EPC-15-048: Rate Analysis and Modeling for the Optimization of Customer and Grid Impacts with Smart Home Energy Management Technologies

Final Tariff Analysis Assessment

Center for Sustainable Energy™

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PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewables and other advanced clean energy generation, energy-related environmental protection, energy transmission and distribution, and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The California Energy Commission (Energy Commission) and the state's three largest investor-owned utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company – were selected to administer EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development of programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer. These ratepayer benefits include the following.

- Providing societal benefits
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with a clean, conventional electricity supply
- Supporting low-emission vehicles and transportation
- Providing economic development
- Using ratepayer funds efficiently

This *Final Tariff Analysis Assessment White Paper* is a product of the Advancing Intelligence to Enable Integration of DERs project (also referred to as EPC-15-048 or the Smart Home Study), *Task 3: Rate Analysis and Modeling.* The information from this project contributes to the Energy Research and Development Division's EPIC Program.

All figures and tables are the work of the authors for this project unless otherwise cited or credited.

For more information about the Energy Research and Development Division, visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

Renewable energy resources are supplying a greater portion of California's electricity needs. However, the intermittent nature of renewable electricity generation has made it more difficult for grid operators to balance the system. Overcoming these challenges requires a more flexible grid that can respond quickly to changes in electricity supply and demand. One approach to increasing grid flexibility is through the management of distributed energy resources that can shift load to periods of low demand. This analysis is an evaluation of such technology and its potential benefits on customer and grid impacts, specifically Itron's Residential Distributed Energy Resource Management System (RDERMS) used in combination with energy storage systems and/or electric vehicle (EV) chargers. This assessment used four analyses or Models A – D), observed electricity usage patterns for participants in a Smart Home Study, and five existing San Diego Gas & Electric (SDG&E's) electric rate structures (including two Time-of Use (TOU) and one dynamic rate) to identify which rate structures and operational schedules for EV charging and energy storage dispatch maximize customer and grid benefits. Model A is the baseline scenario that evaluated customer and grid impacts with no shifting of EV charging and battery dispatch. Model B evaluates customer and grid impacts when energy storage and EV operations are optimized to reduce customer costs. Model C evaluates simulated load profiles that have been optimized to reduce grid impacts, and Model D evaluates simulated load profiles optimized to reduce both customer and grid impacts. Overall, modeling results indicate that current TOU rate structures offered by SDG&E allow considerable benefits to customers and the grid through optimized EV charging and energy storage dispatch. In fact, operational schedules for EV and energy storage loads were nearly identical between the model that maximized customer benefits versus the model that maximized grid benefits. This indicates that current rate structures offered by SDG&E incentivize customers to use electricity in a manner that provides maximum grid benefits. Further, the analysis indicates that the EV-TOU-5 rate structure allows for the greatest savings potential when EV and energy storage loads are optimized due to its low super-off-peak rates.

Keywords: Customer Costs, Distributed Energy Resources, Dynamic Rate, Grid Impacts, Grid Costs, Grid Optimization, Rate Structures, Residential Management Systems, Tariff Analysis, TOU Rate

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I. Executive Summary

Introduction

To overcome the environmental and health effects of traditional electricity generation sources, renewable resources are supplying a greater portion of California's electricity needs. However, the intermittent nature of renewable electricity generation (from wind and solar, for example) has made it more difficult for grid operators to balance the system that must safely and consistently deliver electricity. Overcoming these challenges requires a grid that can respond quickly and flexibly to changes in electricity supply and demand. One approach to increasing grid flexibility is through the management of distributed energy resources (DERs) that can shift load to periods of low demand.

Project Process

The goal of this *Final Tariff Analysis Assessment White Paper* is to understand the potential impact of Residential Distributed Energy Resource Management Systems (RDERMS) on customer and grid impacts as part of the "Smart Home Study" (EPC-15-048). RDERMS software and hardware were deployed at participant homes to automate smart technologies such as energy storage systems and Level 2 electric vehicle charging stations that were integrated to normalize the grid during evening ramping (4-9 p.m.) when renewable energy resources are limited and energy demand is high (i.e., duck curve). This paper quantifies effects resulting from the use of these technologies by evaluating customer and grid impacts when operational schedules are optimized.

This assessment used annual electricity usage data from 95 San Diego Gas & Electric (SDG&E) customers and five existing SDG&E rate structures. The residential rate structures included Domestic Residential (DR), Domestic Residential-Low Income (DR-LI), Electric Vehicle-Time-of-Use 2, (EV-TOU-2), and Electric Vehicle-Time-of-Use 5 (EV-TOU-5). Additionally, an electric vehicle charging station rate for Power Your Drive (PYD) customers was evaluated only for a dynamic rate comparison. Using these observed load shapes and SDG&E structures, the research team conducted four analyses: Model A (baseline), Model B (customer-optimized), Model C (grid-optimized), and Model D (customer and grid-optimized or dual-optimized). Model A is the baseline scenario that evaluated customer and grid impacts with no shifting of EV charging and battery dispatch. Model B evaluates customer and grid impacts when energy storage and EV operations are optimized to reduce customer costs. Model C evaluates simulated load profiles that have been optimized to reduce grid impacts, and Model D evaluates simulated load profiles optimized to reduce both customer and grid impacts.

Project Results

Model A results indicated that, without any load shifting or optimization, PYD is typically the most economical of the rate structures for consumers with higher energy consumption, but it is typically the least economical rate for consumers with lower energy consumption. The DR rate structure is typically the most economical for households with lower energy consumption. Models B, C and D demonstrated that optimized operations of EV charging and energy storage can provide considerable benefits to the customer and grid simultaneously using existing SDG&E rate structures. For every participant evaluated customer bills are lowered and grid costs decreased when operations were optimized. Also, operational schedules for DERs were similar whether optimized for the customer or the grid, indicating that the rates structures evaluated are successful at aligning customer and grid benefits. The EV-TOU-5 rate, paired with households with longer commutes in their EVs and larger energy storage capacity, provided the greatest savings potential when smart load-shifting technologies, such as RDERMS, are deployed.

Benefits to California

This research demonstrates how both SDG&E customers on TOU or dynamic rates and the local electric grid can benefit from the use of RDERMS to optimize EV charging and energy dispatch to shift load. Residential customers have the potential to save money on electric bills, while helping utilities (e.g., SDG&E) to avoid paying high prices on the “spot market” for energy produced during peak demand times — energy often produced by greenhouse gas-emitting fossil fuel power plants. However, future research is needed to evaluate RDERMS precooling strategies with web-programmable thermostats and additional high value rate structures that may not currently be available to SDG&E customers.

II. Chapter 1

Introduction

Electricity demand has traditionally been met with fossil fuel and nuclear electricity generation. However, these traditional sources of generation are being replaced by renewable energy sources due to health and environmental concerns, including climate change. Although integrating renewables onto the grid has provided cleaner energy, the intermittency of many renewable energy sources (e.g., solar, wind) has made it more difficult for grid operators to balance the system. Furthermore, peaks in system-wide demand, such as the pattern in many households to turn on air conditioners and other appliances in the early-evening hours, can add to this issue. Overcoming these challenges requires a grid that can respond quickly to changes in electricity supply or demand. One approach to increasing grid flexibility is through the management of distributed energy resources (DERs) that can shift loads to periods of low demand.

To incentivize the use of DERs to reduce impacts on the grid, utilities offer time-varying rate structures. These rate structures are characterized by increased costs of electricity during peak periods and decreased costs during off-peak periods. Time-of-use (TOU) rates use consistent energy (kW/kWh) pricing based on static peak/off-peak times. Dynamic rates, on the other hand, use real-time hourly or sub-hourly pricing based on a forecast of grid supply and customer demand. Smart technologies can take advantage of these rate structures by shifting loads from high-cost peak periods to low-cost off-peak periods to reduce customer bills and grid impacts.

This research, conducted by the Center for Sustainable Energy in partnership with Alternative Energy Systems Consulting, Inc., Itron, Oxygen Initiative and San Diego Gas and Electric (SDG&E), assesses the ability of Itron's Residential Distributed Energy Management System (RDERMS) to provide benefits to the grid and the customer. Specifically, the analysis consisted of evaluating participants' SDG&E load data and then building four model simulations (Models A – D) to evaluate and quantify the impacts of adding RDERMS and optimizing two flexible DERs loads - EV charging and energy storage dispatch– by operating during super-off peak periods. SDG&E rate structures used to determine optimum pricing and grid stabilization included volumetric tiered, TOU, and dynamic rate structures. The modeling methods, results, and discussion are presented in the following chapters.

III. CHAPTER 2: Methodology

This chapter provides an overview of participant homes, load shapes, and rates used in each of four models (A - D) with descriptions and assumptions of each model.

Participant Homes

The load shapes used for this analysis came from 100 single-family homeowners in a Smart Home Study (SHS) intended to measure the impacts of using RDERMS to shift load of various DERs. At the time of this research, the RDERMS equipment had not been installed long enough to analyze post-installation data. Thus, the research team used historical, pre-RDERMS installation energy consumption data and simulated load data for this analysis. Of the 100 participants, five were excluded from this analysis because they had less than 12 months of historical energy consumption data available.

Upon entering the study, participants completed an on-site interview, in which 99 reported having an air conditioning (AC) unit, 91 reported having a solar photovoltaic (PV) system, and 51 reported having an electric vehicle (EV). For EVs, there were only 70 responses received. Table 1 details technologies represented by participants in the SHS when enrolled.

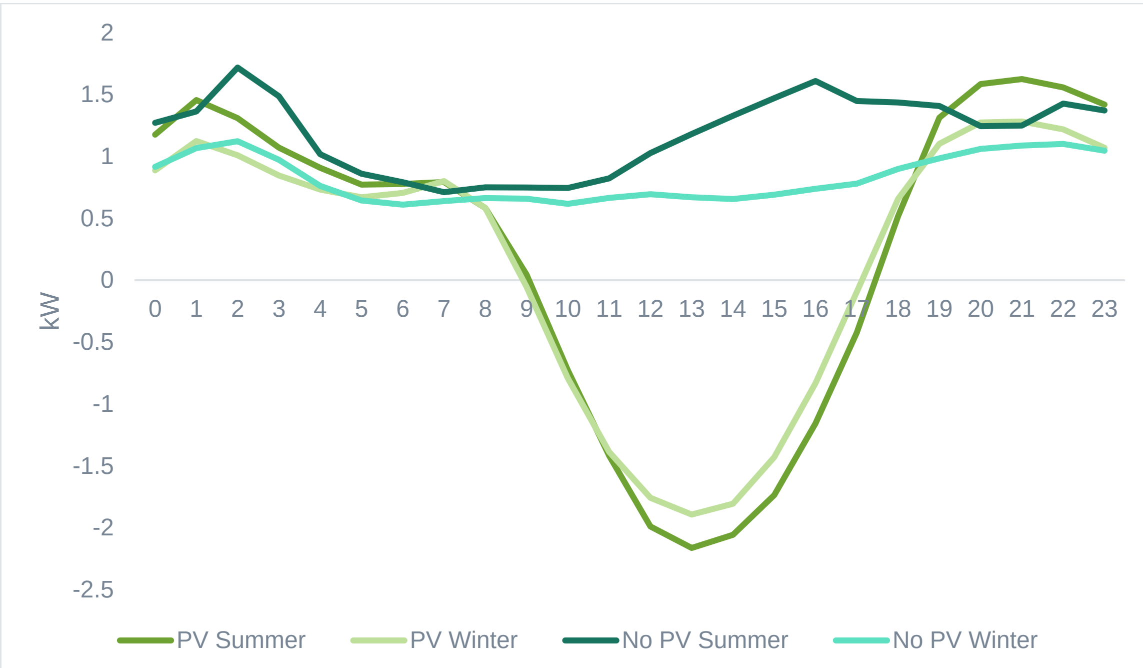
Table 1: Participants by Technologies

Technology	Number of Participants
AC	99
PV	91
EV	51 (of 70 responses)

Load Shapes

Green Button data, historical energy consumption data available to all SDG&E customers in a computer-friendly format, was used to construct a 12-month electric load shapes for each participant home. Calendar year 2018 was used when possible, but approximately two-thirds of participants did not have data for December 2018. In these cases, data from December 2017–November 2018 were used. Average daily load shapes for participants by season are shown in Figure 1. There are clear differences in both summer and winter seasons between the load shapes of PV and non-PV participants. The average daily consumption of participants without PV is 28 kWh in summer (summer is defined as June through October, winter includes all other months) and 20 kWh in winter. During the winter, the hourly load for non-PV participants remains relatively flat, while summer peaks are at 2 a.m. and in the afternoon. Because PV participants meet some of their energy needs with on-site generation, they have a lower load profile with average daily grid consumption of 5 kWh in the summer and 4 kWh in the winter. In addition, during the middle of the day when solar production exceeds energy use, surplus energy is exported to the grid contributing to the “duck curve” profile. However, since the sample size of participants without PV was small (n=9) and all of those participants had an EV at home, the load curve is not representative for households without PV.

Figure 1: Average Daily Load Shapes for Participants With and Without PV by Seasons



Rates

To quantify customer impacts relative to different rate structures, we selected five SDG&E rate structures for analysis. These five structures were Domestic Residential (DR), Domestic Residential-Low Income (DR-LI), Electric Vehicle-Time-of-Use Two (EV-TOU-2), Electric Vehicle-Time-of-Use Five (EV-TOU-5), and Power Your Drive (PYD). Tables 2 and 3 list details of DR, DR-LI, EV-TOU-2, and EV-TOU-5. DR and DR-LI are tiered rate structures where an increase in electricity usage results in increased rates. DR-LI is similar to the DR rate structure, but it is discounted for low-income customers. Unlike tiered rate structures, both EV-TOU-2 and EV-TOU-5 are TOU rates that have specific rates for “peak,” “off-peak,” and “super-off-peak” time periods. The rates and rate periods vary seasonally and by weekday/weekend (Figures 2 and 3). For example, summer on-peak rates are significantly higher compared to the winter and the super-off-peak period is extended on weekends relative to weekdays. In addition to the hourly rates, a minimum bill is required for DR, DR-LI, and EV-TOU-2 rates. For this analysis, they are applied daily at $0.329, $0.164, and $0.329 respectively. EV-TOU-5 has a monthly basic fee of $16 (instead of a minimum bill) but customers get a reduced super off-peak rate of about $0.09 per kWh. Compared to EV-TOU-2, all hourly rates with EV-TOU-5 are similar except during the “super-off-peak” period. Additionally, another popular TOU rate is Domestic Residential-Solar Energy System; however, this rate was not analyzed because its hourly rates are nearly the same as EV-TOU-2.

Table 2. SDG&E DR and DR-LI Rates

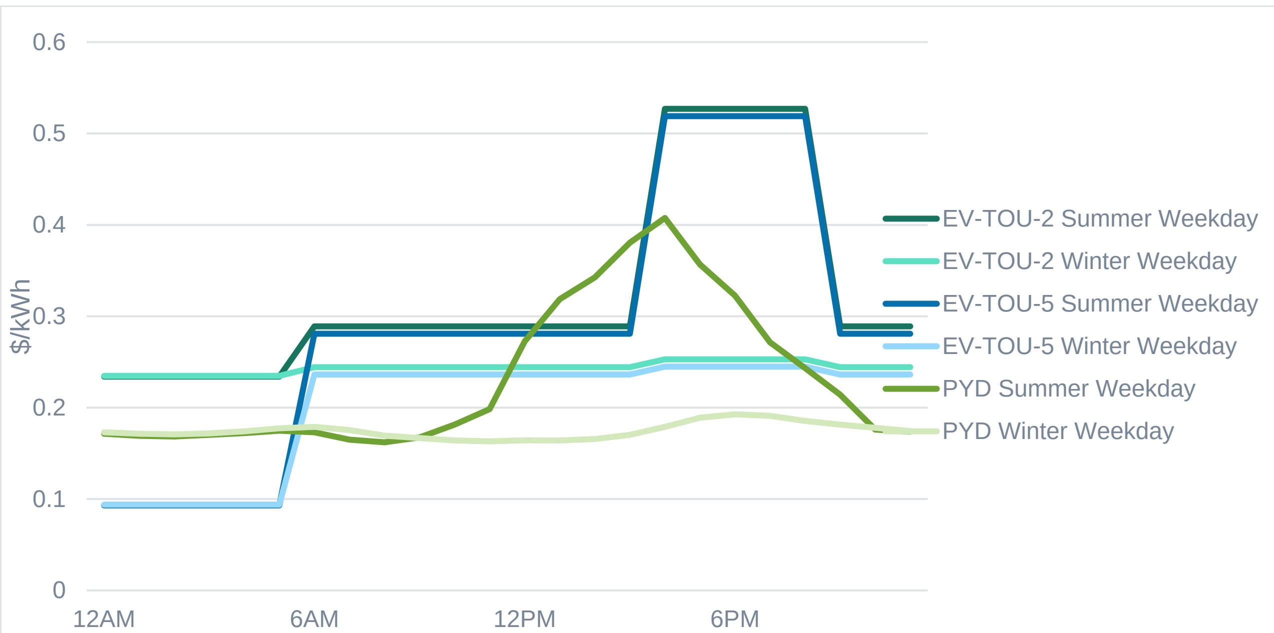
Billing Component		DR	DR-LI
Summer energy charges ($/kWh)	Tier 1	$0.26454	$0.16368
	Tier 2	$0.46375	$0.29396
	Tier 3	$0.54033	$0.34405
Winter energy charges ($/kWh)	Tier 1	$0.22379	$0.13703
	Tier 2	$0.39232	$0.24725
	Tier 3	$0.45711	$0.28962
Minimum bill ($/day)		$0.329	$0.164

Table 3. SDG&E EV-TOU-2 and EV-TOU-5 Rates

Billing Component		EV-TOU-2	EV-TOU-5
Summer energy charges ($/kWh)	Peak	$0.52698	$0.51892
	Off-peak	$0.28888	$0.28082
	Super off-peak	$0.23393	$0.09302
Winter energy charges ($/kWh)	Peak	$0.25285	$0.24479
	Off-peak	$0.24427	$0.23621
	Super off-peak	$0.23475	$0.09384
Minimum bill ($/day)		$0.329	
Basic fee ($/month)			$16

In addition to DR and TOU rates, the effect of the PYD rate also known as the Electric Vehicle Grid Integration (VGI) rate[1]—a non-residential hourly dynamic rate designed for vehicle charging—was assessed to examine impacts on customers since a residential SDG&E dynamic rate was not currently available. SDG&E offered a pilot dynamic rate from October 2016 to December 2017, but due to other recent rate reform efforts and peak period uncertainty, SDG&E closed the pilot and did not develop other dynamic rate options for residential customers.[2] The PYD rate changes hourly and consists of: 1) base rate, 2) an hourly commodity base rate with an adjustment based on the California Independent System Operator (CAISO) day-ahead hourly price and an adder to reflect the system's top 150 system peak hours and an adjustment to reflect day-of CAISO surplus energy hours, and 3) an hourly distribution base rate with an adder to reflect the top 200 annual hours of peak demand for the individual circuit feeding the charging stations. PYD rates are typically lower than EV-TOU-2 and EV-TOU-5 rates (Figures 2 and 3). However, during the time of day when the grid is constrained (i.e., in the afternoon) PYD rates can be greater than TOU rates. A minimum bill is also required for the PYD rate at $0.329/day.

Figure 2: EV-TOU-2, EV-TOU-5, and PYD Weekday Hourly Rates by Season

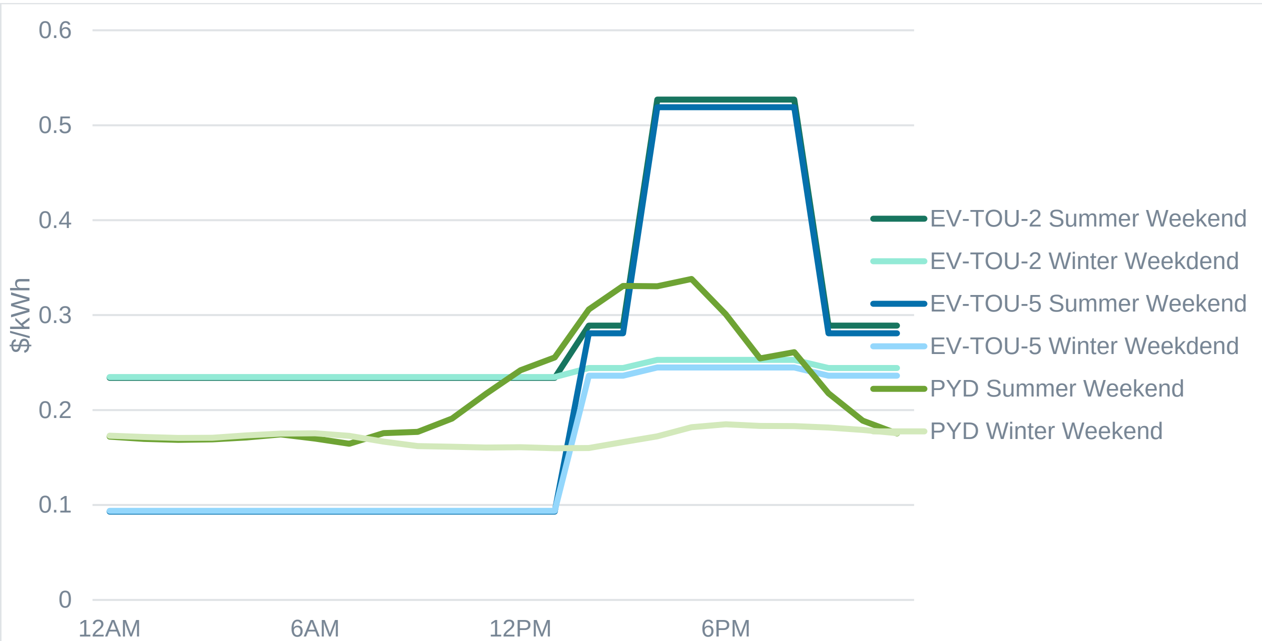


[1]. SDG&E. 2017. *Schedule VGI*. https://www.sdge.com/sites/default/files/elec_elec-scheds_vgi.pdf
[2] Butler, Sabrina. 2016. *Smart Pricing Program: Customer Outreach and Education Quarterly Briefing.* https://www.sdge.com/sites/default/files/Q2%25202016%2520SDG%2526E%2520Interested%2520Parties%2520Briefing.pdf.

Models

This section describes the construction of Models A - D. Model A calculates customer impacts (i.e., bills) based on observed participant baseline load profiles. Model B - D use a mixture of observed load profiles and simulated loads to assess the effects of optimized EV and energy storage operations on customer and grid costs (Table 4).

Figure 3: EV-TOU-2, EV-TOU-5, and PYD Weekend Hourly Rates by Season



Model A: Baseline

Model A assesses the impact of the various rates structures applied to customer load profiles without RDERMS (i.e., no shifting of EV charging and energy storage dispatch). The real hourly energy consumption patterns shapes for each customer were first multiplied by the corresponding energy charges (Table 2), and then nonbypassable charges (explained below) were applied to periods of PV overgeneration (generating more renewable electricity then the customer consumes) to derive hourly costs. Hourly costs were added and adjusted by the minimum bill to calculate monthly costs. Finally, monthly costs were aggregated to calculate the annual bills.

For PV customers, there were additional calculations applied to the model to mirror SDG&E's required nonbypassable charges and generation credits. Nonbypassable charges were applied to any overgeneration exported to the grid. In particular, customers are compensated at the retail rate minus the nonbypassable charge of $0.02368 per kWh. Although charges are bypassable for solar customers under the original NEM tariff, in this analysis, all customers were assumed to be on the NEM successor tariff[3,4] Also when PV customers overgenerate, they receive generation credits. These generation credits can be applied to electric energy charges but not to other charges such as minimum bills and monthly basic fees also referred to as "monthly fees." However, for simplicity, this analysis did not separate monthly fees and generation credits. Specifically, if a monthly bill was negative before the monthly fees were applied, the monthly bill was calculated as the bill amount plus the monthly fee. Further, excess generation compensation was not considered when the final customer bill was calculated as it was assumed that customers rolled their remaining generation credits over to the following 12-month period. It should be noted, however, that the value of overgeneration would be significantly reduced if the customer chose to receive direct payment instead of credits toward future monthly electricity costs because they are redeemed at the wholesale market rate.[5]

Table 4: Summary of Models A, B, C and D

Model	Objective	Additional Comments
Model A **(Baseline)**	• To evaluate the effects of different rate structures on customer costs	• No load shifting was performed • Included observed load data for 95 of 100 customers • Includes five existing SDG&E rate structures
Model B **(Customer-optimized)**	• To evaluate the effects of optimized operations on customer costs	• EV and energy storage loads optimized • Includes load data from 18 customers with PV and no EV • Includes three existing SDG&E rate structures
Model C **(Grid-optimized)**	• To evaluate the effects of optimized operations on grid costs	• EV and energy storage loads optimized • Includes load data from 18 customers with PV and no EV • Uses CAISO day-ahead wholesale market prices
Model D **(Dual-optimized)**	• To evaluate the effects of optimized operations on customer and grid costs	• EV and energy storage loads optimized • Includes load data from 18 customers with PV and no EV • Includes three existing SDG&E rate structures and CAISO day-ahead wholesale market prices

Model B: Customer-optimized

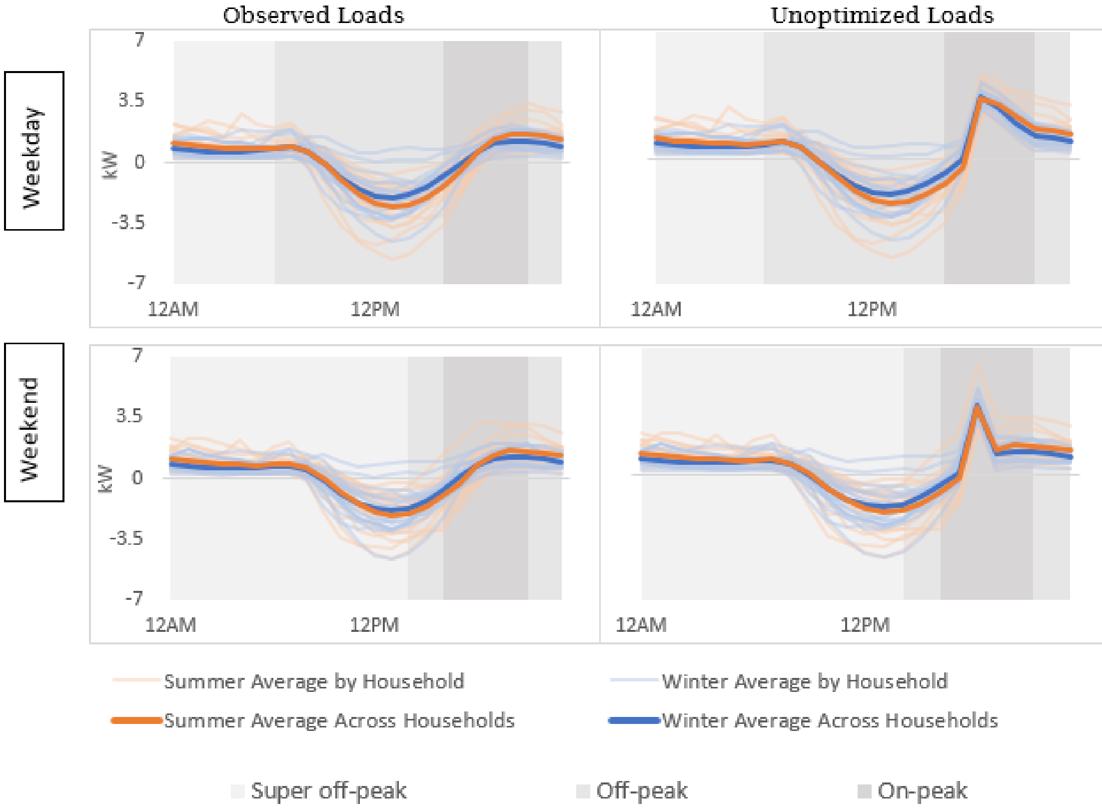
The remaining three models (B - D) used the 18 participant load shapes associated with homes that confirmed they had no EV (see Table 1) to allow the research team to simulate and manipulate EV-charging loads. This was necessary since EV charging loads were already embedded in all other load shapes and could not be shifted accurately with data obtained by the on-site participant survey.

Model B identified EV and energy storage operational schedules that minimize annual customer costs. The effect of these customer-optimized operations on customer costs were defined through their comparison with a customer-optimized model to an “unoptimized” model. For the unoptimized model, an EV load was superimposed onto the observed loads during the peak period to simulate after-work charging, and there was no energy storage. Figure 4 shows the change in average customer load profiles for the unoptimized model. The optimized model, on the other hand, superimposes optimized EV and energy storage loads on the observed loads. For each household, there were 81 simulated scenarios consisting of combinations of various commute distances, home battery storage capacities, vehicle types, and rate structures. Linear programming/optimization was used to identify the operational schedules for each household and scenario that minimized annual customer costs. Customer bills were calculated as they were for Model A.

Model C: Grid-optimized

Model C identified EV and energy storage operational schedules that minimized annual grid costs. The research team used CAISO day-ahead wholesale market rates from the SDG&E sub-LAP as the measure of grid costs. The SDG&E sub-load aggregation points (sub-LAP) corresponds geographically with SDG&E’s service territory. While the SDG&E sub-LAP locational marginal price (LMP) is not an exact measurement of the marginal cost of operating the grid, the LMP considers the physical attributes of operating the local transmission grid, including transmission congestion and constraints. Consequently, the LMP is correlated with grid impacts and needs and therefore acts as a suitable proxy for marginal grid costs. Other than assessing grid costs (versus customer costs), Model C was identical to Model B.

Figure 4: Average Observed and Unoptimized Household Loads



Model D: Dual-optimized

Model D identified EV and energy storage operational schedules that minimized the combination of customer and grid costs (see Assumptions section for more details). Other than optimizing for a combination of customer and grid costs, Model D is identical to Models B and C.

Assumptions

Models B, C, and D

The assumptions for Models B - D are nearly identical and described below. The only differences between the three models is that Model B minimizes customer costs, Model C minimizes grid costs, and Model D minimizes a measure of both customer and grid costs.

EV and Commuting Scenarios

The EV models used in the analysis were the Mitsubishi i-MiEV, Nissan Leaf, and Tesla Model S (Table 5). These vehicles were selected because they span the range of battery energy capacities and efficiencies in EVs currently on the market. Several constraints were placed on EV charging in the model. First, all EVs had to be fully charged by 8 a.m. each morning. The charge rate was allowed to vary between the vehicle specific maximum charge rate and 0 kW (Table 5). EVs were assumed to be available to charge between 6 p.m. and 8 a.m. on the weekdays and at all hours on the weekend. For the unoptimized model we assumed that the EV would be charged each day beginning at 6 p.m. at the maximum charge rate until the EV was fully charged. The total energy consumed by EV charging for the optimized and unoptimized models was equivalent across respective scenarios. Energy used during the commute/weekend driving was subtracted from each EV's battery at 12 p.m. each day. Commute scenarios included 5-, 15- and 30-mile round-trip commutes. Customer were assumed to drive 10 miles on both Saturday and Sunday across all scenarios (Table 6).

Table 5: Vehicle Characteristics Used in Scenarios

EV Make & Model	Minimum Charge Rate	Maximum Charge Rate	Battery Capacity	Efficiency	Charge Efficiency
Mitsubishi i-MiEV	0 kW	3.3 kW	16 kWh	3.875 mi/kWh	0.90
Nissan Leaf	0 kW	6.6 kW	40 kWh	3.75 mi/kWh	0.90
Tesla Model S	0 kW	7.0 kW	75 kWh	3.35 mi/kWh	0.90

Table 6: Commute Distances Used in Scenarios

Commute Description	Weekday Commute Distance (round trip)	Weekend Daily Travel Distance (round trip)
Short	5 miles	10 miles
Medium	15 miles	10 miles
Long	30 miles	10 miles

Energy Storage Scenarios

The models included three energy storage capacity possibilities: no storage, 3 kW/4 kWh, and 4 kW/8 kWh (Table 7). The storage systems were available for charging and discharging at all hours and days but were not allowed to generate negative load (i.e., discharge to the grid). The energy storage maximum charge and discharge rates were assumed to be equal, and they were allowed to vary between these maximum values and zero (Table 7). The model also included parasitic losses of 0.3% of the usable energy storage capacity per hour.

Table 7: Energy Storage Characteristics Used in Scenarios

Name	Usable Energy	Power Rating	One-way Efficiency	Estimated Parasitic Losses
No Storage	--	--	--	--
Eco 4	4 kWh	3 kW	0.927%	0.3% of usable capacity
Eco 8	8 kWh	4 kW	0.927%	0.3% of usable capacity

Rate Structure Scenarios

For the customer-optimized model, two time-of-use rate structures, EV-TOU-2 and EV-TOU-5, were evaluated and one dynamic rate, PYD (Figure 2). The volumetric tiered rates, DR and DR-LI were not evaluated for Models B, C, and D because they do not have time-varying characteristics that would add value to optimized operations. For Model C, only grid costs were considered (Figure 5). For Model D, the same rate structures were used as in Model B but customer costs were combined with grid costs. To force the customer and grid costs to have equal importance in Model D, standard scores (z-scores) were calculated for each metric. Then a minimum standard score across customer and grid costs were added to force hourly rates to be positive (Figure 6). After that, hourly grid and customer costs were added to generate an hourly customer-grid "score." Accordingly, customer-grid scores can only be interpreted on a relative scale, with low scores representing low impacts and high scores representing high impacts.

Figure 5: Weekday vs. Weekend Daily & Seasonal Rate Prices

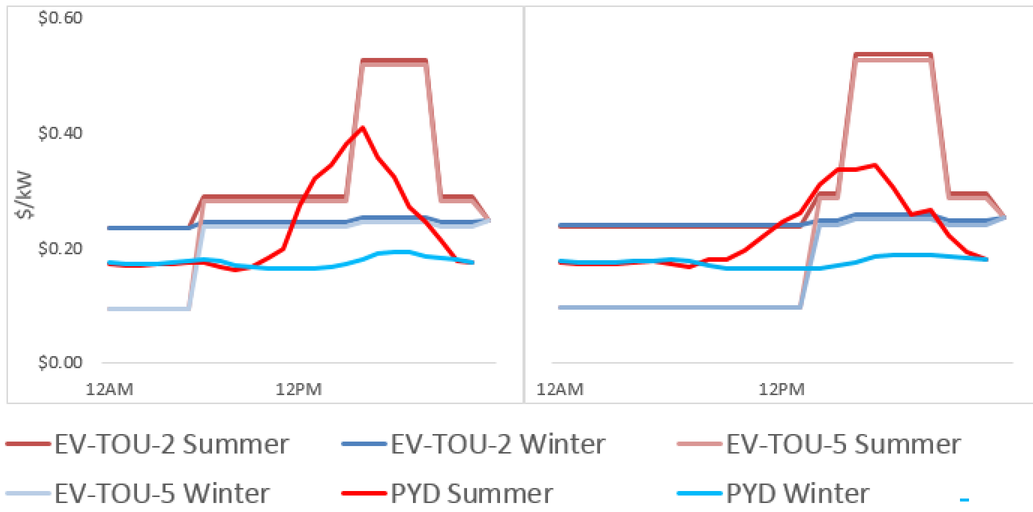
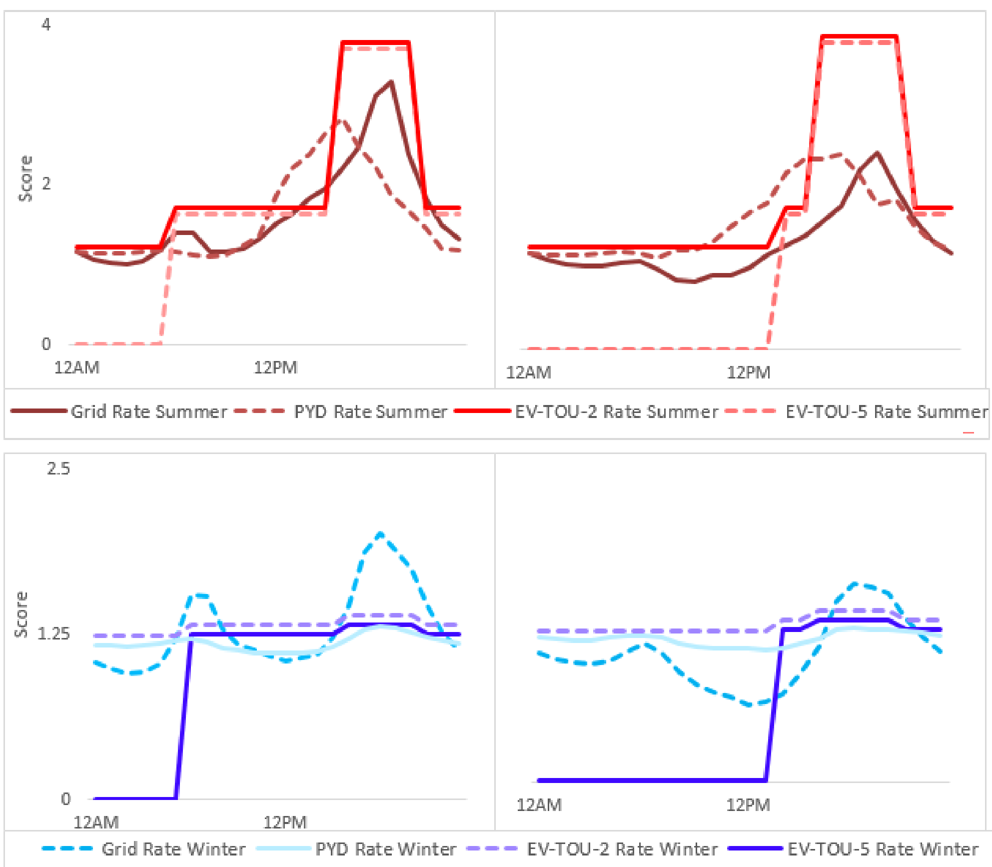


Figure 6: Weekday vs. Weekend Average Hourly Customer and Grid "Score"



IV. CHAPTER 3: Results

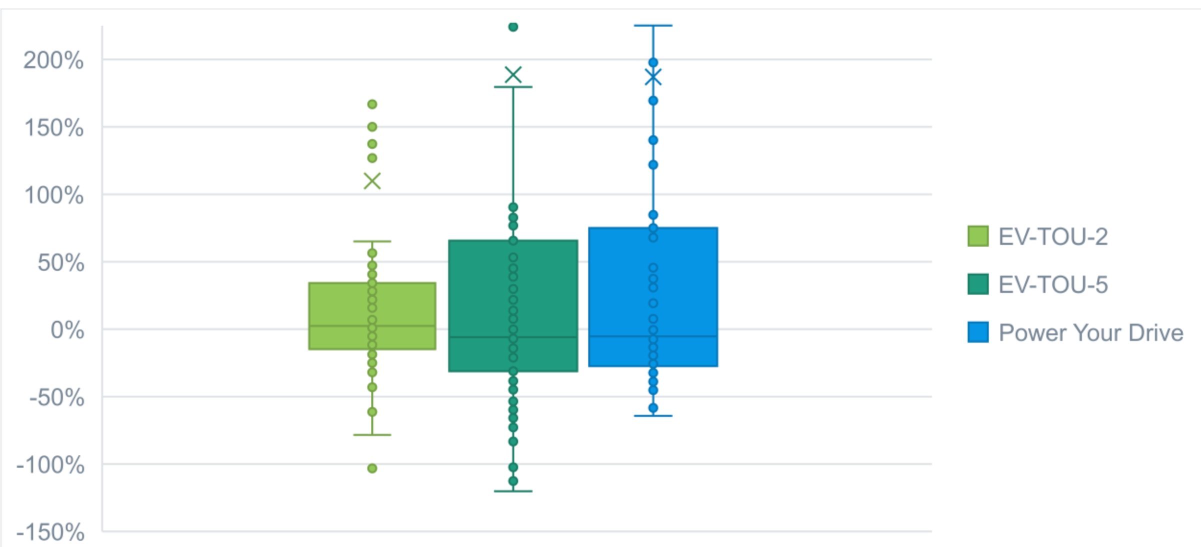
Model A: Baseline

Model A assessed the effects of different rate structures on annual customer costs. Appendix A displays the annual estimated total bill of each participant under the five rate structures. To understand the effects of the various rate structures on customer costs, participant annual bills were compared across DR, EV-TOU-2, EV-TOU-5, and PYD rates. As a discount rate under schedule DR, bills of DR-LI were later compared with bills of DR to assess the potential savings to low-income customers.

Comparison of DR, EV-TOU-2, EV-TOU-5, and PYD Rates

Figure 7 shows the percent differences in annual bills between DR and three other rate structures: EV-TOU-2, EV-TOU-5 and PYD. For each participant, the annual bill differences were calculated as the annual bill corresponding to a specific rate structure (such as EV-TOU-5) minus the annual DR bill, divided by the DR bill and then multiplied by 100. Accordingly, positive values indicate the percentage increase in an annual bill (for EV-TOU-5, for example) relative to the annual bill when the DR rates structure was applied. Box plots (Figure 7) were used to visualize the distribution of these differences across households by rate structure.

Figure 7: Comparison of Annual Bills for EV-TOU-2, EV-TOU-5, and PYD vs. DR



The box plots show that the annual bills for EV-TOU-2, EV-TOU-5 and PYD can vary significantly relative to DR. The significant variability associated with those three structures, and the fact that they all span positive and negative values, suggests that no single structure is most cost effective for all customers; instead, unique characteristics of each customer's load size and shape determine which structure is most cost effective. EV-TOU-2 shows the least amount of variability, suggesting that customers on this rate have annual bills that are most similar to DR bills. The EV-TOU-5 and PYD rate structures show greater variability indicating that customer costs have the tendency to diverge substantially from the annual costs of DR. This large variability is likely due to the time-of-use nature of the EV-TOU-5 structure and the dynamic nature of the PYD structure, which would have large impacts on customers with large monthly usage on certain hours.

Large outliers (i.e., >200%, <-125%) are observed for all three comparison rates. These differences typically arise for customers with low annual costs since small changes in the annual cost can create large relative differences. The cause of these annual cost differences are utility related fees and charges. For example, if participant 050 were on the EV-TOU-5 rate, his/her annual bill would be about 500% higher than his/her bill of DR due to the $16 monthly fee required by EV-TOU-5 (Table 8).

Table 8: Annual Bills for Participant 050 Under Various Rate Structures

Site ID	Power Your Drive ($)	EV-TOU-5 ($)	EV-TOU-2 ($)	DR ($)	Average Across Rate Structures ($)
050	$30	$86	$-8	$-22	$22

To gain a more nuanced understanding of the factors that contributed to differences in the annual customer costs across rate structures, the research team analyzed the data using a linear mixed model. The model predicted the customer annual bills as a function of a customer's annual observed load, rate, and interactions between customer's annual observed load and rate structure. The random effects controlled for the repeated measures for each household. Table 9 shows the results of the model.

These results reinforce the fact that the optimal rate structure is dependent, at least to some degree, on a customer's electricity consumption. Specifically, the model suggests that each rate structure becomes more cost-effective relative to DR, as the size of annual energy consumption increases. This is due to the increased rates (corresponding to higher tiers) that are applied with higher consumption for the DR rate structure. This makes DR the least economical for households with higher electricity consumption. The increase in the annual bill grows less rapidly for the PYD rate structure relative to the other structures,, which often make it the most economical rate for high consumption households. Indeed, Table 10 shows the top 10 electricity consumers in the study along with their annual costs under each rate structure. The lowest bill for each customer is highlighted in green.

Table 9: Results of Regression Analysis for Model A

Variable Estimate Variable	Estimate (95% CI)
	Cost ($) per kWh
Observed energy consumption (kWh)	0.33 *** (0.32, 0.34)
Observed energy consumption × DR	--
Observed energy consumption × PYD	-0.12 *** (-.13, 0.11)
Observed energy consumption × EV-TOU-5	-0.10 *** (-.11, -.09)
Observed energy consumption × EV-TOU-2	-0.06 *** (-0.70, -.0479)
	Cost ($) per year
DR (rate structure)	--
PYD (rate structure)	154.49 *** (106.69, 202.29)
EV-TOU-5 (rate structure)	98.83 *** (51.03, 146.62)
EV-TOU-2 (rate structure)	86.59 *** (38.80, 134.39)
Intercept	77.62 ** (26.09, 129.14)

DR is the most expensive rate for all of these households, whereas PYD is the most economical rate structure for eight of them. EV-TOU-5 is the most economical residential rate structure and the corresponding annual bills are generally commensurate with PYD bills.

Table 10: Annual Bills of Participants with Highest Annual Energy Use

Site ID	PV	EV	Annual Energy Use (kWh)	PYD ($)	EV-TOU-5 ($)	EV-TOU-2 ($)	DR ($)
060	No	Yes	15,602	3,661	3,934	4,578	5,979
421	Yes	Yes	11,987	3,332	3,394	3,775	4,844
085	No	Yes	11,416	2,295	2,577	3,142	4,188
164	Yes	Yes	11,211	2,796	2,869	3,284	4,168
169	No	Yes	10,688	2,476	2,727	3,110	3,766
138	No	Yes	9,804	2,190	2,460	2,816	3,354
284	Yes	Yes	7,651	2,096	1,741	2,222	2,605
442	Yes	Yes	7,188	1,688	1,584	2,028	2,427
019	Yes	No	7,118	1,492	1,757	1,979	2,228
036	Yes	N/A	7,062	1,695	1,946	2,073	2,238

Although the data indicates that PYD is typically the most economical of the structures for large energy users, it is typically the least economical rate for lower energy users. By contrast, the DR structure is typically the most economical for households with lower consumption. This is because as energy consumption decreases (especially when it is negative) the minimum bills and monthly fees contribute to a greater proportion of the bill. Further, low consumption is associated with overgeneration and rate structures with lower rates will receive generation credits at a lower rate than those with higher rates. Table 11 shows the 10 participants with the least annual electricity consumption along with their annual bills for each rate. The lowest bill for each customer is highlighted in green, and the highest bill is highlighted in red. For these customers, DR is the least expensive for five of them and PYD is the most expensive rate for six households. However, the general patterns observed are not consistent across all households (i.e., participant 345, 380) showing that complexities, such as the period energy is used, can affect which rate is most economical.

Table 11: Annual Bills for Participants with Lowest Annual Energy Use

Site ID	PV	EV	Annual Energy Use (kWh)	PYD ($)	EV-TOU5 ($)	EV-TOU-2 ($)	DR ($)
345	Yes	N/A	-3,539	-856	-581	-809	-775
030	Yes	No	-3,262	-325	-523	-683	-670
346	Yes	No	-3,080	-117	-254	-396	-542
446	Yes	No	-2,862	-423	-380	-579	-622
380	Yes	Yes	-2,845	-609	-1,001	-924	-454
236	Yes	Yes	-2,390	-275	-801	-663	-463
400	Yes	N/A	-2,046	-63	-71	-179	-410
364	Yes	Yes	-1,795	-240	-100	-249	-347
326	Yes	N/A	-1,606	-30	-232	-316	-313
130	Yes	No	-1,578	-98	-260	-174	-305

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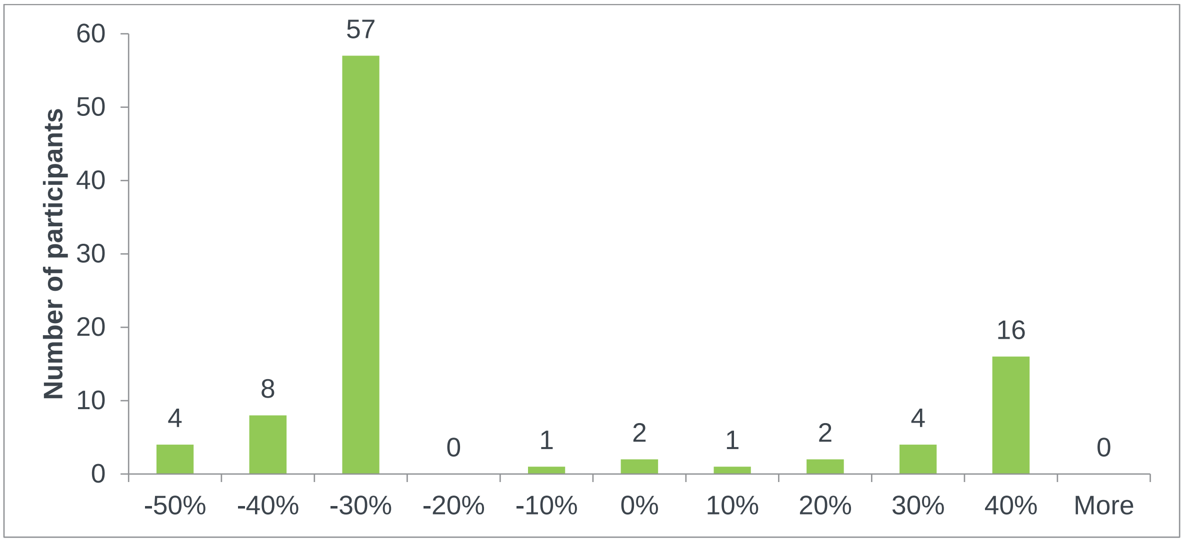
Comparison of DR and DR-LI

To determine the benefits that DR-LI can provide to low-income customers in SDG&E territory, the research team calculated the percent differences between each customer's annual bill under DR-LI and DR. Figure 8 shows the differences between annual customer costs between the two rates. The results show that DR-LI would provide cost savings to approximately 70% of participants, with most participants saving 30%-40% on their annual bill.

Figure 8: Annual Bill Percentage Differences Between DR-LI and DR



This analysis also shows that for participants with negative annual bills due to solar PV (i.e., they are net generators), DR-LI provides less value to them than it provides to participants with positive annual bills. This is because DR-LI customers receive lower generation credits (due to the discounted rate) when they export excess electricity to the grid.

Model B: Customer-optimized

Model B identified the operational schedules for EV chargers and energy storage that minimized customer costs. The research team then assessed the contribution of scenario variables at reducing customer costs. See Appendix A for the model's average customer, grid and customer-grid costs, and scores.

Optimized Operational Schedules

Figures 9 and 10 show loads by season and day of the week (weekdays vs. weekends) across all scenarios and rate structures after optimizing EV charging and energy storage operations. The result is a significant decrease in load during the peak hours for both TOU and PYD rate structures (Figures 11 and 12). Indeed, when the operations were optimized in the model, EV charging shifted to the super off-peak period beginning at 12 a.m. for the TOU rates. Figure 11 presents the combined average of EV-TOU-2 and EV-TOU-5 operational schedules since they were highly correlated. A large spike in energy storage charging near 5 a.m. is an artifact of the optimization technique (multiple optimums) and the costs would not change if the load was spread out more uniformly across the super-off-peak period. For the PYD rate, optimal charging times occurred between 1 a.m. and 7 a.m. corresponding to low rates (Figure 12).

Findings suggest that although most energy storage charging during the weekday occurred during early morning hours (12 a.m. – 6 a.m.) for TOU structures, daytime energy storage charging occurred during the winter due to the super-off-peak rates offered during several daytime hours in March-April. On the other hand, energy storage charging primarily occurs in midday for PYD since this coincides with the lowest rates during the winter, whereas in the summer the costs are not at a minimum but avoiding nonbypassable charges is typically sufficient to make this the most cost-effective time to charge during periods of overgeneration (Figure 12). Furthermore, a vast majority of storage discharging occurs during the on-peak period, but discharging also occurs in the morning hours during the week corresponding to increased rates for both PYD and TOU rate structures (the TOU rate increase corresponds to moving from super-off-peak to off-peak rates as shown in Figure 2). For TOU rates, the morning energy storage discharging during the off-peak period occurs when the load during the on-peak period is less than the energy storage capacity.

Figure 9: Average Customer-optimized Household Loads (TOU)

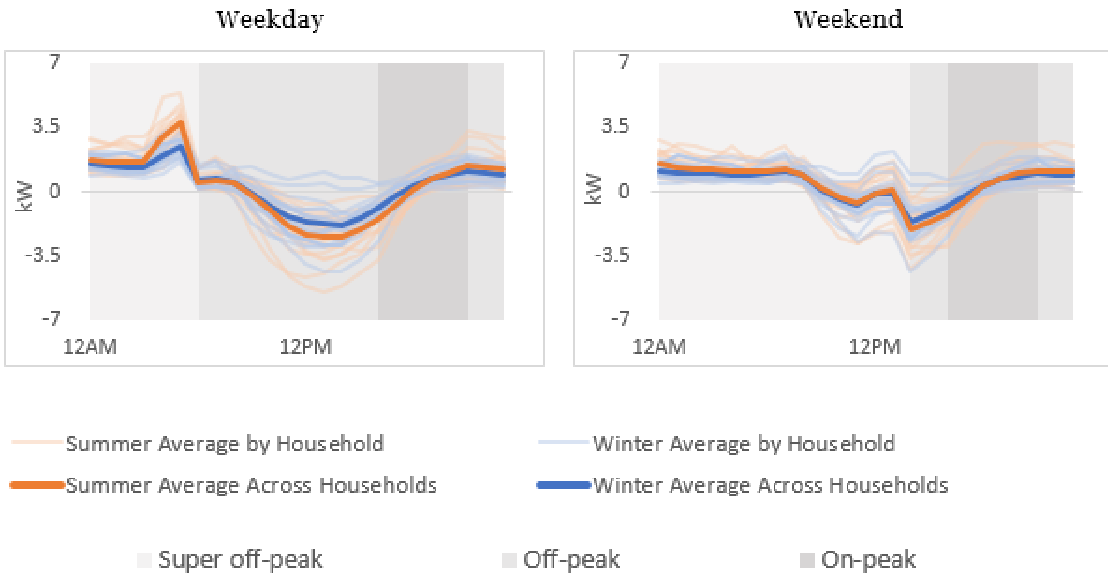
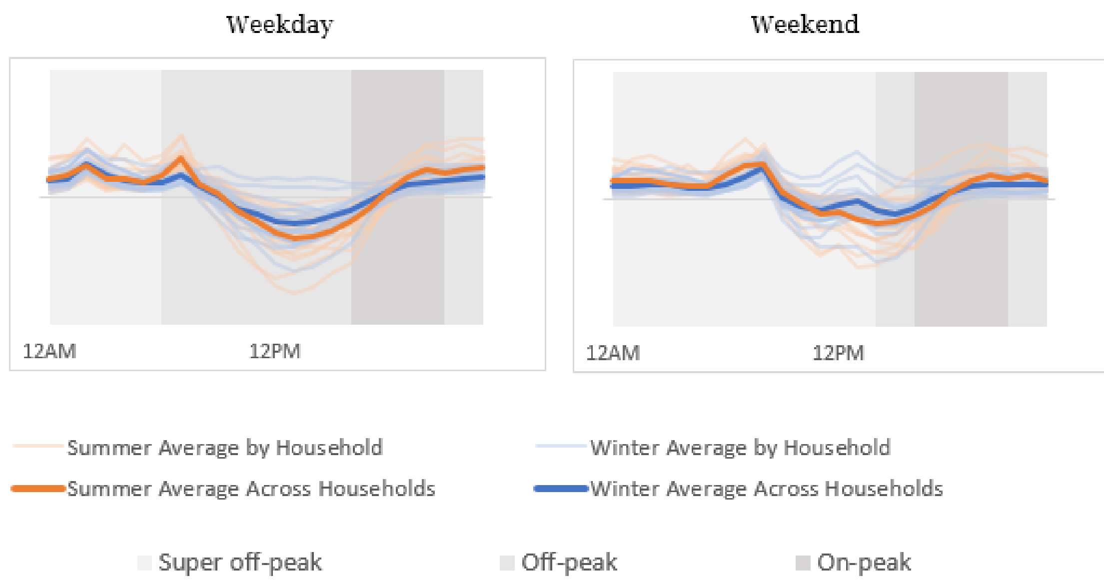


Figure 10: Average Customer-optimized Household Loads (PYD)



Additionally, during the weekends, EV and energy storage charging shift from the early morning to 10 a.m. to 2 p.m. for TOU rate structures because the super-off-peak period extends until 2 p.m. For PYD, the weekday and weekend operational schedules are highly similar, although there is a decrease in charging at 2 a.m. and an increase in charging from 7-8 a.m. Model constraints created spikes in EV charging during the weekend since 100% charge was required for the EV by 8 a.m., the EV was available to charge all day and the effect of weekend driving was not added until noon.

Overall, the optimal operational schedules for EV and energy storage are similar across seasons, weekdays vs. weekends, and rate structures. Given that, EV and energy storage charging only occurs during super-off-peak times for the TOU rates, whereas there is significantly more midday charging for the PYD rate. The extended super-off-peak period on the weekend for the TOU structures causes a significant expansion in the times that are cost-effective to charge energy storage and EV batteries.

Figure 11: Average Operational Schedules for Customer-optimized Model (TOU)

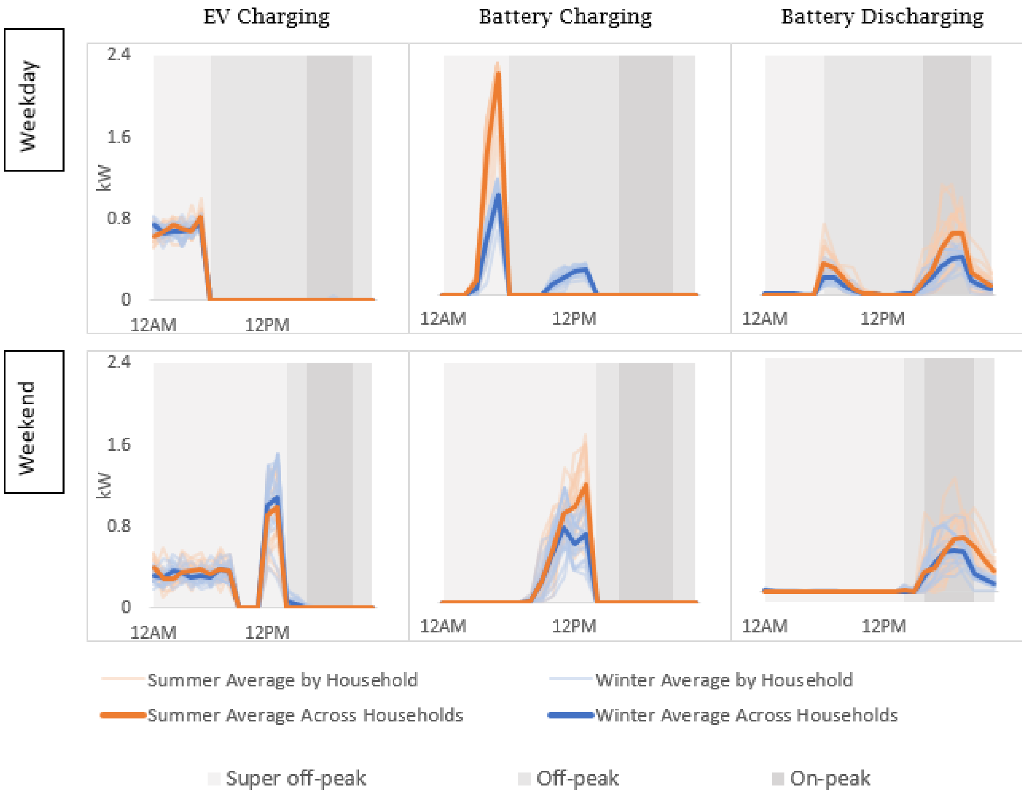
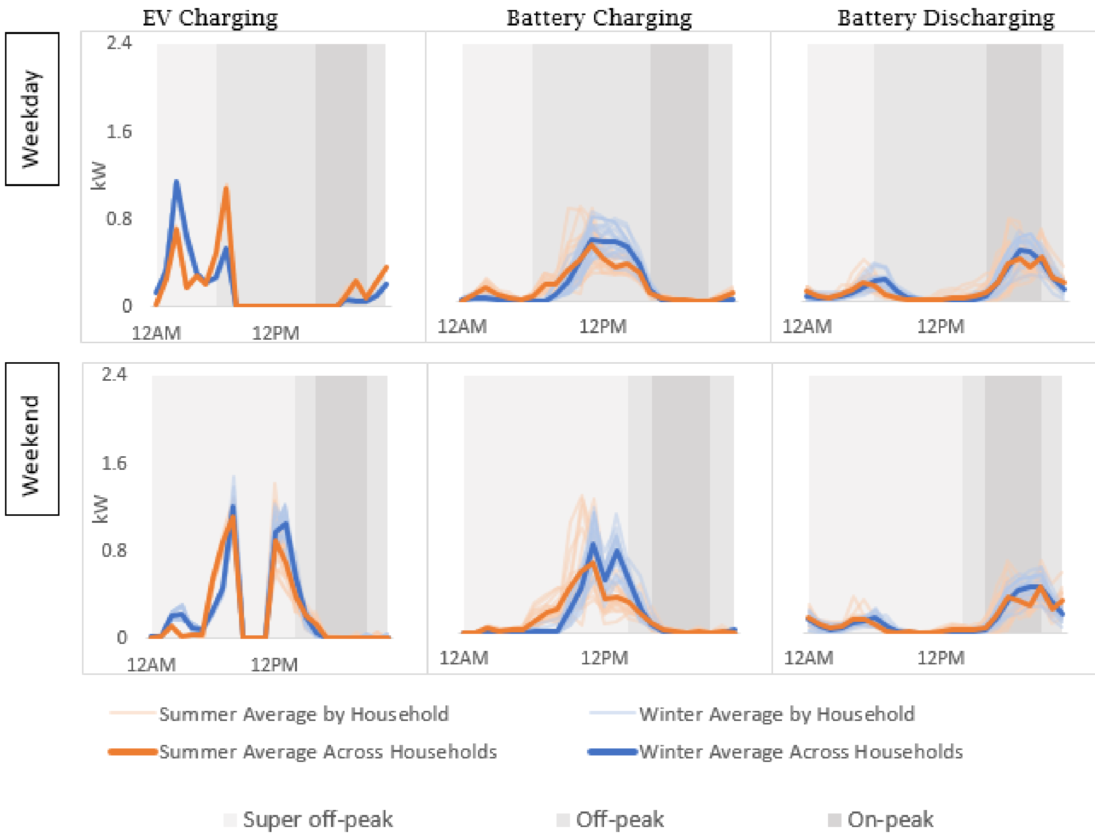


Figure 12: Average Operational Schedules for Customer-optimized Model (PYD)



Customer Benefits of Load Shifting

Customer and grid costs were significantly reduced by flexing EV and energy storage loads. However, these benefits varied significantly by rate structure, commute distance, energy storage capacity, and vehicle type.

Table 12 shows the effect of commute distances and rate structures on the average annual difference (annual costs for optimized model versus annual costs for unoptimized model) for Model B. By far, the rate structure that generates the greatest incentive to shift EV loads is EV-TOU-5 due to its low super-off-peak prices. These savings average over $700 and $400 per year for customers with 30- and 15-mile commutes, respectively. For comparison, EV-TOU-2 and PYD customers with 30-mile commutes would average approximately $350 and $200 per year. Due to differences in efficiencies, vehicle type also affected customer savings, but these differences were generally less than $50 a year.

Table 12: Annual Cost Differences by Rate Structure and Commute Length for Model B

Rate Structure	Commute Length (miles)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
EV-TOU-5	30	$-723	$-149	-95
EV-TOU-5	15	$-406	$-86	-54
EV-TOU-2	30	$-355	$-149	-80
EV-TOU-2	15	$-199	$-86	-45
EV-TOU-5	5	$-194	$-38	-25
PYD	30	$-190	$-141	-46
PYD	15	$-116	$-82	-28
EV-TOU-2	5	$-99	$-38	-21
PYD	5	$-57	$-37	-13

Table 13 shows the effect of energy storage scenarios and rate structures on the average annual differences for Model B. The table shows that EV-TOU-5 is the rate structure that generates the greatest incentives to shift energy storage loads. For instance, customers with 8 kWh energy storage average $450 in savings per year when operations are optimized. Highlighting the benefits of EV-TOU-5 to customers, the analysis also shows that customers with 4 kWh storage have greater savings potential than customers on EV-TOU-2 (or PYD) with 8 kWh storage.

Table 13: Annual Cost Differences by Rate Structure and Energy Storage Size for Model B

Rate Structure	Energy Storage Size (kWh)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
EV-TOU-5	8	$-450	$-65	-53
EV-TOU-5	4	$-285	$-42	-34
PYD	8	$-107	$-53	-18
EV-TOU-2	8	$-92	$-45	-29
EV-TOU-2	4	$-74	$-29	-20
PYD	4	$-73	$-34	-12

Table 14 shows the average annual customer cost benefits for scenarios that generate the greatest and least customer cost savings for Model B. These results strongly mirror the results in Tables 12 and 13, with the greatest potential savings for customers enrolled in the EV-TOU-5 rate structure with long commutes and large storage (8 kWh). Table 14 also shows that optimizing EV charging operations provides minor, but increased, benefits to customers with less efficient vehicles. The scenario with the greatest cost benefits can save over $1,200 per year; whereas optimizing operations for customers with short commutes and no storage enrolled in EV-TOU-5 (or PYD) may only reduce average annual costs by less than $100.

Table 14: Scenarios with Greatest and Least Savings for Customer-optimized Model

	Rate Structure	Commute Length (miles)	Battery Size (kWh)	Vehicle Type	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
Greatest Savings	TOU5	30	8	Model S	$-1236	$-238	-160
	TOU5	30	8	LEAF	$-1152	$-205	-145
	TOU5	30	8	Mi-EV	$-1130	$-200	-142
	TOU5	30	4	Model S	$-1071	$-216	-140
	TOU5	30	4	LEAF	$-987	$-182	-125
Least Savings	TOU2	5	0	LEAF	$-97	$-37	-20
	TOU2	5	0	Mi-EV	$-93	$-35	-20
	PYD	5	0	Model S	$-61	$-40	-14
	PYD	5	0	LEAF	$-56	$-35	-12
	PYD	5	0	Mi-EV	$-54	$-34	-12

The major limitation of this analysis was that only households with PV systems were included due the study eligibility requirement of having either PV and/or an EV (only 9 total participants in the study without PV) and the need to use load data from customers without EVs. As such, the results are not necessarily generalizable to households without PV. However, PV solar generation did not have an important effect on the operation of the EV chargers or energy storage (except for daytime charging for the PYD rate structure and daytime weekend charging for TOU), thus the values reported are expected to be similar to homes without PV.

Overall, our results suggest that smart EV charging and energy storage operation can provide significant bill savings for SDG&E customers, particularly those with long commute distances on TOU and dynamic hourly rate structures. These cost savings are maximized when the customer has the EV-TOU-5 rate structure, a large EV charging need, and large energy storage.

Model C: Grid-optimized

Model C identified the operational schedules for EV chargers and energy storage that minimized grid impacts. The research team then assessed the contribution of scenario variables at reducing grid costs. See Appendix A for the model's average customer, grid and customer-grid costs, and scores (customer - optimized).

Optimal Schedules

Figure 13 shows the grid-optimized loads by season and day of the week (weekdays vs. weekends) across all scenarios (note: different rates structures were not evaluated since the model only considers grid costs). The grid-optimized loads are similar to the customer-optimized loads (Figures 9 and 10). However, there is a more prominent peak in load from 2-3 a.m. during the week in the grid-optimized model (Figure 14) coinciding with the period of lowest grid costs (Figure 5). The optimized operations also show both early morning and daytime energy storage charging during the week in both summer and winter, with charging in summer occurring slightly earlier than in winter. The grid-optimized operational schedules on the weekend are slightly different than during the week. In particular, the research team observed EV and energy storage charging shift to around 8-9 a.m. in the summer and noon in the winter. These seasonal differences correspond to seasonal shifts in the daily shape of the grid costs (Figure 5).

Figure 13: Average Grid-optimized Household Loads

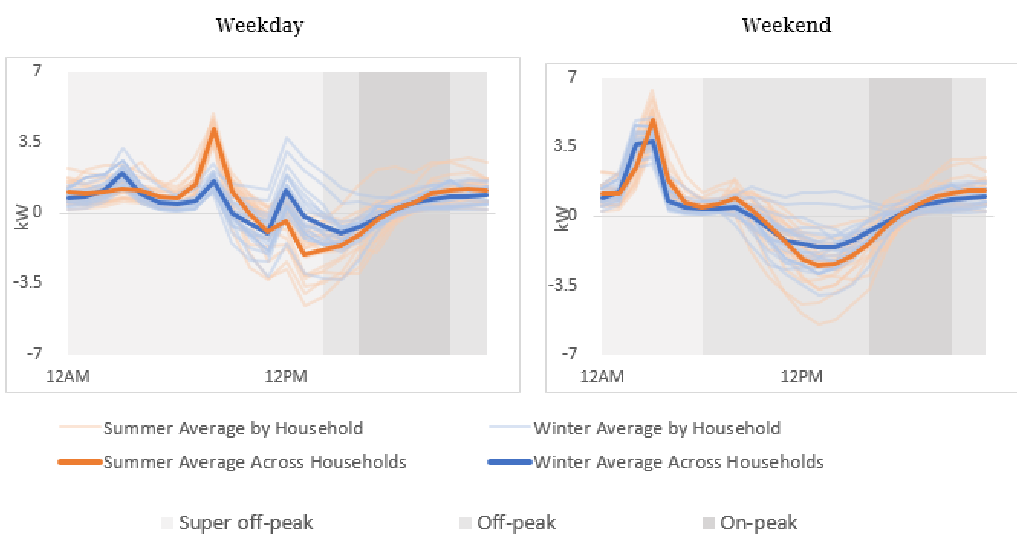
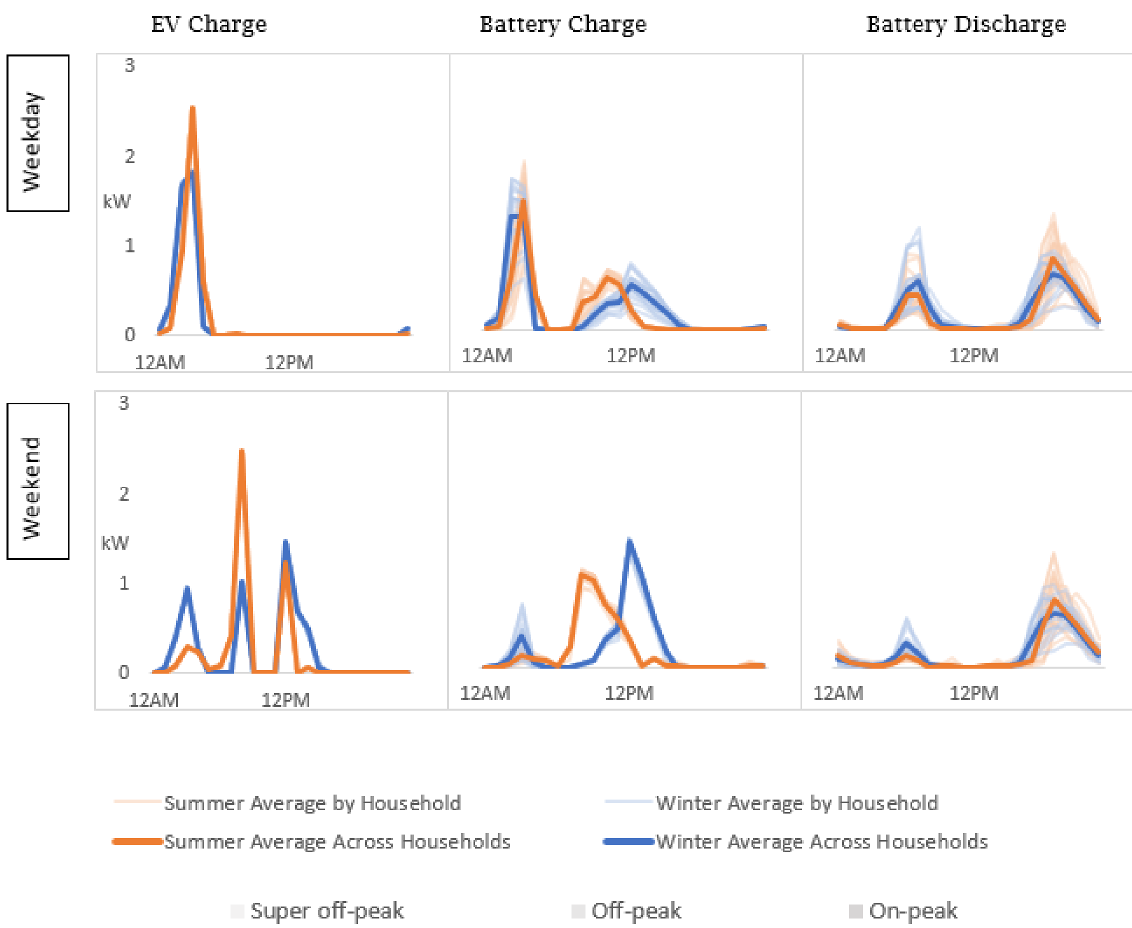


Figure 14: Average Operational Schedules for Grid-optimized Model



Grid Benefits of Load Shifting

Grid costs were significantly reduced by shifting EV and energy storage loads. Given the operations were optimized to grid costs, customer rates did not affect the model.

Table 15 shows the impact of commute distances and rate structures on the average annual difference (annual cost for optimized model minus the annual cost of the unoptimized model) for Model C. The rows in the table are sorted by the average grid cost differences. The table shows longer commute distances are the scenarios where optimizing operations can add the greatest grid benefits. Likewise, Table 16 shows that 8 kWh energy storage provided more grid benefits (an average decrease of $101 in grid costs) relative to 4 kWh storage (an average of $69 in grid benefits). Together, the Tables 15 and 16 show that scenarios with the greatest amount of flexible load (long commute distances and energy storage) allowed for the greatest increase in grid benefits.

Table 15: Annual Cost Differences by Rate Structure and Commute Length for Model C

Rate Structure	Commute Length (miles)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
PYD	**30**	**$-178**	**$-161**	**-50**
EV-TOU-2	**30**	**$-351**	**$-161**	**-82**
EV-TOU-5	**30**	**$-709**	**$-161**	**-97**
PYD	**15**	**$-108**	**$-94**	**-30**
EV-TOU-2	**15**	**$-196**	**$-94**	**-47**
EV-TOU-5	**15**	**$-395**	**$-94**	**-55**
EV-TOU-5	**5**	**$-185**	**$-42**	**-25**
PYD	**5**	**$-52**	**$-42**	**-14**
EV-TOU-2	**5**	**$-96**	**$-42**	**-22**

Table 17 shows the average annual cost differences for scenarios that generate the greatest and least grid cost savings for Model C. Again, the results show that scenarios with the greatest amount of flexible load (long commute distances and energy storage) provide the greatest benefits when operations are optimized. The residential rate structure had no impact on the operations for this grid-optimized model since the model was minimizing grid costs (wholesale day-ahead market rates). However, the customer costs for the grid-optimized operation schedules were calculated for comparison with the results from the customer-optimized model. The results show that optimizing operations to minimize grid costs results in costs savings for customers compared to the un-optimized model. In fact, the median customer costs increase by only about 5% relative to those calculated for the customer-optimized model. This relatively small difference is consistent with the observation that the operational schedules of the grid-optimized and customer-optimized models were highly similar and indicate that TOU and the PYD rate structures are, in general, aligned with grid impacts.

Table 16: Annual Cost Differences by Rate Structure and Energy Storage for Model C

Rate Structure	Energy Storage Size (kWh)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
EV-TOU-5	8	$-292	$-101	-50
EV-TOU-2	8	$-29	$-101	-39
PYD	8	$-39	$-101	-25
EV-TOU-5	4	$-206	$-69	-34
EV-TOU-2	4	$-36	$-69	-28
PYD	4	$-21	$-69	-17

Table 17: Scenarios with Greatest and Least Savings for Customer-optimized Model

	Rate Structure	Commute Length (miles)	Battery Size (kWh)	Vehicle Type	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-Grid Score Difference (10^2)
Greatest Savings	PYD	30	8	Model S	$-241	$-288	-83
	TOU2	30	8	Model S	$-410	$-288	-131
	TOU5	30	8	Model S	-1063	$-288	-157
	PYD	30	4	Model S	$-223	$-257	-75
	TOU2	30	4	Model S	$-416	$-257	-119
Least Savings	TOU2	5	0	LEAF	$-94	$-41	-21
	TOU5	5	0	LEAF	$-180	$-41	-24
	PYD	5	0	MiEV	$-50	$-40	-13
	TOU2	5	0	MiEV	$-91	$-40	-20
	TOU5	5	0	MiEV	$-174	$-40	-24

Model D: Dual-Optimized

The dual-optimized model identified the operational schedules for EV chargers and energy storage that minimized a measure of customer and grid costs, or customer-grid “scores” (see the Assumptions chapter for a detailed definition of customer-grid scores). The research team assessed the effects of scenario variables with these optimized operations to reduce customer-grid scores. See Appendix A for the model’s average customer, grid and customer-grid costs, and scores (customer-optimized).

Optimal Schedules

The dual-optimized loads for the TOU and PYD rate structures (Figures 15 and 16) are similar to their respective customer-optimized (Figures 9 and 10) and grid-optimized (Figure 13) average loads. However, the dual-optimized load shape shows the increased 2-3 a.m. load that characterizes the grid-optimized load. As with the grid-optimized model, this is because grid impacts are at a minimum during these hours, which makes it beneficial to charge energy storage and EVs during this time (Figures 17 and 18). The shifting and concentration of charging during this short period has no effect on customer costs for TOU structures (and little effect on PYD-related customer costs) since this is still the super-off-peak period. More daytime energy storage charging takes place during the week for the dual-optimized model than for the customer-optimized model, particularly for the TOU rates (Figure 17). This is a response to reduced grid impacts during these hours that are not reflected in the TOU rates. The optimized operations for the dual-optimized model for PYD and the grid-optimized model are nearly identical, highlighting the strong correlation between these dynamic rates.

Figure 15: Dual-optimized Household Loads (TOU)

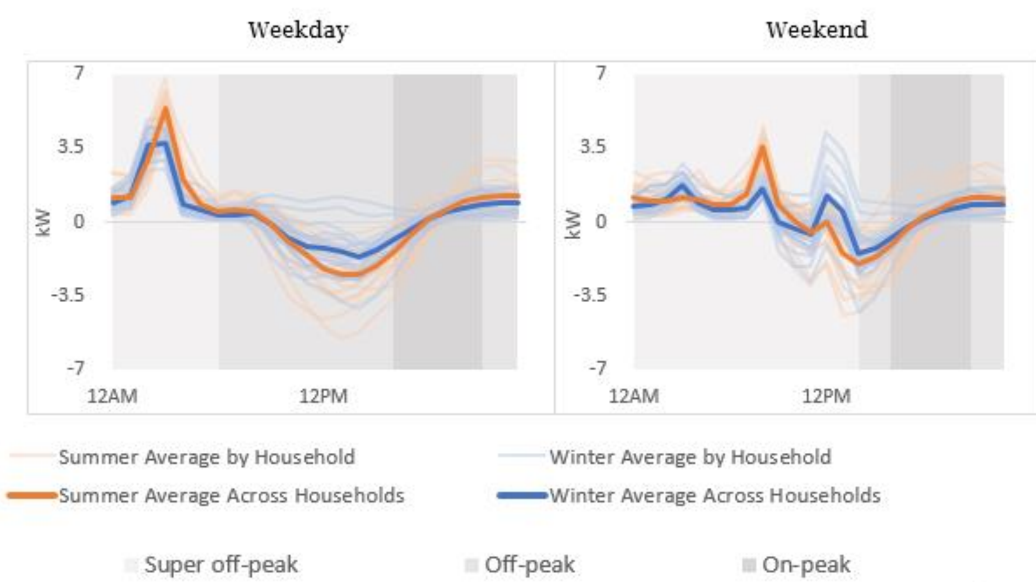


Figure 16: Dual-optimized Household Loads (PYD)

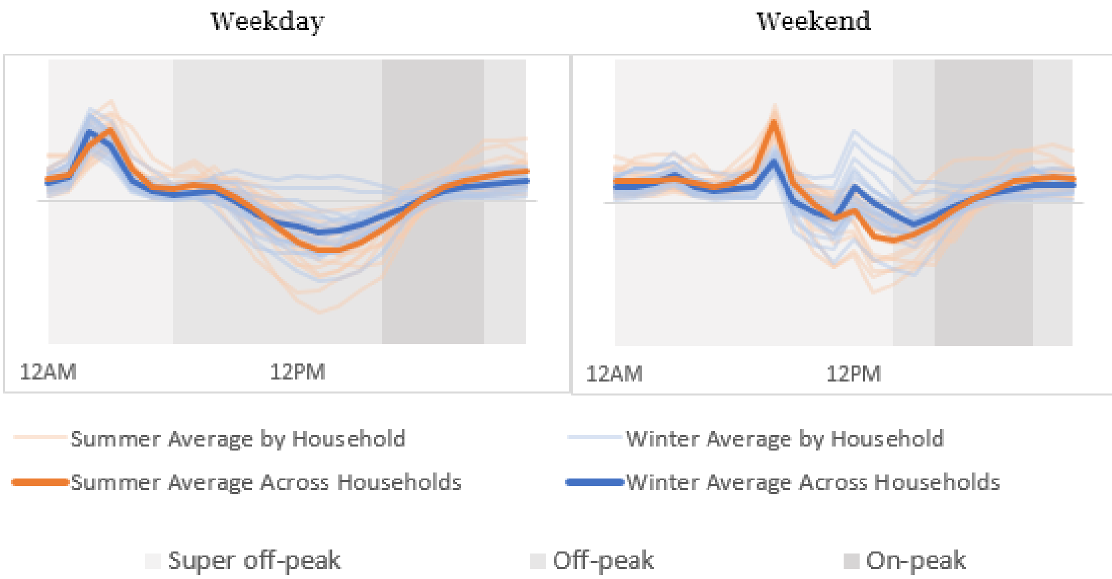
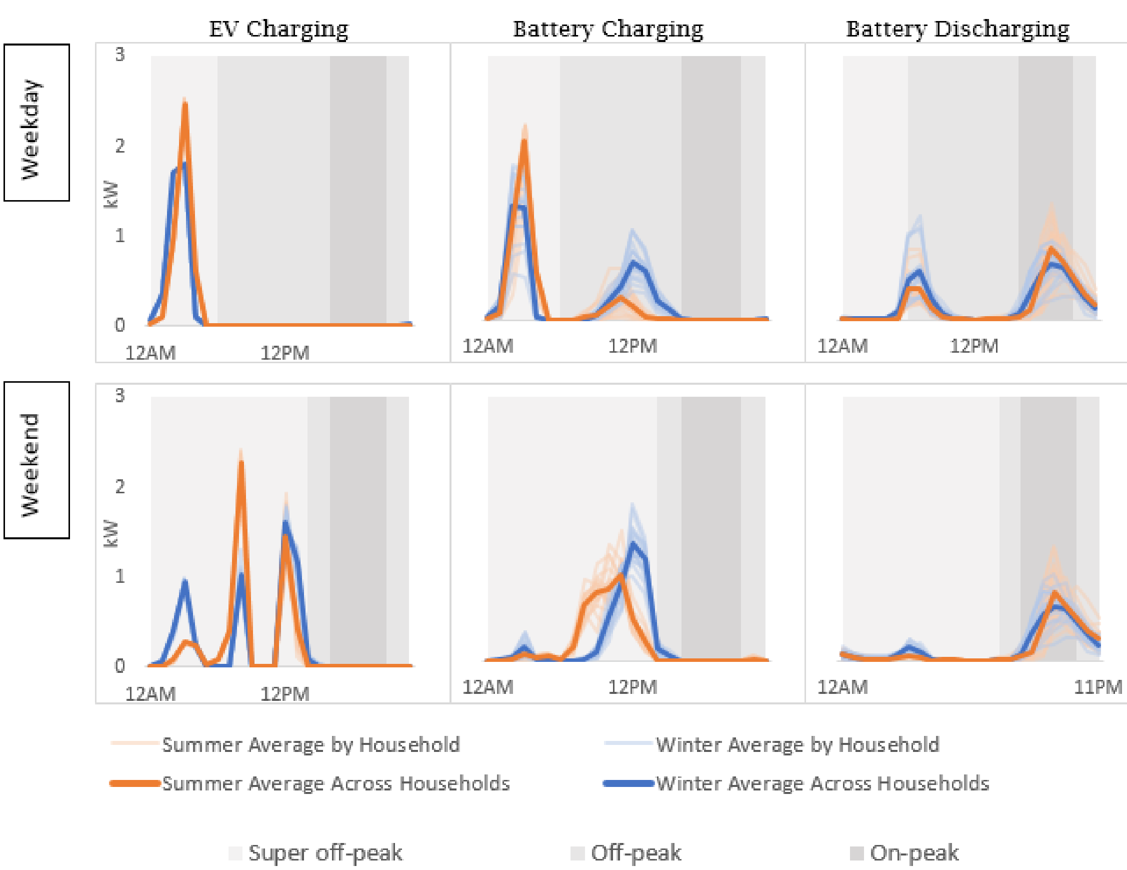
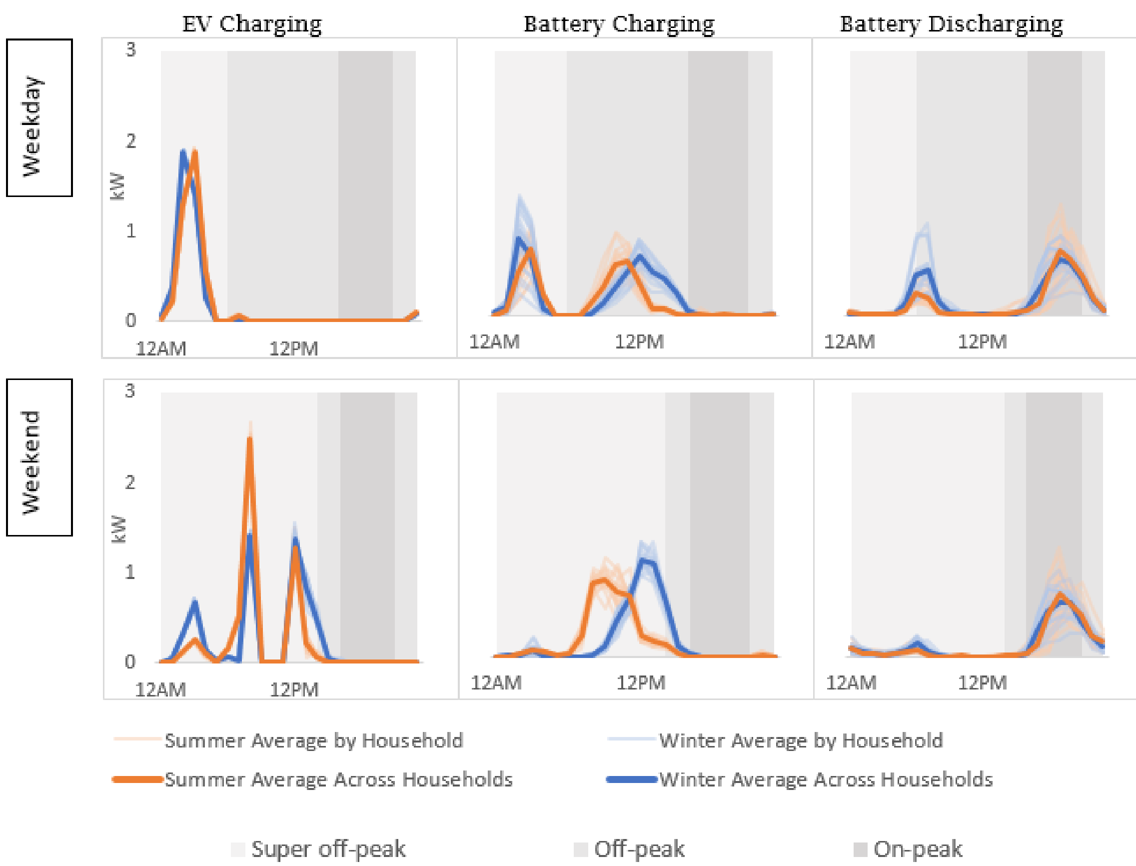


Figure 17: Average Operational Schedules for Dual-optimized Model (TOU)



Overall, there are no differences in the optimal operational schedules between the customer-grid optimized models and the models optimizing for customer costs or grid impacts individually. This is particularly true when the PYD rate structure is applied to the customer-grid score due to its high correspondence to the grid impacts signal. For the TOU rates structures, there are some slight changes with a more concentrated period of EV and energy storage charging in the early morning hours and increased daytime energy storage charging on weekdays.

Figure 18: Average Operational Schedules for Dual-optimized Model (PYD)



Customer-grid Scores and Scenarios

Customer-grid scores were sensitive to the operations of EV charging and energy storage. The scores were strongly impacted by all variables, including commute distance, vehicle type, energy storage capacity, and residential rate structure. Tables 18 and 19 show the individual impacts of commute distances, energy storage capacity, and rate structures on the average annual differences (annual bill for optimized model minus the annual bill of the unoptimized model) for Model D. Although the customer-grid score was a useful metric for the optimization process, it is difficult to interpret and the focus of the discussion here is on customer and grid costs. Tables 18 and 19 show that using the customer-grid score to optimize operations generated customer and grid benefits of nearly the same magnitude of the individual models (in other words, Models B and C).

Table 18: Annual Cost Differences by Rate Structure and Commute Length for Model D

Rate Structure	Commute Length (miles)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
EV-TOU-5	30	$-721	$-161	-97
EV-TOU-2	30	$-354	$-161	-82
EV-TOU-5	15	$-404	$-94	-55
PYD	30	$-182	$-160	-50
EV-TOU-2	15	$-198	$-94	-47
PYD	15	$-111	$-94	-30
EV-TOU-5	5	$-193	$-42	-26
EV-TOU-2	5	$-98	$-42	-22
PYD	5	$-55	$-42	-14

Table 19: Annual Cost Differences by Rate Structure and Energy Storage for Model D

Rate Structure	Energy Storage Size (kWh)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-grid Score Difference (10^2)
EV-TOU-5	8	$-440	$-95	-60
EV-TOU-2	8	$-62	$-96	-41
EV-TOU-5	4	$-277	$-66	-39
EV-TOU-2	4	$-55	$-67	-29
PYD	8	$-79	$-96	-26
PYD	4	$-53	$-65	-18

Although the customer-grid score was a useful metric for the optimization process, it is difficult to interpret and the focus of the discussion here is on customer and grid costs. Tables 18 and 19 show that using the customer-grid score to optimize operations generated customer and grid benefits of nearly the same magnitude of the individual models (in other words, Models B and C).For instance, the annual costs difference for a customer on EV-TOU-5 with a 30-mile commute was $-721 for Model D and $-723 for Model B; and the grid costs were $160 for Model D and $-161 for Model C. Thus, the similarity between the scenarios that generate the greatest and least score differences in Table 20 with those identified in Model B and C are not surprising. Overall, these results show that operations can (nearly) provide both optimal grid and customer benefits within the existing TOU and PYD rates structures.

Table 20: Scenarios with Greatest and Least Savings for Dual-optimized Model

	Rate Structure	Commute Length (miles)	Battery Size (kWh)	Vehicle Type	Annual Energy Consumption Difference (kWh)	Average Customer Cost Difference	Average Grid Impacts Difference	Average Customer-Grid Score Difference (10^2)
Greatest Savings	TOU5	30	8	Model S	644	$-1224	$-282	-169
	TOU5	30	8	LEAF	644	$-1141	$-245	-154
	TOU5	30	8	MiEV	644	$-1118	$-240	-151
	TOU5	30	4	Model S	379	$-1061	$-253	-148
	TOU2	30	8	Model S	642	$-446	$-283	-133
Least Savings	TOU2	5	0	LEAF	0	$-96	$-40	-21
	TOU2	5	0	MiEV	0	$-93	$-39	-21
	PYD	5	0	Model S	0	$-59	$-45	-15
	PYD	5	0	LEAF	0	$-54	$-41	-13
	PYD	5	0	MiEV	0	$-52	$-39	-13

V. CHAPTER 4: Discussion

This chapter summarizes findings and important policy considerations resulting from this research as well as future research to be pursued.

RDERMS Optimization with TOU and Dynamic Rates

Limitations of Analysis

There are several limitations of this study that need to be addressed. First, it should be noted that customers recruited for this study are not representative of the general population. Participants signed up voluntarily and met certain eligibility criteria, and because of this, the generalization of the findings (i.e., the rate structure that provides the most customer and grid benefits) is limited. For example, 91% of the enrolled participants had PV, which is substantially higher than the solar penetration level in California. Furthermore, for Models B – D the study only used data from households without EVs, which due to eligibility criteria, meant they all had operating PV systems. Thus, the findings from Models B -D are not necessarily representative of households without PV. Another limitation of this study was the unavailability of a residential dynamic rate for comparison with the DR and TOU rates structures assessed. The research team used the PYD rate as an example of a dynamic rate, but this rate is a special rate for public EV charging stations and tends to have lower rates than residential rates. Thus, comparisons between customer costs for TOU/DR rates and PYD are not valid.

Rates Structures and Customer Costs

Five customer rate structures were assessed in this analysis. The analysis shows that no single rate structure was most cost-effective for all customers but, rather, unique characteristics of each customer's load shape and total consumption determined the cost-effectiveness of the rate structures. With the exception of PYD (which is not a residential rate structure), EV-TOU-5 tends to be the most cost-effective for households with larger annual energy consumption since the cost benefits of its low super-off-peak rates can overcome the large monthly fixed fee. On the other hand, DR tends to be the most cost-effective for customers with low/negative annual energy consumption since it does not have fixed monthly fees or nonbypassable charges, and its tier one rate is lower than peak and off-peak rates of TOU rates. Accordingly, current NEM rules that require customers with new PV systems to enroll in TOU rates may reduce the value of these systems depending on the timing of peak periods.

Aligning Customer Costs and Grid Benefits

Operational schedules that minimized customer and grid costs were highly similar when TOU rates structures were applied. This suggests that the design of the current TOU rate structures offered by SDG&E incentivize customers to flex load in ways that are beneficial to grid impacts. Given that, the slight differences that exist between the TOU price signals and grid costs suggest that the TOU structures assessed could be improved to better reflect grid impacts. For instance, midday weekday TOU rates do not correspond strongly to grid impacts at these times; and low grid costs in the early morning hours are more concentrated than the constant rate during the super-off-peak period. These observations may seem to imply that a rate design with more granular rate variability across time would further align customer pricing signals with grid impacts. However, the benefit of such structures would be transient as the load response to a more granularized pricing signal would eventually shift grid benefits to other periods. This would seem to argue that a dynamic pricing signal, such as the PYD rate structure, could be the best solution for aligning customer costs and grid benefits. Indeed, PYD rates and grid costs were highly aligned, however, the relatively flat profile of PYD did not incentivize customers to shift flexible loads as well as EV-TOU-5.

EV Charging

This analysis showed that delaying EV charging from the evening on-peak period (when customers typically arrive home from work) to super-off-peak periods is a simple way of reducing the cost of charging an EV (and reduce grid impacts) for customers on TOU or dynamic rates. This is particularly true for customers that have long commute distances and are on a rate structure with low super-off-peak rates (for example, the EV-TOU-5 rate structure has super-off-peak rates of approximately $0.09 per kWh). Indeed, the analysis shows that shifting EV load for a 30-mile round-trip commute can save a customer up to $720 per year when they are enrolled in the EV-TOU-5 rate. These savings exceed the costs of a residential level 2 EVCS that have costs as low as $200,[6] although installation and management system costs would also need to be considered. Further, Model D showed that since TOU rate structures and grid costs are already highly aligned there is little impact to customer costs when the EV load is shifted to minimize grid impacts. However, current TOU rates structures only allow for these co-benefits to be realized, but a dynamic pricing structure that aligns customer incentives and grid benefits more precisely incentivize customers to act in accordance with grid impacts thereby providing both the customer and the grid the most benefits.

Energy Storage

The analysis also shows that energy storage can reduce customers costs and reduce grid impacts. These savings increase with the increasing size of energy storage. On average, 4 kWh energy storage saved customers approximately $275 per year and 8 kWh of storage saved customers $450 per year on EV-TOU-5 when their operations were optimized. The EV-TOU-5 rate structure also provided the greatest reduction in grid impacts when energy storage was dispatched. However, energy storage currently costs approximately $2,000 per kWh. In addition to the installation costs and management services, battery degradation would also need to be considered when determining the cost-effectiveness of energy storage with the existing rates.[7]

[6] Edmunds. 2019. *The True Cost of Powering an Electric Car.* https://www.edmunds.com/fuel-economy/the-true-cost-of-powering-an-electric-car.html

[7] Self-Generation Incentive Program. 2019. *Weekly Statewide Report*. https://www.selfgenca.com/home/resources/

Policy Considerations of TOU and Dynamic Rates

Residential Rate Reform

Integrating distributed energy resources, such as smart EV chargers and energy storage, can make the grid more efficient, flexible, and clean. However, traditional rate structures, such as flat-rate pricing and tiered rate structures, do not sufficiently incentivize customers to shift flexible loads that provide the range of potential benefits. To provide these incentives utilities offer TOU and dynamic rate structures that better align customer costs with grid impacts, but these rate structures are subject to state policy and are continually changing.

In 2013, Assembly Bill 327 was enacted to reform residential rates. A later CPUC decision (D.15.07-001) provided direction to investor-owned utilities (IOUs) on how to implement residential rate design structure and subsequently required IOUs to switch all customers to TOU rates beginning in 2019 (although, residential customers will have the option to opt out of TOU rates and to remain on tiered rates).[8] IOUs have already begun refining their TOU rate structures, shifting peak energy use periods (when rates are highest) from midday to evening hours, for example, SDG&E has shifted its peak to 4–9 p.m. However, all effects of this reform are currently unknown.

Rule 21 and Energy Storage

Historically, behind-the-meter energy storage systems have been prohibited from discharging to the grid, per Rule 21 interconnection rules.[9] While solar PV can export electricity to the grid and receive NEM credits for these exports, energy storage has not been permitted to export electricity to the grid. However, a recent decision from the CPUC has offered a new option for energy storage systems to discharge to the grid if the systems are charging only from the on-site NEM generator.[10] This could allow storage systems to shift solar export from midday to evening peak hours and receive NEM credit for storage export. Given that this is a recent development, it remains to be seen whether storage systems are operated in this manner and what the customer benefits will be.

Low-Income Customers

IOUs in California offer three programs to low-income customers requiring long-term bill assistance: California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), and the Medical

[8] California Public Utilities Commission. *Residential Rate Reform.* http://www.cpuc.ca.gov/general.aspx?id=12154.
[9] California Public Utilities Commission. 2014. *Decision Regarding Net Energy Metering Interconnection Eligibility for Storage Devices Paired with Net Energy Metering Generation Facilities (14-05-033)*. http://docs.cpuc.ca.gov/publisheddocs/published/g000/m091/k251/91251428.pdf
[10] California Public Utilities Commission. 2019. *Decision Granting Petition for Modification of Decision 14-05-033 Regarding Storage Devices Paired with Net Energy Metering Generating Facilities.* *https://static1.squarespace.com/static/54c1a3f9e4b04884b35cfef6/t/5c5a02ff104c7b5f073745dc/1549402881064/STORAGE+DEVICES+PAIRED+WITH+NET+ENERGY+METERING+GENERATING+FACILITIES.PDF*

Baseline Program.[11] All three programs offer monthly bill discounts to income-qualifying customers on tiered rates, not TOU rates. Model A analyzed customer bill impacts of the DR-LI rate and found that these customers' bills tended to be 30%-40% lower than customers on the standard DR rate and would not generate as much in savings when customers are net PV generators because of the rate discounts.

This is because when customers export excess generation to the grid, they will receive less generation credits under DR-LI.

This will need to be a consideration in 2019 as SDG&E transitions residential customer to TOU rates (although customers can opt out) except for certain CARE, FERA, and Medical Baseline customers who will remain on tiered rates. SDG&E plans to exclude customers living within certain ZIP codes within "Hot Zones" where the percentage of CARE- or FERA-eligible customers is at or above the average (e.g., the average percentage of FERA-eligible customers in the Hot Zone ZIP codes is 2.6%).[12] So, if there are CARE customers in a ZIP code, but the number of customers is below the average, then those customers would not be excluded from TOU. Also, there are customers that should be enrolled in CARE or FERA but are not, so they will be automatically defaulted to TOU rates starting in 2019. Some customers may be accidentally enrolled in TOU rates because they are not excluded through the ZIP code analysis, and there may be some customers who are also transitioned to TOU because they never enrolled in CARE initially.

Future Research

Precooling is a proven strategy to achieve both energy cost savings and peak load reduction for households using central air conditioning (AC) systems,[13] and it will be tested with RDERMS and smart technologies installed on-site during the SHS. However, due to the unavailability of information on participants' housing and AC system characteristics, precooling optimization was not performed in this analysis. To model and optimize AC systems for precooling, multiple types of information are needed such as household hourly load values, hourly temperature, housing types and characteristics (e.g., area, floors, height, insulation, etc.) and AC system characteristics, which were not available. Additionally, the research team will prepare another tariff assessment using modeling of other high-value rate structures not currently available to SDG&E customers to supplement this research.

[11] Pacific Gas and Electric. *Longer-Term Assistance*. https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/longer-term-assistance/longer-term-assistance.page

[12] SDG&E. 2018. *Rebuttal Testimony of Horace Tantum IV on Behalf of San Diego Gas & Electric Company*. https://www.sdge.com/sites/default/files/regulatory/A1712011%20and%20Related%20Matters%20-%20SDGE-%20Tantum%20-%202018%20RDW%20Rebuttal%20Testimony.pdf

[13] Herter Energy Research Solutions. 2012. *SMUD's 2012 Residential Precooling Study – Load Impact Evaluation*. http://www.herterenergy.com/pdfs/Publications/2013_Herter_SMUD_ResPrecooling.pdf

Glossary

Term	Definition
CAISO	California Independent Systems Operator. A nonprofit benefit corporation that oversees the operation of most of California's wholesale power grid.
DR	Domestic Residential. A tiered domestic electric utility rate available for SDG&E residential customers. https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/standard-rate-plan
DR-LI	Domestic Residential - Low Income. A discounted tiered domestic electric utility rate available for SDG&E residential customers. https://www.sdge.com/sites/default/files/regulatory/1-1-19%20Schedule%20DR-LI%20Total%20Rates%20Table.pdf
EV-TOU	Electric Vehicle-Time-of-Use. Electric utility rates available for SDG&E residential customers with electric vehicles. https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans
PYD	Power Your Drive. A utility electric vehicle charging station program that uses an hourly vehicle dynamic rate and is available for SDG&E electric vehicle customers. https://webarchive.sdge.com/clean-energy/electric-vehicles/poweryourdrive
RDERMS	Residential distributed energy resource management system. Software and hardware that enables dynamic, transactive control of load and distributed energy resources interacting with the smart grid through closed-loop, bidirectional communication.
SDG&E	San Diego Gas & Electric. A regulated public utility that services San Diego and southern Orange counties.
TOU	Time-of-use. A utility rate that considers the time of day a customer uses energy and charges a higher price per kWh during on-peak hours and a lower price per kWh during off-peak hours.

Appendix A: Model Results

Model A: Annual Estimated Customer Costs of Each Participant Under Various Rate Structures (Baseline)

Site ID	PV	EV	Annual Consumption (kWh)	EV-TOU-2 ($)	EV-TOU-5 ($)	PYD ($)	DR ($)
060	No	Yes	15,602	4,578	3,934	3,661	5,979
S421	Yes	Yes	11,987	3,775	3,394	3,332	4,844
085	No	Yes	11,416	3,142	2,577	2,295	4,188
164	Yes	Yes	11,211	3,284	2,869	2,796	4,168
169	No	Yes	10,688	3,110	2,727	2,476	3,766
138	No	Yes	9,804	2,816	2,460	2,190	3,354
284	Yes	Yes	7,651	2,222	1,741	2,096	2,605
442	Yes	Yes	7,188	2,028	1,584	1,688	2,427
019	Yes	No	7,118	1,979	1,757	1,492	2,228
036	Yes	N/A	7,062	2,073	1,946	1,695	2,238
090	Yes	Yes	6,862	2,340	2,348	1,783	2,162
076	No	Yes	6,769	1,939	1,751	1,456	2,145
338	Yes	Yes	6,683	1,837	1,675	1,271	2,078
126	No	Yes	6,563	1,986	1,915	1,810	2,035
175	No	Yes	6,239	1,832	1,705	1,486	1,971
177	Yes	No	5,997	1,460	1,196	866	1,903
107	No	Yes	5,365	1,437	1,222	1,146	1,529
292	Yes	N/A	5,172	1,312	1,103	929	1,684
343	Yes	Yes	4,539	1,697	1,335	1,400	1,465
189	No	Yes	4,453	1,244	1,173	1,004	1,176
330	Yes	No	4,096	1,537	1,530	1,520	1,378
075	Yes	Yes	3,922	967	536	778	1,151

Site ID	PV	EV	Annual Consumption (kWh)	EV-TOU-2 ($)	EV-TOU-5 ($)	PYD ($)	DR ($)
203	Yes	N/A	3,845	1,206	1,186	1,058	1,294
141	Yes	No	3,763	1,274	1,106	1,144	1,361
461	Yes	N/A	3,599	1,424	1,365	1,650	1,465
040	Yes	N/A	3,592	1,075	992	1,006	1,063
120	Yes	Yes	3,457	794	517	729	1,012
068	Yes	Yes	3,425	1,056	1,014	769	1,115
212	Yes	Yes	3,418	1,092	1,020	848	1,020
017	Yes	Yes	3,327	924	773	684	902
218	Yes	Yes	3,326	870	481	771	873
042	Yes	Yes	3,056	717	-109	706	867
0273	Yes	Yes	2,771	951	873	1,041	939
276	Yes	Yes	2,746	666	510	365	875
367	Yes	Yes	2,603	1,261	1,239	1,127	1,047
214	Yes	Yes	2,581	862	628	886	1,011
192	Yes	Yes	2,427	760	624	609	704
438	Yes	N/A	2,413	948	944	1,002	840
217	Yes	No	2,372	894	894	659	659
262	Yes	Yes	2,339	796	718	730	789
041	Yes	No	2,331	735	568	899	904
353	Yes	Yes	2,269	720	734	517	577
395	Yes	Yes	2,267	591	97	436	582
028	Yes	Yes	2,200	851	628	703	698
159	Yes	No	2,127	844	838	1,087	817
161	Yes	Yes	2,100	543	417	416	577
365	Yes	N/A	2,077	1,011	990	1,022	763
302	Yes	Yes	1,766	361	-13	447	531

Site ID	PV	EV	Annual Consumption (kWh)	EV-TOU-2 ($)	EV-TOU-5 ($)	PYD ($)	DR ($)
356	Yes	N/A	1,676	468	480	370	422
465	Yes	Yes	1,630	634	476	565	644
389	Yes	N/A	1,598	582	638	769	440
290	Yes	N/A	1,560	409	453	261	372
301	Yes	Yes	1,497	512	225	487	396
373	Yes	N/A	1,452	563	613	561	459
243	Yes	N/A	1,315	420	459	265	374
023	Yes	N/A	1,314	670	790	641	477
409	Yes	Yes	1,103	702	603	771	561
063	Yes	Yes	1,028	238	182	154	282
261	Yes	No	1,021	362	349	392	528
198	Yes	N/A	626	279	373	289	208
021	Yes	No	452	248	304	245	168
363	Yes	Yes	401	199	269	102	140
091	Yes	Yes	172	255	169	386	96
413	Yes	Yes	97	139	182	230	96
376	Yes	No	-88	245	374	278	31
288	Yes	Yes	-227	3	6	116	15
133	Yes	Yes	-245	75	121	33	-19
322	Yes	N/A	-272	180	341	227	-17
279	Yes	N/A	-305	23	20	161	60
277	Yes	N/A	-314	9	55	123	-32
050	Yes	No	-393	-8	86	30	-22
280	Yes	N/A	-400	136	206	318	8
359	Yes	N/A	-454	140	252	190	3
248	Yes	N/A	-480	-152	-116	-149	-38

Site ID	PV	EV	Annual Consumption (kWh)	EV-TOU-2 ($)	EV-TOU-5 ($)	PYD ($)	DR ($)
430	Yes	No	-521	165	335	333	-60
306	Yes	N/A	-621	188	301	275	-64
137	Yes	Yes	-702	40	214	127	-102
049	Yes	Yes	-713	$-146	-104	-153	-93
388	Yes	No	-720	154	218	320	-45
305	Yes	Yes	-848	65	103	222	-129
047	Yes	N/A	-912	146	285	589	-107
255	Yes	No	-1,005	-140	-52	34	-158
153	Yes	Yes	-1,183	110	351	198	-203
370	Yes	N/A	-1,232	54	181	364	-146
271	Yes	Yes	-1,562	-360	-326	-225	-330
130	Yes	No	-1,578	-174	-260	-98	-305
326	Yes	N/A	-1,606	-316	-232	-30	-313
364	Yes	Yes	-1,795	-249	-100	-240	-347
400	Yes	N/A	-2,046	-179	-71	-63	-410
236	Yes	Yes	-2,390	-663	-801	-275	-463
380	Yes	Yes	-2,845	-924	-1,001	-609	-454
446	Yes	No	-2,862	-579	-380	-423	-622
346	Yes	No	-3,080	-396	-254	-117	-542
030	Yes	No	-3,262	-683	-523	-325	-670
345	Yes	N/A	-3,539	-809	-581	-856	-775

Model B: Average Customer, Grid and Customer-Grid Impacts and Scores (Customer-optimized)

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU5	30	8	Model S	601	-1,236	-238	-160
TOU5	30	8	LEAF	601	-1,152	-205	-145
TOU5	30	8	MiEV	601	-1,130	-200	-142
TOU5	30	4	Model S	333	-1,071	-216	-140
TOU5	30	4	LEAF	333	-987	-182	-125
TOU5	30	4	MiEV	333	-965	-177	-122
TOU5	15	8	Model S	601	-891	-158	-112
TOU5	15	8	LEAF	601	-844	-149	-106
TOU5	15	8	MiEV	601	-831	-146	-105
TOU5	30	0	Model S	0	-787	-173	-106
TOU5	15	4	Model S	333	-726	-136	-93
TOU5	30	0	LEAF	0	-703	-140	-91
TOU5	30	0	MiEV	0	-680	-135	-88
TOU5	15	4	LEAF	333	-679	-126	-87
TOU5	15	4	MiEV	333	-666	-123	-85
TOU5	5	8	Model S	601	-661	-106	-81
TOU5	5	8	LEAF	601	-639	-102	-78
TOU5	5	8	MiEV	601	-633	-100	-77
TOU5	5	4	Model S	333	-496	-83	-61
TOU2	30	8	Model S	406	-478	-218	-118
TOU5	5	4	LEAF	333	-474	-79	-59
TOU5	5	4	MiEV	333	-468	-78	-58
TOU2	30	4	Model S	224	-459	-203	-109

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU5	15	0	Model S	0	-441	-93	-58
TOU2	30	8	LEAF	406	-436	-185	-105
TOU2	30	8	MiEV	406	-425	-180	-103
TOU2	30	4	LEAF	224	-419	-169	-96
TOU2	30	4	MiEV	224	-407	-164	-94
TOU5	15	0	LEAF	0	-394	-84	-52
TOU2	30	0	Model S	0	-387	-173	-89
TOU5	15	0	MiEV	0	-382	-81	-51
TOU2	30	0	LEAF	0	-344	-140	-76
TOU2	30	0	MiEV	0	-333	-135	-74
PYD	30	8	Model S	534	-327	-216	-73
TOU2	15	8	Model S	406	-311	-139	-78
TOU2	15	4	Model S	224	-293	-123	-69
PYD	30	4	Model S	303	-291	-198	-66
TOU2	15	8	LEAF	406	-289	-129	-73
PYD	30	8	LEAF	535	-285	-185	-62
TOU2	15	8	MiEV	406	-281	-126	-72
PYD	30	8	MiEV	535	-279	-180	-61
TOU2	15	4	LEAF	224	-270	-113	-64
TOU2	15	4	MiEV	224	-263	-111	-63
PYD	30	4	LEAF	303	-250	-166	-56
PYD	30	4	MiEV	303	-244	-162	-55
PYD	15	8	Model S	534	-244	-141	-49
PYD	30	0	Model S	0	-220	-164	-54
TOU2	15	0	Model S	0	-216	-93	-49

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
PYD	15	8	LEAF	535	-215	-133	-45
PYD	15	8	MiEV	535	-213	-130	-44
PYD	15	4	Model S	303	-211	-123	-43
TOU5	5	0	Model S	0	-211	-41	-27
TOU2	5	8	Model S	406	-198	-86	-52
TOU2	15	0	LEAF	0	-194	-84	-44
TOU5	5	0	LEAF	0	-189	-37	-24
TOU2	5	8	LEAF	406	-188	-82	-50
TOU2	15	0	MiEV	0	-187	-81	-43
TOU2	5	8	MiEV	406	-185	-80	-49
TOU5	5	0	MiEV	0	-183	-35	-23
PYD	15	4	LEAF	303	-182	-114	-39
TOU2	5	4	Model S	224	-180	-70	-43
PYD	15	4	MiEV	303	-179	-111	-38
PYD	30	0	LEAF	0	-178	-132	-43
PYD	30	0	MiEV	0	-172	-128	-42
TOU2	5	4	LEAF	224	-170	-66	-41
PYD	5	8	Model S	534	-167	-92	-33
TOU2	5	4	MiEV	224	-167	-65	-40
PYD	5	8	LEAF	535	-163	-88	-31
PYD	5	8	MiEV	535	-161	-87	-31
PYD	15	0	Model S	0	-137	-89	-30
PYD	5	4	Model S	303	-133	-74	-26
PYD	5	4	LEAF	303	-129	-70	-25
PYD	5	4	MiEV	303	-128	-68	-25

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
PYD	15	0	LEAF	0	-107	-80	-26
TOU2	5	0	Model S	0	-106	-41	-23
PYD	15	0	MiEV	0	-104	-77	-26
TOU2	5	0	LEAF	0	-97	-37	-20
TOU2	5	0	MiEV	0	-93	-35	-20
PYD	5	0	Model S	0	-61	-40	-14
PYD	5	0	LEAF	0	-56	-35	-12

Model C: Average Customer, Grid and Customer-Grid Costs and Scores (Grid-optimized)

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU5	30	8	Model S	654	-1,063	-288	-157
TOU5	30	4	Model S	395	-977	-257	-142
TOU5	30	8	LEAF	654	-981	-251	-142
TOU5	30	8	MiEV	654	-959	-247	-139
TOU2	30	8	Model S	654	-410	-288	-131
TOU5	30	4	LEAF	395	-896	-220	-127
TOU5	30	4	MiEV	395	-873	-215	-124
TOU2	30	4	Model S	395	-416	-257	-119
TOU2	30	8	LEAF	654	-368	-251	-117
TOU2	30	8	MiEV	654	-356	-247	-115
TOU5	15	8	Model S	654	-721	-204	-109
TOU5	30	0	Model S	0	-771	-187	-108
TOU2	30	4	LEAF	395	-375	-220	-106
TOU2	30	4	MiEV	395	-365	-215	-103
TOU5	15	8	LEAF	654	-675	-193	-103
TOU5	15	8	MiEV	654	-663	-190	-101
TOU5	15	4	Model S	395	-635	-172	-94
TOU2	30	0	Model S	0	-382	-187	-92
TOU5	30	0	LEAF	0	-689	-150	-92
TOU2	15	8	Model S	654	-246	-204	-90
TOU5	30	0	MiEV	0	-667	-145	-89
TOU5	15	4	LEAF	395	-590	-161	-88
TOU5	15	4	MiEV	395	-577	-158	-86
TOU2	15	8	LEAF	654	-223	-193	-84

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
PYD	30	8	Model S	654	-241	-288	-83
TOU2	15	8	MiEV	654	-215	-190	-83
TOU2	30	0	LEAF	0	-341	-150	-78
TOU2	15	4	Model S	395	-251	-172	-78
TOU5	5	8	Model S	654	-493	-147	-77
TOU2	30	0	MiEV	0	-330	-145	-76
PYD	30	4	Model S	395	-223	-257	-75
TOU5	5	8	LEAF	654	-472	-142	-74
TOU2	15	4	LEAF	395	-228	-161	-73
TOU5	5	8	MiEV	654	-466	-141	-73
TOU2	15	4	MiEV	395	-221	-158	-72
PYD	30	8	LEAF	654	-202	-251	-71
PYD	30	8	MiEV	654	-198	-247	-70
PYD	30	4	LEAF	395	-184	-220	-63
PYD	30	4	MiEV	395	-179	-215	-62
TOU2	5	8	Model S	654	-131	-147	-62
TOU5	5	4	Model S	395	-408	-115	-62
TOU2	5	8	LEAF	654	-124	-142	-60
TOU2	5	8	MiEV	654	-121	-141	-59
TOU5	15	0	Model S	0	-429	-102	-59
TOU5	5	4	LEAF	395	-386	-110	-59
PYD	30	0	Model S	0	-204	-187	-58
PYD	15	8	Model S	654	-165	-204	-58
TOU5	5	4	MiEV	395	-381	-109	-58
PYD	15	8	LEAF	654	-137	-193	-53
TOU5	15	0	LEAF	0	-384	-91	-53

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
PYD	15	8	MiEV	654	-134	-190	-52
TOU2	15	0	Model S	0	-213	-102	-51
TOU2	5	4	Model S	395	-139	-115	-51
TOU5	15	0	MiEV	0	-371	-89	-51
PYD	15	4	Model S	395	-148	-172	-50
TOU2	5	4	LEAF	395	-130	-110	-49
TOU2	5	4	MiEV	395	-127	-109	-48
PYD	30	0	LEAF	0	-167	-150	-47
PYD	30	0	MiEV	0	-161	-145	-45
PYD	15	4	LEAF	395	-120	-161	-45
TOU2	15	0	LEAF	0	-191	-91	-45
PYD	15	4	MiEV	395	-117	-158	-44
TOU2	15	0	MiEV	0	-184	-89	-44
PYD	5	8	Model S	654	-94	-147	-40
PYD	5	8	LEAF	654	-90	-142	-38
PYD	5	8	MiEV	654	-88	-141	-38
PYD	15	0	Model S	0	-128	-102	-33
PYD	5	4	Model S	395	-77	-115	-31
PYD	5	4	LEAF	395	-72	-110	-30
PYD	5	4	MiEV	395	-70	-109	-29
PYD	15	0	LEAF	0	-100	-91	-28
PYD	15	0	MiEV	0	-96	-89	-28
TOU5	5	0	Model S	0	-202	-46	-27
TOU2	5	0	Model S	0	-103	-46	-24
TOU5	5	0	LEAF	0	-180	-41	-24
TOU5	5	0	MiEV	0	-174	-40	-24

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU2	5	0	LEAF	0	-94	-41	-21
TOU2	5	0	MiEV	0	-91	-40	-20
PYD	5	0	Model S	0	-56	-46	-15
PYD	5	0	LEAF	0	-52	-41	-13

Model D: Average Customer, Grid and Customer-Grid Costs and Scores (Customer/Grid-optimized)

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU5	30	8	Model S	644	-1,224	-282	-169
TOU5	30	8	LEAF	644	-1,141	-245	-154
TOU5	30	8	MiEV	644	-1,118	-240	-151
TOU5	30	4	Model S	379	-1,061	-253	-148
TOU2	30	8	Model S	642	-446	-283	-133
TOU5	30	4	LEAF	379	-978	-216	-133
TOU5	30	4	MiEV	379	-955	-211	-130
TOU2	30	4	Model S	384	-438	-253	-121
TOU2	30	8	LEAF	642	-404	-246	-120
TOU5	15	8	Model S	644	-880	-197	-120
TOU2	30	8	MiEV	642	-393	-241	-117
TOU5	15	8	LEAF	644	-833	-186	-114
TOU5	15	8	MiEV	644	-820	-183	-112
TOU5	30	0	Model S	0	-784	-187	-109
TOU2	30	4	LEAF	384	-398	-216	-108
TOU2	30	4	MiEV	384	-387	-212	-105
TOU5	15	4	Model S	379	-717	-168	-100
TOU5	30	0	LEAF	0	-701	-150	-93
TOU5	15	4	LEAF	379	-670	-157	-93
TOU2	30	0	Model S	0	-385	-187	-92
TOU2	15	8	Model S	642	-281	-198	-92
TOU5	15	4	MiEV	379	-657	-154	-92
TOU5	30	0	MiEV	0	-678	-145	-90
TOU5	5	8	Model S	644	-650	-140	-88

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU2	15	8	LEAF	642	-257	-187	-87
TOU2	15	8	MiEV	642	-251	-184	-86
PYD	30	8	Model S	604	-289	-282	-85
TOU5	5	8	LEAF	644	-628	-135	-85
TOU5	5	8	MiEV	644	-622	-134	-85
TOU2	15	4	Model S	384	-273	-169	-80
TOU2	30	0	LEAF	0	-343	-150	-78
PYD	30	4	Model S	360	-261	-252	-76
TOU2	30	0	MiEV	0	-333	-145	-76
TOU2	15	4	LEAF	384	-249	-158	-75
PYD	30	8	LEAF	604	-250	-245	-74
TOU2	15	4	MiEV	384	-243	-155	-73
PYD	30	8	MiEV	604	-245	-241	-72
TOU5	5	4	Model S	379	-487	-112	-67
PYD	30	4	LEAF	360	-223	-215	-65
TOU2	5	8	Model S	642	-168	-141	-65
PYD	30	4	MiEV	360	-218	-210	-64
TOU5	5	4	LEAF	379	-465	-107	-64
TOU5	5	4	MiEV	379	-459	-105	-64
TOU2	5	8	LEAF	642	-158	-136	-63
TOU2	5	8	MiEV	642	-155	-135	-62
PYD	15	8	Model S	604	-211	-197	-60
TOU5	15	0	Model S	0	-440	-102	-60
PYD	30	0	Model S	0	-210	-186	-58
PYD	15	8	LEAF	604	-182	-187	-55
PYD	15	8	MiEV	604	-179	-184	-54

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU5	15	0	LEAF	0	-393	-91	-54
TOU2	5	4	Model S	384	-161	-112	-53
TOU5	15	0	MiEV	0	-380	-88	-52
PYD	15	4	Model S	360	-186	-167	-51
TOU2	15	0	Model S	0	-215	-102	-51
TOU2	5	4	LEAF	384	-151	-107	-50
TOU2	5	4	MiEV	384	-147	-106	-50
PYD	30	0	LEAF	0	-171	-150	-47
PYD	15	4	LEAF	360	-156	-156	-47
PYD	15	4	MiEV	360	-153	-153	-46
TOU2	15	0	LEAF	0	-193	-91	-46
PYD	30	0	MiEV	0	-165	-145	-45
TOU2	15	0	MiEV	0	-186	-88	-44
PYD	5	8	Model S	604	-138	-141	-42
PYD	5	8	LEAF	604	-133	-136	-40
PYD	5	8	MiEV	604	-131	-135	-40
PYD	15	0	Model S	0	-132	-102	-33
PYD	5	4	Model S	360	-111	-111	-33
PYD	5	4	LEAF	360	-107	-106	-32
PYD	5	4	MiEV	360	-104	-105	-31
PYD	15	0	LEAF	0	-103	-91	-29
PYD	15	0	MiEV	0	-100	-88	-28
TOU5	5	0	Model S	0	-210	-45	-28
TOU5	5	0	LEAF	0	-188	-41	-25
TOU2	5	0	Model S	0	-106	-45	-24
TOU5	5	0	MiEV	0	-182	-39	-24

Commute Length (miles)	Rate Structure	Battery Size (kWh)	Vehicle Type	Annual Net Load Difference (kWh)	Average Customer Cost Difference ($)	Average Grid Impacts Difference ($)	Average Customer-Grid Score Difference (10^2)
TOU2	5	0	LEAF	0	-96	-40	-21
TOU2	5	0	MiEV	0	-93	-39	-21
PYD	5	0	Model S	0	-59	-45	-15
PYD	5	0	LEAF	0	-54	-41	-13

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