Rewarding Grid-Friendly Behavior: Estimating the Potential Bill Reduction and Load Shifting Benefits of Dynamic Prices

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ABSTRACT

Shifting electric load from times of peak demand can be a key strategy to slow price growth as reducing peak demand avoids the cost of upgrading generation, transmission and distribution infrastructure. Utilities are releasing time-varying prices, such as time of use rates or dynamic prices, to incentivize grid-friendly load shifting. New dynamic price programs provide insight into the true cost of operating electricity grids and the potential economic benefits of load shifting. Program developers and device manufacturers need to understand the economic opportunities in terms of 1) the variation in prices across hours, days, and seasons; 2) the change in utility bills for customers who don't shift load; and 3) the potential load shifted and economic value of different technologies if manufacturers or aggregators deploy price-responsive controls.

This paper estimates possible impacts of dynamic price adoption and load shifting controls if customers paid the dynamic rate from one pilot program. Statistical analysis of historical prices identified annual and seasonal metrics as well as representative price curves for each circuit in the pilot. Simulations for residential technologies with price-responsive controls including unitary heat pump water heaters, central multifamily heat pump water heaters, heating & cooling + storage systems, and pool pumps estimated the potential impacts of highly dynamic prices both with and without load shifting controls. Results showed the potential to reduce electricity costs on representative days by 42-94% and reduce consumption during times of high electricity prices by 63-100% compared to baseline operation for those flex-friendly devices.

Introduction

The United States expects summer and winter peak demand to increase, driven by adoption of technologies such as electric vehicles and data centers, by 79 and 91 GW respectively, while adoption of intermittent power sources reduces utility company's ability to control supply (NAERC 2023; Jha, Jha, and Islam 2025; CAISO 2013). These trends create higher risk of imbalance on electricity grids, driving a need for more demand flexibility (DOE 2024; Langevin et al. 2023).

Utilities are exploring several options to support grid stability including demand response programs, aggregator-led load shifting programs, and time-varying electricity prices (Gerke et al. 2024; Langevin et al. 2024; Paterakis, Erding, and Catalao 2017; Albadi and El-Saadany 2007). Time-varying prices can take the form of either time-of-use rates or highly dynamic prices. Time of use rates, which have been adopted by several utility companies, feature prices that change throughout the day with typically 2-3 different prices during different time periods (PG&E 2026; SCE 2026; SMUD 2026). They are typically stable across seasons by weekday type. For example, a utility may have 4 total price schedules: winter weekday, winter weekend, summer weekday, and summer weekend. Dynamic prices represent constantly fluctuating electricity prices, typically changing each hour, to represent the operating conditions and/or needs of the electricity grid based on forecasted supply and demand (PG&E 2024; SCE 2024). For example, hot summer days with high forecasted cooling loads will likely have high prices in the late afternoon while days with milder temperatures will have lower late afternoon demand and prices. This approach results in a unique price of electricity each hour of the year, typically released as a 24 hour price schedule the day beforehand (e.g. prices for January 2 will typically be finalized and released on January 1).

California now requires all utilities to provide optional highly dynamic price pilot programs, giving consumers the opportunity to reduce their utility bills by shifting load. These programs create a market opportunity to develop and commercialize devices or services that automatically respond to dynamic prices to reduce operating costs (Gerke et al. 2024).

Meanwhile, research efforts have developed price-responsive control algorithms that could be deployed either directly in products or via aggregator-led fleet control (Grant et al. 2025; Pfotenhauer et al. 2024; Piette et al. 2022; Woo-Shem 2025; Zanetti et al. 2024). These solutions provide consumers an opportunity to participate in dynamic pricing programs, shift load, and reduce their electricity bills without changing their day-to-day behavior or paying attention to electricity prices. Control algorithms are now available for devices including residential heat pump water heaters (HPWHs), central HPWHs for multifamily buildings, residential pool pumps, and air-to-water heat pump (AWHP) + thermal energy storage (TES) systems for heating and cooling.

These developments raise several important research questions from the point of view of consumers, device manufacturers, and program developers. Some key questions are:

- How will paying dynamic prices change utility bills ***without*** shifting load?
- How will paying dynamic prices change utility bills ***with*** price-responsive controls?
- What are typical dynamic price profiles? How much do they differ day to day?
- What is the load shifting benefit of fleets of devices participating in dynamic pricing programs?

This paper addresses those questions by:

- Identifying characteristics of 15 months of prices from one dynamic pricing program. Specific outputs include 1) average and extreme price profiles for each month, 2) shapes of typical price profiles, and 3) identification of regions in the grid with more/less variation in electricity price.
- Evaluating the impacts of paying those dynamic prices without price-responsive control to estimate the impact of dynamic prices on consumers who do not purchase load shifting equipment or participate in programs. Specific outputs include operating cost and load curve from simulations emulating available equipment with real use patterns for 1) fleets of unitary HPWHs, 2) central HPWHs, 3) AWHP + TES heating/cooling systems, and 4) residential pool pumps.
- Evaluating the impacts of paying those dynamic prices with price-responsive control, to estimate the cost saving and load shifting impacts of dynamic prices with high adoption of load shifting technologies. Specific outputs include operating cost and load curve from simulations emulating available equipment with the same real use patterns and program participation for the same technologies.

Methods

Price evaluation

The study analyzed 15 months (December 2024 through February 2026) of dynamic prices from one pilot program, providing sample data from all four seasons. The prices are split into 58 different circuits representing areas of the grid with different operating conditions. To estimate the typical characteristics of the prices, the following metrics were calculated for each circuit during:

- Average price for each hour of the day calculated for each month,
- Standard deviation in price for each hour of the day calculated for each month, and
- Typical daily price curves identified using time series K-means clustering and the elbow method to determine the number of clusters (Tavenar et al. 2020).

The average and standard deviation outputs enabled identifying months and circuits with high or low load shifting economic potential, as well as identifying typical daily price profiles for each circuit. Four circuits were selected for further analysis, aiming to estimate the impacts of dynamic prices and price-responsive control in different pricing scenarios. One selected circuit showed the scenario with the highest delta between the maximum and minimum daily prices, examining a circuit with high load shifting economic potential. A second showed the lowest delta in prices, examining a circuit with low load shifting potential. A third showed the circuit with the median delta in prices, estimating the impacts in a commonly experienced scenario. And the fourth identified a price curve that matches the typical expectation of low prices most hours and high prices during the evening peak period.

For each selected circuit clustering identified groups of days with similar electricity price profiles, specific days that represent each group, and the number of days represented by each group. This provided insight into the types of electricity prices commonly experienced in each of the four selected circuits. Representative days, identified from the clustering analysis, were selected based on 1) representing a large number of days in that circuit, and 2) providing a price profile different from the other selected price profiles. These price profiles were then input into load shifting simulation studies to estimate the load shifting and bill reduction potential arising from each price profile.

Technology simulation

The selected electricity price profiles were used to estimate the resulting load shifting impacts of four devices with price-responsive controls. Simulations estimated the a) change in electricity cost when paying dynamic prices instead of TOU rates, b) electric load curve impacts of price-responsive control, and c) operating cost impacts of price-responsive control. The simulations were performed twice, once with and once without price-responsive controls, to generate demand and cost curves for both baseline and price-responsive scenarios. Post-processing calculations estimated the operating cost under current TOU rates, enabling comparing operating costs between the dynamic prices and current utility prices. Each scenario was evaluated using the following metrics:

- **Operating Cost ($)**: The 24 hour electricity cost for a technology over a given price profile.

- **High-price electricity consumption (%, kWh)**: The amount of electricity consumed when the price is **above or equal to the 75th percentile**. This is expressed both as a quantity (kWh) and as a percentage of the electricity consumed in the 24 hour period.
- **Low-price electricity consumption (%, kWh)**: The amount of electricity consumed when the price is **below or equal to the 25th percentile**. This is expressed both as a quantity (kWh) and as a percentage of the electricity consumed in the 24 hour period.

The simulation results enabled comparisons between scenarios for each technology:

- **Operating Cost Reduction (%, $)**: Shows the reduction in 24 hour electricity cost when comparing between scenarios, expressed both as a financial value and as a percentage. This comparison showed the impacts of switching from TOU to dynamic prices, of adding price responsive control, and of making both changes.
- **Change in electricity during key periods (kWh, %)**: Treats prices as a proxy to grid conditions, with high prices indicating constraints and low prices indicating oversupply. Calculates the reduction in consumption during times of constraint and increase during times of oversupply between the baseline electric load curve and the price-responsive control simulation.

The four selected devices are as follows:

- **Unitary HPWHs**: Designed primarily for a single dwelling, these water heaters employ a 40-80 gallon storage tank, a ~450W-el heat pump, and ~4 kW-el backup resistance elements. They maintain the temperature of water in the tank to ensure that users can receive their desired hot water. Load shifting is provided using the CTA-2045-B Shed, Load Up, and Advanced Load Up signals. The presence of thermal storage and mixing valves enable adjusting the set temperature for load shifting purposes without impacting the temperature of water sent to the occupants. This study used a fleet of 148 HPWHs with different, monitored draw profiles.
- **Central HPWHs**: These are designed primarily for multifamily residential buildings, consisting of several large hot water storage tanks and AWHPs. The system maintains hot water in storage at all times enabling building occupants to access hot water. These systems typically use single-pass AWHPs and maintain highly stratified tanks. Similarly to unitary HPWHs, controls can change the amount of energy stored in the tank without impacting the temperature of water received by the occupants. Load shifting is provided using either CTA-2045-B Shed, Load Up, and Advanced Load Up or direct control of the AWHPs. This study emulates one CHPWH from a prior field study using the measured draw profile.
- **Residential Pool Pumps**: Residential swimming pool pumps provide circulation and filtration flow. Modern pumps commonly use variable speed drives, consuming 0-1,000 W when operating. Recent regulations in California require pool pumps to shift load to times when electricity prices are low (CEC 2024). Load shifting is provided using the CTA-2045-B Critical Peak, Shed, Normal, Load Up, and Advanced Load Up signals. Older single-speed pumps may use connected plugs or controllers to communicate on/off status. This study used a fleet of 5 pool pumps, 3 variable speed and 2 fixed speed, each with monitored pumping schedules from a prior field study.
- **Residential Heating & Cooling (HVAC)**: Novel systems now provide residential space heating and cooling using AWHP + TES combinations. The AWHP in these systems can

either directly serve the space or charge the TES, and the space loads can be served by either the AWHP or the TES. Controls for these systems are typically hosted directly on the system. This study used a single 12 kW-thermal + 1.5 m^3 water-based TES tank with simulated heating and cooling loads serving 6 dwellings in a multifamily building.

The selected devices, control deployment approach, and deployment readiness status details are described in Table 1.

Table 1: Price-Responsive Devices, Controls, and Deployment Readiness

Technology	Control Location	Control Level	General Control Strategy	Deployment Readiness
Unitary HPWHs	Cloud	Fleet	Identify groups of homes with similar baseline electricity consumption. Create CTA-2045 signal schedules customized for each group and price profile (Grant et al. 2025). Minimizes operating costs including avoiding resistance element activation around runouts	Being adopted by utility programs. The simulations estimate the impact of field deployments
Central HPWHs	Device	Single	Identify average hot water consumption profile for the site. Schedule AWHP operation at low-price times to ensure adequate hot water supply (Woo-Shem 2025)	Discussing adoption with one manufacturer. The simulations emulate controls embedded in products
Residential pool pumps	Device	Single	Use machine learning or direct input from users to understand daily pumping needs. Schedule pump operation to meet needs at lowest operating cost	Field testing has shown that product improvements are needed. The simulations emulate ideal field deployment
Residential HVAC	Device	Single	Model predictive control adjusting the temperature of water in the storage tank and using machine learning to forecast loads on the building	Both system and control in development stages. The simulations are theoretical

To evaluate the impacts of the dynamic prices, the analysis used the sample price days identified in the price evaluation and simulation models for each device. Details of the simulation approaches are presented in

Table 2.

Table 2: Simulation Approaches for Each Device

Technology	Model Description	Model Validation Status
Unitary HPWHs	Multi-node model designed to match hardware and control logic of one manufacturer's product	Validated against 12 months of field data (Hoeschele 2022)
Central HPWH	Simple thermodynamic model of stratified tank heated by single-pass AWHPs directly controlled by the load shifting algorithm	AWHP performance and baseline load from field testing (Woo-Shem 2025)
Residential pool pumps	Pump power, revolutions/minute, and behavior at specified modes from lab testing of one manufacturers product (Thomas 2017)	Baseline schedules and pumping requirement from five customer interviews. Lab testing supports assumption that pumps perform consistently at a given mode.
Residential HVAC	12 kW-thermal AWHP + 1.5 m3 of water-based TES. AWHP model based on manufacturer data, TES leverages stratified storage tank. Serves 6 apartments in South Lake Tahoe, California. Compared to a standard HVAC system with no TES	AWHP model validated against laboratory data. TES model previously verified against other simulation tools

Results

Price evaluation

Figure 1 presents the hourly mean price for each month of the year in four circuits. While the prices were calculated for each circuit in the program, Figure 1 presents a subset of circuits representing different price ranges. **High** represents the circuit with the highest average daily difference between the maximum and minimum price. **Low** represents the circuit with the lowest average daily difference, and **Median** presents the circuit with the median average daily difference. **Typical** presents the circuit with the highest average daily difference in price that displays the "typical" price curve characterized by high demand and high prices in the late afternoon.

The **High** subplot shows a challenge in which some grid circuits are heavily constrained during all daytime hours. In this case grid-stabilizing and bill-reducing load shifting needs to move electricity consumption from the daytime to overnight, differing from the typical assumption that load needs to be shifted from the evening to mid-day or overnight. Low prices overnight in many months fall below $0.10/kWh while mid-day prices often exceed $1.00/kWh, indicating a very high potential for cost-reductions from load shifting. This pattern holds most months of the year except for January, December, and May which provide the opportunity for 50-60% price reductions instead of the 90% in the other months. The **Low** subplot shows that some circuits have low load shifting economic value driven by low variation in prices. August shows some potential, with an average of \$0.26/kWh during the evening peak and \$0.05/kWh overnight, but most other months feature prices ranging from a minimum of \$0.04/kWh to a maximum of \$0.07/kWh. The **Median** shows a little more variation than **Low**, with slightly higher price increases in August and September. The limited variation in the median circuit implies that most days and most circuits provided limited price difference and limited economic value for load shifting. The **Typical** price profile presents substantial cost saving opportunities, surprisingly, from November through February with average evening prices reaching as high as \$0.65/kWh before falling to \$0.05/kWh overnight. The late summer prices also show potential, reaching as high as \$0.30/kWh during the evening while being ~\$0.05/kWh the rest of the day.

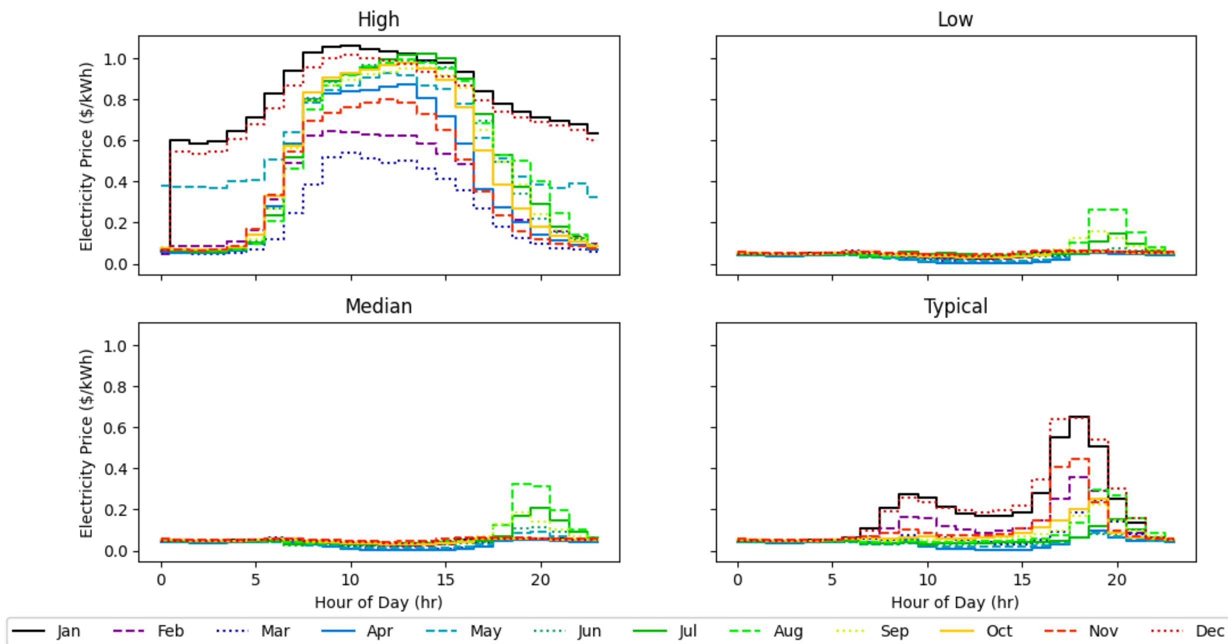

Figure 1: Mean hourly prices for each month in representative circuits

Figures 2 and 3 show statistics for the price in each circuit for the winter and summer seasons, respectively. Typical prices are lower in the winter, with many circuits showing a maximum winter price of approximately \$0.10/kWh and maximum summer price exceeding \$1.00/kWh. Common daily variations are also more intense in the summer, with most circuits showing higher maximum daily prices. Load shifting potential is typically higher in the summer, as most circuits show larger difference between the maximum and minimum daily price means in the summer, especially when taking into account the variability represented by the standard deviation. Notably, the High and 22 circuits are very expensive in both the winter and summer, indicating that these circuits are more challenging to manage and provide more economic value for load shifting than other circuits.

Figure 4 presents representative days and number of days for each cluster identified using time series K-means analysis in the same circuits. K-means analysis identified clusters of days with similar price profiles, and each line on the plot provides the price curve that is most representative of each cluster. The number next to each line states the number of days in that cluster, out of a total 451 days in the monitoring period. The **High** price cluster shows that most days experienced a dramatic increase in prices during the mid-day, indicating that the potential for cost savings through load shifting remains high throughout the year. The **Low** circuit showed that the majority of days have very flat price profiles, with only 26 days showing notable price differences. The **Median** profile also showed low potential for cost savings, with 90% of all days showing very minor price changes and 8% showing price differences on the order of $0.35/kWh or more. The **Typical** circuit showed a more mixed result, with 52% of days experiencing very little price change and the other 48% yielding significant price reduction opportunities.

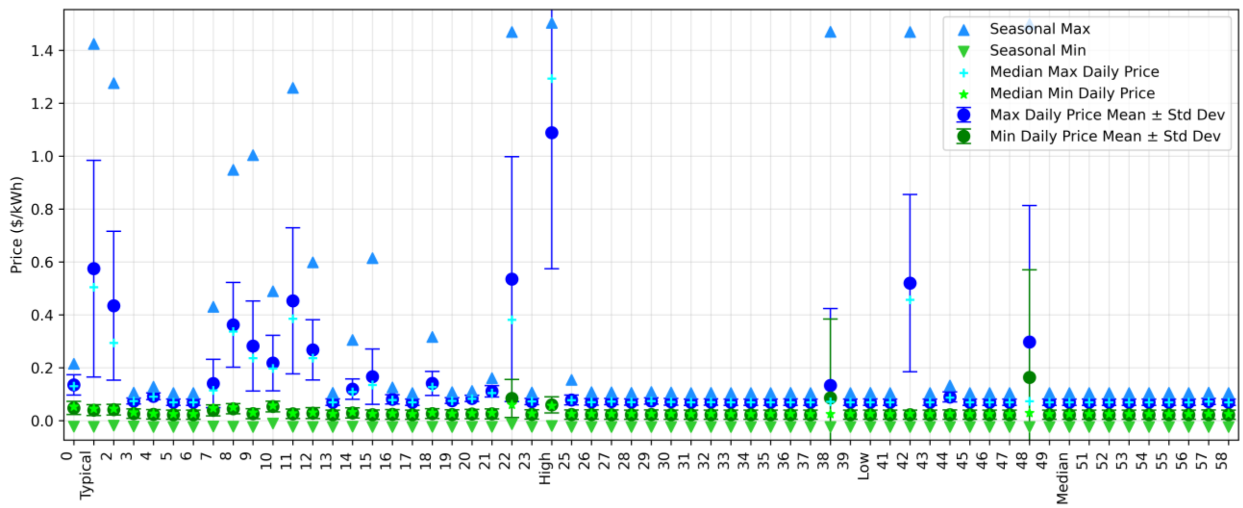

Figure 2: Overall seasonal max, seasonal min, maximum median and mean daily price, and standard deviation of the max and min daily price for each of the circuits in the winter season

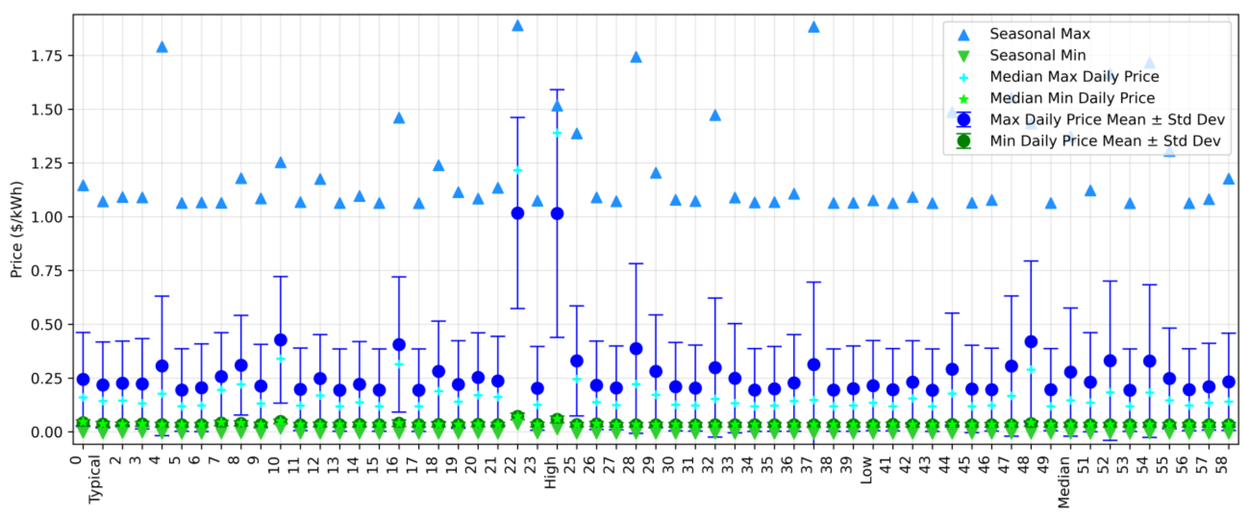

Figure 3: Overall seasonal max, seasonal min, maximum median and mean daily price, and standard deviation of the max and min daily price for each of the circuits in the summer season

Four price profiles were selected from those displayed in Figure 4 as described in Methods, and highlighted in bold in Figure 4. The four selected price profiles, highlighted with the bold line, were: 1) the profile from the High circuit with 250 similar days, 2) the profile from the Low circuit with 218 similar days, 3) the profile from the Median circuit with 38 represented days, and 4) the profile from the Typical circuit with 27 similar days.

On average, the prices in the dynamic pricing program are below current time of use rates indicating potential to substantially reduce electricity costs. For many circuits the mean maximum daily price is below current TOU rates in both winter and summer. Most of the daily price profiles represented in Figure 4 include extremely low prices at some time of day, providing the potential for customers to reduce their electricity bills by shifting loads to time of lower prices. Only two, 22 and High, of the studied 58 circuits show consistently high prices, implying that current TOU prices may be elevated by a few particularly challenging portions of the grid.

Technology simulation

As an example of the impacts, Figures 5 and 6 present the simulation results for all four technologies in the High and Low pricing profiles. These two profiles were selected as they show how the technologies respond to very different grid operating conditions (represented as very different prices). In all plots the dashed blue line shows the baseline operation with no load shifting ("No Shift"), the green solid line shows operation with load shifting control ("Shift"), and the red line shows the electricity price ("Price"). Shading between the No Shift and Shift lines highlight the difference, with green showing a decrease and red showing an increase.

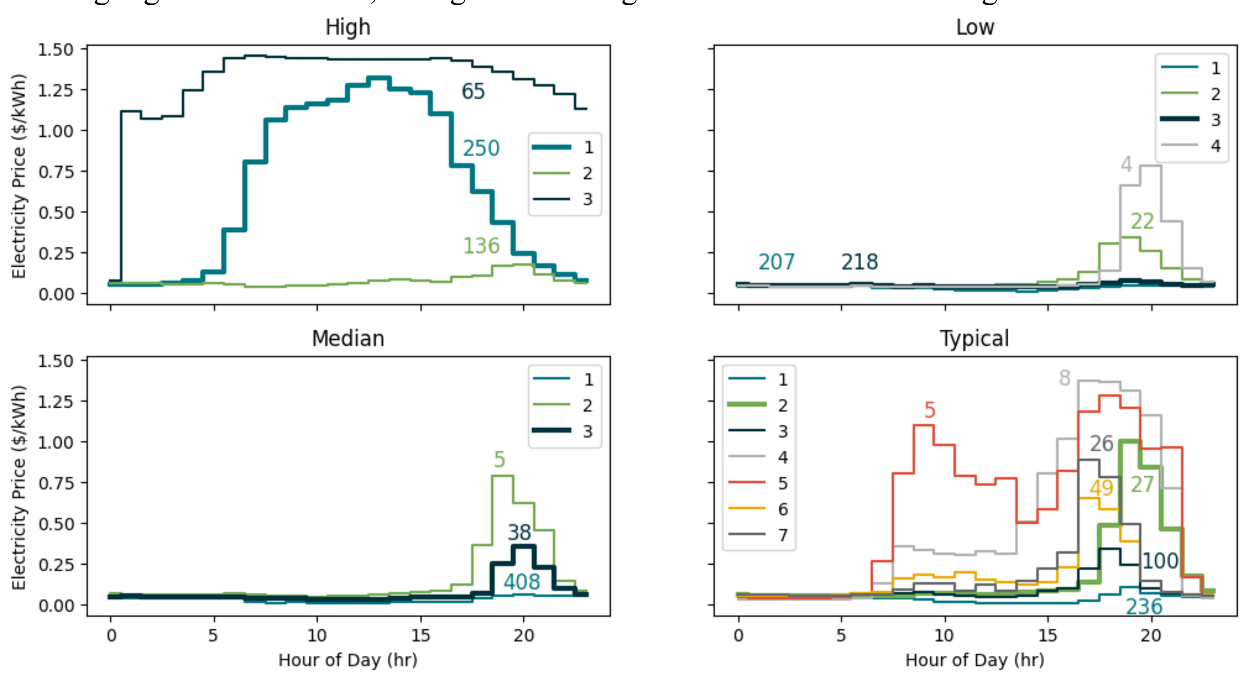

Figure 4: Cluster centroids for representative circuits

The High price profile in Figure 5 features a low price, less than $0.10/kWh, overnight and a high price, consistently greater than $1.00/kWh, during the day. In each case the price responsive control responds by shifting the majority of the electricity consumption from midday to overnight, as demonstrated by the dramatic decrease in demand between 9 AM and 9 PM as well as the increase between midnight and 3-6 AM (depending on technology). The HVAC simulation stands out as the system ran out of stored energy at 2 PM and had to resume operating the heat pump, after removing all heat pump operation during the earlier high price hours. This had the impact of dramatically reducing costs for consumers of all four technologies, as evidenced by the large reduction in operating cost from 9 AM to 9 PM and the negligible increase between midnight and 6 AM. Across the four technologies price-responsive control reduced the electricity costs in the High price profile by 62-91%. The total cost savings varied by technology driven largely by the load of the controlled units, reaching as high as $138.53/day for the CHPWH system.

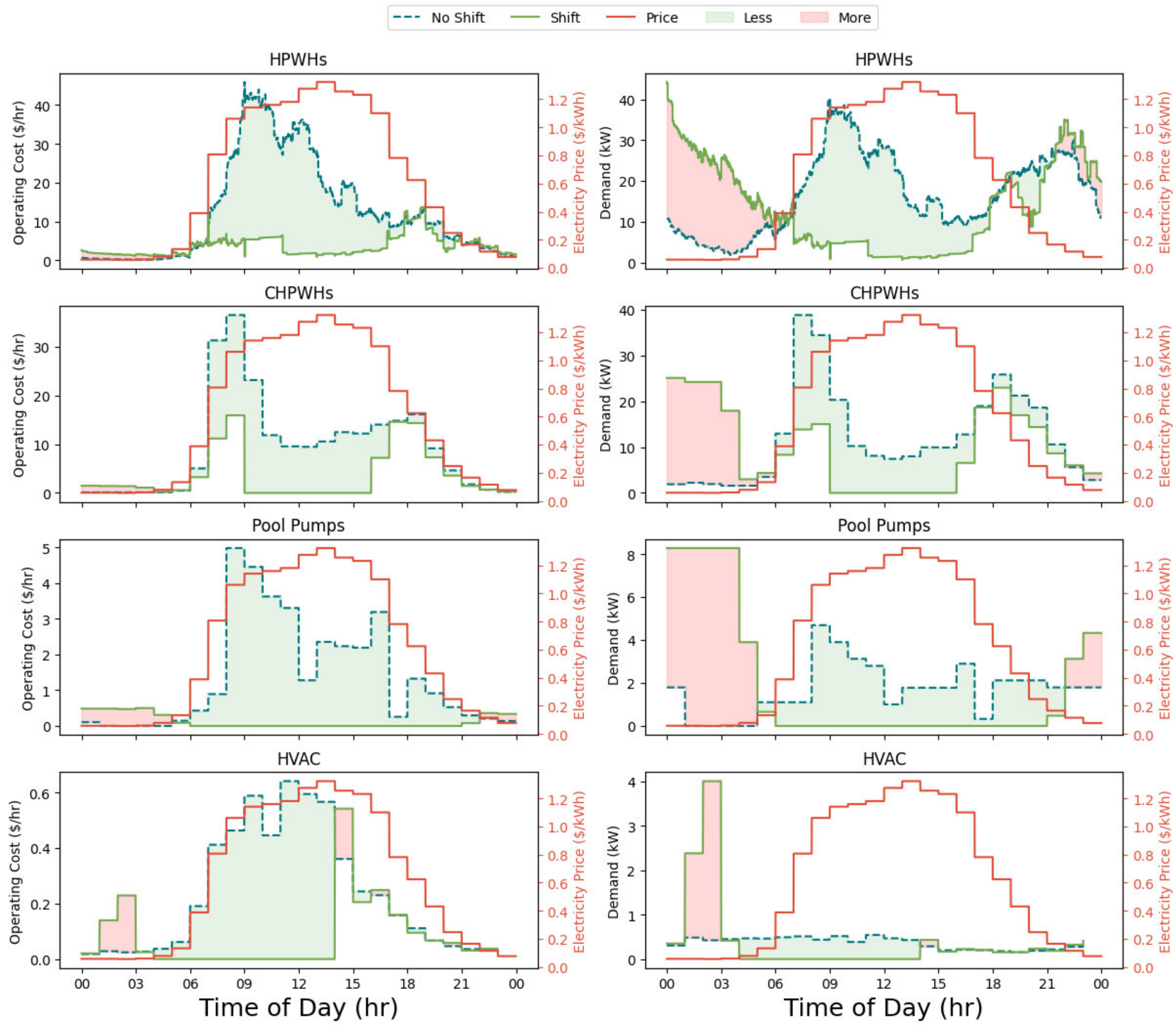

Figure 5: Load shifting results for all four technologies in the High price profile. (Left) Operating cost. (Right) Electric demand

Figure 6 shows the results with the Low price profile, which featured a nearly opposite price profile shape. The low prices occurred during the middle of the day, approaching $0.04/kWh between 11 AM and 5 PM. The maximum price was in the evening, though those prices were still low remaining below $0.08/kWh. The control again responded by shifting load from times of elevated prices to times of low prices. Each device significantly increased demand during the 11 AM to 5 PM period and reduced in the evening. This resulted in significant reductions in operating cost during the evening, and increases in operating cost midday. The impacts of price-responsive control were less noticeable in the Low case than the High case, reducing electricity costs by 12-35% with a maximum savings of $5/day for the CHPWH system. This is driven by the much smaller potential savings, a maximum of $0.04/kWh instead of > $1.00/kWh, providing both less incentive and less reward for shifting load.

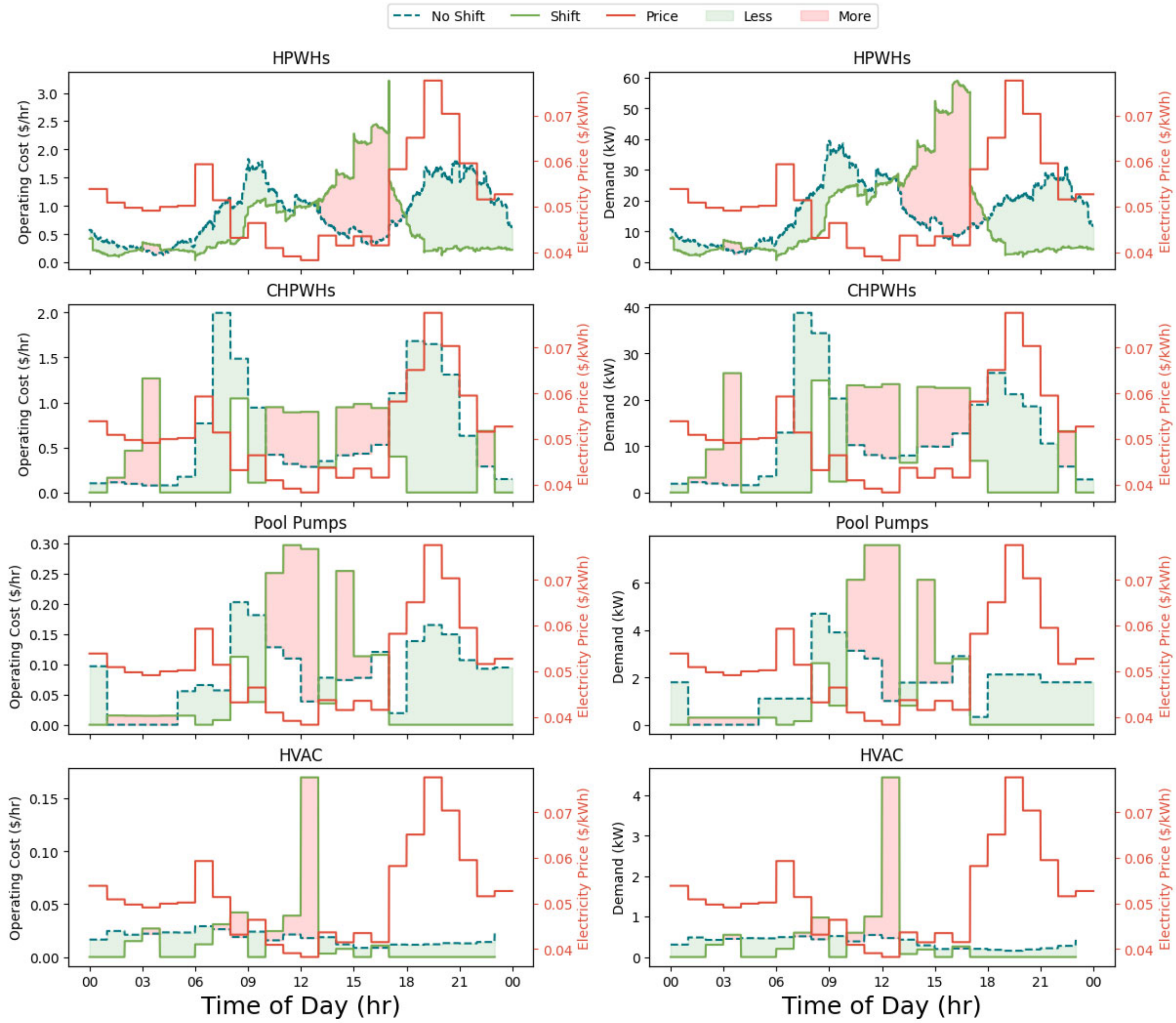

Figure 6: Load shifting impacts for all four technologies in the Low price scenario. (Left) Operating cost. (Right) Electric demand

Figure 7 presents the operating cost of each price & load shift scenario normalized to the electricity cost with TOU rates and no load shifting for each technology. The colors represent the different electricity price schedules. Fully shaded bars show the electricity cost with no load shifting, and lightly shaded bars represent the case with load shifting. For example, the dark blue, lightly shaded bar (third) for each technology shows the electricity cost in the High price scenario with load shifting control compared to the electricity cost for the same technology with no load shifting paying current TOU prices. The results are quite similar across technologies. For all four, paying the High price schedule would increase operating costs by 29-61% without load shifting control. Implementing price-responsive control while paying the high price would yield a 42-85% electricity cost reduction compared to the no shifting TOU case. All other price profiles showed substantial cost reductions without price-responsive control, reducing electricity costs by 52-90% compared to the no shift TOU case. Adding price responsive control further reduced operating costs providing 84-94% savings compared to the no shift TOU case.

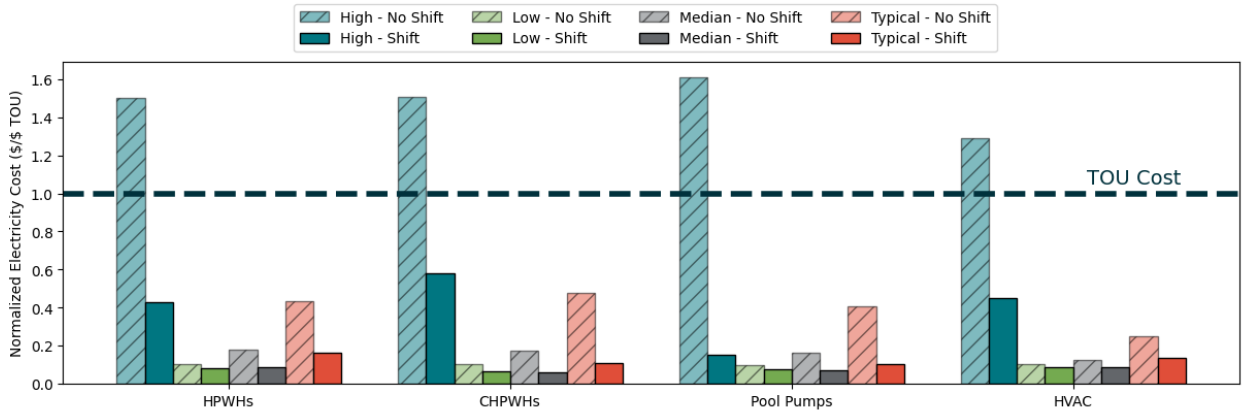

Figure 7: Electricity cost of all scenarios normalized to TOU cost for each technology

The implications of these cost reductions are clear:

- Understanding the dynamic price prior to participating is important, as some circuits have high enough prices that participation without price-responsive control could increase electricity costs.
- That risk can be mitigated by implementing price-responsive control. Even in the High price scenario, where there was a risk of increasing electricity costs by 29-61%, participation with price-responsive control provided large bill savings.
- In all studied cases participation in dynamic price programs and implementing load shifting control yielded large electricity cost reductions. Since the selected price schedules represent most of the days expected to be seen in the program, participation is likely to provide large annual bill savings.

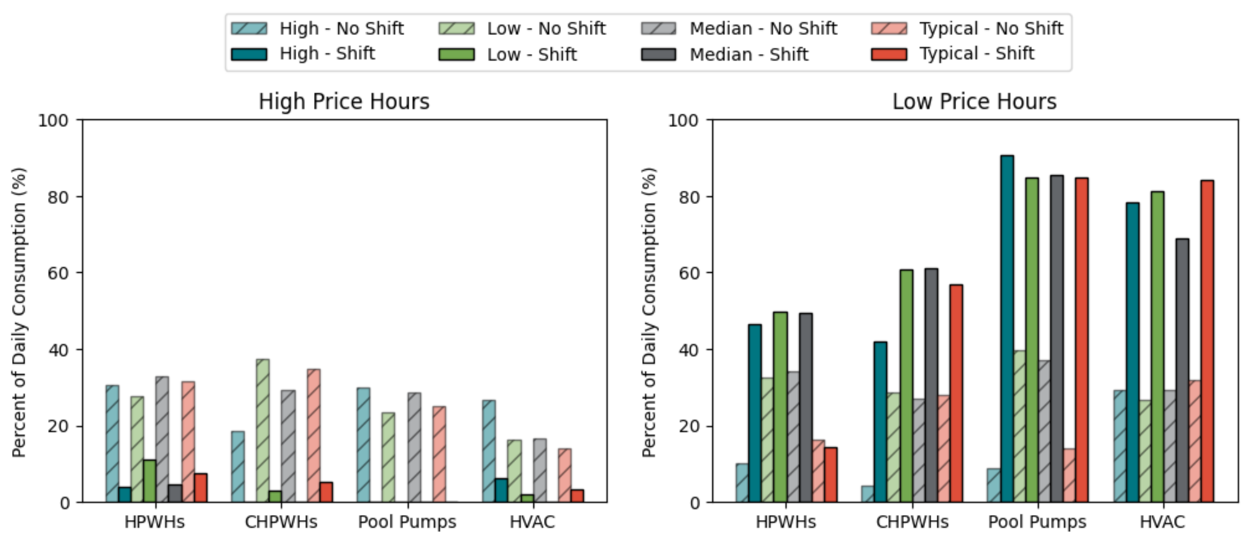

Figure 8: Impact of price-responsive control on the load shape for each technology in each pricing scenario. (Left) Percentage of daily load consumed when prices are at or above the 80th percentile. (Right) Percent of consumption when prices are at or below the 20th percentile

Figure 8 presents the percentage of electricity consumed during high price (left) and low price (right) times of day for each technology and price schedule scenario. The bar color and shading are the same as in Figure 7, with the exception that the TOU scenario is excluded. Without price responsive control the devices consumed between 14 and 37% of their daily electricity during times when the price was at or above the 80th percentile, indicating significant consumption at times when utilities need to reduce electric demand. Implementing price-responsive control reduced high price consumption to 0-11% of daily totals, significantly reducing the contribution of these devices to grid peaks. The effect was especially pronounced for pool pumps, which were able to shift 100% of load out of the high price period in all four pricing scenarios. The effect was less pronounced, though still significant, for the HVAC system in the High price scenario which, as can be seen in Figure 5 did not have adequate storage to coast through the high price period without consuming electricity.

Price responsive control reduced that high price consumption by shifting it to times when the prices were at or below the 20th percentile. Without price responsive control the devices consumed 4-40% of their daily electricity consumption during times of low price. Implementing price-responsive control increased those values to 14-91%. The fleet of unitary HPWHs decreased their percentage of low price electricity consumption, as avoiding the highest cost times with their limited storage and default control logic required consuming electricity a little later in the day when prices were not quite as low. Excluding that unique case, the technologies consumed 42-91% of electricity at low price times with price responsive control.

These results indicate that:

- For these technologies, price-responsive controls are capable of both reducing consumption during times of peak grid stress and increasing consumption during times of overproduction.
- Price-responsive control are capable of adapting to different pricing scenarios, providing grid stabilization benefits as needed in different operating conditions.

Discussion

The prices in the studied dynamic pricing program showed significant variation across seasons and across circuits. Most circuits showed significantly higher price variation in summer than winter, though some circuits are more expensive in winter. A few circuits showed very high prices all year, with the peak not necessarily occurring during the traditional evening grid peak period. Typically, the prices in the dynamic pricing program are lower than Californian TOU rates, with a few circuits appearing to drive elevated TOU prices.

In three of the four studied scenarios, paying dynamic prices would reduce electricity costs for customers by 52-90%, even without load shifting control. This is driven by the prior observation that prices in most circuits are lower than existing TOU rates. Paying dynamic prices would increase costs in the most expensive circuits by an estimated 29-61%, driven by their very high electricity prices, indicating a need to understand the prices that a particular site will pay prior to switching to dynamic prices.

Under all pricing and technology scenarios, paying dynamic prices with load shifting control provided large utility bill reductions. The cost savings ranged from 42-94% when compared to baseline operation paying TOU rates. This includes changing the load curve to match the different price curves. Price responsive control reduced high price consumption from 14-37% of daily load to 0-11%, and increased low price consumption from 4-40% to 42-91%. In every scenario the combination of dynamic prices and price-responsive control provided utility bill reductions to the consumer and beneficial load shifting to the grid.

The two plotted scenarios showed that the controls created different load curves in response to different price curves. The Low scenario featured low prices mid-day, and the controls shifted electricity consumption to those low price times. The High price scenario showed the opposite; high prices mid-day caused the controls to shift load to overnight. The diversity in price profiles highlights that the needs of the grid are not as simple as commonly thought. Load shifting programs typically try to minimize consumption during the ~4-9 PM peak period; however, not all circuits have the same overloading pattern, and different circuits will benefit from different load shifting strategies. Price-responsive controls are able to ingest prices representing the state of the grid, customize electricity load curves to the current operating scenario, and create load curves matching the needs of different grid realities driven by weather or location impacts.

Part of this performance is driven by the characteristics of the selected technologies. HPWHs, CHPWHs, and the studied HVAC system all include thermal energy storage which enables shifting loads without impacting the occupants. They heat or cool the storage when prices are cheap to enable providing needed services without consuming electricity when prices are high. Pool pumps need to pump a certain volume of water per day without much concern about time, also enabling load shifting without decreasing occupant satisfaction. Technologies that do not impact services provided to the occupants, such as these four, are expected to facilitate adoption of load shifting control. In technologies with storage, shifting all load without impacting the occupants requires designing the storage with load shifting in mind. As shown in Figure 5 and 6 neither the CHPWH nor the HVAC system had enough storage to shift all load out of the high price period, and larger storage volumes would yield better results. For unitary HPWHs more storage reduces the risk of cold water runouts during long periods of load shed.

Conclusion

Utilities are releasing dynamic prices to motivate load shifting behavior that reduces grid operating challenges and costs. Industry actors need to understand the potential impacts of these prices prior to opting to pay them, developing load shifting programs around them, or manufacturing new products designed for them. Analysis of prices from one program showed that most circuits have prices lower than current time of use rates, while only a few circuits have higher prices. Switching to dynamic prices without load shifting control would reduce water heating, space heating/cooling, and pool pumping operating costs by 52-90% in most scenarios, but increase costs by 29-61% in the most expensive circuits. Including price responsive control with dynamic prices provided cost savings of 42-91% in all scenarios when compared to baseline operation with time of use rates. Price-responsive control with dynamic prices dramatically changed the load curve, reducing the percentage of load during the high price period from 14-37% to 0-11%. Load shifting also increased consumption of the lowest price electricity from 4-40% without load shifting control to 14-91% of daily electricity consumption. Paying dynamic prices is likely to reduce electricity costs for most ratepayers with or without price-responsive controls, and likely to provide significant discounts for all ratepayers with price-responsive controls. The combination of dynamic pricing and price-responsive control shows potential to shift electric loads in ways that support a stable electricity grid, slowing electric price growth.

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