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Revised Load Management Standard Compliance Plan

December 18, 2024

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2 Executive Summary

The goal of the California Energy Commission's (CEC) Load Management Standard (LMS) regulations, which went into effect in April of 2023, is to: 1) encourage the use of energy at off-peak hours; 2) encourage the control of daily and seasonal peak loads to improve electric system equity, efficiency, and reliability; 3) lessen or delay the need for new electrical capacity; and 4) reduce fossil fuel consumption and greenhouse gas emissions.[1] SMUD is fully supportive of the goals of the LMS regulations.

SMUD has a long history of exploring and implementing innovative rates and programs that deliver outcomes matching the LMS goals. SMUD started testing dynamic pricing for customers over 30 years ago and was the first California utility to implement Time-of-Day (TOD) rates. With TOD rates in place, SMUD used its experience and insights from customer behavior to again sharpen rate design to drive additional off-peak usage among its customer base through the Critical Peak Pricing (CPP) rate. SMUD has also implemented and continues to design and test a range of load flexibility programs. Robust development and implementation processes ensure the rates and programs deliver intended benefits, receive high customers adoption and satisfaction, and help SMUD keep its rates among the lowest in California. As a result, SMUD has seen a significant shift of load away from peak hours, and strong customer adoption of rates and programs that support grid resiliency and its bold Zero Carbon Plan.

SMUD's industry leading decarbonization efforts are also aligned with the LMS goals. In 2021, SMUD's Board of Directors (Board) committed SMUD to completely eliminating greenhouse gas (GHG) emissions from SMUD's electricity supply by 2030, while also maintaining safe, reliable service and affordable rates. This roadmap, referred to as the Zero Carbon Plan, explains that up to 90% of carbon emissions in SMUD's electricity supply can be removed with conventional technologies and techniques, but the remaining 10% will require new technologies and strategies. Load flexibility programs are an important part of SMUD's strategy to achieve this last 10%. These programs reduce carbon emissions, reduce the need for new peak resources, help SMUD manage and operate the system, and save customers money. The Zero Carbon Plan forecasts that customer-owned resources and SMUD customer-focused programs will contribute up to 1,325 MW of flexible load to SMUD's grid by 2030. SMUD's demonstrated environmental leadership, forward-looking rate design and track record for innovation demonstrate a commitment to the goals of the LMS regulations.

The analysis detailed in this compliance plan shows that the prudent path to achieve the LMS goals is for SMUD to continue its current rates and programs. SMUD considered the experience of other jurisdictions, the input of external experts, and data from the Commission's final LMS staff report in its analysis. This led to the determination that while dynamic pricing offers potential benefits, dynamic pricing rates and programs are neither cost-effective nor a prudent investment for SMUD or its customers at this time. SMUD's analysis shows that offering dynamic rates or programs with hourly or sub-hourly price signals results in approximately $2.4 million to $3.7 million in net annualized costs for the

[1] LMS Regulation, Section 1621(a). Unless otherwise noted, all references to regulatory sections refer to the LMS regulations (California Code of Regulations, Title 20, Division 2, Chapter 4, Article 5).

combined residential and non-residential customers. SMUD estimates that the initial investment to roll out optional dynamic rates with hourly or sub-hourly price is approximately $17.7 million plus ongoing annual expenses of about $1 million. Since SMUD is a non-for-profit utility and does not earn a rate of return on investments, the costs of developing and implementing new rates and programs with hourly or sub-hourly price signals would necessarily be fully reflected in customer rates through a necessary rate increase. SMUD expects these costs would be disproportionately borne by lower-income customers, who are less likely to see benefits and more exposed to bill volatility, and as confirmed by SMUD's analysis, particularly since the analysis shows adoption of technology in its service territory is correlated with income. At times of great market volatility such as has been seen over the past few years the potential risk to customers is exacerbated. Passing these risks to its customers could impose extreme hardship on its customers and, accordingly, SMUD has determined it is more cost effective and equitable to revisit potential dynamic price mechanisms after the necessary tools to automate responses to such prices are widely available to all customers.

Although SMUD currently has a significant pipeline of technology projects benefitting all customers, the systems upgrades required to offer dynamic rates or programs with hourly or sub-hourly prices would not be completed until well beyond the timeline required by the LMS regulations. In addition, SMUD's experience developing complex rates shows that successful implementation takes close to seven years from pilot to enrollment.

SMUD is committed to achieving its 2030 goals which align with the State's aggressive decarbonization policies. SMUD also recognizes that load flexibility and management are critical tools to achieving those goals. As such, SMUD has adopted rates and load flexibility programs that functionally meet the goals of the LMS rate and program requirements. As 2030 approaches, SMUD will continue to evaluate the benefits that dynamic pricing mechanisms may provide and feasible pathway for implementation in a way that supports the LMS objectives.

2.1 LMS Compliance Plan Approach

Since first preparing SMUD's LMS Compliance Plan in 2023 (Original Plan), SMUD has continued to explore the publicly available examples and research related to dynamic rates. SMUD's analysis in this Revised LMS Compliance Plan (Revised Plan) recognizes that there are compelling theoretical concepts and promising examples of dynamic hourly or sub-hourly pricing. However, the results of these early applications are still preliminary, not uniform, and may not be fully transferrable to SMUD's systems, technology, and customer preferences. SMUD takes a conservative, evidence-based approach with a focus on customer data and insights before deploying new technologies and rate designs. SMUD believes this cautious, stepwise approach is not only prudent but necessary to maintain customer confidence and ensure its ability to achieve both SMUD's and the State's shared goals. Fundamentally, the grid cannot be decarbonized without the active participation of SMUD's customers and maintaining customers' trust is critical to SMUD's ability to realize the benefits of decarbonization.

This Revised Plan and the evaluation contained herein are based on a review of the published literature, input from third parties and industry experts, SMUD's experience with rates and programs, and SMUD's quantitative assessment of the required factors. Based on this information and extensive analyses, the evaluation detailed in this Revised Plan shows:

- For both residential and nonresidential customers, a dynamic rate and/or program with hourly or sub-hourly prices[2] would impose a net annual cost ranging from $2.4 million to 3.7 million on SMUD and its customers. The value proposition of a dynamic rate or program with hourly or sub-hourly prices is further eroded when compared to SMUD's current load modifying rates and programs, which already achieve substantial load modification and effectively achieve the LMS regulations' goals.[3]
- While all customers will bear the cost of a dynamic rate structure, lower income customers would be less able to realize any potential benefits due to challenges accessing enabling technology, flatter load shapes, and less ability to bear the risk of bill volatility. Customers who cannot participate in the rate will still pay the additional cost, causing an unintended cost shift from more affluent to lower income customers.
- While it is technically feasible to implement a dynamic rate or program with hourly or sub-hourly price signals, doing so cannot be achieved on either the timeline provided by the LMS regulations or without compromising SMUD's 2030 Zero Carbon Plan commitments.
- Any benefits to the grid would be immaterial compared to SMUD's grid investments, and the complexity and volatility of dynamic rates and programs undermine potential benefits to customers.
- Dynamic hourly pricing will not result in an overall material reduction in peak load for either residential or nonresidential customers.

This Revised Plan concludes that to meet the LMS regulations' goals in a cost-effective and technically achievable manner, SMUD should continue its industry leading clean energy efforts, including time-differentiated rates and load modifying programs. SMUD's existing rates and programs provide similar, and in some circumstances greater, benefits than a dynamic rate or program. Over the next several years, SMUD plans to continue reviewing approaches to dynamic rates and, where appropriate, incorporating these concepts into SMUD's offerings at a pace and scale that supports and protects its customers. Further, SMUD looks forward to continuing cooperation with the CEC and staff regarding ways to prepare the state for the deployment of dynamic rates that achieve the LMS regulations' goals.

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[2] SMUD recognizes that the term "dynamic" rates or pricing is commonly used to describe a broader concept, but for purposes of this Revised Plan, SMUD uses the terms dynamic, real-time prices (RTP), and hourly or sub-hourly prices interchangeably to refer to the marginal cost-based rates described in Section 1623.1(b)(1).

[3] For example, SMUD's successful TOD rate paired with CPP achieves 80% of the potential load reduction from an hourly or sub-hourly price signal, and its non-residential automatic demand response program known as PowerDirect® realization rates are impressive at average of about 80% which would be impossible to achieve with just a dynamic price signal.

3 Background

The following introduces SMUD and provides an overview of the LMS regulations relevant to this Revised Plan.

3.1 SMUD Background

SMUD is a not-for-profit, publicly owned, electric utility (POU) headquartered in Sacramento, California. As a POU, SMUD is governed by a seven-member elected Board of Directors (Board) that determines policy, sets rates, and appoints the Chief Executive Officer and General Manager who is responsible for SMUD's overall management and operations. Responsibility for the development and implementation of this Revised Plan is delegated to SMUD's Chief Financial Officer.

SMUD's service area covers approximately 900 square miles and includes parts of Sacramento County, and small adjoining portions of Placer and Yolo Counties. The service area includes Sacramento, the State Capital, and the populous areas to the northeast and south of the City of Sacramento, and the agricultural areas to the north and south. In total, SMUD serves a population of approximately 1.5 million and has the following distinct customer classes – residential, non-residential (which includes commercial, industrial and agricultural), and street lighting & traffic signals. Marginal cost-based time-dependent rates are default for all SMUD customers, except for lighting and agricultural (AG) customers (which have optional time dependent rates). This includes SMUD's successful residential Time-of-Day (TOD) rate, which encourages customers to reduce their electricity use between 5 p.m. and 8 p.m. All SMUD's rate schedules are posted on SMUD's website.[4]

As a POU, SMUD's Board is its rate-approving body. The Board has authority to establish rates and charges for all SMUD services, and such rates are not subject to oversight by other federal, state, or local governmental agencies. SMUD engages in a comprehensive and robust public process prior to adopting new or revised rates and service regulations. This 3-month public process includes media and public outreach at various community events. The process kicks-off with notice published in the local papers and release of a report detailing the proposed rate changes together with the expected impacts to customer bills. As part of this process, SMUD holds multiple public workshops, a public hearing and conducts a final Board vote on the rate proposal.

As discussed further below, SMUD balances competing objectives when designing and approving rates. SMUD is guided by its long-standing Board policy, which provides several objectives, including designing rates that are competitive with local utilities, reflective of the cost of energy when it is used or exported to the grid, and results in reduced consumption during periods of high demand. Additionally, SMUD prioritizes rates that provide customers with flexibility and choice, are simple and easy to understand, and equitably allocate costs across and within customer classes. Again, these objectives are highly aligned with the goals of the LMS amendments adopted in 2023.

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[4] See Rate Information *available at* https://www.smud.org/en/Rate-Information.

In July 2020, SMUD's Board declared a climate emergency and adopted a resolution calling for SMUD to take significant and consequential actions to reduce its carbon footprint by 2030. On April 28, 2021, the Board approved SMUD's 2030 Zero Carbon Plan (the "Zero Carbon Plan" or "ZCP").[5] The Zero Carbon Plan is SMUD's roadmap to completely eliminating Greenhouse Gas (GHG) emissions from its electricity supply by 2030, less than six years away, while maintaining reliable service and affordable rates.

To achieve these goals, the Zero Carbon Plan focuses on four main areas: natural gas generation repurposing, proven clean technologies, new technologies and business models, including load flexibility, and financial impacts and options. SMUD is partnering with its customers, communities, and a wide range of stakeholders to ensure that its community can benefit from a carbon-free economy.

As SMUD pursues its Zero Carbon Plan, it is committed to keeping electric service affordable and rate increases at or below the rate of inflation. To accomplish this, the Zero Carbon Plan estimates the need for SMUD to realize sustained annual savings. SMUD currently plans to achieve these sustained annual savings by exploring the implementation of operational savings strategies, leveraging innovative approaches including load flexibility, and pursuing partnership and grant opportunities.

Enabling load flexibility is a key strategy in achieving SMUD's Zero Carbon Plan goals. Load flexibility programs support reduced carbon emissions, reduce the need for new peak resources, help SMUD manage and operate the system, and save customers money. SMUD is focused on fully utilizing its intermittent resources when they are available and reducing peak usage at times when such resources are scarce. The Zero Carbon Plan forecasts that customer-owned resources and SMUD customer-focused programs will contribute between 364 and 1,325 MW of capacity to SMUD's grid by 2030, and as such, SMUD is leaning in on programs and learning from cutting-edge pilots to maximize cost-effective resources that can be achieved through partnership with its customers.

A key component of SMUD's Zero Carbon Plan is the electrification of buildings and transportation. These segments are critical to reducing regional and statewide carbon emissions. Growth in these segments is expected to result in significant investments on the distribution system, creating opportunities for local load flexibility to reduce these costs. At the same time, managing a combination of local constraints and bulk system services also introduce significant complexities with integrating Distributed Energy Resources (DERs).

In 2022, after years of planning, SMUD deployed its Advanced Distribution Management System (ADMS) and initial phase of its Distributed Energy Resource Management (DERMS) platform technology. With these two systems online and working together, SMUD will shift from a one-way centralized distribution system to a two-way decentralized distribution system that allows it to manage and optimize distributed energy resources that include battery storage, demand response programs, smart thermostats, connected appliances, electric vehicles (EVs) and more.

SMUD is currently building out DERMS functionality and continuing to evaluate device partners and aggregators that can integrate product offerings into DERMS. In the next few years, SMUD anticipates that its DERMS system will enable full DER integration across bulk and distribution system value

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[5] SMUD's 2030 Zero Carbon Plan (ZCP) *available at* 2030-Zero-Carbon-Plan-Technical-Report.ashx.

streams. These include, but are not limited to, advanced distribution system management applications, scheduling DERs based on economic and reliability considerations, scheduling DER Virtual Power Plants (VPPs) into electricity markets, and integrating with aggregator platforms that allow customers to participate in programs that control and leverage behind-the-meter DERs to respond to grid needs.

3.2 Load Management Standards

The CEC's LMS regulations encourage shifting electricity use from times of day when it is expensive and polluting to times when it is cheaper and cleaner. Load management, or demand flexibility, can save customers money on their energy bills, reduce greenhouse gas emissions, and help strengthen the resiliency of the electricity grid. Load management is defined as "any utility program or activity that is intended to reshape deliberately a utility's load duration curve".[6] Also known as demand management and load flexibility, load management reduces the need for new large electrical generation and backup generation devices. It is also a key strategy to ensure a reliable grid, keep energy costs down, integrate renewable energy resources, and reduce greenhouse gas (GHG) emissions. The intent of load management standards is to encourage electricity customers to shift electricity demand away from high demand periods, when peaking power plants and other polluting generators are in use, to times when lower-cost clean electricity is available.

Amendments to the LMS regulations became effective in April 2023. These amendments require Large POUs, like SMUD, to meet a variety of compliance obligations related to the implementation of rates or programs incorporating dynamic prices. Specifically, Section 1623.1 applies to Large POUs and Large Community Choice Aggregators (CCAs), whereas investor-owned utilities (IOUs) are covered by Section 1623. The focus of this Revised Plan is on the regulations related to preparation, evaluation, and submission of the LMS Compliance Plan. In Section 5, SMUD provides an overview of each of the other LMS compliance requirements, several of which have been satisfied either individually or in coordination with other utilities.

3.2.1 Compliance Plan Requirements

The LMS regulations require POUs to submit a compliance plan to its rate approving body that is consistent with Section 1623.1. SMUD's rate approving body is its Board of Directors (Board). The compliance plan is further required to describe how the POU will meet the goals of (1) encouraging the use of electrical energy at off-peak hours, (2) encouraging the control of daily and seasonal peak loads to improve electric system efficiency and reliability, (3) lessening or delaying the need for new electrical capacity, and (4) reducing fossil fuel consumption and GHG emissions.[7]

The plan is required to consider programs and rate structures that, as specified in Section 1623.1(b)-(d), incorporate dynamic price signals. Specifically, the compliance plan must include an evaluation of rates incorporating dynamic pricing along five factors: (1) cost-effectiveness, (2) equity, (3) technological feasibility, (4) benefits to the grid, and (5) benefits to customers.[8] If the plan does not propose

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[6] Public Resources Code, Section 25132.
[7] Section 1623.1(a)(1).
[8] See Section 1623.1(a)(1)(A).

development of rates with dynamic prices, the plan must evaluate programs that enable automated response to dynamic prices according to the same factors.[9]

Importantly, the LMS regulations also provide deference to POU boards. A board may approve a plan that delays or modifies compliance with the requirements of Section 1623.1(b) and (c) if it meets any of the following criteria:

> (A) that despite a Large POU's or Large CCA's good faith efforts to comply, requiring timely compliance with the requirements of this article would result in extreme hardship to the Large POU or the Large CCA,
>
> (B) requiring timely compliance with the requirements of this article would result in reduced system reliability (e.g., equity or safety) or efficiency,
>
> (C) requiring timely compliance with the requirements of this article would not be technologically feasible or cost-effective for the Large POU to implement, or
>
> (D) that despite the Large POU's or the Large CCA's good faith efforts to implement its load management standard plan, the plan must be modified to provide a more technologically feasible, equitable, safe, or cost-effective way to achieve the requirements of this article or the plan's goals.[10]

Thus, if a POU board determines that the compliance plan demonstrates these criteria, then compliance with 1623.1(b) and 1623.1(c) may be delayed or modified. Section 1623.1(b)(2) requires POUs to propose rates incorporating dynamic prices, and 1623.1(b)(3), in the alternative, requires POUs to propose programs with automated response to dynamic signals, which may be price, marginal GHG emissions, or other Commission-approved signals.[11] Importantly, POUs must only propose such rates or programs for those customer classes that their boards determine will result in a material reduction in peak load.[12]

To summarize, POUs must prepare a compliance plan that analyzes the adoption of dynamic rates and/or programs with dynamic price signals. However, a POU Board is given discretion at two stages within the regulatory scheme. First, the POU board may determine that dynamic rates or programs incorporating dynamic signals will not materially reduce peak load, which can justify the decision of the board to not propose and/or adopt such a rate or program. Second, even if a dynamic rate or dynamic program would materially reduce peak load, a board may determine that one of the four factors above are met, which justifies delaying or modifying compliance with the regulations. Importantly, in both instances, the LMS regulations place the authority to make these determinations with the POU board.

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[9] See Section 1623.1(a)(1)(B).
[10] Section 1623.1(a)(2).
[11] See Section 1623.1(b).
[12] See Section 1623.1(b)(2)(A) ("Large POUs and Large CCAs shall apply for approval of marginal cost-based rates only for those customer classes for which the rate-approving body determines such a rate will materially reduce peak load."); Section 1623.1(b)(3)(A) ("The portfolio of identified programs shall provide at least one option for automating response to MIDAS signals for each customer class that the rate-approving body determines such a program will materially reduce peak load.").

SMUD's Original Plan was approved by its Board on November 16, 2023, in Resolution No. 23-11-04.[13]

3.2.2 CEC Review Process

Section 1623.1(a)(3) specifies that, upon adoption by the POU rate approving-body, the plan must be submitted to the CEC Executive Director within 30 days for review. Following adoption by the Board, SMUD submitted its plan on November 30, 2023, for review by the CEC for a determination of whether SMUD's Board-adopted Plan complies with the regulations.

SMUD's Original Plan provided a theoretical and qualitative justification for the conclusions reached therein. The Original Plan determined that the prudent path forward at that time for SMUD was to delay proposal and adoption of new dynamic rates. SMUD reached this determination based on its analysis that such a rate could neither be determined to materially reduce peak load, nor cost-effective, equitable, or able to provide incremental benefits to the grid or customers. For similar reasons, SMUD's analysis determined that it was prudent to delay the implementation of programs with dynamic price signals.

On September 19, 2024, CEC's Executive Director issued a request for revision of SMUD's Original Plan pursuant to Section 1623.1(a)(3) (Request).[14] The Request indicated the Original Plan did not meet Sections 1623.1(a)(1) or (a)(2) by "declining to conduct the robust analysis or marginal cost-based rates and programs the regulation requires…"[15] The Request further states that SMUD must provide an evaluation of five factors for each customer class: cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers. This analysis must include dynamic rates, and if SMUD chooses not to provide dynamic rates, then the plan must also evaluate the same factors for programs incorporating dynamic price signals. If SMUD chooses not to adopt either dynamic rates or programs incorporating dynamic rates, then SMUD's plan must provide evidence and analysis that supports the criteria in Section 1623.1(a)(2).

SMUD maintains that its Original Plan provided sufficient theoretical and qualitative analysis for SMUD's Board to reach a determination that adoption of dynamic rates or programs incorporating dynamic price signals would not materially reduce peak load and should be delayed until a later date to avoid cost ineffectiveness, technical challenges, and hardship. SMUD's Board exercised the discretion provided by the regulations to determine that implementation of dynamic rates or programs at that time were not appropriate for SMUD customers.[16] The LMS regulations authorize the Executive Officer to determine whether the plan is consistent with Sections 1623.1(a)(1) and (a)(2).[17] The LMS regulations do not provide the Executive Officer with the authority to substitute its judgment for SMUD's Board,

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[13] See SMUD's Load Management Standard (LMS) Compliance Plan (Board Res 23- 11-04), TN# 253401 *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=253401&DocumentContentId=88618.

[14] Request for Revisions of SMUD Compliance Plan, TN#259235 *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=259235&DocumentContentId=95320.

[15] Request at 2 and 3.

[16] See e.g., Original Plan at Sections 7.3 and 7.4; see also Section 1623.1(a)(2) (providing that POU boards are the body determining whether the Plan has demonstrated one of the four listed criteria); Section 1623.1(b)(2)(A) and (b)(3)(A) (providing that POU boards are the body determining whether the rate or program will materially reduce peak load).

[17] See Section 1623.1(a)(3)(B) (stating "[t]he Executive Director shall make an initial determination whether the plan or material plan revision is consistent with the requirements of Section 1623.1(a)(1) and (2).").

determine appropriate rates or programs for the utility, or determine evidentiary standards.[18] While SMUD continues to believe its Original Plan was compliant, SMUD greatly appreciates the careful review, thoughtful input, and direction that supported improvements in SMUD's Revised Plan.

In response to the Request, SMUD reviewed its Original Plan and undertook further analyses. In particular, SMUD consulted outside experts, met with utilities implementing dynamic pricing, and performed internal quantification of the costs and benefits associated with implementing dynamic rates and programs for SMUD customers. This Revised Plan provides SMUD's refreshed analysis.

[18] See Section 1623.1(a)(3)(B).

4 Analysis of Rates and Programs

The following sections provide an overview of SMUD's current rates and load modifying programs. This includes background on SMUD's rate development process, description of SMUD's current load modifying rates and programs, and analysis of each of the factors listed in Section 1623.1(a)(1)(A) and (B). These analyses evaluate SMUD's residential and non-residential rates and programs.[19]

4.1 SMUD's Rate Development Process

SMUD's rate development process is guided by Board policy, first adopted in 2003 and most recently revised in 2021. SMUD's Strategic Direction 2,[20] Competitive Rates (SD-2) includes the following objectives:

- Establish rate targets that are 18% below Pacific Gas and Electric (PG&E) system average rates and at least 10% below PG&E published rates for each customer class
- Be competitive with other local utilities on a system average rate basis
- Reflect the cost of energy when it is used or exported to the grid
- Reduce consumption during periods of high system demand
- Encourage energy efficiency, conservation and carbon reduction
- Encourage cost-effective and environmentally beneficial DER
- Minimize the rate of change in the transition from one rate design to another
- Provide customers flexibility and choices
- Be as simple and easy to understand as possible
- Address the needs of people with low incomes and severe medical conditions
- Equitably allocate costs across and within customer classes

When designing rates, SMUD must balance all these competing objectives – many of which support the objectives of the LMS regulations. While SMUD's rate setting approach includes developing marginal cost-based rates that reflect the cost of energy and reduce consumption during peak demand, it also requires SMUD to consider customer experience, such as by ensuring rates are as simple and easy to understand as possible, ensuring rates are predictable, and avoiding abrupt transitions in rate design or bills.

Consistent with its SD-2 guidance, SMUD takes deliberate measures to ensure that any new rate it develops will be successful, effective, and accepted by its customers. This includes conducting pilots to determine the effectiveness of different rate options and improve upon customer experience prior to adopting and implementing new rates. It also includes iteratively developing and executing on

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[19] Section 1621(c)(6) (excluding street lighting from the definition of customer class). Note that SMUD generally categorizes street lighting and traffic signals in the same rate class; however, only street lighting is specifically exempt from the LMS regulations.
[20] SMUD Board Policy, Strategic Direction (SD) 2, "Competitive Rates" *available at* SMUD Board Policy - Strategic Direction SD-2, Competitive Rates.

communications and outreach strategies, new educational and training tools, rate comparison reports, and any technology or billing system enhancements that are needed to ensure that the implementation of a new rate, once designed, is smooth and successful. In addition, even after rate implementation, SMUD continues to monitor and report to the Board the effectiveness of its rates with respect to shifting peak load.

While, in practice this can be a lengthy and costly process, SMUD attributes the success of its current time-dependent rates, including high customer acceptance and consistent load management benefits, to its careful and comprehensive approach to planning, performing rate design adjustments, gradual implementation, customer education, and strong focus on customer experience.

4.2 SMUD's Existing Rates

SMUD currently offers at least one marginal cost-based time-dependent rate to nearly all its customers. As previously described, SMUD has the following customer classes: residential, non-residential, which includes commercial and industrial (C&I) and agricultural (AG), and lighting customers. Except for lighting, master-metered mobile home parks, and unmetered customers[21], all customers have access to Time-of-Day (TOD) rates, and 97% of residential customers are enrolled in TOD rates. Some customers have access to additional time-dependent rate options based on enabling devices and technology. The following is a summary of the time-dependent rates currently available to SMUD customers.

4.2.1 Residential Rates

SMUD's residential TOD rate described below is the standard rate for residential customers. Customers with enabling devices also can participate in two additional time-dependent rates -Critical Peak Pricing (CPP) and the Electric Vehicle (EV) rate discount - which build on the existing TOD rate.

4.2.1.1 Residential Time-of-Day (TOD) Rate

In summer 2012 and 2013, SMUD conducted a comprehensive SmartPricing Options (SPO) pilot, which evaluated the impacts of time-based rates, enabling technology, and recruitment methods on energy consumption and peak demand, as part of its broader Consumer Behavior Study. The SPO pilot tested three time-varying pricing plans (time of day with a 4 pm – 7 pm peak, critical peak pricing, and a combination of both) and two recruitment strategies (opt-in or default). The pilot included a seven-month recruitment period and over a year and half of planning before the pricing plans took effect.

The SPO pilot and study, released in September 2014, showed that both experimental TOD and CPP rates were effective. These efforts were so successful that the study became a national and international resource used by laboratories and universities to conduct research on time-of-day rates and behavioral studies. The results of the study showed that customers preferred a TOD rate over the more dynamic CCP rate by 2 to 1.

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[21] Unmetered customers include small devices like traffic cameras, telecommunication devices, antennas; all of which are under 20 kW and billed at GFN rates. Legacy master-metered mobile homes also have a non-time-based rate.

Based on the successful results of the SPO pilot, SMUD decided to pursue the development of TOD rates. This decision began significant additional planning and development to ensure that SMUD could successfully roll out the rates with positive customer acceptance and maximal efficacy. At the time of rollout, SMUD was the only utility in the state to plan and roll out standard TOD rates for all its residential customers. Eventually, and given the success story from SMUD, the California Public Utilities Commission (CPUC) ordered the IOUs to follow the same trend with the adoption of time-based rates for their residential customers. SMUD was a pioneer in rate design and its success was the result of several years of planning and testing after the SPO pilot was concluded.

In 2016, SMUD introduced an optional time-of-day rate (4 pm – 7 pm peak) for all residential customers, with the goal to test systems and processes before the actual roll out of the standard TOD rate in 2018. Planned implementation was phased over two years, starting with a small subset of residential customers. This staging allowed staff time to provide customers with education on time-of-use rates, develop new customer tools, and upgrade systems and processes needed to prepare for a larger number of customers transitioning to the rate.

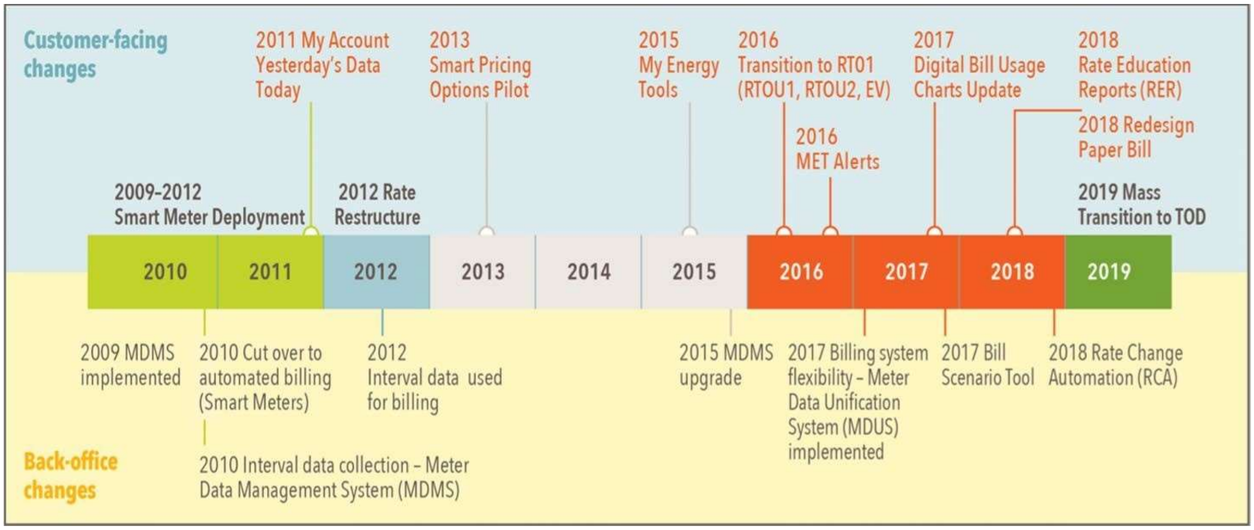
Concurrently, SMUD staff performed research and analysis to refine and adjust the rate design in support of developing a future standard for all residential customers. The results of this analysis shifted the peak period to 5 pm – 8 pm to better align with the highest peak loads and marginal costs. The rate design was also influenced by the feedback received from the community and subject matter experts in the industry to balance several rate design principles and customer experience.

SMUD's Board approved the standard TOD rate in 2017, and SMUD began another staged rollout beginning in late 2018 and completing in 2019. Based on its experience with the pilots and the optional TOD rate, SMUD developed additional customer tools, including an interactive TOD cost estimator, redesigned the billing experience, developed and launched a phased marketing campaign with simple, easy-to-understand messages, and undertook targeted outreach efforts. The education and marketing campaign was the most comprehensive campaign SMUD has ever conducted in the transition from one rate design to another and was key to the successful completion of that milestone.

Each year since full residential TOD implementation, enrollment, peak load reduction, and carbon reduction have met or exceeded expectations based on the pilot. SMUD attributes the continued success of its residential TOD rates to the time invested testing and refining rates, educational tools, and attention to the customer experience. In addition, the TOD implementation process reaffirmed SMUD's understanding that rate simplicity and customer engagement and satisfaction drives the adoption and ultimate success of a rate.

Below is a timeline highlighting the key milestones leading up to the implementation of SMUD's residential TOD rate, starting with the deployment of enabling technology that preceded the SPO pilot.

Figure 1 Residential TOD Planning and Implementation

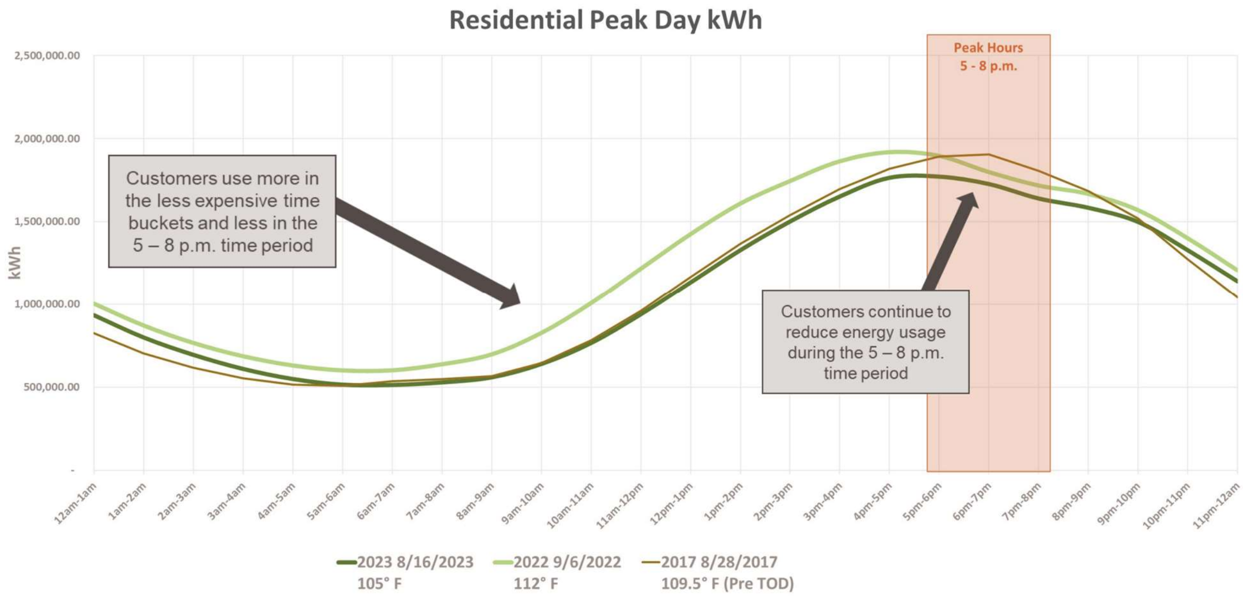


The standard residential rate structure includes the following components: a) System Infrastructure Fixed Charge (SIFC) per month per meter; b) energy charge by TOD period, as discussed below. Under today's residential TOD rate, customers pay different rates depending on the season, day, and hours of energy use. During the summer months (June 1 through September 30), there are three rate periods: Peak (weekdays 5 pm – 8 pm), Mid-Peak (weekdays 12 pm – 5 pm and 8 pm – 12 am), and Off-Peak (weekdays 12 am – 12 pm, weekends, and holidays). In the non-summer months (October 1 – May 31), there are two rate periods: Peak (weekdays 5 pm – 8 pm) and Off-Peak (weekdays 12 pm – 5 pm and 8 pm – 12 am, weekends, and holidays). These time periods were selected because they best aligned with highest peak loads and marginal electricity prices, while also being simple and easy for customers to understand. TOD rates offer customers predictable bills and Off-Peak prices on all weekends to make it easier for customers to manage.

Figure 2 SMUD's Current TOD Rate Structure

Currently, approximately 97% of SMUD's residential customers are enrolled on TOD, and this high adoption and retention has yielded significant benefits for SMUD and its customers. There is an estimated summer peak load reduction of 4-8% (75-130 MW) attributable to the residential TOD rate, corresponding to approximately 12,000 tonnes of avoided GHG emissions and approximately $11 million to 16 million in commodity cost savings.

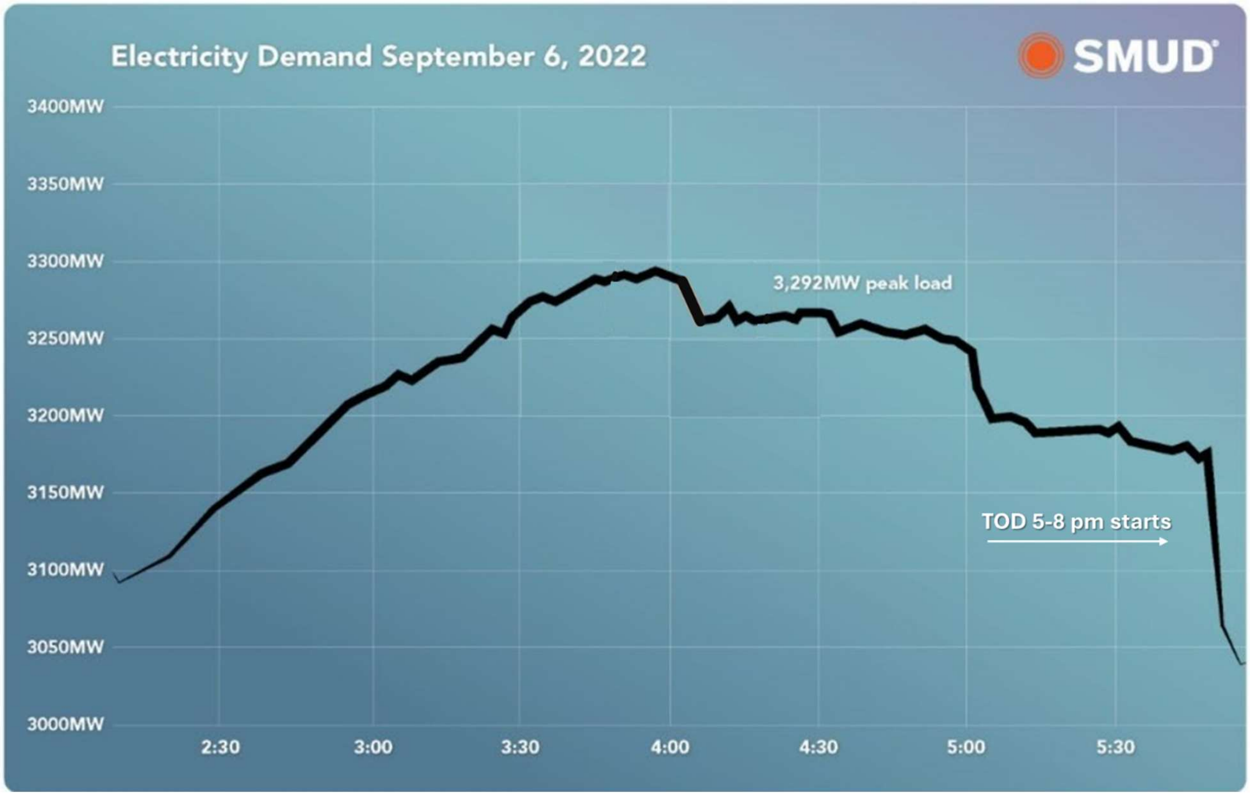
Figure 3 SMUD TOD Rates Reduce Residential Peak



As shown in Figure 3 above, comparing a baseline historical residential load shape on August 28, 2017, before TOD was fully implemented to more recent load shapes post-TOD in 2022 and 2023, there is a clear change in load pattern and peak load reduction. SMUD has monitored this trend since the summer of 2019 when the TOD roll out was completed and has observed a consistent load reduction year over year.

To further illustrate load shift benefits provided by SMUD's time-dependent rates and programs, the Figure 4 below shows SMUD's system load on September 6, 2022. The region experienced 10 straight days of extreme heat and Sacramento reached an all-time high temperature of 116°F on that day. There is a clear reduction in load from a combination of SMUD's demand response programs and customers responding to TOD price signals from 5 pm – 8 pm. The benefits from SMUD's existing TOD rates and load flexibility programs are evident. This consistent load reduction on peak days allows SMUD to reduce its long-term resource adequacy requirements and save on energy costs. The chart shows that significant load reduction was observed on that day due to the combination of demand response, TOD rates, load curtailment agreements, and customer education.

Figure 4 Load Reduction Observed on September 6, 2022

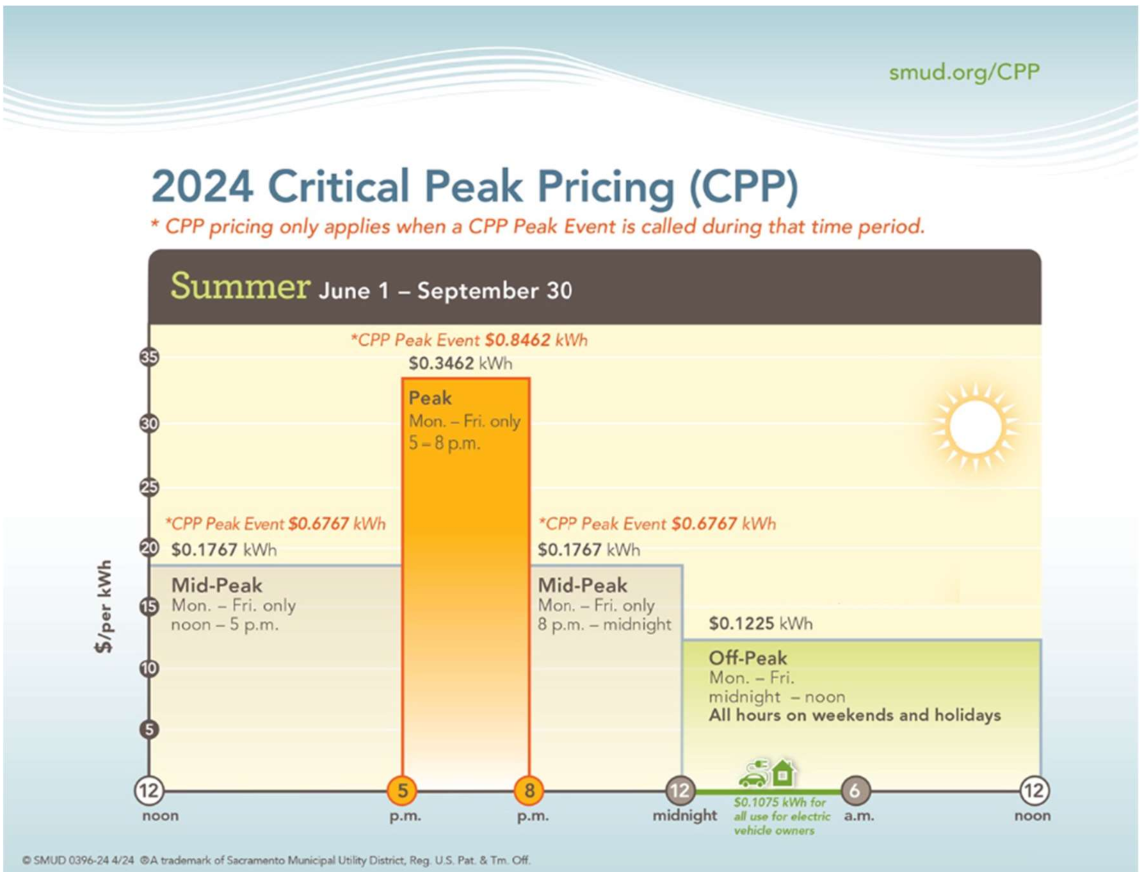


4.2.1.2 Critical Peak Pricing (CPP) Rate

SMUD's residential TOD rates are designed to provide price signals to customers to let them know when conserving energy is most beneficial to the electrical grid and will save them money. However, these price signals are designed for conditions seen on days with average energy use, not for those few hours during the year when the demand for energy is so high it puts stress on the grid, such as during a heat wave. The results of the SPO pilot, discussed above, showed that a CPP rate with an underlying TOD rate structure could achieve an overall load reduction of 20.9% during event hours. To achieve this additional load reduction, SMUD's Board approved the optional CPP rate in 2021, and SMUD began offering it in June 2022 for customers that participate in qualifying programs.

The CPP rate builds off the residential TOD rate structure, with several key pricing differences, as shown in Figure 5 below. Participating customers receive a per-kWh discount for Mid-Peak and Off-Peak prices during the summer months and pay a fixed per-kWh price premium for usage during a program event. SMUD can call program events during any hour of the day during summer months (June through September), up to 50 hours per summer and no more than once per day, and the events may span multiple TOD periods. Currently, CPP enrollees get a discount of $0.02 per kWh during non-event periods on TOD off-peak and mid-peak prices from June 1 to September 30 but pay a premium of $0.50 per kWh during event hours. To show a comparison of the price signal, the standard TOD rate offers a peak to off peak price ratio of 2.42:1 compared to the peak price ratio of 6.91:1 for the CPP option.[22] Customers participating in the CPP rate must enroll in a qualifying SMUD program that allows for automatic adjustments of enrolled devices. SMUD's programs also further customer participation through an upfront signup reward or an incentive toward the purchase of enabling technology. SMUD does extensive outreach to encourage customers to choose the CPP rate, and for customers already on the CPP rate, it runs individual reports and reaches out to customers to help them identify ways they can save money by changing the way they use energy.

Figure 5 CPP Rate Structure

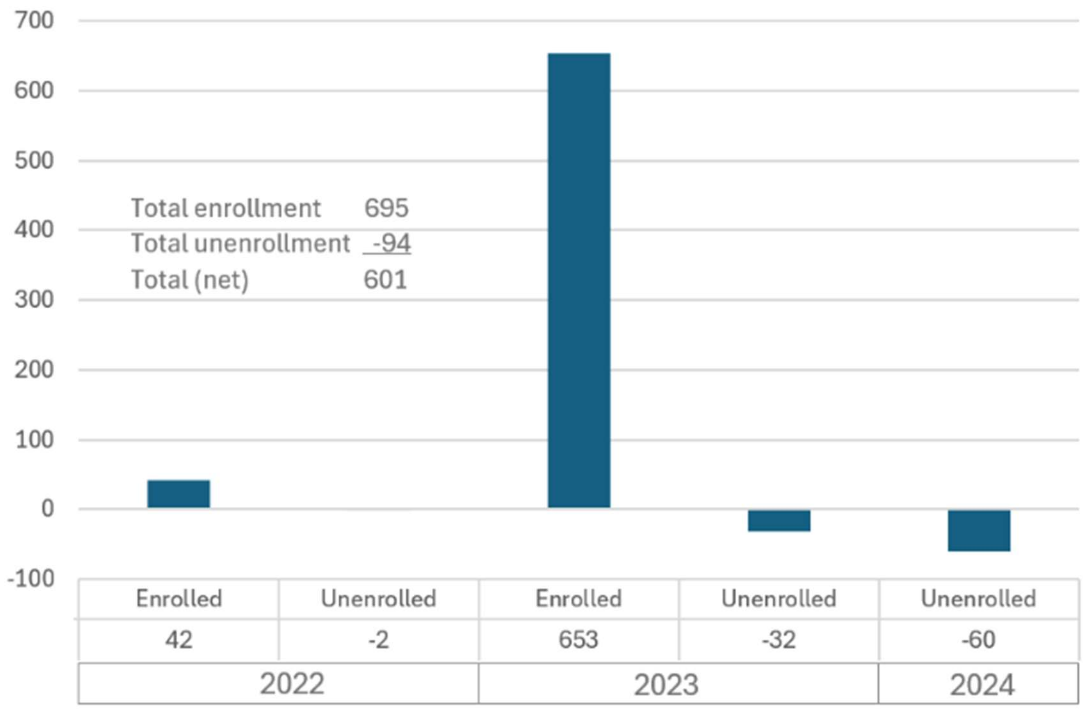


To date, the CPP program is delivering slightly higher demand reduction than a parallel incentive-based approach; however, it has had much lower participation than originally anticipated. In two years of active recruitment, less than 700 customers (as shown in Figure 6, below) have opted for the CPP rate out of the more than 26,000 that are participating in the incentive offer, yielding a participation rate of less than 3% of customers enrolled in an eligible program.[23] This is likely due to the greater uncertainty associated with the CPP rate, where participants are expected to save money with a participating device, however there is

[22] As detailed in the White Paper from Dr. Faruqui included in Appendix A, CPP rates have the potential of significant reduction in peak load compared to just TOD.
[23] For comparison, there are 121,000 total SMUD customers with a smart thermostat. CPP participation compared to total smart thermostat adoption is 0.5%.

the possibility that they will not save money depending on their overall peak to off-peak consumption differences.

Figure 6 Enrollment of Customers on CPP Rate (November 2024)



4.2.1.3 Electric Vehicle Rate Discount

SMUD offers an EV rate discount to the residential TOD rate structure that is available for owners of plug-in EVs. Under the EV rate discount, customers can receive a 1.5¢ per kWh discount on full home energy between midnight and 6 am every day, all year long, which encourages customers with EVs to charge during this period. This shifts the plug-in EV charging load to lower usage hours when it costs SMUD less to serve the customer, reduces the possibility of overloading local distribution transformers, and helps reduce the need for additional generation, transmission, and distribution capacity. Currently, about 28,500 customers are enrolled on this rate, representing approximately half of all SMUD customers with EVs. Separate from its EV rate option, SMUD is piloting a Managed EV Charging program, which is discussed further in Section 4.3.1.1.1.5, below.

4.2.2 Non-Residential (Commercial) Time-of-Day Rates

For decades, SMUD has offered time-dependent rates to all non-residential customers, and customers have adapted to these rates and price signals. In 1995, SMUD offered an experimental real time pricing rate for commercial customers as part of an economic retention measure, but no customers opted in during the three years the rate was offered. SMUD then tried another version of real time rates in 1998, which better managed potential risk through a two-part billing structure. While some customers did enroll in the rate at that time, customers quickly switched back to time-dependent rates when wholesale prices spiked during the energy crisis in the early 2000s. Despite these early experiences, SMUD has continued to explore introducing more real time aspects to commercial and industrial rates.

In 2019, SMUD's Board approved a C&I rate restructure that re-aligned the time-of-day periods with marginal cost signals, aligned variable rate components to fixed rate components to reflect costs, and simplified the pricing structure across all rate categories to improve customer experience when moving from one rate to the next. This realignment gives customers the opportunity to manage their usage and bills while helping reduce peak energy use and the need to buy power from less environmentally sustainable sources. SMUD began implementing these changes to its non-residential TOD customers at the end of 2021 and the initial phase of the full rollout was completed in the first quarter of 2022.

As SMUD implemented this restructuring, SMUD recognized that these new rates created a risk of bill volatility and higher prices for C&I customers. Through an extended and ongoing roll out and targeted outreach, SMUD was able to limit bill impacts to no more than 5% compared to the period prior to the restructuring for 95% of customers. To limit the bill impacts, SMUD implemented the rate restructuring over a span of seven years; some rate categories already completed their transition, and some are still going through gradual rate changes through 2028. For those customers with expected bill impacts larger than 5%, SMUD conducted additional outreach about the new rates, the associated benefits, and potential impacts. SMUD worked with these customers to identify solutions to manage the impacts, including education and participation in a program to help them reduce costs through energy efficiency upgrades or other means. These efforts were necessary to assist these customers in adapting to the new rates and achieving the goals of the restructuring.

SMUD's current non-residential TOD rates are available to all metered commercial and industrial customers. The rates are similar in concept to the residential TOD, except the rate periods differ. During the summer, there are two rate periods: Peak (weekdays 4 pm – 9 pm) and Off-Peak and (weekdays 9 pm – 4 pm, weekends, and holidays). During the non-summer months, the rate periods are Peak (weekdays 4 pm – 9 pm), Off-Peak Saver (weekdays, weekends, and holidays 9 am – 4 pm), and Off-Peak (all other hours).

The standard non-residential rate structure includes the following components: a) SIFC per month per meter and varies depending on the size of the customers; b) Site Infrastructure Charge in $/kW-month based on the last 12 months maximum demand in kW or contract capacity; c) electricity usage charge in $/kWh for energy consumption by time periods and seasons; d) summer peak demand charge in $/kW-month based on monthly maximum kW during the 4 pm – 9 pm peak period during summer months. The summer peak demand charge is offered to customers with 21 kW and higher. Note that SMUD is one of the few utilities that assess a demand charge for customers in the 0-20 kW range, which combined with the TOD electricity charges offers the right price signal to promote load reduction. The group of customers in the 0-20 kW range are still going through a multi-year glidepath to gradually increase the new demand charge.

Agricultural (AG) customers have a combination of rates, including legacy non-time differentiated rates with a flat per kWh energy charge that only varies by season, legacy tiered rates, and time of day rates with electricity prices by period and season. The majority of AG customers are on the legacy non-time differentiated rate. SMUD also offers a TOD rate for non-residential AG customers. During the winter months (Nov through Apr), the Peak period is 7 am – 10 am and 5 pm – 8 pm on weekdays. In the summer months (May through Oct), the Peak period is 2 pm – 8 pm on weekdays. All other hours are considered Off-Peak, including holidays and weekends.

4.3 SMUD's Existing Programs

Load flexibility is a key strategy in helping SMUD achieve its Zero Carbon Plan, particularly in enabling its customers to be part of the solution. As such, SMUD developed and is piloting a number of leading-edge options for customers. This section provides an overview of SMUD's current load flexibility programs.

In recent years, SMUD has focused on expanding its existing programs and piloting new load management offerings because they are simple, effective, flexible, and allow SMUD to make rapid progress in unlocking peak load reduction potential. SMUD has also worked to innovate with technology and software providers to advance functionality that will allow for broad participation and help efficiently manage resources, optimized for customer and grid needs. When SMUD designs programs, it can tailor the programs to specific customer segments or needs to maximize responsiveness beyond just price alone. It can identify where the need is and how SMUD can design the program to have the greatest potential for mutual benefit, since programs must provide benefits to both the customer and SMUD to be effective. To that end, SMUD is piloting multiple approaches, and the lessons from these pilots will inform future program designs and the technology needed to scale adoption. Finally, in comparison to rates, which are set and require a rate process to restructure, existing programs allow SMUD more flexibility to adapt the program to customer needs.

SMUD currently offers a portfolio of load flexibility programs with a diversity of enabling technologies, and different tiers of engagement to provide options that best fit with each customer segment's needs. The portfolio includes at least one load flexibility program offering for residential and non-residential customer classes.

4.3.1.1.1 Residential Programs

SMUD's residential load flexibility programs include (1) My Energy Optimizer (MEO) Partner, (2) MEO Partner+, (3) PeakCorps, (4) PeakConserve, and (5) Managed Electric Vehicle Charging.

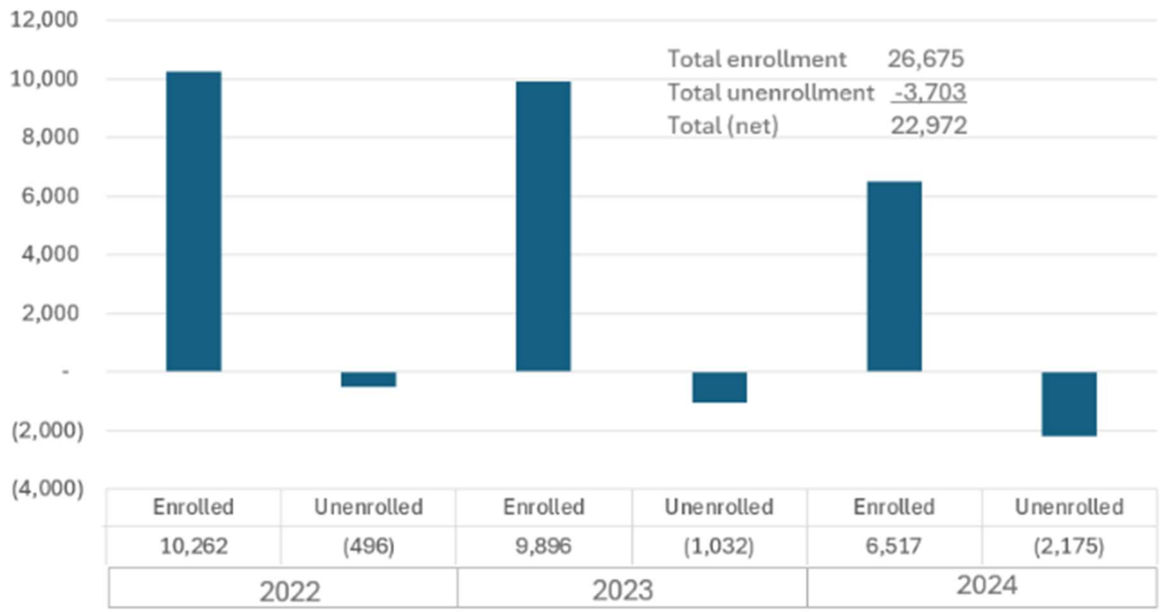
4.3.1.1.1.1 My Energy Optimizer (MEO) Partner

My Energy Optimizer (MEO) Partner is SMUD's fastest growing load flexibility program with the highest curtailment capacity of SMUD's load flexibility programs. It leverages the high adoption rate of smart thermostats in its territory and provides both upfront ($25 per device) and ongoing annual incentives ($25 per premises) to customers with qualifying smart thermostats who agree to have their thermostat setpoint raised during periods of high demand. Participating customers may also enroll in the CPP rate, discussed in Section 4.2.1.2. In the case of customers enrolled on MEO with CPP, they receive $50 initial incentive to sign up, customers could receive an average saving of $39 from load reduction and lower electricity price during the non-peak period.

Under MEO Partner, a customer's smart thermostat setpoints are turned up by a few degrees during program events on a maximum of 15 days (and 50 hours) per summer (June-September), leading to less electricity use and demand during these event hours. In general, setpoints are lowered before events to pre-cool participant's homes, and this produces a slight increase in electricity use before events. SMUD is also currently testing novel approaches to the way these thermostats are dispatched to maximize their contribution to reliability within SMUD territory. Day-ahead marginal prices represent one of several factors that contribute to device dispatch, including forecasted weather and grid conditions.

MEO Partner has been in place since 2022. Overall enrollment has been successful as seen in the Figure 7 below. Currently, there are approximately 23,000 customers enrolled in the program out of an estimated population of about 121,000 customers with smart thermostats. Even with the successful and simple MEO program, SMUD has seen about 14% of participants opt-out. The table below illustrates monthly enrollment and unenrollment since the inception of the program.

Figure 7 My Energy Optimizer Enrollment History (November 2024)



4.3.1.1.1.2 MEO Partner+

MEO Partner+ is SMUD's premier residential Virtual Power Plant (VPP) program and the first program of its kind in California. SMUD's goal is to enroll 15,000 residential batteries with a capacity of 75 MW on the VPP program by 2030.

Eligible participants with both solar and behind the meter battery storage can receive a $500/kWh upfront incentive, up to $5,000 per battery (up to two batteries per premises), for allowing SMUD to control their battery storage system throughout year using Tesla's VPP Control system. Participants also receive ongoing quarterly payments for allowing SMUD to use their battery capacity for myriad grid needs. Developed as a true market transformation program, the incentive decreases gradually over 5 years to align with the expected reduction in battery storage costs over time. This incentive was a compromise to promote adoption of solar with storage as SMUD transitioned from its legacy NEM to its Solar and Storage Rate (SSR) in 2022. This program design provides SMUD's solar + storage customers a meaningful path to value for their investment while creating a maximally flexible resource for SMUD to utilize throughout the year.

Like all SMUD load flexibility programs, MEO Partner+ batteries are dispatched by SMUD based on factors that include, but are not limited to, day ahead marginal prices. Batteries are available for dispatch any time except from 10 am – 3 pm, ensuring they are fully charged with solar energy. Batteries may be dispatched a maximum of 30 events per month, or 240 events per year.

4.3.1.1.1.3 PeakCorps

Originally implemented in the 1970s, PeakCorps is SMUD's legacy Air Conditioning Load Management (ACLM) program utilizing one-way AC switches. Currently there are over 80,000 customers enrolled in this program, of which SMUD estimates that approximately 35,000 have active switches. These active customers provide about 56 MW of emergency load shed. The program offers a $5 per event incentive. This program allows SMUD to maintain reliability during emergency situations by allowing a SMUD installed device to turn off the AC unit when reduction of the overall amount of electricity being used during an emergency is necessary. Resources are dispatched only during critical periods where there is extreme demand on the electricity grid.

The legacy ACLM switches are unable to respond to hourly price signals; however, SMUD is in the process of transitioning this program to PeakConserve, described below, and replacing one-way switches with switches with more advanced capabilities.

4.3.1.1.1.4 PeakConserve

PeakConserve is an updated ACLM program that offers customers a $50 sign-up bonus and an additional post-season annual bonus for agreeing to the installation of a two-way switch to allow for cycling of their air conditioning compressor during summer periods of high demand. The new switches utilize SMUD's mesh meter network to communicate, negating the need for additional communication systems or customer Wi-Fi, which broadens SMUD's customer base that can participate in load management programs. This encompassing approach improves equity, given populations that cannot afford or do not have internet access can participate, and technology barriers are eliminated for some that cannot or will not use smart thermostats.

During conservation days, when the supply of resources is expected to be limited and market prices are very expensive, SMUD sends a signal to cycle off participating air conditioners for up to 40 minutes an hour to help flatten demand and keep prices of electricity down, also reducing customer bills. SMUD anticipates a maximum of 15 conservation events each summer, depending on grid conditions. Day-ahead marginal prices are a factor that contribute to the automated dispatch of participating devices, because it can indicate a potential constraint on the grid.

4.3.1.1.1.5 Managed Electric Vehicle Charging

Managed Electric Vehicle Charging is a SMUD pilot program testing the ability of EVs to respond to simulated day-ahead hourly price signals modeled on projected future system needs as renewables penetration dramatically increases. Over the next 3-7 years, SMUD anticipates that EVs will represent the majority of the load flexibility potential in its territory. While the price signals sent to EVs via telematics are dynamic and change on an hourly basis, customers are not financially exposed to these price fluctuations and are instead paid via a traditional incentive framework. The lessons from this pilot will inform how SMUD rolls out a full-scale managed charging program in late 2025. SMUD hopes to demonstrate and refine use cases such as consuming excess low-cost renewable energy, mitigation of service transformer overloading, and reducing system peak impacts.

The pilot offers retail TOD price signals for the entire year, which is available through the Market Informed Demand Automation Server (MIDAS) and uses SMUD's price application to provide simulated hourly marginal cost-based price signals, including wholesale, distribution, and retail optimization components, for year 2030. SMUD used the year 2030 to align with SMUD's 2030 Zero Carbon Plan. Participating customers' EV charging is directly controlled to avoid grid impacts, high price periods, and manage renewables while ensuring customers do not experience decreased utility from their vehicles. An overview of the key features of the pilot is shown in Figure 8, below.

Figure 8 Key Features of the EV Managed Charging Pilot

	**Objective**: Test managed charging strategies to mitigate grid impacts for light duty EVs
	Program Description • OVGIP enrolls eligible Ford, BMW, General Motors customers • Optiwatt enrolls eligible Tesla customers • Telematics for charging data and optimized charge schedule using dynamic prices • Interim M&V scheduled for Summer 2024 and final M&V scheduled for Summer 2025 Operations • OEM's request 24-hour pricing from SMUD's Pricing API, through an aggregator, daily • The base price signals include simulated 2030 marginal costs (study) in an hourly 8760 format • Price signal adder during the 5-8 pm peak to discourage retail TOU on-Peak charging. • Price signal reduced during staggered 3-hour off-peak discount periods to diversify charging and mitigate secondary peak impacts of TOU on distribution infrastructure. • OEM's optimize customer EV to charge during low price periods.
	Customer Savings • Customers remain on TOU rate • 3rd parties optimize charge schedules • One-time enrollment $150 incentive • Ongoing quarterly $20 incentive

Figure 9, below, illustrates how the pilot dynamic price communication works. The program is testing an experimental design pilot conditions with simulated hourly energy and capacity costs and EV density on the distribution system.

Figure 9 EV Managed Charging Pilot Communication

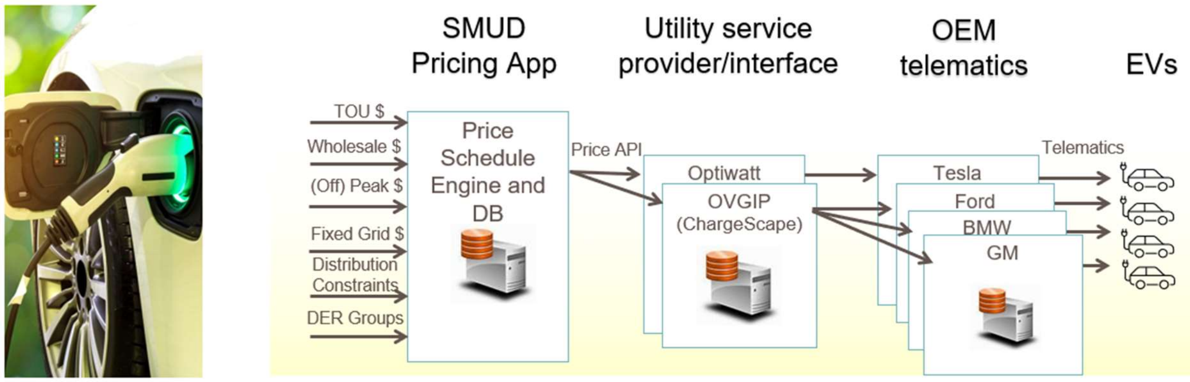
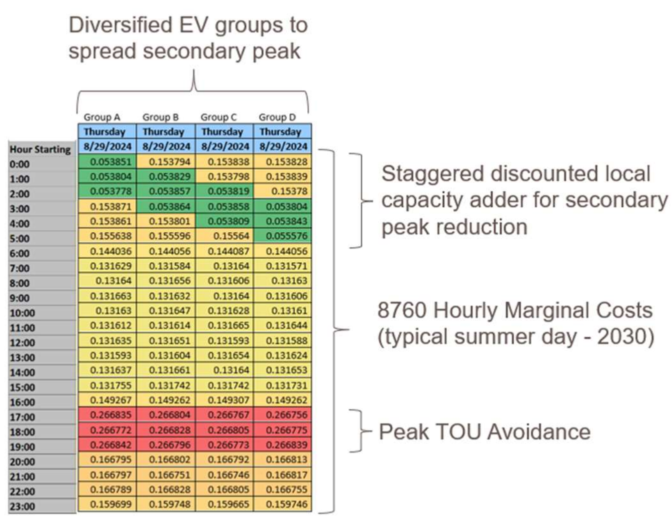


Figure 10, below, is an example of the hourly marginal cost-based price signal offered by the EV managed charging pilot. The pilot randomly assigns customers to four groups and tests the groups with a staggered hourly price signal. If all vehicles react to a single price signal starting at midnight, there would be a much larger EV charging peak. The goal of the pilot is to smooth out the price signal during staggered 3-hour off-peak discount periods to diversify charging, mitigate secondary peak impacts of TOU pricing on local transformers, and align charging load with low-cost/low-carbon intensity power when excess renewables are available. See the 3-hour band marked in green in the Figure 10, below. The pilot maintains a strong price signal during the 5-8 pm peak period to be consistent with the TOD messaging about reducing consumption during the peak hours.

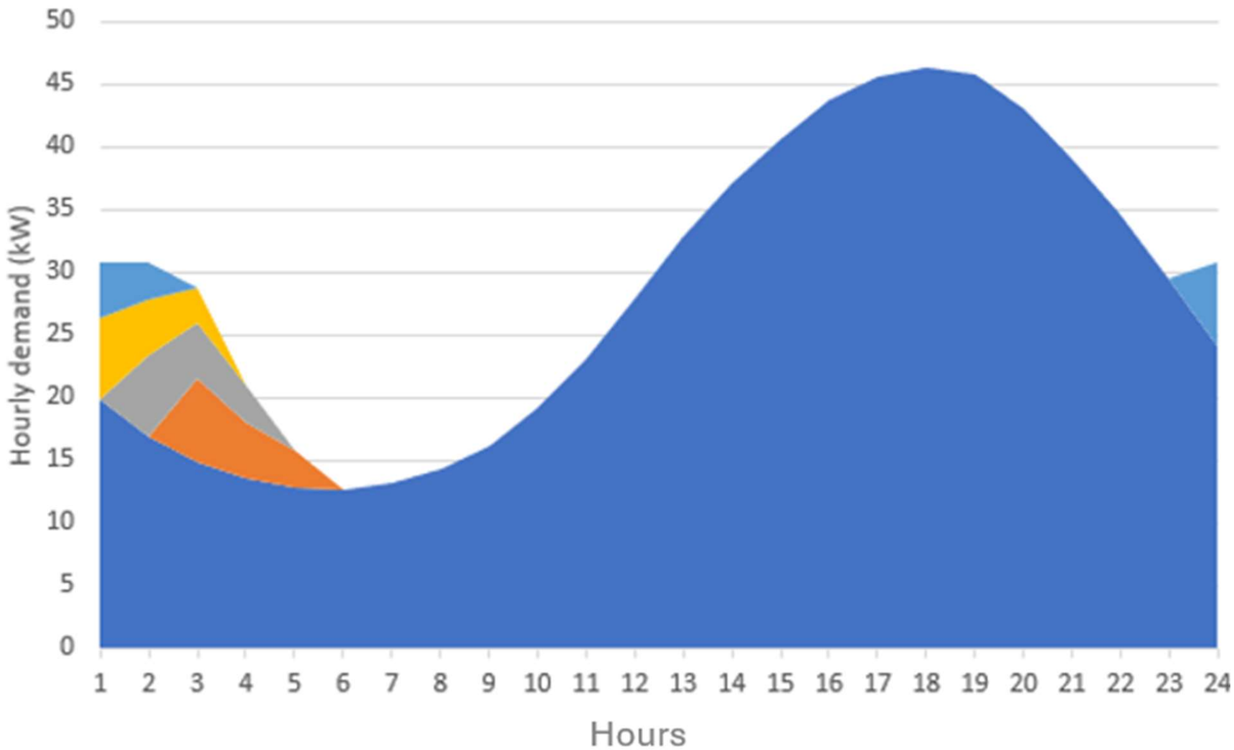
Figure 10 EV Managed Charging Hourly Price Signals



	Group A	Group B	Group C	Group D
	Thursday	Thursday	Thursday	Thursday
Hour Starting	8/29/2024	8/29/2024	8/29/2024	8/29/2024
0:00	0.053851	0.153794	0.153838	0.153828
1:00	0.053804	0.053829	0.153798	0.153839
2:00	0.053778	0.053857	0.053819	0.15378
3:00	0.153871	0.053864	0.053858	0.053804
4:00	0.153861	0.153801	0.053809	0.053843
5:00	0.155638	0.155596	0.15564	0.055576
6:00	0.144036	0.144056	0.144087	0.144056
7:00	0.131629	0.131584	0.13164	0.131571
8:00	0.13164	0.131656	0.131606	0.13163
9:00	0.131663	0.131632	0.13164	0.131606
10:00	0.13163	0.131647	0.131628	0.13161
11:00	0.131612	0.131614	0.131665	0.131644
12:00	0.131635	0.131651	0.131593	0.131588
13:00	0.131593	0.131604	0.131654	0.131624
14:00	0.131637	0.131661	0.13164	0.131653
15:00	0.131755	0.131742	0.131742	0.131731
16:00	0.149267	0.149262	0.149307	0.149262
17:00	0.266835	0.266804	0.266767	0.266756
18:00	0.266772	0.266828	0.266805	0.266775
19:00	0.266842	0.266796	0.266773	0.266839
20:00	0.166795	0.166802	0.166792	0.166813
21:00	0.166797	0.166751	0.166746	0.166817
22:00	0.166789	0.166828	0.166805	0.166755
23:00	0.159699	0.159748	0.159665	0.159746

By staggering the price signals and therefore charging times, it reduces the stress on transformers, as shown in Figure 11, below. The illustration shows a smooth and gradual load increase and decrease between midnight and 6 am making a more efficient use of transformers. The following three figures show “hour ending” load, which means usage is recorded at the end of the hour. For example, consumption between midnight and until 1 am will record in hour ending 1.

Figure 11 Hypothetical Transformer Load



This pilot was a randomized control trial with evaluation objectives that include:

- Estimate load shift from the program, with uncertainty bounds
- Estimate financial and carbon impacts
- Simulate transformer overload probabilities for 2 future projections of EV adoption, with and without the program
- Characterize EV adoption and program impacts by geography and demographics

Figure 12 below shows how staggering the load distributes the peak over several hours rather than all at one time. Figure 13 shows the load of the control group and an average load under the program (treatment group), which is more balanced.

Figure 12 Illustration of Hourly Load Shapes with Load Shifting Results

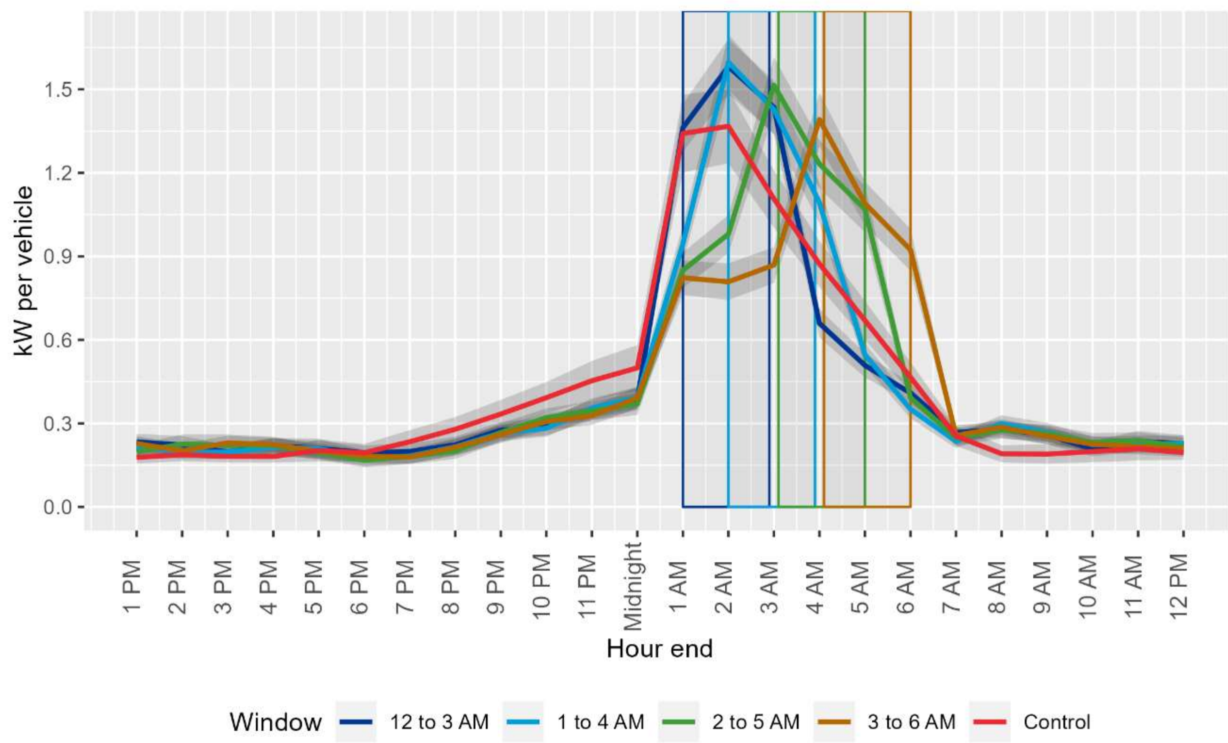
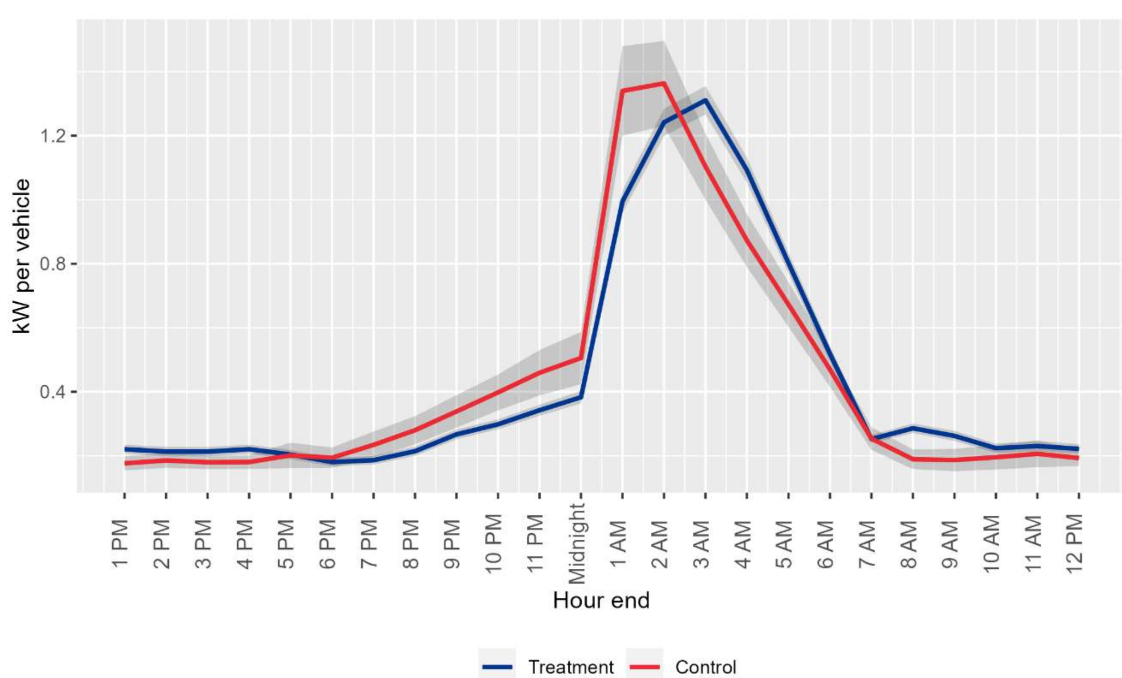


Figure 13 Illustration of Hourly Load Shapes for Treatment and Control Group



Optimization in the Treatment group reduced charging load during peak hours compared to the Control group. Figure 13 shows that the smoothing of the average load for the staggered Treatment group results in a moderate reduction in peak and delays the peak. However, Monte Carlo simulation modeling of the distribution system showed that for 2030 EV adoption forecasts, the Treatment group participants would reduce about 25% of service transformer overloads compared to the Control group. This reduction in overload risk is because of the lowered standard error (shaded area in both load shapes); that is the shorter high side tail of the Treatment group versus the Control group. SMUD is currently in the process of writing a Request-for-Proposals (RFP) expected to be released in Q1 2025 to make the program permanent.

4.3.1.1.2 Non-residential Programs

SMUD's non-residential load flexibility programs include (1) PowerDirect (2) Commercial Virtual Power Plant (Under Development), and (3) Commercial Vehicle to Grid.

4.3.1.1.2.1 PowerDirect

PowerDirect is a summer-only automated demand response (ADR) program available to non-residential customers. The program initiates pre-programmed building controls that are chosen and implemented by the customer, such as thermostat setpoints. In exchange for reducing load, customers are paid a capacity payment based upon their demand commitment. The PowerDirect ADR system has been in effect for approximately 10 years and connects directly to participating customer's energy management, lighting and heating, and/or ventilation and air conditioning (HVAC) systems to automatically scale back energy use. Program response has reduced peak load on days the grid is most stressed and marginal costs are highest.

4.3.1.1.2.2 Commercial Virtual Power Plant

SMUD is in the process of developing a load flexibility program for commercial customers with behind-the-meter batteries. The program will include enrollment and ongoing incentives to customers, based on enrolled capacity, for allowing SMUD to automate their battery's response to dispatch signals. SMUD envisions this program operating in a similar fashion to MEO Partner+, described above.

4.3.1.1.2.3 Commercial Vehicle to Grid

In addition to managed electric vehicle charging, SMUD is conducting a number of activities testing out Vehicle to Grid bi-directional charging (V2X) capabilities. V2X has the opportunity to provide substantial resources in the future given the expected trajectory of vehicle electrification as part of the Zero Carbon Plan and statewide policy. Currently, SMUD is piloting V2X technology on school buses in partnership with a local school district, which is assessing the school bus's ability to respond to a combination of TOD, CPP, and event-based price signals. Light duty V2X fleet technical testing is also underway at SMUD, and a plan to pilot utility-managed V2X within a commercial fleet and for workplace charging is currently proposed for 2025 and SMUD expects to expand into residential in either 2025 or 2026.

4.3.2 Program Performance

SMUD maintains and continues to develop a robust portfolio of load flexibility programs that strike the right balance between customer needs and grid benefits. As summarized above, this portfolio provides at least one option for both residential and nonresidential classes to automate response to dispatch signals from SMUD. These signals are based on several factors, including day-ahead marginal prices. SMUD is also in the process of building out its DERMS technology platform, which is anticipated to optimize and automate dispatch of DER on SMUD's system, as well as investing in next generation metering and technology platforms to enable grid edge intelligence and control.

SMUD programs are piloting how to automate customer response to dynamic price signals in addition to other system events, with some pilots utilizing its Price Communication Application (PCA). SMUD developed the PCA in 2018, recognizing the need for a simple API that provides machine readable price schedules for enabling technologies so SMUD could research price-based signals to devices. However, the pilots are not currently ready for full scale implementation, nor do they use MIDAS signals to automate customer response.

The following table lists SMUD's current and planned load flexibility programs and their expected load reduction target in 2030. As these programs demonstrate their ability to serve as more cost-effective investments compared to utility scale resources, contributions could be substantially higher.

Figure 14 List of Current and Planned Load Flexibility Programs

Load Flexibility Program	Segment	Technology	Capacity in MWs (2030)
My Energy Optimizer Partner	Residential	Wi-fi thermostats	60
My Energy Optimizer Partner Plus	Residential	Battery storage	75
Peak Conserve	Residential	2-way AC switches	16
Power Direct (Auto DR)	Non-Residential	Building EMS	30
Commercial VPP	Non-Residential	Battery Storage	17
EV Managed Charging	All	Electric Vehicles	135
Vehicle-to-Grid	All	Electric Vehicles	140
Total			473

4.3.2.1 MEO Partner and CPP Evaluation

In the fall of 2023, SMUD tasked Det Norske Veritas (DNV) with performing the evaluation of its MEO Partner program for the summer of 2023. DNV found significant reduction during-event curtailment for both the automatic demand response (ADR) and CPP participants. The analysis also found significant load increases due to pre-event pre-cooling of customers' homes, and due to post-event snapback, where customers use more energy to re-cool their homes.

Figure 15 below shows the MEO with ADR average per-premises impacts by hour of event, for non-staggered events. There is an expected curtailment shape, with curtailment decreasing over event hours.

Figure 15 Average MEO with ADR Per-premises Impacts by Hour of Event (non-staggered events only)

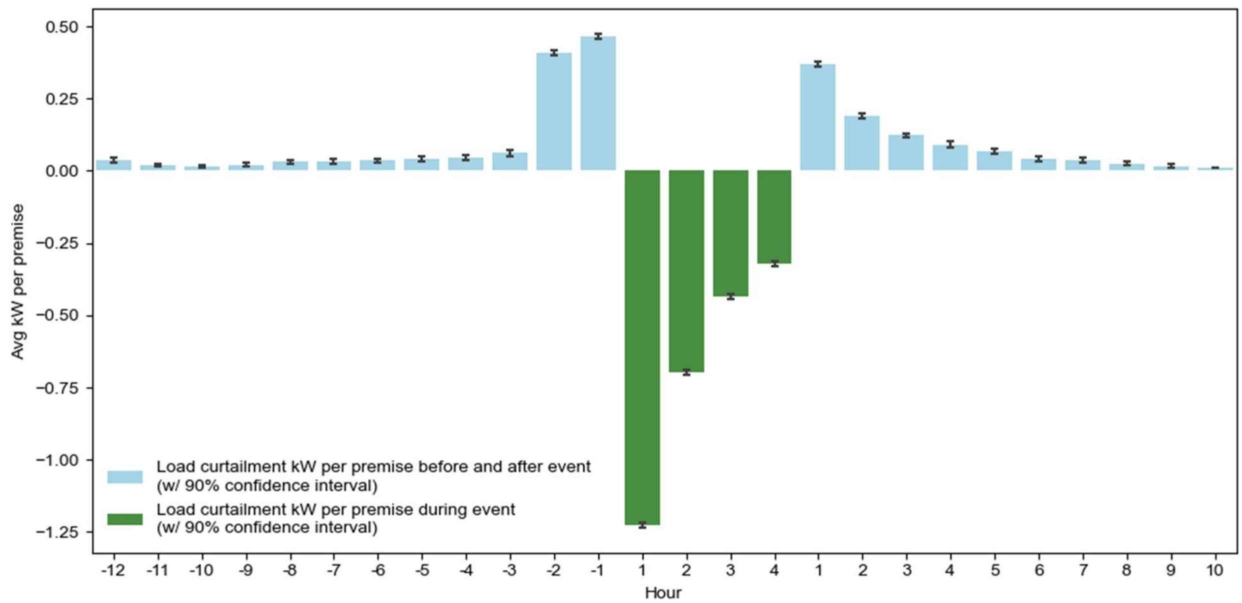


Figure 16 shows the same, but for staggered events. There is less decrease in curtailment over event hours, but the average of the three attempts at staggered events did not yield constant curtailment.

Figure 16 Average MEO with ADR Per-premises Impacts by Hour of Event (staggered events only)

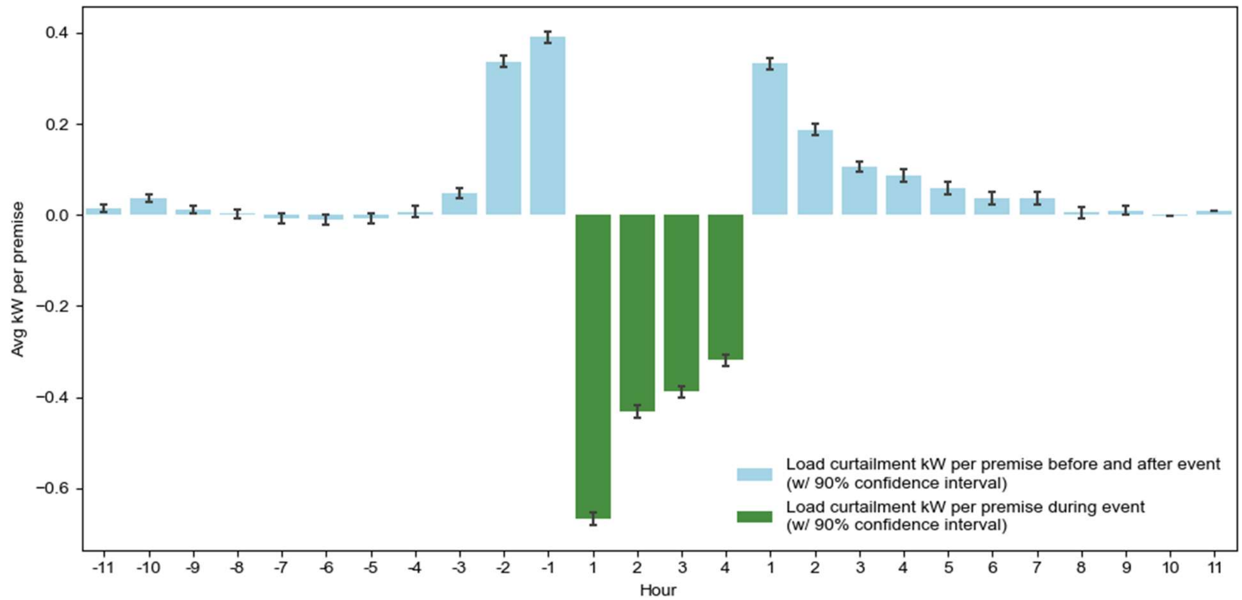
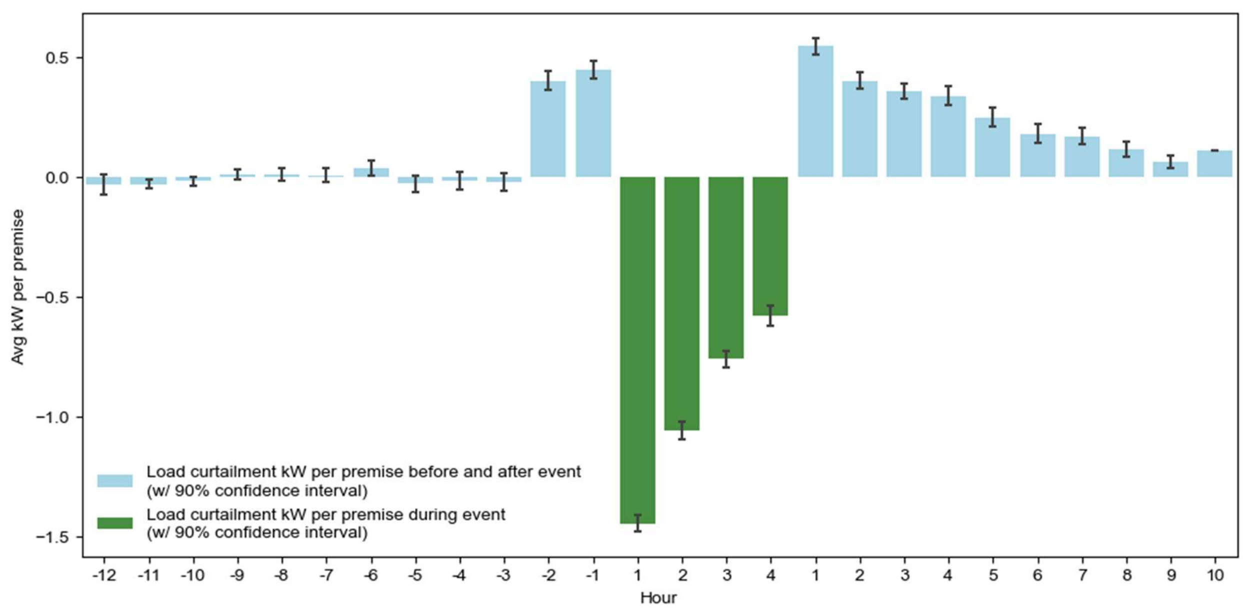


Figure 17 shows similar non-staggered event results for CPP, where there is greater curtailment in every hour than for non-staggered MEO with ADR results, but higher and longer-lasting snapback.

Figure 17 Average CPP Per-premises Impacts by Hour of Event (non-staggered events only)



Figures 18 and 19 show the average MEO and CPP impacts by event day and hour. Each blue bar represents a single hour, up to a maximum 4 hours per event. In 2023, SMUD called eleven events that allow MEO and CPP to respond. As expected, customers enrolled on both programs experienced significant load reductions. As shown for events in August and September, these were cooler days showing less peak load reduction. SMUD is currently performing analysis from summer 2024 and will track impacts over time as enrollment changes.

Figure 18 Average MEO Per-premises Impacts by Event Date and Hour (2023)

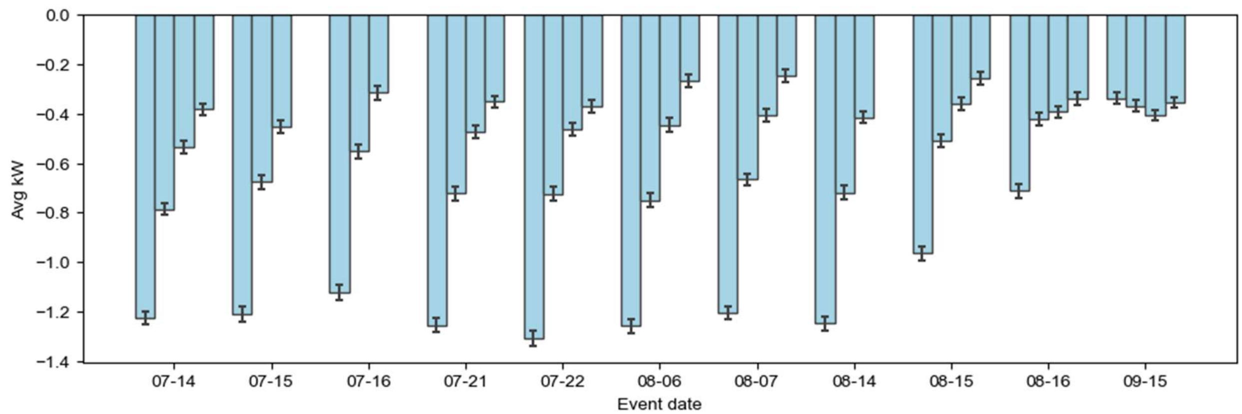
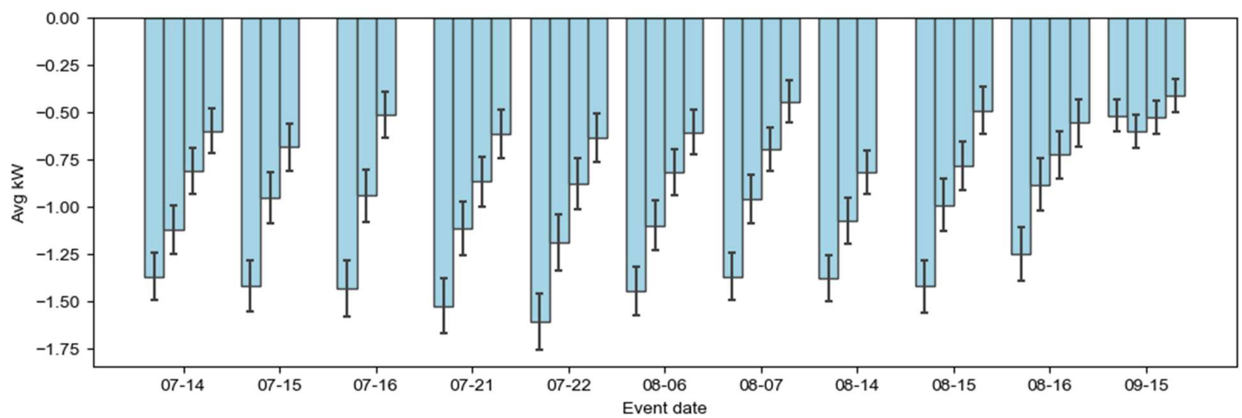


Figure 19 Average CPP Per-premises Impacts by Event Date and Hour



SMUD's recent experience with enrolling customers on the MEO program demonstrates that there is a difference in uptake between automatic response with predictable incentives (MEO) compared to the CPP option which brings some level of risk and higher prices during event days. It is more challenging than initially anticipated to enroll customers on the CPP option, which is a much simpler approach compared to a real time pricing with hourly or sub-hourly pricing. SMUD will continue testing both programs but expects that the MEO program will continue to see higher adoption rates than CPP.

SMUD is currently in the process of evaluating the results of its My Energy Optimizer Partner + battery program and expects to have results in Q1 of 2025.

4.3.2.2 PowerDirect (Auto DR) Program Evaluation

SMUD offers all non-residential customers a successful Automated Demand Response (Auto DR or ADR) program. The Auto DR program is a fully automated, reliable, and sustainable energy demand response resource that promotes peak load reduction when SMUD system operators call events based on grid and electricity market conditions.

The program gives bill credits of $10 per kW-month to customers who participate in conservation days or curtailment events, which SMUD announces the day before the day of an event. Enrollment requires customers to sign an Auto DR Agreement with SMUD, which states how much peak load reduction the customer commits to achieve during events. Consistent with the agreement, SMUD remotely dispatches the curtailable customer load. Customers must reduce load during events by at least 50 kW to receive incentives but may choose to opt-out partially or fully from events.

SMUD uses a combination of systems and technology to allow automatic load reduction and automatic flow of information from the revenue meter to the system operators use to curtail the forecasted load. The systems used include IEE, SEELoad applications along with GridLink communicating devices that are approved open ADR devices 2.0a or 2.0b. SMUD is currently in the process of exploring a new software application to upgrade the SEELoad software. Figure 20, below, shows the load reduction that customers achieved compared to their committed load reduction (realization rate) for 2023 and 2024.

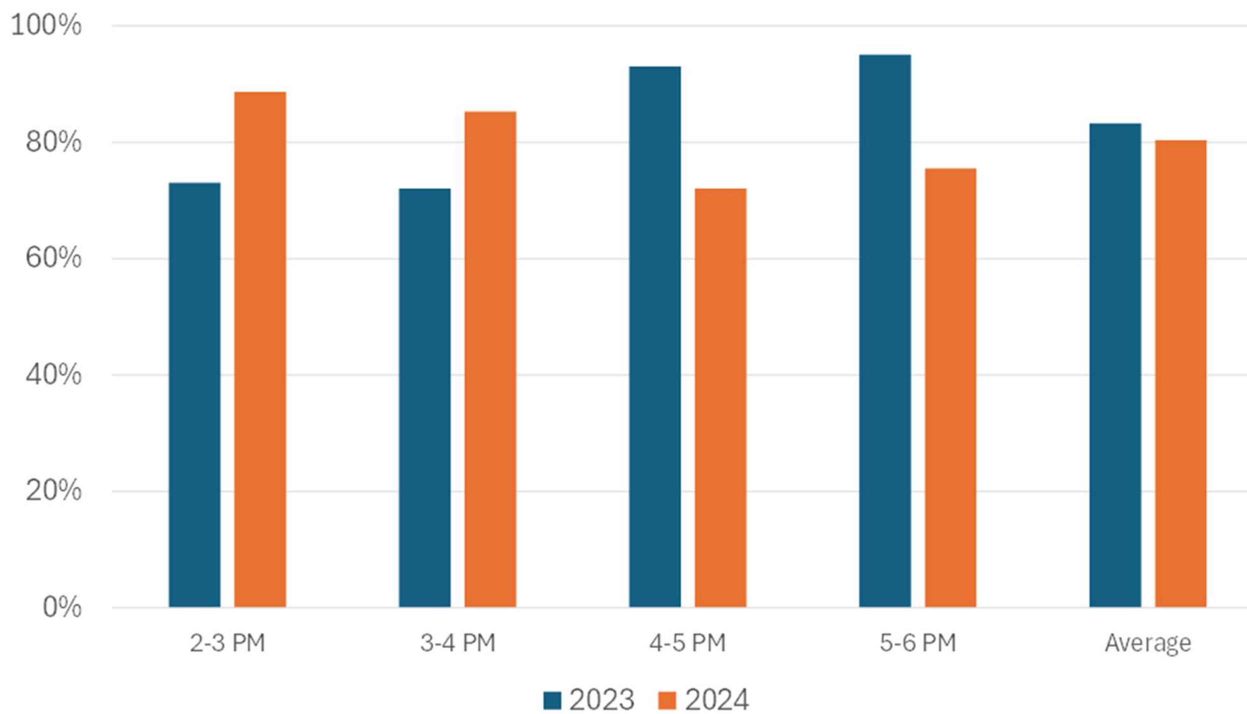
Figure 20 Auto DR Program Demand Reduction in 2024

Customer Size (kW)	Maximum Customer Load (kW)	Load Reduction (kW)	Customers Enrolled
0-20 kW	12	10	1
21-299 kW	2,594	2,047	19
300-499 kW	825	662	2
500-1000 kW	4,875	3,499	7
1000+ kW	18,687	17,272	8
Total	27,994	23,490	37

The non-residential Auto DR Program is an exceptionally reliable resource, delivering on the planned goal for 2024 with a cumulative load reduction of about 23 MW, aligning with SMUD's goal of 30 MW in the 2030 ZCP. In 2024, the program made considerable progress in expanding operations to more industrial customers and integrating semi-automated processes to enable event participation while also prioritizing safe operations. Four new customers were added to the Auto DR Program in 2024, some with multiple sites and including one large industrial customer, which contributed to meeting the goal for the year. Five additional customers are in the on-boarding process.

Performance metrics for 2024, shown in Figure 21 below, reflect a realization factor ranging by hour from 72-89%. This means that when this resource is needed, SMUD can call on it with around 80% confidence that the expected and committed demand response will perform.

Figure 21 Auto-DR Realization Factors 2023-24 Summer Season



In 2024, SMUD called a total of fourteen events throughout the summer season (June through September). As illustrated in Figure 22 below, SMUD observed that the day when SMUD reached its system peak on July 11, 2024, customers participating in the Auto DR program responded immediately to the event. The figure shows in the first hour (hour ending 15-16) an immediate 23 MW load reduction, with continued load reduction until 6 pm (hour ending 18) of 27 MW.

Figure 22 Auto DR Load Reduction (July 11, 2024)

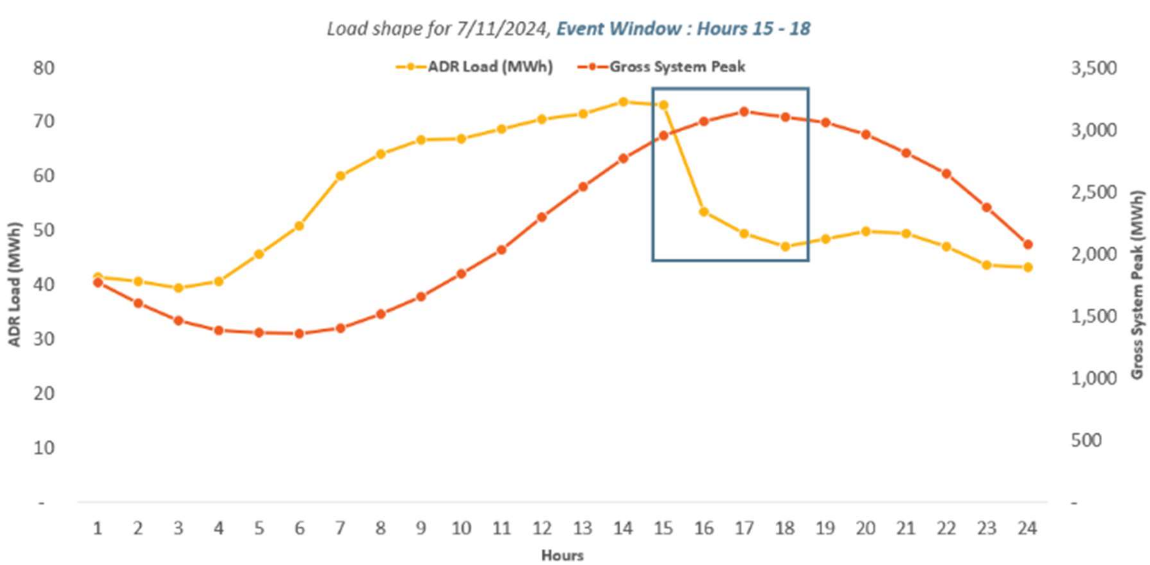
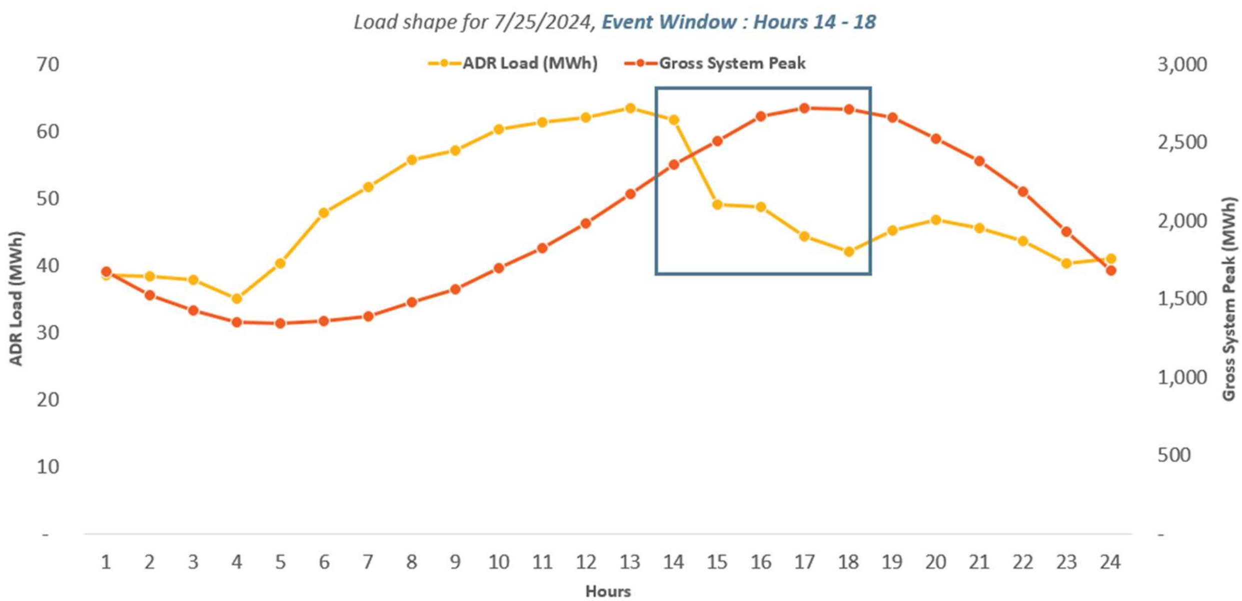


Figure 23 shows another Auto DR event on July 25, 2024, with a response of approximately 20 MW. The gray area illustrates the range of the electricity day ahead market prices at NP15 during the Auto DR called event days in 2024, the highest prices are out of alignment with SMUD's system peak which normally occurs between 4 - 6 pm.

Figure 23 Hourly Non-residential Load Reduction During Auto DR Event (July 25, 2024)



As shown in Figure 24, the Auto DR program was called fourteen times in 2024, and the majority of the event hours happened between 2 pm - 6 pm. In contrast, the price signal from the Day Ahead Market shown in Figure 25 below for the same event days is highest from 6 pm - 10 pm, not from 2 pm - 6 pm when Auto DR customers can reduce load without impacting overall business operation. This misalignment would cause potential load reduction from a Day Ahead Market price signal to target a period that doesn't closely align with the period when enrolled customers are able to reduce loads. SMUD evaluated the potential to extend these hours of dispatch for this program but found that there was not significant potential to enroll evening commercial loads, as many of these loads lacked flexibility and were already responding to SMUD's Time of Day rates for non-residential customers.

Figure 24 Frequency of Event Days in the Summer 2024

Time Period	Number of Events	% of Events
2 to 4pm	1	7%
4 to 6pm	5	36%
3 to 6pm	3	21%
2 to 6PM	4	29%
5 to 6PM	1	7%
Total	14	100

Figure 25 2024 Day Ahead Market Prices ($/MWh) on Auto DR Event Days

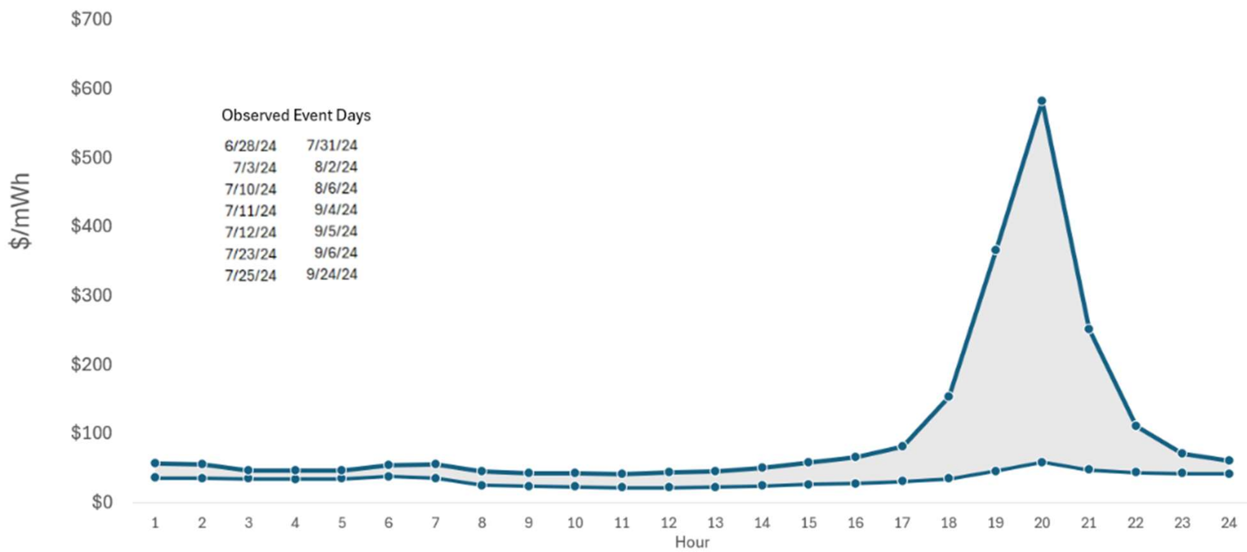
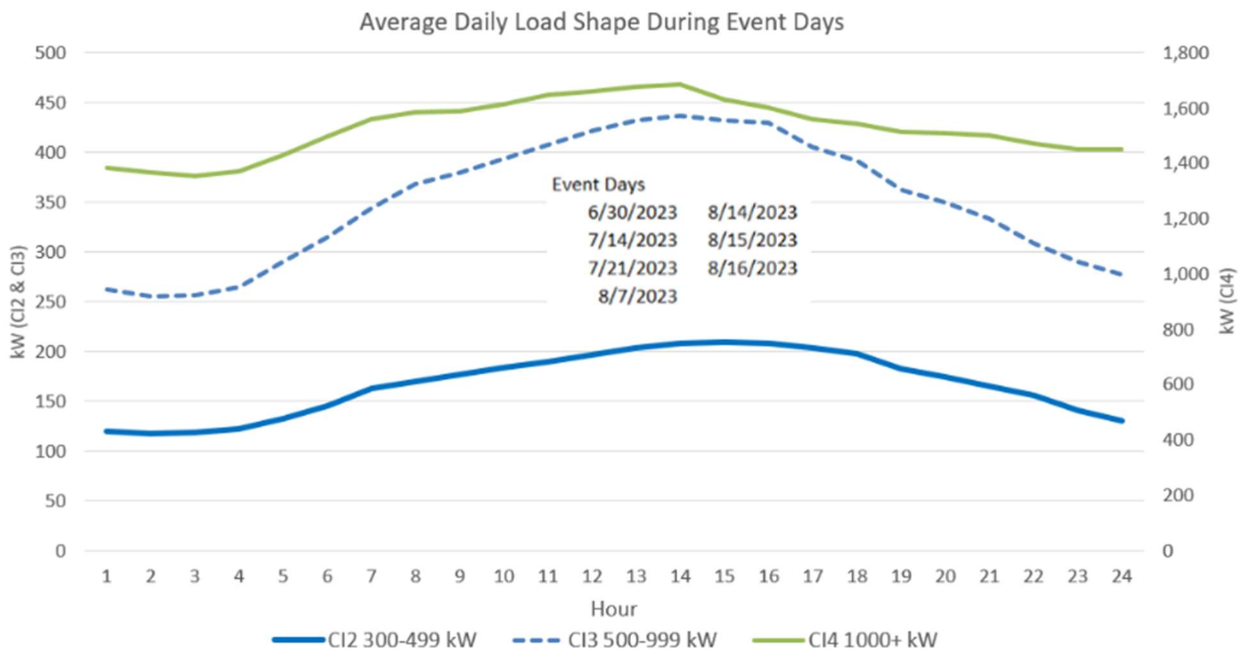


Figure 25, above, illustrates the range of the electricity day ahead market prices at NP15 during the Auto DR called event days in 2024. Comparing Figure 25 to Figures 22 and 23 shows that the highest prices occurring late in the evening at 8 pm (hour ending 20) are out of alignment with SMUD's system peak which normally occurs between 4 pm - 6 pm (hours ending 16-17). This shows that peak market prices are not necessarily aligned with the window of time that nonresidential customers are able to curtail load.

The non-residential load shapes shown below illustrate the load trend throughout the day during peak events in 2024. Actual load and weather normalized load was used to determine the impact of weather as a variable. The charts use data from 2023 since it is the latest weather normalized data for nonresidential customers that is readily available. As seen in the figures, during those event days, load for non-residential larger than 300 kW is relatively flat, despite those days being called for demand response. Load starts to decline right after hours 16 and 17 (4 pm or 5 pm). Additionally, as shown in Figure 26, the very large customer class (1000+ kW) has extremely flat load.

Figure 26 Average Daily Load Shape During Event Days (Large and Very Large Commercial)



The chart below compares the hourly load shapes of the smaller non-residential classes with load of less than 300 kW. Customer class CI0 includes customers with up to 20 kW while CI1 represents customers with load ranging 21-299 kW. The values below are average figures for the class for those specific event dates. As the graph shows, the load pattern is similar for both groups, with load starting to decline at hour 17 and 18, so by the time the electricity market prices are the highest later in the evening load is very low for this group of customers. This load pattern is likely to influence lower response to load reduction later in the evening given that the hourly load has organically decreased at that time as illustrated in the chart.

Figure 27 Average Daily Load During Event Days (Small and Medium Commercial)

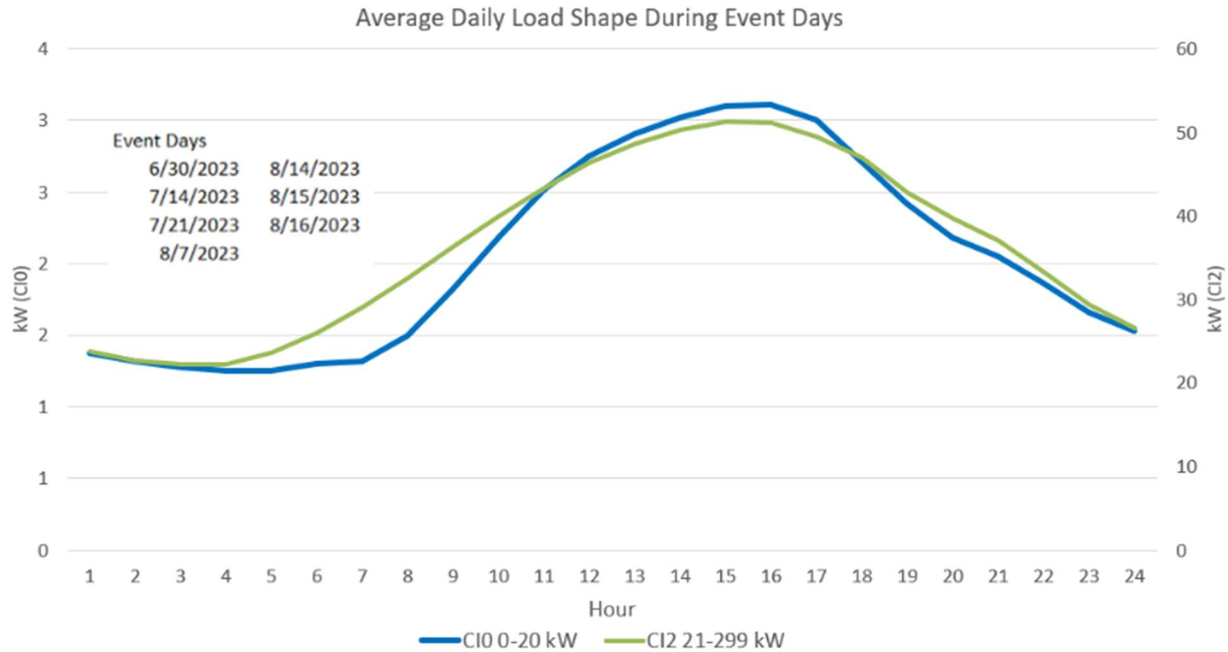
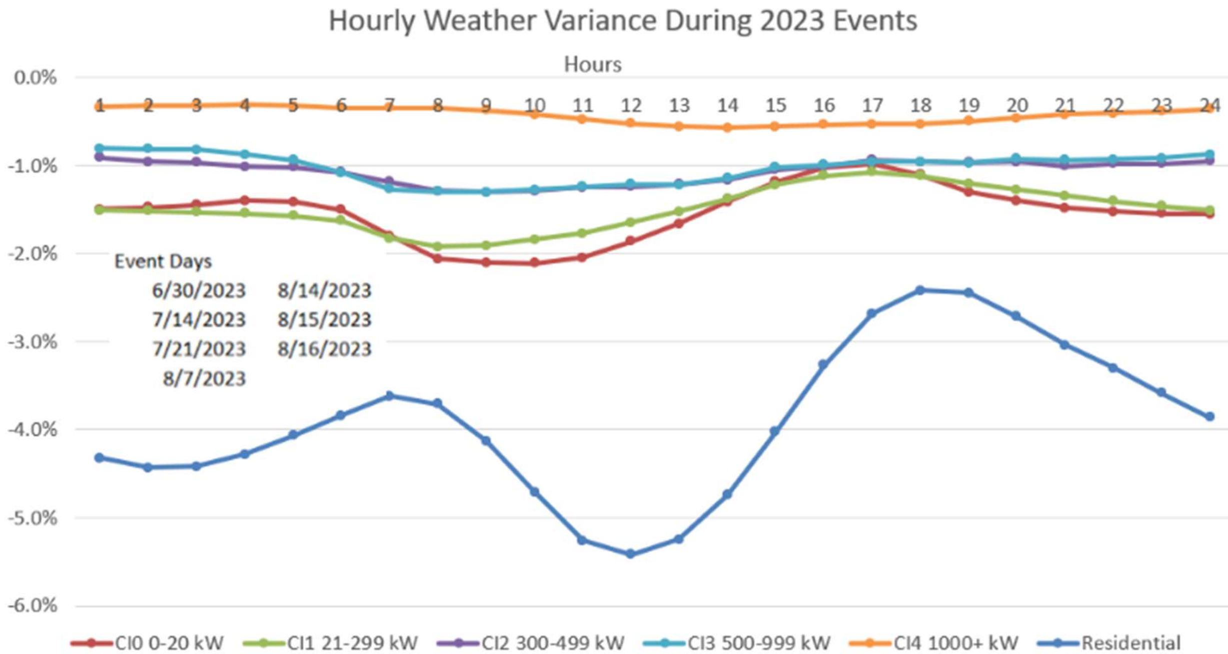


Figure 28, below, shows the impact of weather during those event days in 2023. The values shown in the chart are the variances between actual load and weather normalized load to represent the impact of weather during those event days. These figures illustrate that non-residential customers do not experience the same load effect from weather as residential customers whose load is significantly influenced by the hourly weather. Customers with load of 1,000 kW and higher are not impacted by weather or heat storms. The non-residential load patterns indicate that the potential benefit from reducing load driven by hourly electricity market prices driven by heat storms when prices tend to be high is limited in the case of nonresidential customers.

Figure 28 2023 Weather During Event Days



In summary, SMUD's Auto-DR program achieves an average 80% realization rate when events are called. Further, as shown in Figures 22 and 23, there is seen an immediate decline in load as soon as the events are called. Figure 28 shows that residential load is weather sensitive whereas commercial load is less weather sensitive; therefore, the Auto-DR program for nonresidential customers targets specific amounts of committed load that customers can reduce rather than being targeted at weather events. This shows that the Auto-DR program structure is more effective at driving load reduction for nonresidential customers than if the program were driven by weather, and by extension market price.

4.3.2.3 PeakConserve Program Evaluation

PeakConserve is a direct load control air conditioning cycling and a replacement program for the legacy PeakCorps program. In addition to gradually replacing the legacy program, the objective of the new program includes:

- Ensuring "no customers left behind" (e.g., disadvantaged communities, Wi-Fi/email accessibility, privacy concerns)
- Partnership between SMUD and its customers to fulfill the 2030 Zero Carbon Plan
- 1,800 customers enrolled in 2023; goal of 4,500 per year until 42,000 total
- First season focused on lessons learned, ensuring smooth execution, and customer satisfaction

Currently, there are about 1,800 customers enrolled, representing about 1.4 MW of economic load flexibility between June 1 and September 30. SMUD's program evaluation for 2023 showed that SMUD called three events in August and two events in September. The average load reduction impacts by event ranges from 17.6% to 32.8%.

SMUD has not completed an evaluation of the program for 2024 yet, but the results of the 2024 end of the season customer satisfaction survey shows that the new PeakConserve program has an 85% satisfaction rate, with almost 80% of customers responding that they were able to keep their home at a comfortable temperature during events, and 75% of customers reported that event notifications (email only) met their expectations with 5 of 6 events in 2024 happening with same-day notification.

4.4 Staff Analysis of Factors

This section evaluates the cost-effectiveness, equity, technological feasibility, and benefits to the grid and customers of dynamic rates for residential and nonresidential customers, consistent with the requirements of the LMS regulations.[24] The regulations require dynamic rates to be implemented on a specific schedule, which includes applying for approval of dynamic rates by April 1, 2025, and offering voluntary participation in those rates or programs to all customers by April 1, 2026, where such a rate or program is determined to materially reduce peak load.[25]

There are several examples of utilities and retail suppliers of electricity implementing dynamic rates, particularly internationally, and these examples show a promising theoretical basis to justify evaluation of dynamic rates in California. While SMUD recognizes the potential value of dynamic rates, SMUD's analyses shows that investment in dynamic rates will result in costs, paid by all customers, that will exceed expected benefits. Specifically, SMUD estimates that the initial cost to implement a dynamic rate will result in a one-time cost of $17.7 million plus the ongoing annual cost of approximately $1 million in year 1 and subsequent years. These first-year costs would result in a rate increase of around 1% for all customers. Figure 29 shows the results of SMUD's cost-effectiveness analysis, which concludes that the net annualized cost (after consideration of benefits) of offering an hourly product ranges from $2.4 to $3.7 million.

Figure 29 Annualized Net Benefits/Cost of Individual Programs

<table>
<tr><th colspan="6">Annualized Net Cost/ Benefit ($2025) from Dynamic Pricing</th></tr>
<tr><th colspan="3">Residential</th><th colspan="2">Non-Residential</th><th>Total</th></tr>
<tr><th>1,500 counts* at 7,500 kW</th><th>3,025 counts at 3,623 kW</th><th>10,000 counts at 11,976 kW</th><th>~2 MW</th><th>~13.5 MW</th><th></th></tr>
<tr><td rowspan="4">($951,956)</td><td></td><td>($983,455)</td><td></td><td rowspan="2">($471,675)</td><td>($2,407,086)</td></tr>
<tr><td rowspan="2">($1,645,085)</td><td></td><td></td><td>($3,068,716)</td></tr>
<tr><td></td><td rowspan="2">($1,154,265)</td><td></td><td>($3,751,306)</td></tr>
<tr><td></td><td>($983,455)</td><td></td><td>($3,089,676)</td></tr>
</table>

* Residential storage

Further, the customers expected to realize any potential benefits from RTP would be those with access to load modifying technologies. As demonstrated in this analysis, adoption of technology is correlated with income level, which would likely exclude many low-income customers and under resourced communities. Even if these communities were able to access such benefits, these customers would also be exposed to volatile prices and may not have the ability to avoid periods with higher prices, which can be a significant challenge for low-income customers. SMUD's analysis also concludes that implementing a dynamic rate is technologically feasible, but SMUD cannot implement a dynamic rate on the timeline required by the

[24] See Section 1623.1(a)(1)(A).
[25] See Section 1623.1(b)(2) and (4).

regulations. Finally, SMUD's analysis of a dynamic rates shows the benefit of such a rate to customers and the grid will be minimal relative to TOD and CPP. SMUD's TOD and CPP rates are providing functionally equivalent benefits and are already realizing approximately 80% of the load reduction from a hypothetical dynamic rate. In the case of non-residential, SMUD's automated demand response program has average realization rates of 80%+ which exceeds any estimated potential load reduction from an hourly or sub-hourly price signal alone.

4.4.1 Sources of Data

To develop this analysis, SMUD considered several sources of data. As discussed below, SMUD commissioned a survey of both national and international utility efforts to offer dynamic prices. Further, SMUD reviewed the experience of two Illinois utilities currently offering dynamic rates. SMUD incorporated lessons from these examples, as well as its own experience and expertise in utility operation, current programs, and rate development, to perform the following analysis.

The Experience of Residential Customers with Real-Time Pricing (RTP): An International Study

SMUD commissioned a study (White Paper) performed by Dr. Ahmad Faruqui,[26] which is attached at Appendix A. The White Paper explains that there are two examples of residential real-time pricing in the United States, both of which are in Illinois. These utilities are Commonwealth Edison (ComEd) and Ameren. While ComEd reports that customers enrolled in the dynamic rate generally experience savings, only 1-2% of total eligible customers participated. Internationally, the White Paper surveys a variety of countries with some form of dynamic rate offering. Many of these countries report at least some customer savings through these rates, but it is not clear whether these savings are higher than what would have been achieved with TOD and CPP. Furthermore, many of these examples present unique circumstances that may not be transferrable to SMUD's service territory or the California market structure, which do not have the same retail competition structure as the Illinois or international examples. Other variances include local energy policies, cultural differences, demographics, and weather conditions.

The White Paper then reports a meta-analysis, Arcturus, which contains "arcs of price response." These are estimated econometrically using data from 400 deployments of time-varying rates across many jurisdictions. The results of this analysis yields the following takeaways: (1) the higher the ratio between peak and off-peak prices, the higher the price response, but this relationship is not linear. In other words, price response rises with the price ratio, but at a diminishing rate; (2) enabling technology, like smart thermostats, boosts the price response; (3) price response also depends on the type of price signal being conveyed.

SMUD requested that Dr. Faruqui simulate the impact of several different rates with the Arcturus model. The results, which are summarized below, compare well with the actual results from TOD and CPP load reductions.

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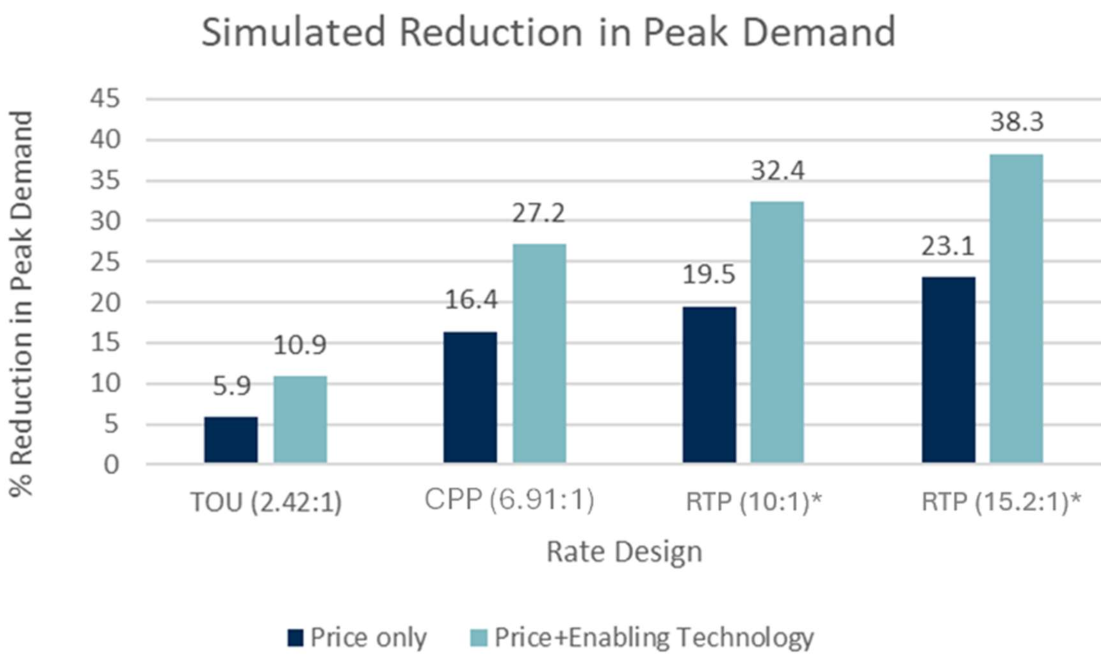
[26] Dr. Ahmad Faruqui is an Economist-at-Large who has published widely on time-varying rates and related topics such as demand forecasting, demand-side management, load flexibility, EVs and DERs. In his career, he has advised more than a hundred clients located across the globe on six continents, published widely on the topic and was featured in many newspaper commentaries. He has worked at several institutions, including the California Energy Commission, EPRI, Charles River Associates and The Brattle Group.

The White Paper further provides perspective on SMUD's current rate offerings compared to the value derived from a dynamic rate. First, it explains that SMUD's TOD, with a high adoption rate of 97%, sends a strong price signal to customers, with a ratio of 2.42:1 between peak and off-peak rates. The simulations with Arcturus predict a reduction of peak demand of 5.9% for TOD, and if coupled with enabling technology, the model predicts a reduction of 10.8%. This result is aligned with what was observed with SMUD's TOD rate. Taking this analysis a step further, SMUD's TOD plus CPP rate yields a 6.91:1 price ratio. Using the same model, this would predict a peak demand reduction of 16.4% without technology and 27.2% with enabling technology. The White Paper explains that if SMUD were to offer dynamic rates, any benefit would depend on the prices that would prevail in the higher load hours, and these are unlikely to differ much from the rates offered through CPP.

In 2023, SMUD's CPP rate impact evaluation showed that participants reduced their peak load by 31% (or 1 kW per participant), aligning with the simulated reduction in peak demand of 27.2% in Figure 30 below. While the load shift/peak demand reduction under a hypothetical RTP pricing is uncertain, historical NP15 day ahead price data from 2023-2024 suggest that RTP could create a price ratio as high as 15.2:1 during CPP events. According to Figure 30, such a high price ratio could yield a 38.3% (or 1.2 kW per participant) load shift. Compared to SMUD's existing CPP program, the hypothetical RTP rate offers an incremental improvement of approximately 7% (or 0.2 kW per participant). In Figure 30 below, the ratio simulated RTP 10:1 and 15.2:1 ratios (noted with *) represent two price signals derived from the highest observed price ratios based on day ahead market prices during CPP events in 2023 and 2024.

The White Paper concludes with a roadmap for SMUD. In the near term, the White Paper's roadmap concludes that dynamic rates will not encourage more load flexibility than the TOD and CPP rates that SMUD is already offering. Further, the paper recommends that SMUD evaluate how dynamic rates perform with other utilities, conduct focus groups with customers to explore interest, then conduct a dynamic rate pilot in 2030.

Figure 30 Simulated Reduction in Peak Demand by Rate Option



Review of Illinois Real-Time Rates

As noted above, two Illinois utilities, Commonwealth Edison Company (ComEd) and Ameren Illinois (Ameren), offer dynamic rates to residential customers. ComEd's 2023 Annual Report[27] showed that approximately 39,000 customers out of approximately 3 million residential customers had enrolled in ComEd's dynamic rate and those customers had generated $24 million in net benefits. ComEd reports that 99% of customers enrolled in the hourly pricing rate save money in comparison to ComEd's default flat rate. The average annual bill savings was $313, and total benefits from the rate are calculated to be $27,153,720, while costs are $2,795,404.

ComEd's hourly rate is funded through a monthly fee on all residential customers of $0.06, and customers not enrolled on the hourly price pay most of the cost of offering the hourly price. Furthermore, ComEd's current hourly rate is based on the real-time price determined by its regional transmission organization, PJM, but ComEd's Annual Report recommends utilizing the day-ahead hourly electricity prices, rather than real-time prices.

Ameren also offers an hourly price to residential customers in Illinois. While ComEd participates in PJM markets, Ameren participates in Midcontinent Independent System Operator (MISO) markets and uses the MISO day-ahead price, rather than the real-time price. Ameren's experience in 2021 and 2022 provides

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[27] Commonwealth Edison Company's Hourly Pricing 2023 Annual Report (April 19, 2024) *available at* https://www.icc.illinois.gov/docket/P2015-0602/documents/350023/files/611973.pdf.

reason for caution before adopting dynamic rates. Ameren states the following in its 2021 Annual Report:[28]

> In 2021, the Power Smart Pricing program experienced a volatile market that negatively impacted hourly pricing, which resulted in roughly 97% of Power Smart Pricing customers not saving as compared to the Ameren Illinois Basic Generation Service (BGS) fixed supply rate, Rider BGS. This irregular market volatility and unpredictable situation began with the challenges of the deep freeze in Texas in February 2021 and continued later in the year with average hourly prices consistently above fixed Rider BGS rates. During higher demand periods, generators fueled by natural gas are often used to provide kWh in those hours, and thus often set the hourly energy price. Higher natural gas prices result in higher electricity prices. U.S. month-ahead natural gas prices more than tripled since October 2020 and in 2021 reached their highest level since 2008.
>
> ….
>
> During 2021, Power Smart Pricing participants saw low hourly electricity prices during the first half of the year. The rise in natural gas costs caused the hourly electricity rate to drastically increase for Power Smart Pricing customers beginning in Q3, and nearly all Power Smart Pricing customers saw a negative savings in the second half of the year. In fact, the rise was so significant that the increased cost wiped out any savings from the first half of the year for approximately 97% of participants, and the average individual savings was -10.9% as compared to what they would have paid on the Ameren Illinois BGS fixed rate supply.

Customers on Ameren's dynamic rate experienced even worse results in 2022, where customers saw net costs of $2.2 million and paid 17.64% more for the dynamic rate than for the flat rate.[29] In 2023, natural gas prices were less volatile, which led to savings for Ameren hourly price rate customers in 2023 of 15.74%, totaling to $3.8M.[30] As of December 31, 2023, the dynamic rate option had 15,614 participants, representing approximately 2.5% of the total 614,162 bundled customers reported for Ameren by the United States Energy Information Administration (EIA).

While Illinois shows that there is potential customer savings from dynamic prices, it is important to put these reported benefits in context. Customer benefits are measured in relation to a standard fixed rate offered by the utility, whereas 97% of SMUD customers are on TOD rates, noted above. Further, Ameren's example illustrates that electric customers on dynamic rates may be exposed to price volatility not only for periods when the electrical grid is strained, but also due to indirect factors like periods when natural gas prices are high.

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[28] Ameren Illinois Power Smart Pricing 2021 Annual Report (May 1, 2022) *available at* https://icc.illinois.gov/docket/P2011-0547/documents/323471.
[29] Ameren Illinois Power Smart Pricing 2022 Annual Report (May 1, 2023) *available at* https://icc.illinois.gov/docket/P2011-0547/documents/337065/files/587223.pdf.
[30] Ameren Illinois Power Smart Pricing 2023 Annual Report (May 1, 2024) *available at* https://icc.illinois.gov/docket/P2011-0547/documents/349725/files/611347.pdf.

CEC Final Staff Report

Another source that SMUD considered was the CEC's *Analysis of Potential Amendments to the Load Management Standards* (Staff Report),[31] which considered several of the factors that this Revised Plan must analyze. SMUD includes analysis of relevant information from the Staff Report in the following sections where appropriate.

4.4.2 Cost Effectiveness

The first evaluation factor specified in the LMS regulations is cost effectiveness.[32] To assess cost effectiveness, it is necessary to consider the costs associated with designing, implementing, and maintaining new rates or programs, as well as the ongoing benefits. In this section, SMUD provides estimates of costs and benefits that SMUD would expect in implementing a dynamic rate or program. This is based on SMUD's knowledge gained during the implementation of the TOD and CPP rates, from SMUD's pilots with time-varying rates, and consideration of other utility examples. In future iterations of this Plan, SMUD anticipates supplementing and refining this analysis with additional data.

For residential customers, SMUD undertook two analyses to assess potential costs and benefits of dynamic rates or programs. As shown in Figure 29 above, SMUD first considered the costs and benefits of customers with smart thermostats adopting a dynamic rate or program, which showed net annual costs of $1 million to $1.6 million. Second, the analysis considers battery storage customers enrolled in a dynamic rate or program, which showed a net annual cost of $1 million. For non-residential customers, SMUD analyzed the benefits of offering a dynamic rate to customers responding like SMUD's existing Auto DR program. SMUD's analysis shows that offering such a rate or program would result in a net annual cost of $471,000 to $1.1 million.

Furthermore, when evaluating a new potential rate or program, SMUD considers cost-effectiveness in relation to existing rates or programs to determine whether new rates or programs are prudent investments on behalf of customers. This analysis is necessary to provide a full assessment of the value of a rate or program to customers. Below, SMUD includes this comparison for the scenarios listed above.

Key Assumptions

SMUD analyzed the cost effectiveness of offering a dynamic price signal though either a program or a rate that allows customers to react to hourly or sub-hourly price signals. As discussed further below, offering a rate would require developing the capability of billing customers on hourly or sub-hourly rates. As SMUD analyzed the possibility of offering a program that exposed customers to the rewards and penalties of an hourly rate, it determined that to enable this functionality for a program would require the same billing and systems infrastructure as required to offer a rate. Since both dynamic hourly rates and programs require similar technology updates, the estimated cost to implement either option is about the same since at this time SMUD systems are not capable of offering and billing customers based on more granular hourly or sub-hourly rates.

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[31] Final Staff Report. Analysis of Potential Amendments to the Load Management Standards. A Document Relied Upon. (December 22, 2021), TN 241067, 21-OIR-03.
[32] Section 1623.1(a)(1)(A).

Further, SMUD determined that analyzing a dynamic rate or program for nonresidential customers provided a reasonable estimate of the costs and benefits, rather than analyzing each nonresidential rate class. SMUD has eleven nonresidential rate categories, which are divided by customer size (in kW) and service voltage level (secondary, primary, and subtransmission). Figures 21 and 22 show that nonresidential customer load shape is directionally similar for all nonresidential sub-classes within nonresidential. Generally, the residential and nonresidential classes have non-coincidental peaks, and nonresidential customers do not drive SMUD's overall system peak. From this, it is reasonable to analyze nonresidential customers as a combined class because it is reasonable to assume the same outcome to the aggregated analysis as analyzing each individual sub-class. Further, the value is measured based on the avoided costs of a kW, which will be the same regardless of whether it is from a small, medium, or large nonresidential customer.

Additionally, there are some costs and benefits that cannot be accurately estimated at this time and are not included in the analysis below. Specifically, the Single Statewide Tool (SST) could add substantial upfront and ongoing costs to the offering of dynamic rates or programs. While utilities have proposed an SST design, the ultimate design has not yet been resolved; further, cost recovery and allocation has not yet been determined. Additionally, estimated costs were based on experience from development of TOD, CPP and the nonresidential rate restructuring. Many of these costs were incurred prior to COVID-19, and since that time there has been considerable inflation in the economy and SMUD would expect these costs to be substantially higher; this introduces an uncertainty that is difficult to estimate at this time. Conversely, SMUD was unable to estimate some benefits, like indirect environmental benefits and avoided greenhouse gas compliance costs. In future compliance plan cycles, SMUD will consider the latest information and additional methods to assess and evaluate these factors.

Uncertainty in ongoing participation in dynamic rates undermines confidence in counting on customer participation to avoid bulk grid investments. While avoiding a purchase for the coming summer may be a benefit, SMUD is investing significantly to address future capacity, and reliability needs in both bulk substations and utility scale battery storage. Without confidence in customer retention for dynamic rate offerings, utility planners cannot count on a dynamic rate response to avoid capacity investments (e.g. only net market shortfalls can be counted), leaving the value of these programs very much dependent on wholesale market conditions, and leaving significant value on the table that these resources could've delivered if they were in a more dependable program. This suggests that the benefits estimated in the program analysis may be over counting capacity and T&D value.

4.4.2.1 Estimated Costs

The following discusses estimated costs of SMUD developing a dynamic rate. As noted above, SMUD's estimate is informed by SMUD's experience developing and implementing the TOD and CPP rates. Among the sources that SMUD considered was the CEC's Staff Report, which estimated various costs associated with implementing the LMS regulations.[33] The portion attributable statewide to all utilities totaled approximately $19.2 million in net present value (NPV).[34] Separately, the Final Staff report

[33] Staff Report

[34] See Final Staff Report at 54, Table 5 (subtracting costs attributed to the CEC and ASPs).

estimated a total cost for SMUD to implement a dynamic hourly rate of $765,000 annually in 2023 and 2024.[35]

SMUD undertook an analysis to estimate these costs for SMUD's system, primarily informed by SMUD's experience developing in TOD and CPP rates and by other utility examples. Implementing new rates for all customer classes, particularly rates that are far more complex than any other rate SMUD currently offers, would require significant investment in planning, customer education and marketing, and technology development. These costs are reflected in Figure 31 and explained in the paragraphs that follow.

Figure 31 Estimated One-Time and Ongoing Costs for Dynamic Rate (dollars in thousands)[36]

	Initial Costs	Ongoing Costs[37]
Rate/Technology Implementation	$8,800	
Billing Tool & Software Licensing	$1,400	$575
Billing Engine & MDMS[38] Update	$700	
Rate Study, Design and Public Process	$1,900	
Bill Presentment	$3,600	
Marketing and Engagement	$1,000	
Data Storage and Backup	$290	
Program Management & Customer Education		$425
Total Cost	$17,690	$1,000

As shown above, SMUD estimates that one-time upfront costs would total approximately $17.7 million, and ongoing annual costs would total $1.0 million. The accounting treatment of technology capital and system upgrade costs are given a lifespan between 3 to 7 years, in this analysis we used a generous upper range of 7 years to depreciate technology capital projects, after which new technologies would need to be implemented, leading to recurring implementation expenses. For the purposes of the analysis, and to more accurately reflect the project's cost, the initial one-time cost is distributed over this period.

For this cost benefit analysis, SMUD allocated costs to residential (60%) and nonresidential customers (40%) as shown in the table below, based on respective contributions to the system peak in 2023.

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[35] See Final Staff Report at 78, Table 16.
[36] For this table, costs have been rounded for presentation purposes, but in our calculations SMUD used non-rounded numbers.
[37] SMUD anticipates the above costs to make a dynamic rate available are fixed and do not vary by load, electricity usage or enrollment level.
[38] Meter Data Management System (MDMS).

Figure 32 Cost Allocation Across Customer Classes

Description	% of Peak	Cost ($2025)
Residential	60%	10,593,958
Nonresidential	40%	7,062,638
Total Cost	100%	17,656,596

For this analysis, it is assumed that residential implementation costs are evenly split between the hypothetical residential RTP offerings (smart thermostat and/or battery storage).

SMUD performed a comprehensive assessment of the resources needed to implement RTP based on prior experience with significant rate changes from the residential Time-of-Day (TOD) and Commercial Rate Restructuring. Implementation costs, including capital implementation costs, one-time initial expenditures and annual ongoing expenses, were developed through discussions with subject matter experts from the relevant business units. The following lists each factor and provides a description:

- ***Rate and Technology Implementation*** estimated $8,769,000 in upfront costs. This line reflects cost associated with setting up IT systems, rate implementation, rate change automation, project planning, process improvement, requirements gathering, testing and quality assurance, rate transition and execution, and customer service representative training.
- ***Billing and Tool Software License*** estimated upfront costs of $1,400,000 with annual costs of $575,000. This line item includes the cost of a bill comparison tool for all rate classes, and corresponding software license and annual operating costs.
- ***Billing Engine and MDMS Update*** estimated $700,000 in initial costs, which includes necessary changes to billing engine to handle hourly or sub-hourly billing determinants, billing exception process with hourly sub-hourly data in meter data management system.
- ***Rate Study, Design and Public Process*** estimated $1,900,000 in initial costs, rate process material and services and labor cost associated with conducting a public rate process, development of in-house full marginal cost study by SMUD's Pricing team, additional cost of key subject matter experts, and review by management, and third party marginal cost consulting firm to validate the study and rate design.
- ***Bill Presentment*** estimated $3,597,000 in initial costs. Managing retail bills with hourly or sub-hourly billing data will be something challenging and new to SMUD. The estimates came from experience with a past project that implemented an omni-channel billing architecture, full bill re-design with digital features in mind. The project would include management of bill presentment channels to provide consistent and dynamic experience in paper, digital, email, text and additional channels, design bills that are simpler, cleaner, and easier for customers to understand and improve customers' experience of the overall billing process under the new dynamic rates. SMUD would need to fully re-design all bills to accommodate the new billing determinants and work with a third party to setup and print new bills and offer on-line digital options to access hour or sub-hourly billing data.
- ***Marketing and Engagement*** estimated $1,000,000 for initial costs, which is an estimate based on SMUD's experience rolling out new more complex rates, includes enrollment, billing, education

campaign, letters, door hangers, and necessary information to inform potential customers of the new more complex dynamic hourly or sub-hourly rate options. Significant outreach to and education for customers would be needed to help customers understand the potential benefits of the rate, how it works and to drive a deep understanding of the behavior changes that would be necessary to realize the intended benefits of the rate for their household or business.

- ***Data Storage and Backup*** estimated one-time $290,000 in costs, which includes software and hardware for physical system storage and backup updates of the hourly or sub-hourly billing data. For backup, the size of storage increases beyond a certain threshold and given the amount of hourly or sub-hourly billing data, SMUD would need to procure data storage in sufficient capacity to handle the new records. SMUD has assumed this data will be hosted in-house, so it would not expect annual expenses associated with this approach.
- ***Program Management & Customer Education*** estimated $425,000 in annual costs, which includes a full-time project manager and approximately $200,000 in ongoing annual effort to keep messaging on new dynamic hourly or sub-hourly pricing.

Estimated annual operating costs were determined using the average unit third-party operating cost per participant from the MEO program. This unit cost was escalated to 2025 dollars and scaled based on the assumed participation rate, with the addition of a single project manager cost.

The analysis includes incentive costs based on customer participation in the CPP program. An initial $25 was provided to recruit each customer into the program, with an additional $25 incentive given for each summer of participation. In the analysis it was assumed that customers would receive an average of $25 per summer, consistent with what was provided MEO customers. The analysis assumes that a similar level of bill savings would be necessary in both CPP and dynamic programs to maintain customer interest. Note that SMUD did not assume any recruitment incentives in the dynamic option because recruitment will be done by third parties.

Initial incentive costs are assumed to depreciate over a seven-year period for simplicity, based on the assumption that on average customers typically move within this time. As a result, these costs would need to be renewed as customers relocate.

As discussed above, these estimates are informed by SMUD's expertise in developing rates for SMUD customers. This estimate of an upfront investment of $17.7 million is relatively consistent with SMUD's previous estimate of $16 million for piloting, developing, and implementing TOD.[39]

4.4.2.2 Estimated Benefits

SMUD undertook three analyses to estimate benefits associated with a dynamic rate. For residential customers, this consisted of an analysis of offering dynamic rate or program with either (1) smart thermostats or (2) battery storage. For nonresidential customers, SMUD analyzed offering a dynamic rate or program in comparison to its existing Auto DR program. Each analysis considered first whether the benefits of the dynamic rate or program would exceed the costs for that program to determine whether it

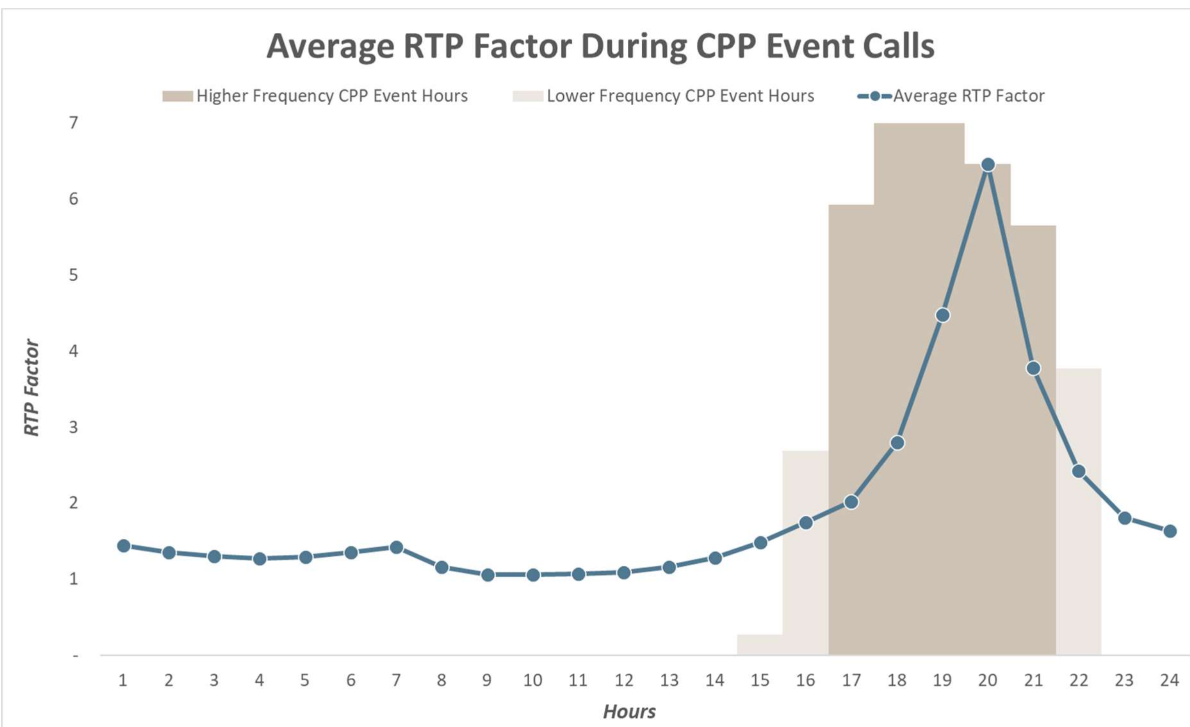
[39] Original Plan at 22.

was cost-effective. Next, each analysis considered whether the rate or program would be a prudent investment for SMUD considering SMUD's current rate and program offerings.

4.4.2.2.1 Dynamic Rate or Program

This section analyzes the costs and benefits of a dynamic rate or program for residential customers with smart thermostats. SMUD currently offers two established residential programs designed to shift load off peak periods. The MEO Smart Thermostat program relies on automated thermostat adjustments, supported by an upfront incentive, but does not include a dynamic pricing component with hourly or sub-hourly price signals. The MEO Smart Thermostat program with CPP builds on the previous program but adds a consistent and simple critical peak pricing structure, encouraging customers to reduce load during peak events in exchange for a lower off-peak rate and a more predictable bill. Both programs aim to reduce peak demand – much like a real-time pricing approach – by responding to system load and/or market conditions like temperature or high day-ahead prices. Although these existing programs are less complex than a real-time pricing option, comparing their cost-effectiveness in terms of peak load shifting is a simplification yet appropriate given their similar objectives to reduce peak load and the significant cost of capacity procurement. Figure 33, below, illustrates that SMUD's simple and easy to understand CPP rate price signal aligns with the hourly price signal the day ahead market would have provided.

Figure 33 Average RTP Factor During CPP Event Calls



The analysis considers two scenarios; the first includes expected customer participation based on SMUD's experience with similar rates and other utilities' experience. The second is a sensitivity analysis that included a much higher customer participation (10,000 customers) to test this analysis. Both the estimated costs and estimated benefits are shown in Figure 34, below. SMUD took the results from MEO only and its cost effectiveness as well as MEO with CPP. The results indicate that those two options are cost effective, with the caveat that CPP has relatively few customers, which distorts the fixed cost recovery. For the dynamic rate analysis, SMUD considered the incremental load reduction based on Dr. Faruqui's analysis in addition to reductions from CPP. It incorporated 60% of the one-time initial investment and ongoing operating costs.

Figure 34 Cost and Benefit Analysis

Annual Cost Benefit Analysis of Individual Residential Dynamic Pricing Programs ($2025)				
Description	**MEO Smart Thermostat Only**	**MEO Smart Thermostat with CPP**	**RTP - Hypothetical**	**RTP - Hypothetical at 10k Participation**
Program Costs				
Rate Implementation (Billing System, Reporting, Education)	$ -	$ -	$ 5,296,979	$ 5,296,979
Annual Operation Cost	$ 1,441,117	$ 326,850	$ 358,969	$ 667,872
Annual Continued Customer Education	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Annual ASP Authorization	$ -	$ -	$ 75,000	$ 75,000
Billing Tool Licensing	$ -	$ -	$ 500,000	$ 500,000
Customer Incentives				
One Time Sign-up Incentive	$ 750,000	$ 242,000	$ -	$ -
Annual per Summer Incentive	$ 750,000	$ -	$ -	$ -
Average Customer Bill Savings	$ -	$ 121,000	$ 75,625	$ 250,000
Annualized Cost Summary				
Upfront Costs	$ 750,000	$ 242,000	$ 5,296,979	$ 5,296,979
Annual Recurring Costs	$ 2,391,117	$ 647,850	$ 1,209,594	$ 1,692,872
Overall Annualized Cost	$ 2,917,465	$ 796,001	$ 2,178,368	$ 2,746,374
Capacity Value				
Participation Count	30,000	4,840	3,025	10,000
Average Load Shift Per Customer (%)	22%	31%	38%	38%
Average Load Shift Per Customer (kW)	0.7	1.0	1.2	1.2
Average Overall kW Shift per Summer	20,175	4,659	3,623	11,976
Levelized Generation Capacity Value ($/kW)	$ 146	$ 146	$ 146	$ 146
Levelized T&D Grid Benefits ($/kW)	$ 1	$ 1	$ 1	$ 1
Total Capacity & Grid Value*	$ 2,971,880	$ 685,752	$ 533,283	$ 1,762,919
Net Benefit/(Cost) of Individual Program	**$ 54,415**	**$ (110,249)**	**$ (1,645,085)**	**$ (983,455)**

SMUD utilized the costs estimated above in Section 4.4.2.1, with the following modifications for this analysis:

The method of annualizing costs are as follows:

- Upfront costs are presented in the project's initial start year dollars (in this case, 2025) and is distributed evenly over the project's 7-year lifespan. Although these upfront costs are expected to occur again in a future period, they are initially already stated in present year terms and should be adjusted for inflation if the project start year changes.

- Annually recurring costs are stated in the project start year dollars and are escalated by inflation over the project's 7-year lifespan and then discounted at SMUD's 5% discount rate to calculate a net present value. An annual levelized value that remains constant over the project's lifespan – equivalent to the net present value – is computed. The levelized value is in nominal dollars, reflects SMUD's cost of capital, and increases with inflation if the project start date shifts.

SMUD estimated benefits associated with grid and capacity value, which is explained in greater detail as follows:

- ***Participation Count***
  - Since customer participation strongly influences cost-effectiveness, SMUD thought it would be relevant to gauge cost-effectiveness at a more mature stage of a rate or program offering. The cost benefit analysis included the participation estimates for the smart thermostat program (MEO) and the smart thermostat program (MEO) with CPP. It is estimated that 30,000 customers with smart thermostats would enroll in SMUD's MEO program because, as understood from leading vendors in this space, participation levels of 10-15% are typical for this type of program. This would correspond to SMUD's expected future adoption level of smart thermostats of 200,000-300,000. For SMUD's optional CPP program, it is conservatively estimated that 4,840 customers would enroll by extrapolating the current enrollment rate in CPP to the current pool of approximately 121,000 eligible smart thermostat customers. While the uptake for a hypothetical RTP offering is unknown, SMUD uses a participation rate of 2.5% - observed in Ameren's service area - and extends it to the total smart thermostat population. Since participation is key to a program's cost-benefit, the hypothetical RTP offering are stress tested by increasing the participation to 10,000 customers, a figure exceeding the CPP participation level, to demonstrate the cost-benefit performance even at this higher-than-expected participation.
- ***Average Load Shift Per Customer (% or kW)***
  - For the capacity value analysis, the average shift was calculated based on the actual load shift observed among MEO and MEO with CPP participants during the summer of 2023, which is approximately 0.7 kW and 1 kW, respectively. As explained in the discussion of Figure 25, while there is a lack of direct data on a hypothetical RTP rate's load shift, it is assumed that customers are responding to high day-ahead market prices in a manner similar to how they respond during CPP events. Using actual high-to-low market price ratios during the event day, Dr. Faruqui simulated an RTP induced reduction in peak load of about 38% based on the potential highest observed price ratios. Applying this reduction to the average pre-shift load of MEO with CPP participants, it is assumed the RTP shifting load to be approximately 1.2 kW, which is higher than the reduction in peak load for both MEO and MEO with CPP offerings.
- ***Average Overall kW Shift Per Summer***
  - As stated previously, with these shift percentages and average participant load shifts in kW for MEO, MEO with CPP and the simulated RTP scenario, the average per-customer shift is calculated in kW. This per-customer shift is then scaled up across different participation scenarios to estimate the overall average kW shift per summer.
- ***Levelized Generation Capacity Value ($/kW)***
  - Forecasted levelized generation capacity values are determined from SMUD's marginal cost data in $ per kW-summer, using a five-year outlook (2025-2029) consistent with typical residential program cost assessments. The primary goal of these programs is to reduce system peak, potentially avoiding substantial resource adequacy costs – assuming reliability is demonstrated through more extensive testing. The $ per kW-summer is

multiplied by the total summer kW shift to compute an overall generation capacity value for MEO, MEO with CPP, and hypothetical RTP offering.[40]

- ***Levelized T&D Grid Benefits ($/kW)***
  - Similarly, levelized transmission, sub-transmission and distribution (T&D) capacity values per summer are also derived from SMUD's marginal cost data in $ per kW, using the same 2025-2029 period. Because the most apparent application of these programs – peak reduction - may not always coincide with local grid needs, a probability-of-peak analysis is used. This analysis is based on 10 years of historical system load data to develop an average effective hourly T&D value distribution by month, day type, and hour. By comparing average load shift behavior during 2023 critical peak events to these hourly T&D values, an effective value is computed and then applied to the total summer kW shift. Without direct evidence of RTP customer load responses to high market prices, the RTP load-shifting T&D value per kW is assumed to match that of MEO with CPP.
- ***Total Capacity and Grid Value***
  - The total levelized generation and T&D values are the sum of these respective calculations. These annualized values developed from 2025-2029 marginal cost data convey the combined capacity benefits for each offering.

As shown in Figure 29 above, under either an expected or high enrollment scenario, a dynamic rate or program would result in a net loss for SMUD to develop and implement. For the expected enrollment (approximately 3,000 customers), SMUD expects an annual benefit of $533,000, and for the high enrollment scenario of 10,000 customers, an annual benefit of approximately $1.8 million. Comparing these benefits to the expected costs results in a net loss of approximately $1.6 million per year for the expected scenario or $1.0 million per year for the high enrollment scenario.

Comparison of Dynamic Hourly Pricing with SMUD Programs

This section analyzes the cost effectiveness of implementing a dynamic rate compared to the cost of SMUD's existing programs. As discussed above, 97% of SMUD customers are on the TOD rate, and this rate provides time-differentiated rates that reduce peak load. SMUD offers residential customers a thermostat-based peak reduction program, MEO, that provides incentives for customers to let SMUD dispatch their smart thermostats during peak events. Furthermore, SMUD offers customers the CPP rate (MEO + CPP), which provides customers a pricing-based incentive in addition to automated dispatch of their thermostat. The CPP rate also encourages them to further reduce load.

Figure 35, below, provides a high-level overview of the cost effectiveness analysis in $/kW-summer. Negative values represent annualized net cost to SMUD. As seen in the table, the results for the two RTP

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[40] SMUD believes that direct, dispatchable programs offer the most dependable capacity benefits and associated value. Although SMUD lacks direct evidence of how hypothetical RTP customers might shift their load or mitigate system peak demands — factors affected by the rate's complexity and the alignment between day-ahead market prices and critical peak events — SMUD has proceeded with this cost-benefit analysis by assigning full capacity value per kW to the hypothetical RTP scenario. In practice, establishing a program or rate's eligibility for full capacity value would require extensive data, years of proven performance, and validation by energy trading teams to ensure reliable capacity cost avoidance. Since such data is unavailable for RTP, this capacity value assumption is generous. Consequently, these results should be considered a benchmark or point of reference, representing the upper range of potential capacity benefits that RTP could achieve.

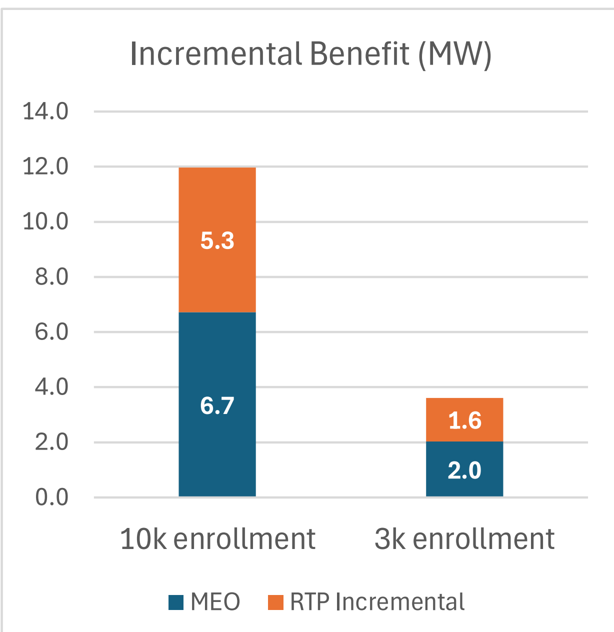
scenarios will bring kW reduction at a much higher cost than the other alternatives already in place, the MEO and MEO + CPP.

Figure 35 Summary of Cost Effectiveness

Cost Benefit Analysis of Individual Residential Dynamic Pricing Programs (in $2025 per kW)	MEO Smart Thermostat Only	MEO Smart Thermostat with CPP	RTP - Hypothetical	RTP - Hypothetical at 10k Participation
Capacity Cost In $/kW Summer	$ 144.6	$ 170.9	$ 601.3	$ 229.3
Estimated Market & Grid Value/Benefit in $/kW Summer				
Generation Capacity Value	$ 146	$ 146	$ 146	$ 146
T&D Grid Benefit	$ 1	$ 1	$ 1	$ 1
Total Market & Grid Value	$ 147	$ 147	$ 147	$ 147
Net Benefit/(Cost) to Programs in $ per kW Summer	**$ 2.7**	**$ (23.7)**	**$ (454.1)**	**$ (82.1)**

Figure 36 and 37, below, compare the results between the MEO program compared to a hypothetical dynamic rate or program. When comparing load reduction in MW from MEO at 10,000 customers enrollment, the incremental MW reduction with a dynamic rate or program would be approximately 5.3 MW at an annualized net cost of $0.8 million. Similarly, with an enrollment of about 3,000 customers, the incremental load reduction from RTP would be 1.6 MW at an annualized net cost of $1.3 million.

Figure 36 Cost Benefit Based on Enrollment



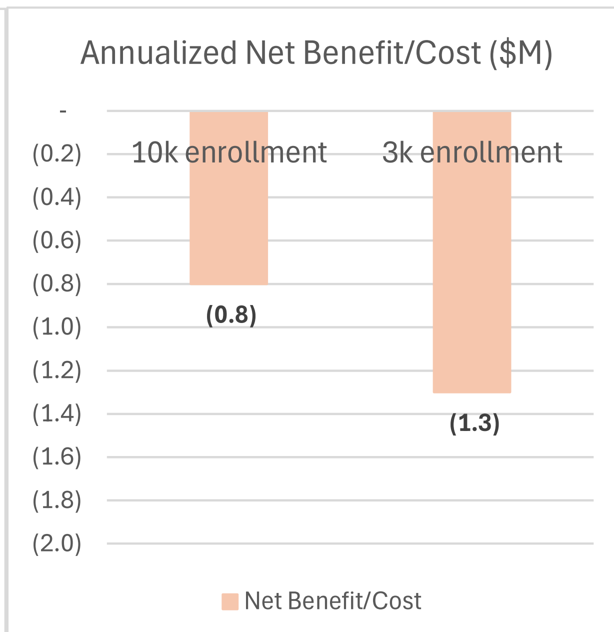


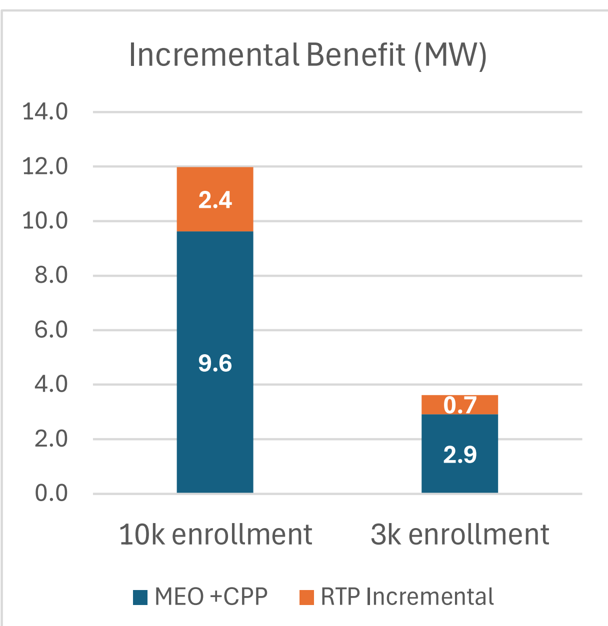
Figure 37 Incremental Benefits

Annual Net Benefit/(Cost) of Program ($M)		High Participation		Low Participation
Incremental Benefit / Value of RTP Programs Versus ------->		**Residential MEO Only**		**Residential MEO Only**
Target Enrollment (Count)		10,000		3,025
Incremental RTP Program Value	$	0.8	$	0.2
Annual Cost of RTP Program	$	1.5	$	1.6
Net Benefit/(Cost) of Program	**$**	**(0.8)**	**$**	**(1.3)**
Baseline KW		6,725		2,034
RTP kW		11,976		3,623
Incremental Summer Peak Load Reduction in kW		5,251		1,588
Load Reduction Achieved by SMUD Existing Program		56%		56%

Figure 38 & 39 below, shows a comparison of the incremental benefit in load reduction and associated annualized net cost from RTP vs. existing MEO with CPP. Same as the prior analysis, two scenarios were run at 10,000 and 3,000 customers enrolled. The chart and table below summarize the results.

The incremental MW reduction of RTP compared to MEO + CPP at 10,000 customers would be approximately 2.4 MW. But it comes at an annualized net cost of $1.1 million. Similarly, with an enrollment of about 3,000 customers, the incremental load reduction from RTP compared to MEO + CPP would be 0.7 MW at an annualized net cost of $1.4 million. The incremental benefit from RTP in this scenario is significantly more expensive than the prior case, primarily because MEO + CPP already recovers approximately 80% of the potential load reduction benefit.

Figure 38 Cost Benefit Based on Enrollment



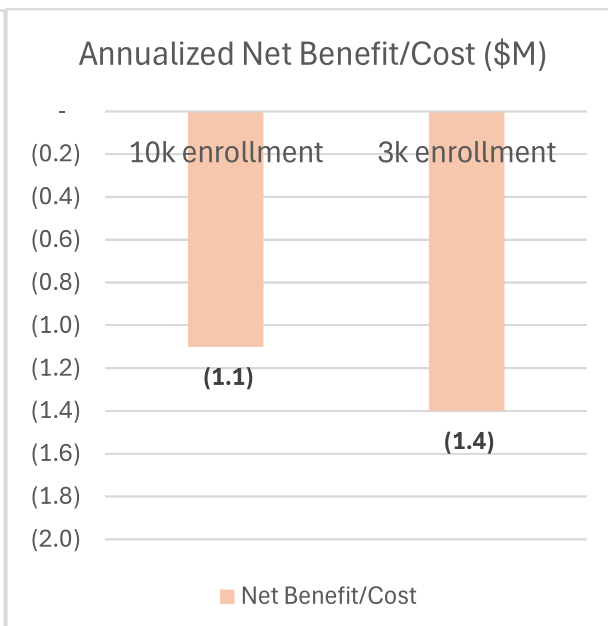


Figure 39 Incremental Benefits

Annual Net Benefit/(Cost) of Program ($M)	High Participation		Low Participation	
Incremental Benefit / Value of RTP Programs Versus ------->	**Residential MEO with CPP**		**Residential MEO with CPP**	
Target Enrollment (Count)		10,000		3,025
Net Benefit/(Cost) of Program	$	0.3	$	0.1
Summer Peak Load Reduction in kW	$	1.5	$	1.5
Net Benefit/(Cost) of Program	**$**	**(1.1)**	**$**	**(1.4)**
Baseline KW		9,625		2,912
RTP kW		11,976		3,623
Incremental Summer Peak Load Reduction in kW		2,351		711
Load Reduction Achieved by SMUD Existing Program		80%		80%

As shown above, offering an RTP program is not cost-effective for SMUD primarily because the main barrier is the associated high implementation cost and lower expected participation rate than the existing MEO and CPP programs. Currently, SMUD has over 25,000 customers on MEO. Since recruitment heavily influences cost-effectiveness, for illustration, SMUD presents a higher RTP adoption scenario for a more robust analysis. The analysis was also extended to compare the successful smart thermostat program (MEO) with higher adoption for comparison purposes.

Furthermore, the cost comparison gets worse when considering the benefits of a new RTP pricing options as incremental to the existing CPP program as follows:

Figure 40 Cost Effectiveness

					RTP Program - Hypothetical with High Adoption			
Incremental Capacity Value of RTP Program	**Incremental Net Benefit/(Cost) vs. MEO Only**		**Incremental Net Benefit/(Cost) vs. MEO with CPP**		**Incremental Net Benefit/(Cost) vs. MEO Only**		**Incremental Net Benefit/(Cost) vs. MEO with CPP**	
RTP Program Participation Count		3,025		3,025		10,000		10,000
Incremental Average Load Shift Per Customer (kW)		0.5		0.2		0.5		0.2
Overall Load Shift		1,588		711		5,251		2,351
Levelized Generation Capacity Value ($/kW)	$	146	$	146	$	146	$	146
Levelized T&D Grid Benefits ($/kW)	$	1	$	1	$	1	$	1
Incremental RTP Program Value Above CPP Program	$	233,823	$	104,688	$	772,968	$	346,075
Annual Cost of RTP Program	$	1,553,939	$	1,543,135	$	1,529,028	$	1,493,314
Net Benefit/(Cost) to Utility RTP as Incremental Program	**$**	**(1,320,116)**	**$**	**(1,438,447)**	**$**	**(756,060)**	**$**	**(1,147,239)**

This analysis finds that the existing MEO with TOD and CPP options already capture a significant portion of the load-shifting benefits, making the additional value from an RTP option insufficient to justify its significant investment and ongoing operational cost.

The analysis shows that the energy value and/or savings from load shifting are minimal. There is also provided a separate analysis for storage as shown in Figure 41 below. Battery storage, when automatically dispatched against the energy market, could yield additional savings for both the customer and SMUD. The analysis focuses on customers peak load reduction by adjusting their behavior in response to dynamic signals, which are high only a few times per year and comparable to CPP events. Because these events primarily result in a reduction in peak load rather than actual energy reduction, the energy reduction value is minimal in the absence of battery technology.

As shown in Figure 39, above, the conclusion from the cost effectiveness analysis is that continuing to offer TOD rates paired with existing programs MEO and CPP are more cost-effective than implementing a more complex hourly dynamic pricing rate at this time. SMUD is pursuing a programmatic approach with enrolling smart thermostat customers on My Energy Optimizer (MEO) which is an automatic demand response program. Under MEO Partner, SMUD, working through a 3rd party, has control of the smart thermostat during program events on a maximum of 15 days (and 50 hours) per summer (June-September) to reduce system peak demand, similar to the intent of more dynamic hourly or sub-hourly prices. Smart thermostats customers can also enroll on the CPP rate option.

4.4.2.2.2 Dynamic Program with Energy Storage

In addition to considering the cost-effectiveness of RTP compared to peak reduction focused programs like the MEO and MEO+CPP offerings, SMUD also evaluated the cost-effectiveness of a year-round dispatchable residential battery storage VPP program to a storage plus RTP combination. Currently storage adoption in SMUD service territory is fairly low, at about 1,400 batteries or 7 MW. This is anticipated to grow to up to 30,000 batteries by 2030, although recently announced storage price increases, tariffs on imports, and income tax credit uncertainty could reduce this forecast. For this analysis SMUD's current MEO Partner + program offering was considered, which offers an upfront incentive and an ongoing capacity payment for participation in its MEOP+ Virtual Power Plant. The upfront incentive was primarily developed as a market transition credit for SMUD's Solar and Storage rate, while the capacity payments were modeled around the anticipated avoided resource adequacy capacity (RA) costs. SMUD also do not anticipate offering upfront incentives beyond 2028, assuming battery prices fall, and uptake accelerates as projected. As a result, the costs of the upfront incentives were not included in this analysis.

Figure 41 Cost Effectiveness of RTP and MEO Partner +

Cost Benefit Analysis (2025$)		
Description	**RTP Storage Customer**	**MEO Partner +**
Program Costs		
Rate Implementation (Billing System, Reporting, Education)	$ 5,296,979	$ -
Annual Operation Cost	$ 68,428	$ 3,150,000
Annual Continued Customer Education	$ 100,000	$ 50,000
Annual ASP Authorization	$ 37,500	$ -
Billing Tool Licensing	$ 250,000	$ -
Data Storage & Back-Up	$ 145,000	$ -
Customer Incentives		
One Time Sign-up Incentive	$ -	$ -
Annual per Summer Incentive	$ -	$ 3,150,000
Average Customer Bill Savings	$ 696,817	$ 4,692,857
Annualized Cost Summary		
Upfront Costs	$ 5,296,979	$ -
Annual Recurring Costs	$ 1,297,745	$ 11,042,857
Overall Annualized Cost	$ 2,054,456	$ 11,042,857
Capacity Value		
Participation Count	1,500	15,000
Average Load Shift Per Customer kWh	10	10
Average Load Shift Per Customer (kW)	5	5
Average kW Shift per Summer	7,500	75,000
Levelized Generation Capacity Value ($/kV	$ 146	$ 146
Levelized T&D Grid Benefits ($/kW)	$ 1	$ 3
Total Capacity & Grid Value*	$ 1,102,500	$ 11,175,000
Net Benefit / Cost	**$ (951,956)**	**$ 132,143**
Cost Effective?	Not Cost Effective	Cost Effective

The energy storage analysis concludes that when accounting for capacity payments and benefits, the MEO Partner + program can roughly break even, assuming ongoing customer and operational VPP costs of approximately $84/kW-yr split between customers and vendors, which is in the range of SMUD's cost-effectiveness target stated when it issued its original Request for Quotes for the program. However, for the dynamic rate, assuming a generous 5% participation level (as explained in the section above, 4% was considered the highest participation level based on experience summarized in the White Paper), the rate sees very negative net benefits due to the high implementation costs of the dynamic rate offerings. As mentioned in the thermostat analysis, the upfront and ongoing costs for the residential real time rate were split 50/50 between thermostats and storage. In addition, the volume of potential participation is not meaningful in contributing to SMUD's Zero Carbon Plan needs, projected at only 7.5 MW vs. projections of 75 MW for its Partner+ VPP. For this analysis a typical 5 kW, 10 kWh battery was used, which has been a fairly common residential battery size across several vendors. The analysis assumed a customer dispatch incentive that split costs between the customer and the vendor. For bill savings, customers are assumed to arbitrage the battery against SMUD's TOD rates, and for the dynamic rate customers, against a dynamic wholesale rate overlayed on the fixed cost differentials built into SMUD's TOD rate.

This financial analysis does not account for the fact that the VPP program offering will allow SMUD to dispatch batteries on a location-specific basis and to tap into additional benefits like avoiding substation upgrades or delivering other needed grid services such as Energy Imbalance Reserves that a dynamic rate would struggle to provide. As SMUD determines what is needed to retire or retool its natural gas plants, accessing a full set of grid services from battery storage will be critical. Without this kind of control, SMUD will have to build additional, duplicative assets, on the utility side of the meter to be able to deliver locational benefits as well as other grid services. This will also slow the adoption of electric vehicles by putting more pressure on utility planners to more rapidly expand substations that could've been deferred or avoided by effectively tapping behind the meter storage for local grid needs.

While it is possible for a customer to enroll a battery in a DR program in addition to their smart thermostat, the probability of this double enrollment happening is low. This claim is based on discussions with the leading solar and storage vendor in SMUD's service territory. They say that customers with batteries do not want to be troubled with the discomfort of a thermostat DR program. They already have a large battery that helps them manage their energy bill, and the DR payment is not worth the discomfort. As such, the even narrower selection of customers that might opt for a dynamic tariff and dispatch a battery and a thermostat to take advantage of that tariff were not examined.

4.4.2.2.3 Dynamic Rate or Program for Nonresidential Customers

For nonresidential customers, SMUD considered a scenario where the Auto-DR program, described above in Section 4.3.1.1.2.1, was modified to include a dynamic rate. As discussed above, the Auto-DR program's realization rate is approximately 80% and is on track to provide 30 MW of peak load reduction by 2030. In this analysis, SMUD explored two scenarios. The first "low" scenario considered the costs and benefits of achieving an additional 2 MW of peak load reduction with a dynamic rate, which is based on the remaining load reduction needed to meet SMUD's 2030 target. The second "high" scenario considered an estimated cumulative target of 13.5 MW, which is based on annual projections to continue to grow the Auto-DR program by about 2.7 MW per year thru 2030. The costs and benefits of both scenarios are listed below in Figure 42.

Figure 42 Cost Benefit Analysis Auto DR vs RTP

Annual Cost Benefit Analysis of Individual Non-Residential Dynamic Pricing Programs ($2025)	Existing Program	2MW Incremental Program		13.5MW Incremental Program	
Description	SMUD AutoDR	SMUD Incremental AutoDR	RTP Program - Hypothetical Incremental	SMUD Incremental AutoDR	RTP Program - Hypothetical Incremental
Program Costs					
Rate Implementation (Billing System, Reporting, Education)	$ -	$ -	$ 7,062,638	$ -	$ 7,062,638
Annual Operation Cost	$ 226,600	$ -	$ 225,000	$ -	$ 225,000
Annual ASP Authorization	$ -	$ -	$ -	$ -	$ -
Billing Tool Licensing	$ -	$ -	$ -	$ -	$ -
Customer Incentives					
One Time Sign-up Incentive	$ 1,162,680	$ 360,050	$ -	$ 2,423,068	$ -
Annual per Summer Incentive	$ 900,200	$ 64,507	$ -	$ 434,118	$ -
					$ -
Annualized Cost Summary					
Upfront Costs	$ 1,162,680	$ 360,050	$ 7,062,638	$ 2,423,068	$ 7,062,638
Annual Recurring Costs	$ 1,126,800	$ 64,507	$ 225,000	$ 434,118	$ 225,000
Overall Annualized Cost	$ 1,490,445	$ 127,252	$ 1,273,395	$ 856,379	$ 1,273,395
Capacity Value					
Participation Count	35	3	3	20	20
Average Performance	80%	80%	40%	80%	40%
Total Capacity Available (kW)	27,994	2,006.0	2,006.0	13,500.0	13,500.0
Capacity at Average Performance (kW)	22,505	1,613	802	10,853	5,400
Levelized Generation Capacity Value ($/kW)	$ 146	$ 146	$ 146	$ 146	$ 146
Levelized T&D Grid Benefits ($/kW)	$ 3	$ 3	$ 3	$ 3	$ 3
Total Capacity & Grid Value*	$ 3,341,241	$ 239,427	$ 119,130	$ 1,611,301	$ 801,720
Net Benefit/(Cost) of Individual Program	**$ 1,850,796**	**$ 112,176**	**$ (1,154,265)**	**$ 754,922**	**$ (471,675)**

For the cost-benefit analysis of existing and potential nonresidential Auto-DR program, as well as a hypothetical nonresidential RTP offering, the following cost and benefit components were considered:

- ***Rate Implementation (Total Upfront Cost for Dynamic Rate)***: The total upfront cost for dynamic rate implementation discussed in Figure 31 are allocated to both residential and nonresidential RTP offerings based on their respective shares of system peak demand. Since the primary objective of these offerings is to reduce system peak (and thereby potentially avoid significant resource adequacy costs). The allocation results are shown in Figure 32 and are applied here.
- ***Operating Cost***: The existing ADR program currently pays a $16,000 software fee to its vendor. In addition, operating costs include the cost of a project manager. This project manager cost would also be assigned to any hypothetical RTP offering.
- ***ASP Authorization and Billing Tool Licensing***: These costs have been accounted for in the residential implementation analysis. Since the nonresidential customer count is much smaller, it is considered an incremental addition to the residential effort. Therefore, no additional costs of this type are included here.
- ***One-Time Sign-Up Incentive***: In addition to covering the cost of a customer communication device, there is a $175 per-kW technology incentive for customers who install load-shedding equipment. Most customers fully utilize this incentive. Existing ADR participants who have already received their technology incentives are not counted again. Going forward, however, technology incentive payments for new customers are included. The incremental ADR scenario includes the full cost of these technology incentives. For the hypothetical RTP program, the technology incentive does not apply.

- ***Annual Per-Summer Incentive***: The current ADR program offers an ongoing annual performance-based incentive of $40 per kW per summer. These costs are included for ADR participants. The hypothetical RTP offering does not include a similar annual incentive.
- ***Participation Costs***: This is based on the average nominal capacity per participant in the existing program and extended to the kW required to meet the program's target in each scenario. In the case of the incremental ADR program, it helps estimate how many communication devices SMUD would need to fund.
- ***Average Performance***: In the case of ADR, average performance represents the difference between the total nominal capacity enrolled and the actual capacity shed during a peak event in 2024. This serves as a performance adjustment to the nominal capacity. In the case of RTP, SMUD does not have direct evidence to gauge how RTP participants would perform during critical peak events. Unlike ADR, which relies on direct load control, RTP performance is based on customers responding to high-price events in day ahead market prices. SMUD uses as a reference the load shifting performance to be similar to what SCE's Real Time Pricing rate for large industrial customers achieved during peak-hour load - approximately 40%.[41] In a recent 2023 update to SCE's study the stated load shift dropped to 37% during the peak-hours.[42]
- ***Total Capacity Available (kW)***: The total nominal capacity enrolled in each scenario.
- ***Capacity at Average Performance (kW)***: This metric reflects the total nominal capacity available from participants once adjusted for performance levels in 2024.
- ***Levelized Generation Capacity Value ($/kW)***: This is calculated as discussed in the residential cost-benefit analysis and applied here to determine the value of capacity.
- ***Levelized T&D Grid Benefits ($/kW)***: The grid benefit is also calculated similarly to the residential analysis, except that the load-shifting expectations over the call duration was provided by the program team. This data was used to determine the average value of event calls per kW per summer. Since there is a lack of direct evidence of RTP customer load-shifting responses to high market prices, the RTP load-shifting T&D value per kW is assumed to be the same as for the existing ADR program.
- ***Total Capacity and Grid Value***: This is the sum of the levelized generation capacity value and the grid benefits at the expected capacity at average performance.
- ***Net Benefit/(Cost) of Individual Program***: The net benefit/(cost) is calculated by subtracting the standalone costs from benefit of the existing ADR program, the incremental ADR program, hypothetical RTP rate offering at the incremental ADR program size, and a higher-than-target participation RTP scenario for stress testing (projected from the average ADR program growth in kW, extended to 2030).

The cost-effectiveness analysis shows that there would be a substantial net loss associated with including the dynamic rate for these nonresidential customers. As seen in Figure 42 above, the low scenario at 2 MW would result in an approximately $1.2 million net loss annually. The high scenario at 13.5 MW

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[41] *Testimony of Southern California Edison Company (U-338-E) In Support of Application for Approval of the Large Power Dynamic Pricing Rate* at 2, *available at* https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2406014/7572/534344093.pdf.
[42] Id.

would result in a net annualized loss of approximately $472,000. In comparison, under both a low and high scenario, continuing to operate the Auto-DR program as it is currently operating would result in net benefits.

Figure 43 Incremental Benefits

		High Participation		Low Participation
Annual Net Benefit/(Cost) of Program ($M)		**13.5MW Enrollement**		**2MW Enrollment**
Incremental Benefit / Value of RTP Programs Versus ------->		**Nonresidential ADR**		**Nonresidential ADR**
Target Enrollment (Count)		20		3
Net Benefit/(Cost) of Program	$	(0.8)	$	(0.1)
Summer Peak Load Reduction in kW	$	0.4	$	1.1
Net Benefit/(Cost) of Program	**$**	**(1.2)**	**$**	**(1.3)**
Nominal Capacity kW		13,500		2,006
Summer Peak Load Reduction Baseline KW		10,853		1,613
Summer Peak Load Reduction RTP kW		5,400		802
Incremental Summer Peak Load Reduction in kW		(5,453)		(810)
Load Reduction Achieved by SMUD Existing Program		201%		201%

As shown in Figure 42, when comparing the existing ADR program to a new hypothetical RTP program, the existing program is more cost-effective—even at higher-than-targeted participation levels. Figure 42 evaluates these programs individually. When viewed as alternatives to one another, an average RTP participant achieves a lower peak load reduction in this illustrative scenario at a higher cost compared to the existing ADR program.

As shown in the figure 43 above, if the ADR program is considered as a baseline, and the hypothetical RTP offering's impact treated as incremental to that baseline, the RTP program loses about 0.8 MW (or 201%) of incremental benefit at 2 MW target program enrollment, coupled with a greater net loss of $1.3 million. Even if the hypothetical RTP offering participation rose to 13.5 MW, the ADR program alternative would still capture more capacity value at a significantly lower cost.

4.4.2.3 Discussion

The foregoing analysis shows that dynamic rates and programs are not cost-effective for SMUD at this time. For residential customers with a smart thermostat or battery storage enrolled on a dynamic rate or program as shown in Figure 29, SMUD expects an annualized net loss of approximately $1.9 – 2.6. For non-residential customers, SMUD estimates an annualized net loss of approximately $471,000 to $1.2 million. The value proposition of offering dynamic rates and programs is even worse when compared to SMUD's current rate and program offerings, which are cost-effective and functionally meeting the load modification goals of the LMS regulations.

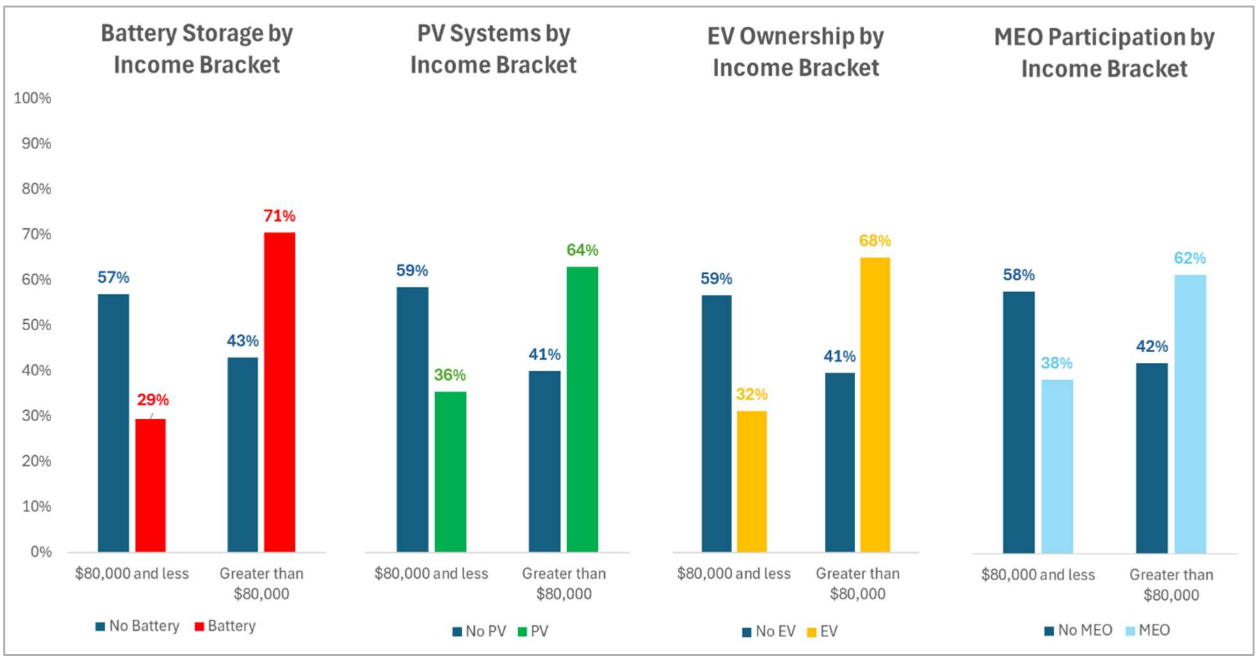
4.4.3 Equity

The second criterion by which to evaluate dynamic rates is equity and the following section analyzes several considerations related to equity. The ability to directly benefit from a dynamic rate depends on several factors, such as access to enabling technology, ability to shift load away from high-cost periods, and ability to benefit from the rate and absorb potential bill shocks. Based on staff research of the Illinois examples, information from Appendix A, and SMUD's experience with its customers, SMUD expects very low participation in dynamic rates by low-income customers. Thus, assuming there were any savings from dynamic rates, SMUD does not expect its low-income customers and customers in under resourced communities to be able to access potential bill savings from dynamic rates.

As discussed elsewhere, SMUD has generally seen low adoption rates (3%) for the CPP program, and the two examples from Illinois show adoption of dynamic rates from 1-2.5% of all customers.

The ability to participate in dynamic rates hinges upon customers' access to technology with specific characteristics that enables response to hourly or sub-hourly price signals. SMUD analyzed a range of technologies and the adoption rates by customers based on income level. Figure 44 shows a connection between income level and the adoption of technology for customers in SMUD's service territory. This data suggests that the high upfront cost for some of these technologies may pose a limitation, particularly for lower income customers.

Figure 44 Adoption of Technology by Population and Income Level



As seen in Figure 44, in all cases, customers with incomes of $80,000 or less are less likely to implement enabling technologies. Customers with incomes over $80,000 are more likely to adopt these enabling technologies and would be more likely to benefit from RTP rates. This threshold aligns with the average income level in Sacramento.[43]

Other factors that could make dynamic rates challenging for lower income customers were also analyzed. For example, SMUD's analysis suggests that lower income customers move more frequently, which may make investments in enabling technology more difficult, and low-income customers may occupy older, less efficient homes. This analysis also shows that low-income customers are more likely to rent or lease

[43] For the household income brackets, data was used from the vendor, Data-Axle, which was obtained by contract in December 2023.

their home or business, which may pose additional challenges with respect to securing permission for technology installations. Appendix B shows the results of these analyses.

Furthermore, as demonstrated later in Section 4.4.5, SMUD's analysis shows that dynamic pricing tends to produce more volatile bills, and this has the potential to adversely impact customers with less flexible load. For example, customers with medical devices tend to be more price inelastic due to their need to maintain health and safety. The ability of customers like these to respond to dynamic rates would be particularly limited. However, the ability to quickly shift load away from high price periods will affect whether participating customers can directly benefit from a dynamic rate. As market signals would be dynamic with potentially very large changes in prices between hours, customers that cannot or do not adopt and/or utilize and embrace enabling technology could see very large bill impacts.

Figure 45 Very Small Users (≤125-amp panels) Load Shape vs All

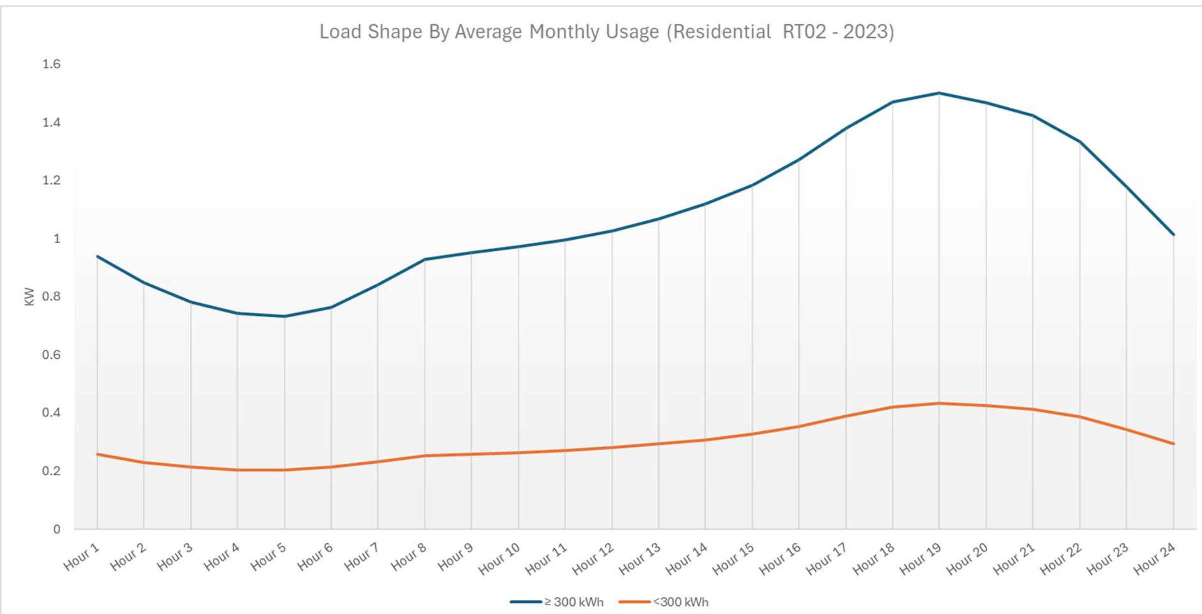


Figure 45, above, shows a comparison of residential load shape based on customer consumption. Customers with consumption of less than 300 kWh-month and up to 125 Amp panels size represent about 13% of SMUD customers. SMUD's analysis shows that these customers have a different, flatter load shape compared to average customers. This low usage and flatter load shape would suggest that these customers would have less ability to modify their load in response to dynamic prices. Nevertheless, these customers would be subject to the rate increase necessary to pay for dynamic pricing. Thus, it is reasonable to assume that these customers would be the least likely to realize any direct benefit from dynamic prices.

In sum, SMUD expects that low-income customers and customers in under resourced communities may face obstacles to participating in and realizing any potential benefits from a dynamic rate. These customers have less access to enabling technologies, in the case of low usage customers typically have flatter load shapes as shown in Figure 45 and may have other structural barriers that prevent utilization of dynamic rates. Like all customers, these customers would still be exposed to any increased rates needed to cover the upfront costs of developing and implementing dynamic rates, regardless of whether they choose to enroll on such rates. While this analysis does not suggest that dynamic rates are inequitable, it does suggest that there may be additional measures necessary to address potential inequities.

4.4.4 Technological Feasibility

The third evaluation factor for dynamic rates is technological feasibility. SMUD considered both SMUD's technology systems and customer enabling technology, and concludes that it is technically feasible to design, implement, and offer a dynamic rate. However, as shown below, there are several technological hurdles that would prevent SMUD from implementing dynamic rates or programs on the timeline set forth in the LMS regulations.[44] These timing challenges are compounded by SMUD's rate development process – requiring necessary pilots, testing, customer education, and iteration, as described in Section 4.1 (SMUD's Rate Development Process) and 4.2.1.1 (Residential TOD Rates).

4.4.4.1 Current Technology Enhancements

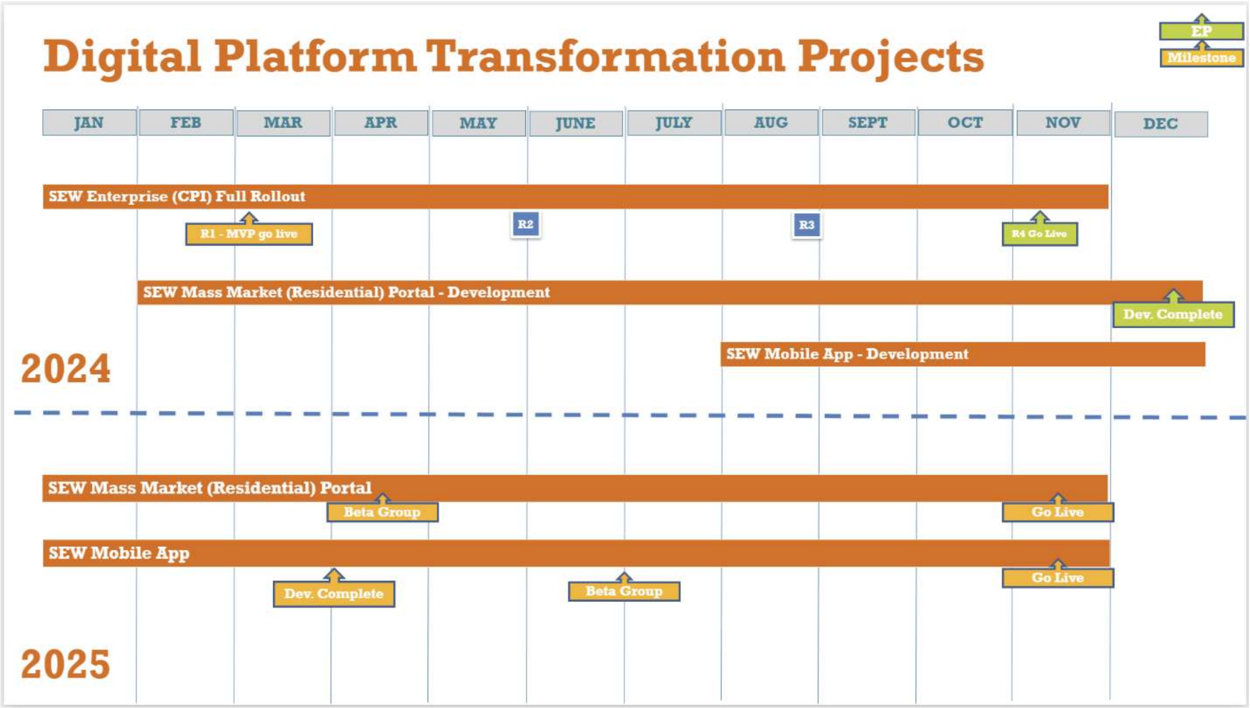
SMUD's Information Technology (IT) business unit currently has 112 IT projects in progress, or planned, through the end of 2027. Included here are several examples of substantial projects that SMUD is implementing, and further data on these projects and timelines can be found in Appendix B.

Customer Digital Platform Transformation

SMUD is currently implementing its new digital platform transformation planned for 2024-2026, which was planned ahead of the implementation schedule shown below. The Digital Platform Transformation is being deployed through a third-party vendor in coordination with SMUD. This is a major project at SMUD which includes transitioning all customers to a completely new platform for My Account, the app and brand-new related tools. Not only is this a significant level of effort from a technology perspective to implement the platform, transition accounts, employee training, customer education and outreach. SMUD expects that the new commercial portal will be available to all commercial customers who use SMUD's "My Account" application by the first quarter of 2025. SMUD is also transitioning residential customers to the new platform, which will occur in 2025, as well as developing a new mobile application for customers. Figure 46, below, shows the expected timeline for deploying these transitions.

[44] See Section 1623.1(b)(3) and (4) (requiring approval of dynamic rate by April 2025 and offering rates or programs by April 2026).

Figure 46 Digital Platform Transformation Project Timeline



Enterprise Business Application

SMUD is updating its enterprise business application SAP to S/4HANA, which is SMUD's main billing engine. Planning work is happening now, with target implementation through mid-2028 as shown in the timeline below. Figure 47 shows SMUD's timeline for implementing the S/4HANA upgrade, which runs through 2028. Like the IT project described earlier, this a major project across SMUD which will impact all business units. It includes major upgrades from the current SAP application and this a significant level of effort and commitment of resources from a technology perspective to implement such upgrade over the next couple of years, plus the associated testing, employee training, and education. SMUD expects to complete the update after 2028, and once the update is complete, SMUD will consider incorporating dynamic rates into a future roadmap.

Figure 47 S/4HANA Upgrade Plan and Timeline

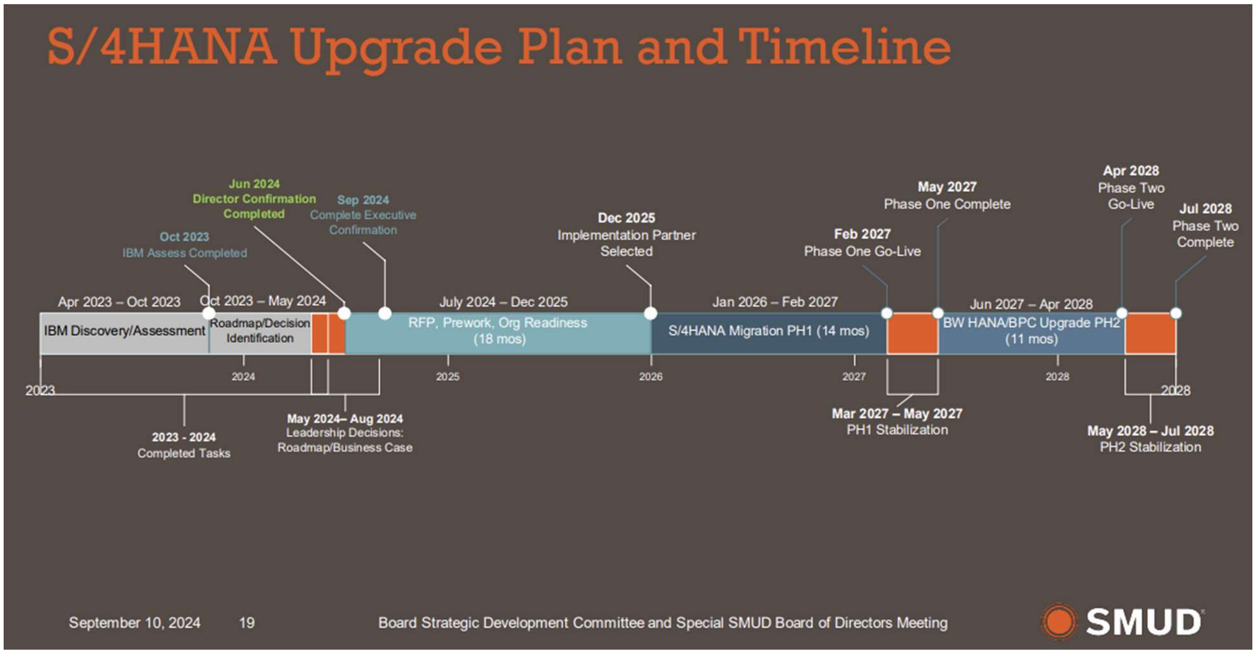
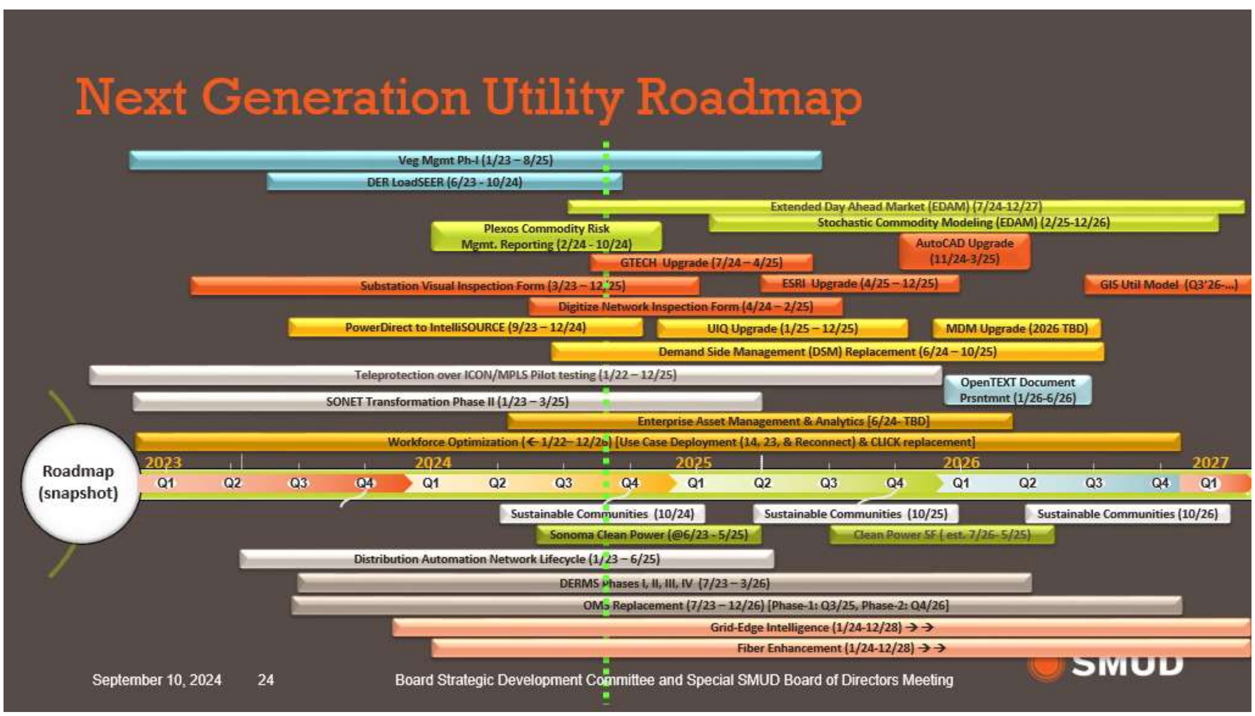


Figure 48 below shows SMUD's Next Generation Utility Roadmap, which illustrates the range of IT projects needed in the next three years. As shown in the timeline, there are several technology upgrades needed through 2027-28 beyond those noted above.

Figure 48 Next Generation Utility Roadmap



Deployment of 200,000 Itron RIVA Meters

SMUD is deploying 200,000 Itron RIVA computing sensors with measurement capabilities (meters) to enable transformer situational awareness, photovoltaic management, electric vehicle management, locational awareness, and non-supervisory control and data acquisition (SCADA) substation management. These meters will allow implementation of 5-minute interval data for commercial and residential customers, increased from current 15-minute data for commercial customers and 1-hour data for residential. This project is planned for 2025 and 2026.

Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS)

A key component of SMUD's Zero Carbon Plan is the electrification of buildings and transportation. These segments are critical to reducing regional and statewide carbon emissions. Growth in these segments is expected to result in significant investments on the distribution system, creating opportunities for local load flexibility to reduce these costs. At the same time, managing a combination of local constraints and bulk system services also introduce significant complexities with integrating Distributed Energy Resources (DERs).

In 2022, after years of planning, SMUD deployed its Advanced Distribution Management System (ADMS) and initial phase of its Distributed Energy Resource Management System (DERMS) platform technology. With these two systems online and working together, SMUD will shift from a one-way centralized distribution system to a two-way decentralized distribution system that allows SMUD to manage and optimize distributed energy resources that include battery storage, demand response programs, smart thermostats, connected appliances, electric vehicles (EVs) and more.

SMUD is currently building out DERMS functionality and continuing to evaluate device partners and aggregators that can integrate product offerings into DERMS. In the next few years, SMUD anticipates that its DERMS system will enable full DER integration across bulk and distribution system value streams. These include, but are not limited to, advanced distribution system management applications, scheduling DERs based on economic and reliability considerations, scheduling DER Virtual Power Plants (VPPs) into electricity markets, and integrating with aggregator platforms that allow customers to participate in programs that control and leverage behind-the-meter DERs to respond to grid needs.

As illustrated above, SMUD is in the process of deploying a variety of IT upgrades through 2025-2028. For many of these projects, the timeline and sequence of these projects was planned several years in advance and cannot be adjusted without significant disruption to SMUD's operations. These efforts are aligned with SMUD's Zero Carbon Plan, and diverting focus at this time to incorporate a dynamic rate would compromise the ability to achieve these existing goals. It is expected that these projects would prevent SMUD from implementing the necessary technology for several years and SMUD's ability to adopt and implement new technologies will be re-evaluated in SMUD's next Compliance Plan.

4.4.4.2 SMUD's Technology Systems

This section evaluates the major technologies needed to provide customers with a dynamic rate or programs. It is understood that there is technology available to implement a dynamic rate or program, however, SMUD's billing system is currently being upgraded and would need to be further upgraded following the current technology improvements to offer dynamic rates. Additionally, SMUD would need to develop additional customer facing tools to educate and provide information to customers.

- *Meters*. SMUD's meters can provide hourly and sub-hourly interval data for all its customers, except the unmetered loads. Currently, load interval data is tracked every fifteen minutes for all non-residential customers and hourly for residential and are currently re-programming all meters to read every five minutes. The roll out of the 200,000 new meters will start in Q1 2025 and is expected to be complete in 2026. Further, the new AMI 2.0 meters will enable transformer situational awareness, solar photovoltaic management, electric vehicle charging management, and locational awareness.

- *Billing system.* SMUD uses SAP to perform its billing processing. SMUD is licensed to use SAP's Energy Data Management (EDM) module, but it is not currently required or used for the TOD billing process. SMUD's meter data management system, Itron Enterprise Edition (IEE), handles the collection of interval load data from the meters.

  Implementation of more dynamic hourly or sub-hourly rates would require system integration work to allow IEE to transfer hourly or sub-hourly data to EDM for proper billing in SAP. Currently, billing under Time-of-Day (TOD) uses monthly billing determinants bucketed into the proper TOD time periods for summer or non-summer billing. The bucketed billing determinants are generated in IEE and transferred to SAP on request ahead of billing processing.

  To bill customers on hourly or sub-hourly basis, such billing determinants would need to be transferred from IEE to EDM. That process does not exist today. Additionally, given the relatively small number of records being created with the current TOD billing structure, dynamic rates would require more storage capacity to save such records within the EDM module of the billing systems. Implementation of dynamic rates would also require completely new integration with an external system to enable determination of real-time prices that will be used within SAP when billing each time increment.

  For illustration, a customer under summer residential TOD prices sees three TOD energy billing determinants and associated prices by period. Under more complex dynamic rates, customers would see an average of 730 prices per month and corresponding billing determinants, which adds complexity, bill presentment challenges, and need for more data storage.

  Monthly billing for dynamic rates would require a different process, and a combination of new paper-based bill presentment and paperless features to communicate details on hourly or sub-hourly billing. All those new billing processes and system upgrades would need to be coordinated, added, and prioritized with the already crowded list of technology projects included in the IT Roadmap. See further discussion of the IT Roadmap above.

4.4.4.3 Customer Educational Tools and Control

The roll out of dynamic rates would require new customer tools to support a positive customer experience. Based on the experience with TOD before, during, and after the roll out, education and tools to assist customers management of their bills would be important if hourly or sub-hourly pricing were to be implemented as an optional rate for all customer classes. Regardless of adoption level, SMUD would need to educate the entire population since all could potentially enroll on the optional rate. Staff estimates that the initial marketing and educational campaign would be equivalent to the level of effort SMUD experienced with TOD in the first year, and then ongoing education would be lower in the subsequent years to maintain the overall messaging and send reminders with season changes. SMUD also expect that given the nature of more complex hourly or sub-hourly pricing will involve more calls to SMUD's contact center and it may be more difficult to explain the new dynamic rates, new bills, and volatility of bills as customers experience dynamic pricing.

4.4.4.4 Enabling Customer Technology

Realizing the potential incremental benefits of dynamic rates depends on customer participation and the widespread availability of devices and technology that can support real time response to hourly or sub-hourly price signals. Currently, some of this technology has already been widely deployed, like smart thermostats, while some is being piloted and evaluated by SMUD through its programs. SMUD tested these technologies and considered customer response and long-term commitment to their response under these programs. The results of the MEO program informed how SMUD can best utilize such technology to support customer adoption, how such technologies could be scaled, and whether such load modification can provide predictable resource adequacy benefits and respond during electric system emergencies.

SMUD provides the following list of common load flexibility technologies in SMUD's service area and discussion of their capability and constraints. SMUD anticipates these same technologies participating in its current programs would be needed to respond to new dynamic rates.

- *Smart thermostats.* Wi-fi enabled smart thermostats are currently by far the most widely adopted load flexibility technology. These devices can receive and respond to dispatch signals within 15-30 minutes; however, doing so could end up sacrificing customer comfort, as market price signals may not allow time for the home to precool. SMUD currently relies on day-ahead real time marginal costs and system conditions to inform the dispatch of resources in its load flexibility programs which allows SMUD time to send the appropriate messaging and customers time to respond to signals.
- *Battery energy storage systems.* Battery energy storage systems are being adopted with increasing frequency by both residential and non-residential customers, particularly as an add-on to solar photovoltaic installations. Batteries have much greater ability to be dispatched on short notice, and SMUD views these as critical to creating load flexibility resources to reach its Zero Carbon Plan. SMUD is proactively seeking to accelerate this adoption and reduce the payback period for solar and storage deployments by offering initial incentives of up $5,000 per premises coupled with ongoing capacity payments. These incentives are designed to promote storage adoption and allow utility dispatch to leverage the storage resource. However, the current adoption rates are relatively low, with just about 1,400 batteries deployed so far, and it will likely be years before storage is affordable for a majority of SMUD customers. By 2030, 30,000

residential battery systems are projected have been adopted, or about 1 in 20 residential customers.

- *Two-way air conditioning (AC) switches.* SMUD's PeakCorps program is discussed above in Section 4.3.1.1.1.3, above. New two-way switches are being installed as part of PeakConserve, discussed in more detail in Section 4.3.1.1.1.4, above. SMUD is also increasing accessibility by providing participation options for customers that have barriers such as lack of internet access. This program is in the pilot stage currently, but these new switches are expected to open new functionality relative to the older technologies.
- *Electric Vehicles (EVs)*. EVs are an emerging source of load flexibility across SMUD's system, and the rate of customer adoption is increasing. There is significant potential for further growth given statewide goals for zero emissions vehicles by 2030. SMUD's goal is to enable 288,000 light duty EVs on the road by 2030, or roughly one in every 4 vehicles, Multiple studies over the years have indicated that managing this load will be critical to avoiding significant overloading of infrastructure, in particular, local transformers. SMUD recently launched a pilot to test the efficacy of sending hourly price signals to participating EVs via telematics and compensating the customer through a quarterly payment, as discussed above in Section 4.3.1.1.1.5. The lessons from this pilot will inform how SMUD rolls out a full-scale managed charging program in 2025-2026. SMUD hopes to demonstrate and refine use cases such as to mitigate overload of service transformers, consume excess low-cost renewable energy, and reduce system peak impact.

4.4.4.5 Discussion

Based on the information currently available, SMUD believes it is technologically feasible to implement dynamic rates over a long-time horizon. SMUD anticipates that its internal systems, with the necessary infrastructure deployments and system configuration implementations, are technically capable of processing settlements for dynamic hourly or sub-hourly rate data, but additional time to develop and enhance the billing experience, develop customer tools, educate employees and customers, and enhancing SMUD's DER functionality and control is necessary. Additionally, SMUD anticipates that the penetration of enabling device automation technology will increase with time and decrease device costs, expanding the potential for load shift benefits.

While technologically feasible to implement dynamic rates or programs, SMUD cannot implement a dynamic rate and offer it to customers by April 2026, as required by the LMS regulations. As discussed above, SMUD's existing IT project timelines will preclude implementing structural billing and other changes through 2027-2028. Changing that timeline would be costly and disruptive since it would divert committed resources and displace upgrades needed for achieving SMUD's Zero Carbon Plan. Furthermore, SMUD's rate process is a years-long effort, and implementing TOD rates from initial studies to full roll-out took approximately 7 years. SMUD expects that implementing dynamic rates, with added complexity, would take at least this long to develop, test, and implement. Thus, any technical upgrades needed for dynamic rates or programs would need to occur as part of this comprehensive project, rather than as a standalone rate or program.

4.4.5 Benefits to the Grid and Customers

The following is a summary of estimated grid and customer benefits associated with implementation of new dynamic rates on the timeline specified in the LMS regulations. While there will be customer benefits, but customers will also be exposed to significant bill volatility that may undermine such benefits.

As part of the cost-benefit analysis in Section 4.4.2, SMUD estimated energy and generation capacity benefits in the form of avoided cost, which are the significant benefits that can be attributable to hourly rates. The analysis included estimated grid benefits from hypothetical avoided transmission and distribution infrastructure (T&D).

For transmission, sub-transmission at 69 kV and distribution capacity below 69 kV costs, a probability-of-peak factor is applied to distribute capacity values on an hourly basis and calculate a load-weighted average value using load reduction behavior observed in the CPP events from 2023-2024. For the nonresidential scenarios, the probability-of-peak factor was applied to hourly load reduction targets for the AutoDR program during 2024 event periods to calculate a load-weighted average value. From these average values, a per kW capacity benefit for residential and nonresidential offerings is estimated, which is also applied to RTP. The estimated grid benefits from hypothetical avoided T&D represents $1.4-$2.6 per kW-year. However, the financial benefit was incorporated in the costs benefits analysis.

Figure 49 Analysis of Potential Grid Benefits ($/kW)

T&D Capacity Values ($/kW)	Residential MEO Only	Residential MEO with CPP	Non-Residential AutoDR
Transmission	$ 0.1	$ 0.1	$ 0.2
Subtransmission	$ 0.6	$ 0.6	$ 1.2
Distribution	$ 0.7	$ 0.6	$ 1.2
T&D Capacity Value per kW	**$ 1.5**	**$ 1.4**	**$ 2.6**

Figure 50 Estimated Financial Value of the Grid Benefits by Scenario ($/kW)

Residential T&D Capacity Value by Rate	MEO Smart Thermostat Only	MEO Smart Thermostat with CPP	RTP - Hypothetical	RTP - Hypothetical at 10k Participation
Participation Count	30,000	4,840	3,025	10,000
Average Load Shift Per Customer (%)	22%	31%	38%	38%
Average Load Shift Per Customer (kW)	0.7	1.0	1.2	1.2
Average Overall kW Shift per Summer	20,175	4,659	3,623	11,976
Levelized T&D Grid Benefits ($/kW)	$ 1.5	$ 1.4	$ 1.4	$ 1.4
Total Capacity & Grid Value*	$ 29,760	$ 6,403	$ 4,980	$ 16,462

Figure 51 Estimated Financial Value of the Grid Benefits by Scenario Incremental Load ($/kW)

NonResidential	2MW Incremental Program		13.5MW Incremental Program	
T&D Capacity Value by Rate	SMUD Incremental AutoDR	RTP - Hypothetical Incremental	SMUD Incremental AutoDR	RTP - Hypothetical Incremental
Participation Count	3	3	20	20
Average Performance	80%	40%	80%	40%
Total Capacity Available (kW)	2,006.0	2,006.0	13,500.0	13,500.0
Capacity at Average Performance (kW)	1,613	802	10,853	5,400
Levelized T&D Grid Benefits ($/kW)	$ 2.6	$ 2.6	$ 2.6	$ 2.6
Total Capacity & Grid Value*	$ 4,252	$ 2,116	$ 28,615	$ 14,238

When applied to expected load reduction by rate the residential analysis finds that grid benefits with CPP are slightly higher than RTP due to its higher expected participation rate. The nonresidential analysis indicates that grid benefits are greater under the AutoDR program compared to a hypothetical RTP offering, due to higher load reduction performance per kW enrolled.

Customer experience. As described previously, SMUD staff balances multiple SD-2 objectives when designing rates, including "reflect the cost of energy when it is used" with "be as simple and easy to understand as possible" and "minimize the rate of change in the transition from one rate design to another". While dynamic rates would reflect the cost of energy at the time it is used, they would also be very complex and difficult for customers to understand, as customers are not experts in energy market dynamics. The likely result of this complexity is confusion and potential negative bill impacts, particularly if there is also insufficient time for SMUD to fully educate customers on the potential benefits and risks of marginal cost-based rates. This, in turn, adversely impacts acceptance, retention, and benefits associated with the rate, and the erosion of trust can hinder future load shift efforts as well.

Customer bill impacts. With dynamic rates, customers have the potential to save money by shifting their usage out of the most expensive hours. However, there are risks to dynamic rates, even if customers can largely rely on device automation to manage their demand. Participating customers in a dynamic rate run the risk of bill shocks if they are unable to shift load away from high price hours. SMUD anticipates that lower income customers and small businesses, who face greater barriers in implementing enabling technology, would be most exposed and least able to absorb potential bill shocks. As explained in prior sections, adoption of technology is driven by income, so only those customers that can afford technology are likely to be part of the potential target population and this would cause a cost shift from participants to non-participants.

Furthermore, the Ameren Illinois experience in 2021 and 2022 illustrates that dynamic rates can result in a majority of customers paying more for electricity compared to a flat rate and suggests that customers may not be able to adjust behavior to avoid higher costs.[45] Ameren customers on the dynamic rate paid 10.9% more in 2021 and 17.64% more in 2022 for electricity than fixed rate customers.

The chart below shows illustrative bill impacts of switching from TOD with CPP to RTP for the 39 CPP customers that stayed on the CPP rate from 2022 through 2024. Customers use energy differently by period, so they would all experience different bill impacts. Figure 52 shows the variations in bill impacts, ranging from average to high bill impacts. As shown, because of the significant market fluctuations, customers would have experienced a large bill increase in the winter of 2022 if they had been on RTP rates, some quite significantly. The energy prices were consistently high during that period, so customers would not have been able to shift their load sufficiently to prevent higher bills.

[45] See Section 4.4.1.

Figure 52 Bill Impact Variation from Dynamic Pricing (RTP)

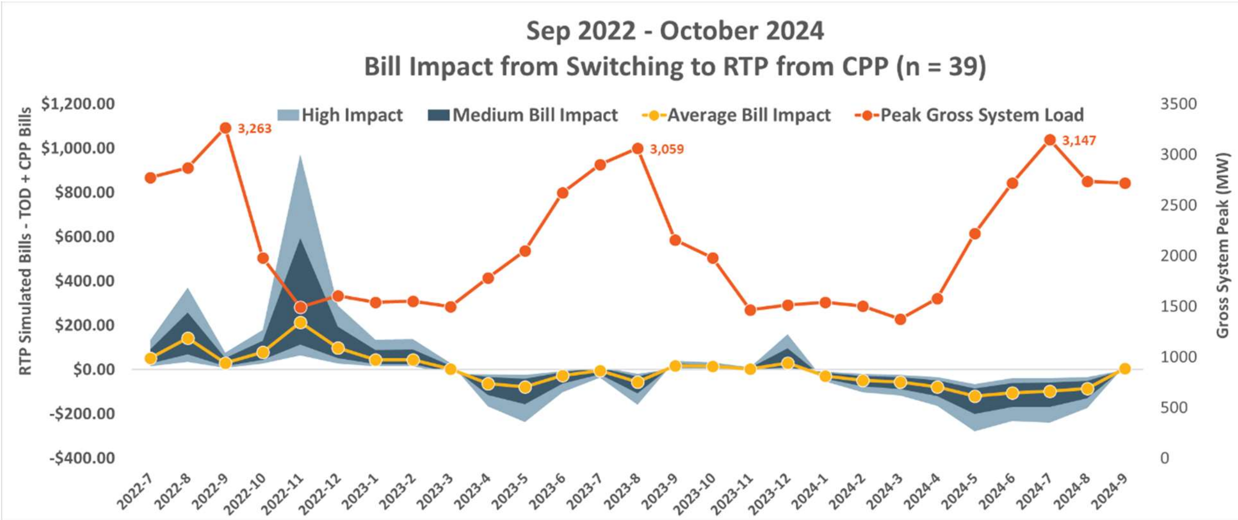
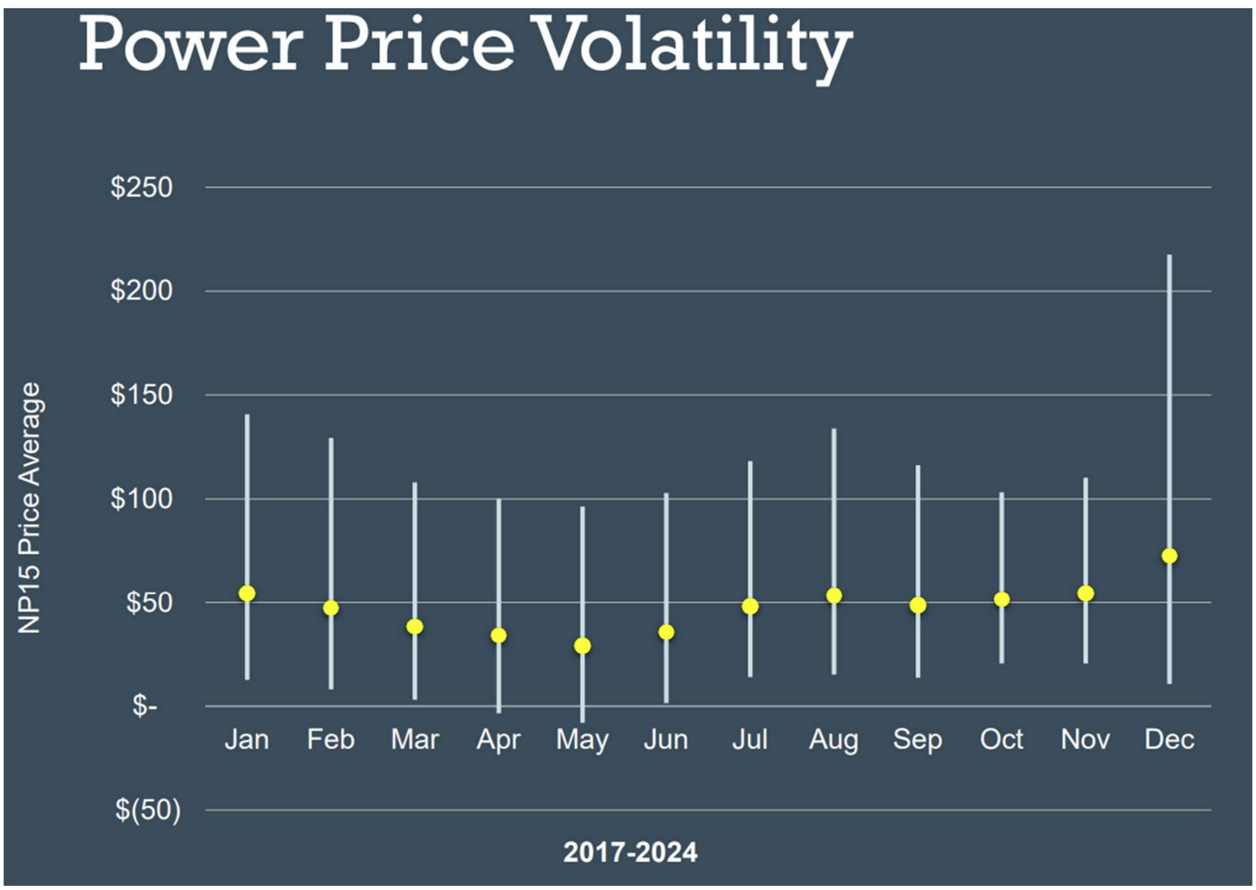


Figure 53 Historical 2017-24 Power Market Price Volatility (NP15)



The chart above shows a band of price volatility in $/MWh observed at the North Path 15 (NP15) node in Northern California. The length of the vertical lines represents the low and high range of market prices by month. The graph represents an average in the yellow dots of those prices by year to simplify the significant hourly data from 2017-24. SMUD hedged its commodity budget to mitigate such price volatility and provide customers with predictable bills. Under a hypothetical dynamic hourly or sub-hourly rate based on market prices, customer would be exposed to such volatility. They could observe low bills during certain times or months, and high bills at other times. As covered in Section 4.4.1, SMUD's review of Ameren's experience with hourly rates suggest significant bill volatility is possible and provides a reason for caution on the impact of bill volatility.

4.4.6 Discussion

As required by Section 1623.1(a)(1)(A) and (B), SMUD considered each of the factors listed as they relate to rates and programs. In the sections above, the analysis for cost-effectiveness is combined, because experience and estimates show that the same costs would be required to develop either a rate or program with a dynamic price signal. The data indicates that SMUD will incur a net annualized loss of $2.4 to $3.7 million from offering dynamic hourly pricing. Comparing a dynamic rate or program to SMUD's existing load flexibility rates and programs highlights that developing new, complex dynamic rates and programs would not be prudent investments for SMUD at this time.

SMUD's equity analysis shows that its lower income customers are less likely to access enabling technologies, low usage customer have flatter load shapes which may make it more difficult to see benefits from dynamic rates, and customers that did enroll on hourly prices may be exposed to substantial bill volatility. Moreover, these customers would still share in the cost of developing the rate or program. As such there is high potential that dynamic rates would not provide a net benefit to these customers and would cause an unintended cost shift.

SMUD believes that it is technologically feasible to implement a dynamic rate or program, and SMUD is building the capability to use sub-hourly signals through its ADMS and DERMS platforms. However, achieving such implementation on the LMS regulations timeline would require diverting committed resources from current IT upgrades necessary for SMUD to reach its 2030 Zero Carbon Plan goals. Such resource commitment would be necessary to develop and integrate the new infrastructure needed for managing, billing and reporting dynamic rates or programs. SMUD is committed to continuing to analyze the value of dynamic rates and programs and further considering the adoption of a rate or program during the next compliance plan cycle.

Similar to the findings resulting from the cost-effectiveness analysis above, SMUD expects only modest, if any, positive benefits on the grid from dynamic rates or programs, particularly in comparison to its existing rates and programs. Further, the data indicates that while there may be some benefits to customers with enabling technology, there are also risks of significant price volatility and high bill impacts for customers.

Based on the foregoing analysis, this Revised Plan concludes that development of a dynamic rate will not be cost-effective or achievable on the timeline required by the regulations. It further concludes that developing a program with a dynamic price signal will not be cost-effective or achievable, for the same reasons.

The following subsections explain why developing a dynamic rate or program should be delayed and reconsidered during the next LMS compliance plan cycle. Until then, SMUD's modified compliance approach involves continuing to offer its current load flexibility rates and programs that are meeting the LMS goals and functionally equivalent to a dynamic rate or program.

4.4.6.1 SMUD Rates and Programs Achieve LMS goals

The LMS has several goals, including (1) encouraging the use of electrical energy at off-peak hours, (2) encouraging the control of daily and seasonal peak loads to improve electric system equity, efficiency, and reliability, (3) lessening or delaying the need for new electrical capacity, (4) reducing fossil fuel consumption and greenhouse gas emissions, with the ultimate goal of lowering the long-term economic and environmental costs of meeting the State's electricity needs.[46] While SMUD's rates and programs do not provide dynamic hourly price signals, they nevertheless meet these goals and are functionally equivalent to the dynamic rates and programs directed by the LMS regulations. In particular, SMUD's various load flexibility programs send control signals based on when Energy Trading most needs these limited resources, ensuring that they can displace the greatest amount of gas-fired generation and associated capacity. As SMUD looks toward a future with increasing electrification, balancing local capacity through Distribution System Operator dispatched control signals will be critical to balancing local capacity needs without over-building the distribution system and driving up overall customer rates.

The following is an overview of the load modification benefits of SMUD's current rates and programs.

- In Section 4.2.1.1 above, SMUD's TOD rates are discussed. These rates are estimated to provide peak load reduction of 75-130 MW (4-8%) compared to a fixed rate, avoided GHG emissions of 12,000 tonnes, and approximately $11 million to $16 million in commodity cost savings.
- In Section 4.3.2, SMUD provides evaluation of several of its existing programs. By 2030, SMUD projects that its load flexibility programs will provide 473 MW of peak load reduction.
- In Section 4.4.1, the findings of Dr. Faruqui's study shows that SMUD's current TOD with MEO plus CPP rates with enabling technology would provide approximately 84% of the load reduction expected from an hourly price with a 10:1 ratio, and 71% of an hourly price with a 15:1 ratio, as shown in Figure 30. Further, the performance of SMUD's TOD/MEO and CPP in 2023 delivered 13% higher than the modeled peak reduction, which would provide 95% of the hourly load reduction expected from the 10:1 price, and 80% of the 15:1 ratio.

SMUD's current rates and programs are achieving the goals of encouraging off-peak energy usage, controlling peak loads, avoiding costs for capacity and transmission and distribution upgrades, reducing reliance on fossil fuels and doing so in a cost-effective manner. Achieving these goals is central to SMUD's purpose and its 2030 Zero Carbon Plan, and it is why SMUD has been actively developing and testing time-dependent programs and rates since well before the LMS regulations were adopted.

4.4.6.2 No Material Reduction in Peak Load

Separate from the analysis in Section 4.4, SMUD also assessed whether any dynamic rates or programs with dynamic prices would be expected to materially reduce peak load.[47] Based on a review of the currently available data,[48] there is evidence suggesting that there is a theoretical reduction in peak load

[46] Section 1621(a).
[47] See 1623.1(b)(2)(A) and (3)(A).
[48] Section 4.4.1.

from dynamic prices. For purposes of this analysis, SMUD defines a material reduction in peak load as delivering 20-25 MW of load reduction.[49] Most of the programs SMUD launches aim to deliver at least this level at full scale, and programs with less peak load reduction would require significant effort from SMUD's energy traders and minimal program benefit.

In Section 4.4.2, SMUD estimated customer participation and expected load reduction. The analysis shows that customers with a smart thermostat enrolled in a dynamic rate or program would be expected to provide about 3.6 to 12 MW of peak load reduction depending on level of enrollment and compared to SMUD's existing rates and load flexibility programs an incremental peak load reduction of 1.6 MW to 5.3 MW. Further, customers with battery storage enrolled in such dynamic rate or program would provide about 7.5 MW of load reduction or result in a deficit in incremental peak reduction of 67.5 MW because SMUD's Virtual Power Plant is expected to have higher enrollment and consequently higher load reduction than a dynamic rate. Nonresidential customers enrolled in a rate or program offering dynamic rates similar to SMUD's Auto DR program would be expected to provide 0.8 MW to 5.4 MW of load reduction or result in a deficit of incremental peak reduction of 0.8 MW to 5.5 MW.

Since each of these hypothetical rates or programs will not reach 20 MW, these rates or program would not result in a material reduction in peak load. Furthermore, SMUD would consider the incremental peak load reduction when it makes investment determinations, and the incremental peak load reduction is even further from this threshold. Therefore, consistent with Section 1623.1(b)(2)(A), SMUD does not propose adopting a dynamic rate, and consistent with Section 1623.1 (b)(3)(A), SMUD does not propose adopting a program with dynamic signals. When SMUD performs the analysis for the next iteration of its compliance plan, SMUD will again consider whether these rates or programs result in a material peak load reduction.

4.4.6.3 Delay or Modification of LMS Compliance is Justified

Section 1623.1(a)(2) provides a POU's board with the authority to delay or modify the adoption of a dynamic rate or program with dynamic price signals if the board determines the plan meet any of the listed conditions.

4.4.6.3.1 Extreme Hardship

Section 1623.1(a)(2)(A) states the that a POU board may delay or modify compliance if it determines:

> (A) that despite a Large POU's or Large CCA's good faith efforts to comply, requiring timely compliance with the requirements of this article would result in extreme hardship to the Large POU or the Large CCA

As discussed above in Sections 4.4.4, requiring SMUD to implement a dynamic rate or program at this time would divert resources that SMUD has committed toward its 2030 Zero Carbon Plan. This includes SMUD's current IT roadmap, as well as staff focus on current load flexibility programs that are helping to achieve GHG reduction goals. Forcing SMUD to refocus its effort on dynamic rates and programs, rather than on rates and programs that fit the needs of its customer and furthers its goals, creates a substantial

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[49] SMUD uses this estimate of material peak load reduction for purposes of assessing this factor at this time in this Revised Plan, but this threshold is subject to future refinement or revision.

and unreasonable hardship. This is particularly true where SMUD's existing rates and programs are providing considerable, and in some cases more, load modification than a dynamic rate or program is estimated to provide.

4.4.6.3.2 Reduced System Reliability or Efficiency

Section 1623.1(a)(2)(B) states that a POU board may delay or modify compliance if it determines that:

> (B) requiring timely compliance with the requirements of this article would result in reduced system reliability (e.g., equity or safety) or efficiency

SMUD does not believe that requiring adoption of dynamic rates or programs would compromise safety. As discussed in Section 4.4.3, SMUD is concerned that hourly rates would impose costs on lower income customers, while such customers may not have equal access to any potential benefits, among other concerns. Further, requiring compliance at this time would reduce system efficiency by forcing SMUD to offer dynamic rates and programs in place of SMUD's current rates and programs. In Section 4.4.2, SMUD's analysis showed that SMUD's current offerings provide net benefits, particularly in comparison to dynamic rates which showed net annualized costs under each evaluation scenario.

4.4.6.3.3 Technological Feasibility or Cost-Effectiveness

Section 1623.1(a)(2)(C) provides that a POU board may delay or modify compliance if it determines that:

> (C) requiring timely compliance with the requirements of this article would not be technologically feasible or cost-effective for the Large POU to implement, or

In Section 4.4.2, SMUD shows that implementing a dynamic hourly pricing is not cost-effective under any of the scenarios analyzed. SMUD considered the benefits of offering dynamic prices to both residential and nonresidential customers and SMUD's analysis showed that under each evaluation scenario dynamic hourly prices would result in net annualized costs to SMUD and its customers. Since SMUD's current rates and programs functionally achieve the same goals, these remain more cost-effective to implement. This justifies delaying consideration of dynamic rates and programs until the next compliance plan cycle and modifying SMUD's LMS compliance approach to focus on continuing and expanding current rates and program offerings.

In Section 4.4.4., SMUD's analysis shows that implementing a dynamic rate or program with dynamic prices is technologically feasible but cannot be accomplished on the timeline provided by the LMS regulations. The LMS regulations require POUs to apply to their board's for approval of dynamic rates by April 1, 2025 and offer a dynamic rate or program by April 1, 2026.[50] As described above, SMUD's process for developing and implementing the TOD rate required approximately 7 years from the pilot phase to the implementation of rates, with substantial customer education and outreach throughout that process. While not every utility may follow the same processes, SMUD's iterative approach to rate development, particularly for novel, complex rates, has proven to be effective and necessary for success. Furthermore, SMUD is currently implementing a range of IT upgrades that would preclude implementing the necessary IT infrastructure for dynamic rates and programs at this time. Thus, while developing and

[50] See Section 1623.1(b)(3) and (4).

implementing a dynamic rate is technologically possible, it is not feasible to do so on the timeline required by the regulations.

4.4.6.3.4 More Technologically Feasible, Equitable, Safe or Cost-Effective Way to Achieve the Requirements or the Plan's Goals

Section 1623.1(a)(2)(D) provides that a POU board may delay or modify compliance if it determines:

> (D) that despite the Large POU's or the Large CCA's good faith efforts to implement its load management standard plan, the plan must be modified to provide a more technologically feasible, equitable, safe or cost-effective way to achieve the requirements of this article or the plan's goals.

As discussed in the foregoing sections, SMUD must delay consideration of dynamic prices to the next LMS compliance plan cycle. Further, SMUD must modify the timeline for compliance to provide a more technologically achievable and cost-effective method of achieving the LMS goals. This can be achieved through continuing and expanding SMUD's current functionally equivalent, load-modifying rates and programs.

4.4.6.4 Summary

This Revised Plan demonstrates implementing dynamic prices must be delayed for SMUD. Implementing such rates or programs is not cost-effective, not technologically feasible on the timeline provided by the LMS, and SMUD can achieve the LMS goals through existing rates and programs. SMUD will continue to analyze and evaluate new information about the effectiveness of dynamic rates and programs, and SMUD will engage in further assessment of dynamic rates and programs in SMUD's next LMS Compliance Plan.

5 Compliance

5.1 Fulfilled LMS Compliance Requirements

The following sections summarize how SMUD has implemented the LMS requirements to date, consistent with its Original LMS Compliance Plan.

5.1.1 LMS Compliance Plan

The LMS regulations require Large POUs to develop and submit plans to comply with the LMS.[51] SMUD submitted its Original Plan to its Board on September 29, 2023. At its duly noticed public meeting on November 16, 2023, SMUD's Board adopted the Plan pursuant to Resolution No. 23-11-04. The adopted Plan was submitted to the CEC for review on November 30, 2023. On September 19, 2024, SMUD received a notice from the Executive Director requesting additional information be incorporated into the Plan. This Revised Plan timely responds to CEC request for additional information and/or recommendations.

As set forth above, the Revised Plan describes how SMUD meets the LMS goals of encouraging the use of electrical energy at off-peak hours, encouraging the control of daily and seasonal peak loads, lessening the need for new capacity, and reducing fossil fuel consumption and GHGs. The Plan evaluates the cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of marginal cost-based rates and programs that enable automated response to marginal cost signals. It also demonstrates that requiring implementation of such rates or programs for all customer classes on the time frames set out in the LMS would result in extreme hardship to SMUD and its customers, would not be technologically feasible or cost-effective, and that SMUD's good faith efforts to maintain rates and programs that are functionally equivalent to dynamic pricing and which successfully achieve reductions in peak loads, provide a more technologically feasible, equitable, safe or cost-effective way to achieve the requirements of this article or the plan's goals.

5.1.2 Upload of Existing Time-Dependent Rates to the MIDAS Database

The LMS regulations require Large POUs to upload existing time-dependent rates to the MIDAS database.[52] SMUD uploaded its existing time-dependent rates to the MIDAS database on June 30, 2023, including 75 rate permutations with time-dependent cost components.

5.1.3 Provide Customers Access to Rate Identification Numbers

The LMS regulations require Large POUs to provide customers with access to their Rate Identification Numbers (RINs) on customer billing statements and online accounts using both text and quick response (QR) codes by April 1, 2024.[53] SMUD provided its customers access to their Rate Identification Numbers

[51] Section 1623.1(a).
[52] Section 1623.1(c).
[53] Section 1623(c)(4).

(RINs) on billing statements and in online accounts using both text and quick response codes beginning March 27, 2024.

5.1.4 Submission of Joint Utility Single Statewide Tool

The LMS regulations require the LMS regulated utilities to develop a single statewide standard tool, submit the tool to the Commission for approval, and implement and maintain the tool.[54] SMUD has been working with the other regulated entities on creating the statewide RIN tool pursuant to 20 CCR Section 1623(c). A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. SMUD will continue to work with the other regulated entities and the CEC to implement and maintain the statewide RIN tool in a timely manner subject to the tool's approval by the Commission.

5.1.5 Submission of Cost-Effective Load Flexibility Programs

The LMS regulations require Large POUs to submit a list of load flexibility programs deemed cost-effective by the Large POU.[55] Consistent with SMUD's Original Plan,[56] on October 1, 2024, SMUD submitted to the CEC its list of load flexibility programs it has deemed cost effective. As more fully described in this Revised Plan, SMUD's portfolio of load flexibility programs has been successful at reducing peak load through price signals, limiting the need for new electrical capacity, minimizing carbon emissions, and saving customers money, while providing bill predictability, and implementing new load flexibility programs that allow for automated response to MIDAS signals, would not be cost effective or materially reduce peak load.

5.1.6 Public Information Program

The LMS regulations require Large POUs to conduct a public information program to inform and educate the affected customers about why marginal cost-based rates or load flexibility programs and automation are needed, how they will be used, and how these rates or programs can save the customer money.[57] SMUD continuously conducts public information programs, including programs that inform and educate affected customers about dynamic rates or load flexibility programs. Providing broad outreach and communication to SMUD's customers and maintaining customer relations are core values of SMUD. Specifically, SMUD's Strategic Direction on Outreach and Communication (SD-15) requires that:

- SMUD shall provide its customers the information, education and tools they need to best manage their energy use according to their needs.
- SMUD will use an integrated and consistent communication strategy that recognizes the unique customer segments that SMUD serves.
- SMUD's communication and community outreach activities shall reflect the diversity of the communities it serves. SMUD shall use a broad mix of communication channels to reach all customer segments. This communication shall be designed to ensure that all groups are aware of SMUD's major decisions and programs.

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[54] Section 1623(c).
[55] Section 1623.1(b)(3).
[56] Original Plan at Section 7.4.1.
[57] Section 1623.1(b)(5).

SMUD recognizes the importance of collaboration and public outreach. SMUD cannot achieve ambitious climate goals alone, and SMUD's customers must be part of the solution to decarbonize the region. SMUD communicates in a wide variety of channels and languages throughout the year to help ensure customers are aware of time-dependent rates and load flexibility programs, and how they can help customers save money. For example, TOD rates have been the standard rate for residential SMUD customers since 2018. When SMUD rolled out its residential TOD rate, it developed a comprehensive marketing and education campaign that was translated into 13 different languages, took nearly 18 months, and leveraged multiple channels, as shown in the figures below. The effort included six personal touchpoints with every SMUD customer.

Figure 54 TOD Marketing and Education Campaign Timeline

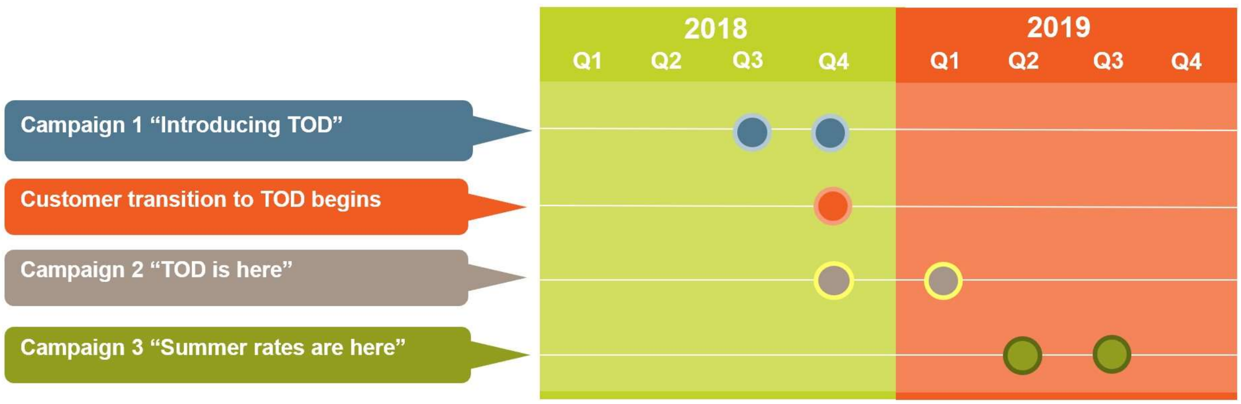

Figure 55 TOD Awareness and Education Campaigns

SMUD's public information campaign did not stop after the rollout of TOD implementation. SMUD continues to communicate extensively throughout the year about the significant benefits to customers and the utility to reducing energy usage between 5 and 8 pm. Throughout the summer rate months (June 1 to

Sept. 30) SMUD undertakes extensive marketing and communications efforts to encourage customers to reduce energy usage during peak hours, highlighting the bill savings and benefits to the grid and environment from doing so. In addition to a Time-of-Day rate campaign each summer, other key channels include media, social media, billboards, email, bill inserts, digital ads, SMUD's website and more.

Figure 56 Example of TOD Messaging

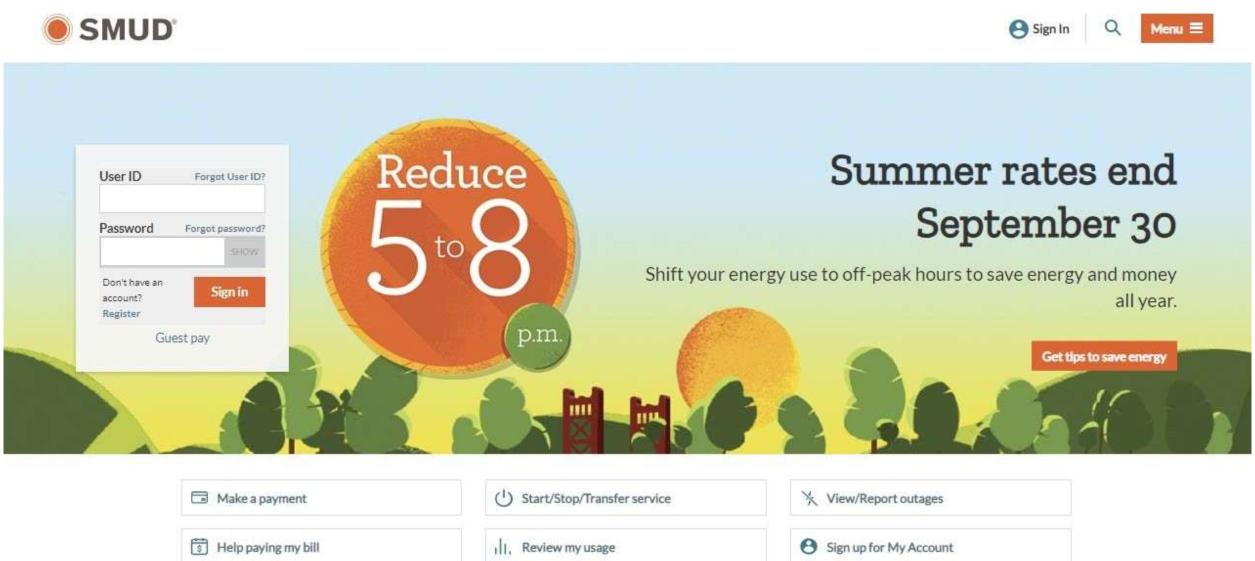

Figure 57 Information About TOD Available on Smud.org

In addition, SMUD has educated customers on how they can participate in support of SMUD's Zero Carbon Plan, which includes a range of new load flexibility programs which are marketed to customers on an ongoing basis. There have been six marquee marketing campaigns to support SMUD's Zero Carbon Plan so far. Key messages include a focus on programs to help customers save energy and money.

In summer 2023, SMUD launched a new multi-channel, multi-language marketing campaign to let customers know about its MEO Partner+ load flexibility program, which includes incentives for battery storage.

Figure 58 Example of Information on Battery Storage Incentives

Recruitment and marketing for other load flexibility programs, including SMUD's new PeakConserve program and thermostat load flexibility program (MEO Partner) is ongoing. SMUD also recently expanded its EV managed charging pilot to include Tesla, with a range of communications, including media, to support the expansion of the program.

Continuing to educate customers on the benefits of peak load reduction through time-dependent rates and load flexibility programs, how they work and how they can save the customer money, is an essential element for achieving decarbonization goals. SMUD will continue its award-winning communication and outreach efforts to fully maximize carbon reductions, grid savings and customer savings. SMUD will continue with existing communication practices to maintain its outreach, education and marketing of rates, programs, and pilots that support load flexibility and recognize the benefits of reducing peak load. SMUD will also update its education and marketing to incorporate discussion of new rates, programs and pilots, along with the role of automation as appropriate, as they are developed.

5.2 Ongoing or Future LMS Compliance Requirements

The following sections provide an overview of upcoming LMS requirements. SMUD expects to meet these compliance requirements over time, as SMUD determines when and how to implement dynamic rates, and programs that include an option for automating response to MIDAS signals, within SMUD's service territory to benefit customers.

5.2.1 Submit Annual Reports to the CEC Demonstrating Implementation of Compliance Plan

The LMS regulations require each Large POU to submit an annual report demonstrating their implementation of the plans approved pursuant to subsection 1623(a)(3), and such reports are due one year after the plans are approved pursuant to subsection 1623(a)(2).[58] SMUD understands, pursuant to email from the CEC, that the first SMUD annual report is required one year after SMUD's Compliance Plan is approved at a CEC business meeting. Nevertheless, this Revised Compliance Plan provides a current update to the CEC on SMUD's implementation of its Original Revised Compliance Plan. SMUD will submit annual reports starting one year after this Plan is approved by the CEC.

[58] Section 1623.1(a)(3)(C).

5.2.2 If It Will Materially Reduce Peak Load, Adopt Marginal Cost-Based Rate

Within two years of the regulations' effective date, Large POUs must submit at least one marginal cost-based rate to their board for approval for any customer class(es) where such a rate will materially reduce peak load.[59] As described in this Revised Plan, SMUD will continue to analyze dynamic pricing and will reevaluate marginal cost-based rates in its next LMS Compliance Plan.

5.2.3 If It Will Materially Reduce Peak Load, Adopt Marginal Cost-Based Program

Within three years of the regulations' effective date, offer customers voluntary participation in either a marginal cost-based rate, if approved by the board, or a cost-effective load flexibility program.[60] As described in this Revised Plan, SMUD will continue to analyze dynamic pricing and will reevaluate marginal cost based programs in its next LMS Compliance Plan.

5.2.4 Upload new and changed time-dependent rates to MIDAS

SMUD will upload all time-dependent rates to MIDAS prior to the effective date of the time-dependent rate each time a time-dependent rate is approved by SMUD's Board and each time a time-dependent rate change.[61]

5.2.5 Review and Submit Revised Plan Every 3 Years

SMUD will review the plan at least once every 3 years after the plan is adopted and submit a plan update to the Board if there is a material change.[62]

[59] Section 1623.1(b)(2).
[60] *Id*.
[61] See Section 1623.1(c).
[62] See Section 1623.1(a)(1)(C).

6 Conclusion

SMUD continues to act in good faith to implement flexible load management initiatives where such rates are determined to be cost effective, technologically feasible, materially reduce peak load, and benefit the grid and its customers. As discussed in Section 4.4.6 above, SMUD's existing rates and programs functionally achieve the goals of the LMS regulations. SMUD will continue to consider inclusion of dynamic rates and programs and incorporate such elements at a pace and scale that is beneficial to SMUD customers and the grid. Further, this Revised Plan demonstrates that a more cost-effective, technologically feasible method of achieving the LMS goals is to continue offering and expanding SMUD's current rates and programs. SMUD will continue to consider inclusion of dynamic rates and programs and incorporate such elements at a pace and scale that is beneficial to SMUD customers.

SMUD has a long history of industry-leading rate setting that supports the goals of the regulations and have been delivering those outcomes since long before the LMS regs were put in place. SMUD does robust work, including research, pilots, tech integration, customer outreach and education, and ongoing assessments/analyses post implementation to ensure its rates deliver the intended benefits, receive high customer adoption, and SMUD can implement them in a way that helps it consistently keep its rates among the lowest in California. As a result, SMUD has seen a significant shift away from peak hours, and strong customer adoption of rates and programs that support grid resiliency and its bold Zero Carbon Plan.

SMUD's analysis of other jurisdictions that offer dynamic pricing, robust internal analyses, and input from external utility pricing experts support the conclusion that while dynamic pricing offers potential benefits, it would deliver little additional benefit to SMUD and its customers beyond the current time-based rates and programs. Further, this Revised Plan demonstrates that a more cost-effective, technologically feasible method of achieving the LMS goals is to continue offering and expanding SMUD's current rates and programs. SMUD will continue to evolve its rates and programs in ways that cost-effectively support the objectives of the LMS regulations on a feasible timeline.

7 Appendices

7.1 Appendix A - Dr. Ahmad Faruqui's White Paper

The Experience of Residential Customers with Real-Time Pricing (RTP): An International Survey

A White Paper

Abstract

This paper surveys the experience of residential customers with real-time pricing in the US and abroad. It finds that real-time pricing does not generate much customer interest in the US but greater interest in Europe. However, even in Europe, there is no evidence that real-time pricing will achieve greater reductions in peak load than can be achieved by time-of-use pricing when it is paired with simpler forms of dynamic pricing, such as critical-peak pricing.

Ahmad Faruqui, Ph. D.

December 14, 2024

The Experience of Residential Customers with Real-Time Pricing (RTP): An International Survey?

A White Paper

Ahmad Faruqui, Ph. D.[1]

The California Energy Commission's (CEC) Load Management Standard (LMS) regulation dealing with real-time pricing (RTP) went into effect in April 2023.[2] It has the following goals:

1. Encourage the use of energy at off-peak hours
2. Promote load flexibility
3. Encourage the control of daily and seasonal peak loads to improve electric system efficiency and reliability
4. Lessen or delay the need for new electrical capacity
5. Reduce fossil fuel consumption and greenhouse gas emissions

The LMS regulation requires the large Investor-Owned Utilities (IOUs) to develop, propose, and offer dynamic rate structures in which the price changes at least on an hourly basis, reflecting marginal costs. The LMS regulation directs large Publicly Owned Utilities (POUs), defined as SMUD and the Los Angeles Department of Water and Power, and large Community Choice Aggregators (CCAs) to develop compliance plans that evaluate these same rate structures and pursue their development for customer classes where the large POU or large CCA rate-approving body has determined the rate would materially reduce peak load.[3]

This type of rate design is called Real-Time Pricing (RTP). Alternatively, the utilities could offer cost-effective load flexibility programs, including programs that allow its customers to automatically respond to hourly or sub-hourly marginal cost-based price signals.

This paper discusses the applicability and incremental benefits of RTP to SMUD's residential customers. SMUD has extensive experience in offering innovative rates that benefit its residential customers. In 2018, SMUD became the first utility in the state to implement an opt-out residential Time-of-Use (TOU) which is labeled a Time-of-Day (TOD)

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[1] The author is an Economist-at-Large who has published widely on time-varying rates and related topics such as demand forecasting, demand-side management, load flexibility, EVs and DERs. In his career, he advised more than a hundred clients located across the globe on six continents, published widely on the topic and was featured in many newspaper commentaries. He worked at a number of institutions, including the California Energy Commission, EPRI, Charles River Associates and The Brattle Group. https://www.brattle.com/wp-content/uploads/2023/04/AhmadFaruqui_CV-2023.pdf.

[2] https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards.

[3] The full LMS requirements applicable to POUs are detailed in Title 20, Section 1623.1 of the California Code of Regulations.

rate by SMUD. The TOD rate has a very high customer adoption rate of 97% and it offers consistent residential peak load reductions year over year. These are driven by the robust price signal embodied in the design of the TOD rate and SMUD's comprehensive customer education program which accompanied the rollout of the rate.

What is Real Time Pricing (RTP)?

In wholesale markets, electricity prices change from minute to minute in "real time", giving rise to the term: real time pricing (RTP). Even where wholesale markets don't exist, RTP can be defined by equating it with variations in the marginal cost of energy, which is sometimes measured by "system lambda" in production costing models. Often, real time prices (RTP) or marginal costs also vary locationally, thus giving rise to the term, location-specific, marginal cost pricing. There are many different approaches to setting RTP. In some cases, RTP can also include capacity prices for generation, transmission and distribution, and may also include GHG emissions.

In all of these approaches, the hourly (or sub-hourly) wholesale energy price is passed through to retail residential customers. This is also true of the proposed RTP in MIDAS (which also includes hourly marginal capacity costs and CO2 emissions).

Where is RTP being offered?

In the US, RTP has only been offered by utilities to residential customers in one state: Illinois. Two investor-owned utilities are offering it: Commonwealth Edison and Ameren Illinois. In 2007, Commonwealth Edison began to offer RTP to residential customers, and later it was followed by Ameren Illinois.

In both cases, the RTP signal only applies to energy sales. Transmission and distribution costs continue to be recovered through a traditional rate design.

It has been offered by at least one retailer in Texas, Griddy.But those prices did not have cap and during a crisis period, when wholesale prices shot through the roof, they caused customer bills to skyrocket into hundreds of dollars a month. The news spread quickly throughout the globe.

In Europe, RTP is being offered in at least five countries: Denmark, Netherlands, Norway, Spain and the United Kingdom. In Denmark, Netherlands, Norway and the United Kingdom, it's being offered by retail providers of electricity.[4] In Spain, it was the default tariff from

[4] https://www.nordicenergy.org/publications/evaluation-of-nordic-electricity-retail-markets/.

October 2015 to December 2023. It was discontinued as the default tariff because customers complained.[5]

In France, RTP used to be offered prior to the 2021-22 energy crisis. When prices rose and became volatile, consumer interest wanted (?). Currently, RTP is not being offered. In its place, retailers offer Critical Peak Pricing (CPP).

In Australia, a form of RTP called Dynamic Operating Envelops is being tested in a pilot called Project Edith.[6] It's operated by AusGrid, a network that serves New South Wales, and Reposit Power. It's only offered to customers that have installed solar panels and applies to imports from and exports to the grid. Prices are set for every five-minute interval and they can be positive or negative (rewards). No results have been published, but an impact evaluation has been published.

How many customers have taken RTP?

In Illinois, less than 2% of customers have taken RTP. That's despite the findings of one study, which found that an overwhelming proportion of customers would have lower bills if they got on the RTP rate as compared to non-time based rates.[7] Specifically, the study concluded:

Using 12 months of energy-use data from smart meters, anonymized by zip code, EDF and CUB calculated what the 2016 electricity bills of 300,000 ComEd residential customers would have been under the Hourly Pricing program.[8] The study found:

- 97% of the households studied would have saved money, comprising total savings of $29.8 million.
- The average ComEd customer would have saved $86.63 for the year, or 13.2% less than they paid under traditional billing.
- The top 5% of savers would have cut their bills by an average of $104 a year, or 31%.
- Of the customers who would have lost money (roughly 3% of the sample), the median increase in bills was an estimated total of $6.23 for the year.

[5] Insert link to document provided by Alcides, via Amparo.
[6] https://reneweconomy.com.au/project-that-calmed-network-fears-about-rooftop-solar-wins-innovation-award/.
[7] https://blogs.edf.org/energyexchange/2017/11/14/data-reveals-real-time-electricity-pricing-would-help-nearly-all-comed-customers-save-money/
[8] EDF stands for the Environmental Defense Fund and CUB for the Citizens Utility Board.

- There are no significant differences between the effects of real-time pricing on the bills of customers who have low-incomes and other customers.

"In sum, the vast majority of ComEd customers would have financially benefitted in 2016 from participating in the Hourly Pricing program. Again, they would have saved while using electricity exactly as they have been."

Despite this positive finding, only 1-2% of customers have signed up to receive service on RTP. Probably because there is little customer interest in being exposed to price volatility and the risk that comes with it. Surveys of the really small percentage of customers who are on RTP show that most of them have figured out that there are some hours in the day that are more expensive and other hours are less expensive. They respond to RTP rates as if they were on a time-of-day (TOD) rate, which defeats the purpose of sending hourly pricing signals. Interestingly, relatively few customers in Illinois are even on a simple TOD rate.

In Denmark there are approximately 40 retailers of electricity. They provide more than 143 pricing products to customers including flat prices, spot prices, and spot prices with a cap. Some 70% of the customers have chosen some form of RTP. But RTP only applies to the energy portion of the bill. Most distribution utilities offer TOD rates. Distribution costs account for a third of the customer bill while taxes account for a similar percentage.

The bill has five elements:

- Cost of electric energy (most customers get the hourly price defined by the day-ahead spot market, but consumers can also choose to get a fixed price or to get the hourly price with a price cap).
- Cost of distribution. These tariffs typically feature time-of-day variation. Typical tariffs have three levels depending on season. Winter is the peaking season. Here's an example from Radius, which operates the distribution grid in the Copenhagen area.[9]
    - Summer: Off-peak (9pm-6am) 12.15øre/kWh =1.9c/kWh, Normal (6am-7pm) 18.22øre/kWh=2.8c/kWh, Peak (5-9pm) 47.38øre/kWh=7.2c/kWh. The peak to off-peak price ratio is 3.9:1.
    - Winter: Off-peak (9pm-6am) 12.15øre/kWh =1.9c/kWh, Normal (6am-7pm) 36.45øre/kWh=6.5c/kWh, Peak (5-9pm) 109.34øre/kWh=16.8c/kWh. The peak to off-peak price ratio is 9:1.
    - On top of the volumetric charge, Radius has a fixed charge of 537kr=$83 per year.
- Cost of transmission. In 2023, it was a flat rate of 11.2øre/kWh (= 1.7 c/kWh).

[9] Tariffer og netabonnement - Radius (radiuselnet.dk).

- Taxes. There is a fiscal energy tax (69.7øre/kWh=10.7c/kWh in 2023, which is planned to decrease gradually to 56.10øre/kWh=8.6c/kWh by 2030) and a value-added tax (VAT)which amounts to (25% of the total bill including the tax).
- Subscription charge. Distribution companies add a charge for the meter (around $100/year), while retailers may also, in some cases, add a fixed charge depending on the customer's tariff plan (typically around $4-6 /month).

Customers pay the bill to the retail company who then subsequently pays the Distribution System Operator and the Transmission System Operator.

In Norway, about 75% of all customers are on RTP, but the prices are not actively communicated to customers. There is no default price for electricity. Distribution utilities set prices for grid services and customers pay a bill for electricity and a bill for the grid, but some retailers combine the two prices into a single price.

In Spain, RTP began to be offered as the default tariff to customers who did not switch to a retailer from October 2015 onwards. Approximately half of the customers were on the default tariff. However, prompted by concerns about price volatility, it is no longer the default tariff. In January 1, 2024, RTP was replaced by a three-period TOD rate whose prices change daily, since they are indexed to the wholesale market prices.[10]

In the United Kingdom, Octopus Energy offers RTP. Their product offering is called the Agile Octopus. It is called an "innovative beta smart tariff." According to information on the company's website, it helps "bring cheaper and greener power to all our customers but is directly impacted by wholesale market volatility." Agile features half-hourly prices that can spike up to 100 p/kWh at any time, although on average a typical household in the winter of 2022/23 would have paid around 35 p/kWh average. [11] In US currency, that would represent a peak price of $1.30/kWh, compared to an average tariff of 45.5 cents/kWh. The prices are set between 4 and 8 pm on the previous day and reflect wholesale market prices.

The beta tariff is being marketed to customers who are in a position to shift large amounts of their energy away from the peak periods by using smart technologies like solar and batteries, EVS and thermal energy storage. It features a price cap that ensures that prices won't rise above 100 p/kWh. [12]

The figure below shows the type of price variation associated with the Agile tariff.[13]

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[10] https://www.ree.es/es/actividades/operacion-del-sistema-electrico/precio-voluntario-pequeno-consumidor-pvpc
[11] https://octopus.energy/smart/agile/.
[12] This is a much lower price cap compared to how prices from MIDAS might go in California.
[13] https://agile.octopushome.net/dashboard.

Figure 1: Real-time price variation in the UK

What have been the results?

In Illinois, a price elasticity of -0.05 has been estimated for RTP. Thus, there is evidence of some load shifting relative to flat rates.

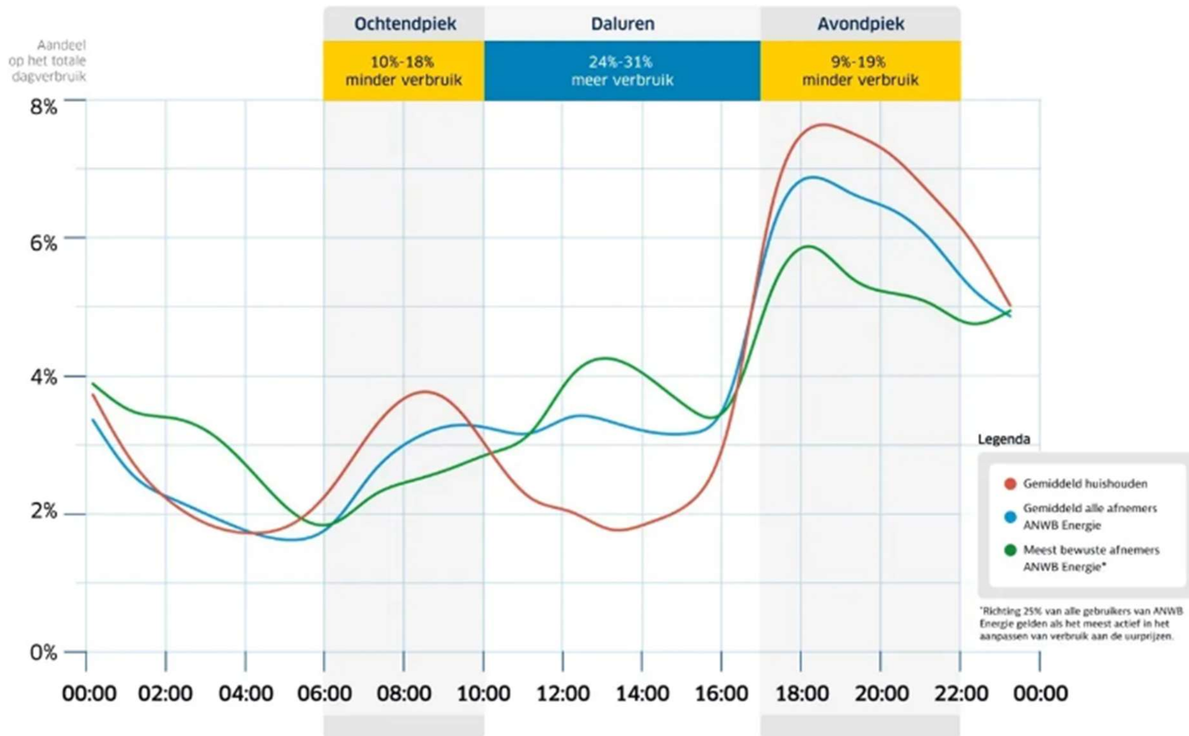
In Denmark, no studies have been published that quantify customer response to RTP. It's also unclear how much money customers save through RTP. Many of them were defaulted onto RTP when they switched to retail suppliers.

In Holland, according to ANWB Energie, customers on RTP have saved an average of more than 200 euros per year. For households with an EV, the savings have exceeded 1,000 euros per year.[14]

Figure 2 shows the changes that occur in load shapes with RTP. It shows that consumers shift their power consumption away from the peak hours to the off-peak hours.

[14] https://solarmagazine.nl/nieuws-zonne-energie/i35666/anwb-bewuster-gebruik-energie-door-dynamische-contracten-met-uurprijzen?trk=article-ssr-frontend-pulse_publishing-image-block.

Figure 2: Customer load shapes change with RTP in Holland



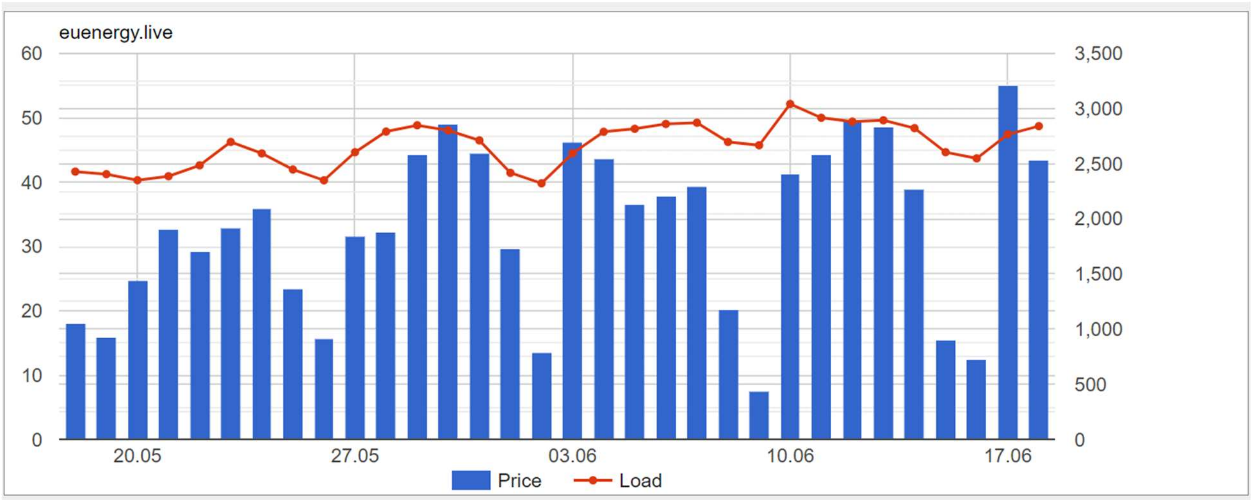
Customer bill savings are relative to what they would pay on flat rates, not TOD rates. One analyst with whom I exchanged emails indicated to me that the savings are modest relative to what would have been achieved under TOD rates. He says the majority of the savings are coming from avoiding the hedging premium embodied in flat rates by switching to RTP.

In Norway, which has an abundance of hydro power, there is some variation in hourly prices but not as much as one might see elsewhere, as seen below in this figure.[15] The price variation is in line with variations between peak and off-peak TOD rates that exist in many countries. Thus, it is not surprising that hourly load does not vary much in response to hourly prices.

Figure 3 shows how load varies with prices. The left vertical axis represents price in $/MWh, the right vertical axis load in MW and the horizontal axis shows time across months.

[15] https://euenergy.live/country.php?a2=NO1.

Figure 3 – Price Variation ($/MWh) and Load (MW) in Norway



A field experiment with peak-time rebates[16] was carried out in Norway to measure customer response to the rebates, which were provided to customers on RTP.[17] There were two sets of results, one for the 2-hour peak period and one for the 13-hour peak period, as shown below.

Figure 4 – The Arc of Price Response in Norway (2 and 13 hours)

[16] Peak-time rebates (PTR) have been successfully deployed in Maryland by BGE, Delmarva Power and Pepco. All customers are defaulted onto PTR. More than 80% of the customers actively engage with PTR and reduce their demand during critical system hours and are compensated at $1.25/kWh.
[17] Evidence of Households' Demand Flexibility in Response to Variable Electricity Prices – Results from a Comprehensive Field Experiment in Norway by Matthias Hofmann, Karen Byskov Lindberg :: SSRN

It's useful to benchmark these results against those from other experiments and full-scale deployment. As of this writing, some 400 time-varying rates have been implemented across the globe, and their impacts on peak demand have been reported. A meta-analysis of this data is contained in *Arcturus*.[18] The meta-analysis yields six "arcs of price response" that (a) plot the percent reduction in peak demand against the ratio of peak to off-peak rates and (b) that differ based on whether (i) the relationship being measured is based only on the price signal or (ii) is paired with an enabling technology and (iii) whether it pertains to TOU, CPP or Peak Time Rebate (PTR).[19]

In general, the higher the ratio between peak and off-peak prices, the higher the price response. However, the relationship between price response and the price ratio is not linear, it's curvilinear. Price response rises with the price ratio but at a diminishing rate.

Enabling technology such as a smart thermostat boosts price response. Finally, price response also depends on the type of price signal being conveyed to the customer – i.e., it varies by TOU, CPP and PTR.

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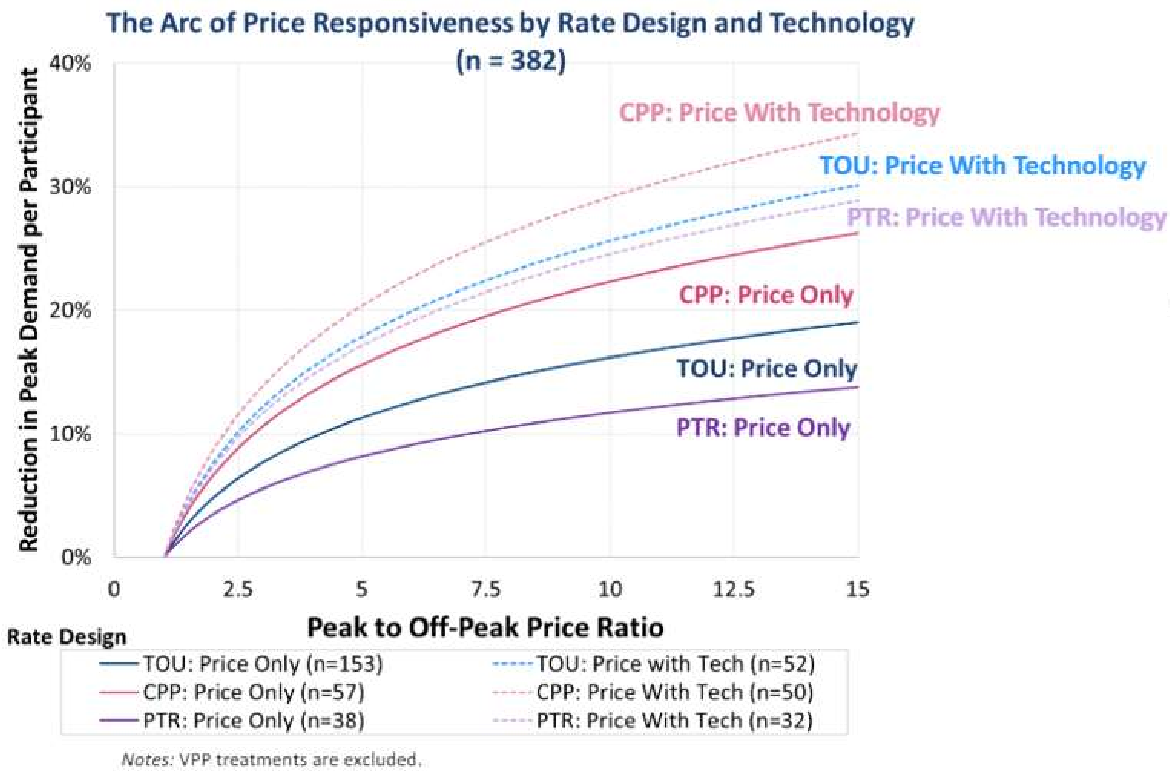
[18] https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf.

[19] Customers who reduce their load during critical time periods are offered a rebate under a PTR program, as opposed to being exposed to a higher price under a CPP rate.

Figure 5 - The six arcs of price-response for TOU, CPP and PTR, with and without enabling technology

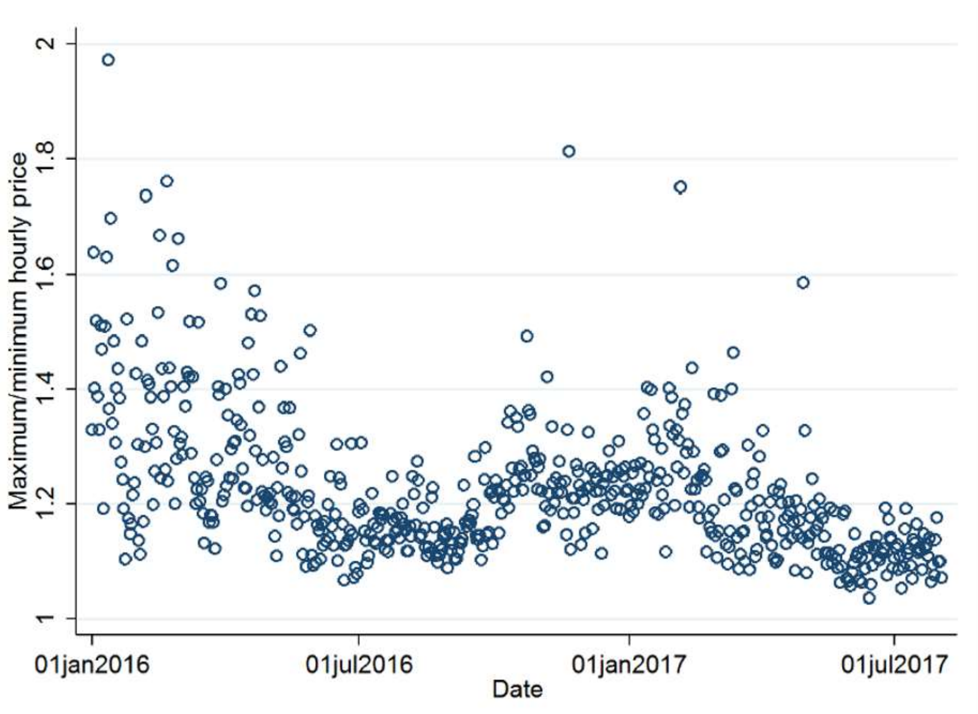


When compared with the meta-analysis in *Arcturus*, the impacts are a lot lower, as shown in the figure below. The green dots come from analyzing the data from 400 deployments of time-varying rates (TVRs) across the globe.

Figure 6 – The Arc of Price Response Norway (2 and 13 hours) and Arcturus

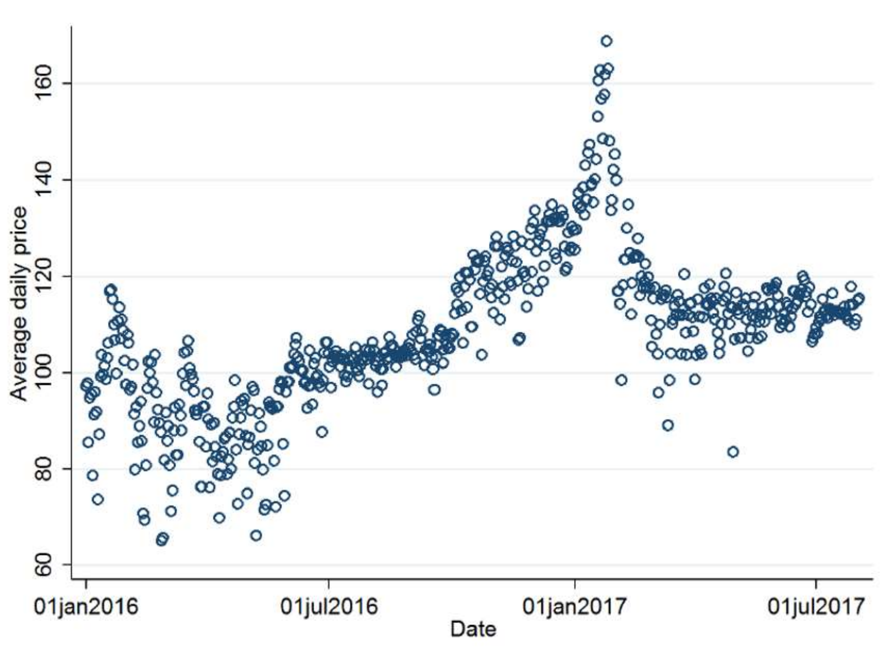
In Spain, between 2015 and 2023, RTP was the default rate, as noted earlier. Roughly half of the households are on it but 77% of them were not even aware of being on RTP. Most RTP customers didn't know what prices they were facing. The ratio of the highest to the lowest prices during the day is shown in the figure below. It does not exceed 2:1.

Figure 7 – Ratio between the highest and lowest price each day in Spain



Price variation across the sample period is shown in the figure below.

Figure 8 – Average daily prices over the same period in Spain (Euro/MWh)



Econometric analysis of load shape and price data for 4 million households has failed to measure any statistically significant value for the price elasticity of demand.[20]

A new survey by the Regulatory Assistance Project in Europe has found that 447 time-varying tariffs are now being offered to customers in Europe.[21] This is by far the largest number of such tariffs being offered on any other continent. Of the 447 tariffs, 135 involve static time-of-use pricing and 241 involve dynamic pricing. Large numbers of customers have chosen to receive electric service on these tariffs and several of them are saving money. But it remains unclear what share of the bill savings is coming from the elimination of the hedging premium in flat tariffs and how much is coming from reductions in peak load and/or shifting load from peak to off-peak periods.

It should be noted that there is a substantial structural difference between energy markets in Europe and California. The biggest difference is that retail competition is widespread in Europe while it no longer exists in California. Retailers are in a much better position to offer complex pricing designs than traditional utilities, as has been observed in Europe

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[20] http://rapson.ucdavis.edu/uploads/8/4/7/1/84716372/frrw_rtp.pdf and https://mreguant.github.io/em-course/materials/day4/slides_rtp.pdf.

[21] https://www.raponline.org/toolkit/strong-growth-in-tariffs-and-services-for-demand-side-flexibility-in-europe/.

How much additional peak load reduction can be expected from RTP over what has been observed with TOD pricing?

This question is salient because SMUD is an early adopter of residential TOD pricing. Today, 97% of customers are on TOD rates. SMUD has also launched CPP rates. Can RTP bring about substantially higher reductions in peak demand than TOD paired with CPP? The answer depends on how much RTP varies across the hours of the year and whether during the peak hours, RTP values are higher than TOU and CPP prices. It's likely RTP prices will be higher than TOU peak period prices since the latter are averaged over 600-1000 hours during the peaking season. However, RTP prices and CPP prices might be quite similar in magnitude since CPP prices focus on the top 50-100 hours of the peaking season. Thus, one should not expect to get much incremental load response from RTP over and above a cost-based CPP rate.

To get the highest response from RTP, three things need to occur.

1. Customers need to be fully informed about the hourly prices, preferably via an app on their phone and on a web portal.
2. They must be educated about the benefits of RTP and be internally motivated to spend time checking the app.
3. They must learn to program their end use loads to automatically respond to prices, which is called getting prices-to-devices. This can be done with smart thermostats and EV chargers but just because something can be done does not mean that it will be done. The same concepts apply to a CPP rate.

<u>Oklahoma</u>

It is worth mentioning that OGE in Oklahoma has implemented a more advanced concept of CPP known as variable-peak pricing, VPP (not be confused with Virtual Power Plants).[22] The VPP program has been in the filed since 2012. It features four levels of critical peak pricing, based on system conditions.

The highest peak period prices can be more than ten times as high as the lowest peak period prices. Currently, the lowest peak price is 3.6 cents/kWh and the highest peak price is 41.6 cents/kWh, with in-between peak prices being 8.5 cents/kWh and 19.7 cents/kWh.

[22] https://www.oge.com/wps/portal/ord/residential/pricing-options/smart-hours/!ut/p/z1/lZDNDoIwEISfhSfo0NaKxxqQVk1KjRTsxXAiJIoejM9vryD-sLdNvtnZGeJJTXzfPLu2eXS3vrmE_eTFmapUqG0Ok5gDh13HjG5SxYyOSTUEjJMZLOPJstgfAQjiZ-lzu1sEPTLpOGcA-0-PDyMx0_8d8N_PV8SPLJxMQwIhjF4VFDIeAxMVDYGJDn59cb-WZVmj020UvQDYS5Sq/dz/d5/L2dBISEvZ0FBIS9nQSEh/

If the customer so desires, OGE sends the prices directly to the customer's thermostat, thereby implementing the variable prices-to-devices concept but much simpler than RTP. The customer can, if they wish, set the thermostat setting so that it varies with the prices but is not required to do so. In addition, it is worth noting that OGE does not control the customer's thermostat. About two-thirds of the customers on the VPP rate have chosen to integrate their thermostat with VPP.

The program is opt-in. Bill savings for customers who participate in the program range between 18020% and peak demand reduction can be almost double that amount. Even then, only 10% of the customers have chosen to enroll in the program.

In California, the three investor-owned utilities have offered CPP on an opt-in basis for years. However, only 2% of the customers appear to have taken it.

<u>New York and New Jersey</u>

To test the concept of a Smart Home, Consolidated Edison conducted a demonstration project in its service territories in New York and New Jersey. The project tested a new rate design whose features are described below. The intent of the Smart Home project was to assess changes in customer load shapes that would be induced by the new rate design, customer willingness to use technologies to enable price responsiveness, and customer satisfaction.

The new rate design includes three categories of charges: time-variant supply charges; embedded delivery charges; and event-based coincident demand charges. In order to manage usage decisions in response to the complex rate, each participant was provided with a smart thermostat to optimize and automate central air conditioning loads and provide the interface for customer participation through a mobile application. Thermostat control was provided by a third party.

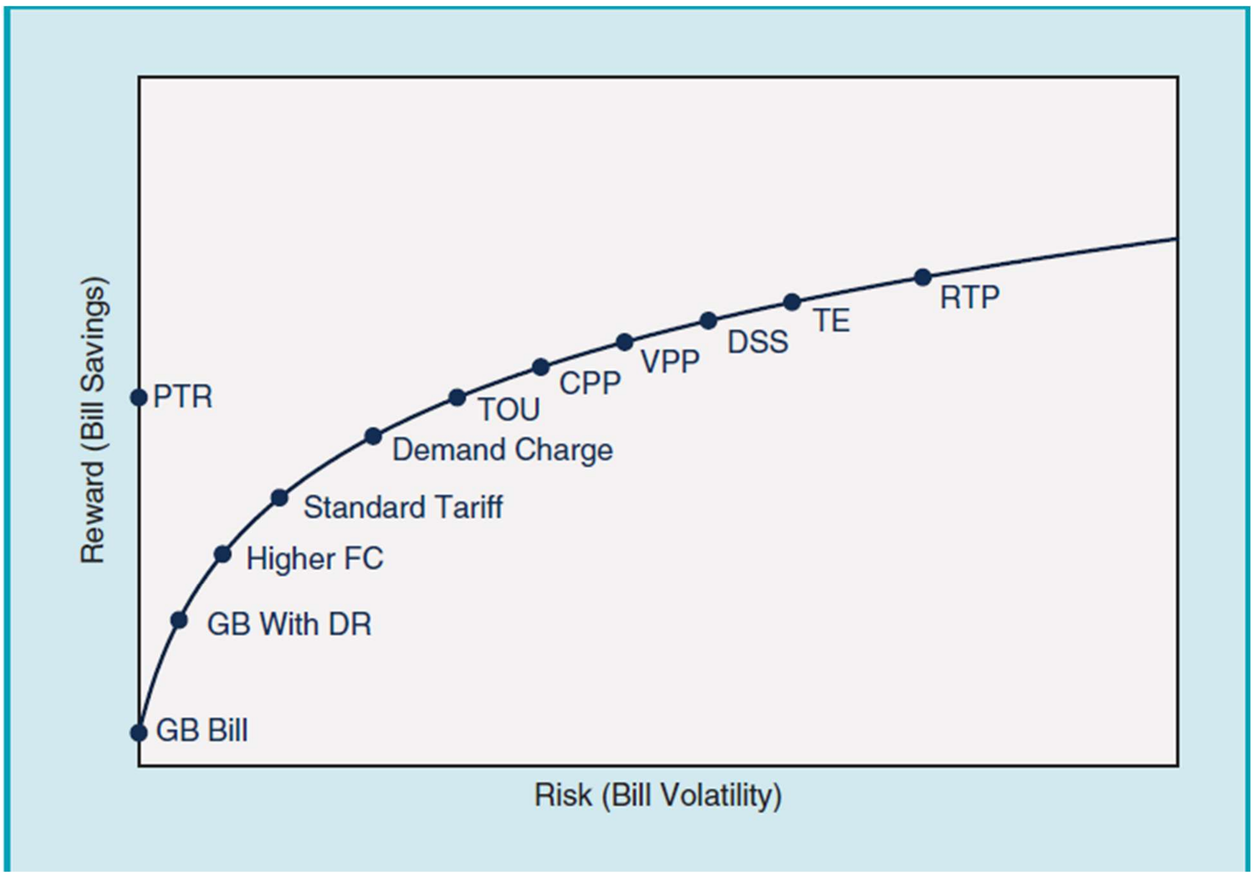
The time-variant supply charges were based on day-ahead hourly locational marginal prices in the appropriate zones of the New York Independent Service Operator.

Customers did respond to the new rate design, but it is difficult to assess how much of the response was triggered by the demand charge and how much by the hourly price. As the pilot progressed, a high rate of customer attrition was observed. Based on the results, the utility decided not to proceed with a full-scale rollout of the rate.

Should utilities offer customers a choice of rate designs?

In general, it is a good idea to offer a choice of rates to customers.[23] No two customers are alike. There are demographic and psychographic[24] reasons for why some are happy with flat rates, some with time-of-day rates and some with dynamic pricing rates. Each rate being offered should be cost-based. When these rates are plotted in the risk-reward space, they create an efficient pricing frontier, as shown in the figure.

Figure 9 – Risk-Reward Trade-Offs along the Efficient Pricing Frontier



The terms are defined in Table 1 below

[23] https://ieeexplore.ieee.org/document/9069846.

[24] Psychographics is a method of market research that classifies groups of people based on their psychological characteristics. It's a combination of the two words "psychology" and "demographics"

Table 1 – Rate design options.

table 2. Rate-design options.

Rate Design	Definition
GB	Customers pay the same bill every month, regardless of usage.
Flat rate	A uniform US$/kWh rate is applied to all usage.
Demand charge	Customers are charged based on peak electricity consumption, typically over a span of 15, 30, or 60 min.
TOU	The day is divided into time periods, which define peak and off-peak hours. Prices are higher during the peak-period hours to reflect the higher cost of supplying energy during that period.
CPP	Customers pay higher prices during critical events when system costs are highest or the power grid is severely stressed.
IBR	Customers are charged a higher rate for each incremental block of consumption.
PTR	Customers are paid for load reductions on critical days, estimated relative to a forecast of what they would have otherwise consumed (their baseline).
VPP	During predefined peak periods, customers pay a rate that varies by utility to reflect the actual cost of electricity.
DSS	Customers subscribe to a kilowatt demand level based on the size of their connected load. If they exceed their subscribed level, they must reduce their demand to restore electrical service.
TE	Customers subscribe to a baseline load shape based on their typical usage patterns and then buy or sell deviations from their baseline.
RTP	Customers pay prices that vary by the hour to reflect the actual cost of electricity.

GB: guaranteed bill; IBR: inclining block rate; PTR: peak-time rebates; DSS: demand subscription service; TE: transactive energy.

What benefits would accrue to SMUD and its customers from RTP?

For decades, SMUD deployed inclining block rates, as did the other large utilities in California. It was the first utility in the state to successfully deploy TOD pricing. In the years 2011-13, it conducted a very well-designed randomized control trial with TOD and CPP rates. The results were encouraging, and SMUD began moving customers to default TOD rates in 2018.[25] More recently, it introduced CPP rates on an opt-in basis for a subset of customers on its smart thermostat demand response program.

Today, some 97% of customers are on TOD rates, showing the popularity of the rate with customers. Only 3% have opted out to the Fixed Rate.

The TOD rates send a strong, consistent price signal to customers to reduce peak demand, unlike the TOD rates of the three investor-owned utilities which send a very diluted price signal. As of May 1, 2024, the peak period price in SMUD's TOD rate during the summer peaking season is 34.62 cents/kWh, the mid-peak price is 19.67 cents/kWh and the off-peak price is 14.25 cents/kWh. There is a robust ratio of 2.42:1 between peak and off-peak rates.

[25] https://www.nber.org/system/files/working_papers/w23553/w23553.pdf.

SMUD's statistical analysis has shown that the TOD rate has consistently reduced peak demand by 4-8% since implementation, with a mean value of 7%. The most recent analysis for the summer of 2023 shown a load reduction of 132 MW or 7.4%. [26]

SMUD has also recently started offering a CPP rate which adds 50 cents/kWh to the peak period price in the summer. The rate can be called up to 50 hours per summer. CPP Peak Events can be called any time of the day during the summer months (June 1 through September 30), including weekends and holidays. Events may span more than one time-of-day period. During these hours, the peak period price rises to 84.62 cents/kWh, yielding a price ratio of 6.91:1. Nearly one thousand customers have signed up to its CPP rate in its first year of implementation. It is too soon to carry out an impact evaluation.

Likely reductions in peak demand from the critical-peak pricing rate can be simulated using the *Arcturus* model, which is based on a meta-analysis of the results from 400 implementations of time-varying rates around the globe. Figure 8 shows the results of that analysis. It presents the simulated impact of SMUD's current TOD and CPP rates, with and without enabling technology and behavioral messaging.

The TOD rate is predicted to reduce peak demand by 5.9%, very close to SMUD's estimate of 6.5%. If coupled with enabling technology, the simulation shows that impact is predicted to rise to 10.8%. At some point in the future, SMUD might consider offering enabling technology with its TOD rate.

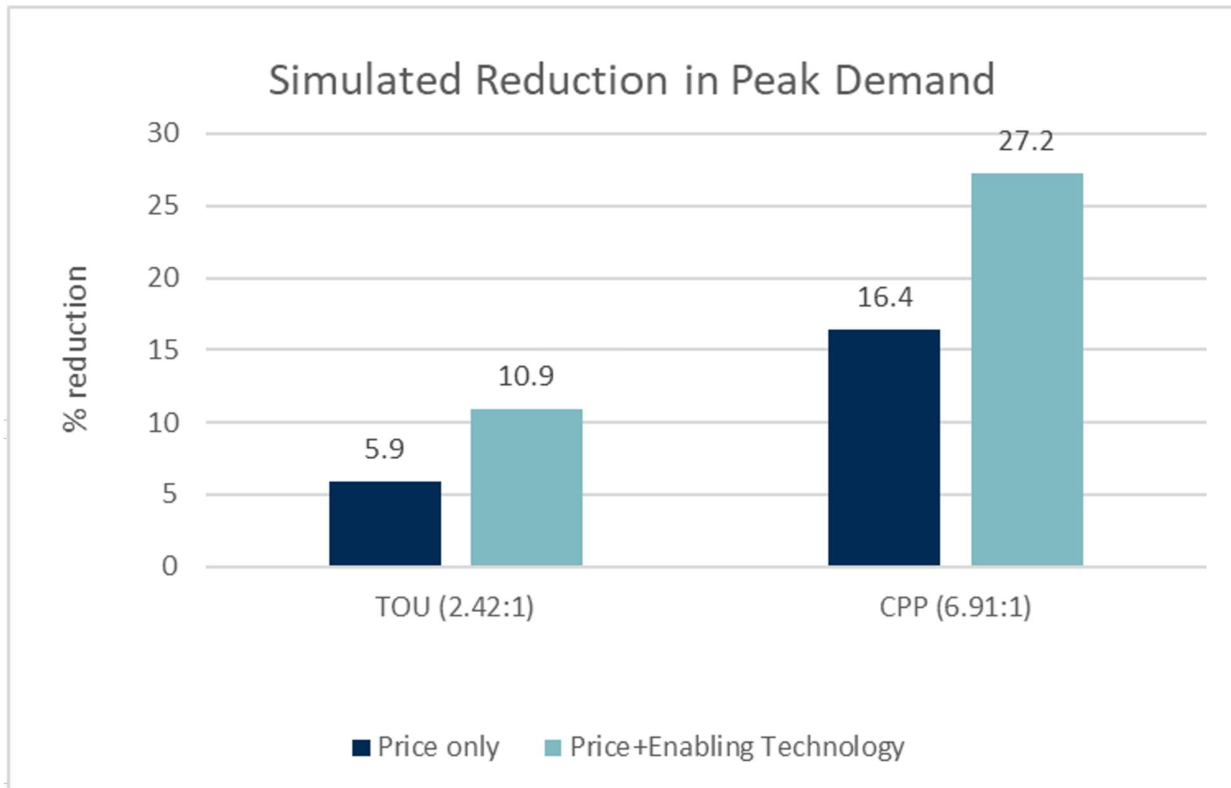
The *Arcturus* simulation shows that CPP rate is predicted to reduce peak demand by 15.1% and, when coupled with enabling technology, the impact would rise to 25.1%. In its current offering, SMUD appears to be offering CPP coupled with enabling technology. Thus, an impact in the 25% range should be expected.

If SMUD were to offer RTP, the impact of that RTP would depend on the prices that would prevail in the highest load hours. Those are unlikely to differ much from those in the CPP rate. The advantage of CPP and RTP rates over TOD rates is that they can be called on short notice. While this is an advantage from a system perspective, it is a disadvantage from a customer perspective. Given a choice, most customers would prefer to just go with a TOD rate which already provides them with a significant benefit. Even the best CPP program in the country, which is run by OGE, has only attracted 10% of customers. The CPP rates offered by the three investor-owned utilities in the state have only attracted some 2% of customers.

[26] Citation to the impact analysis.

From a system perspective, one of the advantages of RTP over CPP is that the prices are not known in advance. But this is a disadvantage from a customer perspective. Thus, given a choice, most customers are unlikely to choose RTP as seen in places where the rate is offered as an optional rate. That is evident from the 1-2% customer participation rate in Illinois. While customer enrollments on RTP are much higher in the European countries discussed in this paper, it's also clear that most customers don't even know they are on RTP and even those who know that they are on RTP, most of them don't know what prices they are paying by hour. Thus, the estimated price elasticities are really low.

Figure 10 – Simulated Reduction in Peak Demand for SMUD Customers on TOU and CPP rates.



It's worth noting that SMUD is also offering a comprehensive menu of load flexibility programs to complement its TOD and CPP rates.[27] These are designed to reduce peak demand and shift load from peak to off-peak periods and support the 2030 Zero Carbon Plan.[28] These programs provide customers an incentive at the time the customer joins the program and they also offer an additional yearly participation incentive (either a standard amount or performance based, depending on the program). In essence, they are a form of

[27] Exhibit to Agenda Item#1 Update and Status of Customer Programs under the 2030 ZCP Sep18, 2024
[28] SMUD's 2030 Zero Carbon Plan

technology-enabled peak time rebates. These programs have reduced SMUD's peak demand by over 170 MW which includes load reduction from residential TOD.[29]

The CEC's Load Management Standard for Tariffs[30] calls for California's large utilities, including SMUD, to offer rates that are based on location-specific hourly and sub-hourly marginal costs. Such an ideal rate has been discussed by academics for decades. For example, William Vickrey of Columbia University, who would later be awarded a Nobel Prize in economics, discussed it in a 1971 paper on "Responsive Pricing of Public Utility Service."[31] In 1981, Fred Schweppe of MIT and several co-authors discussed it in a paper entitled, "Homeostatic control"[32]. In 2005, Severin Borenstein discussed the long-run efficiency of RTP.[33]

However, in a recent paper written by several MIT economists, a different conclusion is reached.[34] The authors reviewed several rate designs, including RTP, CPP and TOU. They stated that there was no doubt that RTP was the first-best option for enhancing economic efficiency and that it was looking more and more attractive with the arrival of renewable energy resources. But they conceded that "pure spot pricing is not popular among consumers; consumers value price predictability and bill stability. Also, sudden increases in bills often become a political problem."

After running several simulations, they concluded: "[W]ell-designed TOU rates, especially when accompanied with a CPP program involving load control during infrequent scarcity price events, are more attractive from an efficiency perspective than the existing literature suggests. There are likely to be efficiency benefits from the acceleration of the adoption of TOU rates accompanied by CPP as a valuable intermediate step towards improved electricity retail rates that balance efficiency considerations and consumer/political pressures for price predictability and bill stability."

Bill Volatility

In general, customers have a natural aversion to bill volatility because they put a premium on predictability. In fact, some customers would happily sign on to a subscription program

[29] Exhibit to Agenda Item#3 Report for Strategic Direction SD-9, Slide 5, Sep 11, 2024
[30] https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards
[31] https://www.jstor.org/stable/3003171.
[32] https://ieeexplore.ieee.org/document/4113911.
[33] https://journals.sagepub.com/doi/abs/10.5547/ISSN0195-6574-EJ-Vol26-No3-5.
[34] https://www.nber.org/system/files/working_papers/w30560/w30560.pdf and https://ceepr.mit.edu/workingpaper/electricity-retail-rate-design-in-a-decarbonizing-economy-an-analysis-of-time-of-use-and-critical-peak-pricing/.

that gives them a fixed bill, even if the implied electric rate is higher than the current rate. For that reason, several utilities are beginning to experiment with subscription plans.

The reason that 97% of SMUD's customers have chosen to stay with TOD rates is (a) because those rates are set in advance and (b) because they offer them a chance for lowering their bills by reducing peak usage and shifting it to off-peak periods. Some SMUD customers are willing to go with CPP rates, because even though they will not know when the days on which CPP rates will be activated will be called, they know what prices will be charged when they are called. And they believe they can save more on their bills with CPP rates than with TOD rates.

It's quite possible that a very small number of a utility's customers might go with RTP because they might think that their bill savings would be even higher with RTP than with TOD or with TOD plus CPP. But it will be a very small percentage, as has been observed in Illinois.

A Roadmap for SMUD

Based on the experience of other regions with RTP, and based on the conclusions in the MIT paper cited above, what are the implications for SMUD? As noted earlier, SMUD has been offering well-designed residential TOD rates as the default tariff for six years and has just introduced CPP rates. These tariffs are supplemented with a comprehensive portfolio of demand response programs that are designed to promote load flexibility. These programs currently have more than 20,000 participants.

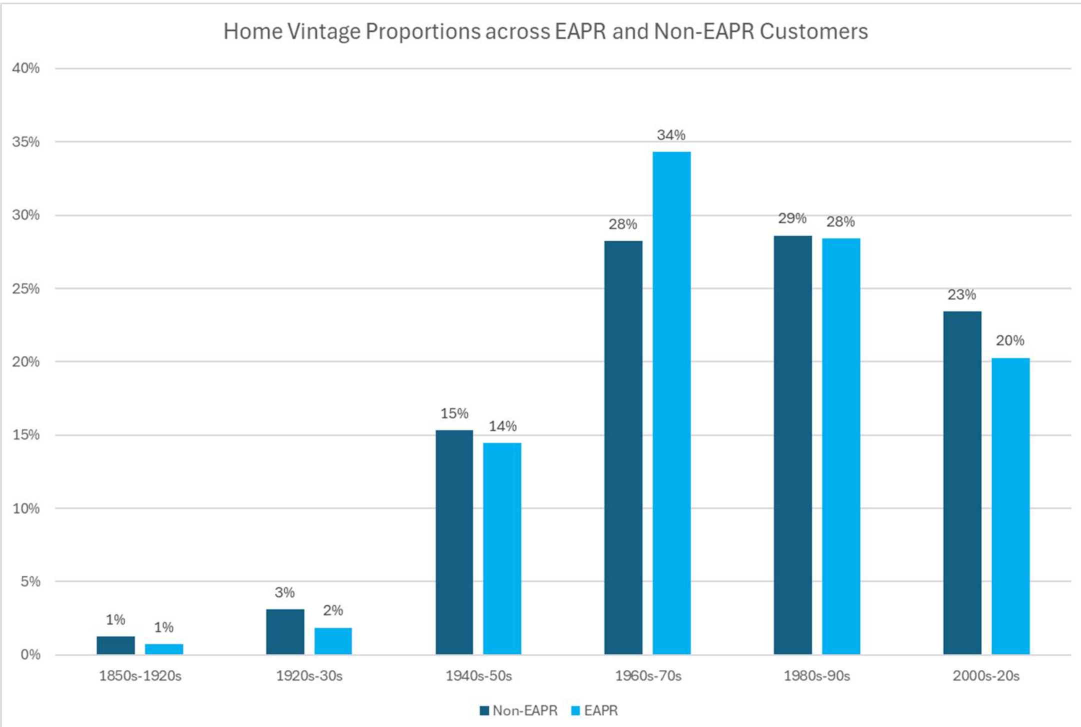
Thus, there is no reason for SMUD to implement RTP in the near future. RTP, based on the experiences reviewed in this whitepaper, is not necessarily going to encourage more load flexibility than the time-varying rates that SMUD is already offering its customers. However, it's a concept worth keeping an eye on.

In the next two years, 2025-27, SMUD should see how RTP plays out with other utilities in California and elsewhere. Then, if the results are encouraging, it might want to conduct focus groups and customer surveys to determine consumer interest in the topic. If customers exhibit interest, then in 2027-28, SMUD might consider doing a pilot with RTP and make a final determination on offering it as an opt-in rate in 2030. As demonstrated with SMUD's roll out of TOD, it takes time, proper planning, customer education, significant system enhancements and customer tools to make a new rate or program effective.

7.2 Appendix B - Supporting Data

Figure 1 - Home Vintage by Population (EAPR vs non-EAPR)

The chart below illustrates the vintage homes between EAPR and non-EAPR customers. EAPR customers are those enrolled in the Energy Assistance Program Rate (EAPR). As seen in the chart, a significant proportion of customers with old homes are EAPR participants. Home ownership and vintage are potential barriers for low-income customer to participate in a dynamic as older homes are less efficient, so those customers are more likely to be hurt by a dynamic rate.



The information shown in Figure 2 below demonstrates that the frequency of customer moves is larger for low-income customers than the rest of the population. So, availability of consistent billing history and load patterns is more challenging for the low-income group. This may influence enrollment on more dynamic hourly or sub-hourly rates as it would be challenging to predict bill impacts for customers with less steady billing history. This would lead to an unintended cost shift for this group which may not be able to participate in RTP due to billing data limitations as compared to the rest of the population.

Figure 2 - Frequency of Moves Between EAPR and non EAPR Customers

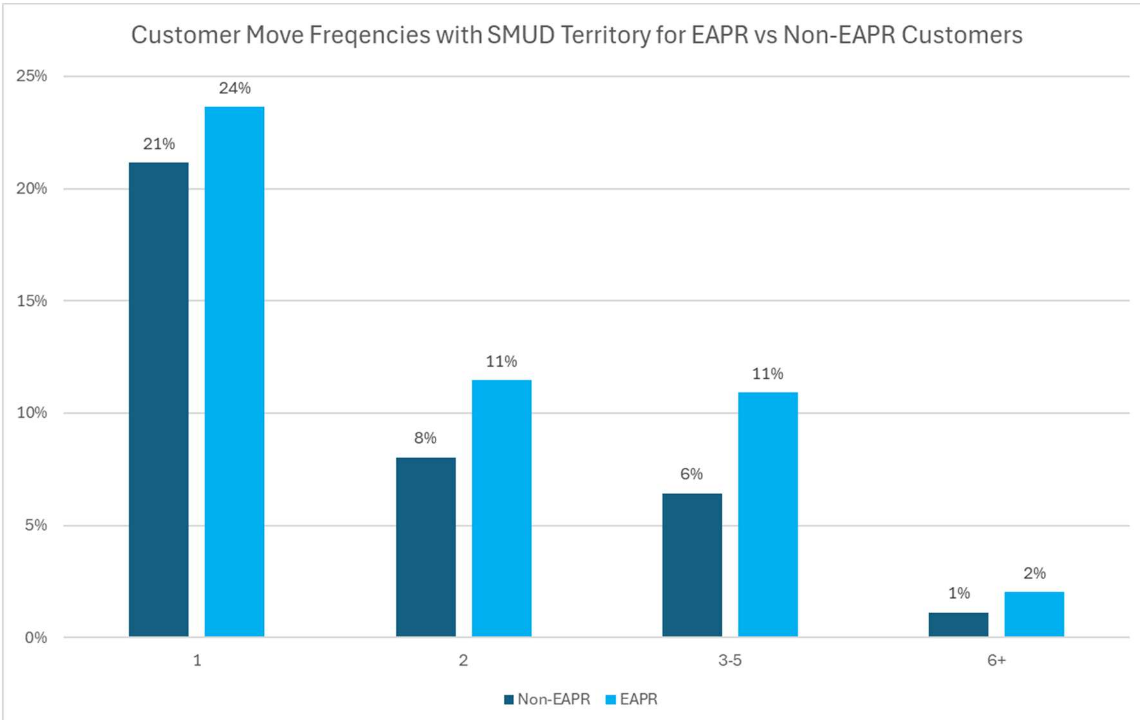
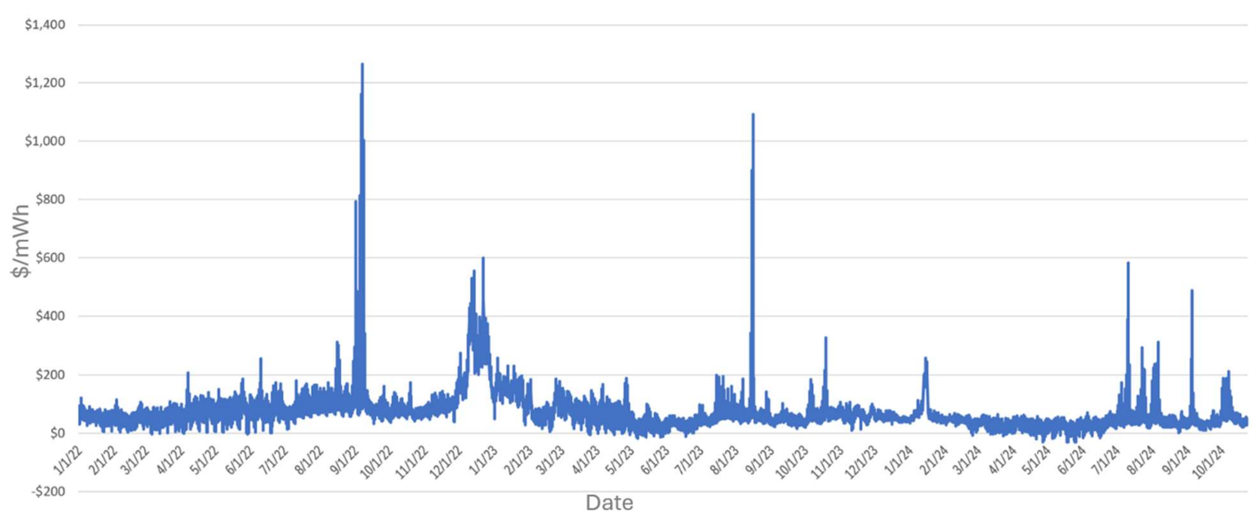


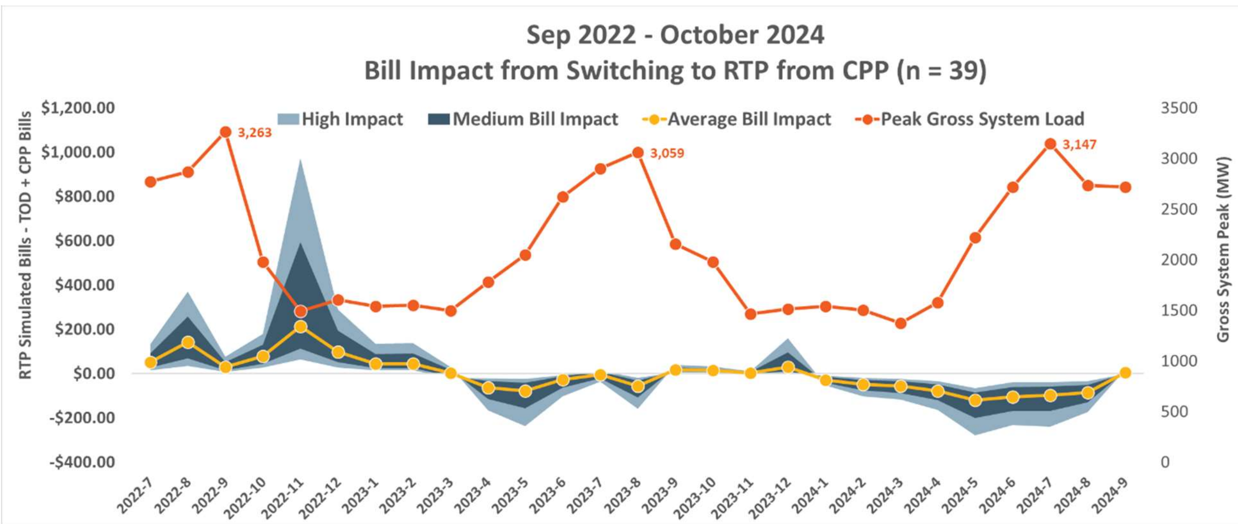
Figure 3 below displays the trend of electricity market prices from 1/1/22 thru 10/23/24. Customer who may enroll on any dynamic hourly or sub-hourly rates based on day ahead market prices will be exposed to market volatility.

Figure 3 –1/1/22 – 10/23/24 Day Ahead Market Prices (NP15) $/MWh



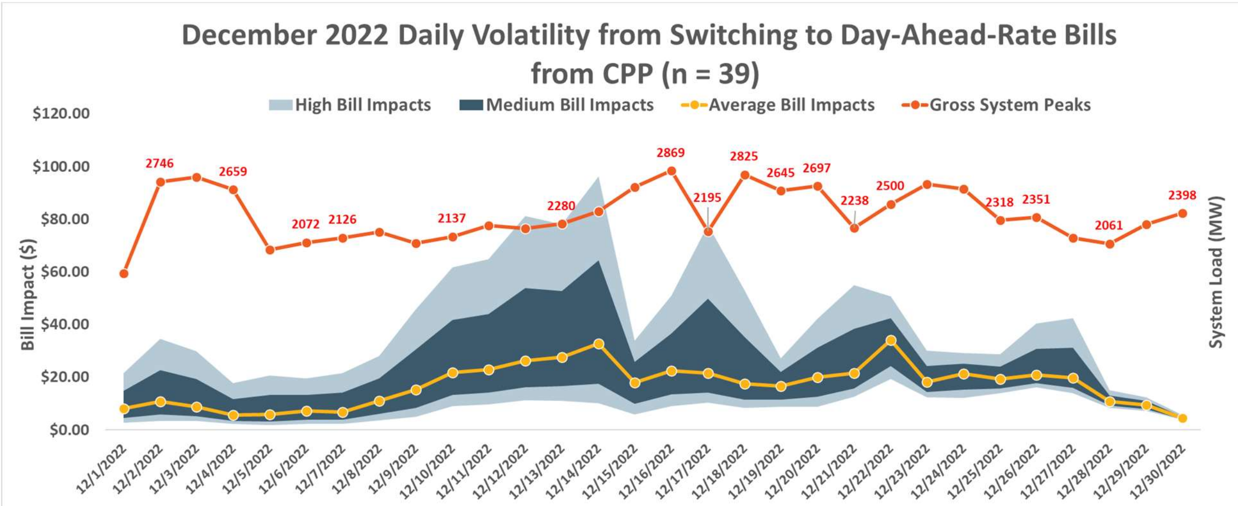
The chart below shows the bill illustrative impacts of switching from TOD + CPP to RTP for sample of 39 CPP customers. The bill impacts were calculated using day ahead market prices from Sep 2022 thru Oct 2024. As shown in the chart, customers would have experienced significant bill volatility in the winter of 2022 if they had been on a dynamic hourly rate. The shaded area represents the variance between RTP and the current TOD bill and the orange line the trend of SMUD's system peak. As observed in the chart, electricity prices increased significantly in the winter of 2022 due cost of natural gas price increases. It is important to note that the system peak was significantly lower during that time than in the summer. SMUD's grid was not stressed, and it was able to provide the needed power without exposing customers to market volatility. If customers had been on an RTP rate during that time, they would have paid significantly more as seen below, when there was no need. SMUD's TOD and CPP rates provided more consistent bills, spreading out the expensive periods across the year, making the volatility easier to handle and a better customer experience. The illustrative bill comparison is for energy charges only and revenue neutral across the year for the group of customers.

Figure 4– Bill Impacts RTP vs TOD + CPP with Sample Customers



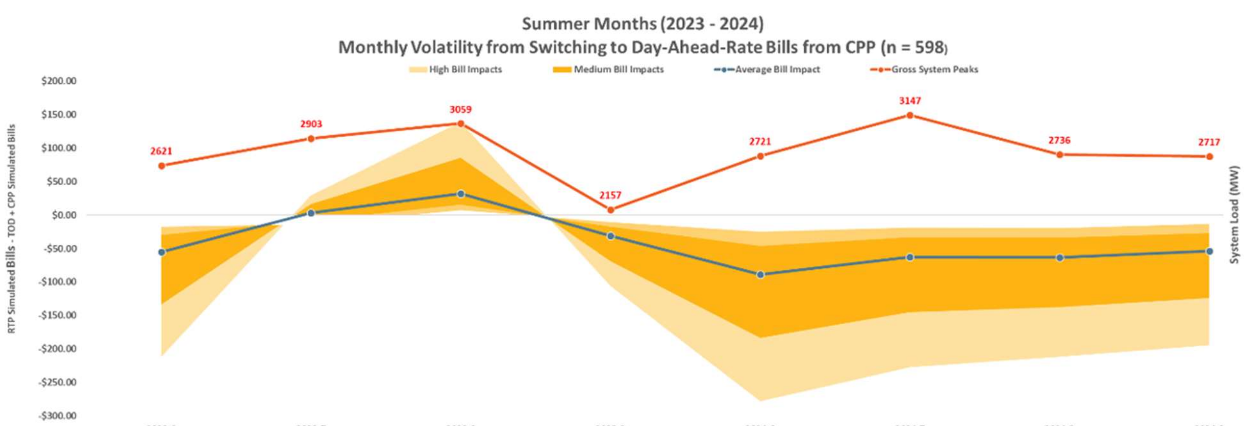
The CPP rate was implemented since the summer of 2022. The chart below displays 39 sample customers who have stayed on the rate in 2022 and 2023. The shaded area below illustrates the bill volatitily that those CPP customers would have experienced if they would have been on a dynamic hourly rate based on day ahead market prices in December 2022. As shown above in Figure 3, there was a spike in electricity market prices trigged by an unrelated load need, it was caused by volatility in natural gas prices that winter. The illustrative bill comparison is for energy charges only and revenue neutral across the year for the group of customers.

Figure 5 - Bill Impacts RTP vs TOD + CPP with Sample Customers.



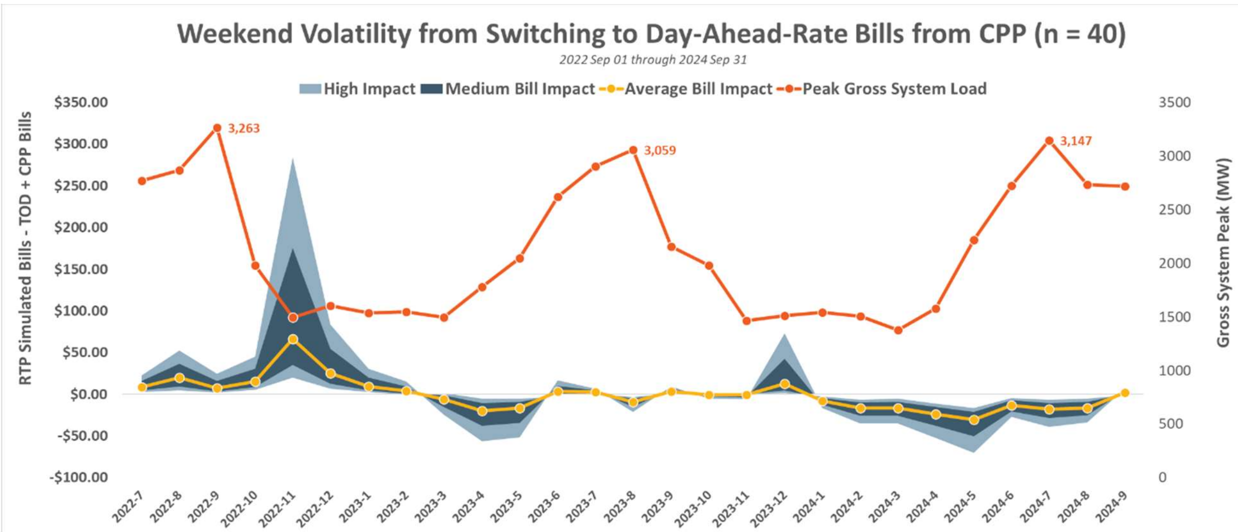
The chart below shows the range of bill volatility that CPP customers would have experienced in 2022 and 2023. The shaded area in orange in the chart shows the variance between an RTP dynamic rate vs. the existing TOD with CPP. There is a significant bill volatility during summer months. The illustrative bill comparison is for energy charges only and revenue neutral across the year for the group of customers.

Figure 6 – Monthly Bill Volatility from RTP - Summer Months (2022-23)



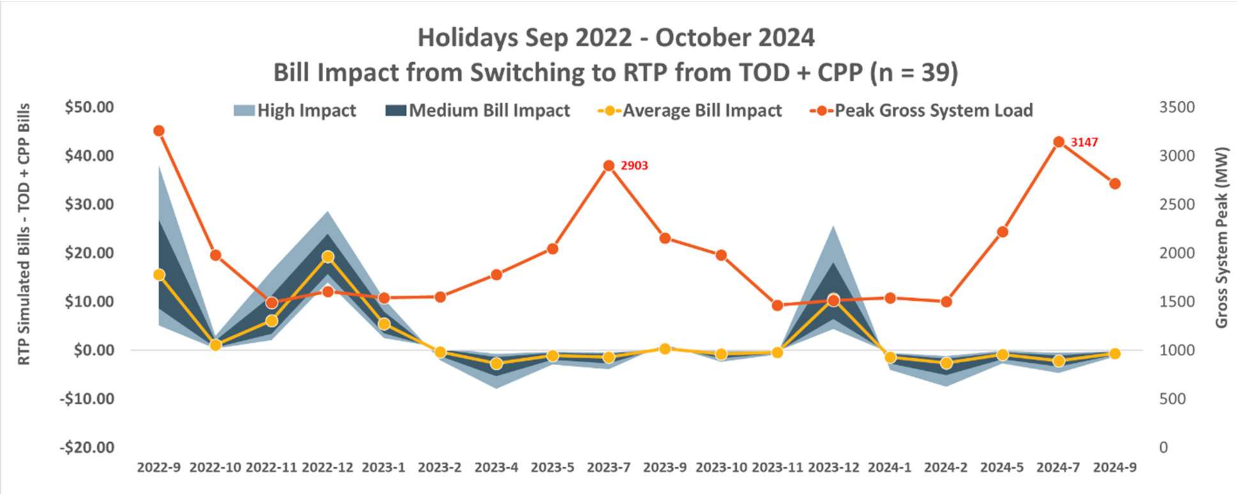
The chart below displays the bill variance between an RTP rate vs. the exiting TOD rate on weekends. The shaded area represents the variance between the two bills. Normally, weekends are billed at off peak prices. In the case of hourly rates, customers would experience unnecessary volatility on weekends. The illustrative bill comparison is for energy charges only and revenue neutral across the year for the group of customers.

Figure 7 – Bill Volatility – Weekend (RTP vs TOD)



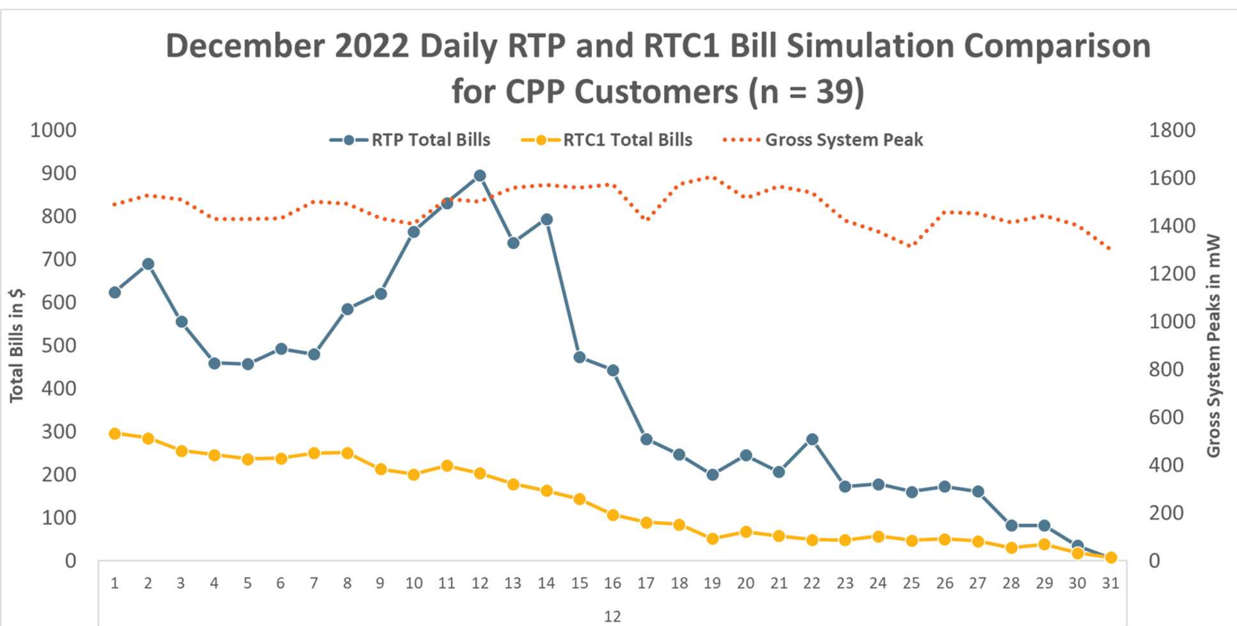
The chart below displays the bill variance between an RTP rate vs. the exiting TOD rate on holidays. The shaded area represents the variance between the two bills. Holidays are normally billed at off peak prices since load tends to be like weekends. In the case of dynamic hourly rates, customers would experience unnecessary volatility on holidays. The illustrative bill comparison is for energy charges only and revenue neutral across the year for the group of customers.

Figure 8 – Bill Volatility - Holidays (RTP vs TOD)



The chart below illustrates that a sample of 39 customers on RTP would have experiences significant volatility in December 2022, despite the system peak being normal. Electricity prices spiked that month due to non-system grid issues. The illustrative bill comparison for the 39 sample customers is for energy charges only.

Figure 9 – Bill Volatility - December 2022 (RTP vs TOD)



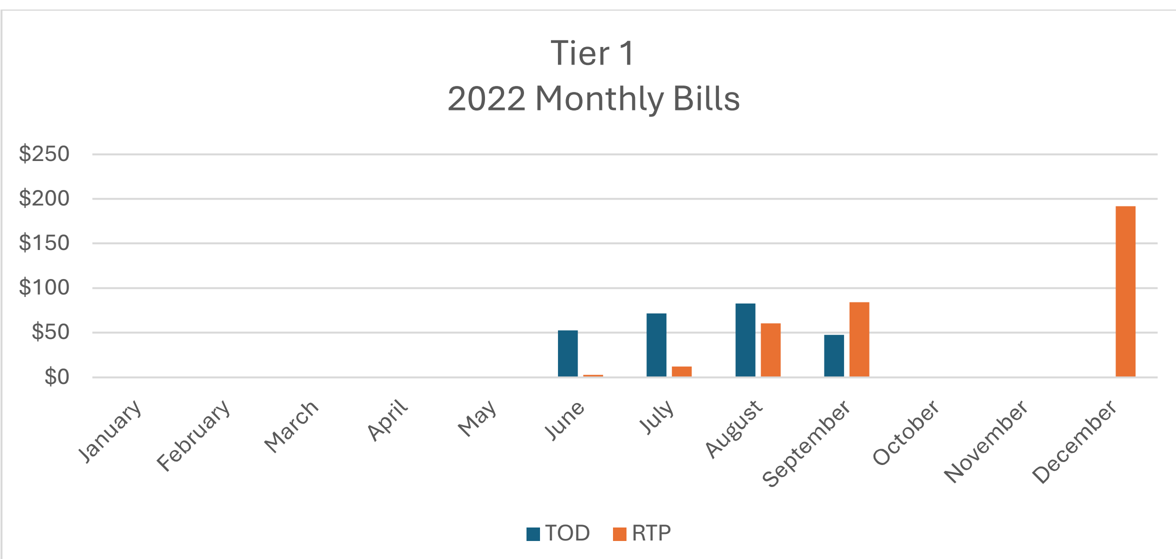
Our low-income customers receive a discount on their energy bills depending on their income level, as shown in the following table.

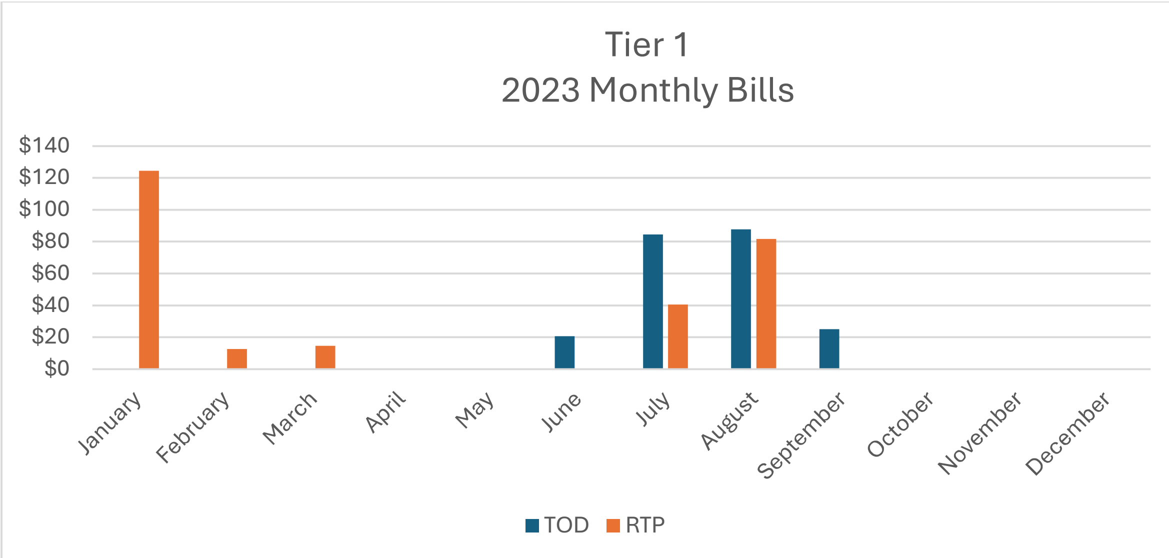
Energy Assistance Program Rate (EAPR) Customer Bill Impacts (RTP vs TOD)

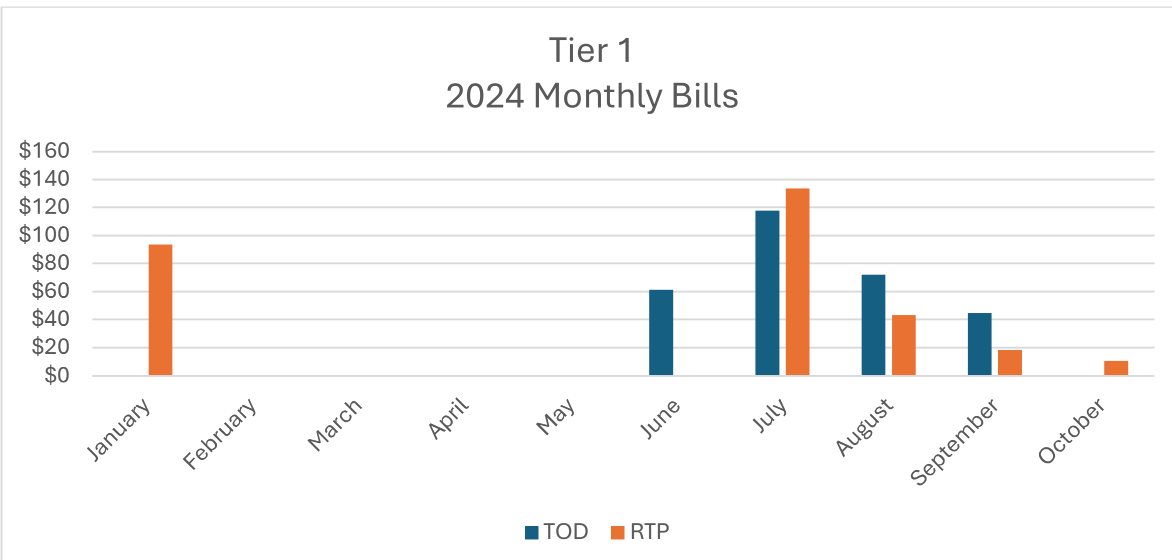
Tier	Energy Discount
1	$95
2	$32
3	$10
4	$0

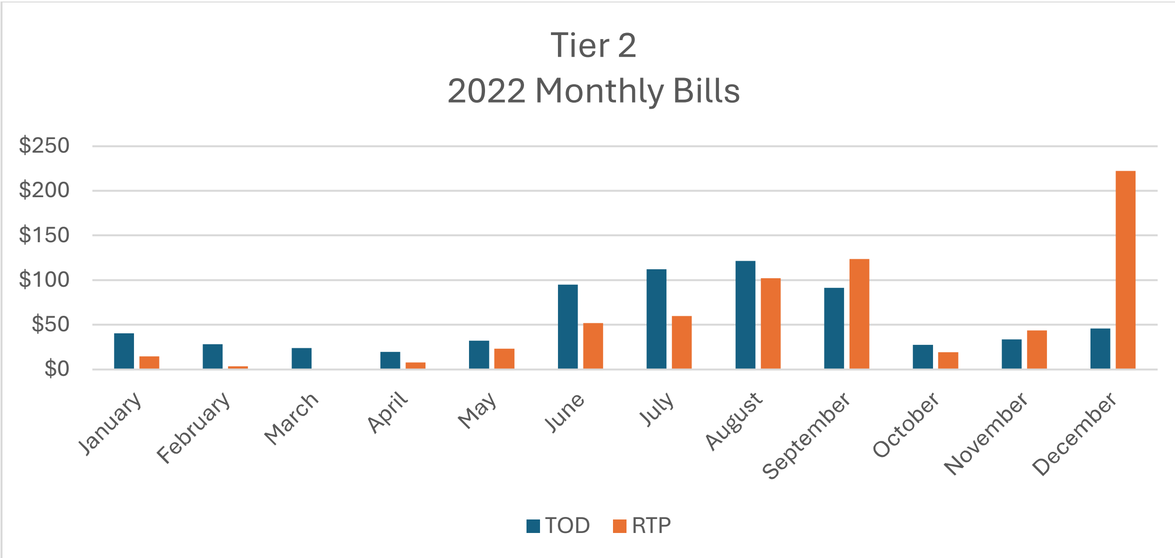
The following charts show the illustrative bill impacts of low-income customers on the standard rate vs. what the rate might have looked like if the customer was on an RTP rate. Customers would have experienced significant bill volatility in 2022, 2023 and 2024. It is assumed the two rates would be revenue neutral across the year and adjusted the RTP rate, accordingly, based on the day ahead NP-15 prices. These examples just show the distribution between the months, not actual bill estimates. The estimated monthly bills are for energy charges only, so no monthly SIFC was included.

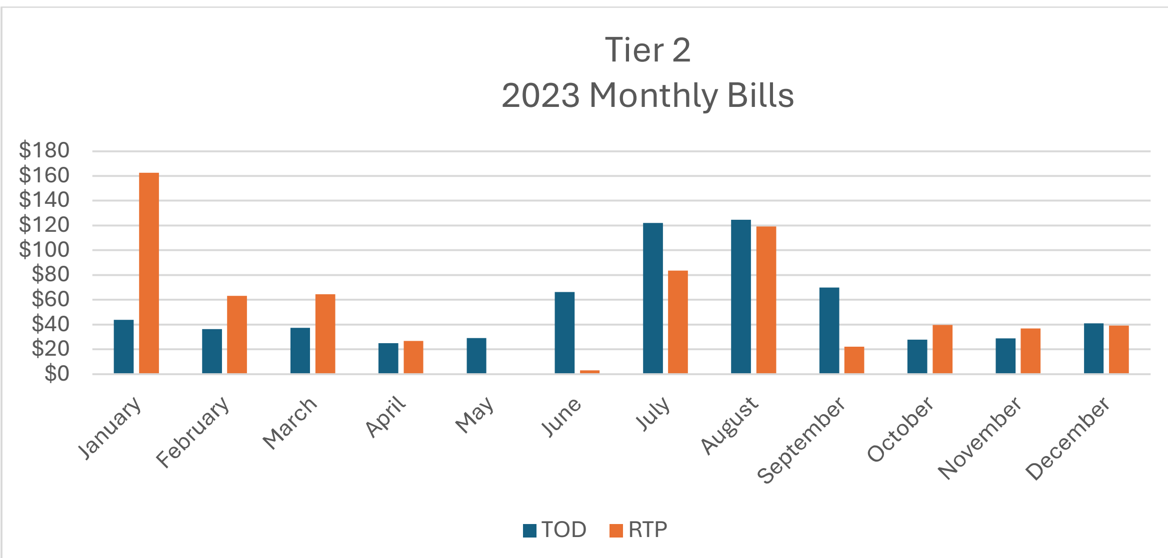
For the tier 1 customers, the discount is sufficient in most months to reduce the energy bill to $0. Those customers rely on that bill stability so they can plan their finances. An unexpected change in the market can cause a dramatic increase in their bill, along with their ability to pay their bill. In each year, there are dramatic increases in at least one month that impacts customer bill distribution.

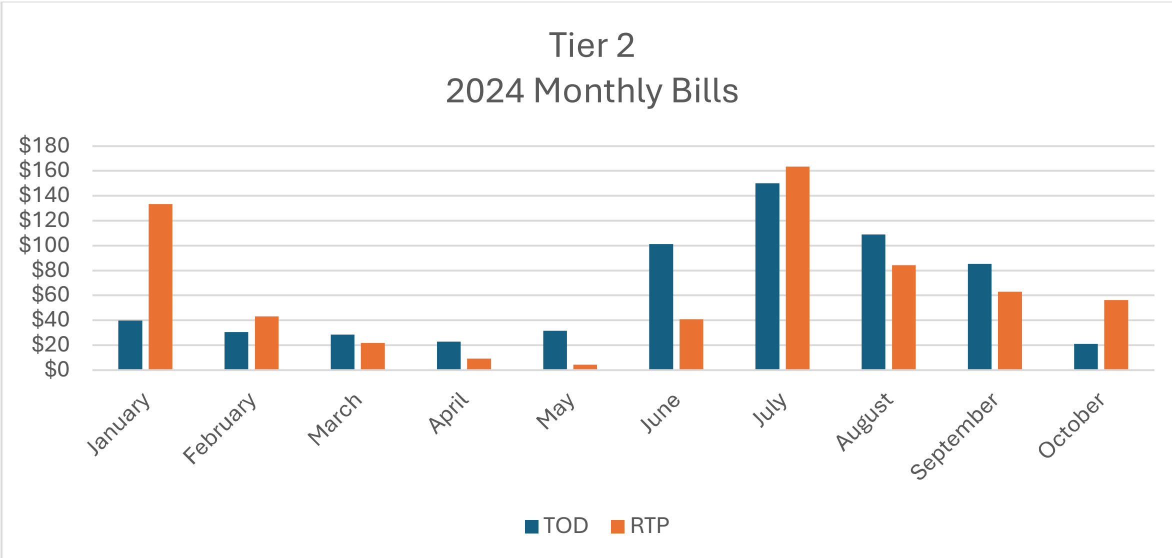


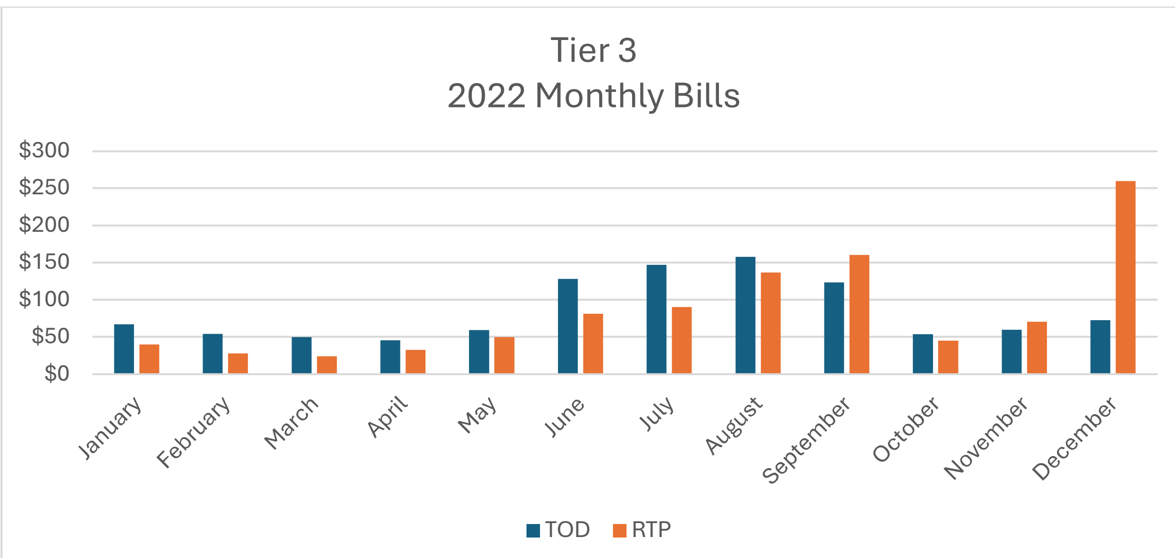

Tier 1
2023 Monthly Bills
$140
$120
$100
$80
$60
$40
$20
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP

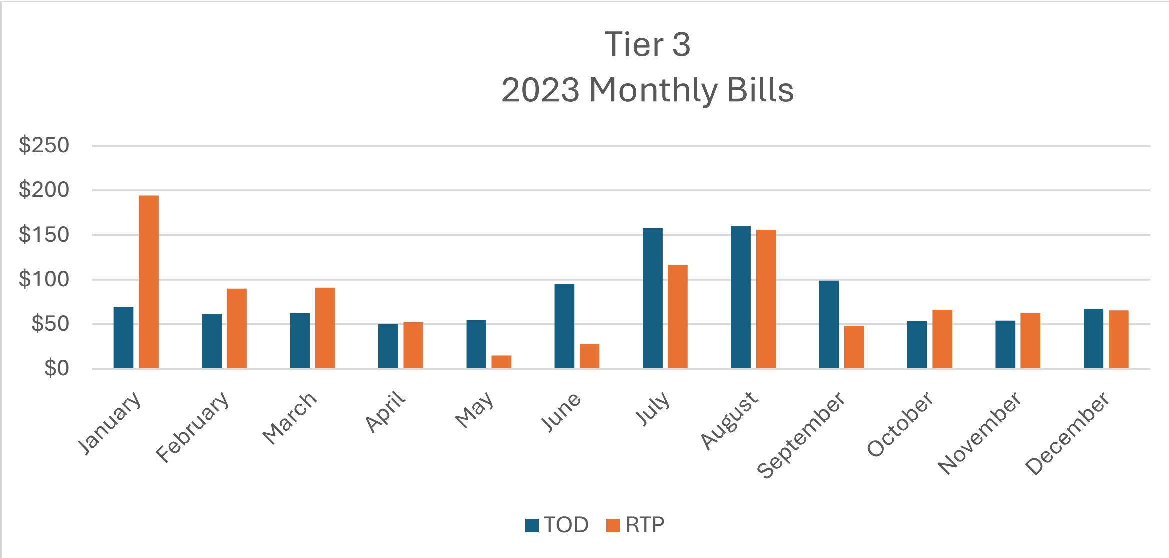

Tier 1
2024 Monthly Bills
$160
$140
$120
$100
$80
$60
$40
$20
$0
January
February
March
April
May
June
July
August
September
October
TOD
RTP


Tier 2
2022 Monthly Bills
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP


Tier 2
2023 Monthly Bills
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP


Tier 2
2024 Monthly Bills
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
January
February
March
April
May
June
July
August
September
October
TOD
RTP


Tier 3
2022 Monthly Bills
$300
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP


Tier 3
2023 Monthly Bills
$250
$200
$150
$100
$50
$0
January
February
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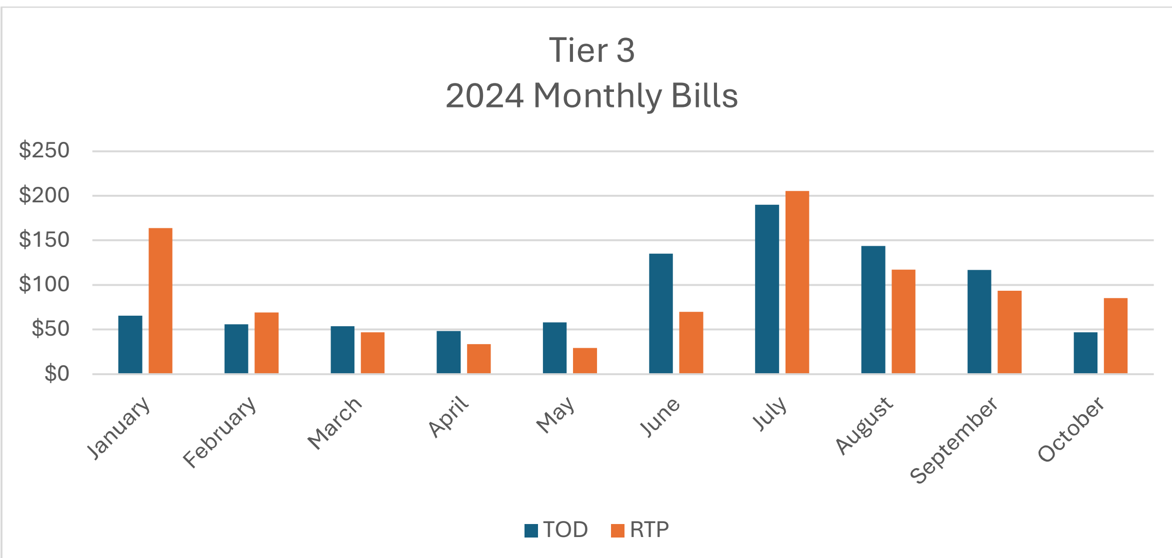
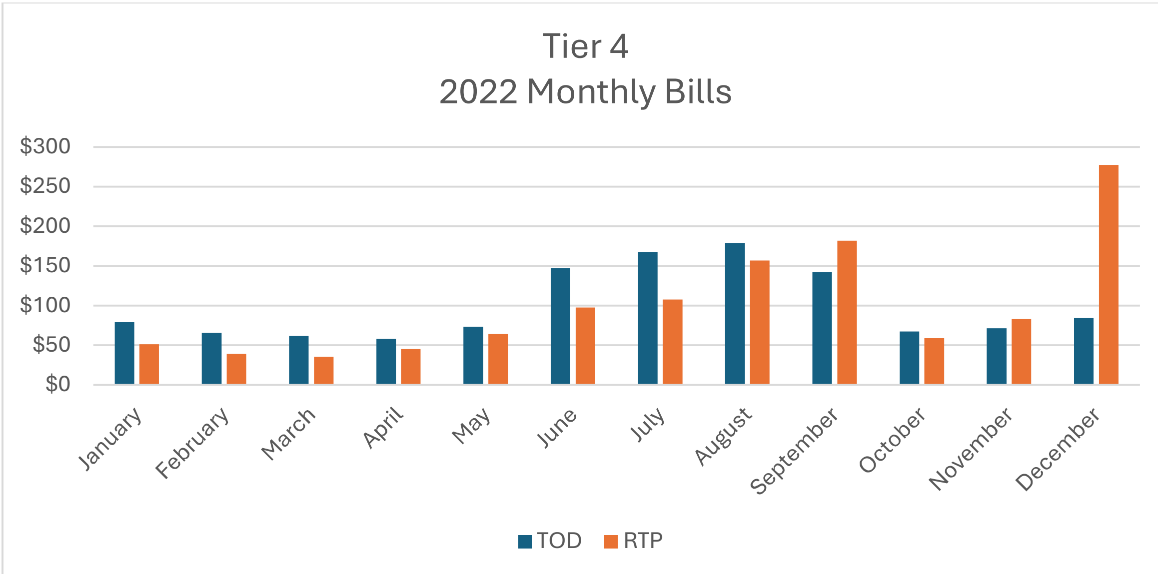
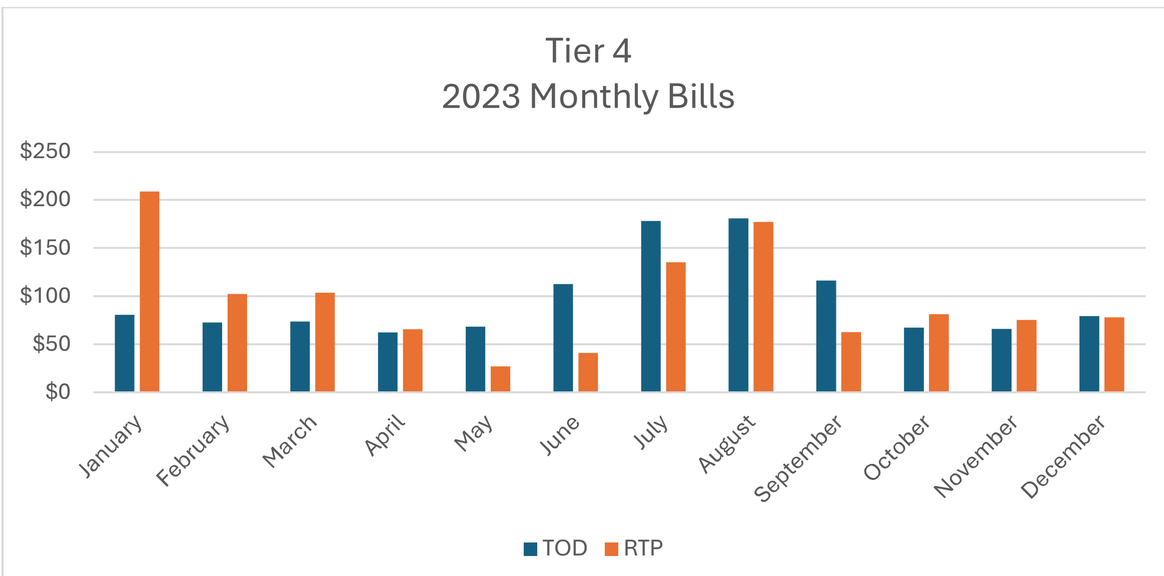
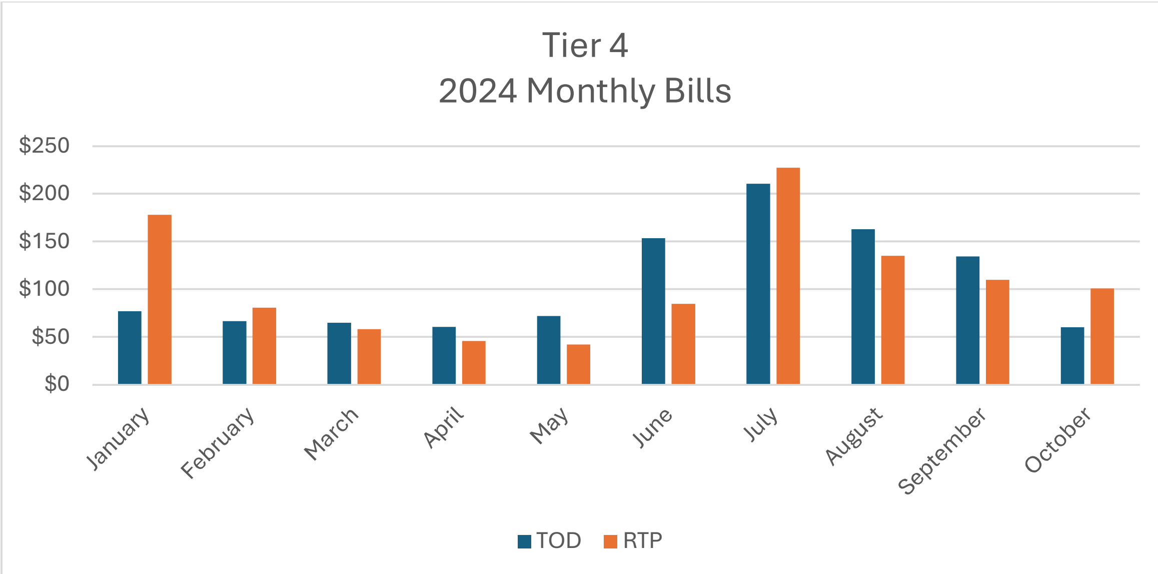
July
August
September
October
November
December
TOD
RTP


Tier 3
2024 Monthly Bills
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
TOD
RTP


Tier 4
2022 Monthly Bills
$300
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP


Tier 4
2023 Monthly Bills
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
November
December
TOD
RTP


Tier 4
2024 Monthly Bills
$250
$200
$150
$100
$50
$0
January
February
March
April
May
June
July
August
September
October
TOD
RTP