The New Grid Demands Flexibility: How Utility Programs Can Encourage Buildings to Play an Active Role in Grid Transformation Through Demand Flexibility

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ABSTRACT

Historically, utility programs have targeted kWh and kW: energy efficiency and demand response (DR). As the transformation of the electricity grid accelerates, this paradigm and these metrics are no longer enough. Cleaner electricity means that simply reducing kWh may not deliver the emissions reductions that policymakers implicitly expect. And the growing penetration of utility-scale variable renewables and behind-the-meter distributed energy resources (DERs: rooftop solar, batteries, and electric vehicles (EVs)) calls for bigger thinking to help buildings change from passive energy consumers to efficient, flexible grid assets.

A few utility programs are looking beyond DR and exploring more holistic, larger-scale demand flexibility (DF) programs, but there are large gaps nationwide in utility building-grid integration programs. A range of efforts, both public (for example, the research underlying DOE's Grid-Integrated Efficient Buildings Roadmap) and private (for example, the GridOptimal Buildings Initiative), have laid the groundwork for utility programs to fill this gap. This paper lays out a framework for fuller integration of demand flexibility into utility programs.

The paper includes brief background and context information then opens with a detailed description of key recommended metrics for DF utility programs. The body of the paper lays out two DF program frameworks: prescriptive and performance-based. For each, the paper describes specific programmatic approaches, gaps, barriers, and recommended solutions. The paper concludes with a section discussing gaps, barriers, and potential paths forward for another important DF driver: electricity rates. Utility programs can drive buildings to be grid decarbonization enablers through scaling DF.

Introduction

Today's utility programs are to a large extent fighting the last war. Programs that focus on energy savings (kWh, therms) and demand response (kW) are increasingly ill-suited for a future energy system supplied predominantly by variable renewable resources such as wind and solar and serving buildings that consume but may also produce energy. Implicit assumptions by policymakers and regulators that tie energy savings to cost and carbon reductions are challenged by these paradigm changes. Utility programs can not only remain relevant but indeed become an indispensable part of the energy transformation across our society. They can do so by encouraging buildings to optimize their capacity for *demand flexibility*: the capability to adjust not only how much power they demand but also when that demand occurs. If provided with the proper incentives and infrastructure, buildings can leverage their mechanical systems, including space conditioning, ventilation, hot water heating, plug loads, appliances, process loads, and lighting, as well as the DERs in the building or controllable from the building, to shed and shift their power demand in line with the needs and conditions on the grid. Currently, demand response programs can accomplish some of these objectives, but today's approaches are limited in scope, accuracy, and scale. There is potential for buildings to do much more.

Today's Demand Response Programs and Current Metrics

Typical demand response programs broadly address energy insecurity. Specifically, this includes the cost of energy to its end users and reliability events due to scarcity within the grid.

Demand response programs play an important role in managing energy costs, and therefore energy affordability to customers. The pricing structures within the market that directly pass through to customers include energy costs and transmission and distribution costs. This means that pricing spikes ($/kWh) in the energy market, largely due to limited capacity or scarcity are paid by customers. This is particularly true in "non-capacity markets" (e.g., Electric Reliability Council of Texas (ERCOT)) that rely on pricing signals to inform the market to add new generators. Transmission and Distribution (T&D) costs ($/kW) are also passed through to customers in ERCOT. The pricing is dictated by an energy market's demand (kW) during the four critical peaks (4-CP), or the highest grid peak hours during each summer month. T&D fees ($/kW) continue to rise due to market conditions, including the infrastructure required to carry far-flung utility-scale renewable energy to dense urban areas and the need for utilities to replace outdated equipment with new technologies to increase the efficiency, security, and reliability of the grid. For these reasons, demand response programs are a timely, critical strategy for keeping energy costs low. These types of programs can call on participating customers to reduce energy demand many (15 to 20) times per season.

Demand response programs also play a role during ordered load sheds, or reliability events when there is not enough generating capacity available on the grid to meet the demand. Markets are directed to reduce kW through appeals to customers asking them to voluntarily conserve, forced outages, or demand response. Demand response is a preferred approach because it is a collaborative and mutually beneficial arrangement between a customer and the utility. Reliability events are rare, with some seasons passing without a single one.

Current demand response program structures are usually seasonal, enabling customers to participate in one or two seasons per year. The seasonal approach reflects the reality that buildings have different loads and capacity based on weather. This is particularly true in markets that rely largely on electricity for air conditioning and heating.

Another structural characteristic of demand response programs relates to "firmness". There is a wide spectrum of approaches between "pay-for-performance" or entirely voluntary, and firm obligations to drop a specific, contractual load within a certain amount of time that is punishable by fine. Voluntary programs typically offer lower $/kW than firm contracts.

Another approach utilities take to structure demand response incentives is to incentivize the energy management equipment that enables participation in the program. This is particularly true for residential programs and the thermostats and water heater switches that empower them. Free, or significantly rebated equipment can entice production home builders, multifamily developers and energy efficiency service providers to install demand response equipment where the split-incentive might have prevented the investment in technology. Residents and homeowners are sold on the increased control over energy use, additional comfort, or ability to save energy and money at no additional cost to the bulder or building owner. In these cases, rebates are awarded based on the number of thermostats or water-heater control devices installed.

This comes with some uncertainty for the utility, as the connected loads (kW) associated with these thermostats and water heater controls can vary significantly. If the resident continues to participate in the demand response events for several years beyond the equipment installation, utilities may encourage continued participation through additional rebates.

Equipment rebates are not reserved for Residential programs alone: Commercial programs can also employ this strategy successfully. Utilities can incentivize AutoDR equipment and real-time energy-use monitoring equipment. In these cases, stipulations often include provisions for a minimum curtailable load.

Program capacities and demand reduction baseline determination continue to be a challenge for both residential and commercial programs, although each market presents different tests. Residential programs are difficult to track due to the nature of communication and equipment volume. Commercial programs are difficult to baseline because energy usage can fluctuate widely based on operations and conditions.

Residential programs rely on many different types of communication between the utility, devices, and large quantities of customer meters. Customer accounts and paired meters can change often, particularly in college towns with a lot of multifamily housing stock. Thermostats and water heaters can be inexpensively controlled blindly with timers, via one-way radio signals, or with two-way communication strategies like Wi-Fi or ZigBee that may rely on the customer's own infrastructure. It can be difficult to determine if the device received the signal, if the device is connected to the communication network, if the device has been removed or if a customer has opted out of participating in a single event. It may be simplest for utilities to perform seasonal "all-drop" events by calling all devices in a program simultaneously to see the demand (kW) reduction at the grid level over a 15 minute period. This crude information is used to inform the approximate demand capacity within the program. The volume of residential 15-minute meter data that would be necessary to accurately measure an event is still difficult and costly to collect and analyze.

Commercial data is more manageable to track and analyze, in part because there is less of it, but it also relies on estimates and special support. Utilities often use a "Three-in-Ten" or "Three-of-Ten" baseline that is determined by the hourly average of the **three** highest energy usages of the immediate past **ten** similar days. The "similar days" designation often excludes weekend energy use from the baseline.

Key Metrics for Demand Flexibility Programs

The simplest and most commonly used metric to quantify demand flexibility is the raw value of load shed or shift, in watts or kilowatts, over the load shed period. While this metric is important to understanding the total demand reduction potential, this does not provide insight into how well the building supports effective grid operations.

An alternative methodology is to score a building's demand flexibility as a percentage of its peak demand[1]. The best definition for "peak demand" can vary by situation. For instance, in some settings it may be critical to consider summer peak separately from winter peak. In some

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1 This may be defined as the single highest net kW draw over a 15-minute period, over a 1-hour period, or by using an average of multiple high-demand periods. One example is GridOptimal, whose metrics use the adjusted maximum reference demand (AMRD): the average of net building demand during the 10 highest-grid-demand hours of the year. Averaging multiple high-demand hours reduces the potential for a single anomalous hour to have an undue impact on the score. (Miller and Carbonnier, 2020)

situations, it may be helpful to consider demand during hours coincident to *grid* peaks, rather than during *building* peak times. The metrics recommended here, however, do not explicitly consider coincident peak demand. This is to reduce complexity and to reduce chances for misalignment between demand charge savings and utility demand flexibility program savings. There are important program design and implementation opportunities to encourage or prioritize demand flexibility savings during grid peak times.

A third approach to evaluating demand flexibility is to evaluate the load shed or shift as a function of the building's gross conditioned area (square feet). This watts per square foot metric is akin to EUI and allows for benchmarking and quantifying the grid interactivity value of a building, where a higher value indicates more demand flexibility.

Another paper published concurrently by some of the authors of this paper goes into more detail on key metrics for demand flexibility and coincident grid peak evaluation (Carbonnier et al 2022). A prior paper describes multiple other building-grid integration metrics (Miller and Carbonnier, 2020).

Short-Term and Long-Term Demand Flexibility

Target event durations vary across today's DR programs, but periods of 1-6 hours are typical, with many programs calling 2-4 hour-long DR events. Some variability is to be expected, but to explain concepts clearly within this paper, we will mainly limit our considerations to the two periods used by the GridOptimal Buildings Initiative: a one-hour (short-term) or four-hour (long-term) period. This is measured on the building's peak day: the day during which the building's highest hourly demand occurs. Short-term demand flexibility is measured during the single peak hour of building demand, while long-term demand flexibility is calculated by averaging the hourly demand change during the four-hour window that includes the peak hour and yields the greatest overall reduction in building demand.

Figure 1 shows an example building's load shape. The lighter blue line ("No DF") shows the building load profile before any demand flexibility measures are implemented, and the darker blue line ("With DF") shows the building load with demand flexibility included, such as HVAC and water heater temperature set point adjustments. In this example, the building's peak hour begins at 3:00 PM, but the four-hour demand flexibility window begins at 12:00 PM, because this is the window that yields the greatest load shed.

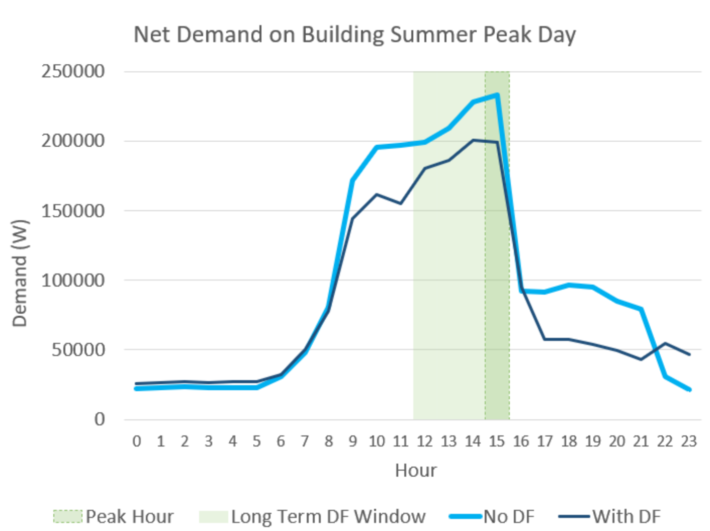

Figure 1. Summer peak demand day for a building before (lighter blue) and after (darker blue) applying demand flexibility measures.

As buildings electrify, winter grid demand will increase, and quantifying the demand flexibility of a strategy in both the summer and winter seasons will accordingly become increasingly important. To account for future electrification, demand flexibility metrics should include a seasonal component. The GridOptimal metrics use a seasonal weighting factor based on projected regional grid conditions to assign relative importance to demand shed in both the summer and winter. This seasonal approach mirrors typical demand response programs in the market today. The demand shed (kW) in each season is multiplied by this weighting factor (0-1) and combined to obtain the overall demand flexibility.

Figure 2 shows the change in winter building demand with the implementation for the same building and demand flexibility measures shown in Figure 1. In this case, the peak demand occurs at 2 PM, and the four-hour maximum demand shed period begins at 12 PM. This sample building is less able to shed load in winter than in summer while maintaining occupant comfort.

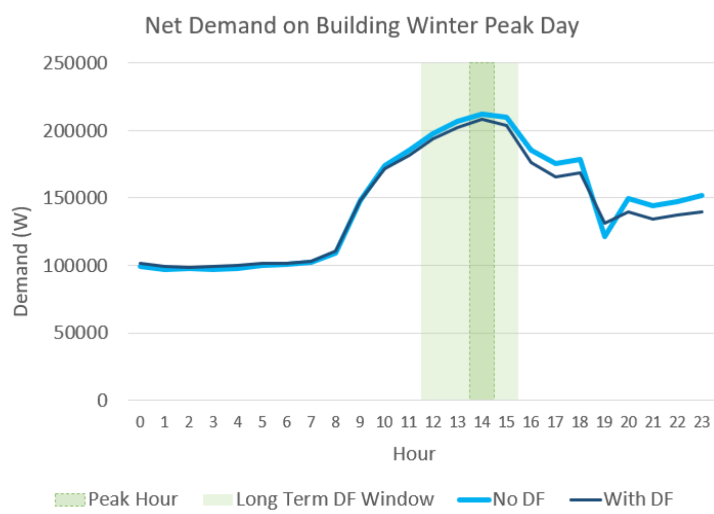

Figure 2. Graphic showing the winter peak demand day for a building before (lighter blue) and after (darker blue) applying the same demand flexibility measures shown in Figure 1.

Dispatchable Demand Flexibility

Dispatchable flexibility measures the *remotely controlled* (i.e. "firm") demand flexibility in the building: demand flexibility that is automatically controlled by a utility or third party (e.g. aggregation service provider or microgrid controller) rather than manually and voluntarily controlled by the building owner or the building's local management system.

Buildings with high potential for reducing their energy demand via flexibility can be a great asset to an electricity grid by becoming a reliable source of demand reduction during priority events, such as demand response calls or reliability events. When some or all of the building's energy storage, interruptible loads, or other load flexibility assets are controlled directly via a utility or third party, utilities may contract with building owners directly to gain valuable, firm demand response assets.

Behind-the-Meter Strategies: Program and Code Examples and Opportunities

A wide range of building systems and distributed energy resources offer demand flexibility opportunities. The available strategies vary by equipment type. Utility programs, codes, and standards can act as proving grounds for "what's next" in this arena. This section discusses selected current and near-term opportunities in the contexts of utility programs and codes and standards.

HVAC: Thermostat Controls

Today's DR programs rely heavily on HVAC controls adjustments, both through thermostat adjustments and through blunter approaches like equipment lockouts. Smart thermostats compliant with a typical internet of things (IoT) communications standard such as OpenADR2.0 can adjust the setpoint based on a grid signal. There is some momentum in codes to standardize this capability to automatically change the setpoint temperature, based on a grid signal, up or down by 4°F. There are proposals currently being considered for inclusion in the 2024 IECC (both residential and commercial standards) that would require this capability for all thermostats. Utility programs and aggregators can use this same approach: send a signal to thermostats that calls for a thermostat setback or setup.

HVAC: Controls for built-up systems

Many options are available for demand flexibility in larger, built-up HVAC systems, such as those seen in large commercial buildings and central plants. Example strategies include adjusting pump and fan speeds, However, because these systems are custom to each site and thus highly variable, typical DR program approaches are often used today. Integration of BMS could automate actions based on a grid signal. Buildings or central plants with large HVAC equipment could be required or incentivized to have the capability to shed a certain percentage of load during peak conditions and/or coincident grid peak hours. In codes, this could be accomplished by allowing exemptions for other grid-integration requirements, such as thermostat or water heating communications capabilities, for buildings that can shed a certain percentage of their peak load. In programs, the same approach can be used to set the minimum barrier to entry for the program (e.g., be able to automatically shed at least 10% of demand during peak conditions) and by setting a minimum participation threshold (e.g., respond to and do not override at least 10 events per season, or at least 75% of called events, etc.).

HVAC: Ventilation and Fans

In existing buildings, DF strategies related to adjusting fan speeds or ventilation rates may be present. In new buildings, the opportunity is more limited because code requirements for demand-controlled ventilation (DCV) reduce the available fan speed reductions: a fan system controlled by a DCV will be operating at a reduced ventilation rate, and thus power, when the area is unoccupied or lightly occupied. When the area is occupied, a reduction in fan speed risks under-ventilating the space, which has potential health, safety, and comfort risks, not to mention code compliance risks. While the area is unoccupied, the fan will already be off or set to minimum, reducing the current and future impact of ventilation for demand response.

Lighting Controls

The opportunity for demand flexibility in lighting controls is one-way: demand shed only. Lighting controls requirements already exist in codes, notably in California's Title 24 since

2008 and the ASHRAE Standard 189.1 energy chapter since 2014. In addition, the IECC requires luminaire level lighting controls to be capable of grid integration. As lighting systems get more efficient and smarter, the demand flexibility potential both increases (better controls that can be more easily dimmed, turned off, or otherwise integrated with the grid) and decreases (lower-wattage systems and fewer cases in which unnecessary lights are on in the first place and thus able to be dimmed or turned off). Building codes and utility programs are advancing energy efficiency and controls capabilities, especially in newer buildings. Caution should be exercised when deploying lighting demand flexibility: when dimming of lights in occupied spaces is noticeable to occupants, it may result in significant occupant disruption and dissatisfaction while delivering relatively small demand reduction results.

Water Heating: Unitary

Automated control of unitary (tank) water heaters has been a mainstay of DR programs for years. The potential for demand flexibility with water heating is enormous: heating water is energy-intensive and hot water holds a lot of thermal energy, enabling it to act as a thermal battery. Whereas in the past most water heating control has been done with a switch (lockout), modern electric water heaters, especially heat pump water heaters, are often equipped with smart grid controllability. The CTA-2045 standard is the most common approach and is required in multiple jurisdictions including California, Oregon, and Washington. New requirements for CTA2045-a and CTA2045-b in electric water heaters are being considered in many new construction codes, and there is progress towards standardizing such requirements nationally. Another example of smart-control requirements is California's Joint Appendix 13, which lists specific actions that water heaters should be capable of performing based on a grid signal.

Water Heating: Central

The automated control of central water heaters is usually conducted through a more customized approach, much like the control of built-up HVAC systems. Including additional (buffer) tank capacity can significantly enhance the capability for load shifting: more tanks are more thermal energy storage. The most common standard for communications equipment in this context is OpenADR2.0, but utilities and aggregators may use other standards or strategies.

Pool Pumps and Heaters

While most buildings do not have pools or spas, the opportunity for DF savings is substantial for those that do. Multiple pool pumps and heaters available today have demand response capabilities, in some cases through the CTA-2045 standard (common in modern smart water heaters). Programs may include prescriptive incentives for CTA-2045 compliant pool equipment alongside or on top of energy efficiency incentives and can include this as an eligible source of custom incentives where applicable.

Electric Battery Storage

The costs for behind the meter batteries have dropped dramatically in recent years. Battery storage dispatch may be a recent focus for utility programs, but it is a fast-growing opportunity. Leading utilities are picking up on this trend and including incentives for buildings to deploy remotely controllable batteries. The incentives are typically tied to an expectation of program participation, much like a typical DR program. Batteries are now required in new buildings in California per Title 24 XXX, with the size of battery tied to the size of the onsite PV system (the intent is to minimize energy exports, or said another way, to maximize self-consumption of onsite generated energy).

Electric Vehicle Charging & Vehicle to Grid

As electric vehicle adoption accelerates, they have the potential to add significant demand to the overall electricity grid. Fortunately, vehicles typically are parked most of the time, and if plugged in, have the potential to shift their consumption around to minimize stress on the grid or soak up renewables. Also emerging will be the opportunity for vehicles to provide power back to the grid. Integrating these capabilities with building energy management systems will create opportunities to connect more load behind the customer panel without triggering panel or transformer upgrades. Many installations are also being deployed with stationary storage to mitigate local impacts. Figuring out how to tap into these assets to create new benefits will be an important challenge to solve as electric transportation reaches scale. Some utilities already offer specific rates for EV charging; we expect this trend to accelerate.

Prescriptive Program Approaches

The most familiar program framework for many customers and utilities across the country is the prescriptive program, in which a fixed incentive is offered per unit of equipment installed. The incentive may be "widget-based," with a certain dollar amount offered per LED light fixture or efficient air conditioner installed, or the fundamental unit may be more variable: square feet of insulation or windows, for example. In any case, prescriptive programs rely on energy modeling and engineering assumptions that define the typical energy savings to be associated with each measure. Usually, a Technical Resource Manual (TRM) or similar formal document provides a state-level transparent and consistent basis for calculating energy and demand savings generated by energy efficiency programs.

The prescriptive program framework can be used to incentivize demand flexibility measures directly and can also be used to incentivize strategies that act as indirect impact multipliers for demand flexibility. An example of a direct demand flexibility strategy is a thermal energy storage system that allows a building's cooling or heating system to operate in a low-power mode during specified times. An example of an indirect impact multiplier for demand flexibility is improved air sealing and insulation, which could allow a building to maintain thermal comfort for a longer time period during an HVAC thermostat reset (setback/setup)

Existing prescriptive programs can be adapted to fold demand flexibility strategies into their portfolio by including the costs and benefits of demand flexibility into the cost/benefit calculations that underlie program development. In the end, incentive levels could be adjusted so that energy efficiency measures already in the program with relatively high demand flexibility benefits are incented at a higher level, and measures with low demand flexibility co-benefits in turn receive lower incentives - and thus are de-emphasized. The following graphic shows the results of NBI analysis into the coincident peak reduction available from selected common energy efficiency measures and packages. Given that the reduction of building demand during grid peak hours (i.e., coincident peak demand reduction) is often the primary driver for DR and DF programs, this may be used to make such programmatic adjustments.

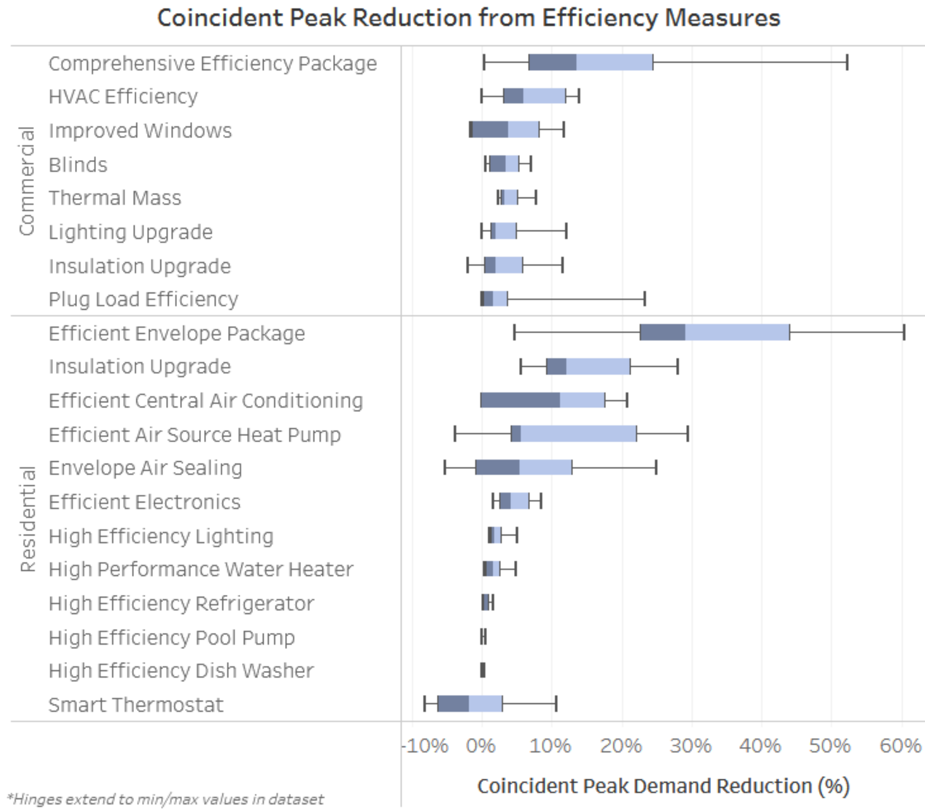

Figure 3. Coincident peak demand reductions associated with selected energy efficiency measures.

Prototype energy modeling is a foundational step to better include direct and indirect demand flexibility strategies in prescriptive programs. Substantial progress has been made in the development of prototypes to evaluate the impacts of demand flexibility strategies in buildings (DOE 2021). Several barriers still exist, including:

- Lack of consistent prototypes calibrated to the hourly or sub-hourly level that are, or easily can be, aligned with code/programmatic baselines
- Lack of capability within energy modeling software and knowledge in the industry related to modeling demand flexibility measures
- Difficulty characterizing the impact-multiplying effect of energy efficiency strategies on the demand flexibility capabilities in a building in a parametric manner
- Lack of consistent information about the estimation of the firmness of demand flexibility
- Inconsistent baselines for the evaluation of demand flexibility

Utility programs can build on current program frameworks to encourage building designers, owners, and operators to deploy key communications infrastructure and to prioritize specific measures and operational strategies. The GridOptimal Buildings Initiative's Utility Program Criteria Memo details specific communications infrastructure recommendations for utility programs. An interactive, web-based dashboard is available to explore the coincident peak demand reduction and demand flexibility implications of various traditional energy efficiency and demand response strategies (GridOptimal 2022).

Performance-Based Program Approaches

Custom, or performance-based, approaches form a mainstay of today's utility energy efficiency programs. Most of these programs pay incentives on the difference between a baseline and a proposed case, usually using these metrics: $/kWh (site electricity), $/therm (of fossil gas), and $/kW (peak demand). In some cases, such as at Sacramento Municipal Utility District, the customer-facing metrics remain the same ($/kWh, etc.) but the utility's explicit goal is the reduction of greenhouse gas, and incentive structures take this into account by incentivizing fuel-switching and by offering higher incentives for strategies that reduce more carbon emissions.

There is some movement toward leveraging performance-based pathways in codes and standards to drive improvements in demand flexibility. A proposal currently under consideration for the 2024 IECC would provide a small number of credits to buildings that can demonstrate that they can reduce their peak demand by a certain amount (10% or 20%). These credits can be used to achieve code compliance in a flexible manner: once a building has achieved enough credits, which can come from a wide range of efficiency and load management options, it is considered sufficiently efficient to comply with the code. The details of this proposal are still being discussed in committee. Another example is in the New York State Stretch Energy Code (currently under development); in this case energy efficiency and demand flexibility targets are separated in the code.

More and more jurisdictions are looking past codes to building performance standards (BPS) to help meet their climate goals related to buildings. For jurisdictions considering electrification and measuring the impact of their building stock in GHG, looking toward integrating a grid integration metric into their BPS compliance should be a major point of consideration. As buildings become more reliant on electricity, the time of use and its relationship to carbon becomes paramount. Asking buildings to consider their actual performance on metrics like self-consumption of on-site generation, ability to shed load, and contribution to coincident peak, will help reduce the use of the dirtiest peaker electric generation, contributing to the overall reduction of GHG.

Several barriers are important to consider in the context of custom programs and performance-based codes. A selection of key barriers and options are discussed here.

- Unknown of variable characterization of the firmness (reliability) of behind-the-meter demand flexibility strategies
- Program structures that do not permit incentivizing demand flexibility capabilities, impact multipliers, or enabling equipment
- Consistent, clear determination of baseline conditions and performance

Additional options for utility programs are possible. By adjusting the core metric for the program away from kW and/or kWh and toward greenhouse gas emissions and avoided costs, utility programs could change frameworks in a fundamental manner. This change in foundational metric could be executed in whole or in part: in whole, by dropping energy and demand as incentive program metrics; or in part, by adding "kicker" incentives calculated based on greenhouse gas emissions reductions. The latter approach is more palatable for leading utilities interested in exploring new approaches. It will be important to consider locationally-specific, temporally-variable values for greenhouse gas emissions.

One intriguing option for custom utility programs is to use incentives to mimic a highly time-dynamic or even real-time rate structure based on greenhouse gas emissions as well as costs. Participants could agree to have their incentive deferred over time, with the understanding that the actual incentive paid would vary based on their actual demand flexibility performance over a set period, such as 1-2 years.

Taking a more holistic approach to demand flexibility strategies in buildings would allow utilities and their customers to value the performance delivered by a variety of assets, including traditional energy efficiency measures as well as DERs such as thermal energy storage, customer owned renewables, electric vehicles, and batteries, based on their actual performance.

Rates as a Driver of Demand Flexibility in Buildings

Electricity rates increasingly are being looked to as an opportunity to influence customer investment and operational decisions. Time of Day rates are the most prevalent, and are currently in place as a default rate in a growing number of states. In addition, dynamic rates, critical peak pricing, and peak time rebates are in operation or pilot in a number of utilities across the U.S. This shifting landscape in utility offerings, from predominantly fully bundled tiered residential rates, towards more time-varying rates, has picked up pace over the last decade for a variety of reasons. These include the deployment of AMI meters, increasing deployment of customer technologies that can enable response to time varying rates, and a shift in wholesale markets that are seeing increasing variation in resource availability as a result of shifts toward increasing levels of renewable energy.

For the last several decades, tiered rates in the residential segment were effective at promoting energy efficiency and solar photovoltaics. As policy objectives evolve and the grid supply shifts, time varying rates are being looked at as important tools to influence customer adoption and operation of flexible loads and DER technologies. This shift in price signals has the potential to unlock 10's of GW of load flexibility over the next decade (DOE 2021). Accessing this flexibility through price signals represents an opportunity to lower costs and bring additional resources to the table, relative to control-based alternatives.

In the commercial segment, demand charges are frequently used as a tool to balance cost-recovery and bill stability while encouraging the customer to flatten their load shapes to minimize grid impacts. However, demand charges are increasingly being tackled with dispatchable technologies that are being used to minimize individual customer loads, but may fail to provide benefits to the larger system. This results in the demand charge being a relatively poor investment and operational signal as we think about deploying flexible loads and storage to assist with energy system decarbonization. Figuring out how to align demand charges to encourage renewable integration and avoid new distribution system costs as we electrify will be a key challenge.

One of the challenges with shifting fully to a rate-control signal paradigm is getting to a place of adequate confidence / certainty for system planners to ensure reliability, while depending on customer response to dynamic rates. Compared to building traditional utility assets, dependence on price response, in particular in the face of a changing climate with increasing weather extremes, can be challenging for a utility planner to accept.

In addition, rate complexity can create challenges for communicating a dependable value proposition to customers faced with opting in from an incumbent rate, as well as understanding and seamlessly responding to that rate. Realizing local system benefits and bulk system benefits together can also add complexity to rate implementation, and potentially challenge current ways of thinking about customer equity in rate design.

As we shift towards a decarbonized energy system, rate setting will likely need to adapt to encourage loads to make use of excess variable renewables, while discouraging consumption during high demand-low renewable periods. Encouraging electrification as a means to make use of abundant and low-cost wind and solar energy will have to be balanced with distribution grid constraints that may limit when and where these new loads can be brought on.

Conclusion

Utilities and program implementers find themselves at a challenging but exciting time. A once-in-a-lifetime convergence of emerging technology, unprecedented market forces, regulations, and policies are driving rapid changes on both sides of the meter. Through prescriptive and custom incentive programs, through rate structures and smart communications infrastructure, utility programs can encourage buildings to become flexible, efficient grid citizens. By enhancing demand flexibility capabilities in buildings, utility programs can help encourage buildings to accelerate the transformation of the energy system and support the efficient, affordable, resilient, safe, and sustainable grid of the future.

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