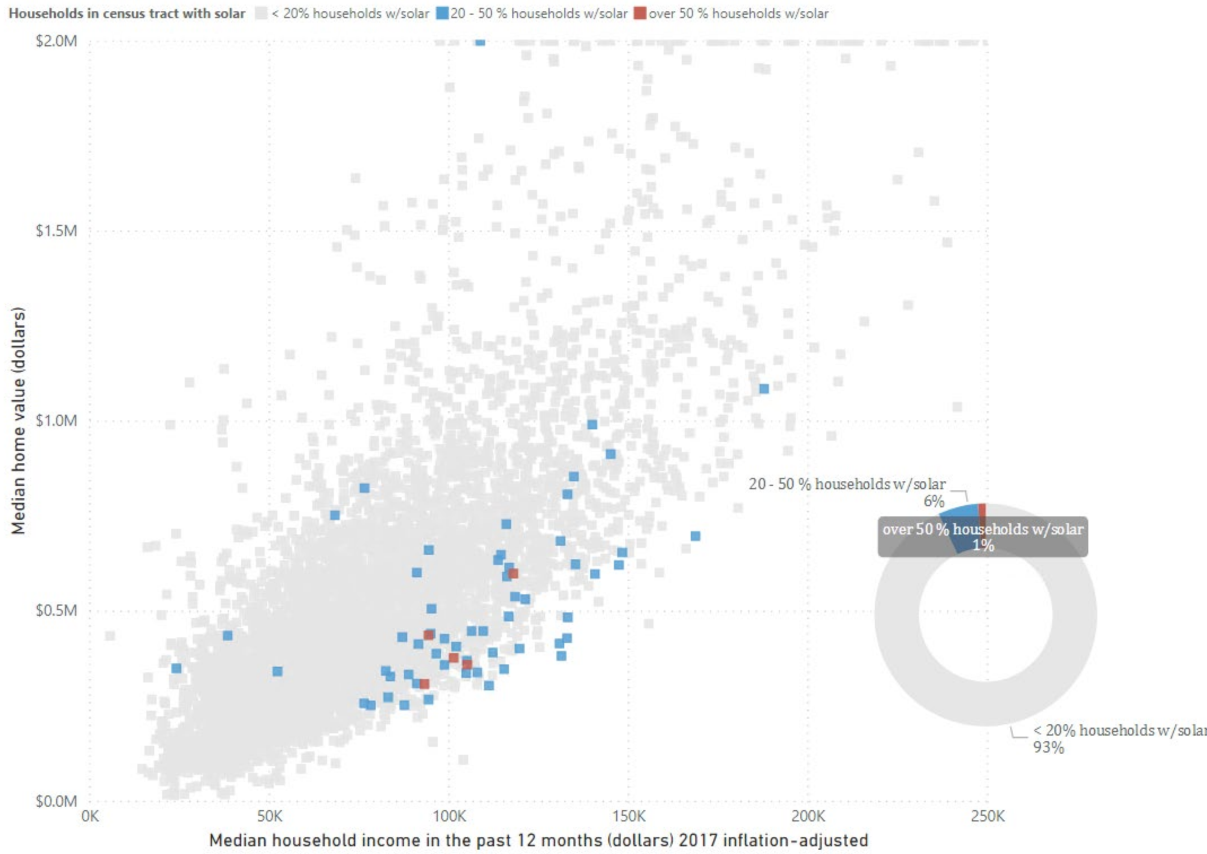
FIGURE 3-10: ADOPTION OF SOLAR BY MEDIAN HOME VALUE (BY CENSUS TRACT) AND INTERCONNECTION YEAR



*Median value of owner-occupied units in California 2014-2018 was $475,900. [42]

[42] https://www.census.gov/quickfacts/CA

FIGURE 3-11: LEVEL OF SOLAR PENETRATION AS A FUNCTION OF INCOME AND HOME VALUE IN A CENSUS TRACT

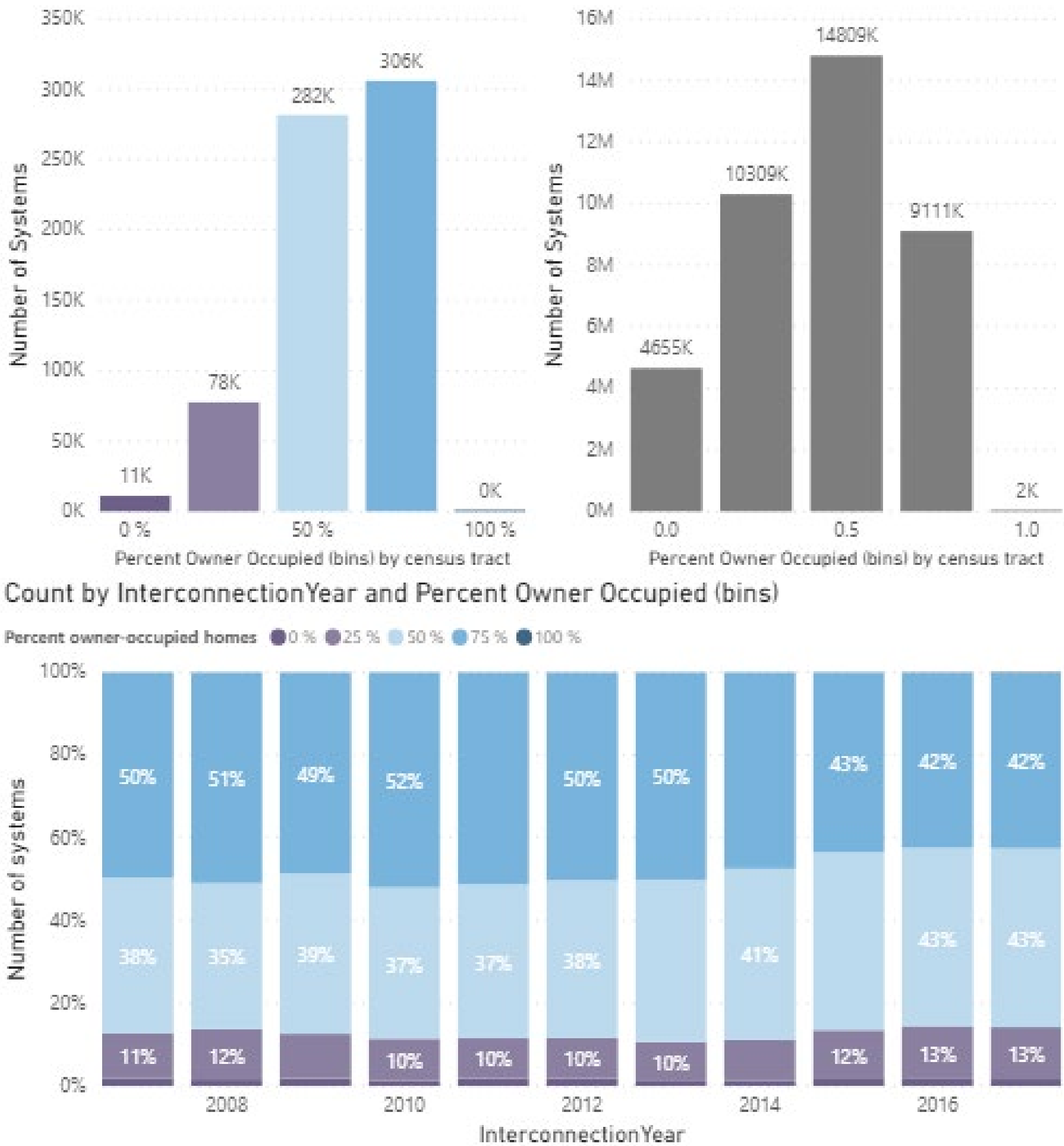


The solar penetration in communities as a function of median income and home value is shown in Figure 3-11. Each pixel represents one of the 8,057 census tracts in California. The grey-colored pixels represent the census tracts where solar adoption is below 20 percent (based on number of solar installations per household). The two sets of red- and blue-colored pixels represent the census tracts with higher adoption trends (blue = 20-50 percent adoption; red = over 50 percent adoption). The scatter plot conveys the level of solar penetration in the context of median income and home value, which are both indicators of economic success. Thus, not surprisingly, most of the census tracts with higher levels of solar penetration have a median income of around $100,000 and a median home value of $500,000.

Home Ownership

Census tracts with higher home ownership rates also show higher solar adoption rates. This intuitively makes sense, given that a property owner who installs solar on his or her rental properties would likely receive minimal or no benefits to reducing his or her renter's utility bills. Some programs, such as SOMAH and Virtual Net Energy Metering (VNEM), have been established, in part, to help solar proliferate on rental housing. As seen in Figure 3-12, most of the solar adoption is in census tracts with 50 percent or higher home ownership. Over time, solar adoption by home ownership status in a census tract has remained fairly consistent, with a higher proportion in tracts with 50 percent or higher home ownership.

FIGURE 3-12: SOLAR INSTALLATIONS BY HOME OWNERSHIP STATUS BY CENSUS TRACT

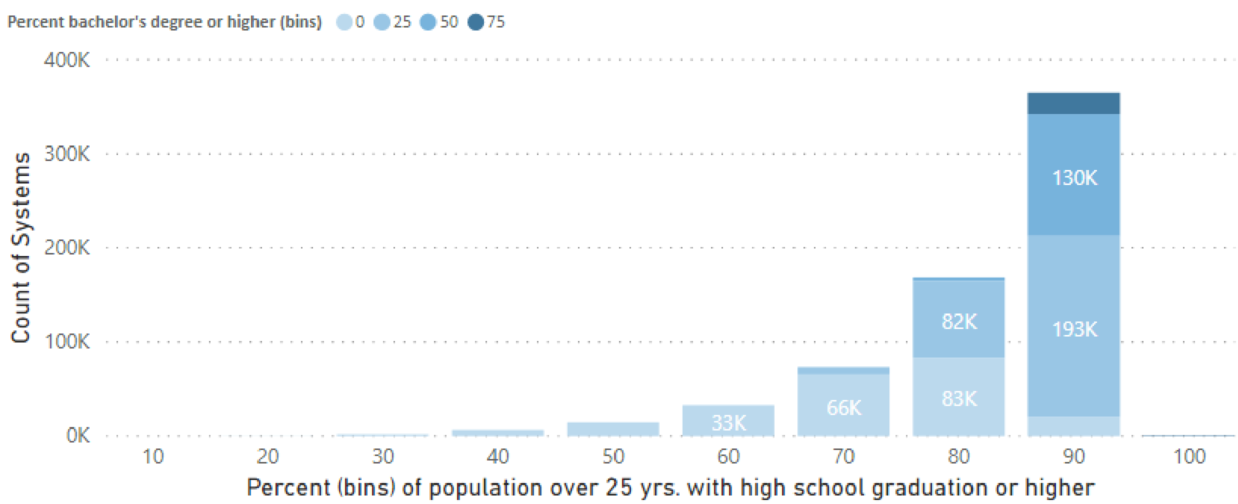


*Median Owner-Occupied Housing unit rate 2014-2018 was 54.6%.

Education

Similar to income and home ownership, census tracts with higher education levels show higher residential solar adoption rates. Figure 3-13 shows the number of installed systems by percentage of high school graduates in a census tract. These solar adoptions are further divided by the fraction of residents with bachelors or professional degrees, representing higher gradation in education levels (the darker blues represent higher percentage of bachelors and professional degrees in the population of the area). Almost all residential solar is installed in areas with very high percentages of high school diplomas. All of the education levels are only tracked for residents who are 25 years old or older.

FIGURE 3-13: SOLAR ADOPTION BY EDUCATION LEVEL – HIGH SCHOOL AND BACHELORS DEGREE OR HIGHER BY CENSUS TRACT

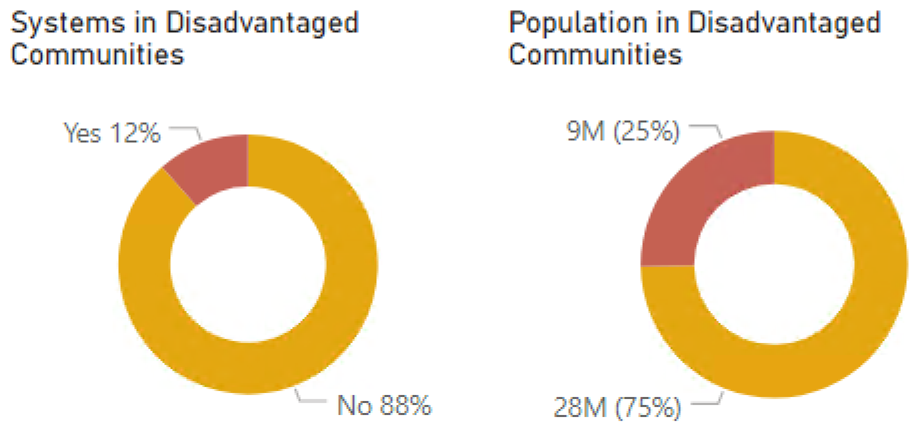


Disadvantaged Communities

Solar adoption in disadvantaged communities is shown in Figure 3-14. Disadvantaged communities are defined as the top 25 percent of scoring areas from CalEnviroScreen (updated 2018), along with other areas with high amounts of pollution and low populations per SB 535.[43] About 12 percent of systems by both count and capacity are installed in disadvantaged communities. This proportion is much lower than the population of the state with the disadvantaged community designation (25 percent).

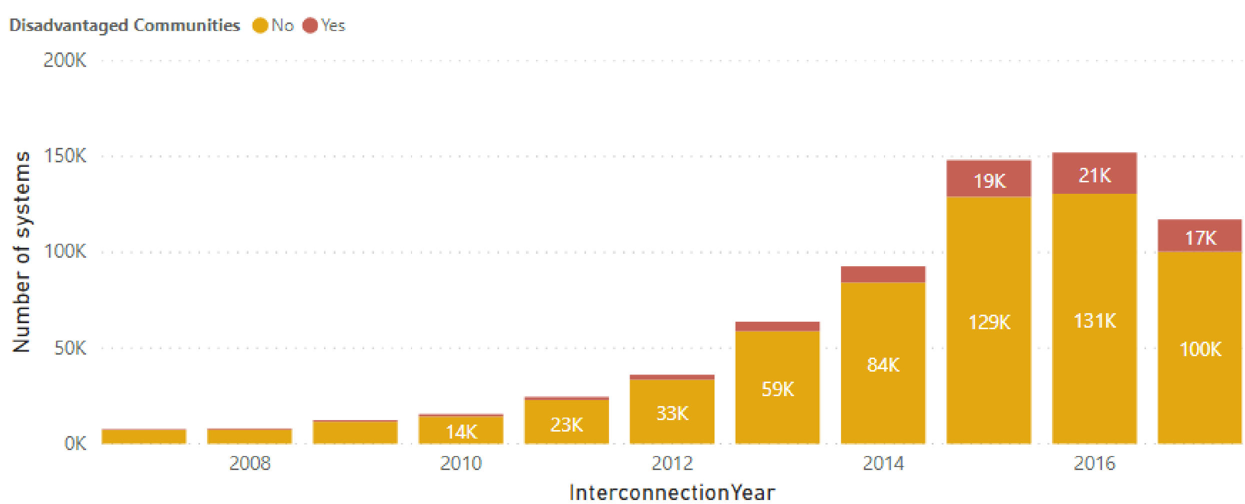
[43] https://oehha.ca.gov/calenviroscreen/sb535

FIGURE 3-14: DISTRIBUTION OF SOLAR AND POPULATION IN DISADVANTAGED COMMUNITIES



Starting in 2011, there has been a noticeable increase in solar adoption in areas designated as disadvantaged. However, the overall adoption still remains lower in the most disadvantaged areas that have the mix of economic, environmental and social hardship.

FIGURE 3-15: SYSTEMS INSTALLED IN DISADVANTAGED COMMUNITIES BY YEAR

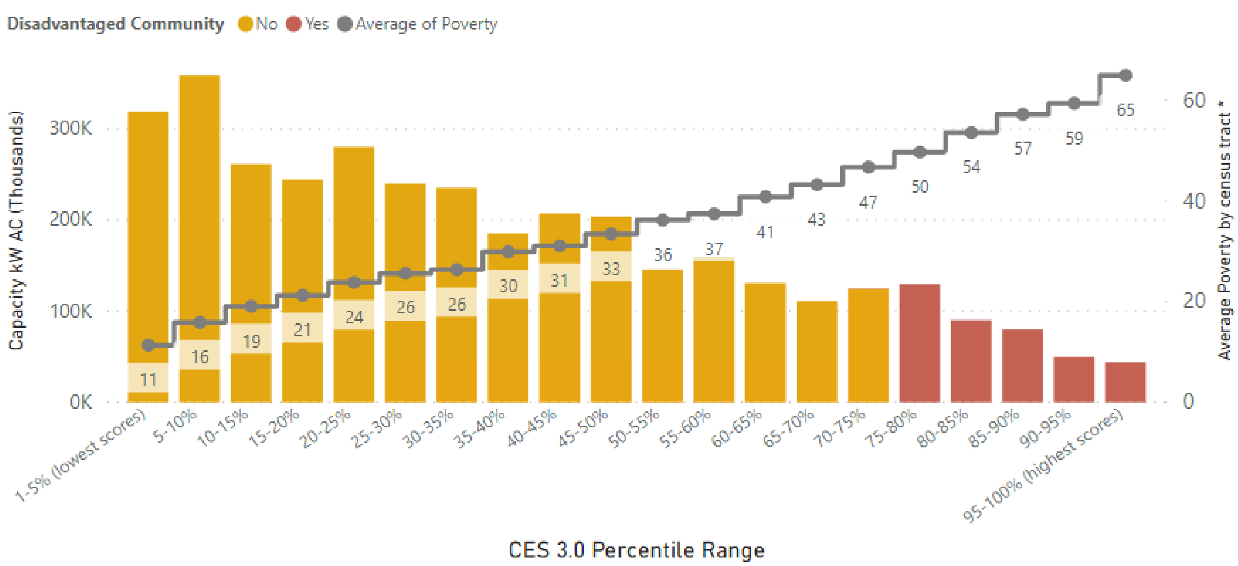


In most disadvantaged communities more than half the population lives significantly below the federal poverty line.[44] The bar chart below shows the distribution of solar adoption across the spectrum of CalEnviroScreen score bins by percentile. The lowest values are the least disadvantaged (in other words, the most advantaged) in terms of economic and environmental factors. These less disadvantaged communities tend to also have much higher levels of solar adoption (bars in yellow). By contrast, the more

[44] The poverty level of over 50 percent of the population is two times below the federal poverty line.

severely challenged communities show the lowest levels of solar adoption (red bars). The stepped line is the percentage of the population living below the poverty line, which negatively correlates to the level of solar in those communities. The higher fraction of the population living below the poverty line correlates to higher disadvantage points for the community in addition to lower solar adoption. All the factors that make a community disadvantaged also imply factors that affect solar adoption, such as poverty, lower home ownership status, lower education, lower median incomes and home values, among other related economic factors.

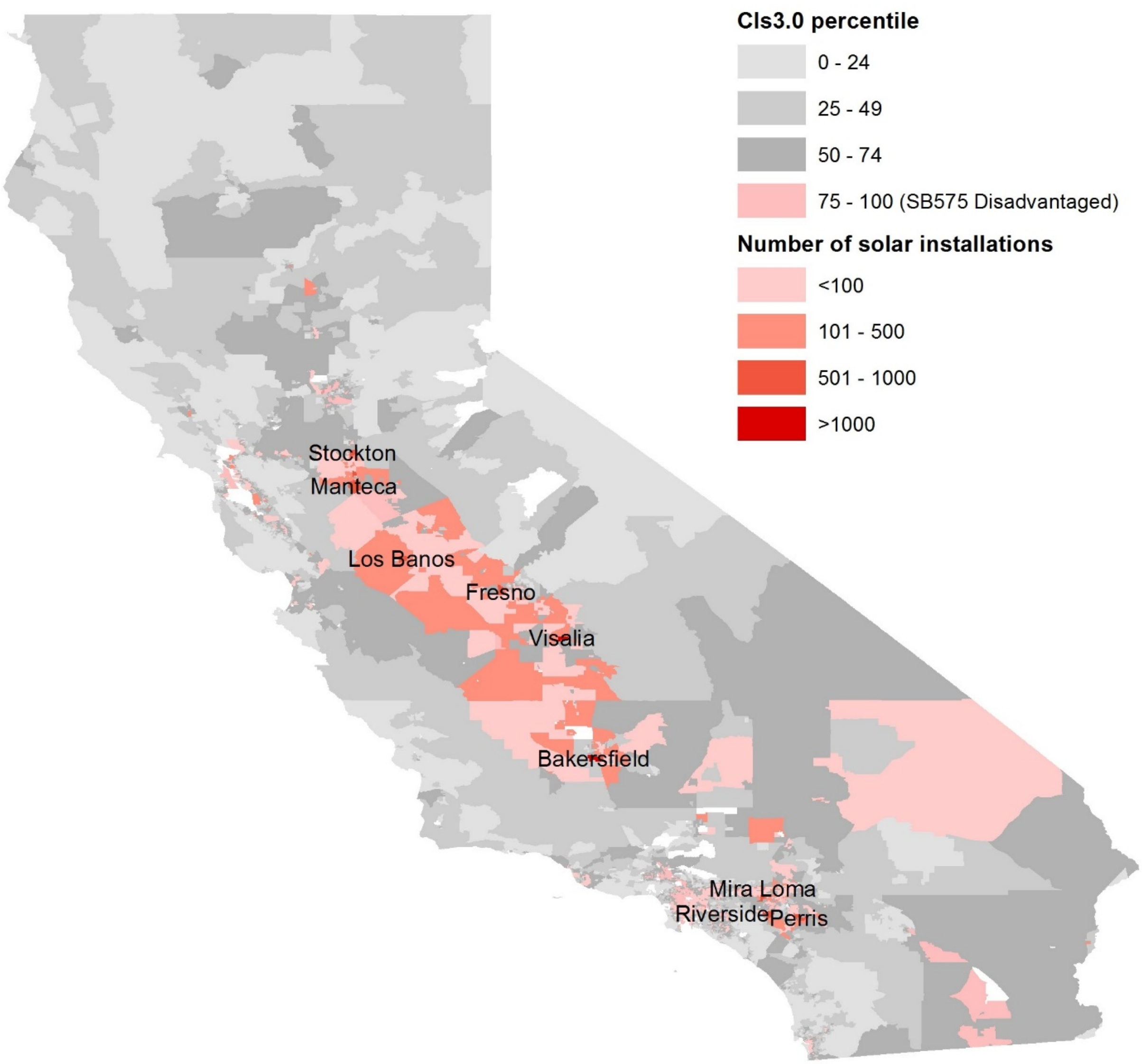
FIGURE 3-16: CAPACITY INSTALLED IN PERCENTILE BINS OF CALENVIROSCORE AND ASSOCIATED POVERTY LEVEL BY CENSUS TRACT



*Poverty is defined as percent of population living below two times the federal poverty level

The map seen in Figure 3-17 highlights the disadvantaged communities in California in shades of red. The red color scale indicates the number of solar installations in these disadvantaged communities. The city center labels represent census tracts that have more than 500 systems, some of the highest among disadvantaged communities. The paler colors of red represent the disadvantaged communities that are lagging in solar installs.

FIGURE 3-17: SOLAR IN DISADVANTAGED COMMUNITIES BY LOCATION AND SOLAR BY CENSUS TRACT



4 BTM PV IMPACTS

4.1 OVERVIEW

The primary objective of this study is to evaluate the impact of California's BTM PV population from calendar years 2011 through 2017. This section presents:

- The generation data sources used to develop the analysis in this section and to support load and feeder impact analyses
- The observed performance impacts, including annual energy impacts, CAISO and ISO system demand impacts, and environmental impacts
- Analysis of PV performance over time and degradation analysis

4.1.1 California's BTM PV Population

The population dataset developed for this study was created by combining information from a variety of sources, including IOU interconnection data, CSI PowerClerk, and other incentive program application datasets such as Low-Income Solar PV Programs (SASH and MASH), New Solar Homes Partnership (NSHP), and Self-Generation Incentive Program (SGIP). Other publicly available datasets that were utilized include Net Energy Metering (NEM) currently interconnected data and Rule 21 interconnection data, which excludes NEM PV. This combined dataset represents all BTM PV systems subject to Rule 21 interconnected in any of the three IOU service territories as of December 31, 2017. The BTM PV population was determined to be 724,816 systems at the end of 2017 and the overall capacity of these systems made up almost 5.9 GW of PV across California. Details of the data and development of the population can be found in Section 3.

4.2 GENERATION DATA COLLECTION AND SOURCES

4.2.1 Data Objectives

PV generation data were collected for systems that received incentives under the CSI[45] with the objective of determining the following for the installed PV population:

[45] The evaluation team attempted to collect data for systems that did not receive CSI incentives, but was unsuccessful, due largely to legal concerns from data providers.

Overall PV System Impacts

- Annual energy production
- Peak hour and top 200 hours energy production
- GHG emission reductions
- Performance trends over time and degradation rates

Load Impacts (in Section 5)

- The metered generation component to combine with simulated generation and utility load for the load shift and change analysis

Distribution Feeder Impacts (in Section 6)

- The metered generation component to combine with simulated generation and feeder load for the distribution feeder impact analysis for PG&E and SDG&E (SCE generation was provided by SCE simulations)

4.2.2 PV Data Sources and Availability

This section presents the available data within the sample; Section 4.2.4 compares this sample of available data to the population. This sample was used as the basis to estimate the performance of all installed systems. The evaluation team received meter data for 19,473 unique CSI systems. Fifty-two percent of these were located in PG&E territory, 37 percent in SCE territory, and 11 percent in SDG&E territory. Three categories of data were received: Performance-based incentive (PBI) hourly metered data, Expected Performance-Based Buydown (EPBB) interval metered data, and daily metered data. The data were received from a variety of performance data providers, including meters installed by host customers, applicants, and third parties, as well as metered data from a number of sites where Itron had installed meters during the 2010 program evaluation cycle. All of these available data were systematically processed and validated. There were several quality control steps taken before the data were determined as useable for impacts calculations:

- **Standardizing data formats:** Metered data were received from a number of different data providers and sources; as such, data formats needed to be uniform across all received data before the data quality control processes could begin. This standardization process included creating consistent field names, merging tracking data such as system characteristics and installation details, and transforming metering date/times into the local standard time.

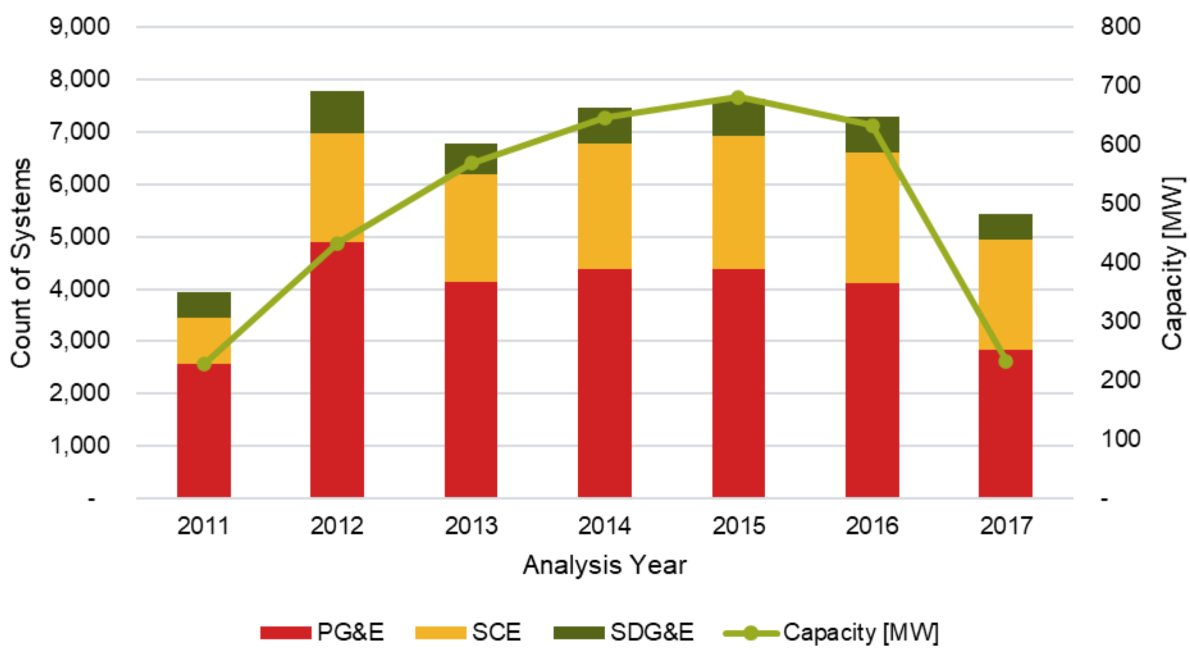
- **Validity of data:** Each site where metered data were received was also simulated using PV_LIB,[46] leveraging system configuration information from PowerClerk and historical weather data from the National Solar Radiation Database as inputs. The simulated and metered data streams were then compared. This allowed the evaluation team to identify any areas of data that were outside reasonable range of potential energy generation for the size of the system. The evaluation team looked for significant gaps in data, issues with timestamps, data issues that appeared to be due to faulty meters, and sites that appeared to have added system capacity from what the initial application claimed. In some cases, data were dropped and flagged as missing, such as when generation was negative, too high for the size of the system, or occurred during nighttime hours.
- **Ensure that metering data exists for the majority of the year:** For evaluation purposes, the team only used metering data where useable data were available for over 300 days of the year. This ensured that only sites with metering data across most of the year would be used to create impacts. Utilizing data from partial years may skew energy impacts up or down, as data from only winter months may result in a lower estimated energy consumption when expanded to the entire year, and data from only summer months would result in a higher annual energy consumption.

The resulting sample consisted of PBI data, interval EPBB data, and daily EPBB data. There was a total of 12,397 unique PV systems in the sample and 46,328 years of site-level data. Note that the 12,307 spanned many years so data available for any particular year were fewer than that total. These data were used to calculate annual energy savings for the entire BTM PV population and are referred to throughout the report as the ***Annual Impacts Sample***.

[46] PV_LIB is a software tool developed at Sandia National Laboratories to simulate the performance of a variety of photovoltaic energy systems. https://pvpmc.sandia.gov/applications/pv_lib-toolbox/

Figure 4-1 displays the number of sites and total capacity by analysis year of the Annual Impacts Sample. The data received for 2017 accounted for about 30 percent fewer sites than the previous few years; additionally, the size of the systems where data were received was much smaller than previous years. The smaller number of sites and smaller relative size of systems in 2017 is partly due to lack of PBI data, which is discussed in more detail further below.

FIGURE 4-1: COUNT AND SYSTEM CAPACITY OF ANNUAL IMPACTS SAMPLE



Over half of all the system-year combinations of data used in the annual impacts analysis were received from providers who provided data at the daily level rather than the hourly level. Nearly all these daily interval data collected were from smaller, residential systems. The impact of PV on peak demand, top 200 demand, and emissions analyses require hourly data to perform so the daily EPBB data were not able to be utilized. Therefore, these analyses relied on only the hourly PBI and EPBB data and included 8,423 unique PV systems for 22,401 years of site-level data. These data are referred throughout the report as the ***Interval Data Sample***.

Figure 4-2 displays the number of sites and total capacity by analysis year of the Interval Data Sample. While the overall trend of data is similar, there is a larger drop-off of data for 2017. Note that the sample is compared to the population in section 4.2.4 below.

FIGURE 4-2: COUNT AND SYSTEM CAPACITY OF INTERVAL DATA SAMPLE

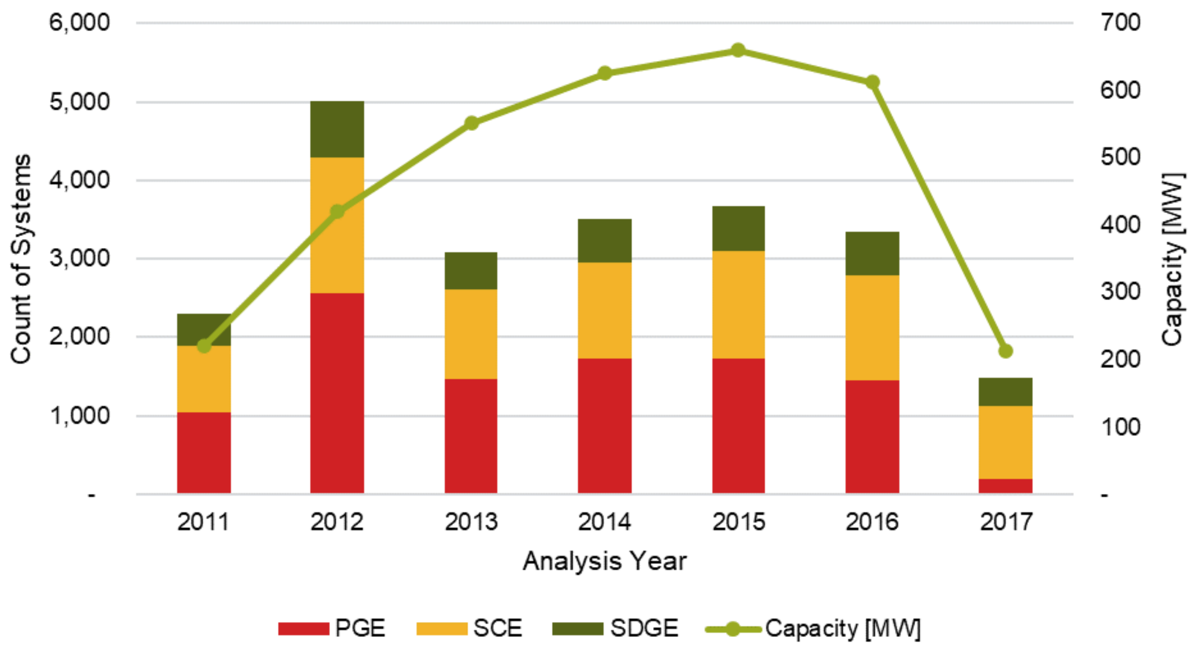


Table 4-1 displays the availability of data for the Annual Impacts Sample by installation year and incentive type. Several observations can be made about these data from this table. As noted above, daily EPBB data make up over 50 percent of the total data. These data represent older systems, which were installed between 2007 and 2010. Similarly, for Interval EPBB data, a large amount of data was available for years 2011 and 2012, mostly for systems installed in 2011 or before. After this, the number of systems where metered data were available dropped off. Data from 2011 and 2012 were readily available because they were collected in 2013 to support planned CSI evaluation. Data for systems between 2013 and 2017 were harder to collect due to the length of time between metered date and request date. No data were available for sites with an EPBB incentive installed after 2014 as CSI program incentives were exhausted for residential systems by this time, and many new residential systems were installed without the support of CSI. Generation data for systems installed without the CSI were not available due to third party confidentiality concerns. PBI data were plentiful for most of the analysis years but dropped off in 2017. PBI systems are only required to provide data for five years and many of these systems received a PBI buyout where the system owner received a lump sum payment based on expected performance after a few years, resulting in a distinct reduction in available data in 2017.

TABLE 4-1: DATA AVAILABILITY BY INSTALLATION YEAR AND INCENTIVE TYPE

Install Years	Analysis Year						
	2011	2012	2013	2014	2015	2016	2017
Daily EPBB							
2007-2010	1,638	2,768	3,703	3,950	3,947	3,945	3,945
Interval EPBB							
LT2007	1						
2007-2010	1,090	888	385	347	309	146	27
2011	258	1,842	268	266	264	259	243
2012		613	199	198	195	195	193
2013			51	208	208	202	200
2014				59	137	135	132
2015							
2016						GAP	
2017							
PBI							
LT2007			1	1	1	1	1
2007-2010	884	986	763	395	154	34	2
2011	74	531	532	527	524	215	7
2012		159	741	754	744	702	64
2013			142	644	627	601	67
2014				120	411	401	78
2015					103	395	245
2016						58	208
2017							17

Interval Data Sample

Annual Impacts Sample

4.2.3 Population Impact Methodology

The evaluation team chose to use a regression model approach to develop annual energy, peak, and emissions savings for the BTM PV population because of the gap in data for later years. A regression analysis uses a set of data records to quantify the relationship between a dependent variable (in this case the Annual Capacity Factor (CF) or the Emissions per kW), and a set of independent variables. The regression estimated a coefficient for each independent variable, which represents the marginal impact of the independent variable on the value of the dependent variable or how a one-unit change in an independent variable would impact the value of the dependent variable. Using the estimated coefficients from the regression model, it is then possible to simulate the value of the dependent variable for different combinations of values of the independent variables. Using this approach, the evaluation team simulated the CF and Emissions per kW for situations where sample data for these results were unavailable, leading to annual estimates of the population's CF based on the regression coefficients and known values of the independent variables.

The evaluation team chose to use regression to estimate PV impacts because it enabled the team to leverage the metered PV production data available to develop population level estimates of CF. This approach helped to balance the following data concerns with the desire to incorporate the largest possible sample of metered PV production data into the analysis to produce an accurate estimate of CF:

- **Metered data on smaller systems are limited for newer systems.** The metered data in the sample decrease significantly for newer, smaller systems. The regression analysis used the data from the available small systems and observed performance trends over time to simulate the CF of more recently installed smaller systems.
- **Older data available at the daily level.** A large amount of daily metered data was available for systems installed prior to 2011. The regression approach allowed the evaluation to include these data, with other more granular data, to calculate the strata CF while including an independent variable in the analysis that controlled for the possibility that the sample data prior to 2011 may differ systematically from more recent data.
- **Missing orientation and tilt data for much of the population.** There are many proven methods of simulating PV performance for a period. These methods, however, require knowing key component information about each system, including azimuth and tilt. Unfortunately, much of this information is missing from non-CSI incentive program PV systems. This severely limits any simulation's ability to accurately predict energy savings. The regression approach uses the metered production and known independent information to predict CF for unmetered systems, including those in the population without information on key components.
- **Regression uses metered PV production data to estimate CF.** Simulating every system, even if all the necessary information was known, would produce theoretical results based on assumptions about how factors such as soiling (panels getting dirty) or outages affect the system production. These are often set based on historical averages but may not reflect actual operation of BTM PV systems in California. The regression model incorporates data from actual systems—some performing less optimally than simulation models may anticipate—to develop estimates of population CF.
- **Difficulties in matching the sample to the population:** Because of the number of different sets of data used to develop the California BTM PV population and because of inconsistent information and site identifiers between each of the datasets, developing a 1:1 match between the sample and population was not possible. There were also some cases when the site data were inconsistent between the two datasets, like capacity of the system, sector, or mounting type. In

some situations, it was not possible to match the metered data to a site in the population. The regression approach allowed the team to develop two separate sets of data (the sample data and the population data) based on strata variables, and then weight the sample by count to develop population estimates using the regression model.

Stratification and Weighting

The first step in estimating population impacts was to develop stratification criteria that could be used to stratify or categorize both the metered sample and overall population. The purpose of this was to create a weighting variable that would be used in the regression model to weight strata consistent with their distribution in the population. The evaluation team defined both the sample and the population by the following stratification variables: Analysis Year category, Utility, Geography, Installation Year, and Size Capacity category.[47] The resulting stratification weight was based on the count of sites in the sample and the population, determined using the following equation:

$$Strata\ Weight_{strata\ j} = \frac{Count\ of\ population\ sites_{strata\ j}}{Count\ of\ sampled\ sites_{strata\ j}}$$

Development of Independent Variables

A regression analysis uses data observations to quantify the relationship between a dependent variable and a set of independent variables, and therefore predict the influence of the independent variables on the value of the dependent variable. The evaluation team reviewed a number of regression model specifications, looking at different sets of independent variables to determine the independent variables that produced the best model. The final independent variables used were:

- **Utility**: Because impact results are reported at the utility level, including the Utility variable in the regression ensured that results could be reported by utility. The different utilities also represent different latitudes within California that may be associated with attributes other than irradiance that could influence CF. Additionally, studies have found different soiling rates by location and the frequency of natural cleaning from rains across the central valley, northern California, and southern California.[48] The utility variable in the regression model helps to account for these impacts on CF.

[47] The strata variables needed to be characteristics that likely influenced CF and were available for all systems.

[48] A. Kimber et al, "The Effect of Soiling on Large Grid-Connected Photovoltaic Systems in California and the Southwest Region of the United States," 2006 IEEE Proceedings.

- **Location (Coastal/Inland):** Coastal communities often have more cloud cover and cooler temperatures, whereas inland communities typically receive more sunlight, although they will also have higher temperatures. Similar to the inclusion of Utility, the use of Coastal/Inland allows the regression model to identify non-irradiance-related climatic and soiling effects on CF. As expected, the regression parameters indicated that systems installed in inland areas generally saw a higher CF than those in coastal areas. The location variable was determined by mapping each site in the population to a California Building Climate Zone[49] by zip code. Coastal locations were then mapped to climate zones 1-7, while Inland locations represented zones 8-16.
- **Mounting Type (Fixed or Tracking):** The system mounting type considered whether a system was in a fixed position or if it included a tracking system. As noted above, tracking systems produce 30 percent or more energy than fixed systems. In some cases, the mounting type was not available for all systems. For systems where no tracking type was provided, the evaluation team assumed that systems less than 30 kW were all fixed. For all other system sizes (30 to 100, and greater than or equal to 100), the evaluation team used the same breakdown by utility that was identified through the CSI[50] database.
- **System Capacity Category (Less than 15 kW, 15 kW to 100 kW, Greater or Equal to 100 kW):** Larger systems are generally expected to perform better than smaller systems. These larger systems may be more likely to have staff associated with ensuring these systems stay online and operating efficiently, rather than smaller residential systems where the homeowner may be less aware of how their system is performing.
- **System Age:** Older systems are more likely to experience problems and degradation to both the panel and the overall system. Therefore, system age was an important factor to consider when developing the regression.
- **Interconnection Year (Pre-2011/2011 or Later):** This interconnection year grouping differs slightly from the system age variable. As discussed in the previous section, there was a significant amount of daily metered data available for EPBB systems installed between 2007–2010 but these data did not extend to systems installed after 2010. Therefore, the evaluation team wanted to make sure that the regression models could determine if there was a difference in the CF based on the interconnection year and the type of data.
- **Average Solar Irradiance:** Because PV performance is so dependent on weather, the evaluation team obtained irradiance data for every PV site. Two types of irradiance data were obtained for evaluation years 2011 through 2017: annual average data and 30-minute interval data. These data

49 https://ww2.energy.ca.gov/maps/renewable/building_climate_zones.html

50 https://www.californiasolarstatistics.ca.gov/data_downloads/

were downloaded through the National Solar Radiation Database (NSRDB)[51] developed by the National Renewable Energy Laboratory (NREL). The NSRDB has an application programming interface (API) tool that easily allowed downloading large sets of weather data for 26,000 locations across California.[52] The evaluation team used these data and was able to spatially map the data to the overall population and the metered sample based on latitude and longitude coordinates. This allowed the evaluation team to determine local irradiance data for each site.

Regression models were used to estimate the impact of the above independent variables on CFs and the Greenhouse Gas (GHG) Emissions Rate (Metric Tons of CO_2 per kW) for each PV system in the population. The CF_{AC}[53] is a determination of how much energy the system is outputting relative to the system's capacity and is calculated using the following equation:

$$Capacity\ Factor\ (CF_{AC}) = \frac{\sum Generation\ (kWh)}{Capacity\ (kW) \times Hours\ of\ Data^{54}}$$

For annual results, the CF is based on the number of hours of available metered data for that year. Peak results are based on just a single hour with the highest CAISO or IOU load. Similarly, top 200 results are based on 200 hours with the highest load (CAISO or IOU) for the year.

The approach used to formulate CO_2 emission rates for this analysis is based on methodology developed by E3 and found in its avoided cost calculation workbook. The E3 avoided cost calculation workbook assumes:

The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and

The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

[51] The NSRDB is a collection of various hourly and sub-hourly meteorological data, including solar radiation, for the United States and other international locations. https://nsrdb.nrel.gov/

[52] Weather data were downloaded from NSRDB through their API service. https://developer.nrel.gov/docs/solar/nsrdb/

[53] All capacities and capacity factors in this report are in terms of "AC" using the CEC PTC Rating for each system. The AC capacity reflects realistic operational temperatures in addition to system losses so is lower than the panel rating or "nameplate" DC capacity. AC capacity factors will therefore be slightly higher than DC capacity factors.

[54] Hours of data represents the total hours of useful data available per year.

The premise for hourly CO_2 emission rates calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the electricity market demand conditions. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO_2. In other words, one can expect an emission rate representing the release of CO_2 associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours. Similarly, when prices are very low or negative, the CO_2 emission rate is assumed to be zero and implies renewable curtailment on the margin.

The Annual Emissions Rate is calculated using the following equation:

$$Annual\ Emissions\ Rate_i = \frac{\sum_{hour=h} Generation_{i,h}\ [kWh] \times CO_2E3Factor_{i,h}\ \left[\frac{Metric\ Tons\ CO_2}{kWh}\right]}{Capacity_i\ [kW]}$$

The *CO_2 E3 Factor* is the rate for region (northern or southern California) for hour *h*. This value is from Energy and Environmental Economics [Metric tons / kWh].

The energy generation of a PV system, which is used to determine both the annual CF and the annual emissions rate, is dependent on many variables, including the orientation of the panels (tilt and azimuth), whether the system is fixed in place or uses a tracking system to direct the panels towards the sun throughout the day, the construction and efficiency of the panels and inverters, the age of the system, the amount of soiling accumulated on the panel, the amount of shading blocking the panels, and the amount of available solar resource (irradiance). The amount of solar irradiance varies widely based on location and climate, with parts of California having more annual insolation per year than anywhere in the world. However, CF can also be calculated on a smaller timescale, such as monthly or even daily, to compare performance with seasonal loads such as air-conditioning. CF varies significantly throughout the year, as performance increases during the summer months when the sun is higher and days are longer.

The final model and parameters for the Annual Energy Impacts Results are listed in Table 4-2.[55]

TABLE 4-2: ANNUAL ENERGY IMPACTS REGRESSION MODEL

Independent Variable	Estimate	tValue[56]	Standard Error[57]	pValue[58]
Intercept	0.129265	21.71	0.005954	<.0001
Flag: Pre2011	0.021166	39.13	0.000541	<.0001
Flag: Capacity: 15-100	-0.00332	-2.64	0.001257	0.0082
Flag: Capacity: >100	-0.00126	-0.6	0.002094	0.5471
Flag: PGE Coastal	-0.0101	-11.5	0.000878	<.0001
Flag: PGE Inland	-0.00481	-6.18	0.000777	<.0001
Flag: SCE Coastal	-0.00626	-6.27	0.000999	<.0001
Flag: SCE Inland	-0.00575	-7.66	0.000750	<.0001
Flag: SDGE Coastal	-0.00124	-1.34	0.000924	0.1805
Flag: Fixed Array	-0.07609	-36.85	0.002065	<.0001
System Age	-0.00337	-28.82	0.000117	<.0001
Annual Avg. Irradiance	0.00062	25.49	0.000024	<.0001

The equation for the model is:

$$\begin{aligned} Annual\ CF = {} & Intercept + Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\ & * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\ & + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\ & * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\ & + AnnualAvg.Irradiance * \beta_{AnnualAvg.Irradiance} + \epsilon \end{aligned}$$

---

55 Regression models for CAISO Peak, CAISO Top 200, PA Peak, PA Top 200, and Emissions can be found in Appendix A – PV Impacts.

56 The tValue represents the coefficient divided by its standard error. The greater the magnitude of the tValue, the greater the evidence that there is a significant difference. If the tValue is greater than 1.645 there is a 90% confidence that the estimated coefficient is statistically different from zero.

57 The standard error is the estimate of the standard deviation of the coefficient. It is a measure of the precision with which the regression coefficient is measured. If the coefficient is large relative to the standard error, it is likely the estimated coefficient is statistically different from zero.

58 The pValue is the probability of seeing the given result in a collection of random data in which the independent variable had no effect. A pValue of 5% or 10% or less is generally the accepted point at which you can reject the null hypothesis - that the coefficient is zero or the independent variable has not effect on the value of the dependent variable. Note the size of the pValue or tValue for a coefficient say nothing about the size of the effect the independent variable has on the dependent variable – size of effect is measured by the coefficient time the value of the independent variable.

Where the *"Flag"* variables are binary variable (0/1) reflecting a sample strata's independent variable value. For example, $Flagcap_{15100}$ is 1 if the strata represent systems with a capacity of 15-100 kW, 0 otherwise. The *β* are the coefficient or parameter estimates generated by the model. The parameter estimates describe the impact of a one-unit change in the independent variable on the value of the dependent variable. Table 4-2 include the parameter estimates from the model and the estimated t-values. If a t-value exceeds 1.645, the estimated coefficient is coefficient is statistically different from zero at a 90 percent certainty. The table shows that increased system age decreases the CF while increases in irradiance increase the CF. The Utility/Coastal/Inland variables are interpreted relative to the baseline choice or SDG&E Inland. The negative parameter estimates for the other utility/geography indicates that SDG&E Inland has a higher capacity factor than the other areas. The finding that, within a utility, the Coastal parameter is more negative than the Inland parameter, is also consistent with expectations.

4.2.4 Comparison of Sample to Population

Annual Impacts Sample

A comparison of the Annual Impacts sample to the BTM PV population is shown below in Figure 4-3. Although the number of systems in the sample were only 2 percent of the population for each utility, the overall fraction of capacity was 18 percent overall, ranging from 11 percent to 24 percent by utility. The disparity in percent of systems and percent of capacity is likely due to the CSI program requirement that larger systems receive a PBI incentive; therefore, they are more likely to have available metered data.

FIGURE 4-3: ANNUAL IMPACTS SAMPLE PERCENT OF POPULATION

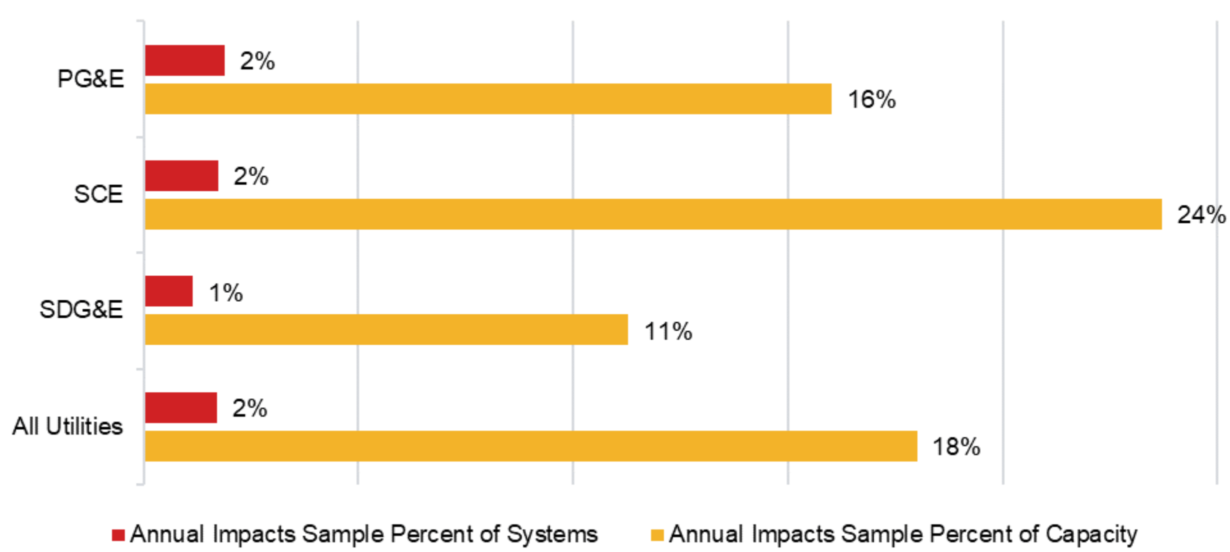
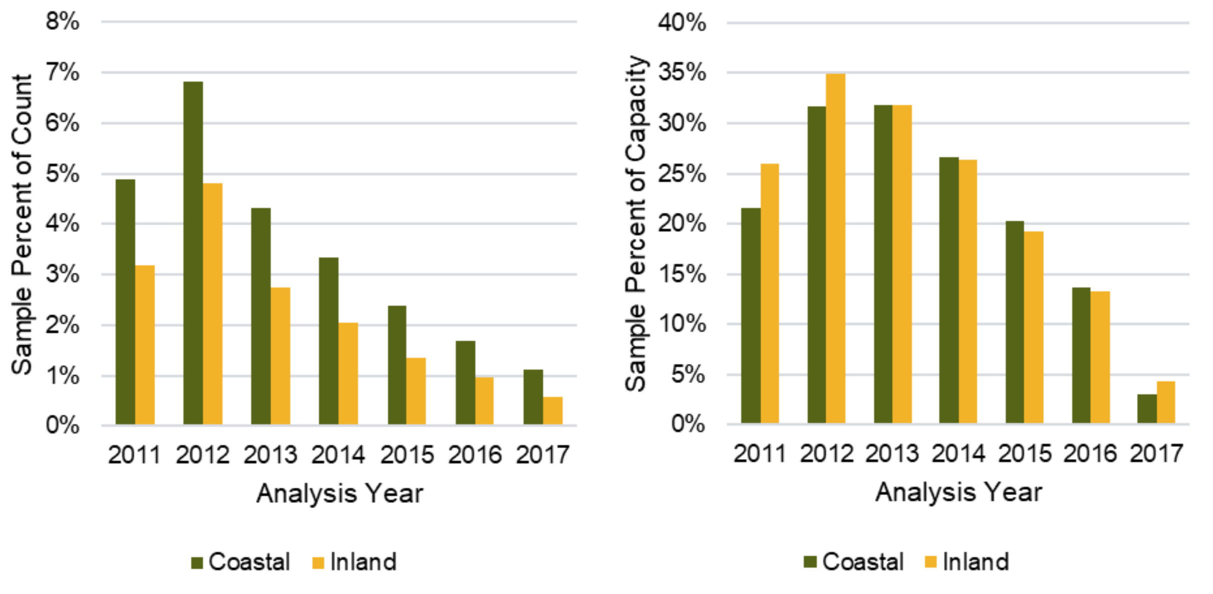


Figure 4-4 shows the percent of sites to the population by location, for inland versus coastal sites. The graph on the left shows results by count, while the graph on the right shows results by capacity. When looking at counts, although there were a higher number of sampled sites in the inland region for most years, there was also a much larger population of BTM PV located in inland regions. The years 2016 and 2017 saw over two times the amount of BTM PV systems installed in inland locations versus coastal locations. When looking at the results by capacity, the sample across inland and coastal locations seem more evenly distributed when compared to the population.

FIGURE 4-4: ANNUAL IMPACTS SAMPLE PERCENT OF POPULATION BY LOCATION



The share of BTM PV population capacity and count that was sampled for each year is shown below in Figure 4-5. Much more metered data were available for projects in earlier years, although the availability of data started decreasing in 2012 due to two reasons:

- Increasing numbers of smaller (usually residential) systems being installed that were not required to have a PBI.
- Starting in approximately 2015, increasing numbers of systems being installed without an incentive from the CSI as incentives for that program ran out. The CSI required access to metered data to receive the incentive, but systems installed without CSI incentives did not have a requirement to provide data. Therefore, data providers were very reticent to share data for non-CSI systems due to customer confidentiality and privacy concerns.

By 2017, metered data were available for less than 5 percent of the overall capacity and 1 percent of overall count. The majority of metered data was available from sites within SCE territory, almost 10 percent of the overall 2017 capacity, while metered data were only available for a few smaller-sized PG&E projects.

FIGURE 4-5: ANNUAL IMPACTS METERED DATA AVAILABILITY BY ANALYSIS YEAR – BY COUNT AND CAPACITY

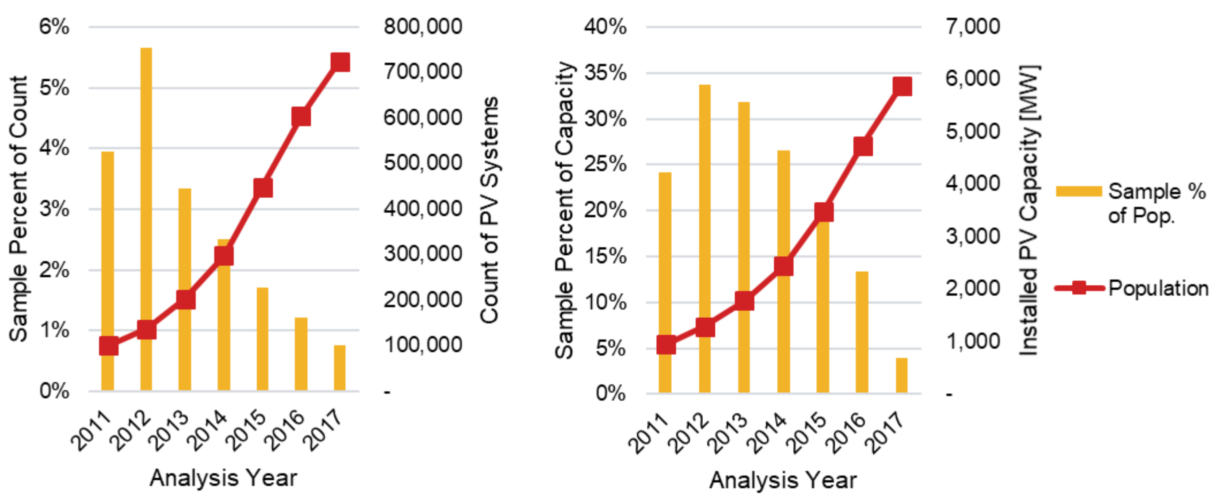
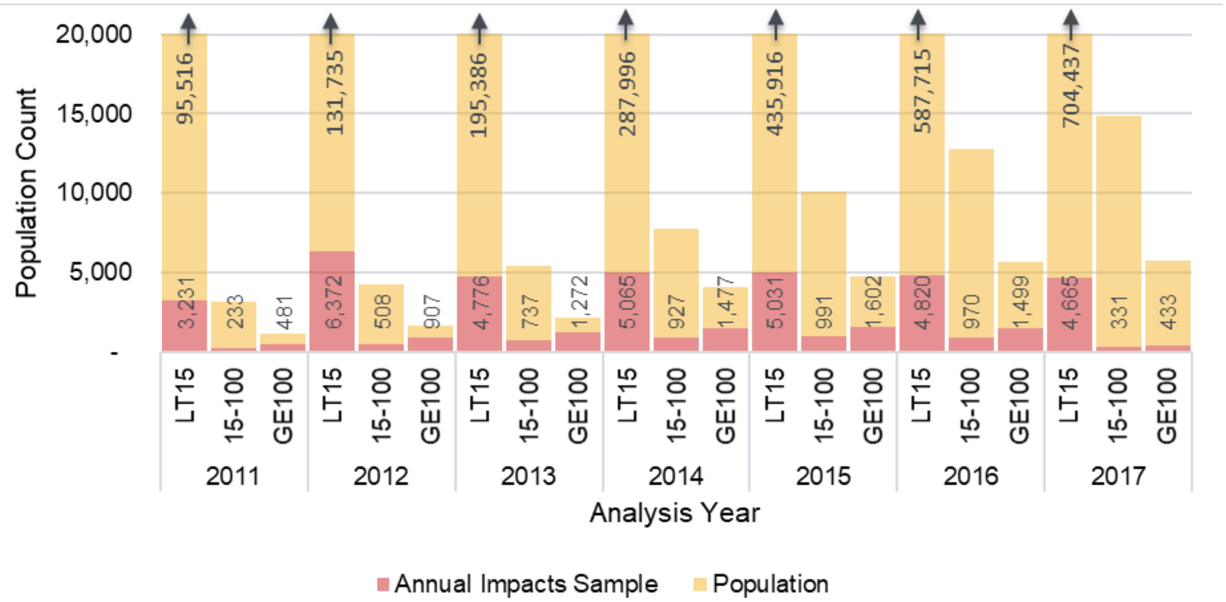


Figure 4-6 displays the metered data availability for each analysis year by system size category. The overall capacity for the smallest capacity category (systems less than 15 kW) made up between 44 percent and 62 percent of the overall BTM PV capacity each year. While this category had the smallest percentage of sample to population data availability, it did have the largest number of metered sites The largest systems (greater or equal to 100 kW) were found to have the largest percentage of available metered data. This is unsurprising, as there were fewer of these systems and many of them had incentives tied to performance, which required metering equipment.

FIGURE 4-6: ANNUAL IMPACTS METERED DATA AVAILABILITY FOR ANALYSIS YEAR BY SYSTEM SIZE



The size categories listed above were used as in place of sector (Non-Residential versus Residential) for several reasons. The first was that the Sector variable was not always complete, nor was it always consistent between the many different datasets that made up the final BTM PV population. The evaluation team examined the CSI population dataset as proxy for the full BTM PV population to see what capacity categories would be representative of residential versus non-residential facilities. The breakdown below in Table 4-3 shows just over 71 percent of CSI systems are residential, and almost all of these are in the 0 to 15 kW capacity category, indicating that 15 kW is an appropriate breaking point between Residential and Non-Residential systems.

TABLE 4-3: COUNT OF CSI SYSTEMS BY SECTOR, INCENTIVE TYPE, AND CAPACITY

Capacity	EPBB	PBI	Total
Non-Residential			
0-15	0.1%	0.2%	0.4%
15-30	0.2%	1%	1%
30-45	0.0%	2%	2%
45-60	0.0%	2%	2%
>60	0.0%	23%	23%
Residential			
0-15	67%	3%	70%
15-30	1%	0.1%	1%
30-45	0.0%	0.1%	0.1%
45-60	0.0%	0.1%	0.1%
>60	0.0%	0.3%	0.3%

Table 4-4 and Table 4-5 below display the distributions of tilt and azimuth by utility. Like Sector, this was not a variable that was well tracked in many of the datasets used to develop the BTM PV population. To compare the sample to the population, the team looked at only the CSI population, which had sufficient data for both variables. The evaluation team separated out the tilt into categories of Near Flat (less than 20º), Tilted (greater than 20º), Multiple, and Tracking. The Multiple category was for CSI applications with multiple arrays with differing tilts.[59]

For most categories, the distribution of tilt in the sample aligns well with the population. Any of the differences in sample and population are less than 10 percent across all utilities.

TABLE 4-4: DISTRIBUTION OF TILT FOR ANNUAL IMPACTS SAMPLE VERSUS POPULATION

Tilt	PG&E		SCE		SDG&E		All Utilities	
	Count of Sites	Count of Population	Count of Sites	Count of Population	Count of Sites	Count of Population	Count of Sites	Count of Population
Near Flat	26%	27%	31%	31%	37%	42%	29%	31%
Tilted	34%	43%	22%	31%	28%	31%	29%	36%
Multiple	37%	29%	44%	37%	34%	27%	39%	33%
Tracking	3%	0%	2%	0%	1%	0%	2%	0%
Mean Tilt	19.6	20.8	16.9	19.3	18.2	19.3	18.5	20.0
Std Dev. Tilt	7.2	6.8	7.4	6.3	7.1	6.1	7.4	6.5

59 PowerClerk, which held data for all CSI applications, had up to 54 tilts and azimuths recorded for a single CSI application.

As expected, most fixed, single direction array systems in both the population and the sample face south, with a smaller percentage facing south-west, and even fewer facing south-east and due west. The mean azimuth for both the population and sample was approximately 190º, or slightly west of south.[60]

TABLE 4-5: DISTRIBUTION OF AZIMUTH FOR ANNUAL IMPACTS SAMPLE VERSUS POPULATION

Azimuth	PG&E		SCE		SDG&E		All Utilities	
	Count of Sites	Count of Population	Count of Sites	Count of Population	Count of Sites	Count of Population	Count of Sites	Count of Population
N	0%	0%	0%	0%	0%	0%	0%	0%
NE	0%	0%	0%	0%	0%	0%	0%	0%
E	2%	2%	2%	3%	2%	2%	2%	2%
SE	8%	7%	6%	6%	8%	9%	7%	7%
S	31%	40%	32%	35%	39%	40%	32%	37%
SW	12%	13%	7%	9%	11%	13%	10%	11%
W	7%	8%	6%	8%	6%	8%	6%	8%
NW	0%	0%	0%	0%	0%	0%	0%	0%
Multiple	37%	29%	44%	37%	34%	27%	39%	33%
Tracking	3%	0%	2%	0%	1%	0%	2%	0%
Mean Azimuth	189.6	190.8	187.0	189.7	186.9	189.8	188.4	190.2
Std Dev. Tilt	42.6	42.0	43.3	45.7	39.3	42.4	42.5	43.7

Interval Data Sample

A comparison of the Interval Data sample to BTM PV population is shown below in Figure 4-7. As discussed previously, there was a large amount of daily-only data for older systems. As metrics like impact on peak demand and GHG emissions are calculated at the hourly level, daily data could not be used for these analyses. When comparing Figure 4-3 to Figure 4-7, we can see that although there is a smaller quantity of sites in the Interval Data Sample, the percent of capacity has not changed from annual to interval samples. That is because the daily metered systems were all smaller residential systems that had a limited effect on the overall capacity of the PV sample.

60 South systems were designated between 157.5º and 202.5º.

FIGURE 4-7: INTERVAL DATA SAMPLE PERCENT OF POPULATION

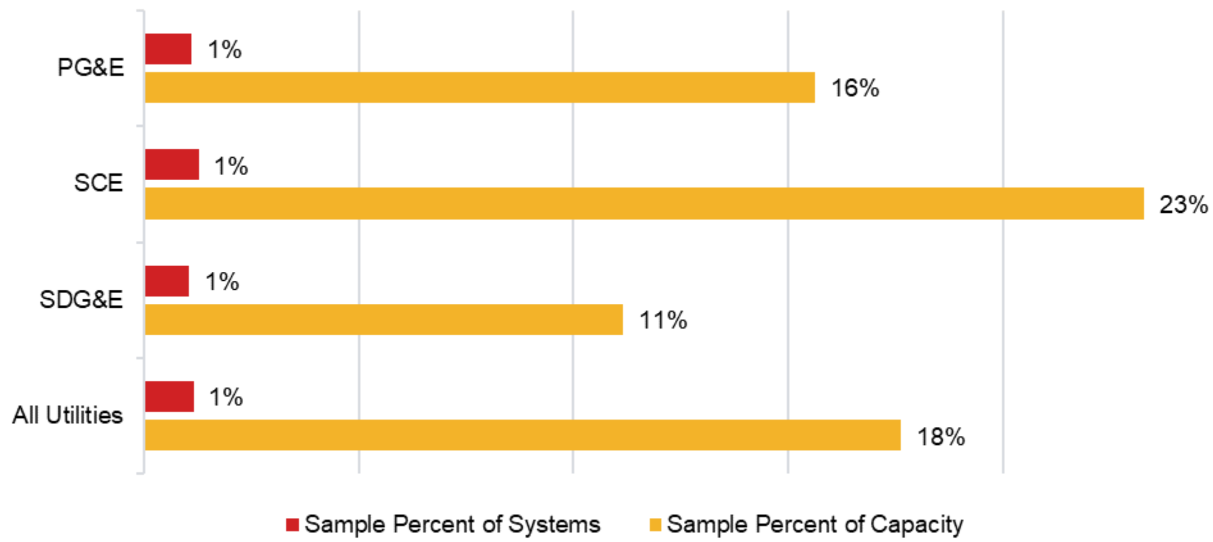
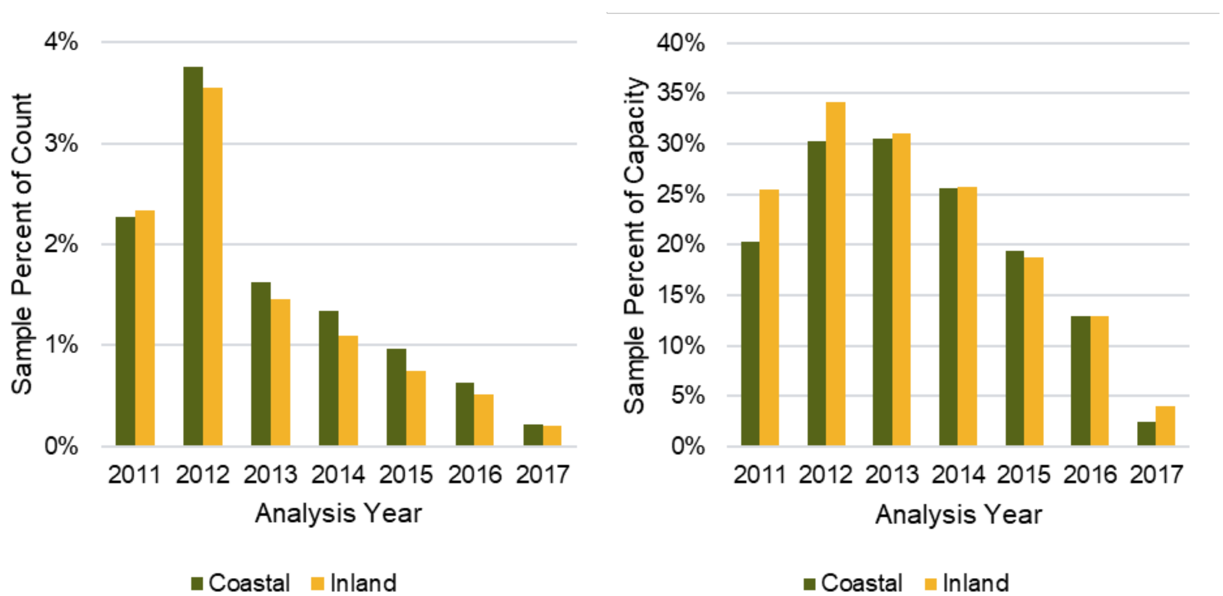


Figure 4-8 shows the percent of interval data sample sites to the population by location, for inland versus coastal sites. The graph on the left shows results by count, while the graph on the right shows results by capacity. When looking at counts, there was only a slightly higher count of coastal sampled sites over inland sites, while the distribution of capacity showed a slightly higher share of inland sites.

FIGURE 4-8: INTERVAL DATA SAMPLE PERCENT OF POPULATION BY LOCATION



The share of BTM PV population capacity and count with interval data for each year is shown below in Figure 4-9. Much more metered data were available for projects in earlier years, and similar to the annual impacts sample, the availability of data started decreasing in 2012.

By 2017, metered data were available for less than 5 percent of the overall capacity and less than 1 percent of overall count.

FIGURE 4-9: INTERVAL DATA AVAILABILITY BY ANALYSIS YEAR

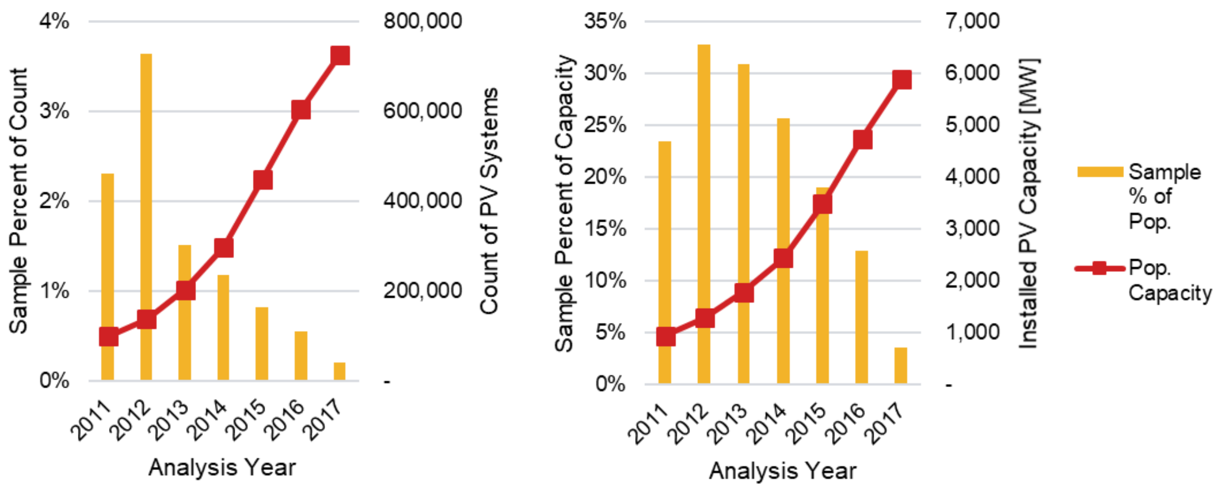
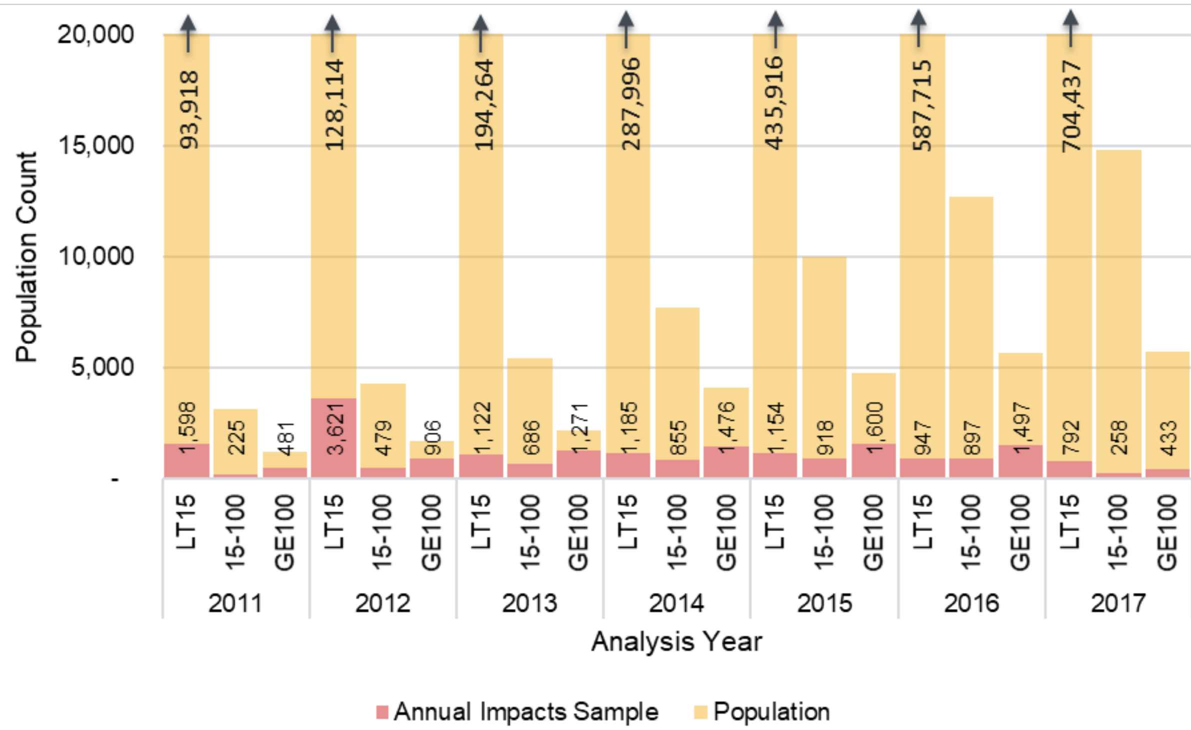


Figure 4-10 displays the interval metered data availability for each analysis year by system size category. The largest difference between the interval data sample and the annual impacts sample can be seen in the LT15 category. The interval metered data availability for this size category is much less than that of the annual impacts sample, especially in the years after 2012.

FIGURE 4-10: INTERVAL METERED DATA AVAILABILITY FOR ANALYSIS YEAR BY SYSTEM SIZE



4.3 OBSERVED PERFORMANCE AND IMPACT OBJECTIVES

The regression approach described above was utilized to estimate annual energy impacts, peak hour and top 200 hours demand impacts, and environmental impacts resulting from the installation of the PV systems.

4.3.1 Energy Impacts Results

The methodology described above was used to estimate energy impacts from all California BTM PV systems during each year from 2011 through 2017. Table 4-6 below summarizes the estimated total annual energy in MWh delivered from all known California BTM PV systems.[61]

TABLE 4-6: ESTIMATED TOTAL ANNUAL ENERGY DELIVERED BY ANALYSIS YEAR

Year	Count of Installed Systems	Installed MW_{AC}	Total Estimated MWh Delivered During Year	Annual CF_{AC}
2011	99,908	944	1,570,910	0.19
2012	137,694	1,288	2,112,933	0.19
2013	202,969	1,789	2,950,795	0.19
2014	297,484	2,439	3,966,454	0.19
2015	448,206	3,479	5,541,818	0.18
2016	603,720	4,738	7,511,380	0.18
2017	724,285	5,885	9,172,665	0.18

During 2017, California BTM PV systems generated nearly 10 TWh of electricity that would otherwise need to have been delivered from other grid resources. This represents just under 5 percent of the total system electric consumption for PG&E, SCE and SDG&E for 2017.[62] During the seven-year evaluation period, the population of BTM PV systems increased to over 700,000 systems across California, increasing between 20 to 50 percent each year. The estimated CF for these systems ranged between 0.18 and 0.19 Annual CFs show a slight downward trend as the population of installed PV systems in California ages over time.

[61] This includes all BMT PV for California's IOUs, not just systems that received a CSI.

[62] http://www.ecdms.energy.ca.gov/elecbyutil.aspx consumption in PG&E territory was 81,945 GWh, in SCE territory 85,602 GWh and SDG&E territory 19,017 GWh, for a total of 186,564 GWh.

Figure 4-11 shows the estimated energy delivered from California BTM PV systems by utility between 2011 and 2017. The fraction of energy delivered by PV systems in each utility is roughly proportional to the population of BTM PV systems installed within each utility's service territory. PG&E has the largest population of BTM PV systems; therefore, it has the highest share of electricity generation. The smallest contribution comes from SDG&E.

FIGURE 4-11: ESTIMATED ANNUAL ENERGY IMPACTS BY UTILITY AND ANALYSIS YEAR

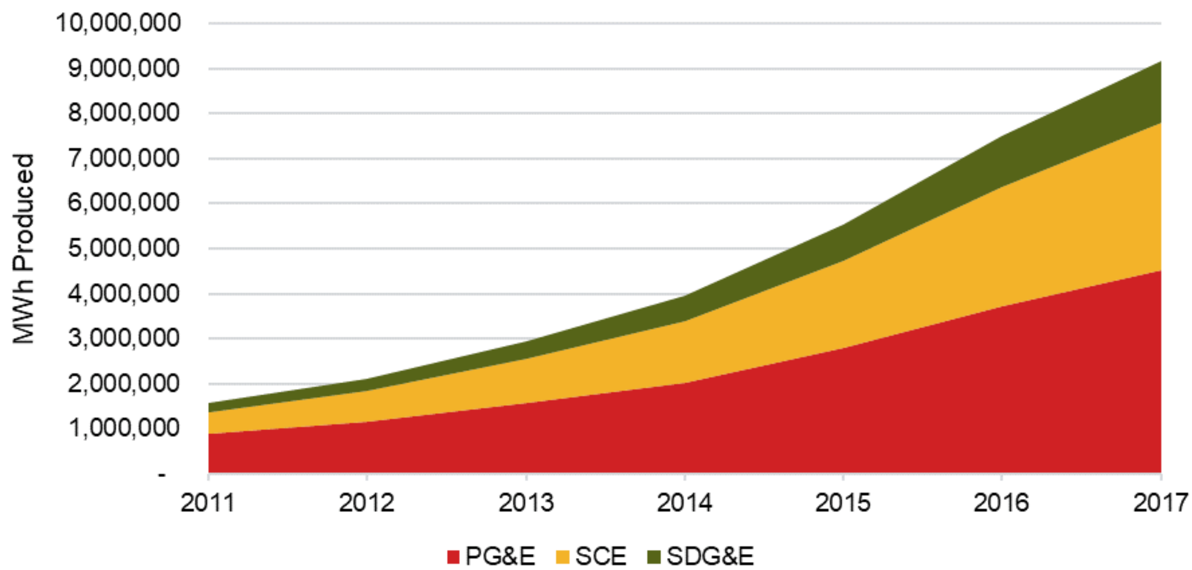


Figure 4-12 shows a similar breakdown as above but separates the estimates annual energy impacts by size category as well. Across all utilities, the largest contribution to energy impacts comes from the smallest systems, those less than 15 kW. As shown in Figure 4-6 and Figure 4-10 above, in 2017 there were over 700,000 systems installed that were less than 15 kW. In comparison, there were under 15,000 systems 15-100 kW, and just over 5,000 systems greater than 100 kW that same year. Given the number of small systems in California, it is no surprise that these make up the biggest share of annual energy impacts each year. Systems greater than 100 kW make up the second largest share of estimated annual impacts.

FIGURE 4-12: ESTIMATED ANNUAL ENERGY IMPACTS BY UTILITY AND ANALYSIS YEAR AND SIZE CATEGORY

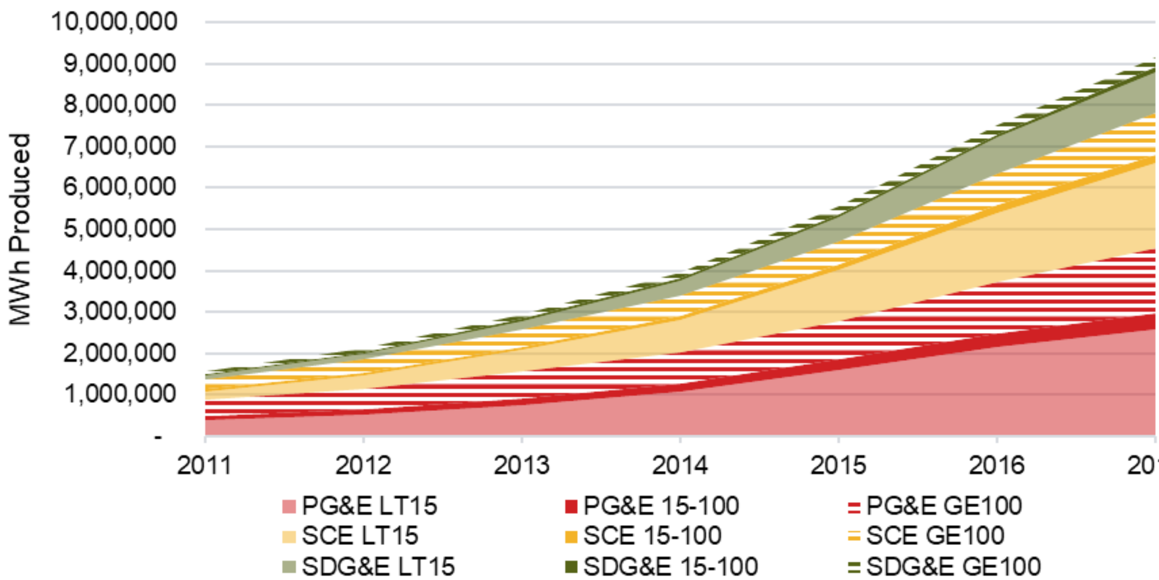


Table 4-7 shows the estimated total annual energy delivered by calendar year and utility from 2011 through 2017. Table 4-7 also shows the total number of systems contributing to the estimate during each year and the average CF of the subgroup of PV systems. CFs remain relatively constant throughout the evaluation period, ranging from a low of 0.17 (PG&E systems during 2017) to a high of 0.20.

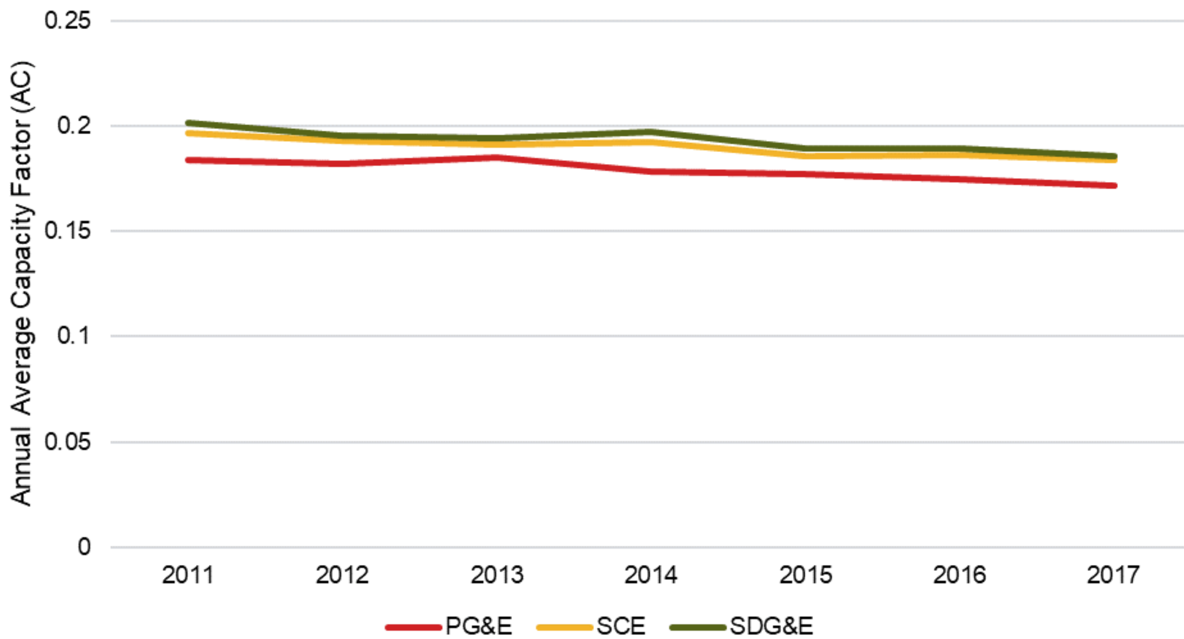
TABLE 4-7: ESTIMATED TOTAL ANNUAL ENERGY DELIVERED BY ANALYSIS YEAR AND UTILITY

Year	Utility	Count of Installed Systems	Installed MW_{AC}	Total MWh*	Annual CF_{AC}*
2011	PG&E	59,155	547	880,289	0.18
	SCE	26,582	282	486,024	0.20
	SDG&E	14,171	116	204,597	0.20
2012	PG&E	76,628	716	1,142,935	0.18
	SCE	41,628	416	702,664	0.19
	SDG&E	19,438	156	267,334	0.20
2013	PG&E	105,768	964	1,563,124	0.19
	SCE	66,852	598	1,003,201	0.19
	SDG&E	30,349	226	384,470	0.19
2014	PG&E	151,350	1,284	2,007,192	0.18
	SCE	100,078	825	1,389,128	0.19
	SDG&E	46,056	330	570,135	0.20
2015	PG&E	219,421	1,793	2,781,993	0.18
	SCE	155,566	1,190	1,935,881	0.19
	SDG&E	73,219	496	823,945	0.19
2016	PG&E	291,667	2,426	3,717,652	0.18
	SCE	208,465	1,617	2,640,574	0.19
	SDG&E	103,588	694	1,153,154	0.19
2017	PG&E	349,442	3,013	4,535,363	0.17
	SCE	252,292	2,035	3,274,285	0.18
	SDG&E	122,551	837	1,363,017	0.19

* All results produced confidence results better than 90/10.

Figure 4-13 highlights trends in CF by electric utility and calendar year. Annual CFs are influenced by irradiance, shading, and PV system orientation. Average CFs are highest in SDG&E and SCE service territories since southern California enjoys fewer rainy days than northern California. PG&E has the lowest CFs on average and the lowest average irradiance among the three electric IOUs. Annual average CFs trend downward over time; however, this should not be confused with an explicit degradation rate. The average age of California BTM PV systems is aging some over time. Degradation effects are discussed in detail in Section 4.4.

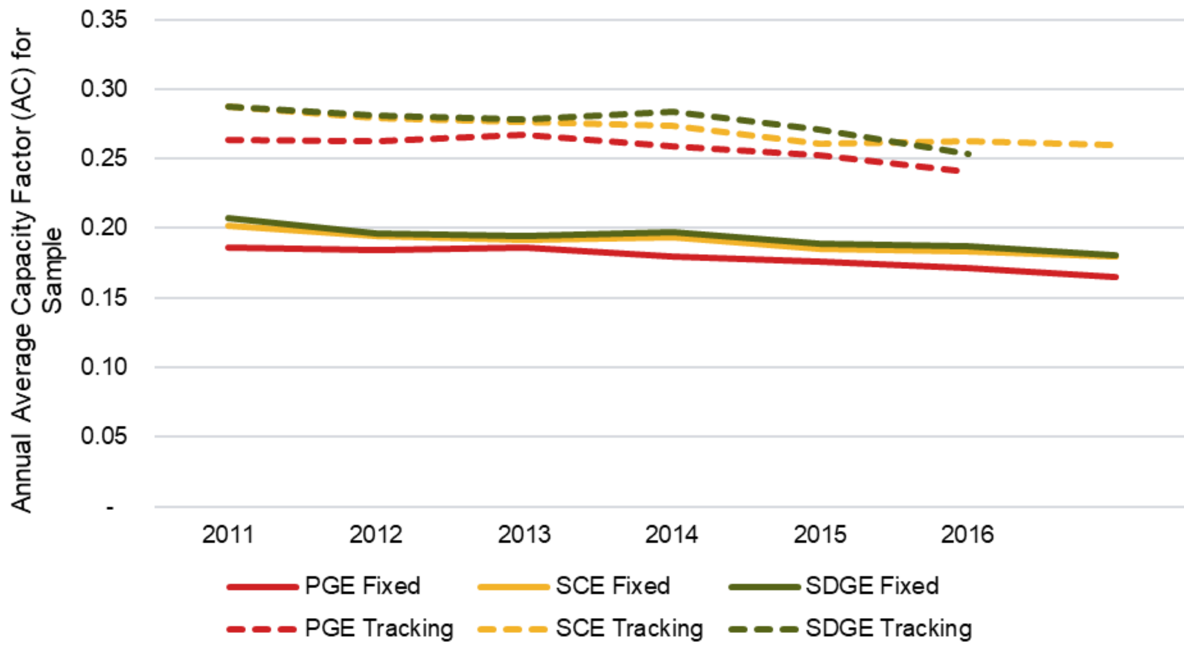
FIGURE 4-13: ESTIMATED AVERAGE ANNUAL CAPACITY FACTOR BY ELECTRIC UTILITY AND ANALYSIS YEAR



The evaluation team also compared estimated annual CFs by electric utility and calendar year for tracking versus fixed systems. Because the regression analysis calculated results by analysis year and utility, and not by tracking versus fixed systems, the comparison below can only be performed for the sample and is not weighted to reflect population-level results. Therefore, the results from the sample may not match the population. Overall, results for sample-level fixed systems are very close to the population-level results, because the majority of the systems in the population are fixed systems rather than tracking systems. Only 2 percent of the sample, and less than 1 percent of the population[63] was identified as a tracking system. These results show that tracking systems produce on average, about 25 percent more energy than fixed systems.

[63] Where the array tracking information was known.

FIGURE 4-14: ESTIMATED AVERAGE ANNUAL CAPACITY FACTOR FOR ANNUAL IMPACTS SAMPLE BY ELECTRIC UTILITY AND ANALYSIS YEAR AND TRACKING TYPE*



* It is important to remember that the results may vary from the population-level estimates because the sample is generally older than the population, and sample-level results, therefore, are based on older systems. While the regression analysis will account for this in its simulation of population level estimates, there is no correction that can be made for the sample results. Insufficient data are available for 2017.

4.3.2 Peak Hour Demand Impacts

This section presents the impact of California BTM PV systems on peak electricity demand. Generation coincident with the CAISO system peak hour for each year was analyzed, along with the individual peak hours for each IOU's system.

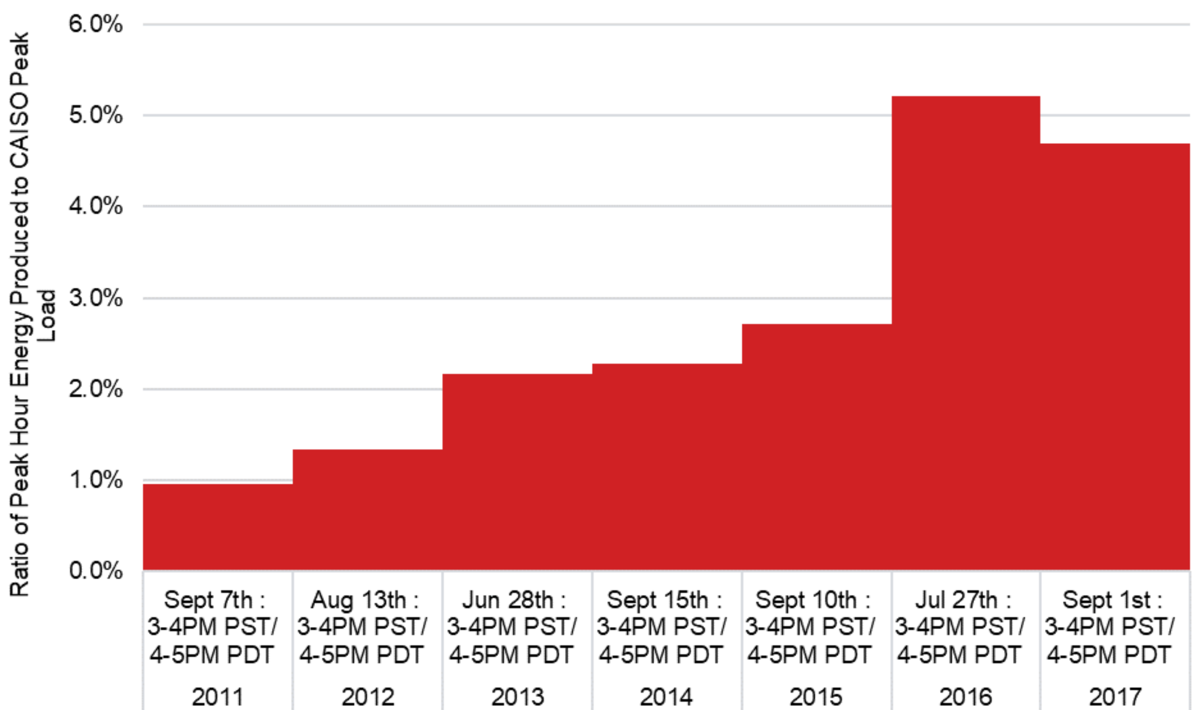
The analysis of PV impact on CAISO and IOU peak loads was performed on a gross demand basis looking at all demand that needs to be served by in front of the meter generation. Utility planners are increasingly using net demand to assess generation needs as utility-scale renewable generation grows. Additional analysis based on CAISO net demand (gross demand minus utility-scale renewable generation) may be of additional value in future work but net demand analysis was outside the scope of this project.

By delivering electricity directly to the customer site during peak hours, PV systems reduce the need for utilities to supply electricity during critical time periods. As a result, PV systems may provide benefits by alleviating the need to dispatch potentially older, more polluting, and more expensive peaking generators, as well as decreasing transmission and distribution line congestion.

To develop peak hour demand impacts for the population, the evaluation team utilized a similar regression methodology to that developed for annual energy impacts. The peak hour model used hourly irradiance instead of yearly average irradiance and hourly CF during the peak hour instead of annual CF.

Between 2011 and 2017, the CAISO peak load varied between 44,924 MW and 49,909 MW.[64] Figure 4-15 displays the ratio of the energy produced from PV systems during the CAISO peak hour to the CAISO peak load for each year. In general, California BTM PV systems produced between 1 percent and 5 percent of the CAISO peak load for each year.

FIGURE 4-15: RATIO OF CAISO PEAK HOUR ENERGY PRODUCED FROM PV SYSTEMS TO CAISO PEAK LOAD



PV systems had more impact during the CAISO peak hour in 2016 due to the peak hour falling earlier in the year (July) than in 2016 and 2017 (September). July is closer to the longest day of the year (the summer solstice in late June) so the sun is higher in the sky and providing more irradiance at 3 PM than at the same time in September. Therefore, a PV system would be expected to produce more energy at 3 PM in July than in September.

[64] As per hourly Total Actual Hourly Integrated Loads downloaded from http://oasis.caiso.com/ for Transmission Access Charge (TAC) Areas. These are fields 'PGE-TAC' for PG&E, 'SCE-TAC' for SCE and 'SDGE-TAC' for SDG&E to calculate CAISO load.

Table 4-8 below shows the CAISO peak load and the BTM PV energy generation during the peak hour, along with the PV CF during that CAISO peak hour. The CAISO peak hour occurred during the 3 to 4 PM hour (Pacific Standard Time, or 4 to 5 PM Pacific Daylight Time) each year between 2011 and 2017; however, the peak hour was not during the same month each year. The CAISO peak hour month ranges from June (2015 peak hour) to September. In general, PV CFs reflect the irradiance during the CAISO peak hours. Peak hour CFs are higher during 2013 and 2016 when the CAISO peak hour occurred in June and July, respectively. In contrast, peak hour CFs are lower when the CAISO peak hour occurs in September.

TABLE 4-8: CAISO PEAK HOUR IMPACT ESTIMATES BY IOU AND ANALYSIS YEAR

Year	Utility	Generated MW*	Peak Hour CF_{AC}*	CAISO Peak Date/Hour[64]	CAISO Peak MW
2011	PG&E	260	0.48	Sept 7th: 3-4PM PST/ 4-5PM PDT	45,569
	SCE	126	0.45		
	SDG&E	52	0.45		
2012	PG&E	364	0.51	Aug 13th: 3-4PM PST/ 4-5PM PDT	46,682
	SCE	185	0.45		
	SDG&E	74	0.47		
2013	PG&E	541	0.56	Jun 28th: 3-4PM PST/ 4-5PM PDT	44,924
	SCE	313	0.52		
	SDG&E	119	0.52		
2014	PG&E	555	0.43	Sept 15th: 3-4PM PST/ 4-5PM PDT	44,671
	SCE	325	0.39		
	SDG&E	134	0.41		
2015	PG&E	722	0.40	Sept 10th: 3-4PM PST/ 4-5PM PDT	47,252
	SCE	418	0.35		
	SDG&E	139	0.28		
2016	PG&E	1,255	0.52	Jul 27th: 3-4PM PST/ 4-5PM PDT	45,981
	SCE	797	0.49		
	SDG&E	343	0.49		
2017	PG&E	1,259	0.42	Sept 1st: 3-4PM PST/ 4-5PM PDT	49,909
	SCE	766	0.38		
	SDG&E	320	0.38		

* All results produced confidence results better than 90/10.

A similar analysis was performed looking at the individual peak load impacts of the three IOU service areas for each year. The results are summarized in Table 4-9 below. Estimated IOU peak demand impacts are similar to the CAISO peak demand impacts; however, there is increased variability in the hours during which each IOU experiences peak load. This variability in peak demand hours translates into variability in the peak hour CF of BTM PV systems. Utilities that experience peak loads closer to noon have higher peak load contributions from BTM PV. The highest BTM PV CF was during SDG&E's 2011 peak load hour, which occurred early in the day from 2 to 3 PM (Pacific Standard Time, or 3 to 4 PM Pacific Daylight Time). The BTM PV energy contribution to peak demand reduction ranges from less than 1 percent of peak load to more than 8 percent of peak load (SDG&E peak load during 2017).

TABLE 4-9: UTILITY PEAK HOUR IMPACT ESTIMATES BY ANALYSIS YEAR

Year	Utility	Generated MW*	Peak Hour CF_{AC}*	Utility Peak Date/Hour[64]	Utility Peak MW
2011	PG&E	314	0.57	Sept 21st: 3-4 PM PST, 4-5 PM PDT	20,604
	SCE	154	0.55	Sept 7th: 2-3 PM PST, 3-4PM PDT	22,107
	SDG&E	73	0.63	Sept 7th: 2-3 PM PST, 3-4PM PDT	4,355
2012	PG&E	363	0.51	Aug 13th: 3-4PM PST, 4-5PM PDT	20,119
	SCE	219	0.53	Aug 13th: 2-3PM PST. 3-4PM PDT	22,428
	SDG&E	78	0.50	Sept 14th: 3-4PM PST, 4-5PM PDT	4,620
2013	PG&E	494	0.51	Jul 3rd: 3-4PM PST, 4-5PM PDT	20,916
	SCE	309	0.52	Sept 5th: 2-3PM PST, 3-4PM PDT	22,498
	SDG&E	116	0.51	Aug 30th: 3-4PM PST, 4-5PM PDT	4,604
2014	PG&E	560	0.44	Jul 25th: 4-5PM PST, 5-6PM PDT	19,526
	SCE	209	0.25	Sept 15th: 4-5PM PST, 5-6PM PDT	22,987
	SDG&E	191	0.58	Sept 16th: 2-3 PM PST, 3-4PM PDT	4,864
2015	PG&E	699	0.39	Aug 17th: 4-5PM PST, 5-6PM PDT	20,470
	SCE	607	0.51	Sept 8th: 2-3 PM PST, 3-4PM PDT	22,822
	SDG&E	218	0.44	Sept 9th: 2-3 PM PST, 3-4PM PDT	4,718
2016	PG&E	988	0.41	Jul 27th: 4-5PM PST, 5-6PM PDT	20,408
	SCE	998	0.62	Jun 20th: 2-3PM PST, 3-4PM PDT	23,564
	SDG&E	335	0.48	Jul 22nd: 4-5PM PST, 5-6PM PDT	4,262
2017	PG&E	886	0.29	Sept 1st: 4-5PM PST, 5-6PM PDT	21,713
	SCE	1,004	0.49	Sept 1st: 2-3PM PST, 3-4PM PDT	24,177
	SDG&E	384	0.46	Sept 1st: 3-4PM PST, 4-5PM PDT	4,481

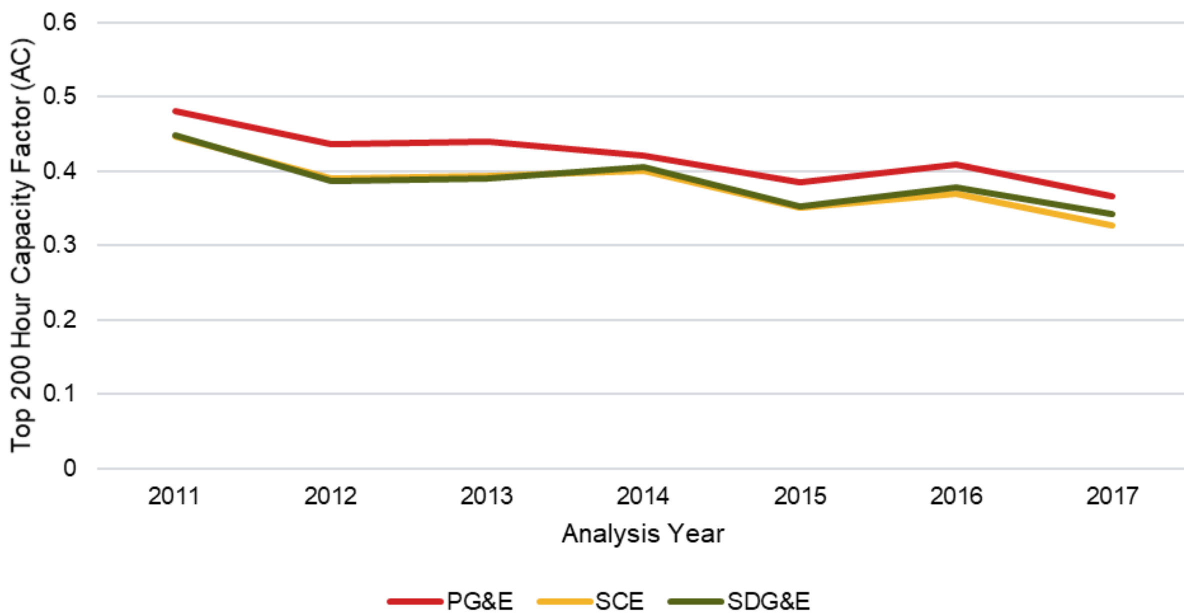
* All results produced confidence results better than 90/10.

4.3.3 Top 200 Hour Demand Impact Estimates

Electricity generated from California BTM PV systems means potentially less need for the utility to rely on expensive peak generating systems and transfer of electricity through the T&D system. However, the peak load hour represents only a single hour out of the 8,760 hours in a year. Consequently, examining only the impact on the single peak hour demand, while helpful, does not indicate the extent to which the utilities can rely on obtaining electricity from the PV resource over the course of the year.

Figure 4-16 below shows the average CF during the CAISO top 200 hours by IOU and calendar year. Each line represents the contributions of PV systems in each IOU's service territory towards the CAISO peak load. In general, CFs during the top 200 CAISO load hours range from 0.35 to 0.50.

FIGURE 4-16: ESTIMATED IMPACT (CAPACITY FACTOR) DURING CAISO TOP 200 LOAD HOURS[65]

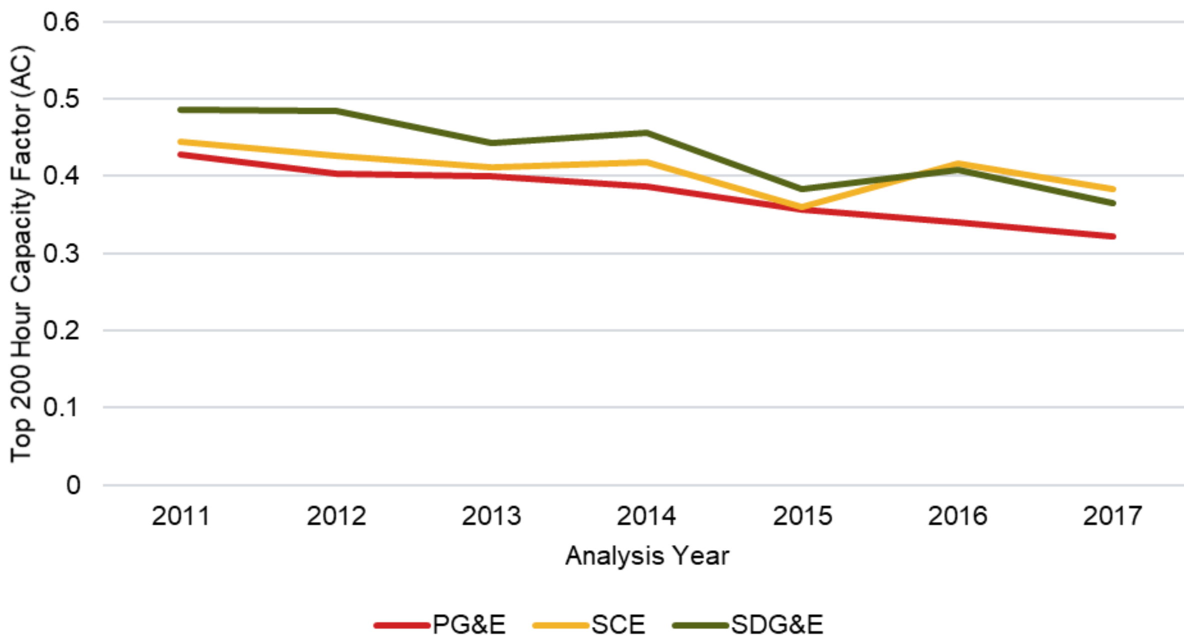


Systems in PG&E territory show somewhat higher CFs during the top 200 hours because of longer summer days and, therefore, more late-afternoon sunlight in more northern latitudes and western longitudes.

[65] The top 200 CAISO hours can be found in Appendix A, Table A-7.

Figure 4-17 below shows the contributions of each IOU's BTM PV systems towards each IOU's top 200 peak load hours. The trends are somewhat similar to those observed for the CAISO top 200 load hours, but with SDG&E showing higher CFs during top demand hours than PG&E. That switch is likely a result of PG&E's IOU specific peak hours being somewhat later in the day than SDG&E's.

FIGURE 4-17: ESTIMATED IMPACT (CAPACITY FACTOR) DURING IOU TOP 200 LOAD HOURS[66]



4.3.4 Environmental Impacts

This section discusses the GHG impacts resulting from California BTM PV systems between 2011 and 2017. The GHG impact is limited to carbon dioxide (CO_2) associated with the operation of PV systems. The scope of the analysis is limited to operational impacts of BTM PV systems and does not discuss lifecycle emissions impacts that occur during manufacturing, transportation, and construction of PV systems. The emissions impact is calculated by multiplying PV generation estimates (MWh) by a grid marginal emissions rate (Metric Tons CO_2/MWh) to arrive at a total avoided emissions value (Metric Tons CO_2).[67] These marginal emissions rates change every year as California's electricity mix changes. Only the rates for the appropriate analysis years are used. For example: in 2014, the emissions rates used in the analysis are

[66] The top 200 IOU hours can be found in Appendix A – PV Impacts, Table A-8.

[67] Marginal emissions rates were obtained from the CPUC's Avoided Cost Calculator (ACC). We used the version of the ACC that would have been publicly available during each year between 2011 and 2017. Note that in 2020 the ACC has shifted from the assumption of a gas fired power plant as the generator on the margin (that will be turned on or off due to demand) to be a solar plus storage utility scale plant to be the generator on the margin.

those for 2014 for all systems, regardless whether a system was installed in 2011 or 2014. For simplification purposes, the evaluation team assumed that the underlying customer usage does not change, so the only change in grid electricity consumption is due to on-site PV generation. Section 5 further investigates how customer load changes after the installation of PV.

An emissions rate (Metric Tons CO_2/PV MWh) was calculated for each project in the interval data sample and then calculated for the population using the regression approach described above in Section 4.2.3 Finally, the evaluation team multiplied this CO_2 impact rate by the population estimate of annual electricity generation to estimate population-level emissions impacts. Results are summarized in Table 4-10. GHG impacts are generally proportional to the size of the BTM PV population. During 2017, the evaluation team estimates that California BTM PV systems reduced GHG emissions by nearly 3.5 million metric tons of CO_2. That is equivalent to removing over 700,000 passenger cars from the road.[68]

[68] https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

TABLE 4-10: POPULATION ESTIMATE OF GHG IMPACT

Year	Utility	Total Estimated GHG Reduction (Metric Tons CO_2)	Total Estimated GHG Reduction (Metric Tons CO_2) per kW
2011	PG&E	431,190	0.79
	SCE	223,594	0.79
	SDG&E	93,037	0.80
2012	PG&E	523,686	0.73
	SCE	301,810	0.73
	SDG&E	114,415	0.73
2013	PG&E	670,629	0.70
	SCE	410,187	0.69
	SDG&E	155,470	0.69
2014	PG&E	835,179	0.65
	SCE	546,929	0.66
	SDG&E	220,112	0.67
2015	PG&E	1,123,767	0.63
	SCE	753,784	0.63
	SDG&E	314,494	0.63
2016	PG&E	1,463,143	0.60
	SCE	998,847	0.62
	SDG&E	429,222	0.62
2017	PG&E	1,731,008	0.58
	SCE	1,203,005	0.59
	SDG&E	491,010	0.59

4.4 PERFORMANCE OVER TIME AND DEGRADATION ANALYSIS

Solar PV systems tend to produce less energy, or degrade, as the systems and components age. Part of that system degradation is due to light-induced module performance degradation and most manufacturers have 20- or 25-year performance guarantees based on degradation rates of 0.5 to 1.0 percent. In addition to module degradation, factors such as module failures (due to delamination, yellowing, moisture intrusion or breakage), inverter failures, and increased shading (due to growing vegetation), among others, contribute to losses of energy and lower PV system performance over time. For simulations such as PVWatts, these loss mechanisms are usually set a static percentage, such as those shown in Table 4-11.

TABLE 4-11: PVWATTS DEFAULT DERATE FACTORS[69]

Loss Mechanism	Default Value
Soiling	2%
Shading	3%
Snow	0%
Mismatch	2%
Wiring	2%
AC Wiring	–
Connections	0.5%
Light-induced degradation*	1.5%
Nameplate rating	1%
Age	0%
Availability	3%
Inverter	–

* From the PVWatts V5 Manual: "Light-induced degradation (LID) is a phenomenon in which the power output of a module decreases when it is exposed to sunlight for the first time. After this initial period, the module power stabilizes and subsequently follows typical long-term degradation over the lifetime of the installation (~ 0.5 %/year). The default light-induced degradation (LID) loss of 1.5 % is a typical value based on measurements of losses in different module types. Some premium modules may experience lower LID losses due to their materials and construction, while others may experience LID losses greater than 1.5 %."[70] This light-induced degradation is unique in its impact on system performance in that it is additive over time and all the other loss mechanisms affect the first years as much as the last year. Under default settings, every year the degradation rate is assumed to reduce system performance by 1.5%, so at the end of a 25-year useful life, a system would be expected to produce less than 70% of the energy that the system produced in its first year. Therefore, accurate degradation rates are critical to accurately understanding PV output over time.

69 https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf

70 Pingel, S., Koshnicharov, D., Frank, O., Geipel, T., Zemen, Y., Striner, B., Berghold, J. "Initial degradation of industrial silicon solar cells in solar panels." 25th EU PVSEC, 2010.

Degradation can be defined in terms of system or equipment:

- **System Degradation** refers to overall change in system performance over time**.** This definition explicitly includes all factors that may lead to reduction in system performance over time. The definition includes the traditional "degradation" that is largely due to module degradation, but adds such factors as soiling, maintenance, system availability, fire, theft, etc. The purpose of this definition is to quantify overall changes in system performance over time.
- **Equipment Degradation** refers to change in system performance with minimization of the effects of soiling and system outages. This is much closer to the definition of "PV degradation" found in many other studies.

To quantify the degradation rates of metered systems, the project team employed two different approaches:

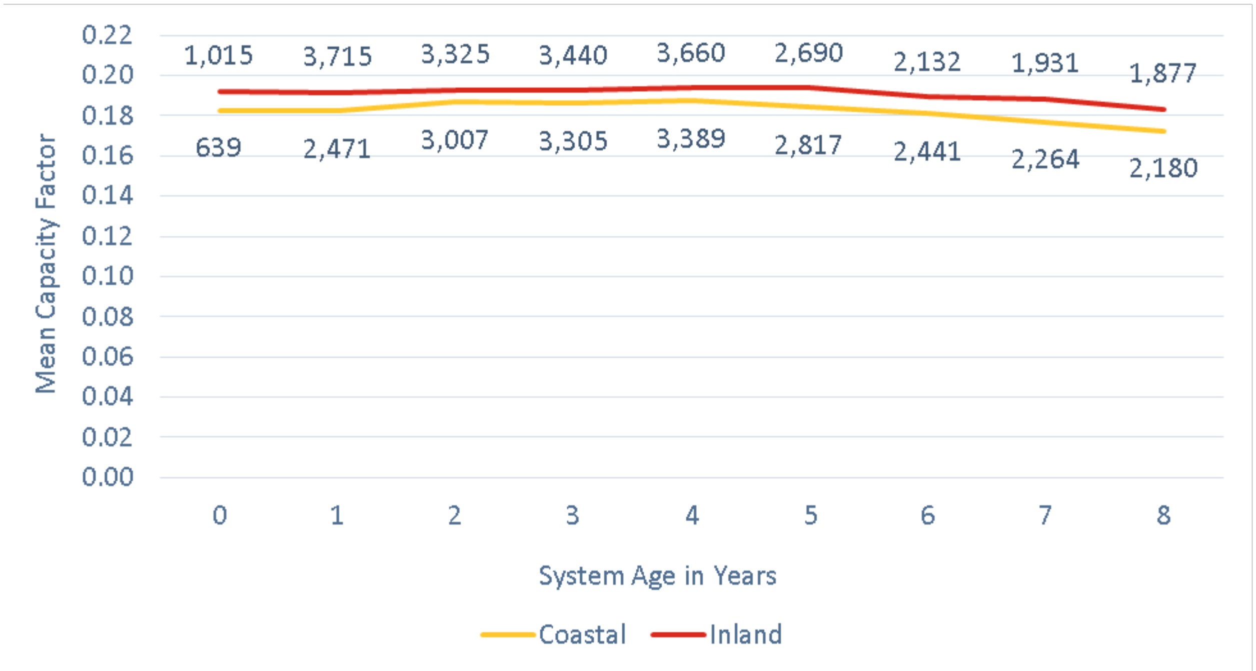
- **Regression Estimate of System Age on Performance:** The impact of system age on annual CF was estimated as a parameter in the regression model that was used to estimate annual energy impacts. The project team only applied this method to analyze system degradation.
- **RdTools Estimate of Degradation:** The evaluation team utilized RdTools,[71] a software program developed by the Department of Energy's National Renewable Energy Laboratory (NREL). This open-source software is comprised of a set of Python scripts that allow analysis of PV time-series data and whose primary function is to evaluation degradation rates over time. Within this analysis, the degradation rate for each project is calculated separately. These rates are then averaged across the systems in each group.

[71] D. Jordan, C. Deline, S. Kurtz, G. Kimball, M. Anderson, "Robust PV Degradation Methodology and Application," *IEEE Journal of Photovoltaics*, 2017.
RdTools, version 1.2.2, https://github.com/NREL/rdtools, DOI:10.5281/zenodo.1210316

4.4.1 Regression Estimate of System Age on Performance

The regression models the project team used to analyze PV impacts provide some insight into how PV systems perform over time. The annual regression model estimates an annual CF for each metered system; these are shown by inland versus coastal locations in Figure 4-18.

FIGURE 4-18: ANNUAL CAPACITY FACTORS BY AGE (NUMBERS ARE SITES IN THE ANNUAL IMPACTS SAMPLE)



Systems show lower performance as they age, with inland systems producing more energy by year than coastal systems due to more irradiance. The population-wide estimate of annual CF is 0.181 and the estimate of the impact of age on CF is -0.00363, so the percent degradation rate using the annual regression model is -0.02 or -2 percent (-0.00363/0.181). Note that this higher than the 0.5-1 percent usually quoted by the PV industry and used in PV module guarantees. However, this parameter estimate of age-related impact includes all factors that impact system performance over time, not just module degradation.

4.4.2 RdTools Estimate of Degradation Rate

RdTools is a Python-based open source tool developed by a collaboration of NREL and the solar industry. This tool compares the weather-normalized performance of an individual system on each day, year over year. For example, the performance of a system on March 15, 2015 is compared to March 15, 2016 and March 15, 2017. By using the same day each year, the impact of seasonal effects, such as soiling and shading, is minimized. RdTools also supports the use of weekly comparisons, but daily comparisons were used for this analysis to make the most use of data that often only spanned two to three years.

RdTools requires data inputs of time series energy yields, cell temperatures, and site-level irradiance. An additional tool, PV_LIB,[72] develops point-of-array irradiance values from global horizontal irradiance based on system azimuth and tilt, and it also calculates PV cell temperatures. Once the initial data are set up, RdTools focuses on several main steps: Data Normalization, Filtering of raw data, Aggregation, and Degradation Calculation.

- **Data Normalization** is used to normalize the AC energy output with meteorological inputs such as global horizontal irradiance, ambient temperature, PV cell temperature, and wind speed. The purpose of this step is the ensure that the degradation calculation takes into account the annual performance and is not affected by weather variations year to year.
- **Data Filtering** excludes data points that represent invalid data, create bias in the analysis, introduce significant noise in the data, or outages and outliers. There are several sets of filtering performed in the model:
  - Irradiance filtering involves removing data where irradiance is less than 200 and greater than 1200.
  - PV cell temperature filters out records where PV cell temperatures is less than -50 °C and greater than 110 °C.
  - Power filters out data that is greater or equal to 99 percent of the quantile and less than a low power cutoff of 0.0 W (for system degradation) or less than or equal to 0.01 W (for equipment degradation).
  - Clear sky index filter. This is usually used when using ground-based irradiance measurements. The project team did not use this filtering step, given the use of NREL's satellite-based irradiance data.
- **Data Aggregation** aggregates data with an irradiance-weighted average. Aggregating to the daily level can reduce the impact of high-error data points in the morning and evening.
- The final **Degradation Calculation** step analyzes the data to estimate degradation rate representing the PV system behavior.

The RdTools approach is often preferred to other approaches, as it utilizes modeled clear-sky irradiance data rather than site-sensor data, which provides reliable degradation rate estimates even in the case of sensor drift, data shifts, and soiling. This approach has been found to produce the lowest uncertainty in degradation rates.[73]

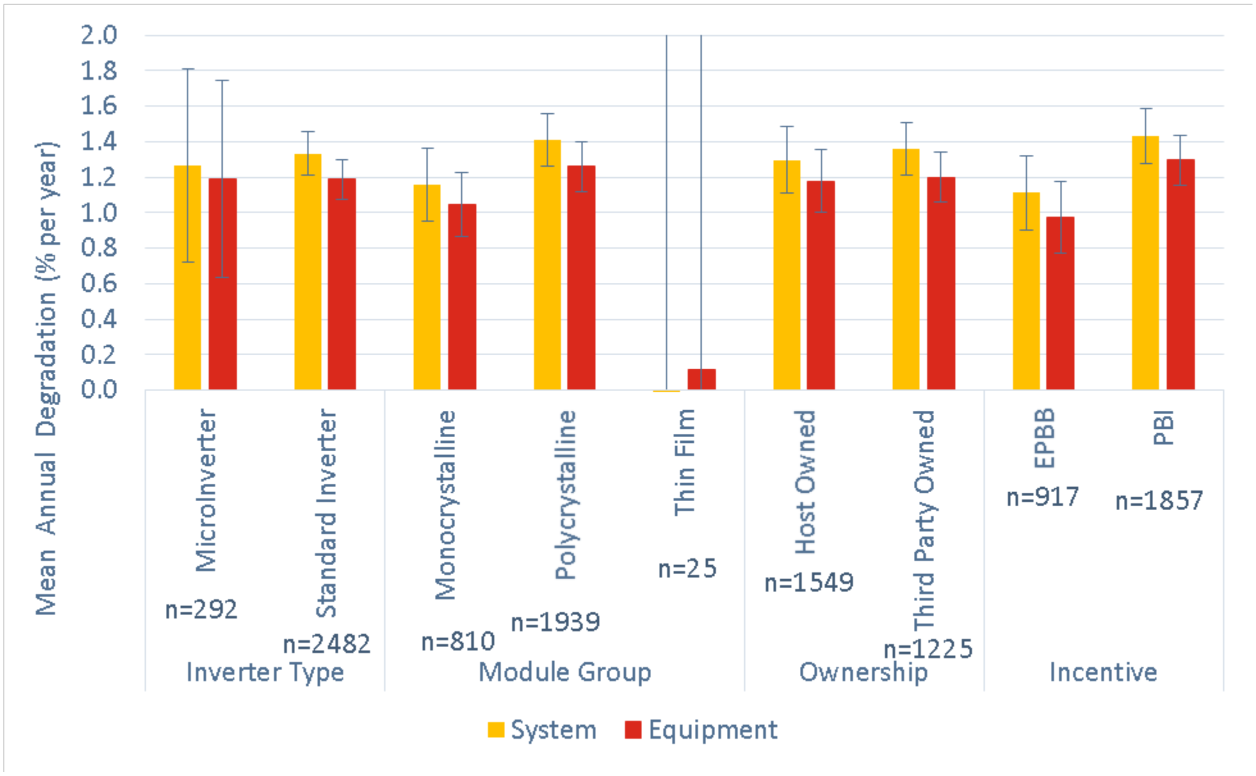
---

[72] PV_LIB is an open source tool which provides a set of functions and classes for simulating the performance of PV systems. https://pvlib-python.readthedocs.io/en/stable/

[73] D. Jordan et al, "Robust PV Degradation Methodology and Application" (2017). https://ieeexplore.ieee.org/document/8233204/

Figure 1-4 shows the mean annual year-over-year degradation rates and error bars at the 90 percent confidence limits by different groupings such as inverter type, module group, ownership, and incentive.

FIGURE 4-19: ANNUAL DEGRADATION RESULTS BY GROUP



The observed mean degradation rate using RdTools was 1.35 percent, which is slightly lower than the 1.5 percent PVWatts default assumption and the 2 percent rate estimated by the annual regression model. An exception is for the thin film subgrouping within the module type group (where sample size is small and error bands are large). However, the different subgroupings are not significantly different between subgroups within each grouping category based on T-tests at the α=0.10 (10 percent) significance level. This is not surprising given that the 90 percent confidence limits overlap between different subgroups within each grouping category. Overall, the default 1.5 percent degradation rate assumed by PVWatts appears to be a reasonable value that, potentially, could be lowered slightly.

5 NET EXPORT

PV generation net export, or negative utility electricity consumption, is a consequence of PV production exceeding a site's electricity consumption. In this section, negative utility electricity consumption is described within the evaluation team's sample of CSI sites (discussed in 5.1) for customers with net export of electricity for three distinct groups:

- **Monthly Net Exporter**: Sites whose PV systems generate more energy on a monthly basis than the site consumes. Many sites are net exporters for only some months, especially in spring when solar production tends to be highest and energy consumption tends to be low.
- **Annual Net Exporter:** Sites whose PV systems generate more energy than the site consumes on a yearly basis. These are sites where the PV system produces more energy on an annual basis than the site consumes. For many sites, the annual net export is made up of a mix of months with net export and months with net import. Net import is more likely in winter when PV generation is low or in late summer when consumption is higher due to air conditioning.
- **Consecutive Net Exporter for 12 Months:** Sites whose PV systems generate more energy than the site consumes every month for 12 consecutive months. These are sites where the PV systems are sized largest in relationship to the site's consumption.

During the early years of the CSI program, PV systems installed under the program were sized based on the participant's historical consumption to avoid the generation of excess energy. AB 920, passed during the 2009-2010 legislative session, further clarified that PV systems that were sized larger than the participant's historical consumption were eligible for incentives. The incentives, however, were only available for the portion of the system's capacity needed to serve the customer's on-site needs. Excess capacity was not eligible for incentives but could be installed simultaneously with the CSI rebated capacity. Both prior to and after AB 920, there were many cases where the electricity produced by the PV system exceeded the customer's requirements. This section characterizes the export of PV production to the electricity grid.

The analysis explores several factors by which export characteristics vary, including customer segment, coastal and inland geography, system size, and length of time since PV system installation.

5.1 SITE COUNTS AND DATA DESCRIPTIONS

In general, the analysis in this section and the other two load analysis sections (6 and 7) relies on two different types of utility electricity data:

- **Billing Data:** Monthly totals of the energy imported to or exported by the premise. These data are provided by the utility in both "Delivered" (energy that flows from the utility to the premise) and "Received" (energy that flows from the premise back to the utility – excess solar generation that is exported to the grid) channels.
- **Interval Load Data:** Hourly values for the energy imported to or exported by the premise. Delivered and Received energy by hour were available from PG&E, SDG&E, and SCE for the period following the installation of the PV system. SDG&E, however, was unable to provide load data for a year prior to PV system installation, which limited one of the three analyses that could be completed for SDG&E.

The analysis relies on post-PV installation monthly billing histories to examine the frequency, timing, and magnitude of exports among CSI host customers. The export analysis relies on three data sources:

- Utility historical monthly billing records for a sample of CSI participants to identify the frequency and magnitude of exports. The evaluation team focused the utility data request on consumers with some available PV metered data, so the net exporter analysis focuses on this sample. As discussed in Section 4, metered PV data were only available for CSI systems.
- Data from PowerClerk, which provide key information on customer segment, geography, and system size.
- Utility interconnection data, which are used to help validate the timing of system installation.

The evaluation team requested billing and load data from the IOUs for CSI sites where the team was able to collect PV meter data. The PV meter data came from third-party installers, Itron-metered sites, and IOU data from sites that received a performance-based incentives (PBI); more detail is available on metered data in Section 4. The evaluation team requested 12 months of pre-installation billing and/or load data and all available post-installation billing and/or load data for PV sites where metered data were available.[74]

[74] PV meter data was only available for CSI participant sites. Therefore, the customers with utility electricity data examined in Sections 5, 6, and 7 represent the CSI subset of all BTM PV installations.

Table 5-1 lists the number of sites in the CSI participant data and the number of sites with at least 12 months of available billing or load data (sample sites) received from each of the three IOUs.[75] The sites are presented by the year of PV installation. The data presented show that the largest number of sample sites included in this analysis are from 2010–2013. These are also the four years with the largest number of CSI participants.[76]

TABLE 5-1: COUNT OF SITES IN CSI PARTICIPANT AND SITES WITH BILLING AND PV METER DATA

Install Year	CSI PG&E Sites	Sample PG&E Sites	CSI SCE Sites	Sample SCE Sites	CSI SDG&E Sites	Sample SDG&E Sites
2007	2,486	74	757	66	322	43
2008	5,520	177	2,075	153	745	61
2009	7,646	367	3,526	190	2,056	95
2010	8,831	1,111	5,205	470	2,600	169
2011	10,902	2,840	8,011	1,382	2,840	312
2012	12,850	3,747	12,107	2,455	3,567	309
2013	11,181	948	18,367	948	2,738	166
2014	564	87	13,135	505	2,730	95
2015	132	45	560	188	1,483	36
2016*	19		235	128	289	15

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

Table 5-2 and Table 5-3 list the count of sites in the net export analysis for non-residential and residential participants by IOU, respectively. These data illustrate that the majority of the sites with PV metered and billing data are in the residential sector. The larger number of residential sites in the team's sample is consistent with residential sites representing a larger share of sites within the CSI program. Non-residential sites have a larger representation in the sample than in the frame because many of the non-residential sites were incentivized based on PBI. This required the sites to provide metered PV production data in order to receive a portion of their incentives, whereas most residential sites received all of their incentives shortly after installation and were not required to provide metered production data. The analysis sample required metered PV data. For residential sites, most of the metered PV data was provided

[75] To be included in the net export sample, the evaluation team must have 12 month of the customer's post-installation monthly utility electricity data.

[76] The analysis will occasionally compare findings from the net export analysis with findings presented in the California Solar Initiative 2010 Impact Evaluation. The 2010 evaluation included sites that participated in the CSI up to and including 2010. The current analysis includes many of these sites, but it also incorporates sites that participated after the 2010 evaluation.

by third parties who supplied the team with these data, whereas much of the PV production data for non-residential sites were PBI data obtained from the PAs.

Table 5-2 and Table 5-3 also list the average size of the installed PV systems in the CSI participant data and for sites in the net export sample. These data are listed by the sector (non-residential in Table 5-2 and residential in Table 5-3), IOU, and the year of installation. These data clearly show that non-residential customers installed larger systems than residential sites. Comparing the size of PV systems in the CSI participant data to those in the net export sample, the sample non-residential sites have a larger average PV system size than the average CSI non-residential participant. For residential participants, the average PV system size for the CSI participant data is slightly larger than observed in the team sample. Because the sample is largely based on the availability of metered PV data for systems and the availability of utility billing/load data, it is not surprising that the sample of systems does not perfectly represent the installed system. Weights were developed based on PV capacity to weight the sample sites to the CSI population for the net export analysis.

TABLE 5-2: AVERAGE SIZE OF INSTALLED PV BY IOU AND YEAR OF INSTALLATION FOR NON-RESIDENTIAL SITES

Install Year	PG&E Non-Residential Sample Sites	Avg Size of PG&E PV – Participant Data	Avg Size of PG&E PV – Sample	SCE Non-Residential Sample Sites	Avg Size of SCE PV – Participant Data	Avg Size of SCE PV – Sample	SDG&E Non-Residential Sample Sites	Avg Size of SDG&E PV – Participant Data	Avg Size of SDG&E PV – Sample
2007	16	68	130	12	180	309	4	58	84
2008	98	114	223	63	203	314	20	153	260
2009	92	121	257	34	161	456	17	84	230
2010	110	131	257	62	125	217	23	116	220
2011	210	174	242	147	182	189	41	198	253
2012	365	137	168	176	217	286	28	126	124
2013	292	144	155	103	164	173	66	129	164
2014	87	261	375	208	172	193	50	129	224
2015	45	196	115	181	221	244	35	103	185
2016*		419		128	403	431	15	309	214

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

TABLE 5-3: AVERAGE SIZE OF INSTALLED PV BY IOU AND YEAR OF INSTALLATION FOR RESIDENTIAL SITES

Install Year	PG&E Residential Sample	Avg Size of PG&E PV – Participant Data	Avg Size of PG&E PV – Sample	SCE Residential Sample	Avg Size of SCE PV – Participant Data	Avg Size of SCE PV – Sample	SDG&E Residential Sample	Avg Size of SDG&E PV – Participant Data	Avg Size of SDG&E PV – Sample
2007	58	4.1	5.1	54	5.0	5.1	39	4.3	4.6
2008	79	4.2	5.5	90	4.7	6.6	41	4.1	4.3
2009	275	4.4	4.5	156	4.7	5.8	78	4.4	4.2
2010	1,001	4.9	4.4	408	4.6	3.6	146	4.6	4.6
2011	2,630	4.7	4.0	1,235	4.8	3.6	271	5.0	4.3
2012	3,382	4.6	4.2	2,279	5.2	5.1	281	5.2	4.2
2013	656	5.0	4.9	845	5.3	6.1	100	5.8	4.9
2014*				297	5.5	7.8	45	5.7	6.7
2015*				7	6.7	9.1	1	5.7	6.9

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

To better represent all the sites in the CSI participant data, weights were developed and applied to the sample of sites being analyzed. The weights were calculated for each of the strata, defined by IOU, year of PV installation, and whether the site has a large or small PV system,[77] as shown below:

$$Weight_s = \frac{\sum_{i \in s}^{population} PV\ kWAC_i}{\sum_{j \in s}^{sample} PV\ kWAC_j}$$

Where *s* stands for strata, by IOU, Installation year, and PV system being large/small.

Therefore, if the sample included 80 percent of the total PV systems, each panel of the PV system would be given a weight of 1.25; if the sample only included 8 percent of the total PV systems, each panel would be given a weight of 12.5 — 10 times as important as in the other strata.

5.2 MONTHLY NET EXPORT

The first analysis examined the frequency with which CSI participants in the sample of sites with PV generation and billing data have at least a single incidence of negative monthly utility electricity usage or a bill or month with net export. The excess PV generation is reflected in the negative usage total for a billing period.

Table 5-4 provides a high-level summary of the incidence of monthly net export for non-residential and residential sites, dividing sites in the sample into those with at least one month of negative utility usage data following the installation of their PV system and those without negative data. The usage data were analyzed to determine if a site has a month of net export, and they include all post-installation usage data provided by PG&E, SCE, and SDG&E. These data include sites having a minimum of 12 months to a maximum of 127 months of billing data after installation of their PV system.[78] Longer periods of post-installation utility data provide the sites with additional opportunities to achieve a net negative monthly utility bill. The sites in Table 5-4 are disaggregated by segment type, including commercial, government, non-profit, and residential customers.

[77] For the residential sample, the cut-offs for large and small systems were 3.6, 4.3, and 3.9 for PG&E, SCE, and SDG&E, respectively. The non-residential cut-offs were 130, 180, and 120 for the three utilities. The cut-off points stayed the same for all three analyses: net exporter analysis, load shift analysis, and load change analysis.

[78] To be included in the utility bill negative usage or monthly net exporter analysis, a site must have at least 12 months of post-installation billing data following the installation of the PV system.

TABLE 5-4: FREQUENCY OF SITES WITH AT LEAST ONE BILL WITH NET EXPORT BY CUSTOMER SECTOR AND IOU[79]

Segment	Total Number of Sample Sites	Number of Sites with Any Monthly Net Export	Percent with Any Monthly Net Export[80]	Net Exporters' Average Monthly Net Export, for Months with Net Export (kWh)
	PG&E			
Commercial	623	354	56%	8,000
Government	541	397	73%	7,471
Non-Profit	102	73	69%	4,429
Residential	8,028	6,295	73%	164
	SCE			
Commercial	592	178	49%	9,232
Government	432	199	48%	7,890
Non-Profit	87	31	34%	2,177
Residential	5,089	3,065	67%	194
	SDG&E			
Commercial	153	67	45%	7,451
Government	94	44	48%	7,599
Non-Profit	52	33	64%	2,831
Residential	1,002	778	83%	202

Across all segments, 72 percent of PG&E PV customers, 65 percent of SCE's, and 82 percent of SDG&E's have at least one month of net export over the time period of the available billing data. This represents a substantial increase from the 55 percent share of PG&E sites, 44 percent for SCE, and 58 percent for SDG&E with at least one month of net export reported in the 2010 CSI Impact Evaluation.[81] While there are likely many reasons why the share of net exporting sites may have increased relative to the 2010 Evaluation, one reason stands out: a longer period with data. The typical site in Table 5-4 has a much

---

79 For the sample of sites presented in Table 5-4, 91 percent of PG&E sites and 87 percent of SCE and SDG&E sites have at least four years of post-installation billing data. For SDG&E, the share of residential sites with at least four years of post-installation billing data is approximately 95 percent, while only 63 percent of non-residential sites have this length of post-installation data. For SCE, 89 percent of residential and 82 percent of non-residential have at least four years of post-installation data, while PG&E's residential and non-residential data are equally extensive.

80 The export percentage is weighted and will not equal the number of sites with export divided by the number of sample sites.

81 The CSI 2010 Impact Evaluation found that 52.3 percent of the sample of sites across all three utilities had at least one month of negative utility billing usage or a month of net export. The 2010 Evaluation included 35,744 sites. Across the three utilities, only 5,314 sites had at least three years of post-installation utility billing information. (See page 7.7 in the 2010 Evaluation.)

longer period of post-installation data than was available during the 2010 Evaluation, providing more opportunity for sites to have a month of export.[82] In the 2010 Evaluation, the analysis included sites with less than one year of post-installation data, and only 28 percent of these sites had a month of energy export. For sites in the 2010 Evaluation with at least one year of post-installation data, the share with at least one month of net export grew to approximately 63 percent, illustrating the importance of additional time in determining the share of sites that will ever have at least one month of net export.

Additional potential reasons for the increase in the share of sites with at least one month of net export include the possibility that more recent participants in the CSI may have installed larger systems relative to their load.[83] Sites installing systems during the early phases of the CSI may have added panels and capacity to their systems, thereby increasing the likelihood of export. Additionally, sites may have installed energy efficiency measures and changed their behavior to reduce their consumption of electricity and increase the likelihood of net export.

Across all three utilities, residential sites have the highest share of customers with at least one month of net negative utility usage or at least one month of net export. For PG&E, 72 percent of residential customers have at least one month of net export while 67 percent of SCE and 83 percent of SDG&E residential customers are monthly net exporters. Table 5-4 also presents the average magnitude of export, which only includes data from months where the billed amount was negative. During months when residential customers are net exporters, PG&E's residential customers average 164 kWh of net export to the utility, SCE's average 194 kWh, and SDG&E's average 203 kWh. The average magnitude of net export found in this analysis is very similar to the 202 kWh of average residential net export from the 2010 CSI Evaluation. The similarities across utilities and across time is preliminary evidence that the sizing of systems relative to residential customer load is similar across utilities and the relative sizing of systems has not changed substantially across time.

5.2.1 Monthly Net Export by Customer Size

Table 5-5 and Figure 5-1 show the share of sites with at least one month of net export by customer segment, IOU, and PV system size. Within the residential sector, the likelihood of sites having at least one month of net export generally increases with system size. For the smallest-sized residential systems, 35 to 60 percent of systems have at least one month of net export, depending on IOU, while 88 to 92 percent of the largest-sized residential systems have at least one incidence of net export. Conversely, for non-

[82] The PG&E utility data for this analysis average over five years in length, whereas only 20 percent of the 2010 Evaluation had three years of utility data.

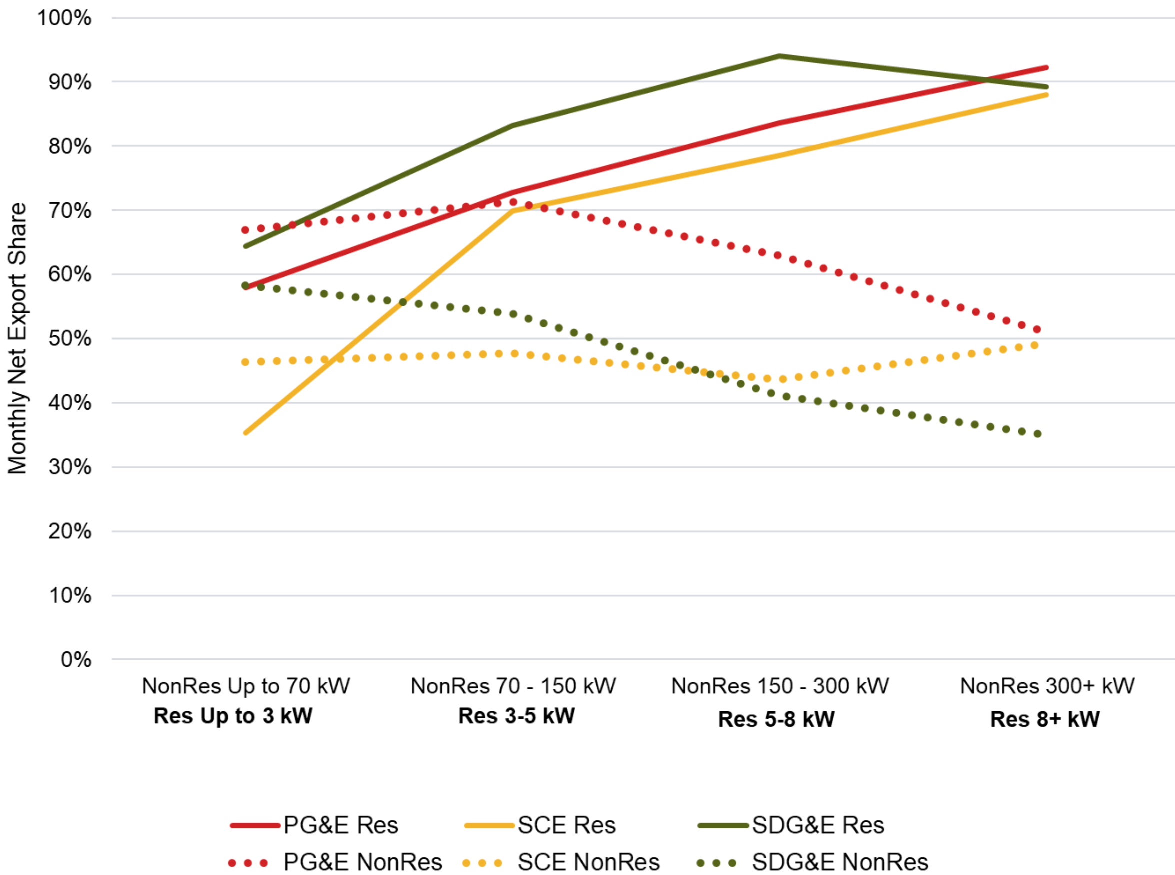
[83] The average size of residential PV systems installed within the CSI program increased slightly over time (see Table 5-3). From the data analyzed for the net exporter analysis, it is not possible to determine if the size of PV system has increased relative to customer electricity consumption.

residential sites, the largest-sized PV systems had the lowest share of sites, with at least one month of net export (35 to 51 percent, depending on IOU), while smaller-sized systems had a slightly higher share of net exporting sites (46 to 67 percent of sites with systems less than 70 kW). The different relationship between the share of sites that are monthly net exporters by system size and sector may reflect that many non-residential customers are limited in the size of the system they can install by the roof space relative to customer electricity consumption. For non-residential customers with large loads, roof space may be insufficient to totally cover customer electricity usage. Non-residential customers with large loads install larger systems, but the size of the PV system relative to their load is smaller than for non-residential customers installing smaller systems, leaving larger non-residential customers with a lower likelihood of net export. For residential customers, the size of customer load is more homogeneous, limiting the share of customers with very high levels of consumption that cannot be covered by the PV production available, given their roof area.

TABLE 5-5: FREQUENCY OF SITES WITH AT LEAST ONE BILL WITH NET EXPORT BY CUSTOMER SECTOR, IOU, AND PV SYSTEM SIZE

Segment	Total Number of Sample Sites	Number of Sites with Any Monthly Net Export	Percent with Any Monthly Net Export[84]	Net Exporters' Average Monthly Net Export, for Months with Net Export (kWh))
Residential	**PG&E**			
0-3 kW	2,671	1,394	58%	95
3-5 kW	3,361	2,387	73%	125
5-8 kW	1,525	1,258	84%	186
8 + kW	471	432	92%	425
Residential	**SCE**			
0-3 kW	1,449	407	35%	86
3-5 kW	1,716	1,136	70%	122
5-8 kW	1,255	953	79%	192
8 + kW	669	569	88%	385
Residential	**SDG&E**			
0-3 kW	323	202	64%	87
3-5 kW	416	336	83%	136
5-8 kW	199	183	94%	275
8 + kW	64	57	89%	447
Non-Residential	**PG&E**			
0-70 kW	458	312	67%	1,913
70-150 kW	337	242	71%	4,280
150-300 kW	240	152	63%	8,037
300 + kW	231	118	51%	26,843
Non-Residential	**SCE**			
0-70 kW	376	174	46%	1,357
70-150 kW	241	114	48%	2,654
150-300 kW	191	79	44%	7,378
300 + kW	303	41	49%	13,584
Non-Residential	**SDG&E**			
0-70 kW	88	51	58%	1,379
70-150 kW	85	44	54%	4,055
150-300 kW	66	28	41%	9,356
300 + kW	60	21	35%	23,869

FIGURE 5-1: MONTHLY NET EXPORT SHARE BY SECTOR, IOU, AND PV SYSTEM SIZE



The average net export amount generally increases with system size for both the residential and non-residential sectors. Across the three IOUs, the average net export amount increases from approximately 90 kWh for residential systems smaller than 3.0 kWh to about 400 kWh for systems 8.0 kWh and larger. For residential sites, all three utilities have approximately the same net export amount by system size. For non-residential sites, the average system export increases with system size but is relatively consistent across the IOUs. For example, for systems smaller than 70 kW, the average monthly net export amount ranges from 1,357 kWh at SCE to 1,913 kWh at PG&E. For systems larger than 300 kW, however, the average monthly net export amount in SCE's service territory (13,584 kWh) is substantially smaller than in PG&E's (26,843 kWh). The average monthly net export amount is generally lower for SCE than for PG&E or SDG&E. This is consistent with findings presented in Table 6.9, Section 6: Load Shape Change, where SCE's non-residential PV customers are shown to have a higher average annual electricity consumption,

[84] The export percentage is weighted and will not equal the number of sites with export divided by the number of sample sites.

higher average electricity import, and lower average electricity export. These findings support a conclusion that SCE non-residential PV systems are generally sized smaller relative to the customers' electricity consumption than for PG&E or SDG&E.

5.2.2 Seasonality of Monthly Net Export

Using the net exporter information and the long period of post-installation billing data, it is possible to illustrate how the net exporter share, or likelihood, and the average net export quantity during months of net export changes by season and over time. Figure 5-2 illustrates PG&E's residential monthly net exporter share and the average quantity of net export, during months the customers have net export, by calendar month for five years following PV installation.[85] The month with the highest likelihood of net export within PG&E's residential solar customers is May, where the likelihood of net export ranged from 37 to 40 percent over these data. The month with the largest average net export quantity for PG&E's residential solar customers is also May, with between 245 to 263 kWh of average net export for customers who export in that month. In comparison, December has the lowest likelihood of net export for PG&E's residential solar customers, with a 0.29 to 0.55 percent share. The smallest average net export amount occurs in January, with 91 kWh average net export for customers who export. The winter months' low export probability and relatively low average net export level is likely due to fewer hours of sunshine producing less electricity and higher electricity usage associated with increased hours inside during inclement weather. In contrast, the spring has the highest likelihood of net export and the largest average net export levels due to more hours of sunshine without the increased air conditioning usage of the summer months.

[85] To be included in this illustration, data must have been available for at least five years of post-installation load or billing. For this analysis, there are a minimum of 5,876 customers.

FIGURE 5-2: PG&E RESIDENTIAL MONTHLY NET EXPORTER SHARE AND AVERAGE NET EXPORT QUANTITY DURING MONTHS WITH NET EXPORT (KWH) BY SEASON FOR CUSTOMERS WITH 5 YEARS OF POST INSTALLATION BILLING DATA

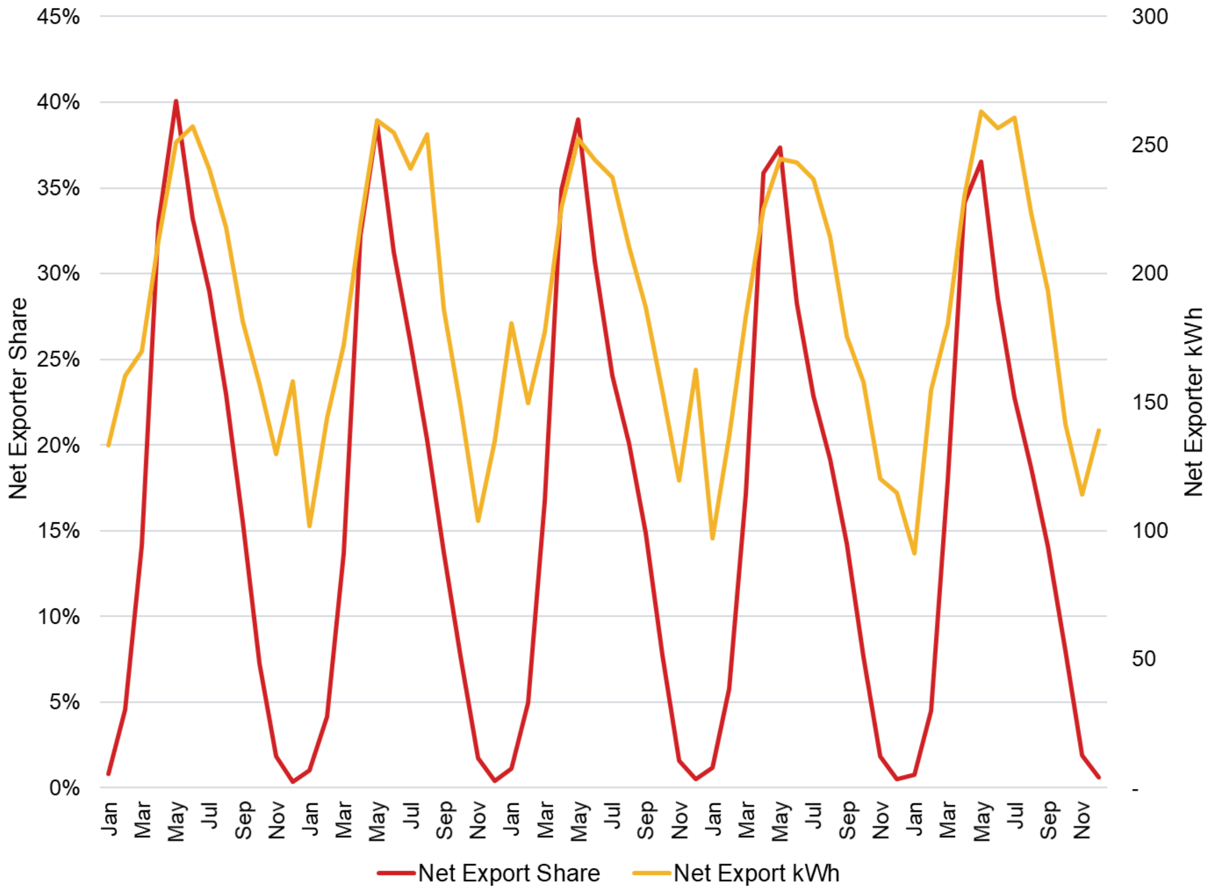


Figure 5-3 shows the net exporter share by month and system size for PG&E residential customers. Larger systems are much more likely to export, especially during the spring. PG&E's likelihood of net export rises in the spring, with April and May having similar shares of net exporting customers. In May, 59 percent of systems 8 kW or larger are exporting, with the share of systems net exporting declining to 29 percent for systems 3 kW or smaller. During the summer months, the share of systems with net export declines, with the likelihood of exporting less dependent on the system size. During August, only 24 percent of systems 8 kW or larger are exporting and 20 percent of systems 3 kW or smaller are net exporters.

FIGURE 5-3: PG&E RESIDENTIAL MONTHLY NET EXPORTER SHARE BY SYSTEM SIZE

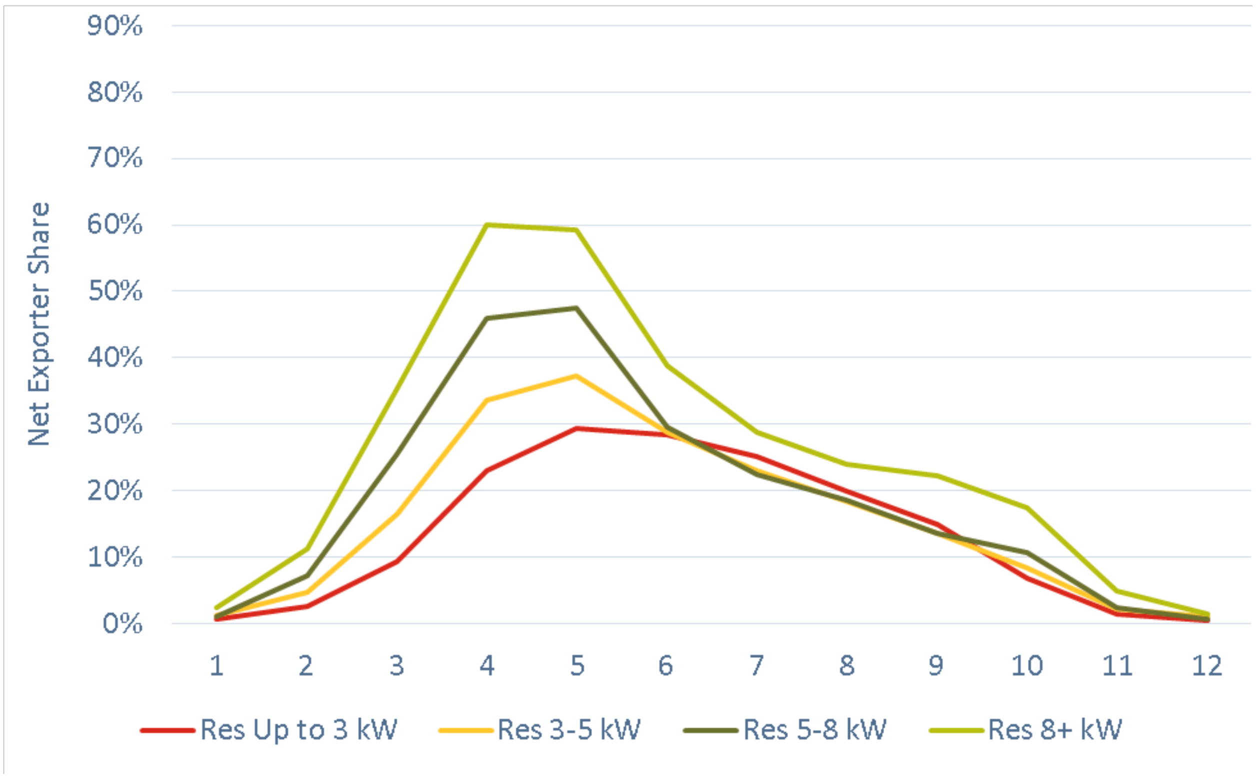


Figure 5-4 illustrates SCE's residential monthly net exporter share and the average quantity of net export by calendar month for five years following PV installation.[86] SCE's monthly net exporter share has similar seasonality to PG&E's. The data provided by SCE often begins multiple months, and potentially a year or more, post-installation. Due to the time gap that often occurs between PV-installation and the availability of SCE billing data, the sample of sites available for the first two years in Table 5-4 is lower than in the subsequent years.[87] The larger sample of sites available in years 3 through 5 after installation may contribute to the reduced likelihood of export in later post-installation years. In the third year following installation, the likelihood of net export peaks in April at 56 percent, with an average net export of 315 kWh per month (the largest monthly average in the third year). In the third year following installation, the likelihood of net export is lowest in December at 3 percent, with an average net export of 241 kWh per month. The smallest average monthly net export occurs in August at 182 kWh, with 9 percent of systems net exporting.

FIGURE 5-4: SCE RESIDENTIAL MONTHLY NET EXPORTER SHARE AND AVERAGE NET EXPORT QUANTITY (KWH) BY SEASON FOR CUSTOMERS WITH 5 YEARS OF POST INSTALLATION BILLING DATA

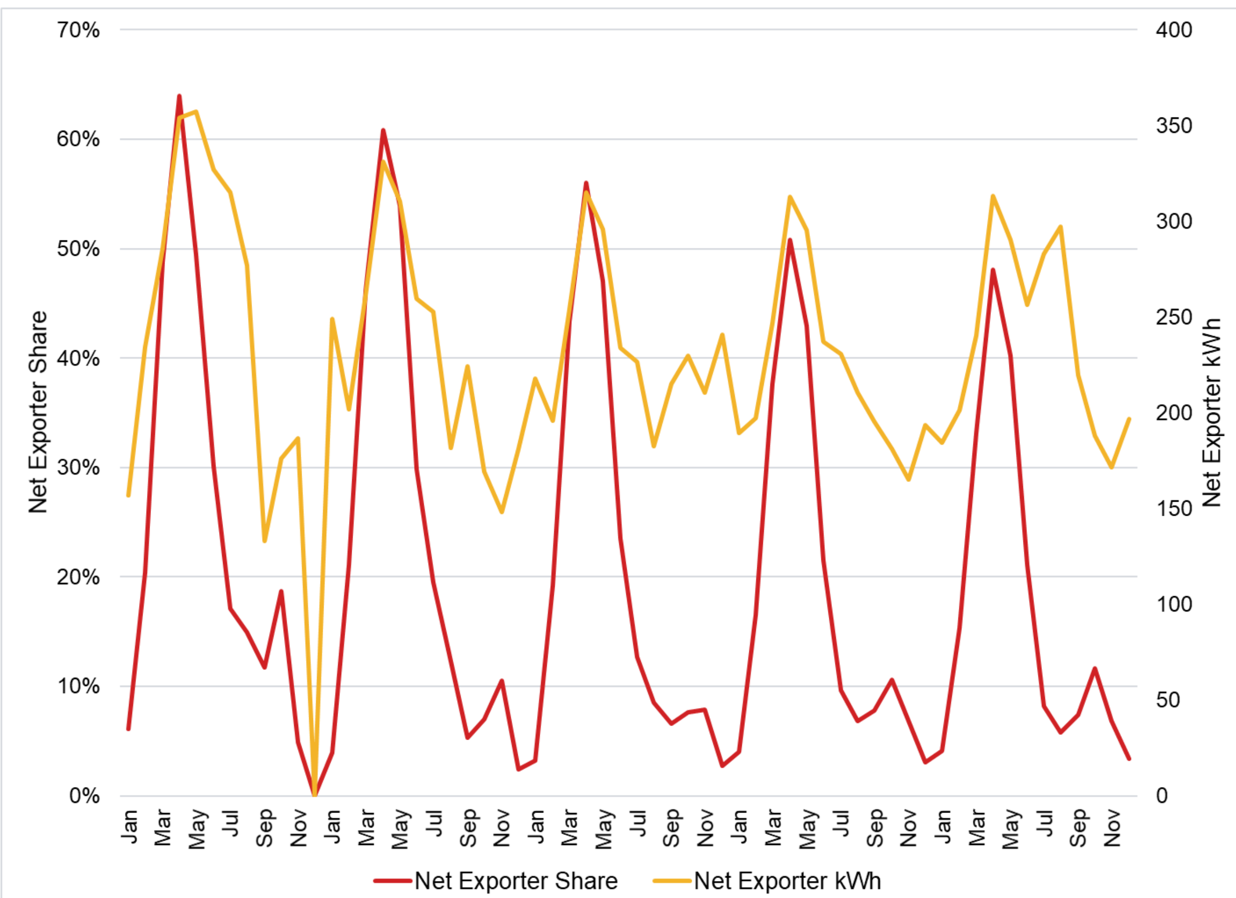


Figure 5-5 shows the net exporter share by month and system size for SCE residential customers. Similar to PG&E, the highest likelihood of net export is in the spring, but SCE's share of net export peaks in April, a month earlier than PG&E's. The spring in Southern California comes earlier than in Northern California. In April, 19 percent of systems under 3 kW and 68 percent of systems over 8 kW within SCE's territory are net exporters. However, the heat in the inland areas of SCE starts earlier than in PG&E, so the net export share of SCE's customers begins to decline in May. The likelihood of net export during the summer months of July, August, and September is lower for SCE's residential customers than for PG&E's, potentially emphasizing the higher air conditioning use in SCE's service territory. In August, only 6 percent of systems smaller than 3 kW and 10 percent of systems over 8 kW are net exporting in SCE's service territory. The October increase in SCE's export share reflects the sunny temperate fall seasons that frequently occur in Southern California.

[86] To be included in SCE's five-year analysis, the evaluation team required 56 months of post-installation billing data. While five years of data is 60 months, the data provided by SCE had large numbers of customers with 56 months of post-installation data and very few customers with 60 months. The evaluation team chose to use 56 months to maximize the amount of data available. For many customers with 56 months of data, the data provided do not include data for the first year following installation. If the evaluation team did not have data for the first year, the customers' share and export information would begin in the post-installation year where their data begins.

[87] The sample sizes range from 57 to 338 sites in the first year following installation, from 416 to 1124 in the second year, from 1,386 to 2,758 in the third year, and from 2,932 to 3,544 in the fourth year.

FIGURE 5-5: SCE RESIDENTIAL MONTHLY NET EXPORTER SHARE BY SYSTEM SIZE

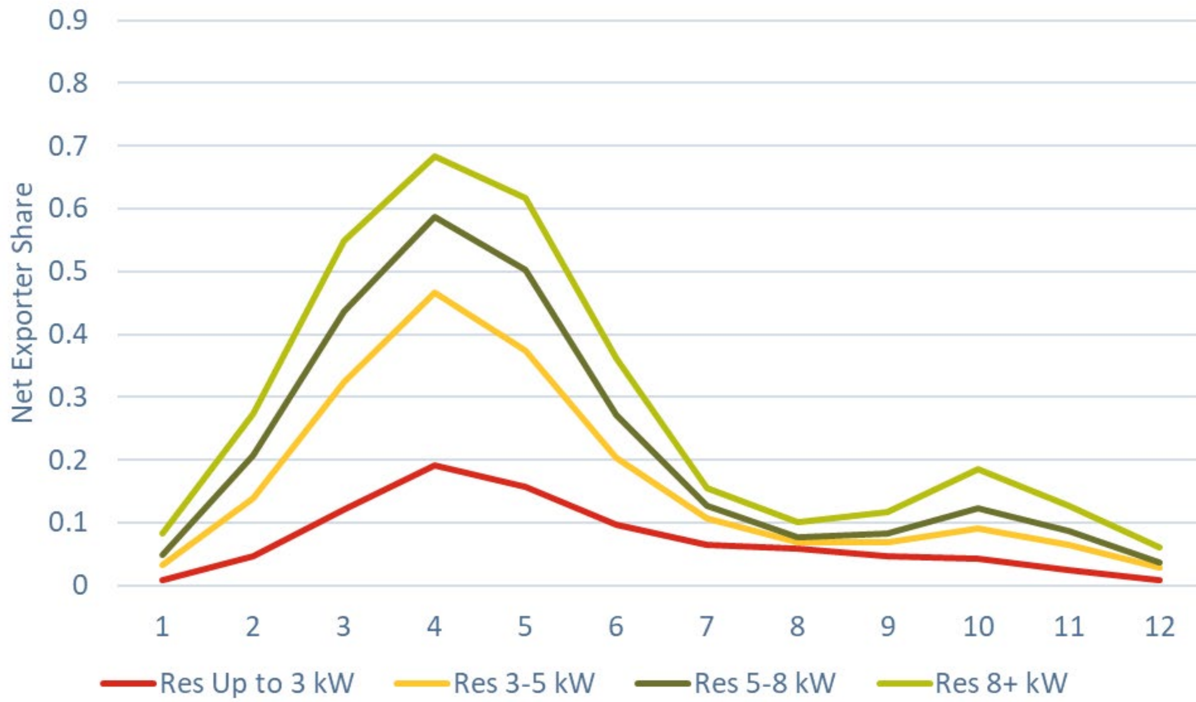


Figure 5-6 presents SDG&E's residential monthly net exporter share and the average quantity of net export by calendar month for five years following PV installation. SDG&E's monthly net exporter share has the seasonality illustrated in both PG&E's and SCE's monthly net exporter share. SDG&E's likelihood of monthly net export peaks in April at 46 to 53 percent, while the average size of net export peaks in June at 235 to 268 kWh. SDG&E's likelihood of spring net export is similar to SCE's, while the average level of net export is more similar to PG&E's. December has the lowest likelihood of net export for SDG&E's residential solar customers, with a 0.6 to 2 percent share. The smallest average net export amount occurs in December and January, with 39 to 82 kWh average net export for customers who export. SDG&E's residential average winter net export for exporters is smaller than that of the other two utilities.

FIGURE 5-6: SDG&E RESIDENTIAL MONTHLY NET EXPORTER SHARE AND AVERAGE NET EXPORT QUANTITY (KWH) BY SEASON FOR CUSTOMERS WITH 5 YEARS OF POST INSTALLATION BILLING DATA

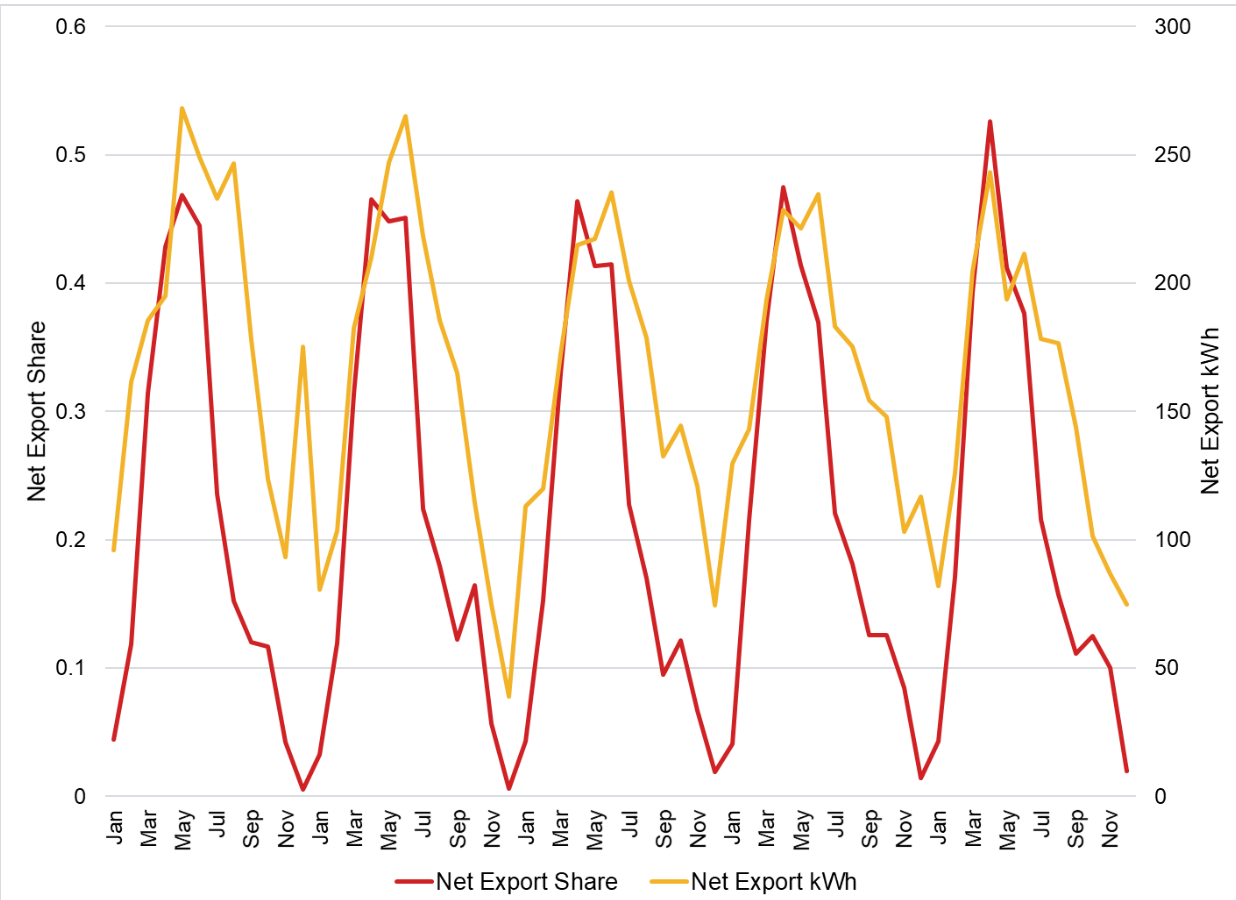
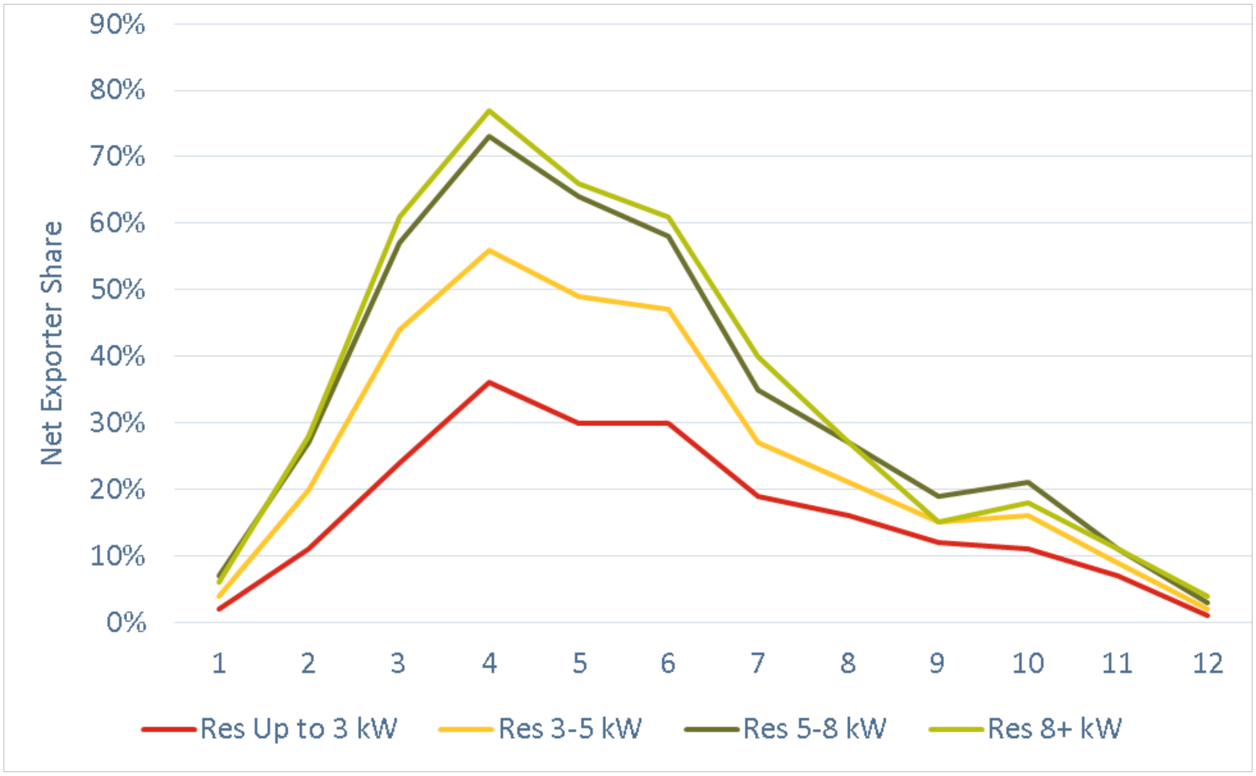


Figure 5-7 shows SDG&E residential net exporter share by month and systems size. The general shape is something between the other two utilities, with a peak in April (similar to SCE) and a larger share of systems net exporting in August (similar to PG&E). In April, 36 percent of systems under 3 kW and 77 percent of systems over 8 kW are net exporters in SDG&E's service territory. The very high share of net exporters in April likely reflects sunny temperate weather in San Diego. In August, 16 percent of smaller-sized systems (under 3 kW) and 27 percent of larger-sized systems are net exporters in San Diego. SDG&E's summer net export share is similar to PG&E's and higher than SCE's. Similar to SCE, there is an increase in the export share in October.

FIGURE 5-7: SDG&E RESIDENTIAL MONTHLY NET EXPORTER SHARE BY SYSTEM SIZE



A similar seasonality analysis was undertaken for non-residential PV systems. PG&E's and SCE's seasonality pattern was very similar for their residential and non-residential customers. For SDG&E, their non-residential sample with at least five years of post-installation utility data is relatively small, leading to a situation where a few outlier sites can have a large impact on average export results. Given that the small sample size for SDG&E non-residential customers may result in less reliable conclusions or generalizations, only PG&E's and SCE's graph is presented for the non-residential seasonality analysis.

Figure 5-8 illustrates the likelihood of monthly net export for non-residential PV customers in PG&E's service territory and Figure 5-9 shows the same information by month and systems size. The presentation is limited to sample customers with at least five years of post-installation utility billing or load data. These data indicate that the likelihood of monthly net export peaks in June and is at its lowest in the months of October and November. The timing of the high and low likelihood of net monthly export is similar to PG&E's residential sector, although the non-residential sector peaks later in the year and has its minimum earlier. The non-residential minimum likelihood of net export in the winter months is also higher than for the residential sector, averaging approximately 5 to 6 percent compared to the 0 to 2 percent common in the residential sector. The average size of net export is more volatile than in the residential sector. The increased volatility of the average may be due to the smaller sample size as well as the larger distribution of system sizes and underlying customer loads in the non-residential sector. In the non-residential sector, a single, very large customer can make a substantial difference in the calculation of average net monthly export.

FIGURE 5-8: PG&E NON-RESIDENTIAL MONTHLY NET EXPORTER SHARE AND AVERAGE NET EXPORT QUANTITY (KWH) BY SEASON FOR CUSTOMERS WITH 5 YEARS OF POST INSTALLATION BILLING DATA

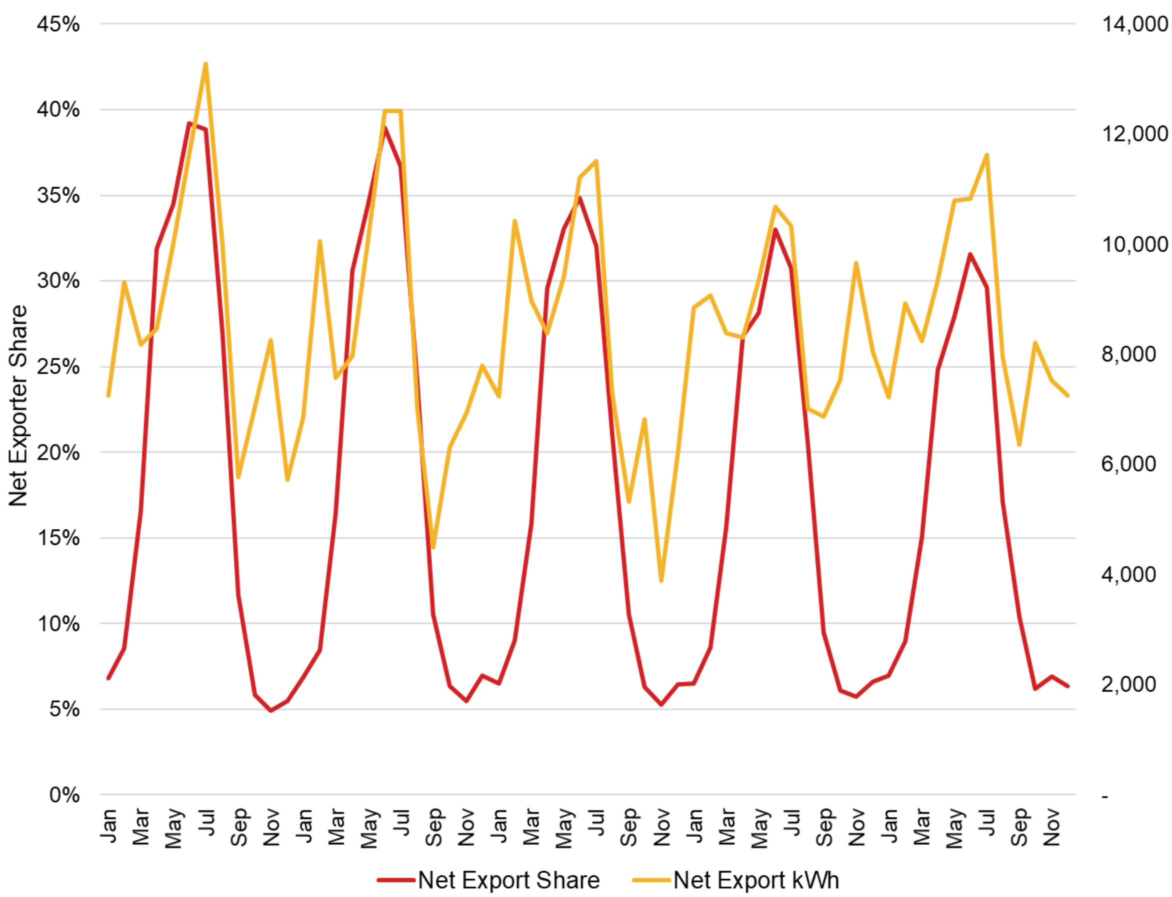


FIGURE 5-9: PG&E NON-RESIDENTIAL MONTHLY NET EXPORTER SHARE BY SYSTEM SIZE

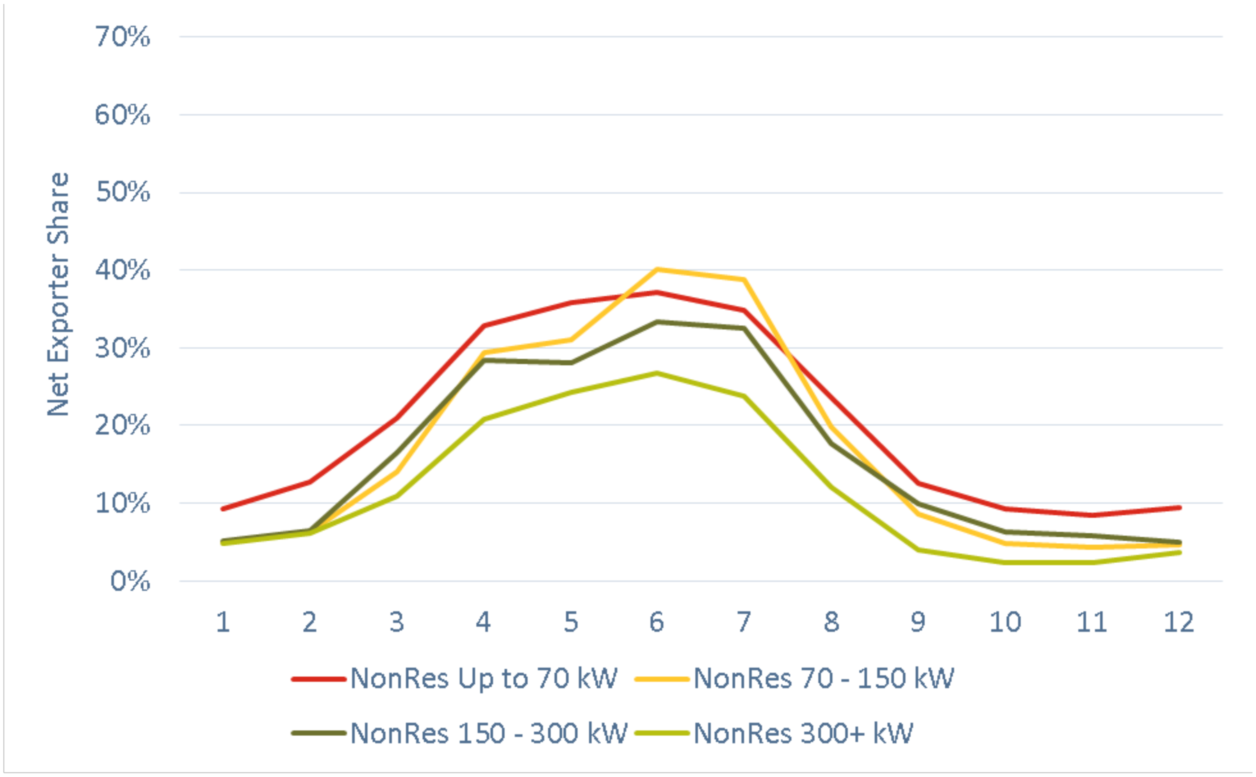


Figure 5-10 illustrates the likelihood of monthly net export and the average size of export for exporters for non-residential PV customers in SCE's service territory. Figure 5-11 shows the net exporter share averaged across the five years by month and systems size. The presentation is limited to sample customers with at 56 months of post-installation utility billing or load data.[88] These data indicate that the likelihood of monthly net export peaks in April (the peak of customers with 70 to 150 kW systems occurs in June, all others occur in April) and is highest for customer with systems in the 150 to 300 kW range (see Figure 5-11). The likelihood of net export is at its lowest in the months of September through December, when customers with all sizes of systems have a very low likelihood of net export. The timing of the high and low likelihood of net monthly export is similar to SCE's residential sector, although the non-residential sector's minimum likelihood of net export can occur earlier in the fall while the residential minimum occurs in November and December. The average size of net export is more volatile than in the residential sector. The increased volatility of the average is due to the smaller sample size as well as the larger distribution of system sizes and underlying customer loads in the non-residential sector. In the non-

[88] The billing data provided by SCE had a large share of customers with 56 months of billing data. The graph illustrates 5 years of net export share and average net export amount.

residential sector, a single, very large customer can make a substantial difference in the calculation of average net monthly export.

FIGURE 5-10: SCE NON-RESIDENTIAL MONTHLY NET EXPORTER SHARE AND AVERAGE NET EXPORT QUANTITY (KWH) BY SEASON FOR CUSTOMERS WITH 5 YEARS OF POST INSTALLATION BILLING DATA

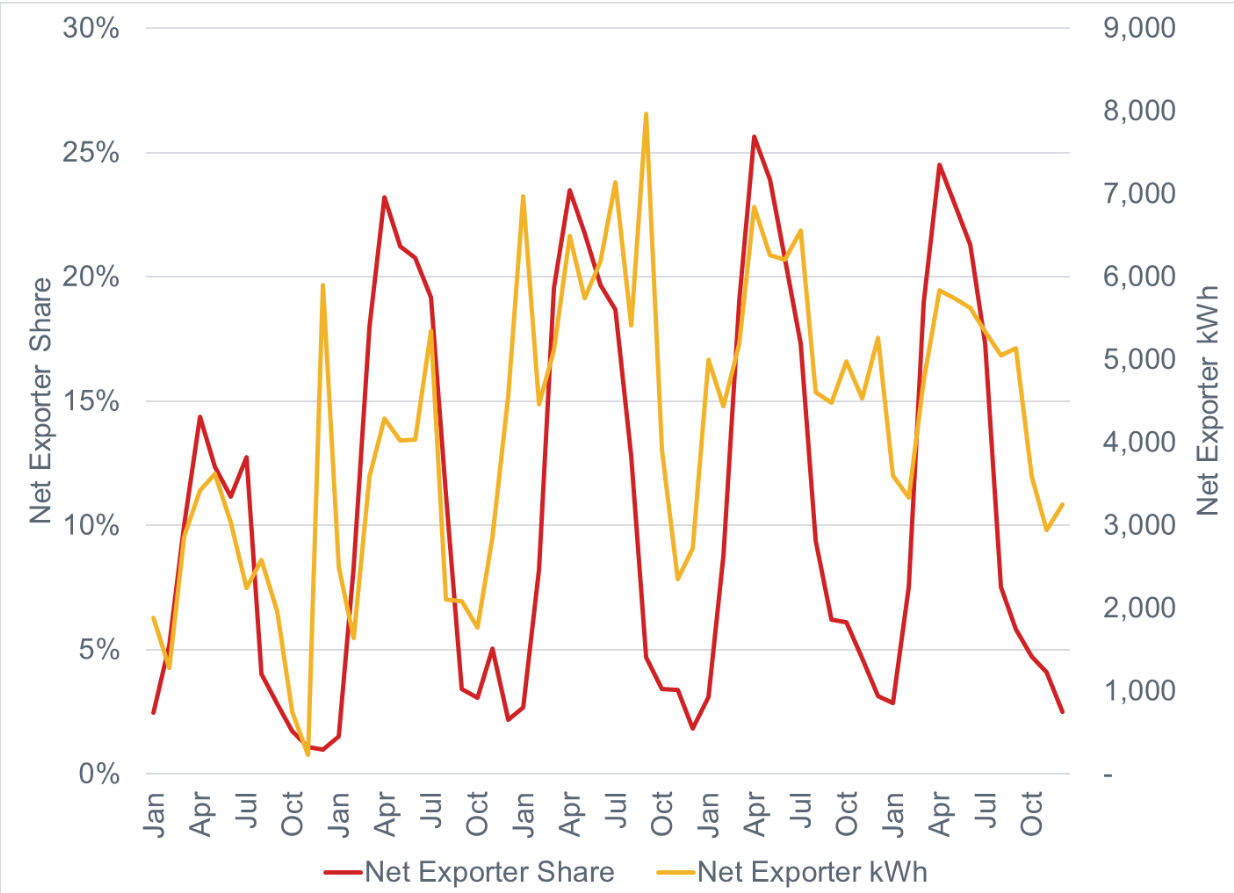


FIGURE 5-11: SCE NON-RESIDENTIAL NET EXPORT SHARE BY SYSTEM SIZE

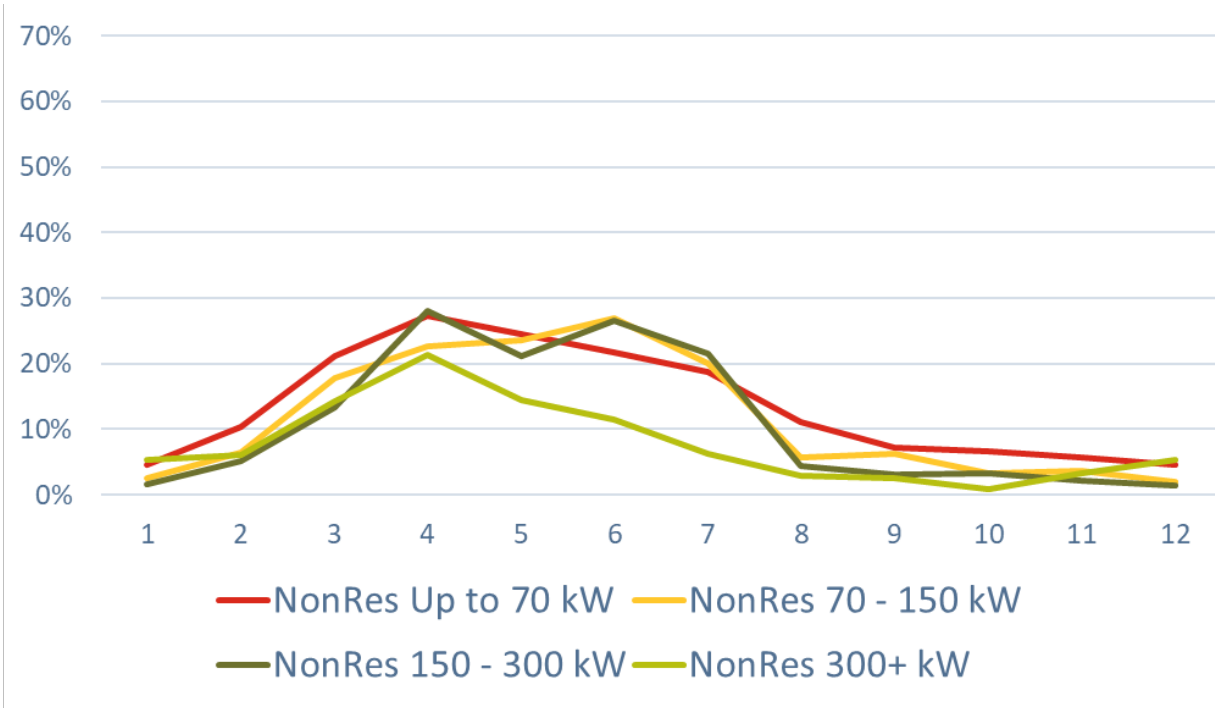
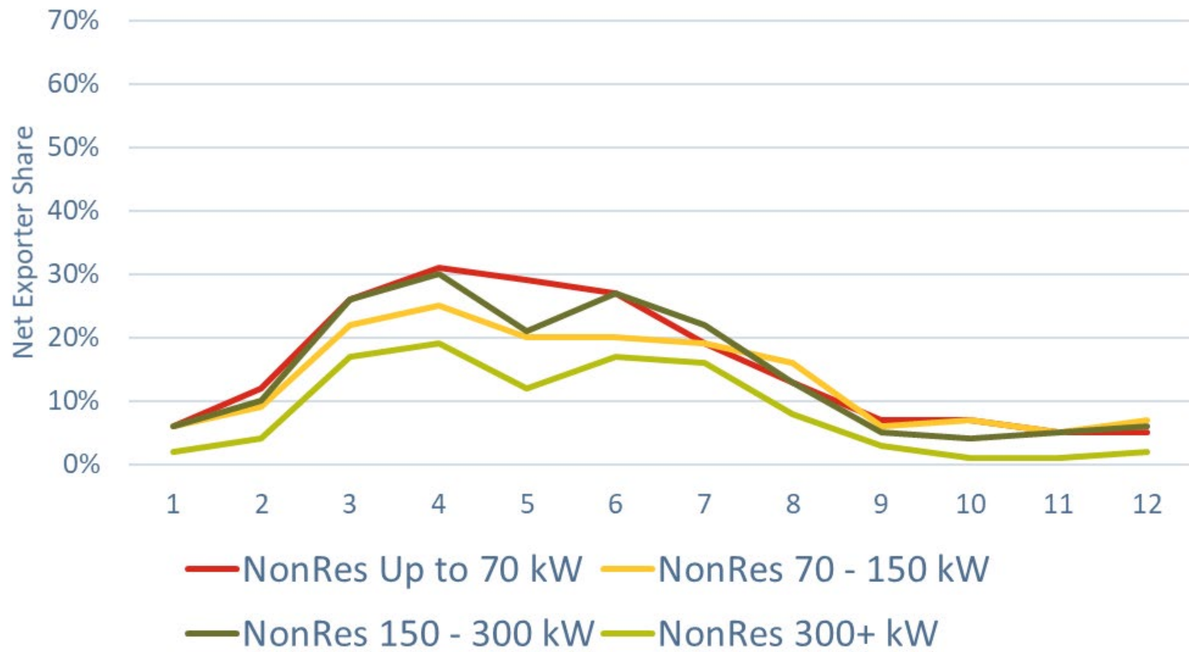


Figure 5-12 presents SDG&E's non-residential customer net export share by customer size and month. Similar to SCE's non-residential customers, SDG&E's likelihood of net export peaks in April.

FIGURE 5-12: SDG&E NON-RESIDENTIAL NET EXPORTER SHARE BY CUSTOMER SIZE AND MONTH



5.2.3 Monthly Net Export for Coastal and Inland PV Systems

The likelihood of monthly net export was also analyzed by the PV systems' location by IOU and coastal versus inland.[89] Figure 5-13 presents the residential average monthly net export, for export sites and months, by IOU and inland versus coastal. This graph shows that the average net export is larger for inland systems than for coastal systems, with the difference between inland and coastal the largest for SDG&E and the smallest for PG&E. The likelihood of sites having at least one month of net export is also higher for inland systems. For PG&E, 69 percent of residential coastal systems have at least one month of net export in the sample data compared to 77 percent for inland systems. For SCE, 64 percent of coastal residential systems have at least one month of net export, while 67 percent of inland are monthly net exporters. SDG&E's coastal residential systems have a 79 percent likelihood of net export at some time during our data period, while 86 percent of inland systems are net exporters.

FIGURE 5-13: RESIDENTIAL AVERAGE MONTHLY NET EXPORT BY IOU AND COASTAL VERSUS INLAND, FOR NET EXPORTERS

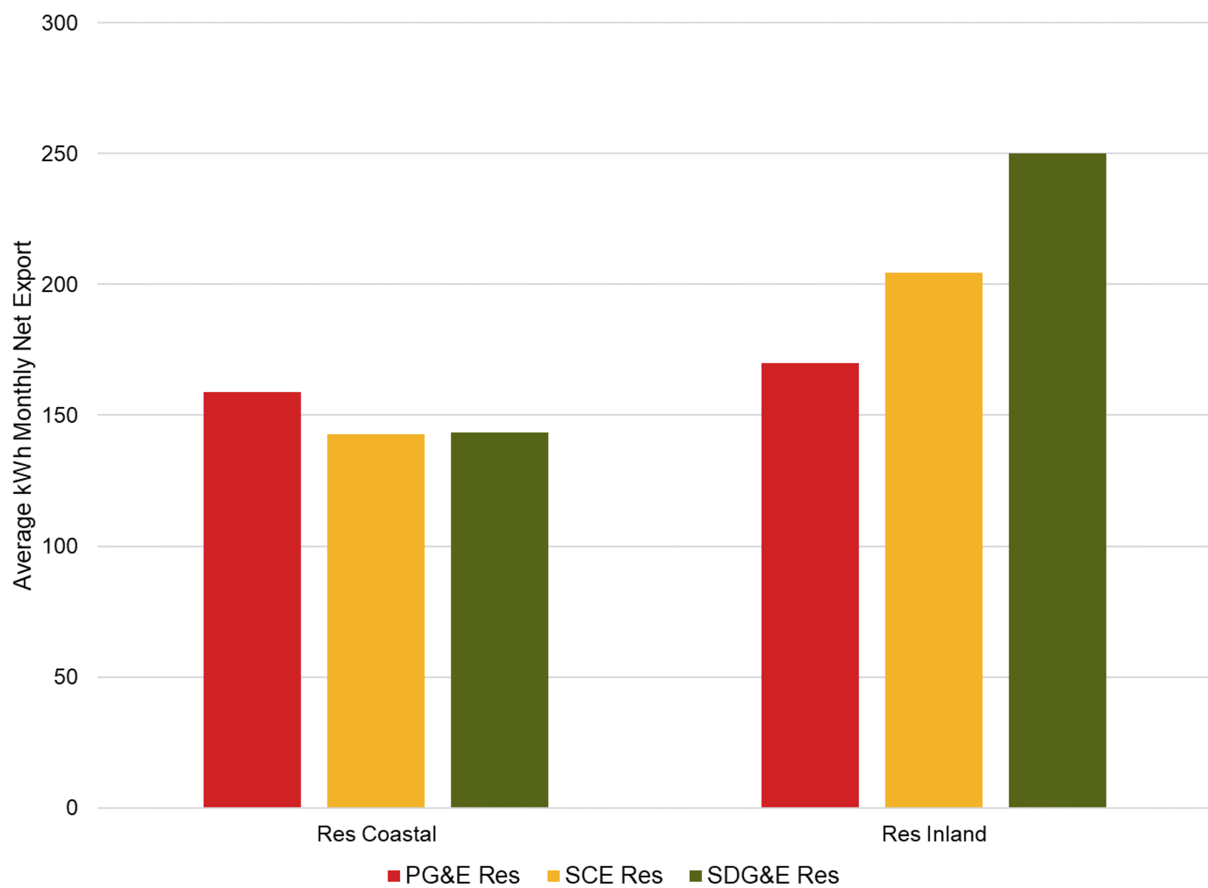
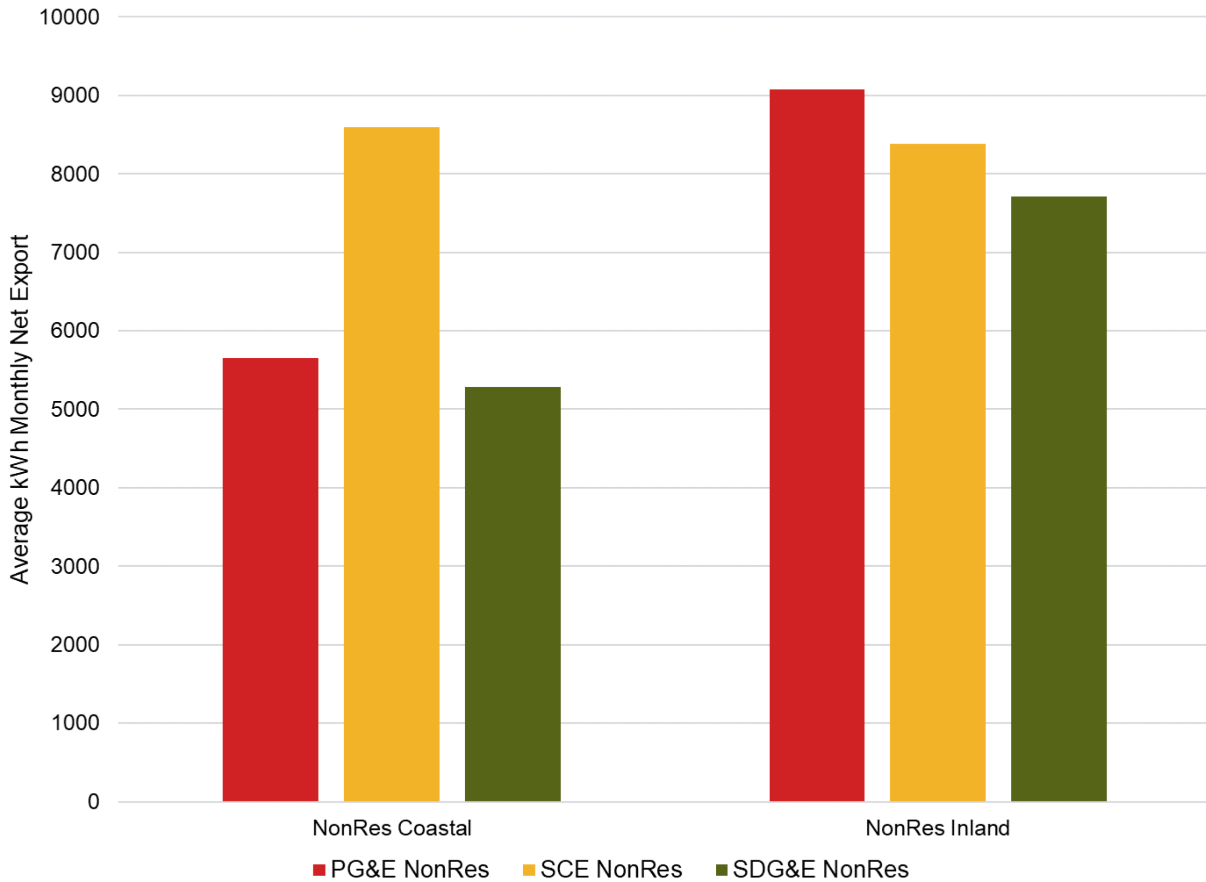


Figure 5-14 illustrates the average monthly net export for non-residential sites during months of net export by IOU and coastal versus inland. Similar to the residential numbers, for PG&E and SDG&E the average size of net export is larger for inland systems than for coastal systems. For SCE, however, the average size of net export is slightly higher for coastal than for inland systems. SCE's non-residential inland PV customers have a substantially higher average consumption than their coastal counterparts; the higher inland consumption may be driven by larger air conditioning load and contributed to a smaller net export size (See Table 6.11 in Section 6 for average consumption data). In addition, the likelihood that a site will have at least one month of net export is higher for inland non-residential sites than for coastal sites for PG&E and SDG&E and approximately the same for coastal and inland for SCE. For PG&E, 59 percent of coastal versus 69 percent of inland non-residential sites have at least one month of net export. For SCE, the comparable shares are 49 percent coastal and 47 percent inland, while SDG&E has 43 percent coastal and 61 percent inland.

[89] Inland and coastal are identified by CEC building climate zone; CZ 1-7 are coastal, and CZ 8-16 are inland.

FIGURE 5-14: NON-RESIDENTIAL AVERAGE MONTHLY NET EXPORT BY IOU AND COASTAL VERSUS INLAND, FOR NET EXPORTERS



5.3 FREQUENCY OF ANNUAL NET EXPORTERS

The previous section showed that 72 percent of PG&E's CSI sites, 65 percent of SCE's, and 82 percent of SDG&E's have at least one month of negative utility usage or one month of net export. This section summarizes the share of sites that are exporting enough energy over a year (or 12-bill period) that their purchase of electricity from the utility is less than their export of electricity or that they have net export over a year. The analysis looks at net export over any 12-bill period, which roughly equates to a full year, and these sites will be referred to as annual net exporters.[90] The analysis found that significantly fewer

[90] The yearly net export analysis does not require that the period of net export goes from December to January, but the analysis looks for any 12-month continuous period where the sum of utility energy consumption is less than the sum of the customer energy export to the utility.

sites are net exporters on an annual basis than on a monthly basis. Nineteen percent of PG&E's and 18 percent of SCE's CSI sites have at least one year of annual net export, whereas 38 percent of SDG&E's sites export more electricity in a year than they import utility electricity.

Table 5-6 lists the number and share of sites with annual net export by customer segment and IOU. The average monthly kWh export for annual net exporters is their average export, during months when the customer exports, and does not reflect the average monthly usage over the period of annual net export for exporters. The data presented in Table 5-6 show that SDG&E's residential sector has a higher share of annual net exporters than their commercial, government, and non-profit sectors.

TABLE 5-6: FREQUENCY OF SITES WITH ANNUAL NET BILL EXPORT BY CUSTOMER SECTOR AND IOU

Segment	Total Number of Sample Sites	Number of Sites with Annual Net Export	Percent with Annual Net Export[91]	Exporters' Average Monthly Export (kWh)
	PG&E			
Commercial	623	137	22%	8,722
Government	541	104	19%	10,345
Non-Profit	102	22	22%	5,262
Residential	8,028	1,346	19%	291
	SCE			
Commercial	592	76	13%	6,665
Government	432	56	11%	4,671
Non-Profit	87	12	14%	2,738
Residential	5,089	788	18%	331
	SDG&E			
Commercial	153	31	21%	12,497
Government	94	15	16%	11,676
Non-Profit	52	13	24%	3,569
Residential	1,002	308	38%	298

When comparing the results in Table 5-4 (the monthly next export shares and average export) with the results presented in Table 5-6, it is clear that the likelihood of annual net export is much smaller than the likelihood of monthly net export. In contrast, the average monthly export, during months when the customer is exporting, is substantially higher for annual net exporting sites than for monthly net exporting sites.

91 The export percentage is weighted and will not equal the number of sites with export divided by the number of sample sites.

Table 5-7 presents a summary of the frequency and share of sites with annual net export by customer sector and system size. Table 5-5 presented similar results for monthly net export. The results presented in Table 5-5 and Table 5-7 find that the likelihood of annual and monthly net export generally increases within the residential sector as the size of the system increases. The size of the average monthly export also increases with the size of the residential system in both tables. For the non-residential sector, the size of the average monthly export for annual net exporters increases with system size but the likelihood of annual net export generally declines with system size, declining substantially for the largest-sized systems (300 + kW). Similar to monthly exports, the decline in the likelihood of annual net export for the largest-sized non-residential systems is likely due to limited roof space for systems installed for customers with very large electrical loads.

TABLE 5-7: FREQUENCY OF SITES WITH AT LEAST ONE YEAR OF ANNUAL NET EXPORT BY CUSTOMER SECTOR, IOU, AND PV SYSTEM SIZE

Segment	Total Number of Sample Sites	Number of Sites with Annual Net Export	Percent with Annual Net Export[92]	Exporters' Average Monthly Export (kWh)
Residential		**PG&E**		
0-3 kW	2,671	362	16%	161
3-5 kW	3,361	505	17%	219
5-8 kW	1,525	321	20%	300
8 + kW	471	158	34%	671
Residential		**SCE**		
0-3 kW	1,449	88	8%	150
3-5 kW	1,716	239	15%	206
5-8 kW	1,255	245	22%	287
8 + kW	669	216	36%	542
Residential		**SDG&E**		
0-3 kW	323	59	19%	131
3-5 kW	416	140	38%	189
5-8 kW	199	81	53%	367
8 + kW	64	28	43%	628
Non-Residential		**PG&E**		
0-70 kW	458	118	26%	2,362
70-150 kW	337	69	20%	5,311
150-300 kW	240	54	22%	11,261
300 + kW	231	22	10%	46,982
Non-Residential		**SCE**		
0-70 kW	376	57	16%	1,735
70-150 kW	241	42	21%	3,186
150-300 kW	191	32	11%	8,882
300 + kW	303	13	7%	10,317
Non-Residential		**SDG&E**		
0-70 kW	88	23	25%	1,986
70-150 kW	85	16	21%	5,973
150-300 kW	66	10	17%	13,893
300 + kW	60	10	13%	47,099

[92] The export percentage is weighted and will not equal the number of sites with export divided by the number of sample sites.

5.4 FREQUENCY OF 12 CONSECUTIVE MONTHS NET EXPORTERS

Section 5.2 showed that 72 percent of PG&E's CSI sites, 65 percent of SCE's, and 82 percent of SDG&E's have at least one month of net export. The annual net export analysis found that 18 percent of PG&E's and SCE's CSI sites have at least one year of annual net export, while 38 percent of SDG&E's sites export more electricity in a year than they import of utility electricity. Less than 2 percent of CSI sites, however, have 12 consecutive months of net export. Table 5-7 lists the share of sites with a 12-month period with continuous monthly net export. The infrequency of continuous net export reinforces the assumption that systems were not designed to export every month of the year. Most systems that were designed to provide annual net export were likely designed to consume more utility electricity than their systems produced during some months of the year.

FIGURE 5-15: FREQUENCY OF SITES WITH 12 CONSECUTIVE MONTHS OF NET BILL EXPORT BY CUSTOMER SECTOR AND IOU

Segment	Total Number of Sample Sites	Number of Sites with 12 Consecutive Months Net Export	Percent with 12 Consecutive Months Net Export[93]	Exporters' Average Monthly Export (kWh)
	PG&E			
Commercial	623	20	4%	7,842
Government	541	5	1%	36,189
Non-Profit	102	0	0%	0
Residential	8,028	76	1%	508
	SCE			
Commercial	592	15	1%	5,850
Government	432	5	1%	4,034
Non-Profit	87	2	2%	7,786
Residential	5,089	66	2%	519
	SDG&E			
Commercial	153	10	7%	24,602
Government	94	3	4%	4,779
Non-Profit	52	2	5%	1,802
Residential	1,002	19	2%	361

93 The export percentage is weighted and will not equal the number of sites with export divided by the number of sample sites.

6 LOAD SHAPE CHANGE

As with other generation resources, the value of PV generation is highest at the time of the IOU and system peak and at other hours when and where the system is strained. The main purpose of this section is to provide IOU, seasonal, time-of-day, and peak-day dimensions to the relationship between energy consumption, PV energy production, and net load. The section also compares the PV energy production and the contemporaneous use of energy generated by a PV system to the whole site's consumption. This section quantifies the amount of electricity imported from and exported to the grid by PV customers. The average PV customer's annual energy consumption exceeds their PV production, though many customers have hourly exports of energy to the grid. The exports to the grid offset some, but typically not all, of the daily and annual energy imported from the grid. Typical customers with PV generation have an ongoing supply and demand relationship with their utility, both importing and exporting electricity to meet the customer's electricity consumption needs.

In this section, the term "consumption" refers to the total electricity used at the site:

$$Consumption = Customer\ kWh\ Import + PV\ kWh\ Production - Customer\ kWh\ Export$$

Imports are the site's electricity use from the utility grid (the utility Delivered channel) and exports are the site's electricity delivered to the utility grid (the utility Received channel). The customer's net load is the energy import and export as observed by the utility, which does not typically have direct visibility to the customer's PV production.

$$Net\ Load = Customer\ kWh\ Import - Customer\ kWh\ Export$$

The addition of a PV system and its energy production changes the utility's understanding of a site's energy usage. The utility no longer has visibility into the customer consumption, the time of the customer's peak consumption, or the maximum energy consumed in a single hour. Following the installation of BTM PV, the utility observes only the customer's net load, the time of the net load peak, and the maximum energy consumed from the utility in a single hour. The following section will describe how the customer consumption differs from the customer net load and how the installation of BTM PV systems changes the observed peak consumption versus net load average peak level, the timing of the peak, and the ramp into the two different peaks.

6.1 LOAD PROFILE EXAMPLE

With the installation of BTM PV at a customer site, the utility no longer provides all of the site's electricity needs or directly measures the site's electricity consumption.[94] Figure 6-1 illustrates a commercial customer's 24-hour net load or their import of energy from the grid minus their export of energy to the grid, using 15-minute interval data. Viewing an individual customer's net load illustrates the dynamic nature of net load. The net load for this customer is positive prior to sunrise; the customer is importing energy from the utility prior to their PV producing electricity. The customer's morning net load is negative, their PV system is producing electricity, and the electricity consumption of the customer's site is relatively low. In the afternoon, the customer's consumption of electricity grows, and the customer's net consumption of electricity is positive. The net load, however, does not illustrate the customer consumption, PV production, or the ongoing import and export by the customer. Further data are needed to provide a complete picture of how loads and generation are behaving behind a customer's meter.

---

[94] Admittedly, some utilities do meter at least some customer-sited PV directly, but this is not standard practice and is not broadly done by California's IOUs.

FIGURE 6-1: CUSTOMER 24-HOUR NET LOAD FOR OCTOBER 1ST

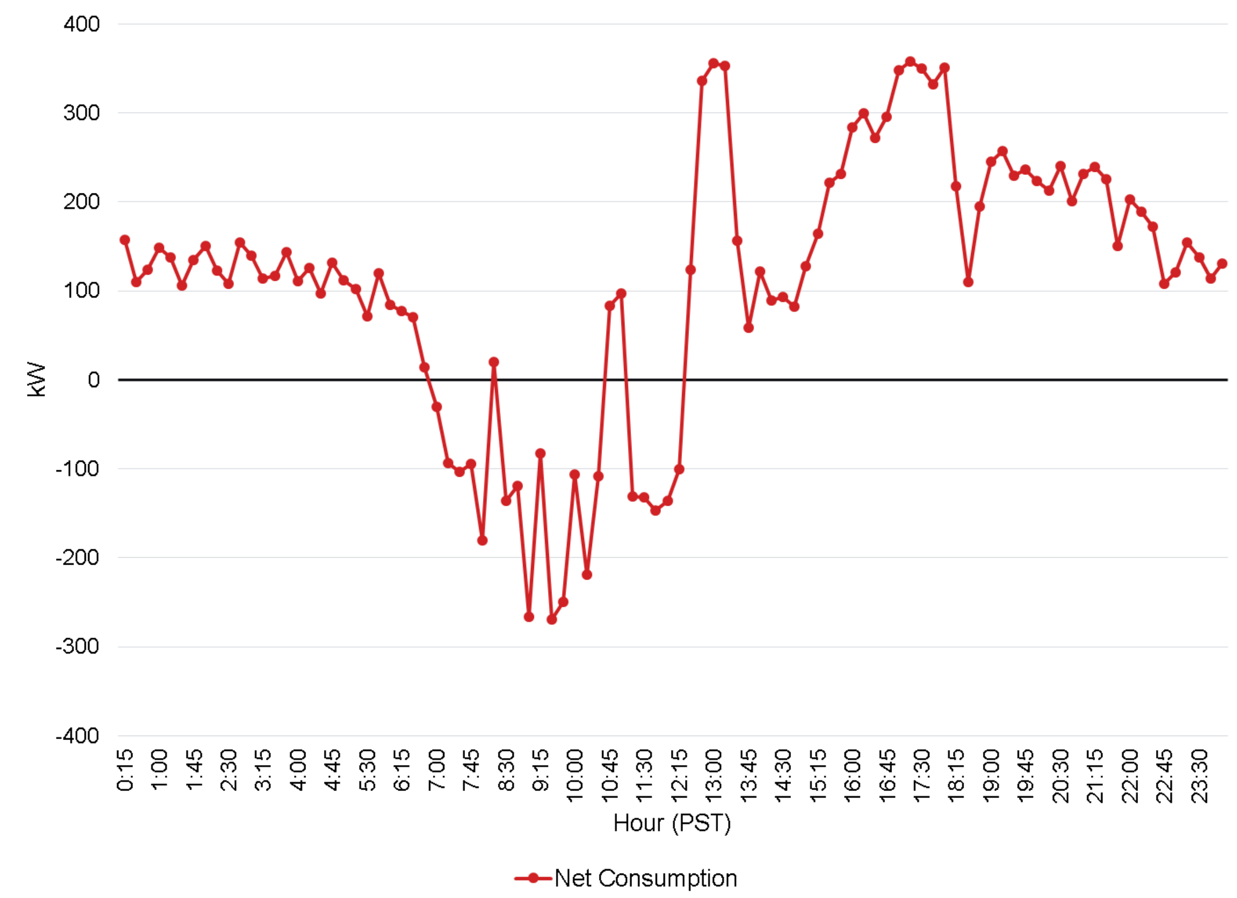
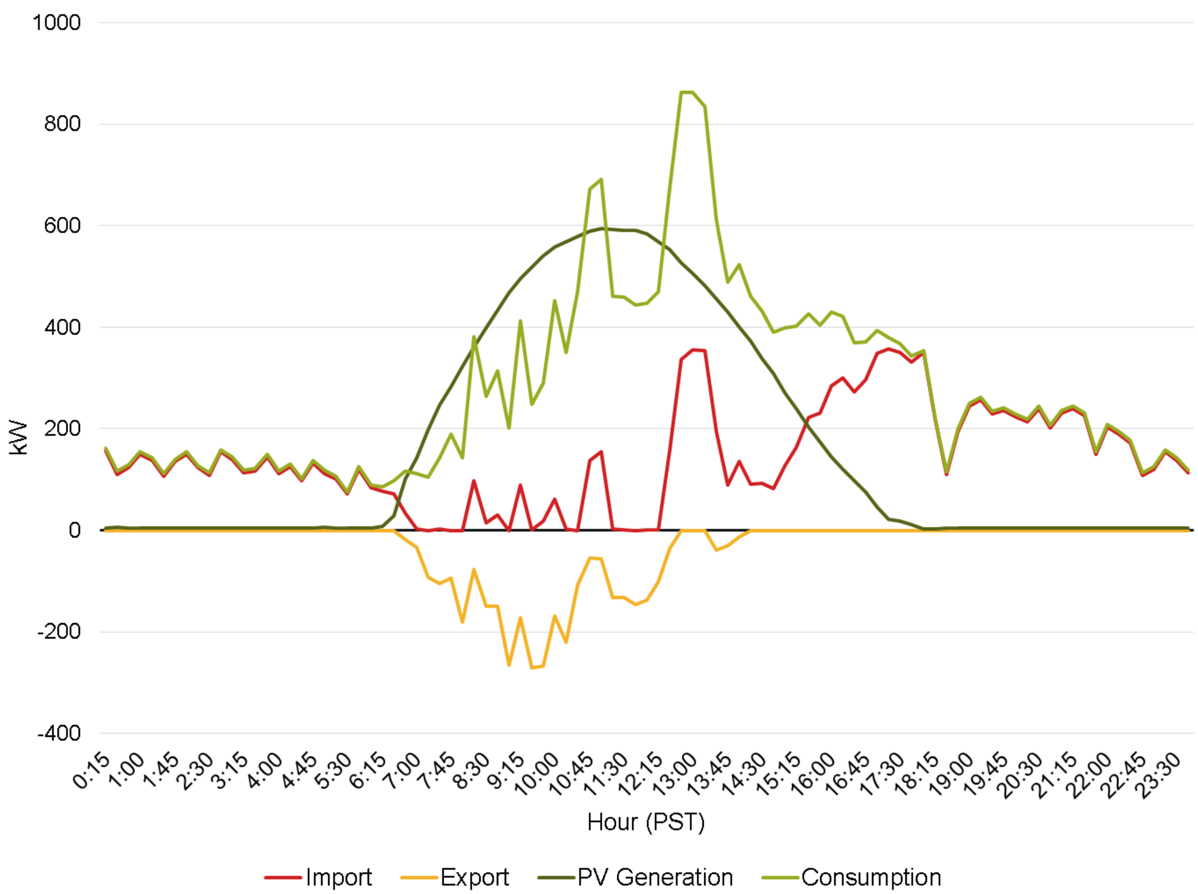


Figure 6-2 and Figure 6-3 illustrate the 15-minute import, export, PV production, and electricity consumption for a site on October 1 and October 13, respectively. The import and export data represented in Figure 6-2 (October 1) are represented as net consumption in Figure 6-1. Having access to the four different sets of energy data provides substantially more information. Reviewing the information presented in Figure 6-1, the customer's net load peaked at approximately 1:15 PM or 13:15 in the graph and has a second peak at 5 PM or 17:00. Reviewing the information presented in Figure 6-2, over half of the site's consumption at the net-load peak of 1:15 PM is satisfied by the customer's PV generation, with the remaining electricity needs provided by imports from the utility. At the secondary net-load peak of 5 PM, the majority of the customer's consumption is satisfied by imports from the utility, with only limited production by the site's PV system. The size of the customer consumption peak at 1:15 PM is largely obscured in Figure 6-1 due to the PV production and is clearly observable in Figure 6-2, while the secondary peak in Figure 6-1 is clarified in Figure 6-2 as a lower, shoulder consumption level with limited PV production.

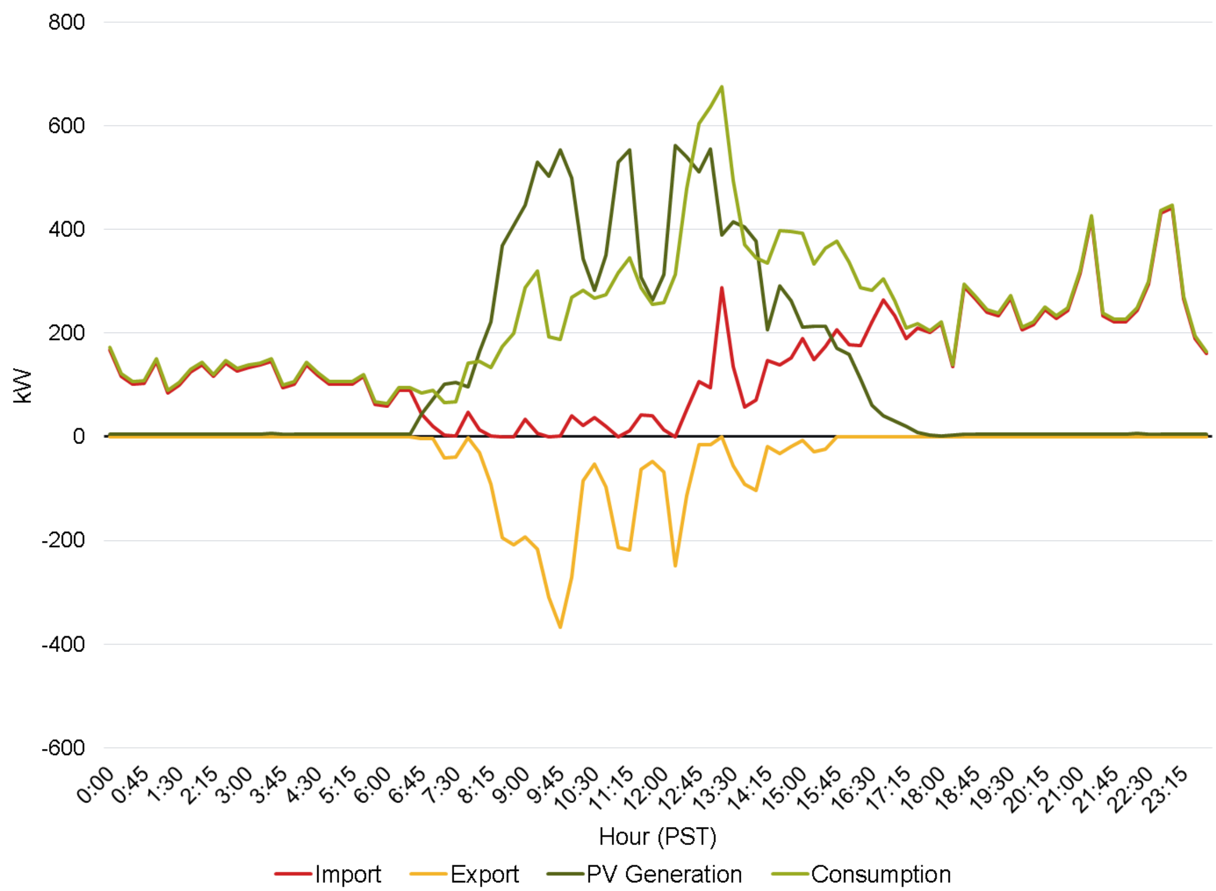
Looking at Figure 6-2 and Figure 6-3, it is clear that the site is both exporting and importing during 15-minute periods from 6:30 AM to noon. Most sites with PV present a similar phenomenon, where in a given hour, half hour, or 15-minute period they may both import electricity from the utility and export electricity to the utility. PV customers and their utilities are seamlessly sending electricity back and forth through the meter, depending on the site's consumption and PV production. Note that this and Figure 6-1 and Figure 6-3 are all based on metered data. October 1st was a clear sunny day so the solar PV output curve is very smooth.

FIGURE 6-2: SITE LEVEL IMPORT, EXPORT, AND PV PRODUCTION & EXPORT FOR OCT 1 2016



The shape of the PV production illustrated in Figure 6-2 is a smooth hill that looks similar to what is often represented when viewing a PV production shape on a consistently sunny day. The PV production in Figure 6-3 illustrates a day with clouds, where there are periods of high electricity production and periods when substantially less electricity is produced. When viewing average or aggregated PV production shapes, the smooth hill is a common representation, but for a given site, on a given day, the PV production of electricity may be jagged, with many hills and valleys. The hills and valleys of PV production may have a substantial impact of site-specific import and export or net consumption of electricity on a given day and time interval. This variability can have other impacts on distribution feeder voltage, frequency, and reliability.

FIGURE 6-3: SITE-LEVEL IMPORT, EXPORT, PV PRODUCTION, & EXPORT FOR OCT 13, 2016



6.2 LOAD ANALYSIS SAMPLE

This section will provide a short description of the number of sites available to describe the CSI residential and non-residential average annual PV production, customer consumption, and net load. To be included in the load analysis, the site was required to have at least one year of hourly data on the electricity delivered by the utility (imported by the customer), electricity received by the utility (exported by the customer), and the electricity generated by the customer's PV system. Ideally utility delivered (imported) and received (exported) data overlaps perfectly with the metered PV electricity generation so that it is possible to directly develop information on customer consumption. For many sites, however, the utility load and metered PV data do not overlap sufficiently to provide at least a year of the data needed to develop customer consumption. For sites where the net load and metered PV do not overlap for at least a year, PV simulations were used to align the PV generation, import, and export data. The simulation and metered PV production data were compared for a small sample of sites to ensure the similarities of these data. This comparison is presented below in the consumption change analysis (see Section 7.2). The simulation and metered PV data were found to be similar.

The data requirements for the load analysis substantially reduce the size of the sample available for the load and production analysis relative to the net export analysis, which relied only on customer billing data. Table 6-1 and Table 6-2 list the size of the customer CSI frame and the number of sites with at least one year of PV production, import, and export data by IOU and the PV system installation year. For many of the sample sites listed below, the analysis includes multiple years of metered PV and utility load data. PG&E provided load data for sites from 2012 to 2017, SCE provided data from 2015 to 2017, and SDG&E provided load data from 2010 to 2017.

TABLE 6-1: NON-RESIDENTIAL LOAD ANALYSIS SAMPLE

Install Year	CSI PG&E Non-Res Sites	Sample PG&E Non-Res Sites	CSI SCE Non-Res Sites	Sample SCE Non-Res Sites	CSI SDG&E Non-Res Sites	Sample SDG&E Non-Res Sites
2007	78	5	41	6	12	4
2008	431	58	192	30	53	18
2009	378	54	141	6	67	15
2010	436	54	186	13	64	17
2011	513	128	343	80	102	28
2012	703	203	441	92	79	20
2013	624	218	288	77	116	39
2014	191	69	438	163	126	40
2015	121	32	314	136	96	25
2016*	12		228	62	42	7

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

TABLE 6-2: RESIDENTIAL LOAD ANALYSIS SAMPLE

Install Year	CSI PG&E Res Sites	Sample PG&E Res Sites	CSI SCE Res Sites	Sample SCE Res Sites	CSI SDG&E Res Sites	Sample SDG&E Res Sites
2007	2,408	33	716	16	310	32
2008	5,089	41	1,883	31	692	30
2009	7,268	68	3,385	59	1,987	61
2010	8,395	306	5,019	234	2,526	121
2011	10,389	1,407	7,668	861	2,728	241
2012	12,147	374	11,666	273	3,493	90
2013	10,557	12	18,079	44	2,638	28
2014*	373		12,697	45	2,607	23
2015*	11		246	1	1,385	1
2016*	7		7		247	

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

For the following analyses, the load data are weighted as described in Section 5.1. The weights were developed based on IOU, sector, installation year, and customer size.[95] While the weighting strategy is the same for the net export and the load shape analysis, a site in both analyses will have different weights for the analyses. The weights are dependent on the number of sites available for each analysis.

6.3 ANNUAL LOAD ANALYSIS FINDINGS

This section presents information on the annual average consumption, import, export, and PV production of electricity for CSI participants using data on PV production and customer import and export of electricity to the utility. The analysis also reports on the size of PV production relative to consumption (PV kWh/Cons), contemporaneous consumption of PV production ((PV kWh – Export)/Cons) and the share of PV production contemporaneously used at the customer site ((PV kWh – Export)/PV kWh). The data will also be used to describe how the size and timing of the consumption and net load peak differ. Results are presented by residential and non-residential groups and within each of those two groups annually, by inland versus coastal, during the top 200 IOU peak hours and by quarter.

6.3.1 Residential Load Analysis Findings

Table 6-3 presents the average annual load statistics. The CSI residential customer's annual consumption averages between 14,830 and 16,118 kWh, depending on IOU. The average consumption of CSI

[95] As for Analysis of Net Export, the residential cut-offs for large and small systems are 3.6, 4.3, and 3.9 for PG&E, SCE, and SDG&E, respectively. The non-residential cut-offs are 130, 180, and 120 for the three utilities.

participants is approximately twice as large as the average consumption for the typical IOU single family residential customer. The 2009 RASS lists the normalized annual consumption of PG&E and SCE single family customers as 7,545 kWh and 7,194 kWh for SDG&E.[96] Part of the higher electricity consumption for CSI participants may be due to their tendency to live in larger homes (see data in Table 6-3). The higher electricity consumption of CSI participants is also likely due to a substantially higher energy intensity or usage per square foot. The escalating block tier structure of the California IOU residential rates encouraged customers with high electricity consumption, who were in the third and fourth tier, to install solar.

With net energy metering (NEM), a PV customer's electricity bill under NEM 1.0 is dependent on their net load or the electricity import minus the electricity export. The data in Table 6-3 support the conclusion that the average residential PV customer effectively reduced their utility bill from one based on their consumption of approximately 15,000 to one based on a net load of approximately 5,000 kWh per year This compares to the baseline or first-tier consumption maximum for a dual-fuel house in PG&E that ranged from slightly over 3,000 kWh to over 7,000 kWh in 2010, depending on climate zone, and from approximately 3,500 kWh to 6,000 kWh for SDG&E's dual-fuel baselines in 2010.[97] Given the estimate of the average net load for customers (5,000 kWh), it appears that many CSI residential customers were successful in reducing their net load to a level associated with the first or second tier of their utility residential rates.

[96] The RASS results can be obtained through the following web tool: https://webtools.dnvgl.com/RASS2009/Default.aspx .

[97] The baseline information for SCE was not readily available. The PG&E baseline values were found here: https://www.pge.com/tariffs/electric.shtml, while the SDG&E baseline values were derived from information available on their website: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR_2010.pdf.

TABLE 6-3: RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS (KWH)

	PG&E Residential	SCE Residential	SDG&E Residential
Average Electricity Consumption CSI Customers	14,830	16,118	15,036
Home Median Square Footage for CSI Customers	2,200	2,356	2,433
Average Consumption for Single Family Residential Customers (RASS)	7,545	7,545	7,194
Home Average Square Footage for Single Family Residential Customers (RASS)	1,859	1,877	2,018
Import	9,671	10,705	9,590
Export	4,202	4,744	4,869
PV Production	9,361	10,157	10,315
% Consumption supplied by PV (PV/Cons)	63%	63%	69%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	35%	34%	36%
% PV used at the site (PV-Ex)/PV	55%	53%	53%

The results presented in Table 6-3 also show that the average residential CSI customer generates 63 to 69 percent of their ***total annual energy*** use **(% Consumption supplied by PV (PV/Cons)**). Even though the PV systems at these sites generate less electricity than the average CSI customer consumes in a year, these customers are frequently alternating between importing and exporting electricity to the grid. PV generation will rise and fall with sunlight, while residential energy usage is driven largely by the occupancy schedule at the premise. In the middle of the day, PV electricity production likely exceeds the customer's electricity consumption, but customer consumption in the morning and evening will exceed PV electricity production. The ratio of PV production to consumption treats production like a bank (or like the NEM rate); it may exceed 100 percent when production exceeds consumption but the excess can be "used" as a credit to reduce the cost of utility consumption during other periods.

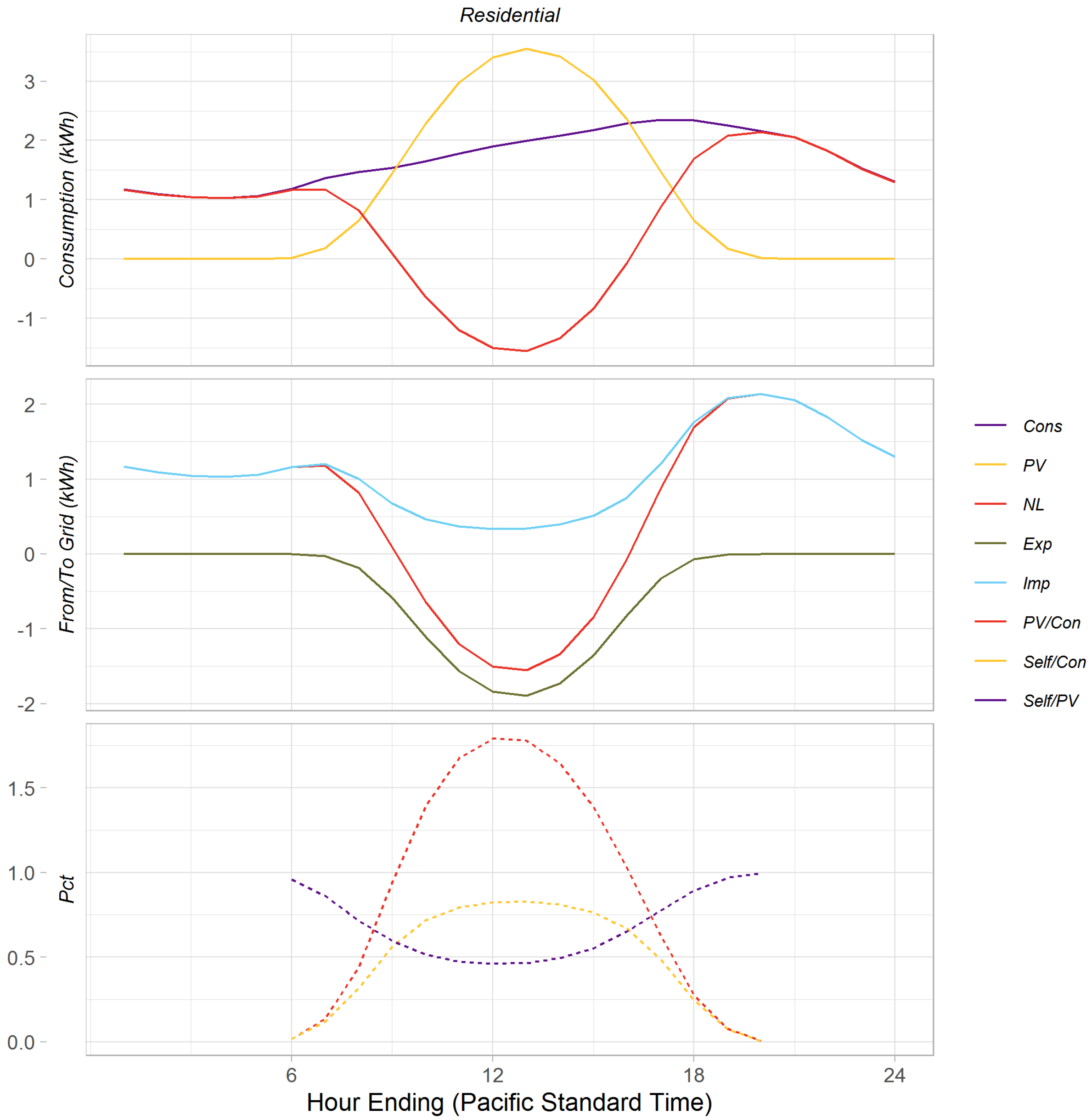
The contemporaneous consumption of PV generation (or consumption of PV generation in real time) describes the average share of consumption that is met by PV as measured using hourly data (**% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons**). Contemporaneous consumption describes the share of customer consumption that is met by PV production in the moment of consumption, or without use of the electricity grid as a bank. Contemporaneous consumption of PV generation can never exceed 100 percent; the PV production that is exported does not contribute to contemporaneous consumption. The opposite, or 1 minus contemporaneous consumption, describes the share of customer consumption that is supplied instantaneously by the utility. Contemporaneous consumption met by PV production is approximately 35 percent. Contemporaneous consumption met by PV production is zero when PV production is zero and highest when production and consumption are both high.

The percent of PV generation used at the site (**% PV used at the site (PV-Ex)/PV**) or PV self-consumption, describes the share of the electricity that is being produced by the PV system that is used at the site instead of exchanging power with the grid. The opposite or one minus the PV self-consumption is the share of PV export to the grid. PV self-consumption only exists when production is non-zero. Self-consumption will be high when production is low. When production is high, a higher share of PV production is export, and self-consumption will be lower, or the share of export will be higher. The average CSI site consumes approximately 55 percent of their PV production in real time. The rest of the production is exported to the grid. During hour when there is already excess renewable generation like the belly of the duck curve, a high fraction of PV self-consumption might be desirable to avoid the need to curtail utility scale renewables. Conversely, during peak hours, a low fraction of PV self-consumption could help offset peak generation for other customers.

Figure 6-4 illustrates the average PG&E CSI residential customer's load profile and the consumption and production share information. Similar load profiles for the other utilities are available in Appendix C. The figure presents three separate groups of information:

- The first panel illustrates the average customer's 24-hour load profile presenting consumption (Cons, purple), PV generation (PV, yellow) and net load (NL red).
- The second panel illustrates the load profiles available to the utility including net load (NL, red), export to the grid (Exp, green), and import from the grid (Imp, blue).
- The third panel illustrates the consumption and generation shares with the percent of generation relative to consumption (PV/Con, dotted red), the share of contemporaneous consumption provided by PV generation (Self/Con, dotted yellow), and the share of PV generation self-consumed in real time (Self/PV, dotted purple). Data for this graph are only presented during daylight hours when PV is generating.

FIGURE 6-4: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT AND IMPORT



The first panel of information in Figure 6-4 and the data presented in Table 6-4 show that the average PG&E CSI residential customer consumption peaks at 5 PM with a very gradual ramp into the peak and a gradual decline following their peak consumption. The average CSI residential evening peak consumption is 2.35 kWh. PV production, however, is highest in the middle of the day, averaging 3.55 kWh per customer at 1 PM. At 1 PM, the average of PG&E CSI residential electricity consumption is only 1.99 kWh per customer, with an average export of 1.90 kWh and 0.34 kWh of import. By 5 PM, the average PV production has fallen to 1.48 kWh, imports have risen to average 1.21 kWh per customer, and average exports have fallen to 0.33 kWh.

TABLE 6-4: RESIDENTIAL AVERAGE ANNUAL HOURLY LOAD STATISTICS

	PG&E Residential	SCE Residential	SDG&E Residential
Consumption Peak	2.35 kWh	2.75 kWh	2.42 kWh
Hour of Consumption Peak	5 PM	5 PM	4 PM
Net Load Peak (Import – Export)	2.14 kWh	2.36 kWh	2.14 kWh
Hour of Net Load Peak	8 PM	7 PM	8 PM
Largest Consumption Ramp (ΔkWh/hour)	0.18 kWh/hour	0.21 kWh/hour	0.24 kWh/hour
Hour of Consumption Ramp	7 AM	11 AM	10 AM
Largest Net Load Ramp (ΔkWh/hour)	0.94 kWh/hour	0.99 kWh/hour	1.01 kWh/hour
Hour of Net Load Ramp	5 PM	5 PM	5 PM

The average CSI residential customer is importing electricity from the utility in the morning, exporting electricity to the utility during peak production, and quickly ramping into importing electricity during the evening peak (Net Load in Table 6-4 and Figure 6-4). The import of electricity from the grid to the household continues to rise after the average customer peak consumption at 5 PM, with average imports peaking at 2.14 kWh per customer at 8 PM. PV production has effectively moved the peak observed by the utility from the CSI residential customers' average peak consumption at 5 PM to the customers' average peak import of electricity at 8 PM. The net load peak observed by the utility at 8 PM is smaller than the customer consumption peak at 5 PM (2.14 kWh versus 2.35 kWh), but the rapid decline in PV production during the late afternoon and early evening hours contributes to a dramatic increase in the steepness of the net load ramp. The relationship between consumption and production leads the net load to represent the now familiar "duck shape," declining and going negative in the middle of the day and rising quickly into the evening.

The third panel illustrates that the ratio of production to consumption peaks between noon and 1 PM, with production equaling approximately 180 percent of consumption. The high level of production relative to consumption leads to substantial average export. Between noon and 1 PM, on an average day, slightly less than 50 percent of PV production is self-consumed ((PV-Export)/PV) and the rest is exported to the grid, while approximately 82 percent of consumption from noon to 1 PM is provided by PV production ((PV-Export)/consumption). These graphs help to illustrate that the utility and the consumer are frequently changing how they exchange electricity as the availability of production and the need for consumption change.

6.3.2 Residential Coastal and Inland Loads

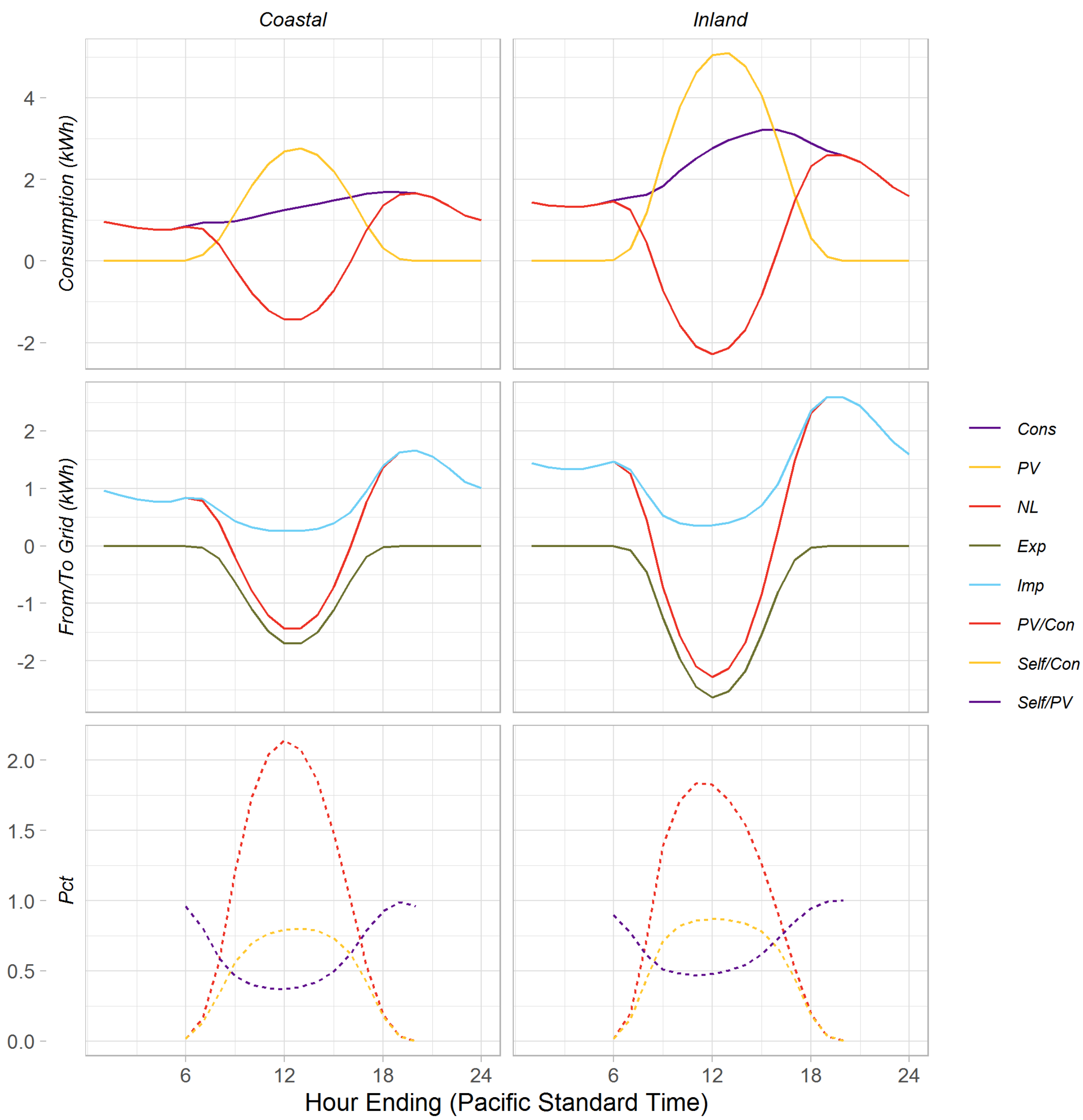
Table 6-5 presents the CSI residential average annual load statistics by coastal and inland customers. These data indicate that the coastal CSI residential sites in PG&E and SDG&E consume and produce less electricity than the inland sites for these utilities. In contrast, SCE's CSI residential sites show more similarities in consumption and production across inland and coastal geographies. One likely reason for this distinction is housing square footage. Within our sample, the median home square footage for PG&E and SDG&E is larger inland than coastal (PG&E inland 2,291 and coastal 2,161, SDG&E inland 2,638 and coastal 2,111) while SCE's median is larger coastal than inland (inland 2,300 and coastal 2,500). Thus, while air conditioning needs may be higher inland for all three territories, the larger coastal square footage of homes in SCE's service territory helps to equilibrate the coastal and inland consumption in SCE. The larger square footage and air conditioning needs for inland homes in PG&E and SDG&E exacerbate the differences in electricity consumption between inland and coastal homes in PG&E's and SDG&E's service territories.

TABLE 6-5: RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS BY COASTAL AND INLAND (KWH)

	PG&E Residential Coastal	PG&E Residential Inland	SCE Residential Coastal	SCE Residential Inland	SDG&E Residential Coastal	SDG&E Residential Inland
Median Square Footage of Sample	2,161	2,291	2,500	2,300	2,111	2,263
Consumption	12,330	17,573	15,113	16,489	10,547	19,194
Import	8,366	11,102	10,049	10,947	7,292	11,719
Export	3,759	4,688	4,791	4,726	3,757	5,899
PV Production	7,723	11,158	9,856	10,269	7,013	13,374
% Consumption supplied by PV (PV/Cons)	63%	63%	65%	62%	66%	70%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	32%	37%	34%	34%	31%	39%
% PV used at the site (PV-Ex)/PV	51%	58%	51%	54%	46%	56%

Figure 6-5 illustrates the average SDG&E CSI residential customer's load profile and the consumption and production share information by coastal and inland. Similar load profiles for the other utilities are available in Appendix C. The first set of panels illustrate the average load shapes for coastal and inland CSI households in SDG&E's service territory. Both the inland and the coastal production shapes show that average production is highest at approximately 1 PM, with an average hourly production of 2.76 kWh coastal and 5.09 kWh inland. The difference in the average hourly peak production is consistent with the substantially smaller average annual PV production of 7,013 kWh for coastal versus 13,374 kWh for SDG&E CSI residential inland systems. The hour of the inland and coastal average consumption peaks, however, occurs at different times of the day. The average coastal consumption load shape peaks at 6 PM at 1.69 kWh, while the inland consumption shape peaks earlier at 3 PM at 3.22 kWh. It is likely that the inland shape peaks earlier than the coastal shape due to higher air conditioning use. Given the timing of the different consumption peaks, the average PV production at the timing of the inland consumption peak is approximately 4.05 kWh, while PV production at time of the coastal consumption peak is near zero (0.32 kWh). Given that the inland average peak consumption occurs closer to the peak in PV production, it is not surprising that their highest average ratio of inland PV production to consumption is 183 percent at 11 AM, while the lower coastal consumption in the middle of the day contributes to their average ratio of PV production to consumption reaching a maximum of 214 percent at noon.

FIGURE 6-5: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT AND IMPORT FOR COASTAL AND INLAND CUSTOMERS



6.3.3 Residential Quarterly Loads

Table 6-6 presents the SCE CSI residential average annual load statistics by quarter. Similar load statistics are available for the other utilities in Appendix C. These data show substantially higher average consumption during the third quarter or during the summer (July, August, and September). The average

PV production is largest in the second quarter (followed closely by the third quarter) and substantially lower in the first and fourth quarters.

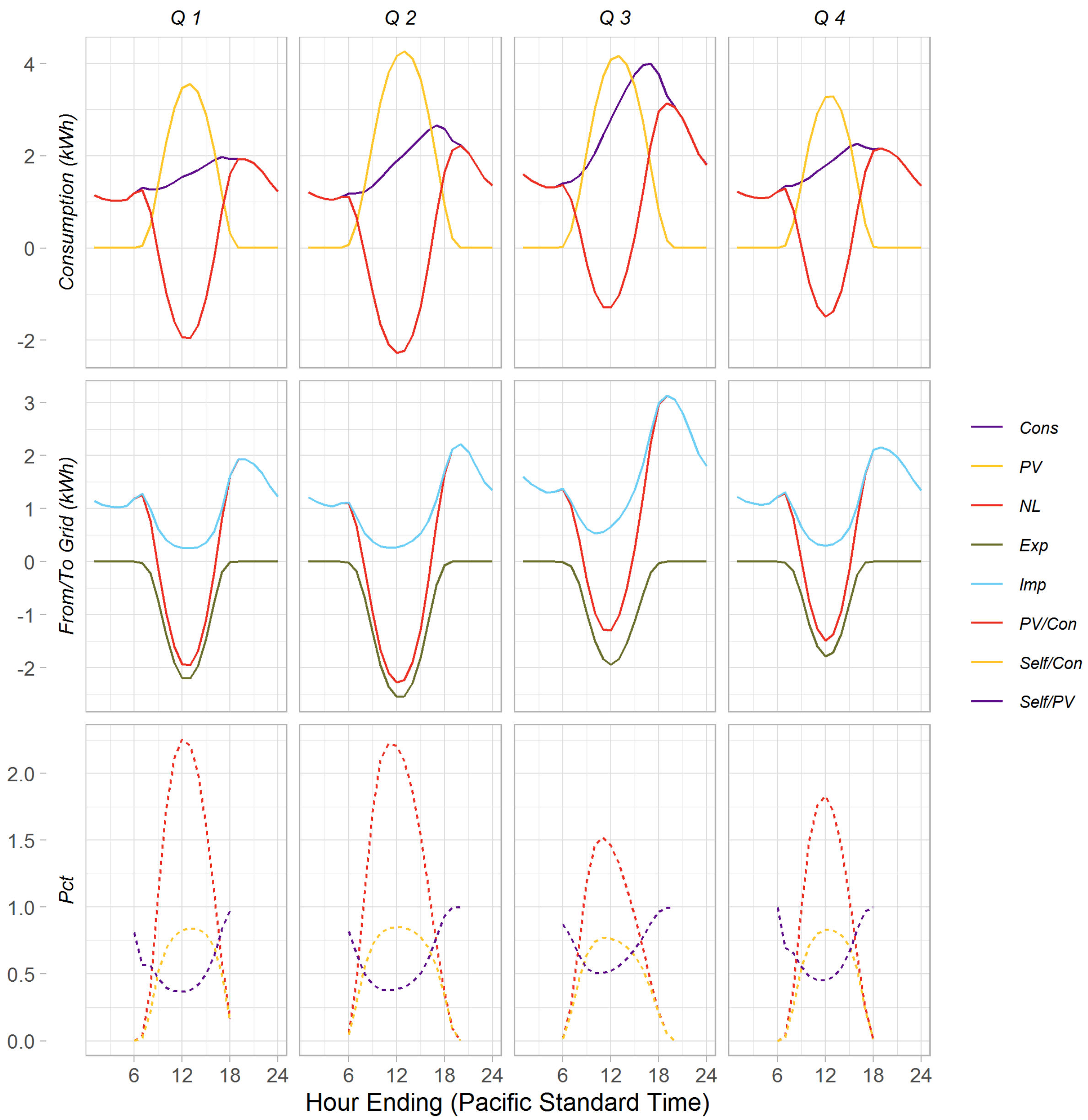
TABLE 6-6: SCE RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SCE Residential Q1	SCE Residential Q2	SCE Residential Q3	SCE Residential Q4
Consumption	3,206	3,760	5,351	3,643
Import	2,202	2,296	3,545	2,575
Export	1,174	1,576	1,114	876
PV Production	2,178	3,039	2,920	1,944
% Consumption supplied by PV (PV/Cons)	68%	81%	55%	54%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	31%	39%	34%	29%
% PV used at the site (PV-Ex)/PV	46%	48%	61%	55%

Figure 1-6 illustrates the average SCE CSI residential customer's load profile and the consumption and production share information by quarter. Similar load profiles for the other utilities are available in Appendix C. The first set of panels helps to illustrate the average load shapes by quarter. The height and shape of the load shapes presented differ by quarter, with Q3 having the highest average hourly consumption (4.0 kWh) and import (3.1 kWh) and Q2 the largest average hourly export (2.6 kWh) and PV production (4.3 kWh). The timing or hour of the largest average hourly import, export, PV production, and consumption, however, varies by no more than an hour over the four quarters.

The statistics presented in Table 6-6 show that the average residential customer generates 68 percent of their energy consumption in Q1, 81 percent in Q2, 55 percent in Q3, and 54 percent in Q4. The average quarterly shares include many hours where consumption is positive and PV production is zero. The lower panel of Figure 1-6 shows the hourly distribution of PV production relative to consumption. The average hourly distribution of customer generation relative to consumption peaks in the first quarter at 225 percent while the peak in Q2 is a close second, at 222 percent. The second quarter's higher average quarterly share of consumption covered by production (81 percent for Q2 relative to 68 percent for Q1) is due to more hours of PV production during the spring than during the winter. The extra hours of PV generation are illustrated in the third panel by a broader PV/Cons shape in Q2 than in Q1. The third quarter has the lowest peak generation relative to consumption at 150 percent, due in large part to higher electricity consumption.

FIGURE 6-6: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT AND IMPORT FOR BY QUARTER



The average contemporaneous share of consumption covered by PV production is highest in Q2 at 39 percent (see Table 6-6) as high levels of production that cover more hours of the day are matched with moderate consumption. The hourly profile of the contemporaneous share of consumption provided by PV generation is illustrated by the yellow dotted line in the lower panel in Figure 1-6. The hourly distribution shows that only a small share of consumption is covered by production during the morning and evening hours, while over 80 percent of consumption may be served by production near noon. The average share of PV generation used at the site is highest in Q3 at 61 percent, as a higher share of electricity generation is used over more hours to cover the relatively high level of consumption. The hourly distribution of the share of PV generation contemporaneously utilized by the site is illustrated by the purple dotted line. The utilization of PV generation by the site is highest when production is low, declining as production rises. The average minimum of the utilization curve is the highest in the third quarter because the usage of air conditioning increases consumption when PV production is highest, limiting exports during these hours.

6.3.4 Residential Load on IOU 200 Peak Hours

The load data analyzed also provide unique insights for the impact of PV production on the load shape of customers during days including the top 200 hours of net load across the multiple years of data provided by the IOUs.[98] Table 6-7 provides average load statistics for the top 200 hours of the system for CSI residential customers. Given the load data provided by the IOUs, PG&E's and SDG&E's top 200 hours of the system peak is the average across customers and hours for the years 2011 to 2017 while SCE's represent their 200 peak hours for each of the years 2015 to 2017. During the top 200 peak IOU system hours, PG&E's residential CSI customer average electricity consumption is 3.46 kWh, SCE's is 4.36 kWh, and SDG&E's is 3.75. It is also important to note that the average consumption of the top 200 hours is much larger than the average hourly consumption over all 24 hours for CSI residential customers, at 1.84 kWh for SCE, 1.72 for SDG&E, and 1.69 for PG&E. During the top 200 hours, residential customers are consuming substantially more electricity than their average hourly consumption as customers likely increase their air conditioning use during these hours.

TABLE 6-7: RESIDENTIAL AVERAGE LOAD STATISTICS DURING THE IOU PEAK 200 HOUR (KWH)

	PG&E Residential	SCE Residential	SDG&E Residential
Consumption	3.46	4.36	3.75
Import	1.90	2.42	2.06
Export	0.59	0.57	0.63
PV Production	2.15	2.51	2.31
% Consumption supplied by PV (PV/Cons)	62%	58%	62%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	45%	44%	45%
% PV used at the site (PV-Ex)/PV	73%	77%	73%

[98] See Section 4 for a description of net IOU and system load and reasoning for use of this metric.

Table 6-7 also shows that the average CSI residential customer generates 58 to 62 percent of their total energy use during the peak hours and about 45 percent of their energy is consumed contemporaneously. The lower share of consumption covered by generation for SCE is consistent with those customers' higher average consumption during the system peak hours. The finding that the contemporaneous energy usage share is less than the PV/Consumption share illustrates that customers are exporting energy to the grid even during the system peak hours. The average energy export during peak hours is highest at SDG&E and lowest at SCE.

The three utility average load shapes across days that include the top 200 hours next to the average over all hours are presented in Figure 6-7 to Figure 6-9. The IOU CSI residential average hourly consumption and net load peak across the top 200 hours are presented in Table 6-8. The annual average hourly consumption and net load statistics are reproduced from Table 6-4 in Table 6-8 to ease the comparison of statistics across the top 200 hours and the annual average. Reviewing the first panel in each of the three figures, SCE's average consumption shape is distinct from those of the other two utilities; it is the only consumption load shape that peaks above the peak of their PV production load shape. It is very clear from the three IOU figures that during days that include the top 200 hours, the customer peak consumption is later in the day than the peak PV production. For days that include the top 200 hours, SCE's residential CSI average consumption peak is 4.6 kWh at 5 PM and its PV production peaks at 1 PM at 4.16 kWh. The late afternoon/early evening peak in SCE's CSI residential consumption allows PV production to contemporaneously provide 34 percent of consumption ((PV-Export)/Consumption). The peak average import of electricity from the utility for SCE's CSI residential customers during days that include the top 200 hours occurs at 7 PM, with 3.68 kWh (PV generation is providing approximately 5 percent of consumption during this time). PV production effectively hides the consumption peak at 5 PM (4.6 kWh), with the peak in the net load occurring two hours later at 7 PM (3.68 kWh). Following the import and net load peak, imports and consumption decline.

TABLE 6-8: RESIDENTIAL AVERAGE HOURLY LOAD STATISTICS DURING THE IOU PEAK 200 HOURS AND ANNUAL AVERAGES

	PG&E 200 Peak Residential	PG&E Annual Residential	SCE 200 Peak Residential	SCE Annual Residential	SDG&E Residential	SDG&E Annual Residential
PV Generation Peak	4.14 kWh	N/A	4.16 kWh	N/A	4.24	N/A
Hour of PV Generation Peak	1 PM	N/A	1 PM	N/A	1 PM	N/A
Consumption Peak	3.71 kWh	2.35 kWh	4.60 kWh	2.75 kWh	4.06 kWh	2.42 kWh
Hour of Consumption Peak	5 PM	5 PM	5 PM	5 PM	4 PM	4 PM
Net Load Peak (Import – Export)	2.91 kWh	2.14 kWh	3.68 kWh	2.36 kWh	3.14 kWh	2.14 kWh
Hour of Net Load Peak	8 PM	8 PM	7 PM	7 PM	7 PM	8 PM
Largest Consumption Ramp (ΔkWh/hour)	0.30 kWh/hour	0.18 kWh/hour	0.48 kWh/hour	0.21 kWh/hour	0.48 kWh/hour	0.24 kWh/hour
Hour of Consumption Ramp	11 AM	7 AM	11 AM	11 AM	10 AM	10 AM
Largest Net Load Ramp (ΔkWh/hour)	1.01 kWh/hour	0.94 kWh/hour	0.95 kWh/hour	0.99 kWh/hour	0.98 kWh/hour	1.01 kWh/hour
Hour of Net Load Ramp	5 PM	5 PM	5 PM	5 PM	5 PM	5 PM

Comparing SCE's average CSI residential customer peak consumption during the top 200 hours with the peak consumption averaged across all hours, the top 200-hour peak is 1.85 kWh higher (4.6 kWh during the top 200 hours versus 2.75 kWh). The peak of the net load is also substantially higher, peaking at 3.68 kWh versus 2.36 kWh when averaged across all days. During the top 200 hours, SCE CSI customers use substantially more energy. The consumption ramp in the morning is also larger (0.48 kWh versus 0.21 kWh), but this ramp is obscured by the PV production and the average net load is negative for CSI residential customers during this time period. In contrast, the net load ramp at 5 PM is largely unchanged during the top 200 days (0.95 kWh) versus the average day (0.99 kWh). The net load ramp does not increase during the top 200 days relative to an average day; while energy usage during days that include the top 200 hours is higher than the average day, the increase in electricity consumption occurs earlier in the day and is maintained, leading to no change in the late afternoon net load ramp.

Figure 6-7 illustrates how PG&E's residential CSI customer load shapes and statistics (in Table 6-8) differ across the average of days that include the top 200 hours versus the average across all days. First, the average customer peak consumption increases from approximately 2.35 kWh to 3.71 kWh. On days that include the top 200 hours, consumption rises to 2 kWh by 10 AM, increasing quickly to approximately 3.1

kWh by 2 PM and then slowly rising to peak at 3.71 kWh at 5 PM.[99] The hour with the highest increase in consumption during the average day is 7 AM for PG&E residential CSI customers and 11 AM during days that include the top 200 hours. The consumption ramp on days that include the top 200 hours is later in the morning, likely due to increased air conditioning use. During the hour of the CSI residential customer peak, on days that include the top 200 hours, PV generation is equivalent to 58 percent of average CSI customer consumption and approximately 80 percent of PV production remains at the site ((PV-Export)/PV) providing electricity for consumption. PG&E CSI residential customers' highest average import of electricity from the utility during days that include the top 200 hours peaks at 8 PM (2.91 kWh) when average CSI customer consumption is nearly equal to imports.

The third panel shows the most distinct difference when looking at a peak day versus an average day. The dotted red line, illustrating the share of residential consumption generated by the PV system, peaks at a substantially lower share than during an average day. For PG&E, the PV/Consumption share has an average peak across all days at 179 percent compared to 157 percent during days that include the top 200 hours. For SCE, the average PV generation compared to consumption is 185 percent (peaking at 10 AM), whereas for days that include the top 200 hours, the PV/Consumption share is 131 percent and peaks at 9 AM. For SDG&E, the average PV generation relative to consumption is 181 percent, declining to 135 percent for days that include the top 200 hours.

[99] The average peak during days that include the 200 peak hours exceeds the average during the top 200 hours because many of the top 200 hours occur on the same peak days. Looking at the average peak of the top 200 hours is similar to, though not exactly the same as, the peak hour consumption.

FIGURE 6-7: PG&E RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON PG&E SYSTEM PEAK DAYS

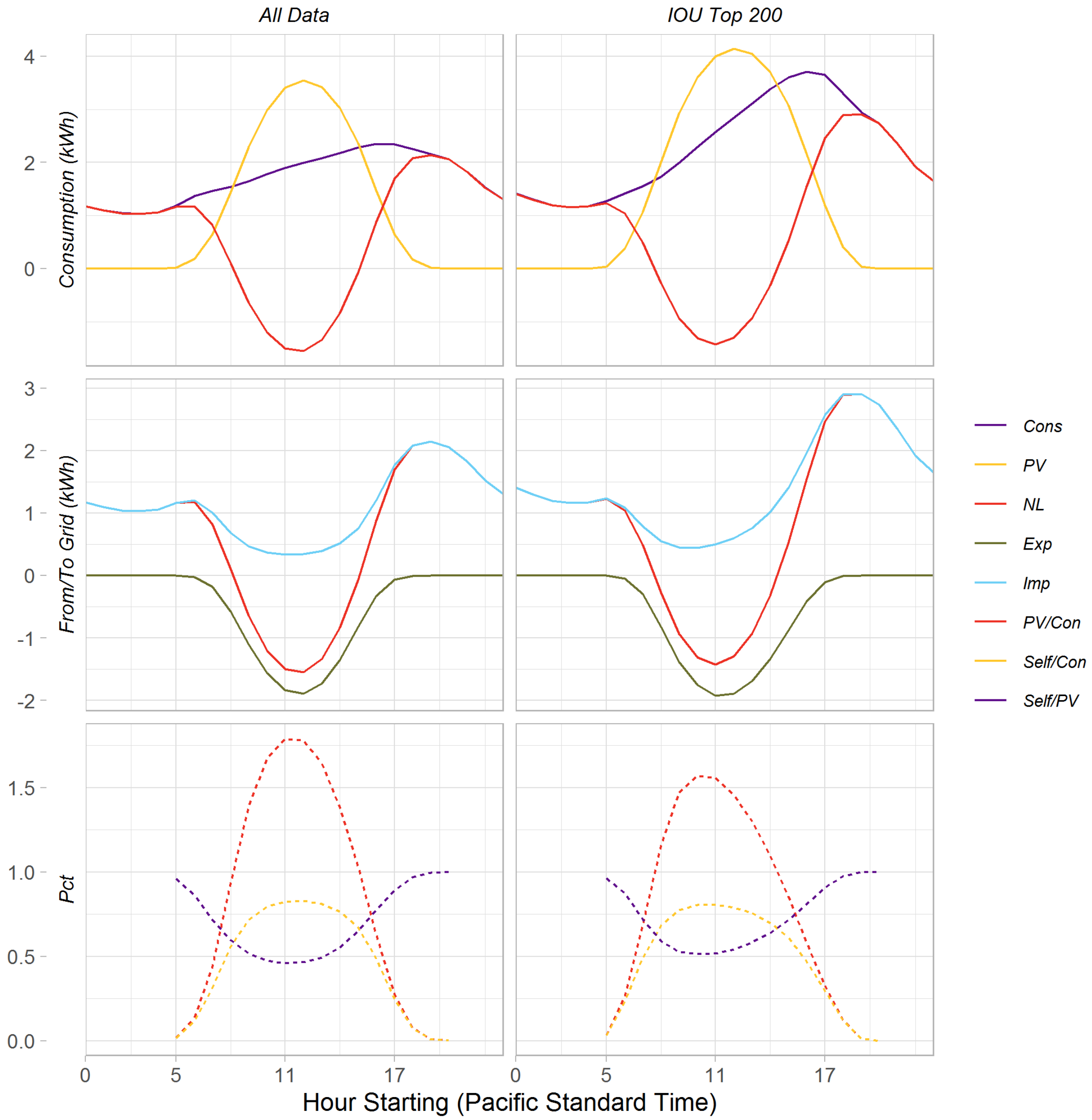
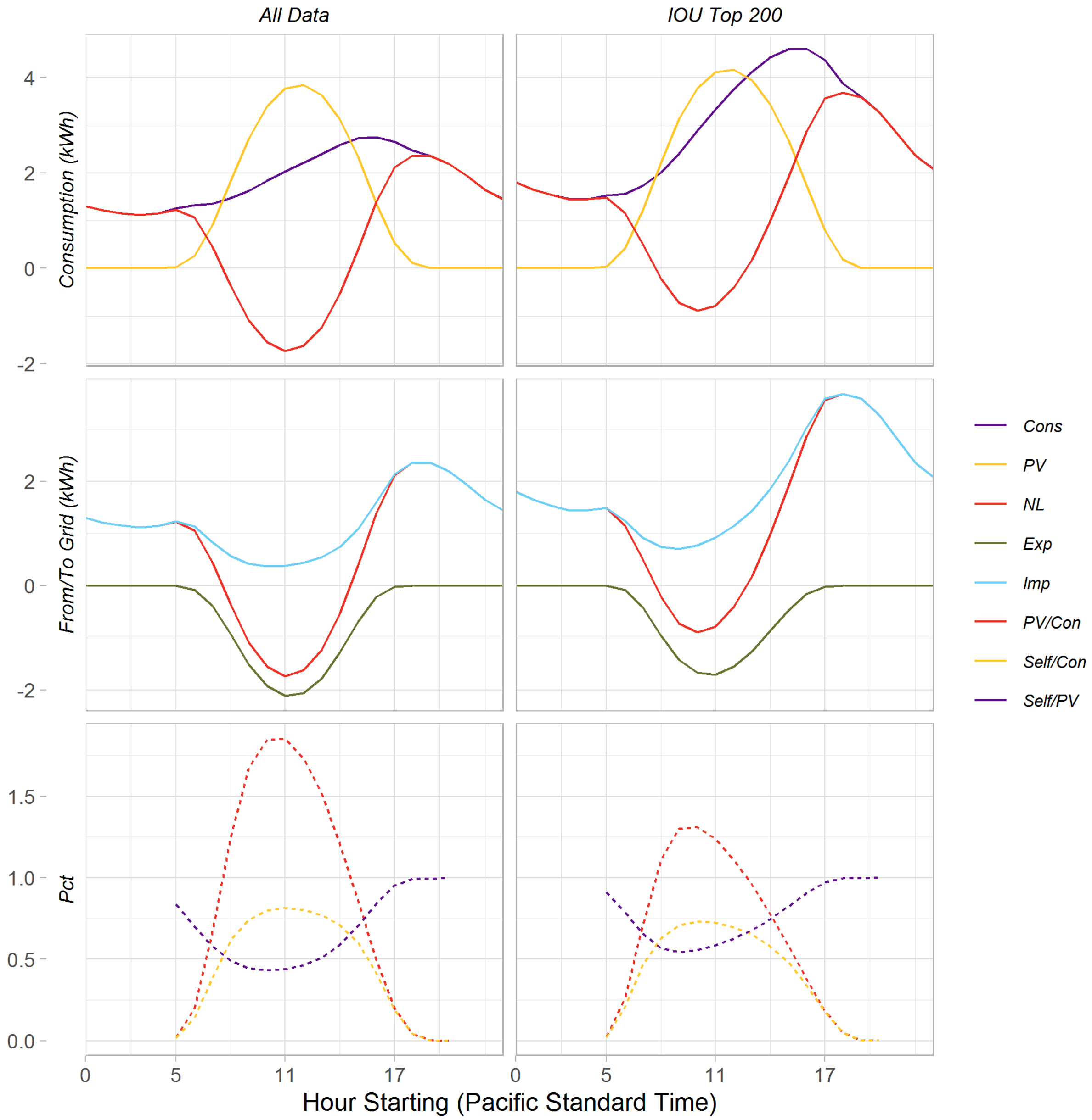


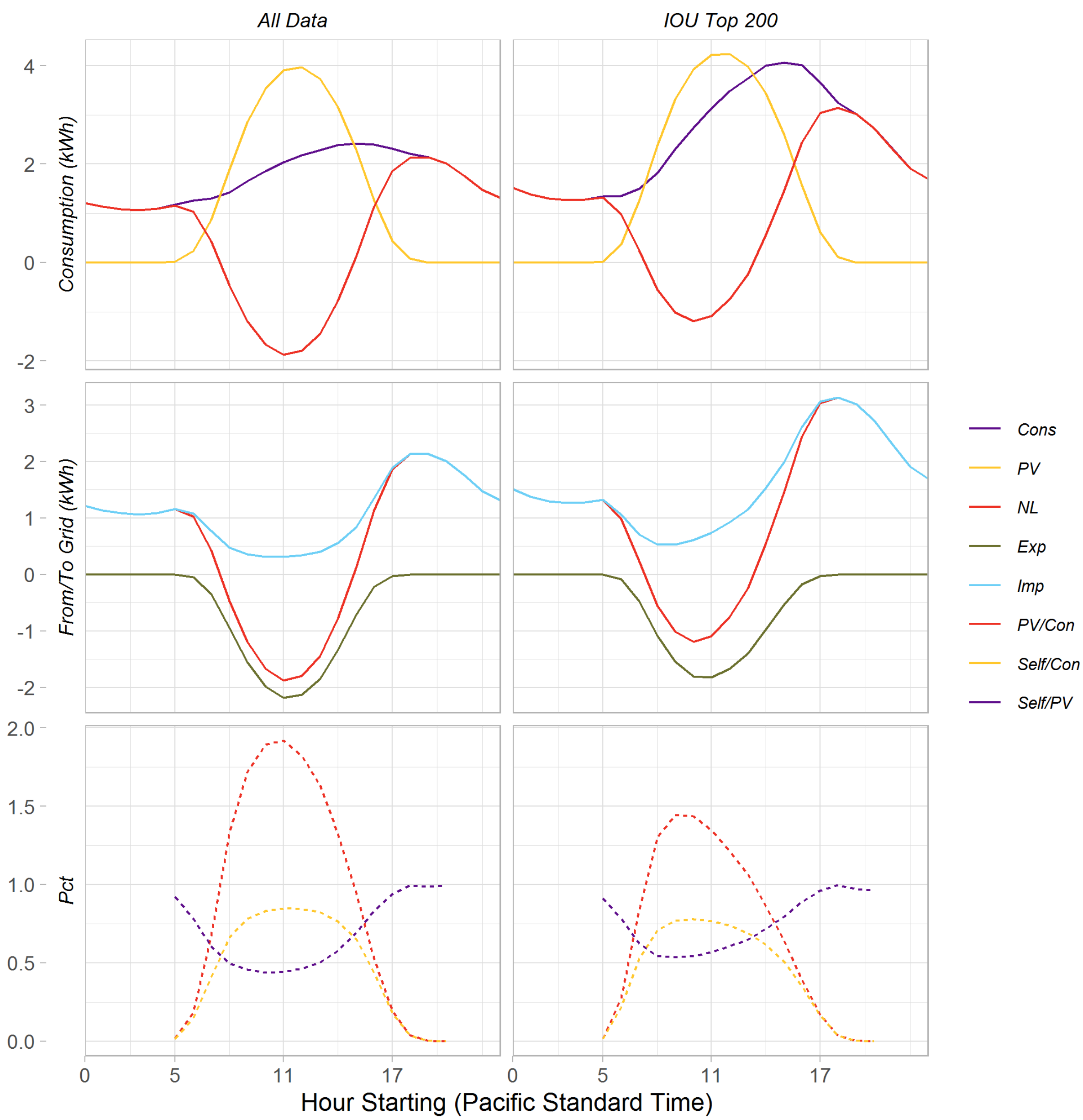
FIGURE 6-8: SCE RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON SCE SYSTEM PEAK DAYS



SDG&E's residential CSI customers' average consumption during days that include the top 200 hours peaks at 4.06 kWh at 4 PM, while PV production peaks at 4.23 kWh at 1 PM. The average consumption peak on days that include the top 200 hours is 1.64 kWh larger than the average peak across all days. The consumption peak on days that include the top 200 hours is associated with 51 percent of the average consumption being contemporaneously provided by PV ((PV – Export)/Consumption)). On days that include the top 200 hours, SDG&E's CSI residential customers average import and net load peak is 3.14

kWh at 7 PM (when PV production averages 0.11 kWh), which compares to a net load peak across all days of 2.14 kWh at 8 PM. On days that include the top 200 hours, for residential customers with PV, the PV production moves the peak as observed by the utility from the consumption peak at 4 PM to the net load peak at 7 PM and the net load peak is associated with a substantially faster late afternoon ramp. When comparing the late afternoon net load ramp on days that include the top 200 hours to the net load ramp across all days, the ramp does not increase on days that include the top 200 hours.

FIGURE 6-9: SDG&E RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON SDG&E SYSTEM PEAK DAYS



Additional CSI residential load results and figures are available in Appendix C. These results are presented by IOU for the average day, IOU top 200-hour days, and the CAISO top 200-hour days. Results are also present by coastal/inland, calendar year, and customer size.

6.3.5 Non-Residential Load Analysis Findings

Table 6-9 presents the average annual load statistics for non-residential CSI participants. PG&E's non-residential CSI customer average annual consumption is 1,164,233 kWh, SCE's is 1,884,772 kWh, and SDG&E's is 898,211. These averages illustrate the larger degree of heterogeneity in consumption for non-residential customers than residential customers, as these averages differ substantially by IOU. The data presented in Table 6-9 show that the average non-residential annual PV production is substantially less than the quantity of electricity imported from the utility, while the average quantity of annual export is 18 to 29 percent of the average PV production.

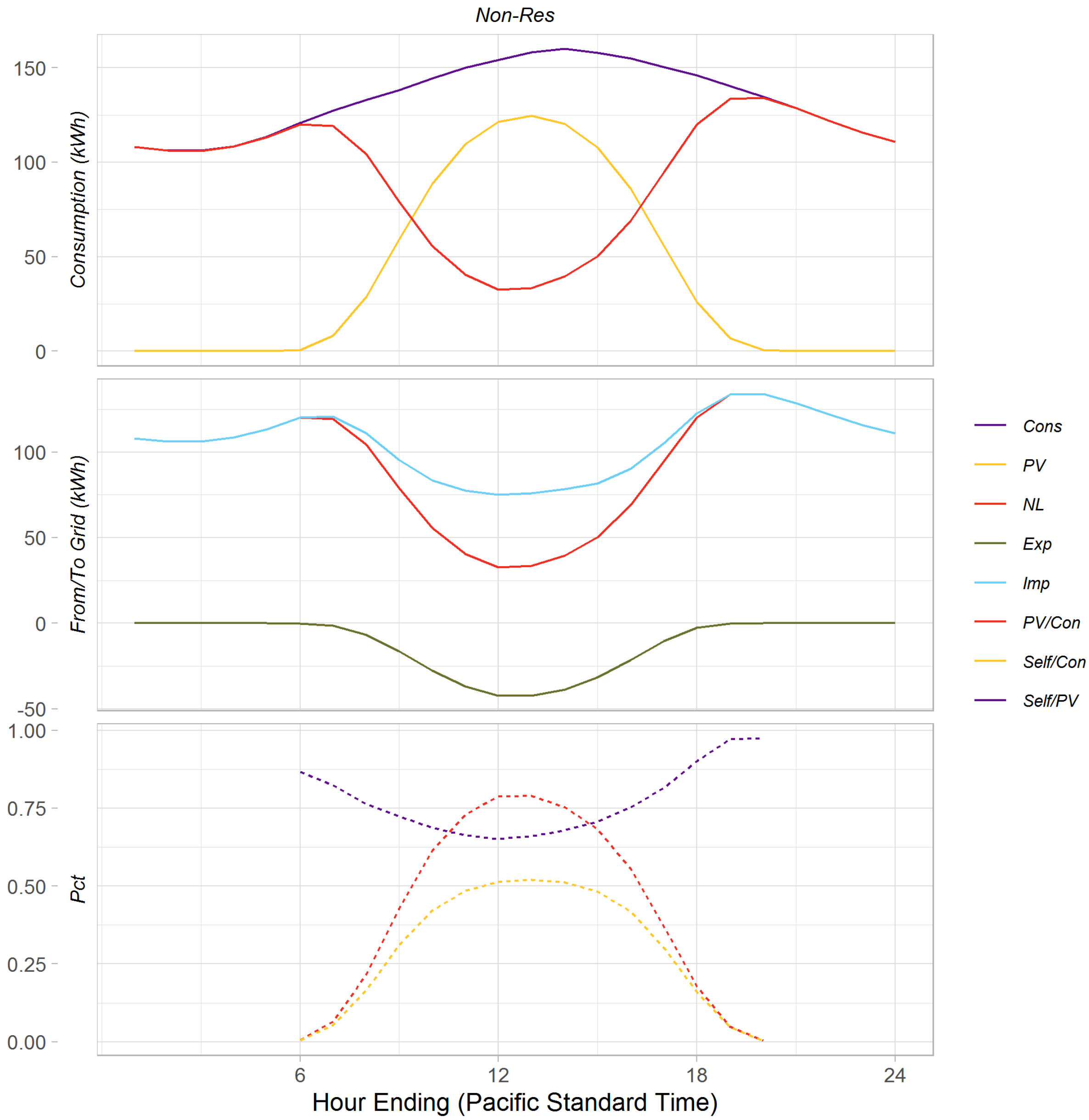
TABLE 6-9: NON-RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS (KWH)

	PG&E Non-Residential	SCE Non-Residential	SDG&E Non-Residential
Consumption	1,164,233	1,884,772	898,211
Import	921,027	1,554,228	643,398
Export	101,728	73,074	78,132
PV Production	344,934	403,619	332,945
% Consumption supplied by PV (PV/Cons)	30%	21%	37%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	21%	18%	28%
% PV used at the site (PV-Ex)/PV	71%	82%	77%

The statistics presented also indicate that non-residential PV generation is much smaller relative to consumption than in the residential sector. The average non-residential customer generates 21 to 37 percent of their consumption versus 63 to 69 percent for the average residential customer. On an hourly basis, the average share of non-residential CSI consumption supplied by PV generation contemporaneously is 18 to 28 percent, while the average CSI site uses over 70 percent of their PV production in real time.

Figure 6-10 illustrates the average PG&E CSI non-residential customer's 24-hour load profile and the consumption and production share information. Similar load profiles for the other utilities are available in Appendix C. Similar to the residential graphics, the figure presents three separate groups of information.

FIGURE 6-10: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT



The first panel of information and the data presented in Table 6-10 illustrate that the average PG&E CSI non-residential customer's consumption is highest shortly after the time PV production peaks, but the non-residential customer's typical consumption exceeds their PV production. This graph differs from the residential figures, where PV production typically exceeded consumption in the middle of the day. The combination of consumption and production leads to the net load (the red line) that forms the now familiar "duck shape." The average non-residential net load curve, however, does not go negative in the middle of the day when the average residential duck shape is negative.

TABLE 6-10: NON-RESIDENTIAL AVERAGE ANNUAL HOURLY LOAD STATISTICS

	PG&E Non-Residential	SCE Non-Residential	SDG&E Non-Residential
Consumption Peak	160 kWh	270 kWh	142 kWh
Hour of Consumption Peak	2 PM	3 PM	2 PM
Net Load Peak (Import – Export)	134 kWh	230 kWh	103 kWh
Hour of Net Load Peak	8 PM	7 PM	7 PM
Largest Consumption Ramp (ΔkWh/hour)	7.4 kWh/hour	14.1 kWh/hour	11.7 kWh/hour
Hour of Consumption Ramp	6 AM	10 AM	10 AM
Largest Net Load Ramp (ΔkWh/hour)	25.8 kWh/hour	30.5 kWh/hour	24.7 kWh/hour
Hour of Net Load Ramp	5 PM	5 PM	5 PM

The second panel illustrates the average imports and exports. Average exports peak during the middle of the day while imports reach their minimum during this time. The peak of the average imports curve is obscured by the net load curve, but it occurs during the evening hours (8 PM) as PV production has declined and is approaching zero. For PG&E non-residential customers with PV, the PV production shifts the average customer peak as observed by the utility from 2 PM at 160 kWh to 8 PM and 134 kWh. The average observed peak served by the utility has declined but the rapid decline of PV production into the observed net load peak changes the timing of the non-residential ramp from the morning hours into the evening and contributes to a much steeper evening ramp.

The third panel illustrates that the ratio of production to consumption peaks about between noon and 1 PM with production equaling slightly more than 75 percent of consumption. These graphs illustrate that the non-residential CSI customer typically relies more heavily, than the average residential CSI customer, on the utility to meet their energy demands while PV generation provides approximately 50 percent of their contemporaneous consumption needs in the middle of the day.

6.3.6 Non-Residential Coastal and Inland Loads

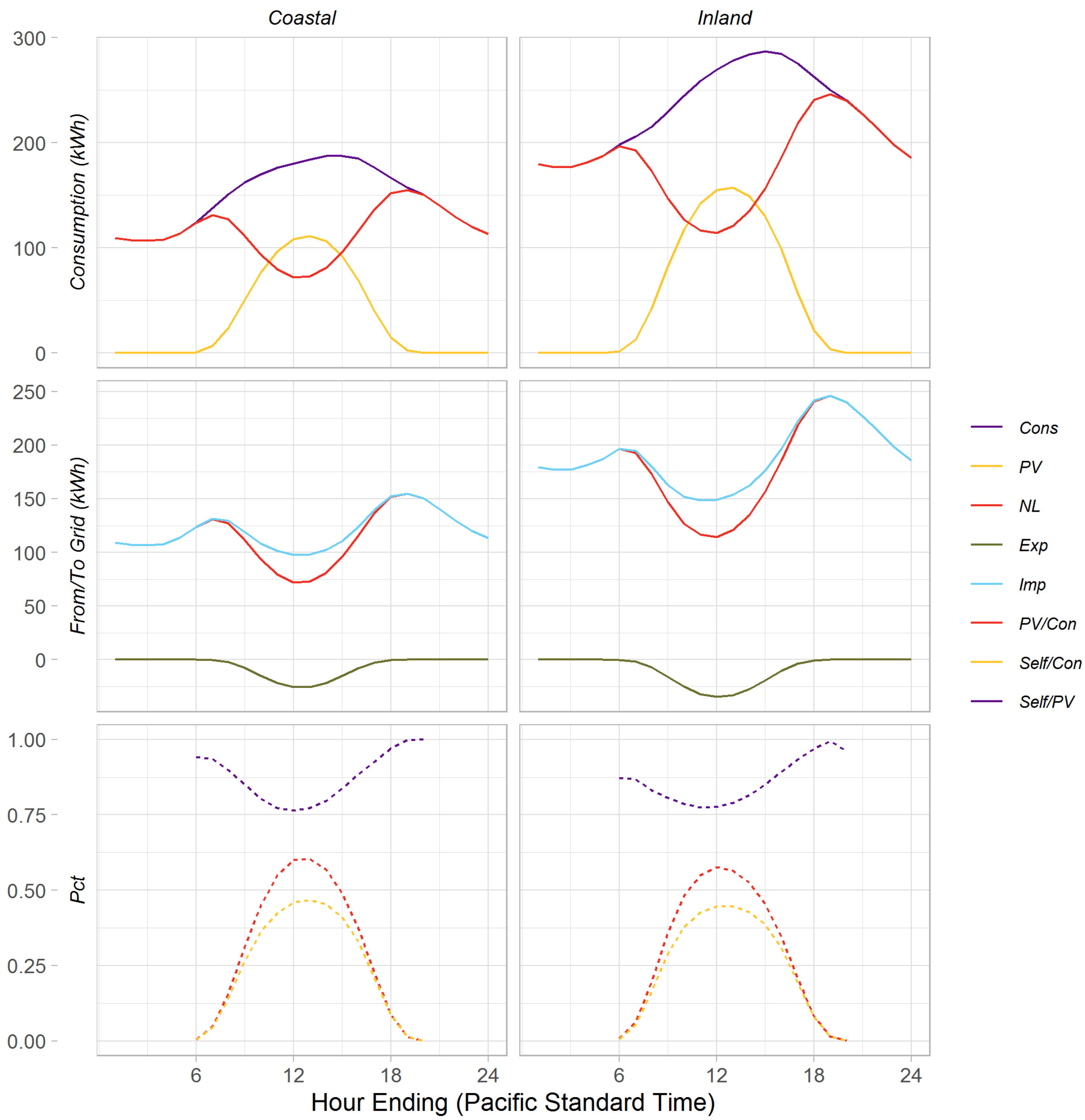
Table 6-11 presents the CSI non-residential average annual load statistics by coastal and inland customers. These data indicate that the coastal CSI non-residential sites in PG&E and SCE consume and produce less electricity than the inland sites in these service territories. In contrast, SDG&E's CSI non-residential sites have larger average consumption and production for coastal than inland.

TABLE 6-11: NON-RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS BY COASTAL AND INLAND (KWH)

	PG&E Non-Residential Coastal	PG&E Non-Residential Inland	SCE Non-Residential Coastal	SCE Non-Residential Inland	SDG&E Non-Residential Coastal	SDG&E Non-Residential Inland
Consumption	1,082,058	1,250,404	1,293,523	2,009,015	936,084	809,067
Import	870,363	974,154	1,055,238	1,659,083	672,783	574,783
Export	78,536	126,047	53,337	77,221	79,678	74,493
PV Production	290,231	402,297	291,621	427,153	343,213	308,777
% Consumption supplied by PV (PV/Cons)	27%	32%	23%	21%	37%	38%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	20%	22%	18%	17%	28%	29%
% PV used at the site (PV-Ex)/PV	73%	69%	82%	82%	77%	76%

Figure 6-11 illustrates the average SCE CSI non-residential customer’s load profile and the consumption and production share information by coastal and inland. Similar load profiles for the other utilities are available in Appendix C. The first set of panels helps to illustrate the different average load shapes for coastal and inland non-residential CSI participants in SCE’s service territory. Both the inland and the coastal production shapes show that average production is highest at approximately 1 PM. The difference in the average hourly highest production is consistent with the substantially smaller average annual PV production of 291,621 kWh for coastal versus 427,153 kWh for SCE CSI non-residential inland systems. The hour of the inland and coastal average consumption peaks also occurs at the same hour (3 PM), with 188 kWh for the average coastal peak and 287 kWh for the average inland peak. During the hour of average peak consumption, the PV production is between 49 and 45 percent of the consumption for the average coastal and inland non-residential CSI customer. During the average customer peak, their PV system is generating a substantial share of the electricity needed by the site, but the average site is also importing more than half of their electricity needs.

FIGURE 6-11: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS



6.3.7 Non-Residential Quarterly Loads

Table 6-12 presents the SDG&E CSI non-residential average annual load statistics by quarter. Similar load statistics are available for the other utilities in Appendix C. These data show substantially higher average consumption during the third quarter or during the summer (July, August, and September). The average

PV production is largest in the second and third quarters and substantially lower in the first and fourth quarters.

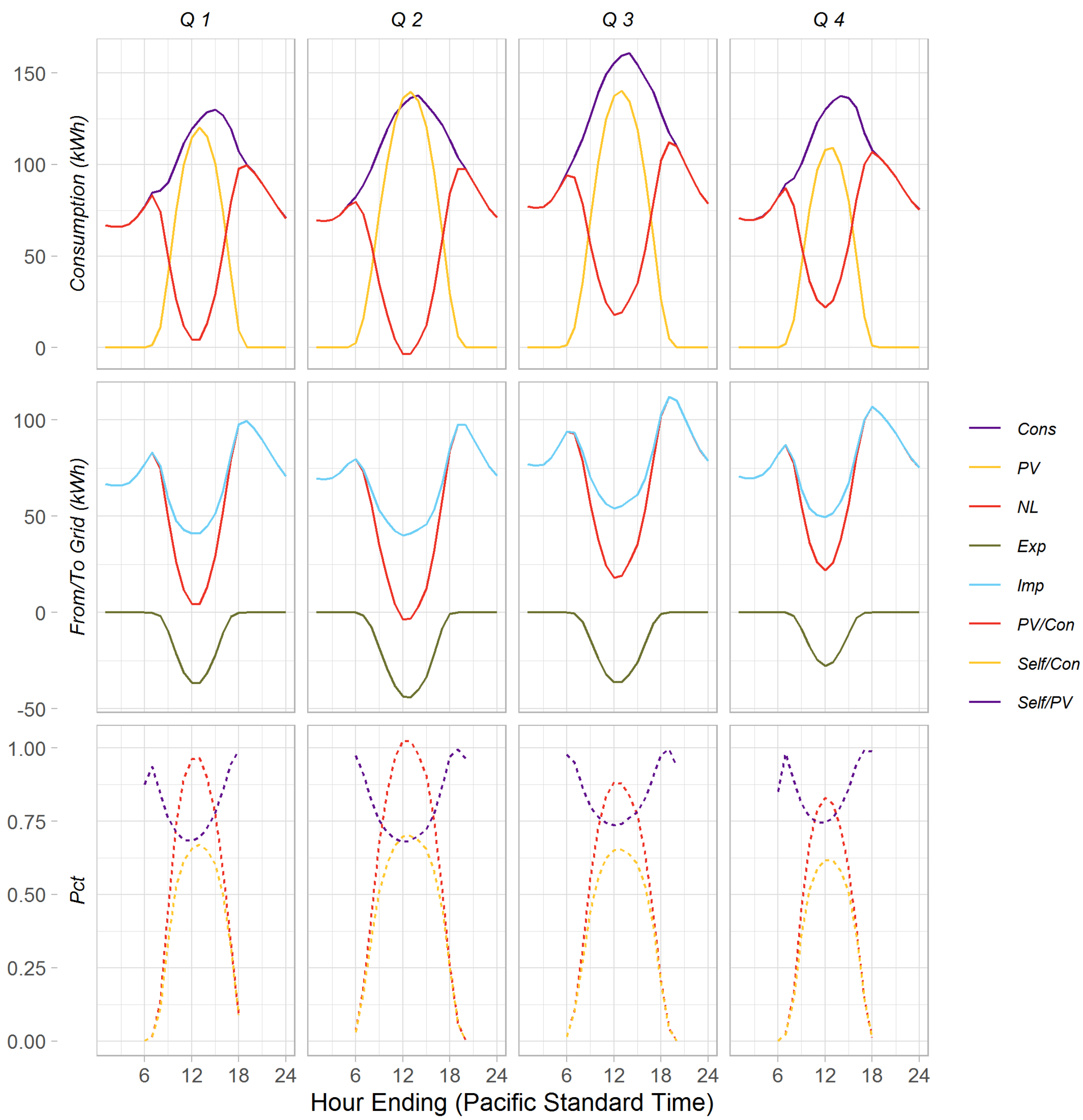
TABLE 6-12: SDG&E NON-RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SDG&E Non-Residential Q1	SDG&E Non-Residential Q2	SDG&E Non-Residential Q3	SDG&E Non-Residential Q4
Consumption	203,255	219,175	253,539	219,769
Import	149,567	146,567	176,824	168,206
Export	18,348	26,106	20,984	12,880
PV Production	72,215	98,714	97,698	64,443
% Consumption supplied by PV (PV/Cons)	36%	45%	39%	29%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	27%	33%	30%	23%
% PV used at the site (PV-Ex)/PV	75%	74%	79%	80%

Figure 6-12 illustrates the average SDG&E CSI non-residential customer's load profile and the consumption and production share information by quarter. Similar load profiles for the other utilities are available in Appendix C. The first set of panels illustrates the average load shapes by quarter. The height and shape of the load shapes presented differ by quarter. The third quarter (Q3) has the highest average hourly consumption and import of electricity from the grid, while the second quarter (Q2) has the largest average hourly export. The average net load shape illustrated in the first and second panel of illustrations (the red line) is slightly negative in the second quarter from noon to 1 PM, while the minimum of the average net load shape is substantially above zero for Q3 and Q4.

The statistics presented in Table 6-12 show that the average SDG&E non-residential CSI customer generates 36 percent of their energy consumption in Q1, 45 percent in Q2, 39 percent in Q3, and 29 percent in Q4. The average quarterly shares include many hours where consumption is positive and PV production is zero. The lower panel of Figure 6-12 shows the hourly distribution of PV production relative to consumption. The average hourly distribution of customer generation relative to consumption peaks midday at 97 percent in the first quarter, 103 percent in the second quarter, 88 percent in the third quarter, and 83 percent in the fourth quarter.

FIGURE 6-12: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR BY QUARTER



The average contemporaneous share of consumption covered by PV production is highest in Q2 at 33 percent (see Table 6-12), as high levels of production over more hours of the day are matched with moderate consumption. The hourly distribution of the contemporaneous share of consumption provided by PV generation is illustrated by the yellow dotted line in the lower panel in Figure 6-12. The hourly distribution shows that only a small share of consumption is covered by production during the morning and evening hours, while over 60 percent of consumption may be served by production near noon. The average share of PV generation used at the site is similar in Q3 and Q4, at 79 and 80 percent, respectively.

6.3.8 Non-Residential Load on IOU 200 Peak Hours

The load data analysis also provides unique insights for the impact of PV production on customer load shapes during days that include the top 200 hours of gross load for each utility. Table 6-13 provides average load statistics on the top 200 hours of each IOU system for CSI non-residential customers. To match the load data provided by the IOUs, PG&E's and SDG&E's top 200 hours of the system peak is the average across customers and hours for the years 2011 to 2017, while SCE's represent their 200 peak hours for each of the years 2015 to 2017. During the 200 peak IOU system hours, PG&E's non-residential CSI customer average electricity consumption is 182 kWh, SCE's is 328 kWh, and SDG&E's is 156 kWh. These statistics once again indicate that the average SCE CSI non-residential customer's consumption in the sample is substantially larger than those in PG&E or SDG&E's service territory. Like residential sites, it is also important to note that the average consumption of the top 200 hours is much larger than the average hourly consumption for CSI non-residential customers at 133 kWh for PG&E, 215 kWh for SCE, and 103 kWh for SDG&E.

TABLE 6-13: NON-RESIDENTIAL AVERAGE LOAD STATISTICS DURING THE IOU PEAK 200 HOURS (KWH)

	PG&E Non-Residential	SCE Non-Residential	SDG&E Non-Residential
Consumption	182	328	156
Import	120	232	90
Export	15	9	10
PV Production	77	105	76
% Consumption supplied by PV (PV/Cons)	43%	32%	49%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	34%	29%	42%
% PV used at the site (PV-Ex)/PV	80%	91%	87%

Table 6-13 also shows that the average CSI non-residential customer generates 32 to 49 percent of their total energy use during the peak hours. The lower share of consumption covered by generation for SCE is consistent with their higher average consumption during the system peak hours. The finding that the contemporaneous energy usage share is less than the PV/Consumption share illustrates that customers are exporting energy to the grid even during the system peak hours. The average energy export during peak hours is highest at PG&E and lowest at SCE.

TABLE 6-14: NON-RESIDENTIAL AVERAGE HOURLY LOAD STATISTICS DURING THE IOU PEAK 200 HOURS AND AVERAGE ANNUAL

	PG&E 200 Peak Non-Residential	PG&E Annual Non-Residential	SCE 200 Peak Non-Residential	SCE Annual Non-Residential	SDG&E 200 Peak Non-Residential	SDG&E Annual Non-Residential
Consumption Peak	200 kWh	160 kWh	347 kWh	270 kWh	181 kWh	142 kWh
Hour of Consumption Peak	2 PM	2 PM	2 PM	3 PM	2 PM	2 PM
Net Load Peak (Import – Export)	158 kWh	134 kWh	275 kWh	230 kWh	120 kWh	103 kWh
Hour of Net Load Peak	8 PM	8 PM	7 PM	7 PM	8 PM	7 PM
Largest Consumption Ramp (ΔkWh/hour)	11 kWh/hour	7 kWh/hour	23 kWh/hour	14 kWh/hour	17 kWh/hour	12 kWh/hour
Hour of Consumption Ramp	10 AM	6 AM	10 AM	10 AM	9 AM	10 AM
Largest Net Load Ramp (ΔkWh/hour)	31 kWh/hour	26 kWh/hour	23 kWh/hour	31 kWh/hour	23 kWh/hour	25 kWh/hour
Hour of Net Load Ramp	6 PM	5 PM	5 PM	5 PM	5 PM	5 PM

The three utility average load shapes across days that include the top 200 hours and the average across all hours are presented in Figure 6-13 to Figure 6-15. Reviewing the first panel in each of the three figures, SCE's average load shapes are distinct from those of the other two utilities; it is the only utility where the net load shape is always above the average PV production load shape. For days that include the top 200 hours, SCE's non-residential average consumption peak is 347 kWh at 2 PM and its PV production peaks at 1 PM with an average of 166 kWh. At the time of the SCE non-residential consumption peak, average PV generation is 41 percent of consumption and the average import of electricity from the grid to the customer is 207 kWh. The peak average import of electricity from the utility for SCE's CSI non-residential customers during days that include the top 200 hours occurs at 7 PM with 275 kWh (PV generation is providing approximately 2.5 percent of consumption during this time). Following the import peak, imports, consumption, and production decline.

Figure 6-13 illustrates how PG&E's non-residential CSI customer load shapes differ when comparing the average of days that include the top 200 hours versus the average across all days. First, the average customer peak consumption increases from slightly above 150 kWh to approximately 200 kWh. PG&E's CSI non-residential highest average import of electricity from the utility during days that include the top 200 hours peaks occurs at 8 PM with 158 kWh. The average peak import across all days for PG&E's CSI non-residential customers at 8 PM is 134 kWh.

FIGURE 6-13: PG&E NON-RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON PG&E SYSTEM PEAK DAYS

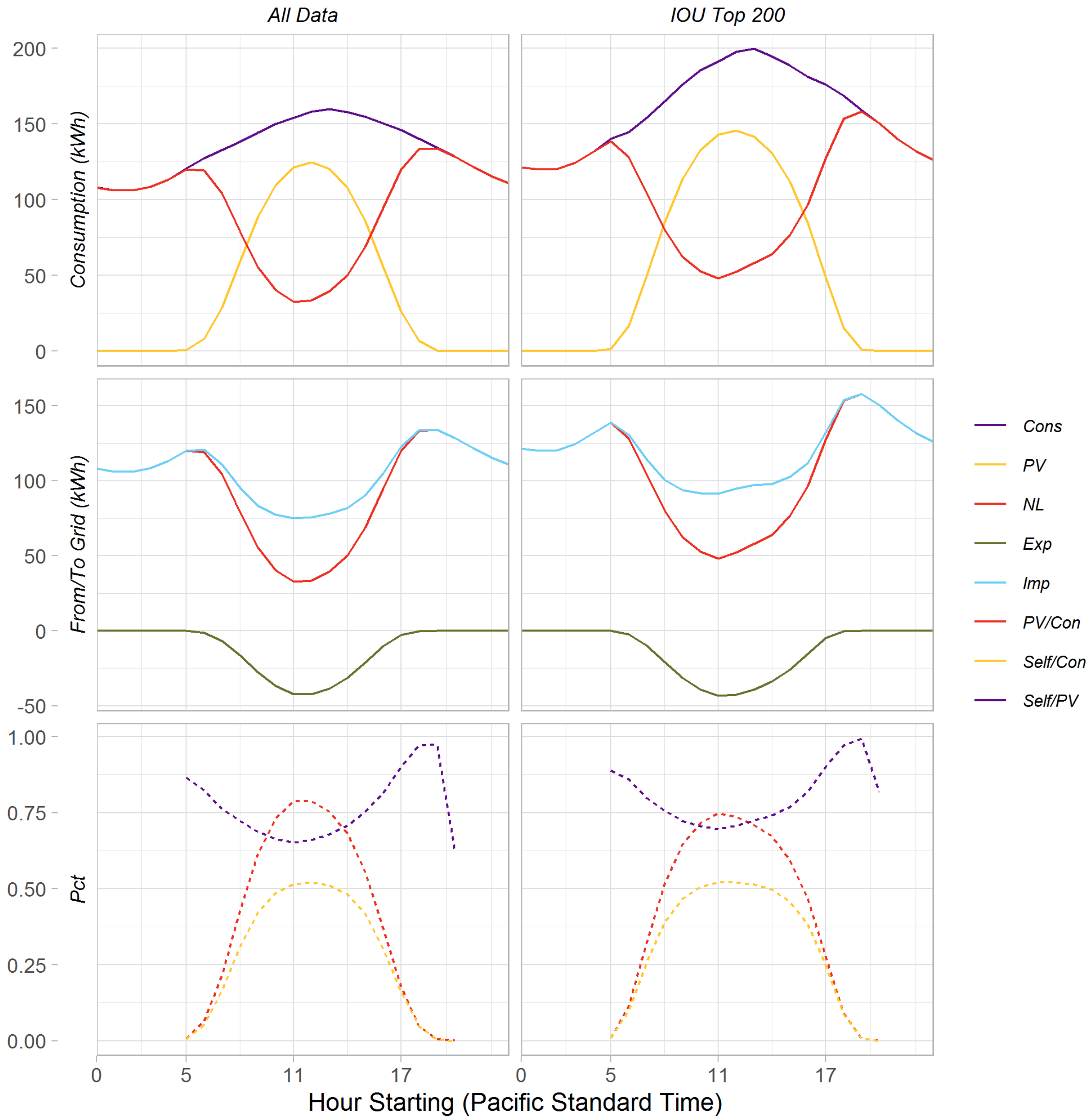
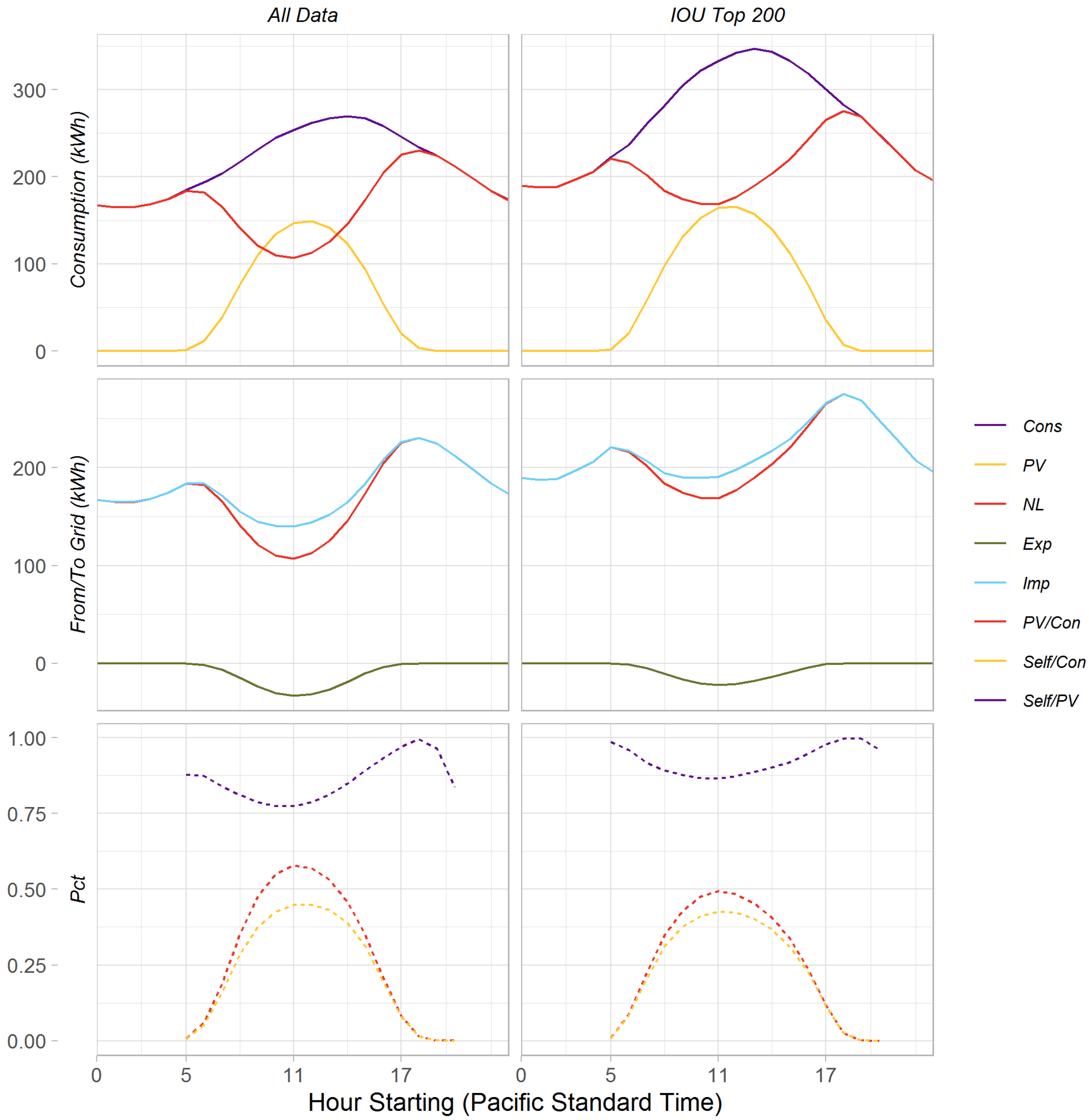
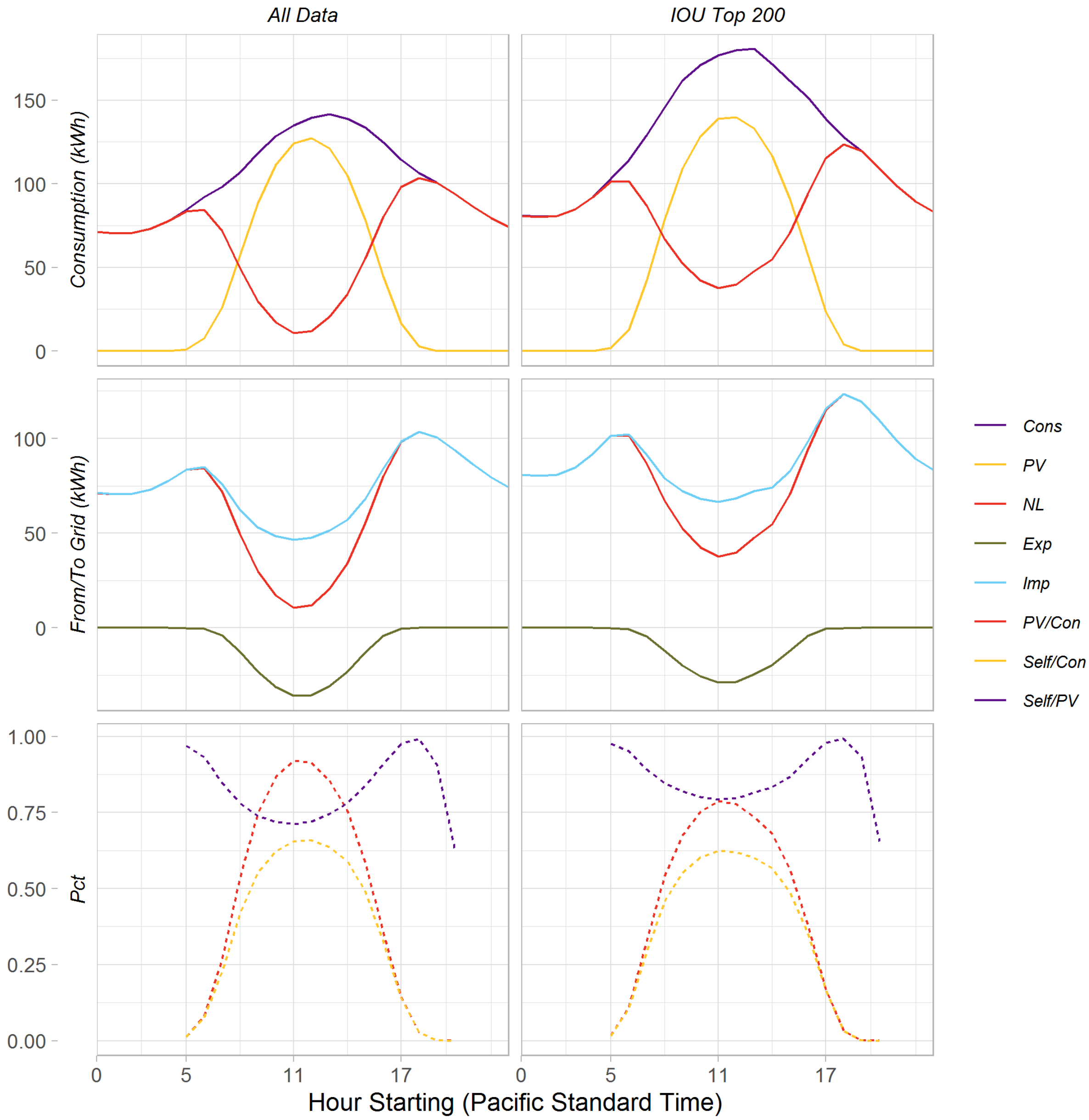


FIGURE 6-14: SCE NON-RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON SCE SYSTEM PEAK DAYS



SDG&E's non-residential CSI customer average consumption during days that include the top 200 hours peaks at 180 kWh at 2 PM and average PV production relative to consumption is 74 percent. The consumption peak has 60 percent of the average consumption being contemporaneously provided by PV ((PV – Export)/Consumption)). On days that include the top 200 hours, SDG&E's CSI non-residential customer average import peak is 124 kWh at 7 PM, when PV production averages 4 kWh.

FIGURE 6-15: SDG&E NON-RESIDENTIAL CSI CUSTOMER AVERAGE LOAD SHAPE ON SDG&E SYSTEM PEAK DAYS



Additional CSI non-residential load results and figures are available in Appendix C. These results are presented by IOU for the average day, IOU top 200-hour days, and the CAISO top 200-hour days. Results are also presented by coastal/inland, calendar year, and customer size.

7 CONSUMPTION CHANGE

The objective of the consumption change analysis is to analyze the impact of PV generation on total electricity consumption. Consumption could increase, decrease, or stay the same following the installation of a BTM PV system. Consumption could decrease, for example, if the occupants of the site are actively trying to reduce their consumption of electricity and their carbon footprint. Following the installation of PV, customers may watch their electricity production and their consumption of utility electricity and try to minimize their net consumption (net consumption = consumption – PV production). Alternatively, consumption could increase following installation if the site treats their excess energy production or export as free or reduced value energy, or if the installation of PV was timed with a remodel or expansion of the site. Consumption could stay the same following the installation of a PV system if customers make no behavioral or equipment changes associated with the installation of the PV system. Lastly, it is likely that all three outcomes occur following the installation of PV systems. The analysis in this section will determine if the changes in consumption lead to an average increase, decrease, or no statistically significant change in consumption by IOU and sector. Each kWh of generation from PV systems is often assumed to reduce the utility's need to supply electricity by 1 kWh and how sites change or do not change their consumption could significantly change that.

7.1 CONSUMPTION CHANGE SAMPLE

This section will provide a short description of the number of sites available to describe the CSI residential and non-residential average consumption change following the installation of PV. There are somewhat fewer of these sites than the sites used for other load analyses because of more stringent data requirements. To know if the customer changed their consumption following the installation of a BTM PV system, it was necessary to compare their electricity consumption prior to and following the installation of the system. For the consumption change analysis, the utilities were asked to provide at least one year of pre- and post-PV installation utility load data for sites with available metered PV production data. The analysis also required at least one year of PV production data, which was derived from the metered and/or simulated PV production data. For the consumption change analysis, the year of pre-installation utility load data is the additional set of data necessary relative to the load analysis presented above.

For this analysis, PG&E was able to provide sufficient pre- and post-installation load data for an analysis of a sample of their CSI residential and non-residential customers, while SCE was only able to provide sufficient load data for an analysis of a sample of their non-residential CSI customers. SCE was not able to provide enough pre-installation residential load data to enable a residential load change analysis. SDG&E

was not able to provide enough pre-installation residential or non-residential load data for the load change analysis.[100]

The consumption change analysis can also be completed using customer monthly billing data, and historical billing data are frequently more readily available than historical load data due to larger file sizes (96 values per day for load versus a single or handful of values per month for billing). A monthly billing analysis, however, cannot be used to describe how the installation of PV changes the customer's hourly distribution of electricity consumption. The load analysis allows for 24 hourly estimates of average increases and decreases in load following the installation of PV, whereas the billing analysis results are limited to the impact on monthly consumption across all hours of the month. The monthly billing analysis consumption change sample description and results for PG&E and SCE are presented in Appendix D. SDG&E was not able to provide billing or load data associated with the pre-installation period.

Ideally, the post-installation utility and PV production data would overlap perfectly and would begin shortly following the installation of the PV system. For many residential sites, however, the utility load and metered PV data do not overlap sufficiently to provide at least a year of the post-installation data needed to develop customer consumption. For sites where the net load and metered PV do not overlap for at least a year, PV simulations were used to augment the metered data to align the PV generation, import, and export data. The simulation and metered PV production data were compared for a small sample of sites to ensure the similarities of the metered and simulated PV production data. This comparison is presented below in the consumption change analysis. The simulation and metered PV data were found to be similar. In general, non-residential sites were found to have substantially more overlap between their utility load data and their metered PV production data, and substantial simulations were not necessary for the non-residential consumption change analysis.

The data requirements for the consumption change analysis substantially reduce the size of the sample available relative to the load and PV analysis, which relied only on post-installation load and PV generation data. Adding the pre-installation data requirement substantially reduced the size of the available sample and eliminated SCE residential sites and SDG&E residential and non-residential sites. Table 7-1 lists the size of the customer CSI frame and the number of sites with at least one year of pre-installation consumption, PV production (both simulated and metered), import, and export data by IOU, sector, and the PV system installation year.

[100] The installation of CSI systems largely occurred from 2007 to 2016, with installations peaking in 2011 to 2013 depending on utility and sector. Utilities often store their historical load data for only a limited amount of time in off-site systems that may be difficult to access for the purposes of evaluation.

TABLE 7-1: RESIDENTIAL AND NON-RESIDENTIAL CONSUMPTION CHANGE SAMPLE

Install Year	CSI PG&E Non-Res Sites	Sample PG&E Non-Res Sites	CSI PG&E Res Sites i	Sample PG&E Res Sites	CSI SCE Non-Res Sites	Sample SCE Non-Res Sites
2007*	78		2,408		41	
2008*	431		5,089		192	
2009*	378	15	7,268		141	
2010*	436	17	8,395	56	186	
2011*	513	51	10,389	719	343	
2012	703	90	12,147	262	441	6
2013*	624	104	10,557		289	50
2014*	191	56	373		439	141
2015*	121	30	11		312	113
2016*	12		7		228	56

* The blank cells in the table represent IOU and years where no sample was available for the analysis.

For many of the sites listed in Table 7-1, the PV production and post-installation utility data provided to the evaluation team begin in the quarter following the installation of the PV system, but for many of the sites there is a gap of one, two, or several quarters between the PV installation and the beginning of the PV production and post-installation utility data that were available. Table 7-2 lists the quarter lag between PV installation and the beginning of post installation data. For sites listed as Q1, the evaluation team has post-installation data in the first quarter following PV installation. For sites listed as Q8+, the post-installation data available to the evaluation team begins in, or later than, the eighth quarter, or two years following installation of the PV system.

TABLE 7-2: TIMING OF POST-PV INSTALLATION DATA BEGINNING FOR RESIDENTIAL AND NON-RESIDENTIAL SAMPLE

First Quarter with Available Data Since PV Installed	Sample PG&E Non-Res Sites	Sample PG&E Res Sites	Sample SCE Non-Res Sites
Q1	157	5	1
Q2	77	5	16
Q3	43	69	100
Q4	44	169	80
Q5	20	271	65
Q6	10	225	33
Q7	6	134	36
Q8+	19	171	36

The data in Table 7-2 illustrate that PG&E's non-residential post-installation data typically begin in the year following PV installation, SCE's non-residential data have a slightly longer lag, while the residential data have a substantially longer lag following the installation of the PV system. The quicker start to the non-residential data may be due to these systems needing to provide the Program Administrators (PAs) with their PV production data in order to receive PBI incentives, while the residential PV production data is largely provided from third party sources or from metering installed by Itron on behalf of the PAs.

7.1.1 Consumption Change Weighting

The weights for the consumption change analysis used an approach similar to that taken for the net export and load shape analysis. The sample of available sites was stratified by IOU, year of PV installation, sector, and whether the site was a large or small site.[101]

7.2 CONSUMPTION METHODOLOGY

The methodology for the consumption change analysis is presented below. The steps for this analysis included the following:

1) Create post-installation consumption data by combining the utility load data and the metered or simulated PV production data (Consumption = Import - Export + PV generation).
2) Merge National Solar Radiation Database (NSRDB) temperature and irradiance data with the pre- and post-installation consumption data.
3) Implement site-specific hourly regressions on the pre- and post-installation consumption data.
4) Develop weather normalized pre- and post-installation consumption data.
5) Implement pooled regression models on the weather-normalized pre- and post-installation consumption data to model the change in consumption associated with PV installation. Note that the regression equation is presented in the Weather-Normalized Consumption section.

[101] For the residential sample, the cut-off for large and small system strata is a PV system sized 3.6 kW or less. The non-residential PV system strata delineation between large and small is 130 kW for PG&E and 180 kW for SCE.

7.2.1 Develop Consumption Data

The post-installation consumption data were created through the combination of the load data and the PV metered or simulated data.[102] The non-residential PV generation data were added directly to the post-installation utility load data to develop customer-specific post-installation consumption.[103] The residential PV generation data, however, had substantial data quality issues, and the development of post-installation consumption within the residential sector relied largely on simulated PV data.

Hourly simulations of PV production were produced using the PV_Lib Toolbox in Python. The PV_Lib Toolbox provides a set of well-documented functions for simulating the performance of PV systems. The toolbox was developed at Sandia National Laboratories and is available in MATLAB and Python versions. The evaluation team ran PV_Lib using irradiance, windspeed, and temperature data from NSRDB developed at the National Renewable Energy Laboratory (NREL). These data are instantaneous snapshots at the top and bottom of the hour. System configuration data, including system size (AC and DC), module type, tilt, azimuth, and other configuration details, were obtained from the population dataset and were used in the simulations.

Given that the consumption change analysis is looking for small changes in consumption that occur at the time of the installation of the PV system, it is important to assess the comparability of the PV simulations to the metered PV data. The comparison used data from 50 PG&E residential PV systems that have what the evaluation team assessed to be high quality metered PV production data (minimal gaps, consistent performance). For these 50 systems, the simulated PV production data were compared to the metered data. The simulated data are an hourly average of 30-minute estimates of production, while the metered data represent hourly reads of PV production.

Figure 7-1 illustrates the average PV production shape for the 50 PG&E residential customer systems, metered and simulated. For these 50 customer systems, the average PV production from 6 AM to 6 PM is 29.08 kWh when using the metered data and 30.27 kWh when using the simulated data—a difference of 4 percent. The hours from 6 AM to noon represent times when the average simulated data are slightly higher than the metered data; from noon to 5 PM, the simulated and metered data are nearly identical. From 5 to 6 PM, the metered data are slightly higher than the simulated PV production data. Given the

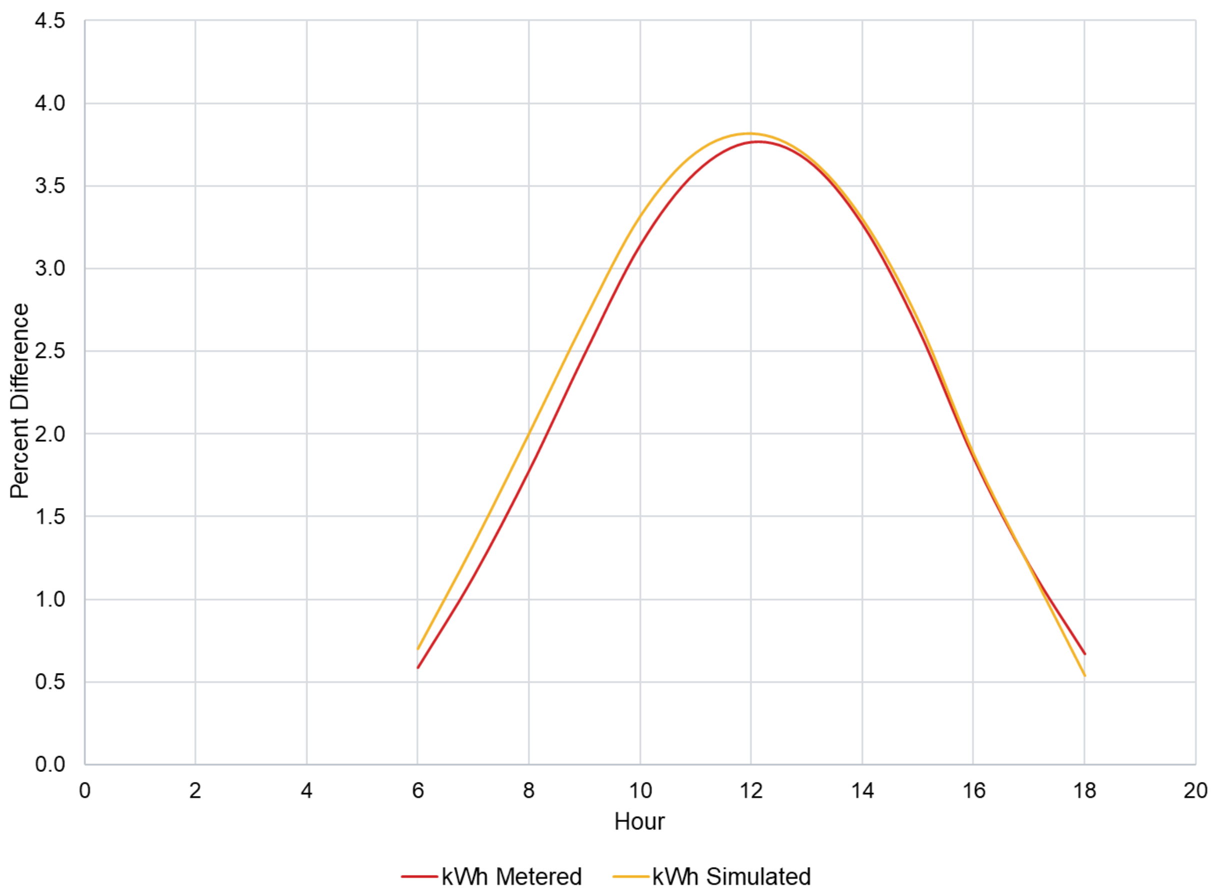
---

102 For the residential sample, only 50 sites had metered data that were of sufficient quality and that overlapped with the post-installation net load data. For the other 998 sites, metered data exist, but the quality of the metered data or the timing of the metered data necessitated the development of simulated PV production data.

103 The non-residential metered PV production data may have been of higher quality than the residential data because the non-residential data formed the basis for the Performance-Based Incentives.

similarities in the metered and simulated data, the evaluation team used the simulated data where necessary within the residential load shift and consumption change analysis.

FIGURE 7-1: PV PRODUCTION METERED VERSUS SIMULATED



7.2.2 Weather-Normalized Consumption

Customer consumption of electricity pre-and post-installation may change for a variety of reasons. Weather-normalizing consumption helps to control for changes in consumption associated with differences in weather between the pre- and post-installation time periods. To control for the impacts of weather on customer consumption, regression models were estimated separately for the pre- and post-installation period. A model was estimated for each customer, for each of the 24 hours, and for the weekday and weekend periods. This resulted in 96 models for each customer: 48 in the pre-installation and 48 in the post-installation period. The regression model functional form is described below:

$$kWh_{it} = \beta_{0i} + \beta_{1i}CDH_{it} + \beta_{2i}HDH_{it} + \sum_{y=1}^{Y} \beta_{3yi}\, Year_{iy} + \sum_{m=1}^{12} \beta_{4mi}Month_{im} + \varepsilon_{it}$$

The following describes the model variables and coefficients:

kWh_{it}	Is customer i kWh during hour h on day t
CDH_{it}	Is the cooling degree hours for customer i during hour h on day t.
HDH_{it}	Is the heating degree hours for customer i during hour h on day t
$Year_{iy}$	Is a binary variable equal to 1 for customer i during calendar year y, zero otherwise
$Month_{im}$	Is a binary variable equal to 1 for customer i during calendar month m, zero otherwise
B_{0i}	Customer i's baseline hour h electricity consumption
B_{1i}	The impact of a unit change in CDH on customer i's hour h electricity consumption
B_{2i}	The impact of a unit change in HDH on customer i's hour h electricity consumption
B_{3yi}	The impact on customer i's hour h electricity consumption during calendar year y
B_{4mi}	The impact on customer I's hour h electricity consumption during month m

This model is very similar to those used for normalized meter energy consumption models. The addition of the month and year independent variables allows the customer's electricity consumption to differ by year and month following weather normalization. Because a given customer may have multiple years of post-installation electricity consumption data, the addition of these variables allows weather-normalized post-installation consumption to change over time.

The basis for the CDH and HDH was determined per site to maximize the model R^2 for each customer, hour, weekday/weekend, and pre- and post-installation period. Following the estimation of the pre- and post-installation models, each site's hourly electricity was weather-normalized to ensure that differences in pre- and post-installation consumption were not due to differences in weather between the two periods. Weather normalization used weather data from NSRDB.[104] The NSRDB irradiance data were also used in the simulations of PV production, and these data have an application programming interface (API) tool that easily allowed downloading large sets of weather data for 26,000 locations across California.[105] The evaluation team used these data and was able to spatially map the data to the overall population and

104 The NSRDB is a collection of various hourly and sub-hourly meteorological data, including solar radiation, for the United States and other international locations. https://nsrdb.nrel.gov/

105 Weather data were downloaded from NSRDB through their API service. https://developer.nrel.gov/docs/solar/nsrdb/

the metered sample based on latitude and longitude coordinates. This allowed the evaluation team to determine location-specific irradiance and weather data for each site. One drawback of locationally specific weather data, however, is that each site can have its own unique set of the data, leading to large weather data files. Given the size of the weather data files and the time required to extract a locationally specific file for each customer in the analysis, weather data were only downloaded for the analysis period. Therefore, the weather normalization did not have 10 years of pre-installation weather data to create an hourly dataset for a year, or 24 x 365 = 8760, estimate of normal weather for each customer. To control for changes in weather pre- and post-installation that may impact electricity consumption, the evaluation team developed an 8760 load dataset of site-specific "normal" weather using the analysis period's weather, or the years of data in the pre- and post-installation period. This approach may not provide estimates of customer electricity consumption under traditional estimates of normal weather, but it will apply the same weather data to a customer's pre- and post-installation weather "standardized" electricity consumption. Going forward, we will continue to describe this process as weather normalization.

The weather-normalized pre- and post-installation consumption are used to determine the change in consumption following the installation of PV. The impact of PV on consumption could be measured by differencing the site-specific weather normalized, pre- and post-installation consumption estimates and calculating average hourly changes in consumption or through the use of a regression model.[106] The evaluation team chose to use a regression approach to estimate the change in consumption. This approach enabled the development of consumption change estimates for the sample of post-installation data and for one, two, and three years post-installation.

Using the weather-normalized pre- and post-installation consumption, a regression model was used to estimate changes in residential consumption for a sample of PG&E customers. The following functional form was used for a pooled regression analysis:

$$
\begin{aligned}
Log(kWh_{it}) = \beta_0 + \beta_1 Post_{it} + \beta_2 PostCDH_{it} + \beta_3 PostHDH_{it} + \sum_{m=1}^{12} \beta_{4m} Month_m \\
+ \beta_5 PostYear1_i + \beta_6 PostYear2_i + \beta_7 PostYear3_i + \beta_8 PostYear4_i \\
+ \beta_9 PostYear5_i + \varepsilon_{it}
\end{aligned}
$$

Where the independent variables include:

Postit A binary variable equal to one during customer i's post period in time t, zero otherwise

106 The results from the regression models were compared to the results found from differencing the weather-normalized estimates of pre- and post-installation consumption to ensure that the reported findings are consistent.

PostCDHit	The normalized CDH during the post period for customer i in time t
Post HDHit	The normalized HDH during the post period for customer t in time t
Monthm	A binary variable equal to one during month m
PostYear1i	A binary equal to one in the first year after customer I's PV installation, zero otherwise
PostYear2i	A binary equal to one in the second year after customer I's PV installation, zero otherwise
PostYear3i	A binary equal to one in the third year after customer I's PV installation, zero otherwise
PostYear4i	A binary equal to one in the fourth year after customer I's PV installation, zero otherwise
PostYear5i	A binary equal to one in the fifth year after customer I's PV installation, zero otherwise[107]

The analysis was estimated for weekdays and weekends for each hour of the day, so 48 models were estimated for each domain of interest. To estimate the yearly change in consumption within the residential sector from the installation of PV, 48 models were estimated. Within the non-residential sector, the distribution of consumption was very skewed towards larger consumers, so the analysis was separated into small and large customers. Therefore, the non-residential analysis includes 96 models: 48 for small and 48 for large customers. Models were also estimated to look at the average quarterly change in consumption following the installation of PV. These models were intended to determine if the average change in consumption was dominated by a specific quarter. To calculate the average hourly change in consumption following the installation of PV, the analysis used the estimated coefficients from the above model for the post period multiplied by the appropriate weather-normalized CDH, HDH, and post period yearly binary.

7.2.3 PG&E Residential Consumption Change Findings

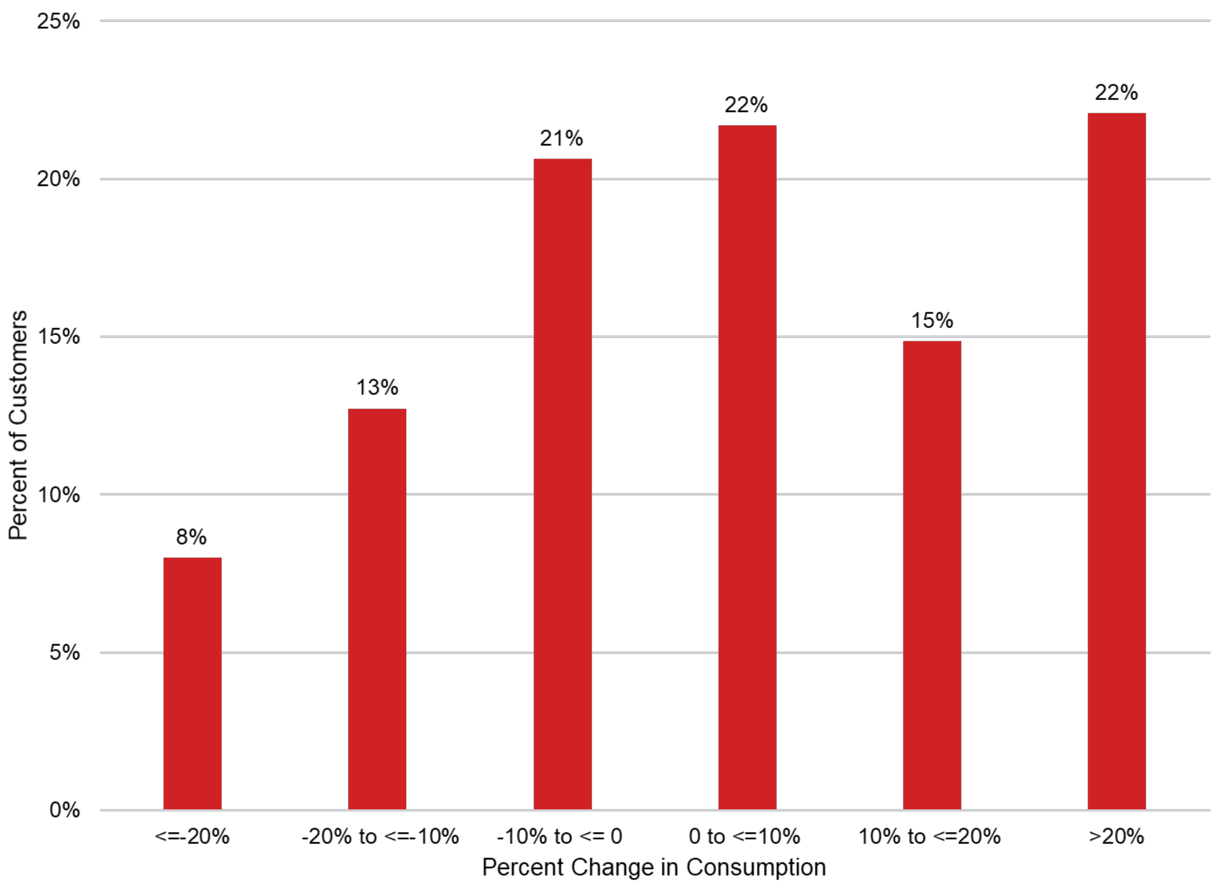
Prior to using the model to estimate changes in consumption, the pre-installation and first-year of available post-installation weather-normalized consumption data were differenced to illustrate the distribution of the sample's change in consumption.[108] Many customers in the residential sample decreased consumption, many had very little change in consumption, and some showed an increase in consumption following PV installation. Figure 7-2 illustrates the distribution of consumption change across the PG&E residential sample. Twenty-one percent (8+13) of the customers decreased their consumption following installation by 10 percent or more, 43 percent (21+22) showed less than 10 percent change in consumption (either increasing or decreasing), while 37 percent (15+22) increased their

[107] Given that very few customers have data into the sixth year following PV installation, the model was only estimated on data up to the end of the fifth year.

[108] For many residential customers, the first year of post-installation data available starts late during the first post-installation year or later.

consumption by 10 percent or more. The data presented in Figure 7-2 illustrate that over 20 percent of the residential sample increased their consumption by 20 percent or more following the installation of PV. These customers may have gone through life events such as an addition to their family or retirement with more time spent at home, they may have remodeled and added to their home, or decided their PV system negated their choice to increase their air conditioning use. Given the data available for this study, it is not possible to determine the reason for the significant increase in electricity consumption by 22 percent of the sample following the installation of PV systems. As California moves toward increased electrification of buildings and transportation, however, the simultaneous or closely timed installation of PV systems with these building and transportation changes may lead to an increase in the share of homes with significant increases in electricity consumption following the installation of PV.[109]

FIGURE 7-2: PG&E RESIDENTIAL WEATHER-NORMALIZED CONSUMPTION CHANGE DISTRIBUTION



109 It is possible that some of the customers with significant increases in consumption had purchased electric vehicles or electrified their homes though other explanations may be more likely during the time period covered by this study.

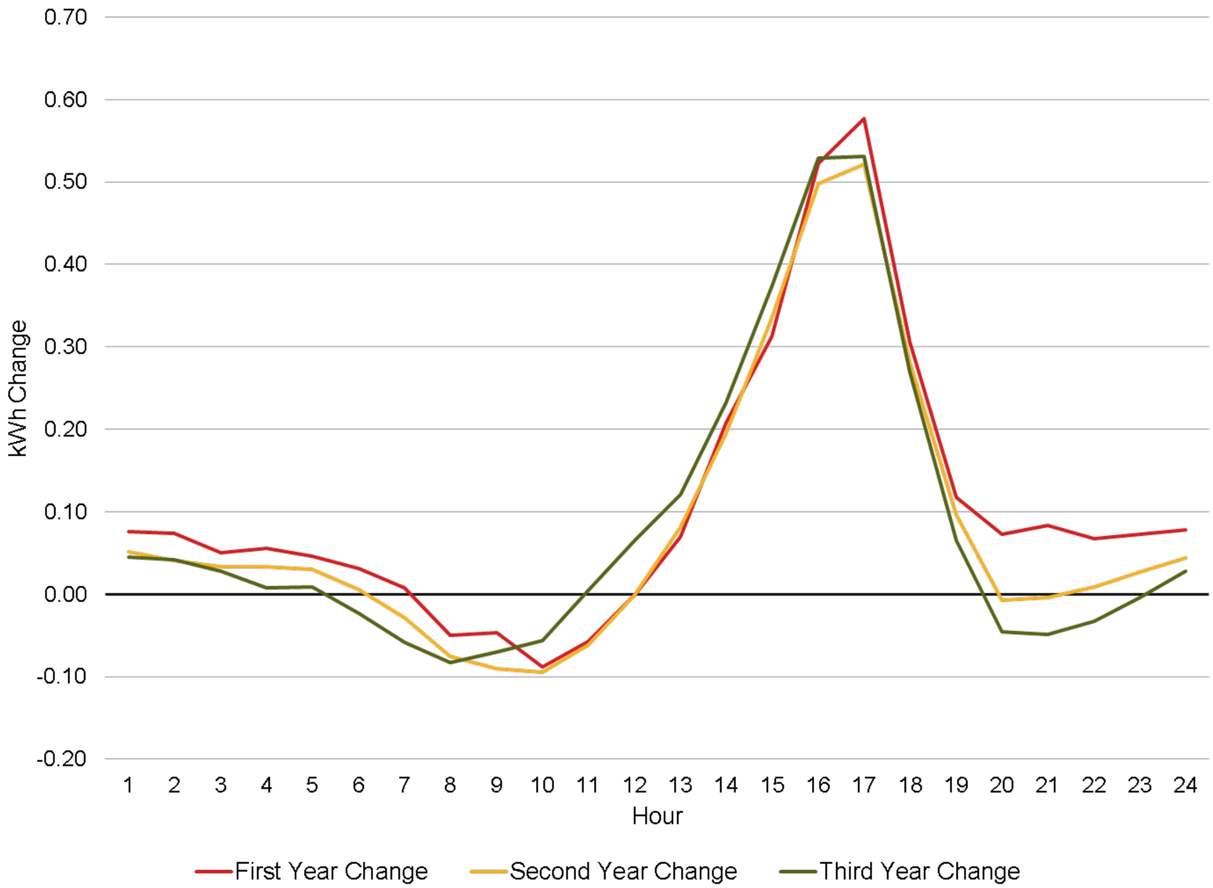
The regression model was used to estimate the average yearly change in residential consumption for the first, second, and third year following PV installation (see Table 7-3). Because the model was estimated at the hourly level, the evaluation team also developed estimates of time-of-day changes in consumption. Figure 7-3 presents the average hourly change in consumption during the first, second, and third year following PV installation. During the first year following PV installation, the estimated average increase in monthly consumption of electricity was 79 kWh or a 7.2 percent increase in average monthly consumption (see Table 7-3 for second and third year post-installation statistics). The median increase in consumption was 64 kWh, smaller than the mean, indicating that the change in consumption is slightly skewed toward larger sized increases (which is consistent with Figure 7-2). Figure 7-3 shows that the increase in consumption was very time-of-day dependent. There is a slight increase in consumption during the early morning hours followed by a slight decrease in consumption from approximately 7 AM to noon.[110] During the afternoon and evening hours, the average residential PG&E CSI customer has a substantial increase in consumption, with the 3 PM and 4 PM hours experiencing an increase of approximately 30 percent. The timing of the increase in consumption is slightly prior to the steepest ramp in residential net load, which occurs at 5 PM (see Section 6 of this report). The dramatic mid-afternoon increase in consumption following the installation of PV is potentially reducing the grid benefits of PV and contributing to the late-afternoon net load ramp.

TABLE 7-3: PG&E RESIDENTIAL AVERAGE MONTHLY CHANGE IN CONSUMPTION (KWH)

	Average Monthly Change	Average Monthly Percent Change	Median Monthly Change	Median Monthly Percent Change
First Year Post	79	7.2%	64	7.1%
Second Year Post	58	5.4%	47	5.2%
Third Year Post	59	5.4%	47	5.2%

[110] Note that the simulated PV production exceeded the metered PV production during the 6 AM to noon time period. If the simulated PV production is overstating actual PV production during this time period, the post-installation fall in consumption would be slightly larger during this time period. The similarity in the simulated and metered PV production during the afternoon and early evening time period implies that that the estimated change in afternoon and evening consumption is unlikely to be impacted by the use of simulated or metered data.

FIGURE 7-3: PG&E RESIDENTIAL AVERAGE CHANGE IN CONSUMPTION FOLLOWING PV SYSTEM INSTALLATION



The analysis also estimated the average quarterly change in consumption following the installation of CSI incentivized residential PV systems in PG&E's territory. Figure 1-7 presents the hourly average consumption changes by quarter and Table 7-4 lists quarterly change statistics. For this analysis, quarters are by calendar and not age of vintage of the system. The first quarter is always the months of January, February, and March following the installation of the PV system, not the first quarter of time following the installation of the system. The other three quarters follow this convention. All four graphs have been developed on a similar axis to help highlight the larger kWh impacts in the third or summer quarter (July, August, and September).

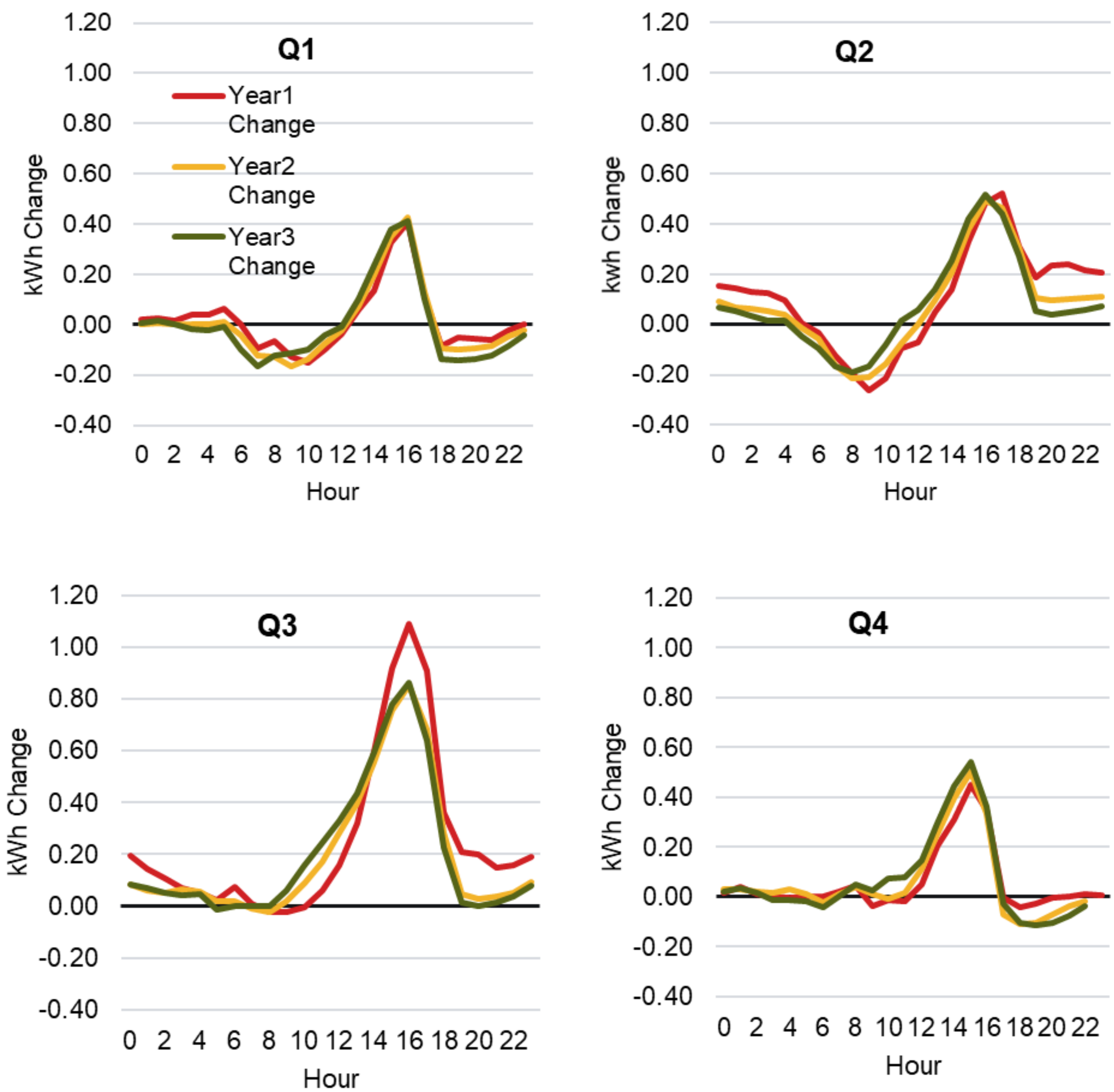
During the first year post-PV installation, the average monthly third-quarter change in consumption was a 181 kWh increase in consumption per customer, while the second- and third-year average increase in third-quarter consumption was approximately 144 kWh per month. The large increase in third-quarter consumption following the installation of PV systems may indicate that customers are increasing their use of air conditioning during the summer months.

The first, second, and fourth quarters of the year post-installation have times of the day with average increases and decreases in consumption. The mid-afternoon and early evening hours are associated with increases in consumption, while mid-morning and late evening hours have decreases. It is possible that residential customers are both increasing their usage of electricity and shifting load from hours when their net load is positive (they are purchasing utility electricity) to hours when their net load is negative (they are exporting electricity to the utility). Some customers believe that their export of electricity is under-valued or that export is "free electricity" for them to use. To determine why customers are increasing their consumption in the middle of the day and reducing their consumption during the shoulder hours would require additional data not readily available to the evaluation team.

TABLE 7-4: PG&E RESIDENTIAL QUARTERLY AVERAGE MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	12	79	181	42
Average Monthly Percent Change: Year 1	1%	8%	14%	4%
Average Monthly Change: Year 2	2	57	143	42
Average Monthly Percent Change: Year 2	0.2%	5.6%	11%	4%
Average Monthly Change: Year 3	-3	55	145	47
Average Monthly Percent Change: Year 3	-0.3%	5.5%	11%	4.5%

FIGURE 7-4: PG&E RESIDENTIAL HOURLY AVERAGE CHANGE IN CONSUMPTION BY QUARTER FOLLOWING PV INSTALLATION



7.2.4 PG&E Non-Residential Consumption Change Findings

The consumption of non-residential customers has a substantially larger range than for residential customers since non-residential customers are relatively more heterogeneous in the amount of electricity they consume. To develop a better understanding of the consumption change following the installation of a PV system, the non-residential analysis was divided into a sample of customers with small consumption and a sample with larger consumption. Customer pre-installation consumption was used to allocate customers into small and large. Customers with less than 41,000 kWh average monthly pre-installation consumption were classified as small, while those with more were classified as large.

Similar to the residential analysis, the distribution of the change in weather-normalized pre-installation and first year of available data post-installation consumption was graphed to develop a high-level understanding of how consumption changed following PV installation. Figure 7-5 illustrates the percentage change in consumption for the sample of all non-residential customers, for smaller customers, and for larger. This graph shows that the non-residential consumption change distribution has a higher share of customers with little change in consumption, or within the 10 percent reduction to 10 percent increase than the residential distribution (see Figure 7-2). For non-residential customers, 63 percent showed little change in consumption compared to 43 percent for the residential sample. Within PG&E's non-residential sample, a slightly smaller share of customers reduced their consumption than increased.

FIGURE 7-5: PG&E NON-RESIDENTIAL WEATHER-NORMALIZED CONSUMPTION CHANGE DISTRIBUTION

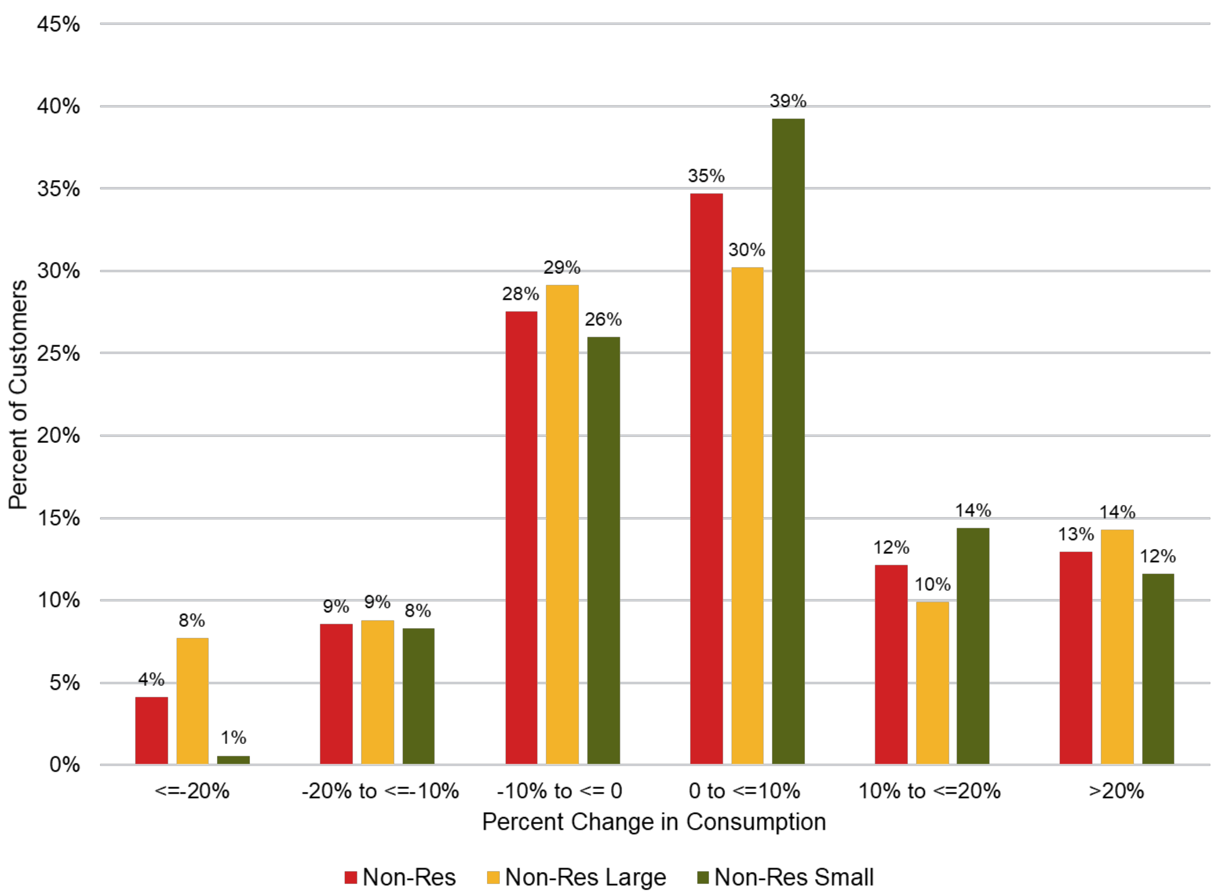


Figure 7-6 and Figure 7-7 present PG&E's small and large non-residential customer average hourly change in consumption during the first, second, and third year following PV installation, while Table 7-5 and Table

7-6 list the first, second, and third year average and median change in monthly consumption following installation.[111] The installation of PV systems is associated with a change in small non-residential average monthly consumption of 1,600 to 2,100 kWh and median monthly consumption of 1,200 to 1,700 kWh. For large non-residential customers (see Table 7-6), the average first, second, or third year change in monthly consumption gradually increased post-PV installation. The increasing post-installation consumption is also observable in Figure 7-7, where the hourly illustration of consumption change during the first-year post-installation is observably lower than the second and third years.

TABLE 7-5: PG&E SMALL NON-RESIDENTIAL ESTIMATED MONTHLY CHANGE IN CONSUMPTION (KWH)

	Average Monthly Change	Average Monthly Percent Change	Median Monthly Change	Median Monthly Percent Change
First Year Post	1,626	7.4%	1,277	7.1%
Second Year Post	1,876	8.6%	1,524	8.5%
Third Year Post	2,168	9.9%	1,787	9.9%

TABLE 7-6: PG&E LARGE NON-RESIDENTIAL ESTIMATED MONTHLY CHANGE IN CONSUMPTION (KWH)

	Average Monthly Change	Average Monthly Percent Change	Median Monthly Change	Median Monthly Percent Change
First Year Post	-866	-0.4%	-669	-0.6%
Second Year Post	6,535	3.4%	3,335	3.1%
Third Year Post	9,298	4,8%	4,827	4.5%

[111] Illustrations of the hourly median change in consumption take the same general shape as the average change. Both set of numbers are derived from the same regression model. The average versus median consumption change numbers are derived from the average versus median consumption inputs.

FIGURE 7-6: PG&E SMALL NON-RESIDENTIAL AVERAGE HOUR CONSUMPTION CHANGES FOLLOWING PV INSTALLATION

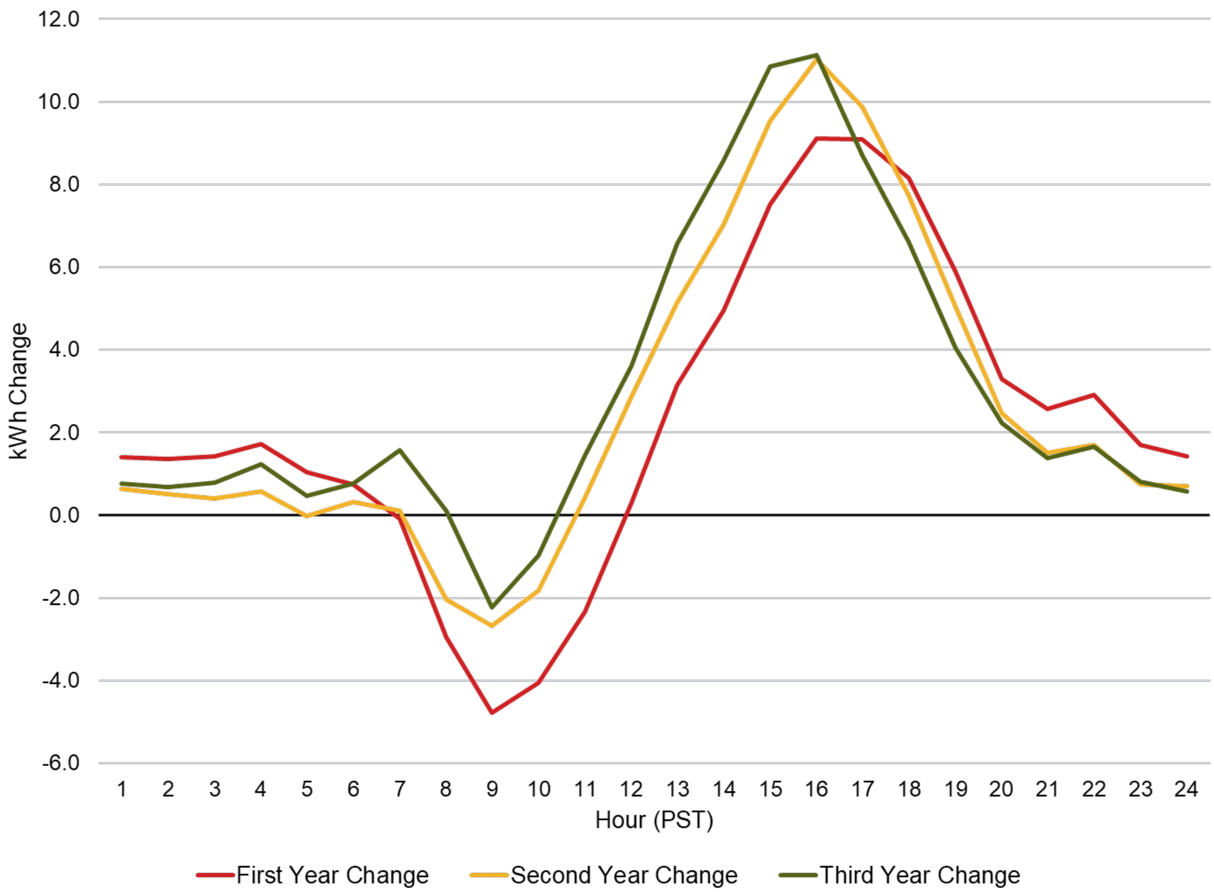


FIGURE 7-7: PG&E LARGE NON-RESIDENTIAL AVERAGE HOURLY CONSUMPTION CHANGES FOLLOWING PV INSTALLATION

The analysis also estimated the average quarterly change in consumption following the installation of CSI incentivized non-residential PV systems in PG&E's territory. Table 7-7 lists quarterly change statistics. The graphs of quarterly change (available in Appendix D) are similar to the average yearly and the residential quarterly change illustrations. For this analysis, like for residential, the first quarter is the months of January, February, and March following the installation of the PV system, not the first quarter of time following the installation of the system. The other three quarters follow this convention. All four graphs have been developed on a similar axis to help highlight the larger kWh impacts in the third or summer quarter (July, August, and September).

For small non-residential customers, the third quarter or summer increase in consumption is largest, averaging approximately 3,500 kWh per month. The consistency of the small customer change differs substantially from the large customer growth in their third quarter change in consumption. During the first year following PV installation, the average large customer increases third-quarter monthly consumption by less than 1,000 kWh per month. The second and third year post-installation, however, saw average third-quarter monthly increases of 13,000 kWh and 18,000 kWh, respectively. Large customers appear to be dramatically increasing their consumption over time. During this analysis, this increase appears to be associated with the installation of PV. It is unclear, however, if the general population of large commercial customers is also increasing their consumption over this time period. To determine if the observed increase is due to the installation of PV, a matched sample of non-PV customers would be necessary. These data were not readily available to the evaluation team and that analysis was outside the scope of this evaluation.

TABLE 7-7: PG&E SMALL NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	707	1,121	3,045	17
Average Monthly Percent Change: Year 1	3.6%	5.6%	14.0%	0.1%
Average Monthly Change: Year 2	986	1,588	3,693	1,595
Average Monthly Percent Change: Year 2	5.0%	7.9%	17.0%	6.2%
Average Monthly Change: Year 3	888	1,308	3,539	1,616
Average Monthly Percent Change: Year 3	4.5%	6.5%	16.2%	6.3%

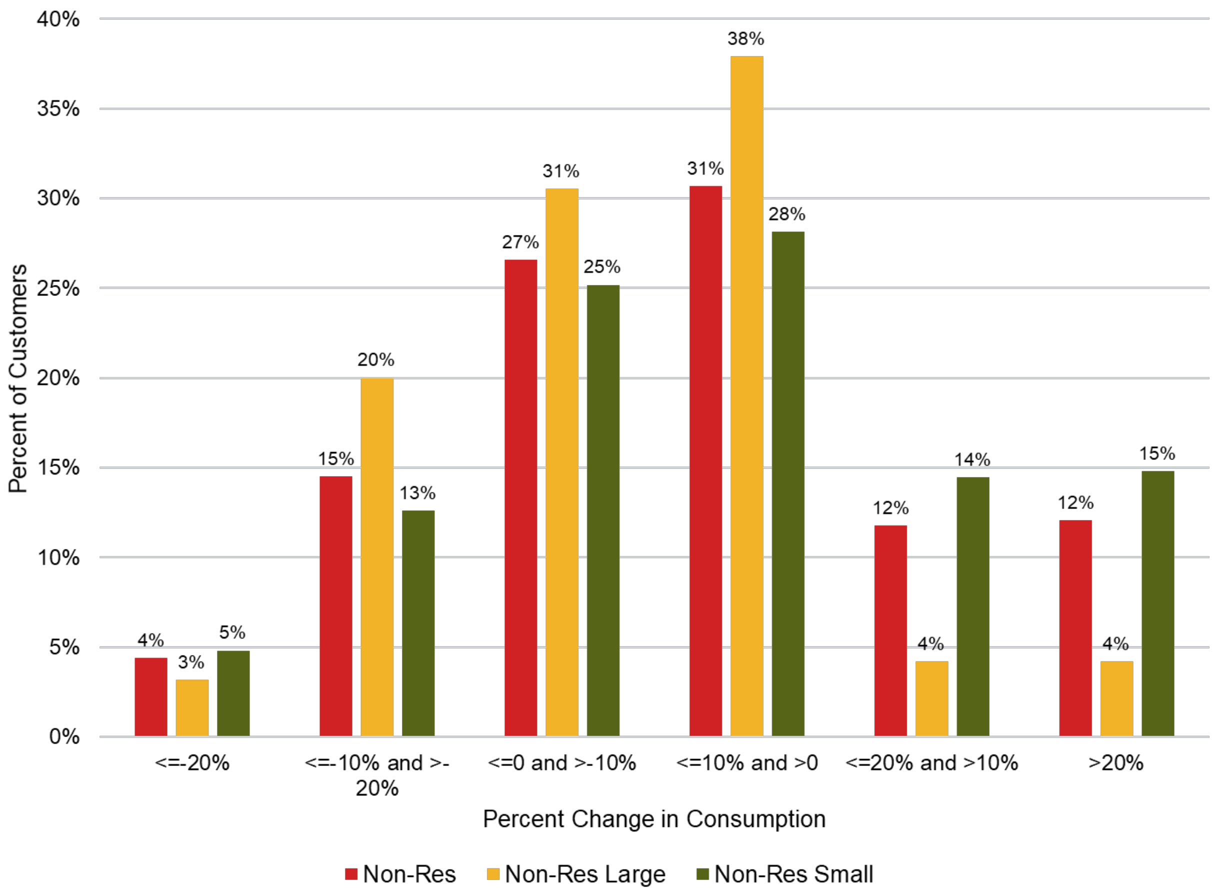
TABLE 7-8: PG&E LARGE NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	-690	-1,662	810	-12,413
Average Monthly Percent Change: Year 1	-0.4%	-0.9%	0.4%	-6.4%
Average Monthly Change: Year 2	2,018	4,912	13,171	4,454
Average Monthly Percent Change: Year 2	1.1%	2.7%	6.1%	2.3%
Average Monthly Change: Year 3	1,857	7,211	18,127	8,418
Average Monthly Percent Change: Year 3	1.0%	3.9%	8.4%	4.4%

7.2.5 SCE Non-Residential Consumption Change Findings

The SCE non-residential consumption change analysis is similar to the PG&E non-residential analysis. The customers were divided into small and larger customer groups. The distribution of weather-normalized change in pre- and first year of available consumption data post-installation was graphed to develop a high-level understanding of how consumption changed following PV installation. Figure 7-8 illustrates the percent change in consumption for the sample of all non-residential customers, for smaller customers, and for larger. This graph shows that the non-residential customers' distribution of consumption change is highly concentrated around the -10 percent to 10 percent range. For SCE non-residential customers, 58 percent showed little change in consumption following the installation of their PV system. The large non-residential sample displays a higher share of customers either reducing or maintaining their consumption relative to the small non-residential sample.

FIGURE 7-8: SCE NON-RESIDENTIAL WEATHER-NORMALIZED CONSUMPTION CHANGE DISTRIBUTION



The following graphs and tables look at time-dependent changes in consumption using the regression impact model. Given the only slight difference in pre- and first available post-year consumption illustrated in Figure 7-8, the regression model impact analysis will provide additional information on how consumption changes with time, since installation extends beyond the first year of post-installation data.

The regression model produces estimates for both changes in total consumption and shifts in the timing of consumption.[112]

The estimated first-, second-, and third-year impacts from the regression model are listed in Table 7-5 and Table 7-6, while Figure 7-9 and Figure 7-10 present SCE's small and large non-residential customer average hourly change in consumption during the first, second, and third year following PV installation.[113] For small non-residential customers in SCE's territory, the installation of PV systems is associated with a 200 to 1,000 kWh average increase in monthly consumption, while PV installation for larger customers is associated with a slight decline in average monthly consumption. The slight increase in average monthly consumption for smaller customers is consistent with 29 percent of these customers showing an increase in their post-installation consumption exceeding 10 percent of pre-installation consumption (see Figure 7-8 above), while only 18 percent showed a similar-sized decline in consumption. The findings in Table 7-6 are also supportive of those illustrated in Figure 7-8, where more large customers have a first-year decline in consumption following PV installation.

TABLE 7-9: SMALL SCE NON-RESIDENTIAL ESTIMATED MONTHLY CHANGE IN CONSUMPTION

	Average Monthly Change	Average Monthly Percent Change	Median Monthly Change	Median Monthly Percent Change
First Year Post	1,093	4.4%	854	4.4%
Second Year Post	1,021	4.1%	793	4.1%
Third Year Post	209	0.8%	152	0.8%
Sample Size 270				

TABLE 7-10: LARGE SCE NON-RESIDENTIAL ESTIMATED MONTHLY CHANGE IN CONSUMPTION

	Average Monthly Change	Average Monthly Percent Change	Median Monthly Change	Median Monthly Percent Change
First Year Post	-5,062	-1.8%	-2,612	-1.6%
Second Year Post	-3,763	-1.3%	-1,678	-1.0%
Third Year Post	-1,293	-0.4%	-281	-0.2%
Sample Size 95				

112 For SCE's load change analysis, 95 larger non-residential and 270 small non-residential customers have the necessary pre- and post-installation data. Given the small samples sizes, care must be taken when drawing conclusions.

113 Average and median results are presented in the tables, while the graphs only include average findings. Illustrations of the hourly median change in consumption take the same general shape as the average change. Both set of numbers are derived from the same regression model. The average versus median consumption change numbers are derived from the average versus median consumption inputs.

Figure 7-9 and Figure 7-10 illustrate the average hourly change in consumption following PV installation. As seen for PG&E's residential and non-residential customers, PV installation for SCE's non-residential customers is followed by a slight reduction in morning electricity consumption and an increase in afternoon consumption.

FIGURE 7-9: SMALL SCE NON-RESIDENTIAL CONSUMPTION CHANGES FOLLOWING PV INSTALLATION

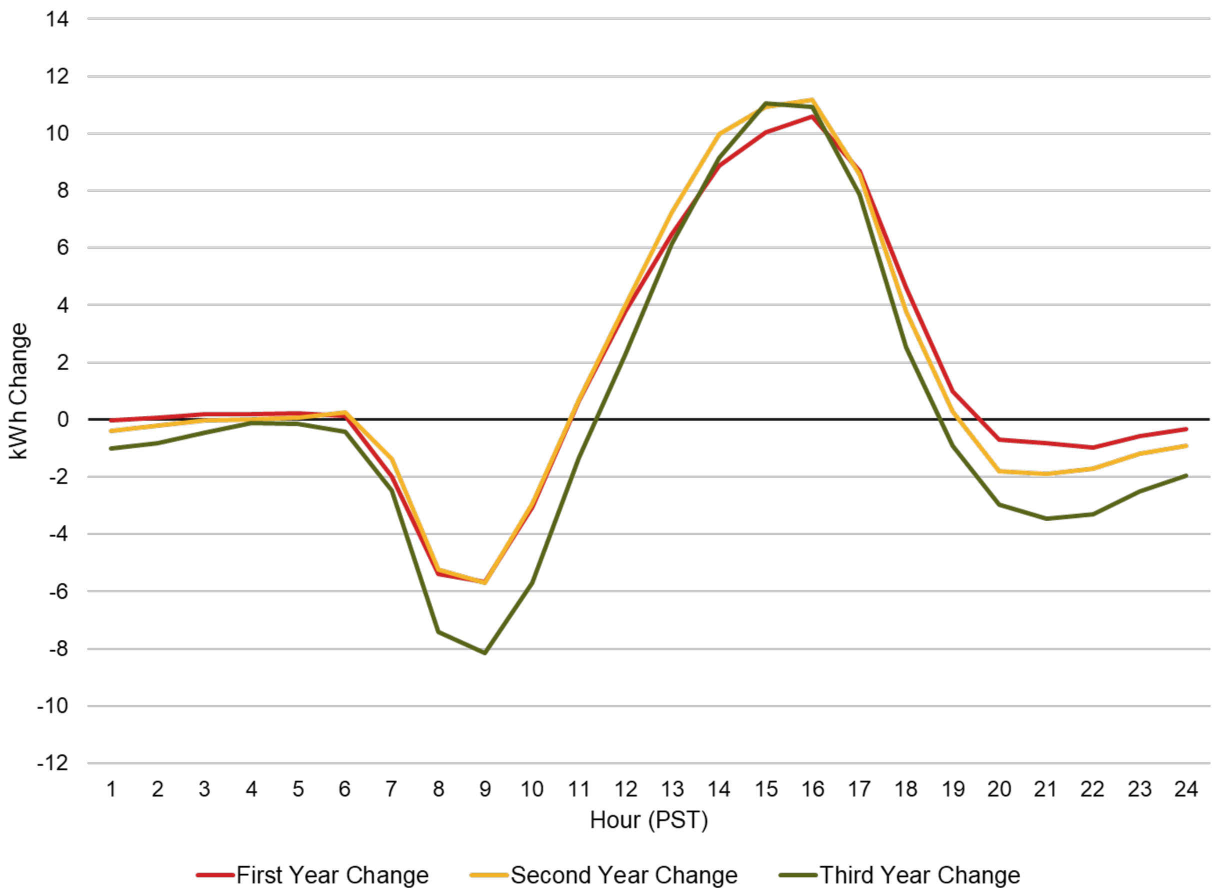
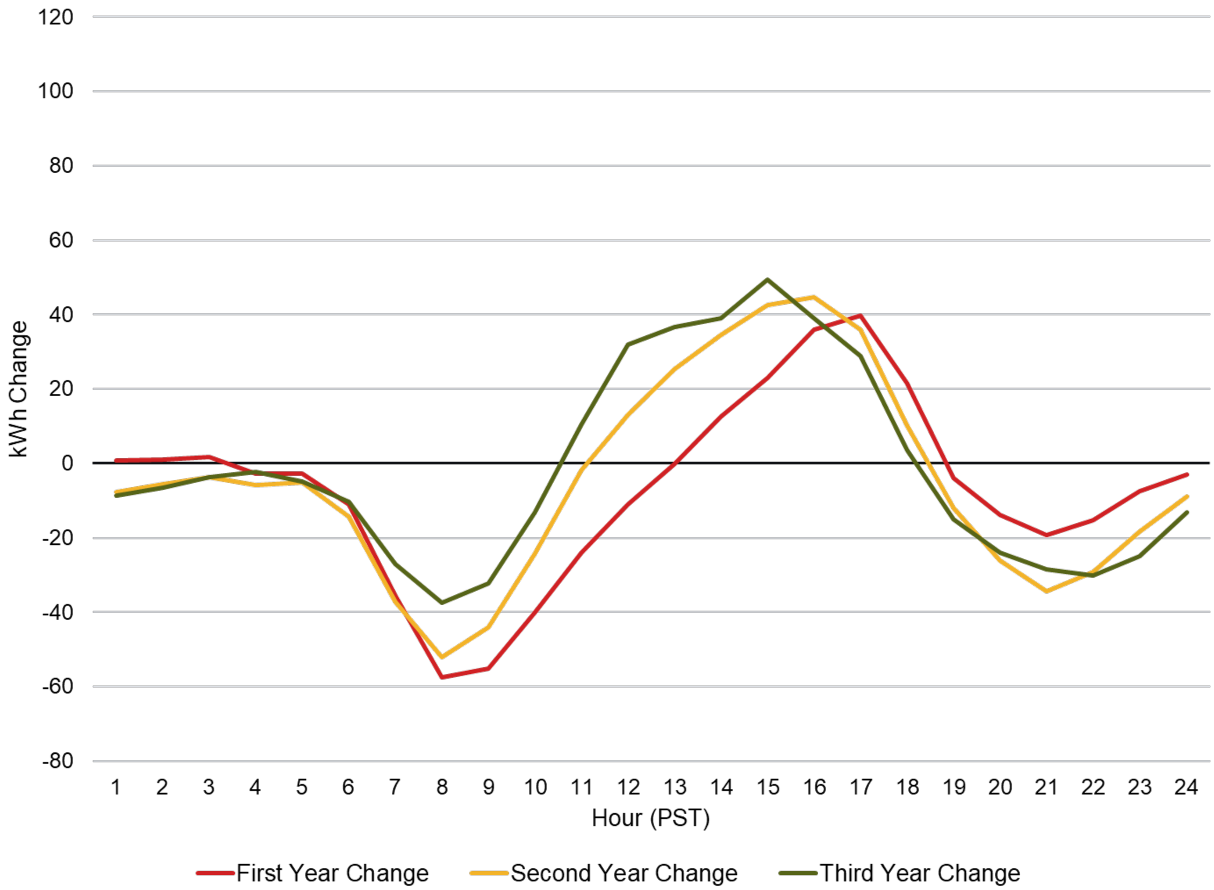


FIGURE 7-10: LARGE SCE NON-RESIDENTIAL CONSUMPTION CHANGES FOLLOWING PV INSTALLATION



The analysis also estimated the average quarterly change in consumption following the installation of CSI incentivized non-residential PV systems in SCE's territory. Table 7-11 and Table 7-12 list quarterly change statistics. For this analysis, the first quarter is the months of January, February, and March following the installation of the PV system, not the first quarter of time following the installation of the system. The other three quarters follow this convention.

For small non-residential customer, the third quarter or summer change in consumption is largest, averaging approximately 1,500 to 2,000 kWh per month during the first two years post-installation. For small non-residential customers, the first, second, and fourth quarters also show average increases in consumption. For the sample of larger non-residential customers in SCE territory, only the summer quarter is associated with an increase in consumption following PV installation; the non-summer quarters are associated with an average decline in consumption.

The hourly consumption shifts for the four quarters follow a pattern very similar to what is observed above.

TABLE 7-11: SCE SMALL NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	979	1,346	1,961	537
Average Monthly Percent Change: Year 1	4.3%	5.6%	6.9%	2.2%
Average Monthly Change: Year 2	1078	1,022	1,640	649
Average Monthly Percent Change: Year 2	4.8%	4.2%	5.8%	2.7%
Average Monthly Change: Year 3	617	405	514	-159
Average Monthly Percent Change: Year 3	2.8%	1.7%	1.8%	-0.7%

TABLE 7-12: LARGE NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	-3,601	-1,650	679	-14,740
Average Monthly Percent Change: Year 1	-1.3%	-0.6%	0.2%	-5.1%
Average Monthly Change: Year 2	-6,414	-31	9,127	-13,800
Average Monthly Percent Change: Year 2	-2.4%	-0.0%	3.0%	-4.8%
Average Monthly Change: Year 3	-4,729	-834	24,937	-13,243
Average Monthly Percent Change: Year 3	-1.7%	-0.3%	8.2%	-4.6%

8 DISTRIBUTION FEEDER IMPACTS

8.1 OVERVIEW

This section presents the methodology and results of analysis on the impact of PV systems on nine different distribution feeders. **THESE FEEDERS WERE CHOSEN BASED ON VARYING QUANTITIES OF INSTALLED PV AND OTHER CHARACTERISTICS BUT ARE NOT INTENDED TO REPRESENT A STATISTICALLY REPRESENTATIVE SAMPLE OF DISTRIBUTION FEEDERS THROUGHOUT CALIFORNIA.** The specific research questions the evaluation team intended to answer include:

- How did California's behind-the-meter (BTM) PV systems impact the distribution system, including substation transformer loading (minimum load, ramp rates)?
- How often is PV causing back feeding at the substation transformer?

8.2 DATA PREPARATION METHODOLOGY

The evaluation team requested supervisory control and data acquisition (SCADA) data[114] from a sample of distribution feeders within each IOU service territory. The requested feeder data were chosen first based on feeders with available metered generation data and second to represent a diversity of load sizes and shapes, sectors (e.g., commercial, residential, industrial) and other demographic information (e.g., urban, rural) where possible. In addition to the SCADA data, information was provided for the selected feeders to identify which PV customers are served by these feeders and to match PV production to the feeder load profiles. Using a combination of metered PV production data and simulations, the evaluation team was able to identify the feeder load profiles observed by the utility and what the load would have been without the influence of BTM PV.

The feeder selection approach and source of PV generation varied somewhat between utilities, based on available data and expediency. Again, these feeders were not chosen to be representation of the thousands of feeders in IOU service territories. For PG&E and SDG&E feeders, the evaluation team could identify PV systems connected to each feeder. PV generation shapes were derived from a combination of both metered and simulated data. For these feeders, Itron simulated generation data when metered generation data were not available. For SCE, mapping of PV systems to feeder was not available, so the evaluation team requested that SCE identify feeders with significant amounts of interconnected PV and provide load and generation data for those feeders. All PV generation was simulated within a tool SCE

114 Hourly min, max, and average amps for each phase.

developed internally to help analyze the impact of PV on feeder loads. These different selection methods were driven by available data and resulted in slightly different feeder mixes by utility. Again, these feeders were not intended to be a statistically representative sample.

Throughout this section, the feeder load observed by the utility is referred to as Net Load, while the load without the influence of BTM PV is referred to as Gross Load.

8.2.1 Data Cleaning, Quality Control and Validation

Before any of these objectives can be met, the evaluation team conducted a rigorous data cleaning, quality control, and data validation process. The first phase of the data cleaning ensured that the data provided by the utilities included a full year of data, free of outages, data errors, or inconsistent loads. The team reviewed the data on an annual basis, as well as maximum and minimum day loads and top and bottom 100 hours, cleaning for common issues such as unreasonably high values (e.g., one reading is 10 times the preceding reading) , negative gross load, and gaps of missing data. Another crucial step was to ensure that time zones and timestamps agreed between SCADA data and PV generation data, and that time series data were all set at hour-beginning.

8.3 OBSERVED IMPACT METHODOLOGY

PV systems can provide distribution system benefits by producing electricity during the top hours of a feeder's load. However, excess PV generation during a feeder's lower load hours can lead to reverse power flow up to the substation and create potential issues related to voltage regulation, protection, and reliability. The objective of this analysis is largely to determine how BTM PV has impacted transformer loading and timing of peak demand on distribution feeders.

To do this, the evaluation team reviewed several metrics, looking at annual averages, quarterly results, and top and bottom 100-hour results. The team also explored ramp rates across different time periods, to see how the presence of BTM PV affects them. Note that this analysis is not meant to be representative of the impact of PV on all California IOU distribution feeders. Instead, this is meant to be an exploration into the relative timing of PV generation relative to feeder top and bottom hours.

8.4 FEEDER SUMMARY

Table 8-1 below displays a summary of the feeders analyzed by utility. The summary highlights the customer mix on the feeder, the timeframe of when the system typically peaks over the maximum load days, and metrics on PV capacity relative to gross load.

For PG&E, customer mix was provided based on the number of customers. PG&E #1 and PG&E #3 served mostly residential customers, while PG&E #2 served entirely commercial customers. The gross feeder loads peaked at different times; one peaked in the very early morning (4:00 AM) while the other two peaked in the early afternoon or evening. PG&E #1 and PG&E #3 had a much smaller relative percentage of PV capacity to maximum gross load on the feeder, while PG&E #2 had a larger relative PV capacity. On PG&E #2, during the minimum peak day, the PV capacity made up almost two-and-a-half times the minimum peak day load.

For SCE, the customer mix for all the feeders analyzed is mostly commercial. Two of the feeders were found to peak at midday, while the last peaked in the early morning. These feeders all have a high relative percentage of PV capacity to total gross load. SCE #1 exhibited a PV capacity greater than the maximum peak load on the maximum peak day, while all three of the SCE feeders had a PV capacity close to two times or higher than the minimum peak day gross load.

The SDG&E feeders selected for analysis served a larger percentage of industrial customers, and only SDG&E #3 had any residential customers. Peak times all fell midday or later, and these systems had a lower percentage of PV capacity on the feeders than the feeders for other utilities.

TABLE 8-1: FEEDER SUMMARY**

Feeder	Customer Mix*	Average Gross Peak Time	PV Capacity / Max Day Peak Gross Load	PV Capacity / Min. Day Peak Gross Load
PG&E #1	Com./Ind. = 7% Residential = 87% Agricultural = 5%	Evening	17%	56%
PG&E #2	Com./Ind.= 100% Residential = 0% Agricultural = 0%	Very Early Morning	71%	233%
PG&E #3	Com./Ind.= 9% Residential = 91% Agricultural = 0%	Early-Afternoon	24%	44%
SCE #1	Commercial = 74% Residential = 26% Industrial = 0%	Midday	117%	187%
SCE #2	Commercial = 99% Residential = 1% Industrial = 0%	Midday	52%	259%
SCE #3	Commercial = 78% Residential = 7% Industrial = 14%	Early-Morning	67%	198%
SDG&E #1	Commercial = 20% Residential = 0% Industrial = 79%	Midday	33%	75%
SDG&E #2	Commercial = 48% Residential = 0% Industrial = 52%	Early-Afternoon	9%	34%
SDG&E #3	Commercial = 69% Residential = 23% Industrial = 8%	Late-Afternoon	13%	35%

* PG&E reports the customer mix by number of customers. SCE and SDG&E provide customer mix by load.

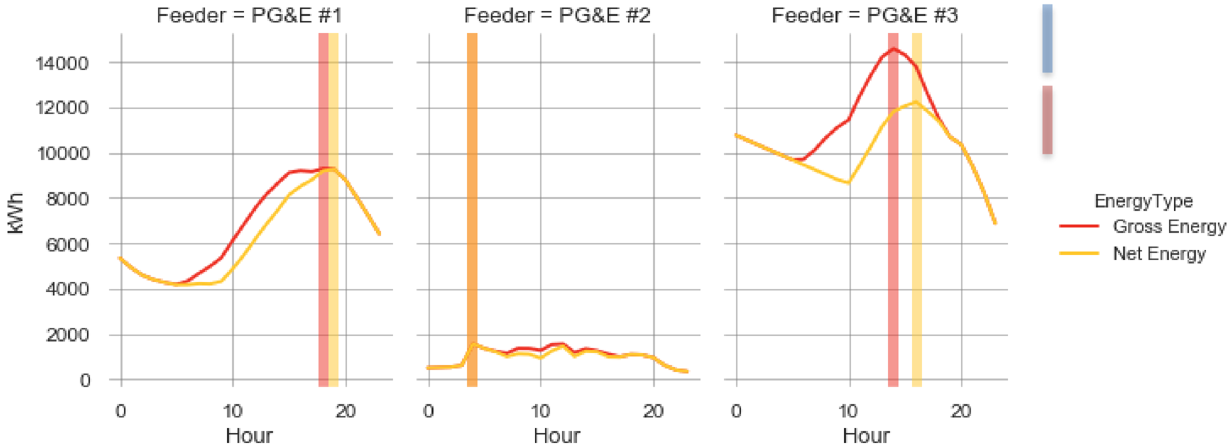
** These feeders were chosen to only be illustrative based on installed PV but are NOT meant to be representative of each utility or the state as a whole

8.5 FEEDER PEAK AND LOAD SHAPE CHANGES

Feeder shapes and peak hours vary greatly across feeders, and they depend heavily on variables like customer sector mix, gross loads, and amount of distributed generation.

PG&E feeders, shown below in Figure 8-1, did not see a large shift in peak hours for their maximum load peak days. PG&E #1 and PG&E #2 both saw peak hours that were just outside or, or on the border of when sun would be shining enough to produce any PV energy. Therefore, the peak load did not shift much for these two feeders. PG&E #3 did see a shift in peak load, reducing the peak load by about 15 percent and shifting it two hours later, from 2 PM to 4 PM.

FIGURE 8-1: FEEDER GROSS AND NET LOADSHAPES FOR MAXIMUM PEAK DAYS – PG&E

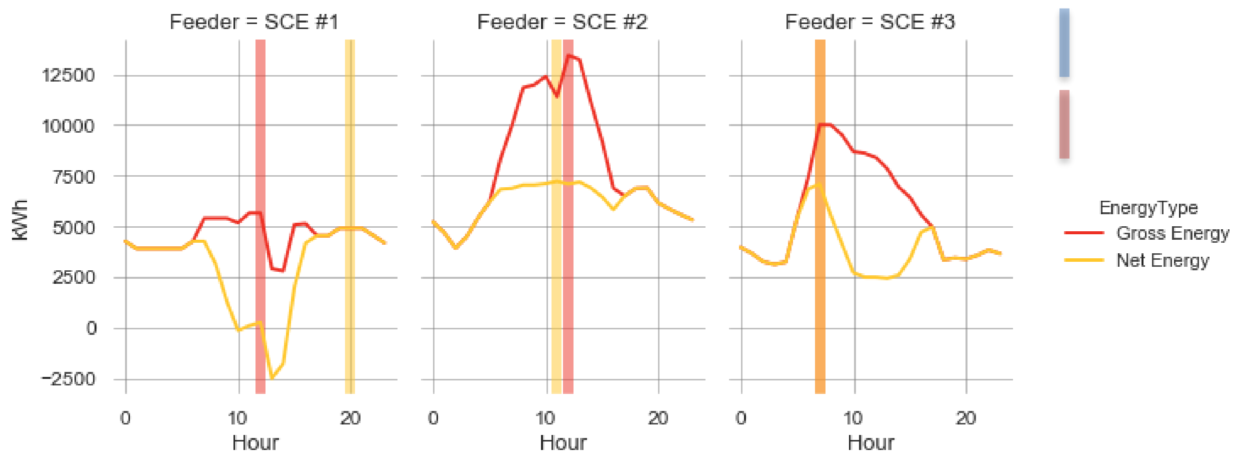


Feeder ID	Peak Gross		Peak Net		Peak Difference		Peak Difference / PV Capacity
	Load [kWh]	Hour	Load [kWh]	Hour	Load [kWh]	Hour	
PG&E #1	9,299	18	9,276	19	23	1	0.01
PG&E #2	1,567	4	1,567	4	-	0	-
PG&E #3	14,589	14	12,244	16	2,345	2	0.67

Feeder PG&E 2 has a very early morning peak load, so even though it has a relatively significant amount of PV installed, this PV has minimal impact on the timing and magnitude of the peak.

The SCE feeders, shown in Figure 8-2, highlight the potential for larger peak hour shifts. SCE #1 shows a shift in peak hour of eight hours, yet there is not much of a magnitude difference between gross and net peak loads. SCE #3 has no change in peak hour but does see a reduction in peak load of approximately 25 percent. SCE #2 also does not show much of a shift in peak time (only a single hour), but the peak load difference makes up almost 90 percent of the total PV capacity for that feeder.

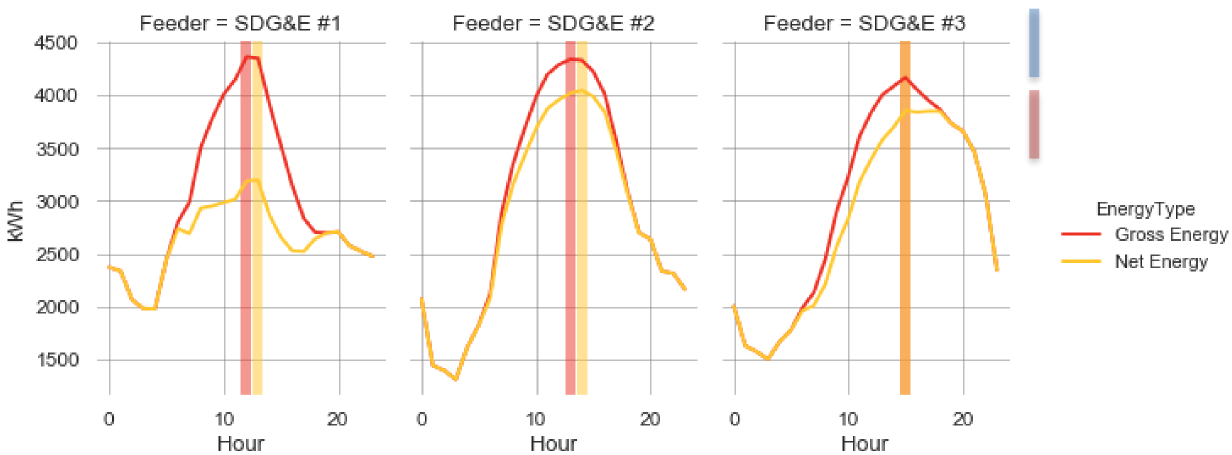
FIGURE 8-2: FEEDER GROSS AND NET LOADSHAPES FOR MAXIMUM PEAK DAYS – SCE



Feeder ID	Peak Gross		Peak Net		Peak Difference		Peak Difference / PV Capacity
	Load [kWh]	Hour	Load [kWh]	Hour	Load [kWh]	Hour	
SCE #1	5,660	12	4,910	20	750	8	0.11
SCE #2	13,433	12	7,227	11	6,205	-1	0.88
SCE #3	10,018	7	7,088	7	2,929	0	0.44

The SDG&E feeders exhibited very little shift in peak hours for their maximum load days. Each of these feeders (including SDG&E #1, which was mostly industrial) exhibit a similar load curve that peaks somewhere between midday and the afternoon. Additionally, neither SDG&E #2 nor SDG&E #3 had a significant amount of PV capacity on the feeder when compared to the gross load; therefore, the PV generation on the feeder did not significantly affect the time when the net load peaked. All three SDG&E feeders show a reduction in peak load of over half of the installed PV capacity, meaning that the PV generation profiles were well matched to the loads, even though there was not a large amount of PV capacity on each feeder.

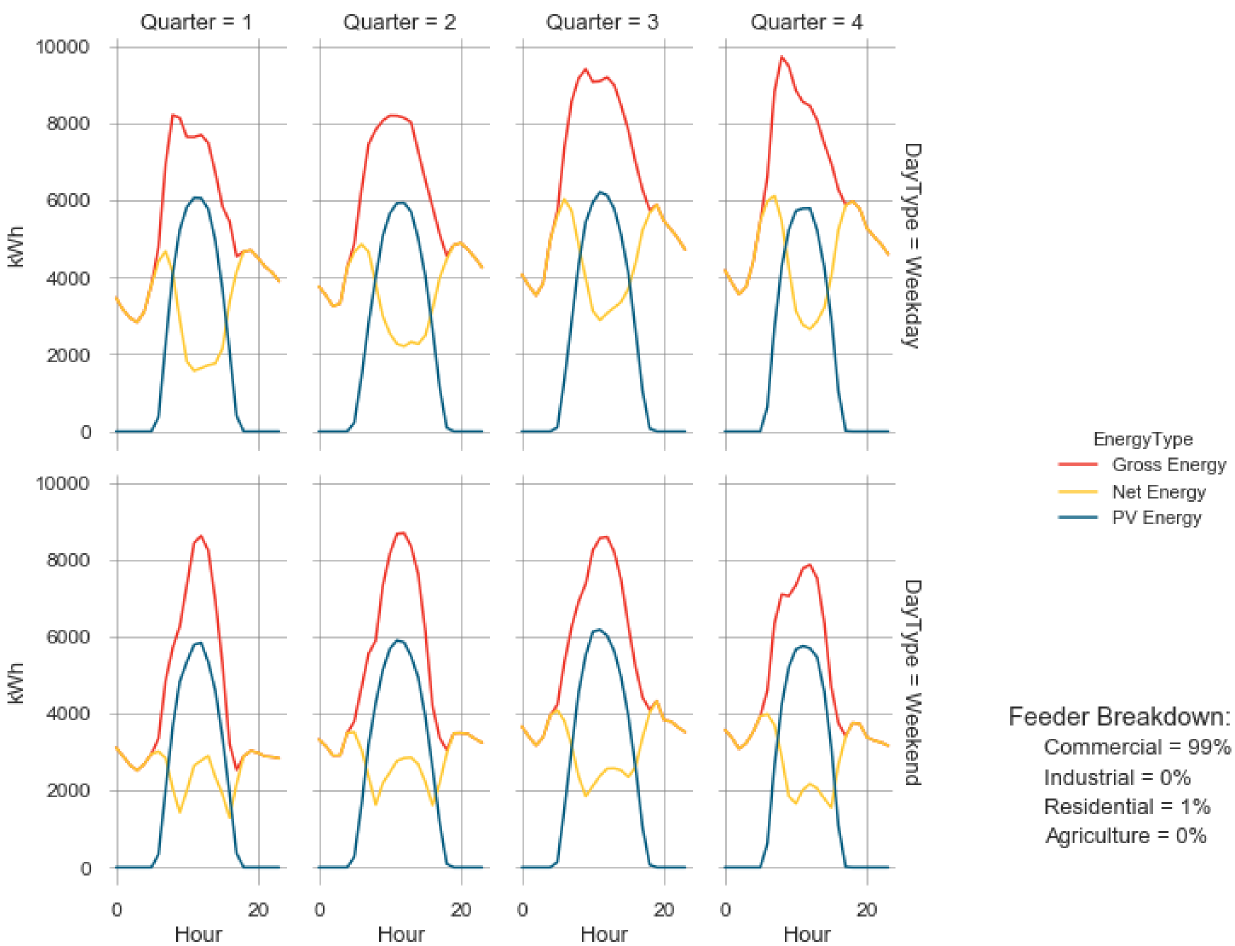
FIGURE 8-3: FEEDER GROSS AND NET LOADSHAPES FOR MAXIMUM PEAK DAYS – SDG&E



Feeder ID	Peak Gross		Peak Net		Peak Difference		Peak Difference / PV Capacity
	Load [kWh]	Hour	Load [kWh]	Hour	Load [kWh]	Hour	
SDG&E #1	4,364	12	3,197	13	1,167	1	0.80
SDG&E #2	4,340	13	4,046	14	294	1	0.77
SDG&E #3	4,169	15	3,856	15	313	0	0.56

Feeder gross load profiles have a significant impact on how PV generation impacts peak net loads. When a feeder tends to peak midday, PV generation matches the load profile well and PV can significantly reduce peak loads. Figure 8-4 is an example of this. For each quarter, both weekday and weekend day types, the system load is reduced by just under 50 percent of the total gross load, as a result of the PV generation on the system. As noted in Table 8-1, the PV capacity on this feeder makes up about 52 percent of the peak gross load on the maximum peak day, which is not enough to cause back feed on this feeder. Back feed occurs when the PV and other distribution generation is generating more power than the gross load on the feeder during any given hour.

FIGURE 8-4: EXAMPLE OF GOOD LOAD AND PV MATCH (SCE #2)



Gross load and PV generation do not match as well on other feeders. Figure 8-5 shows a feeder where the PV generation is higher than the gross load throughout much of the year. The result is a feeder that shows back feed throughout most of the year. Additionally, SCE #3 peaks in the early morning before the PV system achieves maximum energy production. This creates somewhat of a mismatch between the load and the PV system. While the PV system does bring down the feeder's gross load, it does not bring down the peak load on the feeder nearly as much as if the feeder peaked later in the day.

FIGURE 8-5: EXAMPLE OF EXCESS PV COMPARED WITH LOAD (SCE #3)

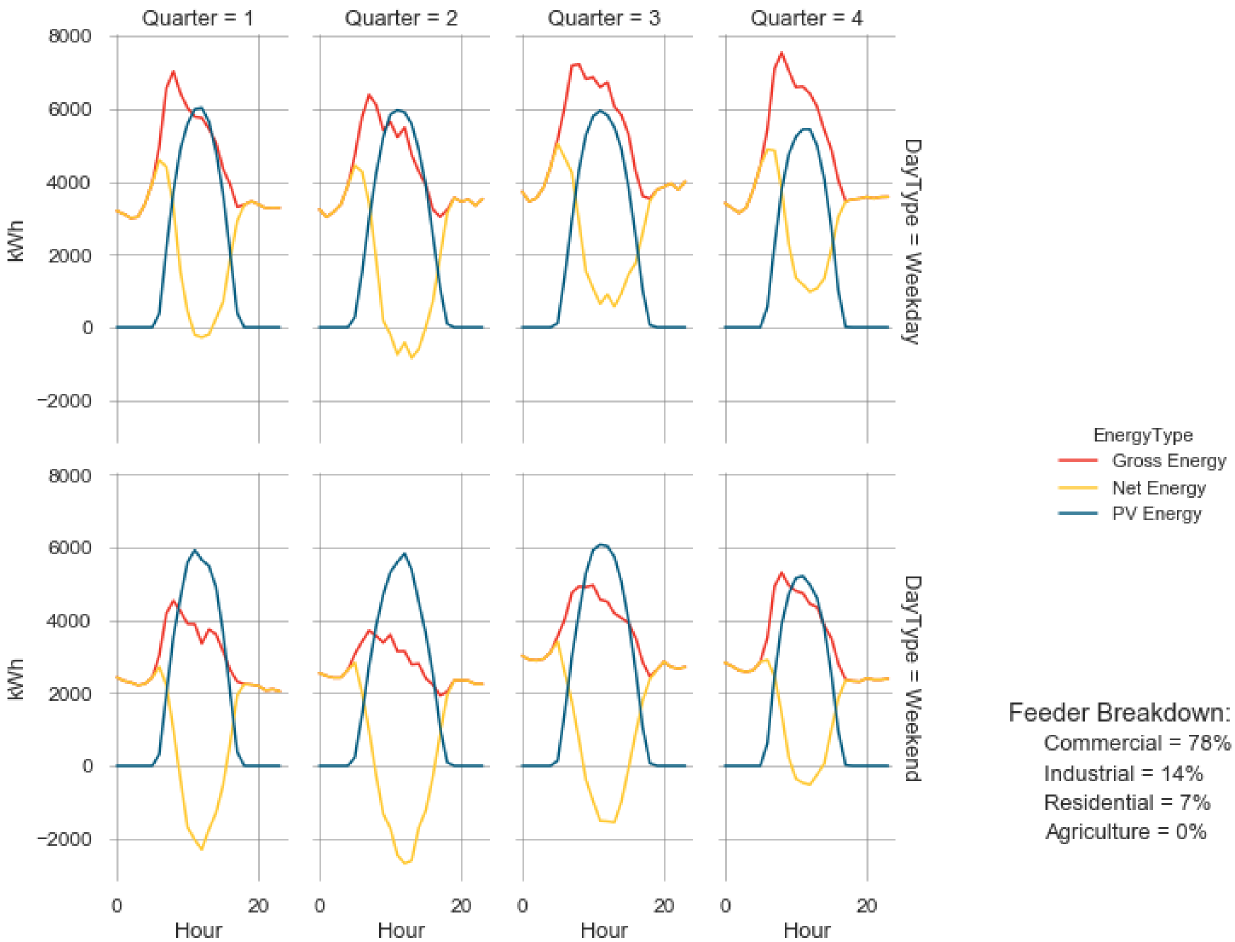
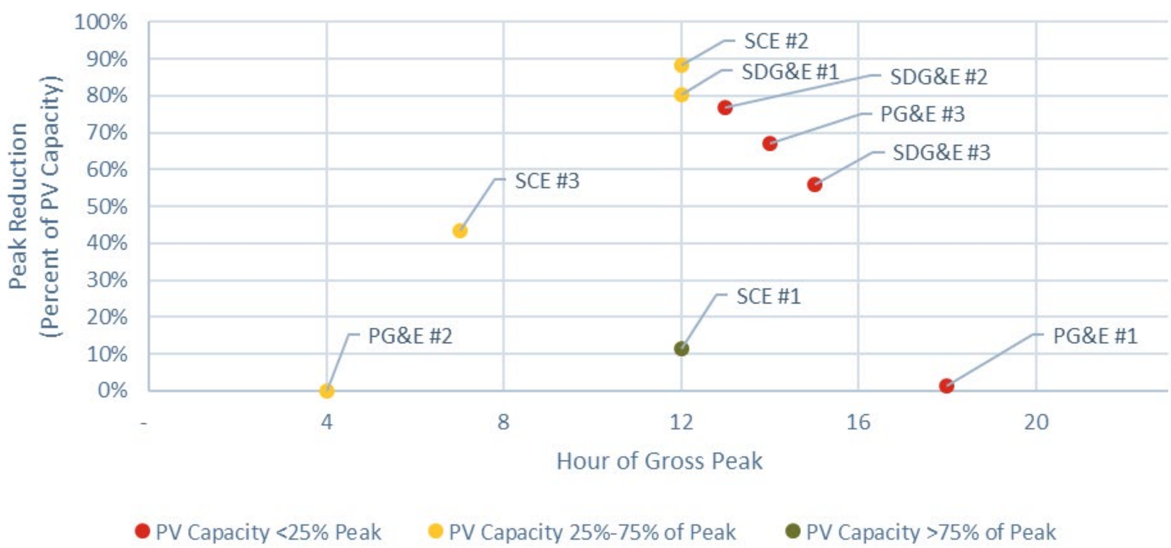


Figure 8-6 shows how much feeder peak load is reduced by PV generation versus the timing of the gross peak. In general, feeders that have a gross peak in the middle of the day have their peak loads reduced more by PV than others. This reduction is also a function of how much PV is installed on the feeder. Feeder SCE #1, for example, has a very significant amount of PV generation (installed PV capacity is 117 percent of the gross peak) but the peak is only reduced by 11 percent of the installed PV capacity; more PV does not always further reduce feeder peak.

FIGURE 8-6: PEAK REDUCTION VS. PEAK TIMING



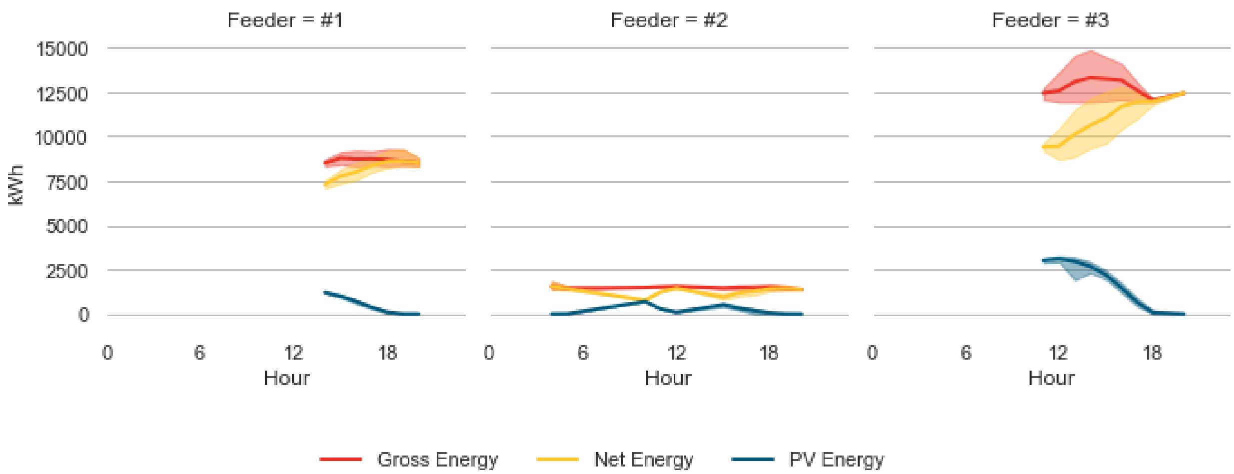
8.6 TOP 100 HOURS SUMMARY

The top hours of feeder load may be more likely to represent hours when PV and other load-reducing measures provide benefit to the feeder. The addition of alternate generation may allow utilities to defer distribution upgrades. Reducing peak load could also potentially extend equipment lifetimes, but the benefits from such are likely less impactful. Conversely, depending on timing, PV may only provide minimal benefit during these high gross load hours.

Figure 8-7 through Figure 8-9 below shows the feeder shapes over the top 100 hours for each utility and demonstrates how these shapes can vary greatly for the different feeders. Some feeders see the top 100 hours range across the entire day, while others show them concentrated to a small portion of the day. The shaded regions reflect the range from minimum to maximum load for those hours, while the lines reflect the average load.

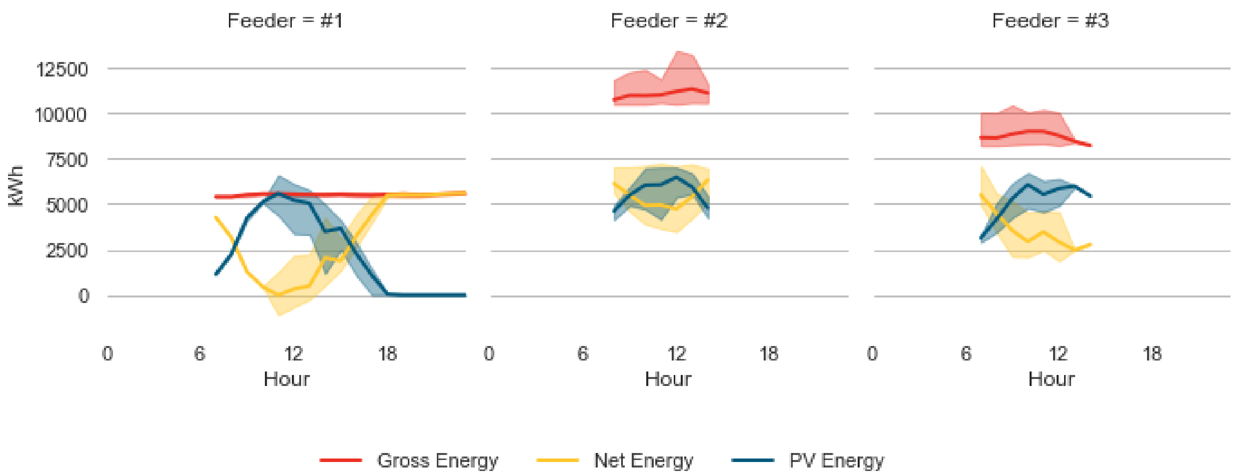
PG&E #2 has the top 100 hours spread out across the hours between 4 AM and 8 PM. During these hours, the gross load stayed very consistent. SCE #1, on the other hand, showed top 100 hours between about 7 AM and midnight. While the gross load stayed consistent, the net load of these hours varied by close to 50 percent between about 10 AM and 6 PM. The error bands highlight the minimum and maximum load values during each hour. SDG&E #1 has only a very small window of the top 100 hours, between 10 AM to 2 PM, while SDG&E #3 has the top 100 hours between 10 AM and 9 PM. The range in top 100 hours and their minimum and maximum load changes of all these feeders demonstrates how the mix of customers on the feeders can drastically change, the time of the highest load, their change in load, and the impact that PV will have on a circuit.

FIGURE 8-7: FEEDER SHAPES OVER TOP 100 HOURS – PG&E



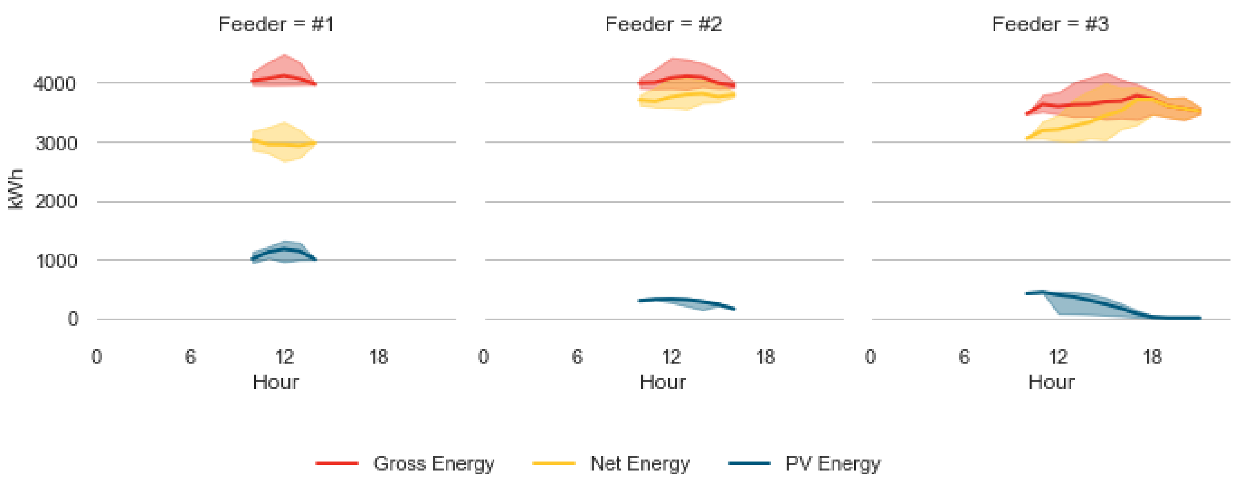
* Shaded areas show minimum and maximum load and generation during top 100 hours

FIGURE 8-8: FEEDER SHAPES OVER TOP 100 HOURS – SCE



* Shaded areas show minimum and maximum load and generation during top 100 hours

FIGURE 8-9: FEEDER SHAPES OVER TOP 100 HOURS – SDG&E



* Shaded areas show minimum and maximum load and generation during top 100 hours

Minimum PV generation during the top 100 hours provides another insight into how reliably PV generation might reduce transformer loading during high demand hours. For Feeder SCE #1, PV generation can be seen to reliably offset a significant portion of load up until late afternoon, when the minimum generation can increasingly be zero, indicating that PV will not reliably offset load later in the day.

The occurrence of the top 100 hours by quarter is shown below in Table 8-2. Both PG&E and SDG&E feeders saw the majority of their top 100 hours in the later summer months. SCE feeders saw a wider range of hours throughout the entire year, but the bulk of their hours were still concentrated in the latter half of the year. SCE #2 and #3 showed the greatest variation throughout the year and had their highest concentration of hours in October-December months.

TABLE 8-2: OCCURRENCE OF TOP 100 HOURS OF GROSS LOAD ACROSS QUARTERS

	Quarter			
Feeder	Jan-Mar	Apr-Jun	Jul-Sept	Oct-Dec
PG&E #1	-	33	67	-
PG&E #2	-	16	72	12
PG&E #3	-	9	91	-
SCE #1	-	17	68	15
SCE #2	4	14	34	48
SCE #3	26	9	12	53
SDG&E #1	-	13	80	7
SDG&E #2	-	23	77	-
SDG&E #3	-	10	90	-

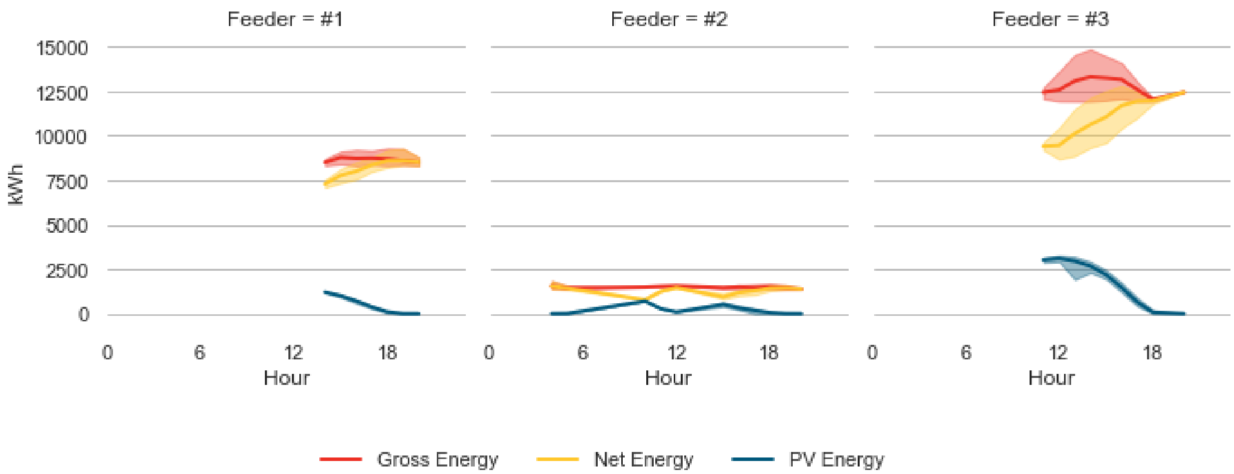
8.7 BOTTOM 100 HOURS IMPACT SUMMARY

One of the potential negative impacts PV can have on distribution feeders is back feeding when power is pushed back to the substation from the distribution feeder. This can cause reliability and other issues, since most distribution feeders were designed for power to only flow outward from the substation.

A similar analysis to the top 100 hours analysis was performed on the bottom 100 hours of gross load for the feeders. The results for each utility can be found below in Figure 8-10 through Figure 8-12. Several conclusions can be made from reviewing this graph. First, the bottom 100 hours of gross load seem to occur more evenly through the day than the top 100 hours, which were often clustered into a more concentrated time period, at least for some feeders. The average gross load for these bottom 100 hours appears to have come down close to 75 percent in many cases. This highlights the final point, which is the amount of back feed seen on these bottom 100 gross hours. Due to the low gross loads, back feed is more likely to occur for a significant portion of these hours.

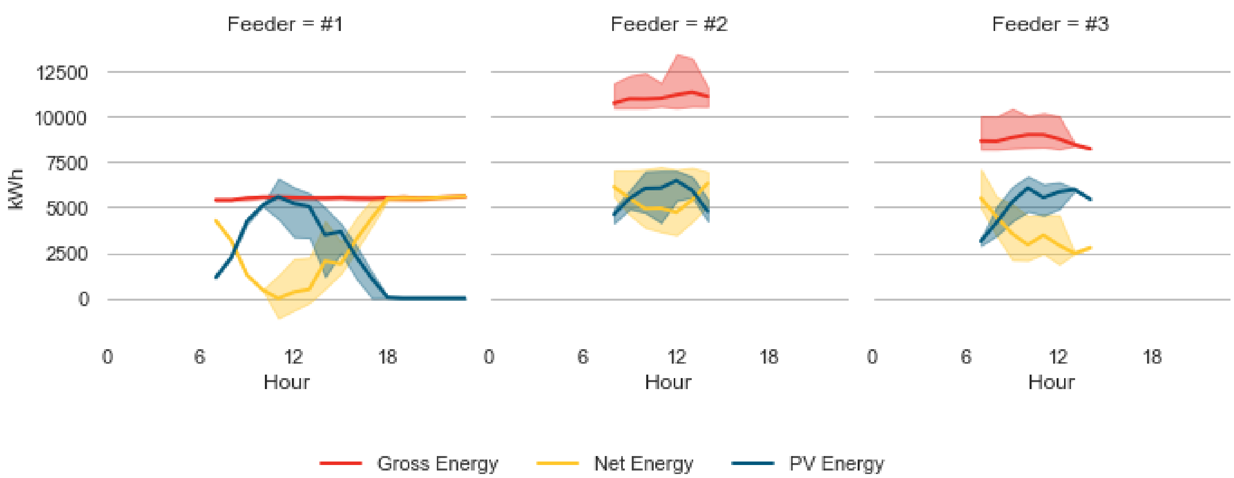
During these lower load hours, PG&E #2, SCE #1, and SCE #3 consistently show negative net load (or back feed) during the middle of the day.

FIGURE 8-10: FEEDER SHAPES OVER THE BOTTOM 100 HOURS – PG&E



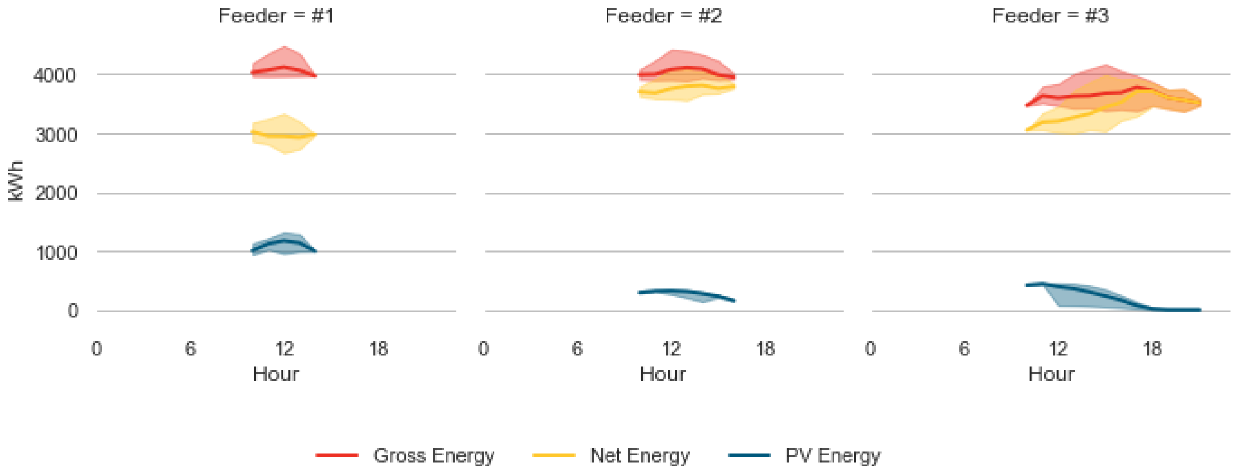
* Shaded areas show minimum and maximum load during the bottom 100 hours

FIGURE 8-11: FEEDER SHAPES OVER THE BOTTOM 100 HOURS – SCE



* Shaded areas show minimum and maximum load during the bottom 100 hours

FIGURE 8-12: FEEDER SHAPES OVER THE BOTTOM 100 HOURS – SDG&E



* Shaded areas show minimum and maximum load during the bottom 100 hours

Table 8-3 displays the occurrence of the bottom 100 hours by quarter. For most of the feeders, their highest concentration of the bottom 100 hours occurred during colder months (as expected), between October and March. PG&E #3, SCE #1, and SCE #2 had their highest concentration of hours during spring months (April–June). There were very few bottom 100 hours occurring during late summer months.

TABLE 8-3: OCCURRENCE OF BOTTOM 100 HOURS ACROSS QUARTER

	Quarter			
Feeder	Jan-Mar	Apr-Jun	Jul-Sept	Oct-Dec
PG&E #1	47	-	-	53
PG&E #2	24	30	21	25
PG&E #3	37	63	-	-
SCE #1	18	66	8	8
SCE #2	96	2	-	2
SCE #3	12	50	1	37
SDG&E #1	95	5	-	-
SDG&E #2	47	2	1	50
SDG&E #3	29	32	13	26

8.8 BACK FEED COMPARISON

Feeder back feed can create issues with grid stability, voltage regulation, and safety. The impact is highly dependent on each substation and feeder configuration. Significant back feed on one feeder may cause coordination issues with other protective elements on feeders connected to the same substation. Voltage regulation can be significantly impacted during back feed conditions that can lead to undesirable voltage levels. Additionally, the equipment designed to help feeders come back online after an outage or to stay online during temporary fluctuations may not function as expected. Therefore, before feeders start to experience back feed, additional care should be taken to ensure continued operations. Many utilities already perform detailed studies of feeders with high levels of solar PV. However, the impact of back feed on distribution is highly dependent on system configurations.

As noted in the sections above, back feed is most likely to occur during the daylight hours when gross load is the lowest, and the PV system is producing. Back feed may occur during the highest gross load hours, but it is far less likely. However, it is also interesting to analyze how much energy is being fed backwards during the rest of the year. Table 8-4 identifies the percent of time[115] that the feeder is seeing back feed due to the PV systems connected to the feeder, as well as the total MW of reverse energy flow. Two of the three SCE feeders showed significant back feed over the course of the year, while none of the SDG&E feeders saw any back feed at all. This is largely due to a higher relative amount of PV installed on the feeders that happened to be selected for SCE. However, as previously stated, these feeders were not chosen to be fully representative of each utility, so differences between utilities are only illustrative and not comprehensive.

TABLE 8-4: BACK FEED COMPARISON

Feeder	PV Capacity / Max Day Peak Gross Load	PV Capacity / Min. Day Peak Gross Load	Annual % of Time*	Top 100 % of Time	Bottom 100 % of Time
PG&E #1	17%	56%	0%	0%	0%
PG&E #2	71%	233%	35%	0%	84%
PG&E #3	24%	44%	0%	0%	0%
SCE #1	117%	187%	56%	11%	99%
SCE #2	52%	259%	0%	0%	0%
SCE #3	67%	198%	27%	0%	63%
SDG&E #1	33%	75%	0%	0%	0%
SDG&E #2	9%	34%	0%	0%	0%
SDG&E #3	13%	35%	0%	0%	0%

* While PV systems are producing energy

115 This reflects the percent of time that PV systems are actually generating energy (generally daylight hours).

In general, feeders with more installed PV are more likely to see back feed. However, the likelihood of back feed also depends on the timing of low load periods. The ratio of PV generation to minimum gross load for SCE #2 alone could lead one to believe that back feed was very likely during the low gross load hours. However, the low loads on this largely commercial feeder occur during the winter months when PV generation tends to be much lower and, therefore, does not see any back feed. The annual loads and generation for SCE #2 are shown in Figure 8-13.

FIGURE 8-13: SCE #2 ANNUAL LOADS AND GENERATION

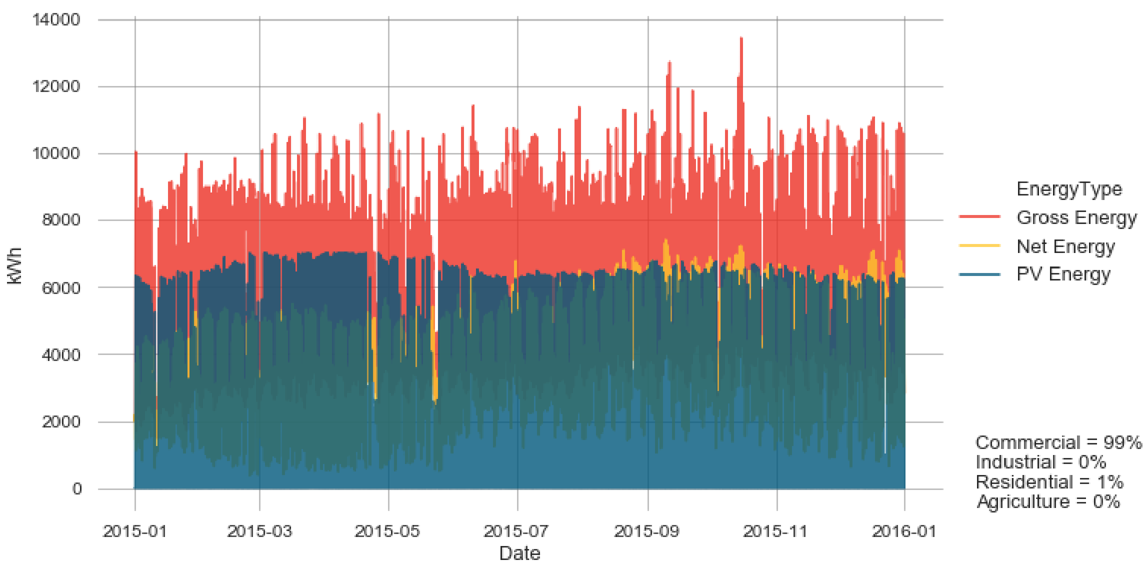
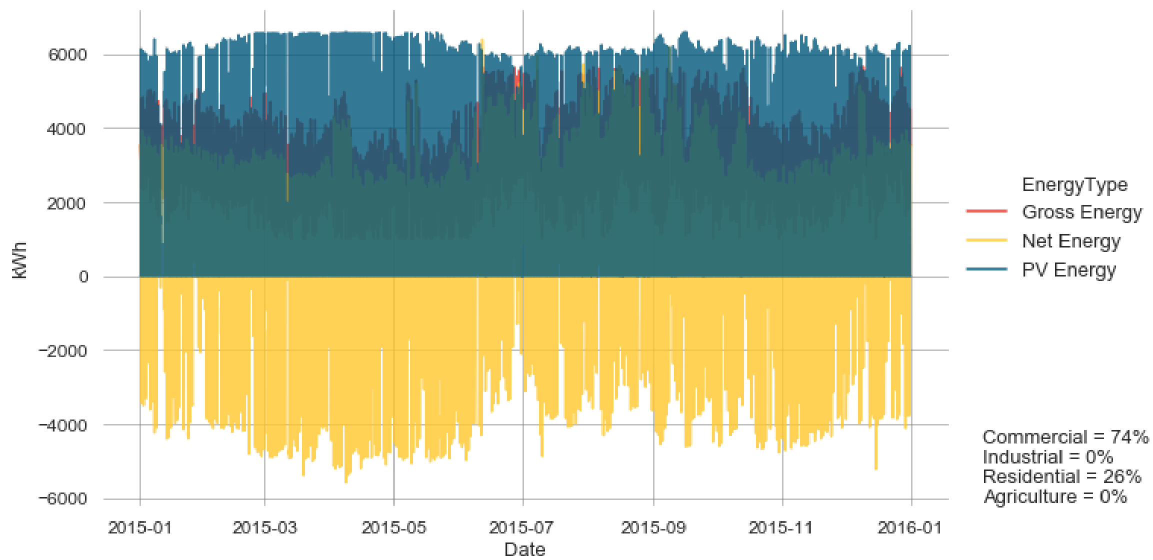


Figure 8-14 below displays the graph of annual load and PV consumption for SCE #1. This feeder showed a significant amount of back feed throughout the entire year.

FIGURE 8-14: EXAMPLE OF SITE WITH SIGNIFICANT BACK FEED (SCE #1)



8.9 PEAK CHANGES

The addition of PV can change the timing and magnitude of feeder peak loads and feeder ramp rates. Ramp rate is defined as the rate at which load increases throughout the day. The amount of PV that is connected to a feeder can also shift this ramp rate up or down, as well as change the timing of the maximum ramp rate. Ramp rate is most applicable at the bulk system level (either at the IOU or ISO level) where generation must respond to changes in load but understanding how ramp rates change at finer levels can provide insights into how these loads are driving changes at the bulk level.

Table 8-5 below compares the gross and net average maximum loads and gross and peak ramp rates for both the annual average and days covering the top 100 hours for sampled feeders. As shown in previous sections, feeder loads are highly variable, and each of the three SCE feeders below act very differently from each other. SCE #1 does not show any change in hours for either peak load or maximum ramp rates between the average annual and the top 100 hours, while SCE #2 shows a significant change, from a net peak load of 7 PM to a peak of 6 AM. The consistency of SCE #1 is likely reflective of a load shape that does not change substantially through the year, whereas SCE #2 is reflective of a load shape that changes some during the year. SCE #1 saw almost 70 percent of its top 100 hours occurring in the third quarter, between July and September, while SCE #2 saw its hours more spread out, with over 80 percent of the top 100 hours occurring between July and December. Similarly, the largest net load ramp for SCE #2 changed from 5 PM to 5 AM between the annual average and the top 100 hours. Another interesting difference is in regard to how the largest average ramp changes between the annual average and the top 100 hours. For SCE #1 and SCE #3, the net load ramp decreases during the top 100 hours, but for SCE #2 the net load ramp increases during the top 100 hours. Because SCE #2 has much less PV capacity on the feeder, the net load is not reduced during the day as much as it is for the other feeders, so the net load ramp back up in the evening when PV generation tapers off is not as distinguished.

PG&E feeders did not see significant ramp rates, even for PG&E #3, which had one of the largest gross peak load of all feeders analyzed. For this feeder, the gross ramp rate was only about 10 percent of the total load, while the net ramp rate was even less at under 5 percent. The SDG&E feeders also had rather low ramp rates, typically around 10 percent of their peak loads.

TABLE 8-5: RAMP RATE COMPARISON FOR SAMPLED FEEDERS

Metric	Average Annual	Top 100 Hours	Average Annual	Top 100 Hours	Average Annual	Top 100 Hours
	PG&E #1		PG&E #2		PG&E #3	
Gross Peak	4,704	4,780	761	763	9,488	9,616
Hour of Gross Peak	6:00 PM	6:00 PM	4:00 PM	4:00 PM	1:00 PM	1:00 PM
Net Load Peak (Gross kWh - PV Generation)	4,669	4,744	723	734	7,937	8,066
Hour of Net Load Peak	6:00 PM	6:00 PM	6:00 PM	6:00 PM	7:00 PM	7:00 PM
Largest Consumption Ramp (ΔkWh/hour)	218	215	140	151	909	899
Hour of Consumption Ramp	7:00 AM	7:00 AM	4:00 AM	4:00 AM	8:00 AM	9:00 AM
Largest Net Load Ramp (ΔkWh/hour)	400	400	277	287	430	426
Hour of Net Load Ramp	4:00 PM	3:00 PM	4:00 PM	4:00 PM	6:00 AM	6:00 AM
	SCE #1		SCE #2		SCE #3	
Gross Peak	3,911	4,996	8,393	9,944	6,294	7,731
Hour of Gross Peak	4:00 PM	4:00 PM	Noon	9:00 AM	8:00 AM	8:00 AM
Net Load Peak (Gross kWh - PV Generation)	3,491	4,571	4,833	5,764	4,017	4,820
Hour of Net Load Peak	7:00 PM	7:00 PM	7:00 PM	6:00 AM	5:00 AM	7:00 AM
Largest Consumption Ramp (ΔkWh/hour)	634	724	1,564	1,722	1,148	1,678
Hour of Consumption Ramp	6:00 AM	6:00 AM	7:00 AM	7:00 AM	7:00 AM	7:00 AM
Largest Net Load Ramp (ΔkWh/hour)	1,849	1,562	764	811	897	848
Hour of Net Load Ramp	4:00 PM	4:00 PM	5:00 PM	5:00 AM	5:00 PM	4:00 PM
	SDG&E #1		SDG&E #2		SDG&E #3	
Gross Peak	3,238	4,092	2,750	4,069	2,428	3,617
Hour of Gross Peak	Noon	Noon	1:00 PM	1:00 PM	2:00 PM	3:00 PM
Net Load Peak (Gross kWh - PV Generation)	2,254	2,929	2,525	3,778	2,325	3,460
Hour of Net Load Peak	8:00 AM	Noon	2:00 PM	2:00 PM	8:00 PM	5:00 PM
Largest Consumption Ramp (ΔkWh/hour)	286	401	303	534	229	402
Hour of Consumption Ramp	7:00 AM	8:00 AM	7:00 AM	7:00 AM	9:00 AM	9:00 AM
Largest Net Load Ramp (ΔkWh/hour)	220	307	265	470	117	315
Hour of Net Load Ramp	5:00 AM	5:00 AM	7:00 AM	7:00 AM	5:00 AM	9:00 AM

APPENDIX A IMPACTS

A.1 REGRESSION ANALYSIS – EQUATIONS

A.1.1 Annual Energy Impacts Results

The final model and parameters for the Annual Energy Impacts Results are listed below in Table A-1. The equation for the model is:

$$\begin{aligned} Annual\ CF = {} & Intercept + Flag_{pre2011} * \beta_{pre2011} + \ Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\ & * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\ & + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\ & * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\ & + AnnualAvg.Irradiance * \beta_{AnnualAvg.Irradiance} + \ \epsilon \end{aligned}$$

TABLE A-1: ANNUAL ENERGY IMPACTS REGRESSION MODEL

Independent Variable	Estimate	tValue[1]
Intercept	0.129265	21.71
Flag: Pre2011	0.021166	39.13
Flag: Capacity: 15-100	-0.00332	-2.64
Flag: Capacity: >100	-0.00126	-0.6
Flag: PGE Coastal	-0.0101	-11.5
Flag: PGE Inland	-0.00481	-6.18
Flag: SCE Coastal	-0.00626	-6.27
Flag: SCE Inland	-0.00575	-7.66
Flag: SDGE Coastal	-0.00124	-1.34
Flag: Fixed Array	-0.07609	-36.85
System Age	-0.00337	-28.82
Annual Avg. Irradiance	0.00062	25.49

1 The tValue represents the size of the difference relative to the variation in the sample data. The greater the magnitude of the tValue, the greater the evidence that there is a significant difference.

A.1.2 CAISO Peak Hour Results

The final model and parameters for the CAISO Peak Hour Results are listed below in Table A-2. The equation for the model is:

$$\begin{aligned} Annual\ CF = Intercept + Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\ * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\ + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\ * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\ + CAISOPeakHourIrradiance * \beta_{CAISOPeakHourIrradiance} + \epsilon \end{aligned}$$

TABLE A-2: CAISO PEAK HOUR REGRESSION MODEL

Independent Variable	Estimate	tValue
Intercept	0.34931	25.11
Flag: Pre2011	0.03412	9.09
Flag: Capacity: 15-100	-0.01164	-1.33
Flag: Capacity: >100	-0.01945	-1.38
Flag: PGE Coastal	0.00831	1.33
Flag: PGE Inland	-0.00312	-0.52
Flag: SCE Coastal	0.01699	2.29
Flag: SCE Inland	-0.01587	-2.71
Flag: SDGE Coastal	0.00074	0.11
Flag: Fixed Array	-0.21489	-18.36
System Age	-0.01145	-14.36
CAISO Peak Hour Irradiance	0.00030	52.13

A.1.3 IOU Peak Hour Results

The final model and parameters for the IOU Peak Hour Results are listed below in Table A-3. The equation for the model is:

$$Annual\ CF = Intercept + Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} + IOUPeakHourIrradiance * \beta_{IOUPeakHourIrradiance} + \epsilon$$

TABLE A-3: IOU PEAK HOUR REGRESSION MODEL

Independent Variable	Estimate	tValue
Intercept	0.34679	36.2
Flag: Pre2011	0.01191	4.25
Flag: Capacity: 15-100	0.00490	0.79
Flag: Capacity: >100	-0.00321	-0.59
Flag: PGE Coastal	-0.07229	-11.63
Flag: PGE Inland	-0.08645	-13.85
Flag: SCE Coastal	-0.08940	-11.92
Flag: SCE Inland	-0.09504	-15.28
Flag: SDGE Coastal	0.00192	0.25
Flag: Fixed Array	-0.17187	-44.67
System Age	-0.01046	-11.39
IOU Peak Hour Irradiance	0.00034	95.51

A.1.4 CAISO Top 200 Hour Results

The final model and parameters for the CAISO Top 200 Hour Results are listed below in Table A-4. The equation for the model is:

$$\begin{aligned} Annual\ CF = {} & Intercept + Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\ & * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\ & + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\ & * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\ & + CAISOTop200HourAvg.Irradiance * \beta_{CAISOTop200HourAvg.Irradiance} + \epsilon \end{aligned}$$

TABLE A-4: CAISO TOP 200 HOUR REGRESSION MODEL

Independent Variable	Estimate	tValue
Intercept	0.2398	18.66
Flag: Pre2011	0.0206	7.6
Flag: Capacity: 15-100	-0.0222	-4.28
Flag: Capacity: >100	-0.0157	-1.87
Flag: PGE Coastal	0.0004	0.11
Flag: PGE Inland	-0.0097	-2.58
Flag: SCE Coastal	-0.0040	-0.91
Flag: SCE Inland	-0.0200	-5.8
Flag: SDGE Coastal	-0.0029	-0.75
Flag: Fixed Array	-0.1436	-20.66
System Age	-0.0103	-17.78
CAISO Top 200 Hour Avg. Irradiance	0.0003	30.16

A.1.5 IOU Top 200 Hour Results

The final model and parameters for the IOU Top 200 Hour Results are listed below in Table A-5. The equation for the model is:

$$
\begin{aligned}
Annual\ CF = Intercept &+ Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\
&* \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\
&+ Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\
&* \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\
&+ IOUTop200HourAvg.Irradiance * \beta_{IOUTop200HourAvg.Irradiance} + \epsilon
\end{aligned}
$$

TABLE A-5: IOU TOP 200 HOUR IMPACTS REGRESSION MODEL

Independent Variable	Estimate	tValue
Intercept	0.23527	21.01
Flag: Pre2011	0.00905	4.63
Flag: Capacity: 15-100	0.00684	1.75
Flag: Capacity: >100	-0.00091	-0.27
Flag: PGE Coastal	-0.03885	-9.98
Flag: PGE Inland	-0.04846	-12.31
Flag: SCE Coastal	-0.05669	-11.84
Flag: SCE Inland	-0.06465	-16.27
Flag: SDGE Coastal	0.00574	1.18
Flag: Fixed Array	-0.12396	-51.34
System Age	-0.00544	-8.61
IOU Top 200 Hour Avg. Irradiance	0.00034	36.8

A.1.6 Greenhouse Gas Emission Results

The final model and parameters for the Greenhouse Gas Emission Results are listed below in Table A-6. The equation for the model is:

$$\begin{aligned} Annual\ CF = {} & Intercept + Flag_{pre2011} * \beta_{pre2011} + Flag_{Cap15100} * \beta_{Cap15100} + Flag_{CapGE100} \\ & * \beta_{CapGE100} + Flag_{PGECoastal} * \beta_{PGECoastal} + Flag_{PGEInland} * \beta_{PGEInland} \\ & + Flag_{SCECoastal} * \beta_{SCECoastal} + Flag_{SCEInland} * \beta_{SCEInland} + Flag_{SDGECoastal} \\ & * \beta_{SDGECoastal} + Flag_{FixedArray} * \beta_{FixedArray} + SystemAge * \beta_{SystemAge} \\ & + EmissionsperkW.Irradiance * \beta_{EmissionsperkW.Irradiance} + \epsilon \end{aligned}$$

TABLE A-6: IOU TOP 200 HOUR IMPACTS REGRESSION MODEL

Independent Variable	Estimate	tValue
Intercept	0.55821	13.09
Flag: Pre2011	0.32135	70.34
Flag: Capacity: 15-100	-0.02254	-2.42
Flag: Capacity: >100	-0.00690	-0.48
Flag: PGE Coastal	0.01063	1.65
Flag: PGE Inland	0.02161	3.84
Flag: SCE Coastal	-0.07189	-9.96
Flag: SCE Inland	0.01958	3.61
Flag: SDGE Coastal	0.01562	2.34
Flag: Fixed Array	-0.20806	-14.36
System Age	-0.04423	-48.2
Emissions per kW Irradiance	0.00140	8.05

A.2 TOP 200 HOURS

Data here are based on Total Actual Hourly Integrated Loads downloaded from http://oasis.caiso.com/ for Transmission Access Charge (TAC) Areas. These are fields 'PGE-TAC' for PG&E, 'SCE-TAC' for SCE and 'SDGE-TAC' for SDG&E to calculate CAISO load cumulative and each IOU's top 200 hours individually.

A.2.1 CAISO Top 200

TABLE A-7: CAISO TOP 200 HOURS

Hour #	2011	2012	2013	2014	2015	2016	2017
1	9/7/2011: 15:00	8/13/2012: 15:00	6/28/2013: 15:00	9/15/2014: 15:00	9/10/2015: 15:00	7/27/2016: 15:00	9/1/2017: 15:00
2	9/7/2011: 14:00	8/13/2012: 14:00	7/1/2013: 15:00	9/15/2014: 16:00	8/28/2015: 15:00	7/27/2016: 16:00	9/1/2017: 16:00
3	9/7/2011: 16:00	8/13/2012: 16:00	6/28/2013: 16:00	9/15/2014: 14:00	9/10/2015: 16:00	7/26/2016: 16:00	9/1/2017: 14:00
4	9/7/2011: 13:00	8/13/2012: 13:00	8/30/2013: 15:00	7/30/2014: 15:00	8/28/2015: 14:00	7/26/2016: 15:00	9/1/2017: 17:00
5	9/6/2011: 15:00	8/10/2012: 15:00	6/28/2013: 14:00	7/31/2014: 15:00	9/10/2015: 14:00	7/27/2016: 14:00	9/1/2017: 13:00
6	7/6/2011: 14:00	8/14/2012: 15:00	7/1/2013: 16:00	9/15/2014: 13:00	9/9/2015: 14:00	7/28/2016: 16:00	9/2/2017: 16:00
7	7/6/2011: 15:00	8/14/2012: 14:00	8/30/2013: 14:00	9/17/2014: 15:00	8/28/2015: 16:00	7/28/2016: 15:00	8/28/2017: 15:00
8	9/7/2011: 12:00	8/9/2012: 15:00	7/1/2013: 14:00	7/24/2014: 16:00	9/8/2015: 15:00	7/26/2016: 17:00	8/28/2017: 16:00
9	7/5/2011: 15:00	8/10/2012: 14:00	8/30/2013: 16:00	9/16/2014: 15:00	9/9/2015: 13:00	7/27/2016: 17:00	9/2/2017: 15:00
10	9/6/2011: 16:00	8/13/2012: 17:00	6/29/2013: 15:00	9/16/2014: 14:00	9/11/2015: 15:00	7/29/2016: 16:00	9/1/2017: 18:00
11	7/6/2011: 13:00	8/14/2012: 13:00	8/30/2013: 13:00	7/24/2014: 15:00	9/8/2015: 16:00	7/29/2016: 15:00	8/29/2017: 16:00
12	9/6/2011: 14:00	8/9/2012: 16:00	6/28/2013: 17:00	7/30/2014: 16:00	9/9/2015: 15:00	7/26/2016: 14:00	8/29/2017: 15:00
13	7/6/2011: 16:00	8/9/2012: 14:00	6/28/2013: 13:00	7/31/2014: 16:00	8/27/2015: 15:00	6/20/2016: 16:00	9/2/2017: 17:00
14	7/7/2011: 15:00	8/10/2012: 16:00	6/29/2013: 16:00	8/1/2014: 15:00	9/10/2015: 13:00	7/27/2016: 13:00	8/31/2017: 15:00
15	8/26/2011: 15:00	8/8/2012: 15:00	7/1/2013: 17:00	7/31/2014: 14:00	9/10/2015: 17:00	6/20/2016: 15:00	8/31/2017: 16:00
16	7/5/2011: 14:00	8/14/2012: 16:00	6/29/2013: 14:00	9/17/2014: 14:00	9/8/2015: 14:00	7/28/2016: 14:00	8/30/2017: 16:00
17	7/5/2011: 16:00	8/13/2012: 12:00	7/2/2013: 13:00	7/30/2014: 14:00	8/28/2015: 13:00	7/29/2016: 14:00	9/2/2017: 14:00
18	9/7/2011: 17:00	8/10/2012: 13:00	7/2/2013: 14:00	9/15/2014: 17:00	8/27/2015: 16:00	7/28/2016: 17:00	8/28/2017: 17:00
19	8/26/2011: 14:00	8/8/2012: 16:00	7/1/2013: 13:00	9/16/2014: 13:00	9/11/2015: 14:00	6/20/2016: 17:00	8/28/2017: 14:00
20	7/7/2011: 14:00	8/8/2012: 14:00	6/29/2013: 17:00	9/16/2014: 16:00	9/9/2015: 16:00	7/25/2016: 16:00	8/29/2017: 17:00
21	8/29/2011: 15:00	8/9/2012: 13:00	9/6/2013: 15:00	8/1/2014: 14:00	9/10/2015: 18:00	7/29/2016: 17:00	8/30/2017: 15:00
22	8/25/2011: 15:00	8/9/2012: 17:00	6/27/2013: 15:00	9/15/2014: 18:00	9/11/2015: 16:00	8/15/2016: 16:00	9/1/2017: 12:00
23	8/29/2011: 14:00	8/10/2012: 17:00	7/3/2013: 15:00	8/1/2014: 16:00	8/27/2015: 14:00	7/26/2016: 13:00	8/31/2017: 14:00
24	7/6/2011: 12:00	8/14/2012: 12:00	7/9/2013: 15:00	7/31/2014: 17:00	9/9/2015: 12:00	6/20/2016: 14:00	9/1/2017: 19:00
25	7/7/2011: 16:00	8/7/2012: 15:00	7/2/2013: 15:00	7/24/2014: 17:00	9/9/2015: 17:00	7/25/2016: 15:00	8/31/2017: 17:00
26	9/7/2011: 18:00	8/29/2012: 15:00	8/29/2013: 15:00	9/12/2014: 15:00	9/9/2015: 18:00	8/15/2016: 15:00	9/2/2017: 18:00
27	8/24/2011: 15:00	10/1/2012: 15:00	9/5/2013: 15:00	9/17/2014: 16:00	9/8/2015: 17:00	7/26/2016: 18:00	8/29/2017: 14:00
28	9/8/2011: 13:00	8/7/2012: 14:00	9/3/2013: 15:00	7/30/2014: 17:00	9/11/2015: 13:00	7/25/2016: 17:00	8/30/2017: 17:00
29	8/25/2011: 16:00	8/13/2012: 18:00	7/9/2013: 16:00	9/16/2014: 18:00	8/17/2015: 15:00	7/29/2016: 13:00	7/7/2017: 16:00
30	8/26/2011: 16:00	8/8/2012: 13:00	9/4/2013: 15:00	7/24/2014: 14:00	9/9/2015: 19:00	7/27/2016: 18:00	7/7/2017: 15:00
31	7/5/2011: 13:00	8/17/2012: 15:00	8/29/2013: 16:00	9/17/2014: 13:00	8/28/2015: 17:00	6/27/2016: 16:00	8/31/2017: 18:00
32	7/7/2011: 13:00	8/17/2012: 14:00	6/27/2013: 16:00	9/16/2014: 17:00	9/10/2015: 12:00	6/27/2016: 15:00	8/28/2017: 18:00
33	8/26/2011: 13:00	10/2/2012: 15:00	8/30/2013: 12:00	7/25/2014: 15:00	8/17/2015: 16:00	7/28/2016: 13:00	9/2/2017: 13:00
34	8/25/2011: 14:00	9/14/2012: 15:00	9/5/2013: 14:00	9/12/2014: 14:00	9/10/2015: 19:00	7/22/2016: 16:00	7/7/2017: 17:00
35	7/8/2011: 15:00	8/20/2012: 15:00	9/4/2013: 16:00	7/29/2014: 15:00	9/8/2015: 13:00	8/15/2016: 17:00	8/30/2017: 14:00
36	8/29/2011: 16:00	8/8/2012: 17:00	6/29/2013: 13:00	9/15/2014: 12:00	8/28/2015: 12:00	8/16/2016: 16:00	8/3/2017: 15:00
37	9/6/2011: 13:00	8/10/2012: 12:00	7/3/2013: 14:00	7/25/2014: 16:00	8/27/2015: 17:00	6/28/2016: 15:00	8/29/2017: 18:00
38	8/24/2011: 14:00	8/14/2012: 17:00	9/4/2013: 14:00	7/31/2014: 13:00	9/8/2015: 18:00	6/28/2016: 16:00	8/3/2017: 14:00
39	7/5/2011: 17:00	8/16/2012: 15:00	7/2/2013: 12:00	8/1/2014: 13:00	8/17/2015: 14:00	8/16/2016: 15:00	8/31/2017: 13:00
40	7/6/2011: 17:00	8/7/2012: 16:00	6/28/2013: 12:00	9/12/2014: 16:00	8/27/2015: 13:00	9/26/2016: 15:00	9/2/2017: 19:00
41	9/6/2011: 17:00	8/9/2012: 12:00	9/5/2013: 16:00	9/16/2014: 12:00	8/16/2015: 16:00	7/22/2016: 17:00	7/7/2017: 14:00
42	7/8/2011: 14:00	8/16/2012: 14:00	9/6/2013: 16:00	7/30/2014: 13:00	8/26/2015: 15:00	7/22/2016: 15:00	8/28/2017: 13:00
43	8/29/2011: 13:00	8/29/2012: 14:00	8/30/2013: 17:00	7/29/2014: 16:00	8/16/2015: 17:00	8/17/2016: 16:00	8/3/2017: 16:00
44	9/8/2011: 14:00	7/11/2012: 15:00	6/28/2013: 18:00	8/28/2014: 15:00	9/11/2015: 12:00	7/28/2016: 18:00	8/30/2017: 18:00
45	9/7/2011: 11:00	8/29/2012: 16:00	6/27/2013: 14:00	7/29/2014: 14:00	8/26/2015: 16:00	7/27/2016: 12:00	8/2/2017: 15:00
46	8/24/2011: 16:00	8/20/2012: 14:00	7/1/2013: 18:00	7/25/2014: 14:00	8/16/2015: 15:00	6/27/2016: 14:00	6/20/2017: 16:00
47	9/7/2011: 19:00	10/2/2012: 14:00	9/3/2013: 14:00	8/1/2014: 17:00	9/8/2015: 19:00	9/26/2016: 16:00	6/19/2017: 16:00
48	9/8/2011: 12:00	10/1/2012: 14:00	7/9/2013: 14:00	9/15/2014: 19:00	8/17/2015: 17:00	8/15/2016: 14:00	8/31/2017: 19:00
49	9/6/2011: 18:00	10/1/2012: 16:00	7/3/2013: 16:00	9/17/2014: 12:00	8/26/2015: 14:00	7/27/2016: 19:00	8/28/2017: 19:00
50	7/8/2011: 16:00	8/13/2012: 19:00	9/6/2013: 14:00	8/28/2014: 14:00	8/28/2015: 18:00	6/27/2016: 17:00	8/2/2017: 16:00
51	7/5/2011: 12:00	8/13/2012: 11:00	9/3/2013: 16:00	9/16/2014: 19:00	8/15/2015: 16:00	6/20/2016: 13:00	8/1/2017: 15:00
52	7/7/2011: 17:00	8/17/2012: 13:00	8/29/2013: 14:00	8/28/2014: 16:00	8/27/2015: 18:00	6/20/2016: 18:00	8/3/2017: 13:00
53	7/7/2011: 12:00	8/17/2012: 16:00	8/28/2013: 16:00	7/31/2014: 18:00	9/11/2015: 17:00	8/17/2016: 15:00	8/29/2017: 13:00
54	8/23/2011: 15:00	7/11/2012: 14:00	7/8/2013: 16:00	9/11/2014: 15:00	8/17/2015: 13:00	6/28/2016: 17:00	8/2/2017: 14:00
55	8/25/2011: 13:00	9/14/2012: 14:00	8/28/2013: 15:00	5/15/2014: 15:00	8/15/2015: 15:00	7/25/2016: 14:00	6/20/2017: 15:00
56	7/6/2011: 11:00	8/16/2012: 16:00	7/9/2013: 17:00	9/14/2014: 16:00	9/9/2015: 11:00	7/29/2016: 18:00	6/20/2017: 17:00
57	7/8/2011: 13:00	9/14/2012: 16:00	9/4/2013: 13:00	7/24/2014: 13:00	7/29/2015: 15:00	8/16/2016: 17:00	6/19/2017: 15:00

Hour #	2011	2012	2013	2014	2015	2016	2017
58	8/23/2011: 16:00	8/7/2012: 13:00	7/8/2013: 15:00	7/8/2014: 15:00	7/29/2015: 16:00	7/26/2016: 19:00	6/19/2017: 17:00
59	8/24/2011: 13:00	7/11/2012: 16:00	6/27/2013: 17:00	7/24/2014: 18:00	8/14/2015: 15:00	6/28/2016: 14:00	7/7/2017: 18:00
60	8/26/2011: 17:00	8/20/2012: 16:00	6/29/2013: 18:00	9/14/2014: 15:00	6/30/2015: 14:00	7/22/2016: 14:00	9/1/2017: 20:00
61	8/26/2011: 12:00	8/15/2012: 15:00	9/5/2013: 13:00	7/8/2014: 16:00	8/14/2015: 16:00	8/17/2016: 17:00	8/29/2017: 19:00
62	8/2/2011: 15:00	8/15/2012: 14:00	7/1/2013: 12:00	9/12/2014: 13:00	8/27/2015: 19:00	9/26/2016: 14:00	9/1/2017: 11:00
63	8/1/2011: 15:00	8/11/2012: 15:00	8/29/2013: 17:00	9/11/2014: 16:00	8/16/2015: 14:00	7/26/2016: 12:00	9/11/2017: 15:00
64	8/25/2011: 17:00	10/2/2012: 16:00	7/2/2013: 16:00	7/25/2014: 17:00	6/30/2015: 13:00	6/29/2016: 16:00	6/21/2017: 16:00
65	8/23/2011: 14:00	8/16/2012: 13:00	7/3/2013: 13:00	8/15/2014: 15:00	8/15/2015: 17:00	7/29/2016: 12:00	8/1/2017: 16:00
66	8/27/2011: 15:00	8/11/2012: 14:00	7/1/2013: 19:00	8/27/2014: 15:00	7/30/2015: 15:00	7/25/2016: 18:00	8/1/2017: 14:00
67	9/6/2011: 19:00	8/6/2012: 15:00	6/28/2013: 19:00	5/15/2014: 16:00	9/11/2015: 18:00	7/28/2016: 19:00	7/10/2017: 16:00
68	9/6/2011: 12:00	8/9/2012: 18:00	6/30/2013: 16:00	9/11/2014: 14:00	8/27/2015: 12:00	6/29/2016: 15:00	8/2/2017: 17:00
69	8/27/2011: 14:00	7/10/2012: 15:00	7/8/2013: 17:00	9/17/2014: 17:00	9/10/2015: 11:00	7/22/2016: 18:00	8/3/2017: 17:00
70	8/2/2011: 14:00	8/10/2012: 18:00	6/30/2013: 15:00	7/29/2014: 13:00	8/28/2015: 19:00	8/15/2016: 18:00	8/2/2017: 13:00
71	8/29/2011: 12:00	8/6/2012: 16:00	9/3/2013: 13:00	7/25/2014: 13:00	10/13/2015: 15:00	6/27/2016: 18:00	8/30/2017: 13:00
72	8/29/2011: 17:00	8/14/2012: 11:00	8/28/2013: 14:00	7/30/2014: 18:00	9/25/2015: 15:00	8/16/2016: 14:00	6/21/2017: 15:00
73	8/1/2011: 14:00	7/10/2012: 16:00	6/27/2013: 13:00	5/15/2014: 14:00	8/26/2015: 17:00	7/21/2016: 16:00	6/21/2017: 17:00
74	8/2/2011: 16:00	8/20/2012: 13:00	9/4/2013: 17:00	7/31/2014: 12:00	7/29/2015: 14:00	9/26/2016: 17:00	7/10/2017: 15:00
75	7/5/2011: 18:00	8/11/2012: 16:00	8/29/2013: 13:00	8/15/2014: 16:00	7/29/2015: 17:00	6/29/2016: 17:00	8/30/2017: 19:00
76	8/1/2011: 16:00	8/7/2012: 17:00	9/6/2013: 17:00	7/8/2014: 14:00	9/8/2015: 12:00	6/20/2016: 19:00	9/5/2017: 16:00
77	6/21/2011: 15:00	8/29/2012: 13:00	7/3/2013: 17:00	7/29/2014: 17:00	8/13/2015: 15:00	6/27/2016: 13:00	9/2/2017: 12:00
78	8/3/2011: 15:00	8/15/2012: 13:00	6/29/2013: 12:00	7/28/2014: 15:00	8/14/2015: 14:00	7/25/2016: 13:00	9/11/2017: 16:00
79	8/24/2011: 17:00	9/4/2012: 15:00	8/30/2013: 18:00	9/13/2014: 15:00	8/16/2015: 18:00	7/28/2016: 12:00	6/20/2017: 14:00
80	7/20/2011: 15:00	7/11/2012: 13:00	9/6/2013: 13:00	7/28/2014: 16:00	8/15/2015: 14:00	8/15/2016: 13:00	7/10/2017: 17:00
81	7/6/2011: 18:00	8/12/2012: 16:00	7/9/2013: 13:00	8/27/2014: 16:00	7/30/2015: 16:00	7/14/2016: 16:00	7/7/2017: 13:00
82	8/27/2011: 16:00	8/28/2012: 15:00	9/5/2013: 17:00	8/1/2014: 12:00	9/25/2015: 14:00	8/18/2016: 16:00	6/19/2017: 14:00
83	8/27/2011: 13:00	9/14/2012: 13:00	7/2/2013: 11:00	9/17/2014: 18:00	8/28/2015: 11:00	7/21/2016: 15:00	9/5/2017: 15:00
84	7/8/2011: 12:00	8/8/2012: 12:00	8/19/2013: 15:00	9/14/2014: 14:00	8/13/2015: 16:00	8/18/2016: 15:00	7/8/2017: 15:00
85	9/8/2011: 11:00	8/12/2012: 15:00	9/7/2013: 15:00	7/30/2014: 12:00	6/30/2015: 15:00	6/28/2016: 18:00	8/31/2017: 12:00
86	8/3/2011: 14:00	8/6/2012: 14:00	8/30/2013: 11:00	7/31/2014: 19:00	9/24/2015: 15:00	8/17/2016: 14:00	8/3/2017: 12:00
87	7/5/2011: 11:00	8/15/2012: 16:00	8/27/2013: 15:00	9/16/2014: 11:00	8/26/2015: 13:00	7/29/2016: 19:00	9/11/2017: 14:00
88	8/2/2011: 13:00	8/29/2012: 17:00	9/3/2013: 17:00	9/14/2014: 17:00	8/17/2015: 12:00	8/2/2016: 16:00	6/19/2017: 18:00
89	7/8/2011: 17:00	8/10/2012: 11:00	7/8/2013: 14:00	9/13/2014: 16:00	10/13/2015: 14:00	7/14/2016: 15:00	8/1/2017: 17:00
90	6/21/2011: 14:00	8/9/2012: 19:00	6/30/2013: 14:00	8/28/2014: 13:00	7/30/2015: 14:00	7/25/2016: 19:00	7/8/2017: 14:00
91	8/28/2011: 15:00	9/13/2012: 15:00	6/29/2013: 19:00	9/12/2014: 17:00	9/9/2015: 20:00	8/1/2016: 16:00	7/17/2017: 16:00
92	8/23/2011: 17:00	10/2/2012: 13:00	8/30/2013: 19:00	8/15/2014: 14:00	9/20/2015: 16:00	8/1/2016: 15:00	8/2/2017: 18:00
93	8/26/2011: 18:00	8/11/2012: 13:00	8/28/2013: 17:00	7/28/2014: 14:00	8/17/2015: 18:00	7/21/2016: 17:00	7/8/2017: 16:00
94	8/25/2011: 12:00	8/17/2012: 12:00	9/7/2013: 14:00	7/8/2014: 17:00	7/28/2015: 16:00	6/27/2016: 19:00	6/20/2017: 18:00
95	9/7/2011: 10:00	8/16/2012: 17:00	6/30/2013: 17:00	9/15/2014: 11:00	8/26/2015: 18:00	6/29/2016: 14:00	7/27/2017: 16:00
96	7/7/2011: 11:00	8/30/2012: 14:00	6/28/2013: 11:00	8/28/2014: 17:00	8/13/2015: 14:00	6/28/2016: 13:00	6/21/2017: 14:00
97	8/28/2011: 16:00	7/11/2012: 17:00	7/9/2013: 18:00	8/27/2014: 14:00	9/11/2015: 11:00	7/24/2016: 17:00	7/7/2017: 19:00
98	8/17/2011: 15:00	8/10/2012: 19:00	8/29/2013: 18:00	7/9/2014: 15:00	10/13/2015: 16:00	7/24/2016: 16:00	7/17/2017: 15:00
99	7/6/2011: 10:00	7/10/2012: 14:00	6/27/2013: 18:00	6/30/2014: 15:00	8/14/2015: 17:00	9/26/2016: 18:00	7/10/2017: 14:00
100	7/5/2011: 19:00	8/8/2012: 18:00	8/19/2013: 16:00	7/24/2014: 19:00	8/24/2015: 16:00	7/20/2016: 16:00	9/2/2017: 20:00
101	7/20/2011: 14:00	8/17/2012: 17:00	8/16/2013: 15:00	7/30/2014: 19:00	8/24/2015: 15:00	6/20/2016: 12:00	8/29/2017: 12:00
102	8/1/2011: 13:00	10/1/2012: 13:00	8/19/2013: 14:00	7/7/2014: 15:00	8/16/2015: 19:00	8/30/2016: 15:00	8/28/2017: 12:00
103	6/21/2011: 16:00	8/30/2012: 13:00	8/29/2013: 12:00	9/13/2014: 14:00	8/24/2015: 18:00	8/2/2016: 15:00	7/17/2017: 17:00
104	7/20/2011: 16:00	8/7/2012: 12:00	9/4/2013: 12:00	7/9/2014: 16:00	9/25/2015: 16:00	7/14/2016: 17:00	6/21/2017: 18:00
105	8/18/2011: 15:00	9/4/2012: 14:00	8/29/2013: 19:00	9/17/2014: 11:00	7/28/2015: 15:00	8/30/2016: 16:00	8/2/2017: 19:00
106	8/24/2011: 12:00	8/28/2012: 14:00	8/28/2013: 13:00	6/30/2014: 16:00	9/24/2015: 16:00	6/30/2016: 16:00	7/27/2017: 15:00
107	8/3/2011: 16:00	8/20/2012: 17:00	9/4/2013: 18:00	9/2/2014: 15:00	6/30/2015: 16:00	6/21/2016: 16:00	7/27/2017: 17:00
108	7/7/2011: 18:00	8/14/2012: 18:00	7/25/2013: 15:00	7/7/2014: 16:00	7/20/2015: 16:00	8/14/2016: 16:00	7/6/2017: 16:00
109	8/25/2011: 18:00	8/28/2012: 16:00	9/5/2013: 12:00	8/1/2014: 18:00	8/17/2015: 19:00	6/21/2016: 15:00	7/8/2017: 17:00
110	8/23/2011: 13:00	8/9/2012: 11:00	8/15/2013: 15:00	9/14/2014: 18:00	7/31/2015: 15:00	8/14/2016: 17:00	9/5/2017: 17:00
111	8/16/2011: 15:00	8/6/2012: 17:00	8/27/2013: 16:00	8/29/2014: 15:00	8/18/2015: 15:00	8/16/2016: 18:00	9/3/2017: 15:00
112	7/6/2011: 19:00	9/4/2012: 16:00	9/7/2013: 16:00	5/15/2014: 17:00	8/26/2015: 19:00	7/20/2016: 17:00	8/1/2017: 13:00
113	6/22/2011: 15:00	8/12/2012: 14:00	9/6/2013: 18:00	9/11/2014: 13:00	9/10/2015: 20:00	7/27/2016: 20:00	9/5/2017: 14:00
114	8/18/2011: 14:00	9/14/2012: 17:00	9/5/2013: 18:00	9/10/2014: 15:00	7/30/2015: 13:00	7/21/2016: 14:00	8/3/2017: 18:00
115	8/27/2011: 12:00	9/13/2012: 16:00	7/24/2013: 15:00	9/10/2014: 16:00	9/20/2015: 15:00	9/27/2016: 15:00	8/1/2017: 18:00
116	8/25/2011: 19:00	10/1/2012: 17:00	8/16/2013: 14:00	7/8/2014: 13:00	7/20/2015: 15:00	6/30/2016: 15:00	8/4/2017: 15:00
117	6/22/2011: 14:00	9/13/2012: 14:00	8/27/2013: 14:00	5/15/2014: 13:00	6/30/2015: 12:00	8/15/2016: 19:00	6/20/2017: 13:00
118	8/17/2011: 14:00	8/30/2012: 15:00	8/20/2013: 15:00	7/7/2014: 14:00	6/25/2015: 16:00	8/17/2016: 18:00	8/2/2017: 12:00
119	8/28/2011: 14:00	8/13/2012: 10:00	7/2/2013: 17:00	7/23/2014: 16:00	7/29/2015: 13:00	7/23/2016: 16:00	7/6/2017: 17:00

Hour #	2011	2012	2013	2014	2015	2016	2017
120	8/26/2011: 19:00	8/21/2012: 15:00	7/1/2013: 11:00	8/27/2014: 17:00	7/28/2015: 17:00	7/13/2016: 16:00	8/27/2017: 16:00
121	9/8/2011: 15:00	7/10/2012: 17:00	7/25/2013: 16:00	9/11/2014: 17:00	9/11/2015: 19:00	8/2/2016: 17:00	9/3/2017: 14:00
122	8/30/2011: 15:00	8/12/2012: 17:00	6/30/2013: 13:00	8/18/2014: 15:00	6/8/2015: 16:00	9/26/2016: 13:00	8/4/2017: 14:00
123	8/2/2011: 17:00	8/11/2012: 17:00	9/6/2013: 12:00	6/30/2014: 14:00	8/18/2015: 16:00	7/27/2016: 11:00	6/19/2017: 13:00
124	9/9/2011: 15:00	8/14/2012: 19:00	7/3/2013: 12:00	7/23/2014: 15:00	6/25/2015: 15:00	7/30/2016: 15:00	7/10/2017: 18:00
125	7/19/2011: 15:00	8/21/2012: 14:00	6/27/2013: 12:00	7/26/2014: 15:00	8/14/2015: 13:00	7/22/2016: 13:00	7/6/2017: 15:00
126	7/25/2011: 15:00	10/1/2012: 18:00	9/5/2013: 19:00	7/9/2014: 14:00	6/8/2015: 15:00	7/22/2016: 19:00	7/11/2017: 16:00
127	7/28/2011: 15:00	10/2/2012: 17:00	6/28/2013: 20:00	7/25/2014: 12:00	6/30/2015: 17:00	7/30/2016: 16:00	7/8/2017: 13:00
128	8/1/2011: 17:00	8/8/2012: 19:00	9/3/2013: 12:00	7/28/2014: 17:00	7/31/2015: 16:00	8/18/2016: 17:00	8/27/2017: 17:00
129	8/3/2011: 13:00	8/16/2012: 12:00	8/16/2013: 16:00	7/28/2014: 13:00	9/20/2015: 17:00	7/23/2016: 15:00	7/31/2017: 16:00
130	7/1/2011: 15:00	8/20/2012: 12:00	8/15/2013: 16:00	7/3/2014: 15:00	7/29/2015: 18:00	8/1/2016: 17:00	8/4/2017: 16:00
131	8/26/2011: 11:00	8/6/2012: 13:00	7/24/2013: 16:00	7/3/2014: 16:00	9/25/2015: 13:00	7/20/2016: 15:00	7/17/2017: 14:00
132	9/9/2011: 14:00	9/10/2012: 15:00	9/7/2013: 13:00	7/14/2014: 15:00	9/9/2015: 10:00	6/30/2016: 17:00	6/22/2017: 15:00
133	8/16/2011: 14:00	8/30/2012: 12:00	9/3/2013: 18:00	6/9/2014: 15:00	8/16/2015: 13:00	8/3/2016: 16:00	9/3/2017: 16:00
134	8/16/2011: 16:00	9/14/2012: 18:00	9/4/2013: 19:00	8/11/2014: 15:00	7/31/2015: 14:00	8/31/2016: 15:00	8/1/2017: 19:00
135	8/17/2011: 16:00	8/18/2012: 15:00	7/24/2013: 14:00	5/14/2014: 16:00	8/13/2015: 17:00	8/3/2016: 15:00	6/22/2017: 16:00
136	8/18/2011: 16:00	8/29/2012: 18:00	8/20/2013: 16:00	8/29/2014: 14:00	7/30/2015: 17:00	8/1/2016: 14:00	9/3/2017: 13:00
137	8/2/2011: 12:00	8/2/2012: 15:00	7/8/2013: 18:00	7/29/2014: 12:00	10/9/2015: 15:00	6/21/2016: 17:00	7/31/2017: 17:00
138	6/21/2011: 13:00	8/15/2012: 12:00	6/27/2013: 19:00	5/14/2014: 15:00	8/15/2015: 13:00	8/18/2016: 14:00	8/30/2017: 12:00
139	8/29/2011: 18:00	8/13/2012: 20:00	8/28/2013: 18:00	9/2/2014: 16:00	9/24/2015: 14:00	8/31/2016: 16:00	7/10/2017: 13:00
140	7/19/2011: 16:00	10/2/2012: 18:00	8/15/2013: 14:00	7/26/2014: 16:00	8/15/2015: 18:00	7/13/2016: 17:00	9/6/2017: 15:00
141	8/15/2011: 15:00	8/7/2012: 18:00	8/21/2013: 15:00	8/14/2014: 15:00	8/5/2015: 15:00	7/26/2016: 20:00	9/11/2017: 17:00
142	8/30/2011: 14:00	8/29/2012: 12:00	7/1/2013: 20:00	7/24/2014: 12:00	8/5/2015: 16:00	9/27/2016: 16:00	8/31/2017: 20:00
143	8/29/2011: 11:00	7/11/2012: 12:00	7/9/2013: 12:00	7/25/2014: 18:00	10/13/2015: 13:00	7/14/2016: 14:00	6/19/2017: 19:00
144	8/24/2011: 18:00	8/28/2012: 13:00	8/20/2013: 14:00	8/15/2014: 17:00	9/21/2015: 15:00	7/28/2016: 20:00	9/11/2017: 13:00
145	7/25/2011: 14:00	8/15/2012: 17:00	7/2/2013: 10:00	9/12/2014: 12:00	9/20/2015: 18:00	7/23/2016: 17:00	7/11/2017: 15:00
146	6/22/2011: 16:00	8/29/2012: 19:00	7/3/2013: 18:00	8/18/2014: 16:00	8/24/2015: 14:00	6/28/2016: 19:00	9/1/2017: 10:00
147	7/21/2011: 15:00	8/14/2012: 10:00	7/9/2013: 19:00	6/9/2014: 14:00	9/21/2015: 14:00	6/21/2016: 14:00	6/20/2017: 19:00
148	7/1/2011: 16:00	7/20/2012: 15:00	6/29/2013: 20:00	8/18/2014: 14:00	6/29/2015: 16:00	6/29/2016: 18:00	7/7/2017: 12:00
149	6/21/2011: 17:00	7/10/2012: 13:00	9/6/2013: 19:00	8/11/2014: 16:00	7/20/2015: 14:00	7/25/2016: 12:00	7/27/2017: 14:00
150	7/20/2011: 13:00	9/14/2012: 12:00	7/8/2013: 13:00	9/2/2014: 14:00	10/13/2015: 17:00	7/24/2016: 15:00	7/11/2017: 17:00
151	7/7/2011: 19:00	8/21/2012: 16:00	8/28/2013: 19:00	7/29/2014: 18:00	6/30/2015: 18:00	9/27/2016: 14:00	9/6/2017: 16:00
152	9/19/2011: 15:00	9/10/2012: 14:00	8/31/2013: 15:00	8/29/2014: 16:00	7/20/2015: 17:00	7/13/2016: 15:00	6/21/2017: 19:00
153	9/20/2011: 15:00	8/7/2012: 19:00	6/29/2013: 11:00	9/12/2014: 18:00	6/29/2015: 15:00	7/29/2016: 11:00	9/5/2017: 18:00
154	8/28/2011: 17:00	8/18/2012: 16:00	9/9/2013: 15:00	8/14/2014: 16:00	8/18/2015: 14:00	6/3/2016: 15:00	8/3/2017: 19:00
155	7/19/2011: 14:00	8/30/2012: 16:00	9/3/2013: 19:00	9/17/2014: 19:00	8/29/2015: 15:00	6/3/2016: 16:00	8/4/2017: 13:00
156	8/1/2011: 12:00	8/18/2012: 14:00	8/30/2013: 10:00	8/28/2014: 18:00	6/26/2015: 15:00	8/15/2016: 12:00	8/3/2017: 11:00
157	7/28/2011: 14:00	8/17/2012: 11:00	6/30/2013: 12:00	7/26/2014: 14:00	8/24/2015: 17:00	8/30/2016: 14:00	9/12/2017: 15:00
158	7/28/2011: 16:00	9/10/2012: 16:00	7/4/2013: 15:00	6/9/2014: 16:00	6/8/2015: 17:00	8/2/2016: 14:00	7/31/2017: 15:00
159	7/25/2011: 16:00	8/11/2012: 12:00	8/16/2013: 13:00	7/15/2014: 15:00	6/25/2015: 17:00	8/16/2016: 13:00	6/22/2017: 17:00
160	9/23/2011: 15:00	8/21/2012: 13:00	8/19/2013: 13:00	7/14/2014: 14:00	8/29/2015: 16:00	7/24/2016: 18:00	8/27/2017: 15:00
161	6/22/2011: 13:00	8/1/2012: 15:00	8/27/2013: 13:00	8/11/2014: 14:00	9/10/2015: 10:00	6/27/2016: 12:00	7/12/2017: 16:00
162	8/27/2011: 17:00	8/12/2012: 13:00	8/21/2013: 16:00	7/7/2014: 13:00	9/8/2015: 20:00	7/23/2016: 14:00	8/28/2017: 20:00
163	7/26/2011: 15:00	8/16/2012: 18:00	6/30/2013: 18:00	7/1/2014: 15:00	8/13/2015: 13:00	6/29/2016: 13:00	6/21/2017: 13:00
164	9/23/2011: 14:00	7/31/2012: 15:00	8/31/2013: 14:00	7/7/2014: 17:00	10/9/2015: 16:00	6/30/2016: 14:00	7/26/2017: 16:00
165	8/15/2011: 14:00	10/2/2012: 12:00	5/13/2013: 15:00	6/30/2014: 17:00	7/28/2015: 14:00	7/21/2016: 18:00	9/12/2017: 16:00
166	8/23/2011: 18:00	8/10/2012: 10:00	9/9/2013: 14:00	9/14/2014: 13:00	10/13/2015: 18:00	7/26/2016: 11:00	7/6/2017: 18:00
167	9/7/2011: 20:00	8/2/2012: 14:00	8/19/2013: 17:00	7/9/2014: 17:00	6/30/2015: 19:00	7/30/2016: 17:00	8/11/2017: 16:00
168	7/20/2011: 17:00	7/11/2012: 18:00	8/22/2013: 15:00	8/1/2014: 19:00	9/20/2015: 14:00	8/16/2016: 19:00	7/27/2017: 18:00
169	7/8/2011: 11:00	8/2/2012: 16:00	6/28/2013: 10:00	8/12/2014: 15:00	8/27/2015: 11:00	8/30/2016: 17:00	7/17/2017: 18:00
170	9/21/2011: 15:00	9/4/2012: 13:00	8/27/2013: 17:00	9/11/2014: 18:00	9/21/2015: 16:00	8/17/2016: 19:00	7/13/2017: 16:00
171	9/2/2011: 15:00	7/20/2012: 16:00	8/21/2013: 14:00	7/1/2014: 16:00	6/26/2015: 16:00	8/14/2016: 15:00	8/26/2017: 16:00
172	7/7/2011: 10:00	8/16/2012: 19:00	8/31/2013: 16:00	9/10/2014: 14:00	6/8/2015: 14:00	7/14/2016: 18:00	9/6/2017: 14:00
173	7/1/2011: 14:00	8/28/2012: 17:00	7/4/2013: 14:00	9/13/2014: 17:00	6/25/2015: 14:00	7/29/2016: 20:00	7/7/2017: 20:00
174	8/24/2011: 19:00	9/13/2012: 13:00	7/25/2013: 17:00	7/23/2014: 14:00	8/26/2015: 12:00	6/20/2016: 20:00	7/8/2017: 18:00
175	9/6/2011: 11:00	9/13/2012: 17:00	7/4/2013: 16:00	7/23/2014: 17:00	10/9/2015: 14:00	7/30/2016: 14:00	6/22/2017: 14:00
176	8/30/2011: 16:00	8/8/2012: 11:00	7/24/2013: 17:00	7/15/2014: 14:00	8/29/2015: 14:00	7/15/2016: 16:00	8/8/2017: 16:00
177	9/22/2011: 15:00	9/15/2012: 15:00	7/3/2013: 19:00	7/14/2014: 16:00	7/2/2015: 15:00	8/3/2016: 17:00	7/12/2017: 17:00
178	9/20/2011: 14:00	7/31/2012: 16:00	7/2/2013: 18:00	7/3/2014: 14:00	7/29/2015: 19:00	8/14/2016: 18:00	9/2/2017: 11:00
179	9/8/2011: 10:00	9/13/2012: 18:00	8/28/2013: 12:00	8/12/2014: 14:00	8/12/2015: 16:00	8/17/2016: 13:00	7/6/2017: 14:00
180	7/21/2011: 14:00	9/10/2012: 13:00	9/16/2013: 15:00	8/15/2014: 13:00	7/31/2015: 13:00	8/3/2016: 14:00	8/11/2017: 15:00
181	7/26/2011: 14:00	7/20/2012: 14:00	8/29/2013: 11:00	8/27/2014: 13:00	8/17/2015: 11:00	8/12/2016: 16:00	7/14/2017: 16:00

Hour #	2011	2012	2013	2014	2015	2016	2017
182	8/23/2011: 19:00	8/1/2012: 16:00	8/14/2013: 15:00	9/14/2014: 19:00	8/18/2015: 17:00	8/31/2016: 14:00	8/31/2017: 11:00
183	8/15/2011: 16:00	8/17/2012: 18:00	9/5/2013: 11:00	7/29/2014: 19:00	7/31/2015: 17:00	6/28/2016: 12:00	7/26/2017: 17:00
184	7/21/2011: 16:00	8/1/2012: 14:00	8/22/2013: 16:00	8/14/2014: 14:00	8/5/2015: 14:00	6/22/2016: 16:00	9/11/2017: 18:00
185	7/5/2011: 20:00	7/31/2012: 14:00	5/13/2013: 16:00	5/14/2014: 17:00	9/24/2015: 17:00	7/20/2016: 18:00	7/13/2017: 15:00
186	8/29/2011: 19:00	8/6/2012: 18:00	9/7/2013: 17:00	6/30/2014: 13:00	6/29/2015: 17:00	8/19/2016: 15:00	9/3/2017: 12:00
187	9/19/2011: 14:00	8/11/2012: 18:00	9/9/2013: 16:00	8/28/2014: 12:00	7/30/2015: 12:00	8/19/2016: 16:00	8/29/2017: 20:00
188	8/3/2011: 17:00	9/4/2012: 17:00	7/18/2013: 15:00	7/31/2014: 11:00	7/28/2015: 18:00	6/27/2016: 20:00	7/12/2017: 15:00
189	8/17/2011: 13:00	8/22/2012: 15:00	7/25/2013: 14:00	7/3/2014: 17:00	8/15/2015: 19:00	7/28/2016: 11:00	8/27/2017: 18:00
190	8/18/2011: 13:00	8/20/2012: 18:00	7/24/2013: 13:00	9/13/2014: 13:00	6/26/2015: 14:00	6/22/2016: 15:00	9/5/2017: 13:00
191	9/8/2011: 16:00	8/12/2012: 18:00	9/7/2013: 12:00	9/24/2014: 15:00	10/12/2015: 15:00	7/15/2016: 17:00	7/26/2017: 15:00
192	7/5/2011: 10:00	9/12/2012: 15:00	7/1/2013: 10:00	9/16/2014: 20:00	9/21/2015: 13:00	7/15/2016: 15:00	8/4/2017: 17:00
193	8/28/2011: 13:00	8/9/2012: 20:00	7/18/2013: 16:00	7/9/2014: 13:00	8/14/2015: 18:00	8/12/2016: 15:00	8/10/2017: 16:00
194	9/22/2011: 14:00	7/30/2012: 15:00	9/4/2013: 11:00	9/17/2014: 10:00	8/28/2015: 10:00	7/21/2016: 13:00	7/9/2017: 16:00
195	7/25/2011: 13:00	9/14/2012: 19:00	8/22/2013: 14:00	9/16/2014: 10:00	9/11/2015: 10:00	8/29/2016: 16:00	7/11/2017: 14:00
196	7/26/2011: 16:00	7/10/2012: 18:00	7/23/2013: 15:00	7/8/2014: 18:00	9/25/2015: 17:00	6/30/2016: 18:00	7/9/2017: 17:00
197	9/2/2011: 14:00	8/17/2012: 19:00	6/26/2013: 15:00	8/1/2014: 11:00	9/8/2015: 11:00	8/13/2016: 16:00	8/26/2017: 17:00
198	8/23/2011: 12:00	8/7/2012: 11:00	5/13/2013: 14:00	9/15/2014: 20:00	9/24/2015: 18:00	7/20/2016: 14:00	7/13/2017: 17:00
199	7/2/2011: 16:00	7/12/2012: 14:00	6/26/2013: 16:00	8/28/2014: 19:00	8/27/2015: 20:00	6/3/2016: 17:00	7/28/2017: 16:00
200	9/9/2011: 16:00	8/12/2012: 19:00	7/8/2013: 19:00	7/15/2014: 16:00	10/12/2015: 16:00	7/13/2016: 18:00	7/14/2017: 17:00

A.2.2 IOU Top 200

TABLE A-8: PG&E TOP 200 HOURS

Hour #	2011	2012	2013	2014	2015	2016	2017
1	6/21/2011: 15:00	8/13/2012: 15:00	7/3/2013: 15:00	7/25/2014: 16:00	8/17/2015: 16:00	7/27/2016: 16:00	9/1/2017: 16:00
2	6/21/2011: 16:00	8/13/2012: 16:00	7/3/2013: 16:00	7/25/2014: 15:00	6/30/2015: 16:00	7/27/2016: 17:00	9/1/2017: 15:00
3	6/21/2011: 14:00	8/13/2012: 17:00	7/2/2013: 15:00	6/30/2014: 15:00	8/17/2015: 15:00	7/27/2016: 15:00	9/1/2017: 17:00
4	7/6/2011: 15:00	8/13/2012: 14:00	7/2/2013: 14:00	6/30/2014: 16:00	6/30/2015: 17:00	7/26/2016: 17:00	9/2/2017: 16:00
5	7/5/2011: 15:00	7/11/2012: 16:00	7/2/2013: 13:00	6/9/2014: 15:00	7/29/2015: 16:00	7/26/2016: 16:00	8/28/2017: 16:00
6	7/6/2011: 16:00	7/11/2012: 17:00	6/28/2013: 16:00	6/9/2014: 16:00	6/30/2015: 15:00	7/26/2016: 18:00	9/2/2017: 17:00
7	7/5/2011: 16:00	7/11/2012: 15:00	6/28/2013: 15:00	7/31/2014: 16:00	8/17/2015: 17:00	7/27/2016: 18:00	8/28/2017: 17:00
8	7/6/2011: 14:00	8/9/2012: 16:00	7/3/2013: 14:00	8/1/2014: 16:00	7/29/2015: 15:00	7/26/2016: 15:00	6/22/2017: 16:00
9	6/21/2011: 17:00	8/9/2012: 15:00	7/3/2013: 17:00	8/1/2014: 15:00	8/28/2015: 15:00	7/27/2016: 14:00	6/19/2017: 16:00
10	6/21/2011: 13:00	7/12/2012: 15:00	7/1/2013: 15:00	7/25/2014: 17:00	9/10/2015: 16:00	7/28/2016: 16:00	6/19/2017: 17:00
11	7/5/2011: 14:00	8/14/2012: 15:00	7/2/2013: 16:00	6/9/2014: 14:00	9/10/2015: 15:00	6/27/2016: 17:00	6/22/2017: 15:00
12	7/5/2011: 17:00	8/13/2012: 13:00	6/28/2013: 17:00	7/30/2014: 16:00	7/29/2015: 17:00	7/29/2016: 16:00	9/1/2017: 14:00
13	7/6/2011: 17:00	8/13/2012: 18:00	7/2/2013: 12:00	6/30/2014: 14:00	9/9/2015: 16:00	7/28/2016: 17:00	6/19/2017: 15:00
14	7/6/2011: 13:00	7/12/2012: 16:00	7/1/2013: 16:00	7/31/2014: 17:00	6/30/2015: 18:00	6/27/2016: 18:00	8/28/2017: 15:00
15	7/7/2011: 15:00	7/11/2012: 18:00	6/28/2013: 14:00	7/31/2014: 15:00	8/28/2015: 16:00	6/27/2016: 16:00	6/22/2017: 17:00
16	7/8/2011: 15:00	8/9/2012: 17:00	7/1/2013: 14:00	6/30/2014: 17:00	8/17/2015: 14:00	7/29/2016: 17:00	9/2/2017: 15:00
17	7/7/2011: 16:00	8/10/2012: 15:00	6/29/2013: 16:00	7/30/2014: 15:00	9/9/2015: 15:00	7/28/2016: 15:00	9/1/2017: 18:00
18	9/20/2011: 15:00	8/14/2012: 16:00	6/29/2013: 15:00	8/1/2014: 17:00	9/9/2015: 17:00	6/28/2016: 17:00	6/19/2017: 18:00
19	6/22/2011: 15:00	8/10/2012: 16:00	7/1/2013: 17:00	6/9/2014: 17:00	8/28/2015: 14:00	6/28/2016: 16:00	6/22/2017: 14:00
20	7/8/2011: 16:00	7/12/2012: 14:00	6/29/2013: 17:00	7/25/2014: 14:00	9/10/2015: 17:00	7/29/2016: 15:00	9/2/2017: 18:00
21	7/5/2011: 13:00	8/14/2012: 14:00	7/3/2013: 13:00	7/14/2014: 15:00	6/30/2015: 14:00	7/26/2016: 19:00	6/21/2017: 17:00
22	9/21/2011: 15:00	8/9/2012: 14:00	7/1/2013: 13:00	7/14/2014: 14:00	9/10/2015: 14:00	6/27/2016: 15:00	8/28/2017: 18:00
23	6/21/2011: 18:00	7/11/2012: 14:00	6/28/2013: 18:00	7/30/2014: 17:00	7/29/2015: 18:00	6/28/2016: 18:00	6/19/2017: 14:00
24	6/22/2011: 14:00	7/31/2012: 16:00	7/1/2013: 18:00	8/1/2014: 14:00	7/29/2015: 14:00	7/28/2016: 18:00	6/22/2017: 18:00
25	6/21/2011: 12:00	7/31/2012: 15:00	7/2/2013: 17:00	6/30/2014: 13:00	8/17/2015: 18:00	6/28/2016: 15:00	6/21/2017: 16:00
26	7/7/2011: 14:00	8/10/2012: 14:00	6/29/2013: 14:00	6/9/2014: 13:00	7/28/2015: 16:00	7/26/2016: 14:00	8/2/2017: 16:00
27	7/6/2011: 12:00	8/8/2012: 16:00	6/28/2013: 13:00	7/25/2014: 18:00	6/8/2015: 16:00	7/27/2016: 13:00	6/20/2017: 16:00
28	7/5/2011: 18:00	8/13/2012: 19:00	7/3/2013: 18:00	7/29/2014: 16:00	7/20/2015: 15:00	7/27/2016: 19:00	8/2/2017: 17:00
29	7/8/2011: 14:00	7/12/2012: 17:00	6/29/2013: 18:00	7/14/2014: 16:00	6/8/2015: 17:00	7/25/2016: 17:00	6/20/2017: 17:00
30	9/20/2011: 16:00	8/10/2012: 17:00	7/4/2013: 15:00	7/14/2014: 13:00	7/28/2015: 17:00	7/14/2016: 16:00	6/21/2017: 18:00
31	8/24/2011: 15:00	8/14/2012: 13:00	8/19/2013: 15:00	7/31/2014: 14:00	7/20/2015: 16:00	7/29/2016: 18:00	9/1/2017: 19:00
32	6/22/2011: 16:00	7/10/2012: 16:00	6/30/2013: 16:00	7/31/2014: 18:00	9/9/2015: 18:00	7/14/2016: 17:00	9/2/2017: 14:00
33	9/7/2011: 15:00	8/8/2012: 15:00	7/4/2013: 16:00	7/30/2014: 14:00	9/21/2015: 16:00	7/25/2016: 16:00	6/20/2017: 15:00
34	9/7/2011: 16:00	7/31/2012: 17:00	8/19/2013: 16:00	6/30/2014: 18:00	9/10/2015: 18:00	9/19/2016: 16:00	8/2/2017: 15:00
35	7/7/2011: 17:00	7/10/2012: 17:00	6/30/2013: 15:00	7/29/2014: 15:00	6/30/2015: 19:00	6/27/2016: 19:00	8/28/2017: 14:00
36	9/23/2011: 15:00	8/2/2012: 16:00	7/2/2013: 11:00	7/29/2014: 17:00	8/17/2015: 13:00	7/28/2016: 14:00	6/22/2017: 13:00
37	9/21/2011: 16:00	8/9/2012: 18:00	7/1/2013: 12:00	6/9/2014: 18:00	9/21/2015: 15:00	6/3/2016: 16:00	6/19/2017: 13:00
38	6/20/2011: 16:00	8/8/2012: 17:00	7/4/2013: 14:00	8/1/2014: 18:00	8/27/2015: 16:00	7/29/2016: 14:00	9/2/2017: 19:00
39	8/23/2011: 16:00	8/2/2012: 15:00	7/9/2013: 17:00	8/1/2014: 13:00	6/8/2015: 15:00	7/14/2016: 15:00	6/21/2017: 15:00
40	9/20/2011: 14:00	8/10/2012: 13:00	7/9/2013: 16:00	7/30/2014: 18:00	7/20/2015: 14:00	7/25/2016: 18:00	9/1/2017: 13:00
41	8/24/2011: 16:00	8/1/2012: 16:00	6/29/2013: 13:00	7/15/2014: 16:00	8/17/2015: 19:00	9/19/2016: 15:00	6/19/2017: 19:00
42	6/20/2011: 15:00	7/12/2012: 13:00	7/2/2013: 18:00	7/15/2014: 15:00	9/9/2015: 14:00	6/3/2016: 17:00	6/20/2017: 18:00
43	9/21/2011: 14:00	8/11/2012: 16:00	8/19/2013: 14:00	7/25/2014: 13:00	6/8/2015: 18:00	6/3/2016: 15:00	8/2/2017: 18:00
44	8/24/2011: 14:00	7/30/2012: 16:00	7/1/2013: 19:00	7/26/2014: 16:00	7/28/2015: 15:00	6/28/2016: 14:00	8/1/2017: 17:00
45	6/22/2011: 13:00	8/1/2012: 15:00	6/30/2013: 17:00	7/26/2014: 15:00	8/27/2015: 15:00	7/13/2016: 17:00	7/7/2017: 17:00
46	7/20/2011: 15:00	8/14/2012: 17:00	6/28/2013: 19:00	7/24/2014: 16:00	7/28/2015: 18:00	7/14/2016: 18:00	6/20/2017: 14:00
47	7/6/2011: 18:00	7/11/2012: 19:00	6/28/2013: 12:00	6/9/2014: 12:00	8/28/2015: 17:00	6/27/2016: 14:00	6/21/2017: 19:00
48	7/20/2011: 16:00	8/13/2012: 12:00	7/4/2013: 17:00	7/14/2014: 12:00	7/20/2015: 17:00	7/28/2016: 19:00	8/1/2017: 16:00
49	9/23/2011: 14:00	7/10/2012: 15:00	7/9/2013: 15:00	7/14/2014: 17:00	6/25/2015: 16:00	9/26/2016: 16:00	8/31/2017: 17:00
50	6/20/2011: 17:00	7/31/2012: 14:00	7/3/2013: 12:00	7/29/2014: 14:00	6/30/2015: 13:00	6/28/2016: 19:00	8/28/2017: 19:00
51	7/8/2011: 17:00	6/16/2012: 16:00	7/3/2013: 19:00	7/8/2014: 16:00	8/28/2015: 13:00	9/19/2016: 17:00	7/7/2017: 16:00
52	8/23/2011: 15:00	10/2/2012: 15:00	8/19/2013: 17:00	7/26/2014: 17:00	7/29/2015: 13:00	7/25/2016: 15:00	6/18/2017: 17:00
53	9/7/2011: 14:00	7/11/2012: 13:00	6/30/2013: 14:00	6/30/2014: 12:00	6/25/2015: 17:00	7/13/2016: 16:00	7/7/2017: 18:00
54	9/19/2011: 15:00	8/2/2012: 17:00	7/4/2013: 13:00	7/24/2014: 17:00	8/16/2015: 17:00	7/26/2016: 13:00	7/17/2017: 17:00
55	7/5/2011: 12:00	8/9/2012: 13:00	7/9/2013: 18:00	7/29/2014: 18:00	9/8/2015: 16:00	6/30/2016: 17:00	8/31/2017: 16:00
56	9/23/2011: 16:00	8/15/2012: 15:00	6/29/2013: 19:00	6/9/2014: 19:00	9/10/2015: 13:00	6/21/2016: 17:00	7/17/2017: 16:00
57	6/22/2011: 17:00	8/11/2012: 17:00	6/27/2013: 16:00	7/15/2014: 17:00	6/25/2015: 15:00	7/26/2016: 20:00	6/18/2017: 18:00

Hour #	2011	2012	2013	2014	2015	2016	2017
58	7/7/2011: 13:00	10/2/2012: 16:00	8/19/2013: 13:00	7/31/2014: 13:00	8/27/2015: 17:00	7/13/2016: 18:00	6/22/2017: 19:00
59	8/23/2011: 17:00	8/11/2012: 15:00	7/1/2013: 11:00	7/31/2014: 19:00	9/21/2015: 17:00	7/29/2016: 19:00	8/2/2017: 14:00
60	9/22/2011: 16:00	7/30/2012: 17:00	6/27/2013: 17:00	7/8/2014: 15:00	9/11/2015: 15:00	6/21/2016: 16:00	9/3/2017: 16:00
61	9/22/2011: 15:00	6/16/2012: 15:00	6/29/2013: 12:00	7/25/2014: 19:00	7/20/2015: 13:00	6/3/2016: 18:00	8/1/2017: 18:00
62	7/8/2011: 13:00	8/1/2012: 17:00	7/2/2013: 19:00	9/12/2014: 16:00	8/16/2015: 16:00	7/27/2016: 12:00	6/22/2017: 12:00
63	9/19/2011: 16:00	7/30/2012: 15:00	6/27/2013: 15:00	7/8/2014: 17:00	9/11/2015: 16:00	6/30/2016: 16:00	9/2/2017: 13:00
64	7/20/2011: 14:00	8/15/2012: 16:00	6/30/2013: 18:00	7/15/2014: 14:00	9/9/2015: 19:00	8/17/2016: 17:00	8/27/2017: 17:00
65	8/24/2011: 17:00	6/16/2012: 17:00	7/1/2013: 20:00	7/24/2014: 15:00	9/8/2015: 17:00	8/17/2016: 16:00	6/19/2017: 12:00
66	6/20/2011: 14:00	7/10/2012: 18:00	7/2/2013: 10:00	7/30/2014: 13:00	7/29/2015: 19:00	6/30/2016: 18:00	8/31/2017: 18:00
67	7/21/2011: 15:00	8/15/2012: 14:00	7/25/2013: 16:00	9/12/2014: 15:00	6/26/2015: 15:00	9/26/2016: 15:00	6/21/2017: 14:00
68	7/5/2011: 19:00	8/10/2012: 18:00	6/28/2013: 20:00	7/30/2014: 19:00	9/10/2015: 19:00	7/28/2016: 13:00	7/7/2017: 15:00
69	9/7/2011: 17:00	7/12/2012: 18:00	7/24/2013: 16:00	6/30/2014: 19:00	6/26/2015: 16:00	7/29/2016: 13:00	9/3/2017: 15:00
70	6/21/2011: 19:00	8/2/2012: 14:00	7/25/2013: 15:00	7/1/2014: 16:00	6/8/2015: 14:00	7/27/2016: 20:00	8/1/2017: 15:00
71	7/28/2011: 15:00	8/16/2012: 16:00	7/3/2013: 20:00	7/26/2014: 14:00	7/30/2015: 16:00	7/14/2016: 14:00	9/5/2017: 16:00
72	7/20/2011: 17:00	8/9/2012: 19:00	7/9/2013: 14:00	8/28/2014: 16:00	6/30/2015: 20:00	6/27/2016: 20:00	8/27/2017: 16:00
73	7/21/2011: 16:00	8/16/2012: 15:00	7/24/2013: 17:00	8/1/2014: 19:00	6/25/2015: 18:00	9/19/2016: 18:00	8/2/2017: 19:00
74	7/28/2011: 16:00	8/1/2012: 14:00	7/24/2013: 15:00	6/10/2014: 16:00	8/27/2015: 14:00	9/26/2016: 17:00	6/18/2017: 16:00
75	8/24/2011: 13:00	8/14/2012: 12:00	6/30/2013: 13:00	6/10/2014: 15:00	7/30/2015: 15:00	9/19/2016: 14:00	7/17/2017: 18:00
76	8/26/2011: 15:00	8/8/2012: 14:00	7/4/2013: 12:00	7/1/2014: 15:00	9/8/2015: 15:00	7/25/2016: 19:00	6/20/2017: 13:00
77	9/6/2011: 15:00	7/21/2012: 16:00	7/25/2013: 17:00	7/27/2014: 17:00	7/1/2015: 15:00	6/21/2016: 18:00	7/17/2017: 15:00
78	9/20/2011: 17:00	8/10/2012: 12:00	6/7/2013: 16:00	9/11/2014: 16:00	7/1/2015: 16:00	6/3/2016: 14:00	8/28/2017: 13:00
79	9/6/2011: 16:00	7/31/2012: 18:00	6/8/2013: 15:00	7/29/2014: 13:00	6/8/2015: 19:00	5/31/2016: 17:00	9/5/2017: 15:00
80	6/22/2011: 12:00	8/8/2012: 18:00	6/28/2013: 11:00	6/8/2014: 16:00	9/21/2015: 14:00	6/21/2016: 15:00	6/20/2017: 19:00
81	6/21/2011: 11:00	10/2/2012: 14:00	6/27/2013: 18:00	7/1/2014: 17:00	8/17/2015: 12:00	7/1/2016: 17:00	7/16/2017: 17:00
82	8/23/2011: 14:00	7/21/2012: 17:00	6/7/2013: 17:00	8/28/2014: 15:00	7/28/2015: 14:00	6/28/2016: 13:00	6/18/2017: 19:00
83	8/25/2011: 16:00	8/15/2012: 17:00	6/29/2013: 20:00	8/1/2014: 12:00	8/16/2015: 18:00	7/24/2016: 17:00	7/27/2017: 17:00
84	8/29/2011: 15:00	8/16/2012: 17:00	8/20/2013: 15:00	7/27/2014: 16:00	7/28/2015: 19:00	8/18/2016: 16:00	6/19/2017: 20:00
85	9/2/2011: 15:00	8/11/2012: 14:00	8/19/2013: 12:00	6/8/2014: 17:00	6/26/2015: 14:00	7/13/2016: 15:00	6/21/2017: 20:00
86	7/27/2011: 16:00	7/10/2012: 14:00	7/4/2013: 18:00	7/8/2014: 14:00	6/26/2015: 17:00	8/17/2016: 15:00	9/1/2017: 20:00
87	9/21/2011: 17:00	6/16/2012: 14:00	8/20/2013: 16:00	7/9/2014: 16:00	7/20/2015: 18:00	7/1/2016: 16:00	8/29/2017: 16:00
88	7/27/2011: 15:00	7/30/2012: 18:00	6/8/2013: 16:00	7/29/2014: 19:00	6/25/2015: 14:00	5/31/2016: 16:00	8/31/2017: 15:00
89	9/9/2011: 15:00	7/21/2012: 15:00	9/9/2013: 15:00	7/14/2014: 18:00	7/1/2015: 14:00	6/27/2016: 13:00	9/11/2017: 15:00
90	7/6/2011: 11:00	7/31/2012: 13:00	8/30/2013: 15:00	7/24/2014: 18:00	9/11/2015: 14:00	8/17/2016: 18:00	9/3/2017: 17:00
91	9/21/2011: 13:00	8/14/2012: 18:00	6/27/2013: 14:00	7/9/2014: 17:00	8/27/2015: 18:00	6/29/2016: 17:00	8/29/2017: 17:00
92	6/20/2011: 18:00	7/12/2012: 12:00	7/9/2013: 19:00	7/28/2014: 15:00	9/9/2015: 13:00	6/30/2016: 15:00	6/22/2017: 11:00
93	7/7/2011: 18:00	7/11/2012: 20:00	9/9/2013: 16:00	7/25/2014: 12:00	7/20/2015: 12:00	7/15/2016: 17:00	9/5/2017: 17:00
94	9/7/2011: 13:00	7/30/2012: 14:00	8/30/2013: 16:00	7/28/2014: 16:00	9/21/2015: 18:00	7/28/2016: 20:00	8/27/2017: 18:00
95	9/20/2011: 13:00	8/7/2012: 16:00	8/19/2013: 18:00	8/6/2014: 15:00	7/30/2015: 17:00	8/18/2016: 17:00	7/27/2017: 16:00
96	8/25/2011: 15:00	8/13/2012: 20:00	7/3/2013: 11:00	8/27/2014: 16:00	8/16/2015: 15:00	7/24/2016: 16:00	7/7/2017: 19:00
97	9/23/2011: 13:00	8/11/2012: 18:00	8/16/2013: 15:00	8/28/2014: 17:00	7/1/2015: 13:00	7/15/2016: 16:00	7/16/2017: 16:00
98	9/20/2011: 18:00	6/16/2012: 18:00	6/8/2013: 14:00	6/10/2014: 14:00	9/8/2015: 18:00	8/16/2016: 17:00	7/16/2017: 18:00
99	9/28/2011: 15:00	10/2/2012: 17:00	6/7/2013: 15:00	6/10/2014: 17:00	6/30/2015: 12:00	7/14/2016: 19:00	9/1/2017: 12:00
100	8/26/2011: 16:00	7/11/2012: 12:00	7/1/2013: 10:00	7/14/2014: 11:00	6/12/2015: 16:00	5/31/2016: 18:00	6/23/2017: 16:00
101	7/21/2011: 14:00	7/22/2012: 16:00	8/15/2013: 16:00	9/12/2014: 17:00	8/28/2015: 12:00	9/26/2016: 18:00	6/23/2017: 17:00
102	8/26/2011: 14:00	8/2/2012: 18:00	7/2/2013: 20:00	7/9/2014: 15:00	8/18/2015: 16:00	6/29/2016: 16:00	8/3/2017: 15:00
103	7/6/2011: 19:00	8/10/2012: 19:00	6/29/2013: 11:00	8/6/2014: 16:00	8/28/2015: 18:00	8/18/2016: 15:00	7/27/2017: 18:00
104	8/29/2011: 16:00	7/23/2012: 15:00	8/15/2013: 15:00	9/11/2014: 15:00	7/1/2015: 17:00	9/27/2016: 16:00	6/18/2017: 15:00
105	9/19/2011: 14:00	10/1/2012: 15:00	6/7/2013: 18:00	6/9/2014: 20:00	9/11/2015: 17:00	8/16/2016: 16:00	9/11/2017: 16:00
106	7/28/2011: 14:00	8/15/2012: 13:00	8/16/2013: 16:00	8/7/2014: 15:00	6/12/2015: 17:00	7/29/2016: 20:00	8/2/2017: 13:00
107	9/22/2011: 14:00	10/1/2012: 16:00	6/30/2013: 19:00	7/1/2014: 14:00	7/29/2015: 12:00	6/30/2016: 19:00	8/3/2017: 16:00
108	8/23/2011: 18:00	7/22/2012: 17:00	7/24/2013: 14:00	7/8/2014: 18:00	8/18/2015: 15:00	7/30/2016: 16:00	8/1/2017: 19:00
109	9/7/2011: 18:00	8/16/2012: 14:00	8/19/2013: 19:00	7/26/2014: 18:00	7/30/2015: 14:00	7/24/2016: 18:00	8/31/2017: 19:00
110	9/2/2011: 16:00	7/23/2012: 16:00	8/20/2013: 14:00	9/11/2014: 17:00	8/16/2015: 19:00	7/13/2016: 19:00	9/2/2017: 20:00
111	9/9/2011: 16:00	8/7/2012: 15:00	7/24/2013: 18:00	8/7/2014: 16:00	6/8/2015: 13:00	8/2/2016: 17:00	9/3/2017: 14:00
112	7/21/2011: 17:00	8/29/2012: 16:00	8/20/2013: 17:00	7/15/2014: 13:00	9/10/2015: 12:00	6/2/2016: 17:00	8/3/2017: 14:00
113	9/21/2011: 18:00	6/20/2012: 16:00	7/10/2013: 15:00	7/28/2014: 14:00	8/27/2015: 19:00	6/28/2016: 20:00	6/22/2017: 20:00
114	7/28/2011: 17:00	10/2/2012: 18:00	6/8/2013: 17:00	7/24/2014: 14:00	6/26/2015: 13:00	7/30/2016: 17:00	7/7/2017: 14:00
115	9/19/2011: 17:00	8/14/2012: 19:00	8/16/2013: 14:00	7/15/2014: 18:00	6/12/2015: 15:00	8/3/2016: 16:00	6/23/2017: 15:00
116	9/22/2011: 17:00	8/1/2012: 18:00	7/8/2013: 16:00	8/27/2014: 15:00	7/1/2015: 12:00	6/26/2016: 17:00	8/29/2017: 15:00
117	9/6/2011: 14:00	8/9/2012: 12:00	7/8/2013: 17:00	9/12/2014: 14:00	8/18/2015: 17:00	6/3/2016: 19:00	8/27/2017: 15:00
118	9/6/2011: 17:00	6/20/2012: 15:00	7/9/2013: 13:00	8/8/2014: 15:00	8/27/2015: 13:00	8/3/2016: 17:00	6/18/2017: 20:00
119	7/20/2011: 13:00	8/13/2012: 11:00	9/9/2013: 14:00	8/8/2014: 16:00	6/25/2015: 19:00	7/1/2016: 15:00	8/26/2017: 17:00

Hour #	2011	2012	2013	2014	2015	2016	2017
120	6/20/2011: 13:00	8/20/2012: 16:00	7/26/2013: 16:00	9/1/2014: 16:00	7/1/2015: 18:00	7/1/2016: 18:00	7/17/2017: 14:00
121	9/28/2011: 16:00	8/17/2012: 15:00	8/15/2013: 17:00	6/30/2014: 11:00	8/26/2015: 16:00	9/7/2016: 16:00	9/5/2017: 14:00
122	8/23/2011: 19:00	6/1/2012: 15:00	7/4/2013: 11:00	7/31/2014: 12:00	7/30/2015: 18:00	5/31/2016: 15:00	7/10/2017: 17:00
123	7/7/2011: 12:00	8/2/2012: 13:00	7/10/2013: 16:00	6/9/2014: 11:00	6/26/2015: 18:00	9/26/2016: 14:00	7/8/2017: 17:00
124	9/2/2011: 14:00	8/29/2012: 15:00	7/25/2013: 18:00	8/15/2014: 16:00	9/11/2015: 18:00	6/1/2016: 16:00	8/1/2017: 14:00
125	7/8/2011: 12:00	8/7/2012: 17:00	8/30/2013: 14:00	8/6/2014: 14:00	7/30/2015: 13:00	6/1/2016: 17:00	7/31/2017: 17:00
126	7/27/2011: 17:00	7/22/2012: 15:00	6/27/2013: 19:00	6/8/2014: 15:00	6/25/2015: 13:00	6/29/2016: 18:00	9/3/2017: 18:00
127	7/29/2011: 15:00	8/8/2012: 19:00	9/9/2013: 17:00	7/25/2014: 20:00	6/29/2015: 17:00	8/2/2016: 16:00	7/8/2017: 16:00
128	7/3/2011: 16:00	8/17/2012: 16:00	6/30/2013: 12:00	7/27/2014: 18:00	7/28/2015: 13:00	9/27/2016: 15:00	6/22/2017: 10:00
129	9/22/2011: 18:00	7/12/2012: 19:00	7/10/2013: 14:00	7/27/2014: 15:00	6/8/2015: 20:00	7/15/2016: 15:00	8/3/2017: 17:00
130	9/19/2011: 18:00	7/10/2012: 19:00	8/30/2013: 17:00	7/26/2014: 13:00	8/16/2015: 14:00	8/15/2016: 17:00	8/3/2017: 13:00
131	8/29/2011: 14:00	8/20/2012: 15:00	6/28/2013: 10:00	7/31/2014: 20:00	9/11/2015: 13:00	7/28/2016: 12:00	6/20/2017: 12:00
132	8/25/2011: 17:00	8/1/2012: 13:00	7/26/2013: 15:00	7/8/2014: 13:00	6/12/2015: 18:00	7/15/2016: 18:00	8/27/2017: 19:00
133	9/9/2011: 14:00	7/23/2012: 14:00	6/8/2013: 13:00	7/1/2014: 18:00	7/29/2015: 20:00	6/2/2016: 16:00	6/19/2017: 11:00
134	7/5/2011: 11:00	6/20/2012: 17:00	6/27/2013: 13:00	7/30/2014: 12:00	7/21/2015: 16:00	7/14/2016: 13:00	6/23/2017: 18:00
135	7/27/2011: 14:00	7/21/2012: 14:00	7/19/2013: 16:00	9/1/2014: 17:00	8/15/2015: 16:00	8/17/2016: 19:00	9/11/2017: 14:00
136	7/8/2011: 18:00	8/8/2012: 13:00	7/2/2013: 9:00	8/27/2014: 17:00	9/8/2015: 14:00	7/25/2016: 14:00	8/26/2017: 16:00
137	9/8/2011: 15:00	8/29/2012: 17:00	7/26/2013: 17:00	6/30/2014: 20:00	8/26/2015: 15:00	6/3/2016: 13:00	9/5/2017: 18:00
138	9/23/2011: 17:00	7/21/2012: 18:00	7/25/2013: 14:00	8/15/2014: 15:00	6/29/2015: 16:00	7/23/2016: 17:00	8/29/2017: 18:00
139	7/4/2011: 15:00	8/12/2012: 16:00	7/9/2013: 20:00	7/28/2014: 17:00	8/15/2015: 17:00	6/26/2016: 18:00	6/21/2017: 13:00
140	7/3/2011: 15:00	7/31/2012: 19:00	7/19/2013: 15:00	9/2/2014: 15:00	7/2/2015: 15:00	9/7/2016: 17:00	9/2/2017: 12:00
141	7/29/2011: 16:00	8/20/2012: 17:00	6/30/2013: 20:00	7/30/2014: 20:00	8/28/2015: 19:00	7/26/2016: 12:00	7/10/2017: 16:00
142	6/21/2011: 20:00	8/14/2012: 11:00	8/19/2013: 11:00	7/3/2014: 16:00	7/17/2015: 16:00	8/16/2016: 18:00	9/12/2017: 16:00
143	7/4/2011: 16:00	6/1/2012: 16:00	8/15/2013: 14:00	9/2/2014: 16:00	9/8/2015: 19:00	6/29/2016: 15:00	7/16/2017: 15:00
144	7/5/2011: 20:00	7/23/2012: 17:00	7/8/2013: 15:00	6/8/2014: 18:00	7/21/2015: 15:00	7/29/2016: 12:00	7/27/2017: 15:00
145	6/22/2011: 18:00	8/7/2012: 14:00	8/16/2013: 17:00	7/14/2014: 19:00	8/26/2015: 17:00	7/30/2016: 15:00	9/12/2017: 15:00
146	8/24/2011: 18:00	8/3/2012: 15:00	6/7/2013: 14:00	7/2/2014: 16:00	7/20/2015: 19:00	8/12/2016: 16:00	7/17/2017: 19:00
147	8/25/2011: 14:00	6/16/2012: 19:00	7/19/2013: 17:00	7/28/2014: 13:00	7/27/2015: 16:00	8/15/2016: 16:00	7/28/2017: 17:00
148	8/29/2011: 17:00	8/11/2012: 19:00	7/10/2013: 17:00	8/11/2014: 16:00	7/2/2015: 16:00	8/12/2016: 17:00	7/31/2017: 16:00
149	9/28/2011: 14:00	6/1/2012: 14:00	6/7/2013: 19:00	8/7/2014: 14:00	9/21/2015: 13:00	9/19/2016: 19:00	7/10/2017: 18:00
150	7/3/2011: 17:00	8/16/2012: 18:00	7/4/2013: 19:00	8/28/2014: 14:00	7/16/2015: 16:00	6/2/2016: 18:00	6/20/2017: 20:00
151	9/9/2011: 17:00	6/12/2012: 15:00	8/29/2013: 15:00	8/6/2014: 17:00	7/27/2015: 17:00	8/18/2016: 18:00	7/6/2017: 17:00
152	7/22/2011: 15:00	8/12/2012: 17:00	7/10/2013: 13:00	6/10/2014: 13:00	6/12/2015: 14:00	8/2/2016: 18:00	7/31/2017: 18:00
153	8/16/2011: 16:00	8/30/2012: 15:00	9/9/2013: 18:00	7/29/2014: 12:00	7/1/2015: 19:00	6/21/2016: 14:00	6/23/2017: 14:00
154	8/17/2011: 16:00	7/30/2012: 19:00	7/3/2013: 10:00	5/14/2014: 16:00	7/30/2015: 19:00	8/14/2016: 17:00	8/2/2017: 20:00
155	8/18/2011: 16:00	8/15/2012: 18:00	8/29/2013: 16:00	7/1/2014: 13:00	7/20/2015: 11:00	8/16/2016: 15:00	7/15/2017: 17:00
156	8/24/2011: 12:00	8/11/2012: 13:00	8/16/2013: 13:00	7/9/2014: 14:00	7/21/2015: 17:00	8/1/2016: 17:00	9/11/2017: 17:00
157	8/16/2011: 15:00	6/12/2012: 16:00	8/20/2013: 13:00	7/9/2014: 18:00	7/17/2015: 17:00	8/3/2016: 15:00	7/28/2017: 16:00
158	9/7/2011: 19:00	8/3/2012: 16:00	7/24/2013: 19:00	8/7/2014: 17:00	8/18/2015: 14:00	6/2/2016: 15:00	6/18/2017: 14:00
159	9/6/2011: 18:00	6/20/2012: 14:00	7/8/2013: 18:00	7/2/2014: 17:00	7/16/2015: 17:00	6/1/2016: 15:00	7/7/2017: 20:00
160	9/8/2011: 16:00	8/17/2012: 14:00	8/20/2013: 18:00	8/8/2014: 17:00	7/17/2015: 15:00	7/27/2016: 11:00	7/8/2017: 15:00
161	6/21/2011: 10:00	8/6/2012: 16:00	7/24/2013: 13:00	8/1/2014: 20:00	7/28/2015: 20:00	9/27/2016: 17:00	9/3/2017: 13:00
162	6/22/2011: 11:00	7/10/2012: 13:00	6/27/2013: 20:00	7/2/2014: 15:00	7/31/2015: 16:00	6/26/2016: 16:00	7/6/2017: 18:00
163	8/18/2011: 15:00	6/11/2012: 16:00	7/26/2013: 14:00	7/3/2014: 17:00	6/29/2015: 18:00	6/21/2016: 19:00	7/16/2017: 19:00
164	8/26/2011: 17:00	10/2/2012: 13:00	8/18/2013: 17:00	5/14/2014: 15:00	8/18/2015: 18:00	9/7/2016: 15:00	7/8/2017: 18:00
165	7/20/2011: 18:00	7/22/2012: 18:00	7/25/2013: 19:00	8/8/2014: 14:00	7/16/2015: 15:00	8/17/2016: 14:00	7/22/2017: 17:00
166	7/6/2011: 10:00	10/1/2012: 14:00	8/28/2013: 16:00	7/3/2014: 15:00	8/17/2015: 20:00	6/28/2016: 12:00	7/27/2017: 19:00
167	7/29/2011: 14:00	10/1/2012: 17:00	8/30/2013: 13:00	8/11/2014: 17:00	8/15/2015: 15:00	7/24/2016: 15:00	8/28/2017: 20:00
168	8/17/2011: 15:00	8/9/2012: 20:00	8/14/2013: 16:00	9/10/2014: 16:00	9/21/2015: 19:00	5/31/2016: 19:00	8/26/2017: 18:00
169	7/28/2011: 13:00	6/16/2012: 13:00	7/20/2013: 16:00	8/15/2014: 17:00	7/27/2015: 15:00	8/1/2016: 16:00	8/30/2017: 17:00
170	8/26/2011: 13:00	8/10/2012: 11:00	6/8/2013: 18:00	7/24/2014: 19:00	7/31/2015: 15:00	7/23/2016: 18:00	8/3/2017: 12:00
171	9/7/2011: 12:00	6/11/2012: 15:00	9/9/2013: 13:00	7/15/2014: 19:00	7/2/2015: 14:00	9/19/2016: 13:00	7/15/2017: 16:00
172	6/20/2011: 19:00	7/31/2012: 12:00	8/20/2013: 19:00	9/11/2014: 18:00	7/1/2015: 11:00	7/13/2016: 14:00	8/30/2017: 16:00
173	7/21/2011: 13:00	8/2/2012: 19:00	9/7/2013: 16:00	8/11/2014: 15:00	7/21/2015: 14:00	7/30/2016: 18:00	8/28/2017: 12:00
174	8/2/2011: 16:00	8/6/2012: 17:00	7/18/2013: 16:00	5/14/2014: 17:00	6/29/2015: 15:00	7/23/2016: 16:00	8/2/2017: 12:00
175	8/23/2011: 13:00	10/1/2012: 18:00	8/18/2013: 16:00	9/11/2014: 14:00	7/3/2015: 16:00	7/25/2016: 20:00	7/10/2017: 15:00
176	7/22/2011: 16:00	8/30/2012: 16:00	8/15/2013: 18:00	9/12/2014: 18:00	9/9/2015: 12:00	8/15/2016: 18:00	8/3/2017: 18:00
177	7/4/2011: 14:00	8/17/2012: 17:00	8/14/2013: 15:00	9/1/2014: 15:00	7/3/2015: 17:00	7/25/2016: 13:00	6/17/2017: 17:00
178	8/2/2011: 15:00	8/12/2012: 15:00	7/20/2013: 17:00	8/27/2014: 14:00	8/17/2015: 11:00	8/18/2016: 14:00	9/5/2017: 19:00
179	7/2/2011: 16:00	7/23/2012: 13:00	6/29/2013: 10:00	7/29/2014: 20:00	6/8/2015: 12:00	8/14/2016: 16:00	7/15/2017: 18:00
180	7/1/2011: 16:00	8/15/2012: 19:00	8/13/2013: 16:00	8/28/2014: 18:00	8/25/2015: 15:00	6/30/2016: 14:00	9/3/2017: 19:00
181	8/24/2011: 19:00	8/16/2012: 13:00	8/29/2013: 17:00	9/15/2014: 15:00	8/25/2015: 17:00	8/18/2016: 19:00	9/6/2017: 16:00

Hour #	2011	2012	2013	2014	2015	2016	2017
182	9/8/2011: 14:00	7/30/2012: 13:00	7/26/2013: 18:00	7/15/2014: 12:00	8/25/2015: 16:00	6/20/2016: 17:00	8/29/2017: 14:00
183	7/1/2011: 15:00	8/15/2012: 12:00	6/8/2013: 12:00	8/14/2014: 16:00	7/15/2015: 17:00	8/3/2016: 18:00	7/6/2017: 16:00
184	9/22/2011: 13:00	6/16/2012: 20:00	7/19/2013: 14:00	7/16/2014: 15:00	6/26/2015: 12:00	6/1/2016: 18:00	8/29/2017: 19:00
185	8/10/2011: 15:00	10/3/2012: 15:00	6/27/2013: 12:00	6/29/2014: 17:00	6/25/2015: 20:00	6/27/2016: 12:00	9/12/2017: 17:00
186	9/28/2011: 18:00	8/1/2012: 19:00	6/28/2013: 21:00	8/6/2014: 13:00	8/26/2015: 18:00	7/1/2016: 14:00	7/28/2017: 18:00
187	8/3/2011: 15:00	8/3/2012: 14:00	9/9/2013: 19:00	5/15/2014: 15:00	6/11/2015: 17:00	8/16/2016: 19:00	7/17/2017: 13:00
188	9/23/2011: 18:00	8/6/2012: 15:00	8/28/2013: 15:00	7/13/2014: 17:00	7/15/2015: 16:00	9/7/2016: 18:00	8/31/2017: 14:00
189	7/6/2011: 20:00	7/22/2012: 14:00	6/26/2013: 16:00	9/2/2014: 14:00	9/11/2015: 19:00	8/2/2016: 15:00	9/10/2017: 17:00
190	8/15/2011: 15:00	8/16/2012: 19:00	8/14/2013: 17:00	7/28/2014: 18:00	6/24/2015: 17:00	6/30/2016: 20:00	6/17/2017: 18:00
191	9/23/2011: 12:00	8/29/2012: 14:00	7/3/2013: 21:00	7/16/2014: 16:00	7/31/2015: 17:00	8/13/2016: 17:00	9/5/2017: 13:00
192	9/2/2011: 17:00	7/9/2012: 16:00	7/18/2013: 17:00	7/26/2014: 19:00	8/26/2015: 14:00	7/24/2016: 19:00	7/22/2017: 18:00
193	9/2/2011: 13:00	8/21/2012: 16:00	8/30/2013: 18:00	6/10/2014: 18:00	8/15/2015: 18:00	6/20/2016: 16:00	7/14/2017: 17:00
194	7/3/2011: 14:00	6/11/2012: 17:00	7/1/2013: 21:00	9/2/2014: 17:00	7/30/2015: 12:00	6/25/2016: 17:00	9/1/2017: 11:00
195	7/7/2011: 19:00	8/28/2012: 15:00	7/25/2013: 12:00	7/8/2014: 19:00	9/9/2015: 20:00	6/22/2016: 17:00	7/28/2017: 15:00
196	9/13/2011: 15:00	8/21/2012: 15:00	7/9/2013: 12:00	9/15/2014: 16:00	6/30/2015: 11:00	8/12/2016: 18:00	9/11/2017: 18:00
197	7/22/2011: 14:00	8/20/2012: 14:00	7/20/2013: 15:00	8/15/2014: 14:00	6/24/2015: 16:00	8/15/2016: 15:00	8/26/2017: 15:00
198	8/29/2011: 13:00	9/13/2012: 16:00	9/7/2013: 15:00	7/14/2014: 10:00	7/1/2015: 20:00	8/12/2016: 15:00	7/26/2017: 17:00
199	8/16/2011: 14:00	6/12/2012: 17:00	7/19/2013: 18:00	9/10/2014: 17:00	9/10/2015: 20:00	7/13/2016: 20:00	9/10/2017: 16:00
200	9/19/2011: 13:00	7/20/2012: 16:00	8/18/2013: 18:00	8/1/2014: 11:00	8/19/2015: 16:00	8/1/2016: 18:00	8/1/2017: 13:00

TABLE A-9: SCE TOP 200 HOURS

Hour #	2011	2012	2013	2014	2015	2016	2017
1	9/7/2011: 14:00	8/13/2012: 14:00	9/5/2013: 14:00	9/15/2014: 16:00	9/8/2015: 14:00	6/20/2016: 14:00	9/1/2017: 14:00
2	9/7/2011: 15:00	8/13/2012: 13:00	9/5/2013: 15:00	9/16/2014: 13:00	9/8/2015: 15:00	6/20/2016: 15:00	8/30/2017: 15:00
3	9/7/2011: 13:00	8/13/2012: 15:00	9/5/2013: 13:00	9/15/2014: 15:00	8/28/2015: 14:00	6/20/2016: 16:00	8/29/2017: 15:00
4	9/7/2011: 16:00	8/10/2012: 15:00	9/3/2013: 15:00	9/15/2014: 14:00	9/9/2015: 13:00	6/20/2016: 13:00	9/1/2017: 15:00
5	9/8/2011: 14:00	8/14/2012: 14:00	9/5/2013: 16:00	9/15/2014: 13:00	9/10/2015: 15:00	6/20/2016: 17:00	8/30/2017: 16:00
6	9/7/2011: 12:00	8/8/2012: 15:00	9/3/2013: 14:00	9/16/2014: 14:00	9/9/2015: 12:00	8/15/2016: 15:00	8/31/2017: 14:00
7	9/6/2011: 15:00	8/10/2012: 14:00	9/4/2013: 14:00	9/16/2014: 12:00	9/10/2015: 14:00	7/22/2016: 14:00	9/1/2017: 13:00
8	9/8/2011: 15:00	8/8/2012: 14:00	9/4/2013: 13:00	9/17/2014: 14:00	8/28/2015: 15:00	8/15/2016: 14:00	8/30/2017: 14:00
9	9/6/2011: 14:00	8/14/2012: 13:00	9/4/2013: 15:00	9/17/2014: 15:00	9/11/2015: 14:00	7/22/2016: 15:00	8/29/2017: 16:00
10	8/26/2011: 14:00	8/9/2012: 14:00	9/4/2013: 16:00	9/15/2014: 17:00	9/8/2015: 13:00	6/20/2016: 12:00	8/31/2017: 13:00
11	8/26/2011: 15:00	8/9/2012: 15:00	8/30/2013: 14:00	9/16/2014: 15:00	9/11/2015: 15:00	8/15/2016: 16:00	9/1/2017: 16:00
12	9/8/2011: 13:00	8/14/2012: 15:00	8/30/2013: 13:00	9/15/2014: 18:00	9/9/2015: 14:00	7/22/2016: 16:00	8/29/2017: 14:00
13	9/6/2011: 16:00	8/7/2012: 14:00	9/3/2013: 16:00	9/17/2014: 13:00	9/10/2015: 16:00	7/26/2016: 15:00	8/31/2017: 15:00
14	8/29/2011: 14:00	8/10/2012: 16:00	9/3/2013: 13:00	9/15/2014: 12:00	9/8/2015: 16:00	7/26/2016: 14:00	8/30/2017: 17:00
15	8/25/2011: 15:00	8/7/2012: 15:00	8/30/2013: 15:00	9/16/2014: 18:00	8/27/2015: 15:00	6/20/2016: 18:00	8/30/2017: 13:00
16	8/29/2011: 15:00	8/9/2012: 13:00	9/5/2013: 12:00	9/16/2014: 16:00	8/28/2015: 13:00	7/27/2016: 15:00	8/29/2017: 17:00
17	8/26/2011: 13:00	8/13/2012: 16:00	9/6/2013: 15:00	9/17/2014: 12:00	9/11/2015: 13:00	7/27/2016: 14:00	8/31/2017: 12:00
18	9/6/2011: 13:00	9/14/2012: 15:00	8/30/2013: 12:00	9/16/2014: 17:00	9/10/2015: 13:00	7/29/2016: 15:00	9/1/2017: 12:00
19	9/7/2011: 17:00	8/13/2012: 12:00	9/4/2013: 12:00	9/17/2014: 16:00	8/27/2015: 14:00	7/25/2016: 15:00	8/29/2017: 13:00
20	8/25/2011: 14:00	8/8/2012: 13:00	9/5/2013: 17:00	7/24/2014: 15:00	8/28/2015: 16:00	7/28/2016: 15:00	8/28/2017: 15:00
21	9/7/2011: 11:00	8/29/2012: 15:00	9/6/2013: 14:00	9/16/2014: 11:00	8/27/2015: 16:00	7/29/2016: 14:00	9/1/2017: 17:00
22	9/8/2011: 12:00	8/29/2012: 14:00	9/4/2013: 17:00	9/15/2014: 19:00	9/11/2015: 16:00	7/26/2016: 16:00	8/31/2017: 16:00
23	8/29/2011: 13:00	8/10/2012: 13:00	8/29/2013: 14:00	7/24/2014: 16:00	8/14/2015: 15:00	7/22/2016: 17:00	8/30/2017: 18:00
24	8/26/2011: 16:00	8/9/2012: 16:00	8/29/2013: 13:00	7/24/2014: 14:00	9/9/2015: 11:00	7/26/2016: 13:00	8/28/2017: 14:00
25	8/25/2011: 16:00	9/14/2012: 14:00	8/29/2013: 15:00	9/16/2014: 19:00	9/11/2015: 12:00	7/21/2016: 15:00	8/28/2017: 16:00
26	9/8/2011: 16:00	8/8/2012: 16:00	9/6/2013: 13:00	9/14/2014: 15:00	8/14/2015: 14:00	7/21/2016: 14:00	8/29/2017: 18:00
27	9/7/2011: 18:00	8/7/2012: 13:00	8/30/2013: 16:00	9/12/2014: 14:00	9/8/2015: 12:00	8/15/2016: 13:00	7/7/2017: 15:00
28	8/29/2011: 16:00	8/17/2012: 14:00	8/29/2013: 16:00	9/17/2014: 11:00	9/10/2015: 17:00	7/29/2016: 16:00	8/30/2017: 12:00
29	7/6/2011: 14:00	8/14/2012: 16:00	9/6/2013: 16:00	9/14/2014: 14:00	9/10/2015: 12:00	7/28/2016: 16:00	9/2/2017: 15:00
30	7/6/2011: 15:00	8/20/2012: 14:00	9/3/2013: 12:00	9/15/2014: 11:00	8/27/2015: 13:00	7/28/2016: 14:00	7/7/2017: 14:00
31	8/27/2011: 14:00	8/20/2012: 15:00	9/3/2013: 17:00	7/31/2014: 14:00	9/8/2015: 17:00	7/29/2016: 13:00	9/1/2017: 18:00
32	7/6/2011: 13:00	8/17/2012: 13:00	8/29/2013: 12:00	7/30/2014: 15:00	8/28/2015: 12:00	7/25/2016: 16:00	8/3/2017: 14:00
33	8/27/2011: 13:00	8/14/2012: 12:00	9/5/2013: 18:00	7/24/2014: 17:00	8/14/2015: 16:00	7/27/2016: 13:00	8/30/2017: 19:00
34	7/7/2011: 14:00	10/1/2012: 15:00	9/6/2013: 12:00	9/14/2014: 16:00	8/26/2015: 14:00	7/21/2016: 16:00	8/3/2017: 15:00
35	9/6/2011: 12:00	9/14/2012: 16:00	8/28/2013: 15:00	7/31/2014: 15:00	9/9/2015: 15:00	8/15/2016: 17:00	7/7/2017: 16:00
36	7/7/2011: 15:00	8/9/2012: 12:00	9/4/2013: 18:00	9/12/2014: 15:00	9/10/2015: 18:00	6/20/2016: 19:00	8/29/2017: 12:00
37	8/25/2011: 13:00	8/7/2012: 16:00	8/30/2013: 11:00	7/24/2014: 13:00	8/26/2015: 15:00	7/22/2016: 13:00	9/2/2017: 14:00
38	7/5/2011: 15:00	8/29/2012: 13:00	8/28/2013: 16:00	7/30/2014: 14:00	9/8/2015: 18:00	8/16/2016: 15:00	8/31/2017: 17:00
39	8/26/2011: 12:00	8/17/2012: 15:00	7/1/2013: 15:00	9/17/2014: 17:00	9/25/2015: 14:00	7/27/2016: 16:00	9/2/2017: 16:00
40	9/7/2011: 19:00	8/6/2012: 15:00	8/28/2013: 14:00	8/1/2014: 15:00	8/13/2015: 15:00	7/25/2016: 14:00	8/31/2017: 18:00
41	8/27/2011: 12:00	9/14/2012: 13:00	6/28/2013: 15:00	8/1/2014: 14:00	8/15/2015: 15:00	8/30/2016: 15:00	8/29/2017: 19:00
42	8/27/2011: 15:00	10/1/2012: 14:00	9/5/2013: 11:00	9/12/2014: 13:00	9/8/2015: 19:00	8/16/2016: 16:00	8/28/2017: 13:00
43	9/6/2011: 17:00	8/6/2012: 14:00	7/1/2013: 16:00	9/16/2014: 10:00	9/25/2015: 15:00	7/28/2016: 13:00	8/3/2017: 16:00
44	8/24/2011: 15:00	8/20/2012: 13:00	6/28/2013: 14:00	7/31/2014: 13:00	8/14/2015: 13:00	6/20/2016: 11:00	8/3/2017: 13:00
45	7/7/2011: 13:00	8/13/2012: 17:00	7/8/2013: 15:00	5/15/2014: 15:00	8/28/2015: 17:00	8/16/2016: 14:00	8/31/2017: 11:00
46	7/6/2011: 12:00	8/29/2012: 16:00	9/5/2013: 19:00	8/28/2014: 14:00	10/9/2015: 15:00	7/20/2016: 16:00	7/7/2017: 13:00
47	7/5/2011: 14:00	8/10/2012: 12:00	9/6/2013: 17:00	9/14/2014: 13:00	8/15/2015: 14:00	7/26/2016: 17:00	9/1/2017: 19:00
48	8/1/2011: 14:00	8/10/2012: 17:00	6/27/2013: 15:00	7/30/2014: 16:00	8/15/2015: 16:00	7/20/2016: 15:00	9/1/2017: 11:00
49	8/1/2011: 15:00	8/16/2012: 14:00	8/29/2013: 17:00	7/31/2014: 16:00	8/13/2015: 14:00	8/30/2016: 14:00	8/28/2017: 17:00
50	9/6/2011: 18:00	8/16/2012: 13:00	6/27/2013: 14:00	5/15/2014: 16:00	9/9/2015: 19:00	7/21/2016: 17:00	9/2/2017: 13:00
51	9/8/2011: 11:00	8/17/2012: 12:00	6/28/2013: 16:00	7/30/2014: 13:00	8/26/2015: 16:00	8/31/2016: 15:00	7/7/2017: 17:00
52	8/24/2011: 14:00	8/9/2012: 17:00	7/8/2013: 16:00	9/17/2014: 10:00	8/13/2015: 16:00	7/21/2016: 13:00	8/1/2017: 14:00
53	8/29/2011: 12:00	8/8/2012: 12:00	8/27/2013: 15:00	9/17/2014: 18:00	9/10/2015: 19:00	8/30/2016: 16:00	8/31/2017: 19:00
54	7/6/2011: 16:00	8/6/2012: 16:00	9/4/2013: 19:00	8/28/2014: 15:00	10/13/2015: 15:00	7/29/2016: 12:00	7/8/2017: 14:00
55	7/5/2011: 16:00	8/13/2012: 11:00	9/3/2013: 18:00	9/12/2014: 16:00	8/27/2015: 17:00	7/26/2016: 12:00	7/10/2017: 15:00
56	7/7/2011: 16:00	8/28/2012: 15:00	8/28/2013: 13:00	9/13/2014: 15:00	10/13/2015: 14:00	7/25/2016: 17:00	9/2/2017: 17:00
57	8/26/2011: 17:00	8/7/2012: 12:00	9/4/2013: 11:00	5/15/2014: 14:00	9/9/2015: 16:00	7/29/2016: 17:00	7/8/2017: 15:00
58	9/7/2011: 10:00	8/16/2012: 15:00	8/27/2013: 14:00	9/14/2014: 17:00	9/9/2015: 10:00	7/22/2016: 18:00	7/10/2017: 16:00
59	7/5/2011: 13:00	8/20/2012: 16:00	7/1/2013: 14:00	7/31/2014: 17:00	9/11/2015: 11:00	6/29/2016: 15:00	8/1/2017: 15:00

Hour #	2011	2012	2013	2014	2015	2016	2017
60	8/1/2011: 13:00	10/1/2012: 16:00	8/30/2013: 17:00	8/1/2014: 13:00	8/26/2015: 13:00	7/27/2016: 17:00	8/4/2017: 15:00
61	8/2/2011: 14:00	8/17/2012: 16:00	7/8/2013: 14:00	9/11/2014: 14:00	9/24/2015: 15:00	7/25/2016: 13:00	7/10/2017: 14:00
62	7/7/2011: 12:00	8/8/2012: 17:00	7/9/2013: 14:00	8/1/2014: 16:00	10/9/2015: 14:00	7/27/2016: 12:00	8/4/2017: 14:00
63	8/25/2011: 17:00	8/28/2012: 14:00	6/28/2013: 13:00	9/15/2014: 20:00	8/16/2015: 16:00	7/28/2016: 17:00	8/3/2017: 17:00
64	8/24/2011: 16:00	9/4/2012: 15:00	6/27/2013: 16:00	8/29/2014: 15:00	8/27/2015: 12:00	8/31/2016: 14:00	8/3/2017: 12:00
65	8/1/2011: 16:00	8/6/2012: 13:00	8/29/2013: 18:00	8/28/2014: 13:00	8/16/2015: 15:00	6/27/2016: 14:00	8/28/2017: 18:00
66	8/2/2011: 15:00	9/13/2012: 15:00	9/6/2013: 18:00	9/11/2014: 15:00	9/9/2015: 18:00	6/29/2016: 16:00	8/30/2017: 11:00
67	8/28/2011: 15:00	8/14/2012: 17:00	6/27/2013: 13:00	9/13/2014: 14:00	8/24/2015: 15:00	8/15/2016: 12:00	7/8/2017: 13:00
68	7/8/2011: 14:00	8/29/2012: 12:00	7/1/2013: 17:00	7/30/2014: 17:00	9/11/2015: 17:00	7/20/2016: 17:00	7/7/2017: 12:00
69	9/6/2011: 19:00	8/7/2012: 17:00	8/30/2013: 10:00	8/15/2014: 15:00	9/25/2015: 13:00	7/20/2016: 14:00	10/24/2017: 15:00
70	8/25/2011: 12:00	9/14/2012: 17:00	9/3/2013: 19:00	7/23/2014: 15:00	9/10/2015: 11:00	6/29/2016: 14:00	9/2/2017: 18:00
71	8/28/2011: 14:00	10/2/2012: 14:00	6/29/2013: 15:00	7/29/2014: 15:00	8/5/2015: 15:00	8/16/2016: 17:00	7/10/2017: 13:00
72	8/29/2011: 17:00	8/30/2012: 13:00	9/7/2013: 14:00	7/24/2014: 18:00	8/14/2015: 17:00	8/31/2016: 16:00	8/28/2017: 19:00
73	8/2/2011: 13:00	10/2/2012: 15:00	8/27/2013: 16:00	9/14/2014: 18:00	8/28/2015: 18:00	7/22/2016: 12:00	9/1/2017: 20:00
74	8/27/2011: 16:00	8/20/2012: 12:00	9/7/2013: 13:00	7/7/2014: 15:00	9/20/2015: 15:00	6/27/2016: 15:00	8/4/2017: 16:00
75	8/24/2011: 13:00	9/10/2012: 14:00	7/9/2013: 15:00	7/29/2014: 14:00	8/15/2015: 13:00	8/15/2016: 18:00	7/8/2017: 16:00
76	7/8/2011: 15:00	8/11/2012: 14:00	8/29/2013: 19:00	7/23/2014: 16:00	9/20/2015: 16:00	6/28/2016: 15:00	8/28/2017: 12:00
77	7/6/2011: 11:00	8/12/2012: 14:00	8/29/2013: 11:00	9/16/2014: 20:00	10/9/2015: 16:00	8/1/2016: 15:00	6/26/2017: 15:00
78	8/23/2011: 15:00	10/1/2012: 13:00	8/28/2013: 17:00	8/29/2014: 14:00	8/29/2015: 15:00	8/17/2016: 15:00	7/10/2017: 17:00
79	8/27/2011: 11:00	8/9/2012: 11:00	5/13/2013: 15:00	7/7/2014: 14:00	9/9/2015: 17:00	8/17/2016: 16:00	8/2/2017: 14:00
80	9/8/2011: 17:00	8/14/2012: 11:00	7/8/2013: 17:00	9/13/2014: 16:00	8/24/2015: 18:00	9/26/2016: 15:00	6/26/2017: 16:00
81	7/5/2011: 12:00	9/4/2012: 14:00	9/3/2013: 11:00	7/8/2014: 15:00	8/28/2015: 11:00	9/26/2016: 14:00	7/6/2017: 15:00
82	8/28/2011: 16:00	8/10/2012: 11:00	8/30/2013: 18:00	7/24/2014: 12:00	8/24/2015: 14:00	6/20/2016: 20:00	9/11/2017: 15:00
83	8/26/2011: 18:00	9/10/2012: 15:00	9/6/2013: 11:00	9/15/2014: 10:00	9/25/2015: 16:00	8/29/2016: 15:00	8/2/2017: 13:00
84	8/2/2011: 16:00	9/10/2012: 13:00	6/29/2013: 14:00	8/18/2014: 14:00	8/27/2015: 18:00	6/28/2016: 14:00	8/4/2017: 13:00
85	8/23/2011: 14:00	9/13/2012: 14:00	6/29/2013: 16:00	8/27/2014: 15:00	8/24/2015: 16:00	8/29/2016: 16:00	10/24/2017: 14:00
86	8/28/2011: 13:00	8/30/2012: 12:00	8/30/2013: 19:00	8/28/2014: 16:00	8/13/2015: 13:00	7/22/2016: 19:00	9/2/2017: 12:00
87	7/8/2011: 13:00	8/12/2012: 15:00	5/13/2013: 14:00	8/18/2014: 15:00	8/5/2015: 16:00	7/23/2016: 14:00	8/1/2017: 13:00
88	8/1/2011: 12:00	9/14/2012: 12:00	7/9/2013: 13:00	8/15/2014: 14:00	8/16/2015: 17:00	7/28/2016: 12:00	7/7/2017: 18:00
89	8/3/2011: 15:00	9/15/2012: 15:00	9/16/2013: 15:00	7/31/2014: 12:00	10/13/2015: 13:00	8/30/2016: 13:00	6/26/2017: 14:00
90	8/3/2011: 14:00	8/28/2012: 16:00	8/27/2013: 13:00	7/23/2014: 14:00	8/29/2015: 14:00	8/1/2016: 14:00	8/30/2017: 20:00
91	8/2/2011: 12:00	8/11/2012: 13:00	6/28/2013: 17:00	8/15/2014: 16:00	8/16/2015: 14:00	7/25/2016: 12:00	7/6/2017: 16:00
92	8/26/2011: 11:00	8/16/2012: 16:00	9/7/2013: 15:00	7/25/2014: 15:00	9/20/2015: 14:00	6/27/2016: 16:00	8/29/2017: 11:00
93	7/5/2011: 17:00	9/15/2012: 14:00	9/16/2013: 14:00	9/12/2014: 12:00	9/8/2015: 11:00	6/27/2016: 13:00	6/20/2017: 16:00
94	9/6/2011: 11:00	8/15/2012: 14:00	8/22/2013: 15:00	7/7/2014: 16:00	8/5/2015: 14:00	6/29/2016: 17:00	10/24/2017: 16:00
95	7/6/2011: 17:00	8/12/2012: 16:00	7/8/2013: 13:00	9/11/2014: 13:00	8/15/2015: 17:00	6/28/2016: 16:00	6/20/2017: 15:00
96	8/23/2011: 16:00	8/6/2012: 17:00	7/9/2013: 16:00	5/15/2014: 17:00	8/29/2015: 16:00	7/23/2016: 15:00	9/1/2017: 10:00
97	7/25/2011: 15:00	8/28/2012: 13:00	9/6/2013: 19:00	7/8/2014: 16:00	9/24/2015: 14:00	8/2/2016: 15:00	8/2/2017: 15:00
98	7/19/2011: 15:00	9/14/2012: 18:00	8/31/2013: 15:00	8/29/2014: 16:00	10/13/2015: 16:00	7/23/2016: 13:00	7/6/2017: 14:00
99	7/25/2011: 14:00	8/30/2012: 14:00	6/27/2013: 17:00	7/8/2014: 14:00	8/17/2015: 15:00	8/1/2016: 16:00	9/11/2017: 14:00
100	9/8/2011: 10:00	7/11/2012: 14:00	8/22/2013: 14:00	9/14/2014: 12:00	8/14/2015: 12:00	8/31/2016: 13:00	9/2/2017: 19:00
101	9/8/2011: 18:00	8/17/2012: 11:00	8/31/2013: 14:00	7/7/2014: 13:00	8/28/2015: 19:00	8/17/2016: 14:00	7/10/2017: 12:00
102	7/8/2011: 16:00	8/11/2012: 15:00	9/7/2013: 12:00	7/30/2014: 12:00	8/27/2015: 19:00	6/20/2016: 10:00	8/11/2017: 15:00
103	8/29/2011: 11:00	8/29/2012: 17:00	5/13/2013: 16:00	9/11/2014: 16:00	8/26/2015: 17:00	8/16/2016: 13:00	9/11/2017: 16:00
104	7/7/2011: 11:00	8/21/2012: 14:00	8/28/2013: 12:00	7/25/2014: 14:00	9/24/2015: 16:00	6/29/2016: 13:00	8/31/2017: 10:00
105	7/7/2011: 17:00	8/13/2012: 18:00	6/28/2013: 12:00	8/27/2014: 14:00	8/13/2015: 17:00	9/26/2016: 13:00	9/5/2017: 15:00
106	8/30/2011: 15:00	8/15/2012: 15:00	6/29/2013: 13:00	7/29/2014: 16:00	8/17/2015: 14:00	9/26/2016: 16:00	7/11/2017: 15:00
107	8/17/2011: 15:00	9/13/2012: 16:00	9/5/2013: 10:00	9/13/2014: 13:00	10/9/2015: 13:00	7/21/2016: 18:00	6/26/2017: 17:00
108	8/25/2011: 18:00	8/15/2012: 13:00	6/27/2013: 12:00	5/16/2014: 15:00	9/11/2015: 18:00	8/2/2016: 16:00	7/11/2017: 16:00
109	8/18/2011: 15:00	8/12/2012: 13:00	7/1/2013: 13:00	7/24/2014: 19:00	7/31/2015: 15:00	7/29/2016: 11:00	9/5/2017: 16:00
110	7/19/2011: 14:00	9/10/2012: 12:00	8/22/2013: 16:00	5/15/2014: 13:00	8/26/2015: 12:00	8/14/2016: 16:00	8/8/2017: 15:00
111	8/26/2011: 19:00	8/16/2012: 12:00	6/29/2013: 17:00	9/17/2014: 19:00	8/26/2015: 18:00	7/21/2016: 12:00	8/10/2017: 15:00
112	8/30/2011: 14:00	7/11/2012: 15:00	8/21/2013: 15:00	7/29/2014: 13:00	9/9/2015: 20:00	7/29/2016: 18:00	6/26/2017: 13:00
113	8/28/2011: 12:00	9/4/2012: 16:00	7/9/2013: 12:00	8/18/2014: 13:00	7/31/2015: 14:00	7/20/2016: 13:00	7/27/2017: 15:00
114	8/18/2011: 14:00	7/10/2012: 15:00	5/13/2013: 13:00	7/25/2014: 16:00	9/20/2015: 17:00	7/28/2016: 18:00	6/20/2017: 17:00
115	8/3/2011: 16:00	8/21/2012: 15:00	8/31/2013: 13:00	8/1/2014: 12:00	8/29/2015: 13:00	8/30/2016: 17:00	8/29/2017: 20:00
116	8/1/2011: 17:00	8/10/2012: 18:00	9/16/2013: 13:00	9/10/2014: 15:00	9/11/2015: 10:00	7/26/2016: 18:00	8/8/2017: 16:00
117	7/25/2011: 13:00	10/2/2012: 13:00	7/2/2013: 13:00	5/16/2014: 14:00	7/30/2015: 15:00	8/15/2016: 19:00	7/8/2017: 17:00
118	9/7/2011: 20:00	8/21/2012: 13:00	8/31/2013: 16:00	8/18/2014: 16:00	8/26/2015: 19:00	8/17/2016: 17:00	8/10/2017: 16:00
119	8/3/2011: 13:00	8/18/2012: 15:00	9/4/2013: 10:00	8/1/2014: 17:00	9/8/2015: 20:00	6/19/2016: 17:00	7/8/2017: 12:00
120	7/19/2011: 16:00	8/18/2012: 14:00	8/28/2013: 18:00	7/9/2014: 15:00	8/15/2015: 12:00	8/18/2016: 15:00	8/11/2017: 16:00
121	8/17/2011: 14:00	8/13/2012: 19:00	9/16/2013: 16:00	7/31/2014: 18:00	9/25/2015: 12:00	7/27/2016: 18:00	8/11/2017: 14:00

Hour #	2011	2012	2013	2014	2015	2016	2017
122	8/23/2011: 13:00	8/17/2012: 17:00	8/21/2013: 14:00	9/24/2014: 15:00	8/17/2015: 16:00	7/23/2016: 16:00	8/31/2017: 20:00
123	7/8/2011: 12:00	9/10/2012: 16:00	7/2/2013: 14:00	9/14/2014: 19:00	7/30/2015: 14:00	6/19/2016: 16:00	8/3/2017: 18:00
124	8/25/2011: 19:00	8/13/2012: 10:00	8/23/2013: 15:00	7/3/2014: 15:00	9/10/2015: 10:00	8/29/2016: 14:00	6/20/2017: 14:00
125	8/29/2011: 18:00	9/15/2012: 16:00	9/5/2013: 20:00	7/23/2014: 17:00	8/17/2015: 13:00	8/2/2016: 14:00	6/21/2017: 15:00
126	8/24/2011: 12:00	8/20/2012: 17:00	8/22/2013: 13:00	8/27/2014: 16:00	10/12/2015: 14:00	7/27/2016: 19:00	8/3/2017: 11:00
127	8/16/2011: 15:00	7/10/2012: 14:00	9/7/2013: 16:00	7/28/2014: 15:00	6/30/2015: 13:00	7/26/2016: 11:00	7/6/2017: 17:00
128	7/25/2011: 16:00	9/20/2012: 15:00	8/23/2013: 14:00	8/12/2014: 14:00	9/26/2015: 15:00	6/28/2016: 13:00	7/27/2017: 14:00
129	7/6/2011: 10:00	8/9/2012: 18:00	8/27/2013: 12:00	9/2/2014: 15:00	8/16/2015: 13:00	7/21/2016: 19:00	8/1/2017: 16:00
130	7/5/2011: 11:00	9/15/2012: 13:00	9/2/2013: 14:00	8/12/2014: 15:00	8/27/2015: 11:00	8/18/2016: 16:00	6/21/2017: 14:00
131	8/24/2011: 17:00	8/8/2012: 11:00	8/28/2013: 19:00	9/17/2014: 9:00	10/13/2015: 12:00	8/1/2016: 13:00	7/11/2017: 14:00
132	7/1/2011: 15:00	8/10/2012: 19:00	8/15/2013: 15:00	7/28/2014: 16:00	8/24/2015: 13:00	7/25/2016: 18:00	10/24/2017: 13:00
133	8/28/2011: 17:00	7/11/2012: 13:00	9/2/2013: 15:00	8/28/2014: 12:00	8/4/2015: 15:00	8/14/2016: 17:00	7/27/2017: 16:00
134	8/27/2011: 17:00	10/2/2012: 16:00	7/15/2013: 15:00	7/25/2014: 13:00	9/20/2015: 18:00	8/14/2016: 15:00	10/25/2017: 15:00
135	8/16/2011: 14:00	8/29/2012: 11:00	7/15/2013: 14:00	7/9/2014: 14:00	9/23/2015: 15:00	8/4/2016: 15:00	8/2/2017: 16:00
136	7/26/2011: 14:00	8/20/2012: 11:00	9/6/2013: 10:00	8/29/2014: 13:00	7/31/2015: 16:00	6/30/2016: 15:00	10/24/2017: 17:00
137	8/2/2011: 17:00	9/4/2012: 13:00	7/1/2013: 18:00	7/8/2014: 13:00	9/26/2015: 14:00	6/21/2016: 14:00	7/7/2017: 19:00
138	9/8/2011: 19:00	8/11/2012: 12:00	9/4/2013: 20:00	7/3/2014: 16:00	8/5/2015: 13:00	7/19/2016: 16:00	7/9/2017: 15:00
139	8/30/2011: 13:00	9/20/2012: 14:00	8/16/2013: 15:00	9/6/2014: 15:00	8/5/2015: 17:00	7/28/2016: 19:00	8/4/2017: 12:00
140	7/26/2011: 15:00	8/6/2012: 12:00	8/27/2013: 17:00	9/25/2014: 15:00	10/9/2015: 17:00	6/21/2016: 15:00	6/21/2017: 16:00
141	8/15/2011: 15:00	8/7/2012: 18:00	7/9/2013: 17:00	9/9/2014: 15:00	6/29/2015: 15:00	7/27/2016: 11:00	8/2/2017: 12:00
142	7/19/2011: 13:00	7/10/2012: 16:00	6/29/2013: 12:00	9/10/2014: 14:00	10/13/2015: 17:00	7/23/2016: 12:00	8/8/2017: 14:00
143	8/25/2011: 11:00	8/31/2012: 14:00	8/16/2013: 14:00	7/3/2014: 14:00	8/12/2015: 15:00	7/25/2016: 19:00	9/6/2017: 15:00
144	10/13/2011: 14:00	8/7/2012: 19:00	9/1/2013: 14:00	9/24/2014: 14:00	8/12/2015: 16:00	6/28/2016: 17:00	9/5/2017: 14:00
145	9/7/2011: 9:00	9/21/2012: 14:00	6/28/2013: 18:00	9/12/2014: 17:00	8/16/2015: 18:00	8/31/2016: 17:00	7/26/2017: 15:00
146	8/15/2011: 14:00	9/13/2012: 13:00	9/1/2013: 15:00	9/16/2014: 9:00	9/10/2015: 20:00	7/19/2016: 15:00	9/11/2017: 13:00
147	8/30/2011: 16:00	8/7/2012: 11:00	8/21/2013: 16:00	8/14/2014: 15:00	7/30/2015: 16:00	7/24/2016: 16:00	8/4/2017: 17:00
148	8/2/2011: 11:00	10/1/2012: 17:00	6/27/2013: 18:00	8/11/2014: 15:00	8/13/2015: 12:00	7/20/2016: 18:00	7/19/2017: 15:00
149	7/1/2011: 14:00	8/12/2012: 17:00	7/8/2013: 18:00	9/25/2014: 14:00	9/20/2015: 13:00	8/16/2016: 18:00	8/10/2017: 14:00
150	7/1/2011: 16:00	9/7/2012: 14:00	8/15/2013: 14:00	7/28/2014: 14:00	8/14/2015: 18:00	6/30/2016: 14:00	7/20/2017: 15:00
151	10/13/2011: 15:00	9/7/2012: 15:00	5/13/2013: 17:00	9/10/2014: 16:00	8/24/2015: 17:00	8/29/2016: 17:00	7/13/2017: 15:00
152	7/20/2011: 15:00	8/31/2012: 15:00	8/30/2013: 9:00	7/23/2014: 13:00	8/4/2015: 16:00	8/18/2016: 14:00	9/6/2017: 14:00
153	7/18/2011: 15:00	7/20/2012: 15:00	9/7/2013: 11:00	5/16/2014: 16:00	9/25/2015: 17:00	7/30/2016: 15:00	10/25/2017: 14:00
154	9/9/2011: 14:00	9/6/2012: 15:00	9/3/2013: 10:00	8/28/2014: 17:00	7/30/2015: 13:00	6/27/2016: 17:00	7/7/2017: 11:00
155	8/1/2011: 11:00	9/14/2012: 19:00	8/30/2013: 20:00	7/8/2014: 17:00	10/12/2015: 15:00	6/27/2016: 12:00	7/10/2017: 18:00
156	7/25/2011: 12:00	8/9/2012: 19:00	6/28/2013: 19:00	8/11/2014: 14:00	9/9/2015: 9:00	6/19/2016: 15:00	9/3/2017: 13:00
157	8/16/2011: 16:00	8/10/2012: 10:00	7/2/2013: 15:00	9/2/2014: 14:00	9/24/2015: 13:00	8/3/2016: 15:00	6/19/2017: 16:00
158	8/17/2011: 16:00	8/18/2012: 16:00	7/2/2013: 12:00	9/13/2014: 17:00	6/30/2015: 14:00	7/29/2016: 19:00	7/11/2017: 17:00
159	8/18/2011: 16:00	8/8/2012: 18:00	8/29/2013: 10:00	7/9/2014: 16:00	9/23/2015: 14:00	8/4/2016: 14:00	7/9/2017: 14:00
160	8/23/2011: 17:00	8/30/2012: 11:00	8/26/2013: 15:00	8/15/2014: 13:00	9/11/2015: 19:00	8/4/2016: 16:00	7/12/2017: 15:00
161	8/29/2011: 19:00	7/11/2012: 16:00	8/26/2013: 14:00	7/7/2014: 17:00	8/29/2015: 17:00	8/1/2016: 17:00	6/19/2017: 15:00
162	8/17/2011: 13:00	8/29/2012: 18:00	6/28/2013: 11:00	9/9/2014: 14:00	10/12/2015: 13:00	6/22/2016: 15:00	7/26/2017: 16:00
163	8/18/2011: 13:00	9/21/2012: 15:00	8/29/2013: 20:00	9/11/2014: 12:00	6/29/2015: 14:00	7/22/2016: 11:00	7/19/2017: 16:00
164	10/12/2011: 15:00	8/16/2012: 17:00	6/29/2013: 18:00	7/31/2014: 19:00	7/31/2015: 13:00	6/21/2016: 13:00	7/6/2017: 13:00
165	7/7/2011: 10:00	8/14/2012: 10:00	7/8/2013: 12:00	9/6/2014: 14:00	9/7/2015: 15:00	9/29/2016: 15:00	7/20/2017: 16:00
166	8/26/2011: 10:00	8/18/2012: 13:00	8/31/2013: 12:00	8/14/2014: 14:00	9/23/2015: 16:00	8/15/2016: 11:00	7/9/2017: 16:00
167	7/6/2011: 18:00	8/30/2012: 15:00	7/15/2013: 16:00	7/7/2014: 12:00	9/28/2015: 15:00	7/24/2016: 15:00	7/31/2017: 16:00
168	7/20/2011: 14:00	8/11/2012: 16:00	7/1/2013: 19:00	5/16/2014: 13:00	8/28/2015: 10:00	6/30/2016: 16:00	8/30/2017: 10:00
169	8/27/2011: 10:00	7/20/2012: 14:00	7/1/2013: 12:00	8/27/2014: 13:00	6/29/2015: 16:00	7/22/2016: 20:00	7/31/2017: 15:00
170	8/28/2011: 11:00	8/15/2012: 16:00	7/15/2013: 13:00	8/12/2014: 13:00	10/13/2015: 18:00	6/21/2016: 16:00	7/17/2017: 15:00
171	8/3/2011: 12:00	8/28/2012: 17:00	6/30/2013: 12:00	7/30/2014: 18:00	8/17/2015: 12:00	7/26/2016: 19:00	7/12/2017: 16:00
172	7/5/2011: 18:00	9/10/2012: 11:00	6/30/2013: 15:00	7/25/2014: 12:00	9/7/2015: 16:00	8/2/2016: 13:00	7/13/2017: 16:00
173	7/26/2011: 13:00	8/29/2012: 19:00	6/27/2013: 19:00	8/14/2014: 16:00	8/15/2015: 18:00	7/24/2016: 17:00	7/20/2017: 14:00
174	9/9/2011: 15:00	8/15/2012: 12:00	9/2/2013: 13:00	8/27/2014: 17:00	9/25/2015: 18:00	6/19/2016: 18:00	9/2/2017: 11:00
175	8/28/2011: 18:00	9/12/2012: 15:00	8/21/2013: 13:00	8/12/2014: 16:00	8/4/2015: 14:00	9/27/2016: 15:00	8/9/2017: 16:00
176	7/18/2011: 14:00	9/21/2012: 13:00	8/23/2013: 16:00	9/2/2014: 16:00	9/26/2015: 13:00	7/30/2016: 14:00	9/7/2017: 15:00
177	7/6/2011: 19:00	8/19/2012: 15:00	6/30/2013: 13:00	9/6/2014: 16:00	8/13/2015: 18:00	8/2/2016: 17:00	8/9/2017: 15:00
178	7/19/2011: 17:00	7/10/2012: 13:00	8/14/2013: 15:00	7/9/2014: 13:00	10/10/2015: 15:00	8/17/2016: 13:00	9/3/2017: 12:00
179	7/8/2011: 17:00	9/6/2012: 14:00	8/15/2013: 16:00	8/15/2014: 17:00	7/29/2015: 15:00	9/26/2016: 17:00	9/3/2017: 14:00
180	7/7/2011: 18:00	10/2/2012: 12:00	8/23/2013: 13:00	5/15/2014: 18:00	6/30/2015: 12:00	8/30/2016: 12:00	8/3/2017: 19:00
181	9/6/2011: 20:00	8/31/2012: 13:00	9/3/2013: 20:00	8/13/2014: 15:00	8/17/2015: 17:00	9/29/2016: 14:00	7/5/2017: 16:00
182	7/18/2011: 16:00	8/21/2012: 12:00	6/30/2013: 14:00	9/5/2014: 15:00	9/24/2015: 17:00	6/29/2016: 12:00	8/7/2017: 16:00
183	8/24/2011: 18:00	8/14/2012: 18:00	7/25/2013: 15:00	7/31/2014: 11:00	9/28/2015: 14:00	7/28/2016: 11:00	8/7/2017: 15:00

Hour #	2011	2012	2013	2014	2015	2016	2017
184	7/5/2011: 19:00	8/21/2012: 16:00	5/13/2013: 12:00	8/11/2014: 16:00	8/14/2015: 19:00	6/22/2016: 14:00	8/8/2017: 17:00
185	10/12/2011: 14:00	9/12/2012: 14:00	9/1/2013: 13:00	8/18/2014: 12:00	9/26/2015: 16:00	7/19/2016: 17:00	7/10/2017: 11:00
186	7/26/2011: 16:00	8/17/2012: 10:00	8/16/2013: 16:00	8/11/2014: 13:00	10/9/2015: 18:00	7/30/2016: 16:00	6/26/2017: 12:00
187	8/29/2011: 10:00	9/9/2012: 15:00	8/16/2013: 13:00	7/29/2014: 12:00	8/16/2015: 19:00	8/3/2016: 14:00	7/26/2017: 14:00
188	7/8/2011: 11:00	10/1/2012: 18:00	7/3/2013: 15:00	9/25/2014: 13:00	9/24/2015: 18:00	7/14/2016: 15:00	7/17/2017: 16:00
189	8/15/2011: 16:00	8/12/2012: 12:00	7/3/2013: 14:00	7/28/2014: 17:00	10/10/2015: 14:00	6/29/2016: 18:00	8/11/2017: 13:00
190	9/6/2011: 10:00	9/13/2012: 17:00	6/27/2013: 11:00	8/28/2014: 18:00	9/7/2015: 14:00	9/27/2016: 14:00	9/5/2017: 17:00
191	8/3/2011: 17:00	8/19/2012: 14:00	7/9/2013: 11:00	9/12/2014: 18:00	8/29/2015: 12:00	6/22/2016: 16:00	7/13/2017: 14:00
192	10/13/2011: 13:00	8/9/2012: 10:00	9/2/2013: 16:00	5/14/2014: 15:00	7/29/2015: 14:00	8/3/2016: 16:00	6/20/2017: 13:00
193	7/19/2011: 12:00	9/9/2012: 14:00	6/30/2013: 16:00	5/15/2014: 12:00	8/12/2015: 17:00	7/14/2016: 16:00	6/21/2017: 17:00
194	7/20/2011: 16:00	7/19/2012: 15:00	7/24/2013: 15:00	5/14/2014: 16:00	10/12/2015: 16:00	6/30/2016: 13:00	7/27/2017: 13:00
195	8/15/2011: 13:00	10/1/2012: 12:00	6/29/2013: 19:00	9/11/2014: 17:00	10/9/2015: 12:00	7/23/2016: 17:00	8/2/2017: 17:00
196	8/4/2011: 15:00	8/28/2012: 12:00	7/24/2013: 14:00	7/28/2014: 13:00	8/12/2015: 14:00	9/26/2016: 12:00	9/6/2017: 16:00
197	8/23/2011: 12:00	8/8/2012: 19:00	8/28/2013: 11:00	9/24/2014: 16:00	10/12/2015: 18:00	7/19/2016: 14:00	7/17/2017: 14:00
198	7/7/2011: 19:00	8/6/2012: 18:00	9/1/2013: 16:00	8/29/2014: 17:00	8/18/2015: 15:00	8/14/2016: 14:00	9/7/2017: 16:00
199	8/27/2011: 18:00	9/7/2012: 13:00	8/20/2013: 15:00	9/13/2014: 12:00	8/14/2015: 11:00	8/19/2016: 15:00	9/2/2017: 20:00
200	8/16/2011: 13:00	9/13/2012: 18:00	7/23/2013: 15:00	7/29/2014: 17:00	10/14/2015: 14:00	8/30/2016: 18:00	7/12/2017: 14:00

TABLE A-10: SDG&E TOP 200 HOURS

Hour #	2011	2012	2013	2014	2015	2016	2017
1	9/7/2011: 14:00	9/14/2012: 15:00	8/30/2013: 15:00	9/16/2014: 14:00	9/9/2015: 14:00	7/22/2016: 16:00	9/1/2017: 15:00
2	9/7/2011: 13:00	9/14/2012: 14:00	8/30/2013: 14:00	9/16/2014: 15:00	9/9/2015: 13:00	7/22/2016: 15:00	9/1/2017: 14:00
3	9/7/2011: 15:00	9/14/2012: 16:00	9/6/2013: 15:00	9/15/2014: 15:00	9/9/2015: 15:00	7/22/2016: 17:00	9/1/2017: 16:00
4	9/7/2011: 12:00	9/14/2012: 13:00	8/30/2013: 13:00	9/15/2014: 14:00	9/9/2015: 18:00	8/15/2016: 16:00	9/2/2017: 16:00
5	9/6/2011: 15:00	9/14/2012: 17:00	8/30/2013: 16:00	9/16/2014: 13:00	9/10/2015: 15:00	9/26/2016: 16:00	9/1/2017: 13:00
6	9/6/2011: 16:00	9/14/2012: 12:00	9/4/2013: 14:00	9/16/2014: 16:00	9/10/2015: 14:00	9/26/2016: 17:00	10/24/2017: 15:00
7	9/8/2011: 13:00	9/14/2012: 18:00	9/4/2013: 15:00	9/15/2014: 16:00	9/9/2015: 19:00	9/26/2016: 18:00	10/24/2017: 16:00
8	9/7/2011: 16:00	9/15/2012: 14:00	9/6/2013: 14:00	9/16/2014: 18:00	9/10/2015: 13:00	8/15/2016: 15:00	8/30/2017: 16:00
9	9/8/2011: 12:00	9/15/2012: 15:00	9/5/2013: 15:00	9/16/2014: 12:00	9/9/2015: 12:00	7/22/2016: 14:00	9/2/2017: 17:00
10	9/6/2011: 14:00	8/17/2012: 13:00	8/30/2013: 12:00	9/15/2014: 13:00	9/9/2015: 16:00	9/26/2016: 15:00	8/30/2017: 15:00
11	9/7/2011: 11:00	8/13/2012: 14:00	9/6/2013: 16:00	9/17/2014: 14:00	9/8/2015: 15:00	7/22/2016: 18:00	9/2/2017: 15:00
12	9/8/2011: 11:00	8/13/2012: 15:00	9/4/2013: 16:00	9/17/2014: 13:00	9/10/2015: 16:00	8/15/2016: 17:00	9/2/2017: 18:00
13	9/7/2011: 18:00	8/17/2012: 14:00	9/5/2013: 16:00	9/17/2014: 12:00	9/9/2015: 17:00	8/16/2016: 16:00	8/29/2017: 16:00
14	9/6/2011: 18:00	8/13/2012: 13:00	9/4/2013: 13:00	9/17/2014: 15:00	9/8/2015: 14:00	8/16/2016: 15:00	9/1/2017: 17:00
15	9/6/2011: 17:00	8/17/2012: 15:00	9/5/2013: 14:00	9/15/2014: 12:00	9/10/2015: 12:00	7/21/2016: 16:00	9/2/2017: 19:00
16	9/7/2011: 17:00	8/17/2012: 12:00	9/3/2013: 15:00	9/16/2014: 19:00	9/8/2015: 16:00	8/15/2016: 14:00	8/29/2017: 15:00
17	9/6/2011: 13:00	9/15/2012: 13:00	8/30/2013: 11:00	9/16/2014: 17:00	9/9/2015: 11:00	6/20/2016: 16:00	9/1/2017: 12:00
18	9/7/2011: 10:00	8/13/2012: 16:00	9/6/2013: 13:00	9/17/2014: 11:00	9/10/2015: 18:00	8/17/2016: 16:00	10/24/2017: 17:00
19	9/7/2011: 19:00	9/15/2012: 16:00	9/3/2013: 14:00	9/16/2014: 11:00	9/11/2015: 14:00	6/20/2016: 15:00	8/30/2017: 17:00
20	9/6/2011: 19:00	8/17/2012: 16:00	9/3/2013: 16:00	9/15/2014: 18:00	8/28/2015: 15:00	7/22/2016: 13:00	8/31/2017: 16:00
21	9/8/2011: 10:00	8/13/2012: 12:00	9/5/2013: 13:00	9/15/2014: 17:00	9/10/2015: 19:00	9/26/2016: 14:00	10/24/2017: 14:00
22	7/7/2011: 14:00	10/1/2012: 15:00	9/4/2013: 12:00	9/17/2014: 16:00	9/10/2015: 17:00	7/21/2016: 15:00	8/30/2017: 14:00
23	7/7/2011: 15:00	8/14/2012: 14:00	8/30/2013: 17:00	9/17/2014: 10:00	9/8/2015: 13:00	7/22/2016: 19:00	9/1/2017: 18:00
24	7/7/2011: 13:00	10/1/2012: 14:00	9/3/2013: 13:00	9/15/2014: 11:00	9/11/2015: 13:00	7/21/2016: 17:00	9/2/2017: 14:00
25	8/26/2011: 14:00	8/14/2012: 15:00	9/5/2013: 17:00	9/14/2014: 15:00	9/11/2015: 15:00	8/17/2016: 15:00	8/31/2017: 14:00
26	8/29/2011: 14:00	8/17/2012: 11:00	9/5/2013: 12:00	9/15/2014: 19:00	8/28/2015: 16:00	8/15/2016: 18:00	8/31/2017: 15:00
27	7/6/2011: 14:00	9/14/2012: 11:00	9/4/2013: 17:00	9/14/2014: 16:00	8/28/2015: 14:00	6/20/2016: 14:00	10/25/2017: 15:00
28	8/26/2011: 13:00	9/14/2012: 19:00	8/30/2013: 10:00	9/14/2014: 14:00	9/10/2015: 11:00	8/15/2016: 13:00	8/31/2017: 17:00
29	7/7/2011: 12:00	10/2/2012: 15:00	9/6/2013: 12:00	9/17/2014: 17:00	9/8/2015: 17:00	7/27/2016: 16:00	8/29/2017: 17:00
30	8/29/2011: 13:00	10/2/2012: 14:00	8/30/2013: 18:00	9/16/2014: 10:00	9/20/2015: 15:00	9/26/2016: 19:00	8/30/2017: 18:00
31	7/7/2011: 16:00	8/14/2012: 13:00	9/5/2013: 18:00	9/17/2014: 18:00	10/9/2015: 15:00	8/16/2016: 14:00	9/1/2017: 19:00
32	7/6/2011: 13:00	9/15/2012: 12:00	9/6/2013: 17:00	9/14/2014: 13:00	9/8/2015: 18:00	8/16/2016: 17:00	8/29/2017: 14:00
33	8/26/2011: 15:00	8/10/2012: 14:00	9/4/2013: 11:00	9/16/2014: 20:00	9/11/2015: 12:00	7/28/2016: 16:00	8/31/2017: 13:00
34	9/6/2011: 12:00	8/13/2012: 11:00	9/3/2013: 17:00	9/14/2014: 17:00	9/20/2015: 16:00	7/27/2016: 15:00	10/24/2017: 18:00
35	8/29/2011: 12:00	8/20/2012: 14:00	9/3/2013: 12:00	9/17/2014: 9:00	8/26/2015: 15:00	6/20/2016: 17:00	9/2/2017: 20:00
36	8/29/2011: 15:00	10/1/2012: 13:00	9/4/2013: 18:00	9/14/2014: 18:00	10/9/2015: 16:00	8/17/2016: 17:00	10/25/2017: 14:00
37	7/6/2011: 12:00	10/2/2012: 13:00	8/30/2013: 19:00	9/9/2014: 15:00	8/26/2015: 16:00	7/28/2016: 15:00	9/2/2017: 13:00
38	8/2/2011: 15:00	8/14/2012: 16:00	9/5/2013: 19:00	9/9/2014: 14:00	9/9/2015: 20:00	7/26/2016: 16:00	8/31/2017: 18:00
39	9/7/2011: 9:00	8/31/2012: 14:00	9/5/2013: 11:00	9/15/2014: 10:00	9/11/2015: 16:00	7/21/2016: 14:00	10/25/2017: 16:00
40	8/26/2011: 12:00	8/20/2012: 13:00	9/3/2013: 18:00	5/15/2014: 15:00	8/27/2015: 16:00	9/27/2016: 14:00	9/1/2017: 11:00
41	8/2/2011: 14:00	8/16/2012: 13:00	9/7/2013: 14:00	9/12/2014: 15:00	9/20/2015: 14:00	8/15/2016: 19:00	10/24/2017: 13:00
42	7/6/2011: 15:00	8/29/2012: 15:00	9/7/2013: 15:00	9/13/2014: 15:00	9/8/2015: 12:00	6/20/2016: 13:00	8/3/2017: 15:00
43	7/7/2011: 11:00	10/1/2012: 16:00	9/4/2013: 19:00	9/8/2014: 15:00	8/27/2015: 15:00	7/22/2016: 12:00	8/29/2017: 18:00
44	8/25/2011: 15:00	8/16/2012: 15:00	9/6/2013: 18:00	5/15/2014: 16:00	9/9/2015: 10:00	7/26/2016: 15:00	8/30/2017: 19:00
45	8/25/2011: 14:00	8/16/2012: 14:00	9/6/2013: 11:00	9/9/2014: 13:00	8/28/2015: 17:00	7/21/2016: 18:00	8/31/2017: 12:00
46	7/6/2011: 11:00	8/20/2012: 15:00	9/3/2013: 11:00	9/12/2014: 14:00	8/27/2015: 14:00	8/15/2016: 12:00	8/30/2017: 13:00
47	8/2/2011: 13:00	9/15/2012: 17:00	9/7/2013: 13:00	9/8/2014: 14:00	10/9/2015: 14:00	9/27/2016: 13:00	8/31/2017: 19:00
48	7/5/2011: 14:00	8/14/2012: 12:00	8/31/2013: 15:00	5/15/2014: 14:00	10/13/2015: 15:00	7/28/2016: 14:00	10/25/2017: 13:00
49	8/2/2011: 16:00	8/31/2012: 13:00	9/3/2013: 19:00	8/28/2014: 15:00	9/8/2015: 19:00	9/26/2016: 13:00	8/3/2017: 16:00
50	8/29/2011: 11:00	8/31/2012: 15:00	8/28/2013: 15:00	9/12/2014: 16:00	8/27/2015: 17:00	7/27/2016: 14:00	8/3/2017: 14:00
51	7/6/2011: 16:00	8/13/2012: 17:00	8/28/2013: 14:00	9/14/2014: 12:00	10/13/2015: 14:00	7/28/2016: 17:00	9/2/2017: 12:00
52	9/8/2011: 9:00	8/10/2012: 15:00	9/4/2013: 10:00	9/13/2014: 16:00	8/14/2015: 15:00	7/27/2016: 17:00	10/25/2017: 17:00
53	7/5/2011: 15:00	9/4/2012: 14:00	8/28/2013: 13:00	9/17/2014: 19:00	8/28/2015: 13:00	9/27/2016: 15:00	9/11/2017: 16:00
54	8/26/2011: 16:00	8/20/2012: 12:00	8/29/2013: 15:00	9/14/2014: 19:00	8/26/2015: 14:00	7/26/2016: 17:00	8/3/2017: 17:00
55	10/12/2011: 15:00	9/4/2012: 15:00	8/29/2013: 16:00	8/28/2014: 14:00	9/20/2015: 17:00	8/17/2016: 14:00	8/29/2017: 13:00
56	7/5/2011: 13:00	8/29/2012: 14:00	8/30/2013: 9:00	9/9/2014: 16:00	9/25/2015: 15:00	9/29/2016: 15:00	8/29/2017: 19:00
57	8/25/2011: 13:00	9/10/2012: 13:00	8/31/2013: 14:00	9/13/2014: 14:00	9/11/2015: 11:00	9/28/2016: 15:00	9/11/2017: 15:00
58	8/2/2011: 12:00	8/17/2012: 17:00	9/7/2013: 12:00	9/8/2014: 16:00	8/14/2015: 16:00	9/29/2016: 16:00	8/2/2017: 13:00
59	7/7/2011: 17:00	10/2/2012: 16:00	9/7/2013: 16:00	9/12/2014: 13:00	8/14/2015: 14:00	7/22/2016: 20:00	9/1/2017: 20:00

Hour #	2011	2012	2013	2014	2015	2016	2017
60	8/26/2011: 11:00	8/10/2012: 13:00	9/6/2013: 19:00	9/8/2014: 13:00	9/20/2015: 18:00	7/21/2016: 19:00	8/3/2017: 13:00
61	10/13/2011: 14:00	9/10/2012: 15:00	8/28/2013: 16:00	9/16/2014: 9:00	10/13/2015: 16:00	8/16/2016: 18:00	9/2/2017: 21:00
62	8/3/2011: 15:00	9/15/2012: 18:00	9/5/2013: 10:00	7/24/2014: 16:00	9/10/2015: 10:00	6/20/2016: 12:00	8/2/2017: 12:00
63	10/12/2011: 14:00	8/17/2012: 10:00	8/31/2013: 16:00	7/24/2014: 15:00	10/13/2015: 13:00	7/20/2016: 16:00	9/1/2017: 10:00
64	7/5/2011: 12:00	8/30/2012: 14:00	8/30/2013: 20:00	9/11/2014: 14:00	10/9/2015: 17:00	8/16/2016: 13:00	9/11/2017: 14:00
65	8/29/2011: 16:00	8/8/2012: 14:00	8/31/2013: 13:00	8/28/2014: 16:00	9/25/2015: 14:00	7/21/2016: 13:00	8/4/2017: 16:00
66	9/7/2011: 20:00	9/10/2012: 14:00	8/28/2013: 12:00	9/9/2014: 12:00	8/27/2015: 13:00	7/26/2016: 14:00	10/23/2017: 15:00
67	8/25/2011: 16:00	8/8/2012: 15:00	8/29/2013: 19:00	9/11/2014: 15:00	8/27/2015: 18:00	9/28/2016: 16:00	10/23/2017: 16:00
68	10/13/2011: 13:00	8/29/2012: 16:00	8/29/2013: 18:00	7/30/2014: 15:00	9/10/2015: 20:00	7/20/2016: 17:00	8/28/2017: 15:00
69	7/7/2011: 10:00	9/10/2012: 12:00	9/6/2013: 10:00	7/30/2014: 16:00	8/28/2015: 18:00	9/28/2016: 14:00	8/28/2017: 16:00
70	7/5/2011: 16:00	9/4/2012: 13:00	9/7/2013: 11:00	8/28/2014: 13:00	10/14/2015: 15:00	6/20/2016: 11:00	10/24/2017: 12:00
71	7/6/2011: 10:00	9/15/2012: 11:00	8/29/2013: 17:00	5/15/2014: 13:00	8/16/2015: 15:00	8/17/2016: 18:00	8/31/2017: 11:00
72	8/3/2011: 14:00	8/30/2012: 13:00	9/3/2013: 10:00	8/27/2014: 15:00	10/9/2015: 18:00	7/29/2016: 15:00	10/24/2017: 19:00
73	7/8/2011: 14:00	8/31/2012: 12:00	8/31/2013: 12:00	7/31/2014: 15:00	8/28/2015: 12:00	9/27/2016: 12:00	8/30/2017: 12:00
74	10/13/2011: 15:00	8/13/2012: 10:00	8/29/2013: 14:00	9/15/2014: 20:00	8/16/2015: 16:00	6/20/2016: 18:00	7/10/2017: 16:00
75	8/28/2011: 15:00	10/1/2012: 12:00	8/31/2013: 11:00	7/28/2014: 16:00	8/26/2015: 17:00	7/27/2016: 13:00	6/26/2017: 16:00
76	9/6/2011: 11:00	10/2/2012: 12:00	8/27/2013: 15:00	7/30/2014: 14:00	10/10/2015: 15:00	8/31/2016: 16:00	10/25/2017: 12:00
77	8/1/2011: 15:00	8/8/2012: 13:00	9/5/2013: 20:00	5/15/2014: 17:00	9/8/2015: 11:00	7/29/2016: 16:00	6/26/2017: 17:00
78	8/1/2011: 14:00	9/5/2012: 15:00	8/28/2013: 17:00	7/28/2014: 15:00	10/14/2015: 14:00	8/16/2016: 19:00	8/2/2017: 15:00
79	10/12/2011: 16:00	8/16/2012: 16:00	8/27/2013: 13:00	9/11/2014: 13:00	9/11/2015: 18:00	8/31/2016: 15:00	8/3/2017: 18:00
80	7/8/2011: 13:00	8/30/2012: 15:00	9/4/2013: 20:00	7/31/2014: 16:00	10/13/2015: 17:00	9/29/2016: 17:00	8/4/2017: 15:00
81	8/3/2011: 16:00	8/9/2012: 15:00	9/4/2013: 9:00	7/28/2014: 14:00	9/25/2015: 16:00	9/29/2016: 18:00	8/2/2017: 14:00
82	8/28/2011: 14:00	8/20/2012: 11:00	8/28/2013: 11:00	7/29/2014: 15:00	10/13/2015: 18:00	7/28/2016: 13:00	8/3/2017: 12:00
83	7/8/2011: 15:00	9/5/2012: 14:00	9/5/2013: 9:00	8/27/2014: 14:00	10/9/2015: 13:00	9/29/2016: 14:00	10/23/2017: 17:00
84	8/25/2011: 12:00	8/20/2012: 16:00	9/7/2013: 17:00	9/8/2014: 12:00	8/29/2015: 16:00	9/27/2016: 16:00	7/10/2017: 15:00
85	7/5/2011: 11:00	9/10/2012: 16:00	8/28/2013: 18:00	9/12/2014: 12:00	9/24/2015: 15:00	7/22/2016: 11:00	10/25/2017: 18:00
86	10/13/2011: 12:00	8/12/2012: 15:00	8/29/2013: 11:00	7/24/2014: 14:00	8/14/2015: 13:00	8/14/2016: 17:00	7/7/2017: 16:00
87	8/2/2011: 11:00	10/1/2012: 18:00	8/31/2013: 17:00	9/11/2014: 16:00	8/29/2015: 15:00	7/20/2016: 15:00	9/2/2017: 11:00
88	7/8/2011: 12:00	8/14/2012: 11:00	8/31/2013: 10:00	9/13/2014: 13:00	10/10/2015: 14:00	7/27/2016: 18:00	9/11/2017: 18:00
89	8/1/2011: 13:00	8/29/2012: 13:00	9/2/2013: 15:00	9/15/2014: 9:00	8/15/2015: 16:00	8/1/2016: 16:00	7/12/2017: 16:00
90	8/3/2011: 13:00	8/16/2012: 12:00	6/28/2013: 15:00	8/4/2014: 13:00	9/11/2015: 17:00	8/15/2016: 11:00	8/4/2017: 17:00
91	9/6/2011: 20:00	8/9/2012: 14:00	8/29/2013: 12:00	8/15/2014: 15:00	10/14/2015: 16:00	9/28/2016: 18:00	8/28/2017: 14:00
92	8/29/2011: 10:00	9/4/2012: 16:00	9/7/2013: 10:00	7/29/2014: 14:00	10/13/2015: 12:00	7/29/2016: 14:00	8/28/2017: 17:00
93	10/12/2011: 18:00	10/1/2012: 17:00	8/28/2013: 19:00	8/27/2014: 16:00	9/12/2015: 14:00	9/30/2016: 15:00	8/2/2017: 16:00
94	8/26/2011: 17:00	8/10/2012: 16:00	8/27/2013: 14:00	7/31/2014: 14:00	8/16/2015: 14:00	7/27/2016: 19:00	7/11/2017: 16:00
95	7/6/2011: 17:00	8/31/2012: 16:00	6/28/2013: 14:00	7/24/2014: 17:00	9/25/2015: 13:00	9/27/2016: 18:00	9/11/2017: 17:00
96	10/12/2011: 17:00	8/7/2012: 14:00	9/6/2013: 9:00	9/7/2014: 15:00	8/28/2015: 19:00	7/26/2016: 13:00	8/4/2017: 14:00
97	8/28/2011: 16:00	8/8/2012: 12:00	5/13/2013: 15:00	9/10/2014: 15:00	9/11/2015: 10:00	8/30/2016: 16:00	7/10/2017: 17:00
98	8/24/2011: 15:00	8/8/2012: 16:00	8/31/2013: 18:00	5/16/2014: 15:00	8/26/2015: 13:00	8/2/2016: 15:00	8/3/2017: 19:00
99	10/12/2011: 13:00	8/12/2012: 14:00	9/3/2013: 20:00	8/4/2014: 15:00	10/14/2015: 13:00	8/18/2016: 16:00	10/23/2017: 14:00
100	7/7/2011: 19:00	8/10/2012: 12:00	9/7/2013: 18:00	8/4/2014: 14:00	9/24/2015: 14:00	8/17/2016: 19:00	8/1/2017: 16:00
101	8/1/2011: 16:00	9/5/2012: 13:00	5/13/2013: 14:00	9/17/2014: 8:00	8/27/2015: 19:00	6/20/2016: 10:00	6/26/2017: 15:00
102	8/24/2011: 14:00	9/6/2012: 14:00	9/6/2013: 20:00	9/10/2014: 14:00	8/15/2015: 15:00	8/14/2016: 16:00	8/31/2017: 20:00
103	8/27/2011: 15:00	9/6/2012: 15:00	8/31/2013: 19:00	8/15/2014: 14:00	10/10/2015: 16:00	7/26/2016: 18:00	7/7/2017: 15:00
104	8/2/2011: 17:00	9/4/2012: 12:00	6/28/2013: 16:00	9/13/2014: 17:00	8/26/2015: 18:00	7/28/2016: 18:00	7/13/2017: 16:00
105	8/26/2011: 10:00	9/14/2012: 10:00	9/16/2013: 15:00	5/16/2014: 16:00	9/11/2015: 19:00	8/2/2016: 16:00	8/29/2017: 12:00
106	8/27/2011: 14:00	8/30/2012: 12:00	8/27/2013: 16:00	5/14/2014: 15:00	8/29/2015: 14:00	8/17/2016: 13:00	8/28/2017: 18:00
107	8/26/2011: 18:00	10/2/2012: 18:00	8/27/2013: 12:00	9/7/2014: 14:00	10/12/2015: 18:00	8/1/2016: 15:00	7/12/2017: 17:00
108	8/28/2011: 13:00	8/9/2012: 16:00	8/27/2013: 11:00	9/14/2014: 11:00	8/27/2015: 12:00	8/18/2016: 15:00	8/2/2017: 19:00
109	7/7/2011: 18:00	8/14/2012: 17:00	9/16/2013: 14:00	8/28/2014: 12:00	10/12/2015: 16:00	6/19/2016: 17:00	8/30/2017: 20:00
110	7/25/2011: 15:00	8/18/2012: 14:00	9/1/2013: 15:00	7/30/2014: 17:00	9/12/2015: 16:00	9/28/2016: 17:00	7/11/2017: 17:00
111	8/27/2011: 13:00	9/5/2012: 16:00	9/2/2013: 16:00	7/29/2014: 16:00	10/12/2015: 17:00	8/30/2016: 15:00	8/2/2017: 11:00
112	7/8/2011: 11:00	8/18/2012: 15:00	5/13/2013: 16:00	8/4/2014: 16:00	8/16/2015: 17:00	9/30/2016: 16:00	7/10/2017: 14:00
113	8/27/2011: 12:00	8/7/2012: 15:00	6/28/2013: 13:00	9/8/2014: 17:00	9/12/2015: 15:00	6/20/2016: 19:00	7/12/2017: 15:00
114	8/27/2011: 11:00	8/17/2012: 18:00	9/3/2013: 9:00	5/14/2014: 16:00	9/20/2015: 13:00	7/27/2016: 12:00	7/7/2017: 17:00
115	8/1/2011: 12:00	8/17/2012: 19:00	8/29/2013: 20:00	9/7/2014: 16:00	10/14/2015: 17:00	7/28/2016: 19:00	8/1/2017: 15:00
116	7/25/2011: 14:00	9/7/2012: 14:00	5/13/2013: 13:00	7/28/2014: 13:00	9/9/2015: 9:00	7/26/2016: 19:00	6/26/2017: 18:00
117	8/26/2011: 19:00	9/21/2012: 14:00	7/1/2013: 15:00	8/27/2014: 13:00	9/24/2015: 16:00	9/27/2016: 11:00	8/3/2017: 11:00
118	8/27/2011: 16:00	8/13/2012: 19:00	8/28/2013: 10:00	9/8/2014: 18:00	8/14/2015: 17:00	7/20/2016: 18:00	9/11/2017: 13:00
119	7/6/2011: 9:00	8/12/2012: 16:00	9/2/2013: 14:00	9/9/2014: 11:00	9/20/2015: 19:00	7/21/2016: 12:00	9/12/2017: 16:00
120	7/8/2011: 16:00	8/13/2012: 18:00	7/8/2013: 16:00	7/31/2014: 13:00	8/26/2015: 19:00	9/26/2016: 12:00	7/11/2017: 15:00
121	8/3/2011: 12:00	9/10/2012: 18:00	9/1/2013: 14:00	9/11/2014: 12:00	9/10/2015: 9:00	8/14/2016: 18:00	10/23/2017: 18:00

Hour #	2011	2012	2013	2014	2015	2016	2017
122	7/5/2011: 17:00	8/18/2012: 13:00	9/7/2013: 19:00	8/15/2014: 16:00	8/15/2015: 14:00	9/26/2016: 20:00	7/13/2017: 15:00
123	10/13/2011: 11:00	9/10/2012: 11:00	8/30/2013: 8:00	9/13/2014: 18:00	8/28/2015: 11:00	9/30/2016: 14:00	8/8/2017: 16:00
124	8/24/2011: 13:00	9/6/2012: 13:00	7/8/2013: 15:00	5/16/2014: 14:00	10/11/2015: 15:00	9/28/2016: 13:00	9/6/2017: 16:00
125	7/25/2011: 13:00	8/30/2012: 16:00	9/1/2013: 16:00	7/30/2014: 13:00	10/14/2015: 12:00	8/14/2016: 19:00	8/30/2017: 11:00
126	7/5/2011: 10:00	8/9/2012: 13:00	8/27/2013: 18:00	9/9/2014: 17:00	8/15/2015: 17:00	8/16/2016: 12:00	9/11/2017: 19:00
127	10/13/2011: 16:00	8/31/2012: 11:00	9/16/2013: 16:00	8/29/2014: 14:00	10/10/2015: 13:00	8/31/2016: 17:00	8/2/2017: 17:00
128	7/5/2011: 19:00	8/20/2012: 10:00	9/8/2013: 15:00	9/12/2014: 17:00	10/14/2015: 18:00	6/19/2016: 16:00	9/5/2017: 16:00
129	8/25/2011: 11:00	9/7/2012: 15:00	7/1/2013: 16:00	7/24/2014: 13:00	8/17/2015: 15:00	7/20/2016: 19:00	8/2/2017: 18:00
130	7/7/2011: 9:00	9/21/2012: 15:00	8/27/2013: 17:00	8/4/2014: 12:00	10/11/2015: 14:00	7/24/2016: 17:00	8/28/2017: 19:00
131	9/7/2011: 8:00	8/7/2012: 13:00	9/2/2013: 19:00	9/10/2014: 13:00	10/12/2015: 15:00	7/29/2016: 13:00	7/7/2017: 14:00
132	7/25/2011: 12:00	9/15/2012: 19:00	9/16/2013: 13:00	5/15/2014: 12:00	8/14/2015: 12:00	7/21/2016: 20:00	8/7/2017: 16:00
133	8/24/2011: 16:00	9/20/2012: 15:00	7/1/2013: 14:00	8/15/2014: 13:00	9/12/2015: 13:00	9/27/2016: 17:00	9/6/2017: 15:00
134	9/6/2011: 10:00	8/29/2012: 12:00	8/30/2013: 21:00	7/29/2014: 13:00	8/29/2015: 17:00	8/2/2016: 14:00	7/27/2017: 16:00
135	8/30/2011: 14:00	10/3/2012: 14:00	9/2/2013: 18:00	8/29/2014: 15:00	9/24/2015: 13:00	7/28/2016: 12:00	9/1/2017: 9:00
136	7/6/2011: 19:00	8/12/2012: 13:00	9/8/2013: 14:00	8/28/2014: 17:00	8/15/2015: 13:00	8/1/2016: 17:00	7/13/2017: 17:00
137	8/25/2011: 17:00	9/12/2012: 15:00	7/9/2013: 15:00	9/10/2014: 16:00	8/29/2015: 13:00	8/15/2016: 20:00	7/19/2017: 16:00
138	7/8/2011: 10:00	8/18/2012: 12:00	8/29/2013: 10:00	7/28/2014: 17:00	10/13/2015: 19:00	7/26/2016: 12:00	7/20/2017: 16:00
139	7/25/2011: 16:00	9/13/2012: 15:00	7/9/2013: 16:00	9/12/2014: 18:00	8/16/2015: 13:00	9/29/2016: 13:00	9/5/2017: 18:00
140	8/3/2011: 17:00	9/20/2012: 14:00	8/22/2013: 15:00	5/15/2014: 18:00	9/28/2015: 15:00	8/1/2016: 14:00	8/29/2017: 20:00
141	7/19/2011: 15:00	9/21/2012: 13:00	9/1/2013: 13:00	9/8/2014: 11:00	8/13/2015: 15:00	7/20/2016: 14:00	9/12/2017: 15:00
142	8/2/2011: 10:00	9/12/2012: 14:00	6/28/2013: 12:00	7/31/2014: 12:00	8/17/2015: 16:00	8/31/2016: 14:00	7/19/2017: 15:00
143	8/2/2011: 19:00	9/14/2012: 20:00	8/26/2013: 14:00	9/9/2014: 18:00	10/9/2015: 19:00	7/29/2016: 17:00	9/7/2017: 16:00
144	8/30/2011: 13:00	9/7/2012: 13:00	8/29/2013: 13:00	10/3/2014: 15:00	9/8/2015: 20:00	8/18/2016: 14:00	8/8/2017: 17:00
145	8/28/2011: 12:00	9/13/2012: 14:00	8/27/2013: 19:00	9/7/2014: 13:00	9/25/2015: 17:00	9/29/2016: 19:00	8/28/2017: 13:00
146	8/28/2011: 17:00	8/8/2012: 11:00	6/27/2013: 15:00	5/14/2014: 14:00	10/10/2015: 17:00	7/24/2016: 16:00	8/4/2017: 13:00
147	8/30/2011: 15:00	10/2/2012: 17:00	5/13/2013: 12:00	8/29/2014: 13:00	9/8/2015: 10:00	8/18/2016: 17:00	9/2/2017: 22:00
148	7/19/2011: 14:00	8/18/2012: 16:00	8/22/2013: 14:00	9/18/2014: 15:00	9/12/2015: 17:00	8/2/2016: 17:00	8/1/2017: 17:00
149	8/1/2011: 11:00	8/15/2012: 14:00	7/8/2013: 14:00	9/8/2014: 19:00	8/5/2015: 15:00	8/17/2016: 12:00	8/4/2017: 18:00
150	8/23/2011: 15:00	10/3/2012: 15:00	9/8/2013: 16:00	9/18/2014: 14:00	9/25/2015: 12:00	8/31/2016: 18:00	7/10/2017: 18:00
151	9/8/2011: 8:00	9/5/2012: 12:00	7/1/2013: 13:00	7/31/2014: 17:00	9/7/2015: 16:00	8/30/2016: 14:00	6/26/2017: 19:00
152	8/29/2011: 17:00	9/24/2012: 14:00	8/31/2013: 9:00	8/27/2014: 12:00	8/26/2015: 12:00	7/25/2016: 16:00	8/7/2017: 17:00
153	10/12/2011: 12:00	8/9/2012: 12:00	6/29/2013: 15:00	5/15/2014: 19:00	10/13/2015: 11:00	9/26/2016: 11:00	10/24/2017: 11:00
154	8/24/2011: 12:00	8/29/2012: 17:00	7/15/2013: 15:00	9/24/2014: 15:00	9/7/2015: 15:00	9/27/2016: 19:00	7/10/2017: 13:00
155	10/13/2011: 17:00	9/6/2012: 16:00	8/23/2013: 14:00	7/30/2014: 19:00	8/5/2015: 16:00	8/30/2016: 17:00	9/5/2017: 19:00
156	8/25/2011: 19:00	8/17/2012: 9:00	6/27/2013: 14:00	8/27/2014: 17:00	8/17/2015: 14:00	6/27/2016: 16:00	7/20/2017: 17:00
157	8/27/2011: 10:00	8/14/2012: 10:00	8/26/2013: 15:00	9/13/2014: 12:00	8/27/2015: 11:00	8/29/2016: 16:00	9/5/2017: 15:00
158	8/3/2011: 11:00	9/10/2012: 19:00	7/8/2013: 17:00	10/2/2014: 15:00	9/28/2015: 16:00	6/29/2016: 16:00	9/11/2017: 12:00
159	8/25/2011: 18:00	8/15/2012: 15:00	6/28/2013: 17:00	9/14/2014: 20:00	10/11/2015: 13:00	7/26/2016: 11:00	8/31/2017: 10:00
160	7/6/2011: 18:00	9/6/2012: 12:00	6/29/2013: 16:00	7/24/2014: 18:00	9/13/2015: 16:00	8/14/2016: 15:00	8/8/2017: 15:00
161	8/2/2011: 18:00	10/3/2012: 13:00	8/26/2013: 13:00	7/30/2014: 12:00	8/16/2015: 18:00	9/27/2016: 10:00	9/5/2017: 17:00
162	10/13/2011: 18:00	8/30/2012: 11:00	6/29/2013: 14:00	7/30/2014: 18:00	9/28/2015: 14:00	7/24/2016: 19:00	8/3/2017: 10:00
163	8/23/2011: 14:00	9/24/2012: 13:00	7/15/2013: 14:00	9/11/2014: 18:00	10/10/2015: 18:00	7/24/2016: 18:00	6/26/2017: 14:00
164	7/19/2011: 16:00	9/10/2012: 17:00	9/2/2013: 17:00	10/3/2014: 14:00	9/12/2015: 18:00	9/28/2016: 19:00	9/7/2017: 15:00
165	7/5/2011: 18:00	8/16/2012: 11:00	9/1/2013: 17:00	5/16/2014: 13:00	9/25/2015: 18:00	7/30/2016: 15:00	8/1/2017: 19:00
166	7/25/2011: 11:00	9/20/2012: 13:00	9/1/2013: 12:00	9/12/2014: 11:00	8/13/2015: 14:00	9/30/2016: 13:00	10/25/2017: 11:00
167	8/29/2011: 9:00	10/1/2012: 11:00	7/15/2013: 16:00	7/24/2014: 19:00	8/13/2015: 16:00	7/25/2016: 17:00	7/12/2017: 18:00
168	8/27/2011: 17:00	9/24/2012: 15:00	8/22/2013: 16:00	7/29/2014: 12:00	9/11/2015: 9:00	6/27/2016: 15:00	9/1/2017: 21:00
169	8/28/2011: 18:00	8/7/2012: 12:00	5/13/2013: 17:00	8/4/2014: 11:00	9/13/2015: 14:00	7/27/2016: 11:00	7/7/2017: 18:00
170	7/7/2011: 20:00	9/4/2012: 11:00	8/22/2013: 13:00	8/29/2014: 16:00	10/11/2015: 16:00	8/15/2016: 10:00	7/8/2017: 14:00
171	8/1/2011: 17:00	8/16/2012: 17:00	9/1/2013: 18:00	9/7/2014: 18:00	9/24/2015: 18:00	9/30/2016: 17:00	7/27/2017: 15:00
172	8/26/2011: 9:00	8/18/2012: 11:00	9/1/2013: 19:00	8/28/2014: 11:00	9/7/2015: 14:00	7/20/2016: 13:00	7/27/2017: 17:00
173	7/19/2011: 13:00	10/2/2012: 11:00	8/23/2013: 13:00	5/14/2014: 17:00	8/16/2015: 19:00	7/29/2016: 12:00	9/6/2017: 18:00
174	8/4/2011: 14:00	8/10/2012: 17:00	9/9/2013: 14:00	9/11/2014: 17:00	8/29/2015: 18:00	6/29/2016: 15:00	7/12/2017: 14:00
175	8/4/2011: 15:00	8/7/2012: 16:00	8/26/2013: 16:00	9/24/2014: 14:00	10/9/2015: 12:00	8/19/2016: 16:00	10/26/2017: 15:00
176	8/30/2011: 12:00	9/23/2012: 15:00	9/16/2013: 12:00	7/7/2014: 15:00	10/10/2015: 12:00	6/19/2016: 18:00	7/13/2017: 14:00
177	8/28/2011: 19:00	8/10/2012: 11:00	6/27/2013: 16:00	7/7/2014: 14:00	8/5/2015: 14:00	7/22/2016: 10:00	9/12/2017: 14:00
178	10/12/2011: 19:00	8/13/2012: 9:00	8/31/2013: 20:00	9/13/2014: 19:00	8/15/2015: 18:00	7/25/2016: 15:00	7/19/2017: 14:00
179	8/23/2011: 16:00	8/15/2012: 13:00	9/8/2013: 13:00	9/16/2014: 21:00	9/24/2015: 17:00	7/27/2016: 20:00	7/19/2017: 17:00
180	8/27/2011: 18:00	9/12/2012: 13:00	6/28/2013: 11:00	8/4/2014: 17:00	10/14/2015: 11:00	7/23/2016: 16:00	7/17/2017: 16:00
181	8/27/2011: 19:00	9/13/2012: 13:00	8/23/2013: 15:00	9/7/2014: 17:00	9/24/2015: 12:00	8/2/2016: 13:00	9/6/2017: 17:00
182	8/17/2011: 15:00	9/23/2012: 16:00	9/5/2013: 8:00	7/28/2014: 12:00	9/13/2015: 15:00	8/30/2016: 18:00	7/11/2017: 18:00
183	8/29/2011: 18:00	8/29/2012: 19:00	7/9/2013: 14:00	9/10/2014: 12:00	8/29/2015: 12:00	6/19/2016: 19:00	7/18/2017: 16:00

Hour #	2011	2012	2013	2014	2015	2016	2017
184	8/25/2011: 10:00	8/11/2012: 14:00	8/21/2013: 15:00	5/16/2014: 17:00	8/15/2015: 12:00	8/3/2016: 16:00	8/1/2017: 14:00
185	10/13/2011: 10:00	8/29/2012: 18:00	8/26/2013: 12:00	10/2/2014: 14:00	10/12/2015: 19:00	8/19/2016: 15:00	8/1/2017: 18:00
186	8/4/2011: 13:00	9/20/2012: 16:00	6/27/2013: 13:00	7/24/2014: 12:00	8/14/2015: 18:00	7/28/2016: 11:00	7/10/2017: 19:00
187	12/12/2011: 18:00	10/17/2012: 15:00	6/29/2013: 13:00	10/3/2014: 16:00	9/11/2015: 20:00	8/3/2016: 15:00	7/7/2017: 13:00
188	8/17/2011: 14:00	9/15/2012: 10:00	9/4/2013: 8:00	7/23/2014: 16:00	8/14/2015: 11:00	7/19/2016: 16:00	7/7/2017: 19:00
189	8/23/2011: 13:00	8/14/2012: 19:00	8/21/2013: 14:00	9/18/2014: 13:00	8/13/2015: 13:00	9/30/2016: 18:00	8/4/2017: 19:00
190	8/3/2011: 19:00	9/13/2012: 16:00	7/1/2013: 12:00	8/28/2014: 18:00	10/11/2015: 18:00	7/23/2016: 17:00	9/6/2017: 14:00
191	7/5/2011: 20:00	8/11/2012: 15:00	7/8/2013: 13:00	9/24/2014: 16:00	10/12/2015: 14:00	7/21/2016: 11:00	7/11/2017: 14:00
192	7/8/2011: 9:00	9/7/2012: 12:00	7/9/2013: 17:00	9/12/2014: 19:00	8/14/2015: 19:00	8/31/2016: 19:00	9/7/2017: 18:00
193	7/25/2011: 17:00	10/17/2012: 14:00	9/9/2013: 15:00	9/25/2014: 14:00	8/15/2015: 19:00	7/25/2016: 13:00	6/27/2017: 16:00
194	12/13/2011: 18:00	8/12/2012: 12:00	9/6/2013: 8:00	8/15/2014: 12:00	10/14/2015: 19:00	6/19/2016: 15:00	8/2/2017: 20:00
195	7/19/2011: 12:00	8/20/2012: 17:00	9/2/2013: 13:00	9/17/2014: 20:00	8/28/2015: 20:00	8/4/2016: 16:00	8/9/2017: 16:00
196	7/8/2011: 17:00	8/9/2012: 11:00	7/15/2013: 13:00	9/9/2014: 19:00	8/17/2015: 13:00	6/27/2016: 17:00	9/7/2017: 17:00
197	8/1/2011: 19:00	8/14/2012: 18:00	9/7/2013: 9:00	8/1/2014: 14:00	9/26/2015: 15:00	7/25/2016: 14:00	9/2/2017: 10:00
198	8/28/2011: 11:00	9/4/2012: 18:00	9/9/2013: 13:00	9/6/2014: 15:00	9/20/2015: 12:00	8/16/2016: 20:00	10/26/2017: 16:00
199	12/12/2011: 17:00	8/12/2012: 17:00	8/27/2013: 10:00	8/18/2014: 15:00	8/29/2015: 19:00	7/30/2016: 16:00	7/14/2017: 16:00
200	8/17/2011: 13:00	8/8/2012: 17:00	5/13/2013: 11:00	8/14/2014: 15:00	9/28/2015: 13:00	8/29/2016: 17:00	7/20/2017: 15:00

APPENDIX B NET EXPORT

B.1 DESCRIPTION

The Net Export appendix includes three Excel workbooks attached to this pdf. These contain a series of tables describing the net export data. There is one workbook per utility, and each utility's workbook includes both the residential and non-residential findings. This document provides a high-level description of the data in the workbook.

The data in the net export analysis relied largely on utility billing data, which were only requested for customers with available metered PV production data.

The following describes the data in the workbook tabs. There may be minor differences by utility in the available tabs and tables, depending on the utility data provided.

1) **Net Exporter Sample:** Unweighted tables describing the sample received, the sample requested, and the frame of CSI customers by system size.
2) **Monthly Net Exporter Info:** Weighted tables describing the sample by monthly net exporter status. Data include the number of customers who have at least one month of net export, the average net monthly load for the customers, and the average net export for customers when net export exists. Tables include the following:
    a) By sector
    b) By sector and size
    c) By sector and coastal/inland
    d) By sector and year of system installation
    e) By residential/non-residential
    f) By sector and calendar month for five years of post-installation data
    g) By sector and number of years since system installation
    h) By sector, system size, and calendar month
3) **Annual Net Exporter Info:** Weighted tables describing the sample by annual net exporter status. Data include the number of customers who are annual net exports, the average net monthly load for the customers, and the average net export for customers for months when net export exists. Tables include the following:
    a) By sector
    b) By sector and size
    c) By sector and coastal/inland

d) By sector and year of system installation

e) By residential/non-residential

f) By sector and number of years since system installation

4) **12 Consecutive Months of Net Exporter Info:** Weighted tables describing the sample by 12 consecutive months of net exporter status. Data include the number of customers who have any 12 months of consecutive net export, the average net monthly load for the customers, and the average net export for customers for months when net export exists. Tables include the following:

   a) By sector

   b) By sector and size

   c) By sector and coastal/inland

   d) By sector and year of system installation

   e) By residential/non-residential

   f) By sector and number of years since system installation

5) **Sample with One Year of Pre-Installation Data**: Unweighted tables describing the sample received, sample requested, and the frame of CSI customers by system size.

6) **Export by Pre-Usage Group:** Weighted tables describing the sample with pre-usage data by net exporter status.

   a) By sector and pre-installation customer consumption describing monthly net exporter status

   b) By sector and pre-installation customer consumption describing annual net exporter status

   c) By sector and pre-installation customer consumption describing 12 consecutive months of net exporter status

7) **Net Exporter Sample 5Y:** Unweighted tables describing the sample received for customers with at least five years of post-installation data, sample requested, and the frame of CSI customers by system size.

8) **Monthly Net Exporter Info 5Y:** Weighted tables describing the five-year sample by monthly net exporter status. Data include the number of customers who have at least one month of net export, the average net monthly load for the customers, and the average net export for customers when net export exists. Tables include the following:

   a) By sector

   b) By sector and size

   c) By sector and coastal/inland

   d) By sector and year of system installation

   e) By residential/non-residential

f) By sector and calendar month for five years of post-installation data

g) By sector and number of years since system installation

9) Annual Net Exporter Info 5Y: Weighted tables describing the five-year sample by annual net exporter status. Data include the number of customers who are annual net exports, the average net monthly load for the customers, and the average net export for customers for months when net export exists. Tables include the following:

a) By sector

b) By sector and size

c) By sector and coastal/inland

d) By sector and year of system installation

e) By residential/non-residential

f) By sector and number of years since system installation

10) 12 Consecutive Months of Net Exporter Info 5Y: Weighted tables describing the five-year sample by 12 consecutive months of net exporter status. Data include the number of customers who have any 12 months of consecutive net export, the average net monthly load for the customers, and the average net export for customers for months when net export exists. Tables include the following:

a) By sector

b) By sector and size

c) By sector and coastal/inland

d) By sector and year of system installation

e) By residential/non-residential

f) By sector and number of years since system installation

11) Monthly Net Exporter Info by Quarter 5Y: Weighted table describing the five-year sample monthly net exporter by calendar quarter.

12) Sample with One Year Pre and 5Y Post: Unweighted tables describing the sample received for customers with at least one year of pre-installation and five years of post-installation data, sample requested, and the frame of CSI customers by system size.

13) Export by Pre-Usage 5Y: Weighted tables for the sample of sites with at least one year of pre-installation and five years of post-installation data.

a) Monthly net exporter by sector and pre size

b) Annual net exporter by sector and pre size

c) 12 consecutive months of net export by sector and size

APPENDIX C LOAD SHAPE RESULTS

This appendix presents additional results for the load shape analysis, and an Excel workbook accompanies this appendix. The Excel workbook includes four data tabs: NonResCoastal, NonResInland, ResCoastal, and ResInland. There is also a Notes tab at the beginning of the workbook. The data tabs include a weighted average 8760 of customer electricity import, export, PV production, electricity consumption, net load, and PV capacity factor. These averages were developed using the sample of sites used in the Section 6 analysis.

C.1 RESIDENTIAL LOAD SHAPES FOR ALL HOURS

FIGURE C-1: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT

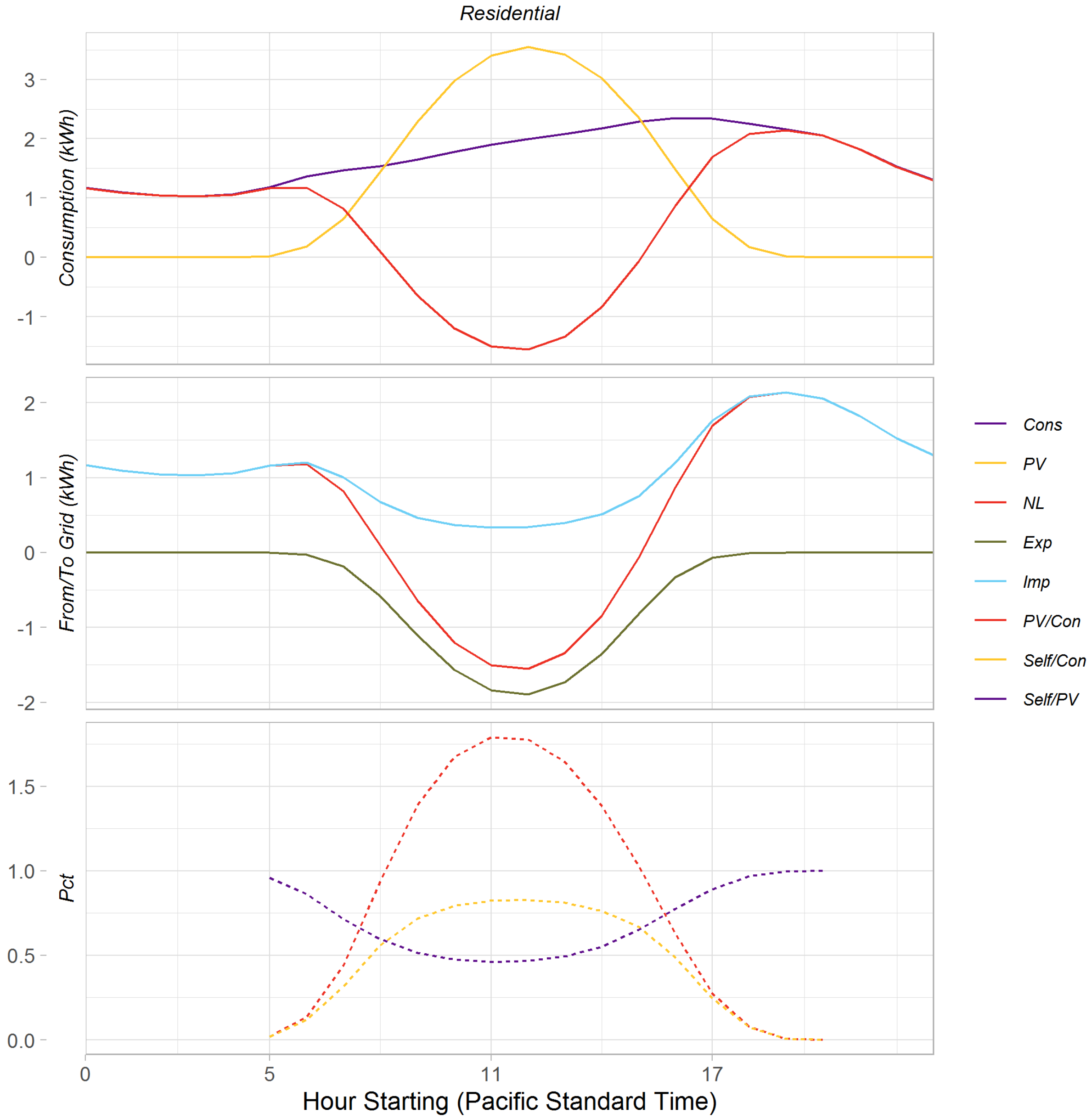


FIGURE C-2: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT

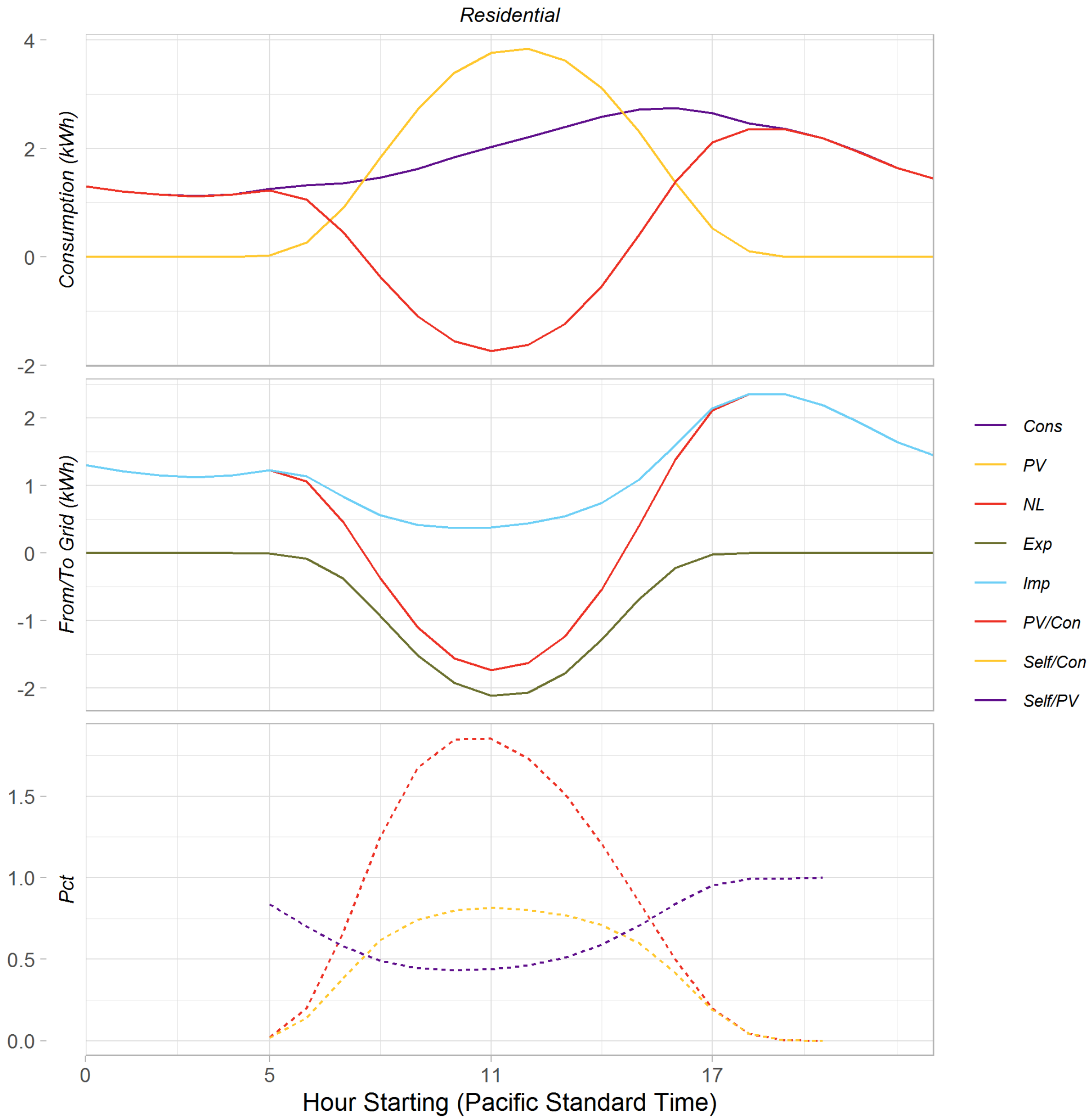
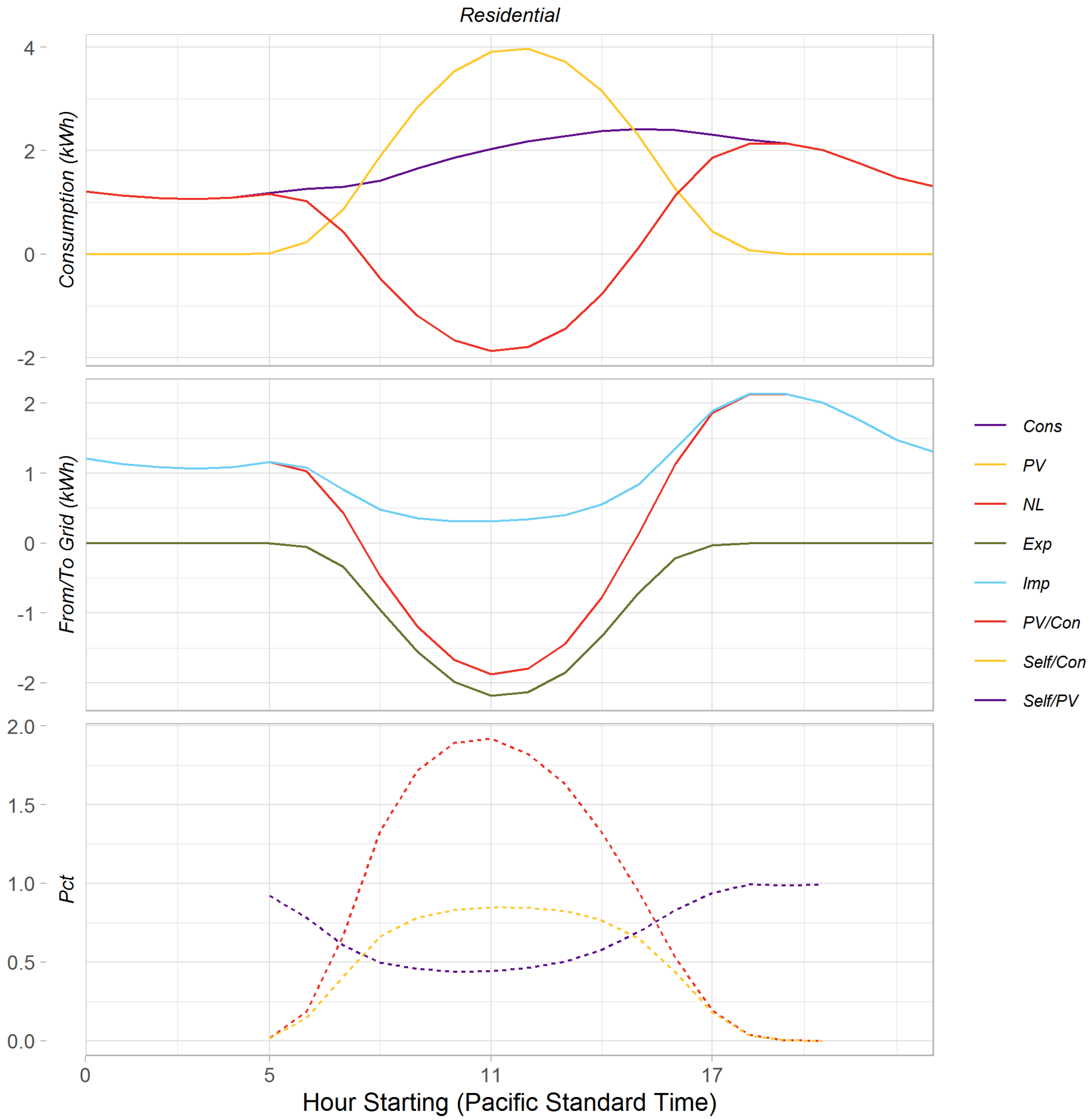


FIGURE C-3: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT



C.1.1 Residential Load Results for Coastal and Inland Locations

TABLE C-1: RESIDENTIAL AVERAGE INLAND AND COASTAL LOAD STATISTICS (KWH)

	PG&E Residential		SCE Residential		SDG&E Residential	
	Coastal	Inland	Coastal	Inland	Coastal	Inland
Consumption	12,330	17,573	15,113	16,489	10,548	19,194
Import	8,366	11,102	10,049	10,947	7,292	11,719
Export	3,759	4,688	4,791	4,726	3,757	5,899
PV Production	7,723	11,158	9,856	10,269	7,013	13,374
% Consumption supplied by PV (PV/Cons)	62.6%	63.5%	65.2%	62.3%	66.5%	69.7%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	32.1%	36.8%	33.5%	33.6%	30.9%	38.9%
% PV used at the site (PV-Ex)/PV	51.3%	58.0%	51.4%	54.0%	46.4%	55.9%

FIGURE C-4: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS

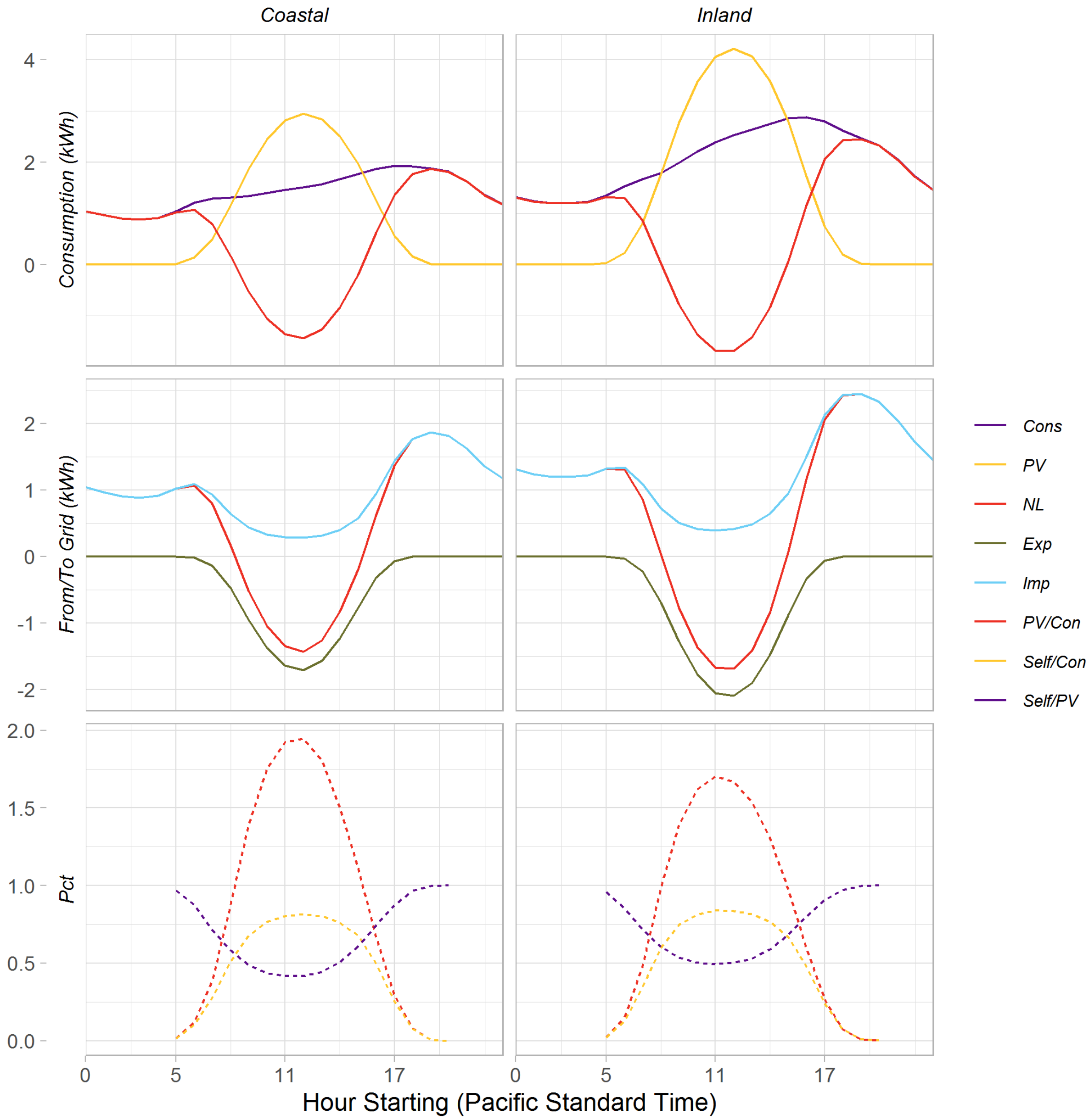


FIGURE C-5: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS

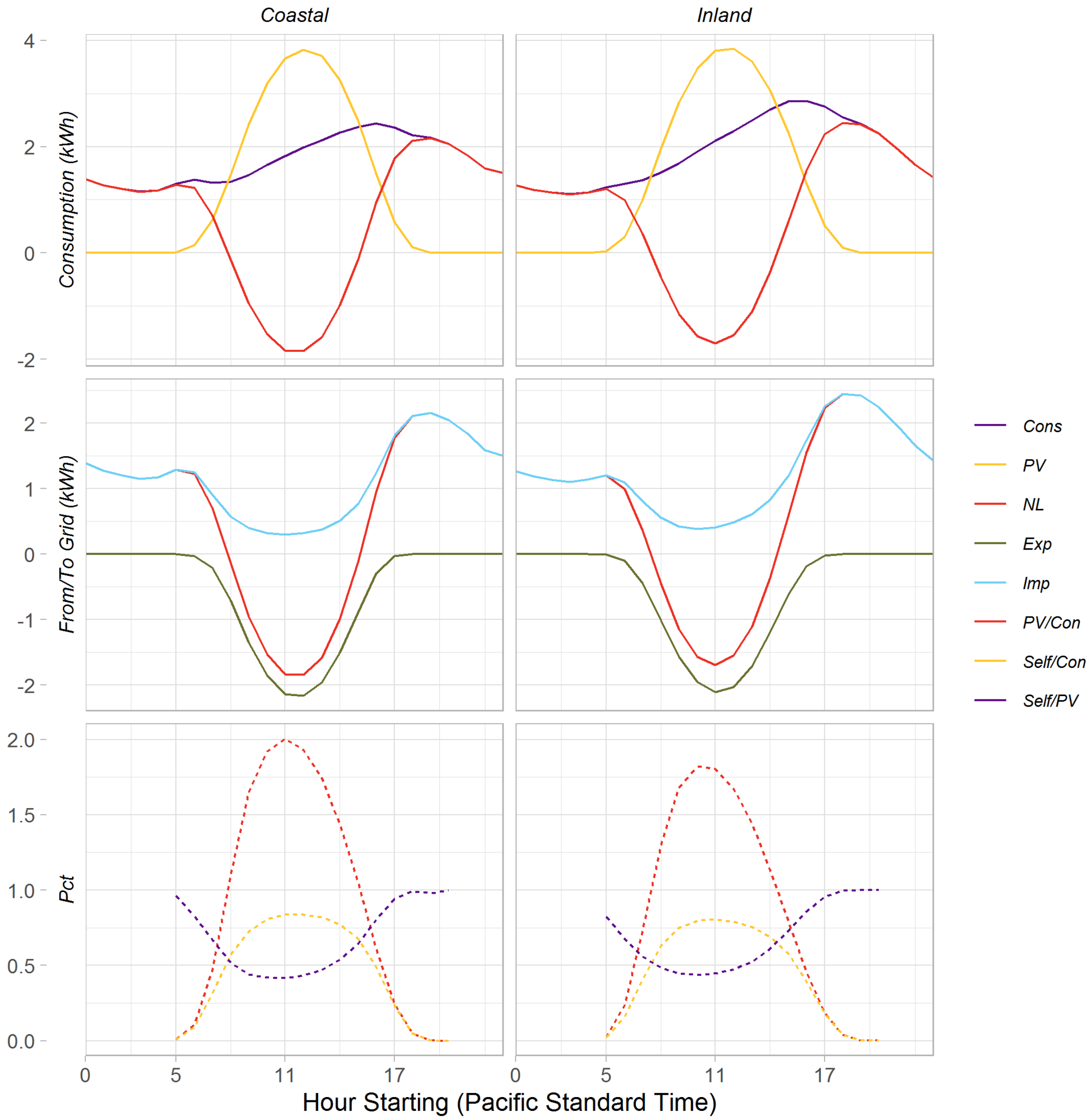
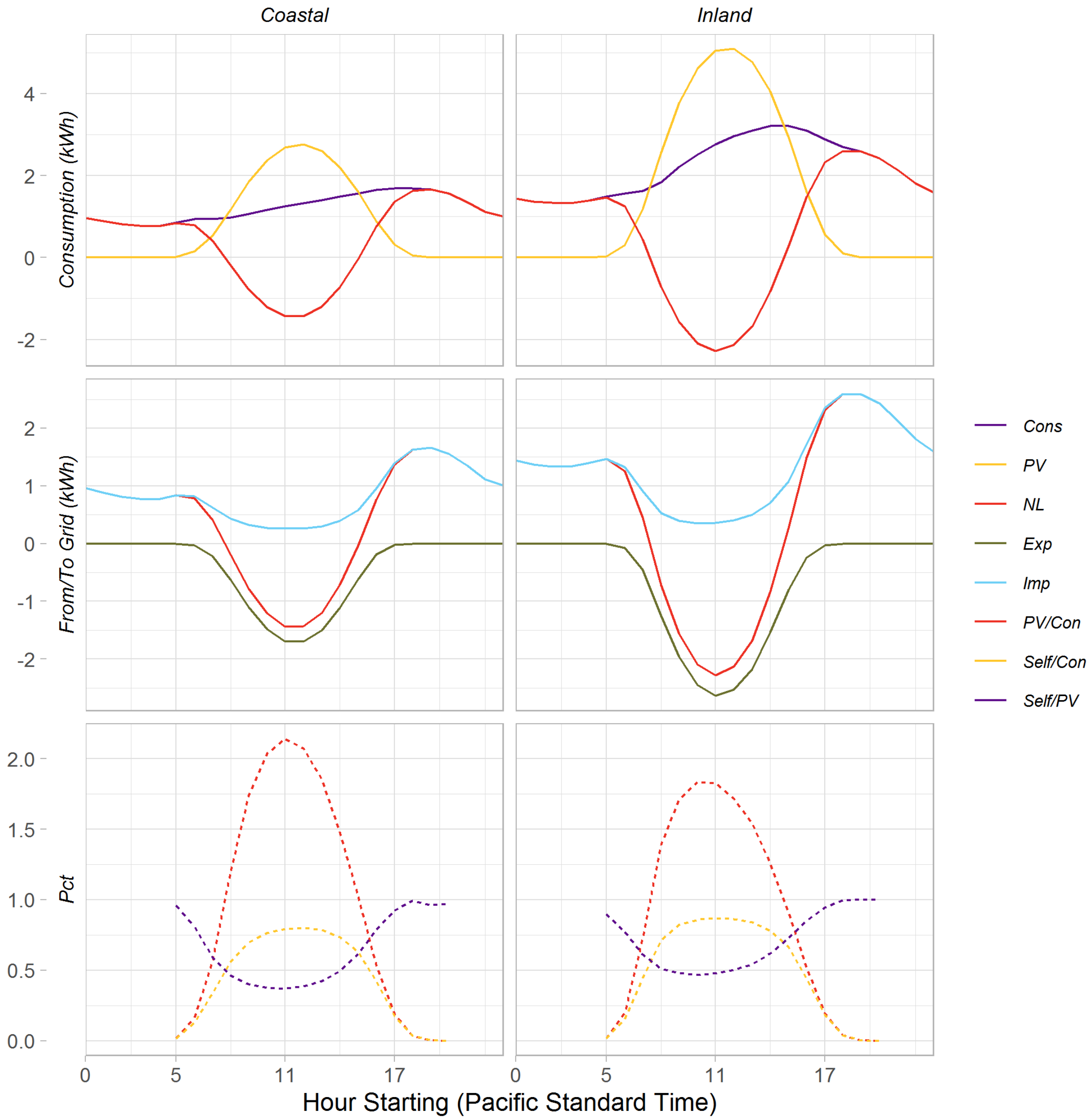


FIGURE C-6: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS



C.1.2 Residential Load Results by Quarter

TABLE C-2: PG&E RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	PG&E Residential Q1	PG&E Residential Q2	PG&E Residential Q3	PG&E Residential Q4
Consumption	3,251	3,682	4,349	3,546
Import	2,300	2,139	2,694	2,542
Export	846	1,470	1,187	690
PV Production	1,797	3,013	2,842	1,694
% Consumption supplied by PV (PV/Cons)	55.3%	81.8%	65.3%	47.8%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	29.3%	41.9%	38.1%	28.3%
% PV used at the site (PV-Ex)/PV	53.0%	51.2%	58.2%	59.3%

TABLE C-3: SCE RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SCE Residential Q1	SCE Residential Q2	SCE Residential Q3	SCE Residential Q4
Consumption	3,206	3,760	5,351	3,643
Import	2,202	2,296	3,545	2,575
Export	1,174	1,576	1,114	876
PV Production	2,178	3,039	2,920	1,944
% Consumption supplied by PV (PV/Cons)	67.9%	80.8%	54.6%	53.3%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	31.3%	38.9%	33.7%	29.3%
% PV used at the site (PV-Ex)/PV	46.1%	48.1%	61.8%	54.9%

TABLE C-4: SDG&E RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SDG&E Residential Q1	SDG&E Residential Q2	SDG&E Residential Q3	SDG&E Residential Q4
Consumption	3,255	3,482	4,603	3,644
Import	2,139	1,993	2,872	2,551
Export	1,148	1,581	1,229	909
PV Production	2,264	3,070	2,961	2,002
% Consumption supplied by PV (PV/Cons)	69.6%	88.2%	64.3%	54.9%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	34.3%	42.8%	37.6%	30.0%
% PV used at the site (PV-Ex)/PV	49.3%	48.5%	58.5%	54.6%

FIGURE C-7: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER

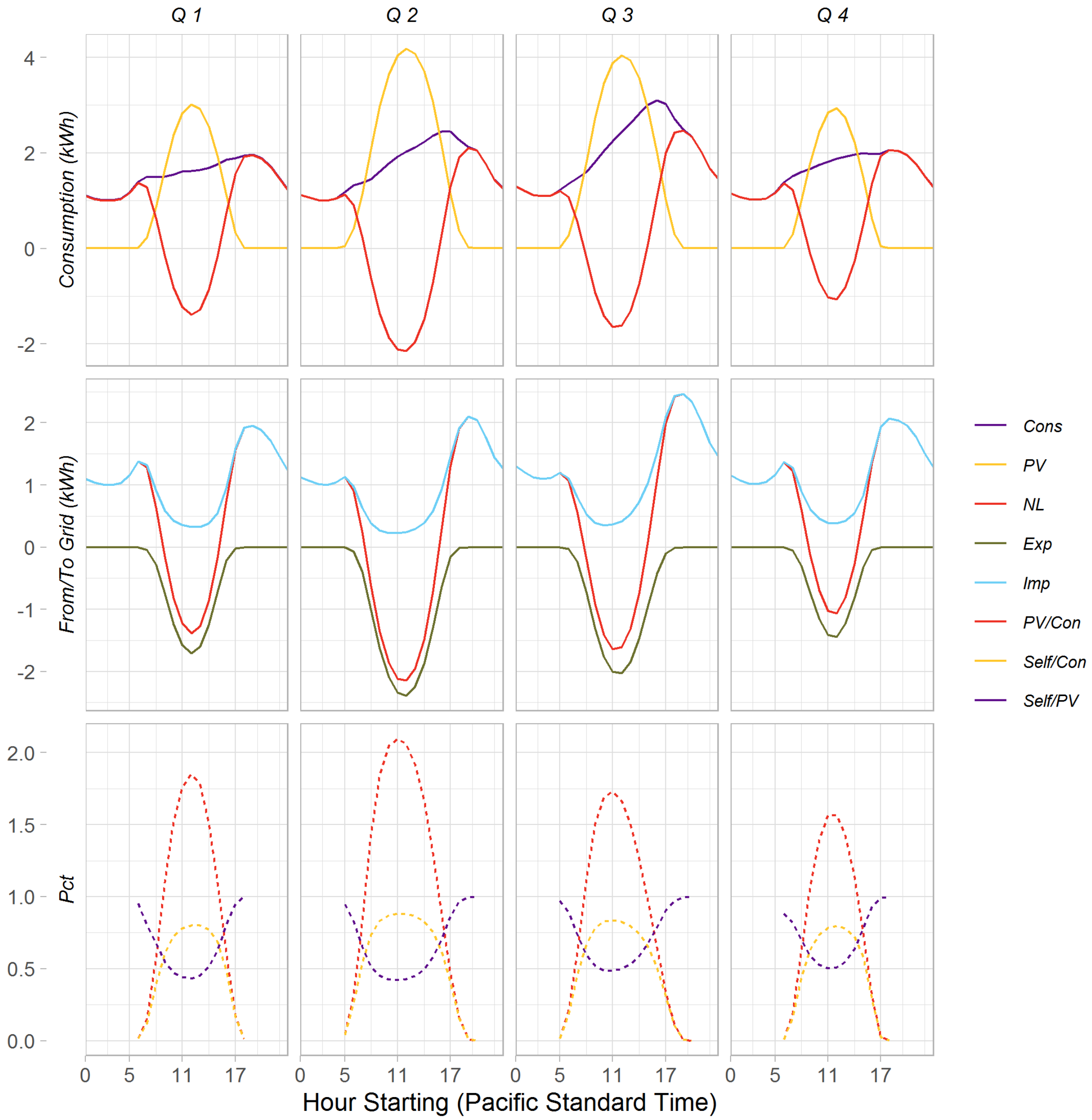


FIGURE C-8: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER

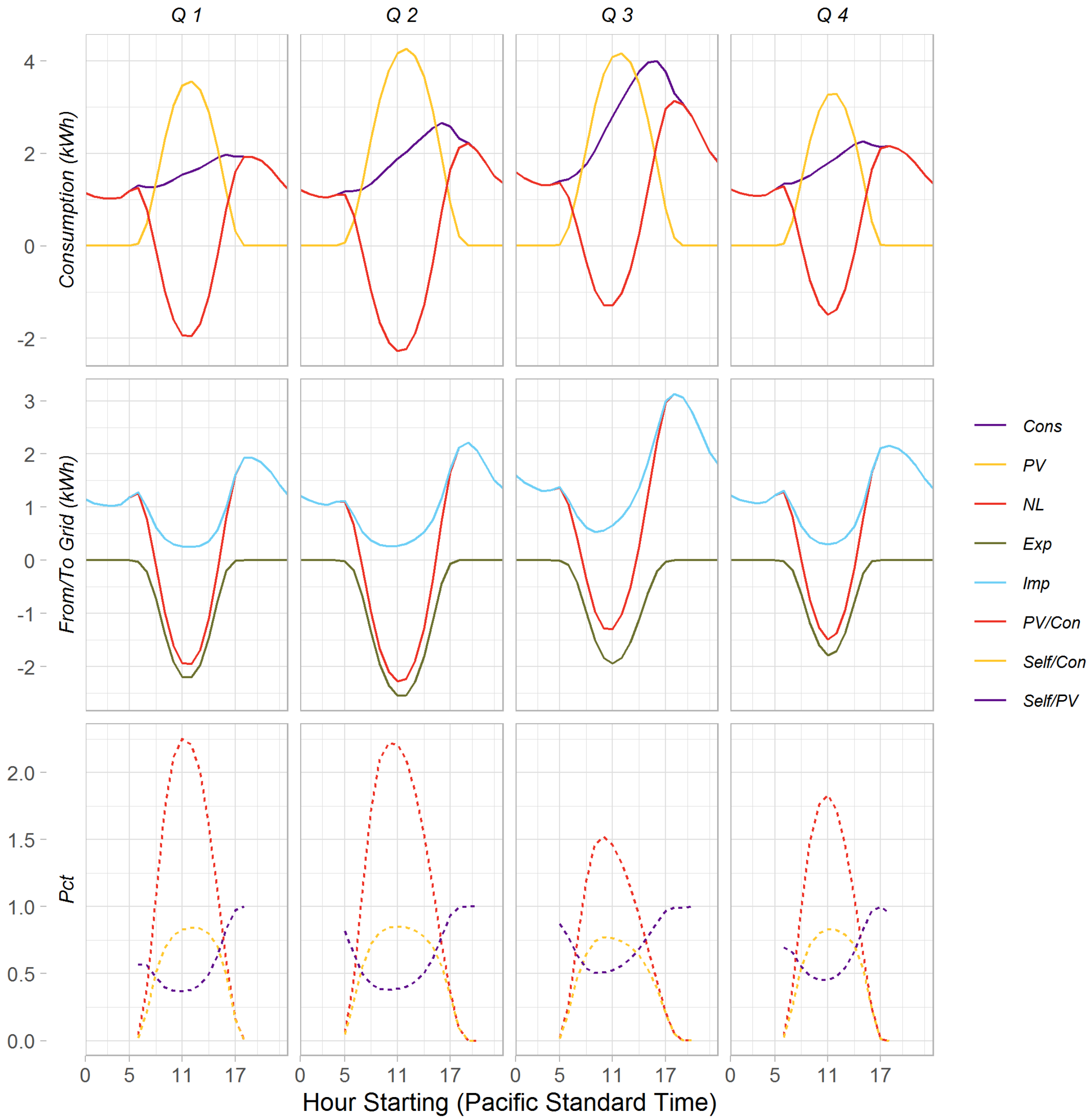
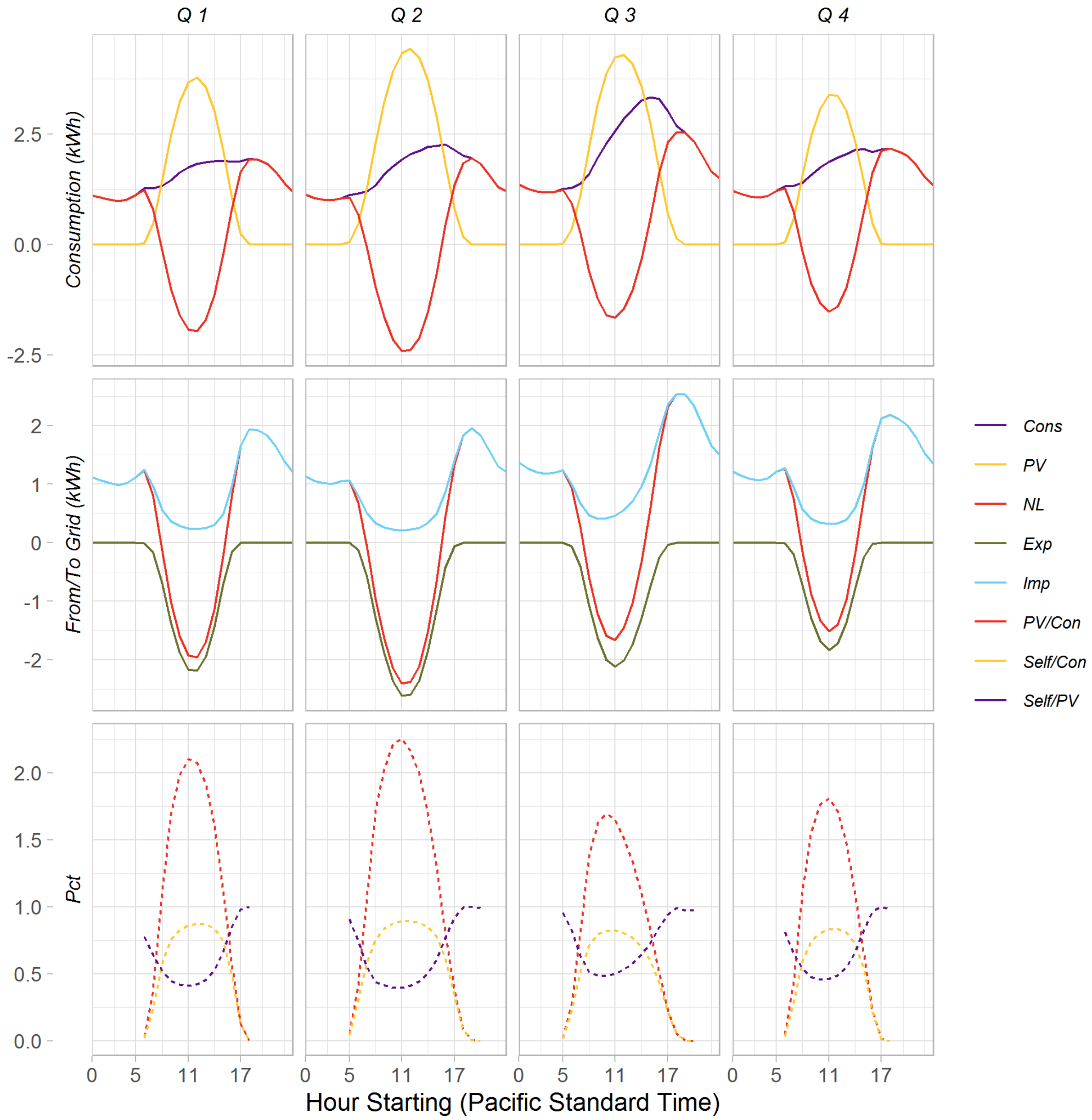


FIGURE C-9: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER



C.1.3 Residential Load Results by System Size

TABLE C-5: PG&E RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	PG&E Res Up to 3 kW	PG&E Res 3 - 5 kW	PG&E Res 5 - 8 kW	PG&E Res 8+ kW
Consumption	9,569	12,677	17,581	37,450
Import	7,093	8,672	11,385	19,327
Export	1,978	3,771	5,812	9,795
PV Production	4,454	7,776	12,008	27,919
% Consumption supplied by PV (PV/Cons)	46.5%	61.3%	68.3%	74.5%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	25.9%	31.6%	35.2%	48.4%
% PV used at the site (PV-Ex)/PV	55.6%	51.5%	51.6%	64.9%

TABLE C-6: SCE RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	SCE Res Up to 3 kW	SCE Res 3 - 5 kW	SCE Res 5 - 8 kW	SCE Res 8+ kW
Consumption	11,088	13,061	17,042	36,191
Import	8,290	8,943	10,996	21,506
Export	1,625	3,721	5,598	14,131
PV Production	4,422	7,839	11,644	28,816
% Consumption supplied by PV (PV/Cons)	39.9%	60.0%	68.3%	79.6%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	25.2%	31.5%	35.5%	40.6%
% PV used at the site (PV-Ex)/PV	63.3%	52.5%	51.9%	51.0%

TABLE C-7: SDG&E RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	SDG&E Res Up to 3 kW	SDG&E Res 3 - 5 kW	SDG&E Res 5 - 8 kW	SDG&E Res 8+ kW
Consumption	7,847	11,111	14,950	51,562
Import	5,747	7,649	9,455	28,720
Export	2,227	4,011	5,763	13,501
PV Production	4,327	7,473	11,259	36,343
% Consumption supplied by PV (PV/Cons)	55.1%	67.3%	75.3%	70.5%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	26.8%	31.2%	36.8%	44.3%
% PV used at the site (PV-Ex)/PV	48.5%	46.3%	48.8%	62.9%

FIGURE C-10: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE

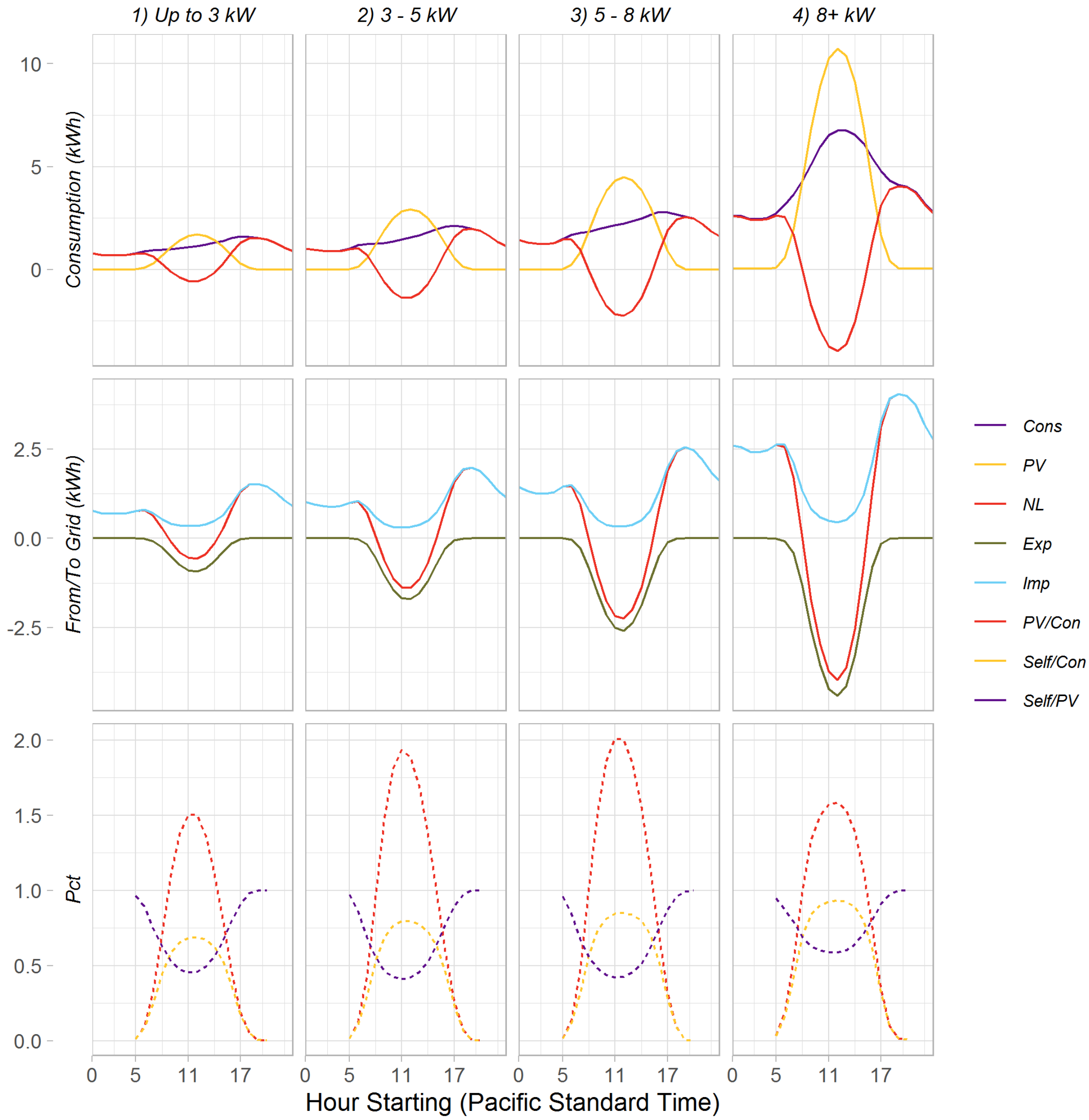


FIGURE C-11: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE

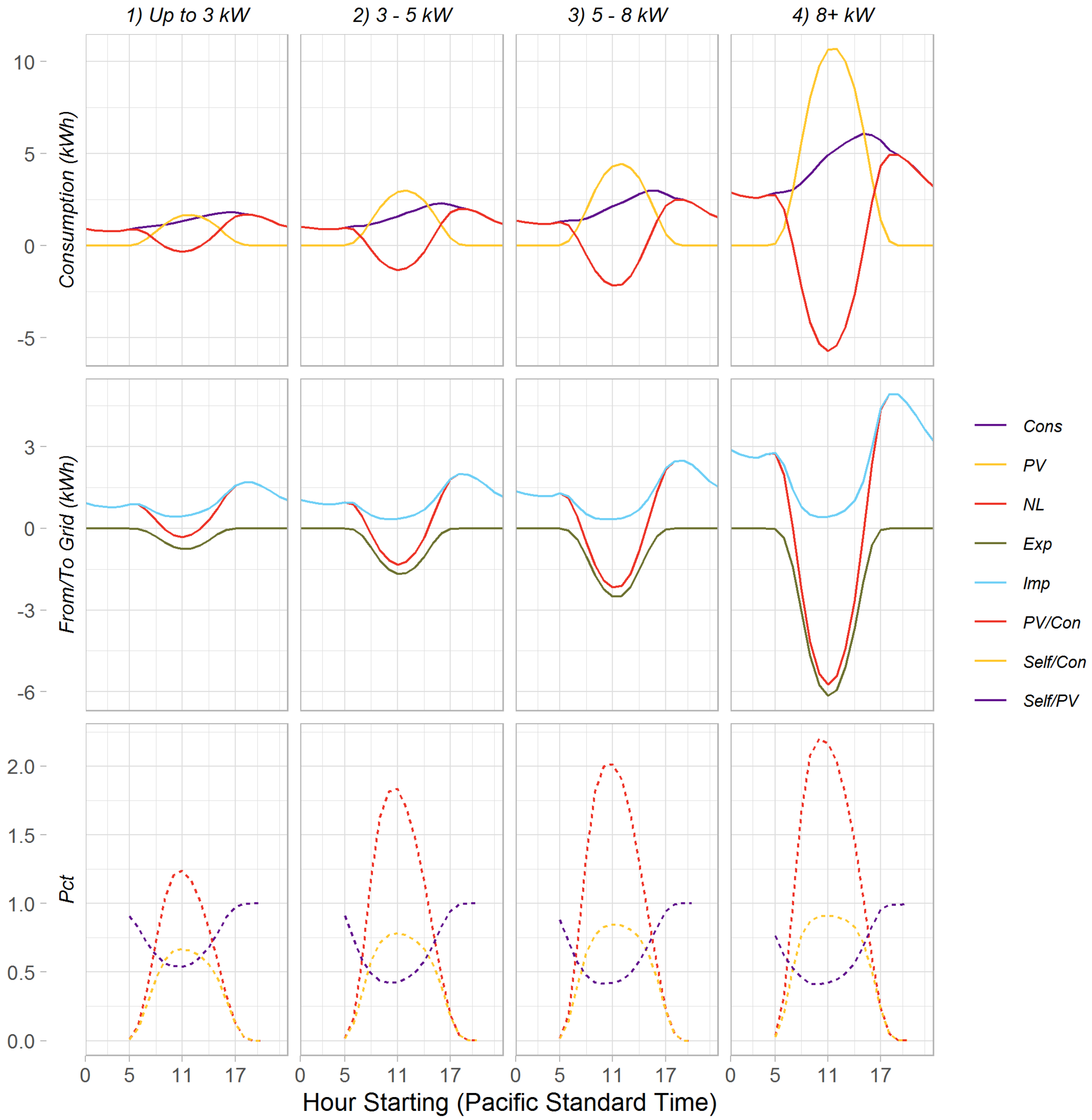
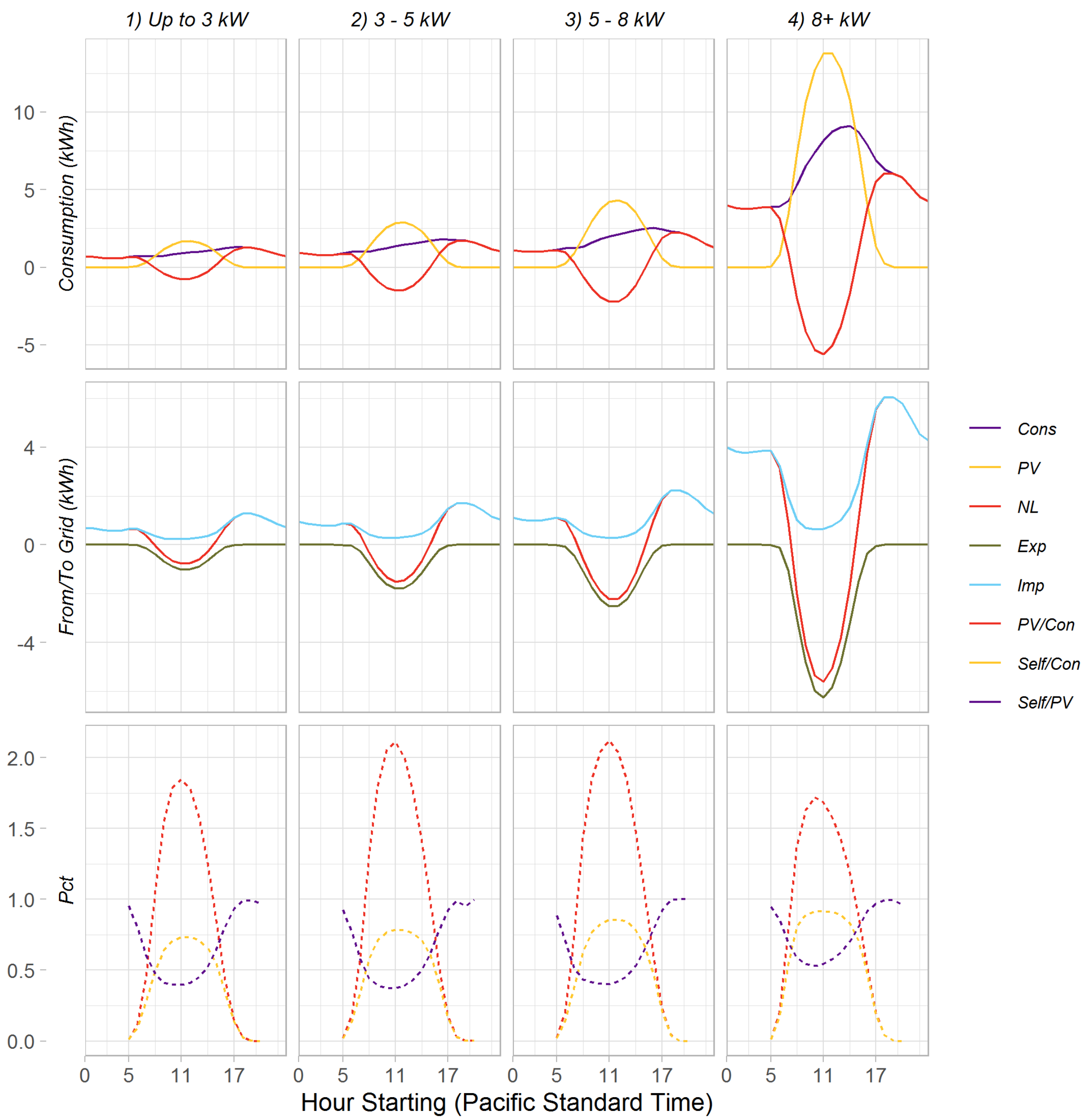


FIGURE C-12: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE



C.2 RESIDENTIAL LOAD SHAPE RESULTS DAYS THAT INCLUDE THE TOP 200 HOURS OF IOU GROSS LOAD

This sub-section presents residential load shape graphs only for days that include the top 200 hours of gross IOU load. In general, inland sites see a larger difference than coastal sites between these graphs and those for all hours, likely due to increased air conditioning load driving higher consumption and less export. Additionally, larger systems show more difference than smaller systems when comparing these top 200-hour results to all-hour results.

C.2.1 Residential Load Shapes by Location during Top 200 IOU Load Hours

FIGURE C-13: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 PG&E GROSS LOAD HOURS

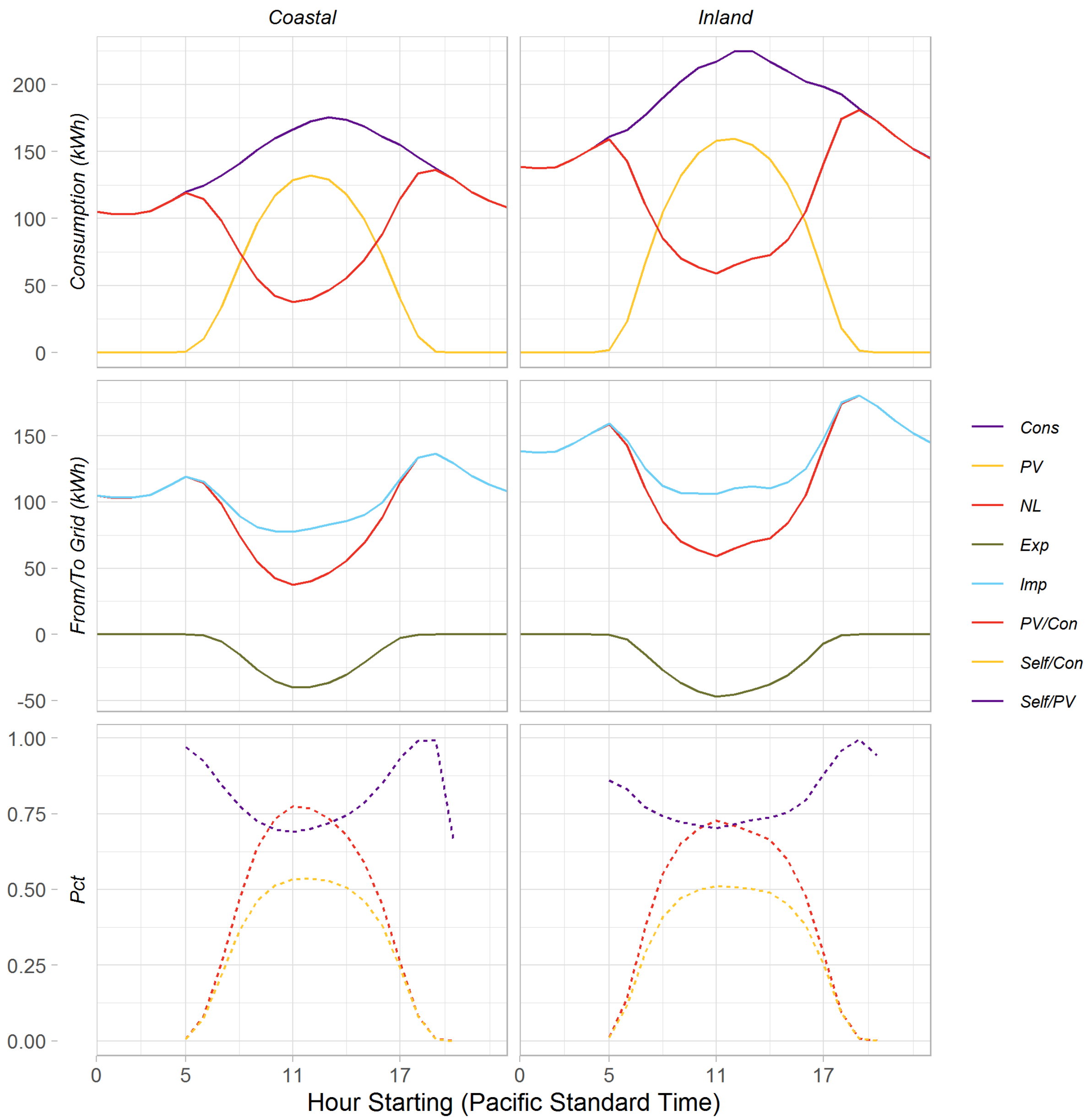


FIGURE C-14: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 SCE GROSS LOAD HOURS

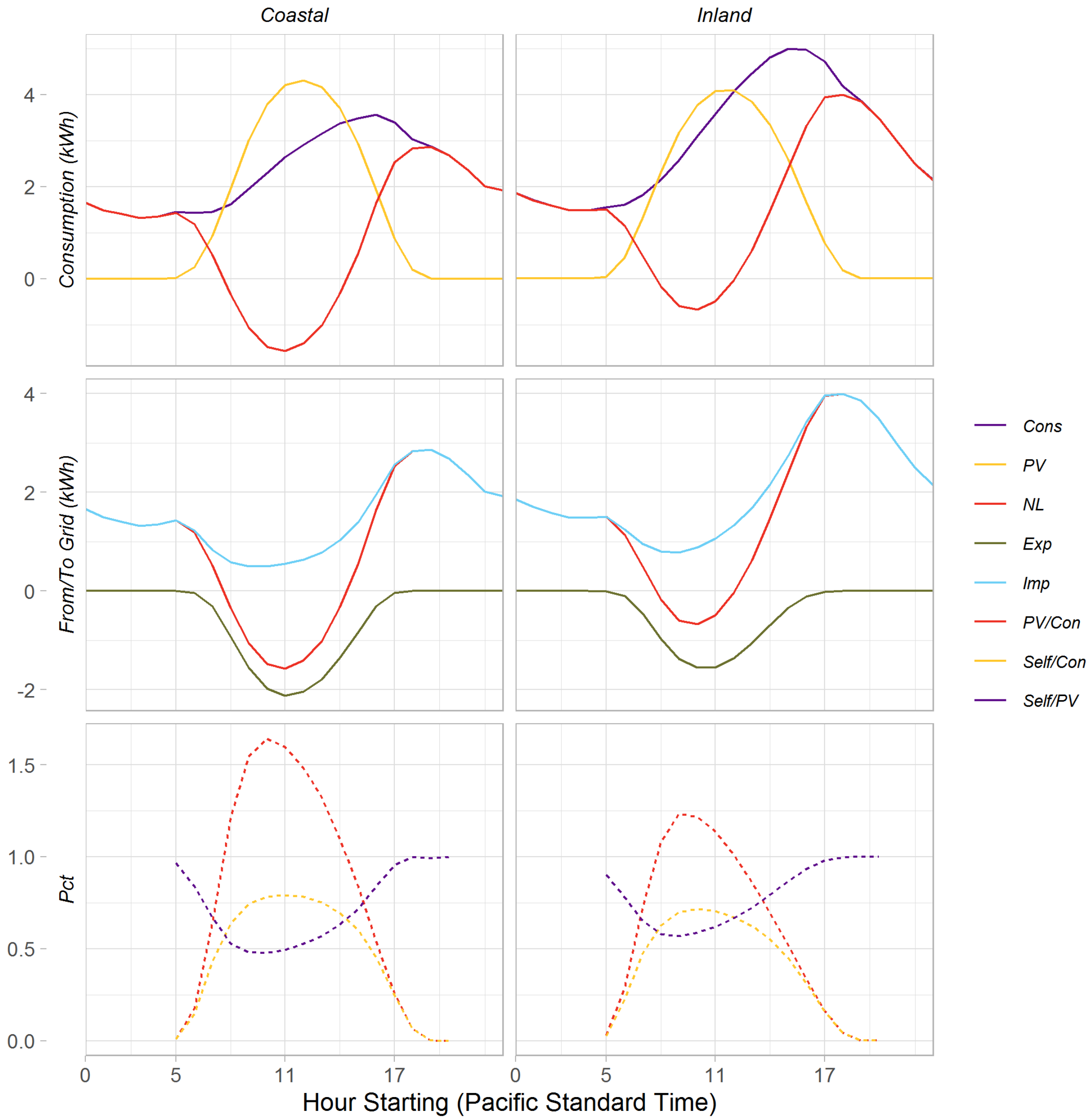
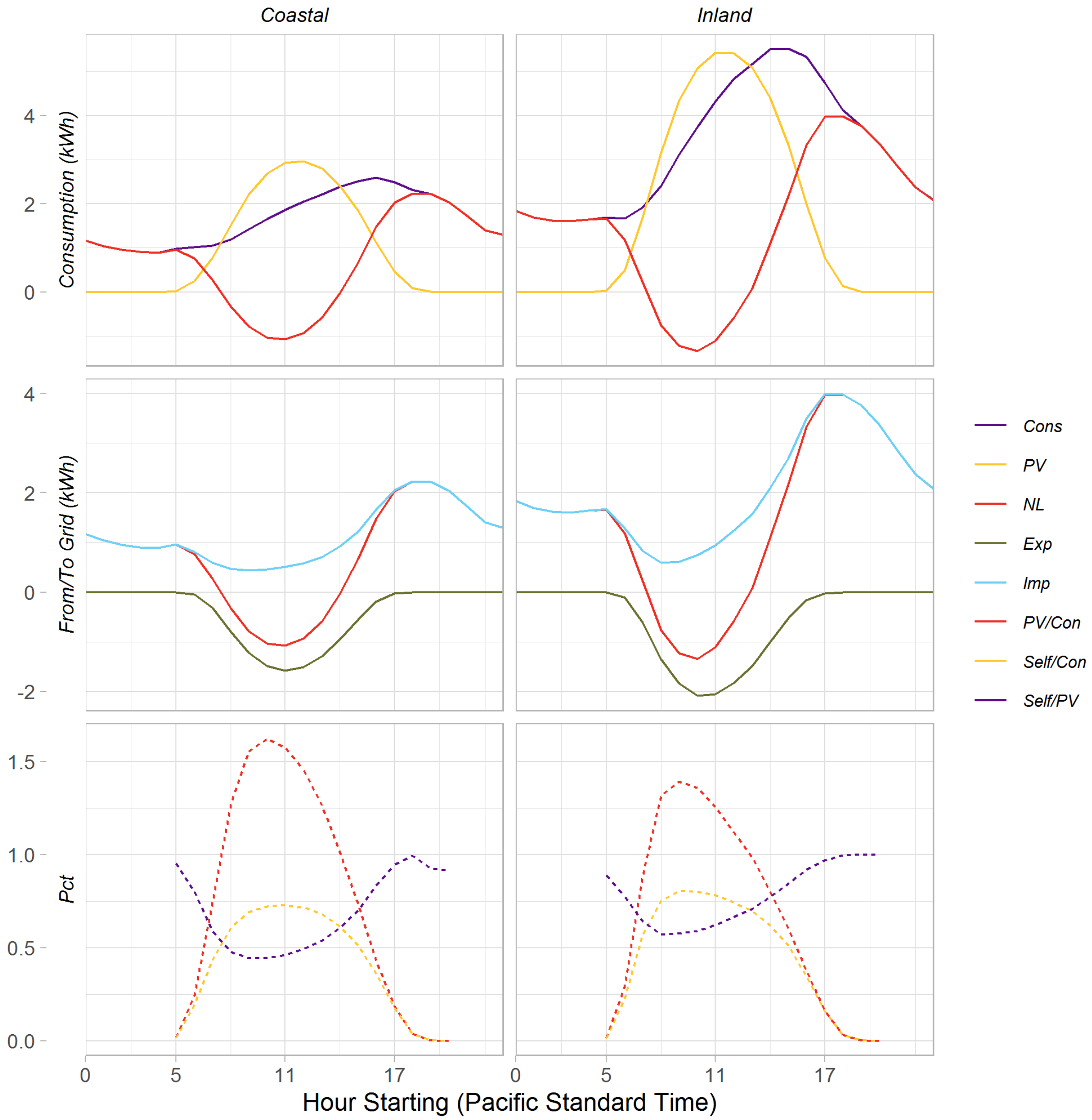


FIGURE C-15: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 SDG&E GROSS LOAD HOURS



C.2.2 Residential Load Shapes by System Size during Top 200 IOU Load Hours

FIGURE C-16: PG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 PG&E GROSS LOAD HOURS

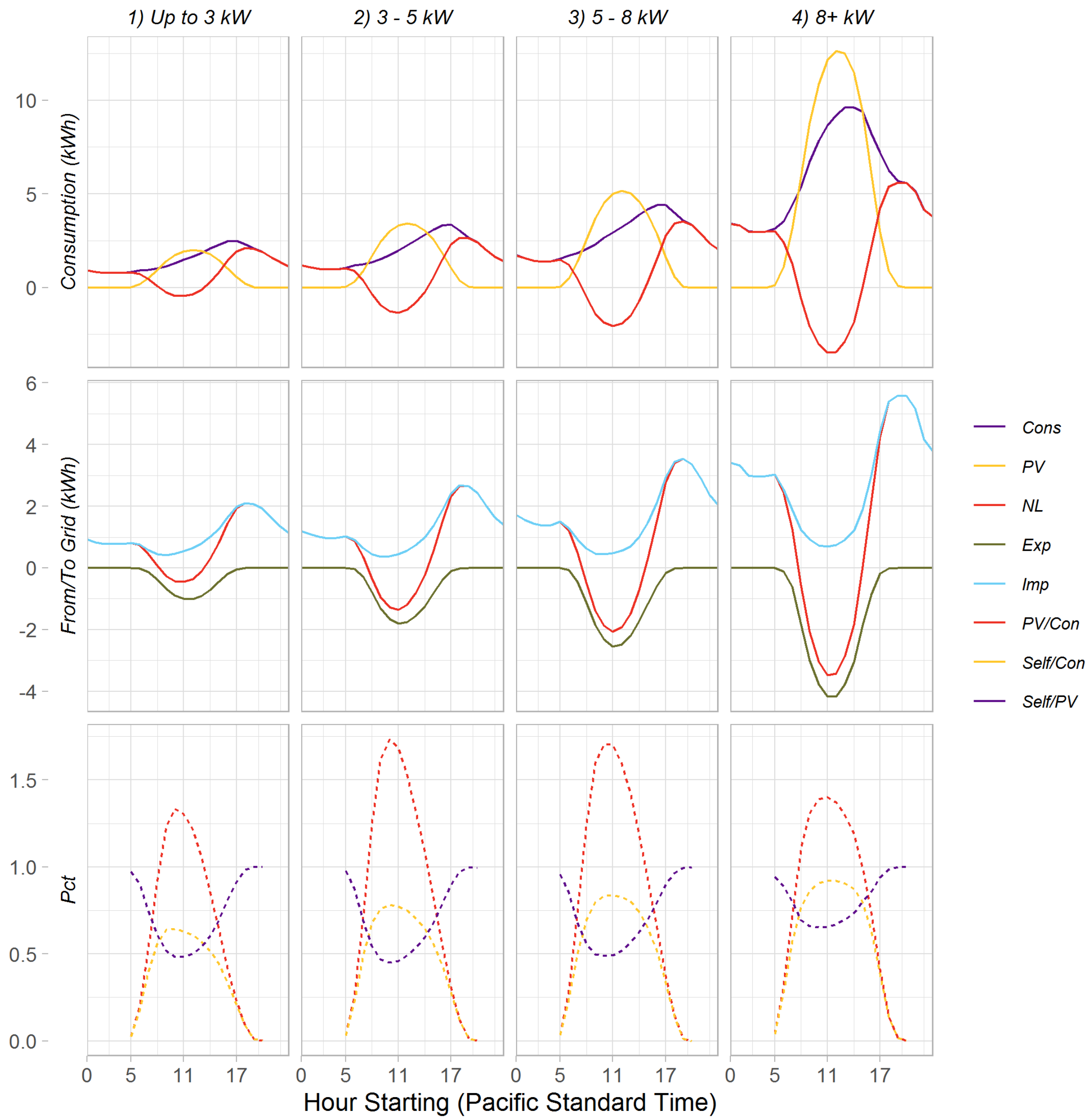


FIGURE C-17: SCE RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 SCE GROSS LOAD HOURS

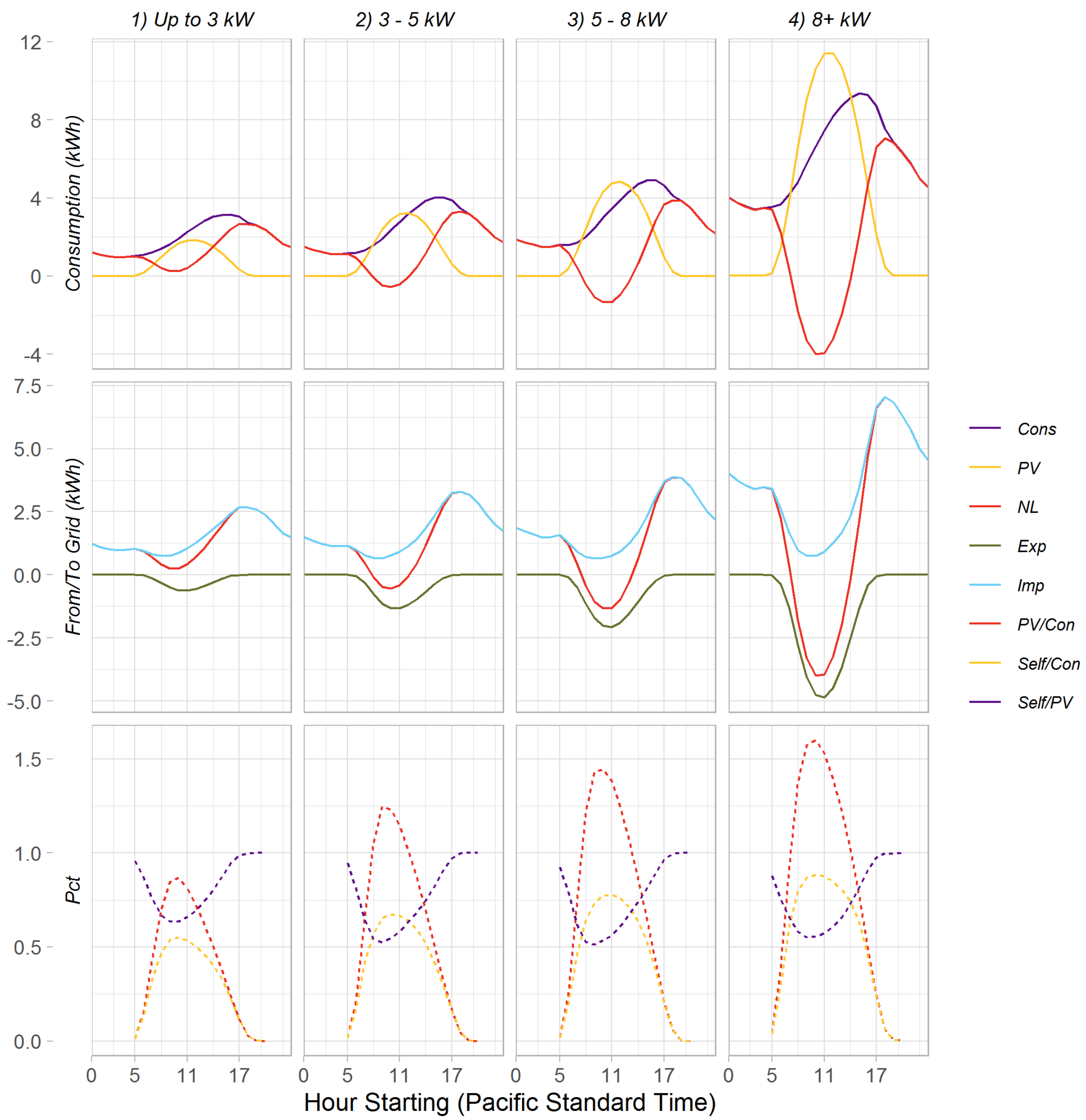
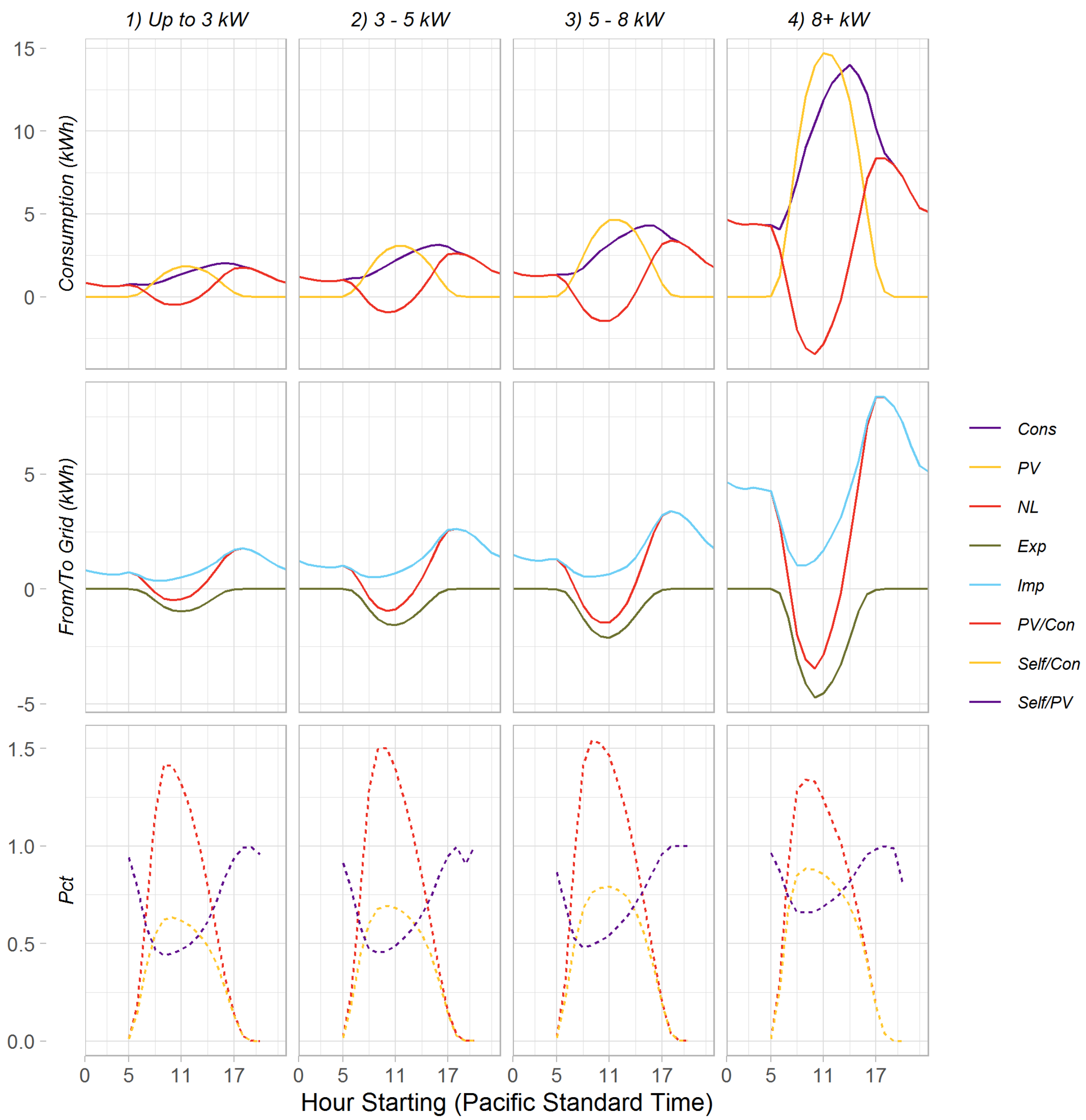


FIGURE C-18: SDG&E RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 SDG&E GROSS LOAD HOURS



C.3 NON-RESIDENTIAL LOAD SHAPE RESULTS FOR ALL HOURS

FIGURE C-19: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT

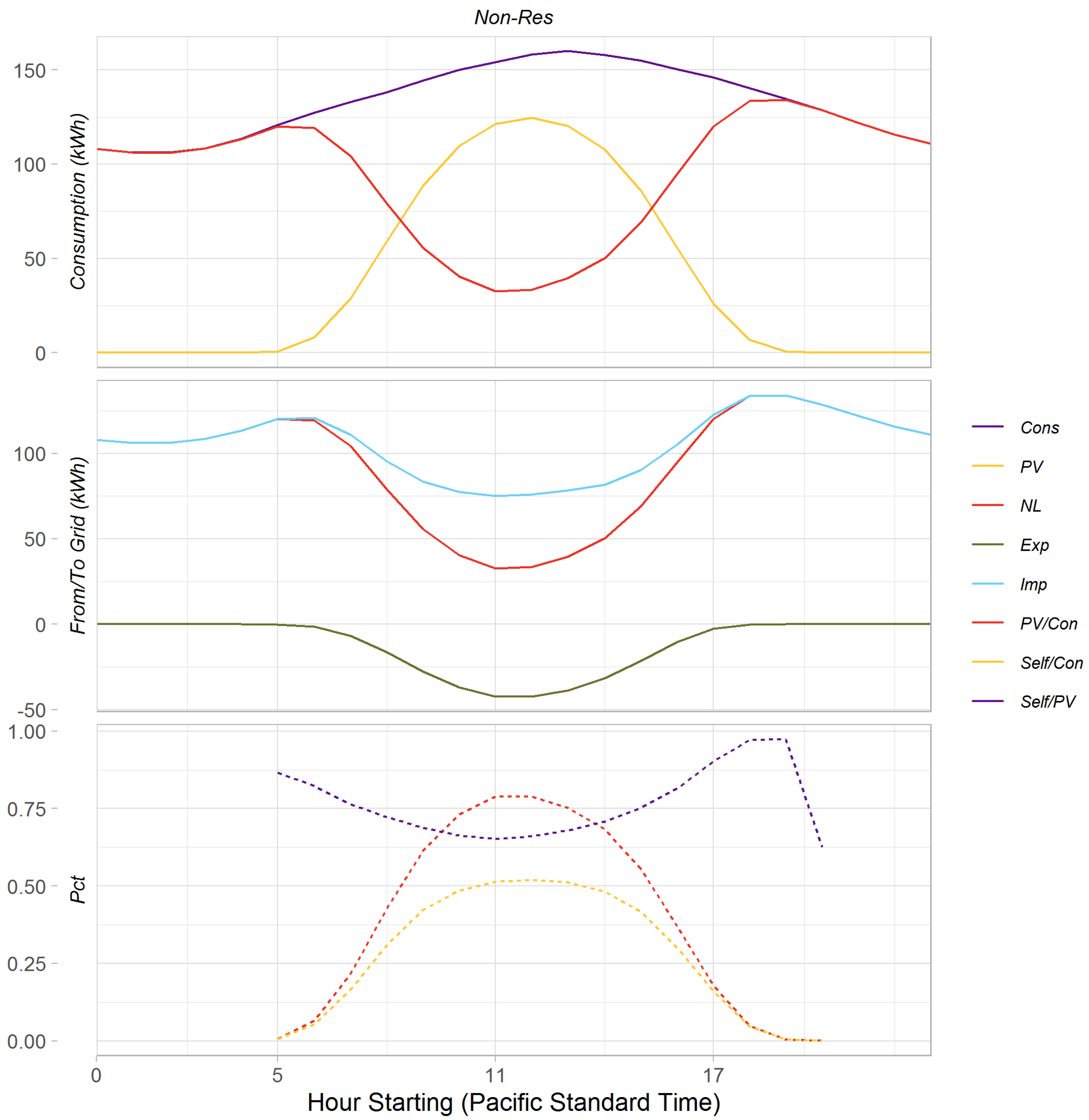


FIGURE C-20: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT

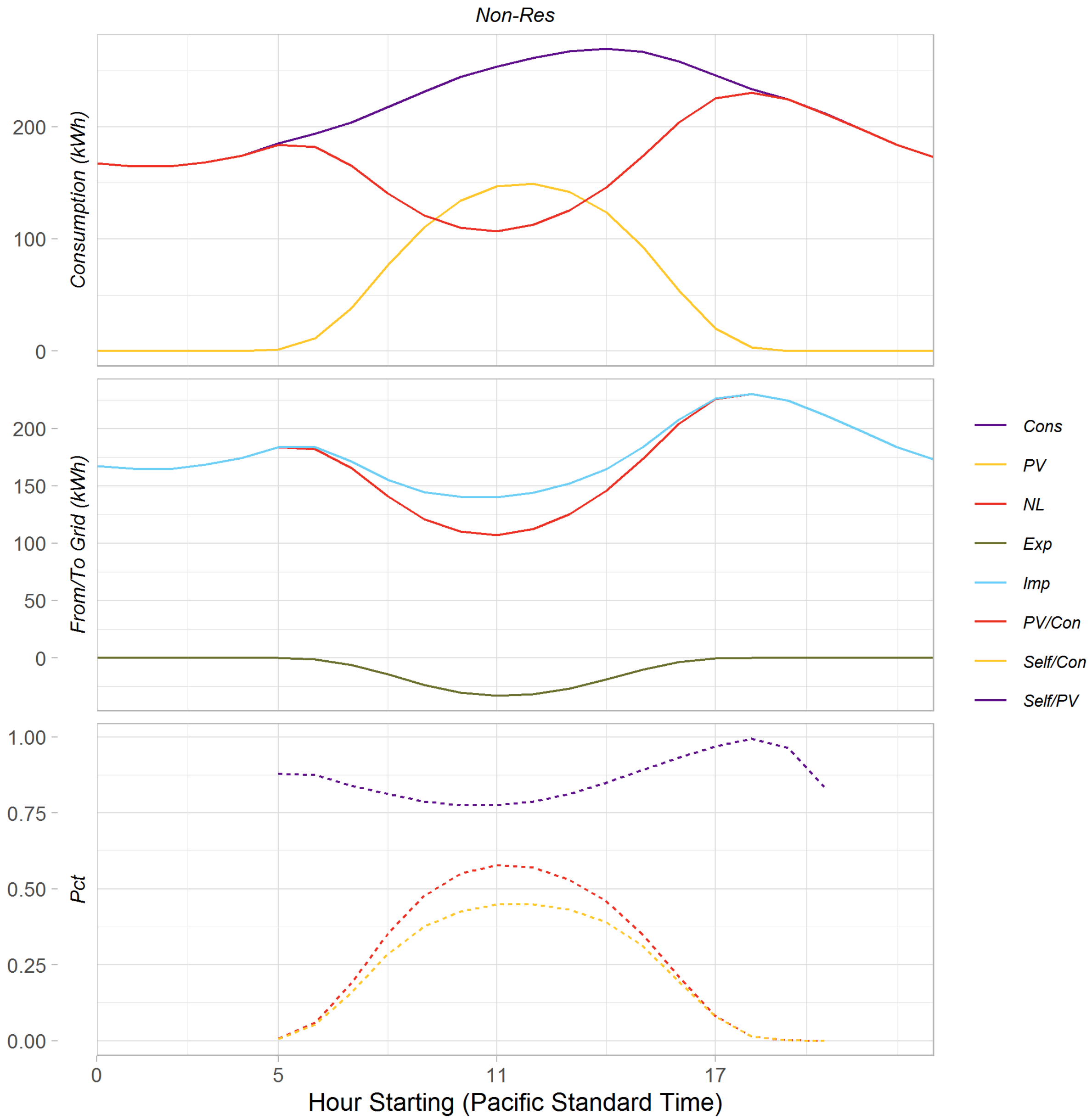
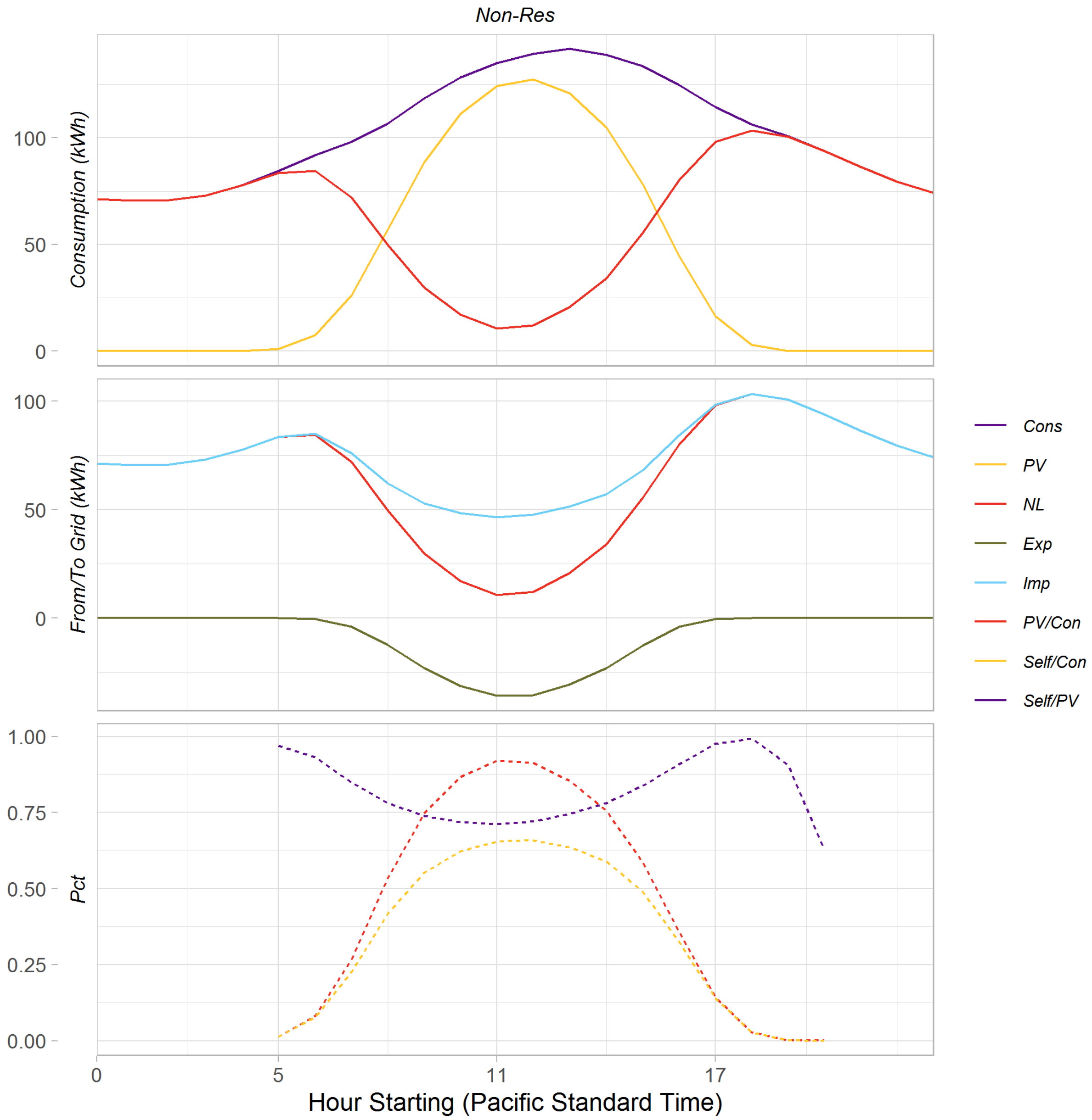


FIGURE C-21: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT



C.3.1 Non-Residential Load Results for Coastal and Inland Locations

TABLE C-8: NON-RESIDENTIAL AVERAGE COASTAL AND INLAND LOAD STATISTICS (KWH)

	PG&E Non-Residential		SCE Non-Residential		SDG&E Non-Residential	
	Coastal	Inland	Coastal	Inland	Coastal	Inland
Consumption	1,082,058	1,250,404	1,293,523	2,009,015	936,084	809,067
Import	870,363	974,154	1,055,238	1,659,083	672,550	574,783
Export	78,537	126,047	53,337	77,221	79,678	74,493
PV Production	290,231	402,297	291,621	427,153	343,213	308,777
% Consumption supplied by PV (PV/Cons)	26.8%	32.2%	22.5%	21.3%	36.7%	38.2%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	19.6%	22.1%	18.4%	17.4%	28.2%	29.0%
% PV used at the site (PV-Ex)/PV	72.9%	68.7%	81.7%	81.9%	76.8%	75.9%

FIGURE C-22: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS

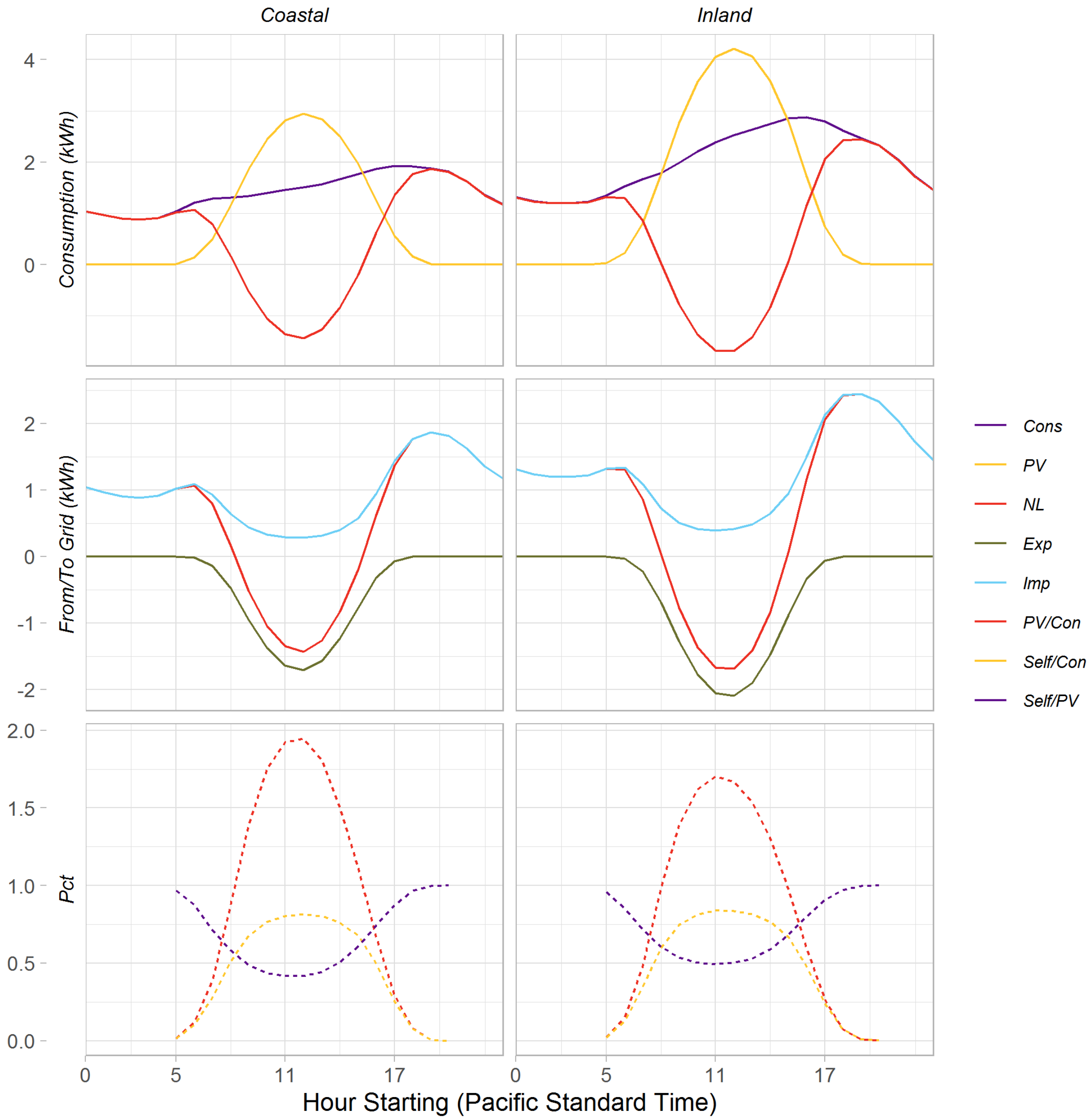


FIGURE C-23: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS

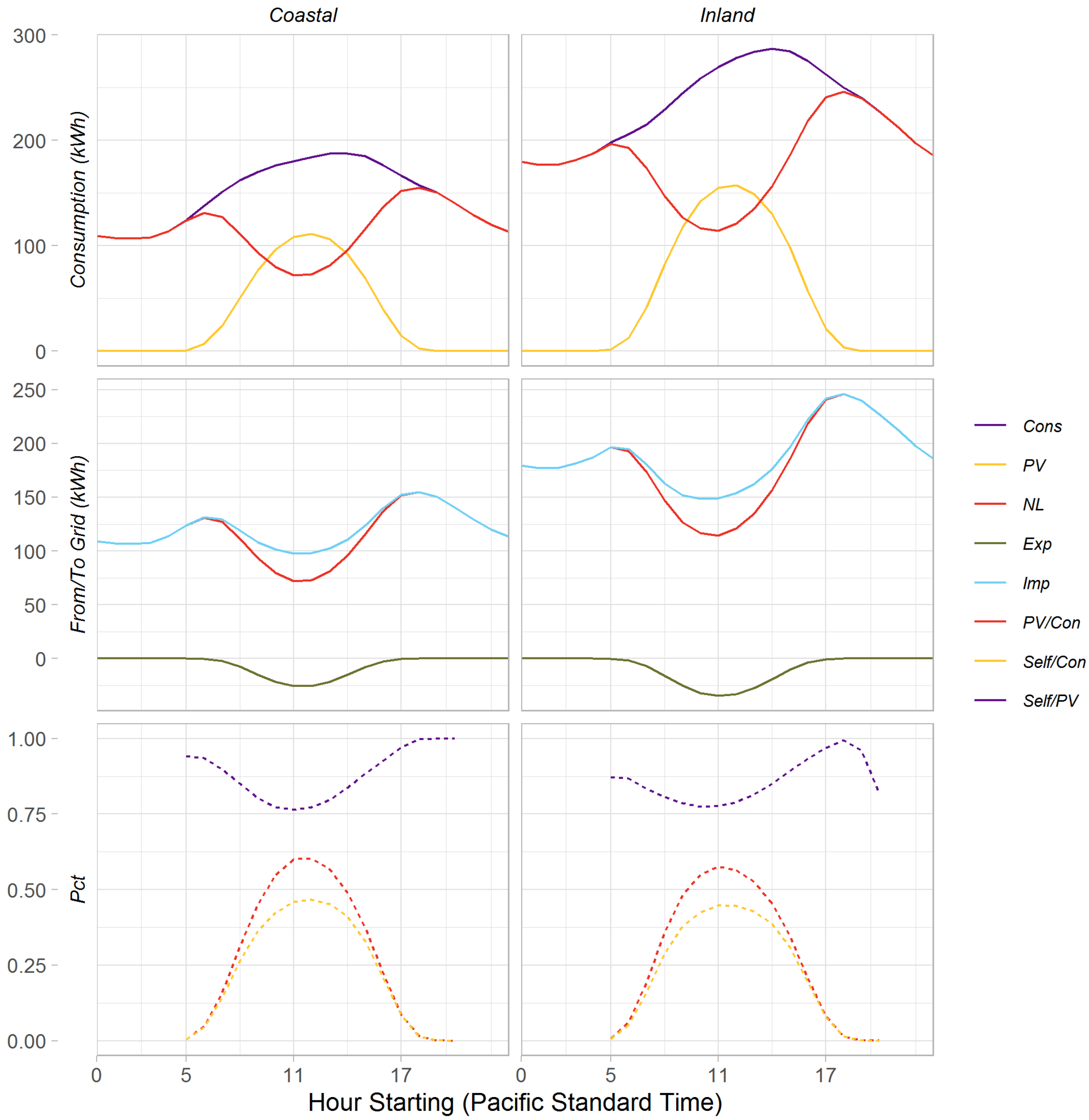
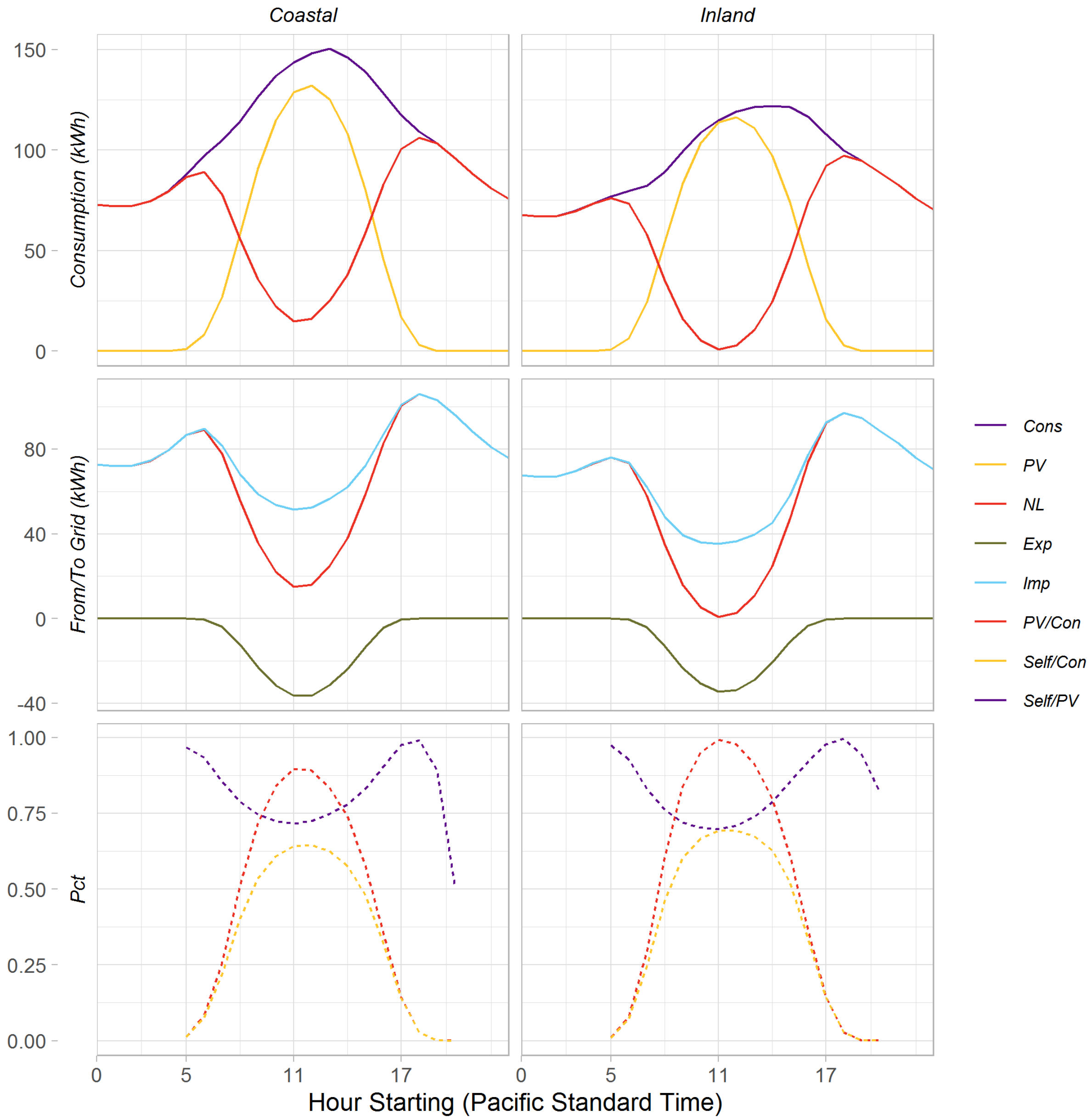


FIGURE C-24: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS



C.3.2 Non-Residential Load Results by Quarter

TABLE C-9: PG&E NON-RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	PG&E Non-Residential Q1	PG&E Non-Residential Q2	PG&E Non-Residential Q3	PG&E Non-Residential Q4
Consumption	258,733	278,059	340,984	285,532
Import	212,901	200,906	264,419	242,694
Export	19,533	39,180	29,191	13,589
PV Production	65,365	116,332	105,756	56,427
% Consumption supplied by PV (PV/Cons)	25.3%	41.8%	31.0%	19.8%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	17.7%	27.7%	22.5%	15.0%
% PV used at the site (PV-Ex)/PV	70.1%	66.3%	72.4%	75.9%

TABLE C-10: SCE NON-RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SCE Non-Residential Q1	SCE Non-Residential Q2	SCE Non-Residential Q3	SCE Non-Residential Q4
Consumption	421,313	470,450	540,628	456,248
Import	354,024	368,723	437,485	391,918
Export	18,490	26,703	17,483	12,354
PV Production	85,778	128,430	120,626	76,684
% Consumption supplied by PV (PV/Cons)	20.4%	27.3%	22.3%	16.8%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	16.0%	21.6%	19.1%	14.1%
% PV used at the site (PV-Ex)/PV	78.4%	79.2%	85.5%	83.9%

TABLE C-11: SDG&E NON-RESIDENTIAL AVERAGE QUARTERLY LOAD STATISTICS (KWH)

	SDG&E Non-Residential Q1	SDG&E Non-Residential Q2	SDG&E Non-Residential Q3	SDG&E Non-Residential Q4
Consumption	203,255	216,767	253,539	219,769
Import	149,388	146,567	176,824	168,206
Export	18,348	26,106	20,984	12,880
PV Production	72,215	97,629	97,698	64,443
% Consumption supplied by PV (PV/Cons)	35.5%	45.0%	38.5%	29.3%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	26.5%	33.0%	30.3%	23.5%
% PV used at the site (PV-Ex)/PV	74.6%	73.3%	78.5%	80.0%

FIGURE C-25: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER

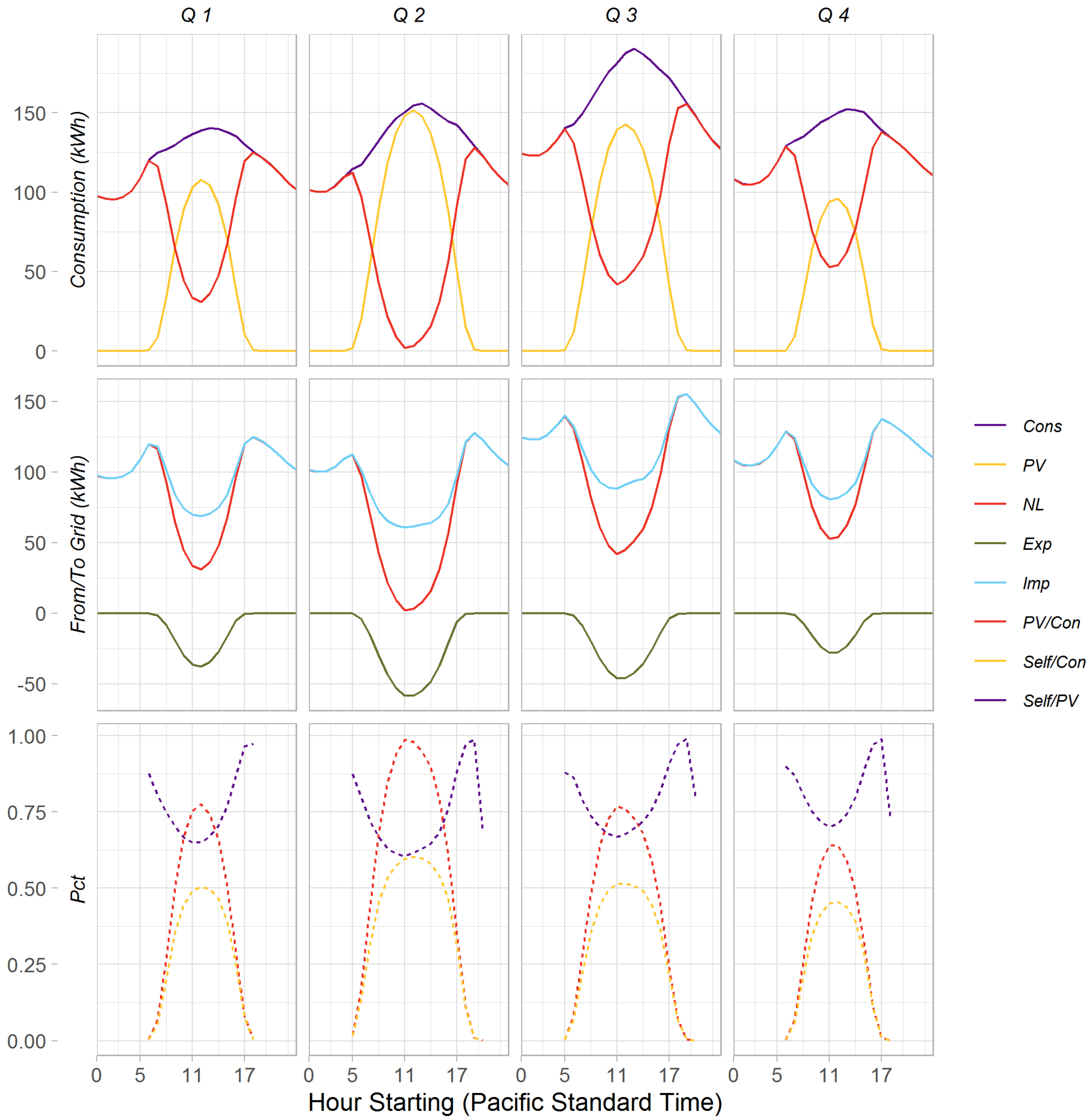


FIGURE C-26: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER

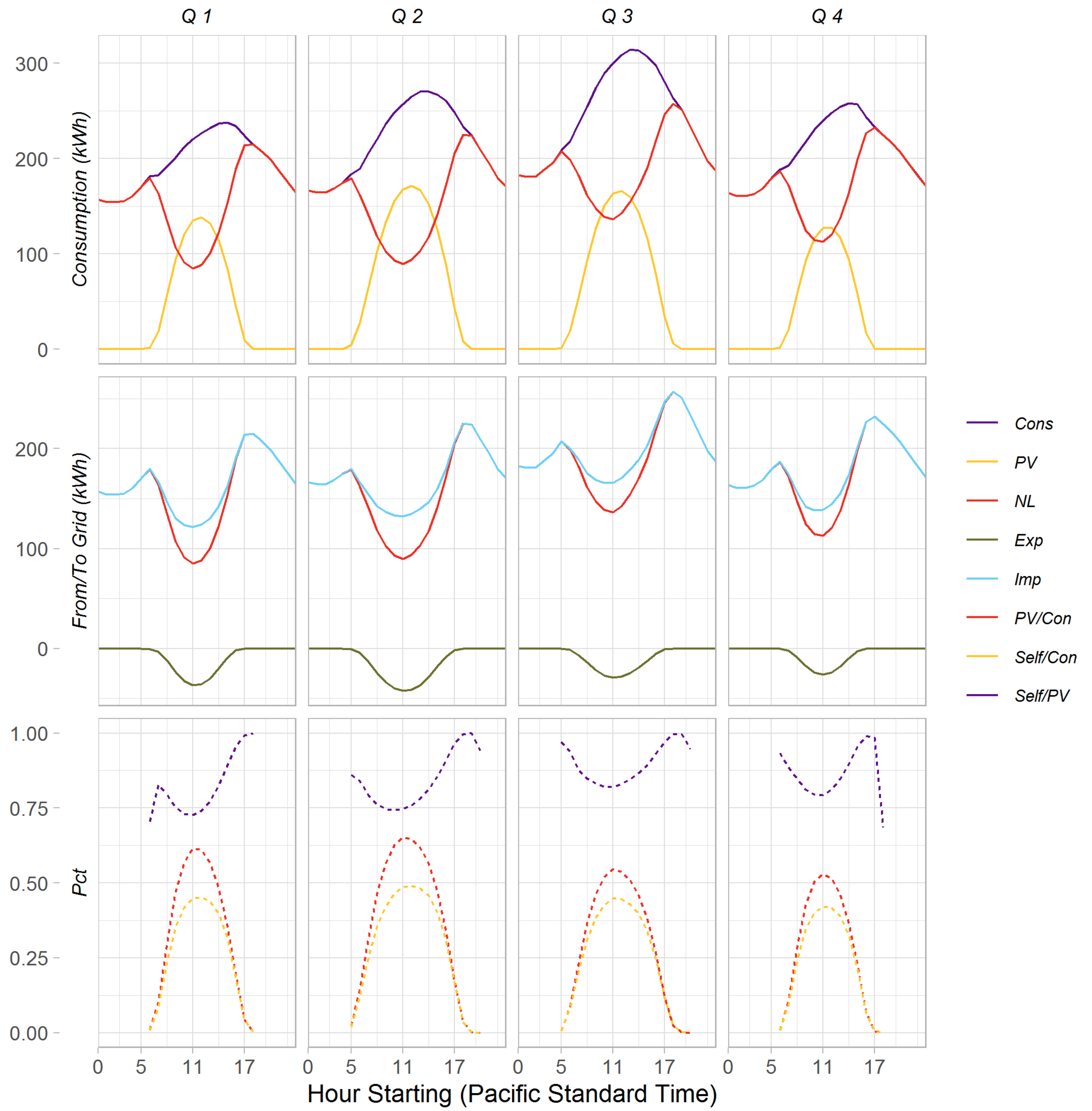
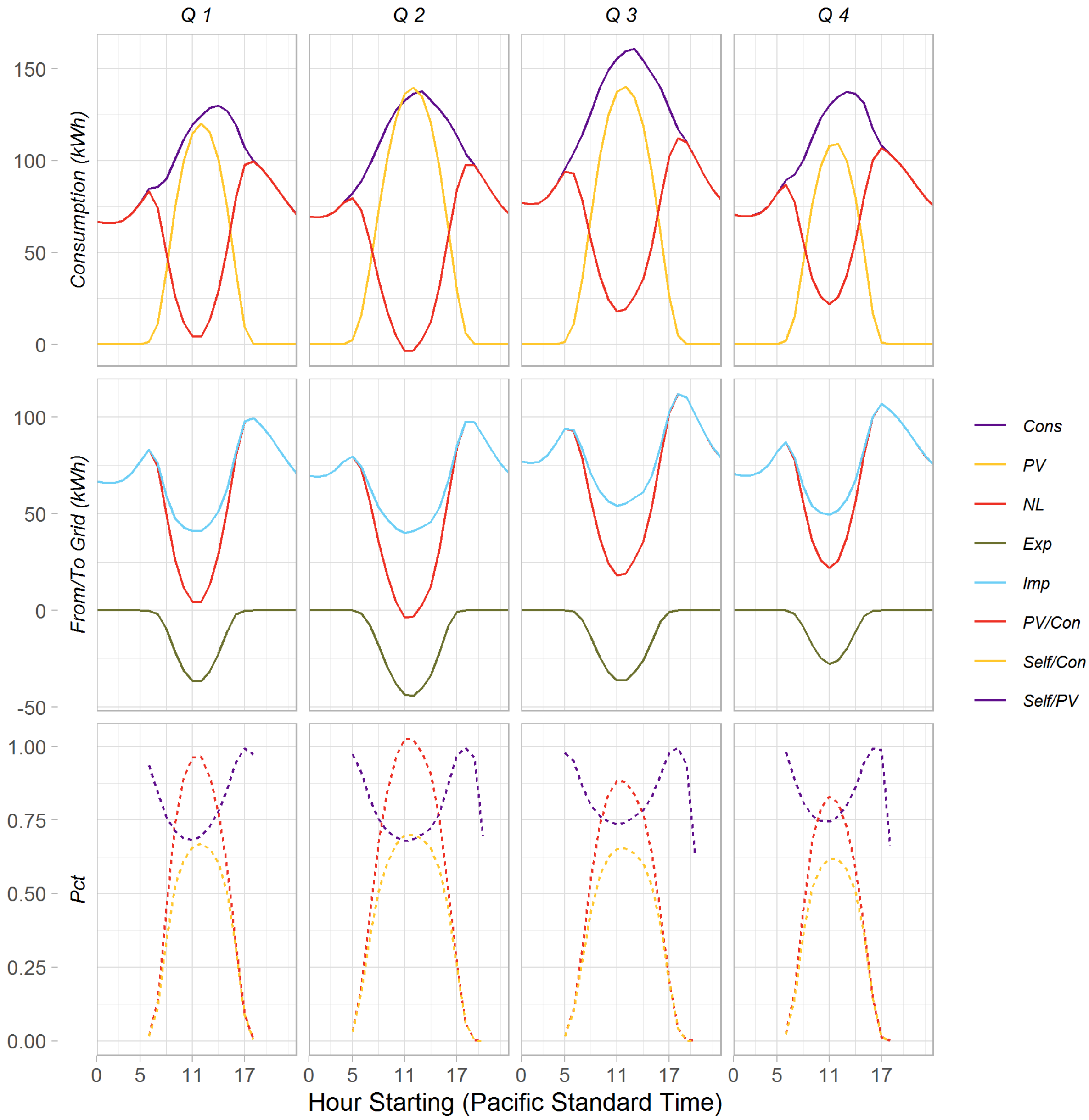


FIGURE C-27: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY QUARTER



C.3.3 Non-Residential Load Results by System Size

TABLE C-12: PG&E NON- RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	PG&E Non-Res Up to 70 kW	PG&E Non-Res 70 - 150 kW	PG&E Non-Res 150 - 300 kW	PG&E Non-Res 300+ kW
Consumption	212,549	481,820	1,035,545	3,955,505
Import	166,025	355,163	790,460	3,199,310
Export	20,272	59,230	108,135	300,198
PV Production	66,795	185,888	353,220	1,056,258
% Consumption supplied by PV (PV/Cons)	31.4%	38.6%	34.1%	26.7%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	21.9%	26.3%	23.7%	19.1%
% PV used at the site (PV-Ex)/PV	69.7%	68.1%	69.4%	71.6%

TABLE C-13: SCE NON- RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	SCE Non-Res Up to 70 kW	SCE Non-Res 70 - 150 kW	SCE Non-Res 150 - 300 kW	SCE Non-Res 300+ kW
Consumption	508,838	740,147	1,866,343	4,104,060
Import	456,614	622,368	1,587,296	3,290,700
Export	20,353	51,798	100,477	117,419
PV Production	72,577	169,577	379,524	930,629
% Consumption supplied by PV (PV/Cons)	14.3%	22.9%	20.3%	22.7%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	10.3%	15.9%	15.0%	19.8%
% PV used at the site (PV-Ex)/PV	72.0%	69.5%	73.5%	87.4%

TABLE C-14: SDG&E NON- RESIDENTIAL AVERAGE LOAD STATISTICS BY SYSTEM SIZE (KWH)

	SDG&E Non-Res Up to 70 kW	SDG&E Non-Res 70 - 150 kW	SDG&E Non-Res 150 - 300 kW	SDG&E Non-Res 300+ kW
Consumption	210,022	455,437	1,211,546	2,530,799
Import	157,107	316,768	918,368	1,756,153
Export	20,525	48,452	92,752	215,385
PV Production	73,441	187,121	385,930	990,031
% Consumption supplied by PV (PV/Cons)	35.0%	41.1%	31.9%	39.1%
% Consumption Contemporaneously supplied by PV (PV-Ex)/Cons	25.2%	30.4%	24.2%	30.6%
% PV used at the site (PV-Ex)/PV	72.1%	74.1%	76.0%	78.2%

FIGURE C-28: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE

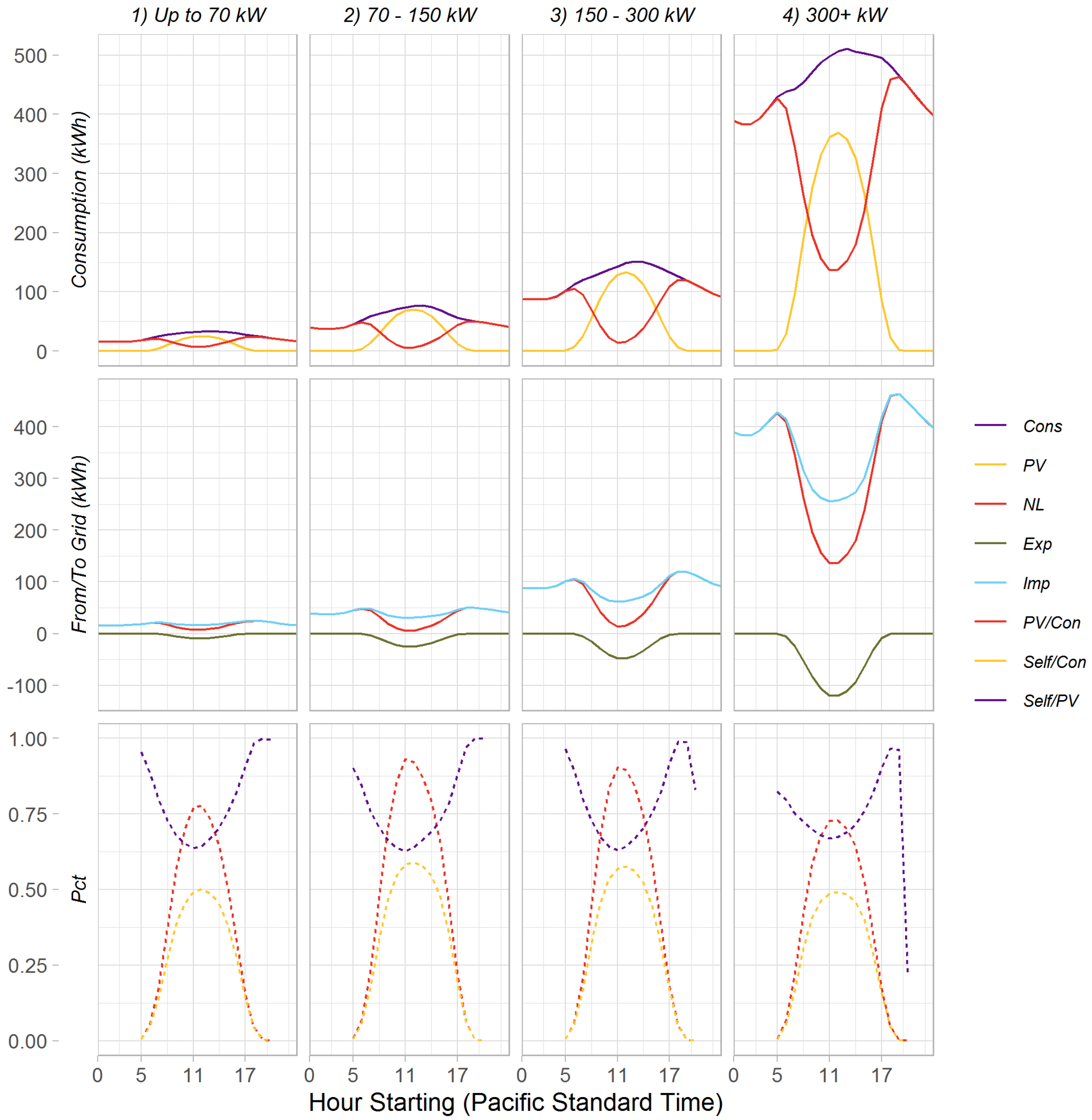


FIGURE C-29: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE

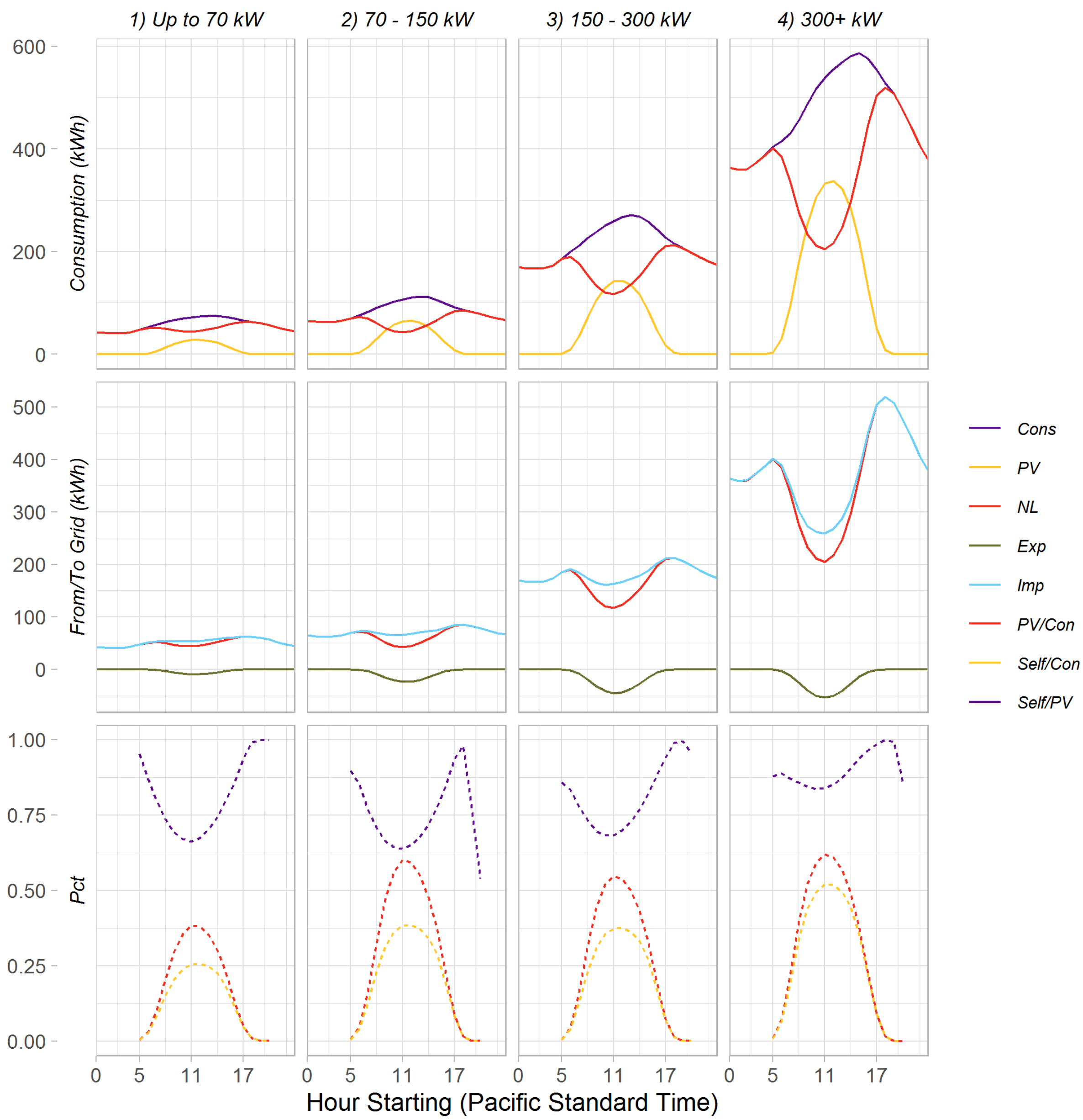
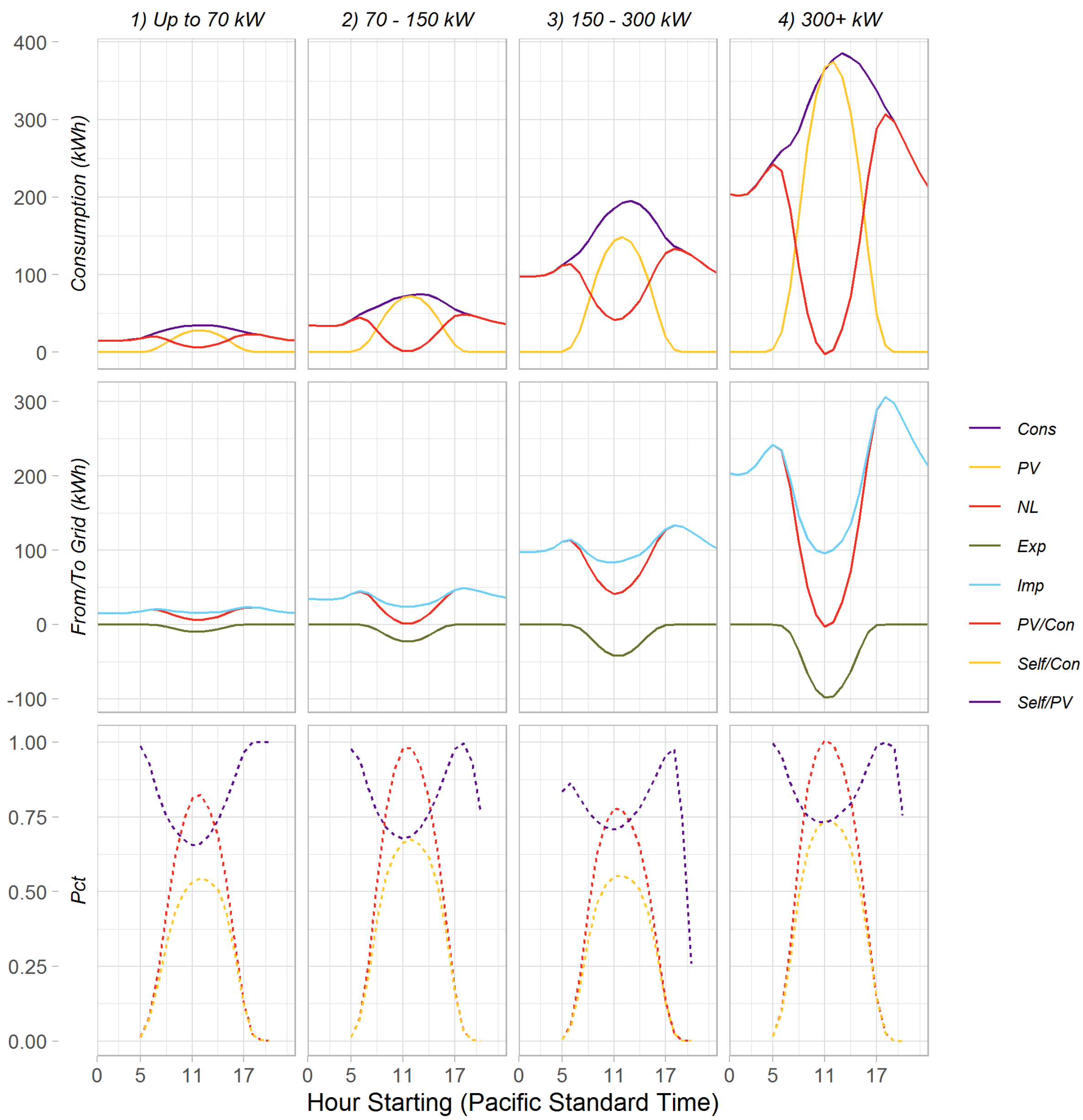


FIGURE C-30: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE



C.4 NON-RESIDENTIAL LOAD SHAPE RESULTS DAYS THAT INCLUDE THE TOP 200 HOURS OF IOU GROSS LOAD

This sub-section presents non-residential load shape graphs only for days that include the top 200 hours of gross IOU load. In general, inland sites see a larger difference than coastal sites between these graphs and those for all hours.

C.4.1 Non-Residential Load Shapes by Location during Top 200 IOU Load Hours

FIGURE C-31: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 PG&E GROSS LOAD HOURS

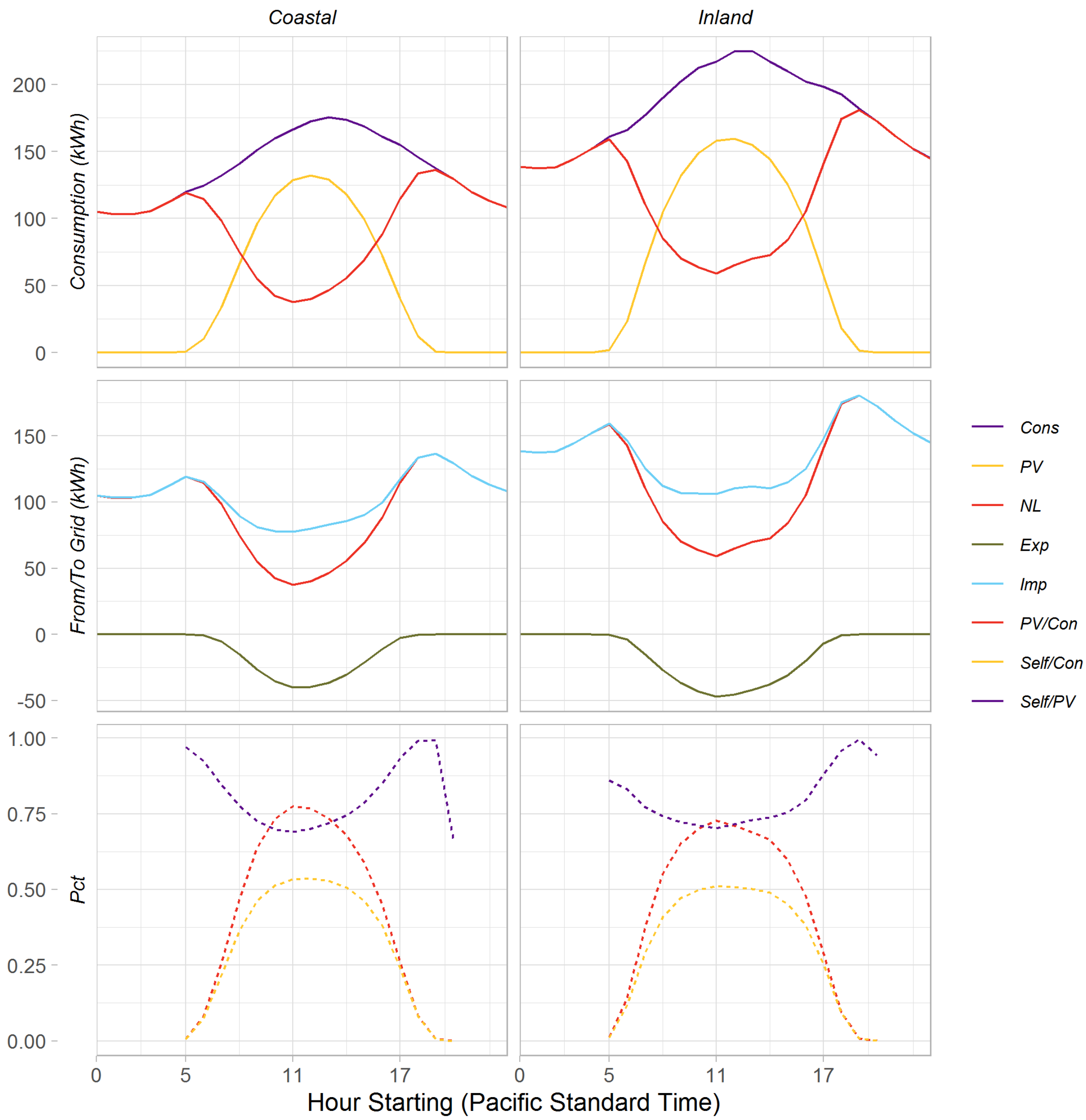


FIGURE C-32: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 SCE GROSS LOAD HOURS

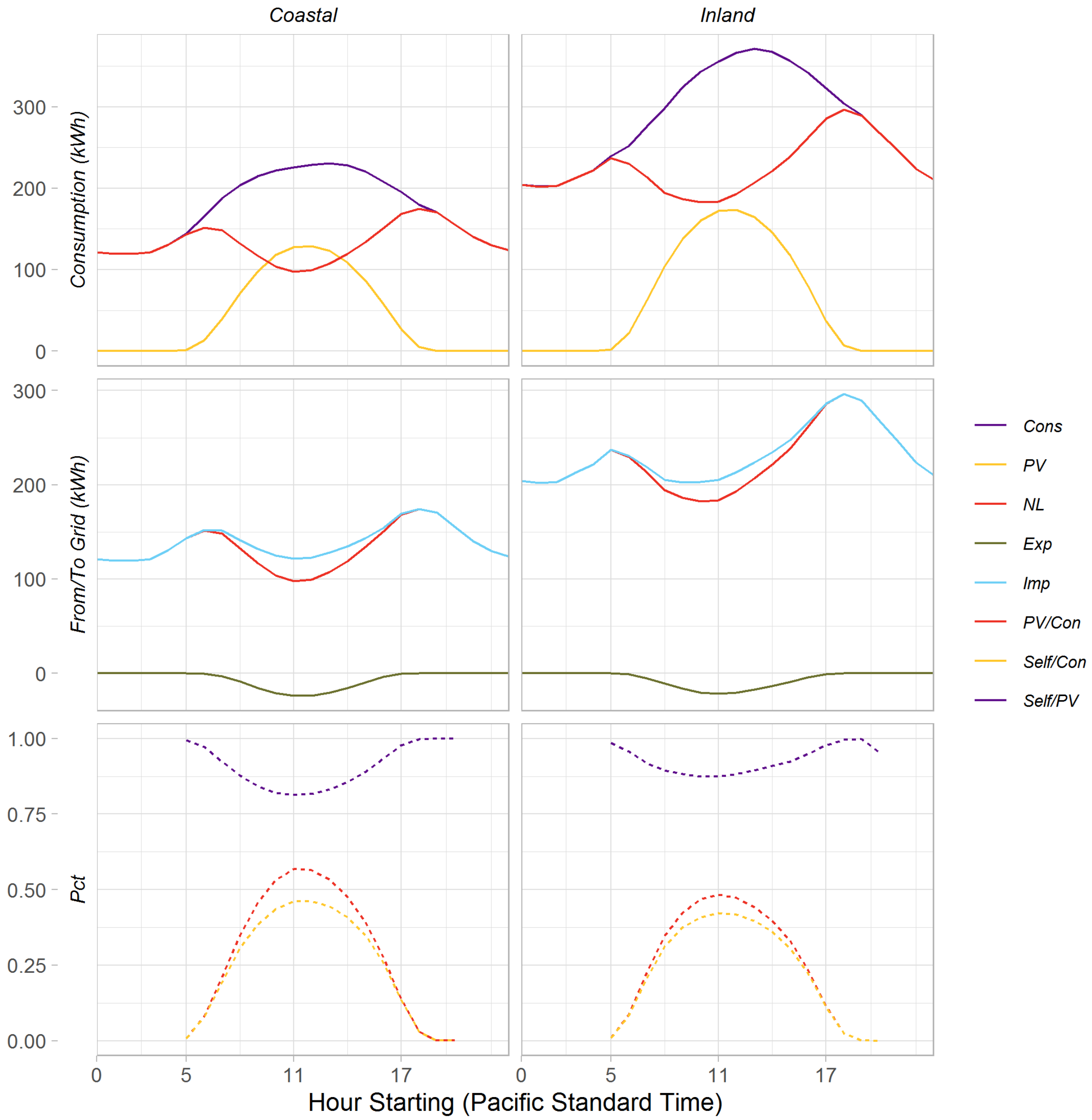
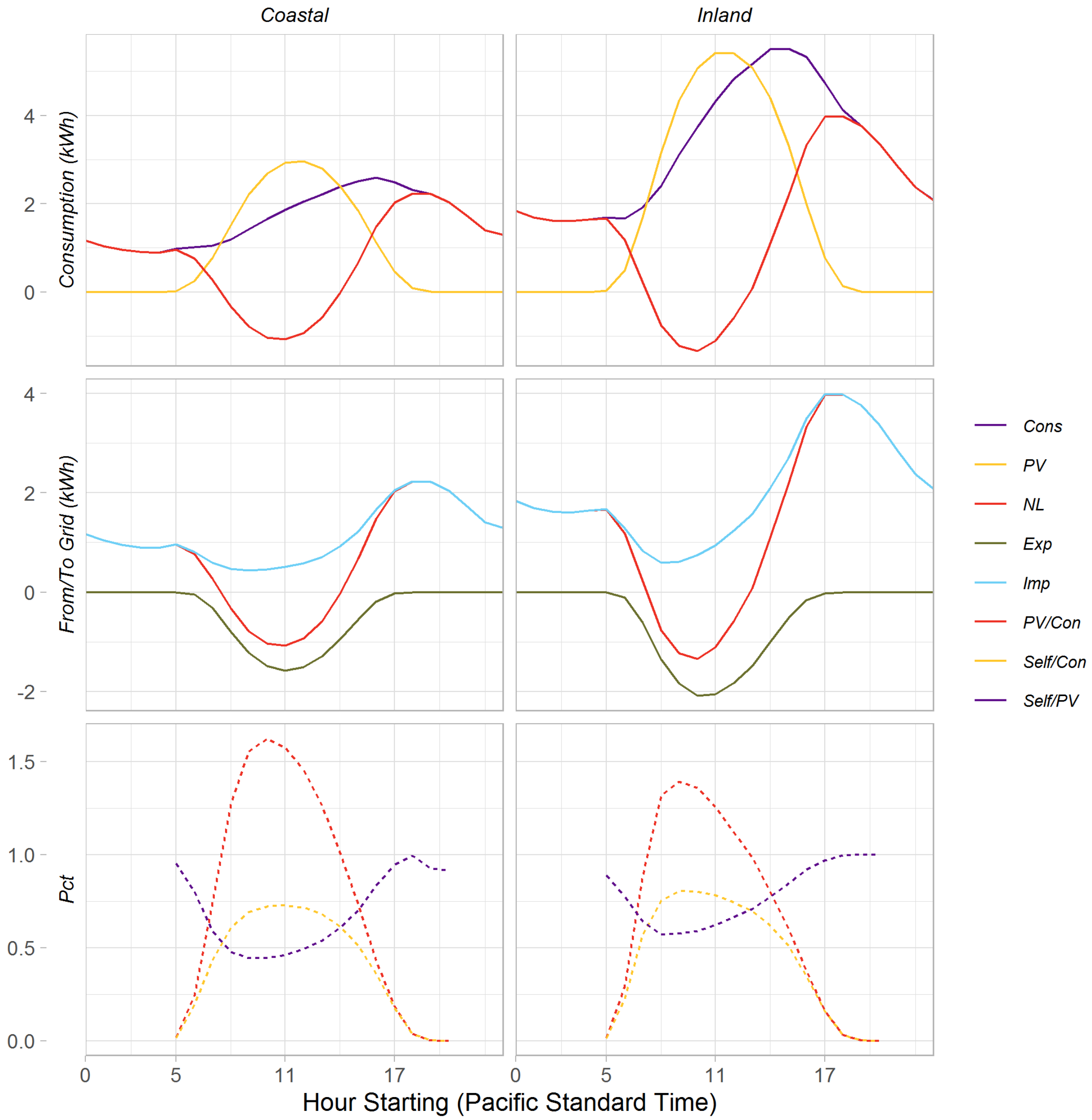


FIGURE C-33: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT FOR COASTAL AND INLAND CUSTOMERS DURING TOP 200 SDG&E GROSS LOAD HOURS



C.4.2 Non-Residential Load Shapes by System Size during Top 200 IOU Load Hours

FIGURE C-34: PG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 PG&E GROSS LOAD HOURS

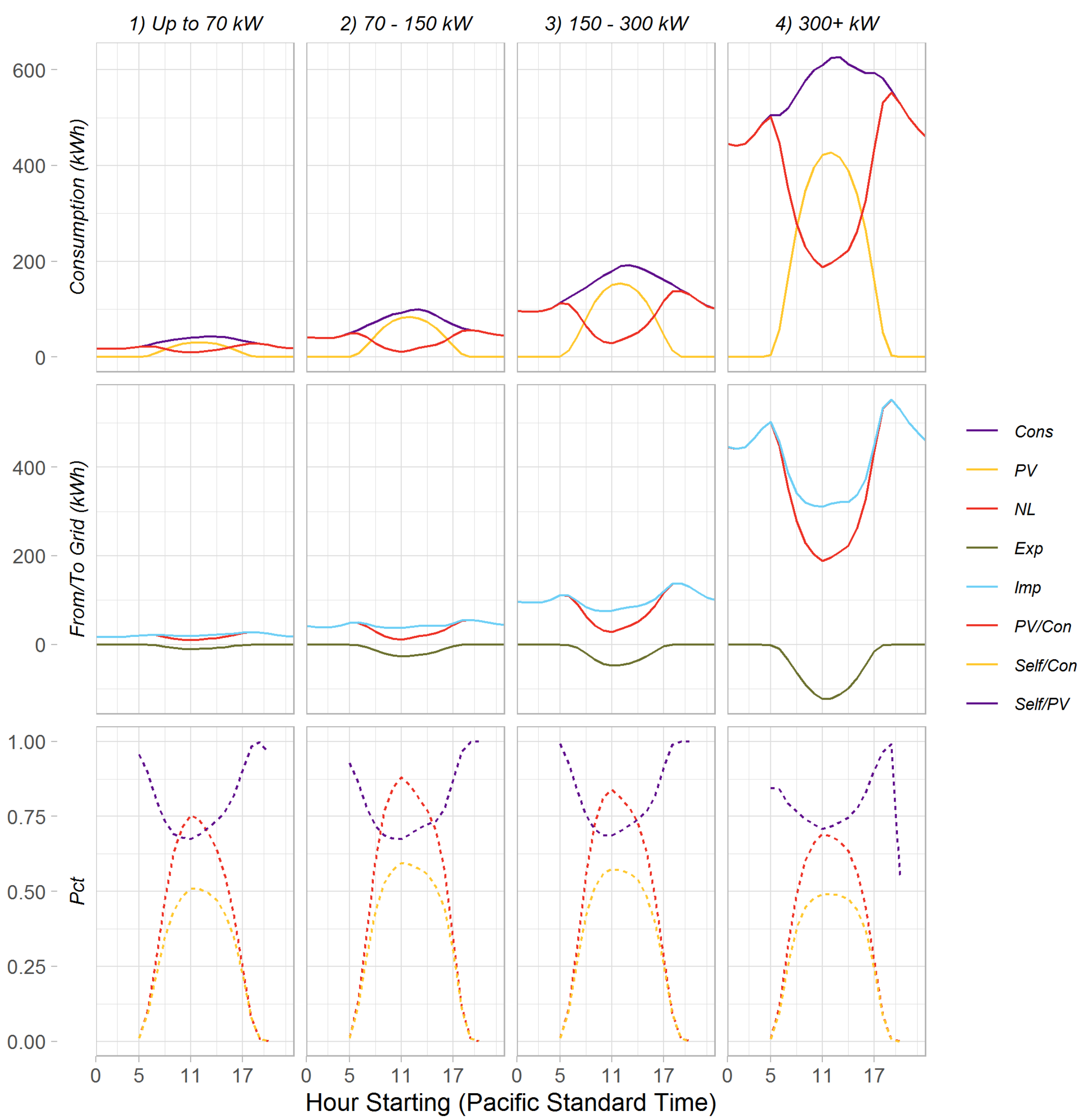


FIGURE C-35: SCE NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 SCE GROSS LOAD HOURS

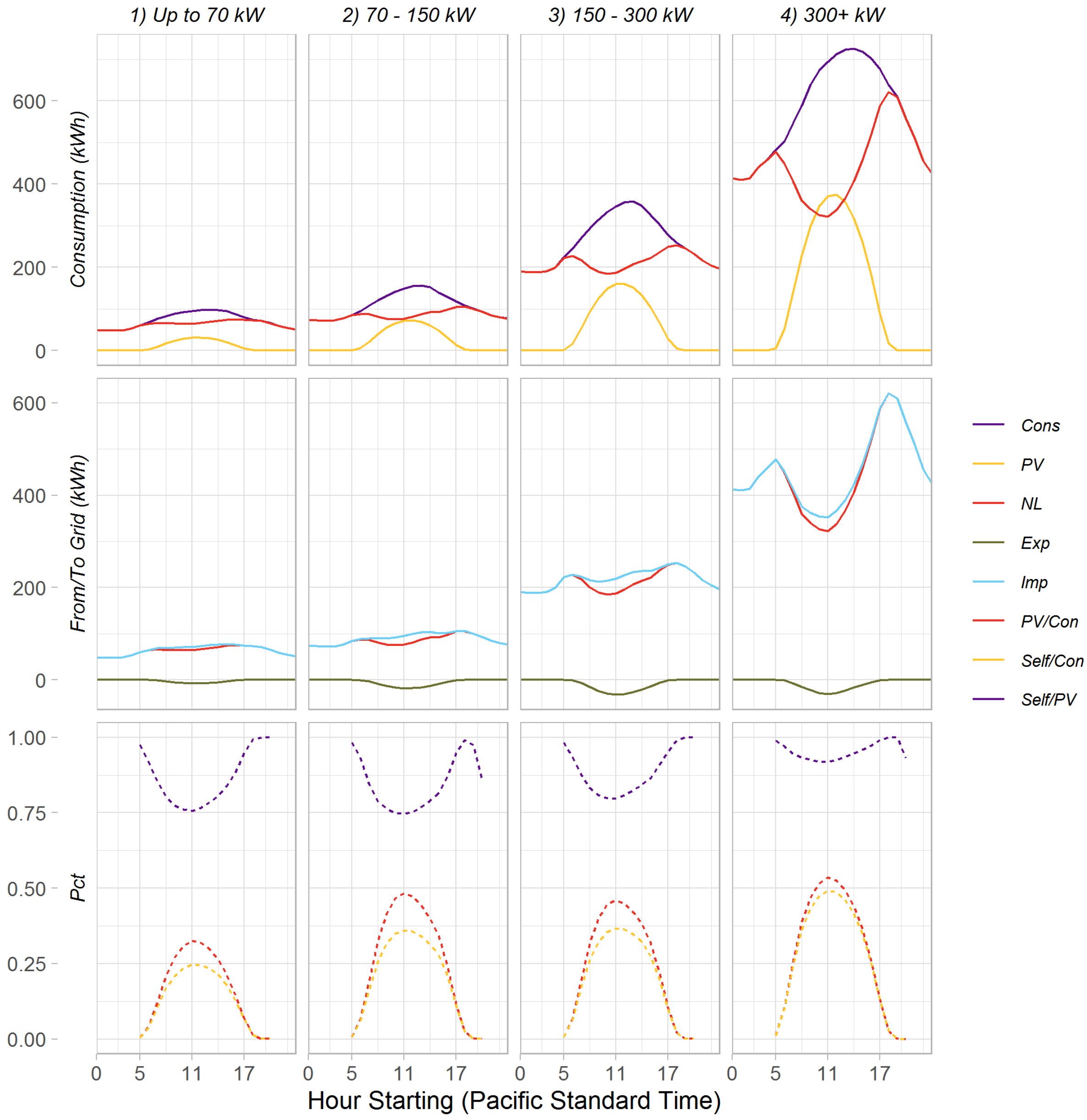
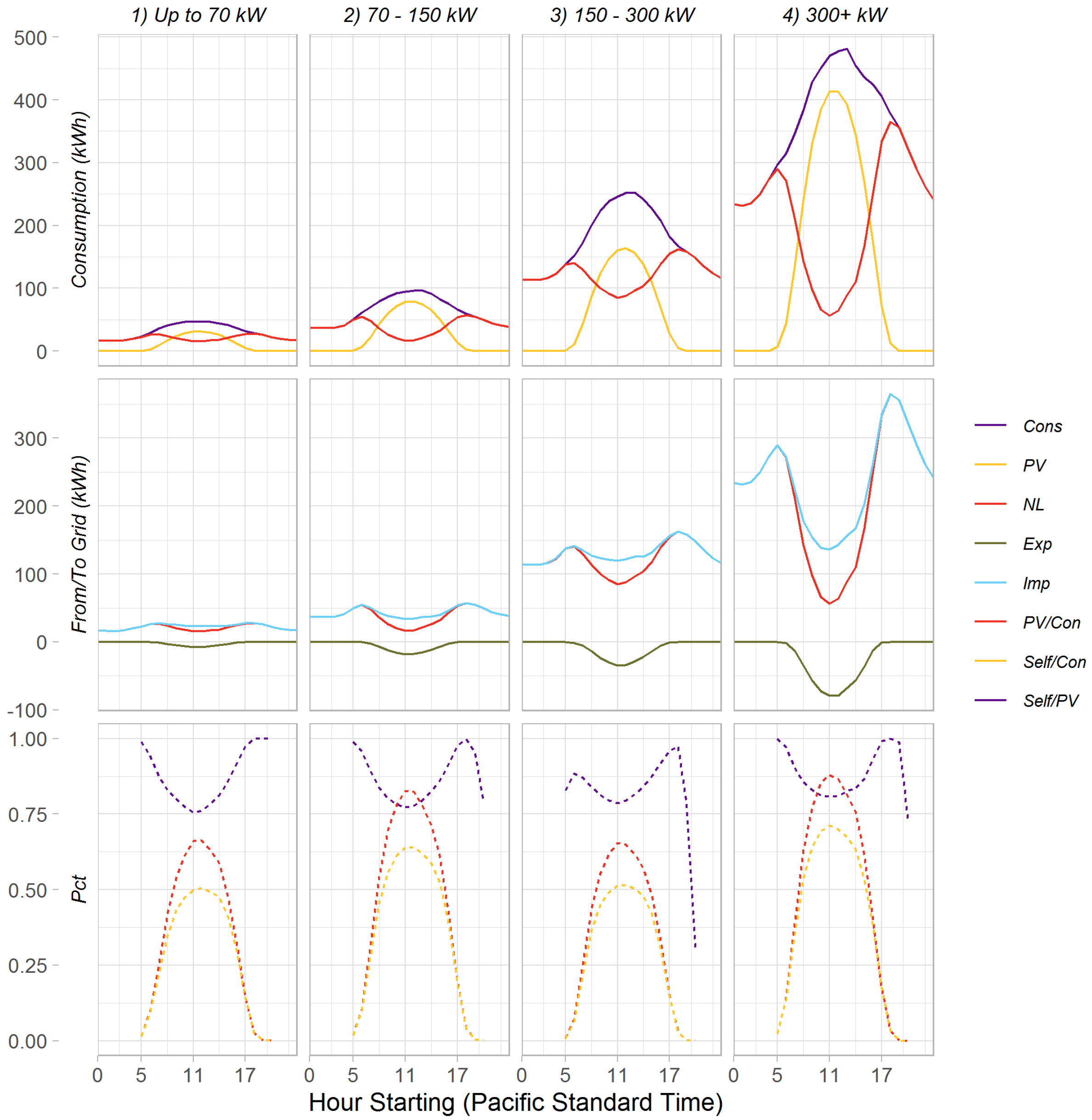


FIGURE C-36: SDG&E NON-RESIDENTIAL CSI CUSTOMER CONSUMPTION, PV PRODUCTION, EXPORT, AND IMPORT BY SYSTEM SIZE DURING TOP 200 SDG&E GROSS LOAD HOURS



APPENDIX D CONSUMPTION CHANGE

This appendix includes additional results for the hourly consumption change analysis and describes the findings for the monthly consumption change billing analysis. The hourly consumption change findings are limited to additional results for PG&E's non-residential sample and SCE's small non-residential sample. PG&E's residential sample hourly consumption change results are presented in Section 5 of the report. SCE's large non-residential sample was too small to provide consistent hourly consumption change results. The analysis sample for the hourly consumption change analysis included 1,037 PG&E residential customers, 363 PG&E non-residential customers, and 310 SCE non-residential customers. Due to the substantial heterogeneity in non-residential customers, the non-residential load analysis was further disaggregated into large and small customers.

In addition to hourly load results, monthly billing analysis findings are presented for PG&E's and SCE's residential and non-residential samples. The billing analysis was undertaken to determine if the hourly consumption change findings were maintained when using the larger samples that are available with the billing data. The analysis sample for the monthly consumption change analysis included 1,696 PG&E residential customers, 821 PG&E non-residential customers, 94 SCE residential customers, and 943 SCE non-residential customers. While the samples available for the monthly consumption change analysis are substantially larger than for the hourly analysis, the prime factor restricting the sample size for the monthly and hourly consumption change analysis is the requirement that each customer have at least one year of pre- and post-installation billing data.

D.1 HOURLY CONSUMPTION CHANGE RESULTS (BASED ON HOURLY LOAD DATA)

Table D-1 through Table D-3 list the quarterly change results for the PG&E small and large non-residential and SCE small non-residential sector regression analysis.[1] The graphs of quarterly change are similar to the average yearly and the residential quarterly change illustrations in the body of the report. These tables and graphs illustrate that the largest average increase in consumption occurs during the third or summer quarter. Small non-residential customers have a larger average percentage increase in consumption than large non-residential customers.

[1] SCE's large non-residential hourly sample was limited to less than 100 customers. The timing of the customer data was such that it was not possible to develop sample regression models.

TABLE D-1: PG&E SMALL NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	707	1,121	3,045	17
Average Monthly Percent Change: Year 1	3.6%	5.6%	14.0%	0.1%
Average Monthly Change: Year 2	986	1,588	3,693	1,595
Average Monthly Percent Change: Year 2	5.0%	7.9%	17.0%	6.2%
Average Monthly Change: Year 3	888	1,308	3,539	1,616
Average Monthly Percent Change: Year 3	4.5%	6.5%	16.2%	6.3%

TABLE D-2: PG&E LARGE NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	-690	-1,662	810	-12,413
Average Monthly Percent Change: Year 1	-0.4%	-0.9%	0.4%	-6.4%
Average Monthly Change: Year 2	2,018	4,912	13,171	4,454
Average Monthly Percent Change: Year 2	1.1%	2.7%	6.1%	2.3%
Average Monthly Change: Year 3	1,857	7,211	18,127	8,418
Average Monthly Percent Change: Year 3	1.0%	3.9%	8.4%	4.4%

TABLE D-3: SCE SMALL NON-RESIDENTIAL AVERAGE AND MEDIAN MONTHLY CHANGE IN CONSUMPTION (KWH)

	Q1	Q2	Q3	Q4
Average Monthly Change: Year 1	979	1,346	1,961	537
Average Monthly Percent Change: Year 1	4.3%	5.6%	6.9%	2.2%
Average Monthly Change: Year 2	1078	1,022	1,640	649
Average Monthly Percent Change: Year 2	4.8%	4.2%	5.8%	2.7%
Average Monthly Change: Year 3	617	405	514	-159
Average Monthly Percent Change: Year 3	2.8%	1.7%	1.8%	-0.7%

FIGURE D-1: PG&E LARGE NON-RESIDENTIAL CHANGE IN CONSUMPTION BY QUARTER FOLLOWING PV INSTALLATION

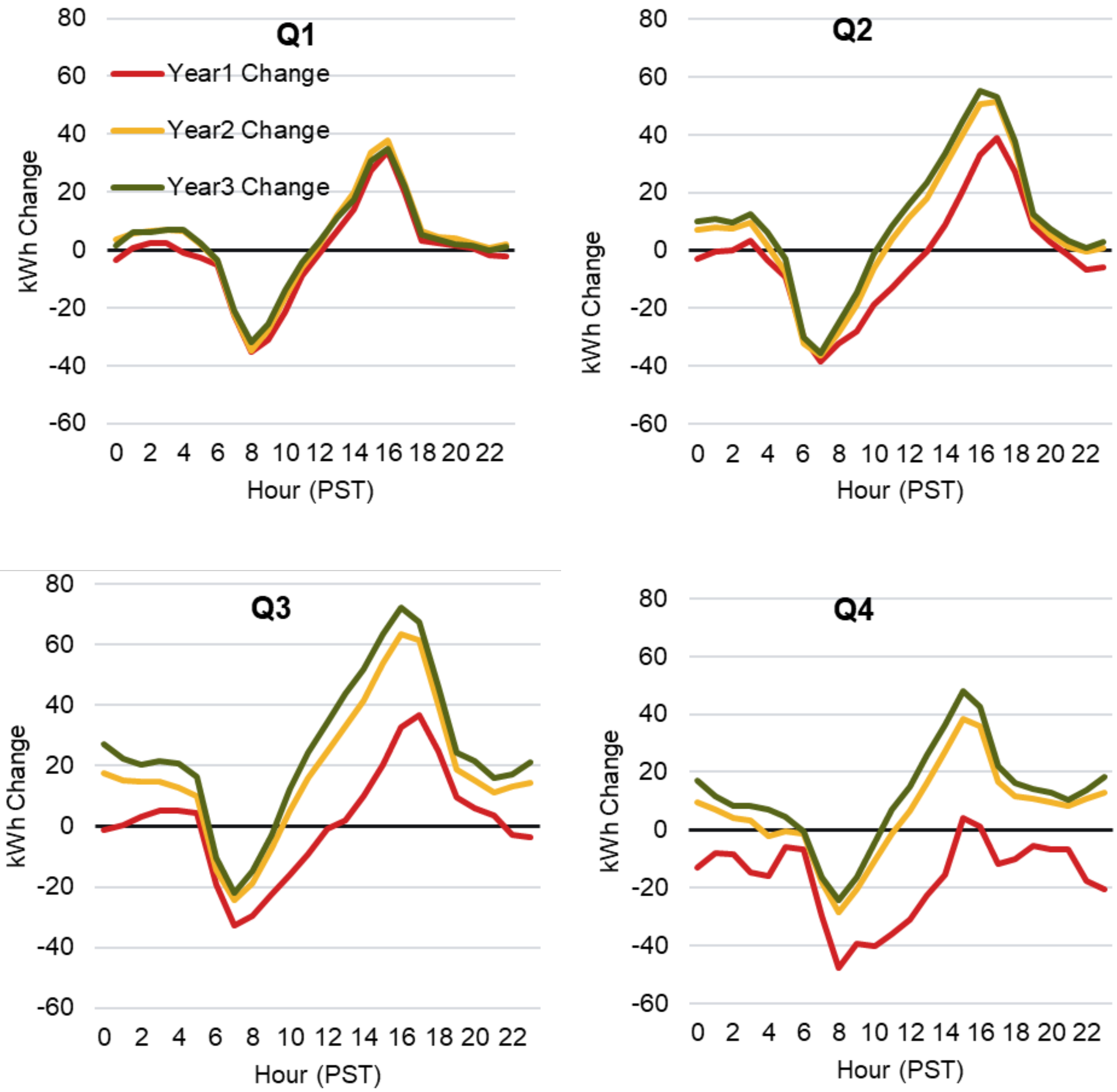


FIGURE D-2: PG&E SMALL NON-RESIDENTIAL CHANGE IN CONSUMPTION BY QUARTER FOLLOWING PV INSTALLATION

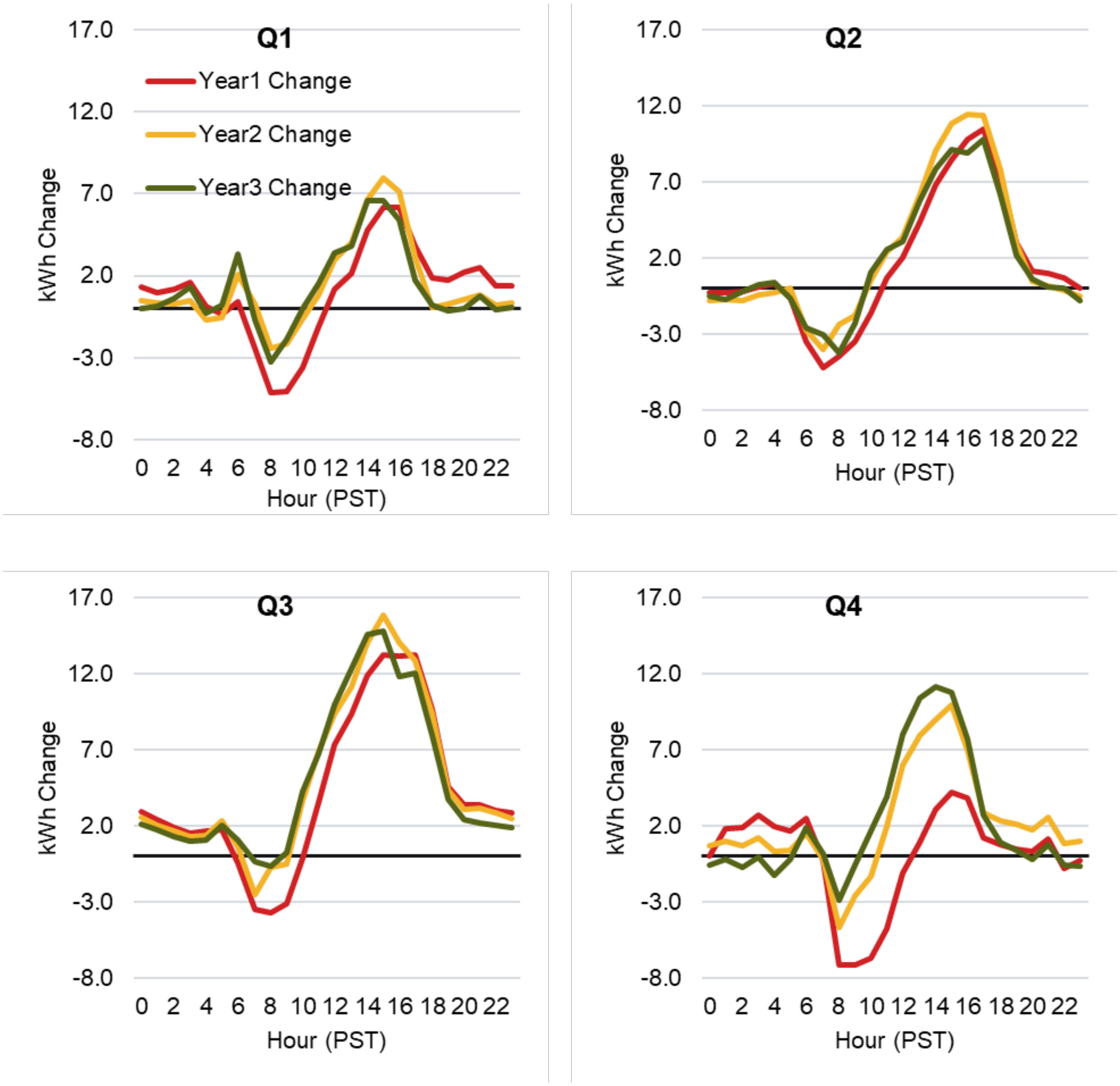
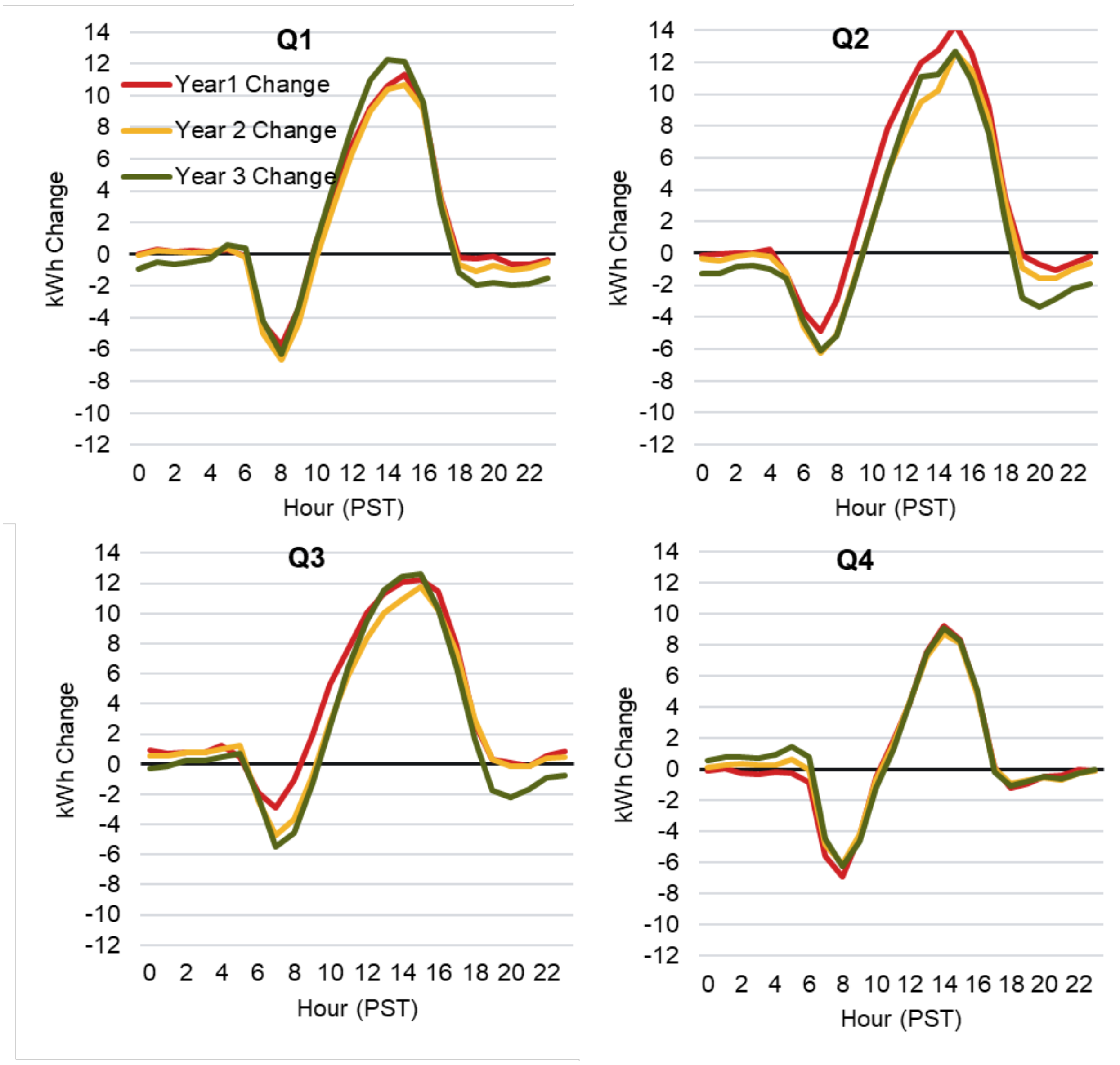


FIGURE D-3: SCE SMALL NON-RESIDENTIAL CHANGE IN CONSUMPTION BY QUARTER FOLLOWING PV INSTALLATION



D.2 MONTHLY CONSUMPTION CHANGE RESULTS (BASED ON MONTHLY BILLING DATA)

The first step of the monthly consumption change analysis weather-normalized customer bills, which is similar to the first step of the hourly consumption change analysis. Using the weather-normalized bills, the evaluation team examined the share of customers increasing, decreasing, and maintaining their consumption following the installation of their PV systems. Where possible, the data from the hourly and monthly samples are presented on the same graph for ease of comparison. These graphs show that the monthly and hourly samples are substantially consistent. Figure D-4 presents PG&E's residential weather-normalized consumption change following the installation of PV for the monthly and hourly samples. The graph shows that the change in consumption by 10% buckets is very similar across the two samples.

FIGURE D-4: PG&E RESIDENTIAL SITES WEATHER-NORMALIZED CHANGE IN CONSUMPTION – MONTHLY AND HOURLY SAMPLES

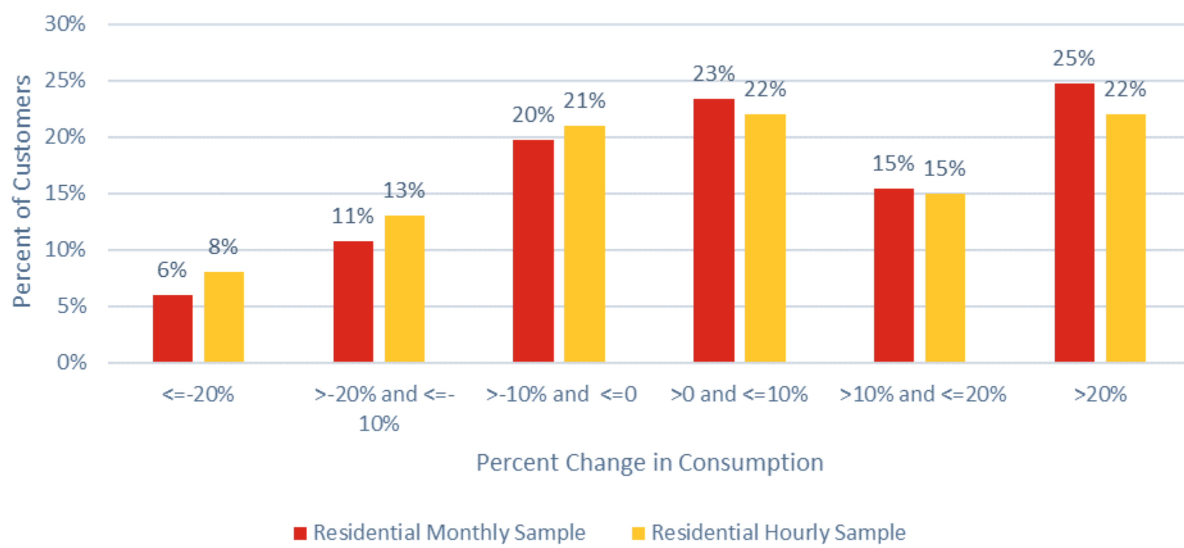


Figure D-5 and Figure D-6 list PG&E's small and large non-residential consumption change for the monthly and hourly samples. The small non-residential monthly sample has more change in consumption following the installation of PV than the hourly sample; 26 percent of the small monthly sample increased their consumption by over 20 percent following the installation of PV, while only 12 percent of the hourly sample had a similar level of increase. The large non-residential monthly and hourly samples' change in consumption are similar to each other.

FIGURE D-5: PG&E SMALL NON-RESIDENTIAL SITES WEATHER-NORMALIZED CHANGE IN CONSUMPTION – MONTHLY AND HOURLY SAMPLES

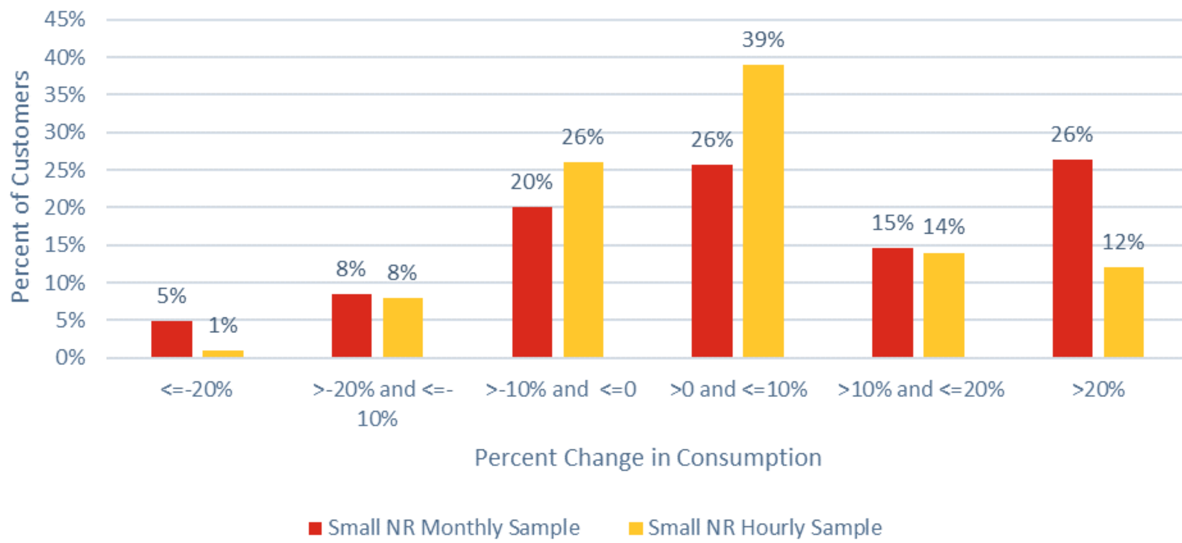
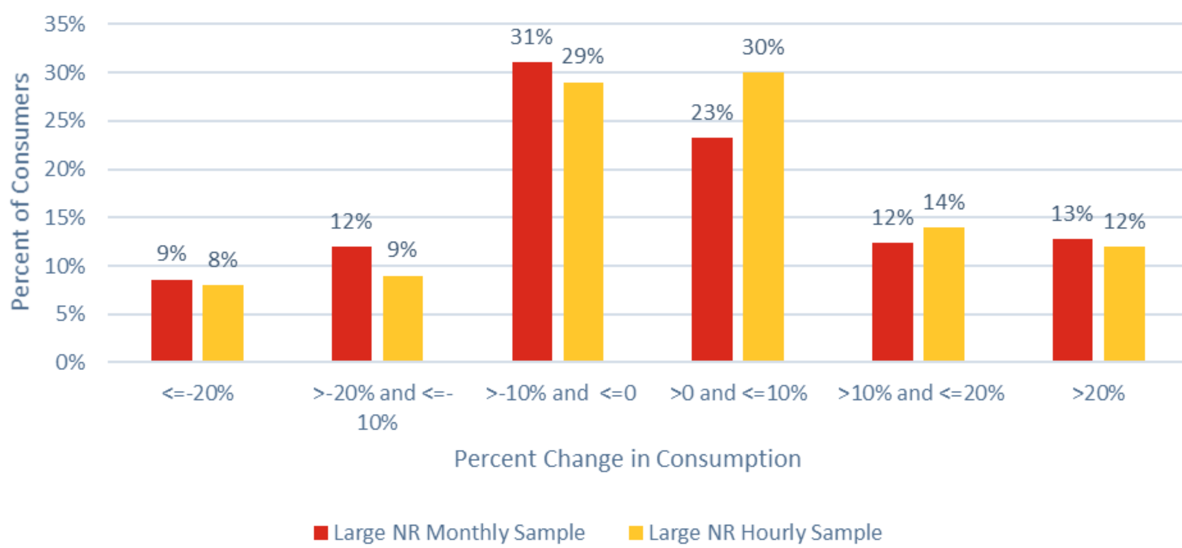
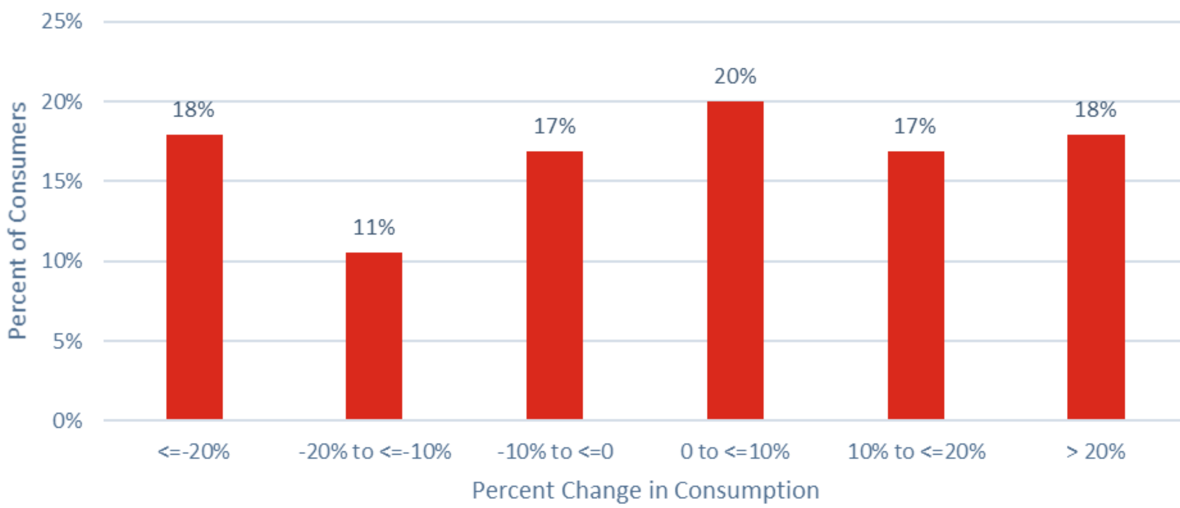


FIGURE D-6: PG&E LARGE NON-RESIDENTIAL SITES WEATHER-NORMALIZED CHANGE IN CONSUMPTION – MONTHLY AND HOURLY SAMPLES



The SCE residential weather-normalized change in consumption is illustrated in Figure D-7. There is no matching distribution from the hourly sample due to the small size of the residential hourly sample. SCE's monthly consumption change sample shows a slight increase in residential customer consumption following the installation of a PV system.

FIGURE D-7: SCE RESIDENTIAL SITES WEATHER-NORMALIZED CHANGE IN CONSUMPTION – MONTHLY SAMPLE



SCE's non-residential weather-normalized consumption change graph is provided in Figure D-8. Similar to PG&E, these data indicate that small non-residential customers have a larger share of sites increasing their consumption than decreasing their consumption following the installation of PV systems.

FIGURE D-8: SCE NON-RESIDENTIAL SITES WEATHER-NORMALIZED CHANGE IN CONSUMPTION – LARGE AND SMALL CUSTOMERS, MONTHLY AND HOURLY SAMPLES