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Contents

Executive Summary

The rapid growth of renewable generation is creating challenges for the California grid in the form of the duck curve, with increasingly steep generation ramping requirements and growing curtailment of renewable resources. In response, there has been increased discussion of promoting dynamic electricity tariffs that vary with conditions on the grid in near-real time, which could incentivize customers to shift consumption and help flatten the duck curve. Dynamic tariffs may raise concerns about financial impacts on utility customers, bill volatility, and equity issues arising from potential cost shifting among customer groups. In this report, we leverage smart meter data for more than 400,000 California utility customers to assess potential customer bill impacts arising from a multi-component dynamic tariff that is conceptually informed by the "California Flexible Unified Signal for Energy" (CalFUSE[1]) tariff structure that has recently been proposed by staff at the California Public Utilities Commission (CPUC). Specifically, we compute impacts on customer bills and bill volatility under the assumption of fully inelastic demand, i.e., where customers do not change their consumption patterns in response to the tariff. Implicit in this assumption is that even flexible loads, such as storage and EV charging, do not respond to the dynamic tariff. In practice, customers would have the opportunity to reduce their bills by modifying their consumption patterns and operational profiles of flexible devices under a dynamic tariff; thus, the results of this study represent a worst-case set of bill impacts, which could provide a useful benchmark for future studies of customer response to dynamic tariffs.

We develop a single hypothetical dynamic tariff for each IOU, which applies to all of that IOU's customers regardless of sector or customer class. The tariff is constructed to be revenue-neutral for the utility, relative to presently active IOU tariffs, so that any increase or decrease in one customer's bill will be offset by changes in other customers' bills, allowing us to assess any changes in cost allocation among customer classes (i.e., "cost-shifts") that would accompany a universal dynamic tariff. The hypothetical dynamic tariff recovers all required utility revenue through a purely volumetric energy charge (i.e., with no demand charges or fixed charges) whose rate varies hourly based on expected conditions on the grid, as reflected in the CAISO day-ahead market. The following categories of utility cost are allocated across the hours of the year to construct the hourly dynamic rate:

- **Wholesale electricity prices**, both for energy delivered to the consumer and line losses occurring in the delivery system,
- **Generation capacity costs**, including both traditional capacity and flexible capacity resources,
- **Distribution system capacity costs**, for energy delivery infrastructure, and
- **Other costs**, including costs for transmission system infrastructure, account administration, public-purpose programs, wildfire mitigation, and other areas.

Figure ES-1 presents an example dynamic rate over a ten-day period in the spring, showing the breakdown across each of the cost components in each hour.

[1] Formerly referred to as UNIDE in some CPUC workshops and presentations.

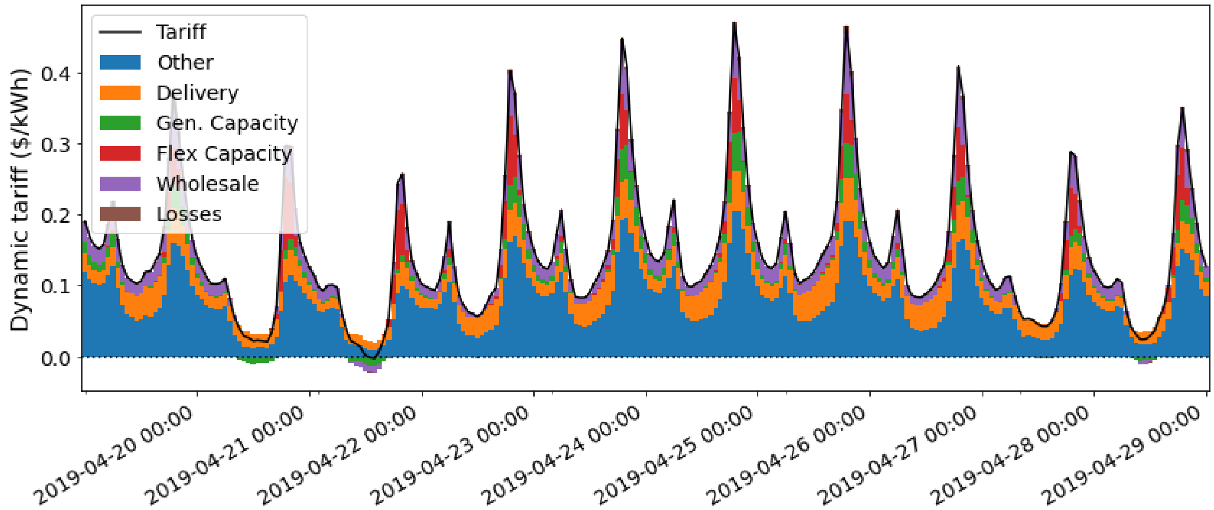

Figure ES-1. Example hourly rates for the dynamic tariff structure considered in this study, disaggregated into the different cost components included in the tariff.

To compute customer bill impacts, we first compute bills under a set of business-as-usual (BAU) tariffs that reflect present-day default rates for a set of broad customer classes, including residential customers; small, medium, and large commercial and industrial (C&I) customers; and small, medium, and large agricultural customers. We then compute dynamic-tariff bills under the assumption of a one-part tariff structure—in which all customer load is billed at the hourly dynamic rate—and also a two-part, subscription-based tariff structure—in which customers pre-purchase a subscription load shape that is billed under their BAU tariff (including demand charges, if any, based on the subscribed load shape), and with any difference between the subscription and actual consumption levels billed or credited at the dynamic hourly rate. The two-part tariff structure is intended to provide customers with a hedging instrument to reduce bill volatility risk, and we consider three different subscription load shapes to investigate the importance of load-shape accuracy to the effectiveness of the hedge. Thus, we calculate bill impacts for four different tariff scenarios:

- A **dynamic-only** scenario, in which all of the customer's load is billed at the dynamic rate (i.e., with no load-shape subscription);
- A **flat-load-shape** subscription scenario, in which the customer subscribes to a completely flat load shape, scaled to their total energy consumption from a different year, representing a low-accuracy subscription;
- A **cluster-load-shape** subscription, in which the customer subscribes to a representative load shape defined by a set of customer clusters originally developed for Phase 4 of the CPUC Demand Response Potential Study and scaled to a different year's energy consumption, representing a moderate-accuracy subscription; and
- A **self-load-shape** subscription, in which the customer simply subscribes to their own load shape from a different year, representing a high-accuracy subscription.

For each customer, we compute the annual electricity bill that occurs under the customer's BAU tariff and for each of the four dynamic tariff scenarios. Figure ES-2 shows the distributions of customer bills (characterized as box-and-whisker plots[2]), under each of the tariff scenarios, for residential customers subdivided according to their BAU tariffs into those on default tariffs, those on electric-vehicle (EV) tariffs, and those with rooftop PV who are on net-energy-metering (NEM) tariffs. Figure ES-3 shows the distributions of customer bills for small, medium, and large C&I customers with and without rooftop PV.

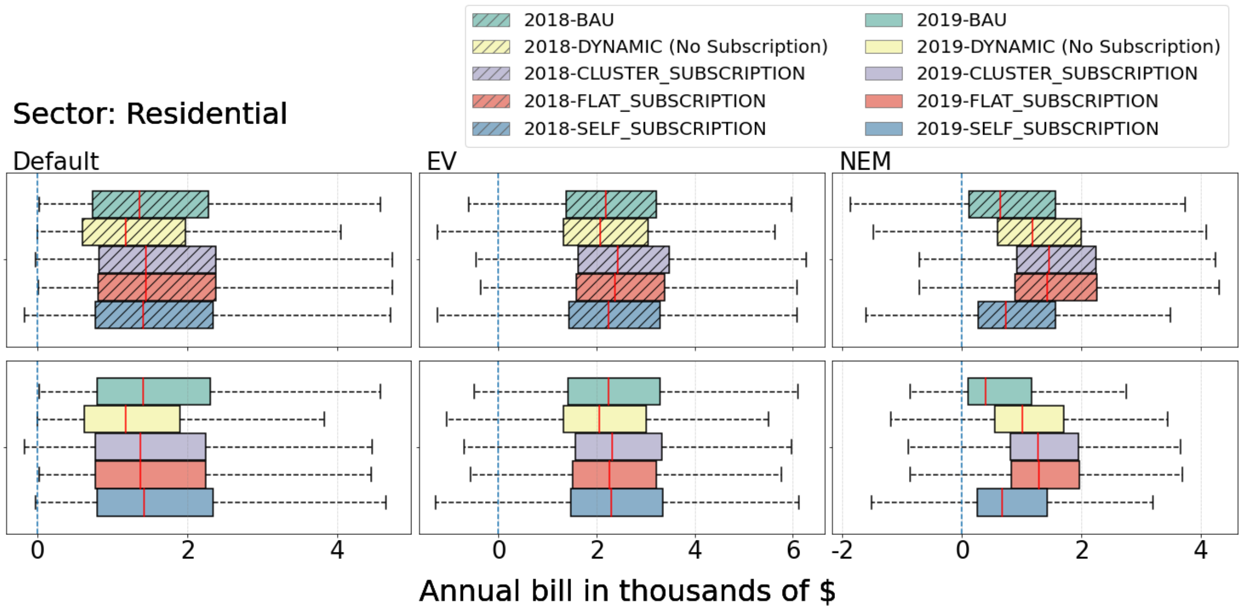

Figure ES-2. Distributions of residential customer bills, under BAU tariffs, the dynamic-only tariff, and the three subscription-based dynamic tariffs. Bill distributions are shown for 2018 (top) and 2019 (bottom), for customers without EVs or rooftop PV ("Default"), for customers with EVs (who may or may not have rooftop PV), and for customers with rooftop PV without EVs ("NEM"). For each analyzed case, the distribution of customer bills is represented as a box-and-whisker plot, with the median bill shown as a red line, a box indicating the interquartile range (IQR, the 25th to 75th percentile), and whiskers indicating the range of the data excluding extreme outliers. Bill distributions are shown for 2018 and 2019.

As shown in these figures, there is considerable variation in the observed bill impacts, by customer type and subscription load shape. Under the dynamic-only tariff (i.e., with no load-shape subscription), a large majority of residential and small C&I customers see bill decreases relative to the BAU tariff, while most of their counterparts with PV see increases. Large C&I customers also largely see bill increases relative to BAU, with medium C&I customers experiencing near-neutral impacts. The load-shape subscriptions generally temper, and in some cases reverse, the bill impacts experienced by non-PV customers,[3] while they can exacerbate the bill increases experienced by customers with PV. In addition to these analyses of residential and C&I customer bill impacts, we also consider in the main report the bill impacts on agricultural customers of different sizes, customers in different climate regions, low-

[2] Box-and-whisker plots present a summary of the distribution of a variable, with the red line indicating the median value, the box indicating the interquartile range (IQR), i.e., the range from the 25th to the 75th, and the whiskers showing the minimum and maximum outlier-rejected data values, where outliers more than 1.5 times the IQR above or below the box edges are excluded.

[3] It is also noteworthy that a small fraction of customers without PV receive negative bills under the subscription tariffs. This effect occurs because, in rare cases, the discrepancy between a customer's subscription and actual load shape can cause them to be reimbursed in a way that yields a net profit. This effect has implications for the design of subscription load shapes, which we discuss in the main text of the report.

income customers, and customers in disadvantaged communities (DACs). We also examine the bill impacts for customers in different load shapes and building type categories in the main report.

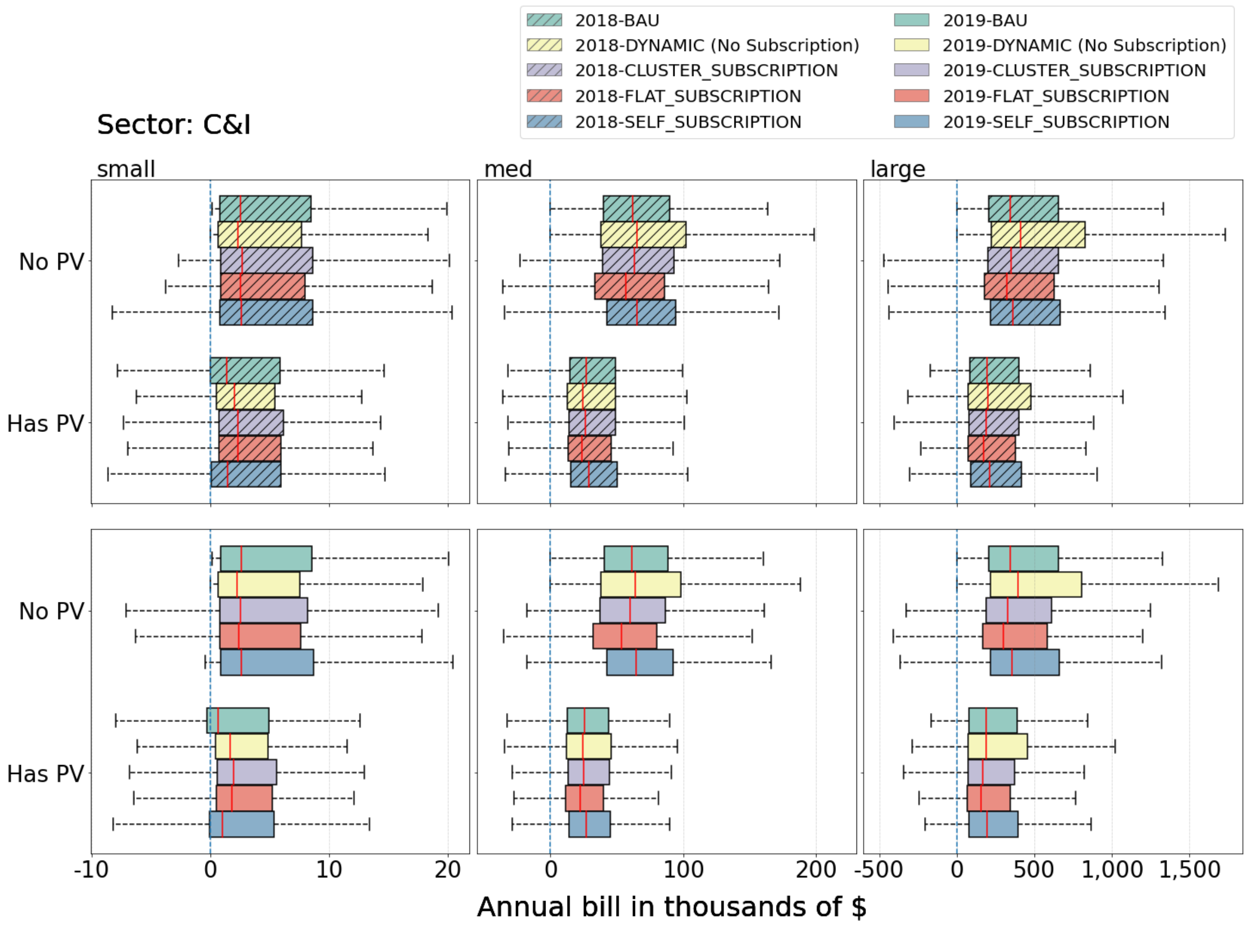

Figure ES-3. Distributions of annual customer bills for commercial and industrial customers with and without rooftop PV under each of the dynamic tariff scenarios. Bill distributions are shown for 2018 and 2019 by customer size.

We also consider the impacts of our dynamic tariff options on customers' month-to-month bill volatility. We define a volatility metric as the absolute minimum-to-maximum range of each customer's monthly bills in 2018-2019, divided by their average bill. Thus, a customer with an average bill of \$100, a maximum of \$150, and a minimum of \$50 would have a volatility of (150-50)/100 = 100%. Figure ES- 4 shows the distributions of customer bill volatility under each of the analyzed tariff options in the same customer categories considered above, and Figure ES- 5 shows the same for C&I customers. For all customers without PV, the dynamic-only tariff significantly increases bill volatility, owing to the increased variability in electricity rates, whereas each of the subscription options is able to mitigate this effect to some degree and provide some bill stability. In particular, for residential and small C&I customers, the subscriptions return bill volatility back to near the levels experienced in the BAU case. For customers with PV, by contrast, the dynamic-only tariff and some of the subscription options reduce bill volatility (largely by reducing the rates at which energy exports are compensated, thereby increasing these customers' lowest bills and narrowing the overall range of monthly bills they experience).

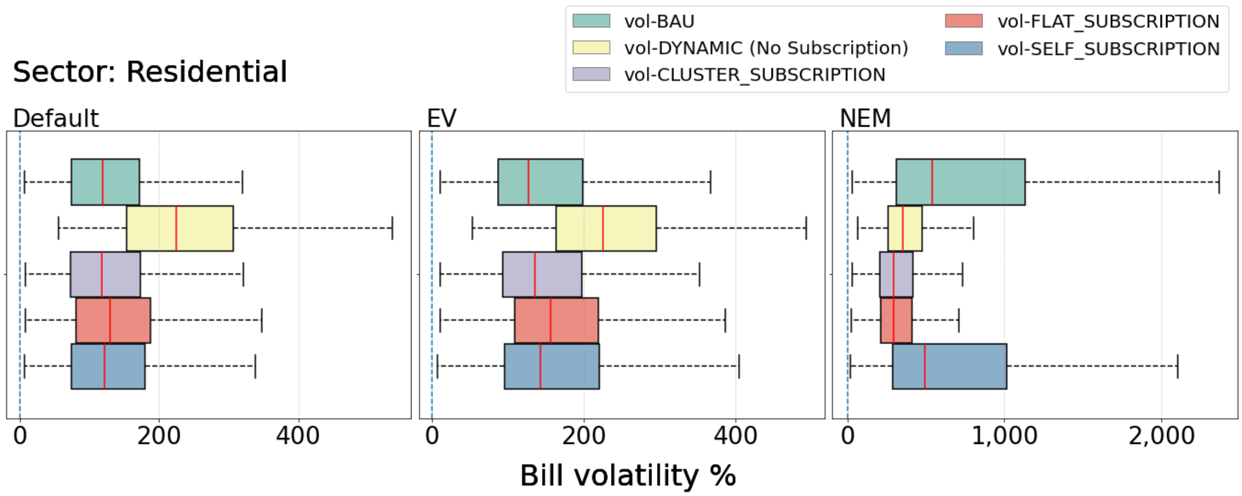

Figure ES- 4. Volatility distributions of residential customer bills displayed for the BAU tariff as well as the dynamic tariffs with and without subscription across both years 2018 and 2019.

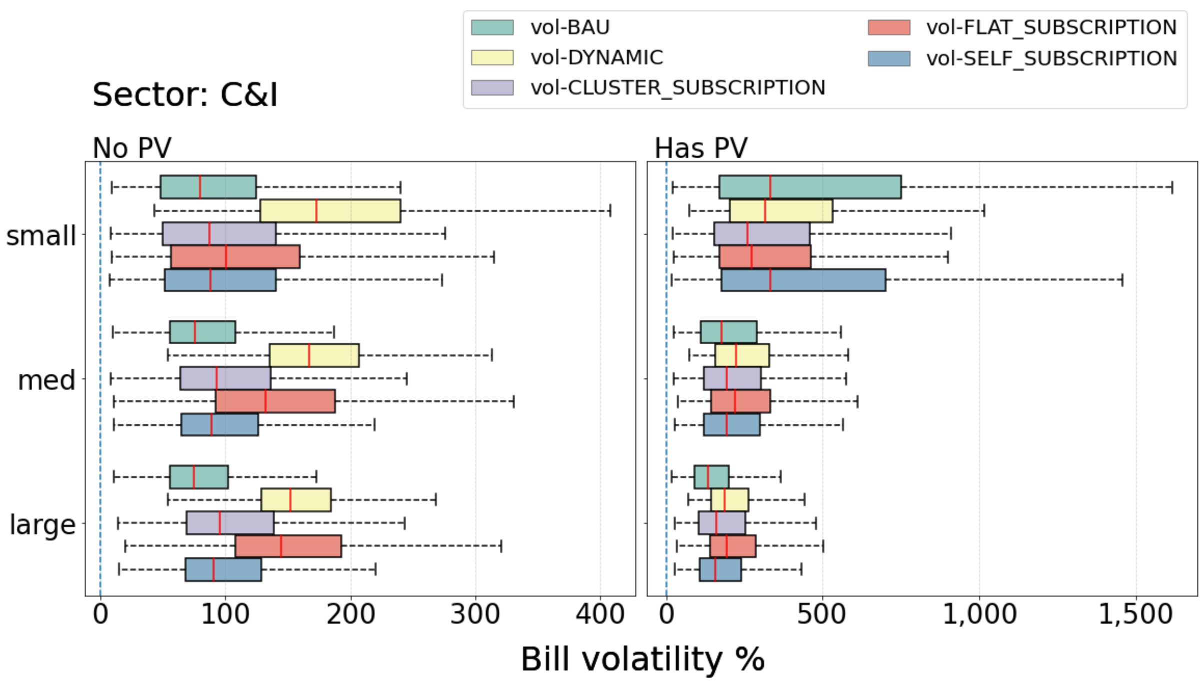

Figure ES- 5. Distributions of bill volatility for C&I customers displayed for the BAU tariff as well as the dynamic tariffs with and without subscription, for customers with and without PV in different size categories.

The key findings of this study, which assumed fully inelastic demand under a dynamic tariff, can be summarized as follows.

1. Bill impacts are similar across calendar years 2018 and 2019, despite the fact that these years had very different wholesale price and system load-shape characteristics, suggesting that year-to-year tariff variability will have limited importance for customer bill impacts.
2. The dynamic-only tariff (no load-shape subscription) would tend to reduce bills for residential, agricultural, and small C&I customers without PV—while increasing bills for the corresponding

customer classes with PV—since they are compensated at a lower rate, on average, for exports to the grid.

3. The dynamic-only tariff (no load-shape subscription) tends to increase bills for large C&I customers regardless of the presence of PV generation.
4. For all customer types without PV, the dynamic-only tariff (no load-shape subscription) leads to a significant increase in month-to-month bill volatility. Residential and small C&I customers with PV see decreases in volatility due to the reduced occurrence of very low or negative bills.
5. Bill savings and volatility impacts for residential low-income and DAC customer subgroups are similar to what is seen for the general population. These customers are not disproportionately impacted by the dynamic tariff.
6. For residential and small C&I customers without PV, all three load-shape subscriptions are highly effective at mitigating volatility increases. This suggests that detailed knowledge of the customer load shape is not necessary to hedge against bill volatility for these customer classes.
7. For medium and large C&I customers and agricultural customers, the different subscription options can yield very different impacts on overall bills and bill volatility. This indicates that the details of the subscription load shape are important for these customers, due in large part to the demand charges these customers face on their BAU tariff.
8. Overall, the self-load-shape subscription yields the greatest bill stability for all customers studied, limiting impacts on both overall bills and bill volatility. A subscription customized to each customer's historical load shape would likely be the least disruptive to customer bills and utility revenue recovery when transitioning to a dynamic tariff.

Our findings suggest that complex interactions exist among the dynamic tariff, the load-shape subscriptions, the presence of rooftop PV, and the underlying design of the BAU tariffs (e.g., the presence or absence of demand charges). Small customers with PV tend to have increased bills and reduced volatility, in stark contrast to their counterparts without PV. Customers with substantial demand charges (e.g., large C&I customers) tend to experience significant bill increases under the dynamic-only tariff, but they can achieve substantial bill reductions without modifying their load if they are offered a subscription load shape that reduces their demand-charge burden.[4]

The presence of such discrepancies in impacts and benefits among customer classes may not be desirable from the standpoint of revenue recovery or equity. Furthermore, it suggests that a transition to dynamic tariffs would require a reassessment of cost causation and cost allocation to different customer classes, to determine appropriate dynamic rate and subscription designs that achieve the desired allocations. The variability by customer class also points to the importance of considering the design of the subscription load shape that customers are offered. In particular, the self-load-shape subscription yields bills and volatility levels that are close to the BAU levels for most customers, suggesting that this or a similar subscription approach may be attractive from the perspective of stable revenue recovery and equitable cost apportionment, while limiting the number of structural benefiters and non-benefiters.

[4] The subscription load shapes are billed under the BAU tariff, including demand charges. Thus, a subscription load shape that does not accurately reflect customer peak demand, such as the flat-load-shape subscription, can significantly reduce overall bills for customers with significant demand charges.

1 Introduction

California climate policy under SB 100 (De León 2018) specifies that 100% of California electricity must be generated by renewable and zero-carbon resources by 2045. To meet this goal, continued substantial growth in non-dispatchable variable renewable energy (VRE) generation, particularly solar, is expected in the state over the intervening period. As a result, the California Independent System Operator (CAISO) and California utilities will need to manage increasingly variable grid conditions, in which the net demand (i.e., the gross demand less VRE generation), which must be met by dispatchable generation resources, takes on a profile with steep morning and evening ramps, known as the "duck curve" (CAISO 2016). At these times, a significant proportion of demand must be met by generation resources that have the flexibility to rapidly modulate their output, placing a constraint on the available generation portfolio that will tend to increase the cost of meeting demand at those times. Further, curtailment of VRE generation is necessary when supply exceeds demand or when ramping needs exceed the flexible generation capacity. Such curtailments have grown rapidly in recent years in CAISO, reaching more than half a terawatt-hour in April of 2022 (CAISO 2022); they represent a significant opportunity cost in terms of foregone savings in energy generation costs, capacity costs, and greenhouse gas emissions.

Simultaneously, California's policies and retail rates have led to an increasing penetration of rooftop solar photovoltaic (PV) generation and other distributed energy resources (DERs) such as behind-the-meter (BTM) batteries, electric vehicles (EVs) and other building technologies such as networked controls that can enable flexibility in customer demand. DERs can add to grid management challenges in certain contexts (e.g., distributed PV generation can increase curtailment of utility-scale PV at certain times), but they can also provide new grid management tools in the form of enhanced demand response resources (e.g., virtual power plants composed of BTM batteries, EVs, and dispatchable demand flexibility can offset the need for traditional peaking capacity).

The changing landscape for electricity in California highlights certain inefficiencies and shortcomings in the way that utility system costs are commonly recovered via retail electricity tariffs. In the present and future CAISO system, costs will be low during times of high VRE generation (when production costs are low) and will be high during peak periods of net demand (when generation capacity is strained) and around steep net-demand ramps (when generation flexibility is strained). In this situation, a traditional time-invariant retail rate will overcharge for electricity generated by VRE and undercharge for other forms of generation, providing a disincentive to the utilization of surplus renewables. Current rates also do not provide a signal to reduce long-term costs for generation or delivery capacity, which also tends to undervalue the utilization of excess VRE generation when it is available. Time of use (TOU) rates that charge different prices at different times of day on a fixed schedule can be an improvement, but the fixed nature of the periods and prices means that extreme peak and overgeneration events will still be inaccurately priced. In addition, non-residential customers are commonly subject to demand charges, which are assessed based on the customer's peak demand in each month. If a customer's peak demand tends to occur during periods of high VRE generation (i.e., during daytime hours in California's solar-heavy system), these charges will incentivize load reductions at times when increased load is desirable. This situation can be mitigated by demand charges that are only assessed during hours of the day when the system peak typically occurs (referred to as coincident demand charges), but even in this case the customer's monthly demand peak may not occur on a system peak day, leading to a mistargeted incentive. Finally, net energy metering (NEM) tariffs for distributed PV generation have historically compensated customers at their retail rates for energy that they export to the grid. Since the retail rates tend to be considerably higher than the real-time value of electricity at times of surplus generation, this structure requires additional revenue to be recovered from non-NEM customers. These contentious cross-subsidy issues have been at the forefront of a recent CPUC rulemaking revisiting NEM tariff construction (CPUC 2022b).

It has been argued for decades (Borenstein, Jaske, and Rosenfeld 2002) that an effective approach to incentivizing demand-side flexibility and efficient utilization of renewables is to present customers with a retail electricity rate that varies dynamically with time to reflect the varying costs of production and delivery. The most frequently considered example of this is so-called real-time pricing (RTP), in which the per-kilowatt-hour rate for electricity consumption varies hourly or more frequently to reflect the wholesale market price of electricity. Such a price can increase economic efficiency in electricity markets both in the short run (Holland and Mansur 2006) and in the long run (Borenstein 2005). There has been considerable utility experience with RTP (Barbose, Goldman, and Neenan 2004), primarily for commercial and industrial customers, who have been shown in numerous studies to exhibit significant responsiveness to time-varying prices (Herriges et al. 1993; Patrick and Wolak 2001; Schwarz et al. 2002; Taylor, Schwarz, and Cochell 2005; Boisvert et al. 2007). There are considerably fewer examples of RTP pricing among residential customers, but evidence exists showing that such customers are responsive to dynamically varying rates (Faruqui and Sergici 2010; Allcott 2011).

However, the variability of dynamic pricing can lead to concerns about customer bill impacts, including overall bill increases, increased bill volatility from month to month, and cost-shifting onto customers who cannot modify their consumption in response to varying prices (Borenstein 2007b). Concerns about customer impacts have come to the fore following news coverage of the extraordinary bills that some residential RTP customers faced during the Texas grid crisis in February, 2021 (Blumsack 2021). Previous studies have found that residential customers can save money overall on RTP (Zethmayr and Kolata 2018), even if they do not respond to them, and that bill volatility risk under RTP can be mitigated via simple forward-contract hedging strategies (Borenstein 2007a). However, these studies have generally been focused on a single sector or customer class in a single grid region and so may not be broadly applicable to customers in California. Moreover, these studies only considered the impacts of varying the energy component of the tariff; varying additional tariff components, such as those related to generation or delivery capacity, may lead to different results.

In this study, we investigate the potential impacts of dynamic electricity pricing on customer bills for a representative sample of California utility customers under a hypothetical dynamic tariff that implements time variation across all cost components that make up the tariff, including energy costs, generation capacity costs, delivery-system costs, and other miscellaneous cost components. First, we develop the hypothetical dynamic electricity tariff structure based on approaches that have recently been proposed and piloted in California. Then, using hourly energy consumption data for a representative sample of more than 400,000 residential, commercial, industrial, and agricultural customers from the three California investor owned utilities (IOUs)[5], we consider the impact that such a tariff would have on customer bills, compared to prevailing present-day tariffs. Specifically, we consider an inelastic-demand scenario in which customers are transitioned onto the dynamic tariff but cannot or

[5] The California IOUs are Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).

do not modify their energy consumption in response, reflecting the worst-case bill impact for each customer. We consider these impacts for a pure dynamic tariff and for scenarios in which the dynamic tariff is coupled with a hedging product to reduce bill volatility risk. Our customer sample has ample representation from all sectors across the majority of the state of California, allowing us to consider how a universal dynamic tariff might impact bills among all types of customers.

Electricity rate design is complex and multifaceted, and although our study has a broad scope in terms of the customers we consider, it is also subject to several significant boundaries. First, we consider a revenue-neutral multi-component dynamic tariff that varies hourly, with each day's rates communicated to customers on the prior day, and with the opportunity to subscribe in advance to a load shape for the whole year. We do not consider tariffs that update at a higher frequency or that allow transactions over shorter timescales than the annual subscription. Based on this tariff, we compute bill impacts in a purely inelastic demand scenario—in which customers do not change their consumption in response to prices—and we do not attempt to estimate the bill savings that price-elastic customers may be able to realize by modifying their demand. Relatedly, we do not analyze the changes to utility costs or revenue that would occur as a result of customer price elasticity, which would need to be accounted for in any real-world ratemaking process. Finally, we do not attempt to assess the degree to which revenues recovered by present-day tariffs, or by our hypothetical tariff, are consistent with principles of cost causation or equity. We apply a single, unified dynamic tariff structure to all customers of each IOU, comparing the resulting bills to present-day tariffs, which vary substantially by customer class; this will naturally result in apparent cost shifts among customer classes. In practice, fair apportionment of costs may require dynamic tariff structures to differ by customer classes, but determining what cost apportionment is most appropriate and equitable is a topic for an intensive, stakeholder-involved process and lies beyond the scope of the present research.

In section 2, we give additional background on dynamic tariffs. We then introduce the data used in this study in section 3, including our selection of representative present-day tariffs for different customer classes. Next, we provide a detailed description of our hypothetical dynamic rate structure in section 4, including the approach to recovering all required utility revenue via such a tariff. Section 5 details the specific tariff scenarios we consider and our approach to computing customer bills for both the conventional and the dynamic tariffs. In section 6, we explore how the dynamic tariff would change the distribution of bills and of bill volatility both within and between different customer classes, both with and without hedging, to understand the various ways that different customers could be impacted by such a tariff. Section 7 summarizes our study and presents conclusions.

2 Background on Dynamic Electricity Pricing

The historical approach to electricity rate design is predicated on foundational principles that stretch back more than a half-century (Bonbright 1961). These dictate that electricity rates should allow utilities to recover their prudently incurred costs, while fairly and equitably apportioning those costs among customer classes and encouraging optimal economic efficiency in the consumption of electricity. Utility costs to be recovered typically include the cost of wholesale energy procurement; costs for building or contracting electricity generation capacity; costs for building and maintaining energy delivery infrastructure; account administration and metering costs; and various other costs required by regulation, including, in the California context, energy-efficiency programs, low-income subsidy programs, and wildfire mitigation efforts. Recently, some authors have revisited these historical rate-design principles in light of the rapid expansion of DERs and VRE generation (Lazar and Gonzales 2015; Rábago and Valova 2018). High VRE penetration can lead to dramatic time variation in the cost of delivering electricity to customers and in the value of DERs; in this situation, fairly compensating DER owners while incentivizing efficient consumption leads straightforwardly to consideration of time-differentiated electricity pricing.

Before proceeding, it will be helpful to define some key terms. In this report, a **tariff** refers to the structure by which utility customers are charged for their electricity consumption. It is made up of several different types of charges:

- **Energy charges** are charges that scale with the customer's total volumetric energy consumption,
- **Demand charges** scale with the customer's peak demand within a defined time frame, and
- **Fixed charges** are charges that customers pay regardless of their consumption.

Each charge is computed at a particular **rate**, which is the relevant per-unit, typically dollars per kWh for energy charges, dollars per kW for demand charges, and dollars per billing period for fixed charges. Rates may vary in certain contexts, for instance, increasing when customers exceed a certain consumption threshold, in the case of inclining block rates, or changing at certain times of the day or week in the case of time-varying rates.

Broadly speaking, time-varying electricity rates at present fall into three categories:[6]

1. **Time-of-use (TOU) rates**, in which rates (for energy or demand, or both) vary among different periods of the day according to a fixed schedule that does not change from day to day (but may change seasonally), usually reflecting the typical periods of high and low demand on the grid;
2. **Peak-day pricing (PDP)** schemes, such as **critical-peak pricing (CPP)** in California, in which energy rates temporarily rise to a high level for a few hours (sometimes as an adder to an underlying TOU rate) on a small number of days during the year that are typically identified a day or less in advance; and
3. **Real-time pricing (RTP)**, in which the energy rate varies on an hourly basis, or more frequently, with hourly prices determined a day or less in advance.

TOU and PDP rates are fairly common in the US at present, especially for non-residential customers, and they are now the default option for most customers in California. Despite lengthy utility experience with RTP, however, customer uptake of RTP rates has historically been low (Barbose, Goldman, and Neenan 2004).

Throughout this study, we will use the phrase **dynamic tariff** to refer broadly to tariffs incorporating electricity rates that vary in response to wholesale prices, or (actual or anticipated) grid conditions, or both.[7] This usage encompasses PDP and RTP rates; TOU rates are not considered "dynamic" for our purposes because they have preset prices in each period and do not vary in response to grid conditions. Historically, dynamic rates have often varied to reflect wholesale electricity prices, but some versions (particularly PDP, but also some RTP structures) may also include scarcity-pricing schemes to recover

[6] The risks and benefits of these different rate options, and best practices for designing time-varying rates, have been discussed in detail elsewhere (Faruqui, Hledik, and Palmer 2012).

[7] Because the specific dynamic tariff structure we analyze here consists of a single energy rate, without fixed or demand charges, we sometimes use the terms "dynamic tariff" and "dynamic rate" interchangeably.

capacity costs during peak hours. RTP tariffs can be structured either as “one-part” RTP, in which customers’ full energy consumption is exposed to the real-time rate, or “two-part” RTP, in which customers can mitigate bill volatility risk by pre-purchasing a fixed amount of energy with an assumed load shape as a hedge, paying the RTP rate only on the difference between their actual consumption and the advance purchase.

Dynamic tariffs have received increased regulatory attention in California in the past few years in response to the challenges of increased VRE penetration as well as newly emergent resource adequacy challenges, such as occurred in the summer of 2020. In the discussion of such tariffs, there has been a focus on including capacity cost recovery as a dynamic cost component, given the high cost of flexible generation capacity needed to manage a renewable grid. A 2016-2019 pilot program, called the Retail Automated Transactive Energy System (RATES), implemented an hourly-varying tariff in southern California that incorporated both wholesale electricity prices as well as price components for generation and delivery capacity that increased as load approached capacity limits (Cazalet, Kohanim, and Hasidim 2020). In 2021, CPUC staff held a workshop proposing a dynamic tariff structure based closely on the RATES tariff (Gupta 2021). This tariff concept was subsequently incorporated in a CPUC staff white paper (Madduri et al. 2022) proposing a dynamic tariff framework known as the California Flexible Unified Signal for Energy (CalFUSE). The CPUC has also ordered two pilot programs implementing CalFUSE-like tariffs in its 2021 summer reliability rulemaking (CPUC 2021b). The hypothetical tariff we analyze in this study is intended to be conceptually similar to the tariff structure in CPUC’s CalFUSE proposal, in that it includes dynamic prices for other bill components besides wholesale prices, including utility capacity costs.[8] The specific tariff structure we consider is closely modeled on the tariff used in the RATES pilot mentioned above. To distinguish from traditional RTP tariffs (which typically only include wholesale prices as a time-varying component), we will refer to the hypothetical tariff in this study as a “multi-component dynamic tariff.” Such a tariff would incentivize shifting load away from high-cost periods, while also compensating customer electricity exports at a rate consistent with their real-time value to the grid, which would encourage increased self-consumption or storage by NEM customers.

3 Data Used in this Study

3.1 Utility customer data

This study computes dynamic pricing bill impacts using hourly energy consumption data for a sample of some 411,000 customers[9] of the California IOUs, which was provided by the IOUs via a CPUC data request in support of Phase 4 of the CPUC’s California Demand Response Potential Study. Data were requested and collected through a two-stage data request process. The first stage included demographic data for every single account that was active in 2019, a total of 13.6 million customers. In the second data request, 2018-2019 hourly consumption data from utility advanced metering infrastructure (AMI, commonly known as “smart meters”) was requested for a sample of 3% of the accounts in the demographic data. The consumption data sample was developed using a stratified random sampling approach, in which customers were first grouped by sector, building type, site size, and other

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[8] Specifically, our hypothetical tariff incorporates elements 1 through 5 of the CalFUSE framework. It excludes the more complex transactions proposed in element 6.

[9] In this context, “IOU customers” includes all electric utility customers whose metering and billing is handled by the IOU. Specifically, this includes customers of Community Choice Aggregators (CCAs) whose electrical delivery is handled by an IOU (i.e., it includes both “bundled” and “unbundled” IOU customers).

parameters, and then customers were randomly sampled from within each group to ensure that each one was adequately sampled. Each sampled customer was assigned two weights: a *customer weight* reflecting the number of total customers they represent within their group and an *energy weight* representing the fraction of total energy consumption they represent within their group. These weights can be used to aggregate the sampled customers to create aggregate hourly energy consumption estimates for various customer classes.

3.2 Cluster load shapes

As part of the analysis for the Phase 4 DR Potential Study, the sampled customers were grouped into clusters made up of similar customers, representing a highly granular set of customer classes for aggregate analysis. In this study, we use the load shapes of the clusters to construct a precisely targeted class-average load shape that can be used as a subscription load shape for each customer in a hedged two-part tariff scheme. We also leverage certain clustering parameters to assess bill impacts for specific customer subgroups.

The customer clustering will be described thoroughly in the forthcoming Phase 4 DR Potential Study report. Here we provide a brief overview of the clustering approach, focusing on the aspects that are most relevant to this study. The clustering proceeds in two stages. First, customers are categorized according to similarity in their load shape patterns, using a novel load-shape clustering methodology developed for the Phase 4 study. Then customers are grouped according to their load-shape cluster and a number of additional demographic and geographic parameters to produce a final set of customer clusters. We describe these steps in more detail in the following sections.

3.2.1 Load-shape clustering

The load-shape clustering process aims to segment customers according to similar patterns of energy use throughout the day and throughout the year, using a two-level strategy based on the k-means algorithm, which is a commonly used algorithm for identifying clusters in multidimensional data. In level 1, the customer AMI data were clustered according to the energy consumption in each hour of the day, resulting in a set of prototypical daily load shapes. Level 2 clustering begins by computing the frequency of occurrence of each prototypical day, as a fraction of 365 days in each customer time series. Thus, each customer's full-year load pattern can be represented as a point in the N-dimensional space of the N prototypes, falling between 0 and 1 on each axis. These points were then themselves clustered, again using k-means clustering, to produce a final set of 9 residential and 7 commercial load-shape clusters.[10] Figure 1 presents the average daily load shape for each of the load shape clusters. Each cluster is also assigned a short name that describes key features of its average daily load shape: for instance, in the residential sector, the MrnEve cluster has peaks in the morning and evening, while the LateEve cluster has a late evening peak; and in the commercial sector the EarlyDay and LateDay clusters have operations that begin relatively early or late, respectively. Because the load-shape clustering groups customers according to the similarity of their daily load shapes and the frequency of different daily load shapes throughout the year, the clustering captures significantly more information than can be seen in Figure 1 regarding the diversity of energy consumption throughout the year. This allows customers with

[10] Load-shape clustering was performed only for customers in the residential and commercial sectors. In other sectors, this clustering was not performed because the smaller number of customers available meant that load shape clustering was unlikely to provide additional information about customer similarity beyond what could be gleaned from clustering customers along the dimensions of building type and site size.

similar average daily load shapes to be distinguished based on longer-period energy consumption patterns.

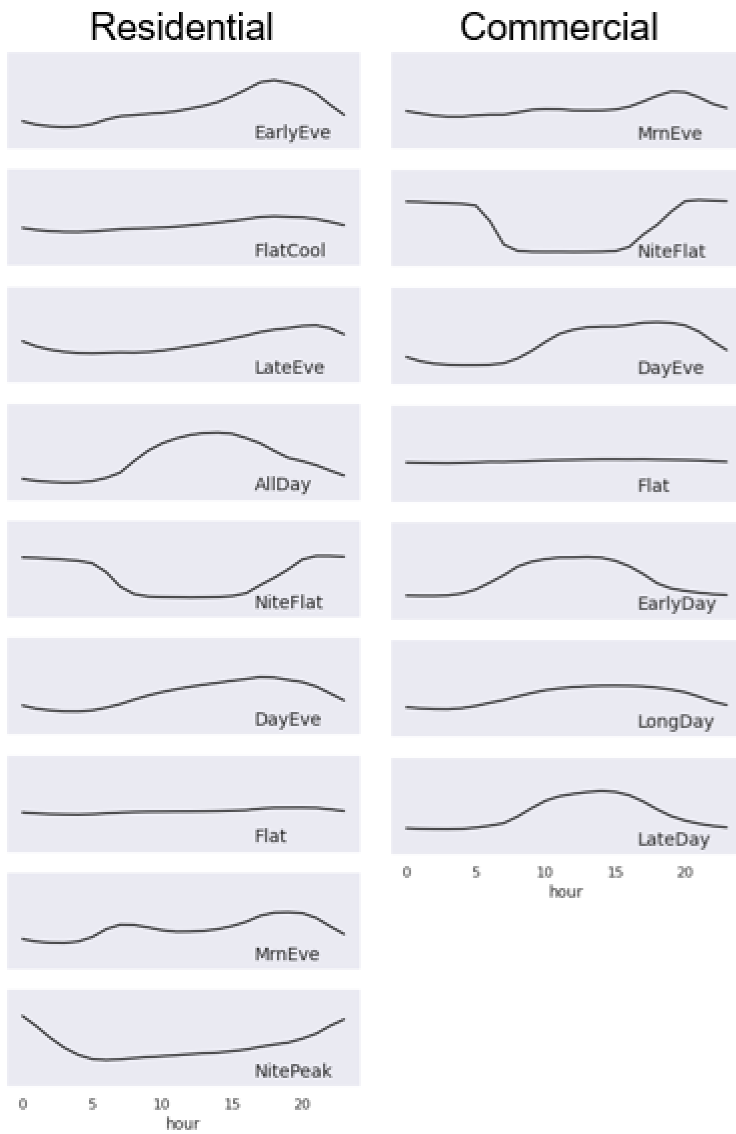

Figure 1. Average daily load shapes for each of the load shape clusters used in this study.

3.2.2 Final cluster load shape development

The final stage of customer clustering combines the results of load shape clustering with demographic and geographic characteristics of each customer. First, customers were assigned to climate regions by mapping their granular CEC Title 24 building climate zones to three broader climate regions, consistent with the approach used in the CPUC Energy Efficiency Potential & Goals study (Sathe et al. 2021). The regions are defined as follows:

- **Marine:** climate zones 1 through 6
- **Hot-dry:** climate zones 7 through 15
- **Cold:** climate zone 16.

Customers are then segmented into a final set of clusters according to customer sector, IOU, building type, size, local capacity area (LCA), load shape cluster, climate region, receipt of a rate subsidy through the low-income California Alternative Rates for Energy (CARE) program, location in a disadvantaged community (DAC[11]), and quintiles of total annual energy consumption among the class of customers defined by similarity on all of the above dimensions. This yielded a set of 6070 clusters[12] across five sectors: residential, commercial, industrial, agricultural, and other.[13] In this study, we will generally group the commercial, industrial, and other customers into a broader commercial-and-industrial (C&I) category, since these customers tend to face similar tariffs.

For each cluster, we aggregated the 2019 load data of all sampled AMI customers that belonged to the cluster, weighted by their assigned energy use weights from the sampling process (described in section 3.1), to produce an hourly cluster-level aggregated load shape. We also summed the customer weights for the sampled customer in each cluster to yield an estimate of the total number of IOU customers who would fall into each cluster. Dividing the aggregated load shape by the weighted customer count yields a class-average load shape for each cluster.

3.3 System and market-level data

In addition to the customer data, the dynamic tariff described in section 4 depends on various hourly datasets at the utility or grid-system level, which reflect hourly conditions on the grid. We obtained these data inputs from the commercially available ABB Ventyx tool. The key system-level inputs were the following:

- The hourly day-ahead wholesale price, averaged across all pricing nodes in each California IOU service territory;
- The hourly gross demand within each California IOU service territory; and
- The hourly net demand within the CAISO system, calculated as the difference between
  - the hourly gross demand in the CAISO system, and
  - the hourly supply-side VRE generation (wind plus solar) in the CAISO system.

3.4 Utility tariffs

Our aim in this study is to calculate the change in utility customer bills that would occur under a dynamic tariff, compared to the bills that customers face under prevailing present-day, non-dynamic tariffs, which we refer to as "business-as-usual" (BAU) tariffs. To compute BAU customer bills, we selected a set of present-day electricity tariffs offered by the California IOUs for residential (res) customers, C&I customers, and agricultural (ag) customers. In particular, we selected the tariff that customers in a given class would be placed on by default today if they chose not to be on an existing dynamic rate (e.g., a CPP tariff). These tariff selections are presented in Table 1. In practice, there is a much broader diversity of tariff options than this for each IOU, so the real-world impacts of a transition to dynamic tariffs would vary among customers on different present-day tariffs. Since much of this variation has to do with

[11] DAC status defined according to California's CalEnviroScreen tool, using criteria set by California SB 535 (California OEHHA 2017)

[12] This study relies on a preliminary set of clusters developed for the Phase 4 DR Potential Study. The final set of clusters for that study has slight differences that are immaterial to our research goals here, and the total number of clusters is slightly different.

[13] The "other" sector as defined for this study includes construction, transportation, waste, and utilities.

differences among the existing tariffs, however, we choose to calculate each customer's BAU bill according to the default tariff for the sake of clarity in understanding the impacts of the dynamic tariff.

Table 1. Tariffs used to compute business-as-usual bills for different customer classes in this study. The specific rate schedules used were those effective as of January, 2022.

Sector	Utility	Customer Type	Tariff Name (short)
Ag	SCE	< 200 kW peak load	TOU-PA-2, Option D
		>= 200 kW peak load	TOU-PA-3, Option D
		>= 500 kW peak load	TOU-8, Option D
	PG&E	< 35 kW peak load	AG-A1
		>= 35 kW peak load	AG-B
	SDG&E	<= 20kW peak load	TOU-PA
		> 20kW peak load	TOU-PA-3, Option D
C&I	SCE	<= 20kW peak load	TOU-GS-1
		> 20 kW peak load	TOU-GS-2
		>= 200 kW peak load	TOU-GS-3
		>= 500 kW peak load	TOU-8, Option D
	PG&E	< 75 kW peak load	B1
		>= 75 kW peak load	B-10
		>= 500 kW peak load	B-19
		>= 1000 kW peak load	B-20
	SDG&E	< 20kW peak load	TOU-A
		>= 20kW peak load	AL-TOU
Res	SCE	Default	TOU-D-4-9PM
		NEM	TOU-D-4-9PM
		EV	TOU-D-PRIME
	PG&E	Default	E-TOU-C
		NEM	E-TOU-C
		EV	EV2A
	SDG&E	Default	TOU-DR-1
		NEM	DR-SES
		EV	EV-TOU-2

Note—Non-residential customers were assigned to the highest peak-load category for which they qualified. Residential customers who are both EV owners and NEM customers were assigned to an EV tariff.

4 Dynamic Tariff Design and Scenarios

We consider customer bill impacts from transitioning all customers in our sample to a hypothetical dynamic tariff that is based conceptually on the CPUC Energy Division Staff's CalFUSE proposal. Specifically, for this study, we devise a single multi-component dynamic tariff for each IOU, which is then applied to all of that IOU's customers regardless of sector or customer class. The tariff is constructed to recover all required utility revenue through a purely volumetric energy charge (i.e., with no demand charges or fixed charges) whose rate varies hourly based on expected conditions on the grid, as reflected in the CAISO day-ahead market. In practice, such a rate could be communicated to customers using day-ahead notification of the next day's hourly rates, once the CAISO day-ahead market has cleared. This would afford customers time to modify their load patterns in response to the varying prices, though in this study we consider the bill impacts if customers do nothing to respond to the dynamic rate.

The tariff is constructed to be revenue-neutral relative to the amount recovered on presently active IOU tariffs,[14] with the revenue-neutrality being computed across all customers, rather than individual sectors or classes. This means that any increase or decrease in one customer's bill will be offset by changes in other customers' bills, allowing us to assess the changes in utility cost allocation among customer classes (i.e., the "cost-shifts") that would accompany such a universal dynamic tariff.

As discussed in section 2, there are several different categories of utility cost that must be recovered through customer tariffs:

- Wholesale electricity costs, both for energy delivered to the customer and for system losses,
- Generation capacity costs, for meeting peak demand
- Flexible generation capacity costs, for managing steep net-load ramps
- Delivery-system capacity costs, and
- Other "common" costs, including account administration, metering, public-purpose programs, wildfire mitigation, and above-market (i.e., non-marginal) generation and delivery costs.

We discuss the approach to including each of these cost components in the tariff in the following sections.

We also note that a significant difference in tariff design between the approach adopted in this study and the CalFUSE Staff Proposal is the magnitude of the dynamic rate. The CalFUSE proposal recommends that certain common and customer-specific costs should only be recovered through the subscription and not be included in the dynamic part of the tariff. The proposal also states that it may be appropriate to recover non-marginal generation and distribution costs exclusively through the subscription. This approach allows the dynamic price to approach a true marginal cost-based price, which will reduce the potential for unintended cost-shifts. In this study, however, we consider a tariff design option with no subscription component, to gain a baseline understanding of the impacts that might have on customer bills. To achieve revenue neutrality with such a tariff, it was necessary to include all cost components in the volumetric rate. Bill impacts from a CalFUSE-like tariff may therefore be different than the impacts we observe for subscription-based tariffs in this study.

[14] It is possible that this overestimates somewhat the revenue requirements that would apply in a with widespread dynamic tariffs. Under current non-dynamic tariffs, rates include an implicit hedge on the part of the utility to account for volatility in wholesale prices, and transitioning to a dynamic tariff would remove the need for this risk premium. Lacking the data needed to estimate this effect, we simply assumed equal revenue recovery requirements for this study.

4.1 Cost components

4.1.1 Wholesale electricity costs

The most immediate cost that must be recovered from retail electricity tariffs is the wholesale price of electricity delivered to the customer. We represent this cost in the dynamic tariff by directly including the hourly wholesale price as an element of the hourly electricity rate faced by customers. [15] This tariff component is calculated for each IOU by averaging the wholesale price from the CAISO day-ahead market for each hour of 2019 across all price nodes in the IOU's service territory. We will denote this wholesale price component in equations as P_h^{IOU}.

It is also necessary to recover the wholesale price of any losses in the delivery system that are associated with delivering the electricity to the customer. Line losses in a power system scale approximately as the square of the load on the system; therefore, we compute the losses as a quadratic function of each IOU's gross load (i.e., the aggregation of metered customer consumption):

$$L_h^{IOU} = \beta_L (G_h^{IOU})^2,$$

where:

> L_h^{IOU} is the hourly average fractional loss associated with delivering generated electricity to the IOU's customers in each hour,
> G_h^{IOU} is the hourly gross load within the particular IOU's service territory, and
> β_L is a scaling coefficient.

The value of the coefficient β_L is determined by requiring that the average fractional losses over the course of the year are equal to the average losses reported by each IOU, which range roughly from 8 to 10 percent. The wholesale electricity costs associated with losses are included as a component of the dynamic tariff via a term representing the additional cost from losses associated with delivering a kWh of electricity in any hour: $P_h^{IOU} \times L_h$.

4.1.2 Marginal capacity costs

Utilities must also recover the costs of electricity generation and delivery capacity (i.e., of power generation units and grid infrastructure). These costs are typically accounted for in utility ratemaking as *marginal* capacity costs, that is, the forward-looking cost of building an additional kW of generation or delivery capacity. In this framework, the revenue required to recover a particular type of capacity cost is equal to the marginal capacity cost multiplied by the capacity required to reliably serve peak demand for the resource.

In some dynamic pricing structures, and in the CPUC's Avoided Cost Calculator (ACC) (E3 2021), capacity costs are assigned preferentially to peak hours, in which demand is nearing the available capacity limits, since these are the periods that are likely to drive the need for new capital investment. A sharp price increase in these hours reflects the scarcity of capacity and disincentivizes loads that may drive the need for additional capacity. In systems with extreme variability in load (such as California, with its high

[15] Regulated utilities are typically prohibited from making profit when recovering electricity production costs, instead passing these costs through directly to customers. A return on capital investments is, however, built into regulated retail tariffs as profit motive for investor-owned utilities; this would be included in the marginal capacity costs described below.

renewable penetration), it may also be desirable to incentivize increased demand during periods of low net load, to make more efficient use of existing generation capacity or avoid physical instabilities in the delivery system.

Following the approach of the RATES pilot, in this study we assign the costs of different types of capacity to each hour of the year using a piecewise quadratic function that is positive and increasing above a chosen threshold, and negative and decreasing below it:

$$C_h^X(Q_h) = \begin{cases} \beta_X \left(\dfrac{Q_h - t}{Q_{\max} - t}\right)^2 if\ Q_h \geq t \\ -\beta_X \left(\dfrac{Q_h - t}{Q_{\min} - t}\right)^2 if\ Q_h < t \end{cases},$$

where:

- C_h^X is the capacity cost component of the tariff for capacity type X (e.g., energy generation or delivery capacity),
- Q_h is the quantity for which the capacity is being calculated (e.g., net energy demand or load on the delivery system), for which minimum and maximum limits are also specified,
- t is the threshold at which the capacity cost component is zero, and
- β_X is a scaling coefficient that is specific to each IOU.

The coefficient β_X is set to ensure that the annual revenue recovered by this tariff component, divided by the capacity limit $Q_{\max}$ is equal to the utility's marginal capacity cost for capacity type X.

The piecewise quadratic functional form achieves the conceptually desirable goal of assigning capacity costs preferentially to hours in which the system is capacity constrained. There is no rigorous theoretical basis for assigning capacity costs to particular hours, however, and other functional forms are possible. For example, an ongoing PG&E dynamic tariff pilot uses a different functional form for recovering generation capacity costs (Grygier et al. 2022). Figure 2 shows an example of the relation between system net load and generation capacity cost using this equation. Above a threshold of around 13 GW, the cost is positive and increasing, creating an increasing disincentive for customers to increase load. Below this threshold, the cost is negative and decreasing to incentivize increased utilization of existing capacity. We use this functional form to allocate capacity costs across the hours of the year for several different categories of cost, as described in the following sections.

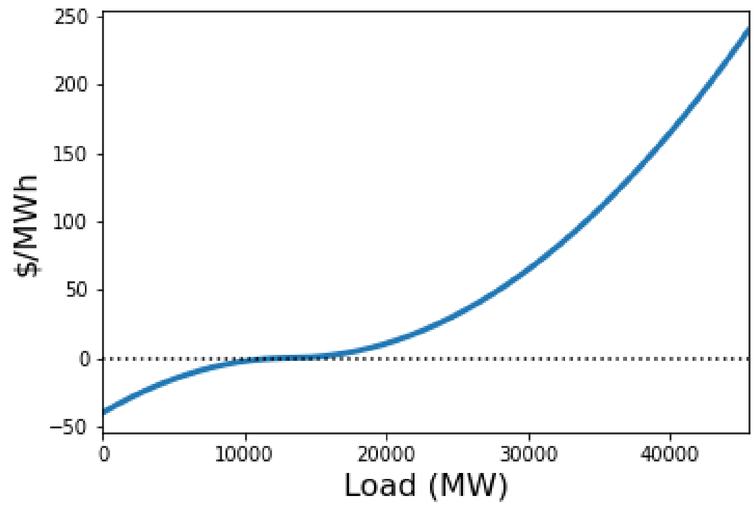

Figure 2. Example of the relation between demand and capacity cost in the dynamic tariff considered for this study.

4.1.2.1 Generation capacity costs

Generation capacity costs reflect the cost for dispatchable generating capacity to meet peak net loads. In principle, the capacity costs should be based on the net load at the level of the individual IOU or other load-serving entity (LSE), since the LSEs are responsible for resource adequacy. But renewable generation data are only available at the CAISO system level, so we use the CAISO-level net load as a proxy. Hence, the quantity in the equation above is

$$Q_h^{gen} = N_h^{CAISO},$$

where:

$N_h^{CAISO} = G_h^{CAISO} - R_h^{CAISO}$ is the hourly net load on the CAISO system, with
G_h^{CAISO} being the hourly gross load on the CAISO system, and
R_h^{CAISO} being the hourly VRE (wind and solar) generation in CAISO.

The $Q_{\max}$ value for generation capacity is set to 15% above the peak net load to reflect the required CPUC planning reserve margin (CPUC 2021a), and the threshold t is set to the highest load at which negative average wholesale prices were observed in CAISO (approximately 13 GW in 2019), which is a good indicator of the point at which capacity is being significantly underutilized. The minimum net load value is set to $Q_{\min} = t - Q_{\max}$, a somewhat arbitrary choice that yields a curve that is symmetrical about the threshold, reflecting a modest incentive to increase load below the threshold. The β_{gen} coefficient is set to ensure recovery of each IOU's stated marginal generation capacity cost in its most recent rate-case filings (less a component assigned to flexible generation capacity, as described below).

4.1.2.2 Flexible generation capacity costs

With the need to manage steep morning and evening ramping due to the duck curve, California utilities have a particular need for flexible generation capacity that can rapidly increase or decrease power output. To assign flexible capacity costs to each hour, the key quantity we consider is the three-hour ramp that has just occurred, which indicates the amount of flexible capacity that is needed to serve load in that hour:

$$Q_h^{flex} = \Delta_{h,3}^{CAISO} \equiv N_h^{CAISO} - N_{h-3}^{CAISO}.$$

The maximum quantity is taken to be 15% higher than the maximum ramp, similar to the generation capacity calculation. The threshold value is set to $t = 0$, given that there is no particular need to incentivize utilization of flexible capacity per se, since it can also be used as a traditional form of capacity. The β_{flex} coefficient is set to recover a fraction of the IOU's total marginal generation capacity cost that is assumed to be assigned to flexible generation resources. [16]

4.1.2.3 Distribution-system capacity costs

We also assign costs associated with marginal distribution-system capacity to the hourly rate.[17] In practice, there is substantial variety in distribution circuit (i.e., feeder) load profiles. Individual circuits can have very different net loads depending on the types of customers that are served by the circuit. In addition, distribution system costs can be allocated proportionally to various parts of the distribution infrastructure (e.g., final-line transformers, distribution feeder circuits, substations, sub-transmission circuits, etc.) In principle, then, distribution capacity costs should be based on the load on each customer's distribution circuit, substation, etc.; however, lacking granular circuit-level and substation-level data, we use the gross load on the utility system as a proxy for the purposes of this study, noting that this will average out what may be considerable geographic variability:

$$Q_h^{dist} = G_h^{IOU},$$

where:

G_h^{IOU} is the hourly gross demand on the IOU system.

The $Q_{\max}$ value for distribution capacity is set to 15% above the peak load to reflect a reasonable capacity margin, consistent with the CAISO required generation reserve margin. Extremely low loads on the distribution system can lead to instabilities, so we set the minimum load value to $Q_{\min} = 0$, and the threshold is set to $t = 0.15 * Q_{\max}$. These choices are informed by the parameters used for distribution system costs the SCE RATES pilot. They yield a very sharply declining negative cost at low load values to strongly disincentivize very low loads on the distribution system. The β_{dist} coefficient is set to ensure recovery of each IOU's stated marginal distribution capacity costs in its most recent rate-case filings.

4.1.3 Other costs

In addition to electricity and marginal capacity costs, California utilities must also recover an array of other or "common" costs associated with such things as above-market (i.e., above marginal price) generation and distribution costs for existing contracts and infrastructure, energy-efficiency program administration, low-income and technology-specific subsidies, per-customer costs for metering and billing, wildfire mitigation, and street lighting. The driver of most of these costs is not directly linked to demand, and the status quo for most customer classes is to recover them via a constant volumetric

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[16] Of the three California IOUs, only SCE has explicitly reported separate costs for flexible and standard generation capacity in its regulatory filings. For the other two IOUs, we subdivide their total capacity costs in the same proportion as reported by SCE (SCE 2021), under the assumption that their flexibility needs are similar.

[17] Transmission system costs are under the jurisdiction of the Federal Energy Regulatory Commission (FERC), which complicates the ability to recover them as a component of a dynamic tariff; therefore, we include transmission system costs among the "other" costs below.

rate.[18] However, this approach has led to customers with distributed generation resources like rooftop solar effectively under-paying or being compensated for these costs when either self-generating or exporting energy to the grid, which increases the total revenue that needs to be recovered from customers without PV. To mitigate this effect, we also include these costs as a dynamic component of the tariff, using the same equation and variables as we used for the generation capacity costs, namely

$$Q_h^{oth} = N_h^{CAISO},$$

using the same $Q_{\max}$ value as for generation capacity, but a threshold value of $t = 0$, since there is no need to avoid periods of low load with this cost component. We set the coefficient β_{oth} by computing the total revenue collected under the final dynamic tariff, and then we adjust this parameter until the total revenue matches the revenue collected under the BAU tariffs, as described in the bill calculation section below. This approach ensures that these costs are primarily recovered during periods of high net load rather than being credited back to customer generators during periods when those resources have very low marginal value to the grid.

It should be noted that another approach to recovering these common costs is through fixed, non-volumetric charges, but the dynamic tariff in this study focuses on the particular case of recovering all costs on a purely volumetric, hourly-varying basis.

4.2 Final tariff

The final IOU-specific dynamic tariffs used in this study consist of a volumetric electricity rate that varies hourly based on the sum of the six components described above:

$$V_h^{IOU} = P_h^{IOU} + P_h^{IOU} \times L_h^{IOU} + C_h^{gen}\left(N_h^{CAISO}\right) + C_h^{flex}\left(\Delta_{h,3}^{CAISO}\right) + C_h^{dist}\left(G_h^{IOU}\right) + C_h^{oth}\left(N_h^{CAISO}\right),$$

where:

V_h^{IOU} is the hourly volumetric rate, and
all other variables are defined in the previous section.

Figure 3 shows an example of the dynamic electricity rate, for SCE's service territory, over a ten-day period in the spring of 2019 (beginning and ending at midnight). The top panel shows the net and gross loads that drive the capacity components of the tariff. The lower panel shows the hourly tariff, as well as the underlying cost components of which it is composed. During the midday hours, the net load is relatively low, owing to significant solar generation, yielding wholesale prices and generation capacity costs that are low or, in some cases, negative. The gross load on the SCE delivery system supports a significant distribution capacity component during these hours, which typically yields a positive overall tariff, although the total tariff can dip into negative territory during extremely low net loads, as shown. In the evening hours, the extreme upward ramp at sunset, coinciding with a peak in demand on the distribution system, leads to a brief spike in the rate, increasing in some cases by more than a factor of five from typical midday levels and creating a strong incentive for shifting load away from these peak hours. Net and gross loads then fall overnight, moderating the rate, before a brief, modest increase in the hours before sunrise.

[18] It would also be reasonable to recover some of these costs through per-customer fixed charges, but in this study we are computing the impacts of a purely volumetric dynamic rate, so we do not consider such a structure.

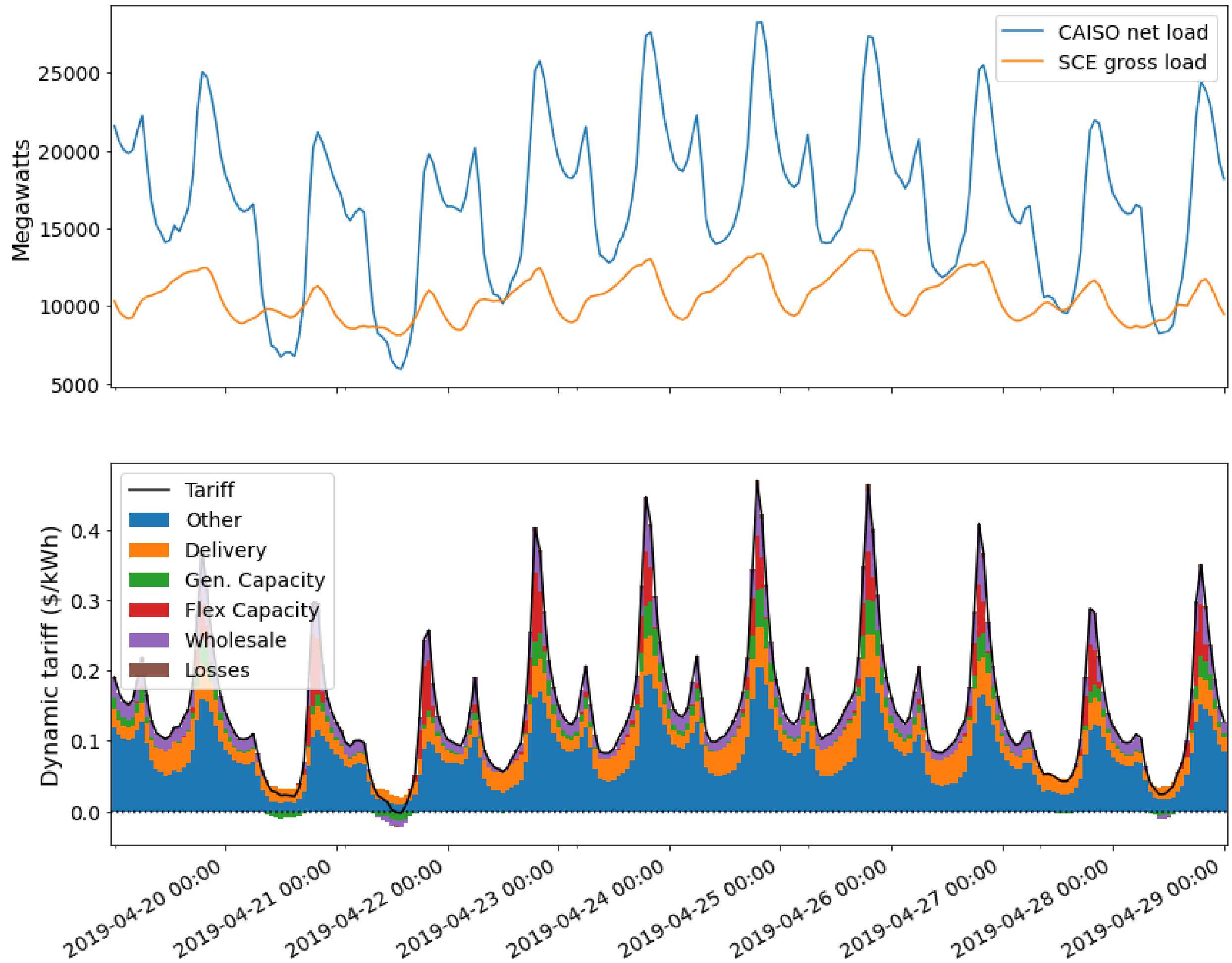

Figure 3. An example of the dynamic rate structure used in this study, for a ten-day period in the spring of 2019, in SCE's service territory. The top panel shows the CAISO net load and the SCE gross load, which drive the capacity components of the tariff. The lower panel shows the hourly dynamic tariff (black curve) and the underlying cost components that compose it (colored bands).

Because the capacity terms vary quadratically with load, the dynamic rate can increase drastically during peak periods, and, depending on the specific year's weather, the peak rate can vary dramatically from year to year. Figure 4 shows the hourly dynamic rate in SCE's service territory for 2018 and 2019, the two years considered in this study. 2018 saw several summer heat waves that drove high peak loads, leading the dynamic tariff to reach levels nearing $2.00/kWh in certain periods. By contrast, 2019 was a comparatively mild weather year, yielding only modestly elevated summertime rates. Both years, and particularly 2019, also saw periods of slightly elevated wintertime prices early in the year, which were a result of high wholesale prices driven by spikes in the price of natural gas during those periods. Such differences in seasonal patterns could yield differences in customer bill impacts from year to year. To investigate the importance of such variation in this study, we calculate annual bill impacts in both 2018 and 2019 for each customer and compare the distribution of bill impacts in each year.

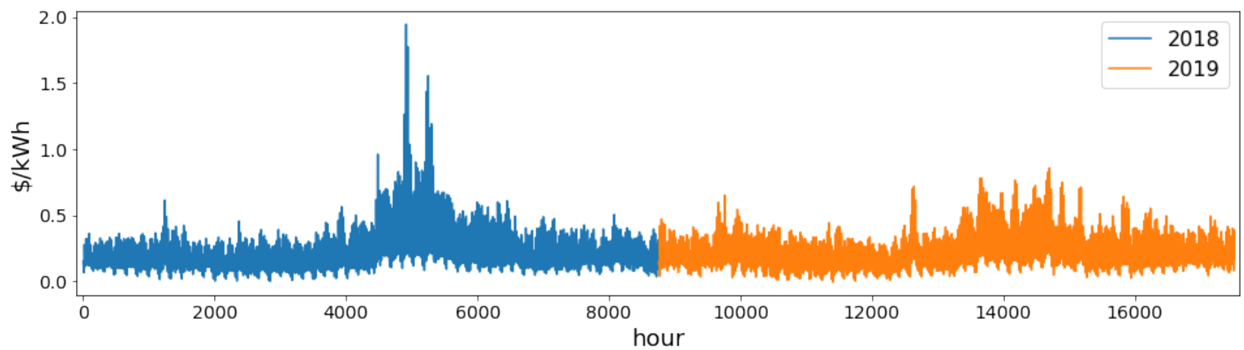

Figure 4. The hypothetical dynamic rate for SCE service territory, for all hours in 2018 and 2019.

5 Tariff Scenarios and Bill Impact Calculations

To estimate the potential bill impacts of the dynamic tariff described above, we compute monthly and annual customer bills in 2018 and 2019 for three different tariff structures:

- A **business-as-usual** (BAU) tariff, in which all customers of a particular IOU are assigned to the tariff that is the present-day default option for their customer class, as summarized in Table 1;
- A **dynamic-only**, or one-part, tariff, in which all customer load is exposed to the IOU-specific dynamic tariff described in section 4; and
- A **subscription-based**, or two-part, dynamic tariff, in which customers pre-purchase an annual load shape at their BAU tariff,[19] with the dynamic tariff being applied to the difference between their subscription load shape and their actual consumption.

In subscription-based structure, the subscription component provides a hedge against bill volatility risk by limiting the fraction of the customer's load that is exposed to the real-time rate. The hedging efficacy of a load shape subscription will depend on how accurately the subscription reflects the customer's actual hourly energy consumption, so a customer's ability to forecast their load shape will impact the volatility of their bill to some degree. To assess the importance of subscription accuracy, we compute subscription-based bills under three different scenarios for customer subscription load shapes, representing different levels of customer information:

- A **flat-load-shape** subscription, in which the customer subscribes to a completely flat load shape (equal consumption in all hours), representing a customer with knowledge of their total energy consumption but no ability to predict their hourly load shape;
- A **cluster-load-shape** subscription, in which the customer subscribes to the average load shape for the cluster to which they were assigned in section 3.2.2, representing a customer who has been provided with a class-average load shape by the utility or a third party; and

[19] As we have structured the calculation here, the subscription is subject to all of the same energy, demand, and fixed charges that are in the BAU tariff. Other more complex structures are possible but would require careful accounting for the effects on revenue recovery of restructuring the subscription tariff, which is beyond our scope here.

- A **self-load-shape** subscription, in which the customer simply subscribes to their own load shape from the "wrong" year (i.e., 2018 for 2019 and vice-versa), representing a customer who uses information from a prior year to develop a subscription load shape.

For the flat and cluster-load-shape subscriptions, the load shapes are normalized to the customer's average annual energy consumption in 2018-2019 [20] to reflect the fact that the total energy consumption a customer subscribes to in any year will be, at best, an informed estimate based on prior years' consumption. By considering each of these scenarios, we are able to assess the importance of having accurate foresight regarding the customer's load shape, relative to the simplest possible hedging strategy (i.e., a flat load shape).

In each of these scenarios, we calculate customer bills under the assumption that customer electricity demand is perfectly inelastic—i.e., that customers do not change their consumption patterns at all in response to the different tariffs. In practice, of course, customers would be expected to modify their consumption to some degree in response to dynamic tariffs, in order to save money. Thus, our calculation here represents the worst-case bill impacts that would be expected from transitioning customers to dynamic tariffs. We detail the calculation of customer bills in each of the above scenarios in the remainder of this section.

5.1 BAU tariff bill and utility revenue calculation

To compute customer bills under the BAU tariffs, we use a public, LBNL-developed software tool called `elecprice`,[21] which calculates monthly customer bills from hourly AMI data, using tariffs encoded in the JSON data format defined for use in the public utility tariff database[22] on the OpenEI website. Because the most up-to-date 2022 tariffs were not available in the OpenEI database at the time of calculation, we manually encoded these tariffs in the OpenEI format in order to carry out our bill calculations.

For those customers with rooftop PV (or other distributed generation) who export more energy to the grid than they consume over the course of the year, an additional adjustment to the BAU annual bill calculation is needed. California IOU customers on NEM tariffs receive bill monthly credits for exported energy, which can be used to offset bills in future months. By calculating monthly customer bills based on customer net load, we are effectively accounting for the value of any energy credits during the month in which they are earned. At the end of each twelve-month period (starting from the commencement of the customer's NEM interconnection agreement), however, any unused energy credits are trued up at a net surplus compensation (NSC) rate based on the rolling average wholesale price of electricity over the previous twelve months (CPUC 2022a), which has historically ranged from \$0.01/kWh to \$0.05/kWh, considerably less than the retail electricity rate. When computing annual bills for NEM customers, it is important to account for the effects of this true-up process. Because we do not know each customer's interconnection date, we cannot know the exact NSC for each customer, so we adopt \$0.03/kWh as a typical value. For any customer with a negative net annual energy consumption,

[20] Our customer load data sample was selected to ensure that all sampled customer accounts were active for the entirety of calendar year 2019. A fraction of customers have an account start date in 2018, meaning that they have no load data for some fraction of that year. For such customers, we compute their expected full-year consumption in 2018 by dividing their actual consumption in that year by the fraction of the year for which their account was active.
[21] https://github.com/LBNL-ETA/elecprice
[22] https://apps.openei.org/USURDB/

when computing their annual bill, we discard the total energy charges from their calculated monthly bills (which will be negative, reflecting their negative overall energy consumption), and we replace them with a compensation for their (negative) net energy consumption at our adopted typical NSC value. This procedure approximates the effect of the annual true-up for NEM customers.

As discussed in the section on dynamic tariff construction above, our aim is to assess the impacts of a dynamic tariff that is revenue-neutral for each IOU, computed across all customer classes and relative to the set of currently active tariffs considered in this study. To ensure such revenue-neutrality, we weight each customer's 2019 bill by the energy weights described in section 3.1, and we sum the results over each IOU to compute the total revenue that would have been collected by the utility in 2019 under the set of BAU tariffs in Table 1. We then set that revenue as a target and adjust the coefficient β_{oth} in the dynamic tariff formula until the total revenue collected by applying the dynamic tariff to the 2019 total utility load shape matches the target revenue.

5.2 Dynamic tariff bill calculation

Calculating customer bills under the dynamic-only scenario is straightforward: each customer's hourly energy consumption, net of any PV generation,[23] is multiplied by the hourly dynamic tariff, and the result is summed. To compute customer bills in the subscription-based scenarios, we first compute each customer's average annual energy consumption (net of PV generation) in 2018-2019. We then use it to normalize the load shape of the cluster to which the customer is assigned for the "cluster" subscription, and we also divide it equally among the 8760 hours of the year, for the "flat" subscription. For the "self" subscription, we assign the 2018 load shape as the 2019 subscription and vice-versa. The customer's subscription cost is then computed by applying their BAU tariff to the subscription load shape. The dynamic-tariff bill component is then computed by applying the hourly dynamic tariff to the difference between the customer's actual load shape (net of PV generation) and their subscription load shape in each hour and summing the result. The final customer bill is the sum of the subscription and the dynamic-tariff components.

5.2.1 A pitfall for subscription-based tariffs with net metering

Before moving on, it is important to make note of a shortcoming in allowing customers to define the shape of their subscription independent of their historic load shape or class-specific billing determinants. Allowing customers (or third parties) to define their subscription load shape exposes an arbitrage opportunity that would pose a significant financial risk to a utility in a real-world context if some customers manipulated their energy consumption to exploit it. This risk is easily mitigated through pre-defining or regulating the methodology to determine a customer's load shape subscriptions. Further, because we are calculating bills under the assumption of fixed customer load shapes, the issue does not arise in a significant way in our study. Nevertheless, we describe the issue here as a caution for real-world implementations.[24]

As a simple example of the hazard of allowing customers to choose their customer shapes without predefined constraints, consider a customer who knows in advance they will have zero energy

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[23] As a result of this approach, any net export of PV generation to the grid is credited at the hourly dynamic rate.

[24] It is also worth clarifying that the CalFUSE proposal avoids these risks by recommending that the customer load shape subscriptions be based on historic customer (or customer class) data. Therefore, as described in the CalFUSE proposal, customers (or third parties) cannot choose the shape of the subscription load shape; the load shapes are determined by historic metered data or other billing determinants.

consumption for a given billing period (e.g., a customer whose site will be unoccupied for some period). Owing to the regular diurnal shape of the duck curve, it is easy to predict that the dynamic rate will be elevated in the evening hours (e.g., from 5 to 8 pm), likely exceeding a customer's BAU energy rate on most if not all days of the year. The hypothetical customer described here, if allowed to, could choose to purchase a subscription that has zero energy consumption in all hours except for the evening hours, in which they subscribe to a very large amount of energy. Since they will consume no energy during those hours, they will be credited back at a higher rate than the one at which they purchased the subscription, making a profit that scales with the quantity of energy purchased in their subscription. More complex arbitrage strategies than this are also possible. Formally speaking, there is no limit to the amount of money that could be extracted from the utility in this manner.

Fortunately, it is easy to eliminate this risk by applying the following restrictions and modifications to the bill calculation approach for subscription-based tariffs:

- Subscription load shapes should be based on historical usage or pre-specified billing determinants, to avoid the risk of baseline manipulation
- Subscription load shapes should be required to be nonnegative in all hours,[25]
- The customer's primary bill calculation should be based on the difference between the energy *delivered* to the customer and the subscription load shape,
- Any rebate to the customer from the above calculation should be capped at the total value of the subscription,[26] and
- Any energy *received* from the customer (i.e., any exports from PV or other distributed generation) should then be separately credited at the hourly dynamic rate.

These modifications ensure that customers with distributed generation resources are properly compensated for their energy exports while guarding against the kind of arbitrage described above by capping the amount of the subscription rebate. The approach would be straightforward to implement in the context of AMI systems, which typically meter delivered and received energy separately. However, since they are primarily meant to guard against intentional load shape manipulation, they would make no material difference to the bills that we calculate here for the overwhelming majority of customers.[27] In the interest of avoiding unnecessary complexity in our calculations, we instead calculate bills under the subscription-based tariff based on each customer's net load, i.e., the difference between delivered and received energy.

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[25] Although negative subscriptions would not create a profit opportunity for customers, per se, if the other restrictions listed here were imposed, they would effectively represent an interest-free loan to the customer. Notably, this restriction would rule out the self-load-shape subscription option that we consider in this study, at least as we have defined it here, since it is allowed to be negative for customers with PV exports. A real-world version of the self-load-shape subscription could be structured to only allow positive hourly subscription values.

[26] Or potentially at some higher value if it is deemed desirable to directly compensate customers for significant load shifting. But the rebate should not be unlimited, as this creates significant risk of manipulation.

[27] That having been said, under this calculation, a small number of customers (a few dozen out of more than 400,000) do realize a profit (i.e., a negative overall bill, with no export of PV generation). On review, these customers are primarily those who have considerably higher energy consumption in one of the analyzed years than the other, often with lengthy periods of zero energy consumption in the lower-consumption year, which serves to demonstrate the risk described above.

5.3 Volatility

In addition to concerns about changes to average energy bills, customers transitioning to a dynamic tariff may reasonably be concerned about changes to the month-to-month volatility of their bill, since unexpectedly high bills in some months can have a negative impact on household or business cash flow, even if the average monthly bill impact is small. Thus, we consider impacts both on the customer's annual electricity bill and on the volatility of monthly bills.

The change in the annual bill is straightforwardly computed by summing the monthly bills for each tariff scenario and taking the difference between the dynamic-tariff and the BAU bills. Estimating the volatility is less straightforward. A natural estimator for volatility would be the coefficient of variation (i.e., the standard deviation divided by the mean) computed on the customer's monthly bills. However, this statistic tends to underemphasize the impact of large outliers, while it is exactly such outliers that would be the most vexing to customers. Therefore, we estimate the monthly bill volatility as the full range of bills (maximum to minimum) over the two-year period, normalized by the average monthly bill:

$$V = \frac{(\max(B_m) - \min(B_m))}{\left|\sum_m \frac{B_m}{24}\right|},$$

where B_m is the bill in a given month and the absolute value in the denominator accounts for the possibility of negative bills among NEM customers.[28] We compute this value for both the BAU tariff and the various dynamic tariffs, and we consider the change in volatility when transitioning from the BAU to one of the dynamic rates.

6 Findings

This section presents the bill and bill-volatility impacts of the analyzed dynamic tariff scenarios for different customer groups and sectors. Section 6.1 shows the impact on residential customer annual bills and monthly bill volatility with a focus on differentiating the impacts on customers on EV or NEM tariffs, as well as examining the relative impacts on customers in CARE and DAC subgroups. Further, the relative bill impacts of the dynamic-only tariff are examined for customers having different building types and load shape clusters, to understand which customer usage patterns may be more positively or negatively impacted by a dynamic rate.

Section 6.2 presents the bill impacts for C&I customers, and section 6.3 shows results for agricultural customers. As shown in Table 1, these customers are assigned to different tariffs depending on the customer's size, as represented by the customer's peak demand in kilowatts. The bill impacts from

[28] Notably, this metric will also capture predictable variability in bills that occurs, e.g., because of seasonal variation in energy consumption, in addition to the unpredictable variation that may cause customer dissatisfaction. To avoid this and focus on unpredictable volatility from price variation, Borenstein (2007) calculated volatility as the maximum excursion from the average bill in each month, calculated over a number of years. We lack sufficient historical data to compute that metric in this study; however, since we typically consider the *change* in volatility compared to the BAU tariff, any bill volatility due to seasonal variation in energy consumption should largely cancel out of the comparison.

dynamic tariffs may vary depending on the BAU tariff being considered, but there is considerable variation among the IOUs in the boundaries of the peak-demand categories used for tariff assignment, as reflected in Table 1. To allow for consistent presentation of results, we present bill impacts here in a set of uniformly applied size categories that split the difference among the various size categories used by the IOUs:

- **Small** customers, with peak demand of less than 50 kW,
- **Medium** customers with peak demand from 50 to less than 200 kW, and
- **Large** customers with peak demand of 200 kW or above.

Despite the variation in size categorization among the IOUs, we find that considering bill impacts within these categories yields qualitatively similar results from IOU to IOU in most cases for non-residential customers. In addition to considering different size categories, we also separately consider the bill impacts for customers with and without PV, to understand how export of PV generation to the grid interacts with dynamic rates.

As a reference, Table 2 presents the counts of customers whose time series data were analyzed in each of the main customer categories considered in this study.

Table 2. Counts of customer bills analyzed in the primary categories considered in this study.

Sector	Customer type	Presence of PV	Customer count
Res*	Non-EV	PV	12,222
		No PV	118,706
	EV owners	PV	3,670
		No PV	9,933
C&I	Small	PV	2,227
		No PV	112,911
	Medium	PV	1,131
		No PV	16,304
	Large	PV	1,483
		No PV	8,338
Ag	Small	PV	273
		No PV	12,559
	Medium	PV	115
		No PV	4,457
	Large	PV	80
		No PV	819

*Overall, 24% of residential customers were on CARE rates and 16% were in a DAC

As we will see, some of the trends in bill impacts appear to be driven by differences in the proportion of BAU customer bills that result from energy charges, demand charges, and fixed charges for customers on different tariffs. For reference, Table 3 shows these proportions for customers in the different sectors and size categories we consider in this study.

Table 3. Proportions of average customer bills arising from energy, demand, and fixed charges, under the BAU tariffs, for customers in different sectors and size categories

Sector	Size	Energy Charges	Demand Charges	Fixed Charges
Res	**-**	93%	0%	7%
C&I	**Small**	85%	10%	5%
	Medium	70%	27%	3%
	Large	58%	41%	1%
Ag	**Small**	71%	20%	9%
	Medium	78%	20%	2%
	Large	83%	16%	1%

6.1 Bill impacts for residential customers

Figure 5 shows distributions of annual customer bills, as box-and-whisker plots[29], for residential customers, under the BAU and each of the dynamic tariffs. Bill distributions are shown separately for 2018 and 2019 for each of the residential-sector tariff categories in Table 1. As a reminder, NEM customers are customers with rooftop PV, EV customers are customers on an EV tariff, and all other customers are analyzed on the default residential tariff for their IOU. As shown, the typical size of customers' BAU varies considerably depending on the presence of DERs: the median default BAU customer bill is around $1500 per year, EV owners have somewhat higher bills, with a median value just above $2000 per year, and median BAU bills for NEM customers are sharply lower, around just a few hundred dollars per year.

Default and EV customers generally save money under the dynamic-only tariff: the median customer sees a bill reduction, and the distribution of bills generally shifts to lower values. Each of the subscription tariffs, by contrast, yields a bill distribution that is similar to the BAU case. The bill impacts for NEM customers are quite different: the distribution of customer bills increases substantially under the dynamic tariffs, and further increases occur for the cluster-load-shape and flat-load-shape subscription options. Only under the self-load-shape subscription scenario do NEM customers experience bills that are similar to their BAU bills, although even in this case a slight increase is evident. These results are generally consistent for both years analyzed, suggesting that the year-to-year differences in the dynamic tariff shown in Figure 4 do not drive major differences in annual bill impacts.

It is noteworthy in Figure 5 that, while all default customers have positive bills under the BAU and dynamic-only tariffs, a small fraction of these customers experience negative bills under some of the subscription tariffs, despite the fact that they export no energy to the grid.[30] It happens to be the case that a small number of residential customers in our analysis had subscription load shapes that netted them a profit based on their 2019 load shape. This is an example of the pitfall we identified in section 5.2.1, whereby certain combinations of subscription and customer load shape can result in a net profit

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[29] Box-and-whisker plots present a summary of the distribution of a variable, with the red line indicating the median value, the box indicating the interquartile range (IQR), i.e., the range from the 25th to the 75th, and the whiskers showing the minimum and maximum outlier-rejected data values, where outliers more than 1.5 times the IQR above or below the box edges are excluded. (In some implementations of box-and-whisker plots, outliers are shown as individual points, but we suppress them here to improve readability.)

[30] EV customers experience negative bills at a higher rate because a portion of these customers are also NEM customers

for the customer. Real-world subscription tariffs would need to be structured to eliminate this possibility, but we do not attempt this here since only a small number of customers are affected.

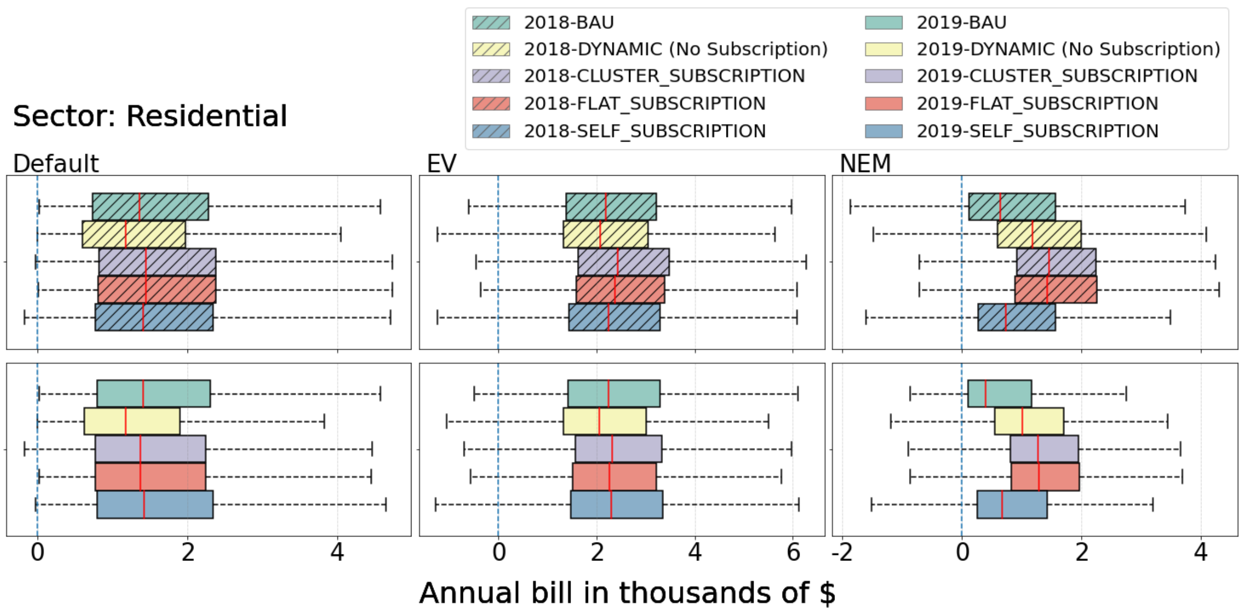

Figure 5. Distributions of residential customer bills, under BAU tariffs, the dynamic-only tariff, and the three subscription-based dynamic tariffs. Bill distributions are shown for 2018 (top) and 2019 (bottom), for customers without EVs or rooftop PV ("Default"), for customers with EVs (who may or may not have rooftop PV), and for customers with rooftop PV without EVs ("NEM"). For each analyzed case, the distribution of customer bills is represented as a box-and-whisker plot, with the median bill shown as a red line, a box indicating the interquartile range (IQR, the 25th to 75th percentile), and whiskers indicating the range of the data excluding extreme outliers.

These results can be understood in a conceptual sense by considering the example hourly dynamic rate values shown in Figure 3, which are relatively low during midday hours and relatively high in the mornings and evenings. For customers on default and EV BAU tariffs, the savings during the daytime hours evidently outweigh any bill increases incurred during morning and evening hours. For NEM customers, by contrast, the rate at which daytime PV exports are compensated (or at which PV generation offsets energy costs) is very low and cannot counterbalance the high morning and evening rates, leading to an overall bill increase.

6.1.1 Changes in annual bills

Although Figure 5 shows a clear overall shift in the distribution of customer bills under the dynamic-only scenario, such a shift does not fully represent how individual customers' bills change. For instance, an overall downward shift in the bill distribution can occur if some customers' bills increase substantially but are offset by a reduction in other customers' bills. To better characterize the impacts on individual customer bills, Figure 6 shows the distribution of *changes* in customer annual bills, under the dynamic-only and each of the subscription tariffs, relative to the BAU tariff.[31] Results are shown for 2019 only;

[31] More specifically, we calculate the change in bills relative to the absolute value of the BAU bill, so that a positive fractional change reflects a bill increase, even for NEM customers with negative BAU bills.

the impacts for 2018 are generally similar. We also investigated bill impacts by IOU and found qualitatively similar results across the three IOUs; hence, we show combined results here.

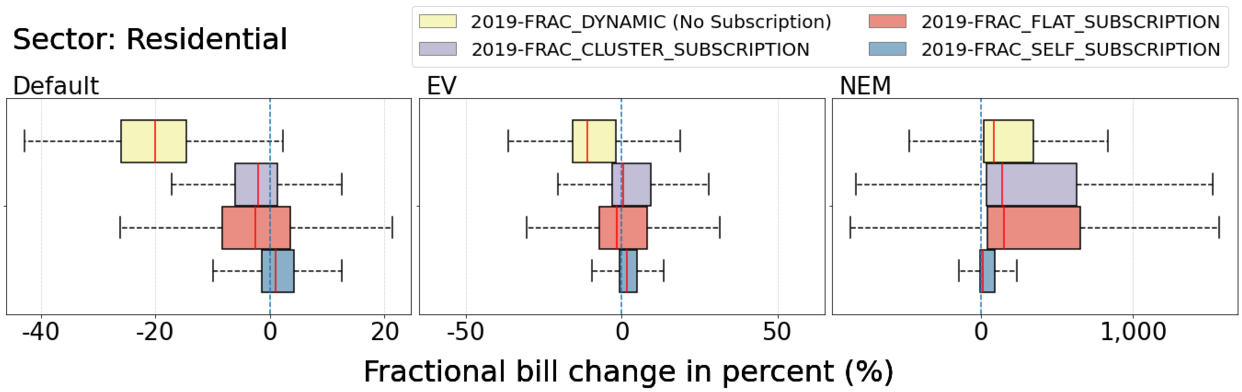

Figure 6. Distributions of changes in bills for residential customers under each of the dynamic tariff scenarios considered in this study. Bill impacts are represented as the percentage change in each customer's bill, relative to that customer's BAU tariff. Impacts are shown for 2019 only, for customers without EVs or rooftop PV ("Default"), for customers with EVs (who may or may not have rooftop PV), and for customers with rooftop PV without EVs ("NEM").

As shown in Figure 6, the dynamic tariff structurally benefits nearly all residential customers relative to the default tariff, with a median bill reduction of some 20%, and it benefits more than 75% of customers on EV tariffs. The subscription-based tariffs reduce the number of structurally benefitting residential customers: the median default-tariff customer saves a small amount on the flat-load-shape and cluster-load-shape subscriptions, but a substantial fraction of residential customers see increased bills; and the median bill impacts are neutral for customers on EV tariffs. The self-load-shape subscription yields a much narrower distribution of bill impacts, reflecting the more accurate match between the subscription load shape and the customer's actual load shape in this scenario, though, the median customer experiences a slight bill increase indicating that the discrepancies between customer loads from year to year may tend to occur during peak periods when the dynamic rate is higher than the BAU tariff. Overall, though, it is clear that using a load-shape subscription to hedge against bill volatility risk tends to erase much of the structural bill savings that residential customers experience under our multi-component dynamic tariff. The question of how well the subscriptions impact bill volatility is addressed in section 6.1.2.

In contrast to default and EV customers, more than 75% of NEM customers experience a bill increase under the dynamic-only and all three of the subscription tariffs. This reflects the fact that much of the grid energy consumption being offset by rooftop PV generation occurs during times when the dynamic rate is relatively low, shrinking the bill savings that are available to NEM customers in comparison to the present day NEM structures, which have been argued to structurally benefit NEM customers. There is a very wide variation in impacts for these customers, however, with some customers' bills changing by more than a factor of ten. This occurs because many NEM customers have very small bills, near zero, so a relatively small absolute bill increase can have a large fractional impact.[32] The self-load-shape subscription again yields a smaller dispersion in results, owing to the more precisely matched subscription load shape for each customer.

6.1.2 Changes in bill volatility

Dynamic tariffs pose the risk of bill volatility, where customers have high bills in one month and low bills in another month. This could be an issue from an equity standpoint, since customers with restricted cash flow depend on having predictable bills. Figure 7 shows the distribution of bill volatility for residential customers under the different tariffs considered in this study. Volatility is measured as the difference between the highest and lowest monthly bill, divided by the mean bill, as discussed in section 5.3.

Under the BAU tariffs, default and EV customers have a volatility around 100%, indicating that a customer with an average monthly bill of $100 may experience monthly bills ranging from $50 to $150. The dynamic-only tariff substantially increases bill volatility, with the median customer experiencing a volatility of around 250%. Recalling that bills for these customers also decreased by roughly 20% for these customers, our customer with a $100 average monthly bill might experience a new average bill of $80, but with individual monthly bills ranging from $20 to $220. The subscription-based tariffs almost entirely eliminate the volatility risk for these customers, however. As shown in Figure 7, all three subscription scenarios eliminate most or all of the volatility increase, shifting the volatility distributions back to levels similar to the BAU tariff. Perhaps not surprisingly, the flat-load-shape subscription is the least effective at eliminating volatility, since a larger fraction of customer load will be exposed to the dynamic tariff in this case, but, somewhat unexpectedly, the reduction in efficacy is very small, with the flat subscription eliminating nearly all of the volatility risk. As we saw in section 6.1.1, however, the subscription tariffs also erase most of the structural bill savings associated with the dynamic tariff for residential customers, with the flat-load-shape subscription yielding the largest residual savings of the three subscriptions. These results suggest that a trade-off exists between structural bill savings potential and bill volatility risk for non-PV residential customers transitioning to a dynamic tariff.

[32] For instance, if a NEM customer has a total annual bill of $10 after accounting for exports under the BAU tariff, then a $100 annual bill under the dynamic tariff will appear as a factor-of-ten increase, while remaining a small bill relative to the average

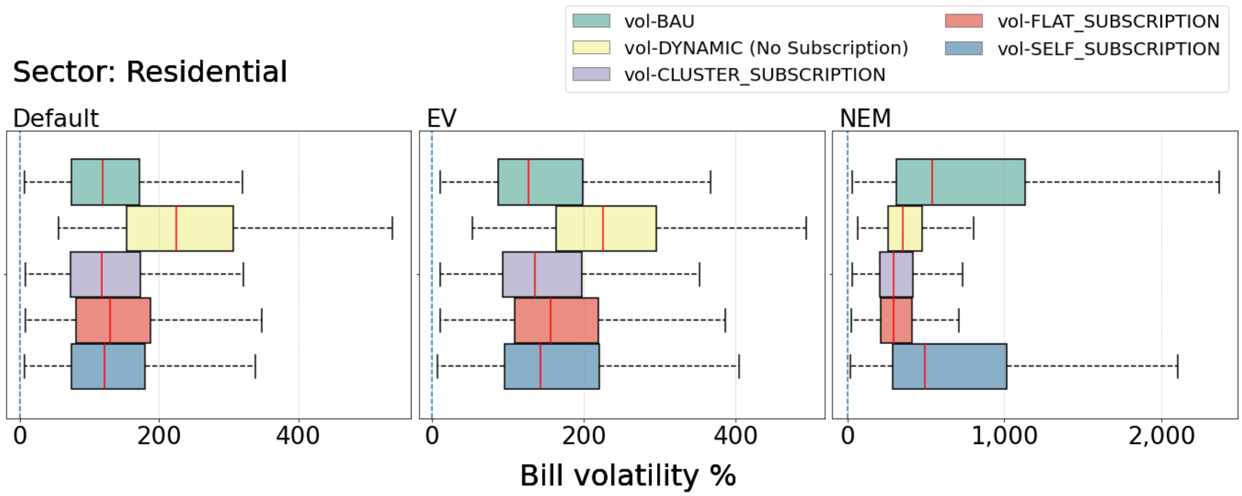

Figure 7. Volatility distributions of residential customer bills displayed for the BAU tariff as well as the dynamic tariffs with and without subscription across both years 2018 and 2019.

NEM customers exhibit considerably higher bill volatility than default or EV customers under the BAU tariff, with more than 25% of such customers experiencing a range in monthly bills that is more than ten times their average bill value. This likely reflects the strong seasonal variation in PV generation and, thus, in the fraction of a customer's bill that is offset by self-generation. For instance, a NEM customer with electric heating may have negative bills in the spring and summer due to significant solar exports, but high bills in the winter when the solar resource is smaller, leading to a low average bill with very high variability. Notably, transitioning to the dynamic-only tariff substantially *reduces* bill volatility for these customers, likely because the reduced rate at which PV generation is compensated increases the lowest monthly bills, while the highest monthly bills are less impacted. The flat-load-shape and cluster-load-shape subscriptions reduce volatility for these customers even further, since they transfer a large proportion of customer bills to a relatively stable subscription load shape, while the original volatility returns under the self-load-shape subscription, as would be expected since this subscription closely matches the BAU scenario. Referring back to the bill impacts in section 6.1.1, we again observe a trade-off between bill size and bill volatility, although in this case the dynamic tariffs yield the highest bills and the lowest volatility, reversing the trends we observed for non-NEM customers.

6.1.3 Bill impacts for customer subgroups

6.1.3.1 Climate Region

It is interesting to consider how residential-sector bill impacts vary by climate region. The BAU tariffs in the residential sector have a tiered rate structure, with a baseline allowance for each customer that is billed at a reduced rate and that is dependent on the customer's local climate. This geographic variation is eliminated in the dynamic-only tariff (which is applied universally to all customers), though it is included in the subscription components of the subscription-based tariffs. Further, customers in hotter climates are likely to have higher evening cooling loads that are coincident with system peaks, and which may drive higher costs during the summer season. For both of these reasons, differences in bill impacts by climate region may be expected, especially for residential customers.

Figure 8 shows the distributions of residential customer bills, by climate region, in each of the tariff scenarios we analyze. Default customers in hot-dry climates tend to have higher bills in general than other customers across all tariff scenarios. For NEM customers, customers in marine climates are able to achieve very low bills, while customers in hot-dry and cold climates see higher bills. For EV customers (some of whom are also NEM customers), the large, climate-independent loads associated with EV charging mean that customer bills tend to be similar across climate regions. Broadly speaking, the bill impacts for the different tariff scenarios show similar trends across climate regions, and these trends are similar to what we saw for all customers in Figure 5. By and large, there appears to be limited variation in bill impacts by climate region.

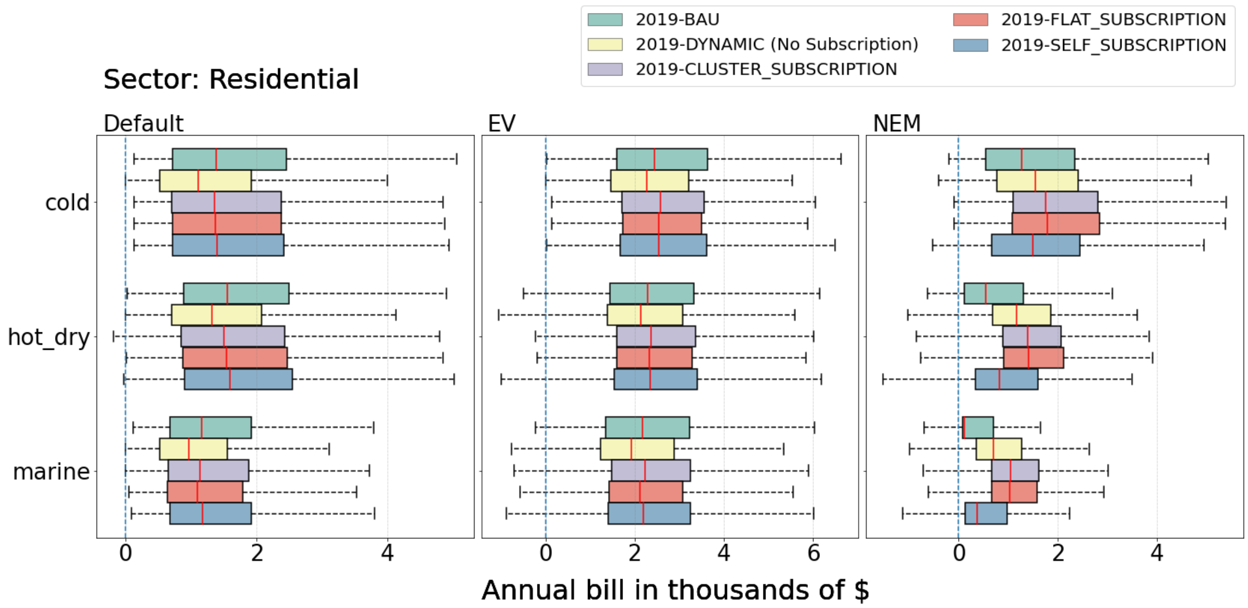

Figure 8. Distributions of residential customer bills, by climate region, in each of the tariff scenarios.

Figure 9 provides a more detailed look at how the dynamic-tariff bill impacts vary by climate region. Here we see that there are small differences in the detailed bill impacts, with customers in hot-dry climates experiencing the smallest structural benefits among default customers, likely owing both to their higher peak loads and to the fact that they have lower bills at a given consumption level given their higher baseline allowances. By contrast, customers in marine climates have the largest structural bill increases among NEM customers, likely because their small cooling loads mean that they are exporting a larger fraction of their PV generation to the grid, and so the impacts of reduced export compensation under the dynamic tariff are larger for these customers.

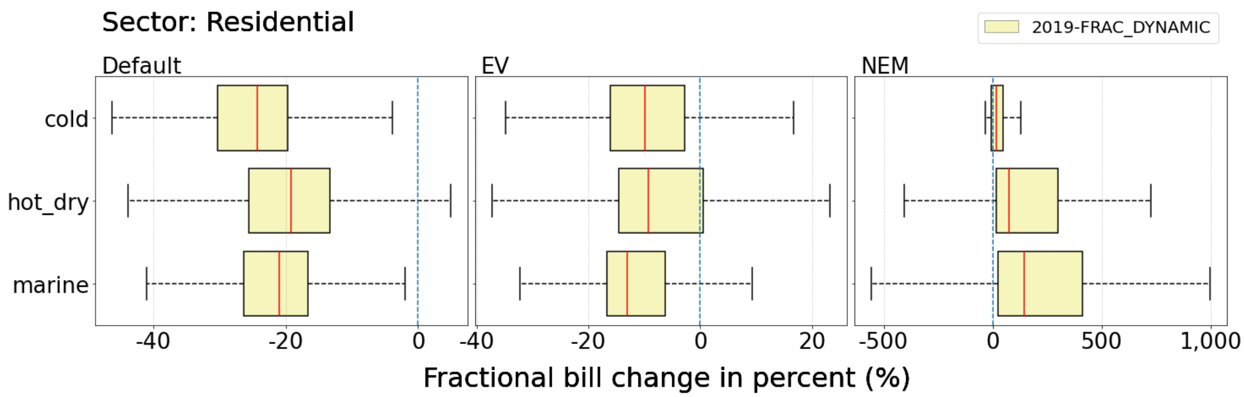

Figure 9. Fractional bill impacts, under the dynamic-only tariff relative to BAU, for residential customers by climate region.

6.1.3.2 CARE and DAC customers

From an equity perspective, it is important to consider how dynamic tariffs might affect low-income and disadvantaged customers. Customers with low household income are eligible for tariffs under the CARE program, in which a discount of 30% to 35% is applied to the customer's bill, subsidized by charges applied to non-CARE bills. Figure 10 compares the fractional bill impact of the dynamic tariffs for CARE and non-CARE customers in the default BAU tariff category. Impacts are broadly similar for the two categories, with the vast majority of customers in both classes structurally benefiting from the dynamic-only tariff, although CARE customers tend to have slightly smaller bill reductions than non-CARE customers for each tariff scenario. To maintain present-day subsidy levels, it may be necessary to adjust the CARE rebate structure slightly when implementing real-world dynamic tariffs. Overall, however, CARE customers do not appear to be disproportionately negatively impacted by dynamic rates. (Bill impacts are also observed to be similar for CARE and non-CARE customers on EV and NEM tariffs.)

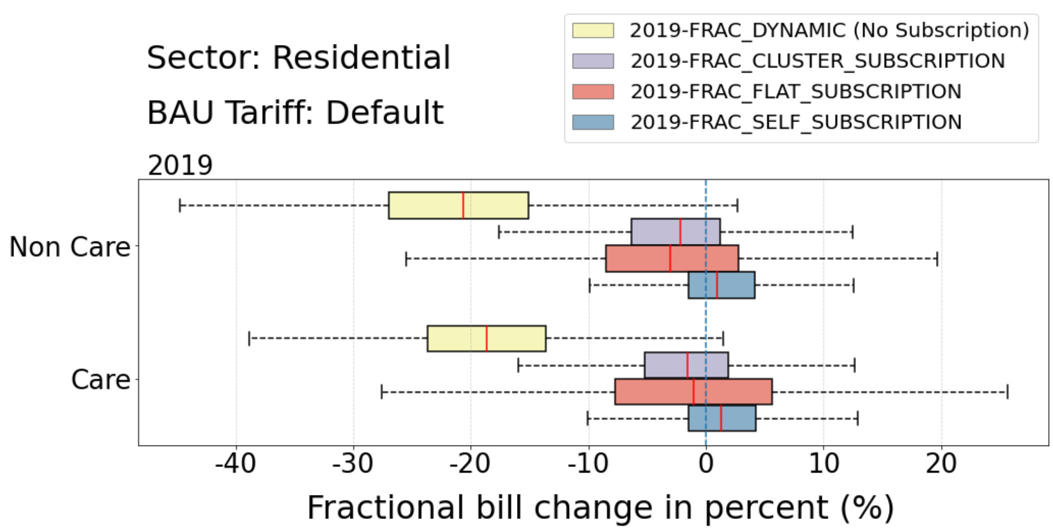

Figure 10. Distributions of bill impacts for residential customers who are eligible for CARE subsidies and for non-CARE customers under each of the dynamic tariff scenarios. The figure shows impacts only for customers who do not have EVs or rooftop PV. Bill impact distributions are presented in the same way as in Figure 6.

DAC customers are defined as living in environmentally disadvantaged communities as identified by the CalEnviroScreen tool (California OEHHA 2017). Looking at the differences between DAC and non-DAC customers in Figure 11, we see the same patterns are visible as we observed when comparing CARE and non-CARE customers, in that DAC customers are slightly less advantaged by dynamic tariffs than non-DAC customers. This may reflect the fact that DACs within the IOU service territories are predominantly located in the hot-dry climate region, where we have already seen that customers experience slightly smaller bill reductions under the dynamic-only tariff. It is notable though that the flat-load-shape subscription is slightly disadvantageous for the median DAC customer, unlike for the general population, which may also reflect that these customers' cooling-driven loads tend to exceed a flat load shape most significantly during high-priced periods. (Bill impacts are also observed to be similar for DAC and non-DAC customers on EV and NEM tariffs.)

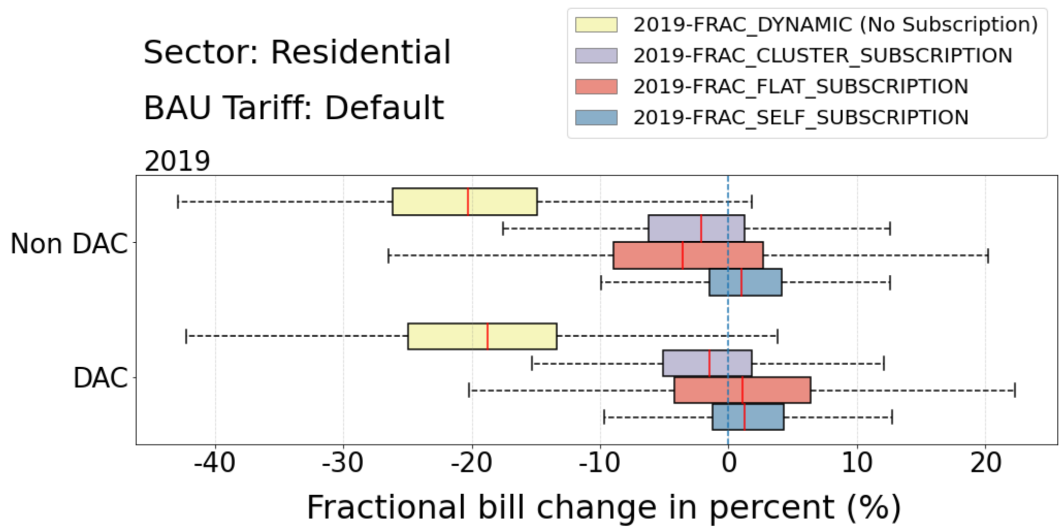

Figure 11. Distributions of bill impacts for residential customers who reside in DACs and those who do not, under each of the dynamic tariff scenarios. The figure shows impacts only for customers who do not have EVs or rooftop PV. Bill impact distributions are presented as in Figure 6.

Because low-income and other disadvantaged customers may be the most negatively impacted by volatile electricity bills, it is also important to consider volatility impacts separately for these subgroups. As depicted in Figure 12, CARE customers typically experience slightly higher bill volatility under the default BAU tariff than non-CARE customers do. This slightly higher volatility persists across all of the dynamic tariff options we considered, but it does not appear that any of the dynamic tariff options create disproportionate impacts on bill volatility for CARE customers.

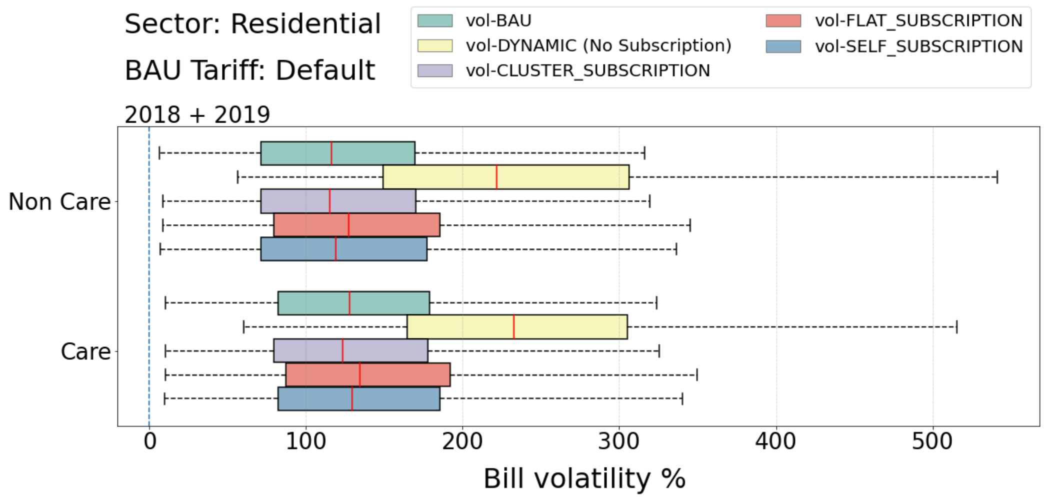

Figure 12. Bill volatility for residential CARE and Non-CARE customers without roof-top PV and without EVs.

As depicted in Figure 13, the DAC customer subgroup also has slightly higher bill volatility than non-DAC customers under the default BAU tariff. However, the increase in bill volatility that these customers experience under the dynamic-only tariff appears to be considerably larger than for other customers. As with the overall bill impacts, this may reflect the fact that the DACs are predominantly located in hot climate regions. (Indeed, we computed distributions of volatility impacts for a subgroup of customers in hot climate regions, and we observed similar a similar shift to the one observed for DAC customers). Regardless, as for other customers, we observe that the bill volatility impacts on DAC customers can be largely eliminated by any of the subscription options we considered.

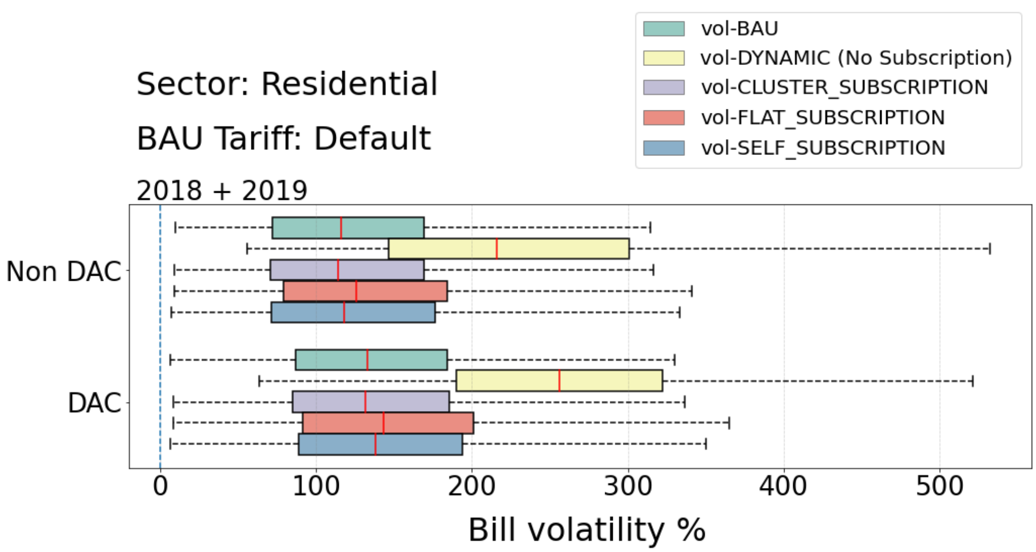

Figure 13. Bill volatility for residential DAC and non-DAC customers without roof-top PV and without EVs.

6.1.3.3 Bill impacts by building type and load shape cluster

Each customer in the dataset is associated with a representative load shape cluster, as discussed in section 3.2 and visualized in Figure 1. The bill impacts for residential customers having each of the representative load shapes are presented in Figure 14. Under the dynamic-only tariff, having a flat or a daytime-peaking load shape (e.g., Flat, FlatCool, and AllDay) yields the largest structural benefit.[33] Load shapes with a peak in the evening or overnight hours (e.g., NitePeak, DayEve, and EarlyEve) are the least advantageous. These results are fairly intuitive: customers with a high proportion of their load occurring during daytime hours, when dynamic rates are low, will tend to realize the highest savings if demand is inelastic. In other words, customers with "solar-friendly" load shapes will tend to be most structurally advantaged by the multi-component dynamic tariff we consider here.

The residential customers in the investigated dataset are further categorized by their building types, either single-family homes or multi-family homes.[34] In general, we find that the multi-component dynamic tariff is slightly more advantageous for customers in multi-family buildings than in single-family buildings. For customers whose building type could be identified, customers in multi-family homes experienced median bill savings that were three percentage points higher than for customers in single-family homes (23% vs. 20%).

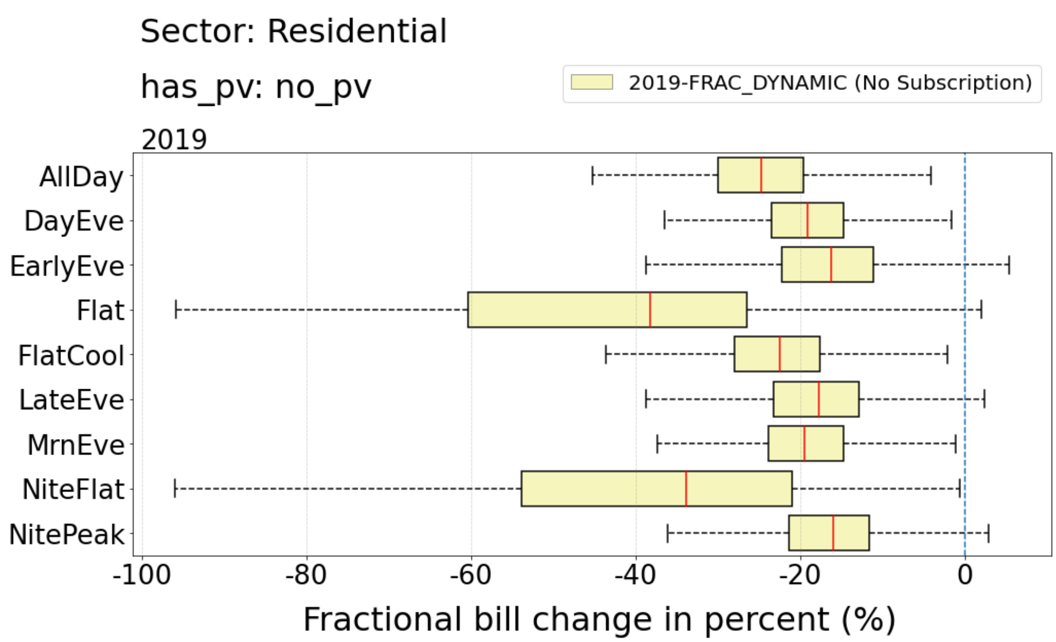

Figure 14. Bill impact of the dynamic-only tariff for residential customers without rooftop PV and without EV. Customers are grouped according to their assigned load shape cluster as described in section 3.2.1. Almost all shown customers experience a bill decrease, but certain load shapes have distinctly larger savings than others.

6.2 Bill impacts for commercial and industrial customers

As discussed at the beginning of this section, we divide C&I customers into small, medium, and large consumers, as determined by their peak demand, when considering their bill impacts. Figure 15 displays

[33] The Flat and NiteFlat load shapes show a particularly large dispersion in bill impacts. This is because a large proportion of these customers have very low total consumption and appear to represent unoccupied buildings. In these cases, small absolute changes in the bill can appear as very large percentages.

[34] PG&E was unable to distinguish between these building types in the data they provided, so we analyzed building-type impacts for SCE and SDG&E only.

the distributions of calculated bills under each of the tariff scenarios, for C&I customers in each size category, in 2018 and 2019, with distributions displayed separately for PV and non-PV customers. As would be expected, systematic variation in typical bill sizes across the size categories is evident, with small customer bills typically falling in the thousands of dollars, medium customer bills in the tens of thousands, and large customer bills in the hundreds of thousands. It is also clear that customers with PV have considerably lower bills than those without PV across all size categories, as would also be expected.

Beyond this, the effects of the dynamic tariffs vary with the customer size and with the presence of PV. Small C&I customers see impacts that are similar to those seen in residential customers: customers without PV experience lower bills under the dynamic-only tariff and see only small bill impacts under the various subscription options, whereas customers with PV see bill increases under all but the self-load-shape subscription option. For medium and large customers, the impacts are different: for medium customers, the dynamic-only tariff has a nearly neutral impact on median customer bills (though it broadens the distribution somewhat, suggesting that there are both winners and losers), and the median large customer experiences a higher bill under the dynamic-only tariff. Interestingly, for both of these customer classes, a noticeable downward shift in the bill distribution is evident for the flat-load-shape subscription. Unlike for residential or small C&I customers, the impacts on the bill distribution are similar for PV and non-PV customers across all tariff scenarios considered, although the impacts appear to be more muted for customers with PV. As in the residential sector, the results are broadly similar in 2018 and 2019, indicating that the year-to-year differences in the dynamic rates do not drive substantial differences in annual bill impacts.

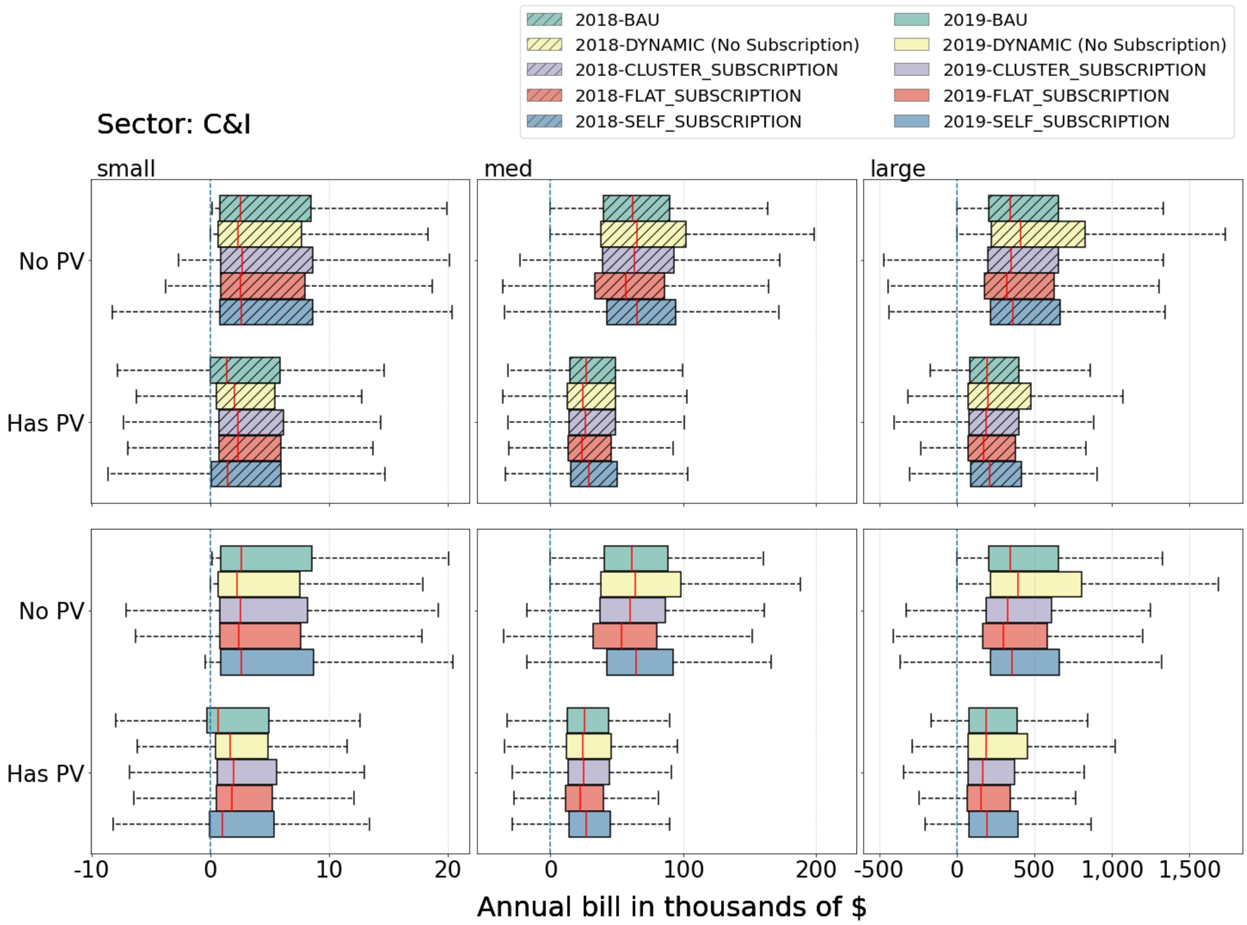

Figure 15. Distributions of commercial and industrial customer bills under each of the analyzed dynamic tariff scenarios. Bill distributions are shown in 2018 (top) and 2019 (bottom) for small, medium, and large customers with and without rooftop PV. Bill distributions are presented as in Figure 5.

We also see in Figure 15 that some non-PV customers have negative bills in each of the subscription-tariff scenarios. As discussed when presenting the residential-sector plots, this is driven by mismatches between the customers' subscriptions and their actual load shapes, which, in rare cases, can yield a net profit for certain customers. See section 5.2.1 for more discussion of this effect.

While all non-PV customers have positive bills under the BAU and dynamic-only tariffs, a small fraction of non-PV customers experience negative bills under each of the subscription tariffs, despite the fact that they export no energy to the grid. This is an example of the pitfall we identified in section 5.2.1, whereby certain combinations of subscription and customer load shape can result in a net profit for the customer. (The effect can also be observed for residential customers in Figure 5, though it is much smaller there.) Real-world subscription tariffs would need to be structured to eliminate this possibility, but we do not attempt this here since only a small number of customers are affected.

6.2.1 Changes in annual bills

As discussed in section 6.1.1, an overall shift in the bill distribution does not necessarily imply that all individual customers' bills move up or down. To explore the diversity in individual C&I customer bill impacts, Figure 16 shows the distribution of *changes* in customer bills for each dynamic tariff scenario, relative to the BAU tariff. As in the residential sector, results are shown for 2019 only, since the impacts for 2018 are generally similar. Despite differences in BAU tariff structures, we also found qualitatively similar results across the three IOUs, so we show combined results for all IOUs here.

For small C&I customers, the results are similar to what we observed for residential customers. A large majority of such customers without PV are structural benefiters under the dynamic-only tariff, while the subscription tariffs typically yield much smaller bill impacts (though, notably, a significant majority of customers experience lower bills under the flat-load-shape subscription). For small C&I customers with PV, the majority of customers experience bill increases on all tariffs, although there is a very large dispersion in the bill impacts for these customers.

For medium and large C&I customers, the bill impacts are quite different. For non-PV customers, the median bill impacts under the dynamic-only tariff are neutral and a significant increase for medium and large customers, respectively. In both cases, there is wide variation in results, and a significant proportion of customers experience lower bills (roughly 50% and 25% for medium and large customers, respectively). Interestingly, the cluster-load-shape subscription and especially the flat-load-shape subscription yield significantly lower bills for a large proportion of medium and large C&I customers, whereas the self-load-shape subscription yields a very small bill increase for most customers. In contrast to smaller customers, medium and large customers with PV experience similar directional bill impacts to their non-PV counterparts, likely reflecting the fact that larger customers' PV generation offsets a relatively smaller fraction of their total energy consumption and has less impact on their load shape and thus bill impacts.

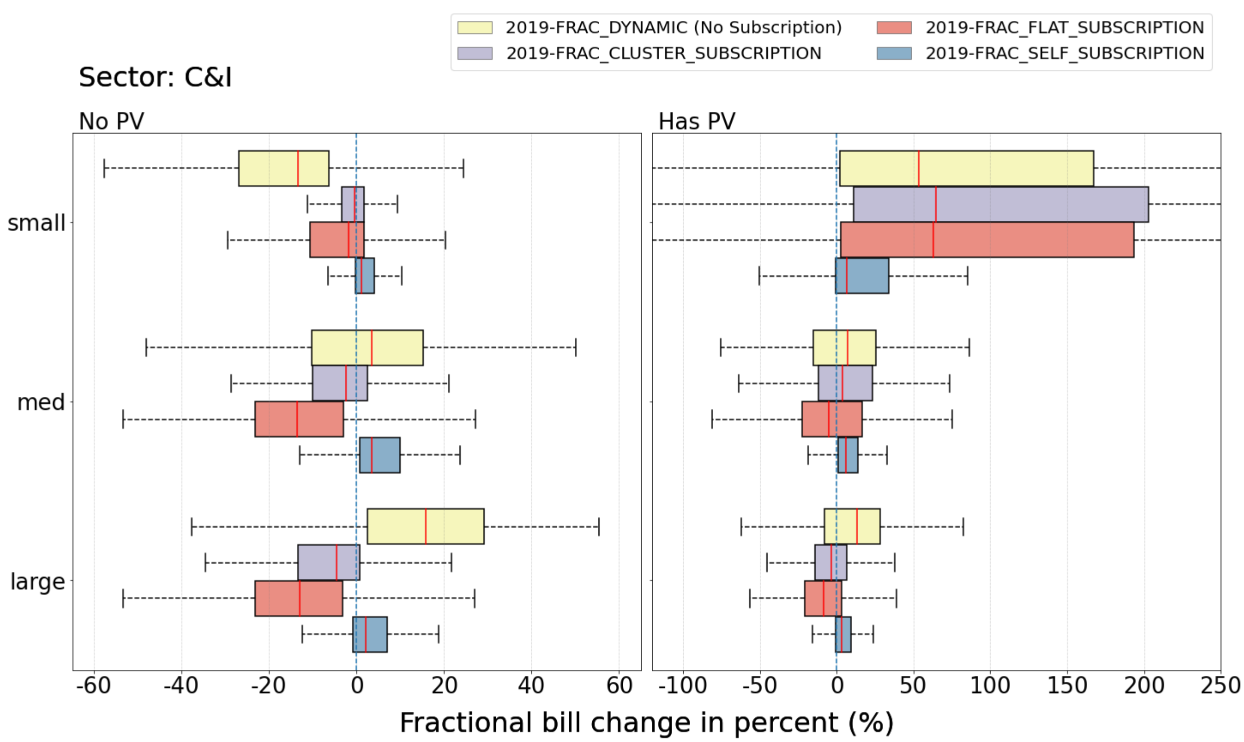

Figure 16. Distributions of bill impacts for commercial and industrial customers with and without rooftop PV under each of the dynamic tariff scenarios. Bill impacts are shown for 2019 by customer size. Bill impact distributions are presented as in Figure 6 as the fractional change in comparison with the BAU tariff.

The qualitative difference in bill impacts between smaller and larger C&I customers is striking. It is worth reiterating that the dynamic tariff we consider in this study is applied universally across all customer classes, and so it stands to reason that there may be some inter-class cost shifting relative to present-day tariffs. In this case, the differences in impacts among customer sizes likely reflect a key difference in the BAU tariff structures faced by these customer classes. By and large, small commercial customers face low or no demand charges in their BAU tariffs, whereas an increasing fraction of medium and large customers' BAU bills come from demand charges, as shown in Table 3. The dynamic tariff trades demand charges for peak-time energy charges, which appears to yield higher bills for most customers. Under the subscription tariffs, the flat-load-shape and cluster-load-shape subscriptions will tend to have smaller demand peaks than an individual customer would, reducing the subscription demand-charge component relative to the BAU bill. The balance of the customer's energy consumption is exposed to the dynamic tariff, but the net impact appears to be a bill reduction. Clearly, the interplay between demand charges and dynamic tariffs is complex; we explore the implications in more detail when we examine bill impacts by load-shape cluster below.

6.2.2 Changes in bill volatility

Figure 17 depicts the distributions of bill volatility that C&I customers experience across the investigated tariffs, by customer size. Volatility levels are generally similar under the BAU tariff for small, medium, and large customers without PV, with median values around 90%, although the distribution is somewhat narrower for larger customers. The dynamic-only tariff significantly increases volatility across all size categories, although the impact on the median volatility is modestly smaller for larger customers. By contrast, the effectiveness of the subscription tariffs in hedging against bill volatility is quite different for the different size categories. For small C&I customers, the subscription tariffs have nearly the same effectiveness as we observed for residential customers, eliminating most, though not all, of the volatility impacts from the dynamic tariff, with the flat-load-shape being slightly less effective than the others. For medium and large customers, the subscription tariffs can eliminate some of the volatility impact of the dynamic tariff, but a substantial increase in volatility persists for the median customer in all cases. In particular, the flat-load-shape subscription has very limited effectiveness as a hedge for large C&I customers, though as we saw previously, it can also yield significant bill reductions for these customers.

For residential customers, we saw a clear trade-off between bill size and bill volatility under the various dynamic-tariff scenarios. Referring back to the bill impacts in Figure 16, we can see that this trade-off persists for small C&I customers, but it is less consistent for medium and large customers. In particular, for the latter groups, the dynamic-only tariff yields the largest increases in both bills and volatility. Looking only at the subscription tariffs, however, the trade-off is still evident, in that the flat-load-shape subscription yields the largest bill reduction at the expense of the largest increase in volatility.

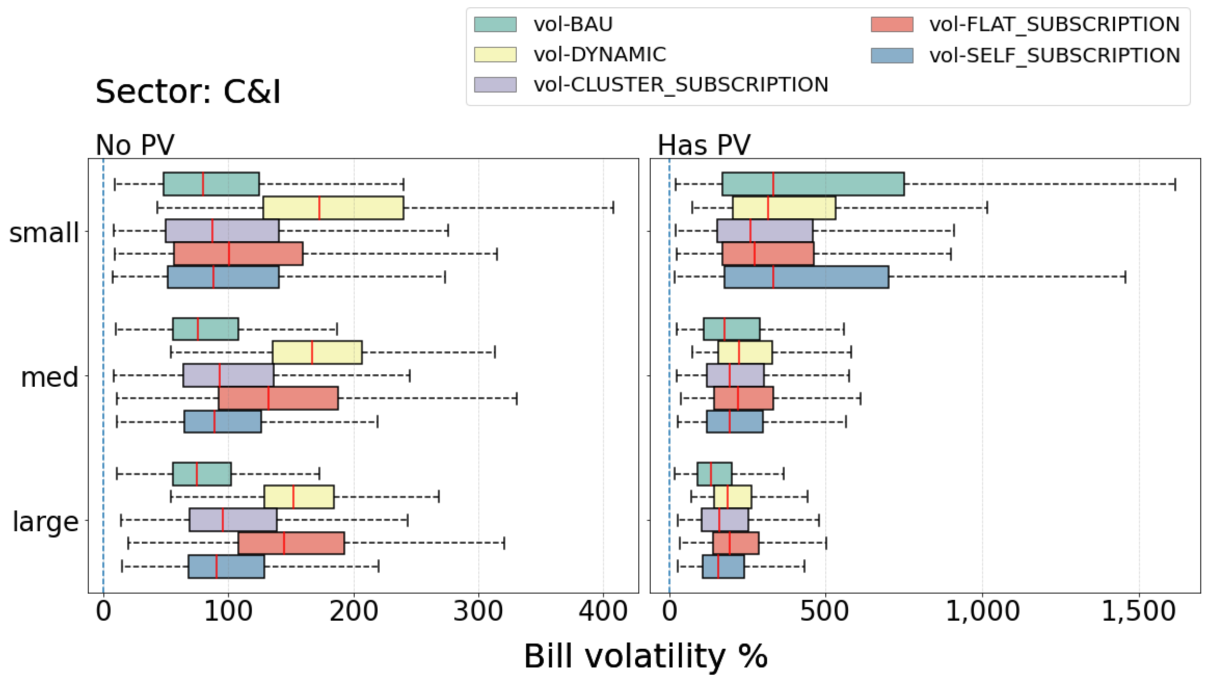

Figure 17. Distributions of bill volatility for C&I customers displayed for the BAU tariff as well as the dynamic tariffs with and without subscriptions, for customers with and without PV in different size categories.

The presence of rooftop PV has a much larger impact on the volatility results for small C&I customers than for medium and large customers, likely reflecting the larger proportion of customer energy consumption that can be offset by distributed PV for smaller customers. For small customers with PV, the volatility impacts are similar to what we observed for residential customers, with elevated volatility levels under the BAU tariff that are reduced under the various dynamic-tariff options (except for the self-load-shape subscription, which yields neutral impacts). For medium and large customers, the volatility impacts for PV customers are directionally similar to the impacts for non-PV customers, though somewhat smaller in size.

6.2.3 Bill impacts for customer subgroups: building type and load shape cluster

Figure 18 displays how small, medium, and large commercial customer bills are affected by the dynamic-only tariff when grouped into the commercial load shape clusters described in section 3.2.1. Also shown are the bill impacts for the self-load-shape subscription scenario. Results are shown only for customers without rooftop PV, since interactions with PV generation will tend to confound effects based on the load shape clusters, which are estimated on the customer's gross demand (without netting out PV generation). For small commercial customers, a large majority (>75%) experience decreased bills under the dynamic-only tariff in all load shape clusters. However, as we saw for residential customers, certain load shapes have a larger structural advantage than others, with relatively "solar-friendly" load shapes having a large proportion of load during the middle of the day (e.g., Flat, LateDay, LongDay) having higher median and maximum bill reductions than load shapes having large morning or evening peaks (e.g., DayEve, MrnEve).

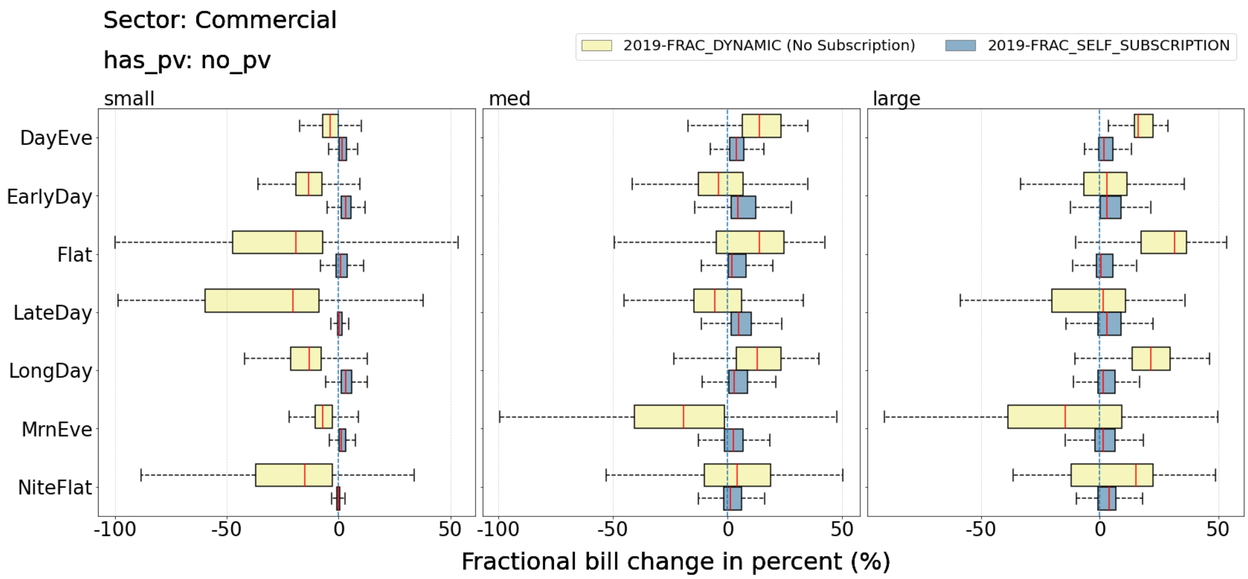

Figure 18. Bill impacts for commercial customers with different typical load shapes in 2019. Impacts are shown for the dynamic-only and self-subscription tariffs for customers without rooftop PV. Customers are grouped according to their load-shape cluster.

For medium and large commercial customers, the patterns of impacts under the dynamic-only tariff are markedly different. Substantial differences in impacts are apparent by load shape, but "solar-friendly" load shapes with a high proportion of daytime consumption (e.g., Flat, LongDay) now appear to have the largest bill increases, whereas the load shapes with proportionally less daytime load (e.g., MrnEve, EarlyDay) have the smallest increases and a substantial proportion of customers with bill reductions. These relative impacts are the opposite of what we observed for small customers. Interestingly, this reversal does not hold in all cases, and some load shapes are more consistently impacted across size categories: for instance, the LateDay load shape is always relatively advantaged under the dynamic-only tariff, while the DayEve load shape is always among the more disadvantaged. These results likely reflect trade-offs for medium and large customers between demand charges under the BAU tariffs and peak-time energy charges under the dynamic tariffs. Customers with flatter load shapes will have smaller demand charges as a proportion of their total BAU bill; paying high energy charges repeatedly during peak periods under the dynamic tariff will tend to increase their bills. By contrast, customers with peaky load shapes will have higher demand charges as a proportion of their BAU bills; paying volumetric charges that reflect only their coincident peak consumption will tend to reduce these customers' bills.

In all cases, however, we find that the self-load-shape subscription largely eliminates the variation in bill impacts by customer load shape and customer size. In this scenario, all customer classes experience bills that are close to their BAU bills, and any variation by customer load shape is small, demonstrating the capacity of an appropriate subscription to substantially mitigate customer-specific bill impacts.

Figure 19 shows how the building type affects bill impacts for small, medium, and large commercial customers without PV under the dynamic-only and self-load-shape scenarios. Substantial variation in impacts by building type is evident across all size categories. Interestingly, however, unlike with load shape clusters, variation by building type tends to be stable across size categories, with the most relatively advantaged building types (e.g., assembly, education) and the most disadvantaged building types (e.g., lodging and food retail) appearing in all categories. This suggests that typical load shapes may vary by size category for certain building types, possibly reflecting a response to present-day demand charges. As we saw previously, the self-load-shape subscription is able to largely eliminate these customer-specific sources of variability by matching the subscription appropriately to the customer.

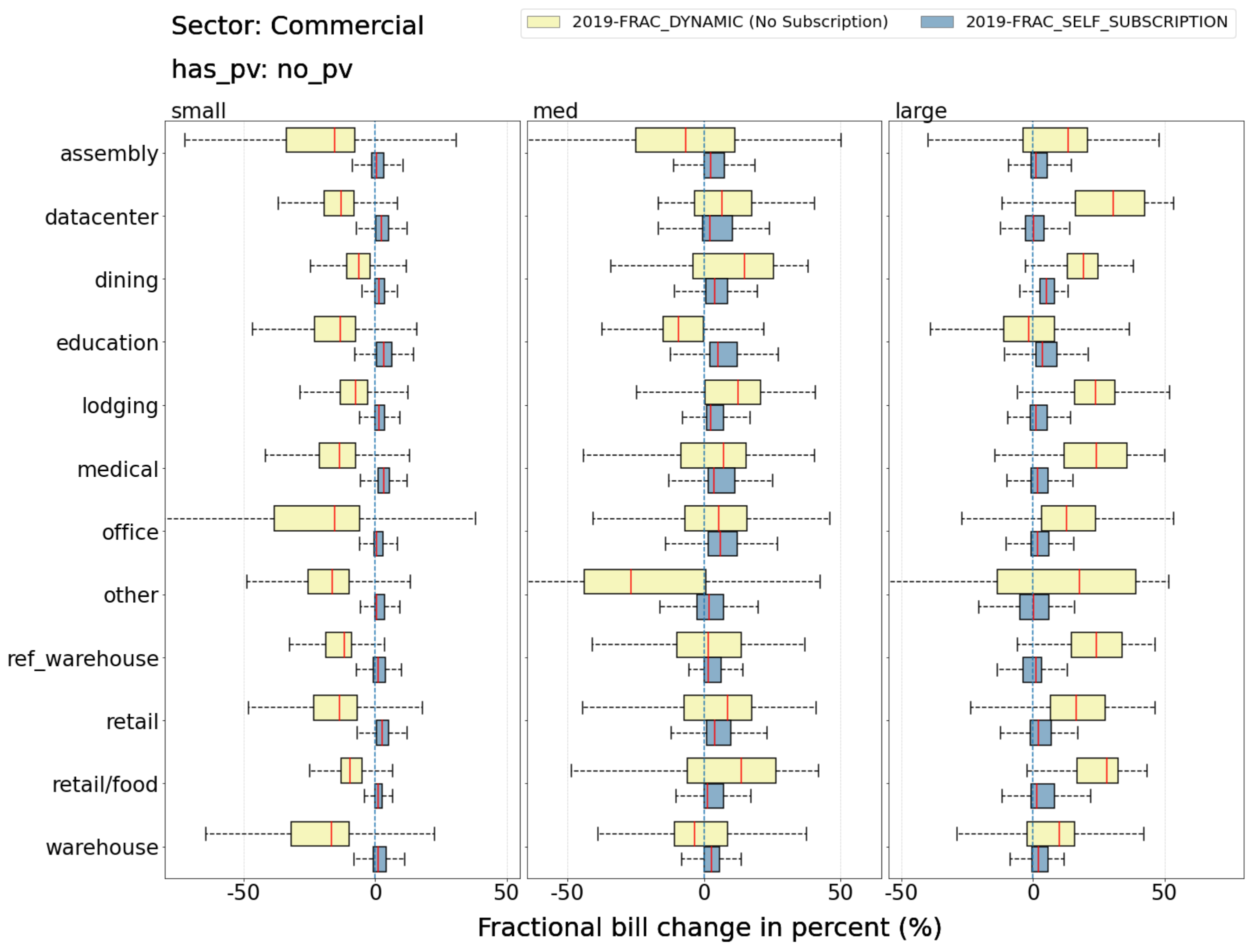

Figure 19. Bill impacts of the dynamic-only and self-load-shape tariffs in 2019, for commercial customers without rooftop PV, grouped according to building type.

Figure 20 shows bill impact distributions by building or site type for the dynamic-only tariff for small, medium, and large industrial customers without PV. As for commercial customers, there is considerable variation by building type, which is broadly consistent across size categories. In general, goods and materials manufacturing facilities are the most advantaged by dynamic tariffs, relative to other building types; and military and food/beverage processing facilities are the most relatively disadvantaged. As before, the self-load-shape subscription is largely able to eliminate the variability by customer class.

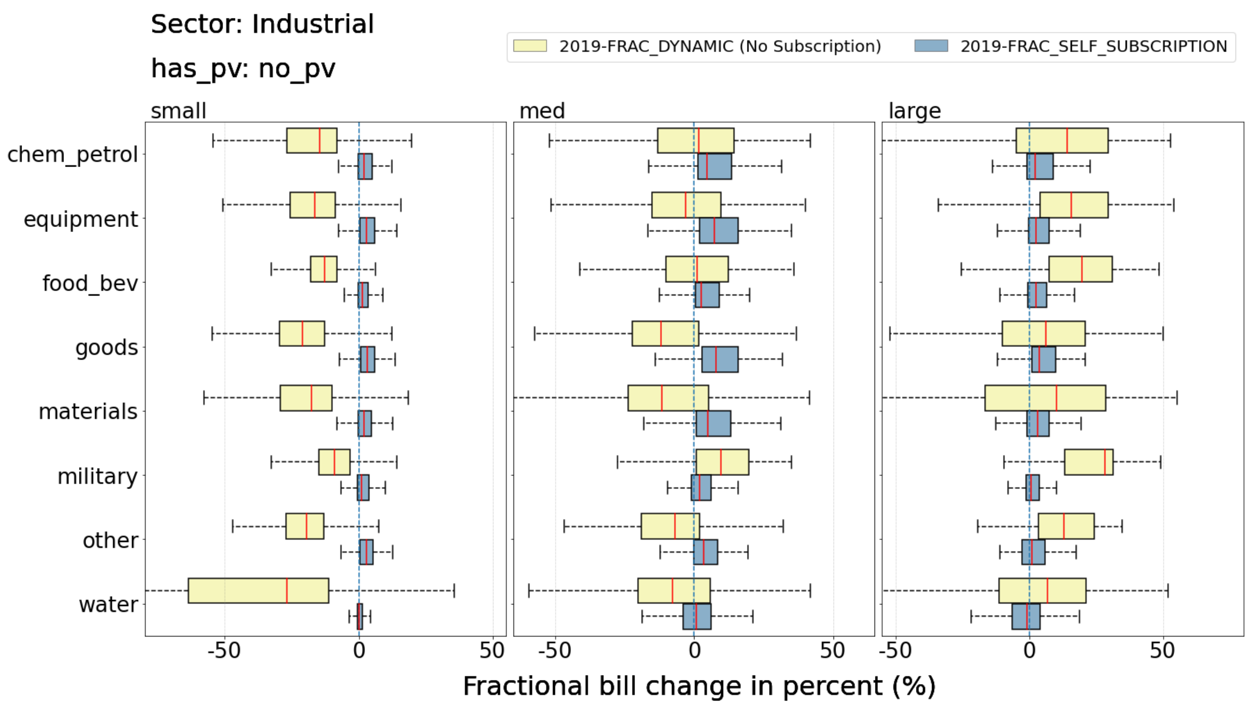

Figure 20. Bill impacts of the dynamic-only and self-load-shape tariffs in 2019, for industrial customers without rooftop PV, grouped according to building type.

6.3 Bill impacts for agricultural customers

Figure 21 shows bill distributions for 2018 and 2019 under each of the analyzed tariff scenarios for small, medium, and large agricultural customers with and without rooftop PV. As with C&I customers, differences in bills among the size categories are evident, with small customer bills typically being a few thousand dollars per year, medium customer bills falling in the tens of thousands, and large customer bills on the order of $100,000 per year. Customers with PV have considerably reduced bills across all size categories, as expected. The effects of the dynamic tariffs in this sector are different from what we observed for C&I customers, with the dynamic-only tariff generally shifting the bill distribution downward for non-PV customers in all size categories. For customers with PV, the impacts on the bill distribution range from near-neutral for small customers to a slight increase for large customers. The impacts of the subscription tariff vary among the different size categories, although the flat-load-shape subscription consistently shifts the bill distribution downward for customers without PV, as can be expected due to the de-facto reduction in demand charges paid under a flat-load-shape. Also, as we saw in the residential and C&I results, a small number of non-PV customers can experience negative bills due to differences between their subscription and actual load shapes.

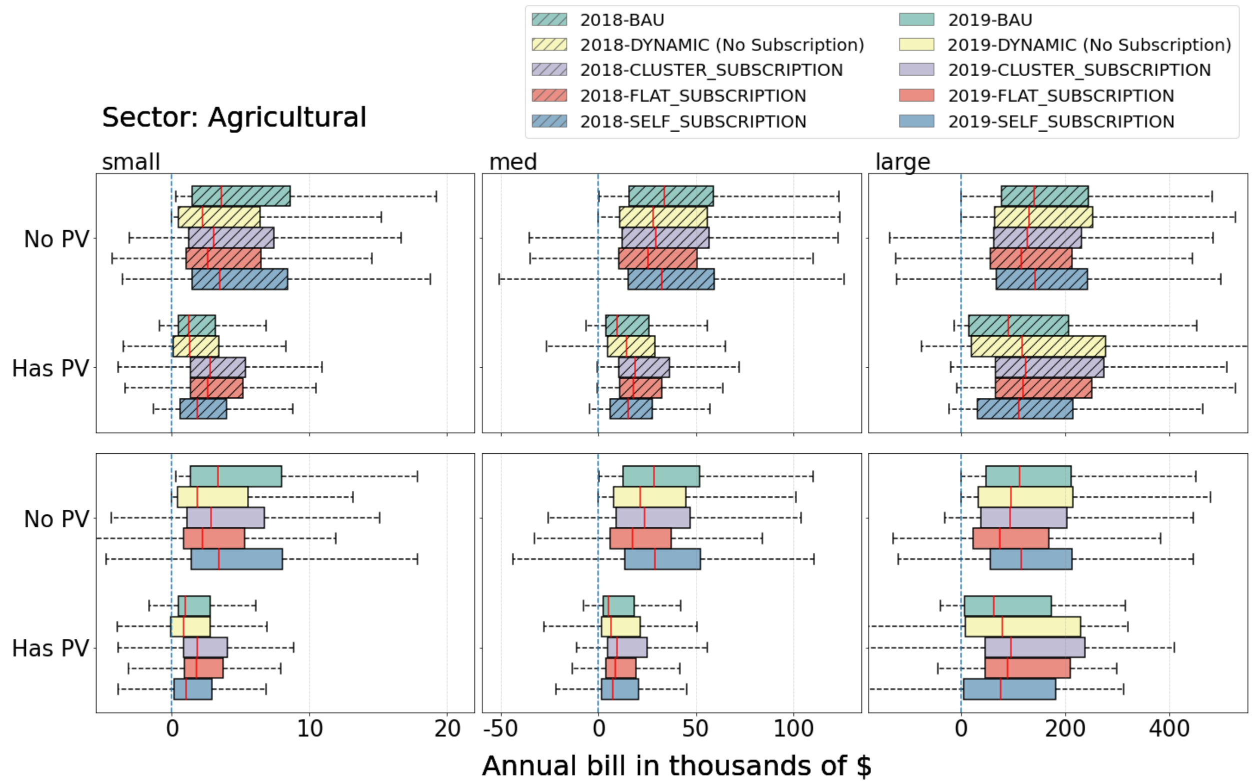

Figure 21. Distributions of agricultural customer bills under BAU tariffs and the various dynamic tariffs. Bill distributions are shown in 2018 (top) and 2019 (bottom) for small, medium, and large customers with and without rooftop PV. Bill distributions are presented as in Figure 5.

6.3.1 Changes in annual bills

To present the bill impacts from dynamic tariffs more clearly, Figure 22 depicts the distribution of fractional changes in individual agricultural customer bills in 2019 under each of the dynamic tariff scenarios relative to the BAU tariff. Across all size categories, the vast majority (>75%) of non-PV customers have structurally reduced bills under the dynamic-only tariff, with fractional reductions typically being larger for smaller customers. This reflects the fact that agricultural customers' bills have fairly modest demand-charge contributions across all size categories (see Table 3), so the bill increases we observed among C&I customers with large demand charges are not evident here. The cluster-load-shape subscription also reduces bills, albeit smaller, for a majority of agricultural customers across all size classes, whereas the self-load-shape subscription yields near-neutral impacts. Interestingly, the flat-load-shape subscription yields the largest reductions among the subscription options for all three size categories, and for medium and large customers it typically yields larger reductions than the dynamic-only tariff. For agricultural customers with PV, the bill impacts are more muted in all cases and are generally close to neutral with the exception that the cluster-load-shape subscription consistently yields a bill increase for the median customer. As in the residential sector, results are shown for 2019 only, since the impacts for 2018 are generally similar.

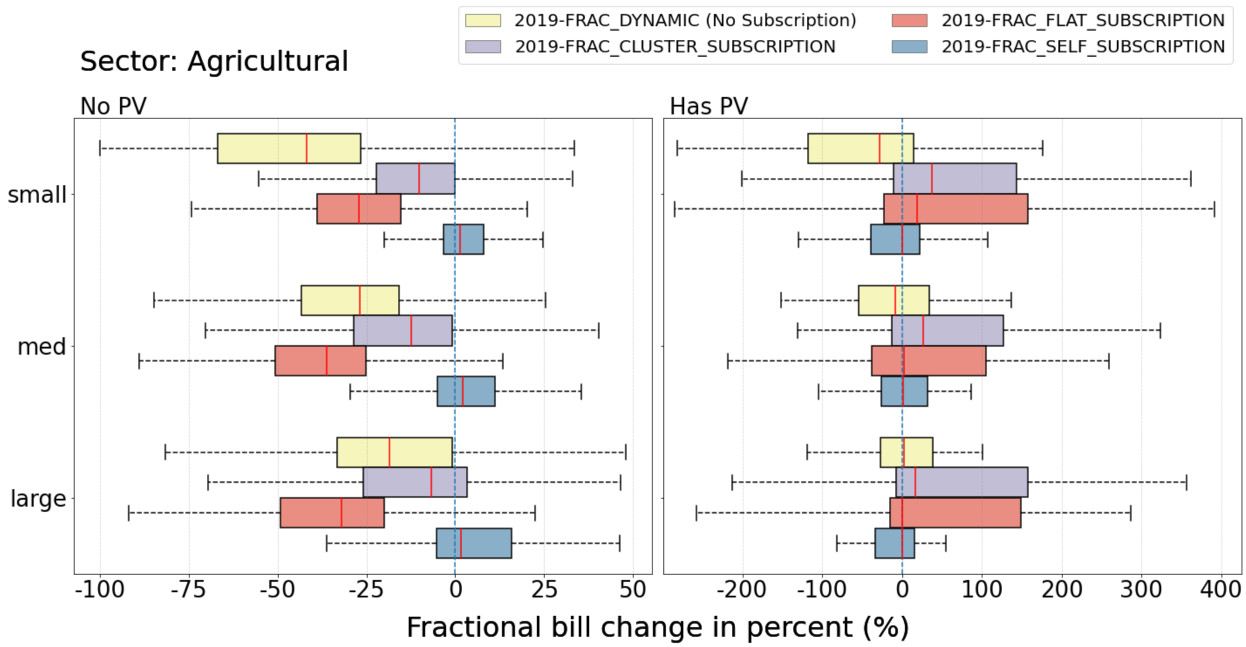

Figure 22. Distributions of bill impacts for agricultural customers without rooftop PV, under each of the dynamic tariff scenarios. Bill impacts are shown in 2019 by customer size. Bill impact distributions are presented as in Figure 6.

When we explored agricultural bill impacts by IOU, unlike for residential and C&I customers, we found substantially different results for the different IOUs. To show the variation, we present the distributions of agricultural bill impacts subdivided by IOU in Figure 23, for non-PV customers. For PG&E agricultural customers, bill impacts are fairly consistent across size categories for all tariff scenarios, whereas impacts vary considerably by size category in SCE and SDG&E service territories. Notably, the median SDG&E agricultural customer has a bill increase under the dynamic-only tariff for all size categories, and all medium and large customers see a very large increase. These results likely reflect the different nature of agricultural operations in the different parts of California serviced by each of the IOUs, as well as significant differences among the BAU tariff structures we considered for agricultural customers in the different IOUs (see Table 1).

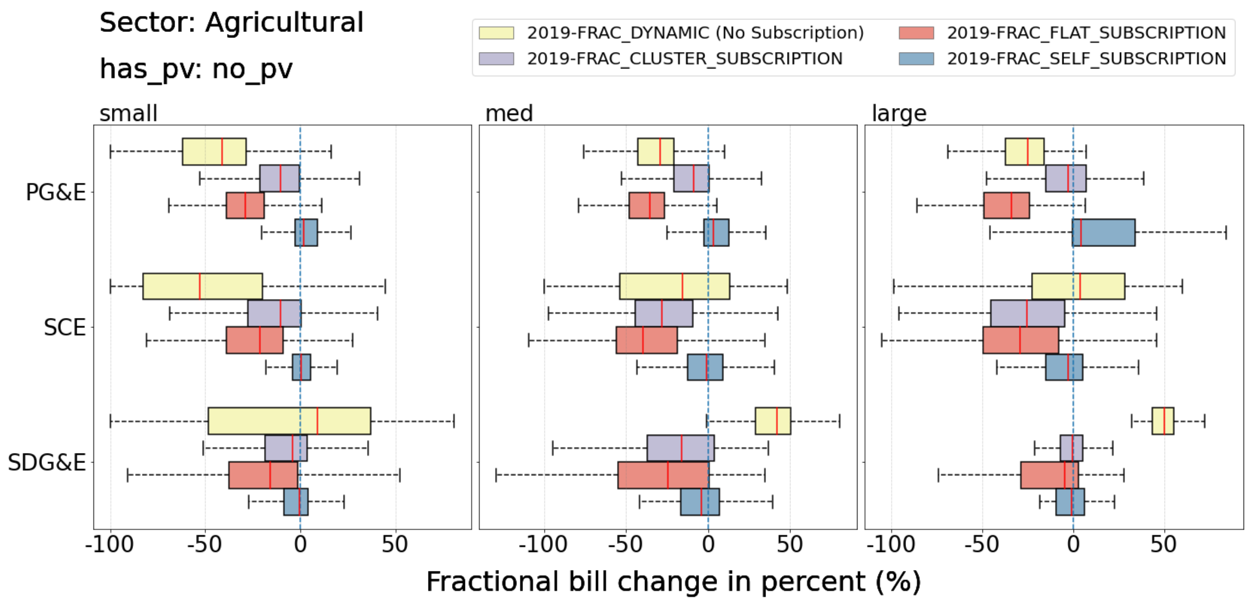

Figure 23. Distributions of bill impacts for agricultural customers without rooftop PV, under each of the dynamic tariff scenarios, by IOU. Bill impacts are shown in 2019, by IOU and customer size. Bill impact distributions are presented as in Figure 6.

6.3.2 Changes in bill volatility

Agricultural customers experience relatively high bill volatility under their BAU tariffs, with median values above 200% for all size categories, as shown in Figure 24. This high underlying volatility likely reflects the seasonal nature of agriculture. For agricultural customers without PV, the volatility impacts of the various dynamic tariff structures are qualitatively similar to what we observed for C&I customers. Volatility increases for all size categories under the dynamic-only tariff, and the various subscriptions are increasingly less effective at reducing volatility as customer size increases, with the flat-load-shape subscription yielding higher volatility than the dynamic-only tariff for medium and large customers. For agricultural customers with PV, the volatility impacts are similar to those for non-PV customers, but more muted in scale.

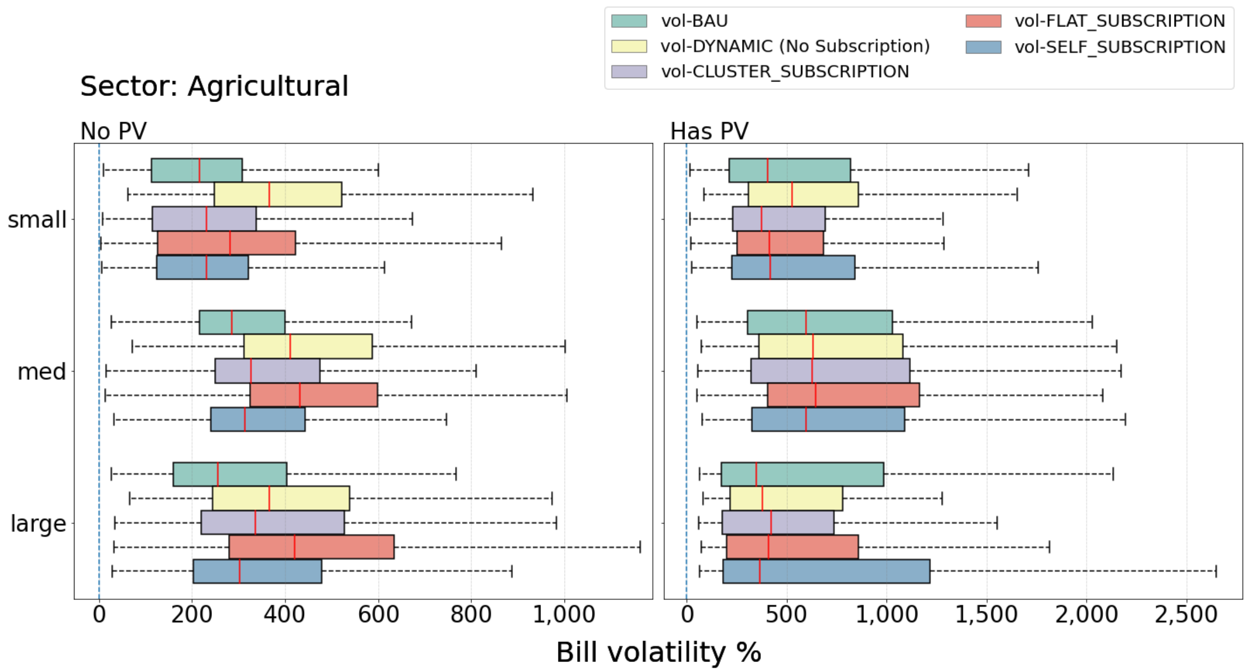

Figure 24. Bill volatility for agricultural customers in different size categories, with and without rooftop PV, under each of the dynamic tariff scenarios.

6.4 Synthesis and discussion

Taken as a whole, our findings indicate that switching to a multi-component dynamic tariff would have considerable impacts on electricity bills, and on bill volatility, for most California IOU customers, if the customers were price-inelastic. We find that these impacts are largely consistent across the years 2018 and 2019, despite the fact that these years had very different system load characteristics, and so we focus our discussion mostly on 2019. The nature and direction of these impacts, and the effectiveness of hedging with a subscription load shape, appear to correlate strongly with two factors: the importance of demand charges to the customer's BAU bill and the presence or absence of distributed PV generation at the customer's site.

First, we find that the dynamic-only tariff would yield substantial structural bill reductions for the vast majority of residential, small C&I, and agricultural customers without rooftop PV, even if the customers do not change their consumption in response to the tariff. Consistent reductions are seen for residential CARE and DAC customer subgroups as well. Because the tariff is constructed to ensure overall revenue neutrality, these decreases are necessarily offset by bill increases for other customers, namely residential customers with PV, large agricultural customers with PV, and large C&I customers with or without PV. (Impacts are mixed for medium C&I customers and small and medium agricultural customers with PV.) In other words, the universal dynamic tariff we consider here would shift costs away from residential, agricultural, and small C&I customers without PV and onto the corresponding customer classes with PV as well as onto large C&I customers.

It is important to emphasize that this result does *not* imply that some customer classes are subsidizing others under present-day tariffs. The BAU tariffs collect revenues from different customer classes based on the CPUC-approved revenue allocation methodology, which is determined in each IOU's GRC 2 rate case. Although we endeavored in section 4 to allocate utility costs to our hourly volumetric tariff in a way that reflected the varying cost of a marginal kWh of energy consumption, the formulas we used for this assignment were more illustrative than rigorous. Moreover, the costs in the “other” category (section 4.1.3) include many costs that could arguably be assigned more appropriately as per-customer fixed costs (e.g., metering infrastructure) or assigned preferentially to certain sectors or customer classes (e.g., billing services, public purpose program costs, non-marginal infrastructure costs, etc.). Notably, residential and small C&I customers have a higher proportion of their bill assigned to fixed costs in the BAU case than do large C&I customers (see Table 3). However, these differences are a matter of only a few percentage points, whereas the median fractional bill impacts seen for these customer categories are greater than 10%. Thus, cost recovery associated with present-day fixed charges is not sufficient on its own to explain the differing bill impacts. The presence of such discrepancies in impact among customer classes suggests that a transition to dynamic tariffs would require a reassessment of cost causation and cost allocation to different customer classes, to determine appropriate dynamic rate and subscription designs that achieve the desired allocations.

Secondly, we find that bill impacts under the dynamic-only tariff vary considerably by customer load shape and building type. In particular, for residential and small commercial customers, “solar-friendly” load shapes that have a high proportion of consumption during daytime hours tend to have a structural advantage that leads to higher bill reductions on the dynamic-only tariff. For medium and large commercial customers, the opposite is true: “solar-friendly” shapes tend to yield relatively poorer outcomes on the dynamic-only tariff, likely owing to the elimination of demand charges for these customers in favor of a purely volumetric rate. These results will have important implications for customer willingness to adopt a dynamic-only tariff, with customers whose load shapes are the costliest for the grid being most strongly incentivized to adopt the tariff among medium and large commercial customers, whereas residential and small commercial customers will be incentivized to adopt the tariff if their load shapes are already least costly for the grid. The latter group may also have limited ability to respond to the tariff, since they may have limited discretionary load during high-price periods, which may limit the load-modification potential of a dynamic tariff. More broadly, for customers who can save money on the dynamic tariff without modifying their consumption, there may also be concerns about “free-ridership.” However, a recent study (Todd-Blick et al. 2020) found that customers who were “structural winners” still tended to modify their loads in response to time-varying rates.

A third key finding is that the multi-component dynamic tariff, applied without a subscription component, leads to increased bill volatility for nearly all customers (with the exception of residential and small C&I customers with rooftop PV), in many cases roughly doubling the relative variability of monthly bills. For many customers, however, adding an appropriate load-shape subscription component to the tariff can serve as an effective hedge against such volatility increases. This is particularly true for residential customers without PV, for whom all three of the subscription scenarios we considered can eliminate nearly all of the increased bill volatility, with the flat-load-shape subscription being only marginally less effective than the cluster or self-load-shape subscriptions. Similar results are observed for small C&I and small agricultural customers without PV, although a slight residual increase in volatility remains under all three subscriptions for these customers.

These are striking results. Intuitively, we expect that a subscription that more accurately matches the customer’s actual load shape would be more effective at reducing bill volatility, and that a customer’s historical load shape might be the best choice of subscription in this regard. One might therefore be concerned about disproportionate volatility impacts on customers undergoing a sudden change in energy consumption patterns (e.g., the birth of a child), or for customers initiating new utility accounts, whose historical load shape is not available. Our results, however, indicate that subscription load-shape accuracy is only a weak determinant of bill volatility for residential and small non-residential customers without PV and without demand charges in their BAU tariffs, suggesting that such customers may be adequately served by a broad class-average load-shape subscription for volatility-hedging purposes. Detailed foreknowledge of the load shape is generally not necessary for these customers to hedge effectively against volatility.

For customer classes other than residential and small non-residential without PV, the effects of the subscriptions on bill volatility are different. For residential and small C&I customers with PV, the flat and cluster-load-shape subscriptions reduce bill volatility by an even larger factor than the dynamic-only tariff, likely because the subscription load shapes do not have net export in any hour, which increases the smallest bills these customers experience. The self-load-shape subscription, by contrast, yields volatility similar to the BAU tariff for these customers, but this is because the subscription load shape includes net export in certain hours, matching the customer's actual load shape.[35] For medium and large C&I and agricultural customers, the subscriptions are generally less effective as hedging instruments against month-to-month bill volatility: the subscriptions generally mitigate the bill volatility for these customers, but none of the subscription load shapes eliminate all of the volatility increases from a transition to dynamic tariffs for medium and large customers without PV. In particular, the cluster and self-load-shape subscriptions eliminate a portion, but not all, of the bill-volatility increase for these customers, while the flat-load-shape subscription has limited value in mitigating the volatility increase.

Notably, the load-shape subscriptions also tend to temper, and in some cases reverse, the annual structural bill impacts that customers experience under the dynamic-only tariff. For residential and small C&I customers, all of the load-shape subscriptions largely erase the structural benefit that occurs under the dynamic-only tariff. For medium and large customers (both C&I and agricultural), the specifics of the load-shape subscription have important implications for customer bill impacts, with the flat-load-shape subscription yielding the lowest annual bill of all the analyzed tariffs, and the cluster-load-shape subscription generally yielding the second lowest bills, while the dynamic-only tariff produces the highest bills.

These outcomes reflect a complex interaction among demand charges, subscription load shapes, and the dynamic tariff, and they speak to the importance of correctly tailoring subscription load shapes to expected customer loads when revenues need to be recovered through demand charges. Customers whose BAU bills have a large contribution from demand charges, such as large C&I customers (see Table 3), will be billed repeatedly for their daily peak demand at the dynamic volumetric rate instead of being billed once per month for their absolute peak demand. This evidently leads to increased bills. Under the flat load-shape subscription, however, these customers will pay lower demand charges than they do under their BAU tariff (since the subscription load shape has lower peaks than the actual load shape), and only a portion of their daily peak demand will be billed at the dynamic rate. This yields considerable bill reductions. Neither of these outcomes may be desirable from the standpoint of equitable revenue recovery.

[35] Because of the risks laid out in section 5.2.1, this kind of subscription load shape would likely be prohibited in a real-world implementation, which would require nonnegative subscription load in all hours.

A related finding that applies to all customer classes is the existence of a trade-off between bill size and bill volatility under subscription-based two-part dynamic tariffs. For all customer classes we analyzed, the subscription with the lowest bill volatility also yielded the highest annual bills among all subscription options and vice-versa. This observed trade-off among subscription options does not always extend to the case of the dynamic-only tariff, under which large C&I customers experience large increases in both bills and bill volatility.

Considering the findings above, a potentially least-disruptive path to a multi-component dynamic tariff emerges, from the perspective of stable revenue recovery and equitable cost apportionment. Recovering adequate revenue may be difficult if large customers experience significantly reduced bills, as occurs under the flat-load-shape and cluster-load-shape subscriptions, and there are also equity concerns if certain customer classes can achieve large structural benefits simply by being provided a load-shape subscription that doesn't accurately match their historical usage.

These issues can be mitigated by ensuring a subscription that closely mirrors each customer's historical usage. Importantly, we find that the self-load-shape subscription yields the smallest overall bill impacts across customer classes, with median impacts being mostly near zero. This subscription is also the most effective at mitigating bill volatility impacts for most customers. From a cost-recovery perspective, a dynamic tariff using this subscription option is guaranteed to be close to revenue-neutral[36] in the inelastic case, since the vast majority of customer load would be billed at the BAU tariff. At the same time, the dynamic component would still provide an incentive for customers to modify their load shape in a manner that reduces grid costs, since they could reduce their bills by shifting consumption from high-price to low-price periods, thereby capturing the difference in price. Thus, a two-part dynamic tariff, with a subscription based on the customer's own load shape (from the previous year, perhaps, or averaged over multiple years[37]) would serve to minimize impacts on both customer bills and utility revenue while incentivizing load modifications that reduce system costs and help to stabilize the grid.

7 Conclusion

This study has investigated how the bills of California IOU customers across various customer classes would be impacted by transitioning to a multi-component dynamic tariff that recovers all utility costs via a purely volumetric, hourly-varying electricity rate, for a purely-inelastic scenario in which customers do not modify their loads in response to the dynamic rate. We constructed a hypothetical dynamic tariff by assigning costs to each hour of the year for wholesale electricity, generation capacity, delivery-system capacity, and other cost categories using illustrative cost-apportionment algorithms designed to reflect the cost impacts of a marginal kWh of electricity consumption in each hour of the year. We then leveraged hourly energy consumption data for a sample of some 411,000 California IOU electricity customers to calculate customer bills under a present-day BAU tariff, under the dynamic tariff, and

[36] An important caveat is that, as noted above, customers with PV were assigned self-load-shape subscriptions that included net export in this study. For the reasons laid out in section 5.2.1, this would likely be prohibited in a real-world implementation. In that case, customers with PV would see higher bills than computed here. Accounting for this effect in the initial design of the tariff would reduce rates slightly for all customers by effectively reversing the cost-shift inherent in present-day NEM tariffs.

[37] For new customers, who lack sufficient billing history to develop a subscription load shape, our analysis suggests that a detailed class-average load shape, such as the cluster load shapes, would provide a reasonable initial subscription load shape that provides much of the hedging advantage of the self-load-shape subscription.

under a two-part subscription-based tariff that combines the dynamic tariff with a subscription load shape. We computed the change in annual bill that each customer experiences, as well as the change in their monthly bill volatility, and we examined how the distributions of these quantities changed for different customer classes under each analyzed tariff structure.

Our findings suggest that complex interactions exist among the dynamic tariff, the load-shape subscriptions, the presence of rooftop PV, and the existence of demand charges under the BAU tariffs. Small customers with PV tend to have increased bills and reduced volatility, in stark contrast to their counterparts without PV. Customers with substantial demand charges (e.g., large C&I customers) tend to experience significant bill increases under the dynamic-only tariff, but, without modifying their load, they can achieve substantial bill reductions if they are provided a subscription load shape that doesn't match their historical usage and thereby under-collects the demand charge component of their BAU tariff. This may not be desirable from the standpoint of revenue recovery or equity and points to the importance of ensuring that subscription load-shapes are appropriately designed to reflect historical usage on an individual-customer basis. By contrast, the self-load-shape subscription yields bills and volatility levels that are close to the BAU levels for most customers, suggesting that this subscription approach may be attractive from the perspective of stable revenue recovery and cost apportionment.

Our analysis in this study was limited to an inelastic scenario, in which customers are assumed not to modify their consumption in response to dynamic pricing. In reality, significant load response is likely, at least among some customer classes, and indeed, modifying load shapes would be a primary purpose of dynamic tariffs. Important future work in this area will include estimating the load-shape changes that dynamic tariffs might introduce at the customer level and determining the additional bill reductions that customers might realize thereby. It will also be interesting to investigate the additional benefits that can be achieved by introducing automation technology at customer sites. Additionally, by aggregating customer-level load modification to the system level, it would be possible to estimate the resulting reductions in system costs and revenue requirements, the long-term reductions in electricity rates that would follow, and the ensuing bill reductions that would accrue to all customers.

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