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Regarding the 2020 Load Management Rulemaking Draft Scoping Memo

Additional submitted attachment is included below.

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January 24, 2020

California Energy Commission
Docket Unit, MS-4
Re: Docket 19-OIR-01
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Docket No. 19-OIR-01 – Comments of Center for Sustainable Energy® regarding the 2020 Load Management Rulemaking Draft Scoping Memo

I. INTRODUCTION

The Center for Sustainable Energy® (CSE) appreciates the opportunity to comment on the 2020 Load Management Rulemaking Scoping Memo. CSE is a 23-year-old national nonprofit driven by one simple mission – decarbonize. We provide program administration, technical assistance, and policy advisement, and serve as a trusted and objective resource helping government agencies implement successful sustainable energy programs. Our vision is a future with sustainable, equitable, and resilient transportation, buildings, and communities, and, as such, we believe increased load flexibility is essential for California to achieve this vision.

CSE commends the California Energy Commission's (Energy Commission) leadership on encouraging load management strategies that benefit the grid, environment, and customers. As the State continues to take action toward meeting its ambitious climate goals through the increased use of renewable resources to power the grid and electrification of the transportation and building sectors, load management strategies will become increasingly important. The intermittent nature of clean energy resources such as wind and solar and additional load from electrification strategies will require significant load flexibility to maximize the benefits of clean electricity and maintain grid reliability. As such, CSE is pleased by the proposed scope of this proceeding. In addition, CSE is encouraged by the Energy Commission's collaboration with the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), and stakeholders in the development of new load management standards. CSE is pleased to provide comments in response to the specific questions posed by the Energy Commission to inform the scope of the Load Management Rulemaking Proceeding.

II. RESPONSES TO QUESTIONS FOR STAKEHOLDERS

1. *What are your recommended additions or modifications to this draft scope?*

CSE strongly supports the broad and inclusive scope drafted by the Energy Commission and offers the following points of emphasis. Consistent with state goals, including those outlined in Senate Bill (SB) 100 and Assembly Bill (AB) 3232, CSE supports emphasizing the consideration of marginal greenhouse gas (GHG) emissions, in addition to marginal avoided costs, in the context of rate design. Such an approach will encourage load shifting that maximizes the environmental and health benefits of renewable energy resources added to the grid. In addition, while the Energy Commission already includes electric vehicle supply equipment (EVSE) as an end-use technology for automation, CSE encourages considering the importance of EV charging throughout the scope of this proceeding. This includes designing rates that specifically encourage certain EV charging behaviors and consider EVs in end-use storage systems, as vehicle-to-grid technology becomes more widespread. As the State continues to make strides in electrifying the transportation sector, resulting in new, flexible load being added to the grid, EV charging will be an increasingly critical component of any load management strategy that aims to maximize the benefits of clean electricity.

2. *Are there additional technologies, strategies, studies, or other materials that should be considered in this this rulemaking? If so, please provide a brief description and a link to relevant information.*

CSE is currently engaged in several projects related to load management, including two Electric Program Investment Charge (EPIC) funded projects (EPC-15-048 and EPC-15-07),[1,2] and will share final results to the Docket as they become available. Modeling results from the Smart Home Study (EPC-15-048) indicate that dynamic real-time pricing can result in more grid and customer benefits when compared to block time-of-use (TOU) rates.[3] In addition, strong price differentials are needed within all seasons to ensure desired load shifting behaviors occur year-round. The study also suggests that the Energy Commission should consider the impacts of negative pricing events on load management strategies. In particular, the research showed that while compensation from negative prices in the wholesale market by themselves do not offer a strong economic signal for behind-the-meter customers to participate in the CAISO's proposed proxy demand,[4] supportive utility rates could build load during these hours and reduce emissions.

In addition to the strategies included in the Draft Scope, CSE recommends considering a forward-looking marginal GHG signal. Insights can be gleaned from a working group report developed to inform the Self Generation Incentive Program (SGIP) within CPUC's Rulemaking 12-11-005.[5] The report found that energy storage systems can achieve greater GHG reductions if they have a forward-looking marginal GHG signal to inform the best times to charge and discharge. The CPUC adopted the signal recommended in August 2019; the interim signal is already available and the final signal will be available

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[1] Smart Home Consortium, Smart Home Study. https://smarthomestudy.com/

[2] Center for Sustainable Energy, Bidding BTM Resources into the Market. http://sites.energycenter.org/btmbidding

[3] See Attachment A for additional details.

[4] California Independent System Operator, Energy Storage and Distributed Energy Resources Phase 3 Draft Final Proposal, July 11, 2018. http://www.caiso.com/Documents/DraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf

[5] AESC, Inc. for California Public Utilities Commission Rulemaking 12-11-005, SGIP GHG Signal Working Group Final Report, June 15, 2018. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457832

April 1, 2020.[6] Such a signal can be expanded beyond energy storage systems within SGIP to other flexible load technologies being explored within this proceeding.

3. *Beyond those mentioned here, what end-uses and customers are likely to be able to benefit from demand flexibility on voluntary hourly and sub-hourly tariffs?*

CSE commends the Energy Commission for specifically noting potential technologies such as end-use storage systems for low-income customers and encourages the Energy Commission to continue to approach this proceeding using an equity lens. Load management controls can help low-income customers manage transitions to new rate structures, but this will also need to be explored in the context of California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance Program (FERA). Beyond low-income customers, the Energy Commission should consider how other hard-to-reach customers can benefit from demand flexibility. CSE recommends assessing which customers and sectors will be most impacted by shifts to new tariffs, and which have the greatest potential for load flexibility.

4. *What economic impacts should be considered? (e.g. positive or negative effects on load serving entities, customers, workforce, vendors, generators, etc.)*

As expressed in our previous comments, CSE encourages an emphasis on reducing GHG emissions through load management strategies. As such, the economic impacts associated with GHG emissions reductions, as well as other benefits associated with reducing the burning of fossil fuels for energy generation, such as public health benefits, should be considered within an economic impact assessment. In addition, effects on load serving entities should encompass impacts related to transmission capacity and siting costs, and deferred investments in transmission and distribution infrastructure upgrades resulting from greater peak efficiency and demand flexibility. Similarly, managing energy loads to help maintain electrical grid reliability will result in economic impacts from more reliable electric service. CSE also recommends the Energy Commission to consider how new load management standards will impact both investor-owned utility bundled and unbundled customers, especially as more California customers are expected to be served by load serving entities other than investor-owned utilities. In addition, any customer impact analysis should include a specific focus on customers in disadvantaged communities.

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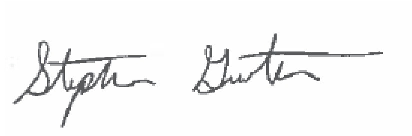
[6] California Public Utilities Commission, Decision 19-08-001, August 1, 2019. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K260/310260347.PDF

III. CONCLUSION

CSE appreciates the opportunity to provide these comments regarding the 2020 Load Management Rulemaking Proceeding Draft Scoping Memo. We look forward to continued collaboration with the Energy Commission, CPUC, CAISO and other stakeholders in developing standards and price signals to increase demand flexibility on the grid in support of the State's energy reduction and climate goals.

Sincerely,



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ATTACHMENT A

EPC-15-048: Assessment of Tariffs - Balancing Renewable Energy Integration and Utility Costs Using an Innovative Residential Tariff Structure and a Wholesale Market Mechanism

Final Tariff Assessment Report

Center for Sustainable Energy™

January 2020

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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 Assessment Report* 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 10: Assessment of Tariffs*. 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 energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

The State of California has established aggressive clean energy and greenhouse gas emissions (GHG) reduction goals that will be achieved largely by adding renewable energy generation from solar and wind to its electric grid. This shift in electric generation will provide significant environmental and public health benefits. For the full benefits of the available renewable energy resources to be realized, however, electric loads must be shifted to periods of higher renewable generation, otherwise fossil-fuel powered resources will continue to meet larger demands than necessary. The primary method to shift customer demand to more optimal times of the day is through price signals. Accordingly, this research investigated the potential of two types of price signals to encourage residential customers to shift demand to periods of high renewable generation in San Diego Gas & Electric (SDG&E) territory: retail rates and a wholesale market mechanism. The analysis shows that SDG&E's Electric Vehicle-Time-of-Use-5 rate structure corresponds, in general, with seasonal and daily variations in utility costs and emissions thereby incentivizing customers to consume low-cost and low GHG-emission energy from the grid; but there is opportunity to use a modified rate structure that can potentially reduce emissions by 0.02 and 0.03 MT annually on average per household (with 4- and 8-kWh energy storage systems, respectively) without significantly affecting utility costs. The analysis also showed that negative pricing events occur frequently during the daytime, particularly in the spring months. However, the maximum potential economic benefit to customers from California Independent System Operator's load shift resource product in the SDG&E Sub-Load Aggregation Point is likely insufficient ($1.87/kW per year) to incentivize residential customer participation.

Keywords: Tariff Analysis, Utility Costs, Greenhouse Gas Emissions, Curtailment, Negative Pricing, Residential Rate Structures, Load Shift Resource

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Executive Summary

Introduction

Approximately one-third of California's electric generation comes from renewable resources—a fraction that will continue to grow as the state moves toward its goal of 100% carbon-free electricity by 2045.[1,2] However, this growth is not without challenges as intermittent renewable generation does not typically correspond to periods of greatest demand, and it increasingly results in curtailment and wholesale negative pricing. Maximizing renewable energy benefits requires that customer electric loads are shifted to periods of higher renewable generation, otherwise fossil-fuel powered resources will continue to meet larger demands than necessary. Currently, renewable energy is often curtailed (reduced below capacity) during some periods of higher renewable generation due to a lack of sufficient demand. Curtailment is a growing problem as more renewable capacity is added to the state's grid, with more curtailment in the first five months of 2019 than in all of 2015 and over three times more curtailment in May 2019 than in May 2018.[3] The primary methods for inducing customers to shift demand to more optimal times of day (i.e., when renewable energy is plentiful and overall demand is not high) is through price signals.

Research Objectives

The research presented here investigates the potential of two types of price signals to encourage residential customers to shift demand to periods of high renewable generation in San Diego Gas & Electric (SDG&E) territory: retail rates and a wholesale market mechanism. In the retail rate analysis, the research team assessed the degree to which utility costs and greenhouse gas (GHG) emissions were aligned and examined opportunities to modify SDG&E's Electric Vehicle-Time-Of-Use-5 tariff (EV-TOU-5) to better align it with the goal of reducing emissions by suggesting a new rate structure. For the wholesale market mechanism analysis, negative wholesale pricing trends were evaluated and the team assessed the potential economic benefits to customers participating in the California Independent System Operator's proposed Load Shifting Resource (LSR) product, which could allow customers with behind-the-meter energy storage to receive compensation through the wholesale market for increasing load during negative pricing periods.

Results

The research showed that the existing EV-TOU-5 rate structure was generally aligned with utility costs and emissions, but relatively minor modifications to the structure, such as expanding super off-peak periods during daytime hours in the spring and winter, could incentivize customers to shift energy use to consume more renewable energy, decreasing household annual emissions by an average of 0.02 and 0.03 MT (for 4- and 8-kWh energy storage systems, respectively) without significantly affecting utility costs. Findings also indicate that the lowest utility costs, lowest emissions and highest frequency of negative pricing in the wholesale market typically occurred during daytime hours in spring months. Additionally, the maximum potential economic benefit for customers from the LSR product in the

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[1] California Energy Commission. 2019. *Total System Electric Generation.* https://ww2.energy.ca.gov/almanac/electricity_data/total_system_power.html

[2] California Legislative Information. 2018. *SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse* gases. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[3] California Independent System Operator. 2019 *Managing Oversupply*. http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

SDG&E Sub-Load Aggregation Point was $1.87/kW of load-shifting capacity per year for 2018, representing minimal financial incentive for residential customer participation.

Benefits to California

California's renewable capacity will continue to grow the next several decades to reach the state's clean energy and GHG emissions reduction goals. Identifying and implementing rates structures and other market mechanisms that incentivize customers to shift loads to periods of higher renewable generation will help support the integration of more renewable energy onto the grid and decrease reliance on fossil-fueled resources.

I. Chapter 1

Introduction

Approximately one-third of California's electric generation comes from renewable resources—a fraction that will continue to grow as the state moves toward its goal of 100% carbon-free electricity by 2045.[4,5] As the percent of renewable generation grows, the need to align demand with supply becomes more important. The intermittent nature of wind and solar (the most prevalent renewable resources) means that electric loads must be shifted to times when the wind blows and the sun shines, otherwise fossil-fuel powered resources will continue to meet large demands during periods of lower renewable generation. In the worst cases, renewable generation is curtailed, or reduced below capacity, inhibiting the state's progress toward its clean energy goals. Indeed, this is a growing problem: the first five months of 2019 saw more curtailment than all of 2015, and more than three times more curtailment occurred in May 2019 than in May 2018.[6]

The primary method of inducing customers to shift demand to more optimal times of day (i.e., when plenty of renewable electricity is available and overall demand is not already high) is through price signals. The research presented in this report examines two potential price signals for residential customers in San Diego Gas & Electric territory: retail rates and a wholesale market mechanism. In the retail rate analysis, the research team examines how strongly an existing residential time-of-use (TOU) rate structure aligns with utility costs and greenhouse gas (GHG) emissions. In addition, the researchers suggest a new, modified rate structure that better optimizes utility costs and emissions. The wholesale market mechanism examined is the California Independent System Operator's (CAISO's) proposed proxy demand resource-load shift resource (PDR-LSR) product.[7] Specifically, the researchers analyzed the LSR component of the product, which will compensate customers who employ behind-the-meter resources to bid load *increases* into the wholesale market during times of negative marginal pricing—an indicator of renewable electricity curtailment.

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[4] California Energy Commission. 2019. *Total System Electric Generation.* https://ww2.energy.ca.gov/almanac/electricity_data/total_system_power.html

[5] California Legislative Information. 2018. *SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse* gases. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[6] California Independent System Operator. 2019 *Managing Oversupply*. http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

[7] California Independent System Operator. 2018. *Energy Storage and Distributed Energy Resource Phase 3.* http://www.caiso.com/Documents/DraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf

II. Chapter 2

Methodology

The research was comprised of two parts: an analysis of retail rates and a wholesale market mechanism analysis. This chapter describes the data and methods used for each analysis.

Retail Rates

The objectives of the first analysis were to 1) assess how effectively an SDG&E retail rate aligns its price signals with utility costs and GHG emissions and 2) design a new rate structure that would induce load-shifting to better optimize these two metrics. As a first step, the researchers compared utility costs (represented by marginal avoided costs) with marginal GHG emissions.[8] Because they were not perfectly aligned, the researchers created a "combined index" incorporating both metrics, which in turn enabled a comparison of the price signals of Electric Vehicle-Time-Of-Use-5 (EV-TOU-5) with the development of a new rate structure that would align with the combined index. EV-TOU-5 was chosen for the analysis because it was identified in a previous tariff analysis of existing SDG&E rates to be the most cost-effective for use with distributed energy resources (DERs)[9] and because it has a similar structure to other SDG&E rate structures such as the Time-of-Use-Domestic Residential-1 and Electric Vehicle-Time-of-Use-2.[10]

Data

Marginal avoided costs were generated using the E3 Avoided Costs Calculator.[11] The E3 model forecasts long-term marginal avoided costs to assess the impact of reducing load at different time intervals on utility costs. The marginal avoided costs were generated using the default settings for 2018 in SDG&E territory. Only data for climate zone 7 (CZ7) was used since a majority of SDG&E revenue comes from this zone and the marginal avoided costs were similar across all zones. The marginal emissions data indicate the change in emissions for a given load increase or decrease and were generated for the CAISO electric grid region SP-15, which contains SDG&E territory, with the Automated Emissions Reduction model from WattTime. The data are hourly and provided in MT/MWh.

Methods

Daily, monthly and seasonal trends in marginal avoided costs and marginal emissions were evaluated by calculating the correlation between the hourly marginal rates by month of the year and season using Spearman's rank correlation coefficient. For consistency, the research team used the seasonal definitions as defined by a subsequent analysis (see description directly following) with winter defined as September-February, spring as March-June and summer as July-August. The marginal avoided costs and emissions were combined into a single metric or the "combined index." The combined index was defined as the mean percentile rank for each hourly value of the marginal avoided costs and the

[8] Marginal avoided costs and greenhouse gas (GHG) emissions consider the incremental costs incurred by the utility and the incremental GHG emissions increase or decrease by adding or taking away a kWh of energy at a given time. To optimize utility costs and/or reduce GHG emissions, electricity consumption should be moved to times with the lowest marginal avoided costs and lowest marginal GHG emissions.

[9] Tamerius, James, et. al. 2019. *Rate Analysis and Modeling for the Optimization of Customer and Grid Impacts with Smart Home Energy Management Technologies*.

[10] San Diego Gas & Electric. 2019. *TOU Pricing Plans*. https://www.sdge.com/regulatory-filing/2227/time-use-tou

[11] State of California. 2019. *Cost-effectiveness: Avoided Cost Calculator.* https://www.cpuc.ca.gov/General.aspx?id=5267

marginal emissions. K-means clustering was then used to identify seasonal patterns in the combined index. The attributes used for clustering were the hourly means of the combined index by month. The median combined index percentile rank was calculated for each season to generate a combined index for each season identified from the clustering analysis.

Next, the research team created a modified rate structure that balances the marginal avoided costs and emissions while retaining the level of complexity and rates of an existing TOU rate structure. The level of complexity of the existing rate structure was retained to highlight how simple changes could better align it with the marginal rates (herein, "marginal rates" refers to both marginal avoided costs and marginal emissions). To do this, the seasonal combined index values were mapped to the nearest percentile ranks of the six unique time-dependent pricing levels assessed under the EV-TOU-5 tariff.[12] Figure 1 is a schematic showing how the combined index values were mapped to different pricing levels (for simplicity the schematic only shows four pricing levels) for a day. There were six modified rates generated corresponding to each season and by day type (weekday/weekend).

Finally, the research team assessed the results of the modified rate structure to reduce both emissions and utility costs. Specifically, the researchers modeled the effects of an optimized energy storage system on utility costs and emissions using net usage data for 95 San Diego County households enrolled in a smart home study.[13] The energy storage system operational schedule was set to minimize customer costs under the EV-TOU-5 and the modified rate structure using linear programming. The optimization included time-variable prices and nonbypassable charges, however, the effects of monthly fees were not considered in the optimization process. The resulting net load profiles for each household were then multiplied by the corresponding hourly marginal rates and summed to determine the total utility costs and emissions associated with household electricity consumption for the year. Total annual emissions and utility costs were assessed for EV-TOU-5 and the modified rate structure for households with 4- and 8-kWh energy storage systems and households with no energy storage system.

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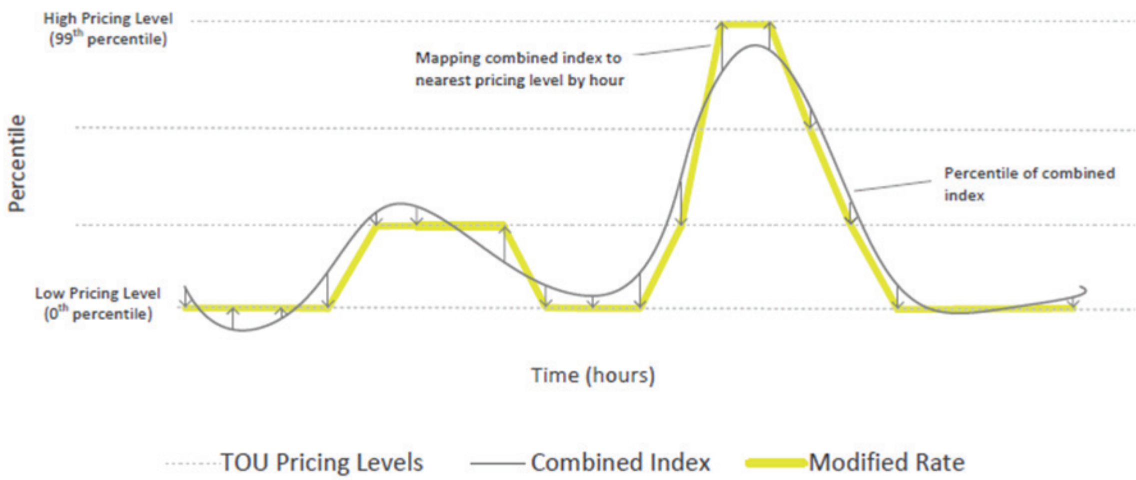
[12] San Diego Gas & Electric. 2019. *Service for Residential Customers with an Electric Vehicle.* https://www.sdge.com/sites/default/files/regulatory/6-1-19%20Schedule%20EV-TOU-5%20Total%20Rates%20Table.pdf

[13] The Smart Home Study was conducted by the Center for Sustainable Energy in partnership with Alternative Energy Systems Consulting, Inc., Itron, Oxygen Initiative and SDG&E; the study assessed the ability of Itron's Residential Distributed Energy Management System to bring benefits to customers and the grid.

Figure 1. Designing the Modified Rate Structure



Wholesale Market Mechanism

The objective of the second analysis was to assess trends in negative pricing events and evaluate the potential economic benefits of customer participation in the CAISO LSR product.

Data

The researchers used 2018 CAISO real-time market prices for the SDG&E Sub-Load Aggregation (DLAP_SDGE_APND) price node. According to the Federal Energy Regulatory Commission,[14] real-time market prices are significantly more volatile than those on the day-ahead market due to demand uncertainty, transmission- and generator-forced outages and other unforeseen events. Thus, there is an increased likelihood of supply and demand imbalances in the real-time market that can result in negative price events.

Methods

Monthly and hourly trends of negative prices in the CAISO 5-minute real-time market were evaluated by summing the total duration of 5-minute intervals with negative prices. Next, the potential economic benefits of the LSR product to residential customers were evaluated. It was assumed that customers were compensated with the negative wholesale market price for shifting flexible DER load, such as energy storage, they were able to receive compensation for shifting more of their electric load to periods of negative pricing. Accordingly, the negative prices for each 5-minute interval was converted to $/kW and summed across the year to derive the maximum potential annual compensation per kW. Since the available flexible capacity in a household would affect potential compensation, the maximum annual economic benefits to a customer were evaluated across a range of capacities.

[14] Federal Energy Regulatory Commission 2015. *Energy Primer: A Handbook of Energy Market Basics.* https://www.ferc.gov/market-oversight/guide/energy-primer.pdf

III. Chapter 3

Results

In the retail rate analysis, the research team assessed the seasonal and hourly trends for marginal avoided costs and emissions, differences between marginal rates and developed a rate structure that is consistent with the goal of reducing emissions. For the wholesale market mechanism analysis, negative wholesale pricing trends and the potential economic benefits to a residential customer participating in CAISO's LSR were evaluated.

Retail Rates

Seasonal and Hourly Trends

Figure 2 shows the distribution of the hourly marginal avoided costs and marginal emissions for 2018 by season. The y-axis units are density, which can be defined as the relative frequency of the values on the x-axis appearing in the data. The mean marginal avoided cost was $88/MWh with a vast majority of values between $25-125. Marginal avoided costs were lowest in the spring and reached maximum values in the summer. The summer was also characterized by a number of outliers (>$250) that were as large as ~$9,500/MWh. Marginal emissions ranged from 0 to 0.7 MT/MWh with an average of 0.3 MT/MWh. As with marginal avoided costs, marginal emissions were lowest in the spring.

Figure 2. Relative Histogram for Marginal Avoided Costs and Marginal Emissions

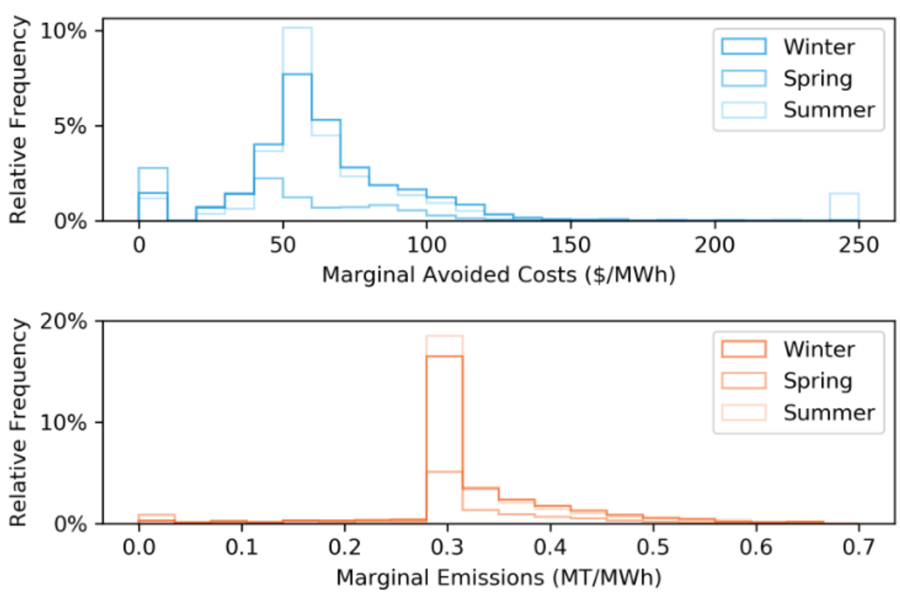


Figure 3 shows hourly marginal avoided costs and marginal emissions (light lines) with a 30-day rolling average (bold lines). The marginal avoided costs are relatively consistent across months, with the exception of a lower average observed in March-July that coincides with many periods of $0/MWh of marginal avoided costs. The upper limit of the y-axis cuts off the large outliers (>$250/MWh). The seasonal trend in marginal emissions is similar to the trend observed for marginal avoided costs, with lower marginal emissions in spring (April-June). Marginal emissions of 0 MT/MWh occur sporadically but are most frequent in spring and are rare in the summer.

Figure 3. Hourly and Seasonal Marginal Avoided Costs and Marginal Emissions

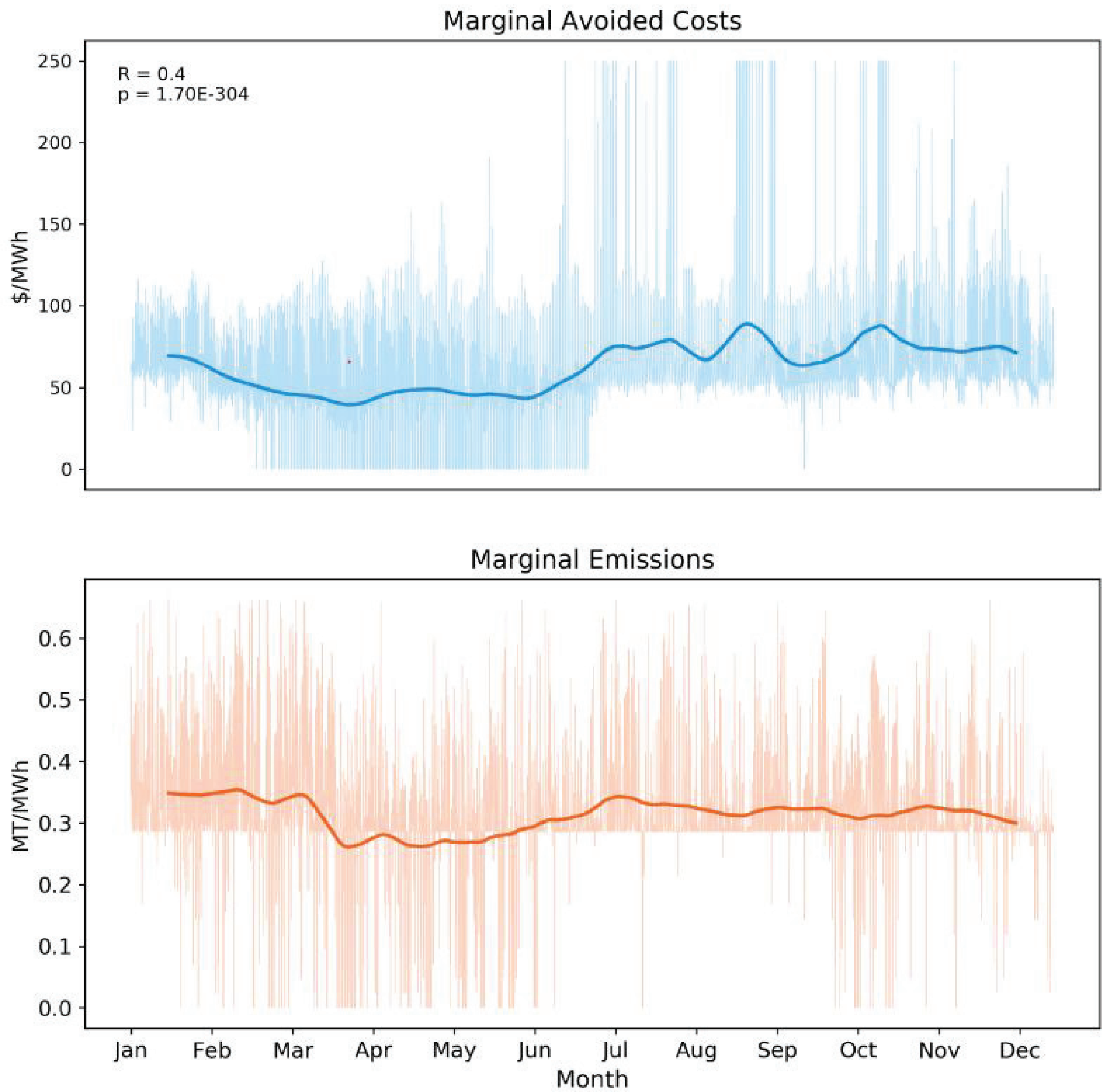
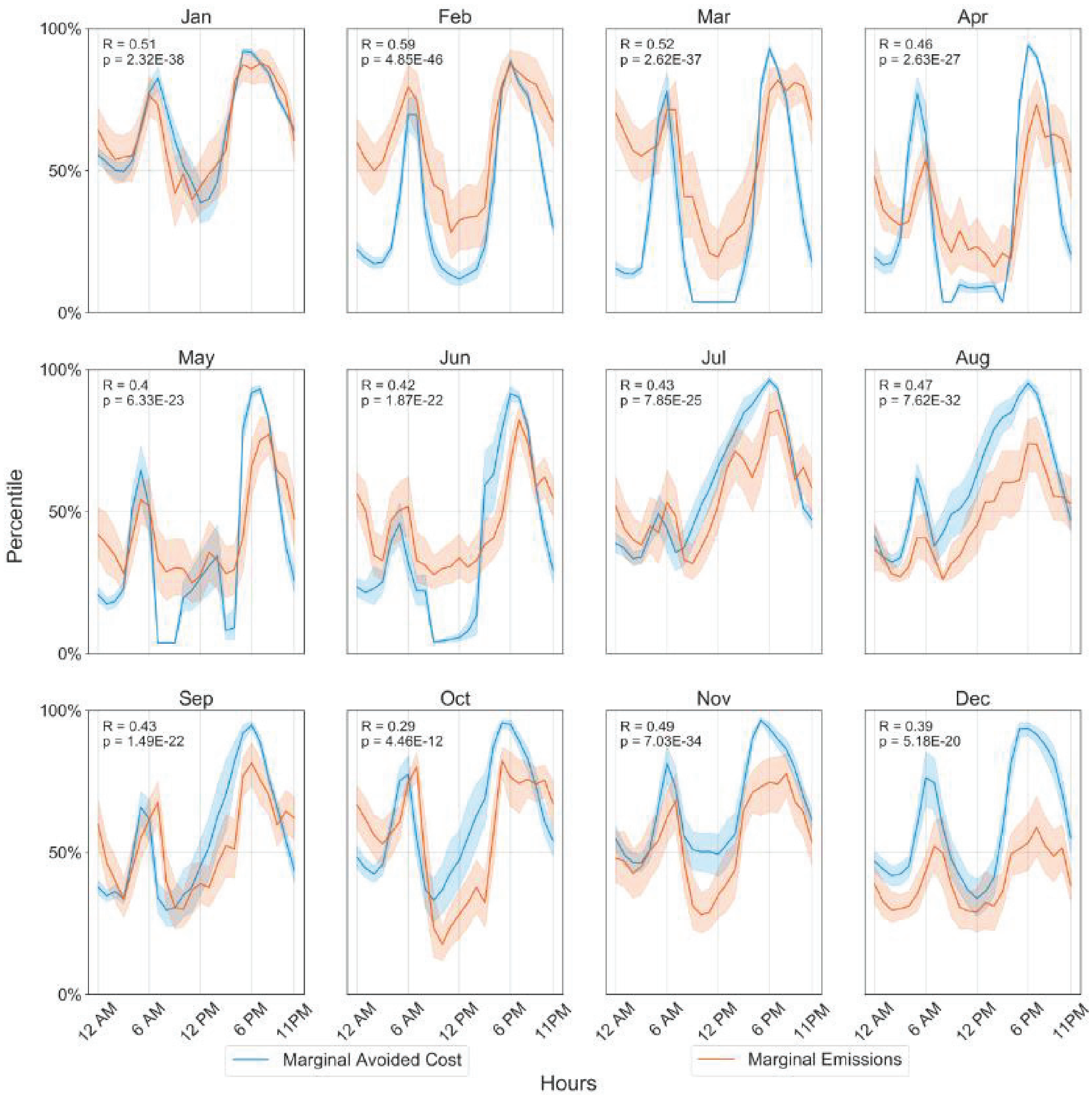


Figure 4 shows the marginal avoided costs and marginal emissions by month and hour for weekdays. The marginal rates were significantly correlated by hour across all months (see correlation coefficient and p-values in upper left corner of subplots in Figure 4). There are four main features observed in both the avoided marginal costs and marginal emissions: a morning peak (5–8 a.m.), a daytime trough (9 a.m.–3 p.m.), an evening peak (4–8 p.m.) and an overnight trough (9 p.m.–4 a.m.). In general, the lowest marginal rates occurred during the midday trough and maximum marginal rates occurred during the evening peak. Marginal rates were highly similar across weekdays and weekends, although the marginal emissions were slightly higher in the early morning hours on the weekends relative to weekdays (Appendix Figure 1).

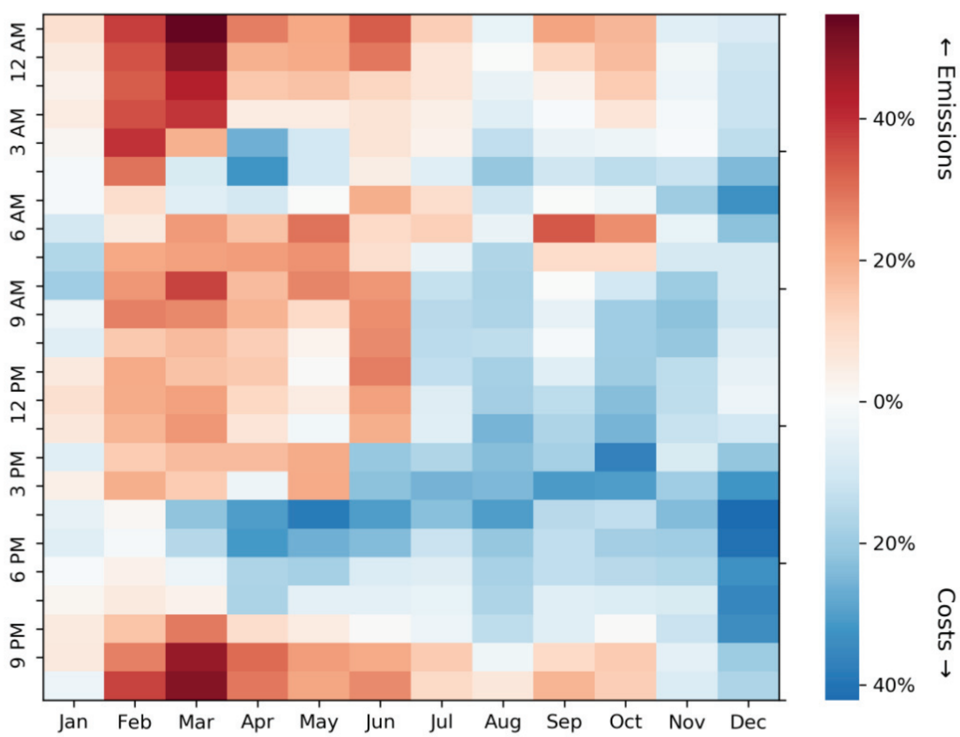
Figure 4. Weekday Marginal Avoided Costs and Marginal Emissions by Month



Differences Between Marginal Rates

Marginal avoided costs and marginal emissions are significantly correlated across all months (see top left corner of subplots in Figure 4), although there are some notable differences. These differences are highlighted in the heatmap in Figure 5 that shows the mean percentile rank difference between the marginal emissions and marginal avoided costs for weekdays. The positive values (red) indicate hours where the percentile rank of the marginal emissions are greater than the percentile rank of the marginal avoided costs; the negative values (blue) indicate hours where the percentile rank of the marginal emissions is less than the percentile rank of the marginal avoided costs. For instance, Figure 5 shows that the marginal rates are highly similar in January. In February-March the marginal emissions values tend to be larger than marginal avoided costs during the overnight trough period, particularly 9 p.m.–3 a.m. Marginal avoided costs tend to be larger during the end of the daytime trough and the first half of the evening peak, particularly in August-October. Finally, during the morning peak marginal emissions tend to be greater than marginal avoided costs in March-May. Differences between the marginal rates over the weekend are highly similar to those during weekdays (Appendix Figure 2).

Figure 5. Differences in Marginal Avoided Costs and Emissions for Weekdays

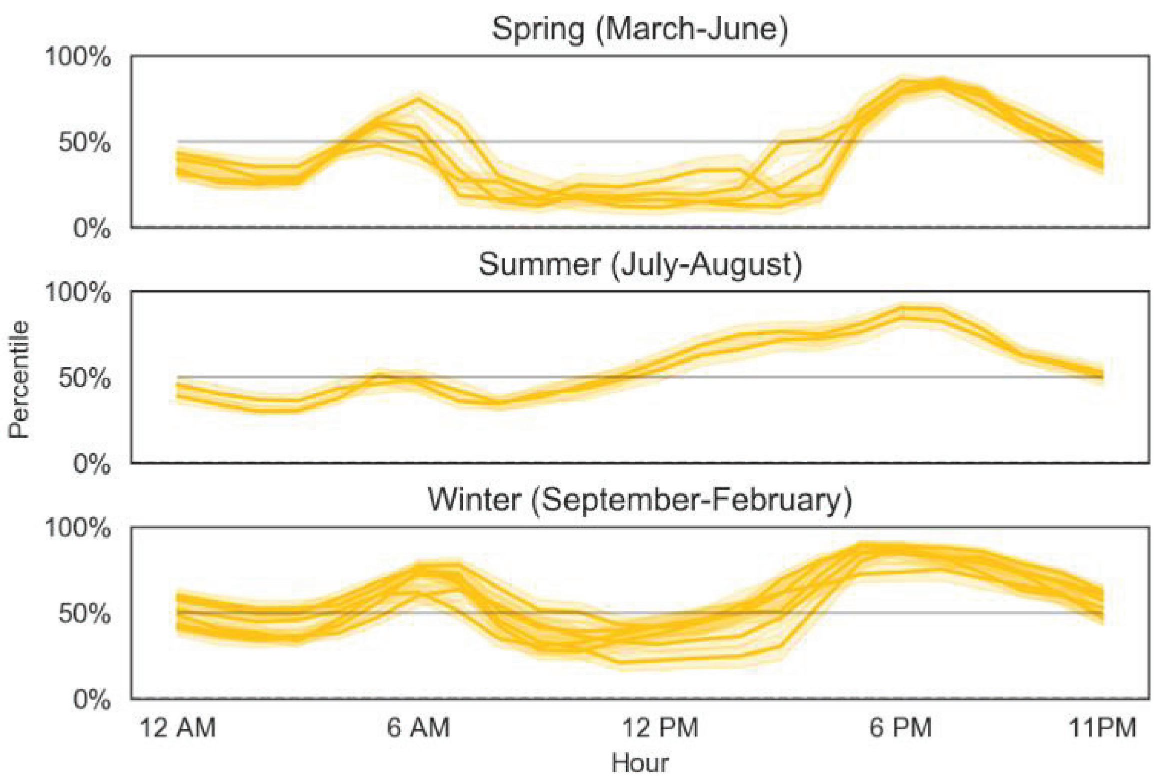


Combined Index and Seasons

The analysis showed that the year can be divided into three unique seasons based on differences in the daily cycles of the combined index across months (Figure 6). The seasons identified were spring (March-June), summer (July-August) and winter (September-February). The seasons identified in this analysis are in contrast to those in the TOU tariffs used by SDG&E that have two unique seasonal rates: winter (November-May) and summer (June-October). There are also special super off-peak rates during the winter months of March-April that coincide with daytime periods of low net demand (10 a.m.–2 p.m.).

The four primary daily features (morning peak, daytime trough, evening peak, overnight trough) are prominent in the combined index; grouping by season highlights how the presence and magnitude of these features varies by season. The spring is characterized by a minor morning peak, a large midday trough and then a moderate evening peak. In the summer the morning peak is extremely subtle, followed by a weak and short daytime trough and a large evening peak. The winter is characterized by the largest morning peak, a moderate decrease in the combined index during the daytime trough and then a moderate—but elongated—increase in the combined index during the evening peak. These patterns were nearly identical for weekends (Appendix Figure 3).

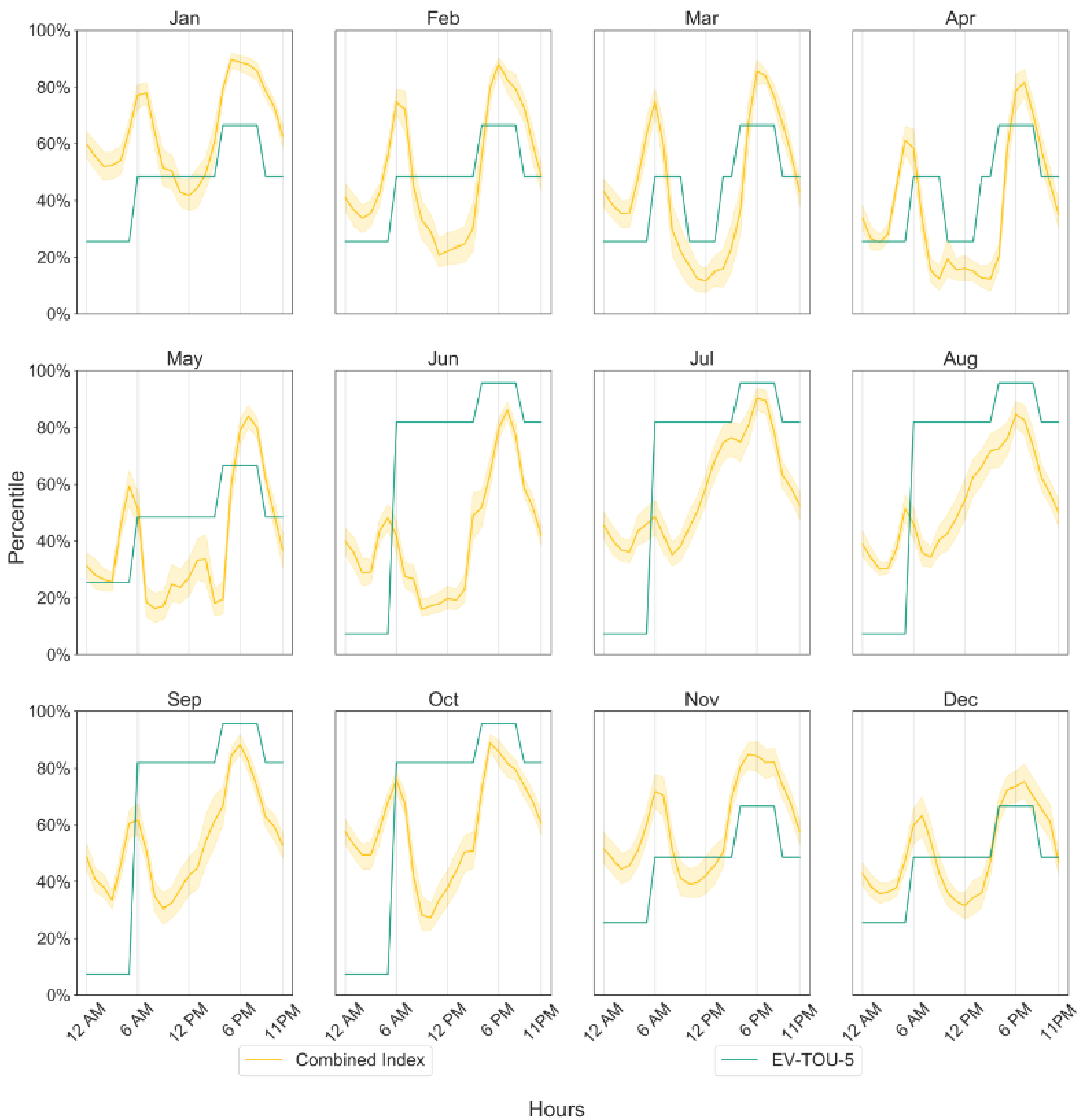
Figure 6. Combined Index by Month Grouped by Season for Weekdays



Comparing the Combined Index with an Existing Rate Structure

A comparison of the combined index to EV-TOU-5 is shown in Figure 7. The percentile ranks of the EV-TOU-5 energy charges are shown for direct comparison with the combined index. The heatmap in Figure 8 highlights the differences between the percentile ranks of the combined index and EV-TOU-5 rates with the positive (red) values indicating the hours that the EV-TOU-5 rate is greater than the combined index and the negative (blue) indicate the hours that the EV-TOU-5 percentile rank is less than the combined index. Together, these figures show that the EV-TOU-5 percentile rank are greater than the combined index throughout spring from the morning peak through the midday trough and in the summer during the evening peak. The EV-TOU-5 rate is also relatively low for the overnight trough year-round. The differences between the combined index and EV-TOU-5 are similar for the weekends (Appendix Figures 4 and 5).

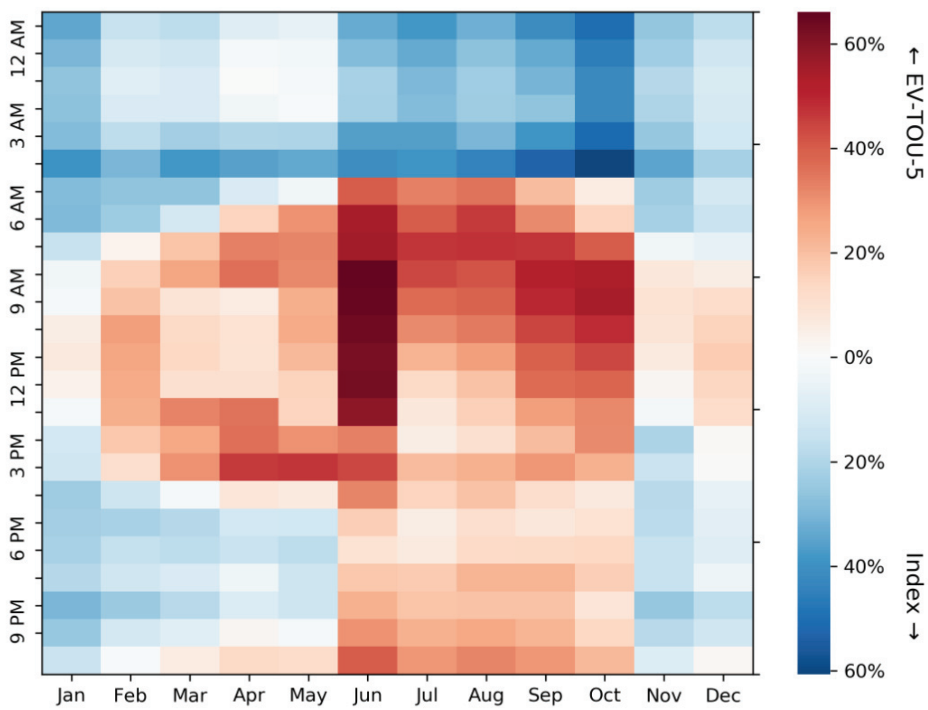
Figure 7. Combined Index vs. EV-TOU-5 by Month and Hour for Weekdays



Combined Index Rate Structure

Using the combined index and EV-TOU-5 comparison results, a modified rate structure was created that more closely aligns with the combined index by "mapping" the combined index values to EV-TOU-5 price levels (see Figure 1). Figures 9 and 10 show the combined index after being mapped to the rates in the EV-TOU-5 rate structure, or the modified rate structure (yellow), versus the EV-TOU-5 rate structure (green). Overall, the modified rate structure and EV-TOU-5 are similar although there are some notable differences. The most consistent difference is the addition of hours with super off-peak rates during the daytime trough in winter, spring and summer. Currently, EV-TOU-5 only has daytime super off-peak rates during the week from 10 a.m. to 2 p.m. in March-April. The modified rate structure also shows a contracted on-peak period during the summer with only three hours of on-peak rates relative to five on-peak rates in EV-TOU-5. The modified rates are typically lower than EV-TOU-5 rates with the exception that super off-peak rates end earlier in the morning for winter and summer. The modified rate structure for the weekend shows similar characteristics except that all seasons show super off-peak rates during the daytime trough; the summer peak rate does not increase to the highest rate (Figure 10).

Figure 8. Differences in EV-TOU-5 and Combined Index for Weekdays



Customer net usage profiles combined with energy storage with optimized schedules aimed at minimizing customer bills for EV-TOU-5 and the modified rate structure both resulted in reduced emissions and utility costs relative to scenarios with no battery storage (Figure 11). However, the emission reductions were 0.02 MT/year and 0.03 MT/year greater on average per household for 4- and 8-kWh systems, respectively, for the modified rate structure. The magnitude of the decrease in utility costs was nearly equal for both EV-TOU-5 and the modified rate structure. The increased reductions in emissions corresponding to the modified rate structure were due to an increase in daytime charging and a commensurate drop in early morning charging (Figure 12). The added super off-peak rates in the modified rate structure also resulted in decreased annual household bills that were disproportionately larger than the decrease in utility costs, which is problematic since this could prevent the utility to recover their costs; however, this could be easily reconciled by shifting or rescaling pricing levels.

Figure 9. Weekday Rate Structure Comparison Based on Combined Index and EV-TOU-5

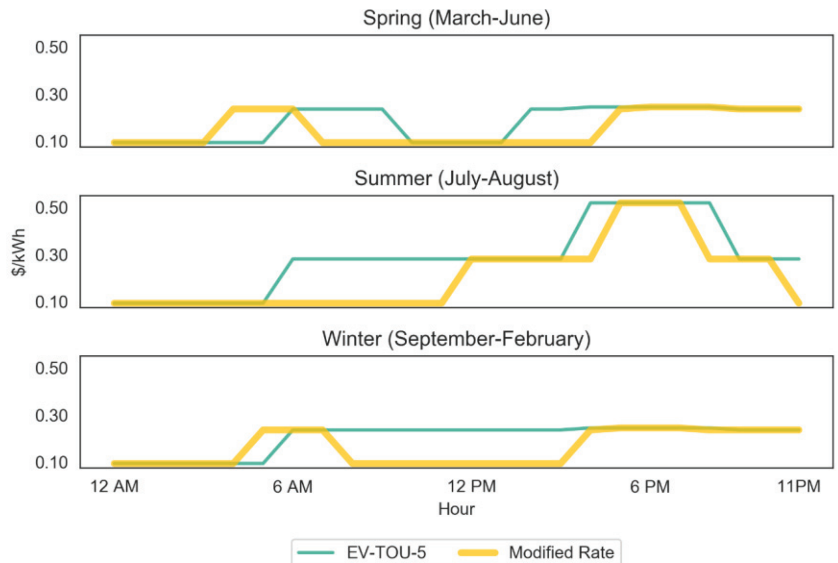


Figure 10. Weekend Rate Structure Comparison Based on Combined Index and EV-TOU-5

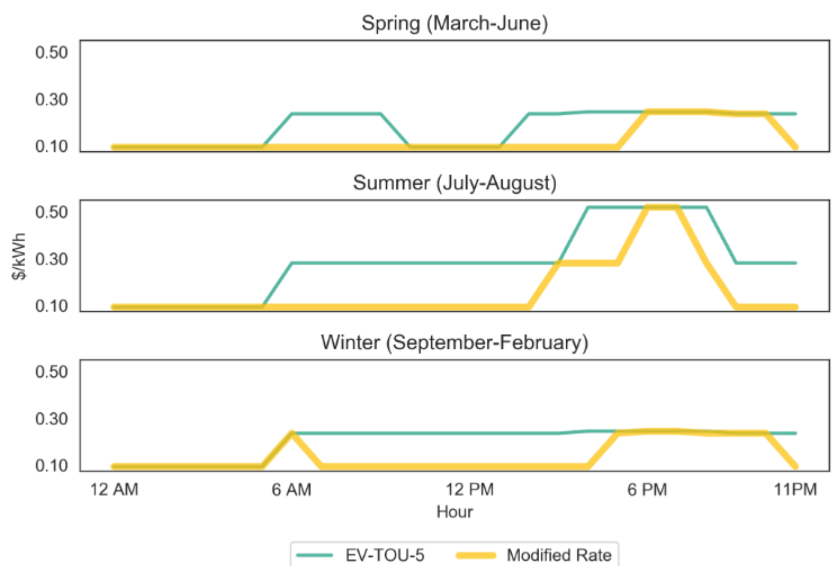


Figure 11. Change in Household Emissions and Utility Costs with Optimized Energy Storage

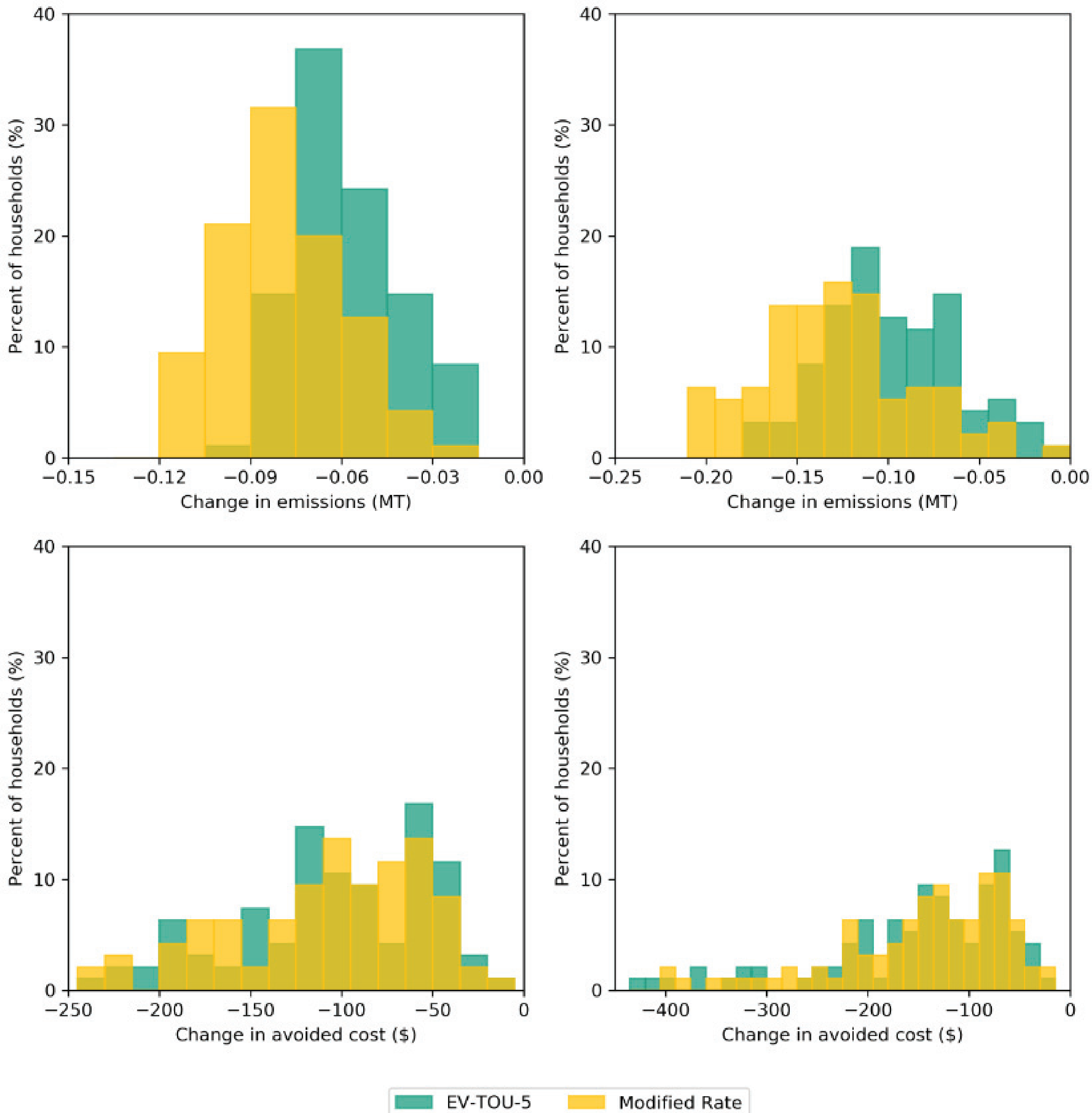
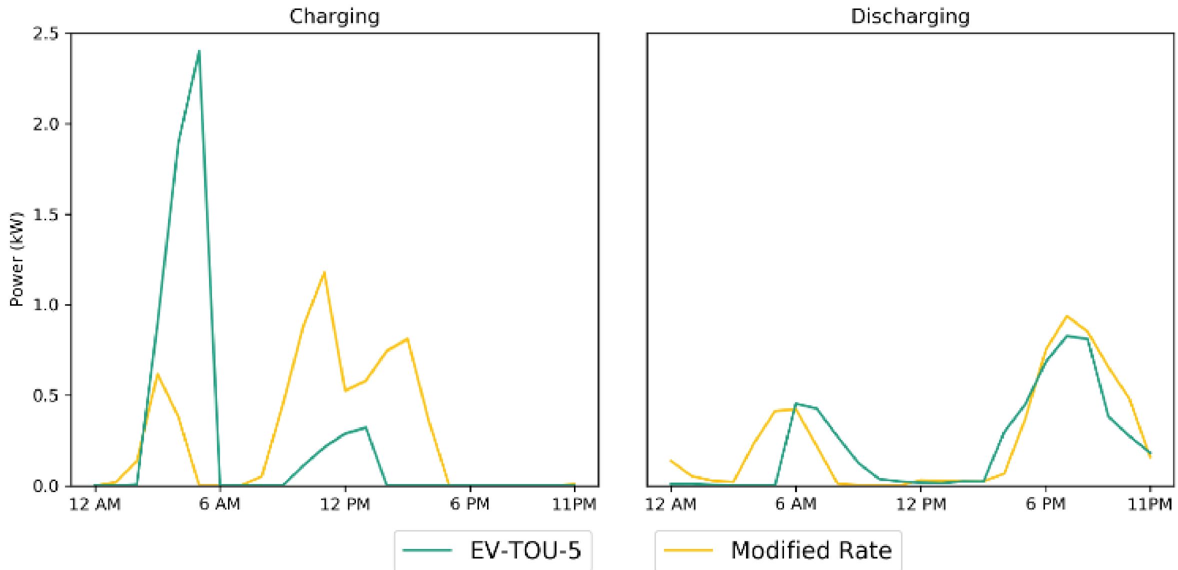


Figure 12. Average Charging and Discharging Profiles of Optimized Energy Storage

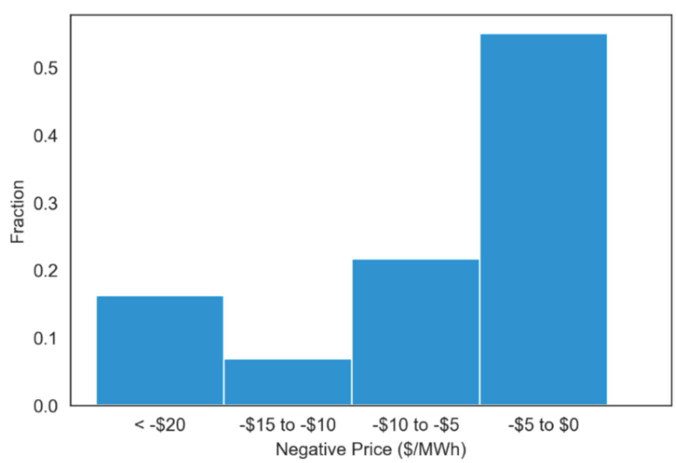


Wholesale Market Mechanism

Real-Time Market Negative Pricing Trends

Negative pricing trends provide insight into the frequency and duration of opportunities to receive compensation through the LSR product on the wholesale market. Figure 13 shows that during 2018 for the SDG&E Sub-LAP negative prices ranged from -$50 to $0/MWh, but more than 75% of the negative prices were between -$10 and $0 with an average negative price of -$6.9/MWh. The magnitude of the negative prices had a slight tendency to be greater (more negative) in March-June and between 4–6 p.m.

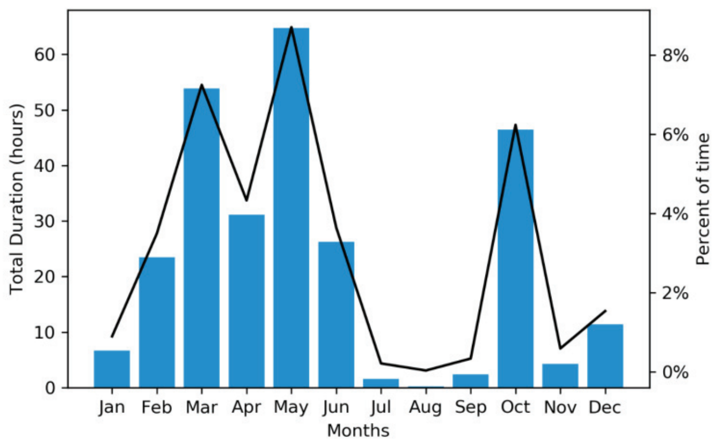
Figure 13: Negative Price Ranges



Negative prices occurred most frequently from February-June with May having the greatest total duration of negative prices, totaling 65 hours or 9% of the month. October also had a high frequency of negative prices with 46 hours of negative prices or 6% of the month. By contrast, July-August had the lowest frequency of negative prices with a total of 1.9 hours.

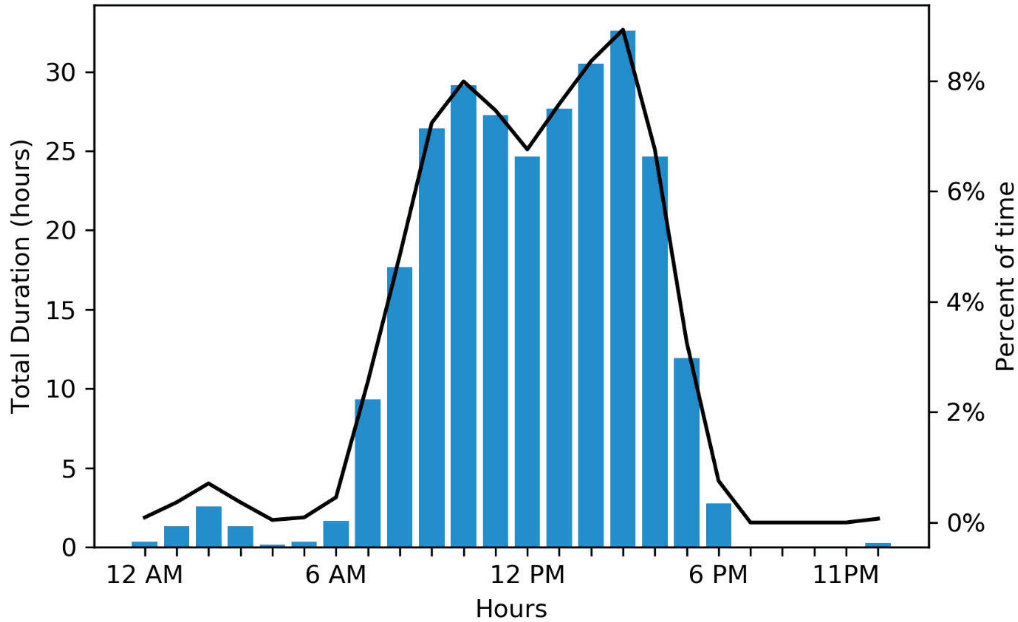
Figure 14 shows the total duration and frequency of CAISO negative prices by month in the 5-minute real-time market. In all, negative pricing occurred for 273 hours (equivalent to more than 11 days) of the year. The longest continuous periods occurred in March-May and September-November. For example, the longest negative price event occurred on March 25 for eight hours from 10:25 a.m. to 6:35 p.m., and the second longest events were 6 hours during the months of May and October.

Figure 14: Total Duration of Negative Price Events by Month



In addition to monthly and seasonal trends, there was significant diurnal variability. Figure 15 shows the total duration of negative prices by hour of the day for 2018. A majority of the negative price events were during daylight hours with negative prices present more than 5% of the time from 8 a.m. to 5 p.m. Negative pricing events peaked near 2 p.m. and represented 8% of all intervals during this period. By contrast, the frequency of negative pricing events during the evening was low with few negative prices observed from 7 to 9 p.m. The strong diurnal cycle of negative pricing events was, in general, consistent across months, although there was an increase in the number of hours that experienced negative prices in the March-June period.

Figure 15: Total Duration of Negative Price Events by Hour



Potential Economic Benefits

Table 1 shows the potential maximum annual economic benefits for the LSR product by load-shifting capacity. The results indicate that the frequency and magnitude of the negative price events limit the economic benefits to residential customers with approximately $1.87 per kW of load-shifting capacity annually.

Table 1: Maximum Annual Economic Benefit from LSR Product

Load-Shifting Capacity (kW)	Maximum Annual Economic Benefit ($)
1	1.87
5	9.35
10	18.70

IV. Chapter 4

Discussion

This chapter provides a result discussion with final conclusions for the retail rate and wholesale market mechanism analyses. The retail rate analysis assessed the degree to which utility costs and GHG emissions were aligned and examined opportunities to modify SDG&E's EV-TOU-5 to better align it with the goal of reducing emissions. The wholesale market mechanism analysis evaluated pricing trends along with the potential economic benefits to customers participating in CAISO's proposed LSR product. Findings indicate opportunities to optimize retail rates to reduce emissions and utility costs as well as to leverage a wholesale market mechanism during negative pricing periods.

Optimizing Retail Rates to Reduce Emissions and Utility Costs

The comparison of the combined index to EV-TOU-5 showed that they are strongly aligned but important differences exist. In particular, the analysis showed that SDG&E's weekday super off-peak period does not coincide with the periods of lowest emissions and utility costs. Instead, the periods of lowest utility costs and emissions typically occur during periods of high solar generation (approximately 9 a.m. to 4 p.m. depending on the season) whereas the weekday super off-peak time period for SDG&E TOU rates is from midnight to 6 a.m. year-round, with daytime super off-peak periods only established for two spring months (March and April) lasting from 10 a.m. to 2 p.m. Thus, modifying existing TOU rate structures to incentivize customers to shift demand to daytime hours with super off-peak rates for additional periods of the year, particularly winter and late spring (May-June), could reduce utility costs and emissions. In addition, extending the daytime hours with super off-peak rates during the spring months from 10 a.m.–2 p.m. to 8 a.m.–4 p.m. would align rates more closely with utility costs and emissions.

Conversely, the nighttime super off-peak periods for SDG&E's existing TOU rates including EV-TOU-5 do not correspond to the periods of lowest utility costs and emissions. However, these nighttime super off-peak rates are reasonable since this rate structure was designed to incentivize electric vehicle (EV) owners to shift load to the overnight hours (12–6 a.m.), which is the best available charging time for many EV owners during the week because they are generally at work during the optimal times (9 a.m.–4 p.m.). This highlights the importance of workplace charging to decrease utility costs and emissions. But non-EV customers or EV customers that have other flexible DERs, such as energy storage, could provide greater emission and utility cost reductions by shifting available load to the daytime. To appropriately incentivize customers to shift loads to the daytime period, rates would need to be as low (if not lower) than the nighttime super off-peak rates.

The research team developed a modified version of EV-TOU-5 that aligns more strongly to utility costs and emissions, with lower rates during the daytime hours, especially in spring and winter (Figures 9 and 10). Further, relative to SDG&E's TOU rates, the modified rate structure decreases the number of months with summer rates to only July and August, and expands the spring season to include March and

June. It was shown that energy storage systems optimized to the modified rate can reduce emissions compared to the EV-TOU-5 rate structure without significantly affecting utility costs.

Leveraging a Wholesale Market Mechanism during Negative Pricing Periods

The seasonal variation in negative price frequencies is due to energy generation and demand patterns. Electricity demand is highest in the summer due to cooling loads, which reduces the likelihood of oversupply and increases electricity costs. However, months that have both moderate temperatures and sunny skies have relatively low demand (limited cooling loads) and high solar generation that results in more frequent oversupply and negative pricing. During seasons with relatively high solar generation and low demand, negative pricing is most likely to occur between 8 a.m.–4 p.m., but the likelihood of negative pricing decreases rapidly in the evening as solar generation declines and demand increases.

Economic Benefit of LSR Product

The results of the LSR product analysis showed that the economic benefit of increasing load during negative pricing intervals is relatively negligible. The maximum potential economic benefit for customers was $1.87/kW of load shifting capacity per year. Thus, the forthcoming LSR product offered by the CAISO will likely be insufficient to encourage residential customers to shift their load to times of negative pricing. Additionally, behind-the-meter resources would be required for customers to participate in the wholesale market and the added cost of such resources resulting from contracting scheduling coordinators[15] and demand response providers would likely surpass the compensation of participating in the market. However, this analysis does not include the other potential economic benefits of the LSR product that includes providing load reduction during periods of grid stress into the wholesale market. Nonetheless, it would be difficult for the combined compensation of increasing load during negative pricing and decreasing load during high pricing to completely cover the administrative costs of participating in the market for residential customers —let alone the cost of acquiring a battery or other resource with load-shifting capacity.

Additionally, times of negative pricing may not coincide with customers' lowest retail rate. As discussed with SDG&E's EV-TOU-5 rate, some tariffs have the lowest cost rates during overnight hours, which do not correlate with frequent times of negative pricing at the wholesale market. Similarly, with aligning grid costs and marginal emissions rates, TOU rates could be revised so that the lowest cost hours are during solar generation hours, which see the highest occurrence of negative pricing and the lowest marginal emissions and avoided costs.

Impact on Load Factor

Load factor is the ratio of the average load of an electric customer (or aggregation of customers) divided by the peak load over a given time period. A higher load factor indicates a larger difference between the peak and average load. Historically, achieving a load factor of 1 (a "flat" load) has been the goal of

[15] The research team was unable to find publicly available data on scheduling coordinators costs.

utilities and regulatory agencies. However, with the increase of negative pricing and renewable curtailment, there are seasons and times of day during which increased load benefits the electric grid and facilitates renewable energy integration. This changes how grid managers view customer load profiles and led the CAISO to create the LSR product in which resources are paid the negative price of energy for increasing load during times of negative prices. As California continues to install solar and wind and experiences greater amounts of curtailment, customer loads that can respond to time-varying price signals will prove essential in mitigating curtailment and achieving the state's renewable energy goals. Thus, load factor is becoming a less important concept as flexible DERs shape consumer profiles to meet changes in supply.

Conclusions

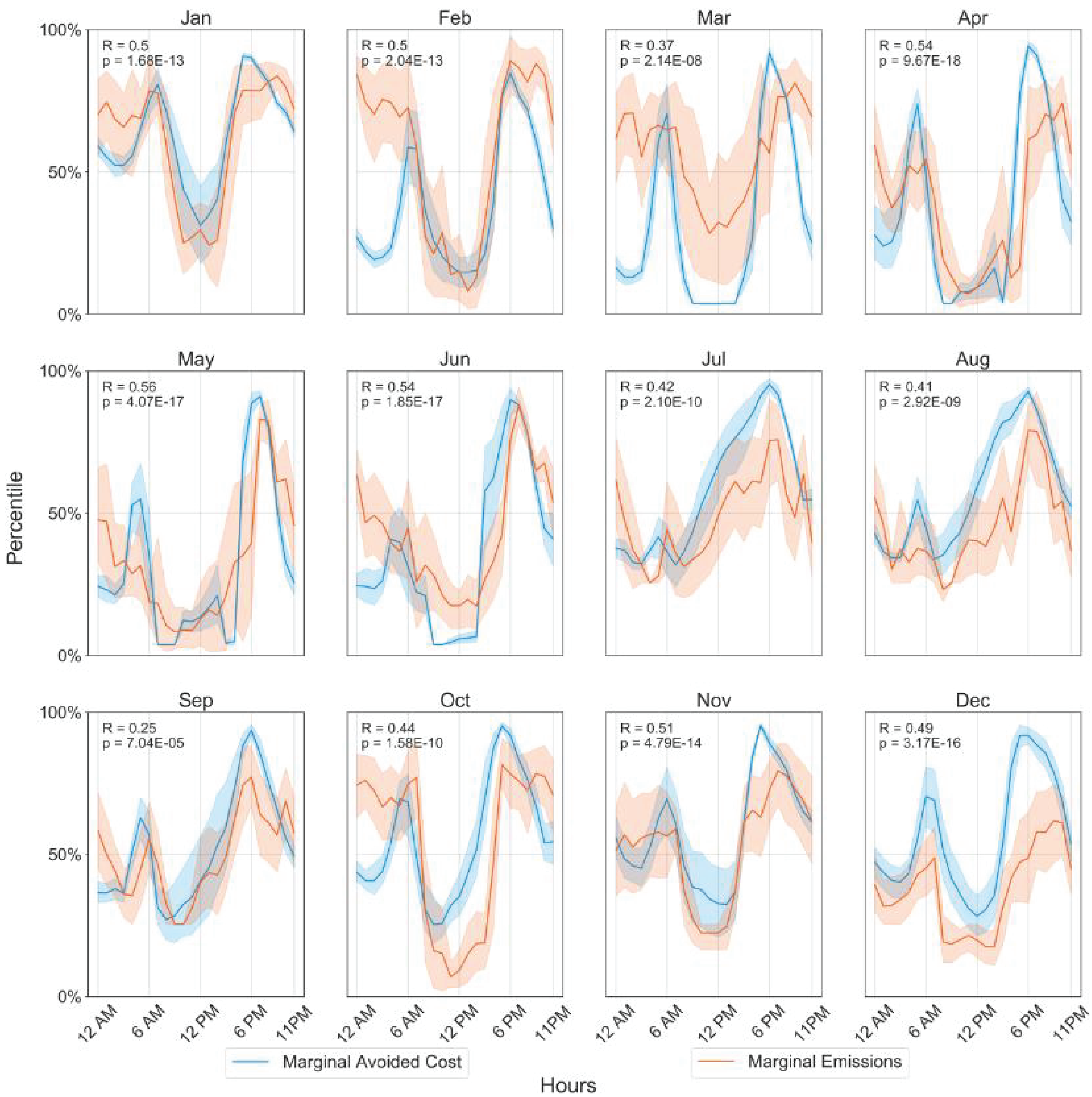
This research investigated the potential of two types of price signals to encourage residential customers to shift demand to periods of high renewable generation in SDG&E territory: retail rates and a wholesale market mechanism. Incentivizing customers to shift loads to these periods through price signals could increase the consumption of renewable energy and lower utility costs. Although this research showed that compensation from negative prices in the wholesale market by themselves do not offer a strong economic signal for behind-the-meter customers to participate in the CAISO's proposed LSR product, relatively minor adjustments to existing TOU rates in the SDG&E territory could build load during these hours and reduce emissions.

Glossary

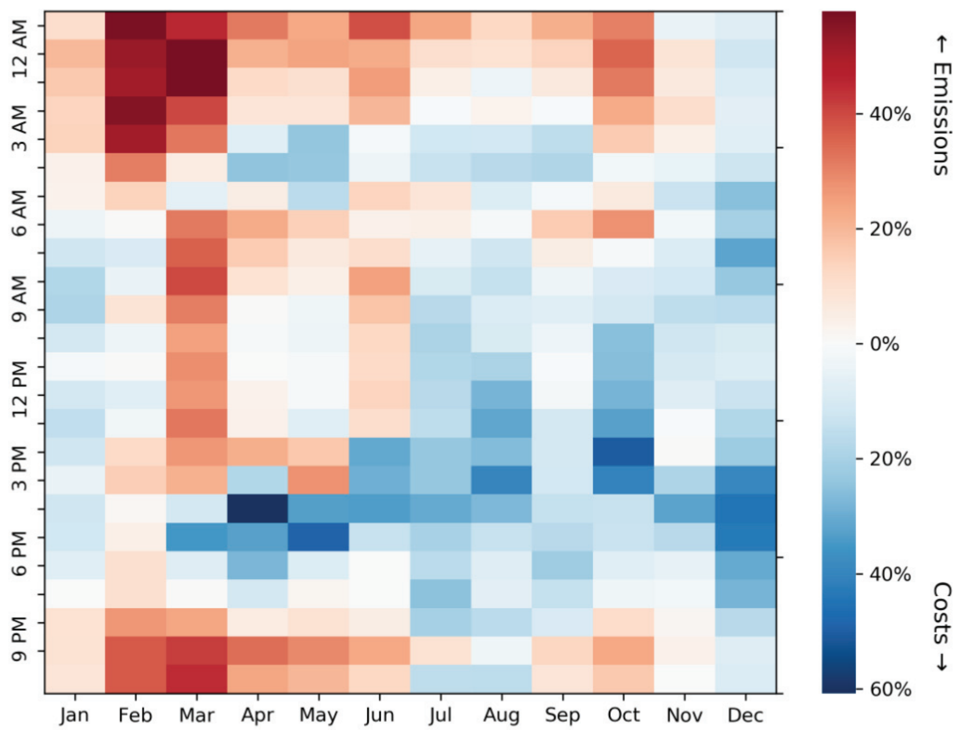
Term	Definition
Marginal Avoided Cost	The reduction in costs incurred by the utility for a unit decrease in electricity.
CAISO	California Independent System Operator. A nonprofit benefit corporation that oversees the operation of most of California's wholesale power grid.
Combined Index	A metric that combines both marginal avoided costs and marginal emissions.
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
GHG	Greenhouse Gas. Any gas that absorbs infrared radiation such as carbon dioxide and methane.
LSR	Load Shift Resource. One component of CAISO's proposed proxy demand resource-load shift resource product that will allow behind-the-meter resources to bid into the wholesale market and customers to be paid the negative marginal price for load increase. http://www.caiso.com/Documents/DraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf
Marginal Emissions	The change in greenhouse emissions due to a change in the electricity consumed.
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

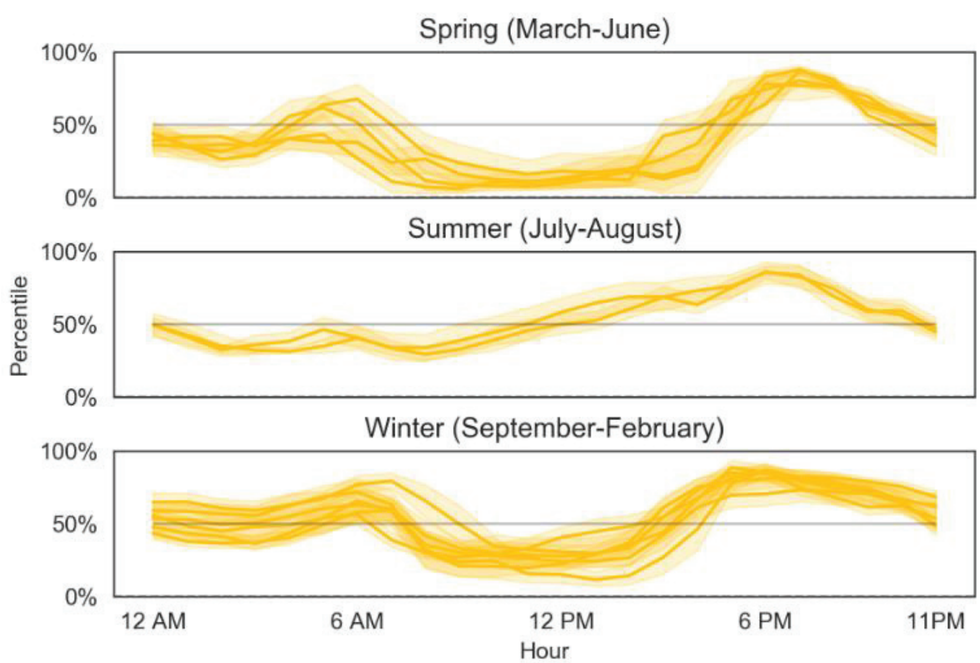
Appendix Figure 1. Marginal Emissions and Marginal Avoided Costs by Month for Weekends



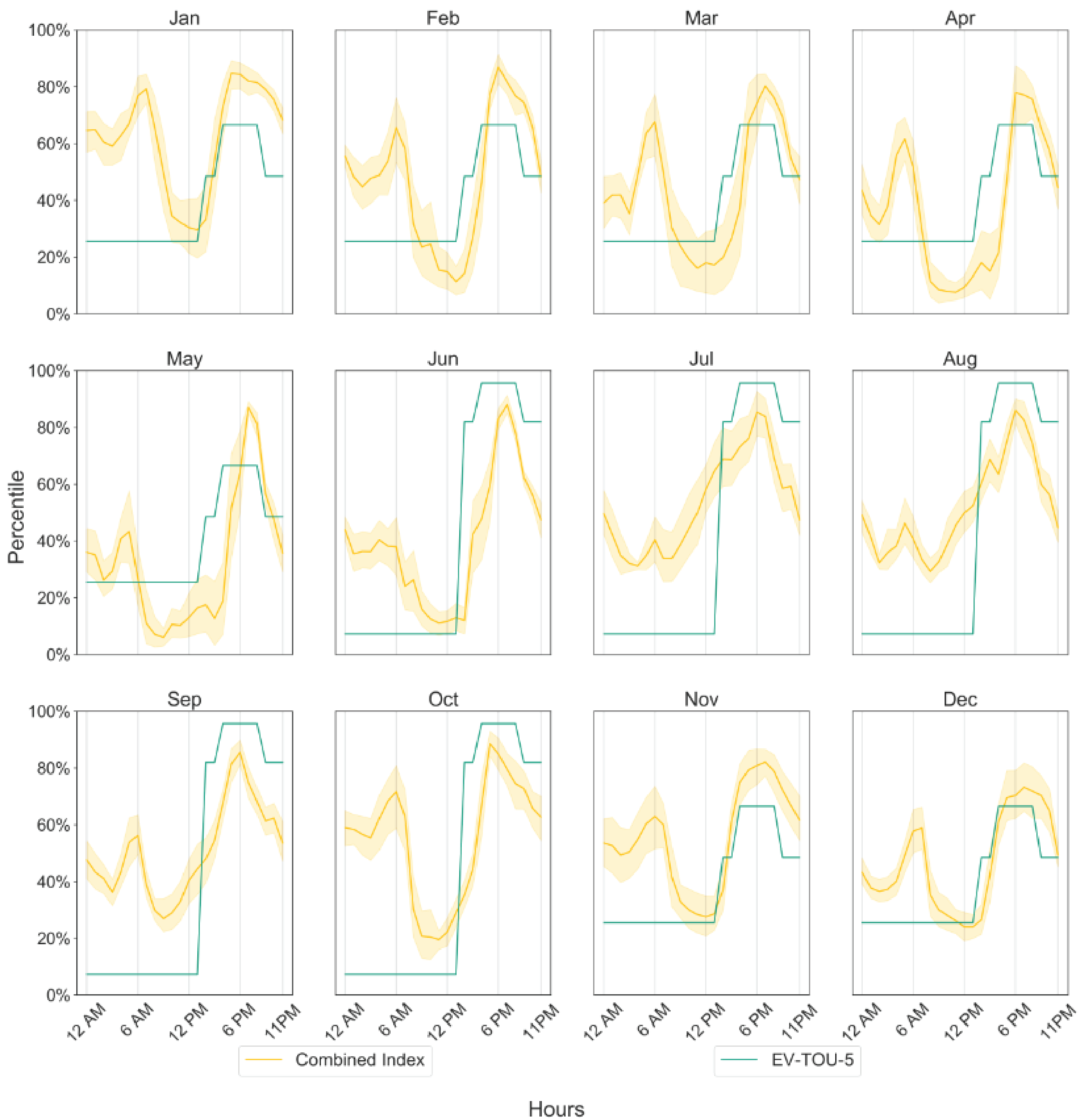
Appendix Figure 2. Differences in Marginal Avoided Costs and Marginal Emissions for Weekends



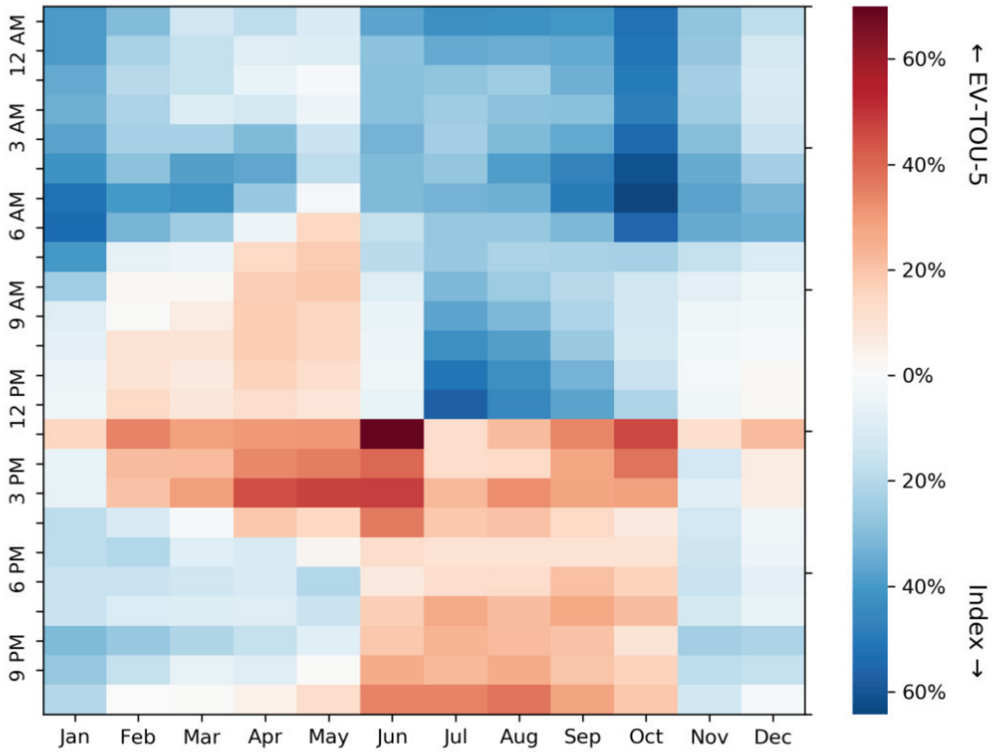
Appendix Figure 3. Combined Index by Month Grouped by Season for Weekends



Appendix Figure 4. Combined Index vs. EV-TOU-5 by Month and Hour for Weekends



Appendix Figure 5. Differences in EV-TOU-5 and Combined Index for Weekends



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