Hawaiʻi Natural Energy Institute Research Highlights

Energy Policy & Analysis

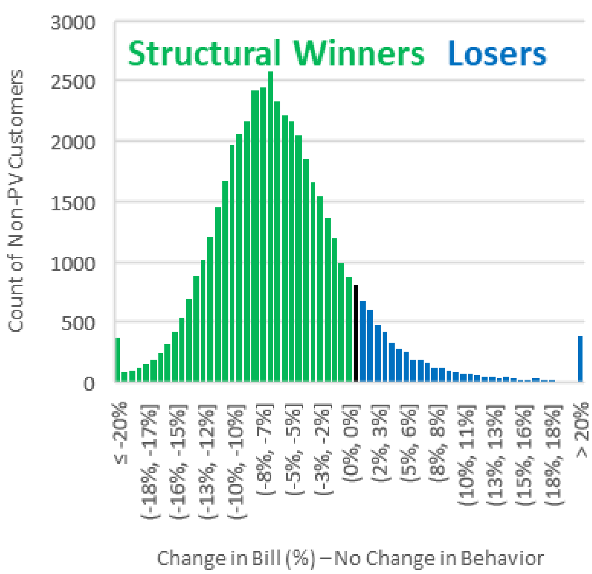
Analysis of Bill Impacts and Equity of Time-of-Use Rate Design

OBJECTIVE AND SIGNIFICANCE: Time-of-use (TOU) rates – electric rates that vary in price based on the time of consumption – are currently being developed and implemented by HECO and the Hawaiʻi PUC. Under the new rate structure, electricity prices during evening peak demand periods would be three times more expensive than in the middle of the day. The intent of these rates is encourage customers to shift load to hours when solar generation is plentiful and out of peak demand hours, which have been historically more expensive. In theory, this would save customers money while also benefiting the grid and Hawaiʻi as a whole through increased solar integration, reduced oil consumption, and avoided grid upgrades. The objective of this study is to assess whether the proposed rates would equitable, calculate bill impacts of proposed rates, and evaluate potential changes to revenue and cost allocation. The results of this study were briefed to HECO and made available to PUC.

KEY RESULTS: The HNEI-Telos team reviewed individual 15-minute advanced metering data across 60,000 customers for a single month. The results showed that large proportions (85+%) of non-PV customers would be Structural Winners – those who would get a cheaper bill just from switching to TOU rates, even without changing their behavior. Customers with PV, in contrast, would see a significant increase in monthly bills (62% or $82/month on average) if they were required to switch to TOU rates. Another analysis, discussed in the "**O'ahu and Maui Load Flexibility**" project summary, shows that even if the TOU rate successfully encourages behavior change, it provides only limited or modest system benefits because much of the load shifting benefits are provided by grid-scale battery storage systems. **As a result, TOU-induced behavior change, as currently constructed, does not provide a meaningful reliability benefit to the grid.** Instead, TOU rates should be designed to move load across days or to mitigate distribution level constraints.

BACKGROUND: TOU rates, like those currently being proposed were first implemented by HECO in 2012 (TOU-R) and the power system has changed remarkably since then, changing the type of load shifting needed. From 2023-2025, each of the HECO grids will see a large increase in battery storage – both in standalone projects as well as utility-scale solar + storage hybrid projects. These batteries will provide much of the load shifting needs on the system, reducing the need for TOU rates.

HECO and the PUC have already committed to large battery projects in recent procurements and most of them are either already operating or under construction. These batteries provide much of the load shifting needs on the system, reducing the need for additional load shifting from TOU rates for the foreseeable future. On Oʻahu, for example, battery



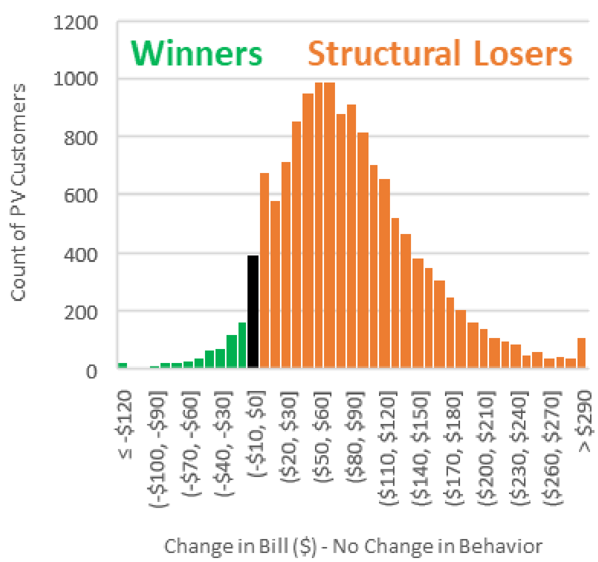


Figure 1. Distribution of bill impacts by non PV customers (left) and PV customers (right).

storage will soon reach 400 MW of capacity, over one-third of evening peak load, with more coming in near-term procurements. The storage deployment on other islands is even more pronounced on a proportional basis – reaching 60% of peak demand on Maui and 40% on Hawai'i Island, with additional storage coming shortly after.

PROJECT STATUS/RESULTS: The results show that while TOU rates will have only limited system reliability benefits, they will create significant changes to the way electricity is billed, and potentially create equity concerns. This could arise if some ratepayers switch to TOU rates to reduce their bill, but the load shift does not have meaningful economic benefits that can be realized by other ratepayers.

To evaluate this further, the study assessed individual customer impacts of the proposed TOU rates. The study found that most non-PV customers would save money by switching to the rate without changing their behavior. The opposite is true for PV customers – they would mostly have to pay more if a switch to TOU is required.

These findings are highly sensitive to the base daytime rate. Increasing the base rate by just one cent (from the proposed $0.19/kWh to $0.20/kWh) would significantly decrease the number of structural winners. In fact, this change would make more structural losers than winners.

These large changes in how electricity is billed should be carefully evaluated for their revenue neutrality. Assuming that Structural Benefiters switch to the appropriate rate for them, non-PV residential customers' total revenue would **drop 1.8% and disproportionately helps high energy users** without a change in behavior. Put simply, TOU rates introduce a long-term risk of revenue collection for grid services.

This analysis was paired with the Load Flexibility modeling effort to develop recommendations for the future of demand side programs in islands systems with high amounts of battery storage. While the analysis showed limited benefits of TOU rates once battery storage is added to the system, there are other opportunities for load flexibility. Principally, as is shown in the Maui load flexibility analysis, there is an opportunity for load shifting induced from TOU rates to capture the energy arbitrage value that batteries could provide. Effectively, the energy arbitrage benefit is saturated by whichever resource (load shifting or batteries) arrives first.

Given that HECO has already contracted and is currently commissioning a large number of grid-scale batteries in the Stage 1 and Stage 2 procurements, it is likely that most short-duration load shifting benefits will already be accrued to battery storage before meaningful amounts of load flexibility can be recognized.

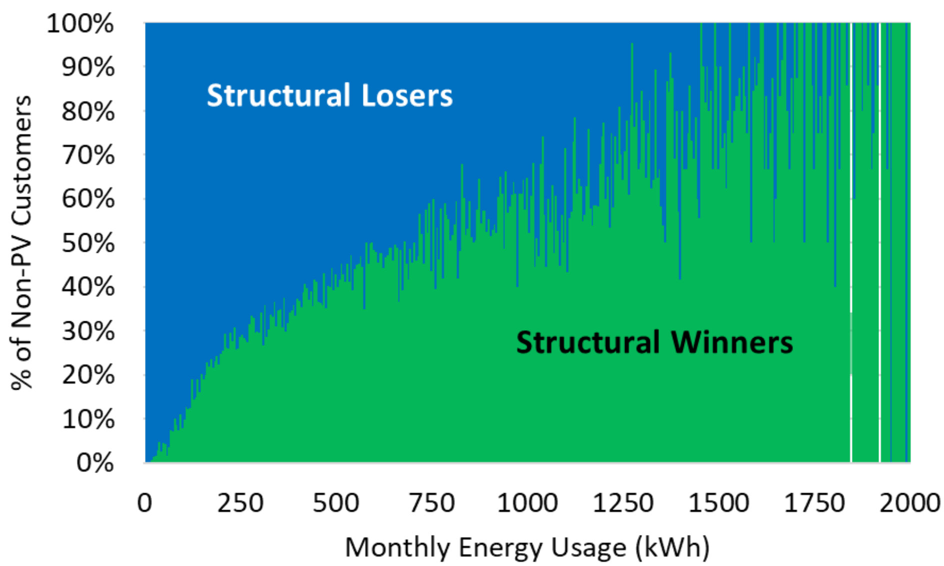


Figure 2. Percentage of structural winners vs. structural losers with TOU rates, by monthly consumption level.

Regardless of the battery deployment schedule, value was identified in load flexibility programs that modified load consumption based on changing system conditions rather than a set schedule. However, such a rate would require more sophistication – from customers, technology providers, and HECO – to implement.

The analysis evaluated potential benefits of these more sophisticated controls, which showed 50% improvement in capacity benefits when load flexibility could be dispatched according to the specific day's needs. This increased to a 95% improvement when load could be flexible across a week, shifting load out of one day (i.e. a cloudy day) and into another altogether (i.e. a sunny day).

A second option to achieve this multi-day flexibility would introduce a day of week billing (or a "Cloudy Day Rate") that effectively prices consumption higher during low solar days to incent load reduction when generation would be strained. This however would only apply to some loads, potentially some electric vehicle charging, large industrial loads, water pumping, or other schedulable processes.

Finally, rates designed to avoid distribution-network upgrades may also provide significant benefits. Rather than provide broad, system-level benefits, load flexibility could target individual distribution circuit needs. This could potentially avoid costly upgrades often attributed to solar PV additions, concentrated EV charging, or new developments. This would again require either direct load control or a more tailored rate schedule unique to each circuit.

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