The State of Demand Flexibility Programs and Rates and Their Role in Managing Peak Demand

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ABSTRACT

Utilities are increasingly offering programs and rates that promote demand flexibility to manage peak demand and integrate renewable energy. To scale these flexible demand-side resources, utilities would benefit from data on program/rate performance and design considerations. However, there is a lack of data on the characteristics and performance of these programs and rates. This paper will focus on results from a nation-wide study of demand flexibility programs and rates, including wi-fi thermostat and customer-sited battery programs and critical peak rates among others, conducted by Berkeley Lab.

The paper will first provide a typology of the programs/rates, identify where they are active, and describe the grid services that they provide. For a range of demand flexibility programs, we will delineate key program design elements, including event structure and incentive levels, and characterize program performance in terms of enrollment, demand savings, and program costs. We will also relate these program design features to the procurement of grid services and discuss important tradeoffs in program design and technology selection. Next, we will describe the structure, timing, and pricing of variable peak and critical peak pricing programs. We will close by discussing how these programs and rates complement each other.

Introduction

This paper provides an in-depth review of current practices among programs and rates that promote demand flexibility in residential and commercial buildings in the United States (U.S.).[1] As defined in the U.S. Department of Energy's National Roadmap for Grid-Interactive Efficient Buildings, demand flexibility is "the capability provided by on-site DERs [distributed energy resources] to reduce, shed, shift, modulate, or generate electricity. *Building* demand flexibility specifically represents the capability of controls and end-uses that can be used, typically in response to price changes or direct signals, to provide benefits to buildings' owners, occupants, and to the grid." (Satchwell et al. 2021). Demand flexibility can lower carbon emissions and energy costs by shedding load during peak hours, or by shifting that load into off-peak hours, potentially reducing curtailment of solar and wind generation (Goldenberg, Dyson, and Masters 2018; Hale, Stoll, and Mai 2016).

In 2020, more than 11.6M U.S. electricity customers provided about 29.5 GW of demand flexibility capacity through retail demand response programs (FERC 2022). Commercial and industrial customers provided half of this capacity. Analysis from Brattle suggests that the entry of new technologies (e.g. thermal storage), the expansion of existing programs (e.g. smart thermostats) and dynamic electricity pricing can increase this potential significantly through 2030 (Hledik et al. 2019).

[1] Industrial customers are also eligible for a number of the rates reviewed here.

Data on the characteristics and performance of these demand flexibility programs and rates can inform their design and refine estimates of their potential. However, policy makers and utilities often lack these data. We address this gap by collecting and summarizing detailed data on demand flexibility programs and rates and describing their characteristics and outcomes. Where possible, we also relate program outcomes to these characteristics. This paper will help policy makers and regulators establish goals for demand flexibility and support utilities designing programs and rates to achieve those goals.

Data and methods

Demand flexibility programs

In this paper we seek to characterize emergent approaches to promoting demand flexibility. As such, we applied the following screening criteria to identify programs for detailed data collection:

- The program *must provide event-based payments or other incentives to flex load*. This criterion ensures that the programs can modify load in response to grid conditions, which is a key condition of demand *flexibility*. This criterion excludes energy efficiency programs that incentivize "passive" reductions in energy and demand in a way that is not directly responsive to specific grid conditions.
- The program *must require use of a technology to flex load*. This ensures that the studied programs promote the adoption of demand flexibility technologies, as opposed to only the dispatch of technologies already in place. This criterion excludes behavior-based demand response programs in which customers manually adjust loads. That said, some participants in studied programs may use technologies already installed in their buildings.
- The program *must not be a longstanding demand response program type* that has been well studied in the past. We excluded central air conditioning compressor, pool pump, electric resistance water heating and commercial and industrial (C&I) direct load control (DLC) programs that involve physical switches. However, we *do* include DLC programs that control heat pump loads. We made this exception because of increasing interest in heat pumps and the potential for demand flexibility to mitigate the peak demand impacts of building electrification. Managed EV charging programs were not in the scope of this analysis.

We identified electricity customer-funded demand flexibility programs for collection by applying the previously described screening criteria to programs found on utility websites and in regulatory reports.[2] First, we screened programs from 96 utilities found in a database of demand-side programs regulatory reports (Esource)[3][4]. To make sure that our screening covered all states in a consistent manner, we then identified the largest utilities that collectively covered 50% or more sales in each state and reviewed programs on their websites[5]. This decision criterion

[2] We collected website data in 2022. Data on current program websites, therefore, may differ from the data we collected. The regulatory reports we reviewed were typically on 2021 programs filed in 2022.
[3] For a description of Esource's data services and products, see www.esource.com
[4] We did not include any programs administered through grid operators in the scope of collection.
[5] We included investor-owned, municipal, cooperative, state, federal, and public power district utilities in this selection process.

resulted in a list of exactly 100 utilities, 41 of which were also in Esource. In some states a single utility covered more than 50% of retail sales on its own (e.g. Public Service Elec & Gas Co in New Jersey). In other states, reaching 50% of retails sales required multiple utilities. We also reviewed the websites of the 45 utilities that we identified in Esource but were not on the list of utilities that accounted for 50% or more of each state's sales.

For each of the programs at these utilities that met our screening criteria, we collected data on program characteristics and performance reported in regulatory filings and published on utility websites. In particular, where available we collected data on demand flexibility event structure, incentive types and amounts, enrollment and participation levels, program spending and energy and demand savings. 155 programs at the studied utilities met our criteria. 89 of these programs (57%) incentivized Wi-Fi thermostats and 42 (27%) supported battery storage. The remaining 24 programs (16%) were a mix of programs that promoted thermal storage and building automation as well as heat pump and heat pump water direct load control programs. Additionally, there was one program that controlled electric dryers (among other loads). In Table 1, we describe how each of these technologies provides demand flexibility in the programs in our dataset.

Table 1: Demand flexibility approaches by program technology

Program technology	Demand flexibility approach
Wi-Fi thermostat	Set-point change: Utility signal increases/decreases thermostat set-point to reduce HVAC cooling/heating demand during an event Cycling: Utility signal turns HVAC system on and off at a regular period (e.g. 15 minutes) during an event Optimization: Thermostat adjusts HVAC operation in response to time-varying electricity rate
Battery storage	Battery discharges stored electricity during an event, avoiding part (or all) of a building's demand
Thermal storage	Electricity is used to cool or heat a material that stores thermal energy that it releases during an event to help meet space conditioning and/or water heating demand
Building automation system	Upon receiving event signal, system automatically reduces various loads throughout building
Heat pump	Direct load control device attached to compressor receives signal to reduce heat pump load or cycle heat pump off
Heat pump water heater	Direct load control device receives signal or is scheduled to shift heat pump water heater load
Clothes dryer	Direct load control device receives signal to shut off dryer load

The programs in our dataset have wide national coverage and are weighted towards investor-owned utilities. The programs we identified came from 38 states and Washington D.C.[6]

[6] Since we did not review every utility in each state, demand flexibility programs may well exist in the 12 states where we did not identify any programs. These states may also have programs that we excluded from our collection such as central air conditioning compressor DLC programs.

We found Wi-Fi thermostat programs operating nationwide, in 33 states. In contrast, we identified battery storage programs in only 13 states, all in the West and Northeast census regions. Investor-owned utilities operated 82% of the programs in our dataset, with the remaining 18% administered by a mix of municipal, co-operative, and state-run entities as well as third-party organizations and community choice aggregators.

The demand flexibility programs in our dataset differ in the electricity customer classes they serve. The Wi-Fi thermostat programs are largely residential (52 of 82, or 63%). In contrast, all seven building automation system programs and six of seven thermal storage programs serve commercial and industrial (C&I) customers. Battery storage programs are more balanced, with 20 of 42 (48%) serving residential customers, 16 of 42 (38%) serving commercial and industrial customers, and the remaining six programs (14%) serving all customer classes.

Demand flexibility rates

Electricity rates that are within the scope of our data collection and analysis included at least one of three features:

- The rate includes *dynamic rate components* that are not defined in advance but depend on grid conditions in some way. In our analysis, we categorized dynamic rates into three sub-categories: critical peak pricing (CPP), variable peak pricing (VPP), and real-time pricing (RTP). All three dynamic rate categories include price components that are subject to change depending on grid conditions.
- The rate lists *one or more demand flexibility technologies as an eligibility condition*. We consider any technology that can provide some level of load shape flexibility to be a demand flexibility technology. We organized eligible rates into nine technology categories: air conditioning; energy storage; smart thermostats; space heating: electric resistance; space heating: heat pumps; thermal storage; water heating: electric resistance; water heating: heat pumps; and other (this includes rates with open-ended language for technology eligibility).
- The rate has *a structural relationship to demand flexibility programs*. This included rates that require participation in a demand flexibility program for eligibility, or rates whose enrollment is a requirement for a demand flexibility program. This condition is satisfied by only a small number of rates we reviewed, and all of those rates also include one of the other two features above, so we do not further consider these rates as their own category in the analysis that follows.

We did not include time-of-use rates without dynamic components, or rates with demand charges but no dynamic components. These rates impact load shape, but they are not responsive to grid conditions on a specific day. We also did not collect technology-specific rates that are commonplace, well studied, or not primarily intended to procure demand flexibility. For example, we did not include rates specific to space or water heating if they are primarily intended for direct load control. We did, however, collect technology-specific rates that enable a higher level of building control such as bundling multiple technologies together. We also did not include rates with baseline allowances or differentiated prices that are specific to heating fuel type.[7]

We collected rates from the same universe of 100 utilities described in our program data collection that cover over half of the customers in each of the 50 states. Where utilities implement dynamic elements through riders, we counted these riders as rates. We included all eligible rates or riders for utilities even where the same dynamic rate is represented multiple times (e.g., separate critical peak pricing rate schedules for single family home and multi-family customers). As a result, the count of rates in the collection represents some utilities more than once and is not equivalent to the total count of utilities that offer a particular type of rate.

68 of the 94 rates we collected are dynamic rates, while 27 have technology requirements that include demand-flexible technologies. Of the dynamic rates, 37 rates are critical peak pricing (CPP), 4 are critical peak rebate (CPR), 6 are variable peak price (VPP), and 20 are real-time price (RTP). We collected three rates with both dynamic and technology features.[8] [9][10] 34 of the rates are residential and 57 are commercial and/or industrial (C&I). We consider general service rates as both commercial and industrial, unless customer class is explicitly defined. Only two rates are exclusively industrial rates. Pilot rates made up only 9 of the 94 collected rates. We found at least one rate that met our criteria for collection in 26 states. 23 of our 94 rates are from California utilities.

Results

Demand flexibility program characteristics and performance

Event structure

Programs limit events to certain months and hours that align with grid needs. We show how many programs utilities report as active (i.e. could have and event) in each month by demand flexibility technology in Figure 1. The programs we identified mostly address summer months, when many utilities experience system peaks driven by space cooling. 57 of 65 Wi-Fi thermostat programs with reported data (85%) and 18 of 22 battery programs (88%) operate exclusively in the summer. The remaining eight Wi-Fi thermostat programs (12%) operate in both summer and winter, with event hours varying by season. Notably, five of these programs are in southern states (South Carolina, Texas, and Georgia) that have a relatively high share of electric space heating (EIA 2023). Six programs (three building automation system, two battery storage, and one thermal storage) operate continuously throughout the year.

[7] See, for example, PG&E's E-1 residential rate, which has differing tiers depending on heating fuel: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-1.pdf

[8] For details on Commonwealth Edison's rates, see: https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf

[9] For details on Duke Energy Carolinas North Carolina's rates, see: https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-nc/ncschedulere-tc.pdf?rev=6507453a4238449a80a7c81fcf8e9908

[10] See Southern Carolina Edison's general service time-of-use rate here: https://www.sce.com/sites/default/files/inline-files/TOU-GS-1%20Rate%20Fact%20Sheet_WCAG.pdf

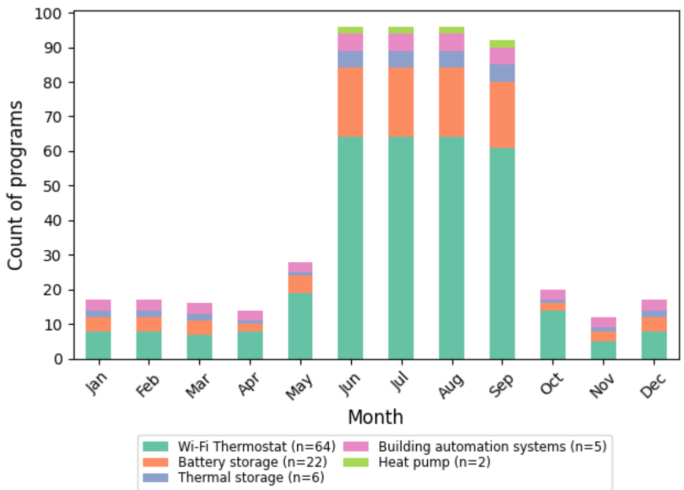

Figure 1. Program event windows by month and technology

Figure 2 shows the number of programs that include each hour of the day in their summer event windows. Figure 3 shows the same for winter programs. In both figures, we include the six programs that operated year-round. Across technology types, summer event windows typically straddle afternoon and early evening hours, which aligns with peak demand driven by space cooling. In the winter, event windows occur in both the morning and afternoon. Wi-Fi thermostat program winter events typically occur in the early morning, which coincides with electric space heating demand. The event periods for the two winter battery storage programs with reported data started at 9AM and 2PM. Battery programs, however, could have also events in early winter mornings by charging or holding a charge overnight. The absence of battery program events occurring in these hours may result from the lack of reported data or battery programs not operating in jurisdictions where early morning winter demand reductions are valuable (e.g. southern states with high levels of electric space heating).

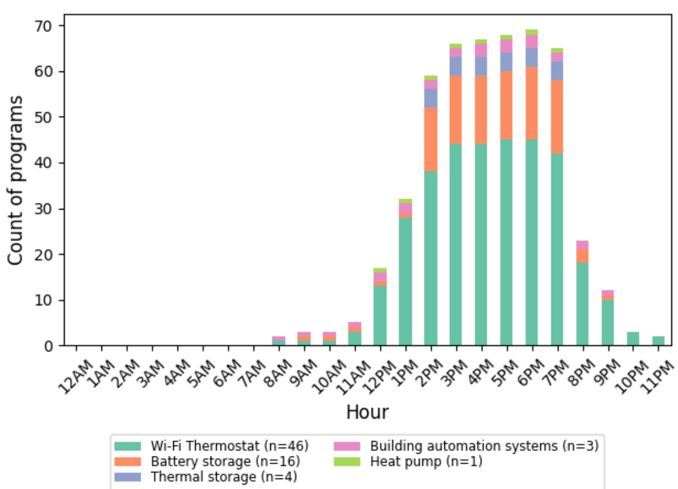

Figure 2. Summer program event windows by hour of the day and technology

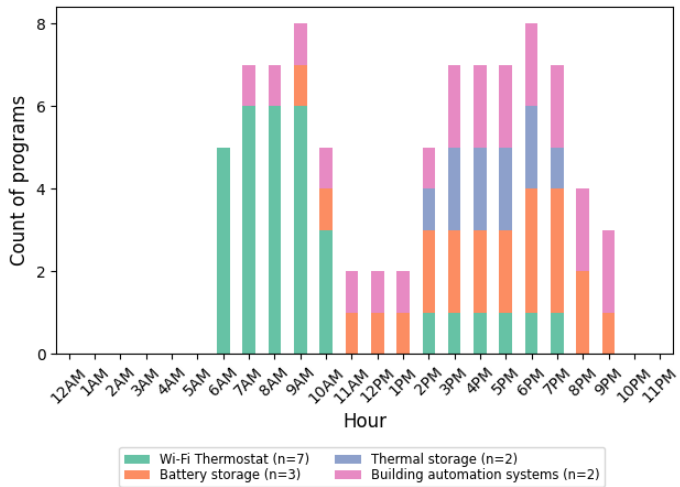

Figure 3. Winter program event windows by hour of the day and technology

Programs often cap the number of demand flexibility events they may call in a year. We find that battery programs generally allow a greater number of potential battery events than Wi-Fi thermostat programs. In our dataset, the median Wi-Fi thermostat program allows a maximum of 15 events whereas the median battery program permitted 60. This difference likely reflects the potential thermal comfort impact of Wi-fi thermostat events. In contrast, battery events do not affect any building energy services. Thermal comfort concerns likely affect the willingness of utility customers to participate, which results in a tradeoff between event frequency and program enrollment.

Programs generally specify the maximum number of hours that a demand flexibility event could last. Of the programs with reported data, 32 of 52 Wi-Fi thermostat program have four-hour maximum lengths and 15 of 18 battery programs have three hour maximum lengths. Since Wi-Fi thermostat programs change the temperature in buildings, often during very hot days, participants are likely unwilling to accept extended periods without their preferred levels of space cooling. The three-hour battery window is slightly longer than the 2.6 hours that the median battery in California's Self Generation Incentive Program (SGIP) could discharge at full capacity.[11] This alignment suggests that these programs set their event hours relative to the full capacity of potential battery discharge.

Incentives

Utilities offer up-front incentives to drive demand flexibility technology adoption and performance incentives to promote event participation. Up-front incentives may come in the form of a rebate or a bill credit that reduces the cost of adoption. Utilities tie these incentives to the purchase or installation of a technology (e.g., a Wi-Fi thermostat) or the rated size of the installed equipment (e.g. a payment per kW of battery capacity). In Wi-Fi thermostat programs that cycle HVAC systems on and off, this upfront incentive may scale with the level of reduction in HVAC operation that participants commit to upon sign-up.[12]

[11] For an archive of GSIP project data, see www.selfgenca.com/report/weekly_statewide_archives/. We accessed data on August 7th, 2023

[12] For details, see: https://energywiserewards.pepco.com/dc/participation/

Retention incentives encourage continued enrollment in a program. Importantly, this approach does not incentivize participants to maximize demand reductions nor discourage event opt-outs. However, by rewarding retention, these incentives may decrease attrition, increasing enrollment overtime as well as the potential for demand reductions. Wi-Fi thermostat retention incentives can be defined in dollars per month, season, or year that a participant remains enrolled. Battery storage retention incentives can be defined in terms of dollars per kW (installed or committed to events) per month, season, or year of enrollment.

Performance incentives connect participants' financial rewards to the outcomes they achieve. For battery programs, performance incentives are generally specified in dollars per kW or kWh provided by the battery. In some cases, a participant's incentives depend on their demand reduction in an individual event; in other cases, they earn incentives based on average reductions across multiple events or the amount of battery capacity committed for dispatch. In Wi-fi thermostat programs, performance incentives may reward average demand reductions[13] across events, participation in individual events[14], or participation in a minimum share of event hours (e.g. 80% in a year[15]).

In Figure 4, we show how incentive types vary by demand flexibility technology for the programs in our dataset. A majority of Wi-Fi thermostat programs (49 of 67 with reported data) provide a combination of up-front and retention incentives while only two offer performance incentives. This distribution of incentive approaches suggests that Wi-Fi thermostat programs are primarily targeting high enrollment numbers rather than attempting to increase per-participant demand reductions. The prevalence of retention incentives also reflects the short enrollment term required by some Wi-Fi thermostat programs, which may be only one year.[16] In contrast, fewer battery storage programs in our dataset offer retention incentives. Battery storage program terms may be longer (up to 10 years[17]), so retention may be less of an immediate concern. Overall, most battery storage programs in our dataset offer up-front incentives, performance incentives, or both. This mix may reflect that both incentive types are important in battery program design. Upfront incentives offset the high costs of installing a battery and performance incentives encourage the demand reductions that motivate the program.

Due to data limitations, we only report incentive results for thermostat programs. We find that upfront incentives for Wi-Fi thermostat programs are typically under $100 for all customer classes, as shown in Figure 5.[18] These incentives can offset the costs of some Wi-Fi thermostat models, which could promote adoption. However, the prevalence of Bring-Your-Own-Device programs that target participants that already have Wi-Fi thermostats suggests that up-front incentives are more important for enrollment than technology adoption. Notably, the only program we identified that offers an incentive beyond $150 serves commercial customers.[19] This

[13] For details, see www.duke-energy.com/business/products/energywise-business
[14] For details, see https://electricideas.com/at-home/energy-saving-programs/smart-thermostat/
[15] For details, see Orange and Rockland Utilities's Wi-Fi thermostat program website: https://www.thermostatrewards.com/oru/faq
[16] For details, see: https://www.xcelenergy.com/staticfiles/xe-responsive/Business%20Programs%20&%20Rebates/Equipment%20Rebates/ST%20DR%20Program%20Terms%202020.pdf
[17] For details, see: https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus
[18] Utilities also offer free thermostats with direct installation as the exclusive delivery channel We do not include the in-kind incentive value of these free thermostats in Figure 12.
[19] See details on Consumer Energy's business Wi-Fi thermostat program here: www.businessthermostatprogram.consumersenergy.com/start

higher incentive level ($300) may reflect the possibility of larger demand reductions with commercial customers. Performance incentives for Wi-Fi thermostat programs in our dataset are generally $30 or less per year and never exceed $60 per year.

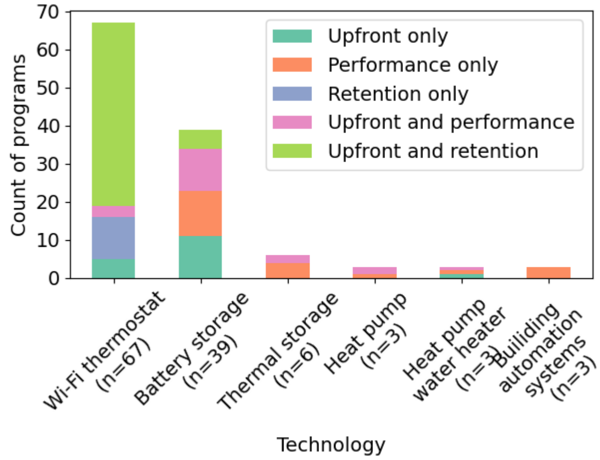

Figure 4. Incentive type by demand flexibility technology

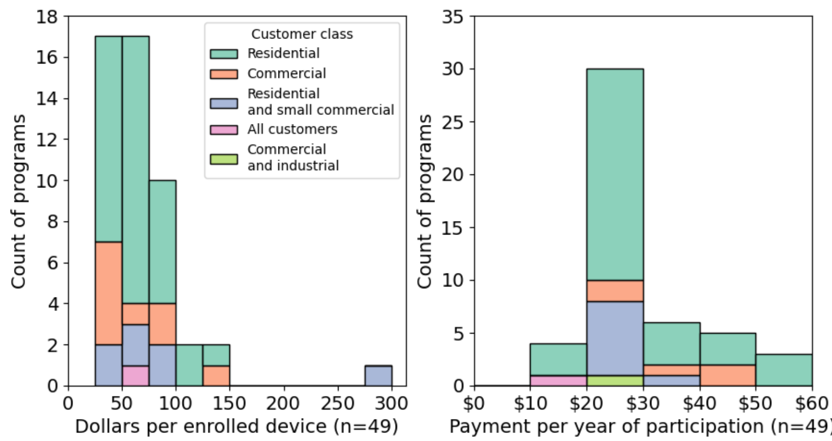

Figure 5. Wi-Fi thermostat program upfront and retention incentives

Enrollment and participation

In general, data on enrollment (customers who sign up for a program) and participation (customers who take part in specific events) were sparse for all technology types. Of the 155 programs in our dataset, we found reported enrollment data for 27 and reported participation data for 13. Lag in regulatory reporting coupled with the recent launch of some of these programs explains some of the lack of data. In other cases, reports simply lack information on enrollment and participation or report it aggregated with other programs.

Wi-Fi thermostat enrollment numbers vary significantly across the programs in our dataset. To account for differences in the number of customers served by utilities, we normalize reported enrollment counts by the number of customers in the customer class(es) that the program serves. Enrollment levels vary by a factor of about 60, ranging from less than 0.1% in Xcel Energy New Mexico’s Smart Thermostat program to 5.7% in Austin Energy’s Power

Partner program (Xcel Energy 2022; Austin Energy 2022). Given that about 10% of households in the U.S. had smart thermostats in 2020, most of the Wi-Fi thermostat programs in our dataset have significant room for growth (Hronis and Beall 2020).

Energy and demand savings and costs

Of the 149 programs in our dataset, we only found 19 programs with reported demand reductions and spending. This lack of program-level savings and spending data is not simply due to an absence of reporting. In many cases, the reported savings and spending combined the program of interest with related initiatives. For example, a utility may aggregate spending from multiple demand response programs, including those that are out of scope in this analysis. With the demand savings and spending data, we calculated the first-year cost of saved peak demand, which we show in Figure 6.[20] 10 of the 19 programs have a cost of saved peak demand below $100 per kW[21]. Across the 15 Wi-Fi thermostat programs, we find a savings-weighted average first year cost of saved peak demand of $39 per kW. Comparing against other data on the cost of capacity, we find that these costs are on par with residential lighting, which is the least-cost energy efficiency program (Frick et al. 2021).[22] The low cost of these demand flexibility programs (which are comprised of nine Wi-Fi thermostat programs and one heat pump direct load control program) show that programmatic demand flexibility can be a low-cost demand resource.[23]

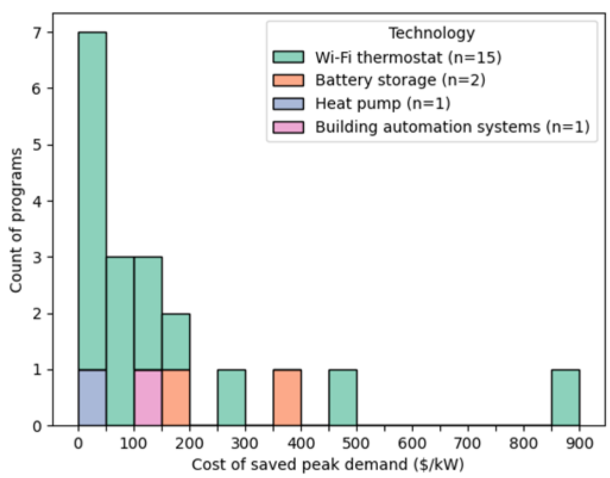

Figure 6. The first-year cost of saved peak demand by demand flexibility technology type

[20] Note that this figure does include pilots, which can have higher cost of peak demand. The Wi-Fi thermostat program in the rightmost bin with a cost of saved peak demand of $875 per kW is a pilot.
[21] Costs include program administration, marketing, evaluation, and customer incentives.
[22] Both the turbine and efficiency costs references here are levelized, which amortizes costs over equipment's useful life and discounts them to the year of investment. We calculate first year costs of peak demand because we do not know how long the demand flexibility measures will be in service nor can we determine what the costs would be over that timeframe. Since the amortization spreads costs out over time, levelized costs are systematically lower than first year costs, which makes our comparison conservative.
[23] $/kW is not a measure of cost-effectiveness. A full assessment of whether a demand flexibility program provides grid services at reasonable costs requires consideration of program benefits, including system avoided costs.

Demand flexibility rate characteristics

Event structure and pricing

CPP rates generally set a maximum number of events that the utility can call in a year, whereas the VPP and CPR rates we collected do not. Every utility applies the same maximum number of events for all of its rates. Maximum number of allowed CPP events range from ten to 20 with a median of 15.CPP rates also set a maximum number of event hours, where the event period often corresponds to the peak period for a utility's time-of-use rate. In most cases, the event length for critical peak events is fixed, meaning it is both the same length and during the same hours every time. In our collection, maximum event lengths range from two to eight hours with a median of five hours.

Generally, dynamic rate peak event windows occur in the afternoon (see Figure 7) and occur during the summer (June through September) (See Figure 8). One CPP rate (Salt River Project), one VPP rate (Eversource Energy), and one CPR rate (Consumers Energy) include events callable throughout the year, including in the winter months. In comparison to program events (see Figure 1), even fewer rates allow winter events to be called.

For the rates in our collection, CPP event prices range from $0.1/kWh (for Duke Energy Ohio) to $1.44/kWh (for Xcel Energy and Southwestern Public Service Company) (see Figure 9).[24][25] All CPP rates with event prices above $0.80/kWh are C&I rates, and six CPP rates have event prices of $1.35/kWh or higher (for Xcel Energy and Southwestern Public Service Company, which are both Xcel Energy companies).

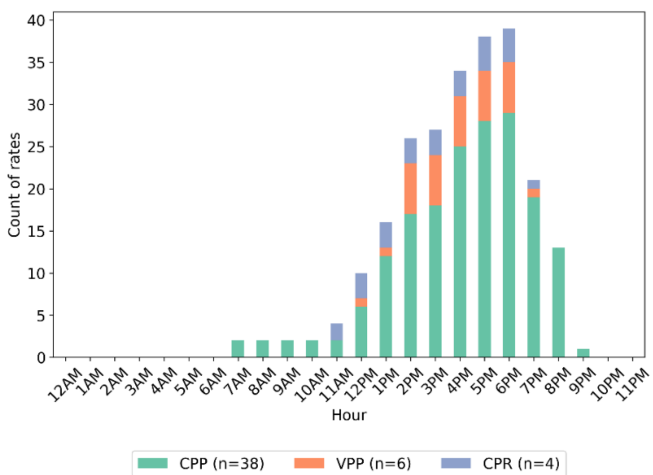

Figure 7. Count of event window occurrence by hour for CPP, VPP, and CPR rates

[24] See Duke Energy Ohio's CPP rate here: https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-oh/sheet-no-32-rate-td-am-oh-e.pdf?rev=a037be54dc3c4615891c740896d4c5d2

[25] See Xcel Energy's CPP rate here: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/PSCo_Electric_Entire_Tariff.pdf

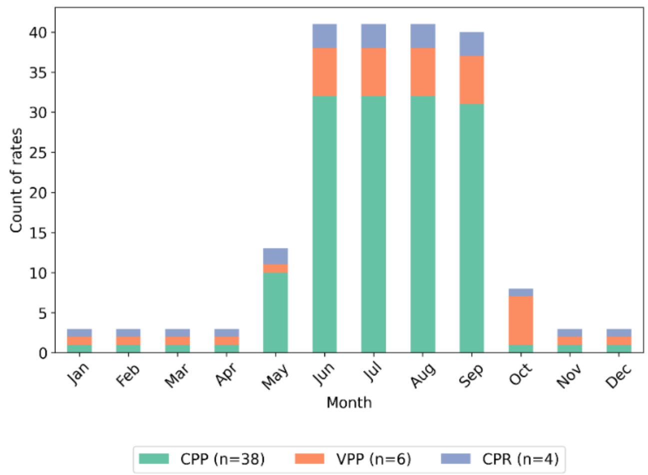

Figure 8. Count of event window occurrence by month for CPP, VPP, and CPR rates

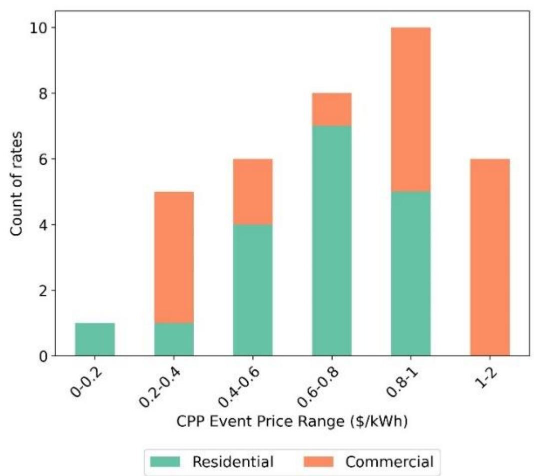

Figure 9: CPP event price range by customer segment

Real Time Pricing

We collected 20 rates that include real time pricing. RTP rates are more difficult to summarize since the retail price of electricity in each interval is directly correlated to current wholesale prices and could take on any value. By contrast, variable peak pricing is often determined based on wholesale prices, but the retail price of electricity falls into discrete, pre-determined levels. Because RTP rates determine prices for every hour of the day, they do not include events in the sense that CPP and VPP rates do.

We find that most RTP rates are determined on an hourly interval where the real time pricing component is added to a flat rate. Generally, hourly prices are posted for each hour of the following day by times from 4 pm to midnight of the previous day. Five RTP rates offered by Southern California Edison have time-of-use charges incorporated into the real time pricing rate.

Technology Rates

We show counts of technology rates by their specific technology requirements in **Error! Reference source not found.**10. Categorization is not exclusive, and rates may have multiple eligible technologies (e.g., Pacific Gas and Electric's Electric Home rate is available to customers with electric vehicles, energy storage, or heat pumps for space conditioning or water heating). Most rates with technology requirements include battery or thermal storage eligibility, 16 and ten respectively. A smaller number list thermostats, space heating, and water heating technologies as conditions of eligibility where they are bundled together and provide greater level of utility control over multiple technologies within the home. The "other" category consists of rates that include open-ended language for technologies with variable speed motors, cycling capabilities, or automated load control.

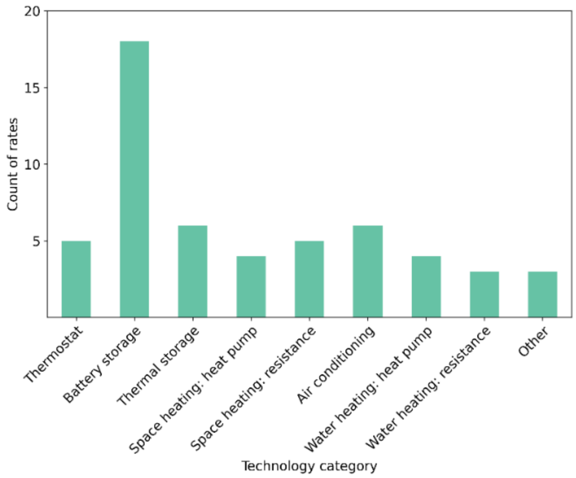

Figure 10. Count of technology rates by demand flexibility technology.

For the 28 rates collected with technology requirements, we analyzed how they might enable demand flexibility. Broadly, we find that every rate includes a time-of-use component unless the rate applies more broadly to whole-building load management. Generally, the rates are defined by five broad categories. First, we find time-of-use rates that are only available to buildings with technology in place, but no requirements around how technology is controlled or managed (e.g., Arizona Public Service rates).[26] Second, there are time-of-use rates where a technology has operating requirements but is not controlled by the utility (e.g., Indiana Michigan Power's Residential Off-Peak Energy Storage rate requires that thermal storage must only be operated during off-peak hours).[27] Third, we find time-of-use rates where energy storage technologies must provide some specific service, such as market participation or grid peak shaving (e.g., Central Maine Power's General Service Energy Storage rate requires energy storage to provide one or more service such as reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern).[28] Fourth, are rates where the utility can control the customer's thermostat to change temperature settings (e.g., Commonwealth Edison's Peak Time Rebate rate).[29] Finally,

[26] See details on Arizona Public Service's TOU rate here: https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Service-Plans/TechnologyTime-of-UsewithDemandCharge.pdf?sc_lang=en
[27] For details on Indian Michigan Power's storage rate, see https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IMINTB1902-29-2024.pdf
[28] For details on Central Main Power's storage rate, see https://www.cmpco.com/documents/40117/46387176/b-es_12.30.22.pdf/1eb01d6d-6480-31c2-44bd-ca125ec64d27?t=1673283671077
[29] For details on Commonwealth Edison's Peak Time Rebate rate, see https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf

we find rates where the utility can cycle multiple devices connected to single load management system (e.g., Consumer Energy's Device Cycling Program within the Summer On-Peak Basic Rate)[30]

Discussion and conclusions

Among the demand flexibility programs we collected, Wi-Fi thermostat and battery storage programs are most common. Wi-Fi thermostat programs are mature and available from many utilities; battery storage programs are still emerging and less widely available. Thermal storage programs are less common. Most programs that directly operate specific building end uses, such as space and water heating, are direct load control programs that fall outside our scope for this project. Some programs we collected allow multiple end-use technologies, and some allow participation by building automation systems that control multiple end uses.

Most rates that promote demand flexibility are dynamic rates that vary electricity pricing based on grid conditions. These dynamic rate elements may be built on top of either "flat" or time-varying base rate structures. Dynamic rates are fairly common, and often available in both residential and C&I sectors. Among dynamic rates, critical peak pricing rates are by far the most common. Real-time pricing rates, variable peak pricing rates, and critical peak rebates (which blur the line between rates and programs) are less common. Among critical peak pricing rates, peak prices and ratios of peak-to-non-peak prices vary significantly by utility; in general, the CPP rates with the most aggressive pricing are C&I rates.

Notably, most programmatic and rate-based efforts to procure demand flexibility focus on reducing demand during summer peaks driven by space conditioning consumption (see Figure 1). Most parts of the country have summer-peaking electricity systems that drive a disproportionate share of costs, so addressing these peaks remains an appropriate focus. Nonetheless, a more fulsome vision for demand flexibility in buildings involves the provision of a wider variety of grid services (Satchwell et al. 2021), and programs and rates will need to evolve in order to support that vision. If building owners electrify space and water heating technologies, more utilities may become winter-peaking (Zhou and Mai 2021); renewables integration may motivate the need for specific dispatch patterns that are different from those to deal with peak load; voltage or frequency support may be needed at very different times. A subset of our collected programs does address other electricity system needs – some programs call events during the winter, while a few programs and rates can potentially call events year-round. Moreover, we did not collect every program and rate, and we expect that other novel and emerging approaches exist.

Data on enrollment, participation, and energy outcomes of demand flexibility programs and rates are largely insufficient to relate differences in outcomes to program and rate characteristics. This is particularly true for rates, whose impacts are not routinely evaluated. Evaluations of demand flexibility program impacts could deliver more value for cross-program analysis by standardizing the way in which enrollment, participation, and energy outcomes are reported. Similarly, the Energy Information Administration (EIA) could modify how it collects and reports utility-level data on dynamic pricing and demand response. EIA Form-861 currently

[30] For details on Consumer Energy's rate, see https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/consumers/Consumers_14_current.pdf?rev=3f02552bac794d6f90b278e11b8ac430&hash=C22AF93016E8E3BD643F1F4EA47EFCC0

tracks demand response program enrollment, energy and demand savings, potential demand savings, and program costs at the utility-level (EIA 2021). The collection of data for individual program types (e.g. Wi-Fi thermostats) would give better visibility into the scale and impact of utility programs that promote demand flexibility. The EIA could also separately track enrollment for each type of dynamic rate (e.g. VPP vs CPP) as opposed to tracking aggregated enrollment across all time-varying rates.

On the program side, the data we were able to collect suggests that Wi-Fi thermostat programs are competitive with energy efficiency programs in terms of the cost required to procure reductions in peak demand, and are often far cheaper than generation-side options. However, we find low levels of enrollment in these programs. These findings suggest that strategies that increase the participation of existing enrollees – such as opt-out rates or programs where such designs are reasonable – may deliver high value.

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