



**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

FILED

04/02/24

04:59 PM

R1812006

Order Instituting Rulemaking to Regarding Transportation
Electrification Policy and Infrastructure.

Rulemaking 23-12-008

Not Consolidated

Order Instituting Rulemaking to
Continue the Development of Rates
and Infrastructure for Vehicle
Electrification.

Rulemaking 18-12-006

**JOINT COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY
(U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND PACIFIC GAS
AND ELECTRIC COMPANY (U 93 E) PURSUANT TO ORDERING PARAGRAPH 2
OF DECISION 16-06-011**

Rebecca Meiers-De Pastino

Walter C. Waidelich

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
Telephone: (626) 302-6016
E-mail: rebecca.meiers.depastino@sce.com

8330 Century Park Court
San Diego, CA 92123
Telephone: (858) 331-0806
Facsimile: (619) 69-5027
E-mail: wwaideli@sdge.com

Attorney for
SOUTHERN CALIFORNIA EDISON
COMPANY

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

Benjamin Ellis

300 Lakeside Drive
Oakland, CA 94612
Telephone: (415) 265-2678
E-mail: Ben.Ellis@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Date: April 2, 2024

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Regarding Transportation Electrification Policy and Infrastructure.

Rulemaking 23-12-008

Not Consolidated

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.

Rulemaking 18-12-006

JOINT COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND PACIFIC GAS AND ELECTRIC COMPANY (U 93 E) PURSUANT TO ORDERING PARAGRAPH 2 OF DECISION 16-06-011

Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), hereby file¹ their Electric Vehicle Charging Infrastructure Cost Report as required by Ordering Paragraph 2 of Decision 16-06-011 and the Administrative Law Judge Ruling Amending the Load Research Report Deadline for 2020 and Beyond issued on January 6, 2020. The report is attached to this pleading.²

¹ Pursuant to Commission Rule 1.8(d), PG&E and SDG&E have authorized SCE to file the attached compliance report on their behalf.

² D.16-06-011 issued in Rulemaking (R.) 13-11-007, R.18-12-006 (at 1) states that it is the “successor proceeding” to R.13-11-007. R.18-12-006, Assigned Commissioner’s Scoping Memo and Ruling (May 2, 2019) at 18, ¶9, directs the respondent utilities to continue filing the subject reports as provided by D.16-06-011. The Administrative Law Judge’s Ruling Amending Load Research Report Deadline for 2020 and Beyond (January 6, 2020) at 3, directs filing the reports “on March 31 of the given reporting year” going forward. Based on guidance from Commission Energy Division, the title of the attached report has been changed from the “Load Research Report” used in earlier reports.

Respectfully submitted,

/s/ Rebecca Meiers-De Pastino

By: Rebecca Meiers-De Pastino

Attorney for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Rosemead, CA 91770
Telephone: (626) 302-6016
E-mail: rebecca.meiers.depastino@sce.com

April 2, 2024

Attachment 1

Joint IOU EV Load and Cost Report

Joint IOU Electric Vehicle Load Research
and Charging Infrastructure Cost Report
and EV Infrastructure Rule Data Report #12
Filed on April 1, 2024

PUBLIC Version

Table of Contents

I.	Executive Summary.....	3
A.	IOU EV Adoption Forecasts.....	4
II.	Background.....	5
III.	Load Research and Customer Behavior on Rates in Various Settings.....	7
A.	Overview and Approach.....	7
B.	PG&E’s Load and Customer Behavior Data.....	8
C.	SCE’s Load and Customer Behavior Data.....	43
D.	SDG&E’s Residential EV Load and Customer Behavior Data.....	75
IV.	Cost Tracking Data.....	91
A.	Overview and Approach.....	91
B.	PG&E’s EV Infrastructure Cost Data.....	94
C.	SCE’s EV Infrastructure Cost Data.....	101
D.	SDG&E’s EV Infrastructure Cost Data.....	108
V.	EV Infrastructure Rule Data.....	111
A.	Overview and Approach.....	111
B.	PG&E’s EV Infrastructure Rule Data.....	113
C.	SCE’s EV Infrastructure Rule Data.....	114
D.	SDG&E’s EV Infrastructure Rule Data.....	115
	Attachment 1 – PG&E.....	117
	Attachment 2 – SCE.....	121
	Attachment 3 – SDG&E.....	125

I. Executive Summary

The Joint Investor-Owned Utility (IOU) Electric Vehicle (EV) Load Research and Charging Infrastructure Cost Report and EV Infrastructure Rule Data for 2023 (Report) examines EV customer charging behavior and service and distribution system upgrade costs related to EV load for California's three large investor-owned utilities (IOUs), including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), collectively the Joint IOUs. An examination of EV charging behavior and EV charging infrastructure costs within the Joint IOUs' territories can provide useful insights on the IOUs' support in helping accelerate widespread transportation electrification (TE). In this report, the Joint IOUs provide EV load and infrastructure costs by (1) pilot-programs and (2) rates or non-programs. Additionally, this report includes information on the IOU EV Infrastructure Rule (Rule 29 or 45¹) data reporting requirements that were directed within Resolutions E-5167 and E-5247. This is a PUBLIC version of this report. Certain information was redacted in PG&E's attachment and excel document to protect confidentiality. PG&E will submit its confidential information to the Commission separately.

To help attain its climate and air quality goals, California has set correspondingly aggressive TE goals, as the transportation sector is the largest source of greenhouse gas (GHG) emissions in the state.² California's aggressive TE goals include Governor Brown's Executive Order (E.O.) B-48-18, which sets a target of five million zero emission vehicles (ZEVs) on California's roads by 2030 and requires installation of 250,000 public charging stations, including 10,000 direct current fast charging (DCFC) stations in operation by 2025. Additionally, on September 23, 2020, Governor Gavin Newsom issued E.O. N-79-20, requiring the sale of all new passenger vehicles to be zero emission by 2035 and, where possible, directs all medium- and heavy-duty vehicles to be zero emission by 2045.

The California Air Resources Board (CARB) adopted the Advanced Clean Cars II Regulation on August 25, 2022, implementing the requirement for the sale of new passenger vehicles to be zero emission by 2035. CARB also adopted the Advanced Clean Fleet (ACF) regulation on April 28, 2023, establishing (1) a 100% medium-and heavy-duty zero emissions vehicle sales requirements beginning model year 2036 and codifying requirements for drayage trucks as well as high-priority, federal, and state and local government agency fleets.

The IOUs have and will continue to play a critical role in TE infrastructure deployment through the IOUs' core business of delivering electricity, supporting the installation of utility-side infrastructure for EV charging, and in the development and implementation of strategically designed ratepayer-funded pilots and programs that support the acceleration of TE.

¹ Rule 29 for SCE and PG&E and Rule 45 for SDG&E.

² CARB, *California Greenhouse Gas Emissions for 2000 to 2018: Trends of Emissions and Other Indicators* (2020 Edition), p. 5. https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2018/ghg_inventory_trends_00-18.pdf

A. IOU EV Adoption Forecasts

The EV market continues to evolve and grow with new vehicle models, larger battery sizes supporting increased charging levels, as well as more choices for charging equipment and charging services.

As of December 31, 2023, the IOUs estimate that more than 1.26 million EVs were on the roads in their service territories. The number of light-duty and medium- and heavy-duty EVs forecast to be operating in the IOUs service territories from 2024 through 2030 are provided in Table 1.

TABLE 1: IOU EV ADOPTION FORECASTS

	Light-duty EVs			Medium- and Heavy-Duty EVs		
Year	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
2024	786,408	755,548	184,611	1,492	24,179	1,044
2025	977,745	1,024,897	236,902	2,496	32,831	2,610
2026	1,211,601	1,379,679	298,574	4,800	44,385	3,915
2027	1,485,471	1,785,783	368,403	8,731	57,534	4,959
2028	1,800,062	2,155,821	446,546	14,367	72,194	6,264
2029	2,154,545	2,498,025	532,517	21,735	88,005	7,569
2030	2,552,499	2,904,022	626,409	30,855	105,006	8,770

Each IOU may use a different methodology to forecast EVs in their service territory. Details on the methodology, and expanded forecast, can be found in Table 1 of the corresponding IOUs' attachments submitted in conjunction with this report.

II. Background

On July 25, 2011, the Commission issued Decision (D.)11-07-029 (the Phase 2 Decision) in the Alternative-Fueled Vehicle Order Instituting Rulemaking (R.) 09-08-009 (AFV OIR), to evaluate policies and develop infrastructure sufficient to overcome barriers for the deployment and use of EVs in California. The Phase 2 Decision of the AFV OIR determined that EV load is new and permanent under Electric Rules 15 and 16 and adopted the interim policy of treating the residential EV charging costs that exceed the allowances in Rules 15 and 16 as common facility costs. The Phase 2 Decision also ordered the California Joint IOUs, to conduct research to examine EV customer charging behavior, as well as track service and distribution system upgrade costs related to EV load. The IOUs filed the first Joint IOU Electric Vehicle Load Research Report (Load Research Report) in December 2012. In D.13-06-014, issued July 3, 2013 (the First Extension Decision), the Commission extended the research for an additional three years⁶ with reports to begin in December 2013.³ The First Extension Decision also directed the Energy Division to work with stakeholders to revise the load research methodology.⁴ In D.16-06-011, issued on June 13, 2016 (the Second Extension Decision), the Commission extended the interim policy of treating the residential electric vehicle charging costs that exceed the allowances in the Electric Rules 15 and 16 of the three IOUs as common facility costs for another three years, to June 30, 2019.⁵ In addition, the annual filing requirement of the Load Research Reports was extended by another three years.

On December 19, 2018, the Commission issued the DRIVE OIR (R.18-12-006) and directed the Energy Division staff to consider “whether Load Research Reports include all relevant data and whether or how to direct the IOUs to continue filing Load Research Reports.”⁶ The subsequent Scoping Memo, issued May 2, 2019, directed the IOUs to incorporate cost data related to EV infrastructure upgrades for commercial customer sites in the 2020 report and extended the interim treatment for Electric Rules 15 and 16 allowances to December 31, 2019.¹¹ An ALJ Ruling as part of R.18-12-006 extended the interim treatment policy once again to December 31, 2021.¹² On November 5, 2019, the IOUs sent a letter to CPUC Executive Director requesting permission to delay the filing of the 2020 report from January 31, 2020 to March 31, 2020 and to adjust the content of the report. On January 6, 2020, the Administrative Law Judge (ALJ) issued a *Ruling Amending the Load Research Report Deadline for 2020 and Beyond*.⁷ The ALJ Ruling established March 31 as the filing deadline for the 2020 report and any subsequent Electric Vehicle Load Research Reports.¹⁴

On October 8, 2021, the Commission issued Resolution E-5167 approving with modifications the requests from PG&E, SCE, and SDG&E to establish new EV Infrastructure Rules (i.e., Rules 29 and 45) and associated Memorandum Accounts, pursuant to Assembly Bill (AB) 841. Among other things, Ordering Paragraph (OP) 9 of Resolution E-5167 directed the Energy Division in consultation with the Joint IOUs

³ D.13-06-014, Ordering Paragraph 4.

⁴ D.13-06-014, Ordering Paragraph 3.

⁵ D.16-06-011, Ordering Paragraph 2.

⁶ R.18-12-006, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007, December 19, 2018, p. 15.

⁷ R.18-12-006, Administrative Law Judge’s *Ruling Amending Load Research Report Deadline for 2020 and Beyond*, January 6, 2020, p.3. The ALJ Ruling approves filing the report on March 31 of the given reporting year going forward.

and other stakeholders to finalize a data collection template related to the EV Infrastructure Rules. The Energy Division and Joint IOUs collaborated on an EV Infrastructure Rule template, which the Energy Division posted on the Commission's website and the IOUs will be including in these reports.

Additionally, the Commission issued Resolution E-5247 on December 15, 2022, adopting an interim service energization timeline for the IOUs' EV Infrastructure Rules and establishing a requirement for the IOUs to collect and report timeline data for the EV Infrastructure Rules.⁸ These requirements will be further addressed within the new EV Infrastructure Rule section (section V) of this report.

⁸ Resolution E-5247, OP 4, p. 32.

III. Load Research and Customer Behavior on Rates in Various Settings

A. Overview and Approach

This report provides residential and commercial EV load from January 2023 through December 2023 by (1) rate and (2) pilot and programs. The report reflects Commission requirements, including the Phase 2 Decision directive that the IOUs:

1. Track and quantify all new load and associated upgrade costs in a manner that allows EV load and related costs to be broken out and specifically identified. This information shall be collected and stored in an accessible format useful to the Commission.
2. Evaluate how metering arrangements and rate design impact plug-in EV (PEV) charging behavior.
3. To the extent relevant, determine whether participation in demand response programs impacts EV charging behavior.
4. Determine how charging arrangements, including metering options and alternative rate schedules impact charging behavior at multi-dwelling units (MDU).⁹

This metering data provides the basis for analyzing how charging behavior is impacted by tariff rates or charging levels. Additionally, the recorded data allowed for the evaluation of metering scenarios on PEV charging behavior for customers in the following residential categories:¹⁰

- Single family home (SF)
- Multi family dwelling unit (MDU)
- Net energy metering (NEM)

Distinctions between single metering and separate metering are shown, as well as NEM participation. The usage and demand of customers were tracked in each rate group. The goal of this structure was to determine how monthly usage varies, how rates impact peak demand, and how usage varies by time-of-use rate among different groups of customers. A baseline for residential customers has been analyzed for context in the form of an average for a month during the season being examined.

To the extent possible, the IOUs provided similar information for easy comparisons. However, there are some cases where this is simply not possible due to differences in the underlying IOU data. Metrics with less than 15 customers are clearly noted and not reported without prior notice due to confidentiality concerns described in the 15/15 Rule adopted by the Commission in Decision 97-10-031 and Decision 14-05-016. All time periods are reported in 24-hour time. SCE's load profiles are reported in Pacific Standard Time while PG&E and SDG&E are provided in prevailing time. Time-of-use periods vary across the IOUs and will be explicitly defined within each IOU section.

⁹ D.11-07-029, Ordering Paragraph 6.

¹⁰ The MDU and SF categories are mutually exclusive. However, the other categories can overlap. For example, a NEM customer that is also on DR would appear in three categories.

B. PG&E's Load and Customer Behavior Data

Load and utilization across PG&E's EV-specific rates and a portion of the Transportation Electrification Programs are reported in the following sections. The study period covers the full calendar year of 2023. PG&E's rates during the study period included residential and commercial products. The residential rates reported include PG&E's Single-Metered Rates (EV-A and EV2-A) and a Separately-Metered Rate (EV-B). However, EV-A was closed to new enrollments with the introduction of EV2-A in July 2019 and most customers were fully transitioned to the EV2-A rate by the end of 2019. The load data for single-metered residential customers in 2023 reflects both EV-A and EV2-A customers.

PG&E launched the BEV-1 and BEV-2 rates in May 2020 for commercial customers. Load data for both rates is reported for the 2023 calendar year. Additionally, utilization and load data for light-duty infrastructure and medium duty/heavy duty infrastructure installed as part of PG&E's Transportation Electrification Programs is reported for the 2023 calendar year. Principally, utilization is from charging infrastructure installed as part of the Electric Vehicle Charge Network (EVCN) program, DC Fast Charge, and the EV Fleet Program.

Residential PEV Rates

Single-Metered and Separately-Metered PEV Residential Rates

As of the date of this report, PG&E has two residential EV rates open to customers, one for single-metered customers (EV2-A) and another for separately-metered customers (EV-B). A previous version of the single-metered rate was closed to new customers in July 2019. The single-metered rate is a residential whole home rate that applies to both typical household electric load and electric vehicle charging on the same meter. The separately-metered rate is designed for customers who wish to bill their vehicle charging separately and requires the installation of a separate meter to do so. Both rate plans use an un-tiered TOU rate structure. They offer on-peak, partial peak, and off-peak energy prices according to the time periods in Table PG&E-1. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. The single-metered rate includes off-peak hours from 12:00 a.m. to 3:00 p.m., and the separately-metered rate from 11:00 p.m. to 7:00 a.m. The separately-metered rate also encourages weekend usage by limiting peak periods to 3:00 p.m. to 7:00 p.m. and expanding the "off-peak" period to all other remaining hours on weekends and holidays.

Table PG&E-1: Tariff Type and Rate (\$/kWh) in 2023
Rates Effective Sep 1, 2023 thru Dec 31, 2023

Rate: EVA					Rate: EV2A			Rate: EVB				
Hour	Winter	Winter	Summer	Summer	Hour	Winter	Summer	Hour	Winter	Winter	Summer	Summer
	Weekday	Weekend / Holidays	Weekday	Weekend / Holidays		All days including Holidays	All days including Holidays		Weekday	Weekend / Holidays	Weekday	Weekend / Holidays
12mn - 1am	0.25922	0.25922	0.28890	0.28890	12mn - 1am	0.27818	0.27818	12mn - 1am	0.25624	0.25624	0.28586	0.28586
1am - 2am	0.25922	0.25922	0.28890	0.28890	1am - 2am	0.27818	0.27818	1am - 2am	0.25624	0.25624	0.28586	0.28586
2am - 3am	0.25922	0.25922	0.28890	0.28890	2am - 3am	0.27818	0.27818	2am - 3am	0.25624	0.25624	0.28586	0.28586
3am - 4am	0.25922	0.25922	0.28890	0.28890	3am - 4am	0.27818	0.27818	3am - 4am	0.25624	0.25624	0.28586	0.28586
4am - 5am	0.25922	0.25922	0.28890	0.28890	4am - 5am	0.27818	0.27818	4am - 5am	0.25624	0.25624	0.28586	0.28586
5am - 6am	0.25922	0.25922	0.28890	0.28890	5am - 6am	0.27818	0.27818	5am - 6am	0.25624	0.25624	0.28586	0.28586
6am - 7am	0.25922	0.25922	0.28890	0.28890	6am - 7am	0.27818	0.27818	6am - 7am	0.25624	0.25624	0.28586	0.28586
7am - 8am	0.33095	0.25922	0.40145	0.28890	7am - 8am	0.27818	0.27818	7am - 8am	0.32797	0.25624	0.39841	0.28586
8am - 9am	0.33095	0.25922	0.40145	0.28890	8am - 9am	0.27818	0.27818	8am - 9am	0.32797	0.25624	0.39841	0.28586
9am - 10am	0.33095	0.25922	0.40145	0.28890	9am - 10am	0.27818	0.27818	9am - 10am	0.32797	0.25624	0.39841	0.28586
10am - 11am	0.33095	0.25922	0.40145	0.28890	10am - 11am	0.27818	0.27818	10am - 11am	0.32797	0.25624	0.39841	0.28586
11am - 12nn	0.33095	0.25922	0.40145	0.28890	11am - 12nn	0.27818	0.27818	11am - 12nn	0.32797	0.25624	0.39841	0.28586
12nn - 1pm	0.33095	0.25922	0.40145	0.28890	12nn - 1pm	0.27818	0.27818	12nn - 1pm	0.32797	0.25624	0.39841	0.28586
1pm - 2pm	0.33095	0.25922	0.40145	0.28890	1pm - 2pm	0.27818	0.27818	1pm - 2pm	0.32797	0.25624	0.39841	0.28586
2pm - 3pm	0.46296	0.25922	0.64556	0.28890	2pm - 3pm	0.27818	0.27818	2pm - 3pm	0.45998	0.25624	0.64252	0.28586
3pm - 4pm	0.46296	0.46296	0.64556	0.64556	3pm - 4pm	0.44687	0.48019	3pm - 4pm	0.45998	0.45998	0.64252	0.64252
4pm - 5pm	0.46296	0.46296	0.64556	0.64556	4pm - 5pm	0.46357	0.59068	4pm - 5pm	0.45998	0.45998	0.64252	0.64252
5pm - 6pm	0.46296	0.46296	0.64556	0.64556	5pm - 6pm	0.46357	0.59068	5pm - 6pm	0.45998	0.45998	0.64252	0.64252
6pm - 7pm	0.46296	0.46296	0.64556	0.64556	6pm - 7pm	0.46357	0.59068	6pm - 7pm	0.45998	0.45998	0.64252	0.64252
7pm - 8pm	0.46296	0.25922	0.64556	0.28890	7pm - 8pm	0.46357	0.59068	7pm - 8pm	0.45998	0.25624	0.64252	0.28586
8pm - 9pm	0.46296	0.25922	0.64556	0.28890	8pm - 9pm	0.46357	0.59068	8pm - 9pm	0.45998	0.25624	0.64252	0.28586
9pm - 10pm	0.33095	0.25922	0.40145	0.28890	9pm - 10pm	0.44687	0.48019	9pm - 10pm	0.32797	0.25624	0.39841	0.28586
10pm - 11pm	0.33095	0.25922	0.40145	0.28890	10pm - 11pm	0.44687	0.48019	10pm - 11pm	0.32797	0.25624	0.39841	0.28586
11pm - 12mn	0.25922	0.25922	0.28890	0.28890	11pm - 12mn	0.44687	0.48019	11pm - 12mn	0.25624	0.25624	0.28586	0.28586

Legend:

	Winter	Summer
On		
Part		
Off		

* While the table depicts 24-hour time, there is a daylight-saving time adjustment as described in the tariff.

** Rates effective through December 31, 2023. For details see Electric Schedule EV, Residential Time-of-Use Service for Plug-in Electric Vehicle Customers, retrieved from [https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS EV%20\(Sch\).pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS EV%20(Sch).pdf)

These rates change seasonally, generally rising in summer and dropping in winter. Table PG&E-2 depicts price ratios for the TOU periods by season to illustrate this seasonal difference.

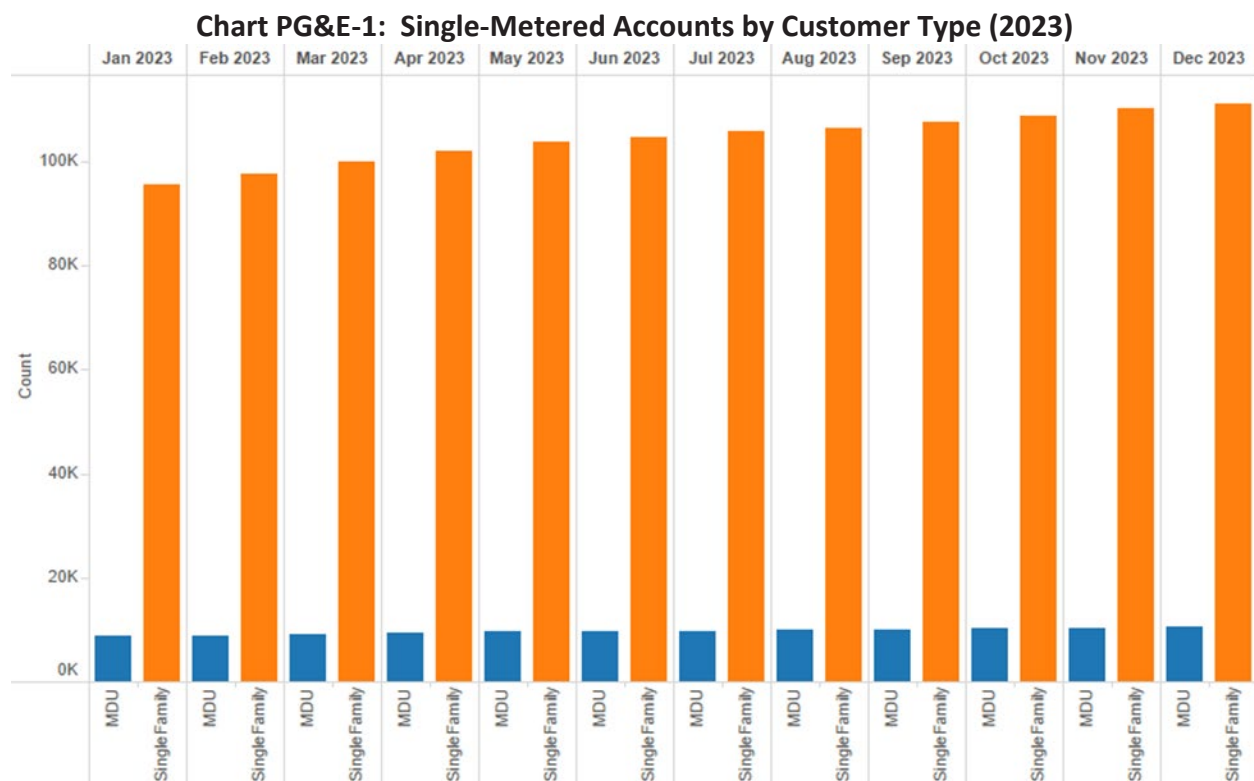
Table PG&E-2: Price Ratios for 2023

Season	EV-A		EV2-A		EV-B	
	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak
Winter	0.78	0.56	0.78	0.56	0.62	0.60
Summer	0.72	0.45	0.72	0.44	0.58	0.47

Single-Metered Rate Growth

Participation in the single-metered PEV rate showed a steady increase during 2023, the duration of the study period, as seen in Chart PG&E-1. Participation in the single-metered PEV rate showed a notable increase among Single Family (SF) customers while enrollment remained relatively steady among multi-dwelling unit (MDU)¹¹ customers during 2023. It is important to note that not all EV customers have adopted PEV rates.¹² Of the customers on PEV rates, the majority are on the single-metered rate.

All Single-Metered Customers: Chart PG&E-1, below, displays the total customers on the single-metered PEV rate in 2023. During the study period, there was a notable increase in single-metered rate enrollment overall, primarily in the SF subcategories. The number of accounts in the single-metered group as a whole increased by 16% between January and December in 2023.



NEM Single-Metered Customers: NEM customers on the PEV rates are an important group to consider. Of all the PG&E customers who were on the single-metered rate, up to 42% were also on NEM at any

¹¹ Multi-dwelling units (MDUs) are defined as a residential unit with a shared wall (e.g. condo or townhouse) and are distinct from multi-unit dwellings (MUDs) (e.g. apartment buildings), which is a term used in this report to refer to a multi-family housing site that is part of a TE Program and could be enrolled in a commercial rate.

¹² The load research figures in this report only represent the number of PG&E PEV customers on PEV rates, not all PEV customers.

given time during the one-year study period. Virtually all dual PEV Rate/NEM customers were on the single-metered rate (see Table PG&E-3).

The fact that NEM customers with PEVs predominately use the single-metered rate presents a load research challenge. The presence of onsite distributed generation (DG) alongside a PEV behind these customers' meters indicates that their utility energy usage data does not reflect their gross consumption. This is because the DG will have offset some portion of consumption. However, without additional metering of the DG, it is not feasible to isolate the effect PEV ownership has on usage patterns for this group using utility metering data alone.¹³

Table PG&E-3: Single-Metered NEM Program Enrollment by Customer Type (2023)

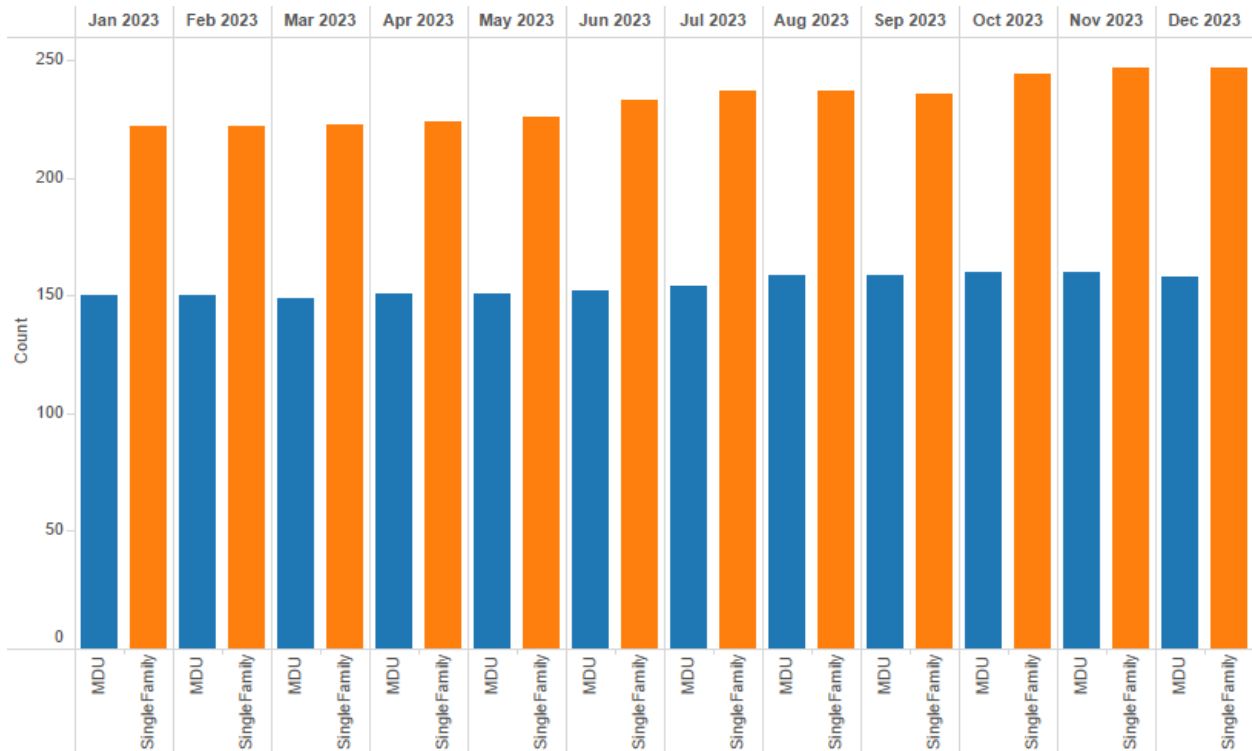
Year	Month	Number of All Single-Metered NEM Enrollments	NEM % of All Single-Metered	NEM % of SF Single-Metered	NEM % of MDU Single-Metered
2023	Jan	39,861	39%	34%	1%
2023	Feb	35,218	37%	34%	1%
2023	Mar	40,927	39%	35%	1%
2023	Apr	37,830	38%	35%	1%
2023	May	41,533	39%	35%	1%
2023	Jun	40,856	38%	35%	1%
2023	Jul	41,868	38%	35%	1%
2023	Aug	46,399	42%	36%	1%
2023	Sep	38,991	39%	36%	1%
2023	Oct	45,335	40%	36%	1%
2023	Nov	41,746	38%	36%	1%
2023	Dec	42,015	38%	36%	1%

Separately-Metered Rate Growth

All Separately-Metered Customers: The separately-metered PEV rate remains a less popular option for PEV rate customers than the single-metered PEV rate. As shown in Chart PG&E-2, compared to the single-metered rate, there was lower participation with the number of customers enrolled. The number of accounts in the separately-metered group as a whole increased by 9% between January and December in 2023. While the installation of a separate meter for EV charging could be financially challenging for some customers, submetering may be another option for accessing EV rates for customers interested in separating their EV load.

¹³ While there are numerous other demographic and behavioral attributes of this early PEV adopter group that affect usage, there was insufficient data or resources to isolate and identify their contribution to load shapes.

Chart PG&E-2: Separately-Metered Accounts by Customer Type (2023)



NEM Separately-Metered Customers: There were only a small number of PEV rate customers on the separately-metered PEV rate enrolled in NEM in 2023, and therefore the specific enrollment numbers cannot be shared publicly. As shown in Table PG&E-4, the number of separately-metered customers enrolled in NEM remained relatively flat during the study period. The single-metered PEV rate continues to be the more popular option for PEV customers wishing to offset their charging with DG.

Table PG&E-4: Separately-Metered NEM Program Enrollment by Customer Type (2023)

Year	Month	Number of Separately-metered NEM Enrollments	NEM % of Separately-metered	NEM % of SF Separately-metered	NEM % of MDU Separately-metered
2023	Jan	<100	<10%	<10%	<10%
2023	Feb	<100	<10%	<10%	<10%
2023	Mar	<100	<10%	<10%	<10%
2023	Apr	<100	<10%	<10%	<10%
2023	May	<100	<10%	<10%	<10%
2023	Jun	<100	<10%	<10%	<10%
2023	Jul	<100	<10%	<10%	<10%
2023	Aug	<100	<10%	<10%	<10%
2023	Sep	<100	<10%	<10%	<10%
2023	Oct	<100	<10%	<10%	<10%
2023	Nov	<100	<10%	<10%	<10%

2023	Dec	<100	<10%	<10%	<10%
------	-----	------	------	------	------

Notes of Caution Regarding Reliance upon Load Research Data

The reader should take careful note of the following issues that make the load research data ill-suited for drawing conclusions for policymaking at this time.

- While PEV ownership has increased, it is still largely comprised of early adopters who are likely to be materially different than future PEV owners. These differences could include, but are not limited to: income, commuting patterns, pre-PEV ownership usage habits, NEM penetration, altruistic tendencies, and willingness/ability to adopt usage patterns beneficial to grid stability.
- New vehicles and charging requirements may lead to changes in charging profiles in the future (i.e., differing charging demands and durations) as more PEVs and technologies are made available in the market.
- The customer counts are growing but were still relatively small in all cases. This is particularly true for separately-metered PEV rate data derived from PG&E’s load research sample. The mix of customers being evaluated changed over time due to customers joining or leaving the single-metered or separately-metered PEV rates.
- While PEV charging for the single-metered PEV rate may be more easily identifiable if it takes place during off-peak rate periods when there is low electric consumption from other sources, the lack of on-site survey or end use data to help disaggregate other loads from PEV charging prevents the identification of PEV charging in other periods (particularly partial-peak) where multiple significant loads are likely present.

Therefore, while the data collected are illustrative of the behaviors of early adopters based on the types of vehicles that are currently available in the market, one cannot conclude that these behavior patterns will hold as PEV technology matures, as charging technology and charging behaviors evolve, and as PEVs achieve greater market adoption beyond the early adopter phase. PG&E will continue to collect and report load data from residential EV rate customers via this report, but specific learnings to influence policy should be obtained via an appropriately funded and carefully designed study that controls for the above issues.

Average Monthly Usage for PEV Rate Customers

Keeping in mind the above cautions about the data collected, Chart PG&E-3 displays the average monthly usage for single-metered customers with NEM during 2023, which means that the average monthly usage of these categories is net of behind-the-meter generation. Chart PG&E-4 displays the average monthly usage for each single-metered category without NEM.

Chart PG&E-3: Single-Metered Average Monthly Usage (kWh) by Customer Type with NEM (2023)

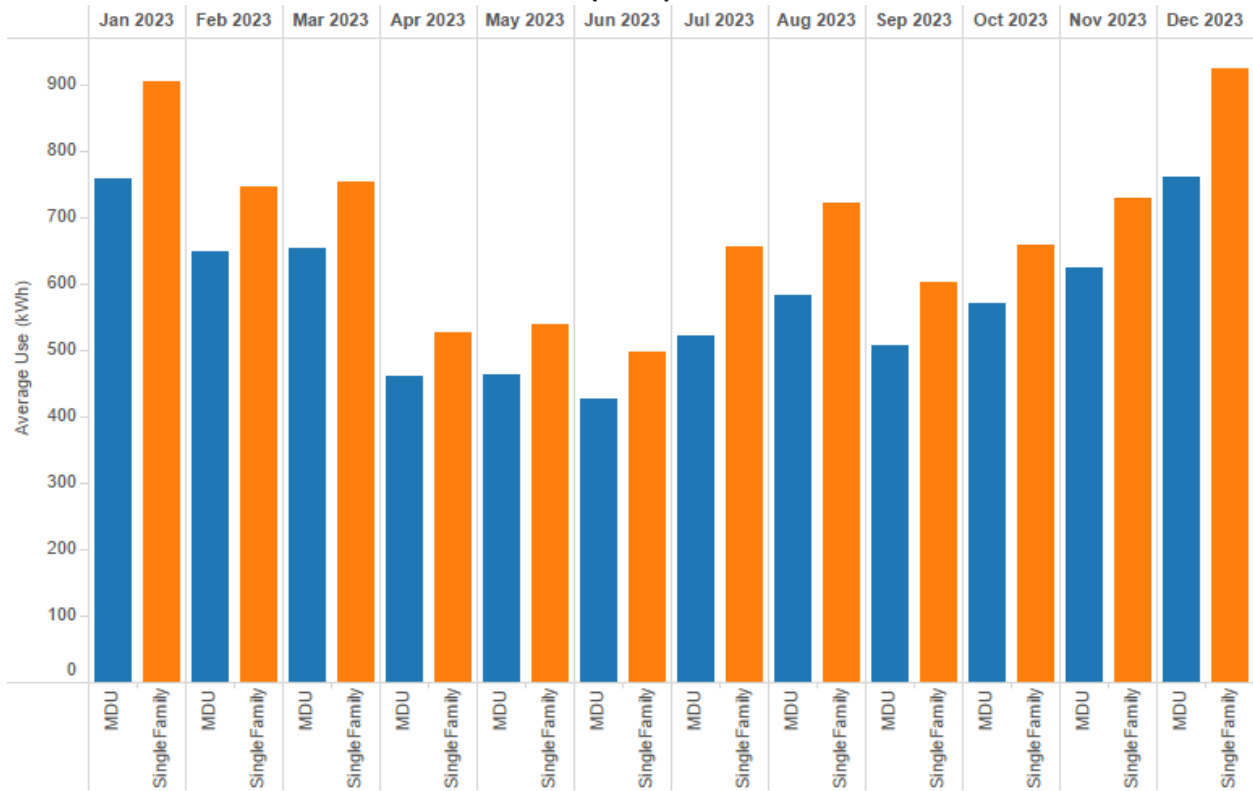
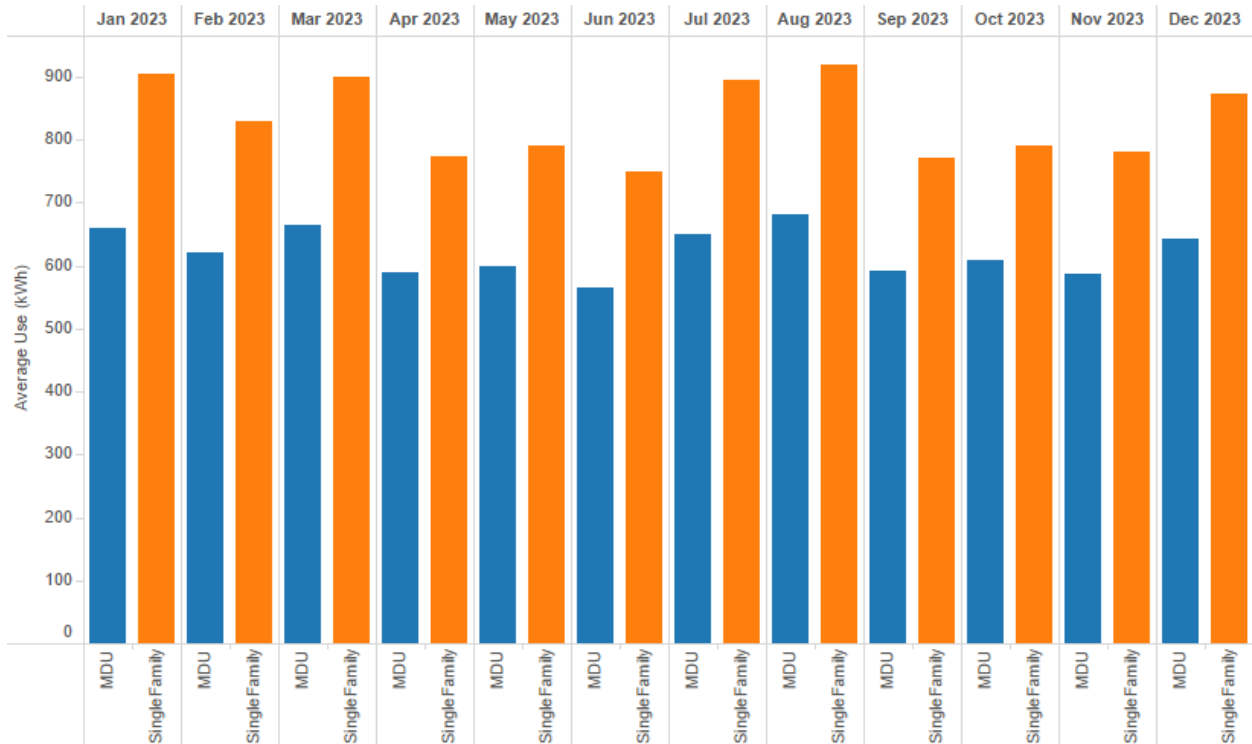


Chart PG&E-4: Single-Metered Average Monthly Usage (kWh) by Customer Type Without NEM (2023)



A comparison of customers with NEM and customers without NEM for 2023 reveals an unsurprising result for both sectors: absent the NEM accounts, usage is relatively flatter for PEV rate customers throughout the study period. This result demonstrates that offsetting consumption with behind-the-meter generation obfuscates researchers’ ability to parse PEV load from other site loads for NEM customers using their consumption data alone. Average usage for customers without NEM across months was relatively flat in 2023.

In Chart PG&E-5, NEM customers are not segregated among separately-metered customers because the average use (kWh) cannot be shared publicly due to the low penetration among separately-metered customers.

Chart PG&E-5: Separately-Metered Average Monthly Usage (kWh) by Customer Type (2023)

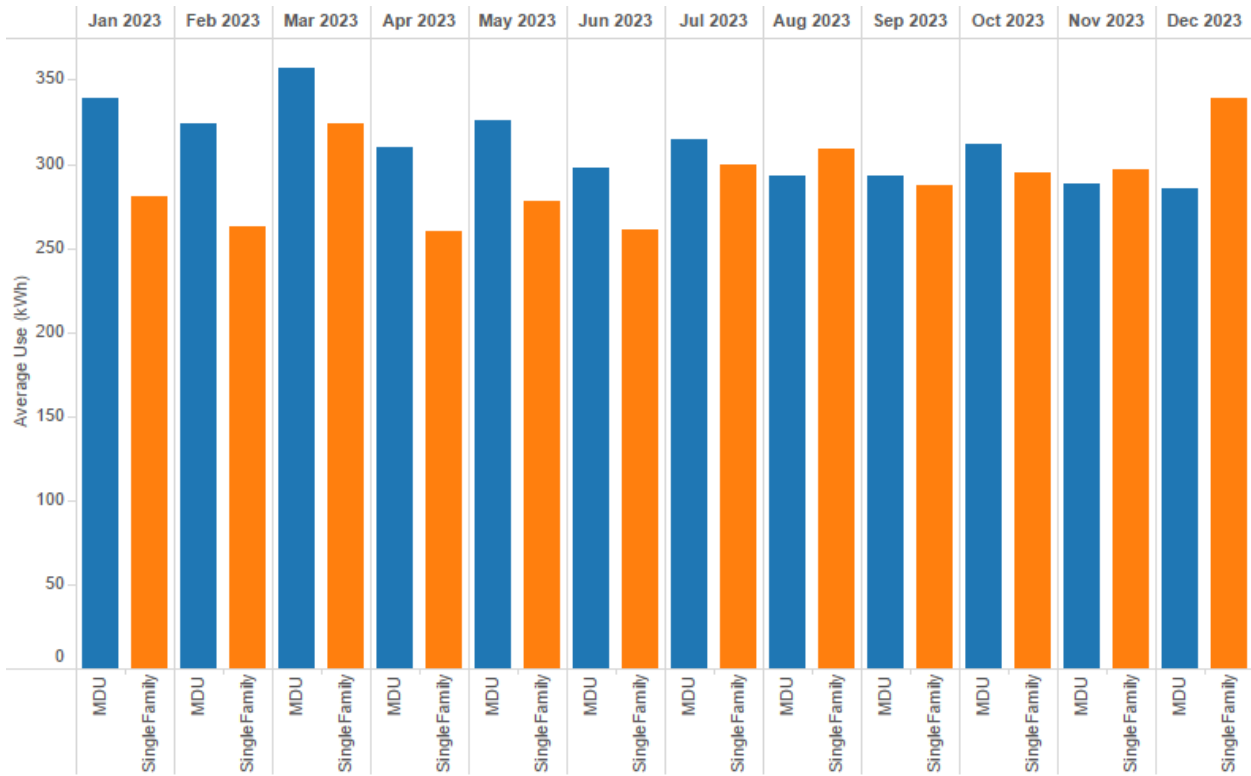


Chart PG&E-5 shows that, absent other loads on the meter, researchers can better observe PEV rate customers’ total charging. The results in Chart PG&E-5 show a relatively varied usage in 2023 for SF customers, with some spikes in March and December. MDU customers showed higher usage during the first half of the year.

Average Usage during Time of Use Periods

TOU PEV rates are designed to discourage charging during peak hours and instead encourage charging during off-peak hours when the grid is less stressed and generation costs are lower. For single-metered and separately-metered customers, the time of use periods in 2023 are defined in Table PG&E-1.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods. Given that NEM customers have a very unique usage profile, they are segregated from all other single-metered customer groups in Tables PG&E-5-7. Note that for the customer usage comparisons, single-metered and separately-metered customers are independently compared to the general population per their respective TOU schedules.¹⁴

¹⁴ For the total residential population data, January to December 2022 data was used to compare to the 2023 PEV data due to the fact that 2023 total residential data is not available until July 2024.

Collectively, Tables PG&E-5 – PG&E-7 below show that customers on both rates are shifting their usage from peak hours to off-peak hours. Specifically, separately-metered customers are completing, on average, over 75% of their charging during the off-peak period and less than 15% during the peak period. Single-metered customers without NEM are using over 65% of their energy during off-peak periods, as well. This suggests that customers on the PEV rates are responding effectively to their rates' price signals and charging during the off-peak periods.

Table PG&E-5 shows the share of peak usage by sector for single-metered and separately-metered PEV customers with and without NEM and compares it to the peak usage of PG&E’s entire residential population. In 2023, the share of energy usage during on-peak hours between customers on the single-metered PEV rate and the general population was very similar. Customers without NEM had an average share of on-peak usage that was 4% less than that of the general population. Similarly, those with NEM had the same during the peak period. The similarity in share of usage during on-peak hours could be a result of increased enrollment in residential TOU rates outside of the PEV rates, as well continued work-from-home arrangements during 2023, causing a shift in overall home utilization throughout the day for the general customer population.

Separately-metered customers showed much lower shares of their usage during peak hours compared to the general population. Customers without NEM used energy an average of 18% less during the peak period than the entire residential population, while their NEM counterparts used energy 17% less during that time. As previously noted, the small customer population of NEM customers on EV-B detracts from the meaningfulness of results produced by its data. Because the goal of PEV rates is to encourage customers to charge their vehicles during off-peak hours, the fact that PEV rate customers’ peak period usage is less than a third of their overall usage indicates that the PEV TOU rates are achieving this goal among early PEV adopters.

Table PG&E-5: Share of On-Peak Usage by Tariff and Customer Type (2023)

		Single-Metered (On-Peak 4 PM - 9 PM)					Separately-Metered (On-Peak 2 PM - 9 PM)				
Year	Season	Total Residential Population* Per Single Metering Tariff	All Single Metering, excluding NEM	SF Single Metering, excluding NEM	MDU Single Metering, excluding NEM	Single Metering NEM	Total Residential Population* Per Separate Metering Tariff	All Separate Metering, excluding NEM	SF Separate Metering, excluding NEM	MDU Separate Metering, excluding NEM	Separate Metering NEM
2023	Summer	24%	20%	20%	19%	24%	32%	12%	11%	13%	12%
2023	Winter	21%	18%	19%	18%	22%	27%	12%	10%	14%	13%
	Max	24%	20%	20%	19%	24%	32%	12%	11%	14%	13%
	Avg	23%	19%	19%	18%	23%	30%	12%	11%	14%	13%

*Residential load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

Table PG&E-6 shows the off-peak share of usage by sector for customers on both rates, with and without NEM, and compares it to the off-peak share of usage of PG&E’s entire residential population. During 2023, single-metered PEV customers showed similar usage to the general population. PEV Customers without NEM had 6% more of their share during off-peak hours, while their NEM counterparts’ share was 2% lower. The similarity in share of usage during off-peak hours for single-metered customers could be a result of the same factors mentioned above.

Non-NEM separately-metered customers used an average of 35% more energy than the general population, and NEM customers on the same rate also used 36% more. Customers on both PEV rates were in line with previous trends and met the off-peak performance expectations consuming most of their energy during this period.

Table PG&E-6: Share of Off-Peak Usage by Tariff and Customer Type (2023)

		Single-Metered (Off-Peak 12AM - 3 PM)					Separately-Metered (Off-Peak 11 PM - 7 AM)				
Year	Season	Total Residential Population* Per Single Metering Tariff	All Single Metering, excluding NEM	SF Single Metering, excluding NEM	MDU Single Metering, excluding NEM	Single Metering NEM	Total Residential Population* Per Separate Metering Tariff	All Separate Metering, excluding NEM	SF Separate Metering, excluding NEM	MDU Separate Metering, excluding NEM	Separate Metering NEM
2023	Summer	58%	64%	64%	66%	55%	39%	77%	79%	74%	77%
2023	Winter	62%	67%	67%	68%	61%	43%	76%	79%	72%	76%
	Max	62%	67%	67%	68%	61%	43%	77%	79%	74%	77%
	Avg	60%	66%	65%	67%	58%	41%	76%	79%	73%	77%

*Residential load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

Table PG&E-7 shows the share of partial peak usage by sector for customers on both PEV rates, with and without NEM, and compares it to the partial peak usage of PG&E’s entire residential population. In 2023, single-metered PEV customers had similar share of usage to the general population. PEV Customers without NEM experienced almost the same share of demand during the partial-peak period as the general population – 2% less – while those with NEM were 2% higher.

Separately-metered customers had a noticeably lower share of usage during the partial-peak period compared to the general population. Customers without NEM used an average of 17% less energy, and those with NEM used 18% less. In general, these groups met the performance expectations for their PEV rate by consuming less energy during the partial peak period than the off-peak period.

Table PG&E-7: Share of Partial-Peak Usage by Tariff and Customer Type (2023)

		Single-Metered (Partial-Peak 3 PM - 4 PM, 9 PM - 12 AM)					Separately-Metered (Partial-Peak 7 AM - 2 PM, 9 PM - 11 PM)				
Year	Season	Total Residential Population* Per Single Metering Tariff	All Single Metering, excluding NEM	SF Single Metering, excluding NEM	MDU Single Metering, excluding NEM	Single Metering NEM	Total Residential Population* Per Separate Metering Tariff	All Separate Metering, excluding NEM	SF Separate Metering, excluding NEM	MDU Separate Metering, excluding NEM	Separate Metering NEM
2023	Summer	18%	16%	16%	15%	21%	29%	11%	10%	12%	10%
2023	Winter	17%	15%	15%	14%	17%	29%	12%	11%	14%	11%
	Max	18%	16%	16%	15%	21%	29%	12%	11%	14%	11%
	Avg	17%	15%	15%	15%	19%	29%	12%	11%	13%	11%

*Load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

Average Load Profiles for PEV Rates

Depicted below in Charts PG&E-6 and PG&E-7 are the average daily load profiles for the single-metered and separately-metered rate groups for each sector during 2023. In 2023, the load profiles demonstrate that for all rates and sectors, high off-peak usage corresponds to the PEV rate price signals, i.e., customers are largely responding to the price signal and primarily charging during off-peak hours (12:00 a.m. to 3:00 p.m. with the bulk of the load occurring from 12:00 a.m. to 5:00 a.m.). The load profile during 2023 for both SF and MDU customers shows a spike in demand at midnight with a second smaller spike during the peak-hour period 6:00 p.m. to 10 p.m. The response to price signals is more clearly depicted in the data from the separately-metered customers (Chart PG&E-7) where the majority of the usage occurs during off-peak hours during 2023.

Chart PG&E-6: Average Load Profile for SF and MDU Single-Metered by Weekday and Weekend (2023)

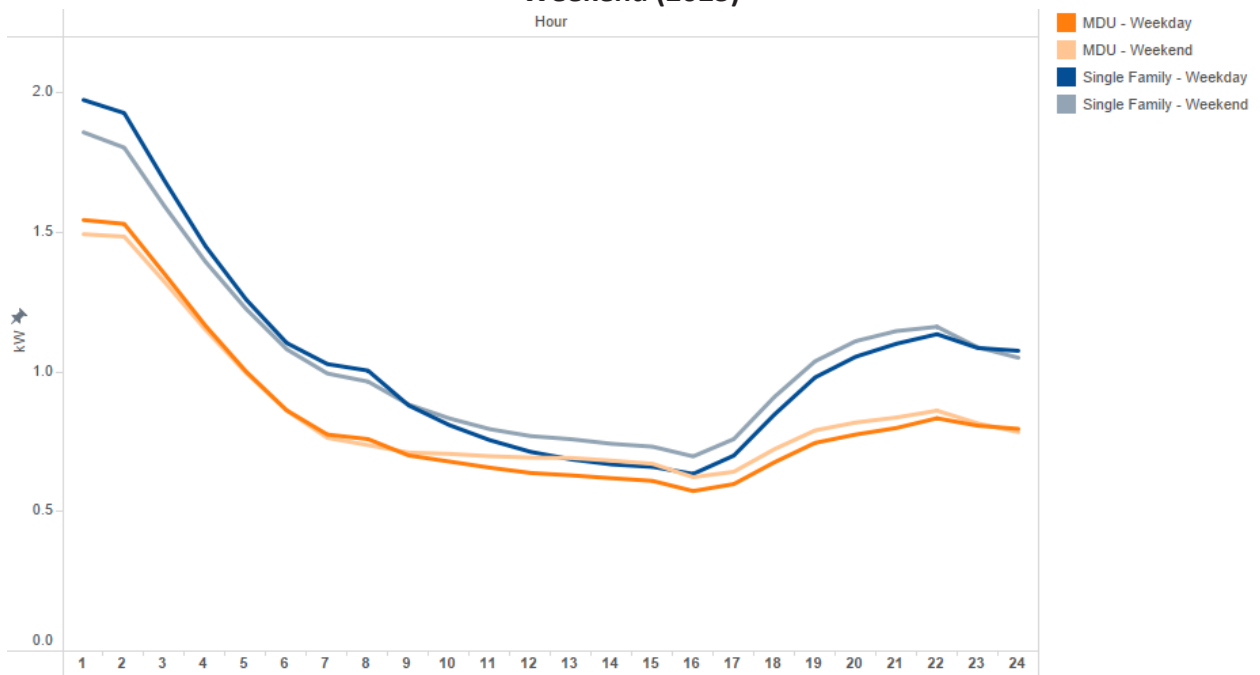
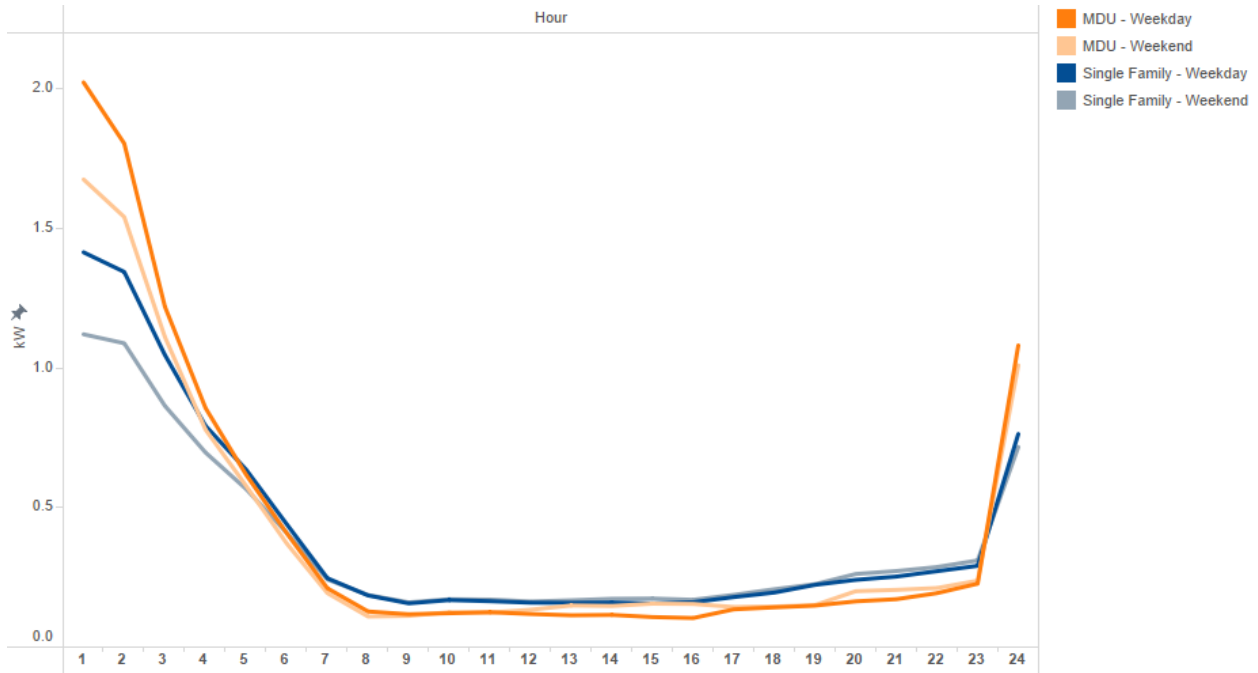


Chart PG&E-7: Average Load Profile for SF and MDU Separately-Metered by Weekday and Weekend (2023)



Non-Coincident Peak Load

Collectively, the data in Table PG&E-8, and Charts PG&E-8 – PG&E-9 suggest that, even though charging is primarily occurring in the off-peak hours, the average household with a PEV will have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.

- Table PG&E-8 shows the monthly comparison of the average non-coincident peak for the single-metered and separately-metered PEV customer sectors and the full residential population. The average non-coincident peak was 3.59 kW higher for the single-metered group category compared to the average residential peak.¹⁵ The average non-coincident peak was 2.93 kW higher for the separately-metered group category compared to the average residential peak.
- Chart PG&E-8 displays the average monthly non-coincident peak loads for single-metered customers during 2023.
- Chart PG&E-9 displays the average monthly non-coincident peak loads for separately-metered customers during 2023.

¹⁵ The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Table PG&E-8: Monthly Average Non-Coincident Peak Load (kW) (2023)

Year	Month	Residential Population*	Single Family Population*	MDU Population*	All Single-metered	Single Family Single-metered	MDU Single-metered	All Separately-metered	Single Family Separately-metered	MDU Separately-metered
2023	Jan	4.19	4.62	3.08	8.13	8.25	6.79	7.80	7.32	8.52
2023	Feb	4.04	4.46	2.93	7.94	8.04	6.82	7.82	7.34	8.54
2023	Mar	3.92	4.34	2.82	8.25	8.38	6.84	7.76	6.90	9.04
2023	Apr	3.81	4.22	2.74	7.54	7.63	6.65	7.60	7.05	8.41
2023	May	4.06	4.54	2.82	7.52	7.60	6.58	7.45	7.14	7.91
2023	Jun	4.63	5.25	3.04	7.49	7.58	6.56	7.43	7.00	8.10
2023	Jul	4.82	5.47	3.10	8.03	8.14	6.87	7.07	6.73	7.59
2023	Aug	4.86	5.53	3.12	8.11	8.22	6.91	6.99	6.74	7.37
2023	Sep	4.90	5.58	3.14	7.65	7.75	6.65	6.97	6.64	7.46
2023	Oct	4.09	4.56	2.86	7.89	7.99	6.81	6.69	6.40	7.13
2023	Nov	4.19	4.64	3.01	8.02	8.13	6.87	6.92	6.73	7.22
2023	Dec	4.44	4.92	3.18	8.40	8.54	7.01	6.61	6.57	6.67
Average		4.33	4.84	2.99	7.92	8.02	6.78	7.26	6.88	7.83

*Residential load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

*Italicized fields are estimates with a precision greater than +/- 10% at a 90% confidence interval.

Chart PG&E-8: Average Non-Coincident Peak Load (kW) for Single-Metered by Customer Type by Month (2023)

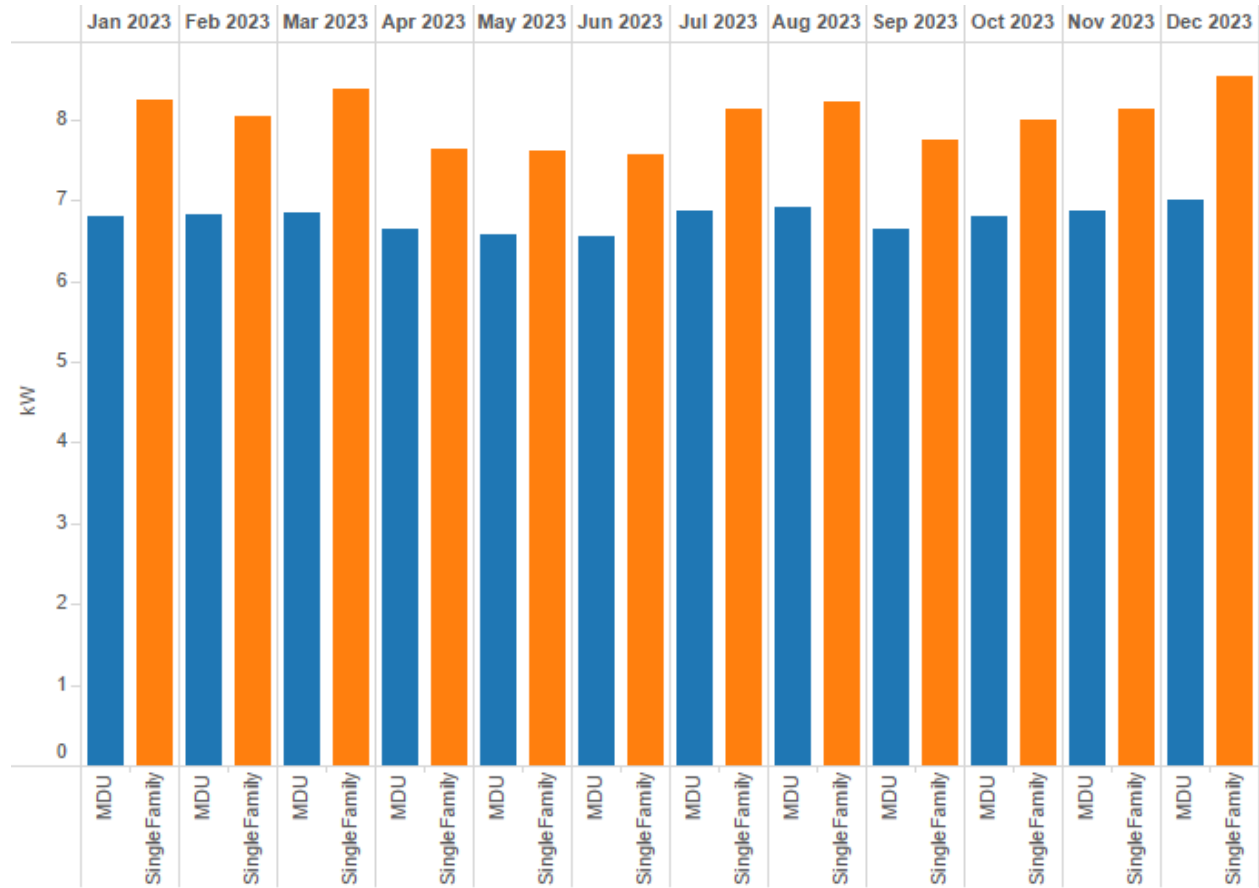
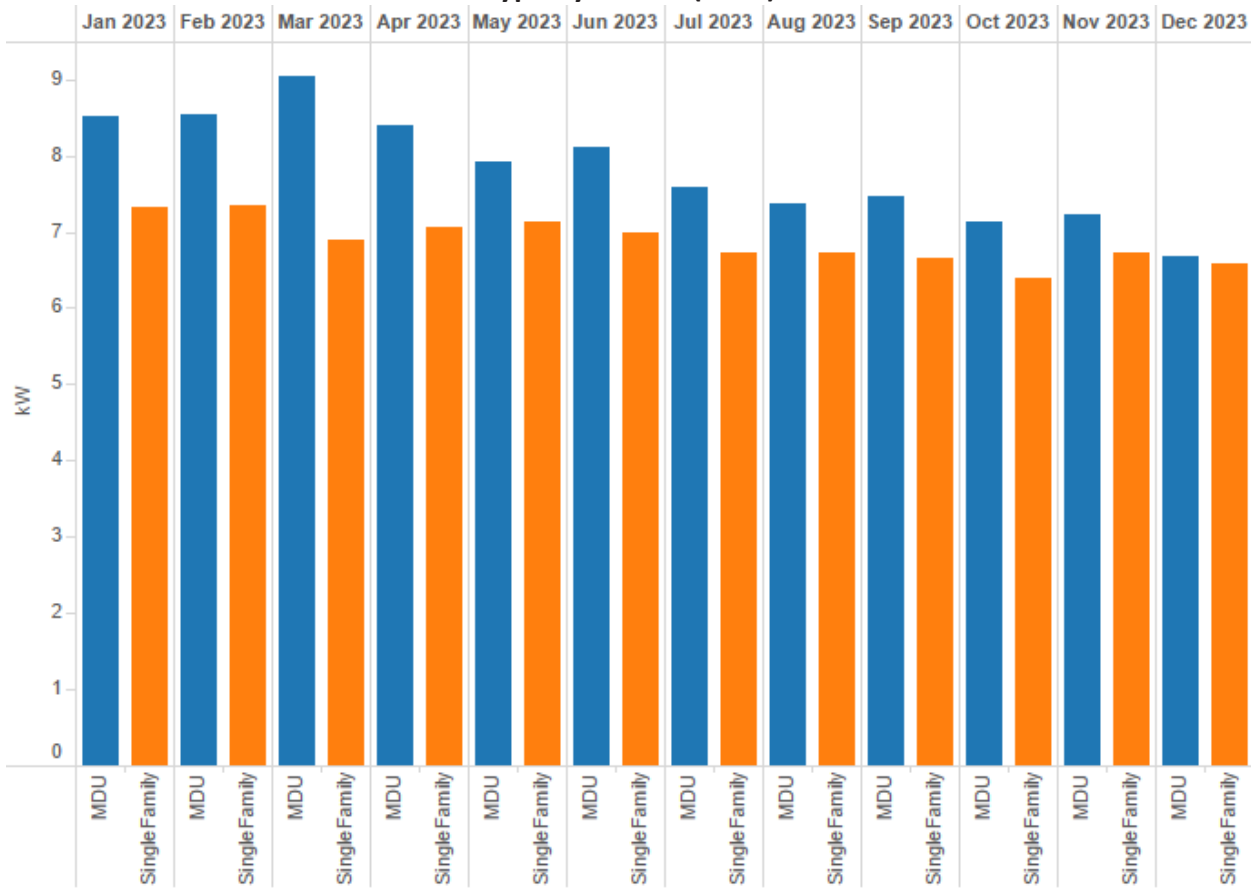


Chart PG&E-9: Average Non-Coincident Peak Load (kW) for Separately-Metered by Customer Type by Month (2023)



Diversified Peak Load

The time of diversified peak load gives the time that the group peaks as a whole. The time of diversified (or group) peak load is generally the same for all categories of single-metered and separately-metered customers. Tables PG&E-9 - PG&E-11 show that the diversified peak load occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2023. Tables PG&E-9a-c show that the diversified peak load generally occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2023. The general trend of the data suggests that the early adopter group of customers on the PEV rates is charging during the off-peak periods thereby achieving the intent of the rate designs.

Table PG&E-9: Time and Associated Demand of Diversified Peak Load (kW) – Entire Residential Population (2023)

Year	Month	Residential Population Demand*	Residential Population Hour*	SF Population Demand*	SF Population Hour*	MDU Population Demand*	MDU Population Hour*
2023	Jan	1.09	13	1.30	13	0.73	20
2023	Feb	1.21	13	1.45	13	0.62	21
2023	Mar	1.22	13	1.49	13	0.57	12
2023	Apr	1.28	14	1.57	14	0.57	14
2023	May	1.30	14	1.60	14	0.67	16
2023	Jun	1.41	14	1.73	14	0.76	17
2023	Jul	1.42	14	1.73	14	0.78	15
2023	Aug	1.42	14	1.72	14	0.78	18
2023	Sep	1.52	19	1.77	19	0.93	16
2023	Oct	1.15	14	1.39	14	0.58	14
2023	Nov	1.06	13	1.28	13	0.62	19
2023	Dec	0.99	13	1.17	13	0.76	20

*Residential load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

Table PG&E-10: Time and Associated Demand of Diversified Peak Load (kW) – Single-Metered (2023)

Year	Month	Single-metered Demand	Single-metered Hour	SF Single-metered Demand	SF Single-metered hour	MDU Single-metered Demand	MDU Single-metered Hour
2023	Jan	2.19	1	2.24	1	1.71	2
2023	Feb	2.15	2	2.19	2	1.67	1
2023	Mar	2.17	1	2.22	1	1.69	1
2023	Apr	1.93	1	1.96	1	1.59	2
2023	May	1.89	1	1.92	1	1.58	1
2023	Jun	1.90	1	1.94	1	1.55	1
2023	Jul	2.12	1	2.16	1	1.67	1
2023	Aug	2.33	1	2.38	1	1.86	1
2023	Sep	2.08	1	2.12	1	1.69	1
2023	Oct	2.12	1	2.16	1	1.74	1
2023	Nov	2.13	1	2.17	1	1.66	2
2023	Dec	2.33	1	2.39	1	1.77	2

*Italicized fields are estimates with a precision greater than +/- 10% at a 90% confidence interval.

**Table PG&E-11: Time and Associated Demand of
Diversified Peak Load (kW) – Separately-Metered (2023)**

Year	Month	Separately-metered Demand	Separately-metered Hour	SF Separately-metered Demand	SF Separately-metered hour	MDU Separately-metered Demand	MDU Separately-metered Hour
2023	Jan	2.08	1	2.15	1	2.59	1
2023	Feb	2.24	1	1.98	1	3.00	1
2023	Mar	2.27	1	1.96	1	2.86	1
2023	Apr	2.29	1	2.00	1	2.72	1
2023	May	2.00	1	1.90	2	2.75	1
2023	Jun	2.12	1	1.91	1	2.56	1
2023	Jul	1.79	1	1.57	2	2.55	1
2023	Aug	1.90	1	1.78	1	2.38	1
2023	Sep	1.90	1	1.69	1	2.55	1
2023	Oct	2.03	1	1.71	1	2.62	1
2023	Nov	1.89	1	1.71	1	2.46	1
2023	Dec	1.91	2	1.86	2	2.37	2

Taken together, Tables PG&E-9 – PG&E-11 suggest that although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at some of their lowest usage. Thus, there is a diversity benefit created by the TOU rates. However, at the most local service assessment level perspective (i.e., a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.

Non-Residential PEV Rates

Business EV Rate

As of the date of this report, PG&E has two non-residential PEV rates - the Business Low Use EV Rate (BEV-1) for customers with up to and including 100 kW demand for their PEV charging infrastructure and the Business High Use EV Rate (BEV-2) for customers with demand equal to 100kW and over for their EV charging infrastructure. Customers on the BEV-2 rate can be secondary or primary/transmission customers and have slightly different energy prices. The BEV rates work as a monthly subscription charge based on customers’ maximum monthly EV charging kW consumption. Both rate plans use a TOU rate structure. The TOU values vary a few cents between the BEV-1 and BEV-2 options but follow largely the same structure: they offer on-peak, off-peak, and super off-peak energy prices according to the time periods in Table PG&E-12. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. Both BEV rates include off-peak hours from 2:00 p.m. to 4:00 p.m. and 9:00 p.m. to 9:00 a.m. and super off-peak hours 9:00 a.m. to 2:00 p.m. during weekdays and weekends.

Table PG&E-12: Tariff Type and Rate (\$/kWh) in 2023
Rates Effective Sep 1, 2023 through Dec 31, 2023

Hour	Rate: BEV-1	Rate: BEV-2-S	Rate: BEV-2-P
	Every day including weekends and holidays, all year	Every day including weekends and holidays, all year	Every day including weekends and holidays, all year
12mn - 1am	\$0.19352	\$0.18648	\$0.18194
1am - 2am	\$0.19352	\$0.18648	\$0.18194
2am - 3am	\$0.19352	\$0.18648	\$0.18194
3am - 4am	\$0.19352	\$0.18648	\$0.18194
4am - 5am	\$0.19352	\$0.18648	\$0.18194
5am - 6am	\$0.19352	\$0.18648	\$0.18194
6am - 7am	\$0.19352	\$0.18648	\$0.18194
7am - 8am	\$0.19352	\$0.18648	\$0.18194
8am - 9am	\$0.19352	\$0.18648	\$0.18194
9am - 10am	\$0.16686	\$0.16321	\$0.15928
10am - 11am	\$0.16686	\$0.16321	\$0.15928
11am - 12nn	\$0.16686	\$0.16321	\$0.15928
12nn - 1pm	\$0.16686	\$0.16321	\$0.15928
1pm - 2pm	\$0.16686	\$0.16321	\$0.15928
2pm - 3pm	\$0.19352	\$0.18648	\$0.18194
3pm - 4pm	\$0.19352	\$0.18648	\$0.18194
4pm - 5pm	\$0.38553	\$0.39971	\$0.39082
5pm - 6pm	\$0.38553	\$0.39971	\$0.39082
6pm - 7pm	\$0.38553	\$0.39971	\$0.39082
7pm - 8pm	\$0.38553	\$0.39971	\$0.39082
8pm - 9pm	\$0.38553	\$0.39971	\$0.39082
9pm - 10pm	\$0.19352	\$0.18648	\$0.18194
10pm - 11pm	\$0.19352	\$0.18648	\$0.18194
11pm - 12mn	\$0.19352	\$0.18648	\$0.18194

Legend:

	All year
On	
Off	
Super Off	

Table PG&E-13 depicts price ratios for the TOU periods.

Table PG&E-13: Price Ratios for 2023

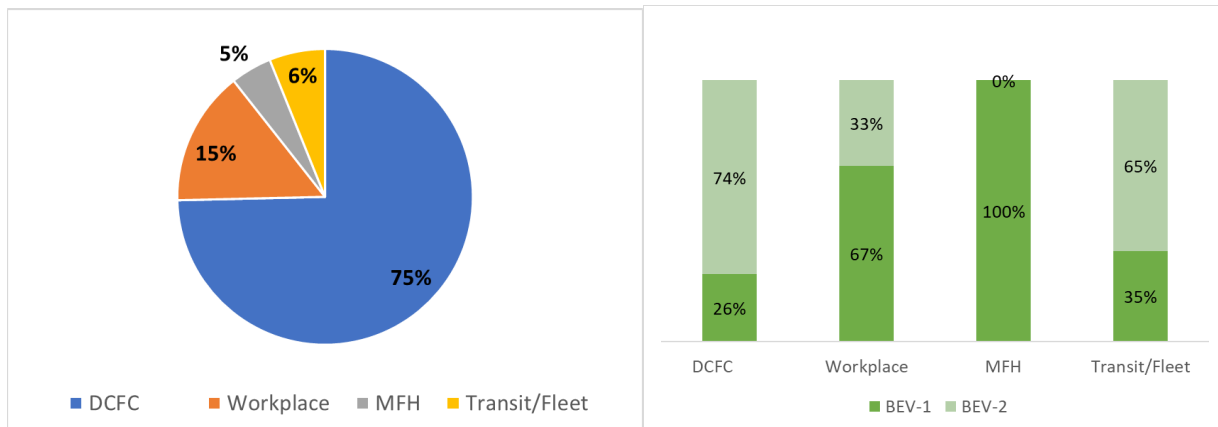
Season	BEV-1		BEV-2-S		BEV-2-P	
	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak
All year	0.43	0.86	0.41	0.88	0.41	0.88

BEV Rate Enrollment and Growth

Per Decision 19-10-055¹⁶ which approved a two-phase launch, PG&E's BEV rate was launched with limited functionality in May 2020 and launched with full functionality in October 2020. There has been steady growth in enrollment for both the BEV-1 and BEV-2 rates since their launch. BEV-1 rate customers tend to be smaller businesses with fewer or smaller vehicles. BEV-2 customers tend to be larger commercial customers such as transit operators with large vehicles, or charging sites with high utilization, often across multiple vehicles or fleets, such as DCFC operators.

BEV customers self-select into five different use case categories: Direct Current Fast Charge (DCFC), Public transit (Transit), Workplace, Medium-Duty Fleets (Fleet), and Multi-family Housing (MFH). The majority of the customers on BEV rate are DCFC operators, or about 75%. See Chart PG&E-10 for rate adoption per use case for details.

Chart PG&E-10: BEV Customers

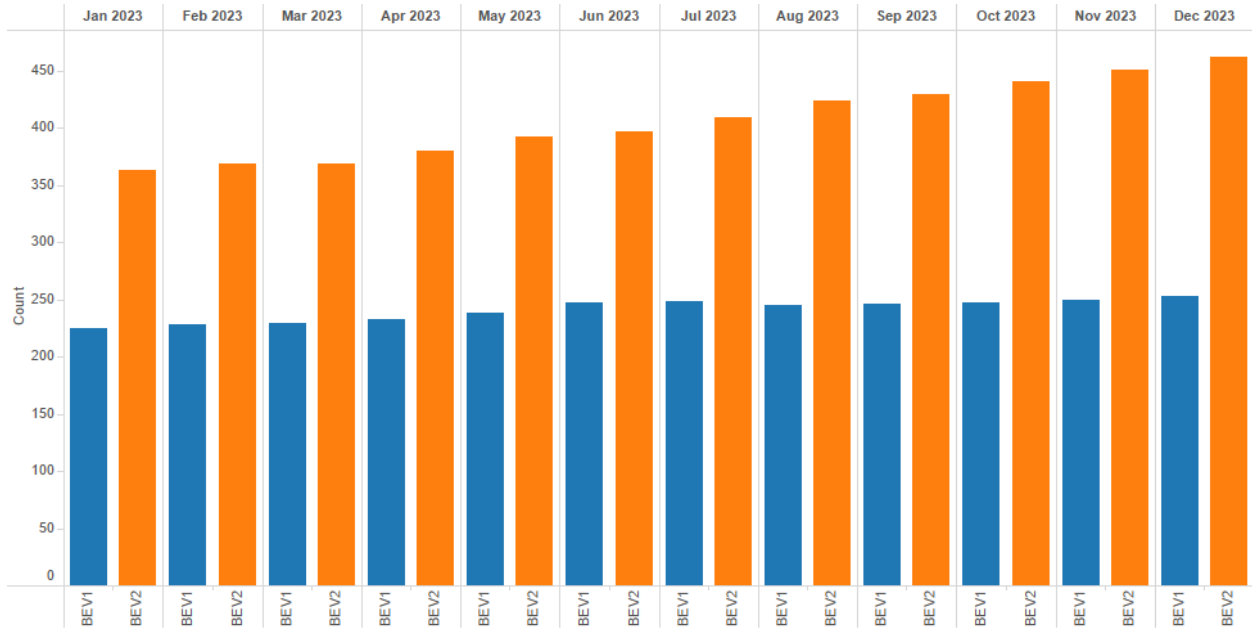


During the 2023 study period, the number of BEV-2 accounts have increased significantly as seen in Chart PG&E-11, and the total number of BEV-2 accounts exceeds the number of BEV-1 accounts.

¹⁶ CPUC. DECISION APPROVING APPLICATION FOR PACIFIC GAS AND ELECTRIC COMPANY'S COMMERCIAL ELECTRIC VEHICLE RATES. D.19-10-055. Issued 10/28/2019.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K552/318552527.PDF>

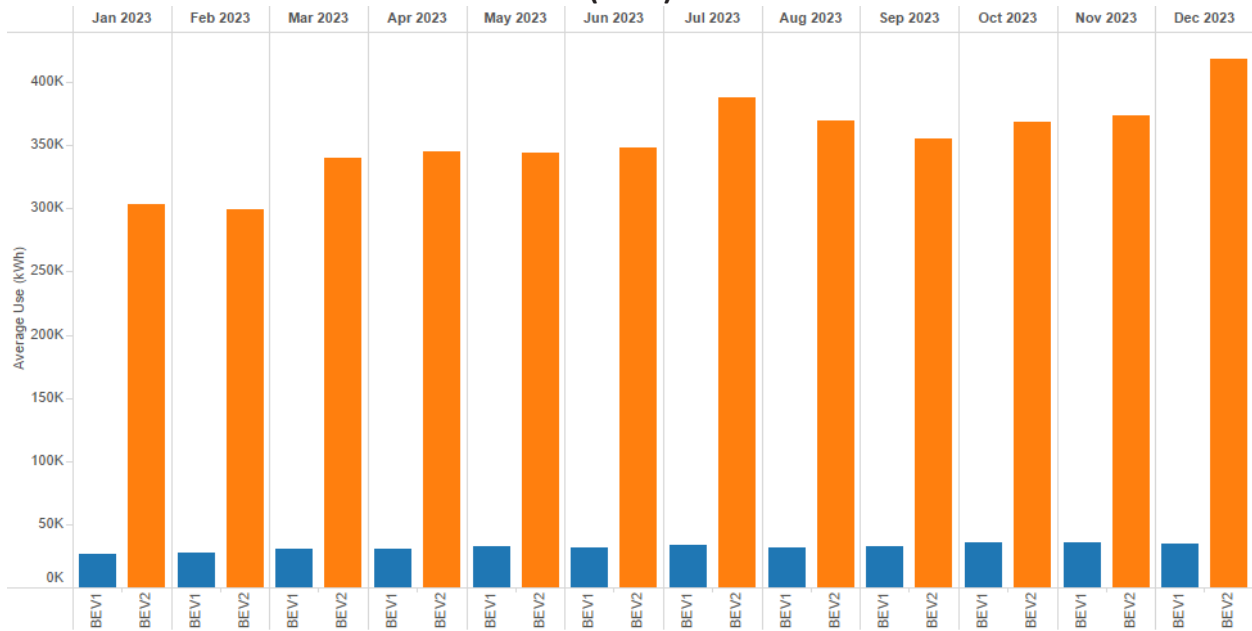
Chart PG&E-11: BEV Rate Accounts by Type (2023)



Average Monthly Usage for BEV Rate Customers

Keeping in mind the cautions about the data collected mentioned in the section on residential PEV rates above, Chart PG&E-12 displays the average monthly usage for BEV-1 and BEV-2 customers in 2023. As expected from the construct of the two rates, BEV-2 customers have a much higher average monthly usage than customers on BEV-1.

Chart PG&E-12: BEV Average Monthly Usage (kWh) by Customer Type (BEV-1 and BEV-2) (2023)



Average Usage during Time of Use Periods

Similar to residential PEV rates, commercial BEV rates are designed to discourage charging during on-peak hours and encourage charging during off-peak and super off-peak hours. The time of use periods for both BEV rates are defined in Table PG&E-12.

One way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods.

- Table PG&E-14 shows the share of on-peak, off-peak, and super off-peak usage for BEV-1 customers for the summer and winter seasons¹⁷. The energy usage is distributed fairly evenly with slightly higher usage in the off-peak period and no notable seasonal differences. Keeping in mind that the majority of the BEV-1 customers are either Workplaces or MFH, the charging patterns reflect the transportation needs of the customers. Comprehensive data on EV charging pricing models is not available and it is possible that TOU pricing signals are not passed to the end customer.
- Table PG&E-15 shows the share of on-peak, off-peak, and super off-peak usage for BEV-2 customers for the summer and winter seasons. The energy usage is distributed fairly evenly between the three TOU periods, with slightly higher usage during the off-peak period and there are no notable seasonal differences. In particular, many DCFC sites choose to use the BEV-2 rate, whose customers may have less price elasticity due to the use case and who may set their own optimal rates that differ than PG&E’s time-of-use pricing.

Collectively, Tables PG&E-14 and 15 show that the majority of energy usage of customers on the BEV rates does not occur during peak hours. BEV-1 customers are completing, on average, 75% of their charging during the off-peak and super off-peak period and BEV-2 customers are completing, on average, 70% of their charging during the off-peak and super off-peak period. Prior to rolling out the BEV rate, customer use patterns were forecasted based on assumed load patterns for the five different use cases in the BEV rate application, A.18-11-003. Specifically, BEV-1 on peak usage was forecasted at 15% and BEV-2 at 20%. This suggests that the actual customers are still using more energy on peak than forecasted, in spite of an artificially high on peak rate.

Table PG&E-14: Share of Usage for BEV-1 by TOU Period (2023)

Year	Season	On-Peak BEV-1	Off-Peak BEV-1	Super Off-Peak BEV-1
2023	Summer	26%	41%	33%
2023	Winter	25%	40%	36%
	Max	26%	41%	36%
	Avg	25%	40%	35%

*Numbers may not add up to 100% due to rounding

¹⁷ The BEV rate does not include seasonality as the winter and summer prices are the same. The distinction is included here to compare customer usage to different weather patterns and time of year.

Table PG&E-15: Share of Usage for BEV-2 by TOU Period (2023)

Year	Season	On-Peak BEV-2	Off-Peak BEV-2	Super Off-Peak BEV-2
2023	Summer	30%	39%	31%
2023	Winter	29%	39%	32%
	Max	30%	39%	32%
	Avg	29%	39%	31%

Average Load Profiles for BEV Rates

Depicted below in Charts PG&E-13 and PG&E-14 are the average daily load profiles for BEV-1 and BEV-2 rate groups for weekday and weekend in 2023. The load profiles demonstrate that high off-peak- usage corresponds to the BEV rate price signals, *i.e.*, customers are largely responding to the price signal and charging during super off-peak hours (9:00 a.m. to 2:00 p.m.). There is still some charging that is occurring during peak hours (4:00 p.m. to 9:00 p.m.) which is likely due to inflexibility of business needs and/or use of public charging by customers on their commute home. As expected from the rate design, the average kW demand is higher for BEV-2 customers and the BEV-2 customer load profiles show that customers are charging during the super off-peak period. It also shows that BEV-2 customers are also still charging during on-peak hours which may be attributable to the DCFC end-customers who are less aware of the TOU price signals or less able to adjust their charging time. The lower usage during the off-peak period despite the low energy prices may be a result of the inability to charge during the middle of the day to meet business needs as well as limited use of public charging by customers during those hours. There is little difference between the weekday and weekend load profiles for the BEV-1 rate, which may suggest that BEV rate customers have similar business operations and charging needs throughout the week.¹⁸ BEV-2 weekend load profiles show higher peaks compared to weekday peaks during the same hours. However, this may change as more customers with varying business operations and needs enroll in the rate.

¹⁸ Weekend and weekday prices are the same on the BEV rates as are the TOU periods. Therefore, any change in charging pattern between weekend and weekday should not be attributed to differences in price signal.

Chart PG&E-13: Average Load Profile for BEV-1 Customer by Weekday and Weekend (2023)

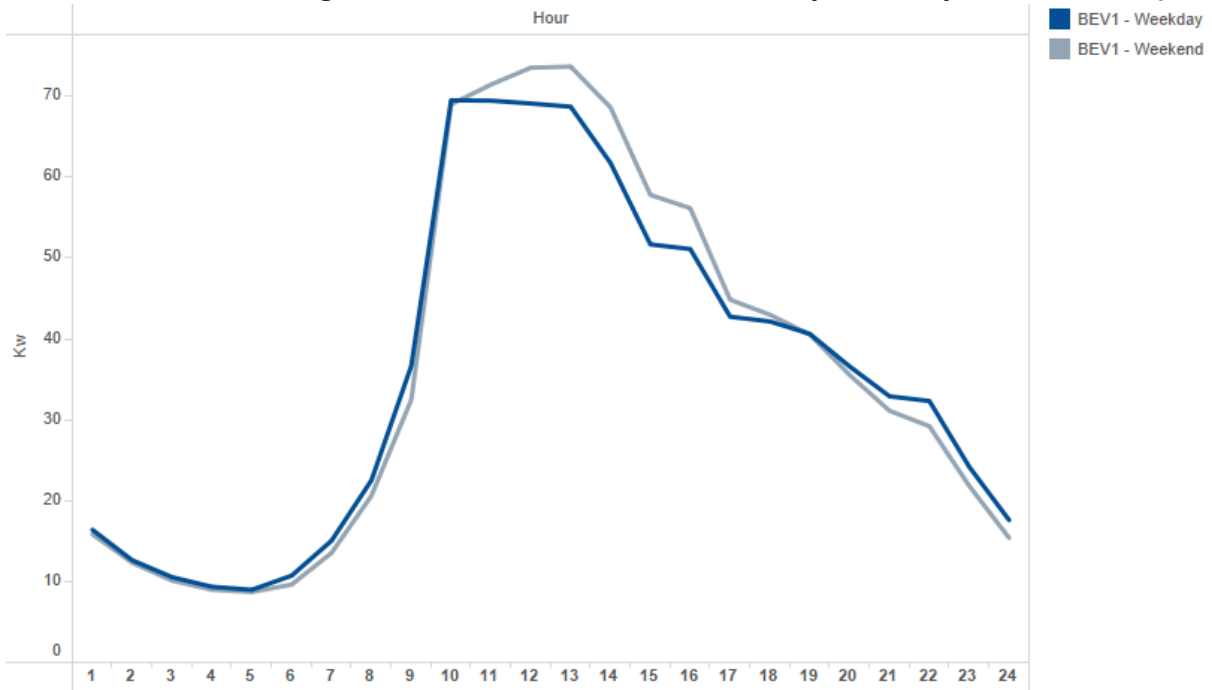
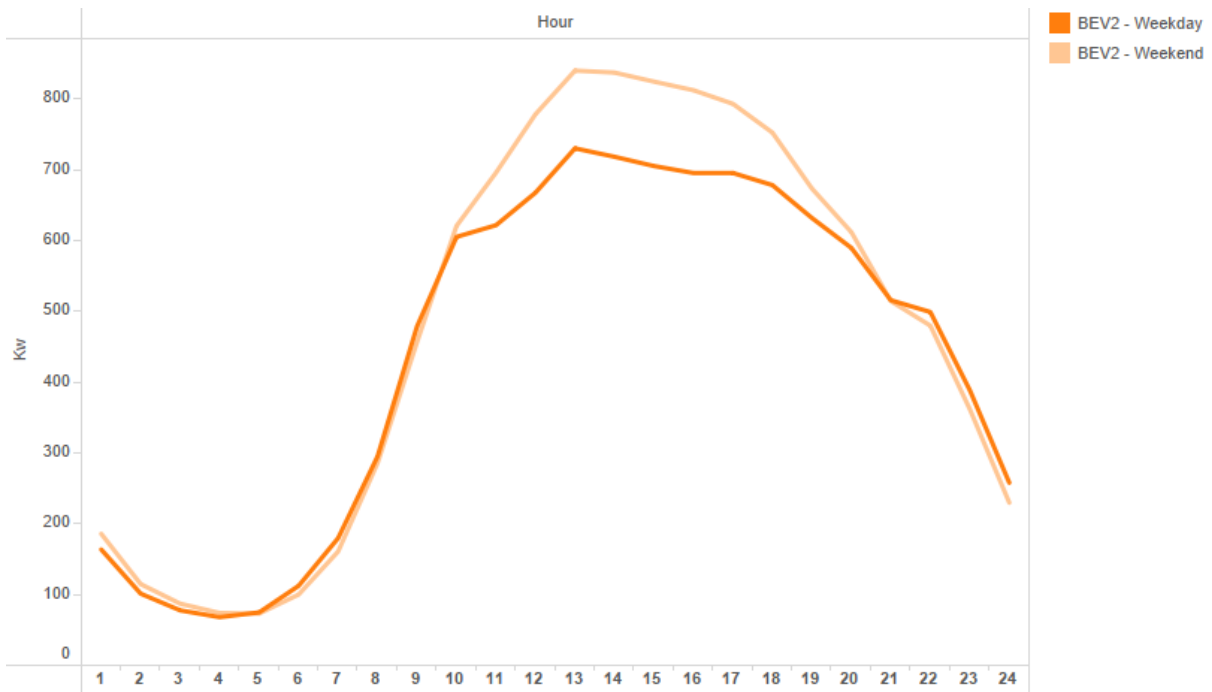


Chart PG&E-14: Average Load Profile for BEV-2 Customer by Weekday and Weekend (2023)



Non-Coincident Peak Load

To compare non-coincident peak loads, the two BEV rates were compared to commercial customers on commercial rates with similar kW demand. The BEV-1 rate was compared to a general population on the A-10 rate, which are commercial customers with kW demand that does not exceed 499 kW. The peak load on the BEV-2 rate was compared to that of customers on the E-19 rate, who are customers with 500 kW demand or higher. Similar to residential customers, the average commercial customer with charging installations will generally have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average commercial customer without PEV charging installations.

- Table PG&E-16 shows the monthly comparison of the average non-coincident peak between BEV-1 and A-10 customers, and between BEV-2 and E-19 customers. The average non-coincident peak was approximately 12.8 kW higher for the BEV-1 group category compared to the average A-10 commercial population peak.¹⁹ For the BEV-2 group, the average non-coincident peak was approximately 53.4 kW higher compared to the average E-19 commercial population peak. Chart PG&E-15 shows a monthly average non-coincident peak load for each rate.

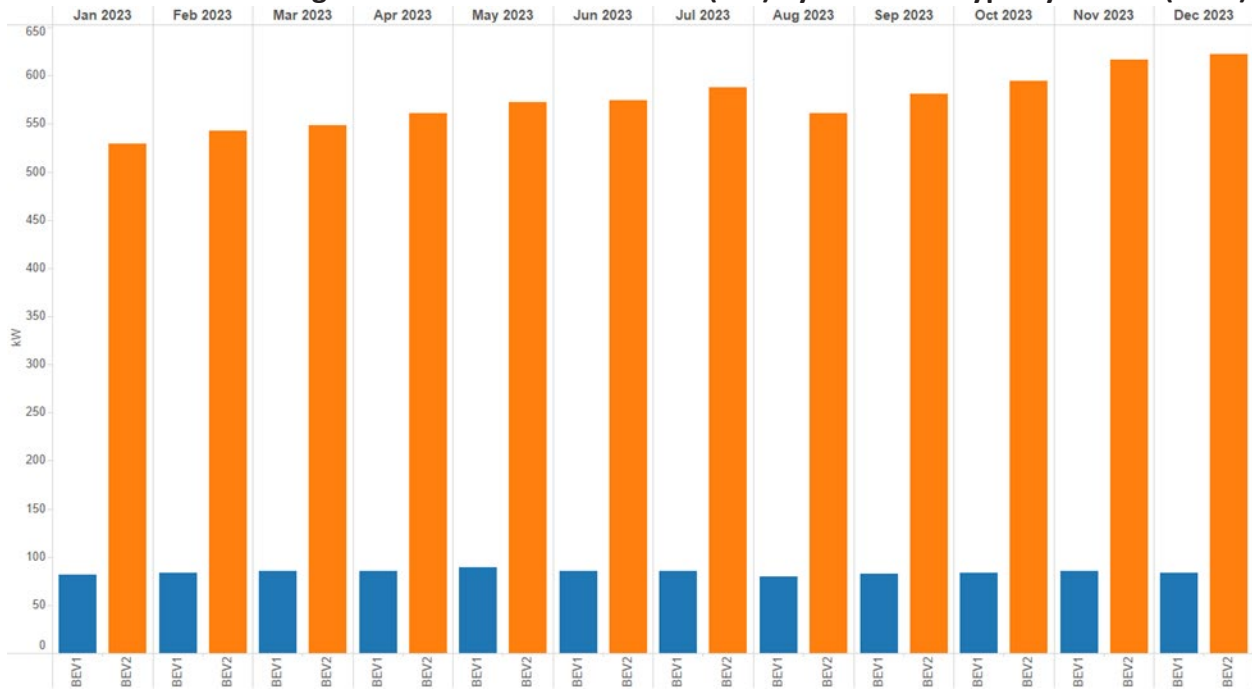
Table PG&E-16: Monthly Average Non-Coincident Peak Load (kW) (2023)

Year	Month	Non-Residential A-10 Population*	BEV-1	Non-Residential E-19 Population*	BEV-2
2023	Jan	59.92	81.14	449.64	529.50
2023	Feb	63.51	83.75	477.89	542.91
2023	Mar	66.76	85.64	506.40	548.07
2023	Apr	68.33	85.19	522.93	560.90
2023	May	72.73	89.01	545.97	572.06
2023	Jun	75.85	85.52	584.73	574.42
2023	Jul	72.30	85.74	543.84	587.46
2023	Aug	77.49	80.02	563.69	560.45
2023	Sep	82.62	82.90	601.68	580.73
2023	Oct	69.23	83.46	523.59	594.51
2023	Nov	63.20	85.05	472.26	616.92
2023	Dec	61.59	83.43	450.96	621.85
Avg		69.46	84.24	520.30	574.15

*A-10 and E19 load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

¹⁹ The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Chart PG&E-15: Average Non-Coincident Peak Load (kW) by Customer Type by Month (2023)



Diversified Peak Load

Different than the residential PEV rates, the time of diversified (or group) peak load for both BEV rates is reached during the afternoon and early evening hours. Table PG&E-17 shows that the diversified peak load occurs between 9:00 a.m. and 2:00 p.m. for BEV-1 customers and between 1:00 p.m. and 5:00 p.m. for BEV-2. This suggests that customers on both BEV rates are generally peaking during non-peak hours, achieving the intent of the time-of-use structure. The BEV-1 customers are primarily peaking at approximately the 10:00 am mark. BEV-2 customers are primarily peaking at the 2:00 p.m. to 3 p.m. mark. This suggests that BEV customers are generally responding to the price signals.

Table PG&E-17: Time and Associated Demand of Diversified Peak Load (kW) – Entire Residential Population (2023)

Year	Month	Non-ResidentialA-10 PopulationDemand*	Non-ResidentialA-10 PopulationHour*	BEV-1 Demand	BEV-1 Hour	Non-Residential E-19 Population Demand*	Non-Residential E-19 Population Hour*	BEV-2 Demand	BEV-2 Hour
2023	Jan	28.00	13	86.43	10	290.42	14	995.29	15
2023	Feb	30.32	13	97.44	10	318.45	14	991.53	13
2023	Mar	33.24	14	108.92	11	340.18	14	1,043.57	14
2023	Apr	34.70	14	104.63	10	355.91	15	1,057.62	15
2023	May	38.31	14	100.61	10	372.34	14	1,108.49	17
2023	Jun	39.23	14	95.02	10	398.28	14	1,042.08	14
2023	Jul	37.76	14	99.32	10	366.75	14	1,163.87	15
2023	Aug	40.92	14	94.52	9	383.05	15	1,109.51	15
2023	Sep	45.86	14	95.66	13	424.29	14	1,152.08	16
2023	Oct	34.56	14	103.29	10	361.49	15	1,090.84	15
2023	Nov	28.69	13	121.67	14	311.87	12	1,263.40	14
2023	Dec	28.25	8	105.47	11	302.26	12	1,290.01	13

*A10 and E19 load data used for the analysis are from Jan 2022 to December 2022. (See footnote 14)

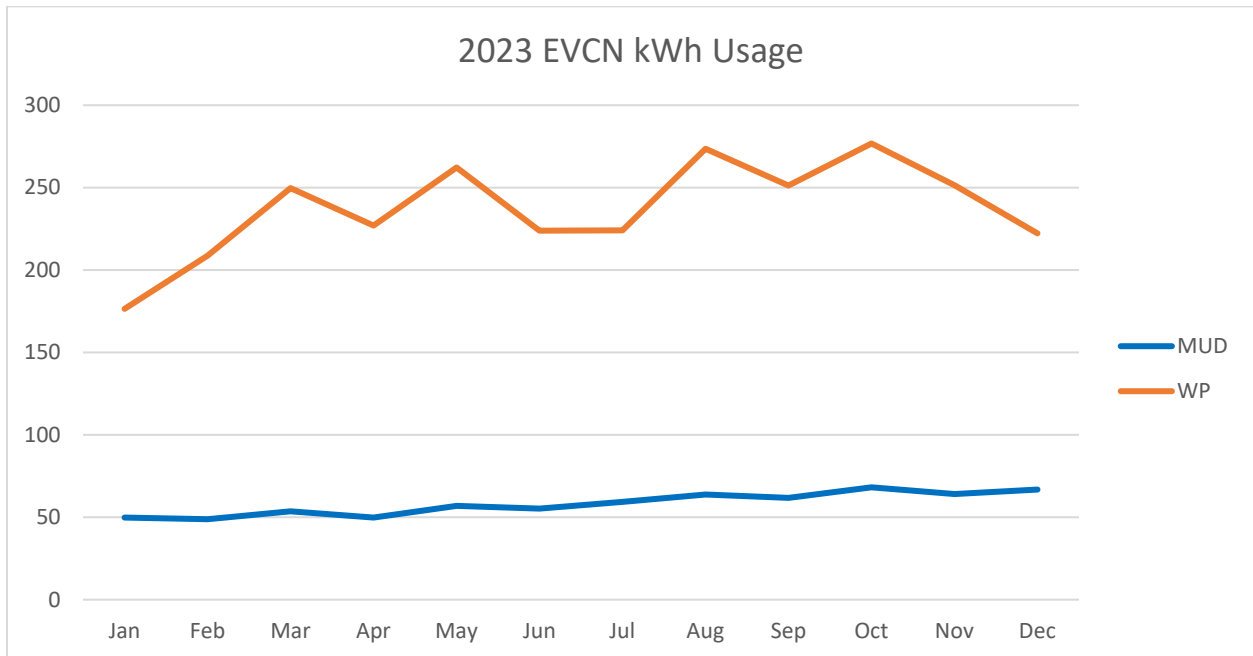
Table PG&E-17 also shows that BEV customers, particularly BEV-2 customers, have significantly higher demand than the non-PEV, non-residential customers. It also shows that BEV rate customers and non-PEV, non-residential rate customers are hitting their maximum demand at similar times in the day. This may change as more customers with diverse business needs enroll in the BEV rate. However, even if BEV customer peak load occurs at a different time than the general non-PEV, non-residential customer peak load, the local service and distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can still charge during those times.

Transportation Electrification Program Load Data

Average Monthly Usage for PG&E Programs

The average monthly usage per port in chart PG&E-15a shows usage for PG&E’s Electric Vehicle Charge Network (EVCN) program for both multi-unit dwellings (MUD) and workplaces (WP) as distinguished in Decision 16-12-065. EVCN is PG&E’s Light-duty Vehicle program. The metric displayed in this chart is defined as the average kWh/port for each month for EVCN sites. As seen in Chart PG&E-16a, the average monthly usage per port has continued to increase in 2023, and is also an increase over the prior year of 2022.

Chart PG&E-16a: PG&E EVCN Program Average Monthly Usage (kWh) (2023)



The average monthly usage per site in chart PG&E-16b shows usage for PG&E’s Electric Vehicle Fleet program. This is PG&E’s Medium Duty/Heavy Duty (MD/HD) EV program. Please note the difference in this chart which measures average monthly kWh/site compared to average monthly kWh/port for EVCN.

The metric displayed in chart PG&E-16b is defined as the average monthly usage per site (kWh/site) for the EV Fleet program. The average monthly usage per site increased throughout the prior year of 2022 and continued to increase in 2023 as well. In 2023, the average monthly usage per site increase was 4% and the number of sites increased by 25% or 11 sites.

Chart PG&E-16b: PG&E EV Fleet Program Average Monthly Usage (kWh) (2023)

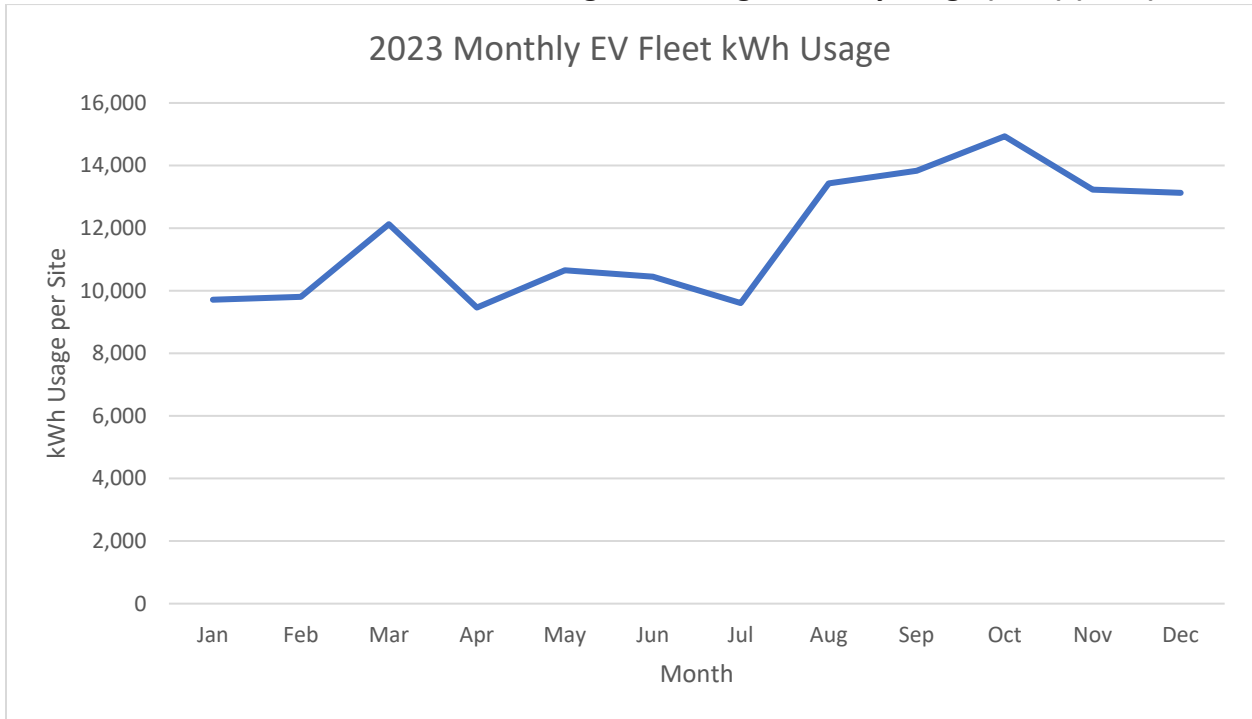
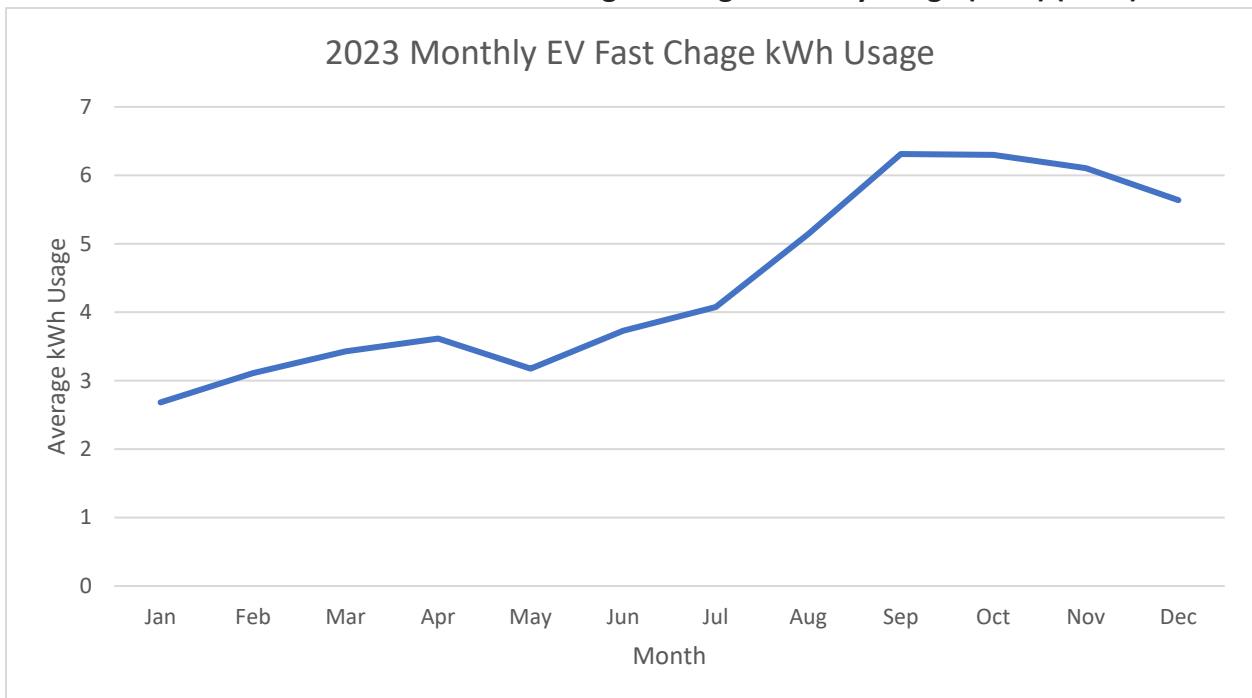


Chart PG&E-16c shows average hourly usage for PG&E’s EV Fast Charge program across the 18 activated sites. In 2023, the average monthly usage per site increase was 7%.

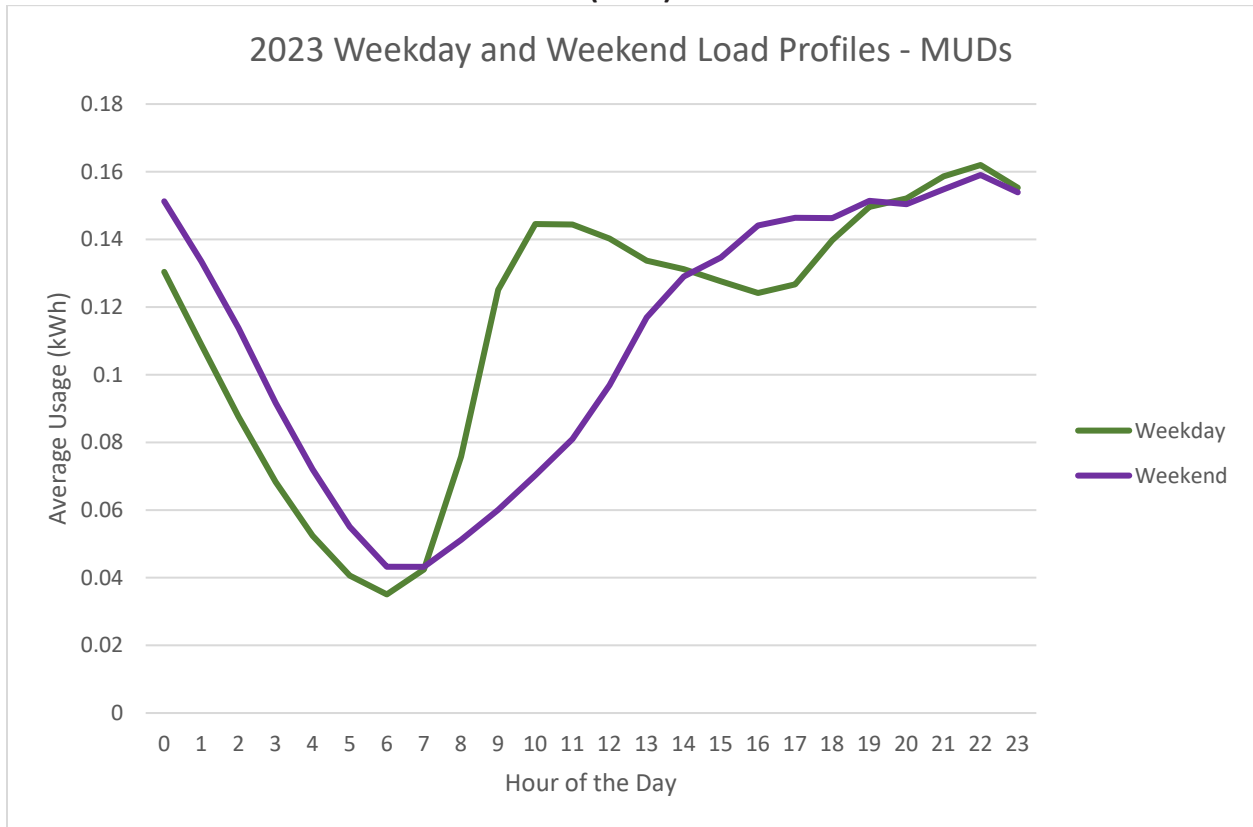
Chart PG&E-16c: PG&E EV Fast Charge Average Monthly Usage (kWh) (2023)



Average Load Profiles for PG&E Programs

Chart PG&E-17a shows the annual average weekday and weekend load profiles per port at MUDs in PG&E's EVCN program in 2023. Chart PG&E-16b shows the annual average weekday and weekend load profiles per port at WPs in PG&E's EVCN program in 2023. The average load profiles for usage at both MUDs and WPs showed variation throughout the day. During 2023, MUD sites experienced similar timing for the weekday and weekend usage peak which was between 7:00 p.m. and midnight. In contrast, weekday usage at WP sites, on average, experienced one large peak during the late morning and middle of the day between 9:00 a.m. and 1:00 p.m. Given that commuters most likely visit workplaces during business hours, it is sensible that usage would peak during this time. Similarly, usage at WP sites during the weekend peaks between the late morning and midafternoon – 11:00 a.m. to 4:00 p.m. – as seen in Chart PG&E-17b. More data on PG&E's EVCN Program can be found in the quarterly updates to the Program Advisory Council and EVCN Quarterly Reports.²⁰

Chart PG&E-17a: EVCN MUD Average Weekday and Weekend Load Profile (kWh) per Port (2023)



²⁰ Program Advisory Council quarterly updates are publicly available at https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page

Chart PG&E-17b: EVCN WP Average Weekday and Weekend Load Profile (kWh) per Port (2023)

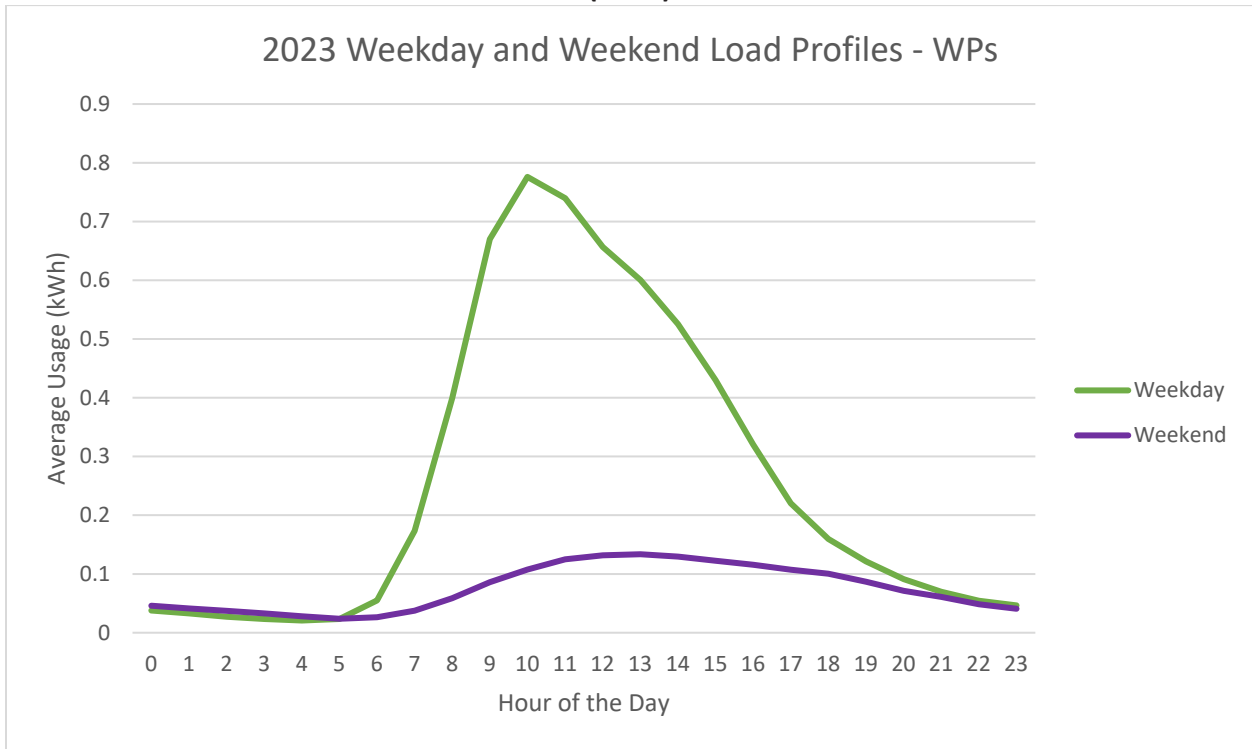


Chart PG&E-17c: EVCN WP and MUD Average Weekday and Weekend Load Profile (kWh) per Port Comparison (2023)

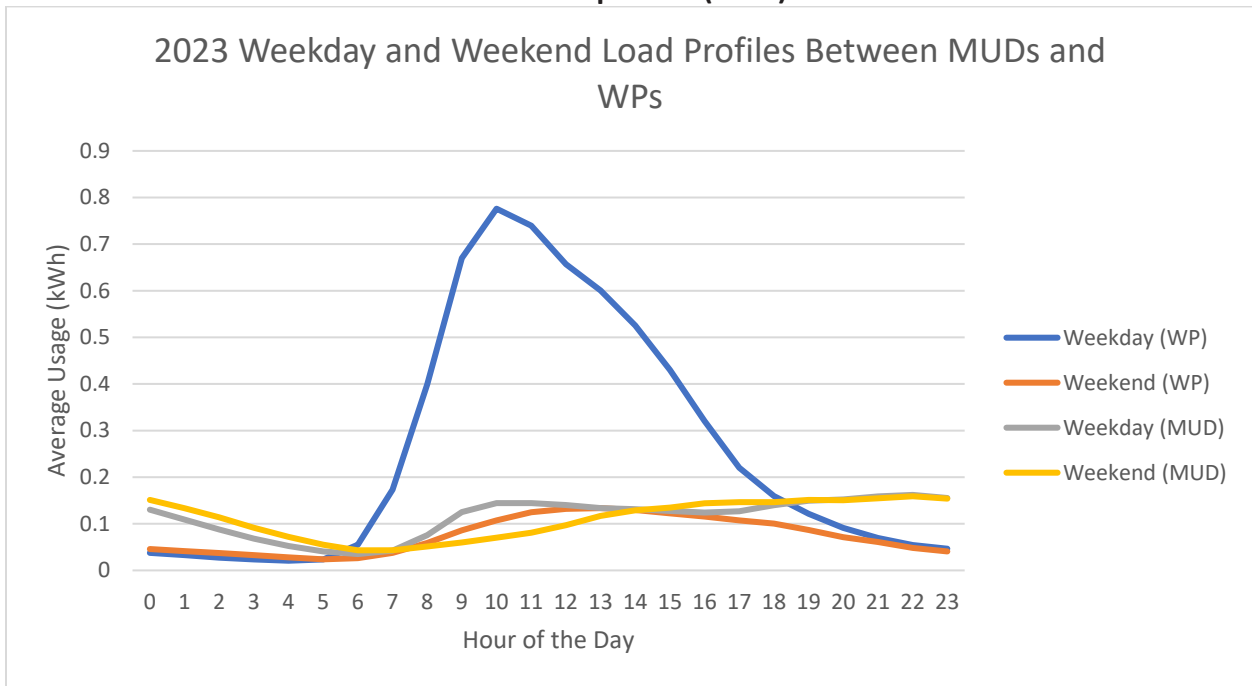


Chart PG&E-18a shows the annual average weekday and weekend load profiles for chargers at sites in the EV Fleet Program during 2023. This is defined as average kWh usage at each hour across all EV Fleet

sites. Peak weekday usage at EV Fleet sites was significantly larger than weekend usage. One of the weekend peaks was around 12:00 p.m., and the second, slightly larger peak around 10:00 p.m. The afternoon peak was driven by transit bus (both private and public), school bus, and heavy-duty vehicle charging. The nighttime peak was dominated by transit bus (both private and public) charging sites. Weekend charging load was much lower (70%) than weekday charging.

Chart PG&E-18a: EV Fleet Average Weekday and Weekend Load Profile (kWh) (2023)

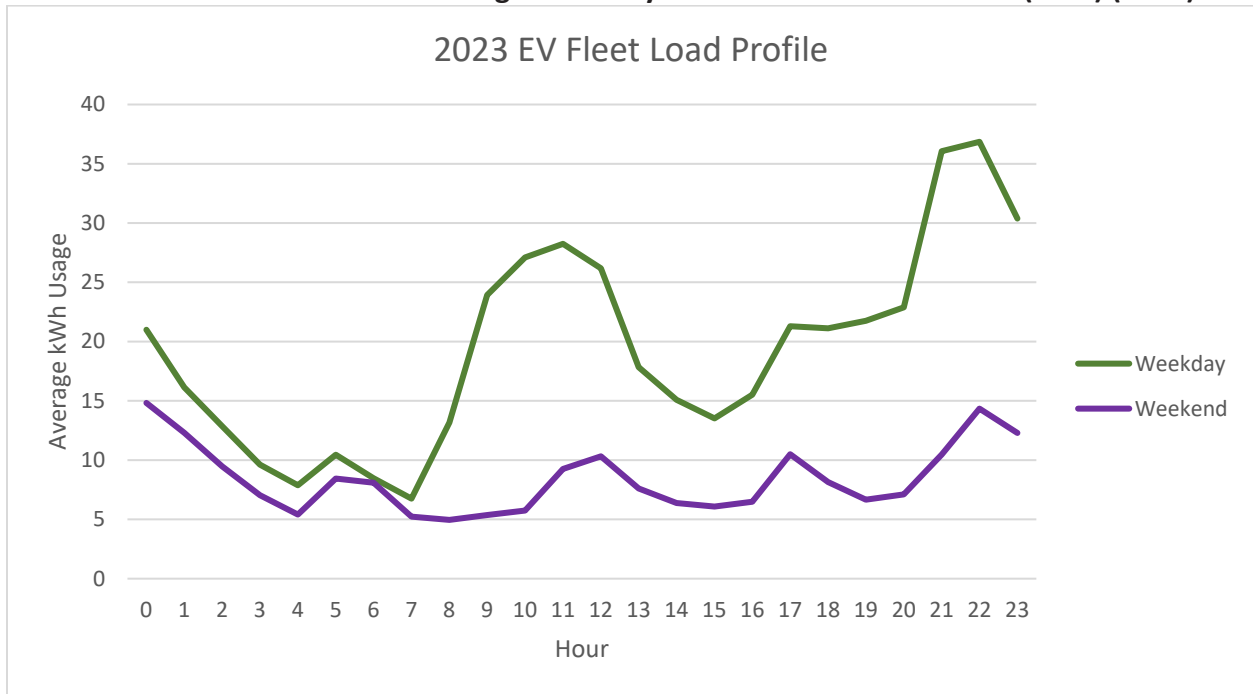
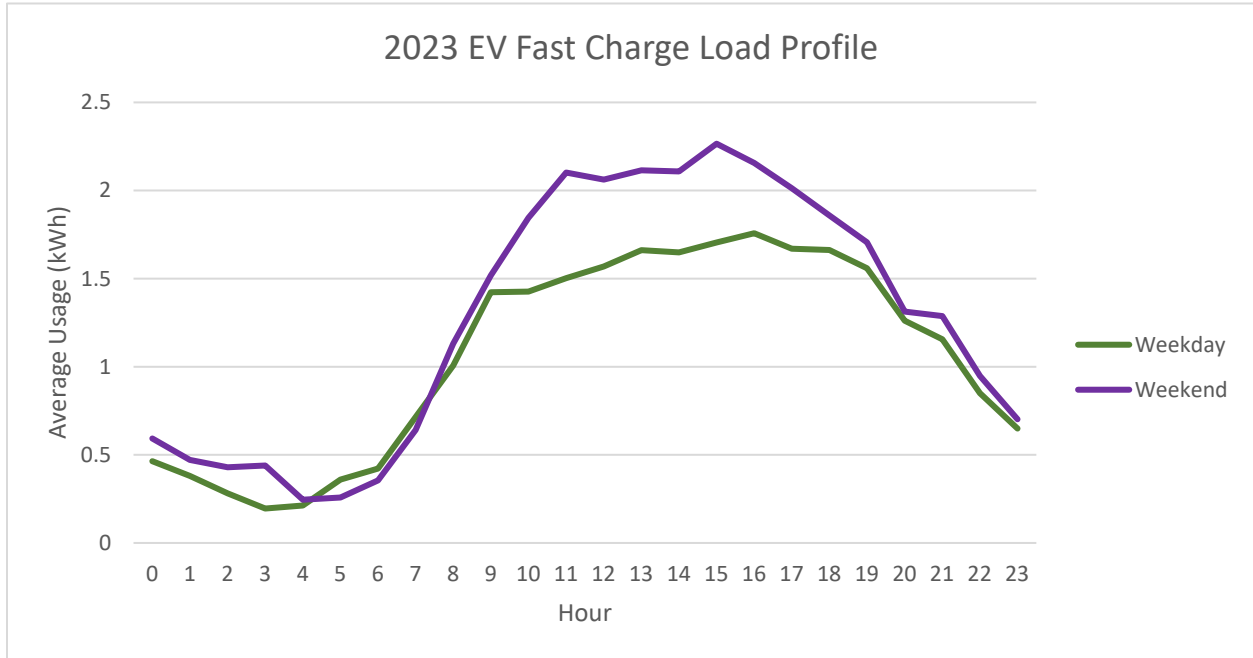


Chart PG&E-18b shows the annual average weekday and weekend load profiles for chargers at sites in the EV Fast Charge Program during 2023. This is defined as average kWh usage at each hour across all 18

sites. For the weekday usage, there is a peak time that runs from 11 am to 5 pm for both weekday and weekend usage. The weekday and weekend usage generally align with one another except during the peak time when the weekend usage is about .5 to .7 kWh greater than the weekday usage.

Chart PG&E-18b: EV Fast Charge Average Weekday and Weekend Load Profile (kWh) (2023)



Average Utilization for PG&E Priority Review Projects

PG&E managed four Priority Review Projects (PRPs) including the Electric School Bus Renewables Integration Project, the Idle Reduction Technology Project, the Medium/Heavy Duty (MD/HD) Customer Fleet Demonstration Project, and the Home Charger Resource Pilot. Please see submittal of SB 350 PRP annual data report to be filed in June 2024 for detail into 2023 load data for PRP programs.

C. SCE's Load and Customer Behavior Data

This report provides data on load and utilization for customers on both residential and commercial EV specific tariffs from January 2023 to December 2023.

During the reporting period, SCE offered only one rate schedule (tariff): TOU-D-PRIME, for residential customers designed to facilitate the charging of PEVs. This schedule employs price-differentiated time-of-use periods. The TOU-D-PRIME tariff applies to both regular household loads and PEV charging loads recorded with a second meter. The time-of-use periods of single-metered TOU-D-PRIME is designed to accommodate PEV charging requirements but apply to all household loads. The separately metered TOU-D-PRIME requires a second meter dedicated to measuring the electricity used at the PEV charger and the rates and time-of-use periods only apply to the electricity consumed by the PEV. Residential customers who have, or install, a second meter for metering EV charging qualify for a monthly "EV Meter Credit" on their bill to offset the Basic Charge associated with that second meter. Starting in October 2022, existing customers on the discontinued TOU-EV-1 rate were migrated to the separately metered TOU-D-PRIME rate. PEV owners may also opt to remain on their existing tariff, such as the default time-of-use schedule TOU-D-4to9 or Schedule D (domestic tiered rate schedule). Based on the number of PEVs SCE estimates are within its service territory, the majority of PEV owners seem to choose to remain on the default TOU or the tiered rate plan.^[1]

The primary focus of this report is on tariffs designed with consideration for PEV charging. For commercial PEV charging, SCE offers three tariffs: TOU-EV-7, TOU-EV-8, and TOU-EV-9, which are applicable exclusively for PEV charging. The following sections report the usage characteristics from January 2023 through December 2023 for residential PEV owners identified on the TOU-D-PRIME with both single-metered and separately-metered, and all commercial customers on TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs.

SCE designed TOU-D-PRIME tariff to provide an attractive charging option to PEV owners. The TOU-D-PRIME tariff, however, is open to all residential customers with any of these end uses: an electric vehicle, behind-the-meter energy storage, or an electric heat pump. To enroll in TOU-D-PRIME, customers must attest that they are eligible and have an electric vehicle or other qualifying equipment. With information system enhancement, this information is now easily accessible for reporting, which helps SCE to obtain substantially more PEV ownership data on TOU-D-PRIME than in previous years. Since May 2017, SCE began accepting applications for its Clean Fuel Rebate Program (CFRP) which provides rebates to PEV owners even if they are not the original owner of that PEV. SCE's Clean Fuel Rebate Program was completed in early 2021. The California Clean Fuel Reward (CCFR) launched in November of 2020, offering an instant reduction in the purchased price of a qualifying PHEV or BEV. Both CFRP and CCFR have provided a significant source of identification of PEV owners, which were included in this analysis as of the first full month following their purchase of the PEV. Additionally, any customers who self-identified as PEV owners with SCE by providing their information through email or contact with SCE's call center before December 2018 and currently take service under TOU-D-PRIME were also included in this analysis.

^[1] See Attachment 2, SCE Table 1.

PEV Rates

Residential

The TOU-D-PRIME tariff is a TOU tariff aimed at accommodating PEV charging. TOU-D-PRIME has the same periods as SCE’s TOU-D-4to9 rate plan option, but the PRIME option offers the lowest off-peak rates of all TOU rate plans. The price varies seasonally. As of October 2023, the latest rates within this report period, the lowest rate in the summer season was \$0.258/kWh during off-peak hours and in the winter season the lowest rate was \$0.236/kWh during super-off-peak hours. The tariff has a Basic Charge of \$0.429/meter/day throughout the year.

Customers with separately metered EV charging qualify for a monthly “EV Meter Credit” on TOU-D-PRIME, which offsets the Basic Charge associated with that second meter. The second meter was provided and installed at no additional cost to the customer, however the home’s electrical infrastructure may have needed to be upgraded with a second panel and wiring to the charging location. Any costs related to the changes to the home’s electrical infrastructure were the responsibility of the customer.

The TOU periods for this TOU-D-PRIME are defined as follows:

TOU-D-PRIME	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-off-peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

Table SCE – 1a represents the price ratios of the latest rates within the reporting period that were effective October 1st, 2023.

Table SCE – 1a: Residential Single-Metered/Separately Metered PEV Rate (TOU-D-PRIME) Price Ratios²¹

TOU-D-PRIME	Summer	Winter
	On-peak : Mid-peak : Off-peak	Mid-peak : Off-peak : Super-off-peak
Weekday	2.6 : N/A : 1.0	2.5 : 1.0 : 1.0
Weekend	N/A : 1.5 : 1.0	2.5 : 1.0 : 1.0

Commercial

Three rate options (tariffs) are available to commercial customers that separately meter the charging of PEVs. TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs are available depending on the expected size of the maximum demand. TOU-EV-7 is applicable to customers with charging demands less than 20 kW; TOU-

²¹ See <https://www.sce.com/wps/portal/home/regulatory/tariff-books>.

EV-8 is applicable to customers with charging demands equal to or more than 20 kW but less than 500 kW; and TOU-EV-9 is applicable to customers with charging demands of 500 kW and greater.

To facilitate the growth of PEV charging at these sites, these tariffs only have energy rates. They also include a customer charge. All these tariffs have the same TOU periods as our residential TOU-D-PRIME rate option shown in the above section. The prices vary seasonally and between tariffs. Beginning on March 1st, 2024, Option D was provided for TOU-EV-7 as an opt-in option in addition to the default energy-only Option E. Option D has Facilities Related Demand Charges. The phase-in of Facilities Related Demand and Time-related Demand charges for TOU-EV-8 and TOU-EV-9 was extended beyond the initial five-year period. At this time, these demand charges are scheduled to begin a five-year phase in with the implementation of rates adopted in Phase 2 of SCE’s 2025 GRC unless an alternative proposal is approved.

Table SCE – 1b, 1c, and 1d represent the price ratios for energy of each commercial PEV rate effective October 1st, 2023. For customers with demand of 500 kW and above, rates are further differentiated by the service voltage level. The associated customer charges as of October 1st, 2023 were: \$0.237/meter/day for TOU-EV-7; \$188.98/meter/month for TOU-EV-8; and \$355.45/meter/month (below 2 kV), \$367.81/meter/month (2 kV to 50 kV), \$3458.53/meter/month (above 50 kV) for TOU-EV-9.

Table SCE – 1b: Commercial PEV Rate (TOU-EV-7) Price Ratios

TOU-EV-7	Summer	Winter
	On-peak : Mid-peak : Off-peak	Mid-peak : Off-peak : Super-off-peak
Weekday	2.6 : N/A : 1.0	3.2 : 1.9 : 1.0
Weekend	N/A : 1.5 : 1.0	3.2 : 1.9 : 1.0

Table SCE – 1c: Commercial PEV Rate (TOU-EV-8) Price Ratios

TOU-EV-8	Summer	Winter
	On-peak : Mid-peak : Off-peak	Mid-peak : Off-peak : Super-off-peak
Weekday	3.1 : N/A : 1.0	3.5 : 2.0 : 1.0
Weekend	N/A : 1.6 : 1.0	3.5 : 2.0 : 1.0

Table SCE – 1d: Commercial PEV Rate (TOU-EV-9) Price Ratios

TOU-EV-9	Summer	Winter
	On-peak : Mid-peak : Off-peak	Mid-peak : Off-peak : Super-off-peak
(Below 2 kV)		
Weekday	3.0 : N/A : 1.0	3.3 : 1.8 : 1.0
Weekend	N/A : 1.7 : 1.0	3.3 : 1.8 : 1.0
(2 kV to 50 kV)		
Weekday	2.9 : N/A : 1.0	3.3 : 1.8 : 1.0
Weekend	N/A : 1.7 : 1.0	3.3 : 1.8 : 1.0
(Above 50 kV)		
Weekday	3.2 : N/A : 1.0	2.9 : 1.7 : 1.0
Weekend	N/A : 1.5 : 1.0	2.9 : 1.7 : 1.0

The Net Energy Metering (NEM) tariff provides compensation for customers with distributed generation resources such as photovoltaic solar systems. The energy produced by these systems may be consumed on-site and excess generation is exported to the grid. This reduces the amount of energy purchased from the grid. As shown in Table SCE – 2a, the coincidence of PEV ownership and enrollment in the NEM rate option has been consistently growing and by December 2023, it increased to 32% of the current, whole-house TOU-D-PRIME tariff.

Table SCE – 2a: NEM Program Enrollment for Residential Single Metering by Customer Type

Month	NEM Customers with Single Metering	NEM as % Single Metering	NEM as % SF Single Metering	NEM as % MDU Single Metering
Jan. 2023	29,413	27%	31%	8%
Feb. 2023	30,531	27%	31%	8%
Mar. 2023	31,527	28%	31%	8%
Apr. 2023	32,780	28%	32%	9%
May. 2023	33,781	28%	32%	9%
Jun. 2023	34,648	28%	32%	9%
Jul. 2023	35,970	29%	33%	9%
Aug. 2023	37,872	30%	34%	9%
Sep. 2023	39,962	30%	35%	9%
Oct. 2023	41,258	31%	35%	10%
Nov. 2023	44,345	32%	36%	10%
Dec. 2023	45,648	32%	37%	10%

There were fewer than fifteen separately-metered residential customers enrolled in the NEM program, therefore no data is reported for the NEM Program Enrollment for Residential Separate Metering.

There was no NEM participation on the commercial PEV tariff TOU-EV-7. During this reporting period, only a couple TOU-EV-8 and TOU-EV-9 customers were enrolled in the NEM program.

Number of PEV Time-of-Use Accounts

SCE’s residential single-metered rate option is open to all residential customers with any of these end uses: an electric vehicle, behind-the-meter energy storage, or an electric heat pump. SCE leveraged its Clean Fuel Rebate program and California Clean Fuel Reward program, which were funded by Low Carbon Fuel Standard credit revenues, to identify customers with EVs. Prior to 2019, some PEV owners were also identified through the California Air Resources Board’s California Clean Vehicle Rebate Project. Additionally, customers previously on the, now closed, TOU-D-TEV tariff were included. This tariff was exclusive to PEV owners. For most customers, the date of PEV acquisition is not known. This report includes any owners of vehicles where the model year of their vehicle is older than the current year. As such, 2023 statistics include any accounts with PEVs from model year 2022 or older.

TOU-D-PRIME became available to customers in March 2019. However, at the time, it was unknown which qualifying clean energy technology was adopted by customers. To enroll in TOU-D-PRIME, customers must attest that they are eligible and have an electric vehicle or other qualifying equipment. As the result of information system enhancement, this information is now easily accessible for reporting which helped SCE obtain significantly more PEV ownership data on TOU-D-PRIME than in previous years. Since 2019 and continuing in 2023, there has been a consistent increase in the number of accounts with PEVs for both single-family and multi-family units as can be seen in Chart SCE – 1. It is not known if this trend reflects growth in the overall market, other factors that may influence the enrollment rate in TOU-D-PRIME, or self-identification rates (e.g. rebate incentives, tariff changes, propensities to contact the Call Center, utility or industry marketing efforts, new vehicle models with different specifications, etc.). As of December 2023, SCE has identified 141,319 single-metered PEV owners, of which 83 percent were single-family units. The substantial increase in the number of accounts during 2023 was largely attributed to SCE’s residential default TOU implementation starting in late 2021, and the contribution of TOU-D-PRIME attestation

**Chart SCE – 1: Residential Single Meter (TOU-D-PRIME) –
Number of Accounts by Customer Type at the Beginning of Each Month**

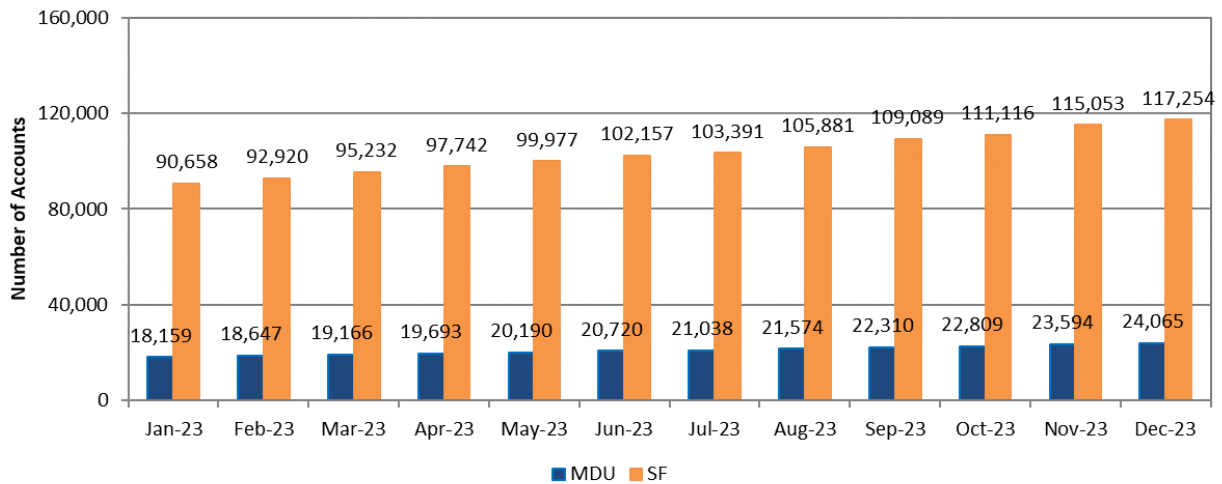
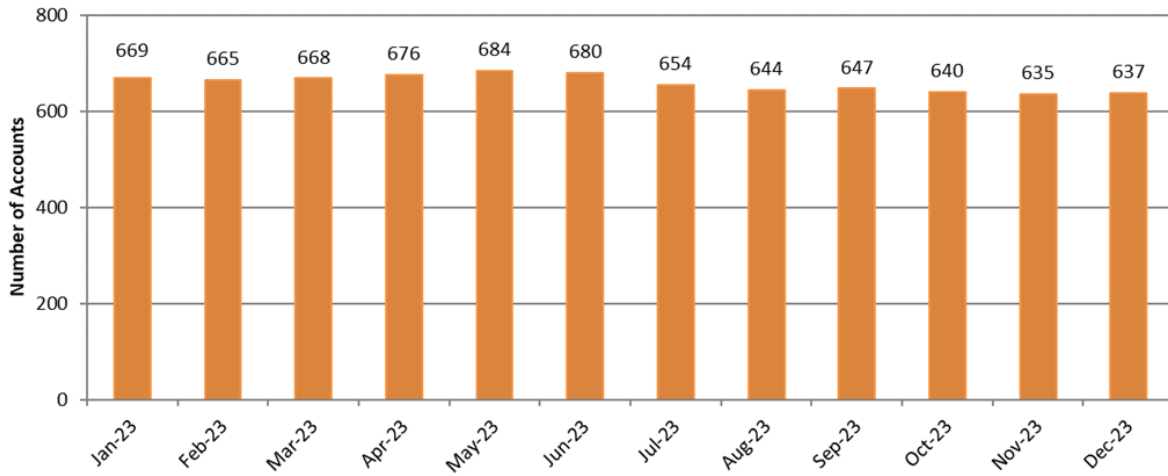


Chart SCE – 2a shows a slight downward trend of separately-metered accounts (TOU-D-PRIME) over this reporting period. As of December 2023, SCE has identified 637 separately-metered PEV owners. Starting in October 2022, TOU-EV-1 was closed and customers taking service on the tariff were transferred to the separately-metered TOU-D-PRIME. The tariff is also open to customers who already have or install a second meter at their household for charging their EV. However, the majority of the customers on the separately-metered TOU-D-PRIME were migrated from the retired TOU-EV-1 tariff, rather than new enrollees, presumably due to the cost of upgrading electrical infrastructure for a second meter. The number of separately-metered accounts reported here are only the accounts which register charging during the month. There are some active accounts which persistently have zero usage. This could occur if the location is not a primary residence or if there was a change of ownership and the PEV is no longer present. It could also occur if all the charging is done away from the residence.

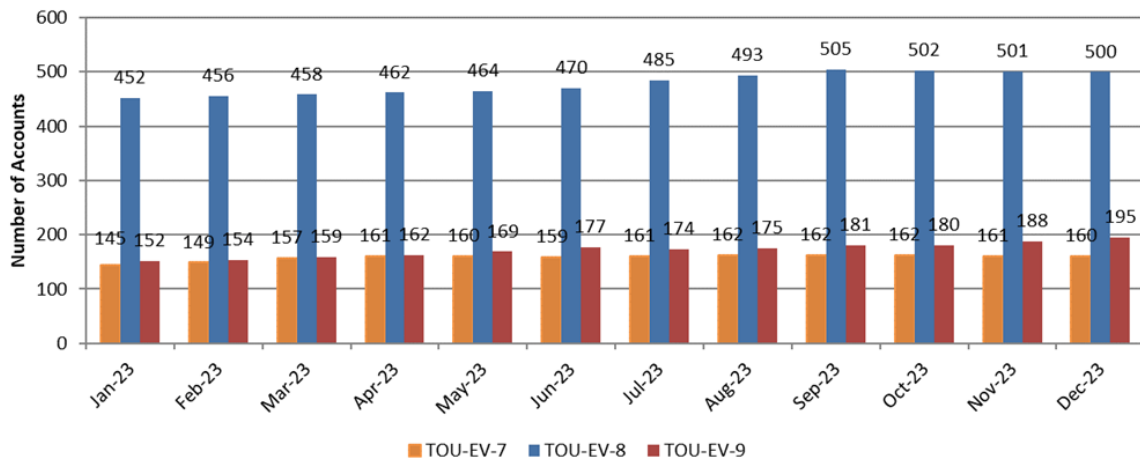
Chart SCE – 2a: Residential Separate Meter (TOU-D-PRIME) – Number of Accounts at the Beginning of Each Month



SCE – 2b reflects the steady upward trend of commercial, separately-metered accounts. As of December 2023, there were 160 customers served on TOU-EV-7 tariff, 500 customers served on TOU-EV-8, and 195 customers served on TOU-EV-9. Demand for commercial TOU-EV rates has been boosted by SCE’s PEV programs which invest in PEV charging infrastructure. The growth rate is the greatest for TOU-EV-9 during 2023.

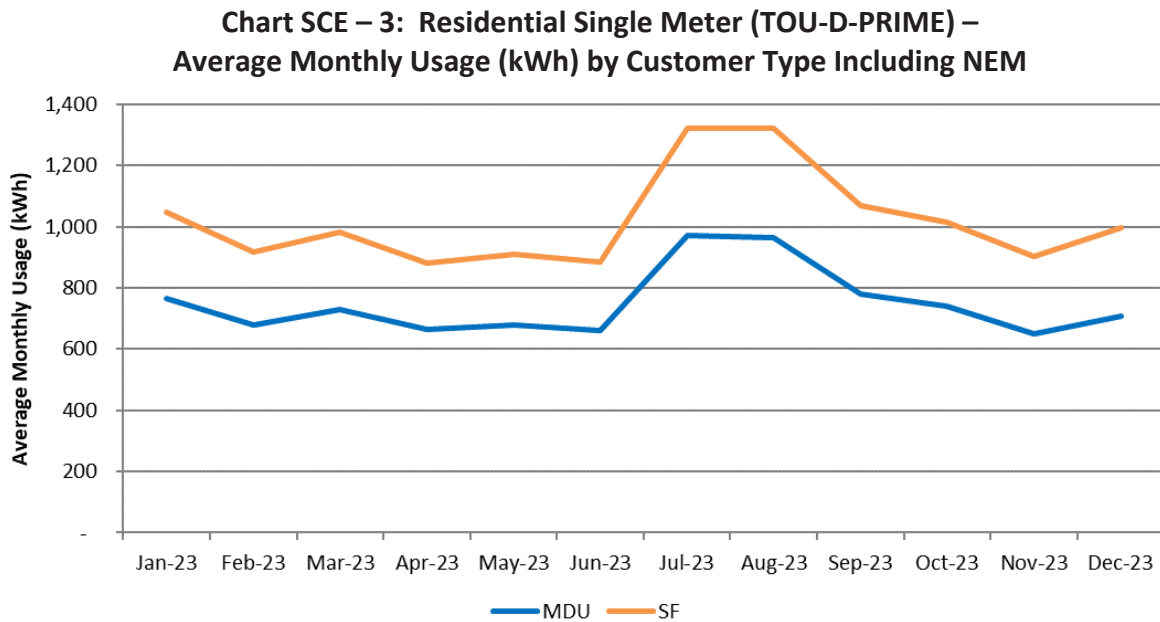
The number of the customers reported here are only the accounts which registered charging during the month. There are a number of accounts which have zero usage, this might occur when the account is first established but has not yet started charging PEVs or does not have any PEV charging due to various other reasons.

Chart SCE – 2b: Commercial Separate Meter – Number of Accounts at the Beginning of Each Month



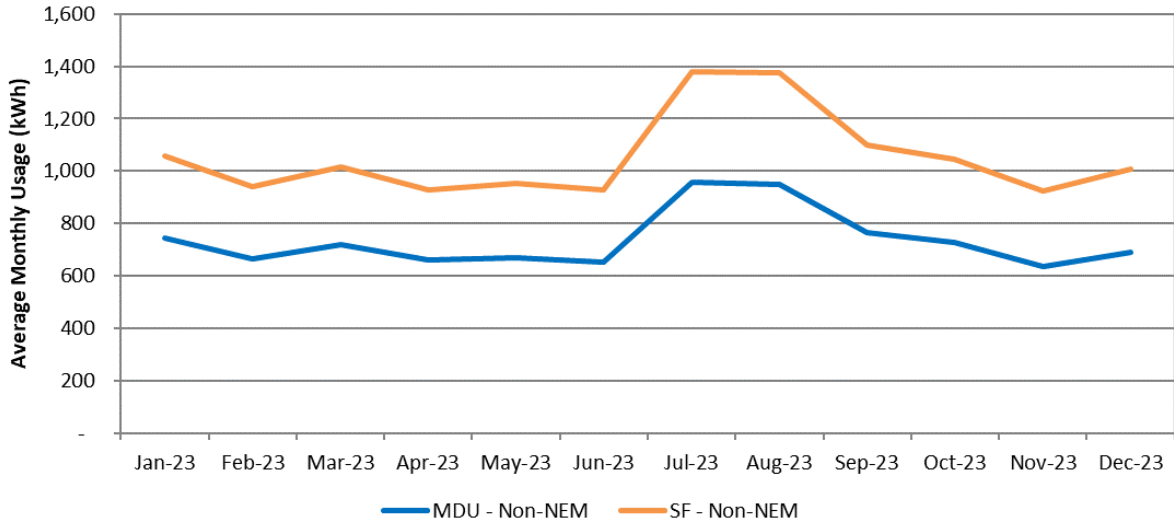
Average Monthly Usage for TOU Accounts with a PEV

The average monthly household usage for single-metered households with a PEV shown in Chart SCE – 3 depicts the same seasonal pattern as in previous years as well as very similar usage levels. Single-family dwellings have 36 percent more usage than multi-family units but the same pattern over the course of the year, with the lowest usage occurring February through June, and again in November. July to September have the highest usage for single-metered households. This is the typical seasonal behavior of residential households, which is primarily driven by cooling. The greatest average usage during the twelve months occurred in July 2023 at 1,322 kWh for SF and at 971 kWh for MDU.



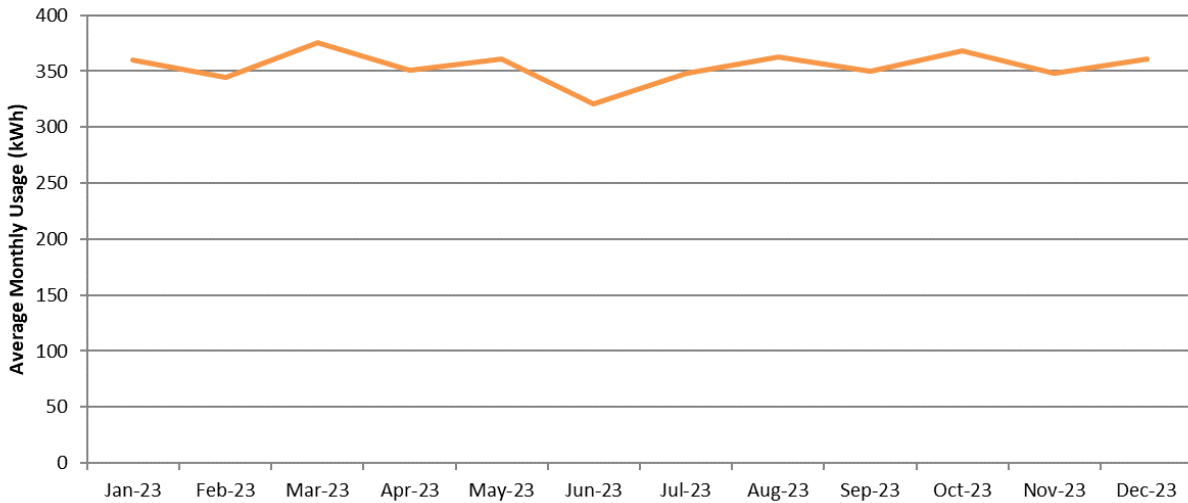
Excluding NEM accounts has very little impact on the average monthly usage of PEV owners, as seen in Chart SCE – 4. The annual monthly usage pattern remains identical to what is shown in Chart SCE – 3. The usage is slightly higher when NEM accounts are excluded, indicating that the NEM households with PEVs take less electricity from the grid than the non-NEM PEV owners. The small impact is in part the result of the relatively small percentage of NEM accounts. Also, the average monthly usage for NEM households is only the energy that is delivered by SCE, not the total consumption or the delivered energy net of exports. If NEM households have higher consumption than non-NEM households, then the balance of their consumption served by SCE might be similar between the two groups. This would also explain why the average monthly usage changes very little when NEM households are excluded.

Chart SCE – 4: Residential Single Meter (TOU-D-PRIME) – Average Monthly Usage (kWh) by Customer Type Excluding NEM



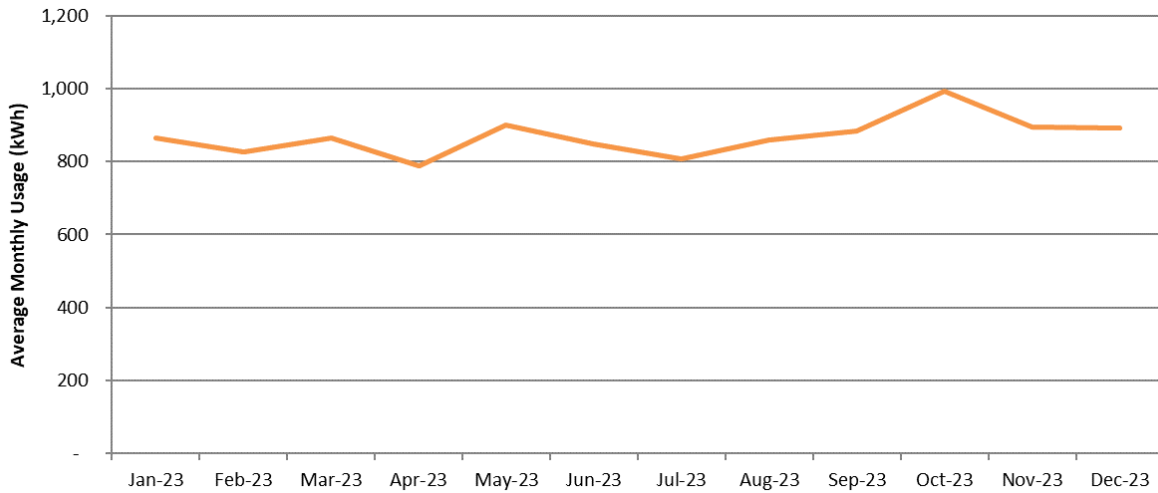
The average monthly usage displayed in Chart SCE – 5a for separately-metered PEVs ranged from 321 kWh to 375 kWh per month during 2023. The consistent usage observed by the separately-metered PEVs supports the presumption that the seasonal trends seen in the household usage of single-metered PEV owners is not the result of PEV charging.

Chart SCE – 5a: Residential Separate Meter (TOU-D-PRIME) – Average Monthly Usage



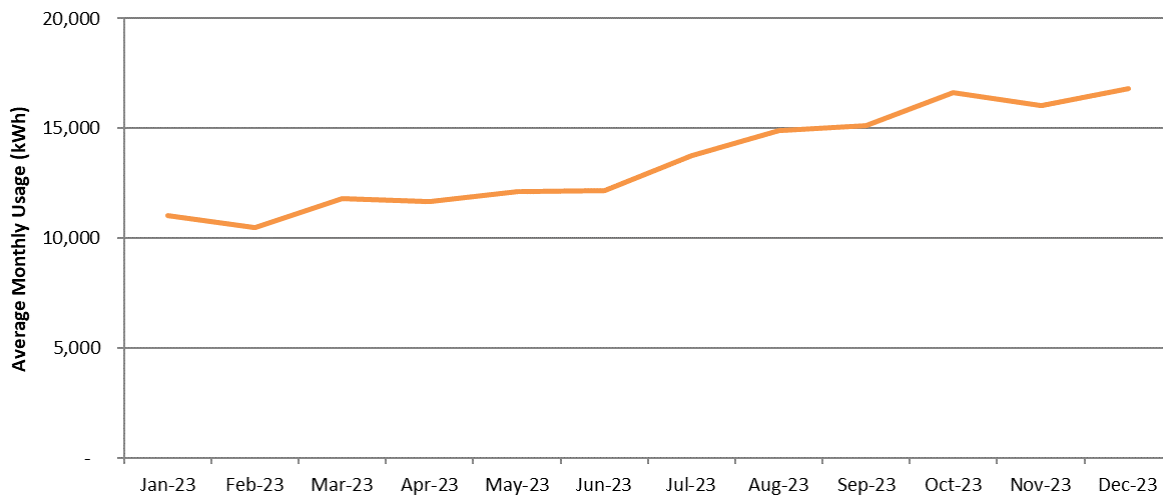
SCE – 5b depicts an upward trend in average monthly usage for commercial separately-metered TOU-EV-7, ranging from 787 kWh to 992 kWh per month during 2023. The average monthly usage remained above 800 kWh level. It shows the same seasonal pattern as in the previous year with slightly higher usage levels.

Chart SCE – 5b: Commercial Separate Meter (TOU-EV-7) – Average Monthly Usage



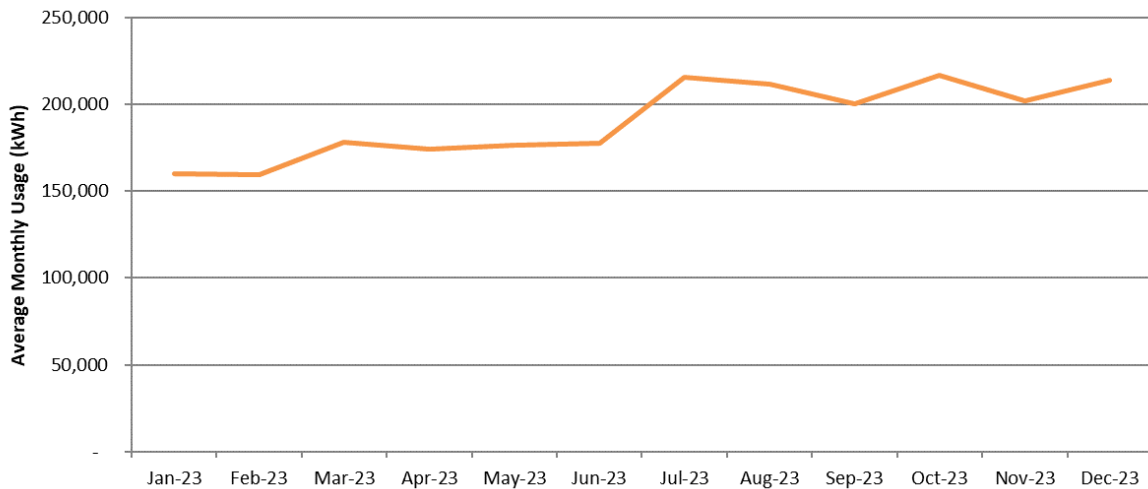
Similar to TOU-EV-7 customers, Chart SCE – 5c depicts a growing average monthly usage for commercial, separately-metered, TOU-EV-8 customers. The average monthly usage nearly doubled the pre-pandemic level of 6,000 kWh. It continues to increase and hit the highest average monthly usage at 16,811 kWh in December 2023.

Chart SCE – 5c: Commercial Separate Meter (TOU-EV-8) – Average Monthly Usage



The average monthly usage for commercial, separately metered, TOU-EV-9 customers shown in Chart SCE- 5d also displays a growing trend as observed for other commercial PEV tariffs. The average monthly usage peaked at 215,603 kWh as of July 2023 and remained stable in the following months.

Chart SCE – 5d: Commercial Separate Meter (TOU-EV-9) – Average Monthly Usage



Average Usage during Time-of-Use Periods

As the number of single-metered TOU-D-PRIME accounts has increased, it has become unmanageable to analyze the entire population. Therefore, subsequent load profiles and usage characteristics are inferred from a random sample of 10,000 accounts.

Some of the subsequent load profiles and usage characteristics will also include the average residential customer as a benchmark for the single-metered PEV customers. This data is derived from SCE’s 2022 Domestic Rate Group Load Study, which is based on the 2022 calendar year.

Tables SCE – 3, 4, 5, and 6 each show the proportion of seasonal usage by time-of-use period for single-metered households. PEV owners have the greatest share of their usage within the off-peak window of the TOU-D-PRIME tariff as shown in Table SCE – 5. During the summer of 2023, 78 percent of usage by PEV owners without NEM occurred during off-peak hours and during winter, the amount of usage was 52 percent. Both are significantly higher than the proportion of usage by the general residential population during off-peak hours at 70 percent and 43 percent, respectively. From Table SCE – 3 to 6, all groups have the lowest proportion of usage occurring in mid-peak hours.

Table SCE – 3: Residential Single Meter (TOU-D-PRIME) – On-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2023	21.5%	15.5%	15.5%	15.4%	15.4%
Winter 2023	N/A	N/A	N/A	N/A	N/A

* On-peak period is defined as 4:00 p.m. - 9:00 p.m., Summer weekdays.

Table SCE – 4: Residential Single Meter (TOU-D-PRIME) – Mid-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2023	8.9%	6.7%	6.7%	6.6%	6.8%
Winter 2023	26.2%	19.3%	19.2%	19.4%	19.8%

* Mid-peak period is defined as 4:00 p.m. - 9:00 p.m., Weekends/Holidays, all year; and 4:00 p.m. - 9:00 p.m., Winter Weekdays.

Table SCE – 5: Residential Single Meter (TOU-D-PRIME) – Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2023	69.6%	77.9%	77.8%	78.0%	77.8%
Winter 2023	42.8%	51.8%	51.5%	53.3%	64.6%

* Off-peak period is defined as all other hours that are not On-peak, Mid-peak, or Super-Off-peak.

Table SCE – 6: Residential Single Meter (TOU-D-PRIME) – Super-Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2023	N/A	N/A	N/A	N/A	N/A
Winter 2023	31.0%	29.0%	29.3%	27.3%	15.6%

* Off-peak period is defined as 8:00 a.m. - 4:00 p.m., Winter daily.

Similarly, PEV owners with a separate meter for their vehicle also have the greatest share of their usage within the off-peak window of the TOU-D-PRIME tariff, as shown in Table SCE – 7. During the summer of 2023, 90 percent of usage occurred during off-peak hours and during winter, the amount of off-peak usage was 76 percent. This behavior may be attributable to the habit of observing the retired TOU-EV-1 time-of-use periods, which had lower rates applied during off-peak hours of 9:00 p.m. to 12:00 noon daily.

Table SCE – 7: Residential Separate Meter (TOU-D-PRIME) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2023	6.9%	2.9%	90.2%	N/A
Winter 2023	N/A	10.4%	75.6%	14.0%

Tables SCE – 8a, 8b, and 8c show the proportion of seasonal usage by time-of-use period for each of the commercial, separately-metered rate options. Each table shows a similar usage pattern, in which the greatest share of their usage falls within the lowest rate window.

In summer, TOU-EV-7 customers charge 76 percent on average during the off-peak window; TOU-EV-8 and TOU-EV-9 customers charge slightly lower, 74 percent and 72 percent, respectively. In winter, each group of commercial, separately metered customers charge over 44 percent during the super off-peak window on average. Nonetheless, this does not necessarily lead to the conclusion that customers on commercial PEV rates are responsive to the TOU price signals, because most charging stations and public facilities do not differentiate TOU prices for individual users.

Table SCE – 8a: Commercial Separate Meter (TOU-EV-7) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2023	17.4%	6.8%	75.8%	N/A
Winter 2023	N/A	22.9%	32.5%	44.6%

Table SCE – 8b: Commercial Separate Meter (TOU-EV-8) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2023	18.6%	7.2%	74.2%	N/A
Winter 2023	N/A	25.3%	26.7%	47.9%

Table SCE – 8c: Commercial Separate Meter (TOU-EV-9) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2023	19.2%	8.7%	72.1%	N/A
Winter 2023	N/A	27.3%	27.1%	45.6%

Average Load Profiles - Residential

Average hourly load profiles provide a clear visual depiction of the daily usage patterns. Load profiles are shown on the same chart for single- and multi-family dwellings. Additionally, average hourly load profiles are shown by day type for accounts which self-identified with SCE as PEV owners and remain on the regular domestic, Schedule D, tariff.

The load profiles for single-family and multi-family households with a PEV that opted for the TOU-D-PRIME tariff are shown in Chart SCE – 6. As is typical with residential annual average hourly usage, usage peaks in the evening around 8:00 p.m. Mid-day usage is lower every day, but not quite as low on the weekend as on weekdays. Rather than declining into the morning hours, however, these profiles exhibit a large spike and peaking at 10 p.m. before tapering until 6:00 a.m. For SF customers, the peak of the weekday spike averages 2.30 kW, 48% greater than the 1.55 kW average usage at 8:00 p.m. The

beginning of the spike at 10 p.m. corresponds directly with the off-peak time period of the TOU-D-PRIME tariff and is abnormal for typical residential customers. The peak is likely attributable to PEV charging; however, the observed usage includes all household loads during these hours. Nearly identical behavior is observed with MDU customers in the same Chart SCE – 6, with the exception that the average hourly usage is lower, peaking at 1.60 kW on weekdays. Altogether it appears that the PEV owners who choose a TOU rate for their household and PEV electricity needs are very responsive to the TOU period prices.

Chart SCE – 6: Residential Single Meter (TOU-D-PRIME), Average Hourly Load Profile by Day Type

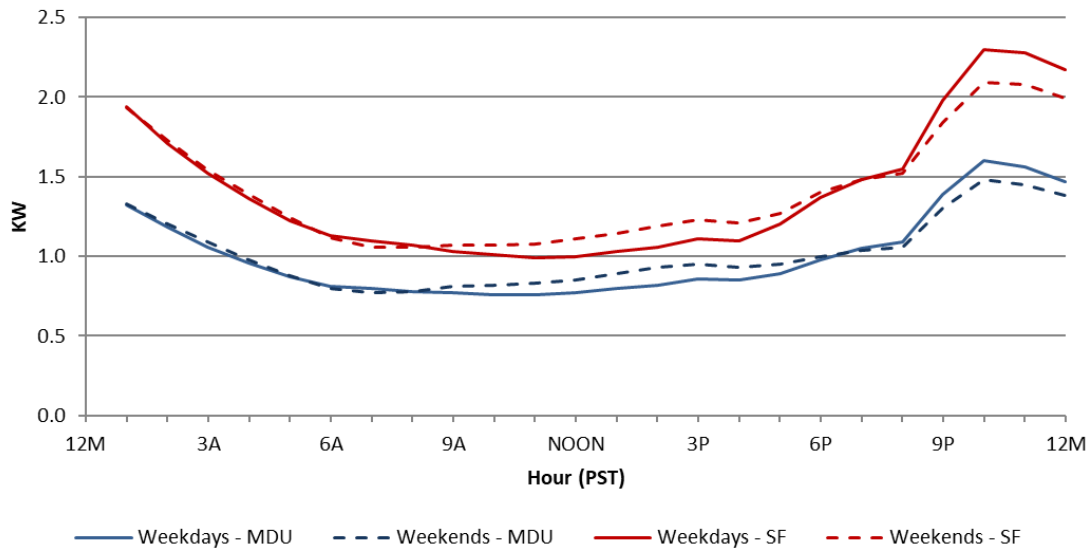


Chart SCE-7 shows that separately metered PEVs commence charging promptly at the beginning of the off-peak period around 9:00-10:00 p.m. After 12:00 a.m., demands begin to taper off as vehicles reach full charges. The highest demand occurs on weekdays and has an average hourly demand of 1.3 kW. Weekend peak demand is around 1.1 kW. Charging during the day between 6:00 a.m. and 8:00 p.m. is very low. Interestingly, the average load profiles for these accounts are nearly identical to the load profiles of the retired TOU-EV-1 tariff. The behaviors of these separately metered PEV owners who migrated from TOU-EV-1, still resemble the charging habits from before the migration.

Chart SCE – 7: Residential Separate Meter (TOU-D-PRIME) - Average Hourly Load Profile by Day Type

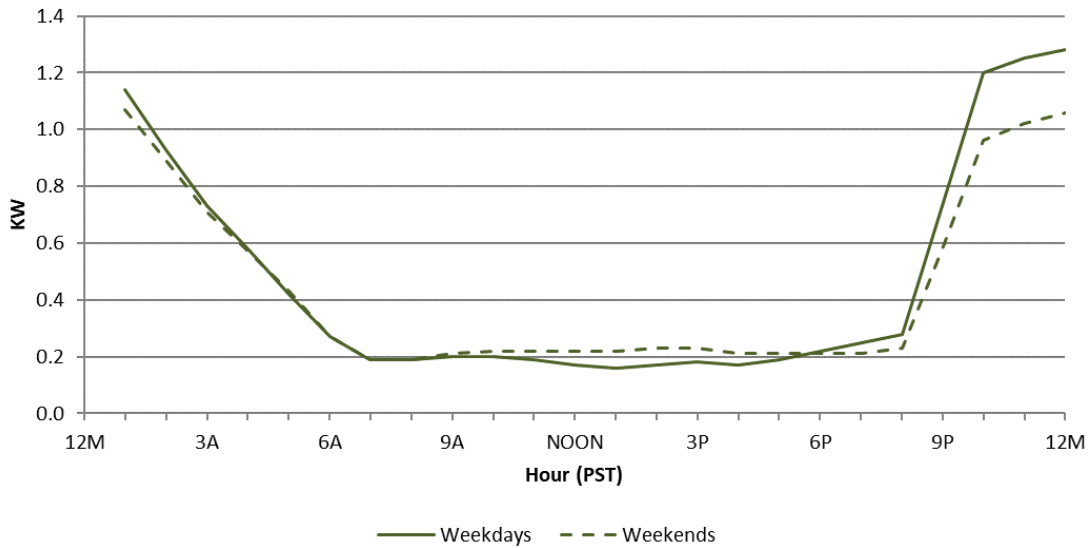
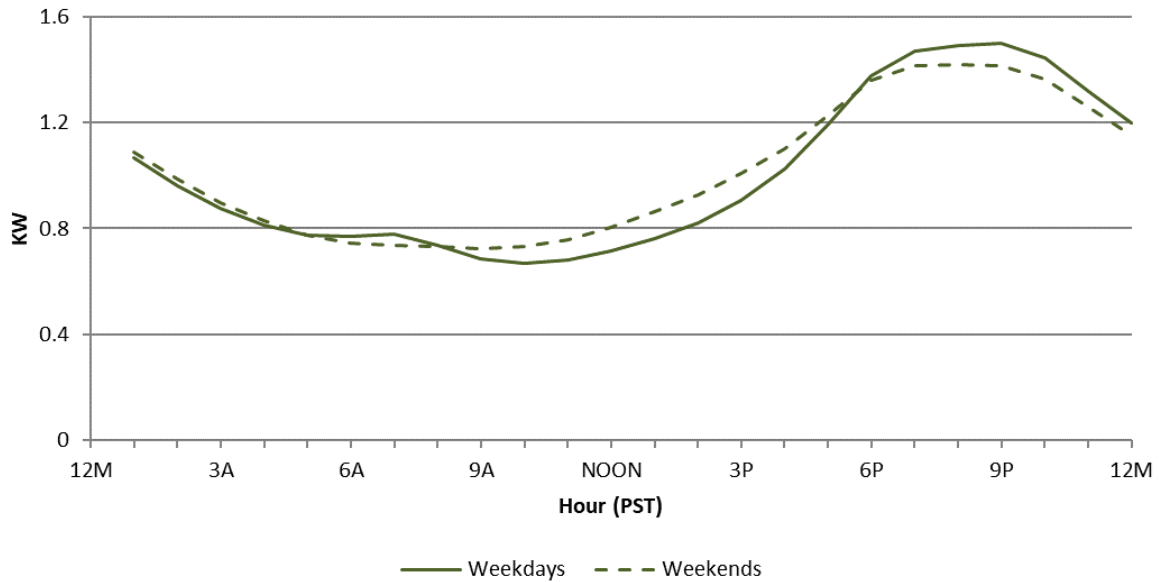


Chart SCE – 8 shows the load profile for a portion of the SF customers who are believed by SCE to own a PEV but choose to remain on the regular, tiered domestic rate. Their daytime demand begins to rise around 10:00 a.m. where it is 0.7 kW on weekdays and increases gradually until it peaks in the evening at 9:00 p.m. at about 1.5 kW on average. Weekend loads are slightly higher during the middle of the day but notably have lower evening peak loads. Late evening loads are also lower presumably due to less PEV charging. As compared to the single-family, single-metered TOU customers in Chart SCE – 6, these non-TOU customers lack the larger peak occurring at midnight.

Chart SCE – 8: Residential Single Meter, SF PEV Owners²² on a Non-TOU Rate – Average Hourly Load Profile by Day Type



Average Load Profiles - Commercial

Chart SCE – 9a shows the load profile for commercial separately-metered TOU-EV-7 customers. The average weekday demand begins to rise from 0.5 kW around 5:00 a.m. and steeply increases to the peak of 1.95 kW around 10:00 a.m., before tapering off for the rest of the day. Weekday daily usage is 30 kWh on average, 28 percent more than weekend daily usage. Before 5:00 a.m. the weekend profile almost overlaps with the weekday profile, however, unlike the weekday load which spikes in the morning, weekend load displays a smoother pattern from 6:00 a.m. to the midnight with the peak demand of 1.2 kW relatively consistently occurring from noon to 6:00 p.m.

²² As of December 2023, there were 50,648 accounts, on the Domestic rate schedule (including NEM customers) with load data, which are known to own a PEV.

Chart SCE – 9a: Commercial Separate Meter (TOU-EV-7) - Average Hourly Load Profile by Day Type

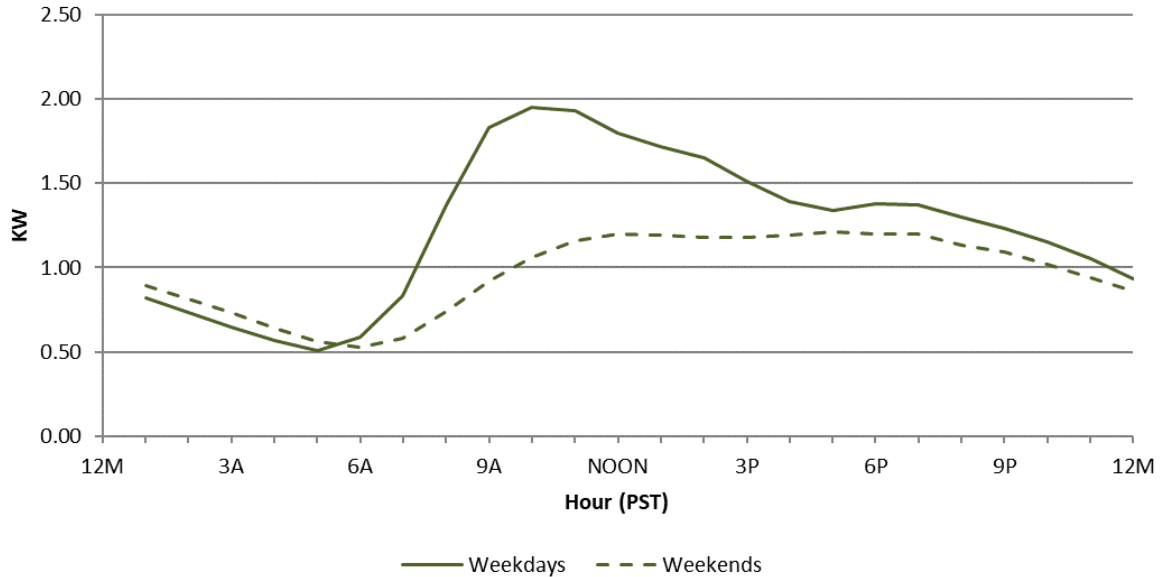
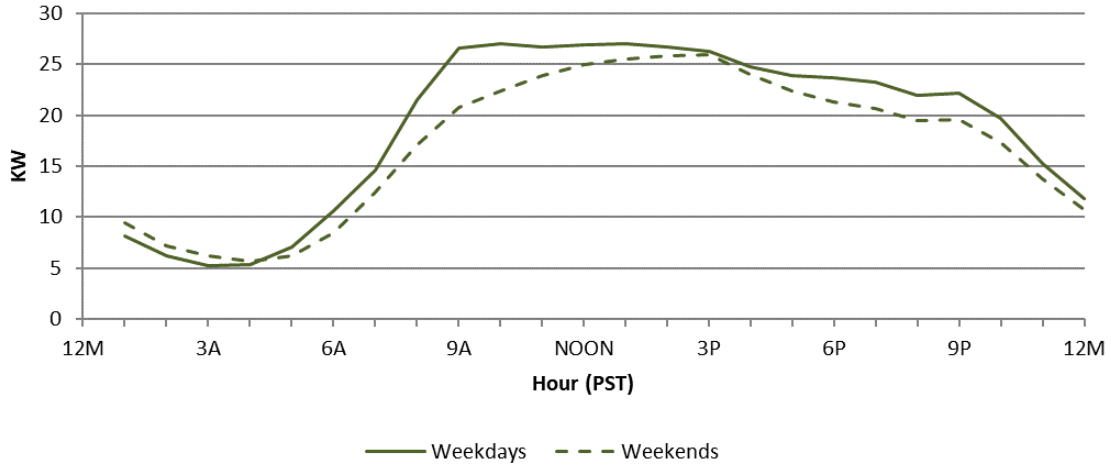


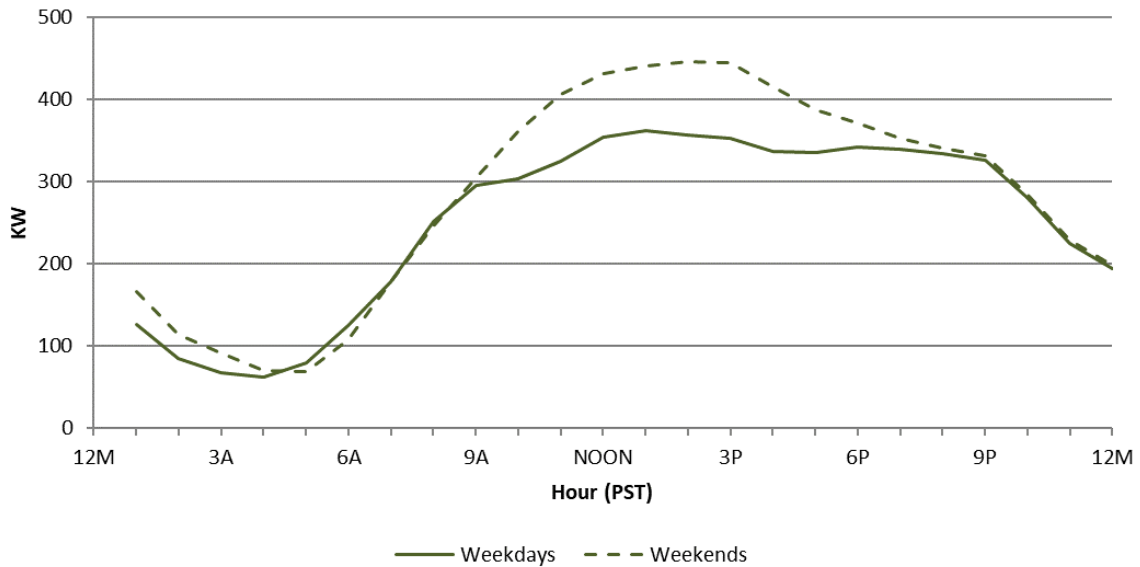
Chart SCE – 9b provides average weekday and weekend hourly load profiles for customers on separately-metered TOU-EV-8. The average weekday demand begins to rise around 5:00 a.m. where it is about 7 kW and peaks at 10:00 a.m. with an average demand of 27 kW. The demand remains near 27 kW until 3:00 p.m. From there it tapers off for the rest of the day. TOU-EV-8 consists of different business types with different load characteristics. The morning load peak is more likely driven by workplaces and school districts, whereas demand from charging networks and destination center charging occurs later in the day. Together they maintain a level load during mid-day from 9:00 a.m. to 3:00 p.m. Weekend demand also begins to rise from about 6 kW around 5:00 a.m. and gradually increases to the peak around 3:00 p.m. From an average peak demand of 26 kW it tapers off for the rest of the day.

Chart SCE – 9b: Commercial Separate Meter (TOU-EV-8) - Average Hourly Load Profile by Day Type



Unlike the other two commercial PEV tariffs, TOU-EV-9, as shown in Chart SCE – 9c, depicts a similar load shape for both weekdays and weekends, but with a lower weekday usage during mid-day. The weekday peak averages 361 kW around 1:00 p.m., 19 percent lower than the weekend peak of 446 kW at 2:00 p.m. Among commercial PEV tariffs, the TOU-EV-9 charging behavior is distinct in that it peaks prominently on the weekend.

Chart SCE – 9c: Commercial Separate Meter (TOU-EV-9) - Average Hourly Load Profile by Day Type



Average Non-Coincident Peak Load

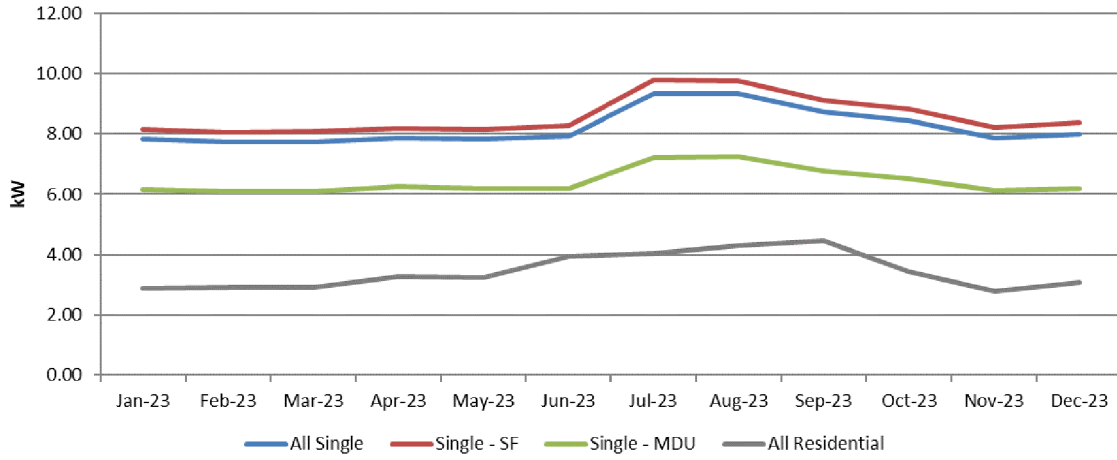
The size and timing of demands on the distribution system as a result of PEV charging is necessary to understand any potential impacts on reliability. This first section will look at the non-coincident peaks for the individual accounts with EVs. Subsequently the diversified group peak will be considered.

The average monthly non-coincident peak for all single-metered PEV households of 8.2 kW, as shown in Table SCE – 9. This is 4.8 kW higher than the residential population as a whole. Chart SCE – 10 shows a seasonal fluctuation in non-coincident demands ranging from a high of 9.4 kW in July 2023 to a low of 7.7 kW in February 2023. The non-coincident demands for single-metered households are about twice as large as the non-coincident demands for general residential population. The general residential population, however, displays a similar seasonal variation in non-coincident demand levels.

**Table SCE – 9: Single Meter (TOU-D-PRIME) –
Monthly Average Non-Coincident Peak Load (kW)**

Month	Residential Pop.	SF Pop.	MDU Pop.	All Single Metering	SF Single Metering	MDU Single Metering
Jan-23	2.87	3.15	2.45	7.83	8.16	6.16
Feb-23	2.91	3.20	2.47	7.72	8.04	6.08
Mar-23	2.91	3.25	2.41	7.73	8.07	6.08
Apr-23	3.27	3.72	2.60	7.86	8.19	6.24
May-23	3.25	3.75	2.50	7.82	8.15	6.18
Jun-23	3.94	4.68	2.84	7.94	8.28	6.20
Jul-23	4.03	4.78	2.92	9.35	9.78	7.22
Aug-23	4.28	5.09	3.06	9.34	9.76	7.25
Sep-23	4.45	5.30	3.19	8.73	9.12	6.77
Oct-23	3.42	3.98	2.58	8.43	8.82	6.52
Nov-23	2.78	3.09	2.32	7.87	8.22	6.13
Dec-23	3.06	3.40	2.55	8.00	8.37	6.19

Chart SCE – 10: Residential Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)

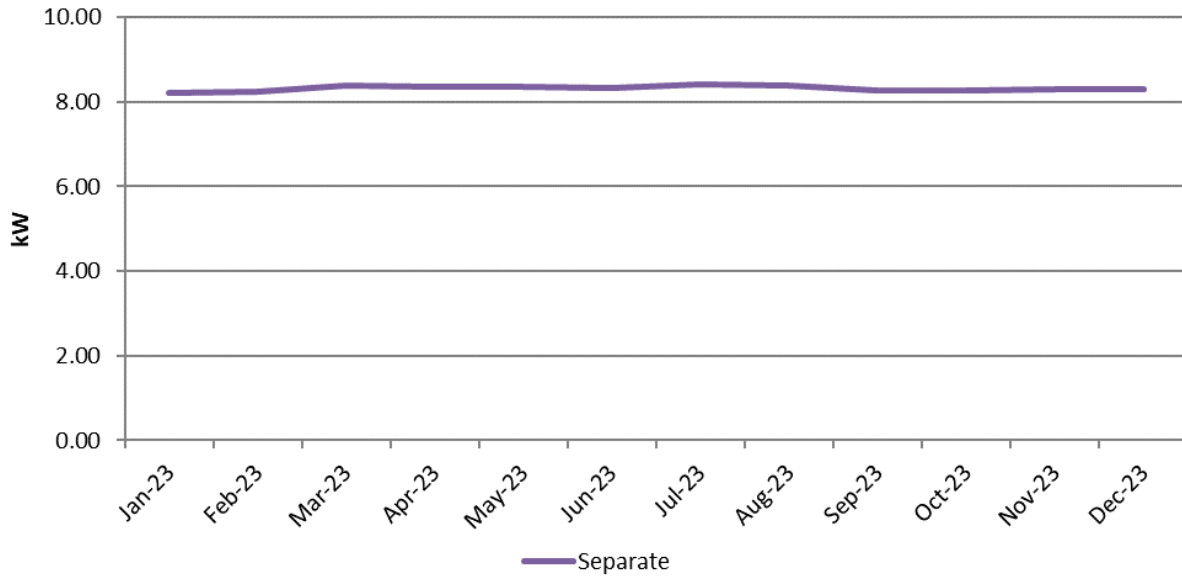


For separately-metered PEV loads, Table SCE – 10 and Chart SCE – 11 show a steady monthly non-coincident demand. The non-coincident demand averaged 8.3 kW over the whole period.

Table SCE – 10: Residential Separate Meter (TOU-D-PRIME – Monthly Average Non-Coincident Peak Load (kW)

Month	Separate Metering
Jan-23	8.21
Feb-23	8.24
Mar-23	8.38
Apr-23	8.36
May-23	8.35
Jun-23	8.33
Jul-23	8.40
Aug-23	8.39
Sep-23	8.28
Oct-23	8.28
Nov-23	8.31
Dec-23	8.31

Chart SCE – 11: Separate Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)



The average monthly non-coincident peak for non-residential customers on TOU-EV-7, TOU-EV-8 and TOU-EV-9, is shown in Chart SCE – 12a, 12b and 12c respectively. They display a steady rise during the study period which corresponds to the pattern in their average monthly usage. The average monthly non-coincident peak for TOU-EV-7 customers fluctuates around 11 kW. Customers on TOU-EV-8 hit their highest average monthly non-coincident peak of 109 kW in December 2023 and TOU-EV-9 hits the highest peak at 869 kW in November 2023.

Table SCE – 11: Commercial Separate Meters – Monthly Average Non-Coincident Peak Load (kW)

Month	TOU-EV-7	TOU-EV-8	TOU-EV-9
Jan-23	10.24	89.57	716.60
Feb-23	10.75	92.16	745.22
Mar-23	10.22	92.10	758.06
Apr-23	10.08	93.72	760.79
May-23	11.24	91.15	766.29
Jun-23	11.95	91.62	772.57
Jul-23	9.91	95.86	840.49
Aug-23	10.17	100.65	853.70
Sep-23	10.53	100.91	850.55
Oct-23	10.80	105.11	861.61
Nov-23	10.58	106.57	868.91
Dec-23	10.75	109.47	853.22

Chart SCE – 12a: Commercial Separate Meter (TOU-EV-7) – Monthly Average Non-Coincident Peak Load (kW)

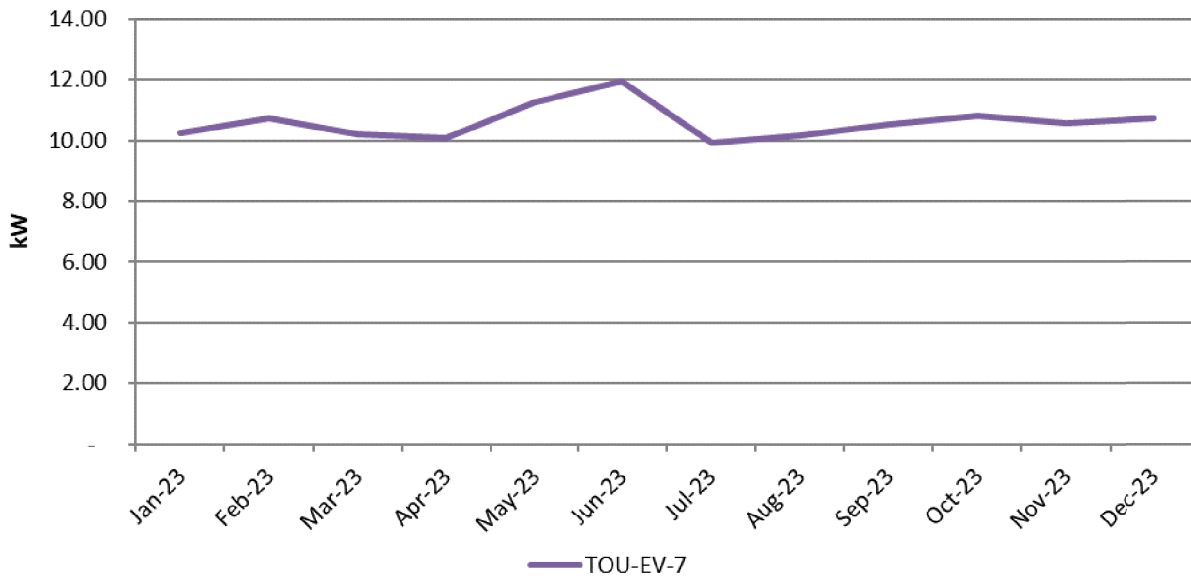


Chart SCE – 12b: Commercial Separate Meter (TOU-EV-8) – Monthly Average Non-Coincident Peak Load (kW)

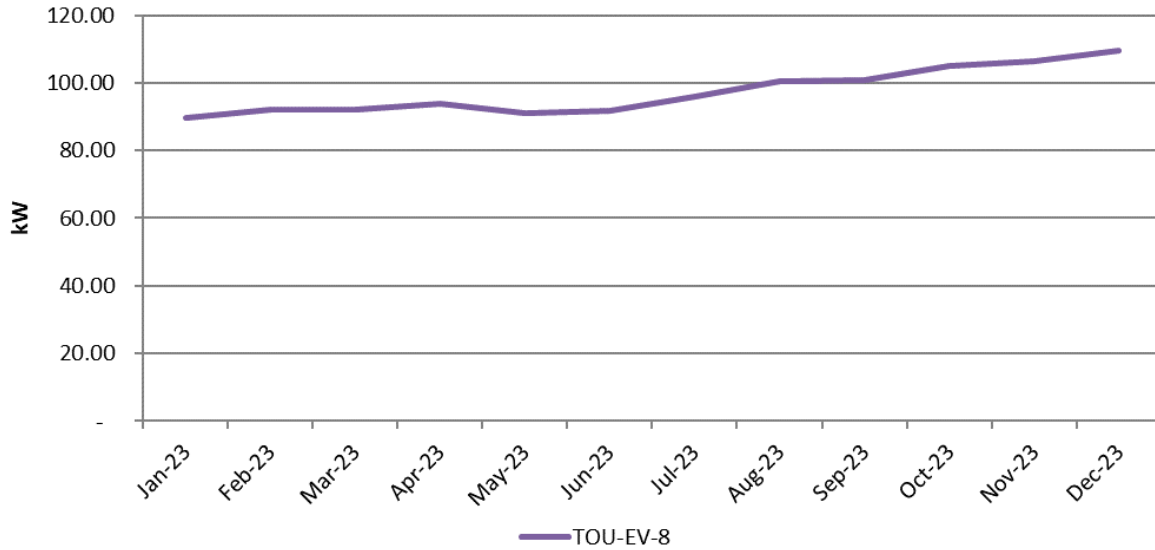
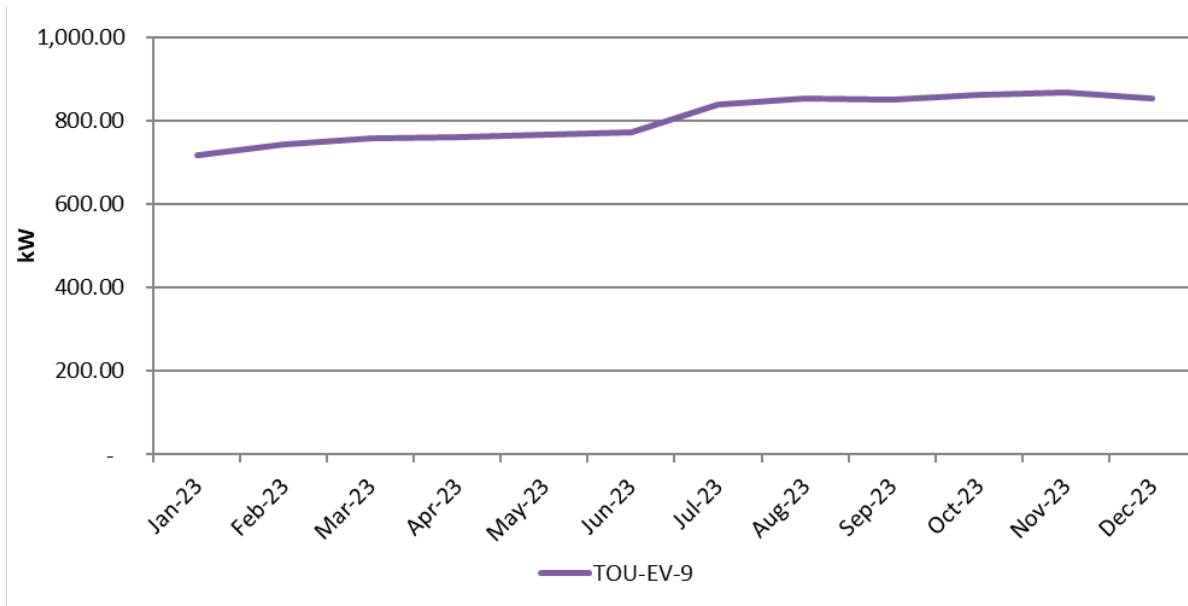


Chart SCE – 12c: Commercial Separate Meter (TOU-EV-9) – Monthly Average Non-Coincident Peak Load (kW)



Average Diversified Peak Load and Timing

In the general population, the hour of residential class peak loads varies throughout the year ranging from roughly 5:00 p.m. in the summer to 6:00 p.m. - 8:00 p.m. in the winter. The magnitude of these peaks also varies, presumably due to different uses. By comparison, the peak load for the single-

metered PEV owners is much more consistent month-to-month, averaging 2.2 kW and occurring between 10 p.m. and 11 p.m. The presumed addition of PEV charging loads in the late-night hours augments household loads enough to surpass the demands occurring at other hours of the day.

Table SCE – 12a: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Residential Demand (kW)	Hour of Residential Demand	SF Population Demand (kW)	Hour of SF Population Demand	MDU Population Demand (kW)	Hour of MDU Population Demand
Jan. 2023	1.07	20	1.26	20	0.79	20
Feb. 2023	1.00	20	1.17	20	0.74	20
Mar. 2023	0.90	19	1.07	19	0.67	18
Apr. 2023	1.47	17	1.75	17	1.05	17
May. 2023	1.34	18	1.63	18	0.93	17
Jun. 2023	1.94	18	2.40	18	1.25	18
Jul. 2023	1.89	17	2.32	17	1.24	17
Aug. 2023	2.27	17	2.83	17	1.45	17
Sep. 2023	2.58	17	3.20	17	1.67	17
Oct. 2023	1.32	17	1.61	17	0.88	17
Nov. 2023	0.89	20	1.05	20	0.64	20
Dec. 2023	1.12	20	1.31	20	0.83	20

Table SCE – 12b cont'd: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Single Metering Demand (kW)	Hour of Single Metering Demand	SF Single Metering Demand (kW)	Hour of SF Single Metering Demand	MDU Single Metering Demand (kW)	Hour of MDU Single Metering Demand
Jan. 2023	2.10	23	2.21	23	1.53	23
Feb. 2023	2.08	23	2.20	23	1.51	23
Mar. 2023	2.02	23	2.13	23	1.46	22
Apr. 2023	2.00	22	2.10	22	1.48	22
May. 2023	2.01	22	2.12	22	1.50	22
Jun. 2023	2.02	22	2.12	22	1.52	22
Jul. 2023	2.70	22	2.84	22	1.98	22
Aug. 2023	2.74	22	2.88	22	1.99	22
Sep. 2023	2.33	22	2.46	22	1.70	22
Oct. 2023	2.17	22	2.29	22	1.59	22
Nov. 2023	1.96	23	2.07	23	1.42	23
Dec. 2023	2.03	23	2.15	23	1.47	23

Average monthly diversified peak loads for separately-metered PEVs is 1.3 kW with the peaks occurring between 10:00 p.m. and 1:00 a.m. This indicates a significant amount of diversity in charging as the non-coincident peak loads were 8.3 kW on average. The profiles in Chart SCE – 7 show a rather narrow peak in charging so the most plausible reason that this diversity would arise would be through vehicles not being charged daily at home.

Table SCE – 13: Residential Separate Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Separate Metering Demand (kW)	Hour of Separate Metering Demand
Jan. 2023	1.29	23
Feb. 2023	1.38	1
Mar. 2023	1.32	24
Apr. 2023	1.32	24
May. 2023	1.31	22
Jun. 2023	1.25	24
Jul. 2023	1.26	24
Aug. 2023	1.34	24
Sep. 2023	1.32	22
Oct. 2023	1.36	22
Nov. 2023	1.29	23
Dec. 2023	1.29	1

The average diversified peak loads for commercial TOU-EV-7 customers in Table SCE – 14, peaked around 2.1 kW in October 2023. The hour of peak load generally varies within the window from 10:00 a.m. to 11:00 a.m.

Table SCE – 14 also provides average diversified peak loads for commercial TOU-EV-8 and TOU-EV-9 customers. For TOU-EV-8, the highest diversified peak load averaged 34 kW in December 2023. The hour of peak load occurs mid-day, varying between the hours from 9:00 a.m. to 2:00 p.m. For TOU-EV-9, the highest diversified peak load averaged 436 kW in July 2023. The diversified peak load for TOU-EV-9 occurs in a narrower window mainly from 1:00 p.m. to 3:00 p.m.

Table SCE – 14: Commercial Separate Meter – Time and Average Diversified Peak Load

Month	TOU-EV-7 Demand (kW)	TOU-EV-7 Hour of Demand	TOU-EV-8 Demand (kW)	TOU-EV-8 Hour of Demand	TOU-EV-9 Demand (kW)	TOU-EV-9 Hour of Demand
Jan. 2023	1.71	11	23.30	12	341.78	14
Feb. 2023	1.76	11	25.78	10	361.81	14
Mar. 2023	1.68	10	26.18	9	357.80	13
Apr. 2023	1.55	11	26.85	9	380.69	13
May. 2023	1.76	11	25.36	9	360.08	13
Jun. 2023	1.76	10	25.15	14	371.56	13
Jul. 2023	1.64	11	26.55	12	435.51	15
Aug. 2023	1.80	11	28.09	12	415.92	15
Sep. 2023	1.85	10	30.02	13	406.49	12
Oct. 2023	2.14	10	32.19	13	424.93	12
Nov. 2023	2.01	11	32.18	13	417.23	13
Dec. 2023	1.84	11	33.71	14	429.45	13

SCE Conclusions and Observations

The statistics and metrics found in this report are based on a sub-population of the total numbers of vehicles sold. As fuel and materials costs fluctuate, vehicle options expand, and technology continues to adapt to customer needs, the future population of owners may have different characteristics and behaviors than the current group. To-date each subsequent report has contained more PEVs but the electric use patterns have remained very consistent.

Residential

- Identification of single-metered TOU and regular domestic accounts of PEV owners relies on voluntarily enrolling in TOU-D-PRIME tariff and/or self-identification, and therefore is subject to selection bias. Furthermore, present ownership of a PEV is not verifiable, thus the extent to which PEV charging load is a component of the metered household load cannot be determined. The reliability of this information therefore cannot be guaranteed.
- To enroll in TOU-D-PRIME, customers must attest that they are eligible and have an electric vehicle or other qualifying equipment. As the result of information system enhancement, this information is now easily accessible for reporting, which helped SCE to obtain substantially more PEV ownership data on TOU-D-PRIME than in previous years.
- SCE was able to utilize participation data from its Clean Fuel Rebate program and the California Clean Fuel Reward program, funded by Low Carbon Fuel Standard credit revenues, as well as the Pre-Owned EV Rebate Program, to identify a significant number of additional PEV customers.
- A total of 141,319 accounts with a PEV charging under the single-meter TOU-D-PRIME tariff have been identified as of the beginning of December 2023. However, as this rate is open to all residential customers with any of the three clean energy technologies, SCE must also rely on self-identification and the Clean Fuel Reward Programs. Therefore, account growth may not represent the actual numbers of PEVs on the single-metered TOU option or the broader PEV market growth.

- Non-coincident peak demand for the residential separately-metered PEVs was 8.2 kW on average during 2023. For comparison, average non-coincident demand was 8.8 kW in the 2022 report and 8.2 kWh in the 2021 report.
- Charging continues to appear concentrated in the off-peak TOU period for single-metered PEV customers. For the separately-metered PEVs, off-peak charging was even higher, over 90 percent during summer. The behaviors of separately-metered PEV owners still resemble the charging habits they exhibited before the migration from TOU-EV-1.
- There are no appreciable seasonal charging patterns from the identified PEVs, however charging appears to be lower on weekends.

Commercial

- There has been considerable customer growth in commercial PEV tariff adoption, driven in part by utility PEV charging infrastructure programs. As of the beginning of December 2023, a total of 855 accounts with PEV charging were under the three commercial PEV tariffs, compared to 695 accounts in December 2022.
- Average monthly usage has continuously increased in 2023. The increasing trend is more notable than in the previous reports. For TOU-EV-8, the average monthly usage was 52% higher in December 2023 than in January 2023; and for TOU-EV-9, the increase was 33%.
- Average monthly demand has been stable with a slight upward trend during the twelve-month period.
- Diversified peak demands for TOU-EV-7 mainly occurred from 10 a.m. to 11 a.m. in the morning. For TOU-EV-8 and TOU-EV-9, diversified peak demands occurred later in the day, mainly occurring from 9 a.m. to 2 p.m., and 1 p.m. to 3 p.m., respectively.
- The greatest share of usage occurs in lowest cost window which is off-peak in summer and super off-peak in winter. However, it is not known if this is natural charging behavior or whether customers are responding to the TOU pricing because most charging stations and public facilities do not differentiate TOU prices for individual users.
- For TOU-EV-7, charging is higher on weekdays than weekends peaking in the morning. TOU-EV-8 charging is also higher on weekdays but to a lesser degree, also peaking in the morning while the demand during mid-day tends to be flat. Conversely, peak charging for TOU-EV-9 accounts occurs on weekends, peaking in the afternoon.

Transportation Electrification Program Load Data

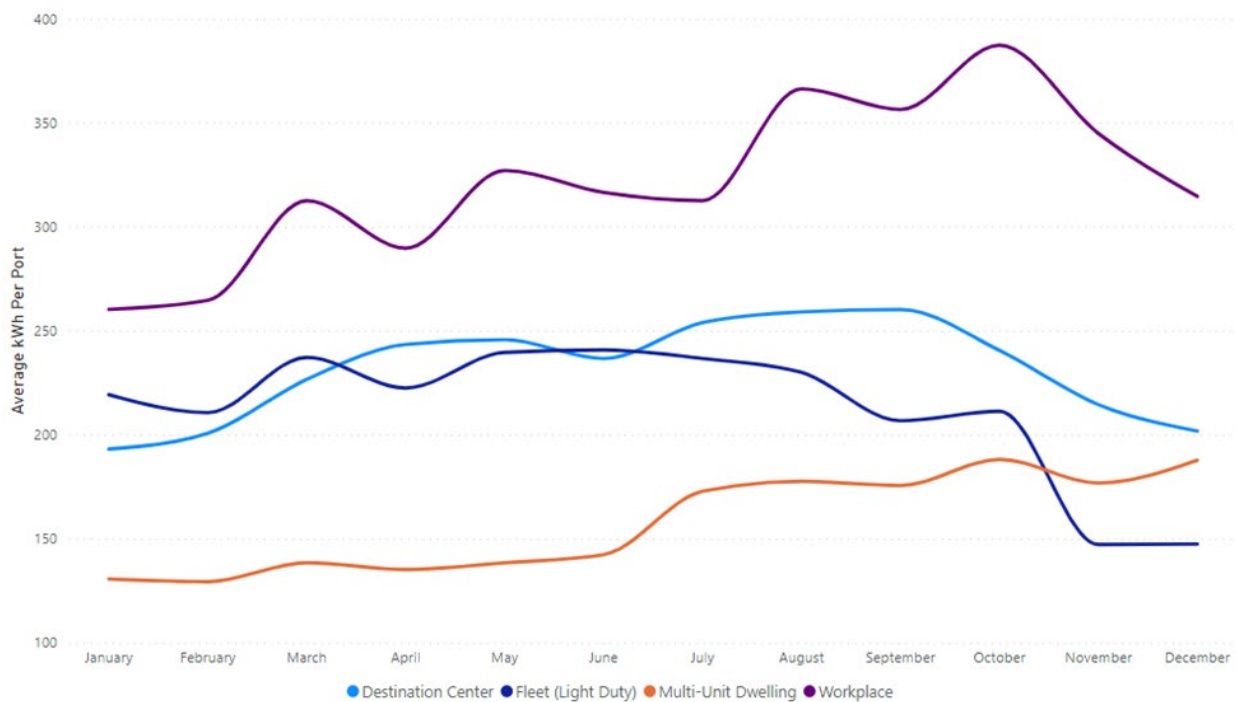
This report includes load data from SCE's Charge Ready Pilot and Bridge, Charge Ready Light-Duty program, and Charge Ready Transport program. The report does not capture load information from SCE's Charge Ready AB 1082 Schools, Charge Ready AB 1083 Parks and Beaches, or Priority Review Projects. Load information for these programs is not included within this report, as the number of completed projects did not comply with the commission's 15-15 rule.

Charge Ready Pilot and Bridge Programs

Average Monthly Usage (kWh) per port

The graph in Chart SCE – 15 provides the average monthly usage per port for SCE’s Charge Ready Pilot & Bridge program in 2023. For 2023, SCE is reporting all 146 Charge Ready Pilot & Bridge program completed sites (2,745 ports). The 2023 graph shows the current usage continuing to trend higher in each market segment. The highest peak of average usage per port for each of the market segment were as follows: workplace peaked in October at 387 kWh, destination centers peaked in September at 260kWh, fleet (light duty) utilization peaked in June at 240 kWh, and multi-unit dwelling peaked in December at 187 kWh. Across all segments, the average per port utilization increased from the beginning of 2023, except for fleet segment which had a decrease toward the end of the year. Workplace continuing to show the highest overall utilization in comparison to other segments. Multi-unit dwelling showed the strongest increased of overall usage amongst the four segments.

Chart SCE – 15: Charge Ready Pilot & Bridge Average Monthly Usage (kWh) by Port (2023)



Average Hourly Load profile (kWh) by Port

Chart SCE – 15a displays the average weekday hourly load profile by port for the Charge Ready Pilot and Bridge program by market segment in 2023. The average weekday hourly load profile by port indicates the peak average usage for workplace is at 9 a.m. Fleet (light-duty) market segment was having a peak average usage per port at 8 a.m. The destination center market segment had the peaks at 10 a.m. while the multi-unit dwelling segment peaks from 11 p.m. to 12 a.m.

In comparison, Chart SCE – 15b displays the average weekend hourly load profile by segment per port for 2023. The overall charging is much lower on weekends in comparison to weekdays for all market segments. The peak average usage during the weekends from the multi-unit dwelling segment was at 12 a.m. The peak average usage during the weekends from the destination center segment was between

the hours of 11 a.m. and 3p.m. Both the fleet (light-duty) segment and the workplace segment had their peaks at 10 a.m.

Chart SCE – 15a: Charge Ready Pilot & Bridge Average Weekday Hourly Load Profile (kWh) by Port (2023)

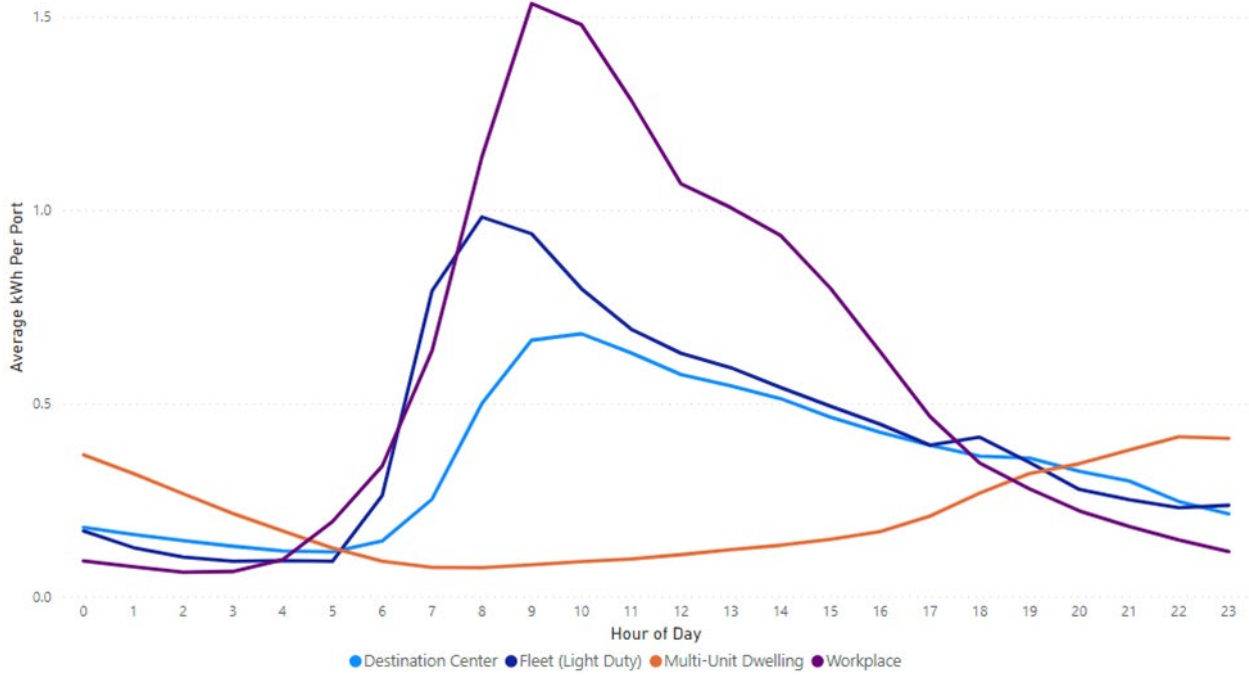
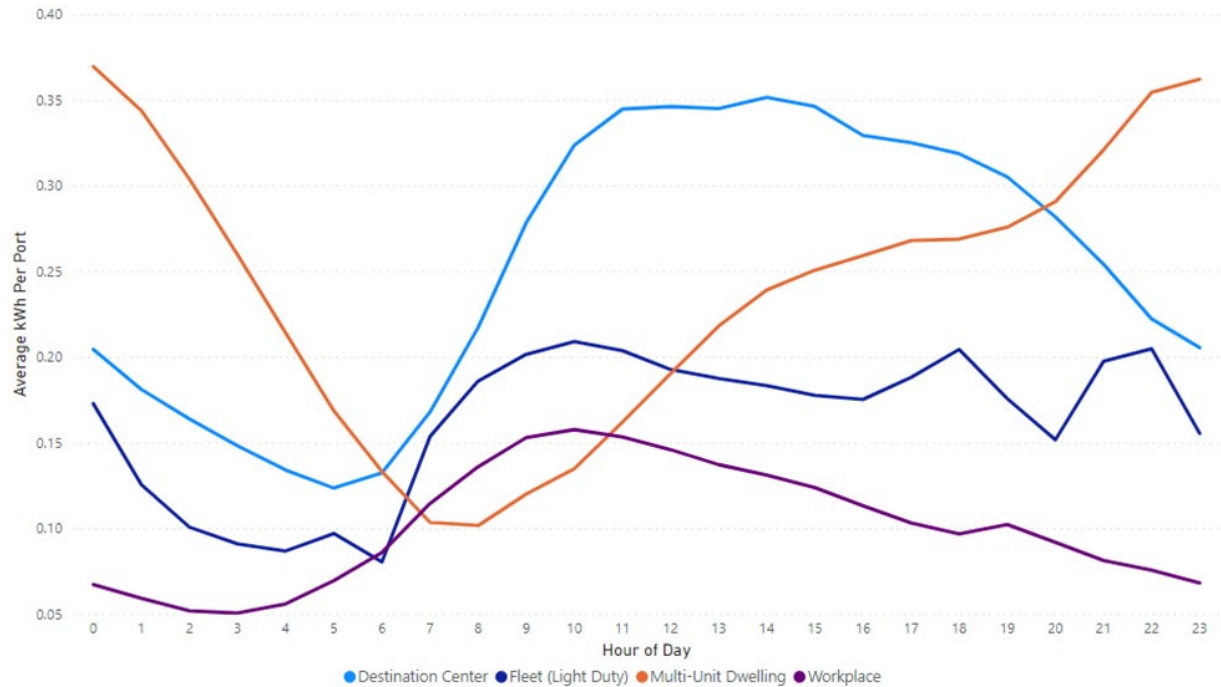


Chart SCE – 15b: Charge Ready Pilot & Bridge Average Weekend Hourly Load Profile (kWh) by Port (2023)





Charge Ready Light-Duty Program

For the Charge Ready Light-Duty program, SCE will report 2023 usage data in aggregate of all energized sites for completeness of data reporting.

Average Monthly Usage (kWh) per port

The graph in Chart SCE – 16 provides the average monthly usage per port for SCE’s Charge Ready Light-Duty program in 2023. By the end of the year across the Charge Ready Light-Duty program, SCE is able to report on 47 sites utilizing 741 ports. The demand grew sharply, in August it was at 60 kWh and the average usage peaked in December at 106 kWh per port.

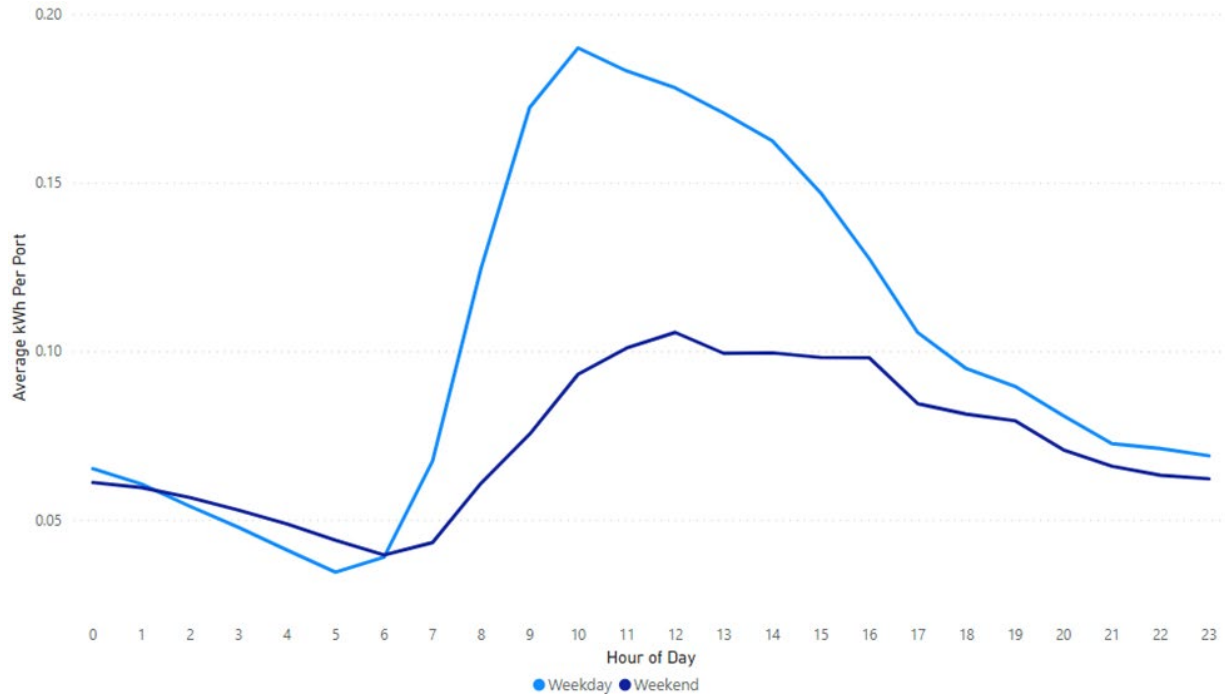
Chart SCE – 16: Charge Ready Light-Duty Average Monthly Usage (kWh) by Port (2023)



Average Hourly Load profile (kWh) by Port

Chart SCE – 16a displays the average weekday and weekend hourly load profile by port for the Charge Ready Light-Duty program in 2023. The average weekday hourly load profile by port usage peaks at 10 a.m. with a 0.19 kWh per port average. The weekend usage indicates softer demand overall, showing a relatively flat curve with one peak at 12 p.m. of 0.11 kWh. The minimum average usage for weekdays occurs at 5 a.m. and weekends occurs at 6 a.m. At no time does weekend average hourly demand exceed the demand for the same hour during the weekday.

Chart SCE – 16a: Charge Ready Light-Duty Average Weekday/Weekend Hourly Load Profile (kWh) by Port (2023)



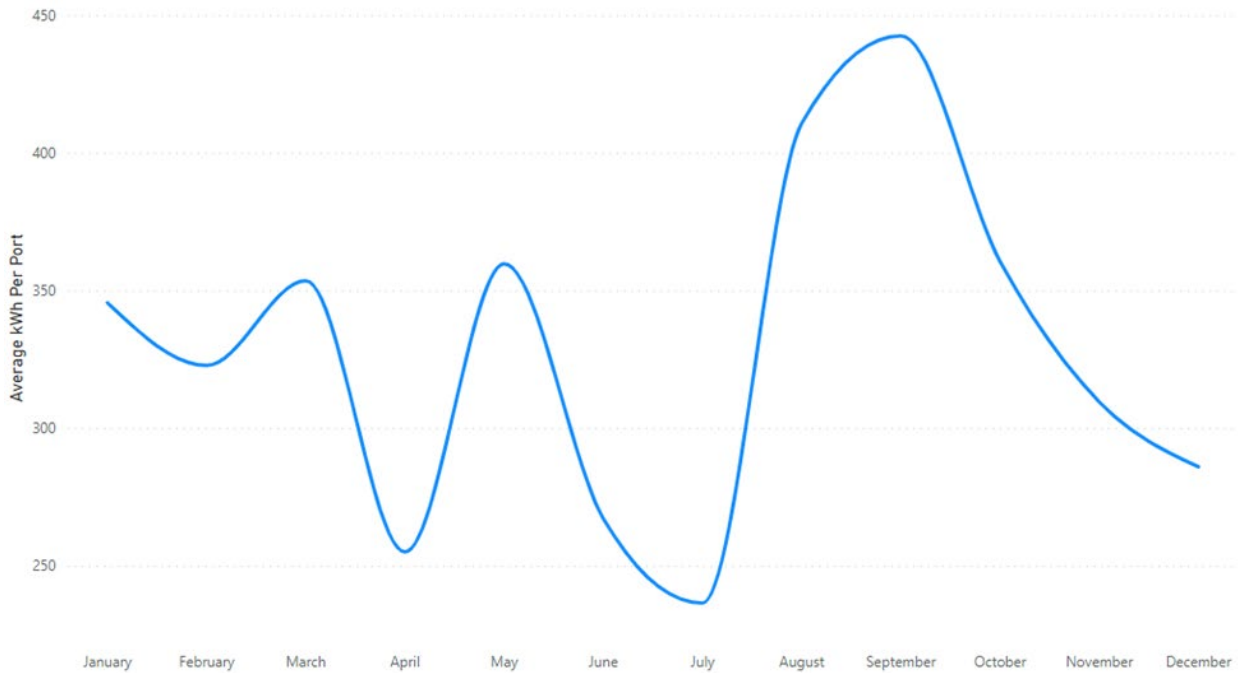
Charge Ready Transport Program

For the Charge Ready Transport program, SCE will report 2023 usage data in aggregate of all energized sites for completeness of data reporting.

Average Monthly Usage (kWh) per port

The graph in Chart SCE – 17 provides the average monthly usage per port for SCE’s Charge Ready Transport program in 2023. By the end of the year across the Charge Ready Transport program, SCE is able to report on 50 sites utilizing 938 ports, supporting the electrification of 1,075 vehicles. The average usage peaked in September at 443 kWh per port.

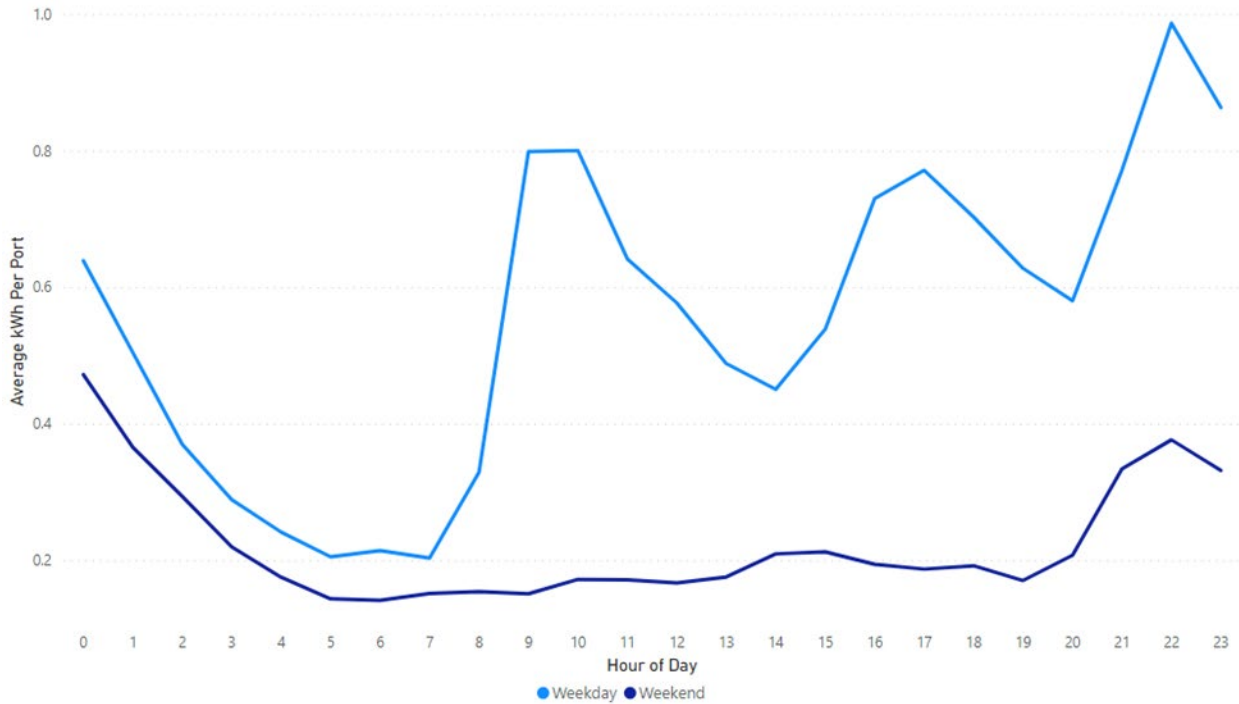
Chart SCE – 17: Charge Ready Transport Average Monthly Usage (kWh) by Port (2023)



Average Hourly Load profile (kWh) by Port

Chart SCE – 17a displays the average weekday and weekend hourly load profile by port for the Charge Ready Transport program in 2023. The average weekday hourly load profile by port indicates 3 usage peaks, the first at 9 a.m. to 10 a.m. with a 0.80 kWh per port average, which then declines until 2 p.m. The second peak appears at 5 p.m. with a 0.77 kWh per port average. The last peak appears at 10 p.m. at 0.99 kWh per port average. The weekend usage indicates softer demand overall, showing a relatively flat curve with one peak at 12 a.m. of 0.47 kWh. The minimum average usage for both weekdays and weekends occurs at 5 a.m. At no time does weekend average hourly demand exceed the demand for the same hour during the weekday.

Chart SCE – 17a: Charge Ready Transport Average Weekday/Weekend Hourly Load Profile (kWh) by Port (2023)



D. SDG&E’s Residential EV Load and Customer Behavior Data

The following section contains analysis of load consumption across SDG&E’s electric vehicle EV specific rates and transportation electrification programs. The analysis covers residential EV rates during the 2023 calendar year. The residential rates reported include SDG&E’s separately metered rate (EV-TOU) and single metered rates (EV-TOU-2 and EV-TOU-5).

SDG&E Separate-Metered PEV Rate

EV-TOU:

The EV-TOU rate option is designed for customers that have their PEV load on a dedicated meter and their electric service on a separate meter. The EV-TOU rate is an optional rate for residential customers who require service for charging their currently registered motor vehicle. The registered motor vehicles include one of the following: (1) a BEV or PHEV recharged via a recharging outlet at the customer’s premise; or (2) an NGV refueled via an HRA at the customer’s premise. The point of service must contain facilities to separately meter PEV or Compressed Natural Gas (CNG) charging. For this report’s purpose, non-residential customers on the EVTOU rate have been removed from analysis.

SDG&E Single-Metered PEV Residential Rates

The SDG&E single-metered rates were designed for residential customers who have their typical load and electric vehicles charging on the same meter. SDG&E has two residential plug-in electric vehicle (PEV) rates open to single-metered customers: EV-TOU-2 and EV-TOU-5.

All EV rate plans use an un-tiered TOU rate structure. They offer on-peak, off-peak, and super off-peak energy prices according to the time periods and pricing shown in Table SDG&E-1A. Regardless of season

or day of the week, both single-meter EV rates seek to encourage usage in off-peak and super off-peak hours.

EV TOU-2:

The EV-TOU-2 rate option is designed for residential customers that have both their household and PEV load on the same meter. Service under this optional rate is specifically limited to residential customers who require service for charging their current registered motor vehicle which is either: (1) a battery electric vehicle (BEV) or plug-in hybrid vehicle (PHEV) recharged via a recharging outlet; or (2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer’s premise.

EV-TOU-5:

The EV-TOU-5 rate has the same design criteria and TOU periods as the EV-TOU-2 rate but with different pricing. The main difference is that customers under this rate pay a \$16 monthly fixed charge and subsequently have a much lower super off-peak energy price.

Table SDG&E-1A: Tariff Type and Rate (\$/kWh) in 2023

EV-TOU				
HOUR	WINTER WEEKDAY	WINTER WEEKEND / HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND / HOLIDAY
12AM - 1AM	0.27649	0.27649	0.28480	0.28480
1AM - 2AM	0.27649	0.27649	0.28480	0.28480
2AM - 3AM	0.27649	0.27649	0.28480	0.28480
3AM - 4AM	0.27649	0.27649	0.28480	0.28480
4AM - 5AM	0.27649	0.27649	0.28480	0.28480
5AM - 6AM	0.27649	0.27649	0.28480	0.28480
6AM - 7AM	0.46373	0.27649	0.49727	0.28480
7AM - 8AM	0.46373	0.27649	0.49727	0.28480
8AM - 9AM	0.46373	0.27649	0.49727	0.28480
9AM - 10AM	0.46373	0.27649	0.49727	0.28480
10AM - 11AM	0.46373	0.27649	0.49727	0.28480
11AM - 12PM	0.46373	0.27649	0.49727	0.28480
12PM - 1PM	0.46373	0.27649	0.49727	0.28480
1PM - 2PM	0.46373	0.27649	0.49727	0.28480
2PM - 3PM	0.46373	0.46373	0.49727	0.49727
3PM - 4PM	0.46373	0.46373	0.49727	0.49727
4PM - 5PM	0.52747	0.52747	0.83227	0.83227
5PM - 6PM	0.52747	0.52747	0.83227	0.83227
6PM - 7PM	0.52747	0.52747	0.83227	0.83227
7PM - 8PM	0.52747	0.52747	0.83227	0.83227
8PM - 9PM	0.52747	0.52747	0.83227	0.83227
9PM - 10PM	0.46373	0.46373	0.49727	0.49727
10PM - 11PM	0.46373	0.46373	0.49727	0.49727
11PM - 12AM	0.46373	0.46373	0.49727	0.49727

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super-Off-Peak		

EV-TOU-2				
HOUR	WINTER WEEKDAY	WINTER WEEKEND / HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND / HOLIDAY
12AM - 1AM	0.27649	0.27649	0.28480	0.28480
1AM - 2AM	0.27649	0.27649	0.28480	0.28480
2AM - 3AM	0.27649	0.27649	0.28480	0.28480
3AM - 4AM	0.27649	0.27649	0.28480	0.28480
4AM - 5AM	0.27649	0.27649	0.28480	0.28480
5AM - 6AM	0.27649	0.27649	0.28480	0.28480
6AM - 7AM	0.46373	0.27649	0.49727	0.28480
7AM - 8AM	0.46373	0.27649	0.49727	0.28480
8AM - 9AM	0.46373	0.27649	0.49727	0.28480
9AM - 10AM	0.46373	0.27649	0.49727	0.28480
10AM - 11AM	0.46373	0.27649	0.49727	0.28480
11AM - 12PM	0.46373	0.27649	0.49727	0.28480
12PM - 1PM	0.46373	0.27649	0.49727	0.28480
1PM - 2PM	0.46373	0.27649	0.49727	0.28480
2PM - 3PM	0.46373	0.46373	0.49727	0.49727
3PM - 4PM	0.46373	0.46373	0.49727	0.49727
4PM - 5PM	0.52747	0.52747	0.83227	0.83227
5PM - 6PM	0.52747	0.52747	0.83227	0.83227
6PM - 7PM	0.52747	0.52747	0.83227	0.83227
7PM - 8PM	0.52747	0.52747	0.83227	0.83227
8PM - 9PM	0.52747	0.52747	0.83227	0.83227
9PM - 10PM	0.46373	0.46373	0.49727	0.49727
10PM - 11PM	0.46373	0.46373	0.49727	0.49727
11PM - 12AM	0.46373	0.46373	0.49727	0.49727

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super-Off-Peak		

EV-TOU-5 (BASIC SERVICE FEE \$16)				
HOUR	WINTER WEEKDAY	WINTER WEEKEND / HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND / HOLIDAY
12AM - 1AM	0.14520	0.14520	0.15351	0.15351
1AM - 2AM	0.14520	0.14520	0.15351	0.15351
2AM - 3AM	0.14520	0.14520	0.15351	0.15351
3AM - 4AM	0.14520	0.14520	0.15351	0.15351
4AM - 5AM	0.14520	0.14520	0.15351	0.15351
5AM - 6AM	0.14520	0.14520	0.15351	0.15351
6AM - 7AM	0.44775	0.14520	0.48129	0.15351
7AM - 8AM	0.44775	0.14520	0.48129	0.15351
8AM - 9AM	0.44775	0.14520	0.48129	0.15351
9AM - 10AM	0.44775	0.14520	0.48129	0.15351
10AM - 11AM	0.44775	0.14520	0.48129	0.15351
11AM - 12PM	0.44775	0.14520	0.48129	0.15351
12PM - 1PM	0.44775	0.14520	0.48129	0.15351
1PM - 2PM	0.44775	0.14520	0.48129	0.15351
2PM - 3PM	0.44775	0.44775	0.48129	0.48129
3PM - 4PM	0.44775	0.44775	0.48129	0.48129
4PM - 5PM	0.51149	0.51149	0.81629	0.81629
5PM - 6PM	0.51149	0.51149	0.81629	0.81629
6PM - 7PM	0.51149	0.51149	0.81629	0.81629
7PM - 8PM	0.51149	0.51149	0.81629	0.81629
8PM - 9PM	0.51149	0.51149	0.81629	0.81629
9PM - 10PM	0.44775	0.44775	0.48129	0.48129
10PM - 11PM	0.44775	0.44775	0.48129	0.48129
11PM - 12AM	0.44775	0.44775	0.48129	0.48129

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super-Off-Peak		

Table SDG&E-1B: Price Ratios for EV Rates

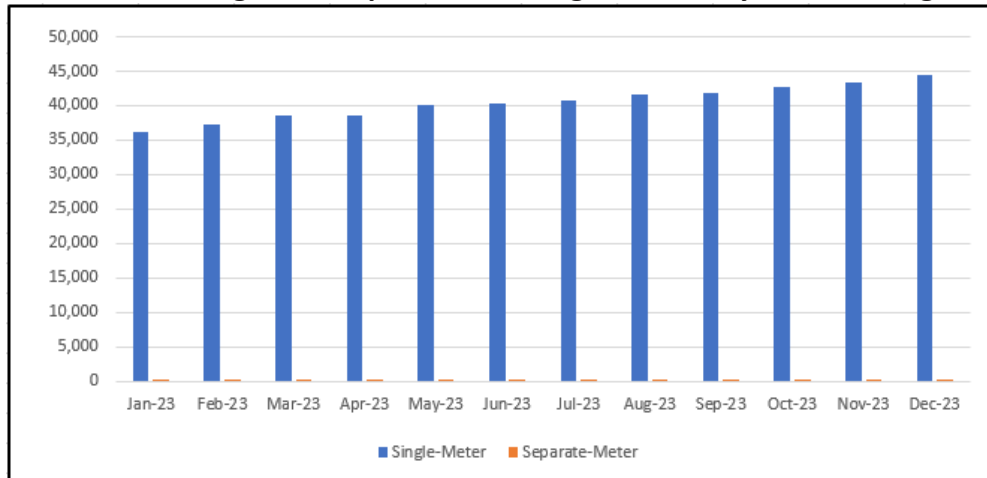
Tariff	Winter		Summer	
	Off-Peak to Super-Off-Peak	On-Peak to Super-Off-Peak	Off-Peak to Super-Off-Peak	On-Peak to Super-Off-Peak
EV-TOU	1.68	1.91	1.75	2.92
EV-TOU2	1.68	1.91	1.75	2.92
EV-TOU5	3.08	3.52	3.14	5.32

Single-Metered Rate Growth

Participation in single-metered PEV rates showed a steady increase during 2023, while participation in the separately metered PEV rate had little movement. It is important to note that not all PEV customers have adopted PEV rates. Of the customers on PEV rates, the majority are on one of the single-metered rates.

Single-Metered Customers: Chart SDG&E-1 below displays the total number of customers on single-metered PEV rates. During the study period, there was a steady increase in single-metered rate enrollment.

Chart SDG&E-1: Single and Separate Metering Accounts by Meter Configuration



As shown in Chart SDG&E-1 and Table SDG&E 3, the number of SDG&E customers taking service under separately-metered EV rates had minimal change.

NEM Single-Metered Customers: NEM customers on the PEV rates are an important group to consider. Of all the SDG&E customers who were on the single-metered PEV rates at the end of 2023, 54% were also NEM customers.

The single-metered rate presents a load research challenge when trying to ascertain how much energy is used by the house versus the energy used while charging an EV(s). Since EV charging energy and residential solar energy are usually not separately metered by the utility, there is a lack of metering data for these customers. In addition, the now-popular installation of onsite distributed generation (DG) in the form of battery storage tends to exacerbate the load research issue due to the lack of metering as well. Without additional metering of the DG and/or solar photovoltaic (PV) systems, it is not possible to isolate the effect PEV ownership has on usage patterns for NEM single-metered customers using the utility metering data alone.

Energy consumption patterns of customers on EV rates are often different from the general residential customer population, which may in part be due to NEM customers with PV systems. Currently, solar PV owners are overrepresented in the PEV-rate class compared to non-PEV customers. At the end of 2023, NEM penetration for the residential population in SDG&E's service territory was 22%, while NEM customers currently represent over 50% of the single-meter PEV-rate class (as seen in Table SDG&E-2A).

Table SDG&E-2A: Total Single-Metered NEM Program Enrollment

Month	Total Customers on Single- Metering	Total Customers on NEM	NEM as a % of Single-Metering
Jan-23	35,910	17,429	48.5%
Feb-23	36,829	18,090	49.1%
Mar-23	37,890	18,786	49.6%
Apr-23	38,100	19,313	50.7%
May-23	39,346	19,890	50.6%
Jun-23	39,994	20,458	51.2%
Jul-23	40,454	20,909	51.7%
Aug-23	41,084	21,441	52.2%
Sep-23	41,535	21,916	52.8%
Oct-23	42,327	22,566	53.3%
Nov-23	42,991	23,129	53.8%
Dec-23	44,251	24,208	54.7%

Table SDG&E-2B: Single-Metered NEM Program Enrollment for EV-TOU-2

Month	Total Customers on EVTOU2	Total Customers on NEM	NEM as a % of EVTOU2
Jan-23	8,375	5,173	61.8%
Feb-23	8,405	5,228	62.2%
Mar-23	8,439	5,281	62.6%
Apr-23	8,369	5,305	63.4%
May-23	8,491	5,380	63.4%
Jun-23	8,535	5,444	63.8%
Jul-23	8,522	5,472	64.2%
Aug-23	8,519	5,508	64.7%
Sep-23	8,489	5,524	65.1%
Oct-23	8,515	5,571	65.4%
Nov-23	8,475	5,574	65.8%
Dec-23	8,516	5,617	66.0%

Table SDG&E-2C: Single-Metered NEM Program Enrollment for EV-TOU5

Month	Total Customers on EVTOU5	Total Customers on NEM	NEM as a % of EVTOU5
Jan-23	27,533	12,256	44.5%
Feb-23	28,422	12,862	45.3%
Mar-23	29,449	13,505	45.9%
Apr-23	29,728	14,008	47.1%
May-23	30,853	14,510	47.0%
Jun-23	31,458	15,014	47.7%
Jul-23	31,931	15,437	48.3%
Aug-23	32,564	15,933	48.9%
Sep-23	33,045	16,392	49.6%
Oct-23	33,811	16,995	50.3%
Nov-23	34,515	17,555	50.9%
Dec-23	35,734	18,591	52.0%

Separately-Metered Rate Growth

All Separately-Metered Customers: The separately-metered PEV rate remains a less popular option for customers than the single-metered PEV rate, due to the expense of installing a new electric service and a separate meter.

Table SDG&E-3: Separately-Metered Accounts Totals

Month	Total Customers on Separate- Metering	Total Customers on NEM	NEM as a % of Separate- Metering
Jan-23	170	70	41.2%
Feb-23	170	70	41.2%
Mar-23	170	70	41.2%
Apr-23	170	70	41.2%
May-23	168	70	41.7%
Jun-23	175	70	40.0%
Jul-23	175	69	39.4%
Aug-23	179	69	38.5%
Sep-23	179	69	38.5%
Oct-23	178	69	38.8%
Nov-23	177	69	39.0%
Dec-23	177	69	39.0%

Average Monthly Usage for PEV Rate Customers

Chart SDG&E-2 below displays the average monthly usage for single-metered customers with and without NEM during 2023. It is the average monthly usage which includes behind-the-meter generation. Monthly consumption is highest in the summer months when temperatures are high, and many

residential customers are using air conditioning (A/C). Monthly consumption is much lower in spring when A/C is not used as much, and NEM customers have higher levels of NEM exports.

Chart SDG&E-2: Average Monthly Net Usage for Single-Meter Customers with and without NEM

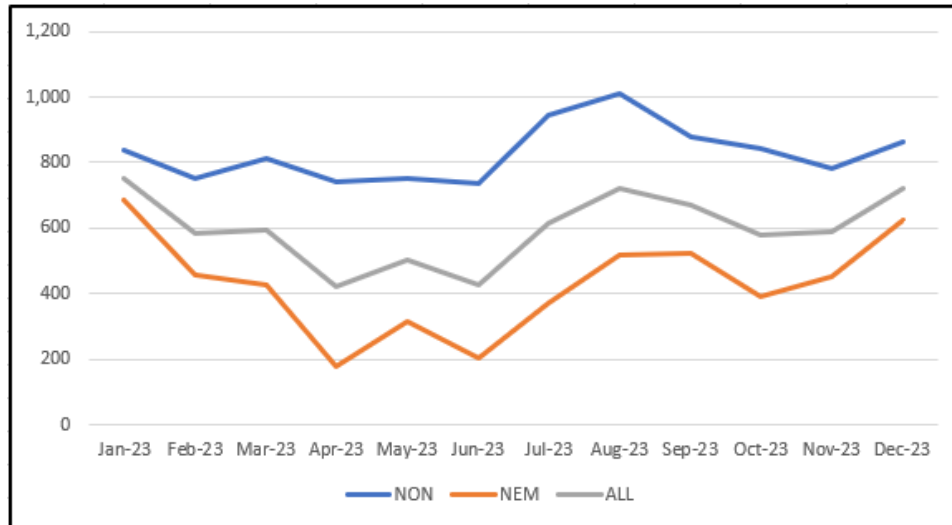
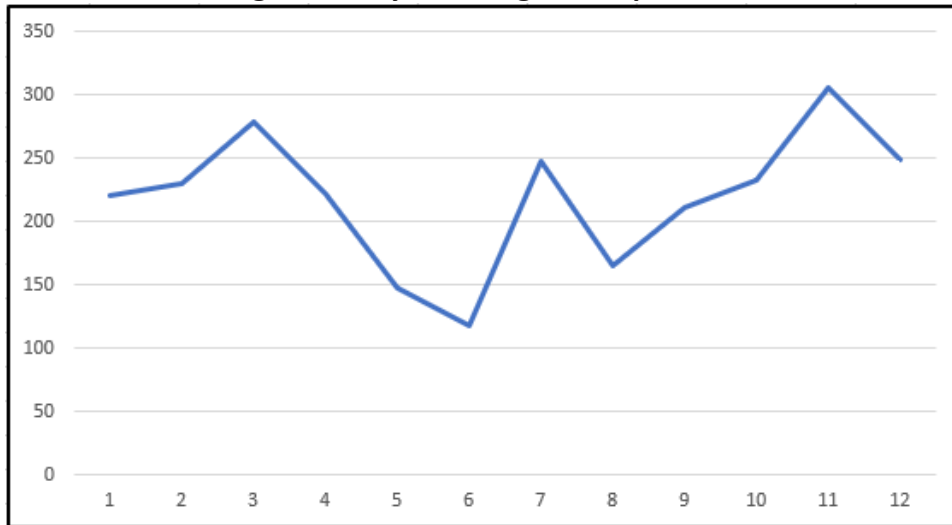


Chart SDG&E-3 displays the average monthly usage for separate-metered customers which is average monthly home PEV charging only.

Chart SDG&E-3: Average Monthly Net Usage for Separate-Meter Customers



Time of Use Analysis of Single- and Separate-Metered Customers

One of the questions addressed in this report is whether being on a TOU rate with higher on-peak pricing is an effective incentive to move EV charging or other household consumption to off-peak or super off-peak times. The load shapes provided in Charts SDG&E-4 and SDG&E-5 suggest that customers respond to differences in prices and charge their vehicles when electricity is the cheapest.

Tables SDG&E-4A through SDG&E-4F below provide the percentage share of monthly kilowatt per hour (kWh) for single and separate-metered rates. EV-TOU-2 and EV-TOU-5 customers consume over 75% of their energy during the off-peak and super off-peak periods. Separate-metered customers respond very well to the signal created by the TOU price differential and consume, on average, 70% of their energy during the super off-peak TOU period.

It is important to note that the time-of-use analysis in this report reflects energy delivered to the home and does not consider exports from excess solar generation for NEM customers. SDG&E customers are billed based on their net consumption, not their delivered consumption. Monthly usage data and load shapes in this report reflect net values to visually display this behavior. Because NEM customers export enough energy during off-peak hours to reach negative levels, time-of-use analysis is reported with delivered load to avoid displaying negative percentage values.

Table SDG&E-4A: Percentage of On-Peak Usage by Single-Meter Configuration

Season	EVTU2 Non-NEM	EVTU2 NEM	EVTU2 Total	EVTU5 Non-NEM	EVTU5 NEM	EVTU5 Total
S	21.6%	19.0%	20.0%	21.0%	20.4%	20.7%
W	20.0%	20.2%	20.1%	19.6%	22.1%	20.9%

Table SDG&E-4B: Percentage of On-Peak Usage by Separate-Meter Configuration

Season	EVTU Non-NEM	EVTU NEM	EVTU Total
S	9.1%	9.1%	9.1%
W	9.5%	9.2%	9.5%

Table SDG&E-4C: Percentage of Off-Peak Usage by Single-Meter Configuration

Season	EVTU2 Non-NEM	EVTU2 NEM	EVTU2 Total	EVTU5 Non-NEM	EVTU5 NEM	EVTU5 Total
S	41.0%	39.7%	40.2%	39.0%	37.9%	38.4%
W	36.9%	38.6%	37.9%	37.1%	35.8%	36.5%

Table SDG&E-4D: Percentage of Off-Peak Usage by Separate-Meter Configuration

Season	EVTU Non-NEM	EVTU NEM	EVTU Total
S	18.8%	17.7%	18.8%
W	17.6%	19.5%	17.6%

Table SDG&E-4E: Percentage of Super Off-Peak Usage by Single-Meter Configuration

Season	EVTU2 Non-NEM	EVTU2 NEM	EVTU2 Total	EVTU5 Non-NEM	EVTU5 NEM	EVTU5 Total
S	37.4%	41.2%	39.8%	40.0%	41.7%	40.9%
W	43.1%	41.2%	41.9%	43.2%	42.1%	42.6%

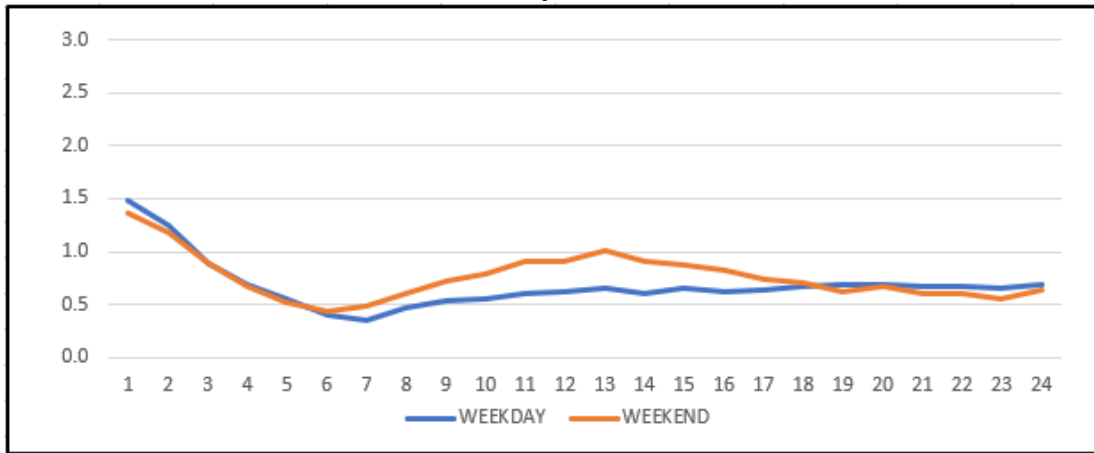
Table SDG&E-4F: Percentage of Super Off-Peak Usage by Separate-Meter Configuration

Season	EVTU Non-NEM	EVTU NEM	EVTU Total
S	72.1%	73.2%	72.1%
W	72.8%	71.2%	72.8%

Average Load Profiles

Chart SDG&E-4 displays the average load profiles for weekdays versus weekends for separate-metered customers. These customers peak between 01:00am and 02:00am and have negligible consumption during the rest of the day. This would indicate that the rate structure and enabling technology are successful in encouraging charging during super off-peak hours.

Chart SDG&E-4: Average Net Load Profile for Separate-Meter Customers (EV-TOU) by Weekday/Weekend



Charts SDG&E-5A through SDG&E-5C compare the average load profiles for weekdays versus weekends for EV-TOU-2, EV-TOU-5, and all single-metered customers. The net load shapes for single-metered customers show high consumption in early morning hours and low midday consumption due to NEM exports. The shapes also show an increase in evening consumption after export hours have ended but a lower peak than the early morning. This behavior is like a typical residential net load profile except that these customers peak in the early morning (super off-peak) hours rather than in the evening (on-peak) hours. This is the effect of customers taking advantage of the super off-peak pricing to charge their vehicles. Weekends tend to have higher midday consumption because many customers are at home rather than going to work. Weekends also have lower charging levels during the early morning hours.

Chart SDG&E-5A: Average Net Load Profile for EV-TOU-2 by Weekday/Weekend

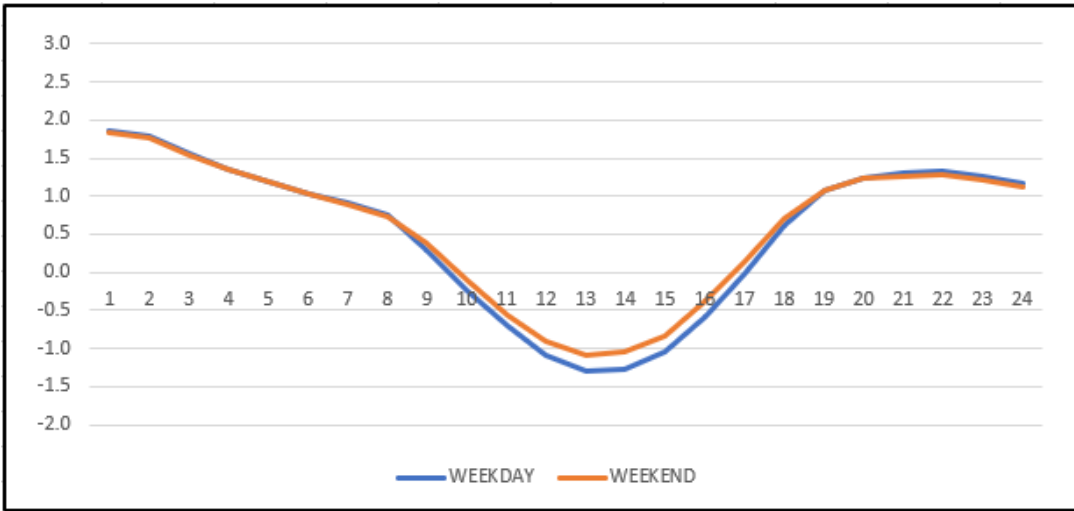


Chart SDG&E-5B: Average Net Load Profile for EV-TOU-5 by Weekday/Weekend

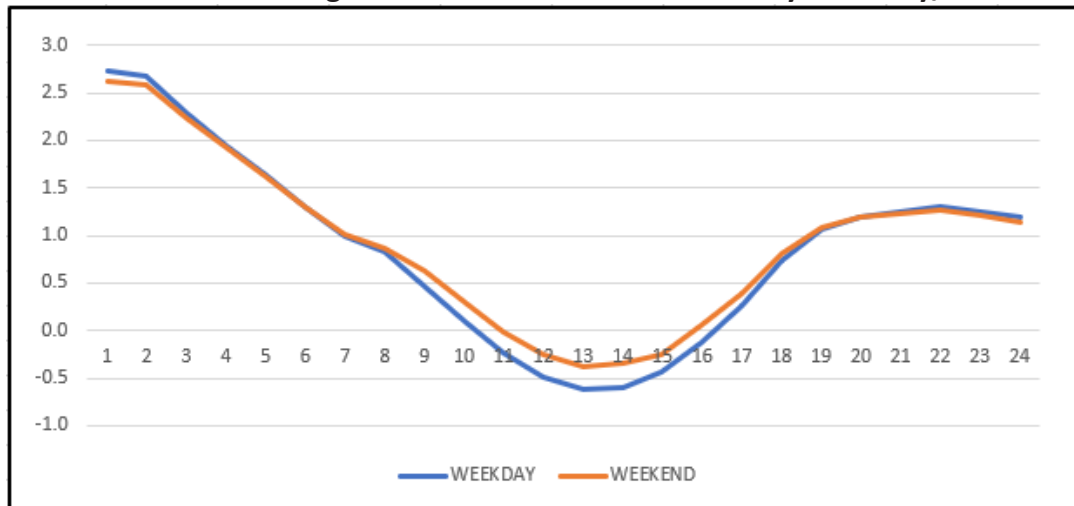
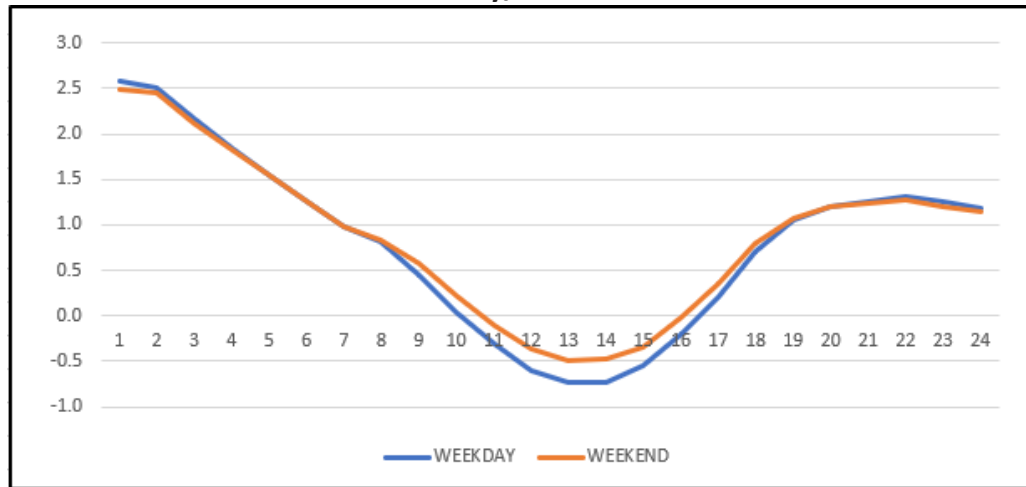


Chart SDG&E-5C: Average Net Load Profile for All Single-Meter Customers by Weekday/Weekend



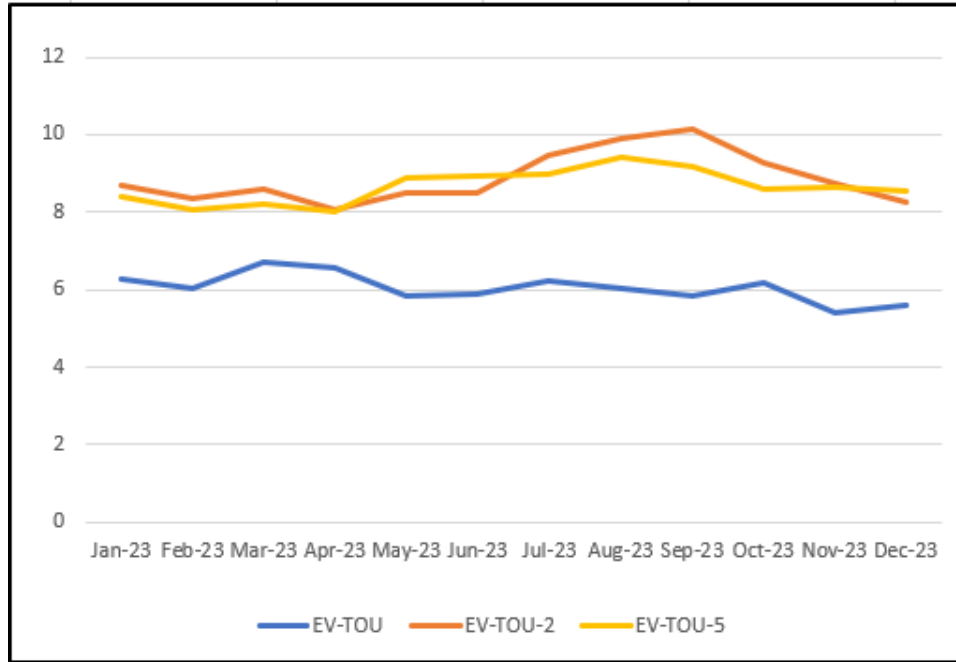
Average Maximum Peak Load (Diversified Demand)

Table SDG&E-5 shows that the average maximum peak demand (also referred to as diversified demand) for separate-meter customers is over 6 kW. Demands are based on maximum hourly kWh values. Single-meter customers have a maximum demand over 8 kW - more than twice that of the average residential customer. The demand is driven by the additional EV charging load being combined with the baseline house load. The data displayed in Table SDG&E-5 is also displayed visually within Chart SDG&E-6.

Table SDG&E-5: Average Maximum Peak Load (kW) by Customer Type and Month

Month	EV-TOU	EV-TOU-2	EV-TOU-5
Jan-23	6.29	8.69	8.41
Feb-23	6.01	8.34	8.08
Mar-23	6.72	8.57	8.20
Apr-23	6.56	8.06	8.02
May-23	5.86	8.48	8.88
Jun-23	5.88	8.52	8.92
Jul-23	6.21	9.44	8.98
Aug-23	6.02	9.88	9.39
Sep-23	5.82	10.16	9.15
Oct-23	6.17	9.27	8.59
Nov-23	5.39	8.76	8.62
Dec-23	5.61	8.26	8.52

Chart SDG&E-6: Average Maximum Peak Load (kW) by Customer Type and Month



Time and Average Class Peak Load

Both single-meter and separate-meter customers peak between 12:00 a.m. and 1:00 a.m. driven by PEV charging behavior and taking advantage of lower super-off-peak prices as shown in Table SDG&E-6. Comparatively, the residential class usually peaks in the early evening hours. Demands are based on maximum hourly kWh values.

Table SDG&E-6: Time and Associated Demand of Class Peak Load

Month	EV-TOU		EV-TOU-2		EV-TOU-5	
	Time	kWh	Time	kWh	Time	kWh
Jan-23	12:00 AM	1.92	12:00AM	2.08	1:00 AM	3.33
Feb-23	12:00 AM	1.85	12:00AM	2.07	2:00 AM	3.36
Mar-23	12:00 AM	2.19	12:00AM	2.10	3:00 AM	3.37
Apr-23	12:00 AM	2.00	12:00AM	1.95	4:00 AM	3.17
May-23	12:00 AM	2.15	12:00AM	1.93	12:00 AM	3.16
Jun-23	1:00 AM	1.76	12:00AM	1.93	12:00 AM	3.17
Jul-23	10:10 AM	2.77	12:00AM	3.40	12:00 AM	4.42
Aug-23	9:00 PM	1.81	5:00 PM	2.86	12:00 AM	4.13
Sep-23	9:00 AM	2.63	12:00AM	2.45	12:00 AM	3.81
Oct-23	9:00 AM	2.38	12:00AM	2.16	12:00 AM	3.54
Nov-23	10:00 AM	3.09	1:00 AM	3.76	1:00 AM	4.34
Dec-23	6:00 PM	2.02	1:00 AM	2.32	12:00 AM	3.77

SDG&E Transportation Electrification Program Load Data

Please note that pursuant to the attached report some of the information included herein is customer usage data, which is treated as confidential by law. In this instance, the program participants have affirmatively consented to the disclosure of their information as part of their participation in the SDG&E Power Your Drive programs.

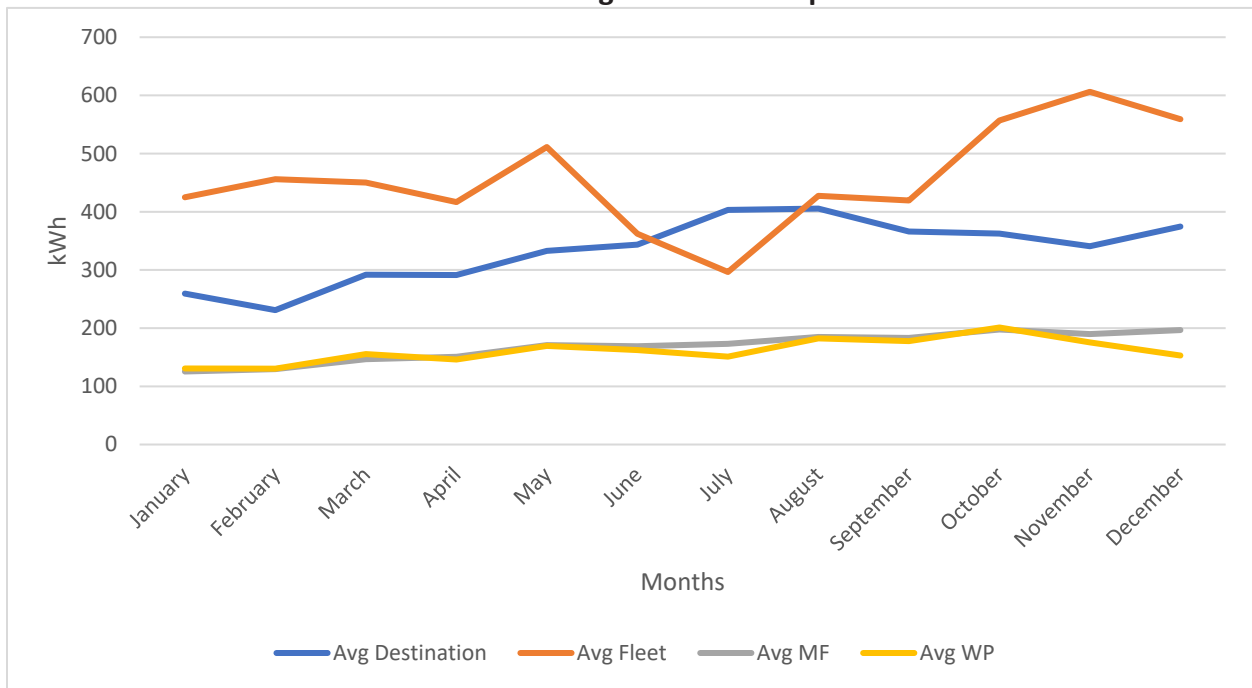
2023 Results

For Chart SDG&E-7 below, total energy consumption was aggregated by site segment per month and divided by the total site segment port count to create the average port consumption per month by site segment. The average port consumption per month for 2023 shows a few spikes (relative maximums) in the Fleet segment during May and November. The number of Fleet ports increased by more than 50% from January to December 2023 from 287 to 436 ports, and consumption doubled between January and December from 122 to 244 MWh. This information demonstrates that the average consumption per port steadily increased throughout the year.

MDU and Workplace charging showed consistent and steady usage per port throughout 2023. Destination usage increased by 67% from January to December, from 37 to 62 MWh, while the port count only increased by 7%, from 143 to 153 ports. This suggests that destination utilization per port is increasing.

Looking back and comparing consumption between 2022 and 2023, the trends were very similar apart from the fleet segment, which showed flatter positive slope overall. All four segments showed higher than average consumption per port in 2023.

Chart SDG&E-7: 2023 Average Port Consumption Per Month

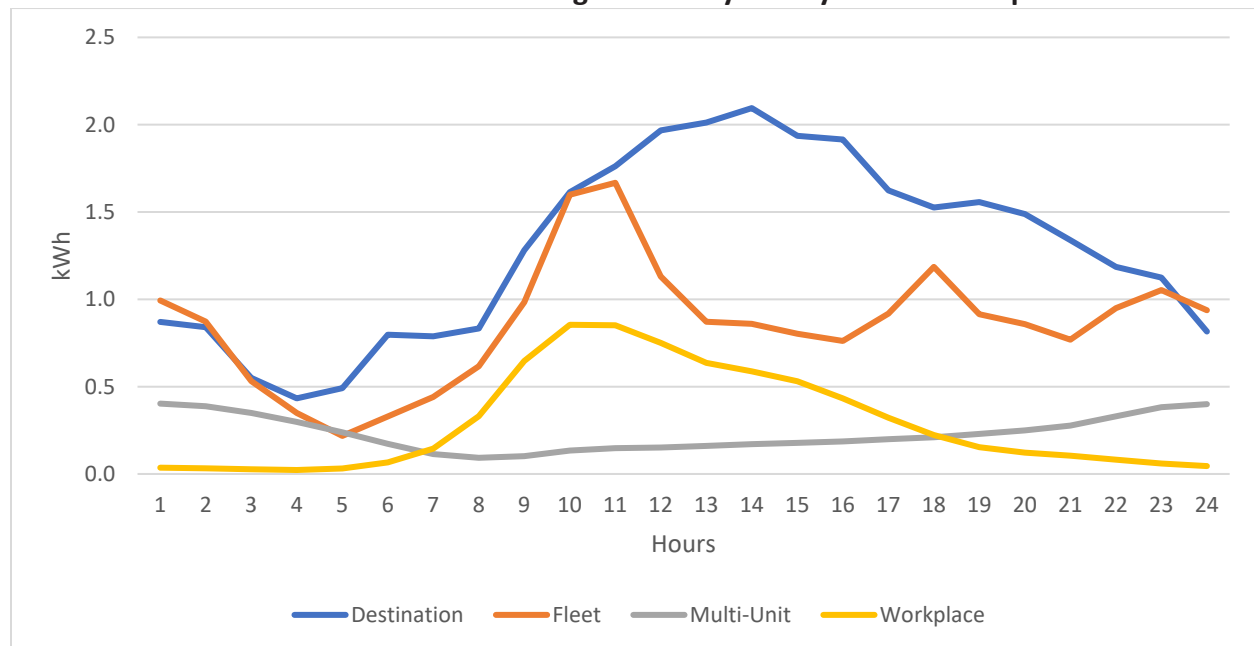


2023 Hourly Results

For Charts SDG&E-8A and SDG&E-8B below, the total energy consumption was aggregated per site segment per part of week per hour per installation. A ratio was then calculated by dividing the total energy consumption by the number of ports per installation and then dividing that quotient by the number of days. That ratio was then averaged across all site segments and weekday types.

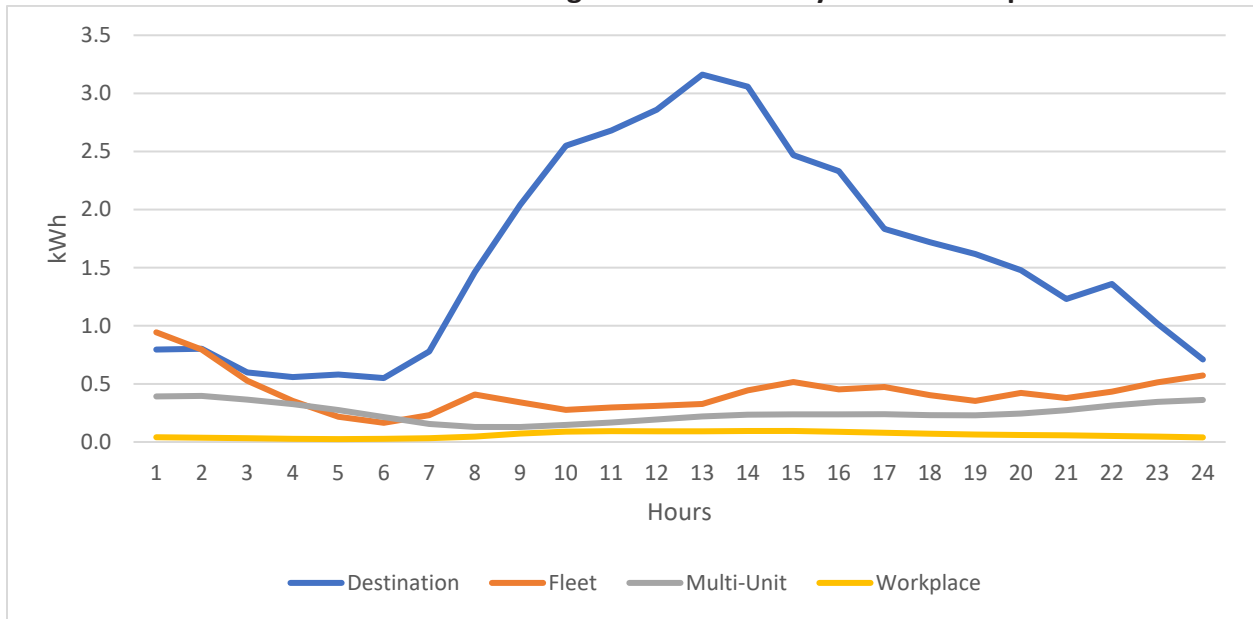
The weekday charging data for 2023 shown in Chart SDG&E-8A shows some interesting trends regarding the fleet and destination segments. Fleet has historically peaked at 10am and 6pm, but in 2023 shifted to a new peak at 11am. This is likely due to an increase in the number of fleet sites, representing different market segments which have potentially unique charging demands and behaviors. As for the destination segment, in 2022 it was a very similar shape with major usage during daytime hours throughout most of the night, but in 2023 the average consumption doubled compared to the previous year. Workplace and multi-unit dwelling charging trends have not changed significantly between 2022 and 2023. While the shapes are largely the same, the workplace segment has seen a peak increase of about 33%.

Chart SDG&E-8A: 2023 Average Weekday Hourly Port Consumption



In Chart SDG&E-8B, weekend charging showed major changes from 2022 to 2023 for the destination segment. SDG&E observed a 75% increase in the peak average hourly usage during the weekend at destination sites. The other segments weekend charging behavior remained almost identical year to year.

Chart SDG&E-8B: 2023 Average Weekend Hourly Port Consumption



IV. Cost Tracking Data

A. Overview and Approach

This report provides aggregated EV Charging Infrastructure cost data, for TE programs and non-TE programs, by IOU. To the extent possible, the IOUs have coordinated to provide consistency in data assumptions. However, because utilities have different methods of tracking their costs, which are unrelated to their EV Infrastructure Rules (i.e., Rules 29/45), the costs calculated for each category may be based on different assumptions. Each IOU section includes information on the general approach and assumptions for the cost data; it also explains why certain data may not be available at this time.

Additionally, this report is limited in that it primarily includes utility-incurred costs. Traditionally, customer-side costs (behind the meter) are generally unknown to the utility unless covered by a utility TE program. As such, certain customer costs, which may be required for deploying EV infrastructure but unknown to the utility, may not be accounted for in this report. One example of this type of cost is the trenching and site excavation for service line extensions, costs that are not utility service facilities under Rules 15 and 16 and are therefore borne by customers and not tracked by the utility. Such customer costs are not included in this report.

Table 1 below provides a summary of the EV infrastructure costs and responsibilities, for Rule 15 and Rule 16 projects, outside of an IOU EV charging infrastructure program and excluding Rule 29/45. Table 1 also notes the residential allowance. Comparing the costs of installing EV charging infrastructure by IOU TE programs and traditional delivery (or nonprogram) is challenging, as the IOUs are unable to track and report on all non-program customer costs. This report includes information on those costs that are known to the IOUs.

Table 2: Summary of EV Infrastructure Costs and Responsibilities

	Customer Assigned Costs	Allowance?	Utility Assigned Costs
Equipment on Customer Side of Meter	Customer pays all costs for charging equipment, including costs to plan, design, install, own, maintain, and operate facilities and equipment beyond the Service Delivery Point		
Service Line Upgrade	<ul style="list-style-type: none"> Excavation: trenching, backfilling, and other digging as required 	Yes, to cover work responsibility assigned to utility. Customer pays amount exceeding	<ul style="list-style-type: none"> Underground Service: service conductors and connectors

	<p>including permit fees</p> <ul style="list-style-type: none"> • Furnishing, installing, owning, and maintaining all conduits (including pulling tape) and Substructures, furnishing riser materials • Protective Structures: Furnishing, installing, owning, and maintaining all necessary Protective Structures as specified by utility for utility’s facilities 	<p>allowance. This is in addition to customer-assigned costs.</p> <p>Note: CPUC policy exemption in place for residential upgrades when EV load is added. Under exemption, amount exceeding allowance is not paid by customer and instead paid by utility and recovered through distribution rates. *</p>	<ul style="list-style-type: none"> • Overhead Service: conductors and support poles • Metering: meters and associated utility-owned metering equipment
Secondary Lines/ Transformer Upgrade (Serving 2 or more Service Lines)			Utility pays all costs for upgrading and maintaining the distribution system. Recovered through distribution rates.

* Similar additional cost coverage will be available to non-residential customers via Rule 29 which was approved by the CPUC in October 2021 and available to customers in April 2022.

Cost data is located within Attachments 1 – 3, by IOU.²³ Attachments 1 - 3 include the following cost tables:

- Table 2: Non-Pilot/Program Costs for 2023
- Table 3: Program Costs for 2023
- Table 4: Historic Costs

²³ See Attachment 1 for PG&E data; Attachment 2 for SCE data, and Attachment 3 for SDG&E data.

The IOUs will continue to work with the Energy Division on opportunities to refine this report in the future.

B. PG&E's EV Infrastructure Cost Data

Table 2 in Attachment 1: Non-Program Costs

General Approach and Cost Assumptions

PG&E performed EV-related upgrade work for 162 residential charging infrastructure projects and 32 non-residential charging infrastructure projects in 2023. These only include projects that were fully invoiced during the period of January 1, 2023, through December 31, 2023, even if the project incurred costs earlier than 2023. Costs related to EV infrastructure installation as part of new building construction are not separately tracked and therefore not included in this report.

Upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers. As described above, residential and non-residential customers participating in Rule 15 and Rule 16 receive an allowance for upgrade costs on the utility side of the meter and are responsible to pay any costs over the allowance. Residential PEV customers are exempt and any costs above the residential allowance are assigned to the utility per current CPUC policy. PG&E does not have information on the customer side of the meter costs and limited insight on the customer assigned costs for service line upgrades, which includes costs over the Rule 16 allowance.

It is important to note that there may be differences in how non-program costs are tracked and reported across the three IOUs and therefore it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- Site Costs
 - PG&E separately estimates and records the costs of specific work types of design, trenching, separate meters, permitting, distribution system work (under Rule 15²⁴), and service line work (under Rule 16²⁵). In this report, PG&E includes costs for projects that were fully invoiced in 2023 and uses the following definitions for the cost categories in Table 2:
 - Design – costs for all utility side of the meter design assigned to the utility or the customer,
 - Trenching and site excavation – Costs for all work related to digging and excavation to lay conduit and wires for projects. This includes costs for work completed by the utility or the customer and assigned to the utility and customer,
 - Separate meter – costs for all meter panels purchased for all projects and assigned to the utility or customer. This excludes meter costs associated with infrastructure charging programs. These costs are included here because meter costs for EVCN and DC Fast Charge are captured under PG&E's GRC proceeding, not covered by these programs.
 - Permitting – cost of all permits necessary for work on the utility side of the meter and assigned to the utility or customer,

²⁴ PG&E Electric Rule 15 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf

²⁵ PG&E Electric Rule 16 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_16.pdf

- Total Distribution System Costs Incurred by Utility for Upgrades – all costs associated with work performed on the distribution system under Rule 15 including design, trenching, permitting and other materials and labor,
 - Total Service Line Costs Incurred by Utility for Upgrades – all costs associated with work performed on the service line under Rule 16 including design, trenching, permitting, meters, and other materials and labor,
 - Total Utility side costs – all costs assigned to the utility for work associated with the EV-related upgrade including Rule 15 and Rule 16 costs, grid betterment work, the allowance and costs above the allowance for residential customers, and
 - Total Customer side costs – all costs assigned to the customer for work performed on the utility side of the meter that PG&E has insight into (e.g. service line trenching, backfilling, and other digging as required including permit fees; furnishing, installing, owning and maintaining all conduits and structures, including riser material, and all rights of way costs, if applicable). The utility or the customer may have performed the work. For residential customers this includes any cost above the allowance even though this is assigned to the utility under the CPUC policy exemption.
- Other (Ports Installed/New Capacity):
 - The capacity reported under “Amount of new capacity resulting from project (kW)” reflects the new capacity added as reflected in customer applications for Non-pilot/program Residential and Commercial Charging Infrastructure.
 - For Residential Charging Infrastructure capacity, the infrastructure projects reported did not explicitly state the amount of new capacity added. They did include, however, information on the type of charger and the number of ports for each project. Therefore, PG&E made an estimation of 7.2 kW of added capacity for each of those 162 residential projects.
- The methodology is the same for recording of costs of both residential and commercial charging infrastructure non-program work.

Explanation of why certain data is unavailable to report

- For Total Customer side costs, PG&E is only able to report on costs assigned to the customer for work on the utility side of the meter that PG&E has insight into. There may be some additional costs for work on the utility side of the meter assigned to the customer that is not reported here. Total customer side costs also do not include costs for the behind-the-meter work performed by the customer.

Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

Explanation of why Total Utility Side Costs and Total Customer Side Costs do not match the sum of all other categories

- The Total Utility Costs and Total Customer Side Costs do not match the sum of all other categories, because some costs accrued do not fit within any of the subcategories as presented (Design Costs, Trenching, Separate Meter Costs, Permitting, Total Distribution, Total Service Line). These include:
 - Mapping: labor for recording project “as-builts” in mapping records to ensure accuracy of asset records
 - Inspection: any work done by the customer on behalf of PG&E needs to be inspected by PG&E.
 - Land: preparation for land rights and easements that PG&E performs on behalf of the customer, which the customer pays for.
 - Administrative Overhead: overhead to cover back office administrative functions.

Project Management: labor costs for managing the project from point of application to execution of construction.

Table 3 in Attachment 1: Program Costs

General Approach and Cost Assumptions

PG&E includes costs for projects in 2023²⁶ across three programs – EV Fleet, EV Fast Charge, and EV Schools. EV Fleet fully invoiced 23 completed projects in 2023, including 13 Small Sites serving a total of 114 vehicles, 7 Medium Sites serving 172 vehicles and 3 Large Sites serving 96 vehicles. EV Fast Charge fully invoiced 18 sites in 2023. EV Schools fully invoiced 7 sites in 2023.

Reported costs are not tracked in this report by individual program. Instead, costs are categorized by Light-duty Vehicle (LDV) Infrastructure and Medium and Heavy Duty (MD/HD) Infrastructure. Light Duty infrastructure is further subcategorized by L2 MUD, L2 Workplace infrastructure, and DCFC infrastructure. DC Fast Charge infrastructure falls under the LDV category, but DCFC has its own column to show costs associated with the EV Fast Charge program. MD/HD is segmented by the capacity that a given site adds to accommodate charging equipment installations: Small – installed charging capacity adds up to 500 kW, Medium – between 500 kW and 3 MW, and Large – beyond 3 MW. Among EV Fleet’s 23 projects, 13 were small sites that added a total of 2,378 kW of new capacity, and 7 were medium sites that added a total of 12,420 kW of new capacity, and 3 were large sites that added a total of 12,663 kW of new capacity.

It is important to note that there may be differences in how program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- Site Costs:

²⁶ Some costs represented in Table 3 in Attachment 1 for TE Programs represent costs for projects that were fully invoiced within 2023 (which, therefore, PG&E has full insight into actual costs for); these costs may include costs incurred for projects whose design, construction, and activation timeline spanned multiple calendar years, and therefore some costs for the projects represented in this table may have been incurred in years prior to 2023. For this reason, it would not be possible to simply add costs from consecutive EV Load and Charging Cost Reports by TE Program and arrive at a mutually exclusive sum of program costs. Other costs represented in Table 3 in Attachment 1 represent those costs that were incurred within calendar year 2023 for that cost category.

- In 2023, PG&E’s site costs included projects that were fully invoiced²⁷ across the EV Fast Charge, EV Fleet, and EV Schools programs. PG&E records each project’s site costs and uses the following definitions for the cost categories in Table 3:
 - Design – utility costs for all final site designs for projects,
 - Trenching and site excavation – estimated costs for all utility work related to digging and excavation to lay conduit and wires for projects fully invoiced in 2023. This does not include restoration costs,
 - Separate meter – estimated total costs for all meter related costs borne by the respective programs, associated equipment, and installation costs for all projects,
 - Permitting – estimated costs associated with permits and labor to apply for permits,
 - Total Utility side costs - “to the meter” construction costs (including trenching), as well as estimated materials and design costs, and
 - Total Customer side costs – “behind the meter” construction costs (including trenching), as well as estimated materials, design, and permitting costs but excluding charger costs, participation payments, and rebates where applicable.
- The categorization is generally the same for the recording of Light-duty and Medium- and Heavy-duty site costs.
- With the exception of Total Utility side costs and Total Customer side costs, “Site Costs” do not include costs and rebates.
- The specific site costs of design, trenching, separate meters, and permitting are a subset of the total utility side costs and total customer side costs reported for projects fully invoiced in 2023.
- Support Activities Costs
 - Support Activities costs are reported for work done in the 2023 calendar year and are in many cases not tracked to specific project sites²⁸. In 2023, PG&E Support Activities costs included reported costs for all programs. PG&E uses the following definitions for the cost categories in Table 3:
 - Project management – all labor costs associated with project management for projects fully invoiced²⁹ during 2023,

²⁷ Fully invoiced indicates that PG&E had full actual cost data because third-party vendor invoices were completed. This is different from “substantially completed”, which for light-duty vehicle infrastructure is.

²⁸ A portion of project management costs are associated with the specific projects fully invoiced in 2023. Some project management costs and the remaining two support activities cost categories are not directly associated with projects fully invoiced in 2023 (i.e. these could include projects that were worked on in 2023 but not fully invoiced in 2023).

²⁹ Fully invoiced indicates that PG&E had full actual cost data because third-party vendor invoices were completed. This is different from “substantially completed”, which for light-duty vehicle infrastructure is defined as projects where all customer side or “behind the meter” (BtM) construction work is complete (excluding charger installation), and all utility side or “to the meter” (TtM) equipment is installed (excluding to the meter wire pulls or energization). Projects substantially completed in 2023 may include projects that in 2023 had not yet completed charger installation or site restoration.

- Customer outreach – all costs associated with customer outreach before contract was signed on any given project, with reported costs representing spend in this category in 2023,
- Outreach and education materials – all costs for program marketing, including collateral, website development, and events spent in 2023, and
- Other costs – these include rebates and incentives for various programs. Specifically, rebates under Medium and Heavy-Duty Infrastructure are primarily from EV Fleet. Those rebate costs include all infrastructure incentives and rebates associated with EVSE equipment that were issued during the 2023 calendar year. These rebates and incentives may have been issued to sites that were fully invoiced before 2023 because site hosts must submit invoices as proof of costs incurred in order to receive payment, and this may occur several months after a site has been completed.
- Other (Ports Installed/New Capacity committed):
 - Ports captured under Medium- and Heavy-Duty Infrastructure are primarily from PG&E’s EV Fleet Program. The ports reported under this category reflect “installed” ports and new capacity reported reflects “committed.” The EV Fleet Program differs from other TE programs because site hosts can acquire and install EVSEs over a 5-year period instead of at site activation. This means that the number of ports installed for these sites may change over time as site hosts install additional equipment.

Explanation of why certain data is unavailable to report

Some cost data from the programs was not available to report. There are different reasons depending on the cost category, and it may also vary between programs. PG&E provides detail on some of the specific data that is unavailable to report below:

- Light-duty Vehicle Infrastructure
 - Design, permitting, and trenching costs are recorded as part of broader cost categories. As a result, these costs have been estimated using contractor submission data.
 - Additionally, design, materials, overheads, and permitting costs are not separately recorded for utility side work and customer side work. As such, the provided costs are prorated between utility side costs and customer side costs based on estimated utility side vs customer side construction labor allocations.
 - In other instances, costs are not consistently separately recorded for each project site in a way that is easily aggregated, and often require manual tabulation/estimation for Light-duty Vehicle Infrastructure, e.g.:
 - Separate meter costs are estimated based on the number of meter panels installed at each project site and an estimated unit price for meter panels, associated equipment, and installation costs.
 - Permitting costs are estimated based on the costs of the labor to apply for the permit, and the permit costs.
- Medium and Heavy-Duty Vehicle Infrastructure

- Site costs include to-the-meter and behind-the-meter costs. Most sites are to-the-meter only.
- PG&E does not separately record distribution system upgrade costs or service line upgrade costs related to EV infrastructure installation through programs. Costs incurred to the utility for any work on the distribution system or service line in the programs are considered to-the-meter costs and are captured under total utility side costs.

Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified during program deployment.

Table 4 in Attachment 1: Historic Costs

General Approach and Cost Assumptions

- Non-program Charging Infrastructure costs:
 - Historic non-program residential charging infrastructure costs from 2011-2018 are pulled from data used in previous Load Research Reports and 2022 costs are pulled from the EV Infrastructure Cost Report submitted in 2023.
 - The process to report utility distribution and service line costs for this Report is different than for previous Load Research Reports and may make a comparison between tables challenging.
 - Historic non-program commercial charging infrastructure costs were first included for 2020 projects.
 - Historic program infrastructure costs were first included for 2020 projects and the latest historical data is pulled from Table 2 in Attachment 1 of the EV Infrastructure Cost Report filed on March 31, 2023.
 - As mentioned in the section on Table 2 of attachment 1, upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers.
 - PG&E does not have information on the customer side of the meter costs nor insight on all the customer assigned costs for service line upgrades.
 - The Customer pays all costs for beyond the Service Delivery Point.
 - The Customer is responsible for trenching, backfilling, and other digging as required including permit fees.
 - The Customer is responsible for furnishing, installing, owning and maintaining all conduits and structures, including riser material.
 - The Customer is responsible for all rights of way costs, if applicable.
 - Per the CPUC policy exemption currently in place, when the Rule 16 costs exceed the allowance provided for residential EV service line upgrades, the amount exceeding the allowance is not paid by the customer, but instead by PG&E (recoverable through distribution rates).

Explanation of why certain data is unavailable to report

- N/A

Steps to report currently unavailable data at a later time

- N/A

C. SCE's EV Infrastructure Cost Data

Table 2 in Attachment 2: Non-Program Costs (Nominal Costs)

General Approach and Cost Assumptions

In addition to SCE's TE programs and pilot activities, SCE completed Non-Program (Rule 15/16), EV-related infrastructure work for 121 residential charging infrastructure projects and 84 non-residential charging infrastructure projects in 2023. SCE is only reporting on projects for which construction was completed between January 1, 2023, and December 31, 2023. Regardless of the year the project originated, all costs associated with a project completed in 2023 are included in this report. Costs related to EV infrastructure installation conducted as part of new building construction are not separately tracked and therefore not included in this report.

Non-program infrastructure costs related to EVs fall into three categories: (1) the utility distribution system that serves multiple customers (Rule 15), (2) the individual customer service line (Rule 16), and (3) equipment on the customer side of the meter (behind the meter). Behind the meter costs related to EV infrastructure installation, which are not specific to a TE pilot or program, are not tracked by the utility and therefore are not included in this report. In this report, EV infrastructure is accounted for only if a work order is opened and identified as an EV work order. The cost reporting methodology is the same for the recording of costs for both residential and commercial charging infrastructure nonprogram work.

Residential and non-residential customers receive an allowance for upgrade costs on the utility side of the meter. Customers are invoiced for utility work and are responsible to pay any costs over the allowance. On December 16, 2021, the Commission issued Decision Extending the Interim Policy on Common Treatment for Excess Plug-in Electric Vehicle Charging Costs Consistent with Assembly Bill 841 (D.21-12-033). The Commission concluded in D.21-12-033 that it is reasonable to interpret the term "residential" as used in Public Utility Code 740.19(d)(2) as being inclusive of all types of residences, and not just applying to single-family residences.³⁰ As applicable, SCE is including both single family and multi-unit dwelling EV upgrade projects in this report.

There are differences in how non-program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- Site Costs
 - If applicable, SCE separately estimates and records the costs of specific types of work including trenching, separate meters, permitting, distribution system work (Rule 15), and service line work (Rule 16). In this report, SCE includes costs for projects where construction was completed in 2023 and uses the following definitions for the cost categories in Tables 2 and 4 in SCE Attachment 2.
 - Design Costs – To report design costs on the utility side of the meter, SCE used the historical recorded Planning and Design costs within Distribution for 2023 that were

³⁰ D.21-12-033, OP 4.

- allocated to all distribution capital orders, which equates to 15.04 percent. The 15.04 percent was applied against the non-program work orders to estimate Design costs.
- Trenching and site excavation – estimated costs, if performed by the utility, for all utility side work related to excavation and installation of underground ducts and structures required for projects.
 - Separate meter – estimated costs are provided only for projects completed in 2023. To better estimate meters, SCE is providing site level estimated meter costs from our design system. Generally, SCE purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received. Meter costs are not recorded against individual work orders. Meter costs are included in the Total Utility side costs total in Table 2 and in the Total Service Lines Costs Incurred by the Utility total in Table 4.
 - Permitting – estimated costs of all utility invoiced permits necessary for work on the utility side of the meter and paid by the customer.
 - Total Distribution System Costs Incurred by Utility for Upgrades – The number provided, a combination of both actual and estimated dollars, represents the total utility side (to the meter) expenditure for all capital direct costs, indirect capital labor overhead recorded costs, and O&M indirect labor costs, up to but not including the meter pedestal or meter panel associated with work performed to install distribution line extensions, Rule 15, and combination distribution line extension and service line extensions, Rules 15 and 16, non-program EV work. Cost categories include, for example, trenching, meter costs, and other material (including transformation costs), and labor, as well as division overhead costs.
 - Includes division overhead costs (e.g., planner activities such as site visits, creating the design, etc., and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
 - Includes estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE's General Rate Case (GRC), and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
 - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to work orders. Transformation costs for transformers sized at or less than 500 kVA are included in the Total Utility side Costs total in Table 2 and in the Total Service Lines Costs Incurred by the Utility total in Table 4.
 - Total Service Line Costs Incurred by Utility for Upgrades – The number provided, a combination of both actual and estimated dollars, represents the total utility side (to the meter) expenditure for all capital direct costs, indirect capital labor overhead recorded costs, and O&M indirect labor costs, up to but not including the meter pedestal or meter panel associated with work performed to install service line extensions, Rules 16, non-program EV work. Cost categories include, for example, trenching, meter costs, and other material (including transformation costs) as well as division overhead costs.

- Includes division overhead costs (e.g., planner activities such as site visits, creating the design, etc., and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
- Includes estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE’s General Rate Case (GRC), and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
- Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to work orders. Transformation costs for transformers sized at or less than 500 kVA are included in the Total Utility side Costs total in Table 2 and in the Total Service Lines Costs Incurred by the Utility total in Table 4.
- Total Utility side costs – total of all Distribution System costs, and Service Line costs incurred by the utility for non-program EV work.
 - Meter and transformation (sized equal to or less than 500kVA) costs are not recorded against program budget. These costs are included in the Total Utility side costs total in Table 2 and in the Total Service Lines Costs Incurred by the Utility total in Table 4.
- Total Customer side costs – all costs invoiced to and paid by the customer for work performed on the utility side of the meter that SCE has insight into (e.g., riser material, all rights of way costs, permit fees, and tax, if applicable).
 - For residential customers this also includes any costs above the allowance even though this is assigned to the utility under the CPUC policy exemption.

Explanation of why certain data is unavailable to report

- N/A

Steps to report currently unavailable data at a later time

- N/A

Explanation of plans to provide additional data in future reports

- SCE and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

Table 3 in Attachment 2: Pilot-Program Costs (Nominal Costs)

General Approach and Cost Assumptions

SCE is providing costs for its TE pilots and programs that were completed³¹ between January 1, 2023, and December 31, 2023. Regardless of the year the project originated, all total capital costs associated

³¹ Pilots and program costs are included for completed sites with rebates paid and fully invoiced with all work orders closed, where applicable, as of December 31, 2023.

with a project completed in 2023 are included in Site Costs (\$) category Table 3. With the exception of rebates, SCE does not track O&M costs per site/project. In the Support Activities (\$) Table 3, all program O&M 2023 recorded costs are provided and grouped into their respective categories. Charge Ready Light-duty and Charge Ready Transport are the only programs that incurred both Capital and O&M costs in 2023.

As of December 31, 2023, SCE's Charge Ready Light Duty program has completed constructing projects for 87 sites and installed 1,500 ports since inception. SCE has provided cost information for 2 small sites with 21 ports that were completed and fully invoiced with all workorders closed from January 1, 2023, through December 31, 2023, based on reporting requirements.

Within the medium- and heavy-duty vehicle Infrastructure segment, as of December 31, 2023, construction was completed at 65 sites and 1,263 ports were installed, supporting the electrification of 1,540 MDHD vehicles since inception. SCE has provided cost information for the 11 sites that were completed and fully invoiced with all work orders closed from January 1, 2023, through December 31, 2023, based on reporting requirements. Of the total 11 medium- and heavy-duty vehicle Infrastructure completed projects, there are 6 small sites with 84 ports and 5 medium sites with 157 ports which total to 241 MDHD ports for 11 sites.

SCE records each project's site costs in separate work orders for:

- Utility-side costs ("to the meter" capital labor and contract construction costs, including design, trenching, permitting, etc.) and
- Customer-side costs ("behind the meter" capital labor and contract construction costs, from the meter to the stub-out for the charging equipment, design, trenching, permitting, etc.)

The methodology is the same for the recording of Light-, Medium- and Heavy-duty construction costs. This methodology will also be consistent with the Charge Ready Parks and State Beaches (AB 1083) and Charge Ready Light-Duty.

- **Site costs** – Includes only Capital costs.
 - Design costs will include both utility-side and customer-side costs.
 - Utility-side: To report design costs on the utility side of the meter, SCE used the historical recorded Planning and Design costs within Distribution for 2023 that were allocated to all distribution capital orders, which equates to a 15.04%. The 15.04% was applied against the EVSE work orders to estimate Design costs.
 - Customer-side: The number provided represents the actual labor and material dollars required to produce the customer-side (behind or beyond the meter) design from meter pedestal up to, but not including the EVSEs. This includes, for example, site visits, research, and design production. SCE is able to provide these customer-side costs due to the implementation of third-party contracts with Architecture and Engineering firms for design work.
 - Trenching, site excavation, and permitting costs provided in the Site Costs section reflect customer-hank side and utility-side costs.
 - Trenching and site excavation – The number provided, a combination of both actual and estimated dollars. Estimated costs represent the total utility-side (to the meter) for all utility-side work related to excavation and installation of

underground ducts and structures required for projects. The number provided on the customer-side represents the actual labor and material dollars required for excavation, installation of customer-side (behind or beyond the meter) conduits and structures (e.g., handholes, transformer pads, vaults, etc.) and site restoration.

- Permitting costs – Total actual costs for customer-side (behind or beyond the meter) permitting costs charged by the Authority Having Jurisdiction (AHJ)
- Separate meter costs are provided for only projects that were completed in 2023. To better estimate meters, SCE is providing site level estimated meter costs from our design system. SCE generally purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received. Meter costs are not recorded against program budget.
- Total Utility-side costs - The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period, separated by respective programs. Cost categories include, for example, trenching, permitting, meter costs, and other material (including transformer cost) as well as division overhead.
 - Includes division overhead costs (e.g., planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
 - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.
- Total Customer side costs - The number provided, a combination of both actual and estimated dollars, represents the total customer-side (behind or beyond the meter) expenditure for all capital direct and indirect labor overheads recorded costs, from the meter pedestal or meter panel, up to but not including the EVSEs for completed projects within the reporting period (programs with Own and Operate offerings will include EVSE costs). Examples of included costs are design, trenching, permitting, labor, and material such as the meter pedestal or meter panel, transformation, cable, and connectors.
 - Includes division overhead costs (e.g., Planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
- **Support Activities** – Includes both Operation and Maintenance “O&M” and Capital expenses
 - Project Management
 - Program-related direct labor such as program management and program support
 - Customer Outreach (Labor) –
 - Labor costs associated with conducting Transportation Electrification Advisory Services (TEAS) provides business customers with a dedicated "one-stop shop" for specialized education, awareness, and support on TE issues. The goal of TEAS

is to promote customer adoption of TE, help with pre-planning activities, generate leads for TE programs (active or in development) and serve the TE needs of our business customers.

- Marketing and Education Materials
 - Marketing, Education & Outreach (ME&O) – Includes third-party costs associated with the development and implementation of customer education and marketing campaigns and materials that are primarily targeted at potential multifamily and non-residential EV and EV charging adopters through educational webinars, fleet fueling calculator, Charge Ready Transport case studies (customer feedback), paid media ads, print collateral and promotional items, web design and content development, email marketing, industry research and data, and targeted industry group membership.
 - Other Costs
 - This category includes various costs not captured in the above categories, for example, rebates, canceled project costs, Capital IT implementation costs, and estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE's GRC and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
- **Other Support Activity**
 - Total number of charge ports installed – total completed project port count based on information provided by the customer at project application/acceptance
 - Amount of new capacity resulting from project (kw) - Total estimated capacity based on information provided by the customer at project application/acceptance

Explanation of why certain data is unavailable to report

- N/A

Steps to report currently unavailable data at a later time

- SCE has taken steps to ensure more detailed tracking of costs by creating separate work orders per site for utility-side costs, customer-side costs, and easements. Within these work orders, SCE uses cost elements, cost descriptions, and purchase order information to further breakdown costs into additional subcomponents. An example of steps taken from 2019 and beyond to include new contracts to provide actuals for permitting and design for customer-side costs.

Explanation of plans to provide additional data in future reports

- SCE continues to work with the Energy Division to refine this report for the future, and as part of that process will consider how to best capture the data needs requested.

Table 4 in Attachment 2: Historic Costs (Nominal Costs)

General Approach and Cost Assumptions

- The current templates (Tables 2 and 3) to report utility distribution system and service line costs for this Report are different than for previous Load Research Reports and may make a comparison between tables/years challenging.

Explanation of why certain data is unavailable to report

- N/A

Steps to report currently unavailable data at a later time

- N/A

Explanation of plans to provide additional data in future reports

- SCE will continue to work with the Energy Division and the other IOUs to determine how future historical (e.g., reporting periods 2019 and beyond) will be organized on future reporting templates.

D. SDG&E's EV Infrastructure Cost Data

Table 2 in Attachment 3: Non-Program Costs

General Approach and Cost Assumptions

Costs provided for all fully invoiced projects as of December 2023 include direct costs, overheads, and Allowance for Funds Used During Construction (AFUDC) incurred for completed sites during the project life.

- Design costs: Overhead costs specifically related to engineering. Design costs are not direct charged to non-program sites.
- Trenching and site excavation: estimated 25% allocation of costs from line "Total distribution system costs incurred by utility for upgrades" and "Total service line costs incurred by utility for upgrades".
- Separate meter costs: charges billed to FERC 370 – Meters.
- Permitting costs: utility permits are not tracked separately.
- Total distribution system costs incurred by utility for upgrades: labor, services, materials, and associated overheads for distribution system upgrades.
- Total service line costs incurred by utility for upgrades: charges billed for construction of new service lines.
- Total utility side costs: Includes accumulated depreciation, miscellaneous expenses, and the sum of the above utility costs.
- Total customer costs: required customer payments (contributions in aid of construction) made to utility.

There are differences in how non-program costs are tracked and reported across the three investor-owned utilities (IOUs) and it is necessary to consider the differences and caveats explained in this report when comparing the cost tables across the three attachments.

Explanation of why certain data is unavailable to report

Permits pulled by the utility are not generally applicable to the utility's scope for residential work. Permit costs for commercial sites vary by local jurisdiction. SDG&E has estimated the average permit costs to be approximately \$1,000 per site in past studies.

Steps to report currently unavailable data at a later time

SDG&E currently captures the number and type of charge port installation and amount of new capacity requested by customers through our customer inquiry portal for new business inquiries only. However, since these are requests and not actuals, SDG&E does not store this data in its system applications and products (SAP) system. While load studies are done to determine customers' EV charger demand, this information is not currently captured in SDG&E systems. SDG&E is working to modify its systems to capture load study results. However, given that SDG&E's work ends at the point of service, SDG&E will still not be able to verify if customers follow through with installations after SDG&E's work is completed.

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

Table 3 in Attachment 3: Pilot-Program Costs

General Approach and Cost Assumptions

Costs provided for all fully invoiced projects as of December 2023 include direct costs, overheads, and AFUDC incurred for completed sites during the project life. Only projects completed in 2023 are included.

- Design costs: Direct charges of billed design cost.
- Trenching and site excavation: Direct charges billed for trenching and site excavation, as well as estimated 25% allocation of costs from line "Total Utility Side Cost".
- Separate meter costs: Charges billed to FERC 370 – Meters.
- Permitting costs: Utility permits are not tracked separately.
- Total utility side costs: Total cost for labor, services, materials, and associated overheads for distribution system upgrades and new service lines, as well as accumulated depreciation, miscellaneous expenses.

Explanation of why certain data is unavailable to report

Costs for SDG&E's Power Your Drive Extension are not available yet as construction was not completed on any sites in 2023.

Permits pulled by the utility are not generally applicable to the utility's scope. SDG&E has estimated the average permit costs to be approximately \$1,000 per site in past studies.

Steps to report currently unavailable data at a later time

N/A

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

Table 4 in Attachment 3: Historic Costs

General Approach and Cost Assumptions

Costs provided are direct costs, overheads, and AFUDC incurred for completed sites during the year.

- Historical upgrade cost from previously submitted Load Research Reports periods 2012-2018.
- 2019 Historical upgrade costs based on actual cost incurred for customer upgrade jobs completed in 2019.
- 2020 Historical upgrade costs based on amended submittal December 13, 2021.

Explanation of why certain data is unavailable to report

N/A

Steps to report currently unavailable data at a later time

N/A

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

V. EV Infrastructure Rule Data

A. Overview and Approach

Per Resolutions E-5167 and E-5247, the CPUC has ruled that IOUs shall provide detailed accounting of materials and labor costs for EV Infrastructure projects, as well as tracking of time and responsibilities for various stages of EV Infrastructure work by the IOU, Authority Having Jurisdiction (AHJ) and EV Service Provider (EVSP). This report provides site level and aggregated annual data for Rule 29/45 EV Infrastructure by IOU. Each IOU section includes information on the general approach and assumptions for the Rule 29/45 EV Infrastructure data; it also explains why certain data may or may not be available now; and provides the chapter within their General Rate Case (GRC) testimony where the IOU will address the reasonableness of the costs cited.³²

Additionally, this report is currently limited, in that customer projects have not been completed by some IOUs in 2023. As per both the Non-Pilot/Program and Program sections of this report, IOUs will report information for Rule 29/45 projects when projects are complete with all trailing costs allocated.

Per Resolution E-5167, Tables 5 and 6 provide site level and aggregated annual data for Rule 29/45 EV infrastructure and utilize the AB 841 data template provided on the CPUC's website.³³ This report includes information on projects that are completed with all trailing costs allocated and reflects only those costs that are known to the IOUs.

General Approach and Cost Assumptions

Costs provided are for all fully invoiced projects as of December 2023 and include direct costs and overheads incurred for completed sites during the project life.

Application Data: Data related to completed and rejected applications is based on the formal application form and will be provided for the year projects are completed or rejected. It is expected that the application numbers will not match completed project numbers since the application numbers reported will be based on total applications received which are completed or rejected annually.

Per Rulemaking, 18-12-006 (12/21/2020), IOUs are required to report on behind-the-meter (BTM) and automated load management (ALM) information. BTM and ALM information are self-reported by customers.

Automated Load Management: The customer is responsible for purchasing and installing ALM. Utilities present ALM options and information to educate customers. For data collection and reporting purposes, the utilities do not have access to the type of ALM installed nor the cost of installation, unless the customer self-reports this information. The current data collection template also requires IOUs to report on the estimated avoided capacity upgrade costs. Calculating this cost would require IOUs to perform two separate designs and estimates, increasing the IOUs design costs.

³² Resolution E-5167, OP 10, p. 65.

³³ Available at <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/resources-and-reporting>

Estimated Additional Cost between EV Infrastructure Rule Compared to Rule 16: The IOUs will report on an aggregated basis, the total additional costs the IOUs and ratepayers will cover as compared to treatment under existing Rule 16. These costs would include items like trenching, excavation, substructures and conduit, risers and permitting.

Labor: Resolution E-5167 requires labor costs to be reported on an aggregate basis for the project.

Net Areas of Trenching, Excavation and Resurfacing Area: These measurements will be estimated based on site design. Trenching for conduit is measured in length. Excavation for structures is measured in volume. General surfacing is measured in square footage. The IOUs need additional guidance on how to combine these varying measurement formats for the combined data reporting required by the data collection template.

Explanation of why certain data is unavailable to report

The current data collection template published by Energy Division on its website requires IOUs to report on transformer unit costs. IOUs treat these costs as confidential to protect bulk pricing contracts and vendor relationships.

Steps to report currently unavailable data at a later time

Resolution E-5247 requires IOUs to track timelines and develop data collection categories for projects related to Rule 29/45 projects which:

- a. have an installed capacity greater than 2 megawatts,
- b. trigger an Electric Rule 15 upgrade,
- c. are required to go through additional Electric Rules, and
- d. require a substation upgrade.

For project timelines which exceed the 125-day timeline, the IOUs are also required to report:

- 1) the reason for delay(s),
- 2) the number of days each step was delayed,
- 3) the actions the utility took to resolve the delay, if any, and
- 4) if the step is in the utility's direct control, utility's indirect control, or customer's direct control.

Explanation of plans to provide additional data in future reports

The Joint IOUs have yet to establish standardized data collection categories for projects that exceed the 125-business day timeline. However, the IOUs anticipate that the Commission's Energization OIR will address data collection requirements for these categories.

B. PG&E's EV Infrastructure Rule Data

On April 6, 2022, PG&E announced that its new EV infrastructure tariff – Rule 29 – was available to customers. Rule 29 is an alternative tariff to PG&E's Rule 16 specifically for commercial and multi-family dwelling customers installing separately metered EV charging infrastructure. It is not available for customers participating in any of PG&E's existing electric vehicle programs.

PG&E implemented Electric Rule 29 on April 6, 2022, and began receiving applications for service under this tariff that week. While PG&E supported a significant volume of projects in 2022, none were fully invoiced in 2022 and were excluded from last year's report. 2023 was the first year there were projects to report on. Rule 29 fully invoiced 36 completed projects in 2023. Four sites were public L2, 24 public DCFC, four public DCFC/L2, two private L2, one private DCFC, and one workplace. In addition to fully invoicing these 36 projects, PG&E received and accepted 632 applications. PG&E had zero applications rejected/fall out of the program in 2023. PG&E has a process to capture the reason for any future rejected/fallen out applications and will report on those, as needed, in future reports.

General Approach and Cost Assumptions

- Site Costs
 - PG&E separately estimates and records the costs of specific work types of engineering and design, trenching, separate meters, permitting, poles, and service line drops, amongst others. Dollar amounts provided are derived using job estimates for those sites. Actual costs may vary from initial job estimate. In this report, PG&E includes costs for projects that were fully invoiced in 2023 and uses the following definitions for the cost categories:
 - Design – costs for all utility side of the meter design assigned to the utility or the customer,
 - Trenching and site excavation – Costs for all work related to digging and excavation to lay conduit and wires for projects.
 - Separate meter – costs for all meter panels purchased for all projects and assigned to the utility or customer.
 - Permitting – cost of all permits necessary for work on the utility side of the meter and assigned to the utility or customer,
 - Total Service Line Costs Incurred by Utility for Upgrades – all costs associated with work performed on the service line including design, trenching, permitting, meters, and other materials and labor

Explanation of why certain data is unavailable to report

Rule 29 bill impact and estimate of additional cost of EV infrastructure rule compared to Rule 16 is not available because PG&E's 2023 General Rate Case (GRC) adopted revenue requirements were computed by function and Unbundled Cost Category (UCC). The adopted revenue requirement for Electric Distribution shown in UCC 301 includes a forecast related to Rule 29 projects. However, as the adopted revenue requirement was not calculated at the project level, PG&E cannot provide the adopted revenue requirements associated with Rule 29 projects forecasted in MWC 16.

C. SCE's EV Infrastructure Rule Data

On April 7, 2022, SCE announced that its new EV infrastructure tariff – Rule 29 – was available to customers. Rule 29 is an alternative tariff to SCE's Rule 16 specifically for commercial and multi-family dwelling customers installing separately metered EV charging infrastructure. It is not available for customers participating in any of SCE's existing Charge Ready programs.

In 2023, SCE received 260 requests to use Rule 29. Since the program's inception on April 7, 2022, SCE has received 374 project requests, which are in various stages of completion. A total of 163 projects were energized as of December 31, 2023, but are still pending receipt of all trailing costs. As is consistent with the Non-Pilot/Program and Program data collection section, SCE only considers a project to be complete after all costs (including trailing) are received.

OP 10 of Resolution E-5167 directs the IOUs to include a reference to the chapter of their General Rate Case (GRC) testimony where the IOU will address the reasonableness of the costs cited. SCE expects to address its Rule 29 costs within SCE-02, volume 8 of its GRC.

D. SDG&E's EV Infrastructure Rule Data

On April 7, 2022, SDG&E launched its new EV infrastructure tariff – Rule 45 – to new customers. Rule 45 is an alternative tariff to SDG&E's Rule 16, specifically for commercial and multifamily dwelling customers installing separately metered EV charging infrastructure. It is not available to customers participating in any of SDG&E's Power Your Drive programs.

For calendar year ending December 31st, 2023, SDG&E received and accepted 39 completed Rule 45 applications. One project was energized as of December 31, 2023, but is still pending receipt of all trailing costs. As is consistent with the Non-Pilot/Program and Program data collection section, SDG&E only considers a project to be complete after all costs (including trailing) are received.

Ordering Paragraph 10 of Resolution E-5167 directs the IOUs to include a reference to the chapter of the GRC testimony that will address the reasonableness of the costs cited within their annual reporting of costs. SDG&E addressed Rule 45 costs within chapter SDGE-21 of its 2024 GRC filing.

SDG&E is currently building on its legacy systems to facilitate data collection and reporting as required by Resolutions E-5167 and E-5247 and based on the current Data Collection template posted on the Energy Division website and conversations with Energy Division which occurred in June of 2022. The personnel and system changes required for these data collection and reporting requirements takes considerable time to build and implement.

General Approach and Cost Assumptions

While no costs are provided within this report for 2023, SDG&E has captured its interpretation and notes related to various cost fields for review. Future reports will include costs for fully invoiced projects and will include direct costs and overheads incurred for completed sites during the project life.

- Permitting: The “My Permit” application will track SDG&E permitting costs and timelines.
- Vehicle served type: Applicants will be presented a shortlist of options, and a freeform “other” field on SDG&E's formal application form. The site number will be based on customer project numbers.
- Transformer unit costs: If required, these confidential costs will be drawn from estimated cost reports, as they are not charged to a work order.
- Charge ports: The total number of ports and type of ports will be provided based on the information listed on the customer's application.
- Total site costs: These costs will be provided based on work orders and civil and administrative costs tracked by project number. SDG&E anticipates it will be able to determine actual project costs when Rule 45 projects are done in conjunction with other projects, such as Rule 15.

Explanation of why certain data is unavailable to report

Costs for SDG&E's Rule 45 EV Infrastructure program are not available as only one site was energized in 2023 and its final costs have not been reconciled.

- Reporting on materials and equipment: SDG&E is investigating ways to report on counts, measurements and costs of poles, vaults, service drops, transformers, mounting pads, conduit, wire, cable, and meters.

- Engineering and design: These costs will be based on the average cost assigned to each project from the overhead pool for engineering and design.
- Timeline tracking and reporting: SDG&E is developing a way to track the number of business days waiting for IOU and non-IOU (Customer or AHJ) work.

SDG&E is exploring ways to enhance its systems to capture and report on the estimate additional costs between the EV infrastructure Rule compared to Rule 16. These enhancements will avoid the need for manual research and data reporting. These enhancements come with significant costs to hire and/or contract personnel and to build and implement software tools for CPUC reporting requirements.

Steps to report currently unavailable data at a later time

Currently, SDG&E systems are not able to separately report on materials, costs, and labor for civil and construction work, more so when projects related to Rule 45 need to be accounted for, i.e., Rule 15. SDG&E is working to resolve these system limitations.

Attachment 1 – PG&E

PG&E Table 1: Number of EVs forecasted In IOU Service Territory

		Light-Duty	Medium-/ Heavy-Duty
Actual ¹	2011		
	2012		
	2013		
	2014	52,527	
	2015	78,574	
	2016	108,153	
	2017	140,667	294
	2018	197,367	360
	2019	242,952	437
	2020	274,518	593
	2021	331,180	735
	2022	425,413	900
	2023	581,545	1,174
Forecasted ²	2024	786,408	1,492
	2025	977,745	2,496
	2026	1,211,601	4,800
	2027	1,485,471	8,731
	2028	1,800,062	14,367
	2029	2,154,545	21,735
	2030	2,552,499	30,855

Notes:

¹ Both Light-Duty (LD) and Medium-/Heavy-Duty (MHD) data reflects vehicles-in-operation. Actual LD data is provided by the Electric Power Research Institute ("EPRI") and represents vehicle classes 1-2. There is significant uncertainty about the number of "actual" MHD vehicles in operation in CA. The underlying state-level data, representing vehicle class 3-8 actuals, was provided by the California Energy Commission in fall 2022. PG&E then prorated the data to represent PG&E's service area. The 2022 MHD data point was extrapolated due to incomplete data. In addition, 2023 MHD data has not yet been shared by the CEC; thus, the forecasted value is included for that year.

² Forecasted values from PG&E's 2024 EV adoption forecast (as of Jan 2024). PG&E's light-duty (Classes 1-2a) and medium and heavy-duty (Classes 2b-8) electric vehicle long-term forecast derives from PG&E's market- and policy-driven probabilistic model. The model considers different scenarios meant to represent compliance uncertainty associated with state electric vehicle regulations (e.g., Advanced Clean Trucks, Advanced Clean Cars II, Advanced Clean Fleets). PG&E's 20-year forecast predicts electric vehicle population, energy demand, and hourly load by class and segment. It tracks electric vehicle sales in California (sources: EPRI, CEC), market trends (sources: BNEF, others), current and future programs and regulations (e.g., from CARB, CPUC, and CEC). PG&E leverages internal data and results from pilot programs directed by state agencies and conducted in collaboration with other IOUs and vehicle manufacturers. PG&E's EV adoption forecast is subject to variables and assumptions regarding EV market demand, evolution, and development that are outside PG&E's control; therefore, the forecast is subject to significant uncertainty and should not be relied upon as a point estimate for policy or planning beyond the current PG&E GRC and distribution planning periods.

PG&E Table 2: Non-Pilot/Program Costs

2023 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs (\$)	Design costs	\$2,241,957	\$64,455
	Trenching and site excavation	\$293,044	\$303,327
	Separate meter costs	\$820	\$82,556
	Permitting costs	\$0	\$21,050
	Total Distribution System Costs Incurred by Utility for Upgrades	\$3,421,866	\$1,953,074
	Total Service Line costs Incurred by Utility for Upgrades	\$1,993,334	\$1,663,354
	Total Utility side costs ¹	\$7,951,021	\$4,087,817
	Total Customer Costs ²	\$2,254	\$838,429
Other	Total number of charge ports installed	162	399
	Amount of new capacity resulting from project (kW)	1,166	24,466

Notes:

1. Includes costs for Mapping, Inspection, Land, Inspection, Project Management, and Administrative Overhead that are not included in other Site Costs subcategories.
2. Total Customer Costs do not reflect ITCC. Customer costs are subject to ITCC.
3. All costs included are for work driven by EV-related upgrades.

PG&E Table 3: 2023 EV-Program Upgrade Costs

Table 3 2023 EV-related Upgrade Costs		Program Commercial Charging Infrastructure Costs								
		Light Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure ³			Medium and Heavy Duty Vehicle Infrastructure		
					Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Workplaces	DCFC - LDV ²	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs (\$)	Design costs ¹	\$0		\$0		\$0	\$94,101	\$59,502	\$38,121	
	Trenching and site excavation	\$0		\$0		\$0	\$248,533	\$159,238	\$61,365	
	Separate meter costs	\$0		\$0		\$0	\$0	\$0	\$0	
	Permitting costs	\$0		\$0		\$0	\$0	\$0	\$0	
	Total Utility side costs	\$0		\$0		\$0	\$1,818,333	\$2,591,145	\$855,064	
Support Activities (\$)	Total Customer Side Costs	\$0		\$0		\$0	\$0	\$0	\$0	
	Project management	\$0		\$0		\$0	\$305,378	\$207,311	\$148,918	
	Customer outreach (labor)	\$11,598		\$328,771						
	Outreach and education materials	\$28,097		\$1,313,343						
Other	Other costs			\$1,331,554						
	Total number of charge ports installed	0		0		0	63	113	33	
	Amount of new capacity resulting from project (kW)	0		0		0	2,378	11,920	12,663	

Certain information was redacted (highlighted in black) due to confidentiality concerns.

Notes:

1. Design costs include only final design costs for 2023 fully invoiced projects
- 2 Any site that has a DCFC, even if L2 chargers are also installed, will be captured in the DCFC column
- 3 Medium and Heavy Duty infrastructure is categorized by site size based on amount of new capacity resulting from each project
- 4 Data has been redacted to preserve customer confidentiality. There are an insufficient number of sites making up the data in the redacted cells to preserve customer anonymity.

PG&E Table 4: Historical Upgrade Costs

	Non-Pilot/program Residential Charging Infrastructure¹	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019²	2020²	2021²	2022²
Historical Upgrade Costs	Total Distribution System Costs Incurred by Utility for Upgrades	\$282,719	\$598,172	\$1,476,647	\$798,367	\$404,236	\$1,734,016	\$927,375	\$0	\$1,181,289	\$468,613	\$283,854
	Total Service Line costs Incurred by Utility for Upgrades	\$39,924	\$69,380	\$103,259	\$41,377	\$37,500	\$27,706	\$52,349	\$10,137	\$8,555	\$28,559	\$8,920
	Total Customer Portion of Utility Costs Covered by the exemption	\$9,226	\$34,125	\$76,046	\$19,669	\$3,856	\$3,983	\$29,618	\$5,649	\$41,247	\$137,774	\$0
	Non-Pilot/Program Commercial Charging Infrastructure											
	Total Distribution System Costs Incurred by Utility for Upgrades								\$757,669	\$3,403,289	\$4,121,638	\$4,810,352
	Total Service Line costs Incurred by Utility for Upgrades								\$1,798,229	\$2,726,958	\$2,544,112	\$2,094,137
	Pilot/Program Commercial Charging Infrastructure											
	Total Utility Side Costs								\$8,125,916	\$11,146,234	\$9,329,408	\$2,348,562
Total Customer Side Costs								\$19,699,909	\$27,375,166	\$20,356,917	\$479,728	

Notes:

¹ Historical upgrade costs are from data from previously submitted Load Research Reports. The data for the 2011 - 2012 report is from July 2011 through Oct 2012. The data for the next five reports and ending with the 2016-2017 report includes data from Nov - Oct of the following year. Data for the 2017-2018 report includes data from Nov 2017 through Dec 2018. The data for 2019 shows data for January-December of 2019.

² Details on the 2019, 2020, 2021, and 2022 historical costs can be found in the EV Infrastructure Cost Reports that were filed on April 2, 2020, April 1, 2021, March 31, 2022, and March 31, 2023 respectively.

Attachment 2 – SCE

SCE Table 1: Number of EVs Forecast in IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual	2012	8,526	
	2013	21,896	
	2014	39,890	
	2015	58,908	
	2016	83,186	
	2017	114,738	
	2018	163,869	
	2019	210,620	
	2020	251,584	
	2021	329,940	
	2022	443,788	
	2023	540,840	
	Forecasted	2024	755,548
2025		1,024,897	32,831
2026		1,379,679	44,385
2027		1,785,783	57,534
2028		2,155,821	72,194
2029		2,498,025	88,005
2030		2,904,022	105,006

Notes:

Notes: Actual LDV values 2012-2022 are provided by the Electric Power Research Institute (“EPRI”) on annual light-duty vehicle sales, based on third party registration data. Actual LDV for year 2023 were provided by the Electric Power Research Institute (“EPRI”) and it's based on EPRI analysis of Experian data, 2023.

SCE’s forecasts incorporate expected decarbonization funding, mandates, and support policies. For LDVs, policies such as CARB’s (California Air Resources Board) Advanced Clean Cars II and 100% ZEV sales by 2035 were considered. For medium and heavy-duty vehicles and buses, policies such as CARB’s Advanced Clean Trucks and Advanced Clean Fleet and Innovative Clean Transit rules were considered. SCE’s forecast also aligns with CARB’s 2022 Scoping Plan for achieving carbon neutrality in the long-term. SCE’s forecast also aligns with CARB’s 2022 Scoping Plan for achieving carbon neutrality in the long-term.

SCE Table 2: Non-Pilot/Program Costs

2022 EV-related Upgrade Costs (Nominal Costs) ¹		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs (\$)	Design costs ²	\$24,865	\$1,171,321
	Trenching and site excavation ³	\$261	\$1,122,157
	Separate meter costs ⁴	\$11,141	\$82,925
	Permitting costs ⁵	\$1,895	\$22,738
	Total Distribution System Costs Incurred by Utility for Upgrades ⁶	\$0	\$8,402,165
	Total Service Line costs Incurred by Utility for Upgrades	\$197,947	\$648,942
	Total Utility side costs ⁷	\$209,088	\$9,682,925
	Total Customer costs ^{8,9}	\$5,601	\$296,483
Other	Total number of charge ports installed	121	931
	Amount of new capacity resulting from project (kW)	847	79,081

Notes:

1. Reference IV. Cost Tracking Data Section C. SCE's EV Infrastructure Cost Data Table 2 narrative to find information regarding this table.
2. Design Costs are estimated for utility-side costs only, and are included in either the Distribution System or Service Line totals.
3. Trenching and excavation costs are estimated and are included in either the Distribution System or Service Line totals.
4. Meter costs are estimated and are added to the Total Utility-side costs totals.
5. Permit costs are estimated and are included in either the Distribution System or Service Line totals.
6. Distribution System and Service Line Costs incurred on a single work order are included in the Distribution System Costs Incurred by Utility for Upgrades totals.
7. Total Utility-side costs include a combination of actual and estimated costs of 'to the meter' expenditures for all capital direct costs, and indirect labor overhead recorded costs, for completed projects within the reporting period. Cost categories include design, trenching/excavation, meter, transformation, as well as division overheads (e.g., planner activities such as site visits and creating the design, etc., and operations activities such as scheduling work, staging material, etc.), and Capital overhead labor loaders (indirect costs) (e.g., pension, benefits, etc.).
8. Total Residential Customer costs include the amount of excess cost of service that would have been billable to the customer if the residential allowance exemption was not in place, as well as, if applicable, any fee's paid by the customer (e.g., riser, permit, right's check, and/or easement documentation).
9. Total Commercial Customer costs is the amount invoiced by SCE and paid to SCE by the Customer.

SCE Table 3: 2023 EV-Program Upgrade Costs

2023 EV-related Upgrade Costs (Nominal Costs) ^{1,2,3,4}		Pilot and Program Commercial Charging Infrastructure											
		Light Duty Vehicle Infrastructure						Medium and Heavy Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Workplace	L2 Chargers - Destination Center	L2 Chargers - Fleet	L2 Chargers - Schools	DCFC - LDV	Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure ⁸		
								Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs (\$) ¹	Design costs ²	\$11,268	\$0	\$0	\$0	\$0	\$0	\$255,318	\$158,758	\$0	\$0	\$103,062	\$0
	Trenching and site excavation ³	\$16,823	\$0	\$0	\$0	\$0	\$0	\$268,452	\$169,732	\$0	\$0	\$116,088	\$0
	Separate meter costs ⁴	\$1,159	\$0	\$0	\$0	\$0	\$0	\$4,603	\$2,853	\$0	\$0	\$2,958	\$0
	Permitting costs ⁵	\$0	\$0	\$0	\$0	\$0	\$0	\$34,146	\$10,730	\$0	\$0	\$0	\$0
	Total Utility side costs ⁶	\$111,367	\$0	\$0	\$0	\$0	\$0	\$906,997	\$847,345	\$0	\$0	\$798,712	\$0
	Total Customer side costs ⁷	\$0	\$0	\$0	\$0	\$0	\$0	\$1,232,513	\$781,412	\$0	\$0	\$0	\$0
Support Activities (\$)	Project management	\$672,151						\$624,747					
	Customer outreach (labor)	\$385,150						\$630,007					
	Marketing and education materials	\$1,869,332						\$182,127					
	Other Costs ⁸	\$4,391,796						\$2,621,294					
Other	Total number of charge ports installed	21						84	43			114	
	Amount of new capacity resulting from project (kW)	167.1						1578.2	3127.5			5144	

Key:	Data not available to report
-------------	------------------------------

Notes:

1. Site Costs (\$) - Capital costs reported for completed projects in 2023.
2. Design costs include estimated Utility-side costs and actual Customer-side costs.
3. Trenching and site excavation costs - Starting 2023, include estimated dollars trenching and excavation costs for utility-side following the non-program reporting practice and actual dollars for customer-side costs.
4. To better estimate meters, SCE is providing site level estimated meter costs from our design system.
5. Only Customer-side costs separated Permitting costs.
6. Total Utility-side costs - The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period, separated by respective programs. Cost categories include, for example, trenching, permitting, meter costs, and other material (including transformation) as well as division overhead.
 - Includes division overhead costs (e.g. planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g. pension, benefits, etc.).
 - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.
7. Total Customer side costs provide a combination of both actual and estimated dollars, represents the total customer-side (behind or beyond the meter) expenditure for all capital direct and indirect labor overheads recorded costs, from the meter pedestal or meter panel, up to but not including the EVSEs for completed projects. Examples of included costs are design, trenching, permitting, labor and material such as the meter pedestal or meter panel, transformation, cable, and connectors.
 - Includes division overhead costs (e.g. Planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g. pension, benefits, etc.).
8. Other costs include rebates, canceled project costs, Capital IT implementation costs, 3rd party evaluation and estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because SCE corporate overhead loaders are authorized in SCE's GRC and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
9. Ports reported are associated with the site classification, which is based on the total load output, that is calculated by EVSE times max output of the EVSE.

SCE Table 4: Historical Upgrade Costs

	Non-Pilot/program Residential Charging Infrastructure	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019	2020	2021	2022
Historical Upgrade Costs (nominal Costs)^{1, 2, 3, 4, 5}	Total Distribution System Costs Incurred by Utility for	\$4,863	\$9,373	\$17,290	\$2,984	\$0	\$1,845	\$0	\$109,434	\$39,436
	Total Service Line costs Incurred by Utility for Upgrades	\$43,586	\$67,627	\$76,000	\$44,561	\$17,152	\$37,538	\$24,969	\$204,055	\$194,213
	Total Customer Portion of Utility Costs Covered by the	\$12,704	\$4,246	\$4,885	\$1,174	\$375	\$8,120	\$0	\$37,255	\$14,640
	Non-Pilot/Program Commercial Charging Infrastructure									
	Upgrades						\$2,814,530	\$6,582,132	\$7,658,436	\$9,572,620
	Total Service Line costs Incurred by Utility for Upgrades						\$358,083	\$660,520	\$411,549	\$1,015,359
	Pilot/Program Commercial Charging Infrastructure									
	Total Utility Side Costs						\$4,286,852	\$5,676,706	\$3,330,482	\$720,771
	Total Customer Side Costs						\$4,955,447	\$14,191,453	\$10,805,751	\$1,195,736

Notes:

1. The 2011-2012 reporting period is from July 2011 to October 2012. The reporting period for the next five reports, ending with the 2016-2017 report is from November through October of the following year. The reporting period for the 2017-2018 report is November 2017 through December 2018. Beginning 2019, the reporting period is from January to December.
2. Meter and Transformation costs were not included in the Total Service Line costs Incurred by Utility for Upgrades or Total Utility Side Costs prior to 2020.
3. Indirect labor O&M costs were not included in Total Distribution, Total Service Line, or Total Utility Side Costs prior to 2020.
4. The figures shown in Pilot/Program Commercial Charging Infrastructure in 2020, are inception to date recorded costs for projects completed in 2020. This method is an update to prior year as the costs shown in 2019 are year to date recorded costs for all Pilot/Program Capital spend.
5. The 2021 Residential Non-Pilot/Program Costs have been revised from the totals originally shown in the March 31, 2022 filing, due to the project count increasing from 2 to 125 projects completed in the 2021 reporting period.

Attachment 3 – SDG&E

SDG&E Table 1: Number of EVs Forecast in IOU Service Territory

		Light-Duty	Medium/ Heavy Duty	
Actual	2012	2,125		
	2013	4,400		
	2014	11,500		
	2015	18,000		
	2016	22,040		
	2017	26,498		
	2018	39,427		
	2019	51,208		
	2020	60,812		
	2021	77,795		
	2022	102,990		
	2023	139,270		261
	Forecasted	2024	184,611	1,044
2025		236,902	2,610	
2026		298,574	3,915	
2027		368,403	4,959	
2028		446,546	6,264	
2029		532,517	7,569	
2030		626,409	8,770	

Notes:

Light-Duty historical/actual counts: Historical EV counts are based off DMV registration counts of electric vehicles within SDG&E's service territory. This includes battery electric vehicles (BEV) and plug-in hybrids (PHEV).

Light-Duty forecasted counts: SDGE's EV forecast derives from the Mobile Source Strategy (MSS) scenario developed by CARB. The forecast considers the growth rate and market share of California's forecasted electric vehicles and applies it to SDGE's historical/actual territory counts.

Medium/Heavy-Duty historical/actual counts: Historical EV count for 2023 is based off DMV registration count of MDHD electric vehicles within SDG&E's service territory.

Medium/Heavy-Duty forecasted counts: SDG&E's medium and heavy-duty forecast derives from the 2023 Integrated Energy Policy Report (IEPR) Additional Achievable Transportation Electrification (AATE3) scenario. The forecast considers the year over year changes in the MDHD electric vehicle market share and applies the growth rate to SDGE's historical/actual territory electric vehicle count.

SDG&E Table 2: Non-Pilot/Program Costs

2023 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs (\$)	Design costs	\$271,072	\$527,023
	Trenching and site excavation	\$169,746	\$449,953
	Separate meter costs	\$43,362	\$64,967
	Permitting costs	\$0	\$0
	Total Distribution System Costs Incurred by Utility for Upgrades	\$164,366	\$1,252,776
	Total Service Line costs Incurred by Utility for Upgrades	\$344,872	\$97,083
	Total Utility side costs	\$460,393	\$110,610
	Total Customer costs	\$22,795	\$98,471
Other	Total number of charge ports installed	419	33
	Amount of new capacity resulting from project (kW)	3771	

Key:	
	Data not available to report

Notes:

1. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Project management, Customer outreach (labor), Marketing and education materials, and Other costs from the Non-Programs Cost table 2 as these categories are not applicable.
2. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Projected ongoing maintenance costs for utility-side infrastructure due to the joint IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.
3. For the purposes of this report, SDG&E estimates the total number of charge ports installed for non-program EV Residential on a 1:1 ratio of one EV charge port per residence that were processed through SDG&E. Given that SDG&E work ends at the point of service, SDG&E does not verify the number and type of EV charger that customers install beyond the meter. The amount of new capacity resulting from project (kW) is difficult to estimate as the kilowatt range for L1 and L2 chargers are anywhere from 2kW to 19kW. The amount of new capacity resulting from project is estimated at 9kW, which is the average of the range and in line with SDG&E design standards, per SDG&E project site.
4. The total number of charge ports installed for non-program Commercial is difficult to estimate because SDG&E work ends at the point of service. SDG&E cannot verify if charge ports are installed, what type of charge ports are installed, or the number of charge ports installed. Given SDG&E cannot verify this information, SDG&E also cannot provide the amount of new capacity resulting from project (kW).

SDG&E Table 3: 2023 EV-Program Upgrade Costs

2023 EV-related Upgrade Costs		Pilot and Program Commercial Charging Infrastructure									
		Light Duty Vehicle Infrastructure					Medium and Heavy Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure	
							Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure	
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Workplace	L2 Chargers - Destination Center	L2 Chargers - Fleet	DCFC - LDV	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW
Site Costs (\$)	Design costs		180,200		136,305	59,913	42,931		43,403	35,974	
	Trenching and site excavation		415,763		478,354	666,202	171,767		85,714	165,375	
	Separate meter costs		6,343		3,974	3,490	2,590		1,826	3,442	
	Permitting costs		N/A		N/A	N/A	N/A		N/A	N/A	
	Total Utility side costs		525,973		254,008	411,771	68,967		257,143	69,368	
Support Activities (\$)	Project management	-	-	-	652,299	515,817	-	-	-	-	-
	Customer outreach (labor)	-	-	-	83,299	121,320	-	-	-	-	-
	Marketing and education materials	-	-	-	313,012	250,443	-	-	-	-	-
	Other Costs	-	-	-	1,805,153	2,002,057	-	-	-	-	-
Other	Total number of charge ports installed	-	-	41	-	30	34	4	-	9	11
	Amount of new capacity resulting from project (kW)	-	-	287	-	548	867	234	-	108	660

Key:	
	Data not available to report

Notes:

1. DCFC-LDV includes any site that has a DCFC installed, even if L2 chargers are also installed.
2. Support Activities are not designated for one specific site. They are categorized by program and are represented under Light Duty Vehicle and Medium and Heavy-Duty Vehicle Infrastructure.
3. For Medium and Heavy-Duty Vehicle Infrastructure Program, "Utility-Owned" is categorized as Option 1 and "Customer-Owned" is categorized as Option 2
4. Breakout of Permit Costs were not available at this time.

SDG&E Table 4: Historical Upgrade Costs

	Non-Pilot/program Residential Charging Infrastructure	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019	2020	2021	2022
Historical Upgrade Costs	Total Distribution System Costs Incurred by Utility for Upgrades	\$4,089	\$0	\$0	\$0	\$0	\$0	\$124,572	\$42,438	\$14,195	\$32,428
	Total Service Line costs Incurred by Utility for Upgrades	\$27,952	\$0	\$1,876	\$2,326	\$2,009	\$15,113	\$23,535	\$44,954	\$133,151	\$318,569
	Total Customer Portion of Utility Costs Covered by the exemption	\$32,041	\$0	\$1,876	\$2,326	\$2,009	\$15,113	\$2,046	\$3,563	\$0	\$0
	Non-Pilot/Program Commercial Charging Infrastructure										
	Total Distribution System Costs Incurred by Utility for Upgrades								\$58,066	\$454,792	\$732,218
	Total Service Line costs Incurred by Utility for Upgrades								\$5,547	\$22,553	\$10,890
	Pilot/Program Commercial Charging Infrastructure										
	Total Utility Side Costs								\$403,332	\$113,138	\$1,568,856
	Total Customer Side Costs								\$0	\$0	\$275,724

Notes:

1. Historical upgrade cost from previously submitted Load Research Reports periods 2012-2018
2. 2019 Historical upgrade costs based on actual cost incurred for customer upgrade jobs completed in 2019
3. 2020 Historical upgrade costs based on amended submittal December 13, 2021
4. SDG&E identified a formula error in the utility-side costs for the 2022 submission. The error has been corrected and the correct utility-side costs are reflected in the above table.