WHITE PAPER

Rate Design for the Energy Transition

GETTING THE MOST OUT OF FLEXIBLE LOADS ON A CHANGING GRID

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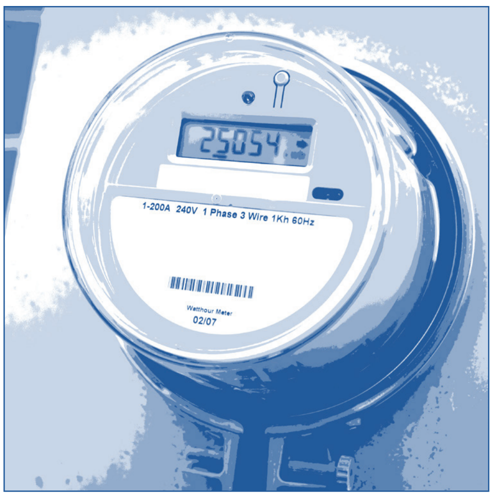
Energy and Environmental Economics, Inc. (E3)



Decarbonization and clean energy policy goals are fundamentally changing grid planning and operations. The two dominant grid planning challenges and cost drivers are now resource adequacy, to provide reliability during net peak load hours, and time shifting of renewable electricity from periods of excess generation to periods when it can be beneficially consumed. Rate designs established under the old paradigm are no longer aligned with marginal grid costs and are an impediment to realizing environmental goals. Aligning customer responses to retail rates with grid needs now requires more complex multi-part dynamic rates. Predictable and reliable impacts of these dynamic rates can be quantified in a statistically robust way to reduce supply-side investments in utilities' integrated resource planning.

A feasible multi-part rate design that aligns with grid needs and environmental goals includes: (1) a dynamic hourly energy rate that is low in most hours of the year when zero/low variable cost resources are abundant and on the margin; (2) either a size-based grid access charge, coincident demand charge, or hourly allocation of long-run marginal capacity costs that encourage reducing and shifting load out of a relatively small number of hours driving new investments in generation, transmission, and distribution capacity; and (3) non-bypassable customer charges designed for equity that recover utility embedded and unavoidable fixed costs.

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

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ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ENERGY SYSTEMS INTEGRATION GROUP

ESIG Publications Available Online

This white paper is available at https://www.esig.energy/aligning-retail-pricing-with-grid-needs. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

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To learn more about the topics discussed in this white paper or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

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Times Have Changed—and Rate Design Must Change Too

The electricity system has changed in fundamental ways in the 50 years since the advent of the energy efficiency era, heralded by Jimmy Carter's cardigan sweater and Jerry Brown's formation of the California Energy Commission. In the 1970s and the following decades, high fuel prices led to high marginal costs for electricity. Reducing electricity consumption saved both fuel and money and reduced emissions of harmful pollutants. Residential and small commercial rate designs increasingly began to feature high volumetric rates. Utilities began eliminating declining block rates that provided a discount to high volume users. Inclining block rates, such as those adopted in California during the early 2000s after the Western Energy Crisis, have higher charges for higher consumption and were increasingly seen as aligning with both environmental and equity goals, since wealthier households generally (though not universally) consume more electricity. Lack of access to affordable real-time metering devices meant that more sophisticated rate designs were not easily implementable or understandable for customers.

In 2023, the industry stands on the precipice of dramatic change. Electric resource portfolios are shifting away from fuel combustion and toward cleaner resources such as wind and solar energy. These resources are available only when the weather cooperates, leading to both periods in which there is an abundance of energy (e.g., midday during late spring) and periods in which energy is increasingly scarce and expensive (e.g., after sundown on cold winter nights). This transformation of the resource mix from one with high marginal fuel costs to one with very low marginal costs and high fixed costs is breaking the link between reduced consumption and both costs and emissions. Indeed, studies of economy-wide decarbonization increasingly point to higher electricity consumption through electrification in the building and transportation sectors as key strategies for reducing emissions in those sectors. And on a power system where nearly all costs are fixed, increasing consumption can lead to lower electricity rates. Therefore, financial and environmental benefits can now be achieved by either decreasing or increasing consumption at specific—and increasingly unpredictable—times and places.

The transformation of the resource mix from one with high marginal fuel costs to one with very low marginal costs and high fixed costs is breaking the link between reduced consumption and both costs and emissions.

The most common residential rate design today is a two-part rate consisting of a fixed charge and a volumetric energy charge, where a substantial portion of embedded costs are recovered through the volumetric charge. Although this rate structure promotes conservation and energy efficiency, it increasingly does not align with grid costs or reflect the cost structure of electricity service. Additionally, high volumetric rates, such as California's very steeply inclining block rates, have now become a barrier to achieving environmental goals, as they discourage electrification with higher charges for increasing electricity consumption. Although existing time-of-use (TOU) rates provide incentives for customers to shift energy use to hours with lower marginal costs, these rates do not fully align with grid needs or offer sufficient signals to focus customer responses on the most critical hours to avoid fixed costs. To align with grid needs and environmental goals, retail rates for customers with

To align with grid needs and environmental goals, retail rates for customers with flexible loads and distributed energy resources must become more complex and dynamic. Multi-part rates that reflect the utility's long-run marginal cost can provide incentives for customers to shift or lower load while encouraging economically efficient grid investments and enabling equitable adoption of DERs.

flexible loads and distributed energy resources (DERs) must become more complex and dynamic. Multi-part rates that reflect the utility's long-run marginal cost (LRMC) can provide incentives for customers to shift or lower load while encouraging economically efficient grid investments and enabling equitable adoption of DERs.

Inducing customers to respond to complex, time-varying rates can be a challenge. However, technological advances are increasingly placing responsive devices in the hands of consumers. The large batteries in electric vehicles allow for significant flexibility in charging patterns. Some customers are investing directly in home storage devices such as the Tesla Powerwall. Advanced thermostats have the potential to enable whole-building responses in ways that are nearly imperceptible to consumers. And advanced meters have the capability of transmitting real-time prices to these devices and programming an optimal response. Thus, while rate design complexity will likely continue to be a barrier to beneficial customer response, analysts should increasingly think of retail rates as a primary mechanism for compensating flexible, behind-the-meter DERs.

Grid Needs Are Changing

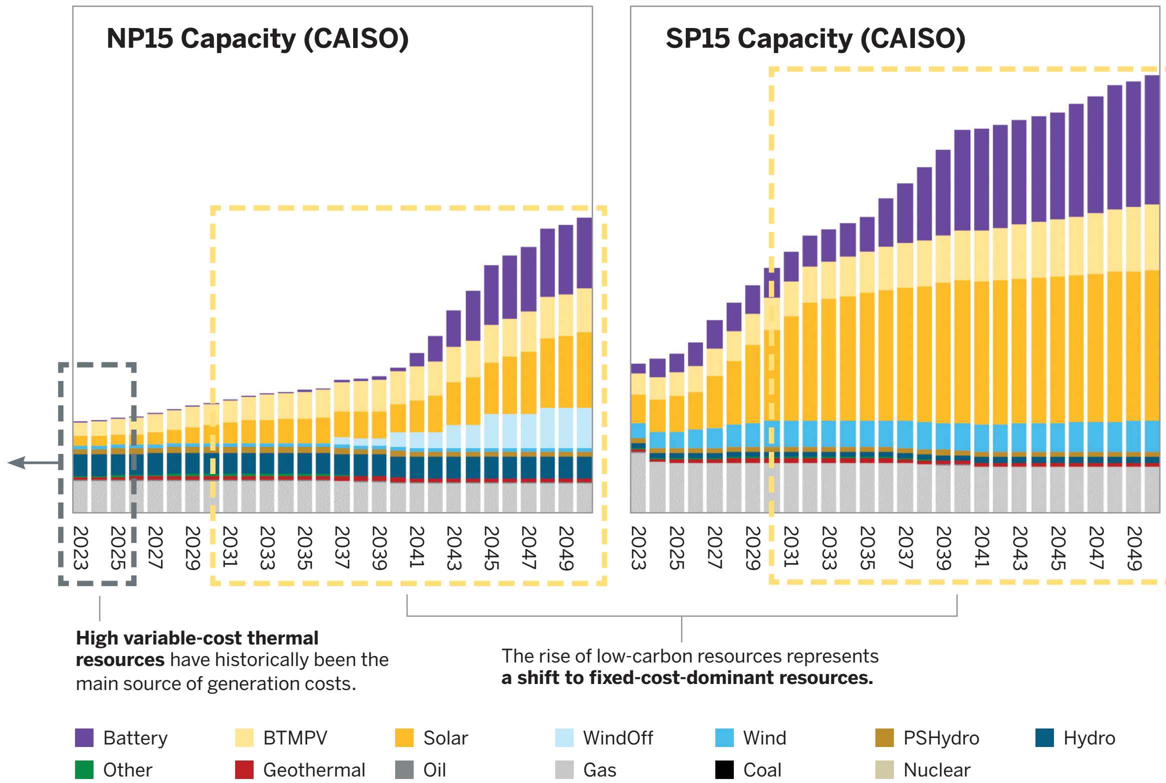
Historically, utility resource planning processes were largely focused on developing an optimal mix of thermal generation. Planners forecasted peak demand over a given planning horizon and selected a portfolio of resources to meet reliability targets driven by summer or winter peak demand. Heuristic approaches provided a reasonable means of screening for resource needs and investment options, and the resulting resource portfolios consisted of a mix of baseload, intermediate, and peaking resources with increasingly high variable fuel and operating costs. The resource portfolio incurred marginal emissions, fuel costs, and operating costs in all hours. Marginal energy costs and emissions rates varied by time of day and time of year, but lower-cost resources were also more environmentally damaging, and customer load reductions were desirable during any hour to save both fuel and emissions.

Wind, solar, and battery storage resources are becoming the predominant new resources selected in many utilities' approved capacity expansion plans due to greenhouse gas emissions limits, renewables portfolio standards, resource carve-outs, and declining costs of clean energy technologies. However, while energy from these clean resources is abundant during many hours of the year, their availability is less uniform than that of thermal resources. Resource adequacy needs that were formerly driven by afternoon peak demand in places like California are now driven by net peak demand occurring in the evening hours when solar generation is no longer available.

The ongoing trend toward low-carbon renewable and battery resources is producing a shift from variable to fixed costs for power systems. As shown in Figure 1 (p. 3), resource additions in northern and southern California are expected to be dominated by solar, wind, and battery resources, which have high marginal fixed costs and very low or zero variable operating costs and marginal emissions. In fact, some resources might even have negative operating costs, if curtailment leads to the loss of the financial benefits available under the federal production tax credit or the loss of renewable energy certificates. Negative operating costs will become increasingly frequent due to the recent passage of the Inflation Reduction Act, which extended the life of the production tax credit and for the first time made solar eligible in addition to wind.

FIGURE 1

The Evolution of Utility Costs: From Variable to Fixed Costs



Resource additions in northern (NP15) and southern (SP15) California are expected to be dominated by solar and wind for low-cost energy and storage for balancing and resource adequacy. The ongoing trend toward low-carbon renewable and battery resources is producing a shift from variable to fixed costs for power systems.

Notes: CAISO = California Independent System Operator; PSHydro = pumped storage hydro; BTMPV = behind-the-meter photovoltaics.

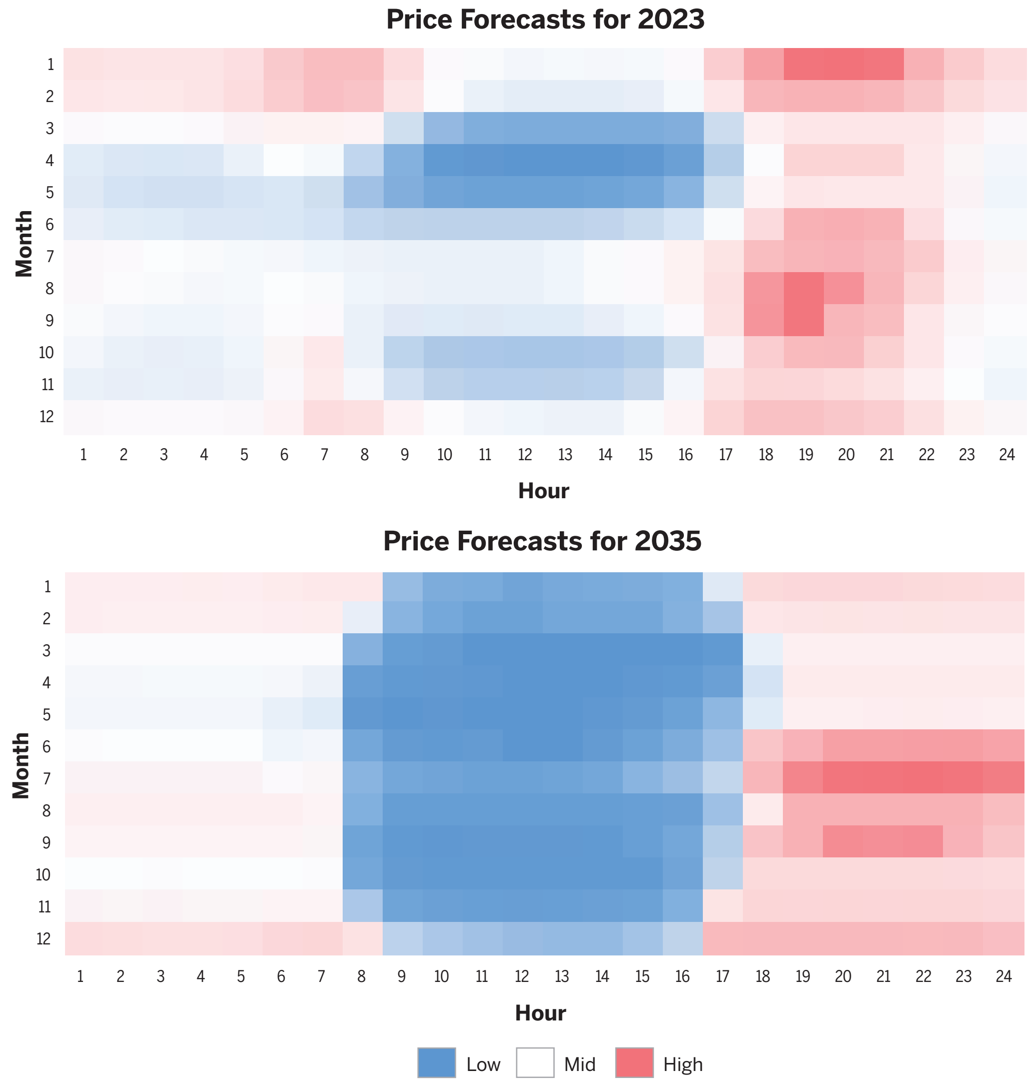
Source: Energy and Environmental Economics, Inc. (E3).

Historically, electricity market prices and emissions rates varied by time of day and time of year, but natural gas generators were almost always on the margin, and the hourly variations were relatively small on most power systems. As more low-carbon resources, particularly solar, are added to a power system, prices become more time-of-day dependent. There are significant differences between hours when renewable or thermal resources are the marginal resource. In California, market prices are frequently negative during daylight hours, especially in the spring, and customer load reductions during these periods no longer save fuel or reduce emissions. Market prices are much higher during the evening after sundown when wind, solar, and storage resources are limited in their ability to provide the required system capacity.

The spread between the highest and lowest energy prices will generally increase as the penetration of renewable resources increases, as illustrated in the deepening of the "duck curve" with more solar year-over-year in California. Figure 2 (p. 4) shows the diurnal and seasonal patterns in E3's day-ahead market price forecasts in southern (SP15) California. The evolution between 2023 and 2035 is clear, with much lower prices during daylight hours throughout most of the year (in blue) and a larger difference in midday and evening prices, particularly during the summer. This occurs despite the fact that more than 10 GW of energy storage resources are added to the California system by 2035, in keeping with the California Public Utilities Commission's Integrated Resource Plan.

FIGURE 2

The Evolution of Energy Prices from 2023 to 2035: A Growing Gap Between Hours of the Day (CAISO SP15)



In E3's day-ahead market price forecasts in southern (SP15) California, the evolution between 2023 and 2035 is clear, with much lower prices during daylight hours throughout most of the year and a larger difference in midday and evening prices, particularly during the summer.

Note: CAISO = California Independent System Operator.

Source: Energy and Environmental Economics, Inc. (E3).

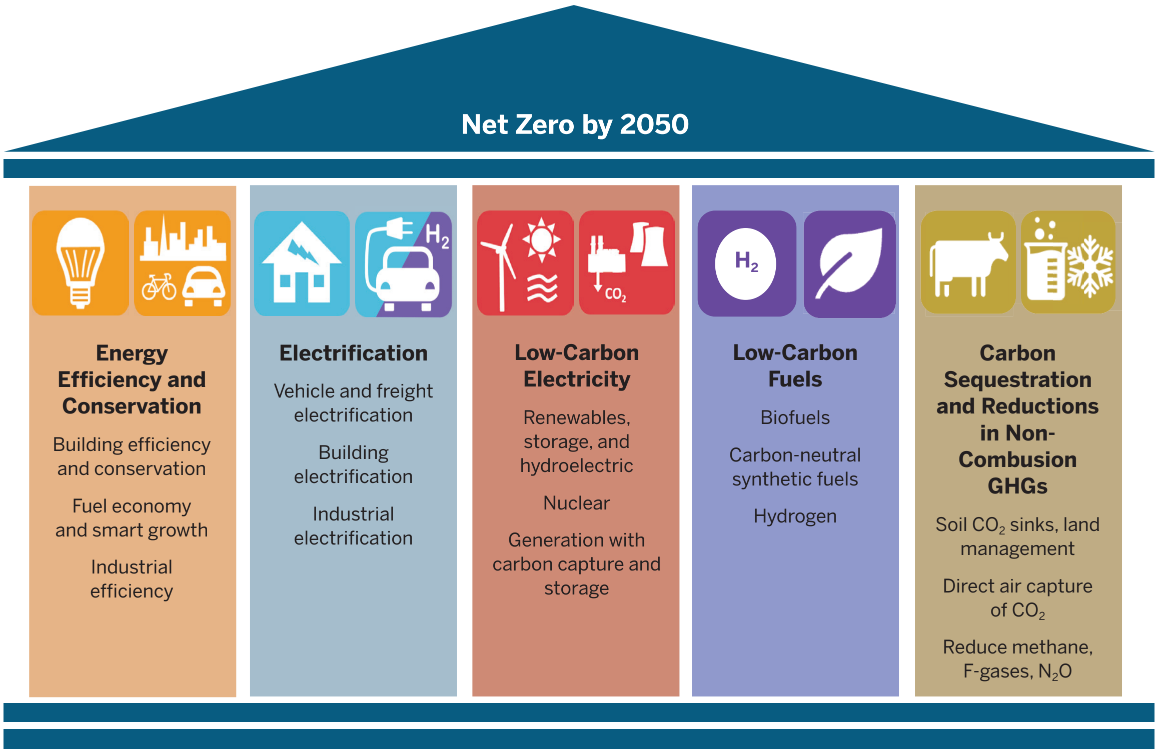
Electrification Is Now a Key Strategy for Meeting Economy-wide Greenhouse Gas Reduction Goals

For resource portfolios largely consisting of thermal generators, customer load reductions during any hour were a key strategy to save fuel and reduce emissions. Rate designs with high volumetric charges or inclining block rates with higher charges for higher consumption were aligned with environmental goals by encouraging conservation in all hours. These price signals were sufficient to encourage predictable, beneficial responses from customers.

Research published in California (E3, 2018a), New York (NYSCAC, 2021), the Pacific Northwest (E3, 2018b),

FIGURE 3

Five Pillars of Greenhouse Gas Reductions



E3's five pillars of decarbonization summarize strategies to meet economy-wide greenhouse gas reduction goals. Increases in electricity consumption through electrification of transportation and buildings are key strategies to reduce greenhouse gas emissions and improve local air quality.

Notes: GHGs = greenhouse gases; F-gases = fluorinated gases.

Source: Energy and Environmental Economics, Inc. (E3).

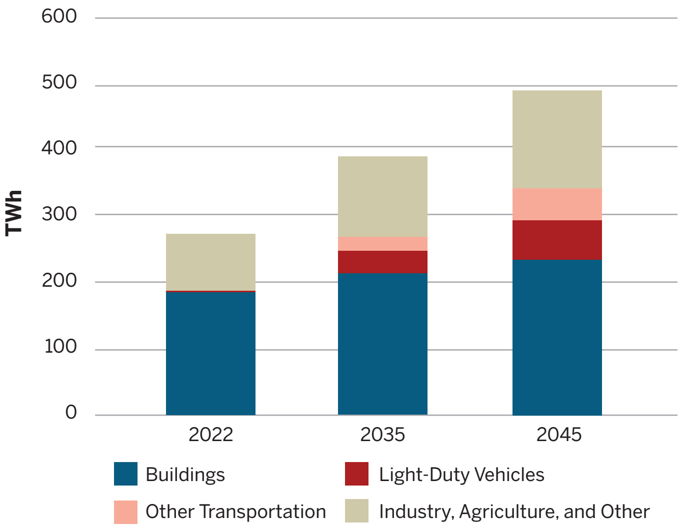
Colorado (CEO and E3, 2021), and nationally (Larson et al., 2021) has identified several strategies to meet economy-wide greenhouse gas reduction goals. These strategies, which E3 terms the five pillars of decarbonization, are summarized in Figure 3. The five pillars are: (1) energy efficiency and conservation, (2) electrification, (3) low-carbon electricity, (4) low-carbon fuels, and (5) carbon sequestration and reductions in non-combustion greenhouse gases.

It is becoming economically and environmentally beneficial to encourage electricity consumption during many hours of the year.

Increasing electricity consumption through electrification of transportation and buildings is a key strategy to reduce greenhouse gas emissions and improve local air quality. Figure 4 (p. 6) shows projected electricity consumption over time for the California Air Resources Board Scoping Plan Scenario to achieve carbon neutrality by 2045 in California (E3, 2022). Electricity use is projected to increase by about 40 percent relative to today by 2035, and by about 80 percent by 2045. High volumetric rates for electricity discourage electrification and therefore now stand as a major impediment to achieving these goals. With increases in electricity generation from renewable resources and the introduction of greenhouse gas emissions reduction goals driving electrification, it is economically and environmentally beneficial to encourage electricity consumption during many hours of the year.

FIGURE 4

Growth in Electric Load to Meet California's 2045 Carbon Neutrality Goals



The projected electric loads over time for the California Air Resources Board Scoping Plan Scenario to achieve carbon neutrality by 2045 in California. Electric loads are projected to increase by about 40 percent relative to today by 2035, and by about 80 percent by 2045.

Source: Energy and Environmental Economics, Inc. (E3).

In the absence of a strong price signal to encourage EV charging during specific periods, customer charging behavior may not align with grid needs. Strong price signals are therefore urgently needed to ensure that this new electric load does not add significant costs to the grid.

Customers Are Increasingly Able to Respond to Dynamically Changing Rates

With technological advances and broader access to metering and energy management devices, customers are increasingly able to respond to dynamic rates. Some customer meters can monitor energy consumption and production in real time rather than provide totals at the end of the month, allowing for the implementation of dynamic electricity rates. Additionally, upfront cost reductions and incentives for rooftop solar and batteries are making energy load management more cost effective for utility customers. Cost and emissions savings are encouraging rapid adoption of solar, electric vehicles (EVs), and batteries. Large EV loads create the potential to shift charging dynamically or even discharge back to the grid. Automated responses through customer load management devices as well as partnerships with third-party aggregators are already possible and will become the standard in low-carbon grids.

Moreover, even if customer battery adoption lags, the widespread adoption of EVs will create a significant new electric load with unprecedented potential as a flexible load.[1] With many states setting aggressive EV adoption goals, more than half of U.S. car sales are expected to be EVs by 2030 (Boudway, 2022). Many EVs have batteries with up to 100 kWh of storage capability, meaning that just one million EVs have storage capacity equivalent up to 25 GW of four-hour battery storage. However, this enormous potential for flexible loads could easily turn into newly electrified loads that are difficult to manage; in the absence of a strong price signal to encourage charging during specific periods, customer charging behavior may not align with grid needs. Strong price signals are therefore urgently needed to ensure that this new electric load does not add significant costs to the grid.

1 See the white paper in this series on locationally and temporally flexible EV charging (Chen, 2023).

In the New Planning Paradigm, Avoidable Bulk Grid Needs Are Predominantly Fixed Costs

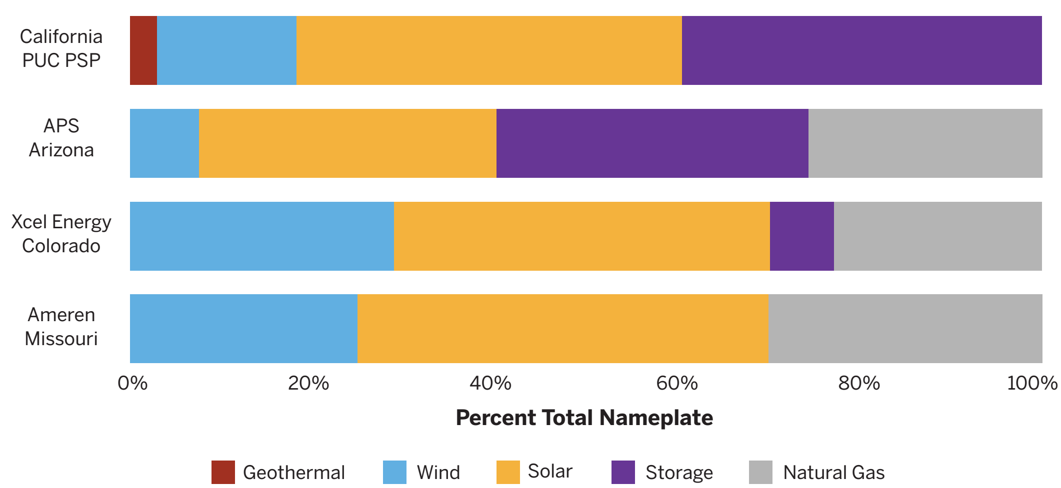
Going forward, utilities and other load-serving entities are increasingly likely to meet both reliability and policy goals largely with renewable energy. Incremental investments are dominated by wind, solar, and storage with high fixed costs and very low or zero marginal costs. Avoiding capacity investments requires predictable and reliable load reductions at specific times and locations. The extent to which customer responses through flexible loads and DERs can avoid electricity system costs varies based on the type of cost. Generation, transmission, and distribution capacity investments have different timing and locational constraints, requiring different customer responses to avoid all three types of investments.

Avoiding Generation Capacity Investments Requires Load Reduction at Key Moments

Driven by state policy goals and declining resource costs, utilities across the U.S. are planning new resource builds with large amounts of low-carbon resources: solar, wind, and battery storage. Figure 5 shows significant planned build-outs of low-carbon resources within several integrated resource plans (IRPs): the California Public Utilities Commission's Preferred System Plan, the Arizona Public Service IRP, Xcel Energy Colorado's IRP, and Ameren Missouri's IRP.

FIGURE 5

Future Resource Procurements by 2030, Dominated by Wind, Solar, and Storage



Resource additions from utility integrated resource plans include large amounts of low-carbon resources.

Notes: CPUC PSP = California Public Utilities Commission Preferred System Plan; APS = Arizona Public Service.

Sources: Energy and Environmental Economics, Inc. (E3); data from CPUC (2021), APS (2020), PSCC (2021), and Ameren Services (2022).

Additions of thermal plants are limited, but may be needed to provide capacity; most new energy will be provided by renewable resources complemented with batteries. Because wind, solar, and battery resources have high marginal fixed costs and very low or zero variable operating costs, the ongoing shift toward these low-carbon resources is changing the shape of utility cost structures.

The type of customer response that can help meet decarbonization goals is different than in the past when thermal generation was the dominant marginal resource:

- In many hours, thermal generation will continue to be on the margin, and reducing electricity consumption during hours when renewable generation is low can reduce emissions in the electricity sector. However, even during these hours, increasing consumption through electrification can result in net reductions in economy-wide greenhouse gas emissions by displacing emissions in buildings and vehicles.
- In some hours, renewable generation will be on the margin, and increasing consumption has no environmental impact and no incremental cost because it is met with clean generation that would otherwise be curtailed.
- During a small number of hours, when generation capacity is tight due to extreme heat or cold, reducing consumption can help defer or avoid generation capacity investments in addition to helping prevent costly involuntary load shedding.
- Energy storage charges during low-priced hours and discharges during high-priced hours, increasing net electric load but helping to avoid capacity investments on the margin. However, energy storage also has high capital costs. Customer response helps avoid the need for front-of-the-meter energy storage investments, as it largely provides a comparable short-duration profile at a cost that may be lower than investing in new front-of-the-meter battery storage.

Investments for resource adequacy are avoided by reducing customer demand during times of extreme grid stress, such as high electricity demand due to extreme heat or cold, extended periods of low renewable energy production, extended periods of fuel unavailability, or large generator outages. However, load reductions during other periods are not beneficial for avoiding these investments, and rate designs that discourage consumption during these periods may be counter-productive with respect to environmental goals if they discourage beneficial electrification.

Because renewable resources have high marginal fixed costs and low/zero variable operating costs, the shift toward the low-carbon resources is changing the shape of utility cost structures.

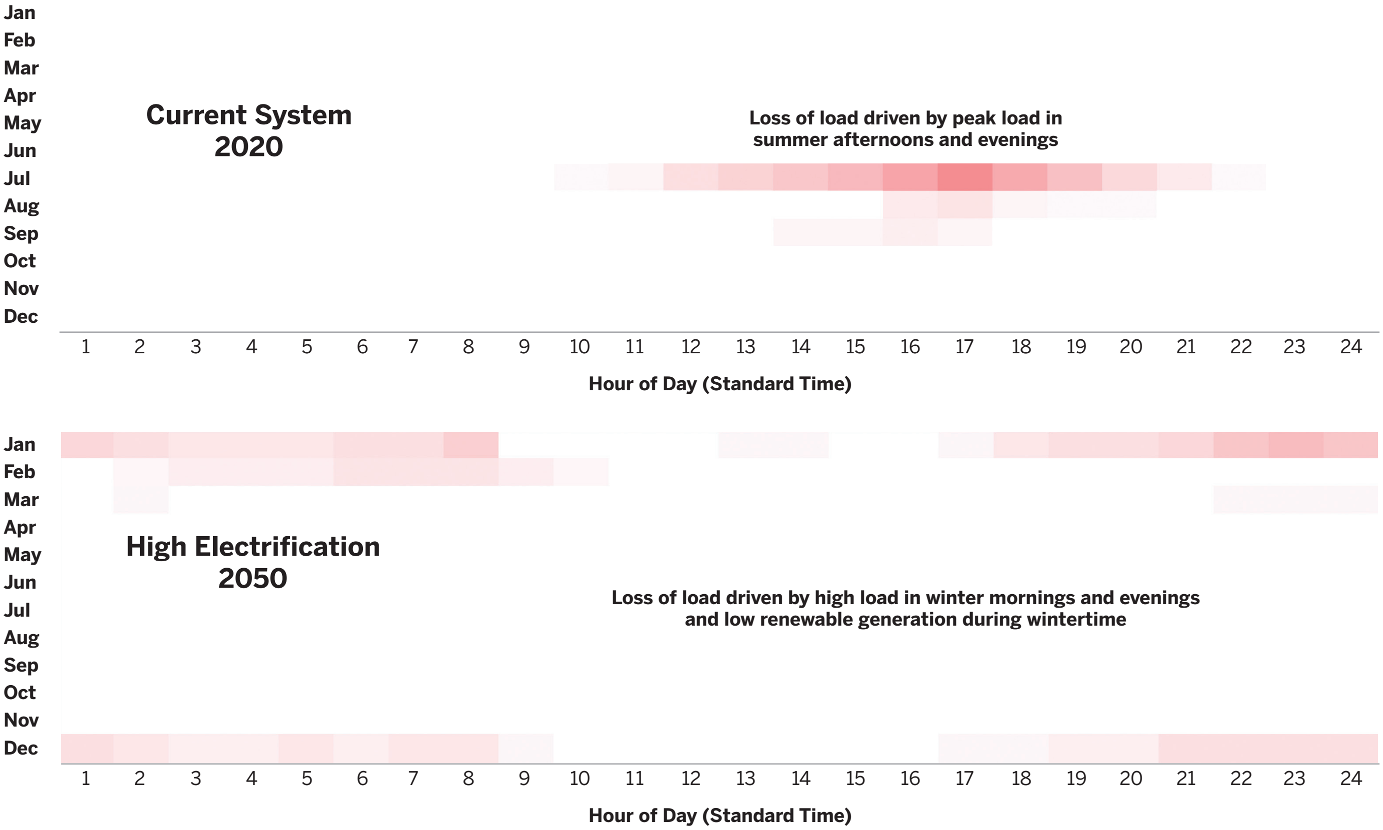
Load growth and planned thermal retirements are expected to increase resource adequacy needs, and the limited (and diminishing) capacity value of renewable resources will increase the value of resources that can provide capacity in times of need (ESIG, 2023). Resource adequacy needs have historically been determined by the combination of high peak load and an unusually large number of thermal resource outages, but grid stress events are increasingly observed during the "net peak" hours—hours when the combination of high load and low wind and solar generation create the greatest need for firm generation. Resource adequacy needs will evolve over time, with the high stress hours shifting to later in the day in solar-dominated systems and to wintertime in cold climates with significant electric heating demand. Figure 6 (p. 9) shows the loss-of-load probability distribution for New York State for the current system as well as a deeply decarbonized, high electrification scenario in 2050. Loss of load is currently driven by peak load in summer afternoons and evenings. In 2050, loss-of-load probability peaks in winter mornings and evenings when high heating loads coincide with low renewable production.

Avoiding Transmission and Distribution Capacity Investments Requires Predictable and Locationally Specific Responses

Additional sources of fixed costs for utilities are the buildout of transmission infrastructure to support resource additions and the growing potential need for distribution upgrades to accommodate the electrification of customer end uses. To avoid transmission and distribution capacity

FIGURE 6

Evolution of Resource Adequacy Needs in Deeply Decarbonized Systems: Loss-of-Load Probability Distribution for New York State



The loss-of-load probability distribution for New York State is shown for the current system as well as a deeply decarbonized, high electrification scenario in 2050. Loss of load is currently driven by peak load in summer afternoons and evenings. In 2050, loss-of-load probability peaks in winter mornings and evenings when high heating loads coincide with low renewable production.

Source: Energy and Environmental Economics, Inc. (E3).

investments, customer responses—whether to increase or decrease load—must be predictable and must occur at the right time and in the right location. Extreme transmission events and distribution system constraints may not occur at the same time as events causing the need for generation capacity. Additionally, the timing of needed load reductions to avoid distribution investments may differ by distribution area or even feeder. The timing and locational constraints associated with transmission and distribution capacity investments require different customer responses than those needed to avoid generation capacity investments.

To avoid transmission and distribution capacity investments, customer responses must be predictable and occur at the right time and place.

Reliability-driven transmission needs are determined by independent system operator (ISO) or utility transmission studies. Reliability transmission investments are frequently driven by the need to keep the lights on in a given load area even after the loss of one or two major elements such as a large transmission line or generator. These investments can, in some cases, be avoided by reducing customer demand in key locations during extreme transmission events. However, these extreme events may or may not line up with the events causing the need for generation capacity. Load reduction upstream of the critical bottleneck or at a different time is not beneficial for avoiding transmission investments and may even contribute to the problem by increasing the power flow over the constrained element. Similarly, customer response may help avoid transmission investments needed to deliver renewable energy to loads, but only if it occurs downstream of the specific transmission constraints in question and during the hours of highest transmission utilization.

Distribution investments are driven by the need to meet maximum demand by groups of customers connected to lower-voltage circuit areas on the distribution system, and they are avoided by reducing customer load during times of peak usage on the constrained distribution element.

Using load shifting to avoid distribution investments is the most difficult due to the precise timing and locational specificity of distribution system constraints and the lack of load diversity in small areas. Distribution investments are driven by the need to meet maximum demand by groups of customers connected to lower-voltage circuit areas on the distribution system, and they are avoided by reducing customer load during times of peak usage on the constrained distribution element. However, the timing of needed load reductions may differ by distribution area or even feeder. In some instances, significant additions of new load may shift the hours of highest distribution system usage and therefore the timing of system constraints, making it more difficult to align customer responses with the time periods needed to avoid investments. The size of potential EV loads, for example, may be enough to noticeably shift the hours of highest loading in low-voltage distribution transformers, depending on how the charging is managed. Load reductions outside of the affected area or at a different time are not beneficial for avoiding distribution system upgrade investments.

The extent to which customer load reductions and DERs can help avoid distribution investments varies by distribution area. Figure 7 (p. 11) shows distribution loads on two different distribution substations. The first is in an area with a mix of commercial and residential customers. Demand peaks during midday, but a secondary peak occurs in the evening hours due to residential demand. The second substation serves almost entirely residential customers, with an evening peak well after sundown. The charts also show the production hours from behind-the-meter solar (photovoltaic (PV) production), which can contribute to avoiding investments in the first area but is completely ineffective in the second area. Even in the first area, there is a limit to how much peak demand can be reduced due to the secondary evening peak.

The different customer responses required to avoid generation, transmission, and distribution capacity are illustrated by the allocation of capacity value in the California Public Utilities Commission's Avoided Cost Calculator (Figure 8, p. 12). Capacity costs for generation, transmission, and distribution are allocated to individual hours based on the likelihood that load will exceed available capacity. In this case, shown for the city of Santa Rosa, customer load response to avoid generation capacity is needed primarily on very hot days in July and August with peaks at hour ending 17 (HE 17). However, not every day is a peak generation day. Mild summer days have low loads, and increasing demand on these days does not contribute to generation capacity need.

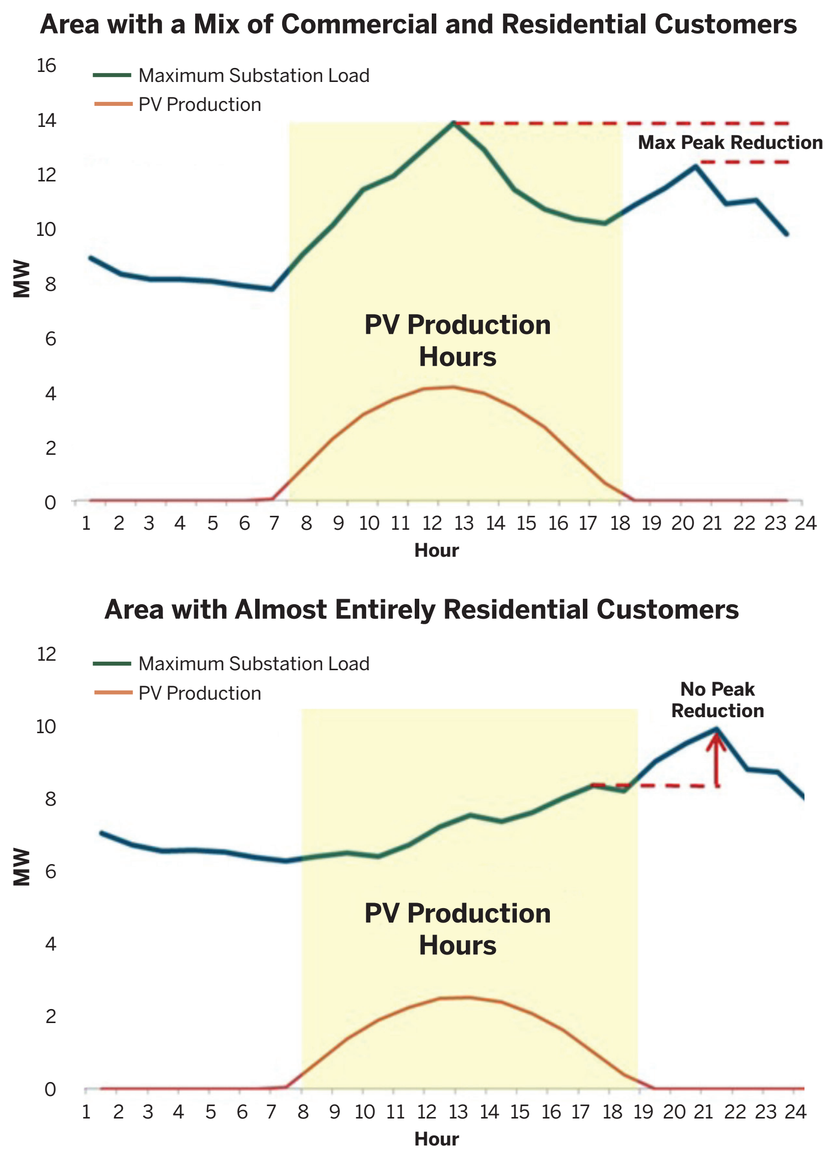
Transmission capacity need is spread out over both more hours of the day and months of the year and peaks earlier, at HE 16. In Santa Rosa, distribution peaks occur later in the year in September and October, and high loads are spread over more hours of the day. For a different region (e.g., Sacramento), the timing of peak distribution loads could be substantially different.

Avoiding Fixed Costs Requires Specific, Predictable Responses During Challenging, Extreme Conditions

Under deep decarbonization goals, the resource mix will be dominated by intermittent solar and wind. In addition, high levels of electrification will increase the system load on very hot and very cold days. Additional resources are needed to maintain reliability in hours when solar and wind output are insufficient to meet load. Front-of-the-

FIGURE 7

Coincidence of Distribution Peak Loads with Behind-the-Meter Solar on Mixed Commercial/Residential and Residential Only Substations



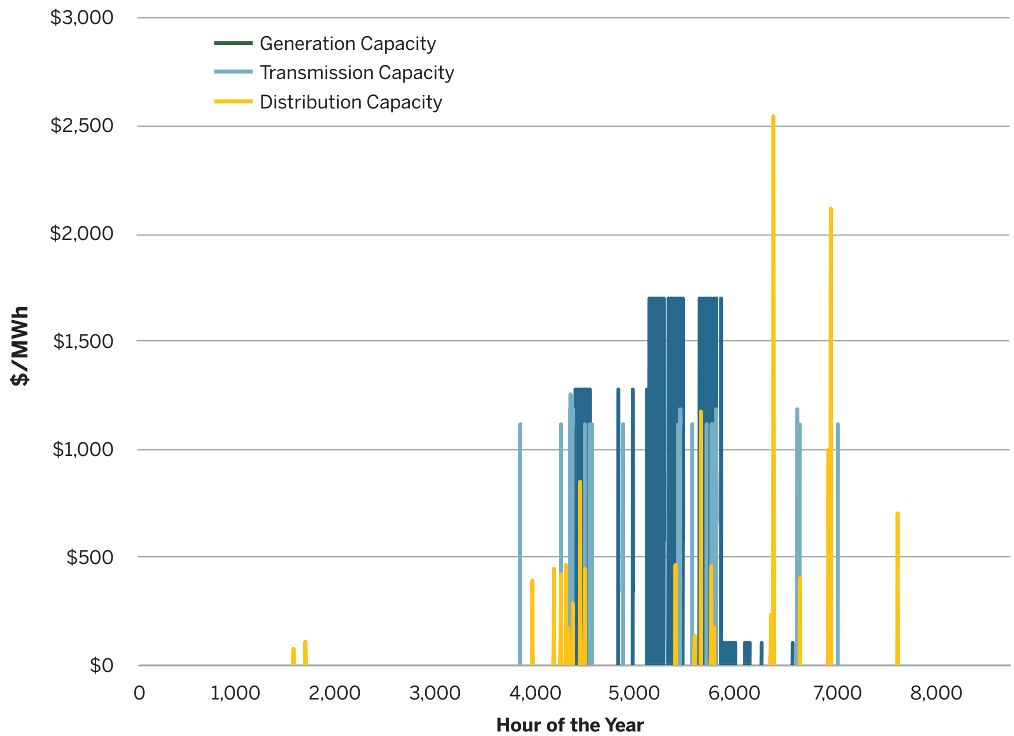
These figures show distribution loads and behind-the-meter solar production on two different distribution substations. The upper figure is for an area with a mix of commercial and residential customers, and the lower is for an area with almost entirely residential customers. Solar production contributes to avoiding investments in the first area but is completely ineffective in the second area.

Source: Energy and Environmental Economics, Inc. (E3).

meter energy storage can fill this gap by charging with excess renewable energy when it exists and shifting the excess energy to times of need. Figure 9 (p. 13) illustrates the role that storage plays in maintaining reliability in a deeply decarbonized New England in 2050 during a week of typical and critical grid conditions (E3 and EFI, 2020). Grid needs can also be met with DERs and load shifting. During critical periods where loads exceed renewable production and storage is not available, DERs and customer load reductions can reduce the quantity of firm fossil fuel generation resources needed to meet reliability.

FIGURE 8

Hourly Generation, Transmission, and Distribution Capacity Value in California Avoided Costs (for Santa Rosa)



The allocation of generation, transmission, and distribution capacity value in the California Public Utilities Commission's Avoided Cost Calculator, illustrating the difference in timing required to avoid generation, transmission, and distribution capacity investments.

Source: Energy and Environmental Economics, Inc. (E3).

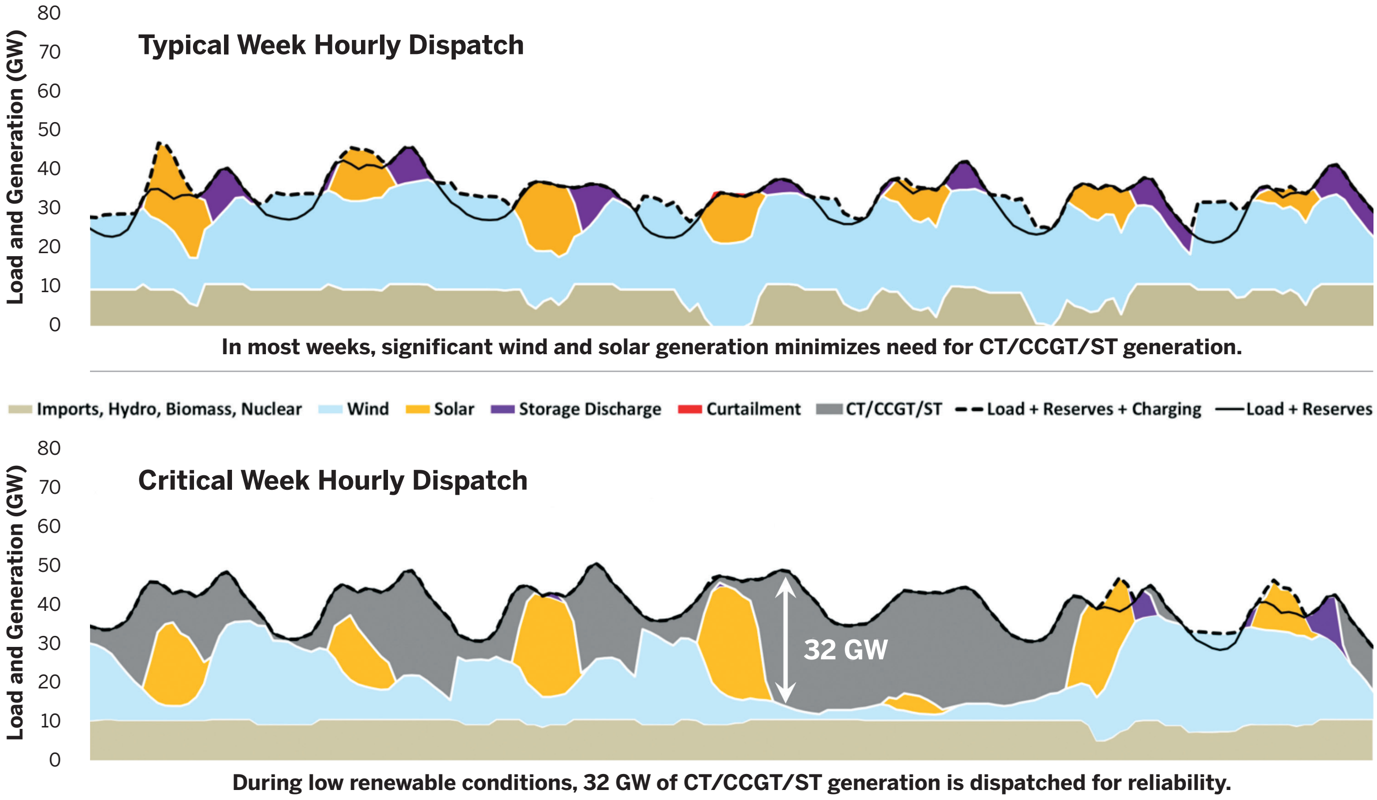
During the typical week, storage charges with excess solar and wind energy, minimizing curtailment, and discharges when the solar and wind output is insufficient to meet load. Storage's ability to ramp up quickly is valuable during the period around sundown when solar output drops rapidly. Storage also provides instantaneous capacity needed during periods of high demand, such as evening hours. These grid needs can also be met with DERs and load shifting. Behind-the-meter storage can be discharged to meet the grid's needs in the same manner as front-of-the-meter storage, reducing costs at the system level. Additionally, if load can be shifted away from hours when solar/wind output is forecasted to be lower than the required load into hours when renewable energy production is abundant, this avoids the round-trip losses associated with the charging and discharging of storage and, more importantly, may not require significant investments in new equipment.

The critical week during low renewable conditions in Figure 9 (p. 13) shows that the high renewables system is limited by energy availability rather than capacity availability, which increases the importance of flexible loads and DERs that reduce energy consumption during critical periods. For the first five days of the critical week, loads exceed renewable production, there is no excess generation to charge energy storage, and firm generation is needed to meet the load. DERs and customer responses that reduce energy consumption during this period would reduce the quantity of firm fossil fuel generation resources needed to meet reliability.

Responses from flexible loads and DERs must be predictable for system planners and operators to rely on them in lieu of investing in supply-side resources to help maintain reliability. The right market constructs and price signals are required to incentivize DERs and

FIGURE 9

Balancing and Flexibility Needs in a Deeply Decarbonized New England in 2050



Front-of-the-meter energy storage plays an important role in maintaining reliability in a deeply decarbonized New England in 2050 during a week of typical and critical grid conditions. Grid needs can also be met with DERs and load shifting. During critical periods when loads exceed renewable production and storage is not available, DERs and customer load reductions can reduce the quantity of firm fossil fuel generation resources needed to meet reliability.

Notes: CT = combustion turbine; CCGT = combined-cycle gas turbine; ST = steam turbine; DERs = distributed energy resources.

Source: Energy and Environmental Economics, Inc. (E3).

Responses from flexible loads and DERs must be predictable for system planners and operators to rely on them in lieu of investing in supply-side resources to help maintain reliability. The right market constructs and price signals are required to incentivize DERs and induce the consistent, demonstrated responses required to avoid grid investments.

induce the consistent, demonstrated responses required to avoid grid investments.

Summary of Avoidable Costs with Customer Response

As resource portfolios shift away from fossil fuels and toward cleaner generation resources, the customer response needed to avoid utility costs must be more targeted. Some cost categories are more easily avoided than others. In Table 1, the content of each cell reflects the degree to which avoiding the cost category requires a specific type of response; the colors of the cells indicate the ease of avoiding the cost category with customer response and contribute to an "avoidability rating." The degree of load diversity contributes to the avoidability rating in that a higher degree of load diversity at the system level makes the cost category easier to avoid. As the load diversity decreases moving further down the system toward the distribution level, there is a higher probability that a larger share of customers will have loads occurring during on-peak periods.

With a resource portfolio dominated by fossil fuel plants, load reductions in virtually any hour or location reduced fuel consumption and greenhouse gas emissions. However, with increasing renewable resources, load reductions must be more focused on those hours when fossil fuel generation remains on the margin to achieve the same benefits. To realize cost savings for generation capacity, a targeted, predictable, and reliable response during specific hours is required, but at the system level a locationally specific response is not necessary and load diversity is high (for example, planners can safely assume that only a portion of EVs will be charging during periods coincident with the system peak). Moving further down the system, realizing cost savings for transmission and distribution capacity requires locationally specific responses from a smaller and smaller pool of customers, and the load diversity decreases (e.g., there is a small but non-zero probability that five of ten customers served by a final line transformer will charge their EVs during on-peak periods). Due to the different timing and locational constraints associated with avoiding generation, transmission, and distribution capacity, aligning customer responses with grid needs requires dynamic rates.

With a resource portfolio dominated by fossil fuel plants, load reductions in virtually any hour or location reduced fuel consumption and greenhouse gas emissions. However, with increasing renewable resources, load reductions must be more focused on those hours when fossil fuel generation remains on the margin to achieve the same benefits.

TABLE 1

Comparison of Avoidable Costs with Customer Response

Cost Category	Degree to Which the Response Must: Occur in Specific Hours	Degree to Which the Response Must: Occur in Specific Locations	Degree to Which the Response Must: Be Predictable and Reliable	Degree of Load Diversity	Avoidability Rating
Fuel and GHG Emissions	Mid	Low	Low	High	★★★★
Generation Capacity	High	Low	High	High	★★★
Transmission Capacity	High	Mid	High	High	★★
Distribution Capacity	High	High	High	Low	★

Cost categories that are easy to avoid — Cost categories that are somewhat easy to avoid — Cost categories that are difficult to avoid

The extent to which customer responses can avoid electricity system costs varies based on the type of cost. The colors in each cell indicate how each factor contributes to an "avoidability rating"—the lightest orange indicates factors that make the cost category easy to avoid, while the darkest orange indicates factors that make the cost category difficult to avoid, and the mid-colored orange cells fall somewhere in between. Avoiding generation capacity costs requires a targeted, predictable, and reliable response during specific hours, but a locationally specific response is not necessary and load diversity is high at the system level, which makes it relatively easy to avoid those costs. In contrast, avoiding transmission and distribution capacity costs requires locationally specific responses from a smaller and smaller pool of customers, and the load diversity decreases, making it harder to avoid those costs.

Source: Energy and Environmental Economics, Inc. (E3)

Dynamic Rates Must Be Designed to Induce the Response Needed to Avoid Grid Costs

Current rate designs established under the old paradigm are no longer aligned with marginal grid costs and are an impediment to realizing environmental goals. Aligning customer responses with grid needs now requires retail rates to be dynamic. Advances in communications and control technologies enable automated responses to dynamic rates that increase benefits for both the customer and the grid. Furthermore, to successfully reduce supply-side investments, utility integrated resource planning must quantify the predictable and reliable impacts of customer response to dynamic rates in a statistically robust way. Dynamic rates will encourage customer responses that are beneficial to the grid and prevent price-responsive customers with DERs from shifting unavoidable fixed and embedded utility costs to customers without DERs.

Rates Can and Should Be Better Aligned with Grid Costs

The most common residential rate design today is a two-part rate consisting of a fixed charge and a volumetric energy charge, where a substantial portion of embedded costs are recovered in the volumetric charge. Although this rate structure promotes conservation and energy efficiency, it increasingly does not align with grid costs or reflect the cost structure of electricity service. At the same time, retail customers are increasingly capable of responding to price signals through investments in behind-the-meter devices such as rooftop solar, battery storage, EVs, and load management devices. For these customers, retail rates provide the compensation mechanism that rewards their investment and consumption behavior. Inducing beneficial responses from these customers requires a shift from thinking of retail rates primarily in the context of cost recovery. Instead, the ideal rate design is one that accurately compensates customer-owned DERs for the benefits they provide to the system.

Inducing beneficial responses from retail customers requires a shift from thinking of retail rates primarily in the context of cost recovery. Instead, the ideal rate design is one that accurately compensates customer-owned DERs for the benefits they provide to the system.

In this paper we propose a multi-part rate designed around the system's long-run marginal cost. LRMC, defined and calculated accurately, reflects the long-run value of customer load reductions at a given time and location as a sum of several individual components based on avoided variable and fixed costs. In organized markets, the LRMCs for energy, capacity, and grid services are defined by forecasts of wholesale market prices. Vertically integrated utilities calculate LRMC values through their integrated resource planning processes. Clean energy costs are based on avoided wholesale energy costs plus the renewable energy certificate or other clean energy attribute price. Hourly values for clean energy resources vary based on wholesale energy market conditions. Clean energy interconnection costs are determined through the generation queue study process. Resource adequacy capacity value and performance requirements are determined through an ISO-defined capacity accreditation methodology or a utility's effective load-carrying capability (ELCC) study.

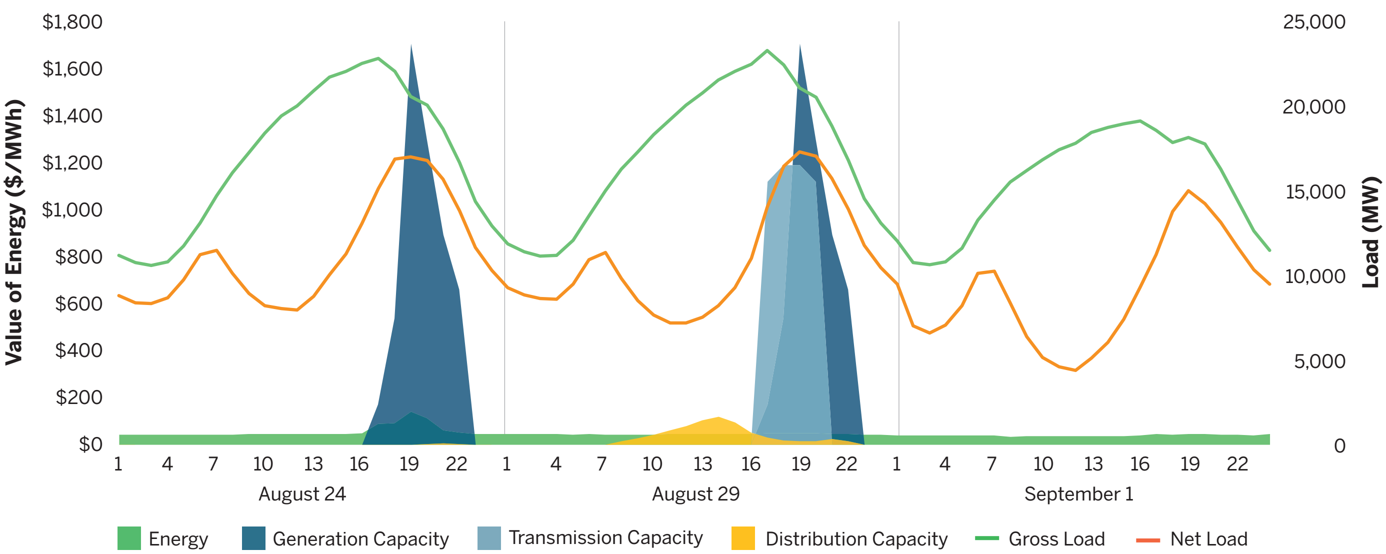
The second section above describes the most costly new investments being driven by grid needs in a limited number of difficult-to-serve hours in the year. The timing of grid needs within and across days is highly variable. This is illustrated with Figure 10, which shows the energy value and the allocation of generation, transmission, and distribution capacity value for each hour over three summer days in Sacramento, California, in 2030. Capacity costs for generation, transmission, and distribution are allocated to individual hours with the need for each type of capacity varying by time and location. With significant solar generation, generation capacity need is highest in peak net load hours after sunset. For example, on the first day shown in Figure 10 (August 24), high energy prices coincide with high generation capacity value around the peak net load period of HE 17. Distribution capacity need is location-specific and not necessarily correlated with peak gross or net system loads or the periods with high generation and transmission capacity value. For example, on August 29, distribution capacity value is highest in the early afternoon (HE 14) when the net load is low, generation capacity value is again highest during the peak net load period (HE 19), and transmission capacity value is high starting two hours earlier (HE 17). The timing of generation, transmission, and distribution capacity value is variable across days, with lower loads on September 1 with no allocation of any type of capacity value.

Seasonal TOU rates would provide the same incentive to reduce load during on-peak hours on all three days, despite the widely varying avoided costs. A multi-part dynamic rate could more precisely target load reductions for the highest value hours in each of the first two days while doing less to discourage EV charging on the third day.

Distribution capacity need is location-specific and not necessarily correlated with peak gross or net system loads or the periods with high generation and transmission capacity value.

FIGURE 10

Avoided Costs Showing Allocation of Capacity Value to Individual Hours over Three Summer Days in Sacramento, California, in 2030



The energy value and the allocation of generation, transmission, and distribution capacity value for each hour over three summer days in Sacramento, California, in 2030. The need for each type of capacity varies by time and location.

Source: Energy and Environmental Economics, Inc. (E3).

Customer Response During Extreme Conditions Must Be Predictable and Quantifiable If It Is to Avoid Supply-Side Utility Investments

To successfully defer or avoid supply-side investments, utility integrated resource planning must quantify the predictable and reliable impacts of customer responses to dynamic rates in a statistically robust way. Historically, although generation capacity needs have been determined using a stochastic, loss-of-load probability modeling approach, generators were accredited toward those needs based on their nameplate capacity, sometimes with a forced outage rate applied. The probability that some of these resources would be unavailable due to forced outages was accounted for in the planning reserve margin. This method is clearly not appropriate for variable and dispatch-limited resources such as wind and solar, which often produce well below their nameplate output, or for most energy storage resources, which cannot operate for more than a few hours before running out of charge. The ELCC method is increasingly used for capacity accreditation for these resources. The ELCC method considers load and resource conditions over many years and provides a statistically robust assessment of their ability to avoid loss-of-load events.

With respect to capacity accreditation, the characteristics of flexible loads and DERs are similar to those of front-of-the-meter wind, solar, and battery storage. The ELCC approach developed for utility-scale wind, solar, and battery storage can be applied to demand response and other DERs to develop accurate estimates of their capabilities. Customer responses modeled in this manner can be included in capacity auctions or resource planning to accurately quantify the capital investments that are avoided.

Quantifying customer responses requires a full understanding of the operating characteristics and key limitations of "event-based" response from flexible loads or DERs, including the maximum number of events per year, maximum duration of each event, available capacity, fixed and marginal cost of capacity, and likelihood of participation and response. Determining these characteristics requires accurately capturing both the technical and behavioral characteristics of flexible loads and DERs. The former is more straightforward; just as heat rate or ramp rates determine the modeled dispatch of a combined-cycle gas plant, the volume and temperature range of a water heater or the capacity of an EV charger are used to characterize the ability to shed and shift load. The behavioral characteristics are more complicated. The magnitude of DER potential will directly depend on available price signals and customers' responsiveness to those signals. In sum, understanding these characteristics will enable capacity auctions and capacity expansion models to select DERs just as they would any other resource and achieve the same reliability, environmental, and hourly operating constraints at lower cost. Alternatively, the resource adequacy contribution of DERs acquired through a separate process could be certified using these techniques to serve as an offset to the quantity of capacity that would otherwise need to be procured.

The ELCC approach to capacity accreditation developed for utility-scale wind, solar, and battery storage can be applied to demand response and other DERs to develop accurate estimates of their capabilities.

The need to develop more robust capacity accreditation frameworks for variable and dispatch-limited resources has also led to a reconsideration of the methods used for conventional thermal resources. Some markets have already moved away from an installed capacity (ICAP) approach that values conventional resources at their nameplate, and toward an unforced capacity (UCAP) approach that applies a resource-specific forced outage rate to conventional generators. The perfect capacity (PCAP) approach is a more robust method that is under consideration in some jurisdictions (CPUC, 2022b). Under the PCAP methodology, the planning reserve margin is determined assuming all resources are perfectly available, and all resources including conventional thermal generators are accredited using the ELCC approach, which compares their expected performance to that of a perfect resource. This enables the accreditation to consider not only forced outages but additional factors that might prevent a conventional generator from being available when needed, such as lack of access to fuel supplies.

Accreditation of DERs toward transmission and distribution needs is different from and potentially more challenging than for generation capacity needs. Transmission and distribution needs are generally evaluated using deterministic powerflow cases that identify potential overloads under certain specified conditions. The underlying generation and load patterns are based on a heavy-load case such as a single hour during a peak season (summer or winter) that represents a peak load condition. Instilling confidence in the reliability of DERs' performance during these conditions will likely require studies that validate program performance or automated technologies with active dispatch and verified response.

Instilling confidence in the reliability of DERs' performance during peak load conditions will likely require studies that validate program performance or automated technologies with active dispatch and verified response.

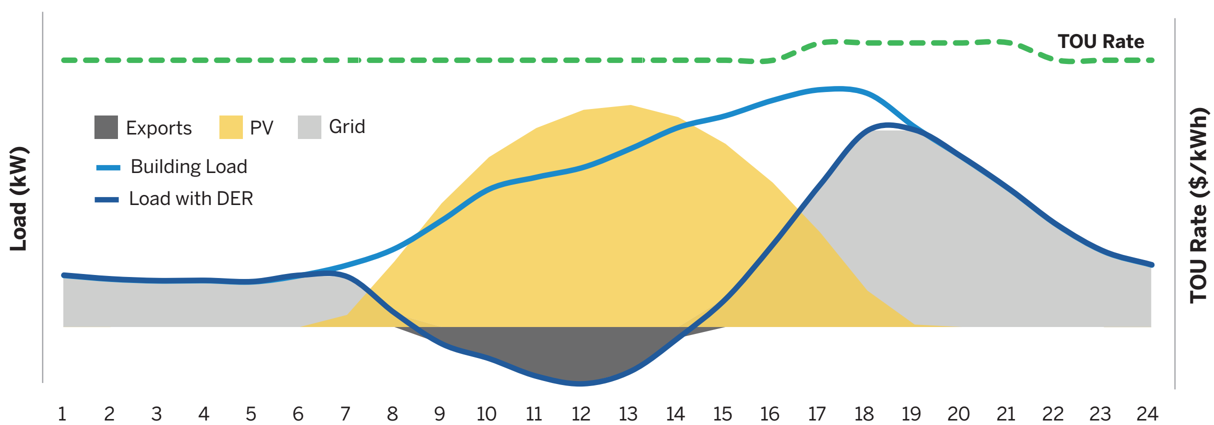
Examples of Improved Customer Response Under Dynamic Rates

Current residential rate designs, where a substantial portion of embedded costs are recovered in the volumetric charge, increasingly do not align with grid costs. Furthermore, potentially rich rewards for customer generation through net energy metering, which compensates generation at retail rates based on the utility's past embedded costs rather than its going-forward avoided costs, have resulted in cost shifts to customers without DERs. Dynamic rates will encourage customer responses that are beneficial to the grid and prevent price-responsive customers with DERs from shifting unavoidable fixed and embedded utility costs to customers without DERs.

The following figures provide examples of customer responses under TOU and dynamic multi-part rates. Figure 11 shows an illustrative residential customer with a solar PV system on a TOU rate without flexible DERs or load management. PV generation exceeds the customer's building load in the middle of the day, providing net exports to the grid. Some of the solar generation overlaps with the beginning of the on-peak TOU period from HE 17 to HE 21, but customer load in the last half of the on-peak period is unchanged.

FIGURE 11

Customer Load with Solar Only, on a TOU Rate



This customer has a solar PV system on a TOU rate without flexible DERs or load management. PV generation exceeds the customer's building load in the middle of the day, providing net exports to the grid. Some of the solar generation overlaps with the beginning of the on-peak TOU period, but customer load in the last half of the on-peak period is unchanged.

Notes: PV = photovoltaic; TOU = time of use; DER = distributed energy resource.

Source: Energy and Environmental Economics, Inc. (E3).

In Figure 12, the customer has adopted energy storage and an EV. In this case, under a net billing construct, exports to the grid are compensated at less than self-consumption, so energy storage is charged from solar to avoid exports and maximize bill savings for the customer. Storage is discharged immediately at the beginning of the on-peak TOU period. (A commercial customer with an on-peak demand charge would discharge the storage to minimize the non-coincident customer load without regard to system conditions.) The EV begins charging immediately at the start of the nighttime off-peak period. The customer load with DERs is significantly reduced throughout the on-peak TOU period. Because high variable on-peak $/kWh rates include a significant allocation of unavoidable fixed and embedded costs, the customer is realizing bill savings far in excess of the value to the grid, shifting those costs to other customers without DERs.

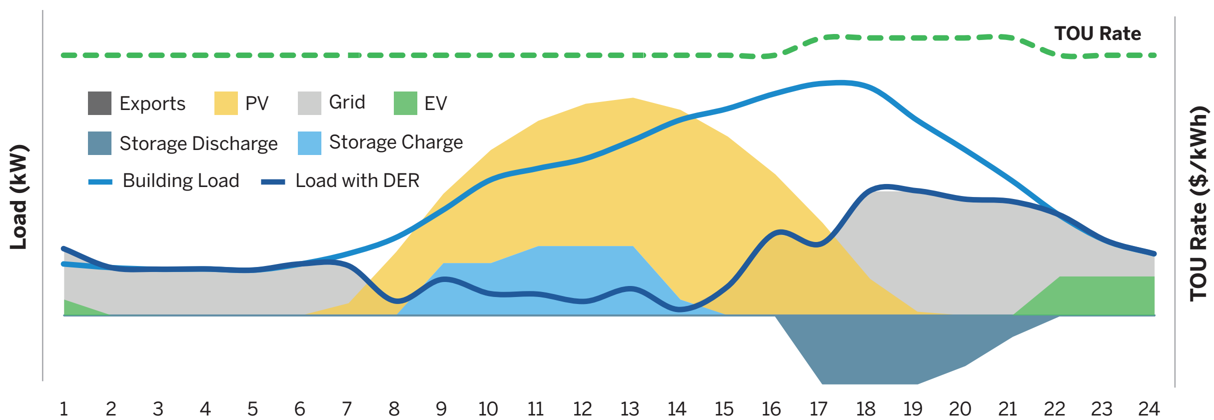
Figure 13 (p. 20) shows how the same customer responds to a multi-part dynamic rate based on LRMC including generation, transmission, and distribution capacity.

In this case, the dynamic rate is modeled based on the California avoided costs for August 29, with increased distribution capacity value in the afternoon and generation and transmission capacity value in the early evening (see Figure 10). The storage discharge, instead of starting at HE 17, is shifted an hour later to coincide with the highest-value hours for the grid. Because the dynamic rate reflects increased distribution capacity value in the afternoon, the customer's solar generation is not used for charging but is instead allowed to export to the grid. Both storage and the EV charge from the grid during

Technologies that enable customers to shift loads in response to dynamic rates are developing rapidly and will be increasingly adopted with building electrification.

FIGURE 12

Customer Load with Dispatchable DER Responding to TOU Rate



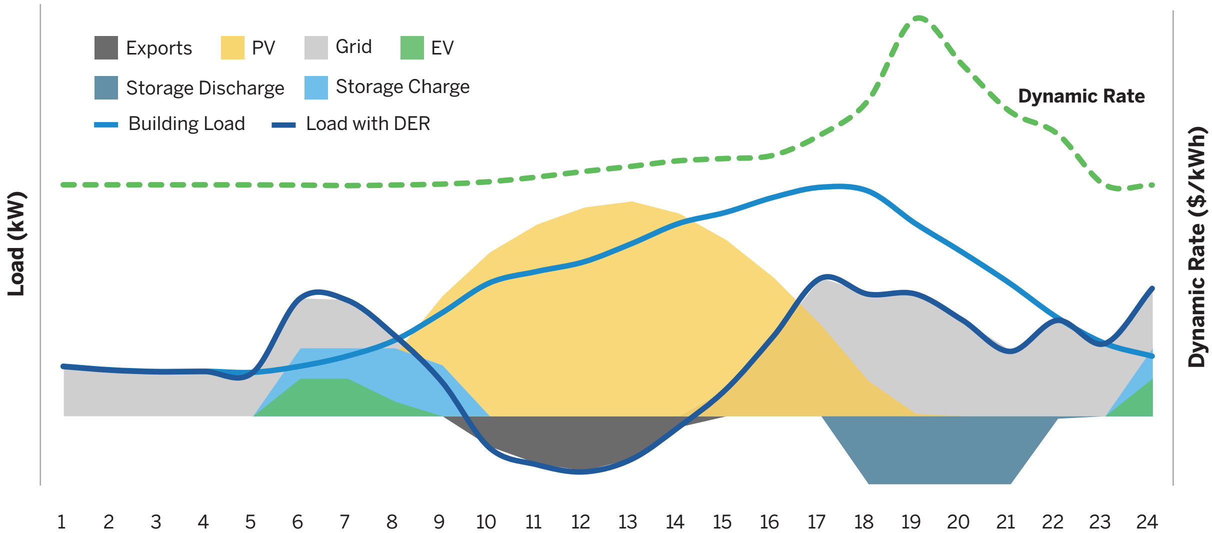
The customer has now adopted energy storage and an EV, with energy storage charged from solar to avoid exports and maximize bill savings. Storage is discharged immediately at the beginning of the on-peak TOU period, and the EV begins charging immediately at the start of the nighttime off-peak period. The customer load with DERs is significantly reduced throughout the on-peak TOU period. Because high variable on-peak $/kWh rates include a significant allocation of unavoidable fixed and embedded costs, the customer is realizing bill savings far in excess of the value to the grid.

Notes: PV = photovoltaic; EV = electric vehicle; TOU = time of use; DER = distributed energy resource.

Source: Energy and Environmental Economics, Inc. (E3).

FIGURE 13

Customer Load with Dispatchable DERs Responding to Dynamic Multi-Part Rate



The customer responds to a multi-part dynamic rate based on LRMC. The storage discharge is shifted an hour later to coincide with the highest value hours for the grid. Because the dynamic rate reflects increased distribution capacity value in the afternoon, the customer's solar generation is not used for charging but is instead allowed to export to the grid. Both storage and the EV charge from the grid during the off-peak hours with the lowest energy prices (midnight and late morning).

Notes: PV = photovoltaic; EV = electric vehicle; DER = distributed energy resource; LRMC = long-run marginal cost.

Source: Energy and Environmental Economics, Inc. (E3).

the off-peak hours with the lowest energy prices (midnight and late morning).

It is not just storage and EVs that will enable customer responses that are beneficial to the grid. Technologies that enable customers to shift loads in response to dynamic rates are developing rapidly and will be increasingly adopted with building electrification. Two examples of flexible load technologies being evaluated by the California Flexibility Research and Development Hub (CalFlexHub) are shown in Figures 14 and 15 (p. 21).

Rates can and should be better aligned with grid costs, as retail customers are increasingly capable of responding to price signals through investments in DERs and load management devices.

These figures illustrate the responses of a smart fan and a dynamic heat pump to California avoided cost price signals. Using pre-cooling or thermal storage, these technologies can shift the hours of operation within a certain window while maintaining building or water temperatures within a desired range. In Figure 14, a smart fan with an integrated thermostat pre-cools the building to reduce load in subsequent hours with high generation capacity value. In Figure 15, a dynamic heat pump heats water early in the day when energy prices are low in order to provide hot water later in the evening.

The above examples illustrate improved customer responses under dynamic rates. Rates can and should be better aligned with grid costs, as retail customers are increasingly capable of responding to price signals through investments in DERs and load management devices. Aligning customer responses with grid needs now requires dynamic, multi-part rates reflecting the long-run value of customer load reductions at a given time and location.

FIGURE 14

Smart Fan with Integrated Thermostat

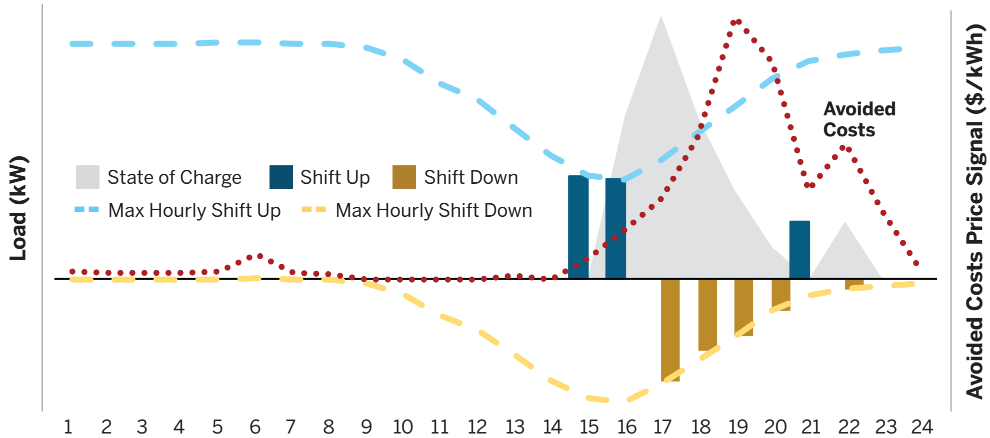
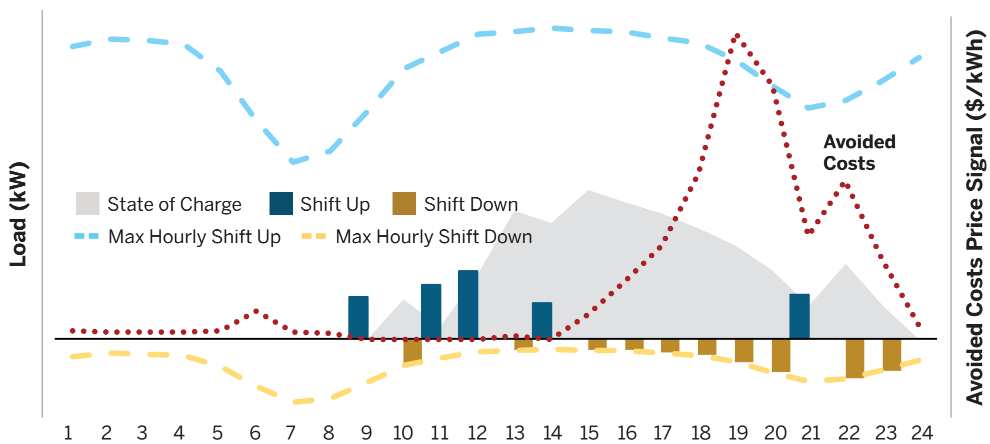


FIGURE 15

Dynamic Heat Pump for Space Heat and Hot Water



These figures show two examples of flexible load technologies being evaluated by the California Flexibility Research and Development Hub (CalFlexHub), illustrating the responses of a smart fan and a dynamic heat pump to California avoided cost price signals. Using pre-cooling or thermal storage, these technologies can shift the hours of operation within a certain window while maintaining building or water temperatures within a desired range.

Source: Lawrence Berkeley National Laboratory and Energy & Environmental Economics, Inc. (E3).

Multi-Part Rates Will Encourage Electrification and Beneficial Responses Aligned with Grid Needs

To align with grid needs and environmental goals, retail rates for customers with flexible loads and DERs must become more complex and dynamic. Multi-part rates that reflect the utility's LRMC can provide incentives for customers to shift or lower load while encouraging economically efficient grid investments and enabling equitable adoption of DERs. Rate designs must also strike a balance between cost recovery and sending the right marginal price signal to customers. We propose a multi-part rate with several individual components based on avoided variable and fixed costs.

Basing volumetric and demand charges on LRMC will result in significant fixed-cost recovery since LRMC greatly exceeds short-run marginal cost during most hours. Remaining fixed costs can be recovered through non-bypassable size-based and/or fixed charges designed for equity.

Multi-Part Rate Design

There is general consensus among economists that multi-part rates with greater fixed cost recovery outside of volumetric charges can enable a more equitable and efficient customer adoption of distributed PV and other DERs (AEE, 2018; E3, 2016; Nieto, 2016; SEPA, 2019; Zinaman, Bowen, and Aznar, 2020). Multi-part rates based on LRMC can include several components such as volumetric charges, fixed charges, demand charges, grid access charges, and subscription charges. To align with both grid needs and costs, variable energy charges should be low during hours when clean energy resources with zero or low marginal costs are abundant and on the margin. Basing volumetric and demand charges on LRMC will result in significant fixed-cost recovery since LRMC greatly exceeds short-run marginal cost during most hours. Remaining fixed costs can be recovered through non-bypassable size-based and/or fixed charges designed for equity.

Table 2 summarizes components of a fully specified multi-part rate design that is aligned with grid needs and can help achieve decarbonization goals while maximizing the grid value of DERs. Several elements are listed, consistent with the avoidable utility costs discussed in the second section. Although existing TOU rates provide incentives for customers to shift energy use to hours with lower marginal costs, these rates do not fully align with grid needs or offer sufficient signals to focus customer responses on the most critical hours to avoid fixed costs. While TOU rates may do a reasonably good job, in some cases, of replicating the load-shifting incentives of real-time rates that expose customers to hourly wholesale market prices (Schittekatte et al., 2022), a multi-part rate design can improve on fixed TOU rates by providing the low variable costs necessary to promote electrification and to reflect utility LRMCs that are dominated by high fixed/low variable cost resources.

Dynamic Hourly Energy Charge

The first element of a multi-part rate design is a dynamic hourly energy charge. Current retail rate structures often fail to send price signals that align with the true marginal energy and capacity costs paid by the utility. This mismatch can be significant, particularly in high-need times. This gap between true utility costs and retail rate constructs results in misaligned incentives that increase total grid

TABLE 2

Components of a Fully Specified Multi-Part Rate Design

Rate Component/ Associated Cost Component	Description
Dynamic hourly energy charge($/kWh) Marginal variable costs	• Variable $/kWh rate aligned with marginal costs of delivered energy • Options for adders: – Adder during coincident peak net load hours to meet resource adequacy needs – Adder for periods driving transmission and primary distribution investments
Generation capacity charge ($/kW or $/monthly kWh) Long-run marginal fixed costs	• Charge aligned with utility long-run marginal costs for new capacity resources • Options include: – Coincident peak demand charge based on load during hours defined by the ISO or utility LOLP study – Per-MWh energy adder during critical hours
Transmission capacity charge ($/kW or $/monthly kWh) Long-run marginal fixed costs	• Locational (likely zonal) charge aligned with utility long-run marginal costs for new transmission • Options include: – Coincident peak demand charge based on load during hours defined by the ISO or utility transmission study – Per-MWh energy adder during critical hours
Distribution capacity charge ($/kW or $/monthly kWh) Long-run marginal fixed costs	• Locational charge aligned with utility long-run marginal costs for new distribution • Options include: – Coincident peak demand charge based on load during hours defined by the ISO or utility distribution study – Per-MWh energy adder during critical hours
Non-bypassable customer charge ($/month, $/kW, or $/monthly kWh) Remaining embedded costs	• Monthly customer charge to recover embedded and unavoidable fixed costs • Options include: – Customer or meter charge – Size-based customer charge – Income-based customer charge – Demand subscription charge – Ratchet demand charge – Demand charge based on the highest load hours

Notes: ISO = independent system operator; LOLP = loss-of-load probability.

Source: Energy and Environmental Economics, Inc. (E3).

costs due to inefficient customer responses. A dynamic hourly rate with energy price signals aligned with LRMCs can better incentivize customer responses that maximize grid benefits. This type of rate allows for a more accurate measurement of real-time costs of service for energy consumption as well as value provided to the grid for energy generation. A dynamic hourly energy charge based on marginal costs will also be low in most hours of the year, facilitating lower bills for customers pursuing building and transportation electrification as compared to a TOU rate.

Charges Reflecting LRMC of Generation, Transmission, and Distribution Capacity Investments

The next elements of a multi-part rate design are coincident demand charges or energy adders designed to reflect the LRMC of generation, transmission, and distribution capacity investments. It is necessary to specify these elements separately because of the different timing and locational requirements for beneficial customer responses. The LRMC could be encapsulated in an energy adder during critical hours, i.e., the hours that drive new investments in generation, transmission, and distribution facilities. The specific, locational nature of transmission and distribution avoided costs means that these components must be locational; customers downstream of a system constraint would see a price signal to reduce consumption during a critical period, whereas customers upstream of the constraint would not. A similar rate structure would be applied based on distribution-level LRMC; however, the locational nature of distribution LMRC is much more specific, and the time dimension would be specific to each distribution facility as well. Rates that provide the same signal to all customers to shift load to the beginning of the off-peak period may create secondary peaks on the local distribution system. Differentiating signals or rates for aggregators to manage loads based on local conditions will be necessary to manage distribution costs under increasing electrification.

The non-coincident demand charges most common in commercial and industrial rates can be a strong disincentive for customers to shift loads in ways that are beneficial to the grid.

It is important to emphasize that the non-coincident demand charges most common in commercial and industrial rates can be a strong disincentive for customers to shift loads in ways that are beneficial to the grid. An analysis of behind-the-meter energy storage dispatch for the California Self Generation Incentive Program found that non-residential customers actually increased on-peak loads (and greenhouse gas emissions) in part because they were often charging on-peak to minimize their non-coincident demand charge (Verdant Associates, 2021; Itron, 2020). It is therefore important to limit any non-coincident demand charges only to those costs such as secondary distribution costs that are truly driven by connected rather than coincident peak loads.

Non-Bypassable Customer Charge

The final element of a multi-part rate design is a non-bypassable customer charge to recover a portion of the remaining embedded and unavoidable fixed costs that are part of the utility revenue requirement. Here, the goal for the rate design shifts from sending a signal for customer responses based on LRMC to equitably recovering embedded costs that customers should not be able to avoid by reducing or shifting load. Assessing some of these charges based on customer size or demand subscription level can help achieve equity goals by ensuring that larger customers pay their commensurate share of embedded and unavoidable fixed costs. Additional examples of rate design elements that are difficult to bypass include ratchet demand charges or demand charges based on an average of the highest load hours in a month.

High fixed charges have historically faced challenges with customer acceptance and political viability; however, these attitudes are changing in response to cost shifts and widespread interest in promoting cost-effective electrification and decarbonization. For example, the California Public Utilities Commission found that cost recovery through volumetric rates has led to rate increases and inequities among customers, especially as electricity sales declined with the increase in adoption of DERs.[2] To ensure equity and affordability in a non-bypassable customer charge, the charge can be income-based. Borenstein, Fowlie, and Sallee (2021) proposed income-based fixed charges as an approach to equitable recovery of embedded costs, where higher-income households pay a larger monthly fixed charge. Income-based fixed charges are included as an option for the non-bypassable customer charge in Table 2 (p. 23).

California AB 205 authorizes the Public Utilities Commission to establish fixed charges on residential rate schedules and eliminates the cap on fixed charges to help stabilize rates and ensure equitable cost recovery.[3] The commission must ensure that the fixed charges do not have a negative impact on incentives for electrification,

2 Assembly Bill No. 205, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB205.

3 Ibid.

conservation, energy efficiency, and greenhouse gas emissions reductions. Additionally, the fixed charges must be income-based with at least three income thresholds in order to reduce the impact on low-income customers. With these income-graduated charges, low-income customers will pay a smaller fixed charge than high-income customers.

Multi-part dynamic rates will simultaneously address some challenges and introduce new ones for utility rate design. Increasing fixed charges provides more revenue certainty but must be implemented in a way that is sensitive to renters and low-income customers with a reduced ability to adopt flexible DERs. Designing equity-based fixed charges will require new mechanisms for gathering and sensitively managing confidential financial data. Rates of DER adoption and customer responses to different rate levels and designs will be uncertain at first, requiring pilots and studies to establish rates that provide economically efficient marginal cost signals and also fully recover utility costs. These challenges are not small but can and must be faced directly in order to plan and build an electricity grid that cost-effectively promotes electrification and decarbonization.

Balancing Accuracy and Simplicity

The "fully specified" multi-part rate design described in the previous section is put forward without consideration of customer understanding and acceptance of such a complex design. As noted above in the second section, avoiding capacity costs requires a targeted, predictable, and reliable response, with increasing locational specificity for avoiding transmission and distribution capacity costs. Accurately compensating customer response and DERs for avoiding these investments requires such complexity, and it is useful to start with a fully specified rate design.

However, rate design necessarily requires achieving a balance among multiple competing policy goals including efficiency, equity, feasibility, and customer acceptance. For customers with flexible loads and DERs, complex rates are readily managed by third-party aggregators or DER control software, with the resulting bill savings clearly communicated to the customer. Simplifications of a complex design such as a fixed TOU design or TOU combined with critical peak pricing may be desirable depending on the level of sophistication of the customer base. Even in a fully specified design, the various components could be combined into a single customer-facing variable energy charge in a similar manner to the California Avoided Cost Calculator, which produces hourly avoided costs for use primarily in DER cost-effectiveness evaluation, but with the California Public Utilities Commission's Net Energy Metering (NEM) 3.0 decision will now also be used to determine export compensation for customer solar resources.

As utilities and customers gain experience with the design and implementation of multi-part rates, additional elements for transmission and distribution capacity costs with the required temporal and locational specificity can be incorporated.

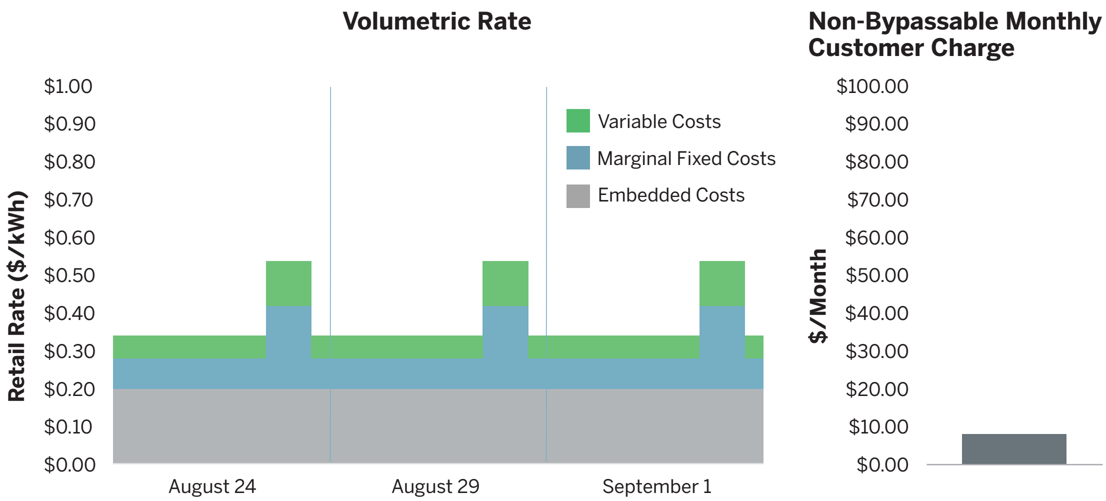
As utilities and customers gain experience with the design and implementation of multi-part rates, additional elements for transmission and distribution capacity costs with the required temporal and locational specificity can be incorporated. Rate elements for transmission and distribution will also need to implement equity protections between customers that live in low vs. high marginal cost-to-serve areas.

Comparison of a Typical TOU Rate and a Dynamic Multi-Part Rate

A comparison of a typical TOU rate and a dynamic multi-part rate is provided in Figures 16 and 17. As shown in Figure 16 (p. 26), high volumetric retail rates ($/kWh) include a significant allocation of fixed and embedded costs (in blue and gray, respectively). A portion of the embedded costs are also collected through a non-bypassable monthly customer charge. The volumetric rates are higher during on-peak periods defined over four to six hours for summer and winter seasons. As noted previously, the allocation of fixed and embedded charges to volumetric rates creates two important challenges. Customers adopting DERs receive compensation that exceeds the grid value and shift those costs to customers without DERs. High volumetric rates also inhibit customer adoption of building and transportation electrification

FIGURE 16

Illustrative TOU Rate



High volumetric retail rates ($/kWh) include a significant allocation of fixed and embedded costs (in blue and gray, respectively). A portion of the embedded costs are also collected through a non-bypassable monthly customer charge. The volumetric rates are higher during on-peak periods defined over four to six hours for summer and winter seasons.

Source: Energy and Environmental Economics, Inc. (E3)

that are both economically and environmentally beneficial.

An illustrative multi-part dynamic rate is shown in Figure 17 (p. 27), modeled on the California avoided costs shown above in Figure 10 (p. 16). In most hours, the dynamic energy rate based on wholesale energy costs (variable costs) is significantly lower than the above TOU volumetric rate composed of variable, fixed, and embedded costs. In the multi-part dynamic rate, marginal fixed costs including generation capacity costs and long-run transmission and distribution avoided costs are allocated to a limited number of hours in which load would drive marginal investments in new facilities. The high volumetric retail rates during these periods give the customer a strong economic incentive to reduce loads driving marginal fixed cost investments in new capacity resources. Finally, embedded costs are collected through an equity based, non-bypassable monthly customer charge.

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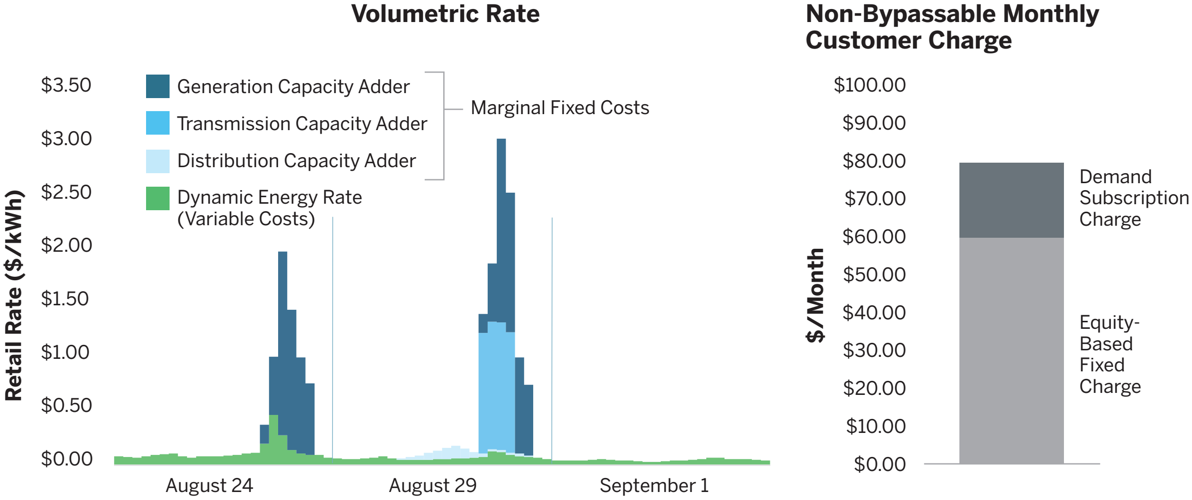
Multi-Part Rate Examples

Several multi-part rate variations have been piloted and implemented. As part of the Power Your Drive Pilot, San Diego Gas and Electric Company deployed a dynamic vehicle-grid integration electricity rate to encourage drivers to charge EVs during hours that maximize grid benefits (SDG&E, 2021). This vehicle-grid integration rate contains several components including base rates to recover transmission and distribution system operating costs, non-bypassable charges, an hourly commodity rate that is adjusted based on the California Independent System Operator day-ahead energy price, an hourly adder for the top 150 hours of demand on the California grid, and an hourly adder for the top 200 hours of demand on a customer's distribution circuit.

FIGURE 17

Illustrative Dynamic Multi-Part Rate



In most hours, the dynamic energy rate based on wholesale energy costs is significantly lower than the above TOU rate in Figure 16. Generation capacity costs and long-run transmission and distribution avoided costs are allocated to a limited number of hours in which load would drive marginal investments in new facilities. Embedded costs are collected through an equity-based, non-bypassable customer charge.

Source: Energy and Environmental Economics, Inc. (E3)

The Pacific Gas and Electric commercial EV rate includes a monthly subscription charge where customers choose their subscription level based on their maximum monthly EV charging load (PG&E, 2022). This subscription amount can be adjusted throughout the month as needed to help customers avoid overage fees when their consumption exceeds the subscribed amount. In addition to the subscription charge, customers still charge using a TOU rate.

In New York, Consolidated Edison has an Innovative Pricing Pilot that includes seven time-variant, demand-based rates known as the Smart Energy Plan and the Fixed Delivery Billing Plan (conEdison, 2022a). Each rate includes a time-variant demand delivery rate, a time-variant demand delivery rate with TOU supply pricing, or a demand subscription delivery rate. One of the rates is a volumetric and time-variant-demand hybrid delivery rate. Each rate is designed to encourage customers to space out the use of electric devices and shift energy use to off-peak hours (conEdison, 2022b).

New Hampshire Electric Cooperative is developing a transactive energy business model where day-ahead price signals will give customers more control over their energy use, and the utility will compensate customers for their energy investments (NH Network, 2021). This business model includes a transactive energy rate pilot that uses day-ahead hourly price signals to encourage customers to use DERs at a time that creates value. These price signals can be for the whole home or a single device so that customers can focus on the DERs and devices they can control.

The California Energy Commission and California Public Utilities Commission are proposing new retail rate strategies in response to several issues including increasing penetration of renewable resources and DERs,

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building and transportation electrification, inequitable fixed cost recovery, and cost shifts in California (CPUC, 2022a). As part of the load management standards update, the California Energy Commission created the Market Informed Demand Automation Server (MIDAS), an online rate database that can be used to enable automatic, price-responsive load shifting. The vision for MIDAS is to serve as a price portal with dynamic hourly rates reflecting locational marginal costs that customers can use to automate the response of flexible loads.

To address grid issues and DER management, the California Public Utilities Commission developed a policy roadmap and retail rate strategy known as CalFUSE (California Flexible Unified Signal for Energy) (CPUC, 2022a). The CalFUSE framework proposes dynamic electricity prices, dynamic capacity charges, bi-directional electricity prices, subscription options based on historical usage, and transactive features to import or export energy at a pre-determined price. Dynamic electricity prices will be based on real-time locational marginal prices in the California Independent System Operator energy market, and dynamic capacity charges will be based on real-time utilization of local capacity infrastructure.

Addressing Bill Volatility

Dynamic multi-part rates can lower average customer bills by realizing DER value and reducing overall grid costs. However, dynamic rates may significantly increase the month-to-month volatility in customer bills. Relative to today's rates, customers on a dynamic multi-part rate would likely see lower bills across most months but would see high bills during the few months where capacity costs are allocated, especially during reliability conditions when market prices are high. Customers would face especially high bills if they were unable to reduce usage during high-price hours.

Concerns regarding bill volatility under dynamic rates are justified and should be taken seriously. As a recent

Concerns regarding bill volatility under dynamic rates are justified and should be taken seriously, and there are many approaches to reducing bill volatility under dynamic rates.

example, the Texas electricity retailer Griddy offered electricity rate options based on wholesale prices. During Winter Storm Uri, market prices skyrocketed and Griddy customers faced very high bills, with some customers seeing monthly bills in excess of $5,000 (Halkais, 2021). These high bills led to widespread shock and anger among both Griddy customers and public officials. Ultimately, the state of Texas sued Griddy, seeking financial relief for ratepayers under the Texas Deceptive Trade Practices Act,[4] and legislation was passed that attempts to ban the direct pass-through of wholesale price to residential customers. Although market pricing in Texas is unique due to the inclusion of scarcity pricing, this example illustrates that both customers and public officials may find extreme levels of bill volatility to be unacceptable, even if customers have opted into dynamic pricing.

There is a range of potential options to reduce bill volatility under dynamic rates. A simple approach could involve capping dynamic pricing at some threshold, with costs above that threshold recovered through a more predictable rate component such as the non-bypassable charge. A more complex approach could involve a hedging process in which customers subscribe to a load profile at a predetermined price (Wolak, 2022). In this approach, customers would only be exposed to dynamic pricing for deviations from the subscribed load profile, paying (or receiving) dynamic pricing for any additional load (or load reduction) relative to that profile. Different customers may have distinct tolerances for bill volatility, and thus a combination of different approaches may be appropriate across various customer groups.

4 United States Bankruptcy Court, Order (A) approving and authorizing debtor to enter into settlement agreement with the state of Texas and (B) granting related relief, 2021, https://www.texasattorneygeneral.gov/sites/default/files/images/executive-management/2021/Griddy%20Bankruptcy%20Settlement.pdf.

Conclusion

Decarbonization and clean energy policy goals have fundamentally changed grid planning and operational challenges. Retail rate design must now change as well to reflect new cost drivers and grid needs and to promote electrification to meet environmental goals. Going forward, grid planning seeks to meet both reliability and policy goals largely with renewable energy and battery storage, incremental investments that are dominated by wind, solar, and storage with high fixed costs and very low or zero marginal costs. The two dominant grid planning challenges and cost drivers are now resource adequacy to provide reliability during net peak load hours and time shifting of renewable electricity from periods of excess generation to periods when it can be beneficially consumed. Dynamic rates must be designed to induce the customer responses needed to help address these challenges and avoid grid costs. These costs include generation, transmission, and distribution capacity costs with different timing and locational constraints, requiring different customer responses to avoid all three types of investments.

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Furthermore, to successfully reduce supply-side investments, organized capacity constructs and utility integrated resource planning must quantify the predictable and reliable impacts of customer responses to these dynamic rates in a statistically robust way. To align with grid needs and environmental goals, retail rates for customers with flexible loads and DERs must become more complex and dynamic with automated responses. These goals are achievable through a feasible multi-part rate design with: (1) a dynamic hourly energy rate that is low in most hours of the year when zero/low variable-cost resources are abundant and on the margin; (2) a coincident demand charge or hourly allocation of long-run marginal capacity costs that encourage reducing and shifting load out of a relatively small number of hours that drive new investments in generation, transmission, and distribution capacity; and (3) non-bypassable customer charges based on size and/or income, designed for equity, that recover remaining embedded and unavoidable fixed costs.

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Rate Design for the Energy Transition

Getting the Most out of Flexible Loads on a Changing Grid

By Arne Olson, Eric Cutter, Lindsay Bertrand, Vignesh Venugopal, Sierra Spencer, Karl Walter, and Aryeh Gold-Parker

Energy and Environmental Economics, Inc. (E3)

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

This white paper is available at https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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