PNNL-39189

Progressing Analysis of Variable Electric Rates

March 2026

Hayden M. Reeve
Lane D. Smith
Jessica R. Kerby
Trevor D. Hardy
Carolyn D. Goodman
Sadie R. Bender
Daniel S. Boff
Jessica A. Shipley
Mitch A. Pelton

U.S. DEPARTMENT of ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

Available to DOE and DOE contractors from
the Office of Scientific and Technical Information,
P.O. Box 62, Oak Ridge, TN 37831-0062
www.osti.gov
ph: (865) 576-8401
fox: (865) 576-5728
email: reports@osti.gov

Available to the public from the National Technical Information Service
5301 Shawnee Rd., Alexandria, VA 22312
ph: (800) 553-NTIS (6847)
or (703) 605-6000
email: info@ntis.gov
Online ordering: http://www.ntis.gov

PNNL-39189

Progressing Analysis of Variable Electric Rates

March 2026

Hayden M. Reeve
Daniel S. Boff
Trevor D. Hardy
Sadie R. Bender
Jessica R. Kerby
Mitch A. Pelton
Lane D. Smith
Jessica A. Shipley
Carolyn D. Goodman

Prepared for
the U.S. Department of Energy
Under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory
Richland, Washington 99352

Abstract

This study analyzed the impact of a range of time-varying electric rates on the performance of a regional electric grid and the resulting costs for participating and non-participating customers. This analysis leveraged and extended the work of PNNL's Distribution System Operator with Transactive (DSO+T) study. Five different rate designs were included: a flat volumetric energy charge, a typical Time of Use (TOU) rate, a dynamic energy (DE) rate (based on wholesale locational marginal prices), a dynamic energy and capacity (DE+C) rate, and, finally, a Block and Swing (B&S) rate that billed customers based on their average load profile at constant pricing, but used the DE+C dynamic price for load deviations from their average profile. These rates were analyzed in a large-scale co-simulation of an entire regional grid with a customer population representative of the current state. A large fraction (80%) of residential and commercial customers were assumed to participate in these time-varying rates with automatically controlled HVAC, water heaters, electric vehicles, and batteries. This study assumed no industrial sector participation. The DE and DE+C rates saw system peak loads reduced by 6-7%, while the large participation in the TOU rate case saw a significant rebound effect and a resulting peak load increase of >5%. The impacts to the annual and peak system demand impacted system wholesale prices and the overall grid operating costs. This cost structure determined the revenue needed to be collected from customers by each rate design.

Participating customers on the DE and DE+C rates (located in one of the modeled DSOs) saw reductions in average annual electricity bills of 11-17% with average increases in monthly bill variation of no more than 13%. At such high participation levels, TOU customers saw 10% higher average annual bills (due to system-wide rebound effects) and average increased monthly bill variation of 16%. Residential owners of large flexible loads (such as electric vehicles) saw larger bill savings (17-20%) when on a fully dynamic rate. The presence of on-site generation (such as rooftop solar) did not appear to appreciably change customer outcomes. Customers on the Block and Swing rate did see 6% lower monthly bill variation (as intended) than the flat rate case, but at the expense of appreciable bill savings, which were only 3%, comparable to the savings seen by non-participants. Given this finding we recommend that additional research be conducted into how best various bill protection mechanisms can balance minimizing customer bill variation with providing financial incentives commensurate with the flexibility customers provide. We also recommend that customer outcomes be explored across a range of regions using current actual customer and system cost data.

Acknowledgments

This project was supported by the Department of Energy, Office of Electricity, Grid Controls and Communications Program. The authors would like to thank Chris Irwin for his support and contributions to shaping the scope and direction of this study.

Acronyms and Abbreviations

B&S	Block and Swing Rate
BAU	Business as Usual
BES	Battery Energy Storage
CBECS	Commercial Building Energy Consumption Survey
CPP	Critical Peak Pricing
DA	Day Ahead
DE	Dynamic Energy Rate
DE+C	Dynamic Energy and Capacity Rate
DSO	Distribution System Operator
DSO+T	Distribution System Operator with Transactive Study
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
HVAC	Heating Ventilation and Air Conditioning
LMP	Locational Marginal Price
PAVER	Progressing Analysis of Variable Electric Rates
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
RECS	Residential Energy Consumption Survey
RT	Real Time
TOU	Time of Use
TSP	Transactive Systems Program
TVR	Time Varying Rate
WH	Water Heater

Contents

Figures

Tables

1.0 Introduction

Operation of the nation's electric grid has become increasingly challenging as grid operators work to provide reliable and affordable power amid historically high levels of load growth and retirement of existing generation capacity. Traditional planning processes focus on supply-side solutions, but research and emerging trends show the practicality and value of demand side solutions to also contribute to this challenge. One approach for managing demand and reducing grid stress that utilities are adopting is the use of time-varying rates (TVR). TVRs seek to better align the electricity prices that customers pay, i.e., retail rates, with the actual cost of providing power at that time. These rates incentivize customers to shift demand to off-peak hours, alleviating strain on the grid and reducing costs for both utilities and customers. Between 2020 and 2024 the number of residential customers participating in TVR has increased 59 percent, with commercial and industrial participation increasing 16 and 19 percent, respectively [EIA, 2025]. Given these trends, there is a need for detailed analysis of how these rate structures perform at scale on a system that represents a current or near-future electric grid.

This study, progressing analysis of variable electric rates (PAVER), uses integrated system simulations to investigate the physical system behavior and economic performance of utilities and customers when increasingly dynamic retail rate structures are deployed at scale. The following rate structures are analyzed within the PAVER study:

- Flat: Residential customers are charged a declining-block flat volumetric tariff at all times. Commercial and industrial customers also have a declining-block volumetric rate, along with a monthly demand charge.
- Time of Use (TOU): Residential and commercial customers pay a predetermined volumetric rate based on the time of day and season.
- Dynamic Energy (DE): Residential and commercial customers pay a volumetric rate that varies in real time based on wholesale energy prices, i.e., locational marginal prices (LMP).
- Dynamic Energy and Capacity (DE+C): Residential and commercial customers pay a volumetric rate that, in addition to the DE rate, includes a dynamic hourly charge for capacity infrastructure investments based on system load and utilization.
- Block and Swing (B&S): Residential and commercial customers are assigned an average load profile based on monthly consumption under the Flat rate structure and able to purchase this load profile under the fixed volumetric rates. Deviations from this profile is charged or credited at a dynamic rate (in this case the DE+C rate).

A majority (80%) of both residential and commercial customers are modeled to participate in these rate structures, with varying levels of flexibility and asset ownership. Industrial electricity usage is modeled as non participating. The PAVER study uses integrated system simulations that enable analysis across individual assets, customers, utilities, the transmission system and generation dispatch. The study captures how customer responses to TVRs impact the peak demand, wholesale prices, and ultimately the annual operating expenses of the grid. These resulting annual expenses are used to determine revenue requirements that each rate recovers through customer bills.

1.1 Motivation

TVRs have proven to be a central tool that utilities use to align electricity consumption with underlying system costs and constraints. TVRs can be static or dynamic; an example of a static TVR is a TOU rate. TOU rates define fixed prices based on time of day, day of week, and season. The frequency of updating a TOU rate depends on the utility and regulator, with updates typically occurring every 1–3 years. Dynamic rates, in contrast, adjust more frequently (e.g., daily or hourly) based on grid conditions.

TOU pricing offers simplicity and predictability and has historically shifted some demand away from system peaks. However, its static nature limits its ability to reflect the variability of changing grid conditions, respond to extreme conditions, or fully capture system costs during periods of rapid load growth [Olson et al., 2023, Faruqui and Tang, 2023]. Recognizing this, the Lawrence Berkeley National Laboratory's Demand Flexibility Maturity Model positions rate design as a key driver of progress toward more advanced forms of demand flexibility, with static TOU representing an early step and dynamic pricing structures enabling higher levels of responsiveness [Schellenberg and Mims Frick, 2025]. This framing underscores the need to understand not only how static rates perform, but also when they begin to lose effectiveness as a function of adoption level and how more dynamic structures might support evolving system requirements.

Utilities are increasingly observing the shortcomings of TOU designs. One concern is the emergence of rebound peaks, which occur when customers collectively delay usage until after a TOU peak price window ends, inadvertently synchronizing load and potentially creating new system constraints in ”off-peak” times. Additionally, TOU rates generally cannot differentiate between normal operating conditions and rare, but critical, reliability events, reducing their effectiveness for system balancing. In response, many utilities implement critical peak pricing (CPP) or peak time rebate events or managed demand response and electric vehicle (EV) charging programs, which allow for more targeted and flexible load shifting to prevent rebound peaks, distribution system impacts and better align customer demand with system needs [Blair and Fitzgerald, 2024].

Recent pilots demonstrate the benefits of dynamic pricing in addressing these challenges. A California EV charging program found that dynamic pricing outperforms TOU, with 98 percent of energy delivered off-peak under dynamic structures, significantly reducing grid strain [Presswire, 2024]. Utilities are experimenting with hourly “flex pricing” options, signaling that dynamic rates are beginning to scale from pilots to mainstream offerings [PG&E, 2024]. Recent analysis further underscores that load growth pushes the grid toward a “tipping point” where static TOU signals alone are insufficient to manage demand and avoid costly infrastructure upgrades [AES, 2024].

Recent regulatory and utility activity signals a clear shift toward broader adoption of dynamic electricity rates. In 2025, the California Public Utilities Commission utilities to propose optional dynamic hourly rates reflecting marginal energy and capacity costs, with utilities now filing real-time pricing tariffs to implement this guidance [California Public Utilities Commission, 2025]. Similar trends are emerging in other states. In Illinois, The Clean and Reliable Grid Affordability Act passed in late 2025 and signed into law in 2026 requires utilities to offer optional TOU rates and embeds demand flexibility into statewide planning processes, signaling regulatory movement toward more granular and responsive rate designs [Illinois General Assembly, 2024]. In Massachusetts, grid modernization proceedings (D.P.U. 21-80, 21-81, 21-82) link advanced metering deployment to the development of TVRs [Massachusetts Department of Public Utilities, 2023]. These regulatory activities indicate that time-varying pricing is transitioning from pilot programs to broader adoption and integration into system planning.

Dynamic rates provide more granular, cost-reflective signals that encourage flexibility, mitigate cross-subsidization, and support long-term system efficiency. They also face significant adoption barriers due to perceived complexity, technology dependence, and the risk of bill volatility. Dynamic rates require careful design, automation, customer education, and consumer protections for success. While static TVRs provide meaningful benefits in managing load, they have inherent limitations, making it essential for stakeholders to assess the conditions under which these designs lose effectiveness and a transition to more dynamic pricing structures is warranted. The PAVER study contributes to this effort by analyzing the performance of increasingly dynamic rate structures at scale.

1.2 Objectives and Approach

The DSO+T study [Reeve et al., 2022b] demonstrated that, at scale, dynamic rates are an effective coordination mechanism that can greatly reduce the costs of operating the electric grid. PAVER builds on this modeling capability to analyze how various rate structures perform as they become increasingly dynamic by simulating a system in which most customers engage with the new rate designs and devices autonomously respond to time-varying retail prices. To achieve this, the study examines how rates engage flexible assets such as heating ventilation and air conditioning (HVAC) systems, water heaters (WH), battery energy storage (BES), and EVs in grid operations using an integrated modeling approach developed within the PNNL Transactive Systems Program (TSP). The PAVER study further assesses the trade-off between the complexity of dynamic rates and their effectiveness in cost recovery and coordination when deployed and adopted at scale in a system that represents the near-term future.

The goal of the PAVER study is to analyze the impact of rate design on the physical and economic performance of the grid when adopted at scale. In doing so, the study addresses several pressing questions facing the industry today:

- Under what conditions might utilities and regulators need to transition from static TVR structures like TOU to more dynamic options?
- What balance of dynamic features within a rate design best supports customer bill stability and predictable participation, while still sending the right incentives across diverse customer types and assets?
- To what extent can dynamic rate structures address broader system objectives—such as reducing peaks, deferring infrastructure investments, and improving cost allocation effectiveness?

The PAVER study compares four rate structures against a flat rate by simulating a system in which 80 percent of customers participate in the rate structure and customer assets respond autonomously based on customer-set flexibility preferences. The degree of flexibility offered is randomized across the customer population. The amount of customer assets and the generation mix are modeled to represent a grid that is likely to emerge within a decade, as detailed in Section 2.1 of this report.

Both the engineering and economic performance of the system are assessed this study. Engineering performance is measured in terms of the ability of flexible assets to provide stable grid services. Peak load reduction and load variation are key output metrics. The integrated market simulation also provides insights into wholesale energy market performance, including variation in LMPs under the different rate designs. As noted in [Reeve et al., 2022a], the simulations capture average prices but under represent price volatility, limiting the impact of extreme price variations captured in the study. Economic performance is analyzed both at a system-wide level, based on total annualized costs for owning and operating the power system (including capital borrowing, infrastructure, flexible assets, and operating and maintenance costs), and at a customer level, based on building characteristics, customer flexibility, and asset types.

The assessment uses an integrated co-simulation and valuation framework that encompasses the entire electric system, from bulk generation and transmission, to the distribution system and individual buildings and assets, developed within the DSO+T study [Reeve et al., 2022b, Reeve et al., 2022a, Pratt et al., 2022a]. The bulk system simulations include both generation and transmission systems, along with day-ahead and real-time scheduling and dispatch of thermal generators. Eight distribution system operators (DSOs), or utilities, are modeled, along with over ten thousand residential and commercial buildings. Flexible end uses responding to time varying price signals are modeled within the buildings based on a customer flexibility parameter.

Autonomous asset participation is modeled using agents for HVAC, WH, EVs, and BES. The agents estimate physical asset behaviors over a 48-hour period and optimize responses based on expected retail prices and customer preferences. This 48-hour forecast load is updated each hour, and under dynamic rates, the agents revise real-time strategies accordingly. Forecast uncertainty is incorporated through price and weather forecasting modules within the simulation [Widergren et al., 2022]. Rather than modeling customers as price-taking actors, the customer demand bid allows for the expected asset responses to be integrated directly into wholesale market conditions, which in turn form the dynamic price signal. This is essential for an analysis of large-scale adoption, as the impacts of customer assets are not negligible to system operations and should not be treated as exclusively price-taking.

Post simulation the analysis of utility costs and customer bill impacts can also be completed. Using the load impacts and resulting wholesale energy market impacts, the utility impacts are analyzed based on the economic framework described in [Pratt et al., 2022a]. Utility expenses for wholesale purchases, distribution system capital, and utility operations are calculated based on simulation outputs. This analysis produces the utilities total expenses for the year simulated, which is also the revenue requirement that inform the rates that are reflected on customer bills. In practice, rates are based on historical data and years of experience. Since the study simulates only one year the analysis is designed to allow rates to be adjusted to ensure revenue collection requirements. After-the-fact rate making enables a customer bill analysis results to reflect the results of the simulation.

By simulating customer behavior, asset flexibility, and system operations within an integrated analysis framework, the study enables a rigorous comparison of rate structures across both engineering and economic dimensions.

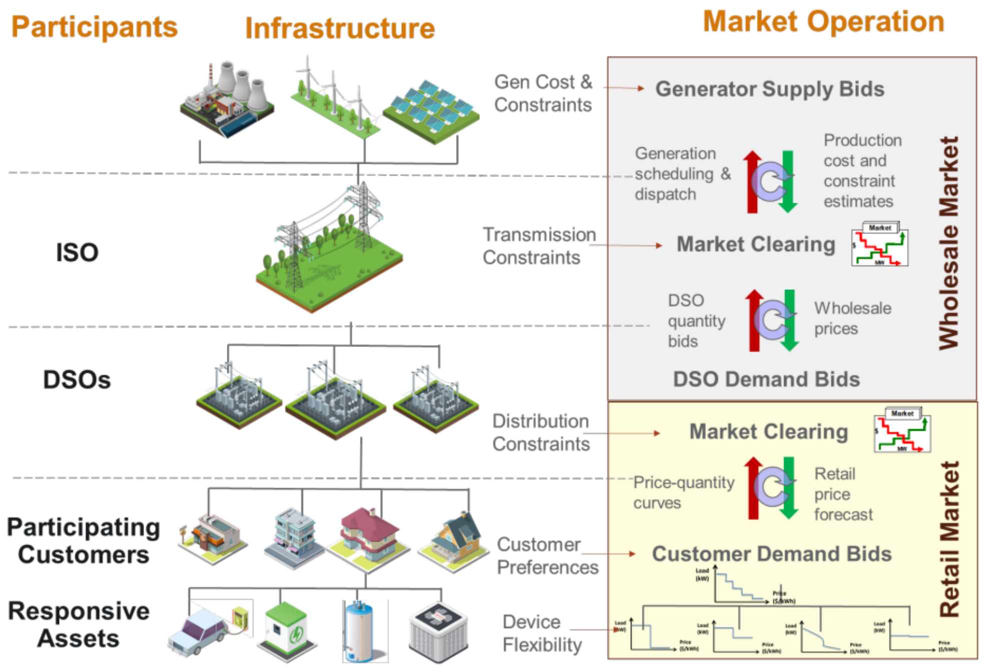


Figure 1: Overview of integrated wholesale and retail market operations [Widergren et al., 2022].

1.3 Report Structure

Following this introduction, this report will present on the PAVER study design. This section will include documentation of the assumptions and sources that informed the system design and the rate design methodology for the rates included within the study. Next, there is a discussion of the results from the PAVER study, comparing each retail price signal, the resulting demand profiles, bulk system and utility impacts, and the resulting customer bills. Following the results is a discussion section that covers rate design and flexible asset considerations. Finally, the report will conclude with a summary of key findings and recommendations for future research directions.

2.0 Analysis Design

This section describes the PAVER study analysis design, including the system on which the rates are evaluated and the rate use cases themselves. Each rate structure is modeled with the same generation profile, customer asset deployment, and participation rates. The objective of the system parameters is to represent a system that is likely to exist within the decade. The system parameters that inform the simulation models primarily include generation mix, flexible asset prevalence, and customer participation and flexibility. The rates that are modeled aim to capture rate design elements consistent with emerging structures being deployed and rate design best practices. The guiding principles that inform the rate design focus on effectiveness in revenue recovery, simplicity, customer acceptance, supporting cost causation and fair cost allocation, and ensuring effective grid coordination. Together these elements provide the basis for understanding how different rate structures perform when applied at scale.

2.1 System Design

2.1.1 Customer Assets

The flexible assets modeled within the customer building are defined to reflect expected near-term distributions. The building populations modeled followed the approach detailed in the DSO+T study [Reeve et al., 2022a], with updated residential building population generation to include additional household characteristics described in [Goodman et al., 2025]. The residential and commercial building types modeled are based on the most recent Residential Energy Consumption Survey (RECS) and Commercial Building Energy Consumption Survey (CBECS) completed by the EIA. The distributions of building types and other key building parameters are derived from the relevant state or census region being modeled, for PAVER this is the Texas or West South Central geography. This approach results in a simulated building population of over ten thousand residential and commercial buildings that represent the current state in terms of major building characteristics. Due to the lag in survey data and the growth of flexible assets, the team used available data and forecasts to define the prevalence of flexible assets such as electric WHs, EVs, rooftop solar photovoltaic (PV), and BES in the residential building population rather than modeling the values reported in the Texas 2020 RECS data.

Table 1 shows the prevalence of customer assets within the households that are simulated. The 2020 RECS provides state level data on many of these assets [EIA, 2023], which is supplemented with forecasts and assumptions to model a near term future of flexible customer assets. The RECS data for Texas shows that over 95% of households used space heating or cooling equipment, and that 87% of households used equipment types that were assumed to be programmable or controllable, which was interpreted as flexible and used to define the prevalence of flexible HVAC equipment. RECS reported that 55% of homes in 2020 used electricity for water heating and that nearly 30% of WHs were over a decade old. Assumptions around electrification upon replacement of electric water heating led to 65% of households modeled with electric water heating. The 2020 RECS showed a very low percentage of households with EVs in Texas despite national projections that over 26% of light duty vehicles on the road in 2035 will be electric [Satterfield et al., 2024]. The PAVER study assumed an 8% prevalence of EVs in households. Similarly, Texas had very low rate of on site solar generation in homes within the 2020 RECS data while some states neared 10%. Given these adoption trends, 11% of households were modeled to have rooftop solar. BES are assumed to be present in a small fraction (3%) of households.

Table 1: Summary of customer flexible asset population

Flexible Customer Asset	Prevalence in Households
HVAC	87%
Water Heaters	65%
Electric Vehicles	8%
Battery Storage	3%
Rooftop Solar	11%

2.1.2 Customer Participation and Flexibility

In addition to the prevalence of flexible assets, the analysis required assumptions regarding the participation in the TVR and the amount of flexibility available from individual customers and assets. Participation indicates that the customer is enrolled in the TVR and that their flexible assets are exposed to the TVR signal. For each rate it was modeled that 80% of customers participated and the remaining 20% continued service on the Flat rate. How responsive any given asset is to the TVR depends on the flexibility of the customer, referred to as a slider setting and described in [Widergren et al., 2022], which is modeled as a random uniform distribution that is not correlated with any customer characteristic. The flexibility of customers is modeled between 0 and 1, with 0 representing no flexibility and 1 representing the most flexible customers who prioritize cost savings, shown in Figure 2. It is important to note that a flexibility setting of 0, meaning no flexibility does not correlate with non participation in the rate. Unlike non participants, participating customers with 0 flexibility will still be exposed to the non-flat rate despite not being willing to flex any of their load. Approximately 20% of customers that are enrolled in the TVR are not responsive, which is a phenomena intentionally modeled to capture at-scale impacts since pilot populations and early adopters are likely more flexible and engaged than what would be observed on average at scale.

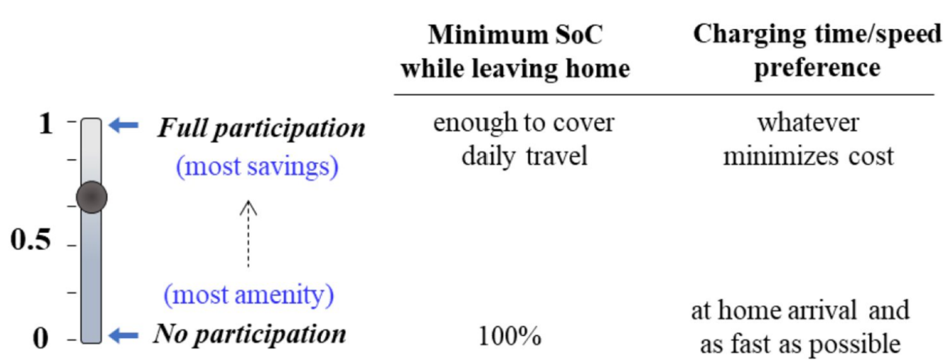


Figure 2: Example of customer flexibility setting on EV charging

2.1.3 Generation Fleet

The PAVER study uses the generation fleet (the “High Renewable Scenario”) from the DSO+T study that most closely reflects the current mix of dispatchable and non-dispatchable generation in ERCOT currently. The modeled generation profile compared to the 2024 ERCOT energy fuel mix can be shown in Figure 3 [ERCOT, 2024]. In 2024 the ERCOT system had 65% of energy sourced from thermal generators (nuclear, gas, and coal) versus 57% in this analysis. Variable generation (wind and solar) effectively makes up the remainder (34% versus 42%). Ultimately, the DSO+T study found that the simulated resulting LMPs are generally representative of the region. Dispite the generation fleet differences mentioned above the LMPs calculated in this study (presented later) appear representative of the more moderate system prices seen in ERCOT.

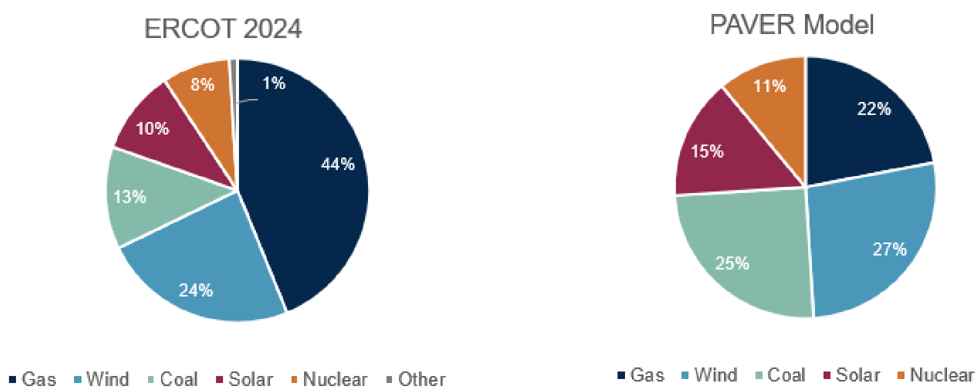


Figure 3: Comparison of modeled generation mix to 2024 energy generation in ERCOT.

Whereas the DSO+T study analyzed the same two rate structures with different system assumptions, the PAVER study keeps the system constant across all use cases to isolate differences in rate performance. All system aspects discussed within Section 2.1 remain constant across each rate that is simulated.

2.2 Rate Design

Retail electricity rate design has long been guided by a set of foundational rate making principles, most notably those outlined by James Bonbright and adapted by regulators and utilities[Bonbright, 1961]. These principles emphasize objectives such as rate simplicity, revenue sufficiency, fairness, economic efficiency, and customer acceptance and continue to serve as a benchmark for evaluating rate structures. Modern interpretations increasingly highlight the growing importance of flexibility and customer engagement as rates and technology evolve to support a more dynamic grid [Glick et al., 2014].

These principles provide a valuable framework, but they often stand in tension with one another. A rate that is highly effective at achieving a fair apportionment of costs between rate classes, for example, may not be easily understood or accepted by customers. Conversely, a rate that is designed to maximize stability and predictability for customers may fail to send the right incentive for shifting load or investing in flexible technologies. These examples underscore that no single principle is easily maximized in isolation without compromising another, and that the success of a given rate structure is dependent on customers and stakeholders determining what rate is the best option for a given customer class.

Retail rates serve a dual purpose in the operation of the grid as both a cost recovery mechanism and a control signal used to influence customer behavior. As a recovery mechanism, rates must generate sufficient and stable revenue to fulfill the utility's revenue requirement. At the same time, as a control signal they guide customers toward behaviors that align with system constraints such as reducing peak demand. This analysis studies how rates perform as a control signal within the integrated simulation model and how customer billing is completed to ensure revenue requirements are met. Balancing the dual functions of rates is challenging and highlights the inherent trade offs within rate design. For example, a rate that exposes customers to granular, cost-reflective signals promotes efficiency and system flexibility but is often a more complex rate with the potential to increase bill volatility. Conversely, rates that emphasize simplicity and predictability often sacrifice cost causation and fail to fully reflect the operational realities of the grid. This tension between accuracy and simplicity remains central to retail rate design, and this study explores how rates perform as they move along the spectrum of static to dynamic providing insights into the opportunities and challenges of designing rates.

The following rates are designed and analyzed as use cases within the PAVER study to capture the progression from static, to fixed time-varying, to fully dynamic rates and provide insight into their relative performance when deployed at scale:

- Flat: Residential customers are charged a declining-block flat volumetric price at all times. Commercial and industrial customers also have a declining block volumetric rate, along with a monthly demand charge.
- Time of Use (TOU): Residential and commercial customers pay a predetermined volumetric rate based on the time of day, day of week, and season.
- Dynamic Energy (DE): Residential and commercial customers pay a volumetric rate that varies in real time based on a retail market cleared price that is informed by wholesale energy prices, i.e., LMP.
- Dynamic Energy and Capacity (DE+C): Residential and commercial customers pay a volumetric rate that in addition to the DE rate, recovers capacity costs in a dynamic hourly charge for infrastructure investments based on system load and utilization.
- Block and Swing (B&S): Residential and commercial customers are assigned an average load profile based on typical seasonal consumption and are able to purchase this load profile under a fixed rate structure. Deviations from this profile are charged (or credited) at a dynamic rate. This rate is implemented as a billing mechanism that utilizes the simulated customer and system outputs from the flat and DE+C use cases.

With the exception of the Flat rate scenario, a combination of participating and non-participating customers are considered, where the participating customers take service under the rate structure being analyzed and the non-participating customer are served under the Flat rate. The Flat rate use case is the only use case that all customers take service under the same rate, all other rates are analyzed with 80% participation in the TVR.

The following sections describe the rate design methodology for the five rates included within this study, with detailed price formation formulas included in Appendix A.

2.2.1 Rate Design Elements

When billing customers for their electricity use there are common elements such as connection charges, volumetric energy charges, and, in some cases, demand charges. The components used within the PAVER study are defined as:

- Fixed Monthly Charges: These do not change from month to month based on customer usage, these are also sometimes referred to as a customer charge or basic charge. Often seen as the price of being connected, these apply to each customer in a customer class and do not change frequently. Fixed charges are not impacted by customers' behavior or total consumption and are set to be $10 per month within the PAVER analysis for all rates under consideration.

- Volumetric Charges: These are charges that are billed on a price per kWh basis. In the Flat rate case, the price per kWh remains constant, so volumetric charges vary only with total consumption. In non-flat rate cases, volumetric charges depend on the price at the time consumption occurs. In the PAVER study, volumetric prices are calculated post-simulation to ensure revenues from customer bills matched DSO expenses. Within the simulation, flexible assets make operational decisions based on expected price changes in the retail market, independent of the post-simulation billing adjustment.

- Demand Charges: This aspect of a rate is charged based on the customer's maximum power usage in a specified period. The measurement for a demand charge is assessing the highest usage period (usually an hour or less) that took place within a billing cycle. These are most commonly billed on a $/kW basis and included for commercial and industrial customers, who also typically experience a lower volumetric price than residential customers. Demand charges are applied to peak system periods, where the charge is based on the highest consumption during the peak period times within a billing cycle.

2.2.2 Flat

The Flat rate structure includes a fixed monthly connection charge, a volumetric energy charge, and a peak demand charge for non-residential customers. The fixed charge of $10 per month applies to all customer classes. All customers are subject to a declining block rate structure and commercial and industrial customers also have a monthly maximum demand charge of $15/kW. The declining block structure has decreasing rates for higher quantities of consumption and is implemented to represent that larger commercial and industrial customers typically have lower volumetric rates than small commercial and residential customers.

2.2.3 Time of Use

The TOU rate modeled also includes a $10 per month fixed charge, a $15/kW monthly maximum demand charge for commercial and industrial customers, and volumetric energy charges. The TOU rate has a schedule for the volumetric energy portion of the rate that customers pay. The TOU rate modeled in the PAVER study is a two-part TOU rate, meaning there are on-peak and off-peak prices based on the time of day and season. The peak and off-peak rates are defined by a ratio, the PAVER study uses a three-to-one ratio for peak-to-off-peak prices, a higher ratio is regarded in the literature as being more effective at eliciting consumer response [Faruqui et al., 2019], Hawaiian Electric Company having been lauded for implementing the same ratio [Spector, 2022]. The on- and off-peak volumetric rate that customers are charged is calculated post simulation to ensure that the DSO meets revenue requirements. Within the simulation the flexible asset agents are exposed to the ratio of peak vs off-peak rates and make operational decisions based on the expected changes in prices.

The summer and winter TOU schedules are shown in Figures 4 and 5, respectively. Summer and winter TOU schedules are modeled based on commonly observed season and peak period definitions, with the summer schedule in effect from May through October and the winter schedule in effect from November through April. The total peak-period duration is six hours for both the summer and winter schedules, with the summer schedule including one consecutive evening peak (4-10 PM) and the winter schedule including two three-hour peak periods, one in the morning (6-9 AM) and one in the evening (5-8 PM).

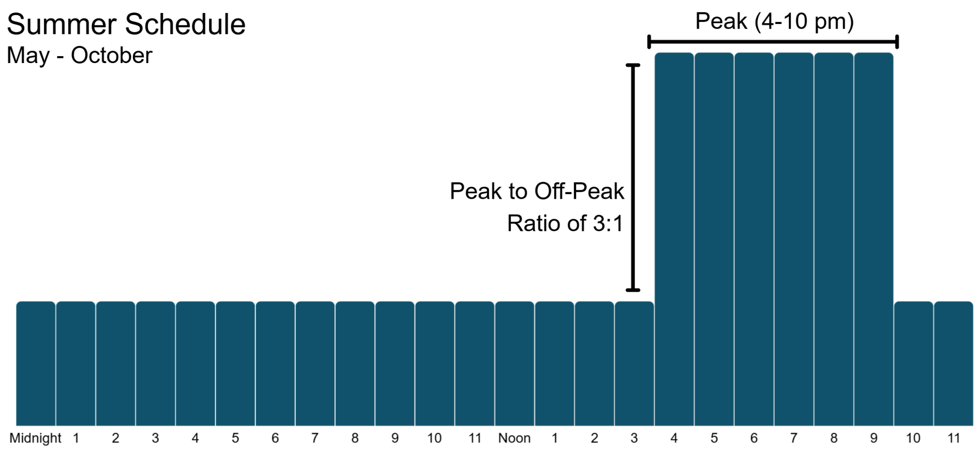


Figure 4: TOU Volumetric Component Summer Schedule

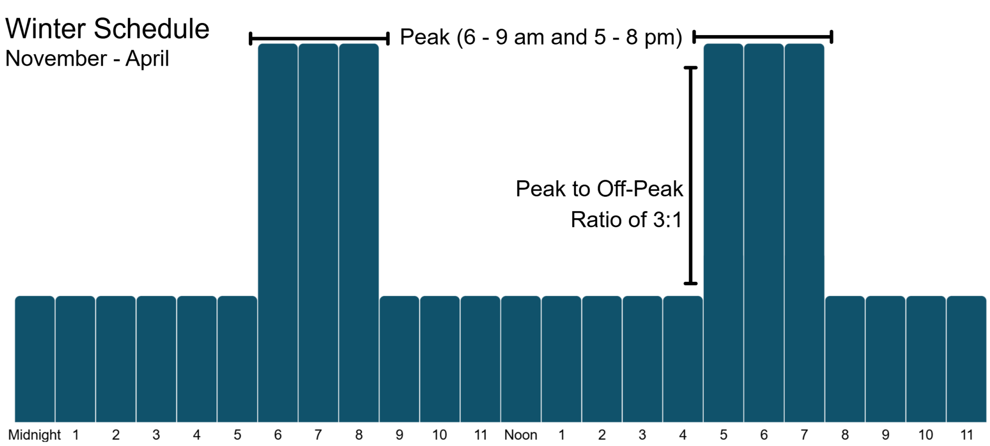


Figure 5: TOU Volumetric Component Winter Schedule

2.2.4 Dynamic Energy

The PAVER study includes two dynamic retail rate use cases using the retail marketplace designed to integrate into an existing day-ahead and real-time wholesale energy market. The flexible assets optimize a 48-hour operational plan based on the day-ahead market prices and adjust to real time. The retail market operator aggregates the operational plans as demand bids and clears them against a forecast supply curve in a double auction mechanism, more details on the retail marketplace can be found in DSO+T study documentation [Reeve et al., 2022b].

The first dynamic rate structure analyzed within the PAVER study is a dynamic energy (DE) rate structure. This rate structure includes a fixed charge of $10 per month and does not include a demand charge. Volumetric charges under this rate structure vary in real time based on market conditions. The volumetric charges within the DE rate have two separate components:

Energy Cost: this is the dynamic energy cost that reflects wholesale energy prices and losses. This would be LMPs or index pricing at the most relevant bilateral hub when LMPs are not available.

Delivery and Fixed Cost Recovery: this is the static portion of the volumetric rate that reflects the elements of costs that are appropriately allocated to customers based on consumption but not present in wholesale prices. This would include infrastructure costs and general utility operations and maintenance costs. The magnitude of this fixed volumetric recovery charge is set such that sufficient revenue is collected to cover the DSOs expenses.

2.2.5 Dynamic Energy and Capacity

The dynamic energy and capacity rate (DE+C) builds on the DE rate described in Section 2.2.4 and adds a dynamic capacity cost recovery component within the volumetric energy price. This method for recovering infrastructure costs applies to generation and transmission infrastructure capital costs within the PAVER study. First, the cost to be recovered is defined. For the PAVER study this represents the capital portion of generation and transmission infrastructure costs. The system's load duration curves then serve to define a utilization pattern against which the annualized costs are allocated. This approach recovers infrastructure costs in the hours that the respective infrastructure is actually utilized, meaning capacity that is developed to accommodate a few hours of a system peak carries a high volumetric rate in those hours to recover the associated costs. An example of this approach is shown in Figure 6.

The inclusion of the capacity volumetric charge renders the DE+C rate inherently more variable than the DE rate, as it shifts more of the fixed system costs from being recovered uniformly across the year to being only recovered the hours it is utilized. This rate component operates similar to a CPP mechanism: it reduces the system costs recovered through the volumetric energy rate for a majority of hours in a year and results in higher prices in the hours coincident with system peak demand.

2.2.6 Block and Swing

The B&S rate, also often referred to as a subscription, hybrid, or two-part real-time rate, aims to expose customers to dynamic price signals while providing bill protections through a fixed price hedge. In this context hedge is referring to a general strategy that can protect consumers from price volatility, not a specific investment product. The block and swing price is a combination of static and dynamic volumetric prices where the customer procures a portion of their expected load at a predetermined rate and pays dynamic rates for usage above or below the predetermined quantities. This rate structure is discussed recently in the literature as a potential way to expose consumers to dynamic prices without overexposing them to the associated risk

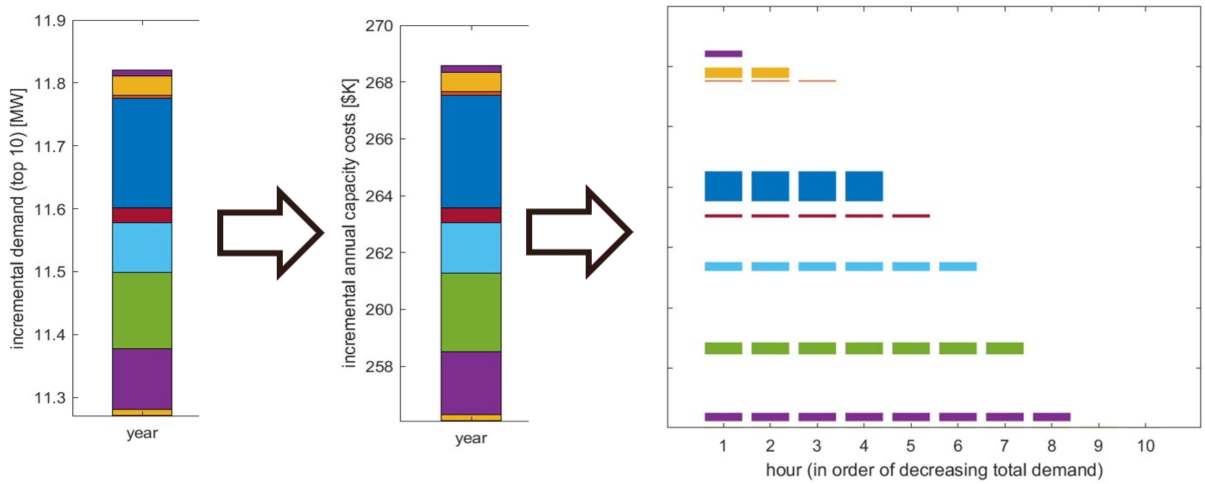


Figure 6: Example of Capacity Cost Allocation to Hourly Schedule

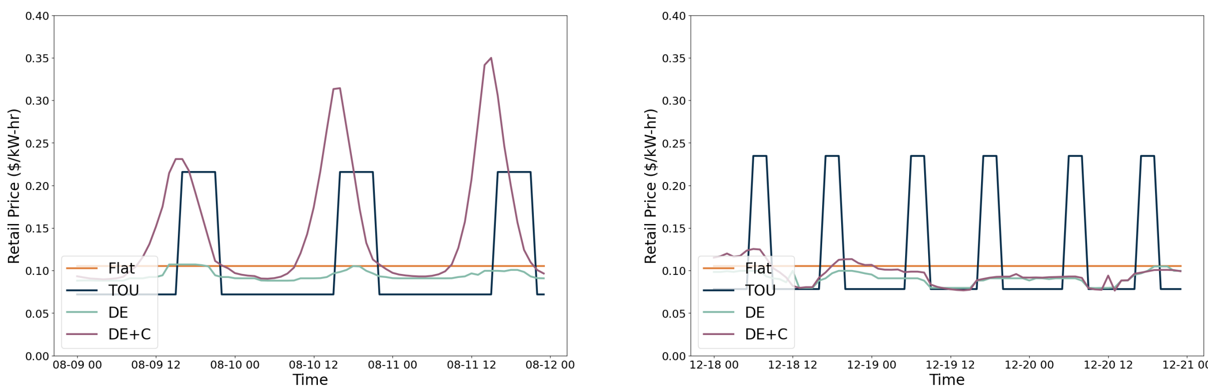
[Wolak and Hardman, 2021], [Madduri et al., 2022]. While dynamic pricing is recognized in the economic community for improved economic efficiency, the risk of bill volatility has caused hesitancy towards implementing market based prices without protections. This rate structure provides a hybrid option that exposes customers to the opportunities of dynamic prices with significant bill protections and has been implemented within Georgia Power's "Real Time Pricing - Day Ahead" [Georgia Power, 2024] rate and the TeMix RATES Pilot administered in the Southern California Edison service territory [Cazalet et al., 2020].

Within the B&S rate, a monthly weekday and weekend baseline demand profile is developed using the individual customer's demand profile under the Flat rate. The volumetric energy charges for a customer's baseline demand profile are billed according to the Flat rate structure, while deviations from this profile are charged, or credited based on the DE+C real time price described in Section 2.2.5. Customer bills under the B&S rate include the fixed $10 per month customer charge. This mimics the real-world implementation strategy of using a customer's historical demand to define baseline demand profiles when a customer moves from a flat rate to a B&S rate. Because the B&S rate is a billing mechanism that consists of the flat and DE+C rate signals, it was analyzed in post-simulation utilizing the simulated outcomes from those rate use cases. Within the results shown in Section 3.0 the B&S rate will only be included within the customer billing results.

3.0 Results

This section presents key simulation results, starting in Section 3.1 with a summary of the different retail price profiles associated with the rate designs considered in this study. The response of customer assets to prices signals and resulting changes in net demand profile and bulk system impacts are presented in Section 3.2. These changes in system demand and wholesale prices alter the cost basis of the distribution utilities' operation, which are presented in Section 3.3. Finally, the changes of overall utility costs affect customer bills in aggregate. Furthermore, the various rate designs can impact various customer classes differently. These effects are discussed in Section 3.4.

3.1 Retail Price Signal Comparisons



(a) Summer

(b) Winter

Figure 7: Example residential retail prices for (a) peak summer days and (b) example winter days (DSO 1).

Examples of the four simulated retail prices signals are presented in Figure 7. All four rate designs are structured to sufficiently recover system costs, however as will be seen in Section 3.3 each rate design can result in different system costs and therefore differing average retail prices. In this example, the residential Flat rate recovers a constant \$0.105/kWh for DSO 1. The TOU rate has a summer evening (4-10 pm) peak price of \$0.216/kWh and an off-peak rate of \$0.072/kWh (to achieve a three-to-one price ratio). The winter TOU peak rate (6-9 am and 5-8 pm) is \$0.234/kWh, with an off peak price of \$0.078/kWh.

The two dynamic rates' price signals are a combination of a dynamic day-ahead prices and a constant volumetric price. The DE rate has a constant volumetric component (in this case \$0.066/kWh) and a dynamically varying component that tracks the associated wholesale LMP. This results in prices ranging from \$0.074/kWh - \$0.121/kWh throughout the year. The DE+C rate extends the DE rate by adding a component to recover capital costs based on utilization, as detailed in Section 2.2.5. This extra component results in a lower required value for the constant price component (in this case \$0.052/kWh). This means that while the DE+C price is higher during peak system loads it is typically lower than the DE price signal during periods of low load for most of the DSOs modeled. The DE+C rate has prices ranging from \$0.076/kWh - \$0.351/kWh throughout the year.

Note that the DE+C rate only exceeds the TOU on-peak rate during periods of actual system peak load (as shown in Figure 7). Even in August, when demand is typically at its highest, there are times when the daily peak DE+C price is below the TOU on-peak price. This feature is amplified during winter and shoulder seasons. Furthermore, the timing of the DE+C peak price varies during the day and season ensuring the price reflects actual grid conditions and making it more accurate and efficient. Finally, because the DE+C rate collects revenue through this dynamic energy and capital cost recovery the fixed volumetric portion is lower than the Flat rate, resulting in times when the total DE+C rate can be lower than than the corresponding Flat rate even at certain times of the peak day (for example, the summer mornings in Figure 7).

In the case that each rate must recover the same amount of revenue, the DE+C rate has a considerable number of times where its price is lower than the DE rate. The simulation resulted in slightly higher annual operating costs for DSO 1 for the DE+C case versus the DE case, meaning the DE+C rate shown in Figure 7 is recovering more revenue than what is shown for the DE rate. This is the case for DSO 1, but system-wide the DE+C rate resulted in lower costs than the DE rate. (Note that the B&S rate utilizes the DE+C price structure but utilizes a different billing structure and its impact on customers will be introduced in Section 3.4.)

3.2 Resulting Demand Profile and Bulk System Impacts

This section details the impact that the various price signals have on net system demand and resulting wholesale market energy prices.

3.2.1 Demand Profile and Load Impacts

Examples of the total net system demand (by end-use) for summer and winter peaks are shown in Figures 8 and 9. The plots stack the industrial loads (grey), plug and miscellaneous loads (olive), HVAC loads (cream), WH loads (blue), and EV loads (green). PV and BES impacts (red dashed lines) are then subtracted or added to this total gross customer demand. Finally, distribution system losses are incorporated to determine the total system net load (black line). In the PAVER study industrial loads are considered flat, residential and commercial plug and miscellaneous loads are assumed to be price inelastic.

The flat case, as expected, does not promote any flexibility and demand shifting in customer assets. This serves as a reference for the other cases and is referred to as business as usual (BAU). The TOU case does result in load reductions during the peak periods. However these benefits were offset by substantial demand rebound effects, primarily from HVAC, when the off-peak price periods resume. Finally, the DE and DE+C cases avoid demand rebound phenomena due to having price signals that avoid large discrete step changes in price. In all three TVR use cases the participating assets (HVAC, EVs, and WHs) shift demand to the night-time period increasing minimum demand.

Direct comparisons of the summer and winter load profiles for the various price signals are shown in Figure 10. Figure 11 presents monthly statistics for both total system load and daily variation in load. These figures show that the rebounds associated with the TOU rate design are seen throughout the year resulting in increased peak loads. The peak TOU load increased 3.8 GW (5.4%) above the flat case (Table 2). In comparison the DE and DE+C rate designs reduce peak loads 6.7% and 6.4% respectively, potentially freeing up over 4 GW of system capacity. Just as importantly, the TOU rate is shown to increase diurnal demand variations by >16% on

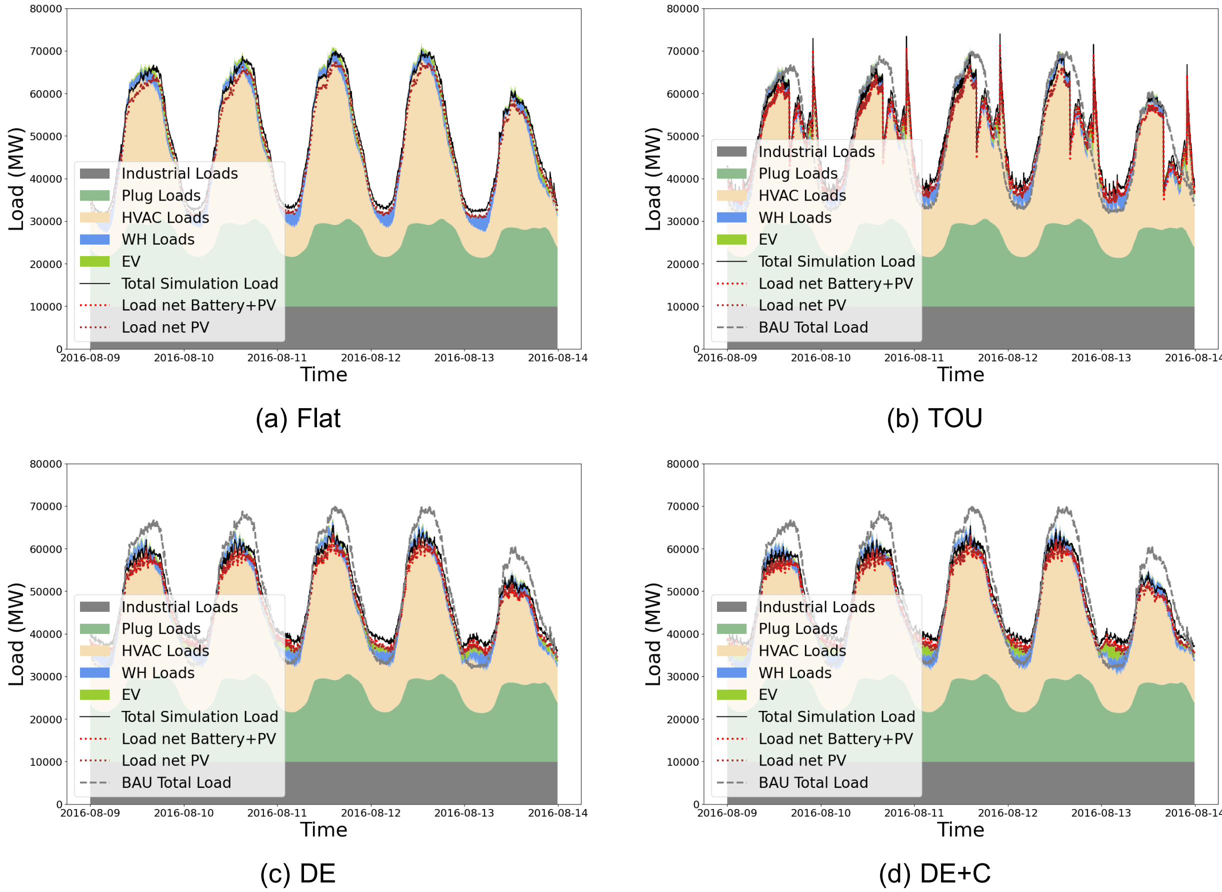


Figure 8: System summer peak loads (by end-use) for the (a) Flat, (b) TOU, (c) DE, and (d) DE+C cases.

average whereas the DE and DE+C cases decrease daily load variations by over 20%. This is most notable in the spring and early summer when daily load variations comparable to peak summer operations occur in the TOU use case.

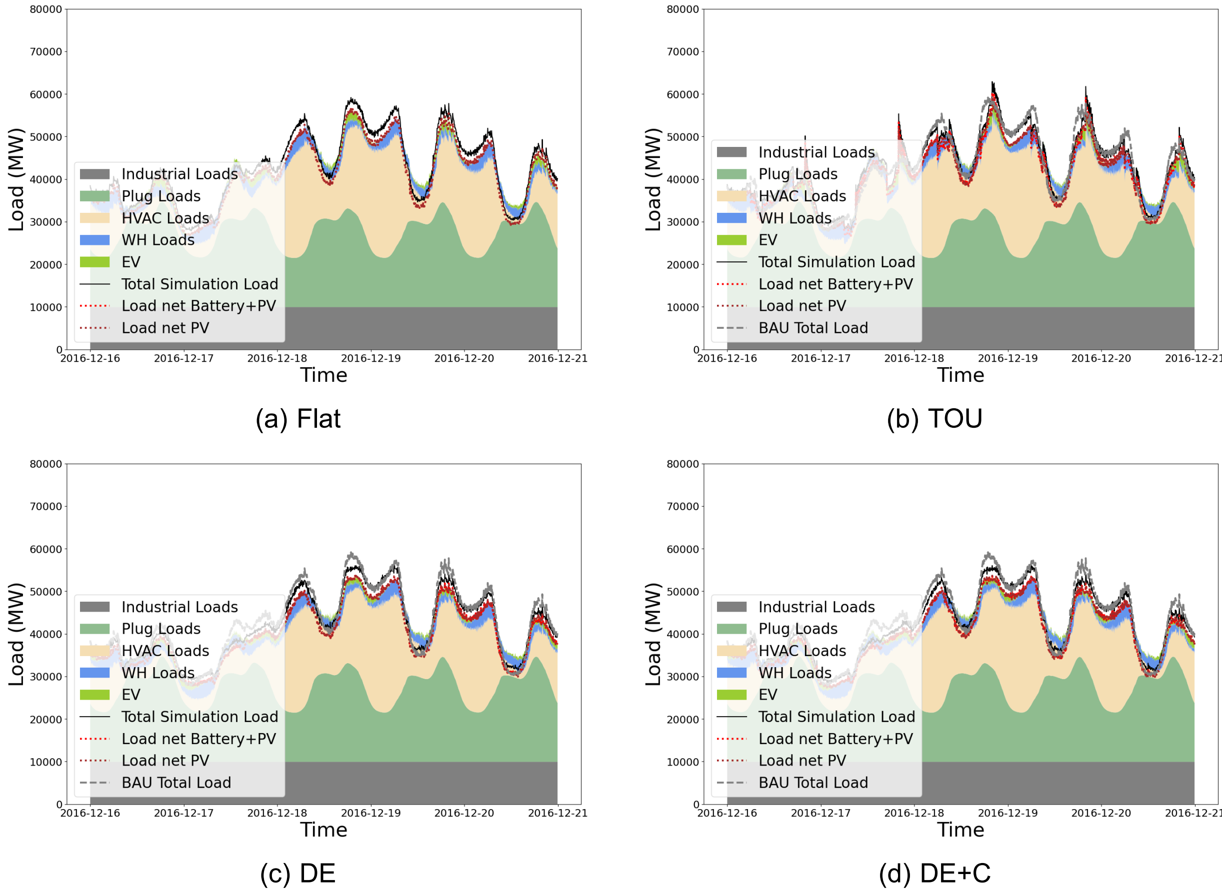


Figure 9: System winter peak loads (by end-use) for the (a) Flat, (b) TOU, (c) DE, and (d) DE+C cases.

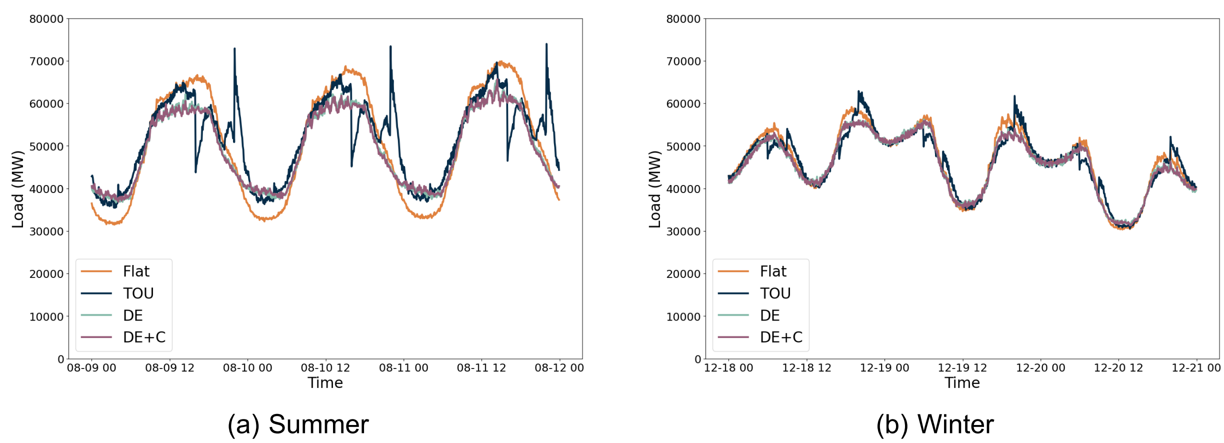


Figure 10: Comparison of total system load profiles for (a) summer and (b) winter.

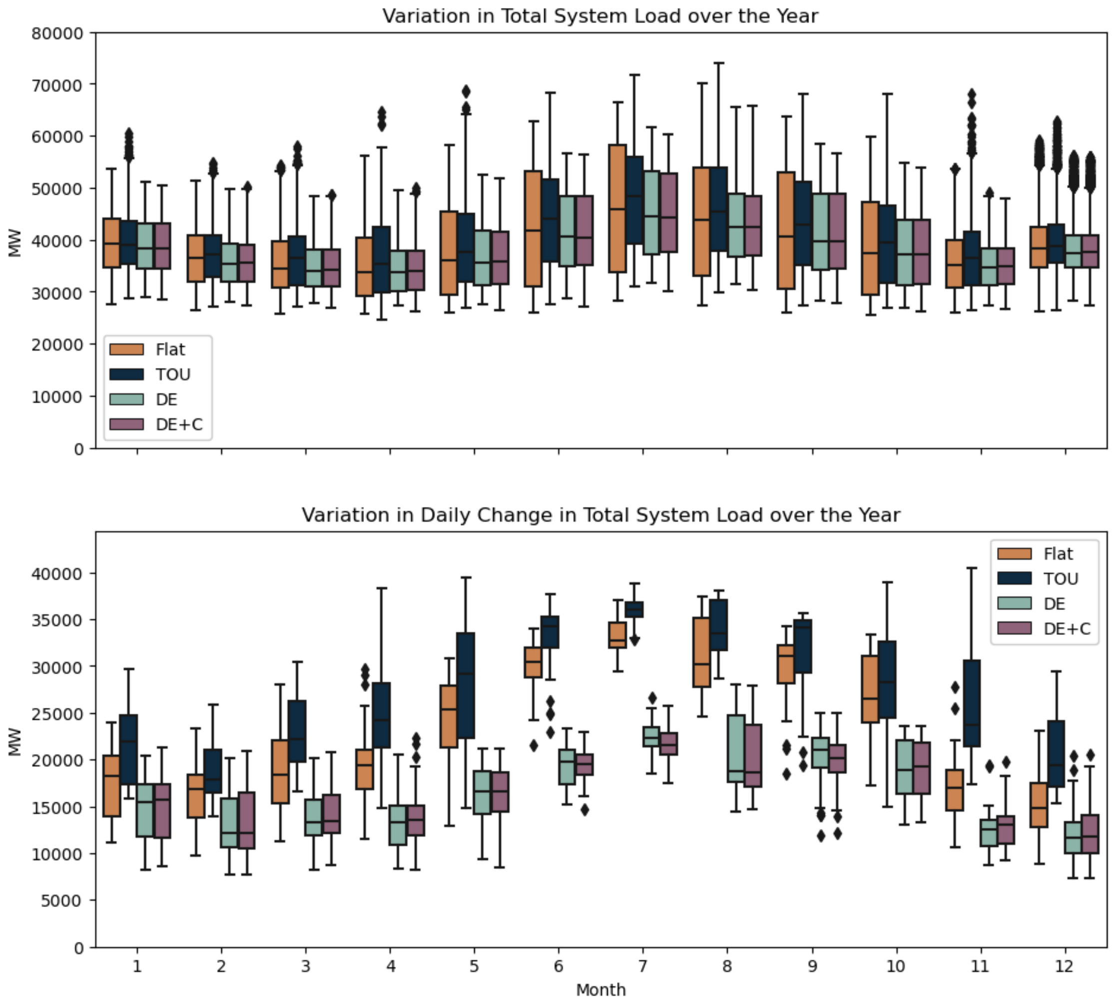


Figure 11: Monthly summary of system load (top) and daily variation in system load (bottom) for the various rate designs.

Table 2: Summary of annual average, maximum, and minimum loads as well as the average daily change in load for all cases.

	Flat	TOU	DE	DE+C
Average (MW)	39,439	40,571 (+2.9%)	38,640 (-2%)	38,629 (-2.1%)
Max (MW)	70,176	73,983 (+5.4%)	65,492 (-6.7%)	65,699 (-6.4%)
Min (MW)	25,626	24,623 (-3.9%)	27,011 (+5.4%)	26,188 (+2.2%)
Average Daily Range (MW)	23,453	27,268 (+16.3%)	16,531 (-29.5%)	16,527 (-29.5%)

3.2.1.1 TOU Sensitivity Analysis

The large TOU rebound is not an indication that such time varying rates do not currently provide benefits, only that when rates with discrete and sudden price changes are presented to a large population of autonomously participating loads, rebounds and other unintended consequences can occur. This study investigated a range of peak period times and durations as well as participation levels. We found that the rebound effect started to introduce new system peaks at participation rates above approximately >50% (see Figure 12). We also explored changing the start time and length of the peak period to better align the TOU rate with system conditions. Given that the daily summer peak load can occur at varying times of day over the season and that the rebound effect can become larger for longer peak periods we were not able to meaningfully improve the at-scale TOU performance presented in Figures 8 and 9.

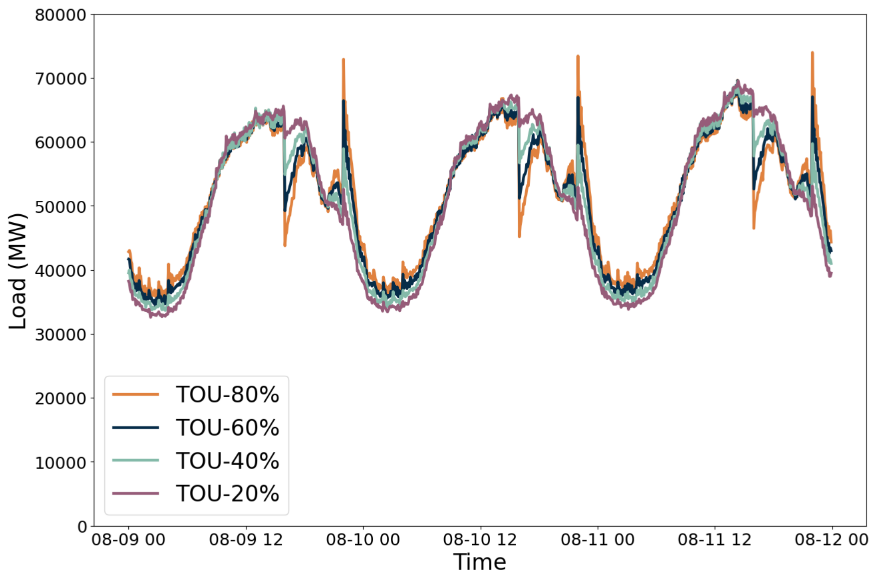


Figure 12: Comparison of TOU case load profiles as a function of participation rate.

3.2.2 Wholesale Energy Market Impacts

The forecast and actual system-wide net demand is used to solve a Security-Constrained Unit Commitment and Unit Dispatch (SCUC/SCUD) model of the transmission system and bulk generation assets. As shown in Figure 13, this determines the required generation mix (of nuclear, coal, natural gas, wind, and solar generation) to meet the system demand. This integrated simulation of the bulk system model is primarily performed to determine the wholesale LMPs for both the Day-Ahead (DA) and Real-Time (RT) markets, as these prices can form the basis of key components for dynamic retail prices.

A summary of DA and RT LMP statistics for the rate analysis is provided in Table 3. While RT LMPs are communicated to customer assets to enable real-time corrections in demand flexibility, for this study the retail rate design and customer billing was solely based on DA LMPs whose variation over the year is shown in Figure 14.

The dynamic retail price approaches (DE and DE+C) not only shift demand from periods of higher prices (e.g., afternoons and evenings) to periods of lower prices (e.g., later evening and early morning) these rates should also lower the wholesale market LMPs during peak periods due to the lower load and reduced need to dispatch higher cost generation. On average the DE and DE+C cases altered annual DA LMPs only $\pm 5\,\%$.

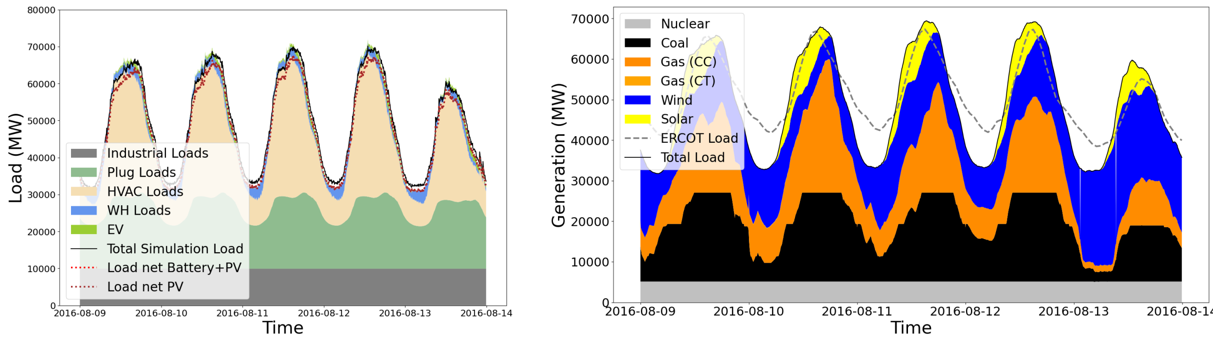


Figure 13: Peak summer system loads (left) and wholesale market generation mix (right) for the Flat case.

Table 3: Summary of annual average day-ahead and real-time LMPs ($/MWh) and average daily change in prices for each case.

	Flat	TOU	DE	DE+C
Day-Ahead LMP: Annual Average	24.4	28.4 (16.6%)	23.3 (-4.5%)	25.8 (5.7%)
Day-Ahead LMP: Average Daily Range	21.6	14.2 (-34.4%)	17.3 (-19.9%)	19.7 (-8.7%)
Real-Time LMP: Annual Average	23.7	23.1 (-2.5%)	25.8 (8.8%)	48.4 (104.1%)
Real-Time LMP: Average Daily Range	59.3	77.7 (30.9%)	61.3 (3.3%)	209.4 (252.9%)

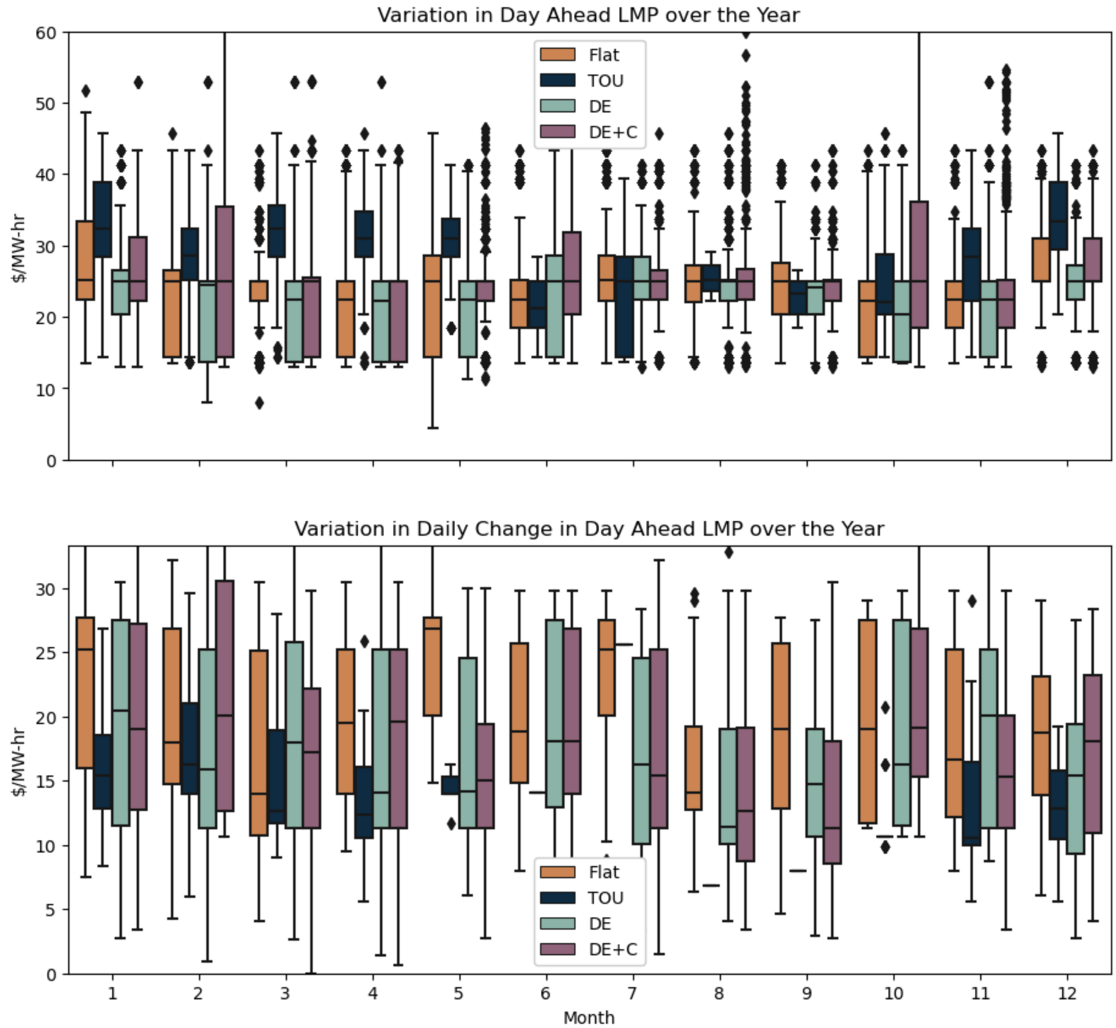


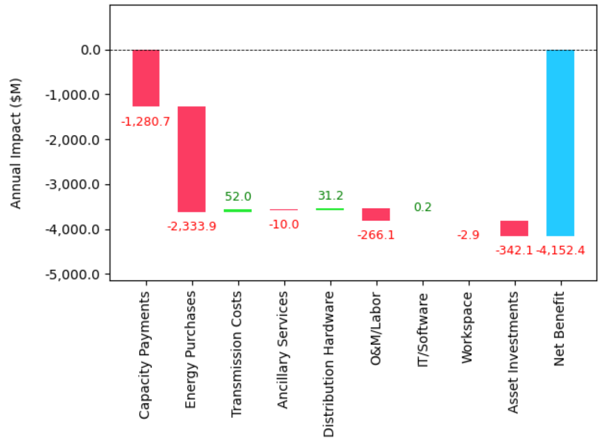
Figure 14: Monthly summary of wholesale day-ahead energy prices (DA LMP) (top) and daily variation in DA LMP (bottom) for the various rate cases.

3.3 Resulting Utility Cost Impacts

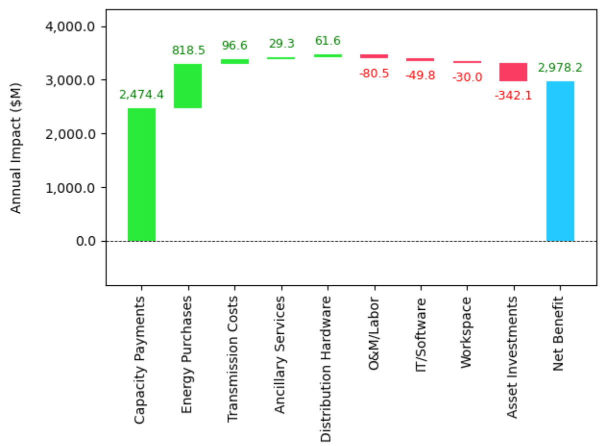
The resulting changes to the total utilities' operating costs across the region for each case are summarized in Figure 15. It is important to note that these costs estimates are for general grid operation and are intended to be illustrative to show the system-wide proportional benefits and costs associated with various rate designs. Results for an actual utility may vary. In addition, while the system implementation is modeled after the ERCOT region, this analysis does assume the presence of a capacity market. The presumption of a capacity market allows for the valuation analysis to distinguish between the impacts of shifting demand to off peak times and avoiding infrastructure build out. The cost estimates for capacity and other DSO costs are based on the economic framework described in [Pratt et al., 2022a]. Actual benefits and costs will be dependent on regional conditions, market performance, and spare system capacity.

The DE and DE+C see overall utility annualized costs reduce 10-16%. The overall system cost benefits stem from two major sources: decreased peak loads reducing needs (and hence payments) for generation capacity, and shifting energy demand resulting in lower wholesale energy costs. The PAVER study finds that in the DE and DE+C cases the economic benefits of generation capacity and wholesale energy equate to approximately $3.3-5.3B per year in savings. For the TOU case where the rebound effect can increase system peak loads and shift energy consumption to time periods immediately adjacent to the peak periods the analysis shows increased capacity and energy procurement costs of $3.6B/year. Potential savings on transmission access fees, ancillary services, and distribution system capital costs were found to be second order in this analysis.

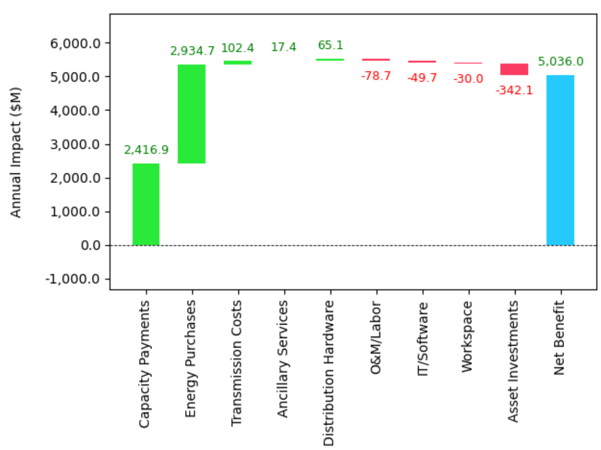
Achieving the potential benefits noted above requires implementation of advanced coordination schemes and equipment on both the utility and customer side of the meter. The cost basis for this was assumed to be the same for all the TVR use cases and was based on [Pratt et al., 2022a]. Implementation costs included estimates for staffing and IT systems for communicating and billing these advanced retail prices. The results shown in Figure 15 reflect the net impact of potential savings and implementation costs for the DSO. In addition, estimates were made for customer costs associated with upgrading to smart devices (e.g., smart thermostat and EV charger installation). Since the adoption of dynamic rates is nascent and has not been deployed at scale it is expected that cost estimates will mature in the future. Utility and customer implementation costs are estimated to be a small fraction of system wide benefits with net benefits for the DE and DE+C cases estimated between $3-5B/year.



(a) TOU



(b) DE



(c) DE+C

Figure 15: Summary of changes in regions' utility annualized cash flow between the Flat and (a) TOU, (b) DE, and (c) DE+C cases showing the economic benefits and costs of implementation.

3.4 Resulting Customer Bill Impacts

This section presents the impact that various retail rate structures and their resulting system-wide cost savings have on the customer population. It starts with a summary of energy usage and Flat rate costs across various customer classes. It then summarizes how various rates recover revenue for an average customer and how this varies throughout the year. Finally, analysis of the utility bill impacts for various customer classes is presented.

The B&S rate is presented within this section of results. This rate structure is designed to provide customers with the incentive signal of a dynamic rate while providing bill stability. The customers on the B&S rate responded to the DE+C price signal and provided the same flexibility results, producing identical system benefits as the DE+C results shown. The customer bill impacts between the two cases differ, as the B&S structure is designed to reduce the risk of bill volatility to the customer and in doing so impacts the amount of bill savings that participating customers see.

3.4.1 Summary of the Customer Population

The PAVER study simulated a range of customer, building, and asset ownership types. This allows estimates and insight into the impact that various customer classes might experience under various rate designs. This section provides a summary of key electricity metrics such as total usage, peak customer load and costs across customer types for the flat case in order to describe the BAU conditions.

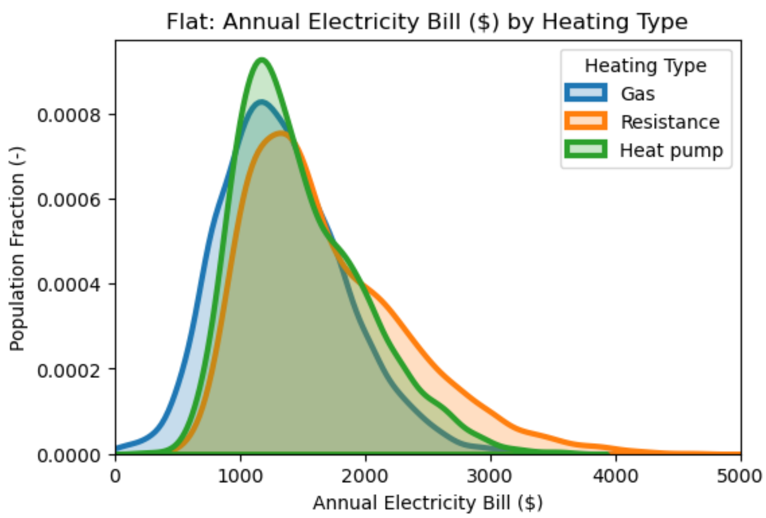
Table 4: Residential customers' average electricity metrics by heating system type for the flat case

Metric	All Residential	Gas	Heat Pump	Resistance
Annual Energy (kW-hrs)	12,720	11,500 (-10%)	12,670 (0%)	15,150 (19%)
Peak Load (kW)	8.6	6.5 (-25%)	9.4 (10%)	11.5 (35%)
Annual Electric Bill ($)	1,480	1,350 (-9%)	1,480 (0%)	1,720 (17%)
Effective Cost of Electricity ($\kw-hr)	0.116	0.117 (1.1%)	0.117 (0.8%)	0.114 (-2%)

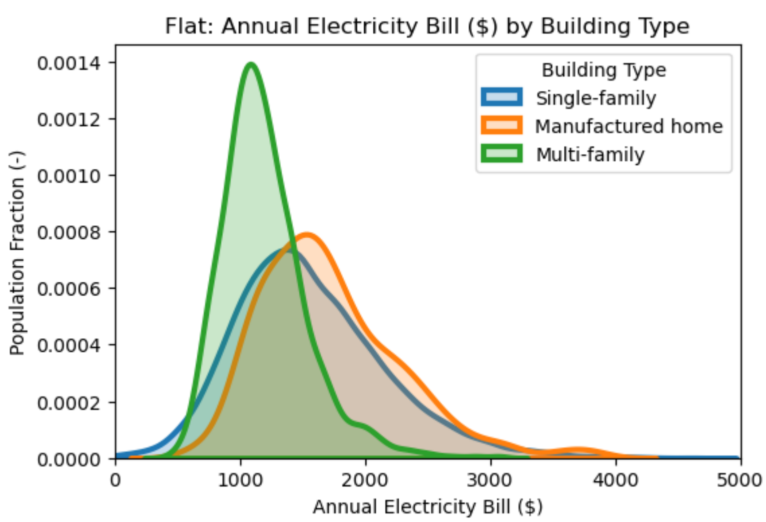
Table 5: Residential customers' average electricity metrics by building type for the flat case

Metric	All Residential	Single-Family	Multifamily	Manufactured
Annual Energy (kW-hrs)	12,720	13,490 (6%)	9,870 (-22.4%)	15,060 (18.4%)
Peak Load (kW)	8.6	8.9 (4.1%)	7.1 (-17.6%)	10.4 (21.8%)
Annual Electric Bill ($)	1,480	1,550 (5.2%)	1,190 (-19.3%)	1,710 (16%)
Effective Cost of Electricity ($\kw-hr)	0.116	0.115 (-0.8%)	0.121 (4%)	0.114 (-2%)

For example, the simulated customer population included a mix of residences with gas, heat pump, and electric resistance heating. As shown in Table 4 and Figure 16(a) customers with gas space heating experience the lowest electricity consumption, demand, and resulting bills. As expected customers with heat pumps have lower consumption and bills versus customers with electric resistance heating. Similarly, energy consumption and costs varied across single-family, multi-family, and manufactured homes (Table 5 and Figure 16(b)). Single-family homes use more electricity than multifamily units, which is expected since they are typically larger and have more exterior walls. Manufactured dwellings consume the most electricity, likely due to inefficiency and a lower availability of natural gas. This analysis also incorporates how customer income levels are associated with housing characteristics and subsequently annual electricity bills (Figure 17).

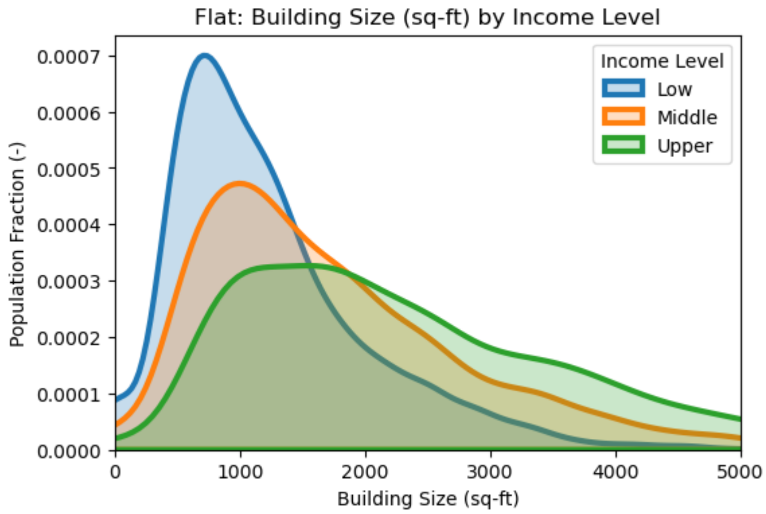


(a) Annual bill by residential heating system type

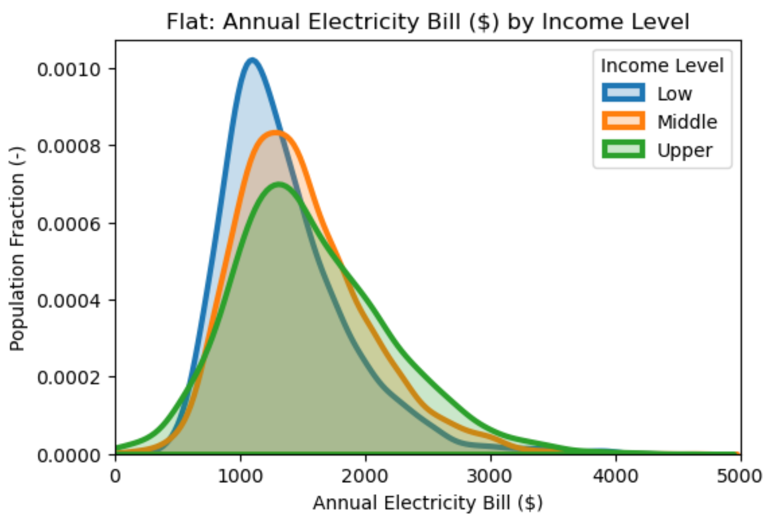


(b) Annual bill by residential building type

Figure 16: Annual residential electricity bill by (a) heating system type and (b) building type for the Flat case (DSO 1)



(a) House size by income level



(b) Annual bill by income level

Figure 17: Residential customer (a) house size and (b) annual electricity bills by income level for the Flat case. (DSO 1.)

3.4.2 Rate Design Impact on Customer Bills

Figure 18 shows illustrative examples from DSO 1 of the average participating residential customer electricity bill broken out by bill component for typical months as well as the annual average bill. The seasonal weather dependence of loads results in higher bills during the summer peak (August) for all rate use cases. All rates also have an identical monthly fixed connection charge of $10/month. The average TOU bill is higher than the Flat rate in order to ensure that additional cost recovery is attained, as is necessitated by the system impacts discussed in Section 3.3 above.

For DSO 1 residential customers participating on both the DE and DE+C rates see reduced annual average bills compared to the Flat rate. Note that in this analysis DSO 1 saw slightly higher resulting wholesale costs under DE+C versus the DE case resulting in slightly higher customer bills. This was not the case in all DSOs modeled and the DE+C rate did produce overall lower system-wide costs. The average customer bill for the entire system would not result in the higher bill for DE+C compared to DE as is shown in Figure 18. System-wide, customers participating in the DE+C rate do see 13% larger monthly variations in bills due to the larger capital cost recovery during peak months (e.g., August). However, due to overall system cost savings the average peak bill is only slightly higher (3%) than the typical August bill for the Flat rate. The shift of capacity cost recovery within the flat volumetric energy charge versus the dynamic volumetric charge can be seen by the proportion of the charges reflected in green and light blue in Figure 18.

Finally, the B&S rate is effective in moderating monthly variations in customer bills' size, but seemingly at the expense of passing benefits onto participating customers. For DSO 1 the average B&S participating customer bill is comparable (within 3%) to what they saw under the flat case despite a 4% decrease in total consumption. Section 3.4.3 below will present a more detailed comparison of relative savings of participating and non-participating customers across the entire region. In addition, Section 4.2.1 provides discussion on possible underlying reasons that customers on the B&S rate may not experience significant savings.

Figure 19 shows a summary of the monthly bill variation, as well as each customer's difference from the Flat case, for the entire residential customer population of DSO 1. These trends are consistent with those seen in Figure 18: TOU customers pay more on average, DE and DE+C customers pay less most of the year, with a sizable portion of DE+C customers paying slightly more in July and August. B&S customer see much lower bill variation but do not experience the larger savings seen in other rates in the winter and shoulder seasons. A greater discussion on the drivers of bill variation is provided in Section 4.2.

3.4.3 Customer Impacts by Participation and Rate Class

Table 6 provides a summary of key electricity metrics for all DSO 1 residential customers simulated in this study. In particular, it compares the outcomes of participating and non-participating customers for each TVR compared to the flat case. In each case non-participating customers stay on the Flat rate, the structure of which has been recalculated to ensure that, in aggregate, it collects the same revenue from all non-participating customers as would have been collected if they were on the TVR. Non-participating customers therefore do not react to prices in any of the simulations and their annual energy consumption and peak loads are practically unchanged. TOU participating customers, on average, do see a slight increase in annual energy consumption, potentially due to the substantial use of HVAC systems at the end of TOU peak periods to return to off-peak set points when outdoor air temperatures are still high and HVAC system efficiency would be lower. DE and DE+C participating customers see slight average decreases in annual energy consumption. Participating residential customers see very minor decreases (<2%) in peak loads across all time varying rates, despite much larger system-wide peak load reductions (>6%). This is due to dynamic rates incentivizing the shifting of peak customer loads away from system-wide coincident peak periods, rather than the reduction of individual customer peak loads (as would be expected with a non-coincident monthly demand charge).

The changes in customers' annual electricity bill are also shown in Figure 20 as probability distribution functions. Both participating and non-participating customers see increased annual electricity bills in the TOU case. This is due to the increased revenue collection required to cover the increased system costs associated with unintended consequences (such as the large

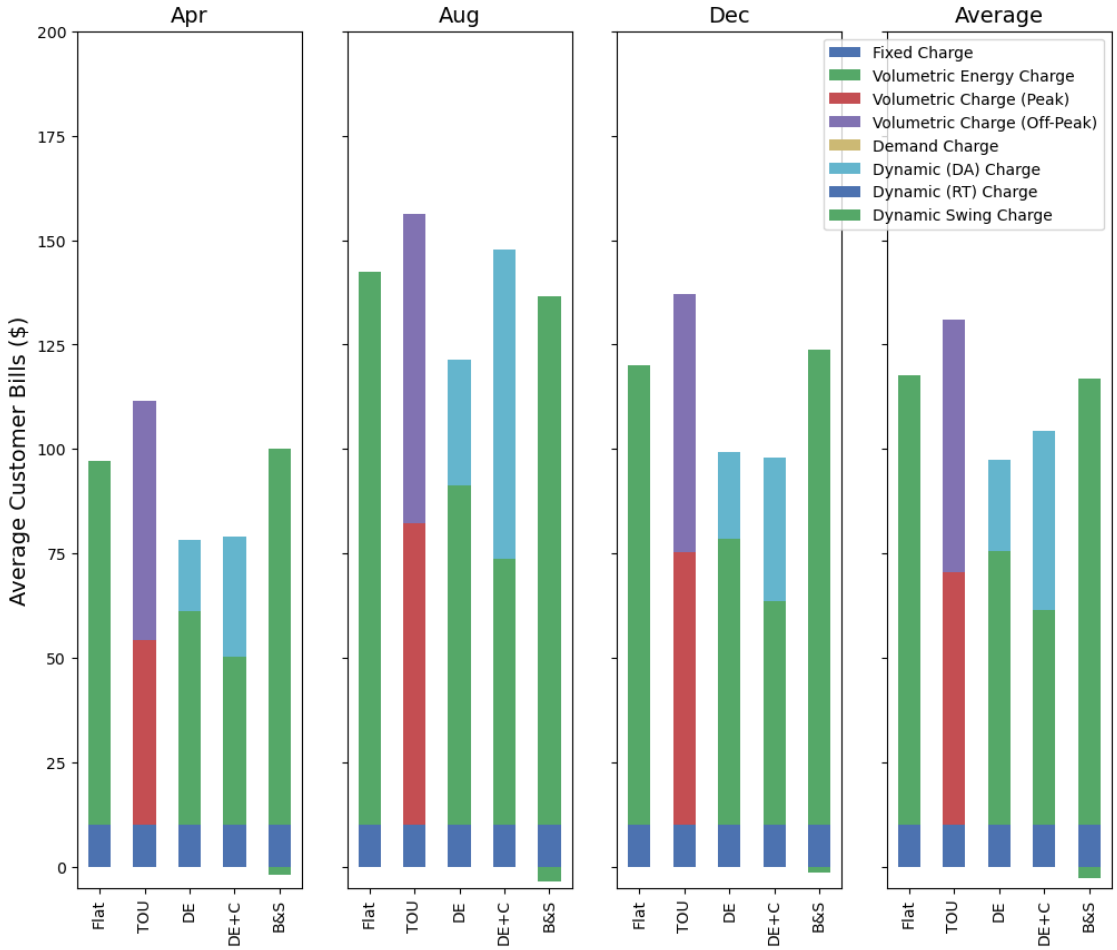


Figure 18: Summary of average residential customer bills broken out by component for key months and the annual average. (DSO 1)

rebound peak and the potential to move peak loads to periods of still relatively high wholesale energy costs). Both the DE and DE+C rate designs see substantial savings for participating customers (>10%) and negligible to small (∼1%) savings for non-participating customers. This results in bill rewards for customers who provide system flexibility and relatively unchanged costs for non-participants. Note that some other DSOs in the simulation saw non-participants see increased bills (up to 10%). This will be discussed more in Section 4.2.3.

Finally, residential customers participating in the B&S rate only saw minor benefits of 3.1% bill savings, which was slightly less than their total electricity usage reductions and bill savings for non-participants[1]. As seen above in the monthly bill analysis (and in Table 6), this particular subscription rate design achieves lower bill volatility (17% lower than the DE+C rate and, in fact, a lower volatility than the flat case) at the expense of conveying only 27% of the bill savings seen in the DE+C case to participating customers, despite providing the same level of flexibility. Discussion of potential mechanisms that may be resulting in B&S customers paying more than

[1]Note that customers of both the DE+C and B&S rates saw the same dynamic prices and provided the same response, netting identical system benefits. As such the population bill savings are, in aggregate, the same. For the B&S rate design the low residential customer savings are also driven in part by larger savings from participating commercial customers.

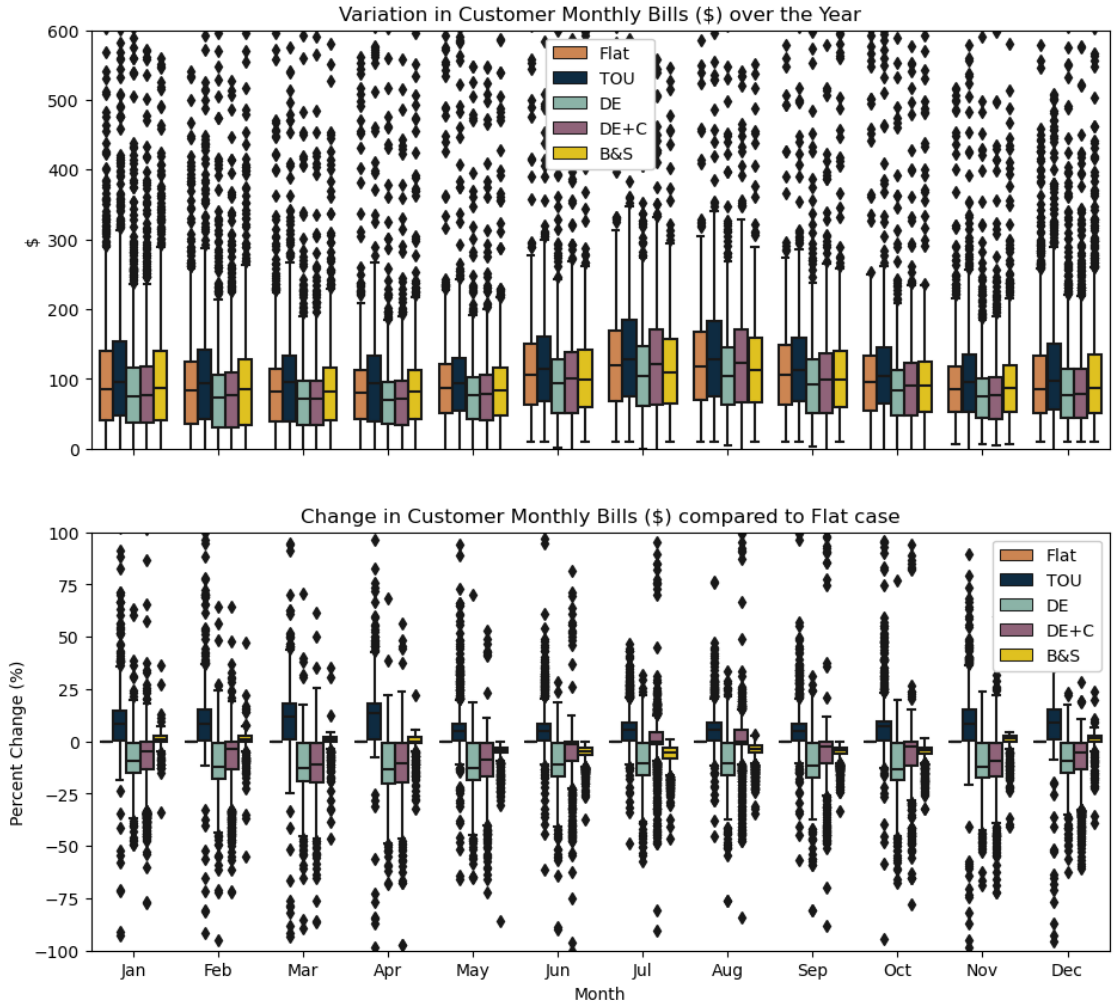
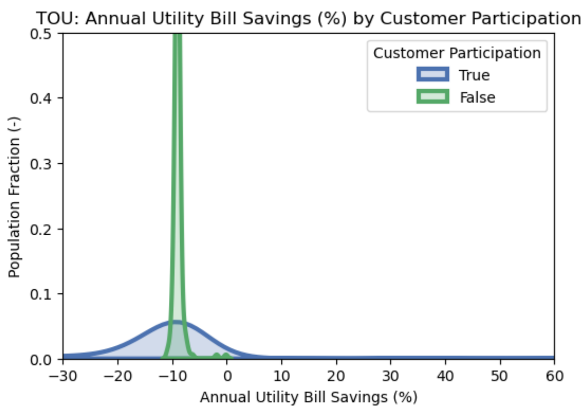
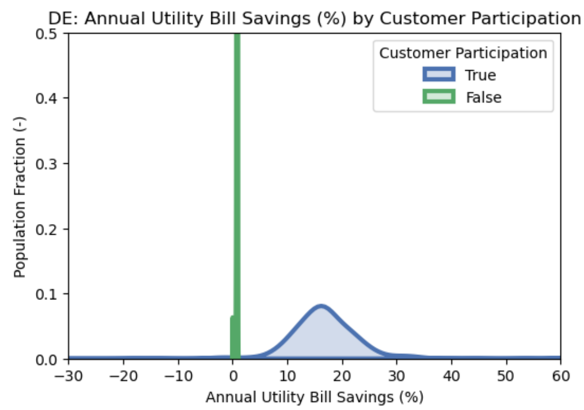


Figure 19: Monthly summary of commercial and residential customer monthly electricity bills and variation compared to the Flat case. (DSO 1.)

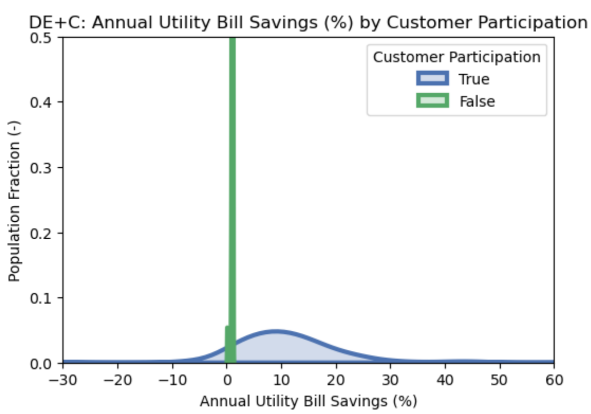
non-participating customers is presented in Section 4.2.1.



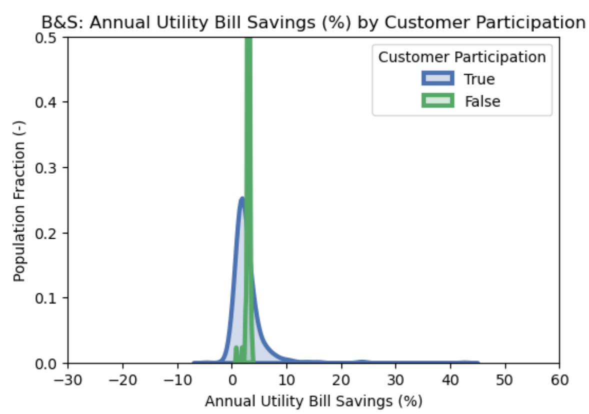
(a) TOU



(b) DE



(c) DE+C



(d) B&S

Figure 20: Change in annual electricity utility bill payments for participating and nonparticipating residential customers for the (a) TOU, (b) DE, (c) DE+C and (d) B&S cases compared to the Flat case. (DSO 1).

Table 6: Summary of metrics for average participating and nonparticipating residential customers and difference from flat case. (DSO 1.)

Metric	TOU		DE	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kWh)	NA	13,270 (4.3%)	NA	12,170 (-4.3%)
Peak Load (kW)	NA	8.4 (-1.9%)	NA	8.3 (-3.4%)
Annual Electricity Bill ($)	1,540 (9.1%)	1,550 (10.0%)	1,400 (-0.9%)	1,170 (-17.0%)
Bill Volatility (-)	0.65 (-0.4%)	0.52 (16.0%)	0.65 (-0.1%)	0.59 (-4.60%)
Metric	DE+C		B&S	
	Nonparticipating	Participating	Nonparticipating	Participating
Annual Energy (kWh)	NA	12,170 (-4.3%)	NA	12,170 (-4.3%)
Peak Load (kW)	NA	8.4 (-1.7%)	NA	8.4 (-1.7%)
Annual Electricity Bill ($)	1,390 (-1.1%)	1,250 (-11.3%)	1,360 (-3.5%)	1,370 (-3.1%)
Bill Volatility (-)	0.65 (-0.1%)	0.70 (+13.0%)	0.65 (-0.5%)	0.58 (-6.4%)

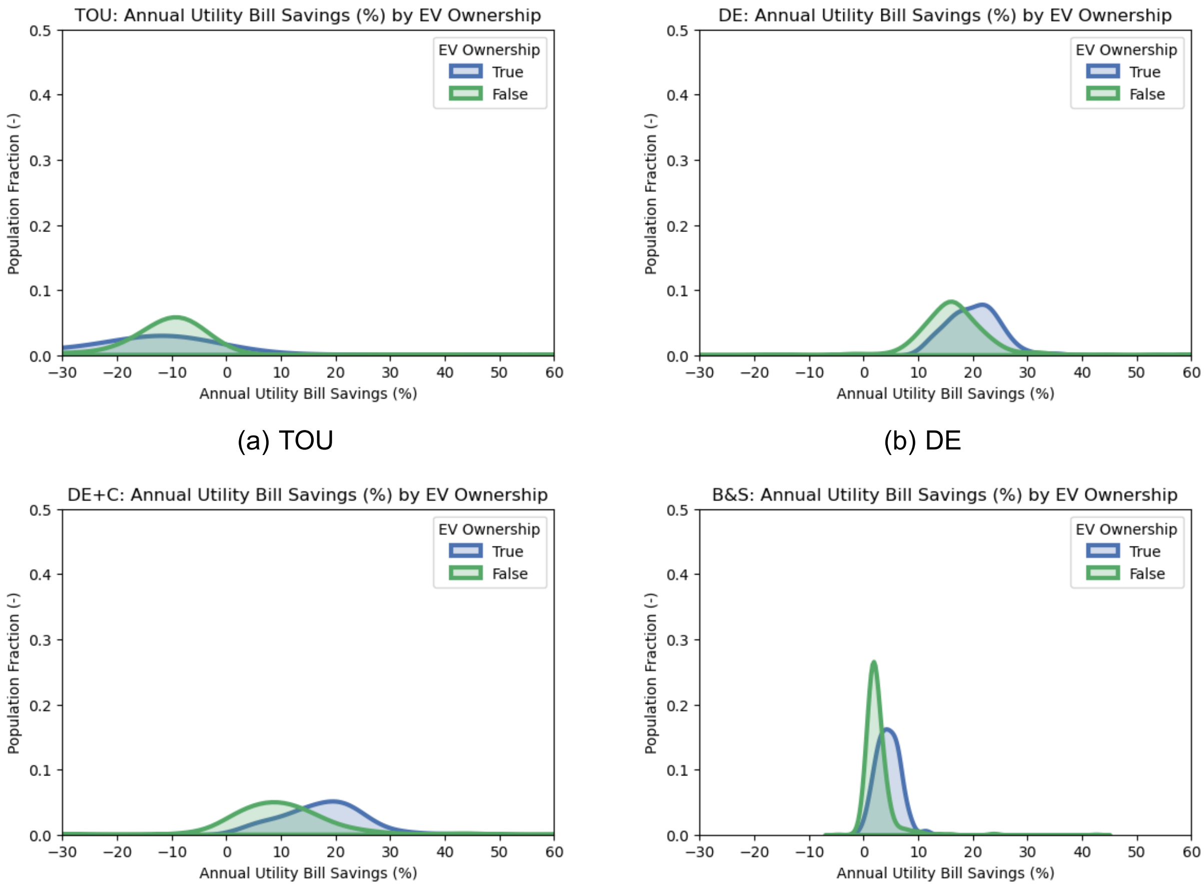
3.4.4 Customer Impacts by Asset Type

The respective electricity bill savings of residential customers with and without EVs and rooftop PV was also analyzed. Table 7 and Figures 21 and 22 show the respective annual bill savings for these customer classes. Both the dynamic pricing rates (DE and DE+C) provide substantial savings to residential customers who own EVs (>15%). This is expected as EV charging is a substantial flexible load compared to other household electricity demands. Consistent with other findings, the B&S rate diminishes the bill savings of participating EV owners making them comparable, but lower than non-EV owners (4.6% versus 3%). Finally, under TOU rates EV owners see increased bills, likely due to the increased system operating costs and upward pressure on rates for all customers.

In general, residential owners of rooftop PV saw slight (<3%) annual electricity bill savings compared to customers without PV when on dynamic rates (DE, DE+C, and B&S). TOU PV customers saw a slight increase (again, less than 3%). These small changes are in part because even under the most dynamic rate (DE+C) peak retail prices occur in the afternoon, rather than evening, aligning with on site solar generation, and a large portion of the price per kWh paid by customers is still a constant volumetric energy charge (see Figure 18). In addition, we assume symmetric import and export rates. We would expect different results in cases where peak retail prices do not align with generation production or where import and export rates differ. Also, an increase in the monthly fixed customer charge could alter the relative savings of PV customers, but is a separate consideration from the inclusion of a dynamic price component.

Table 7: Impact of EV and PV ownership on average annual electricity bill ($) of residential customers across the rate cases. (DSO 1.)

Asset Ownership	Flat	TOU	DE	DE+C	B&S
Non-EV Owners	1,370	1,490 (9.2%)	1,190 (-12.9%)	1,260 (-8%)	1,330 (-3%)
EV Owners	1,960	2,250 (15%)	1,570 (-19.9%)	1,610 (-17.6%)	1,870 (-4.6%)
Non-PV Owners	1,480	1,630 (10%)	1,280 (-13.6%)	1,350 (-8.9%)	1,440 (-2.9%)
PV Owners	930	1,000 (7.6%)	800 (-14%)	830 (-10.4%)	870 (-5.8%)



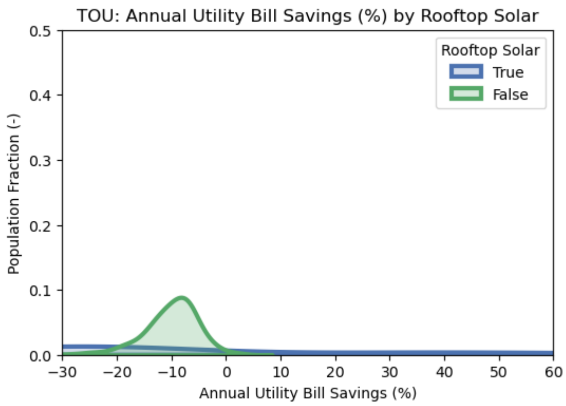
(a) TOU

(b) DE

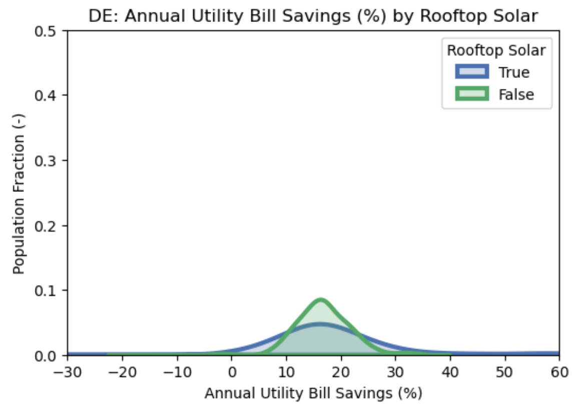
(c) DE+C

(d) B&S

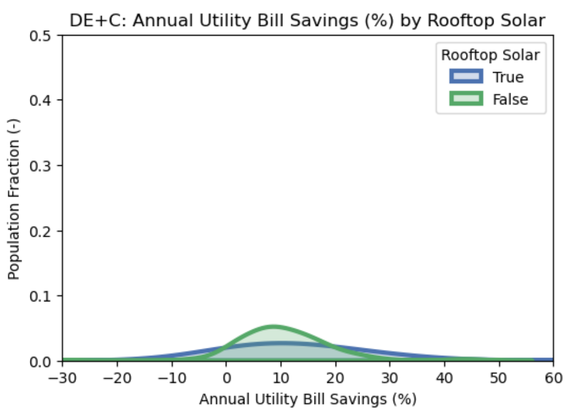
Figure 21: Change in annual electricity utility bill payments for residential customers with and without EV for the (a) TOU, (b) DE, (c) DE+C and (d) B&S cases compared to the Flat case. (DSO 1.)



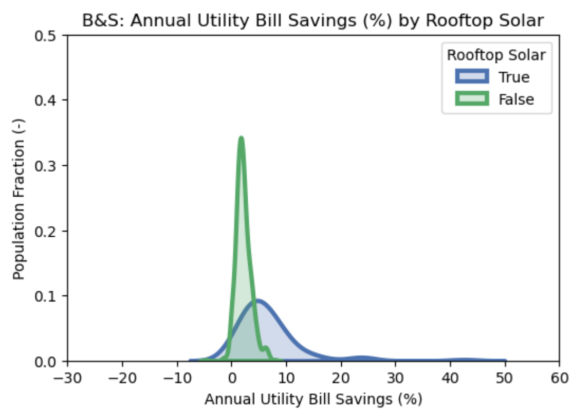
(a) TOU



(b) DE



(c) DE+C



(d) B&S

Figure 22: Change in annual electricity bill payments for residential customers with and without PV for the (a) TOU, (b) DE, (c) DE+C and (d) B&S cases compared to the Flat case. (DSO 1.)

4.0 Discussion

This section includes discussion on general rate design considerations, the time varying components of potential rates and the performance of the B&S rate. These discussion topics arose throughout the design and completion of the PAVER study and directly inform the recommended future directions identified in Section 5.2.

4.1 Rate Design Considerations

In this study, the bill components of all residential customers can be generally represented by the following equation:[2]

$$B = (A \cdot D + V)E + F \tag{1}$$

Where the monthly bill (B) is made up of both a time-varying volumetric component (D, multiplied by a factor A) and constant volumetric component (V) that are applied to the customers' energy consumption (E). Finally, there is a fixed monthly charge (F = \$10/month for residential customers). The Flat rate is represented by setting $A = 0$ and determining the value of V that ensures sufficient revenue recovery to meet costs. The TOU rate can be considered as setting $A = 2$ during peak periods (and $A = 0$ during non-peak) and setting $D = V$ and applying it on top of the constant off peak (V) term. The DE and and DE+C rates set $A = 1.04$ (to account for system losses) and set D to account for wholesale energy and, in the DE+C case, wholesale energy and dynamically allocated capacity costs. How these components are designed within a rate structure influences what customer behaviors are being encouraged.

The proportion of revenue a rate collects via each mechanism is visualized in Figure 23. Collecting all revenue via a constant volumetric charge ($A = F = 0$) is represented in the bottom left of the ternary plot, while the case representing all revenue collected via a time-varying charge ($V = F = 0$) is shown at the top of the figure, and the case of 100% collection via a fixed charge ($A = V = 0$) is represented at the bottom right. This study chose a typical residential fixed component (\$10/month) resulting in ~8-10% of residential customers' bill being a fixed monthly fee that is not impacted by energy consumption. The flat case recovered the remaining revenue (91.5%) from the constant volumetric fee, where all kWh consumed are charged the same price throughout the year. The addition of a time-varying volumetric component (e.g., TOU, DE, or DE+C) results in only ~22-41% of an average customer's bill being recovered by the time-varying component[3]. Of note, the B&S rate actually collects the largest proportion of revenue via the constant volumetric mechanism (93.6%). This is because B&S customers purchase their average baseline monthly profile (taken from the flat case) but on average use 4.3% less energy. Due to the structure of the subscription and dynamic price (to be discussed below), this results in only a 3.1% average credit on their bills.

Rate designers ultimately have to decide what proportion of revenue is recovered from the customer base through these three main components: a fixed monthly charge, a constant (e.g., time-invariant) volumetric energy (or demand) charge, and a time-varying volumetric charge[4].

[2] Detailed price formation and billing equations can be found in Appendix A.

[3] Note that for this analysis for the TOU peak rate we are only counting the price differential above the off-peak price.

[4] This discussion is primarily focused on time-varying volumetric energy charges, but appreciates and considers other charges, such as critical peak prices and peak time rebates as special case examples of time varying charges.

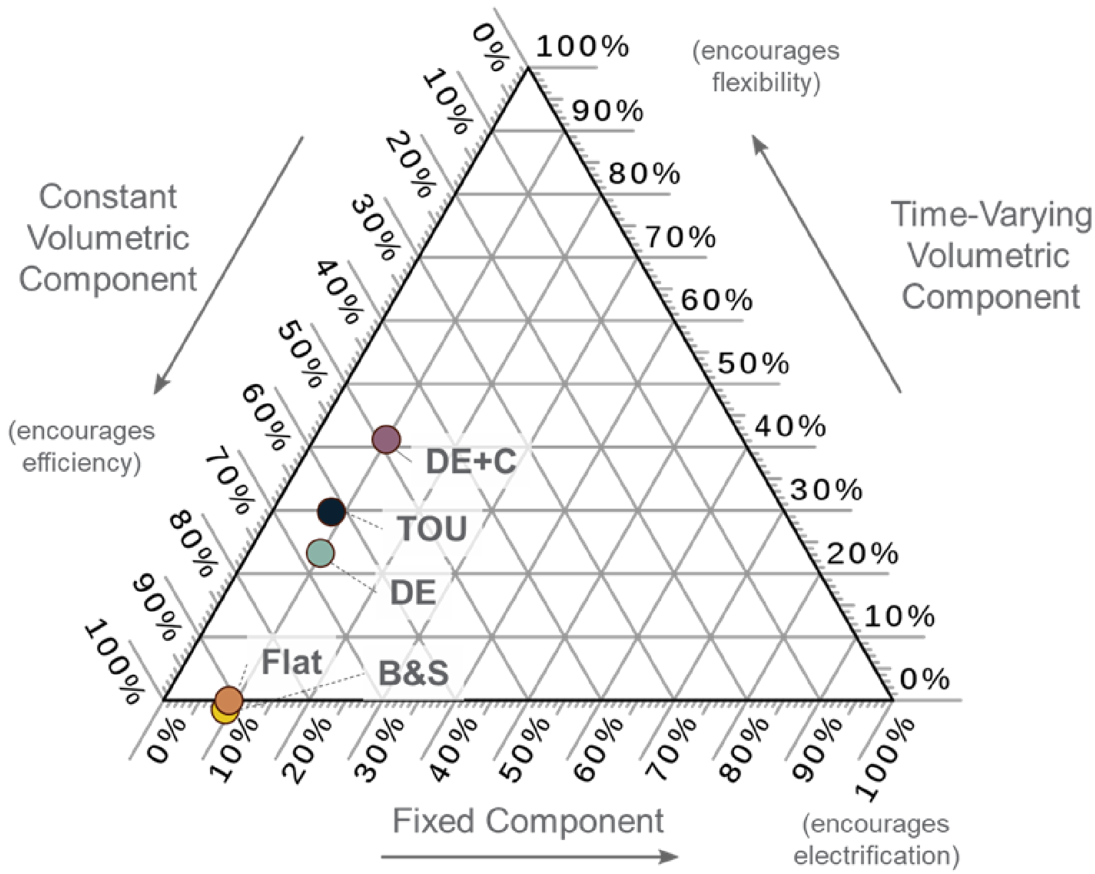


Figure 23: Summary of how rates collect revenue through fixed, constant volumetric, and time-varying volumetric components.

The remainder of this discussion presents considerations related to these mechanisms, both from a rate design, as well as device operation, perspective.

4.2 Time-Varying Rate Component

The time-varying component is instrumental in incentivizing customer assets to reduce, increase, or shift demand in response to changing grid conditions. The primary concerns with the introduction of this component are that customers can be exposed to very high prices (increasing bill volatility) and that these rates may be hard to understand. TOU rates seek to address these concerns by having fixed peak prices, effectively capping price exposure at set times of the day. This makes the price and timing of peak periods highly predictable and customers can easily schedule their consumption based on the peak periods. While the TOU peak periods may not exactly match the ever-evolving grid needs, TOU rates have seen material reductions in peak loads across myriad deployments [Faruqui et al., 2019]. The key challenge with TOU rates are rebound (a.k.a. snap-back or timer-peak) effects. As seen in this study and in the field (for example, PG&E experience with EV customers overloading transformers [Pacific Gas and Electric, 2025, Page 41]) as more automated devices 'recharge' at the start of off-peak periods this will potentially negate the benefits of demand reduction. The PAVER study additionally found that on most days the

TOU peak period price was higher than what the dynamic prices reached, indicating a tradeoff between the predictability and instances of high price periods that customers are exposed to between the rate structures. Ultimately, if not actively managed, large discontinuous changes in price have the potential unintended consequence of synchronizing loads and forming new peaks.

This challenge can be addressed via dynamic prices that vary continuously with the evolving grid conditions. The DE and DE+C rate designs meet this need by basing the dynamic price component on wholesale energy (e.g., LMP) costs and dynamic capital cost recovery based on system demand. However, if appropriate protections are not in place, such approaches can expose customers to very high peak prices. For example, during Winter Storm Uri some ERCOT customers saw prices as high as $9/kW-hr (the wholesale market cap), resulting in Texas outlawing retail pricing indexed to wholesale energy prices. The peak energy price component would likely need to be capped to acceptable values for which there are precedents, for example CPP events are typically ~$1/kW-hr.

The dynamic capital cost recovery component is capped by design, as it only recovers the capital costs of generation and transmission infrastructure based on its utilization. In the worse case, where costs need to be recovered for generation and transmission infrastructure built for peak conditions that is only utilized for one hour a year, this price is $1.20/kW-hr (assuming an annual capacity cost of $55.9/kW-year) and will only occur one hour per year. In reality, the participation of customers lowers and spreads out peak loads lowering this capital cost charge (and also wholesale energy prices) due to overall higher system utilization. In this study the largest DE+C capacity component price seen was $0.265/kW-hr due to the customer responses managing peak loads. Ultimately, any wholesale energy or capacity costs not collected through a dynamic price (due to price caps or other protections) will be collected through the constant volumetric energy component, effectively raising the minimum price that customers can experience. It should be remembered that customers solely on flat rates today are also exposed to, and paying for, high wholesale costs with the risk socialized through a fixed flat volumetric rate. The difference being, that they do not get the incentive signal nor the opportunity to provide flexibility to reduce these costs and their own bills.

Residential customers on the DE+C rate did see high monthly variation in their bills, with monthly variability increased 13% over the Flat case. DE customers actually saw a decrease in volatility. This is due to two reasons. First, in this study the calculated wholesale energy costs (see Figure 14) do not vary significantly across the year. Second, given the bill savings, a larger proportion of the bill comes from the fixed monthly fee, reducing bill variation. For the DE+C case the large response decreased the severity of the capital cost allocation charge. Regions with greater seasonal variation in wholesale energy prices or large unmanaged demand spikes are likely to see higher bill variation.

4.2.1 Block and Swing Rate Options and Considerations

Options exist to enable dynamic pricing while protecting customers from large volatile bills. This study looked at a B&S (a.k.a. a subscription or a two-part real-time rate) that is gaining interest and uptake. This ensures that devices can see and respond (swing) to a dynamic rate but that the bulk of the bill is based on a block purchase under a constant volumetric price. This rate was successful in reducing monthly variations in bills compared with the DE and DE+C rates. However, the subscription rate resulted in participating residential customers seeing savings similar to (and on average lower than) non-participating customers. Additionally, participating customers reduced their total consumption by more than what they experienced in bill savings, indicating that they would have saved more if billed at the Flat rate for their flexible consumption. These trends appear to be consistent with the findings of [Smith et al., 2025] that found that residential customers on a subscription either paid more than the base case or only saw modest savings (for non-PV customers with higher levels of participation).

Understanding the drivers of this phenomena and how best to design B&S rates to balance bill variability with incentivizing participation and flexibility warrants further investigation. One leading cause for this phenomena could be the design of the block purchase. In this study it is based on the customer's average monthly load profile (in practice, practitioners have based the block on the customer's previous year's hourly profile). As shown in Figure 24 (left) during periods of peak demand (which are typically weather related) customers' subscriptions do not cover this need and more electricity must be purchased. Later in August (Figure 24-right) the the total load is lower than the monthly average (due to cooler temperatures) and excess block purchases can be sold at the dynamic price. The issue may be that the dynamic price is higher during the system peak than later in the month when loads are lower. This results in participating customers having to typically buy more power during periods of high prices and sell during periods of relatively lower prices. Having the block purchase cover a smaller fraction of the customers' expected demand may address this. Further research on the underlying causes and how best to design the block purchase is needed.

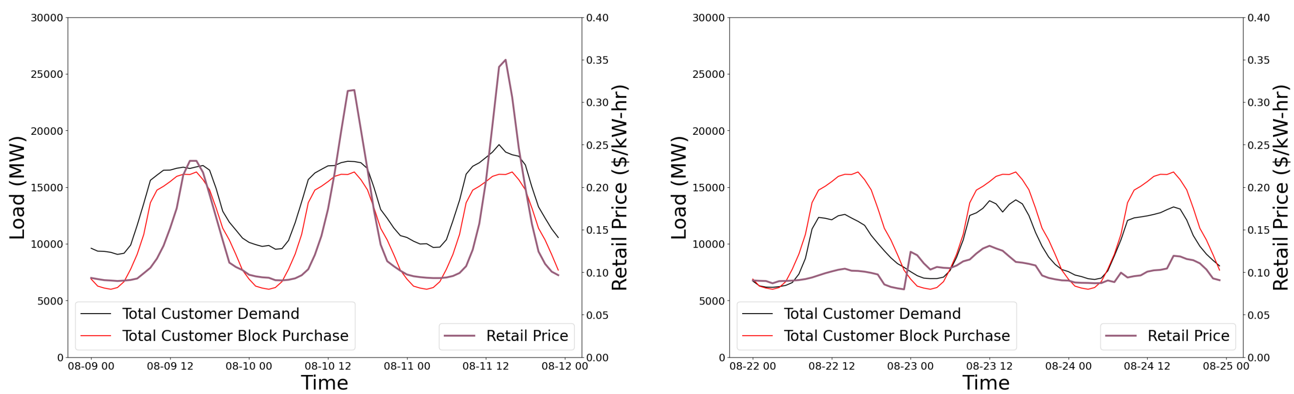


Figure 24: Examples of aggregate residential customer actual load and block allocation during annual peak (left) and later in August (right) for the B&S rate.

4.2.2 Balancing Fixed Volumetric and Monthly Charges

Once the time-varying rate component is determined, the remainder of the revenue collection comes from the fixed volumetric energy and monthly charges. A higher volumetric energy charge encourages energy efficiency (as well as recovering any wholesale costs not recovered by the dynamic time-varying charge due to price caps and other protection mechanisms). Conversely, a higher fixed monthly charge lowers the volumetric energy charge, lowering the marginal cost of electricity, encouraging greater adoption and use of electrical devices and appliances. This study did not study varying the monthly fixed charge and did not include the effects of demand elasticity with price (e.g., Jevon's paradox). The results can, however, be used to bound likely fixed charge limits. For example, for the DE+C case in the extreme limit of recovering the remaining revenue from a fixed monthly charge (and setting the fixed volumetric charge to zero) would lower average per kW-hr costs \$0.052/KW-hr and increase the average monthly residential bill fixed monthly charge from $10/month to $61.4/month. This would have impacts on the economics of BES, PV, and EV ownership (see Section 4.3 below) and how much to increase (or decrease) the fixed monthly charge is ultimately a decision to be made by the rate designer.

4.2.3 Non-Participating Customer Revenue Recovery

Previous work [Reeve et al., 2022b] has shown that non-participating customers can also experience bill savings even though they stay on the Flat rate. In this study, the results are mixed - on some DSOs, non-participating customers saw slightly lower bills than they experienced when the entire system was on the Flat rate, while in other regions, customers saw slightly higher bills. For example, for the DE rate design, two of the eight DSO regions saw slight decreases (~1-4%) while the other regions saw increases (~4-10%) in non-participating customer average annual electricity bills.

There are several arguments that can be made for why non-participating customers should experience higher bills than participating customers. First, participating customers manage their load to utilize periods of lower prices and are rewarded for this. Second, non-participating customers are protected from the risk of higher peak prices by staying on the Flat rate. A case can be made that a premium should be paid for this price protection. (In this study the non-participating customers are billed under a Flat rate that collects the revenue that, in aggregate, they would have provided by being subject to the dynamic rate - so they are, in a sense, in a self-insuring pool.) Regardless, it is harder to justify why non-participating customers may pay more than the counterfactual Flat case, which sees no system-wide cost savings. Understanding the causes for this is challenging in a fully integrated analysis. Further work is warranted to systematically understand the possible conditions (e.g., climate zone, customer type, load types etc.) under which non-participating customers bills may increase or decrease.

4.3 Asset-Specific Design Considerations

The different price signals, rate designs, and the magnitude of the fixed monthly charge can have specific impacts on individual classes of equipment. For example, Section 3.4.4 shows that customers who own EVs save more under dynamic rates and that customers who own PV are not disadvantaged. Additional device-specific effects and considerations are provided in this section.

4.3.1 Impact of Asset's Post Event Recovery

A key tenet of orchestrating grid services from customer-owned assets is to not inadvertently synchronize loads. Unfortunately, the large discrete price changes of the TOU rate can create load rebounds. Such phenomena is seen today in TOU deployments as well as direct load control programs. This can be compounded by the operating strategy of specific devices. For example, heat pumps have been observed to see a "spike in auxiliary heat, often at higher stages, to overcome the reduction in indoor temperature due to the DR event" [Mendon et al., 2025, Section 4.7.2]. This can result in a single heat pump adding 15 kW of auxiliary heating load at the end of a DR or TOU peak period in an effort to recover indoor air temperatures. AHRI Standard 1380 is identifying ways that variable speed HVAC equipment can better exit an event. Similar issues have been seen in EVs with factory-installed defaults for when to charge during off-peak periods. Even with dynamic prices, devices may rely on common default settings on when to charge, resulting in secondary peaks.

Finally, the capacity cost allocation curve in the DE+C rate can result in large price changes for peak load hours. Care will be needed in the implementation of price forecast models and device responses to ensure dynamic price and device response instabilities do not occur.

4.3.2 Rate Design Impacts on Asset Economics

Rate design decisions impact the overall economic feasibility of owning various assets. Rate designs that collect higher proportions of revenue through time-varying portions (such as DE+C) increase the flexibility incentive and increase the potential economic benefit of owning a flexible asset. Beyond this, a higher monthly fixed charge and lower fixed volumetric charge improves the economic payback of larger electric loads (such as EVs and HVAC systems) and potentially decreases the compensation of power generated by customer-owned on-site generation.

In terms of operational strategies, most assets are only concerned with the price-spread (difference between the highest and lowest time-varying price across the time period of which they might shift load). Therefore, the operational strategies of HVAC systems, EV charging, and WHs should not change based on the absolute value of the constant volumetric energy cost. The same can not be said for behind-the-meter battery operation or bi-directional EV operation. In these cases, operation includes a round-trip efficiency loss (typically ~10-15%) that is incurred at the minimum time-varying price. A higher fixed energy cost component will result in higher battery operating costs and smaller envelopes of operation under which load shifting will be economically attractive. That is, the “roundtrip losses for consumer batteries are, in effect, billed at retail rates; whereas for merchant- and utility-owned batteries they are billed at wholesale prices” [Pratt et al., 2022b, Section 8.2.2].

5.0 Conclusions and Recommendations

This study investigated a wide set of TVRs in a full integrated grid simulation in order to understand the impact on both grid operators and customers when a larger proportion of devices automatically participated in these rates. This is critical to understand how well different rates scale as participation grows and to assess the full equilibrium effects within the system.

5.1 Key Findings

This study identified four key findings:

1. Due to the static nature of the TOU rate it is hard to determine the most appropriate periods and durations beforehand to align with grid peaks throughout a summer or winter season. In addition, with the large fraction of automated device participation considered in this study, we found the resulting rebound peak loads exceeded the original system peak and negated any operational cost savings. This occurred with highly automated loads at participation levels above approximately 50%.

2. Rates with dynamically determined electricity prices (such as the DE and DE+C rates) avoided large discontinuities in price, ensuring smooth aggregate demand shifts. Dynamic price schemes also better aligned demand flexibility with the ever-evolving grid conditions. This demand flexibility reduced the peak grid capacity requirement 6-7% and moved energy purchases to periods of lower wholesale prices. Overall, this resulted in lower capital and operating costs that were passed onto the customers through bill savings. The actual cost savings an operator can expect to experience will be highly dependent on local system conditions, such as spare system capacity and current wholesale price levels and volatility.

3. For the DE and DE+C dynamic rates, participating customers saw considerable bill savings (>10%) and saved more than non-participating customers. Dynamic rates have the inherent feature that greater participation reduces the magnitude and volatility of the dynamic prices seen by customers, both for energy and capital cost recovery components. Over time this will result in reduced bill magnitude and variability, but also reduced benefits from providing additional demand flexibility. The study also found that customers with large flexible demand (such as EVs), as expected, saw larger bill savings than customers without. Customers with inflexible on-site generation (such as PV) did not see significant differences in savings to customers without on-site generation.

4. Finally, this study included the assessment of a Block and Swing rate design to assess the impact on customers of avoiding bill volatility via purchasing a large portion of their monthly needs via a fixed price and average load profile. This rate achieved this goal and reduced monthly variations in bill amount, but at the expense of greatly reducing the benefits of participating, to the point where participating customers saw smaller savings than non-participating customers.

5.2 Future Directions

Based on these findings we recommend three key areas that warrant additional investigation:

1. **Better understand the drivers of changes in non-participants' bills:** Prior work has shown that non-participating customers can also experience bill savings, although not as significant as participants. This study produced mixed results, with non-participants sometimes having higher or lower bills than they had when all customers were on the Flat rate. The fully integrated nature of this analysis makes it difficult to identify and separate the conditions and causes that may lead non-participants to pay more than they would have in Flat case. There is a need to systematically determine and analyze the drivers and conditions that affect the outcomes of non-participants. In addition, stakeholder input is required to understand if these conditions and outcomes are acceptable (and whether non-participating customers should pay a slight risk premium) or if changes in the calculation of the non-participating customers' aggregate costs are needed.

2. **Systematically understand the effectiveness of bill protection schemes:** Myriad options are available to ensure participating customers are protected against extreme price and bill variation. Such options include price caps, bill caps, bill guarantees, annual bill averaging, and subscription (e.g., two-part or block and swing) rate designs. There is a need to systematically explore these options to understand how best to ensure a balance between bill protection (e.g. reduced volatility) and participation incentive. Such work should address the following questions: Can bill guarantees ensure a utility can sufficiently recover costs if this mechanism is adopted at scale? How does the effectiveness of a subscription rate vary in balancing volatility and benefit as a function of the size and nature of the "Block" subscription load shape? Could more traditional budget payment plans address volatility without diluting the participation incentive, while providing greater simplicity? How effective are price caps in limiting customer exposure? How might increasing fixed monthly connection charges reduce bill variation, and with what tradeoffs?

3. **Extend analysis environment to assess real-world cases and allow assessment of more independent variables:** The integrated analysis environment used in this study ensures that the fully-coupled equilibrium effects of large-scale demand flexibility participation on the full grid are considered. This does, however, make it challenging to tease out the relative contributions and causality of various effects. In addition, it can make it resource and computationally intensive to consider specific regional cases and populations. There is a need to analyze the impacts of various rates on specific customer classes and regions using real-world data and appropriate representations of flexibility and system cost structure impacts. We expect that customer benefits and changes in bill variation will be dependent on these variations in grid conditions and customer demographics.

In aggregate these recommendations would allow the impact of a very wide range of rate options to be assessed across both participating and non-participating customer classes. This can be used to understand the effect of TVRs across regions and climate zones, variations in customer asset ownership, and grid infrastructure needs and cost structures. The ability to use either customer load and bill data or a simulation environment enables the assessment of both current and future scenarios.

6.0 Bibliography

[AES, 2024] AES (2024). Getting ahead of the ev tipping point. Technical report, AES Corporation. Accessed September 21, 2025.

[Blair and Fitzgerald, 2024] Blair, B. and Fitzgerald, G. (2024). The state of managed charging in 2024. Technical report, Smart Electric Power Alliance (SEPA). Accessed: 2025-09-21.

[Bonbright, 1961] Bonbright, J. C. (1961). *Principles of Public Utility Rates*. Columbia University Press, New York.

[California Public Utilities Commission, 2025] California Public Utilities Commission (2025). Cpuc issues guidance for utility dynamic hourly rates.

[Cazalet et al., 2020] Cazalet, E. G., Kohanim, M., and Hasidim, O. (2020). Complete and Low-Cost Retail Automated Transactive Energy System (RATES). Technical Report CEC-500-2020-038, California Energy Commission, Sacramento, CA.

[EIA, 2023] EIA (2023). 2020 recs. https://www.eia.gov/consumption/residential/data/2020/. Accessed on 2025-09-20.

[EIA, 2025] EIA (2025). Form eia-861: Annual electric power industry report. Accessed: 2025-09-21.

[Entergy Texas, Inc., 2023] Entergy Texas, Inc. (2023). Residential Service - Time of Day. https://www.entergytexas.com/wp-content/uploads/eti_rs-tod.pdf. Accessed on: 2025-12-09.

[ERCOT, 2024] ERCOT (2024). Fuel mix report 2007-2024. https://www.ercot.com/gridinfo/generation. Accessed on 2025-09-20.

[Faruqui et al., 2019] Faruqui, A., Hledik, R., and Sergici, S. (2019). A Survey of Residential Time-Of-Use (TOU) Rates. Technical report, The Brattle Group, San Francisco, CA.

[Faruqui and Tang, 2023] Faruqui, A. and Tang, Z. (2023). Time-varying rates are moving from the periphery to the mainstream of electricity pricing for residential customers in the united states. Technical report, Brattle Group. Accessed September 21, 2025.

[Georgia Power, 2024] Georgia Power (2024). Electric Service Tariff: Real Time Pricing – Day Ahead Schedule: 'RTP-DA-5'. https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/RTP-DA-5.pdf. Accessed on: 2024-02-17.

[Glick et al., 2014] Glick, D., Lehrman, M., and Smith, O. (2014). Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future. Technical report, Rocky Mountain Institute, Boulder, CO.

[Goodman et al., 2025] Goodman, C., Bender, S., Barrows, S., Garbe, J., and Hardy, T. (2025). Residential Building Population Refactoring for Simulation Studies. Technical Report PNNL-38348, Pacific Northwest National Laboratory, Richland, WA.

[Illinois General Assembly, 2024] Illinois General Assembly (2024). Clean and reliable grid affordability act.

[Madduri et al., 2022] Madduri, A., Foudeh, M., Phillips, P., Gupta, A., Hsu, J., Jain, A., Voris, P., Lamming, J., Magie, A., and Huneycutt, J. (2022). Advanced Strategies for Demand Flexibility Management and Customer DER Compensation. Technical report, California Public Utilties Commission, San Francisco, CA.

[Massachusetts Department of Public Utilities, 2023] Massachusetts Department of Public Utilities (2023). Orders approving electric sector modernization plans, d.p.u. 21-80, 21-81, 21-82.

[Mendon et al., 2025] Mendon, V., Keene, K., Rosenberg, S., Rotondo, J., Nwe, K., Young, J., Wind, W., and Goetzler, B. (2025). Performance Results from DOE Cold Climate Heat Pump Challenge Field Validation. Technical Report PNNL-37127, Pacific Northwest National Laboratory, Richland, WA.

[Olson et al., 2023] Olson, A., Cutter, E., Bertrand, L., Venugopal, V., Spencer, S., Walker, K., and Gold-Parker, A. (2023). Rate design for the energy transition: Getting the most out of flexible loads on a changing grid. Technical report, Energy Systems Integration Group (ESIG). Accessed September 21, 2025.

[Pacific Gas and Electric, 2025] Pacific Gas and Electric (2025). Electric Program Investment Charge (EPIC) 2024 Annual Report. Technical report, Pacific Gas and Electric. Accessed: 2025-09-17.

[Pérez-Arriaga, 2013] Pérez-Arriaga, I. J. (2013). *Regulation of the Power Sector*. Springer, London.

[PG&E, 2024] PG&E (2024). Hourly flex pricing. https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/hourly-flex-pricing.html. Accessed September 21, 2025.

[Pratt et al., 2022a] Pratt, R., Bender, S., Reeve, H., Barrows, S., Yin, T., and Hardy, T. (2022a). DSO+T: Valuation Methodology and Economic Metrics. Technical Report PNNL-32170-4, Pacific Northwest National Laboratory, Richland, WA.

[Pratt et al., 2022b] Pratt, R., Bereta dos Reis, F., Bhattarai, B., Jinsiwale, R., Singhal, A., Bender, S., and Reeve, H. (2022b). Potential for Transactive Energy to Improve the Provisioning of Grid Services from Batteries. Technical Report PNNL-33599, Pacific Northwest National Laboratory, Richland, WA.

[Presswire, 2024] Presswire, E. (2024). Dynamic pricing outperforms time-of-use in california ev charging pilot with 98% energy delivered off-peak. https://www.cbs42.com/business/press-releases/ein-presswire/814414083/dynamic-pricing-outperforms-time-of-use-in-california-ev-charging-pilot-with-98-energy-delivered-off-peak/. Accessed September 21, 2025.

[Reeve et al., 2022a] Reeve, H., Singhal, A., Ahmad, T., Hardy, T., Doty, J., Marinovici, L., Bender, S., Pelton, M., and Oster, M. (2022a). DSO+T: Integrated System Simulation. Volume 2. Technical Report PNNL-32170-2, Pacific Northwest National Laboratory, Richland, WA.

[Reeve et al., 2022b] Reeve, H., Widergren, S., Pratt, R., Bhattarai, B., Hanif, S., Bender, S., Hardy, T., and Pelton, M. (2022b). Distribution System Operator with Transactive (DSO+T) Study: Main Report. Technical Report PNNL-32170-1, Pacific Northwest National Laboratory, Richland, WA.

[Satterfield et al., 2024] Satterfield, C., Schefter, K., and Maiorana, J. (2024). Electric vehicle sales and the charging infrastructure required through 2035. Technical report, Edison Electric Institute, Washington, D.C.

[Schellenberg and Mims Frick, 2025] Schellenberg, J. and Mims Frick, N. (2025). Moving beyond direct load control: A maturity model for realizing the promise of demand flexibility. Technical report, Lawrence Berkeley National Laboratory. Accessed September 21, 2025.

[Smith et al., 2025] Smith, S., Stuebs, M., Murthy, S., Baik, S., Cappers, P., Gerke, B., Brown, R., and Piette, M. A. (2025). Potential Impacts of Dynamic Electricity Pricing in California: Load Shape and Customer Bill Impacts Under Elastic Customer Response. Technical report, Berkeley Lab.

[Spector, 2022] Spector, J. (2022). Hawaii moves to time-varying ‘smart’ rates for most utility customers. *Canary Media*.

[Widergren et al., 2022] Widergren, S., Bhattarai, B., Pratt, R., Hanif, S., Singha, A., Tbaileh, A., Bereta dos Reis, F., and Reeve, H. (2022). DSO+T: Transactive Energy Coordination Framework. Volume 3. Technical Report PNNL-32170-3, Pacific Northwest National Laboratory, Richland, WA.

[Wolak and Hardman, 2021] Wolak, F. A. and Hardman, I. H. (2021). *The Future of Electricity Retailing and How We Get There*. Springer, Cham, Switzerland.

Appendix A – Rate Calculations

This section details the billing considerations and price formation of the electricity rate structures considered in this study.

In each rate scenario, billing is straightforward in that all customers receive a bill that corresponds with their status as a "participating" or a "non-participating" customer. However, determining the cost allocation of DSOs' expenses to their participating and non-participating consumers, which is necessary for price formation in each rate structure, is less straightforward. For the purposes of price formation, costs are first allocated as if all consumers are participating under the rate structure specified in the particular rate scenario. This approach serves two purposes. First, it allows prices for the rate scenario's rate structure to be found that ensure system cost recovery. Second, it allows total system costs to be apportioned between the participating and non-participating customers. This goal is achieved by using the discovered prices to calculate the revenue earned from participating customers bills and subtracting that revenue from the total system costs to determine the remaining costs that need to be recovered by the non-participating customers. Based on the remaining costs, the price for the flat rate can be determined in order to calculate the non-participating consumers' bills.

The following subsections describe the designs of the selected electricity rate structures and the equations that govern each rate scenario's billing and price formation.

A.1 Nomenclature

This subsection presents the nomenclature used in the equations presented in Sections A.2 - A.6. The following variables define the sets and associated indices:

$\mathcal{B}_d$	The set of tiers included in DSO d's declining-block rate, indexed by b.
$\mathcal{C}_d$	The set of consumers in DSO d, indexed by c.
$\mathcal{D}$	The set of DSOs, indexed by d.
$\mathcal{F}_{m,h}$	The set of five-minute time steps in month m and within hour h, indexed by f. The five-minute time steps included in this set are a subset of the total five-minute time steps in month m (i.e., $\mathcal{F}_{m,h} \subseteq \mathcal{T}_m$).
$\mathcal{H}_m$	The set of hourly time steps in month m, indexed by h.
$\mathcal{H}_{m,p}$	The set of hourly time steps in month m and time-of-use period p, indexed by h. The hourly time steps included in this set are a subset of the total hourly time steps in month m (i.e., $\mathcal{H}_{m,p} \subseteq \mathcal{H}_m$).
$\mathcal{L}_d$	The set of commercial and industrial consumers in DSO d, indexed by l. The consumers included in this set are a subset of the total consumers in DSO d (i.e., $\mathcal{L}_d \subseteq \mathcal{C}_d$).
$\mathcal{M}$	The set of months under consideration, indexed by m.
$\mathcal{M}_s$	The set of months in season s, indexed by m.

$\mathcal{N}_d$ The set of consumers in DSO d not participating in the rate scenario's rate structure, indexed by n. These consumers instead take service under the flat rate. The consumers included in this set are a subset of the total consumers in DSO d (i.e., $\mathcal{N}_d \subseteq \mathcal{C}_d$).

$\mathcal{P}_d$ The set of time-of-use price periods in DSO d's time-of-use rate, indexed by p.

$\mathcal{S}$ The set of seasons considered in the time-of-use rate, indexed by s.

$\mathcal{T}_m$ The set of five-minute time steps in month m, indexed by t.

$\mathcal{T}_{m,p}$ The set of five-minute time steps in month m and time-of-use period p, indexed by t. The five-minute time steps included in this set are a subset of the total five-minute time steps in month m (i.e., $\mathcal{T}_{m,p} \subseteq \mathcal{T}_m$).

The following variables define the input parameters:

X_d^i Total capital expenditures for DSO d in rate scenario i, where $i \in \{flt, de, dec, bs\}$, with flt, de, and dec referring to the flat, dynamic energy, dynamic energy and capacity, and block-and-swing rate scenarios, respectively.

$X_{d,m}^{tou}$ Total capital expenditures attributed to month m for DSO d in the time-of-use rate scenario.

$q_c(t)$ Electricity demand for consumer c at time t.

$q_c^{bl}(h)$ Baseline electricity demand for consumer c at hour h.

$q_c^{da}(h)$ Energy procured by consumer c in the day-ahead market for hour h.

$q_c^{rt}(f)$ Energy procured by consumer c in the real-time market for time step f.

$\overline{q}_{d,b}$ Electricity demand allowed in block b of DSO d's declining-block rate.

Θ_d^i Total operating expenditures for DSO d in rate scenario i, where $i \in \{flt, de, dec, bs\}$.

$\Theta_{d,m}^{tou}$ Total operating expenditures attributed to month m for DSO d in the time-of-use rate scenario.

$\alpha_{d,p}^{tou}$ Ratio between the price specified in time-of-use period p and the off-peak price for DSO d's time-of-use rate.

γ_d^i The monthly fixed charge levied on each consumer for DSO d's i rate, where $i \in \{flt, tou, de, dec, bs\}$. Depending on the rate structure, this quantity can be provided as a parameter or calculated using the appropriate closed-form solution.

δ_d^i The demand charge levied on commercial and industrial consumers' monthly maximum demand for DSO d's i rate, where $i \in \{flt, tou, bs\}$.

$\zeta_d^i(h)$ The dynamic price in the retail-level day-ahead market that recovers select capacity-based costs at hour h for DSO d's i rate, where $i \in \{dec, bs\}$.

$\kappa_{d,b}^i$ The credit associated with the declining-block rate earned for consuming demand in block b of DSO d's i rate, where $i \in \{flt, tou, bs\}$.

μ_d The transactive retail scaling term, which accounts for distribution losses and other wholesale payments.

$\xi_d^i(h)$	The day-ahead energy market price at hour h for DSO d under rate scenario i, where $i \in \{de, dec, bs\}$.
π_d^i	The volumetric energy price for DSO d's i rate, where $i \in \{de, dec\}$. Depending on the rate structure, this quantity can be provided as a parameter or calculated using the appropriate closed-form solution.
$\upsilon_d^{dec}(f)$	The dynamic price in the retail-level real-time market that recovers select capacity-based costs at time step f for DSO d's dynamic energy and capacity rate.
$\varphi_d^i(f)$	The real-time energy market price at time step f for DSO d under rate scenario i, where $i \in \{de, dec\}$.
ω_d	The weighting factor for DSO d.

The following variables define the supporting expressions:

K_d^i	Total credits associated with the declining-block rate earned by consumers taking service under DSO d's i rate, where $i \in \{flt, bs\}$.
$K_{d,m}^{tou}$	Total credits associated with the declining-block rate earned during month m by consumers taking service under DSO d's time-of-use rate.
R_d^i	Total revenue for DSO d earned from consumers taking service under the i, where $i \in \{flt, tou, de, dec, bs\}$.
Z_d^{dec}	Total dynamic capacity-based cost recovery revenue earned in the retail-level day-ahead market from consumers taking service under DSO d's dynamic energy and capacity rate.
Γ_d^i	Total fixed-charge revenue earned from consumers taking service under DSO d's i rate, where $i \in \{flt, de, dec, bs\}$.
$\Gamma_{d,m}^{tou}$	Total fixed-charge revenue earned during month m from consumers taking service under DSO d's time-of-use rate.
Δ_d^i	Total demand-charge revenue earned from consumers taking service under DSO d's i rate, where $i \in \{flt, bs\}$.
$\Delta_{d,m}^i$	Total demand-charge revenue earned during month m from consumers taking service under DSO d's time-of-use rate.
$\Lambda_{d,m}^{bs}$	Total net revenue associated with consumers' net demand deviations from their baseline demand profiles earned from consumers taking service under DSO d's block-and-swing rate during month m.
Ξ_d^i	Total retail-level day-ahead energy market revenue earned from consumers taking service under DSO d's i rate, where $i \in \{de, dec\}$.
Π_d^i	Total energy-charge revenue earned from consumers taking service under DSO d's i rate, where $i \in \{flt, de, dec, bs\}$.
$\Pi_{d,m}^{tou}$	Total energy-charge revenue earned during month m from consumers taking service under DSO d's time-of-use rate.

Υ_d^{dec} Total dynamic capacity-based cost recovery revenue earned in the retail-level real-time market from consumers taking service under DSO d's dynamic energy and capacity rate.

Φ_d^i Total retail-level real-time energy market revenue earned from consumers taking service under DSO d's i rate, where $i \in \{de, dec\}$.

Ψ_d^i DSO d's remaining revenue that needs to be recovered by consumers taking service under the flat rate after revenue earned by consumers taking service under the i rate is considered, where $i \in \{tou, de, dec, bs\}$.

γ_d^i The monthly fixed charge levied on each consumer for DSO d's i rate, where $i \in \{de, dec\}$. Depending on the rate structure, this quantity can be provided as a parameter or calculated using the appropriate closed-form solution.

$\lambda_d^{bs}(h)$ The composite dynamic price signal passed to consumers for DSO d's block-and-swing rate at hour h.

π_d^i The energy price for DSO d's i rate, where $i \in \{flt, de, dec, bs\}$. Depending on the rate structure, this quantity can be provided as a parameter or calculated using the appropriate closed-form solution.

$\pi_{d,s}^{tou}$ The energy price during season s for DSO d's time-of-use rate.

A.2 Flat

The flat rate considered in this study has three pricing components: (1) a volumetric energy charge, (2) a demand charge (for commercial and industrial consumers only), and (3) a fixed customer charge. The energy charge has a declining-block structure, which provides discounts on the energy charge for larger quantities of consumption. The declining-block structure is implemented to help account for the fact that larger commercial and industrial consumers typically see lower energy charges than smaller residential consumers in exchange for the paying demand charges. The flat rate billing follows from what was implemented in the DSO+T Study. The revenue each DSO $d \in \mathcal{D}$ earns from the flat rate is defined in Equation (A.1):

$$R_d^{flt}\left(\pi_d^{flt}, \delta_d^{flt}, \gamma_d^{flt}\right) = \Pi_d^{flt}\left(\pi_d^{flt}\right) + \Delta_d^{flt}\left(\delta_d^{flt}\right) + \Gamma_d^{flt}\left(\gamma_d^{flt}\right), \quad \forall d \in \mathcal{D} \tag{A.1}$$

where

$$\Pi_d^{flt}\left(\pi_d^{flt}\right) = \frac{1}{12} \cdot \omega_d \cdot \left[\sum_{m \in \mathcal{M}} \sum_{c \in \mathcal{C}_d} \sum_{t \in \mathcal{T}_m} \left[\pi_d^{flt} \cdot q_c(t)\right] - K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)\right] \tag{A.2}$$

$$\Delta_d^{flt}\left(\delta_d^{flt}\right) = \omega_d \cdot \sum_{m \in \mathcal{M}} \sum_{l \in \mathcal{L}_d} \delta_d^{flt} \cdot \max_{t \in \mathcal{T}_m} \{q_l(t)\} \tag{A.3}$$

$$\Gamma_d^{flt}\left(\gamma_d^{flt}\right) = \omega_d \cdot \gamma_d^{flt} \cdot |\mathcal{M}| \cdot |\mathcal{C}_d| \tag{A.4}$$

and

$$K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right) = \omega_d \cdot \sum_{m \in \mathcal{M}} \sum_{l \in \mathcal{L}_d} \sum_{b \in \mathcal{B}_d} \kappa_{d,b}^{flt} \cdot \max\left\{\min\left\{\frac{1}{12} \cdot \sum_{t \in \mathcal{T}_m} q_l(t) - \overline{q}_{d,b-1}^{flt}, \overline{q}_{d,b}^{flt} - \overline{q}_{d,b-1}^{flt}\right\}, 0\right\} \tag{A.5}$$

Equation (A.2) describes the energy charge for the flat rate, including the credits that are provided from the declining-block structure, which are described by Equation (A.5).[5] Equation (A.3) describes the demand charge[6] for the flat rate. Equation (A.4) describes the fixed charge for the flat rate. While some information, such as the electricity demand q_c of each consumer $c \in \mathcal{C}_d$ is determined through the simulation, other information is provided as a parameter. The demand charge δ_d^{flt} and fixed charge γ_d^{flt} are selected based on typical national values. The parameters of the declining-block structure are selected so that the different demand tiers separate residential and smaller commercial consumers from the larger commercial and industrial consumers [Pratt et al., 2022a]. The only term that must be calculated is the energy price π_d^{flt}, which per cost-of-service regulation, must be selected so that revenues from the tariff recover each DSO's capital and operational expenditures [Pérez-Arriaga, 2013]. In this study, energy price discovery is handled slightly different from how it was in the DSO+T Study. The DSO+T study found the energy price by making an initial guess and solving iterative updates until convergence was reached. Instead, this study leverages the linearity of the specified equations to derive a closed-form solution. The flat rate's energy price is shown in Equation (A.6):

$$\pi_d^{flt} = \frac{\Theta_d^{flt} + X_d^{flt} - \Delta_d^{flt}\left(\delta_d^{flt}\right) - \Gamma_d^{flt}\left(\gamma_d^{flt}\right) + K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m \in \mathcal{M}} \sum_{c \in \mathcal{C}_d} \sum_{t \in \mathcal{T}_m} q_c(t)}, \quad \forall d \in \mathcal{D} \tag{A.6}$$

Equation (A.6) is able to provide a closed-form solution of the flat rate's energy price π_d^{flt} because the equation describing the revenue-cost balance (i.e., $R_d^{flt}\left(\pi_d^{flt}, \delta_d^{flat}, \gamma_d^{flt}\right) = \Theta_d^{flt} + X_d^{flt}$) is linear in π_d^{flt}, allowing the energy price that recovers each DSO's expenditures to be found.

A.3 Time of Use

Similar to the flat rate, the time-of-use rate considered in this study has three pricing components: (1) a volumetric time-varying energy charge paired with the declining-block structure, (2) a demand charge (for commercial and industrial consumers only), and (3) a fixed customer charge. Though the structure of the time-of-use rate is similar to that of the flat rate, shown in Equations (A.1) – (A.5), there are structural changes that must be implemented. Namely, the energy charge is now a two-part time-of-use rate, with separate peak and off-peak prices during winter and summer months. The peak and off-peak prices are related through a peak-to-off-peak-price ratio, which allows for specific rate designs to be modeled. For instance, this study considers a peak-to-off-peak-price ratio of three, a higher ratio regarded in the literature as being better for eliciting consumer response [Faruqui et al., 2019], with Hawaiian Electric Company having

[5] When $b = 1$, which corresponds to the first tier of the declining-block rate, $\overline{q}_{d,b-1}^{flt} = 0$. Note that this convention persists with tier credit definitions for other rate structures considered in this report.

[6] Note that demand charges are not considered during real-time operation and are instead calculated in postprocessing. Though demand charges can make a large impact on consumers' electricity bills, the inclusion of demand charges in the real-time decision-making would have been computationally prohibitive. Regardless, the demand charges assumed in this study are smaller, indicating that they would have a lesser impact on a consumers' dispatch strategy.

been lauded for implementing the same ratio [Spector, 2022]. Equation (A.7) defines the annual revenue earned by each DSO $d \in \mathcal{D}$:

$$R_d^{tou}\left(\pi_d^{tou}, \delta_d^{tou}, \gamma_d^{tou}\right) = \sum_{s \in \mathcal{S}} \sum_{m \in \mathcal{M}_s} \left[\Pi_{d,m}^{tou}\left(\pi_{d,s}^{tou}\right) + \Delta_{d,m}^{tou}\left(\delta_d^{tou}\right) + \Gamma_{d,m}^{tou}\left(\gamma_d^{tou}\right)\right], \quad \forall d \in \mathcal{D} \tag{A.7}$$

where

$$\Pi_{d,m}^{tou}\left(\pi_{d,s}^{tou}\right) = \frac{1}{12} \cdot \omega_d \cdot \left[\sum_{c \in \mathcal{C}_d} \sum_{p \in \mathcal{P}_d} \sum_{t \in \mathcal{T}_{m,p}} \left[\alpha_{d,p}^{tou} \cdot \pi_{d,s}^{tou} \cdot q_c(t)\right] - K_{d,m}^{tou}\left(\kappa_d^{tou}, \overline{q}_d^{tou}\right)\right] \tag{A.8}$$

$$\Delta_{d,m}^{tou}\left(\delta_d^{tou}\right) = \omega_d \cdot \sum_{l \in \mathcal{L}_d} \delta_d^{tou} \cdot \max_{t \in \mathcal{T}_m}\left\{q_l(t)\right\} \tag{A.9}$$

$$\Gamma_{d,m}^{tou}\left(\gamma_d^{tou}\right) = \omega_d \cdot \gamma_d^{tou} \cdot |\mathcal{C}_d| \tag{A.10}$$

and

$$K_{d,m}^{tou}\left(\kappa_d^{tou}, \overline{q}_d^{tou}\right) = \omega_d \cdot \sum_{l \in \mathcal{L}_d} \sum_{b \in \mathcal{B}_d} \kappa_d^{tou} \cdot \max\left\{\min\left\{\frac{1}{12} \cdot \sum_{t \in \mathcal{T}_m} q_l(t) - \overline{q}_{d,b-1}^{tou}, \overline{q}_{d,b}^{tou} - \overline{q}_{d,b-1}^{tou}\right\}, 0\right\} \tag{A.11}$$

Equation (A.8) describes the energy charge for the time-of-use rate, including the credits that are provided from the declining-block structure, which are described by Equation (A.11). Equation (A.9) describes the demand charge for the time-of-use rate. Equation (A.10) describes the fixed charge for the time-of-use rate.

Unlike the flat rate scenario, there are multiple price values that must be calculated: the seasonal off-peak energy prices $\pi_{d,s}^{tou}$ for the time-of-use rate and the volumetric energy price π_d^{flt} for the flat rate. The off-peak energy prices will first be found by assuming that all consumers are taking service under the time-of-use rate. Once the time-of-use rate's energy prices are found, the bills of the participating consumers can be found to determine the remaining costs that need to be recovered by the non-participating consumers taking service under the flat rate. To find the off-peak energy prices used in the time-of-use rate, Equation (A.12), which is similar to the closed-form solution shown in Equation (A.6), is specified:

$$\pi_{d,s}^{tou} = \frac{\sum_{m \in \mathcal{M}_s}\left[\Theta_{d,m}^{tou} + X_{d,m}^{tou} - \Delta_{d,m}^{tou}\left(\delta_d^{tou}\right) - \Gamma_{d,m}^{tou}\left(\gamma_d^{tou}\right) + K_{d,m}^{tou}\left(\kappa_d^{tou}, \overline{q}_d^{tou}\right)\right]}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m \in \mathcal{M}_s} \sum_{c \in \mathcal{C}_d} \sum_{p \in \mathcal{P}_d} \sum_{t \in \mathcal{T}_{m,p}} \alpha_{d,p}^{tou} \cdot q_c(t)}, \ \forall d \in \mathcal{D}, \forall s \in \mathcal{S} \tag{A.12}$$

Equation (A.12) provides a closed-form solution for the off-peak energy price for each DSO in each season. Since the peak energy price scales linearly, by a factor of $\alpha_{d,p}^{tou}$, with the off-peak energy price, the revenue-cost balance is linear in $\pi_{d,s}^{tou}$, allowing the off-peak energy price that recovers each DSO's expenditures in season $s \in \mathcal{S}$ to be found. Having found the off-peak energy prices, the revenue attained through participating consumers taking service under the time-of-use rate can be calculated using Equations (A.7) – (A.11). Using this revenue, the remaining revenue requirement Ψ_d^{tou} can be determined, as is shown in Equation (A.14), and used to determine the energy price π_d^{flt} that will ensure recovery of the remaining costs by the non-participating consumers taking service under the flat rate. The flat rate's energy price is shown in Equation (A.13):

$$\pi_d^{flt} = \frac{\Psi_d^{tou}\left(\Theta_d^{tou}, X_d^{tou}, \pi_d^{tou}, \delta_d^{tou}, \gamma_d^{tou}\right) - \Delta_d^{flt}\left(\delta_d^{flt}\right) - \Gamma_d^{flt}\left(\gamma_d^{flt}\right) + K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)}{\frac{1}{12}\cdot\omega_d\cdot\sum_{m\in\mathcal{M}}\sum_{n\in\mathcal{N}_d}\sum_{t\in\mathcal{T}_m} q_n(t)}, \ \forall d \in \mathcal{D} \tag{A.13}$$

where

$$\Psi_d^{tou}\left(\Theta_d^{tou}, X_d^{tou}, \pi_d^{tou}, \delta_d^{tou}, \gamma_d^{tou}\right) = \sum_{s\in\mathcal{S}}\sum_{m\in\mathcal{M}_s}\left[\Theta_{d,m}^{tou} + X_{d,m}^{tou}\right] - R_d^{tou}\left(\pi_d^{tou}, \delta_d^{tou}, \gamma_d^{tou}\right) \tag{A.14}$$

With the flat rate's energy price being determined, the revenue obtained by non-participating consumers taking service under the flat rate can be found using Equations (A.1) – (A.5).

For the time-of-use rate design, each DSO offers the same structure, but has different price magnitudes depending on the DSO's price discovery. These TOU parameters are selected based on a combination of price observations in previous TESP simulations, ERCOT market data, and the Entergy Texas Residential "Time of Day" tariff [Entergy Texas, Inc., 2023].

A.4 Dynamic Energy

The dynamic energy rate is loosely based on the DSO+T rate structure [Reeve et al., 2022b] and has four pricing components: (1) an energy charge based on the retail day-ahead market, (2) an energy charge based on the retail real-time market, (3) a fixed charge, and (4) a volumetric energy charge. The fixed and volumetric energy charges are used to recover all costs attributed to participating customers that are not recovered through the day-ahead and real-time market charges. For the dynamic energy rate, Equation (A.15) defines the annual revenue earned by each DSO $d \in \mathcal{D}$:

$$R_d^{de}\left(\xi_d^{de}, \varphi_d^{de}, \gamma_d^{de}, \pi_d^{de}\right) = \Xi_d^{de}\left(\xi_d^{de}\right) + \Phi_d^{de}\left(\varphi_d^{de}\right) + \Gamma_d^{de}\left(\gamma_d^{de}\right) + \Pi_d^{de}\left(\pi_d^{de}\right), \quad \forall d \in \mathcal{D} \tag{A.15}$$

where

$$\Xi_d^{de}\left(\xi_d^{de}\right) = \omega_d\cdot\mu_d\cdot\sum_{m\in\mathcal{M}}\sum_{c\in\mathcal{C}_d}\sum_{h\in\mathcal{H}_m}\xi_d^{de}(h)\cdot q_c^{da}(h) \tag{A.16}$$

$$\Phi_d^{de}\left(\varphi_d^{de}\right) = \omega_d\cdot\mu_d\cdot\sum_{m\in\mathcal{M}}\sum_{c\in\mathcal{C}_d}\sum_{h\in\mathcal{H}_m}\sum_{f\in\mathcal{F}_{m,h}}\varphi_d^{de}(f)\cdot\left[q_c^{rt}(f) - \frac{1}{12}\cdot q_c^{da}(h)\right] \tag{A.17}$$

$$\Gamma_d^{de}\left(\gamma_d^{de}\right) = \omega_d\cdot\gamma_d^{de}\cdot|\mathcal{M}|\cdot|\mathcal{C}_d| \tag{A.18}$$

$$\Pi_d^{de}\left(\pi_d^{de}\right) = \frac{1}{12}\cdot\omega_d\cdot\sum_{m\in\mathcal{M}}\sum_{c\in\mathcal{C}_d}\sum_{t\in\mathcal{T}_m}\pi_d^{de}\cdot q_c(t) \tag{A.19}$$

Equation (A.16) describes the energy charge associated with the retail day-ahead market. Equation (A.17) describes the energy charge associated with the retail real-time market. Equation (A.18) describes the fixed charge for the dynamic energy rate. Equation (A.19) describes the volumetric energy charge for the dynamic energy rate.

While there are still multiple price values that must be calculated under the dynamic energy rate, there is the ability to determine how the dynamic rate should go about ensuring cost recovery. This dynamic rate recovers all costs not recovered through the retail-level markets by using some combination of a monthly fixed charge and a volumetric energy charge. However, either the fixed charge or the volumetric energy price must be provided as a parameter, with the other being solved for through a closed-form price discovery equation. To find the monthly fixed charge γ_d^{de} and the volumetric energy price π_d^{de} used in the dynamic energy rate, Equations (A.20) and (A.21) are specified:

$$\gamma_d^{de} = \frac{\Theta_d^{de} + X_d^{de} - \Xi_d^{de}\left(\xi^{de}\right) - \Phi_d^{de}\left(\varphi_d^{de}\right) - \Pi_d^{de}\left(\pi_d^{de}\right)}{\omega_d \cdot |\mathcal{M}| \cdot |\mathcal{C}_d|}, \quad \forall d \in \mathcal{D} \tag{A.20}$$

$$\pi_d^{de} = \frac{\Theta_d^{de} + X_d^{de} - \Xi_d^{de}\left(\xi^{de}\right) - \Phi_d^{de}\left(\varphi_d^{de}\right) - \Gamma_d^{de}\left(\gamma_d^{de}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{t\in\mathcal{T}_m} q_c(t)}, \quad \forall d \in \mathcal{D} \tag{A.21}$$

Equations (A.20) and (A.21) provide a closed-form solution for the monthly fixed charge and the volumetric energy price, respectively, for each DSO. Having found either the monthly fixed charge or the volumetric energy price, the revenue attained through participating consumers taking service under the dynamic energy rate can be calculated using Equations (A.15) – (A.19). Using this revenue, the remaining revenue requirement Ψ_d^{de} can be determined, as is shown in Equation (A.23), and used to determine the energy price π_d^{flt} that will ensure recovery of the remaining costs by the non-participating consumers taking service under the flat rate. The flat rate's energy price is shown in Equation (A.22):

$$\pi_d^{flt} = \frac{\Psi_d^{de}\left(\Theta_d^{de}, X_d^{de}, \xi_d^{de}, \varphi_d^{de}, \gamma_d^{de}, \pi_d^{de}\right) - \Delta_d^{flt}\left(\delta_d^{flt}\right) - \Gamma_d^{flt}\left(\gamma_d^{flt}\right) + K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{n\in\mathcal{N}_d} \sum_{t\in\mathcal{T}_m} q_n(t)}, \quad \forall d \in \mathcal{D} \tag{A.22}$$

where

$$\Psi_d^{de}\left(\Theta_d^{de}, X_d^{de}, \xi_d^{de}, \varphi_d^{de}, \gamma_d^{de}, \pi_d^{de}\right) = \Theta_d^{de} + X_d^{de} - R_d^{de}\left(\xi_d^{de}, \varphi_d^{de}, \gamma_d^{de}, \pi_d^{de}\right) \tag{A.23}$$

With the flat rate's energy price being determined, the revenue obtained by non-participating consumers taking service under the flat rate can be found using Equations (A.1) – (A.5).

A.5 Dynamic Energy and Capacity

The dynamic energy and capacity rate builds on the dynamic energy rate by introducing two additional pricing components: (1) a charge associated with the dynamic capacity cost recovery scheme in the day-ahead retail market and (2) a charge associated with the dynamic cost recovery scheme in the real-time retail market. These two capacity-related pricing components effectively reduce the revenue that must be recovered from the fixed and volumetric energy charges. For the dynamic energy and capacity rate, Equation (A.24) defines the annual revenue earned by each DSO $d \in \mathcal{D}$:

$$\begin{aligned} R_d^{dec}\left(\xi_d^{dec}, \varphi_d^{dec}, \zeta_d^{dec}, \upsilon_d^{dec}, \gamma_d^{dec}, \pi_d^{dec}\right) = \Xi_d^{dec}\left(\xi_d^{dec}\right) + \Phi_d^{dec}\left(\varphi_d^{dec}\right) + Z_d^{dec}\left(\zeta_d^{dec}\right) + \Upsilon_d^{dec}\left(\upsilon_d^{dec}\right) \\ + \Gamma_d^{dec}\left(\gamma_d^{dec}\right) + \Pi_d^{dec}\left(\pi_d^{dec}\right), \quad \forall d \in \mathcal{D} \end{aligned} \tag{A.24}$$

where

$$\Xi_d^{dec}\left(\xi_d^{dec}\right) = \omega_d \cdot \mu_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} \xi_d^{dec}(h) \cdot q_c^{da}(h) \tag{A.25}$$

$$\Phi_d^{dec}\left(\varphi_d^{dec}\right) = \omega_d \cdot \mu_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} \sum_{f\in\mathcal{F}_{m,h}} \varphi_d^{dec}(f) \cdot \left[q_c^{rt}(f) - \frac{1}{12} \cdot q_c^{da}(h)\right] \tag{A.26}$$

$$Z_d^{dec}\left(\zeta_d^{dec}\right) = \omega_d \cdot \mu_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} \zeta_d^{dec}(h) \cdot q_c^{da}(h) \tag{A.27}$$

$$\Upsilon_d^{dec}\left(\upsilon_d^{dec}\right) = \omega_d \cdot \mu_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} \sum_{f\in\mathcal{F}_{m,h}} \upsilon_d^{dec}(f) \cdot \left[q_c^{rt}(f) - \frac{1}{12} \cdot q_c^{da}(h)\right] \tag{A.28}$$

$$\Gamma_d^{dec}\left(\gamma_d^{dec}\right) = \omega_d \cdot \gamma_d^{dec} \cdot |\mathcal{M}| \cdot |\mathcal{C}_d| \tag{A.29}$$

$$\Pi_d^{dec}\left(\pi_d^{dec}\right) = \frac{1}{12} \cdot \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{t\in\mathcal{T}_m} \pi_d^{dec} \cdot q_c(t) \tag{A.30}$$

Equation (A.25) describes the energy charge associated with the retail day-ahead market. Equation (A.26) describes the energy charge associated with the retail real-time market. Equation (A.27) describes the charge associated with the dynamic capacity cost recovery scheme in the day-ahead retail market. Equation (A.28) describes the charge associated with the dynamic capacity cost recovery scheme in the real-time retail market. Equation (A.29) describes the fixed charge for the dynamic energy and capacity rate. Equation (A.30) describes the volumetric energy charge for the dynamic energy and capacity rate.

While there are still multiple price values that must be calculated under the dynamic energy and capacity rate, there is the ability to determine how the dynamic rate should go about ensuring cost recovery. This dynamic rate recovers all costs not recovered through the retail-level markets and the dynamic capacity cost recovery scheme by using some combination of a monthly fixed charge and a volumetric energy charge. However, either the fixed charge or the volumetric energy price must be provided as a parameter, with the other being solved for through a closed-form price discovery equation. To find the monthly fixed charge γ_d^{dec} and the volumetric energy price π_d^{dec} used in the dynamic energy and capacity rate, Equations (A.31) and (A.32) are specified:

$$\gamma_d^{dec} = \frac{\Theta_d^{dec} + X_d^{dec} - \Xi_d^{dec}\left(\xi^{dec}\right) - \Phi_d^{dec}\left(\varphi_d^{dec}\right) - Z_d^{dec}\left(\zeta_d^{dec}\right) - \Upsilon_d^{dec}\left(\upsilon_d^{dec}\right) - \Pi_d^{dec}\left(\pi_d^{dec}\right)}{\omega_d \cdot |\mathcal{M}| \cdot |\mathcal{C}_d|}, \quad \forall d \in \mathcal{D} \tag{A.31}$$

$$\pi_d^{dec} = \frac{\Theta_d^{dec} + X_d^{dec} - \Xi_d^{dec}\left(\xi^{dec}\right) - \Phi_d^{dec}\left(\varphi_d^{dec}\right) - Z_d^{dec}\left(\zeta_d^{dec}\right) - \Upsilon_d^{dec}\left(\upsilon_d^{dec}\right) - \Gamma_d^{dec}\left(\gamma_d^{dec}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{t\in\mathcal{T}_m} q_c(t)}, \quad \forall d \in \mathcal{D} \tag{A.32}$$

Equations (A.31) and (A.32) provide a closed-form solution for the monthly fixed charge and the volumetric energy price, respectively, for each DSO. Having found either the monthly fixed charge or the volumetric energy price, the revenue attained through participating consumers taking service under the dynamic energy and capacity rate can be calculated using Equations (A.24) – (A.30). Using this revenue, the remaining revenue requirement Ψ_d^{dec} can be determined, as is shown in Equation (A.34), and used to determine the energy price π_d^{flt} that will ensure recovery of the remaining costs by the non-participating consumers taking service under the flat rate. The flat rate's energy price is shown in Equation (A.33)[7]:

$$\pi_d^{flt} = \frac{\Psi_d^{dec}(\cdot) - \Delta_d^{flt}\left(\delta_d^{flt}\right) - \Gamma_d^{flt}\left(\gamma_d^{flt}\right) + K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m \in \mathcal{M}} \sum_{n \in \mathcal{N}_d} \sum_{t \in \mathcal{T}_m} q_n(t)}, \quad \forall d \in \mathcal{D} \tag{A.33}$$

where

$$\begin{aligned}\Psi_d^{dec}\left(\Theta_d^{dec}, X_d^{dec}, \xi_d^{dec}, \varphi_d^{dec}, \zeta_d^{dec}, \upsilon_d^{dec}, \gamma_d^{dec}, \pi_d^{dec}\right) &= \Theta_d^{dec} + X_d^{dec} \\ &\quad - R_d^{dec}\left(\xi_d^{dec}, \varphi_d^{dec}, \zeta_d^{dec}, \upsilon_d^{dec}, \gamma_d^{dec}, \pi_d^{dec}\right)\end{aligned} \tag{A.34}$$

With the flat rate's energy price being determined, the revenue obtained by non-participating consumers taking service under the flat rate can be found using Equations (A.1) – (A.5).

A.6 Block and Swing

Under the block-and-swing rate, residential and commercial customers are assigned an hourly load profile based on consumption under the flat rate structure and can purchase this load profile at the flat rate. Deviations from this profile are charged or credited at a dynamic rate. The block-and-swing rate considered in this study uses the flat rate structure described in Section A.2 as the rate that is applied to the baseline demand profiles. The baseline demand profiles used in the PAVER study are determined from the simulation use case that implements the flat rate. From the flat rate simulation, a baseline demand profile for both weekends and weekdays is generated for each customer.

For the dynamic price, a composite price signal is created, consisting of the day-ahead energy price from the respective pricing node in the wholesale market and the dynamic price that helps recover capacity-based costs. Equation (A.35) shows this hourly composite dynamic price:

$$\lambda_d^{bs}(h) = \xi_d^{bs}(h) + \zeta_d^{bs}(h), \quad \forall m \in \mathcal{M}, \forall h \in \mathcal{H}_m, \forall d \in \mathcal{D} \tag{A.35}$$

Since the flat rate structure is used for the block-and-swing rate, equations similar to those from Section A.2 are used to govern the billing under the block-and-swing rate. Equation (A.36) defines the annual revenue earned by each DSO $d \in \mathcal{D}$:

$$R_d^{bs}\left(\pi_d^{bs}, \delta_d^{bs}, \gamma_d^{bs}, \lambda_d^{bs}\right) = \Pi_d^{bs}\left(\pi_d^{bs}\right) + \Delta_d^{bs}\left(\delta_d^{bs}\right) + \Gamma_d^{bs}\left(\gamma_d^{bs}\right) + \Lambda_d^{bs}\left(\lambda_d^{bs}\right), \quad \forall d \in \mathcal{D} \tag{A.36}$$

where

$$\Pi_d^{bs}\left(\pi_d^{bs}\right) = \omega_d \cdot \left[\sum_{m \in \mathcal{M}} \sum_{c \in \mathcal{C}_d} \sum_{h \in \mathcal{H}_m} \left[\pi_d^{bs} \cdot q_c^{bl}(h)\right] - K_d^{bs}\left(\kappa_d^{bs}, \overline{q}_d^{bs}\right)\right] \tag{A.37}$$

$$\Delta_d^{bs}\left(\delta_d^{bs}\right) = \omega_d \cdot \sum_{m \in \mathcal{M}} \sum_{l \in \mathcal{L}_d} \delta_d^{bs} \cdot \max_{h \in \mathcal{H}_m} \left\{q_l^{bl}(h)\right\} \tag{A.38}$$

[7] Note that for brevity and formatting purposes, the expression $\Psi_d^{dec}(\cdot)$ is used to represent $\Psi_d^{dec}\left(\Theta_d^{dec}, X_d^{dec}, \xi_d^{dec}, \varphi_d^{dec}, \zeta_d^{dec}, \upsilon_d^{dec}, \gamma_d^{dec}, \pi_d^{dec}\right)$ in Equation A.33.

$$\Gamma_d^{bs}\left(\gamma_d^{bs}\right) = \omega_d \cdot \gamma_d^{bs} \cdot |\mathcal{M}| \cdot |\mathcal{C}_d| \tag{A.39}$$

$$\Lambda_d^{bs}\left(\lambda_d^{bs}\right) = \omega_d \cdot \mu_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} \left(\lambda_d^{bs}(h) \cdot \left[\frac{1}{12} \cdot \sum_{f\in\mathcal{F}_{m,h}} q_c(f) - q_c^{bl}(h)\right]\right) \tag{A.40}$$

and

$$K_d^{bs}\left(\kappa_d^{bs}, \overline{q}_d^{bs}\right) = \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{l\in\mathcal{L}_d} \sum_{b\in\mathcal{B}_d} \kappa_{d,b}^{bs} \cdot \max\left\{\min\left\{\sum_{h\in\mathcal{H}_m} q_l^{bl}(h) - \overline{q}_{d,b-1}^{bs}, \overline{q}_{d,b}^{bs} - \overline{q}_{d,b-1}^{bs}\right\}, 0\right\} \tag{A.41}$$

Equation (A.37) describes the energy charge for the block-and-swing rate, including the credits that are provided from the declining-block structure, which are described by Equation (A.41). Equation (A.38) describes the demand charge for the block-and-swing rate. Equation (A.39) describes the fixed charge for the block-and-swing rate. Equation (A.40) describes the net deviation credit for the block-and-swing rate, where positive differences between the demand and baseline demand indicate an additional charge that is levied against the consumer and negative differences indicate a credit that is returned to the consumer.

Similar to the other rate structures considered, there are multiple price values that must be calculated: the volumetric energy price π_d^{bs} for the flat rate structure used to calculate the baseline bill and the volumetric energy price π_d^{flt} for the flat rate structure used for non-participating customers. To find the volumetric energy price used in the block-and-swing rate, Equation (A.42), which is similar to the closed-form solution shown in Equation (A.6), is specified:

$$\pi_d^{bs} = \frac{\Theta_d^{bs} + X_d^{bs} - \Delta_d^{bs}\left(\delta_d^{bs}\right) - \Gamma_d^{bs}\left(\gamma_d^{bs}\right) - \Lambda_d^{bs}\left(\lambda_d^{bs}\right) + K_d^{bs}\left(\kappa_d^{bs}, \overline{q}_d^{bs}\right)}{\omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{c\in\mathcal{C}_d} \sum_{h\in\mathcal{H}_m} q_c^{bl}(h)}, \quad \forall d \in \mathcal{D} \tag{A.42}$$

Equation (A.42) provides a closed-form solution for the volumetric energy price for each DSO. Having found the volumetric energy prices, the revenue attained through participating consumers taking service under the block-and-swing rate can be calculated using Equations (A.36) – (A.41). Using this revenue, the remaining revenue requirement Ψ_d^{bs} can be determined, as is shown in Equation (A.44), and used to determine the energy price π_d^{flt} that will ensure recovery of the remaining costs by the non-participating consumers taking service under the flat rate. The flat rate's energy price is shown in Equation (A.43):

$$\pi_d^{flt} = \frac{\Psi_d^{bs}\left(\Theta_d^{bs}, X_d^{bs}, \pi_d^{bs}, \delta_d^{bs}, \gamma_d^{bs}, \lambda_d^{bs}\right) - \Delta_d^{flt}\left(\delta_d^{flt}\right) - \Gamma_d^{flt}\left(\gamma_d^{flt}\right) + K_d^{flt}\left(\kappa_d^{flt}, \overline{q}_d^{flt}\right)}{\frac{1}{12} \cdot \omega_d \cdot \sum_{m\in\mathcal{M}} \sum_{n\in\mathcal{N}_d} \sum_{t\in\mathcal{T}_m} q_n(t)}, \quad \forall d \in \mathcal{D} \tag{A.43}$$

where

$$\Psi_d^{bs}\left(\Theta_d^{bs}, X_d^{bs}, \pi_d^{bs}, \delta_d^{bs}, \gamma_d^{bs}, \lambda_d^{bs}\right) = \Theta_d^{bs} + X_d^{bs} - R_d^{bs}\left(\pi_d^{bs}, \delta_d^{bs}, \gamma_d^{bs}, \lambda_d^{bs}\right) \tag{A.44}$$

With the flat rate's energy price being determined, the revenue obtained by non-participating consumers taking service under the flat rate can be found using Equations (A.1) – (A.5).

Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99352
1-888-375-PNNL (7675)

www.pnnl.gov