WHITE PAPER

Tapping the Mother Lode

EMPLOYING PRICE-RESPONSIVE DEMAND TO REDUCE THE INVESTMENT CHALLENGE

By Michael Hogan, Regulatory Assistance Project

The rapid and parallel growth in both variable electricity production from wind and solar, and in large inherently flexible loads (such as electric vehicles and heat pumps) presents an opportunity to ensure that each transition is both reliable and affordable. In a future that will be increasingly capital intensive, demand flexibility can significantly reduce the amount of infrastructure that must be financed. But much remains to be done to access that potential, most of which is beyond the reach of traditional approaches to demand response.

The primary focus must shift from strategies that require flexible demand to mimic centrally dispatched generation, to strategies that empower consumers to save money by linking their consumption more dynamically to daily fluctuations in variable supply. At a retail level, this includes adopting a series of innovations that widen consumers' access to the untapped potential for flexible loads to reduce costs and lower electricity bills. At the wholesale level, it means attacking institutional practices that discriminate against flexible demand reliant on energy market pricing and that artificially depress energy prices by pre-emptively committing consumers to pay for uneconomic investments through forward capacity mechanisms. Overall, it means progressively assessing and integrating responsive demand into forward resource planning and procurement processes.

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

January 2023

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

About the Author

Michael Hogan is a senior advisor at the Regulatory Assistance Project® (RAP) working on wholesale market design, integration of variable resources, and demand response. RAP is an independent, global, nongovernmental organization advancing policy innovation and thought leadership within the energy community. The views expressed here are his own.

Contents

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.

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.

Get in Touch

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.

Suggested Citation

Hogan, Michael. 2022. "Tapping the Mother Lode: Employing Price-Responsive Demand to Reduce the Investment Challenge." A White Paper from the Retail Pricing Task Force. Reston, VA: Energy Systems Integration Group. https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

Mobilizing Flexible Consumption

In recent years it has been observed that we are moving from a world where we forecasted demand and scheduled supply, to a world where we forecast supply and schedule demand. What this succinctly describes is the idea that two inexorable trends will converge: a growing share of supply resources that are "variable"—less determinate as to when and how much energy they can produce—and a growing share of demand that is discretionary—having some degree of latitude to choose when and how much grid electricity to consume depending on what it costs or how it is produced. This latter trend combines advances in technology for controlling familiar end uses in ways that are easy, convenient, and cheap with the onset of new, large, intrinsically flexible loads like electric vehicles and electric water and space heating. Marrying these trends in a coordinated fashion could accelerate both, while yielding significant cost savings for all consumers, flexible and otherwise.

Yet this mutually beneficial convergence is anything but inevitable, and certainly not to the extent needed to approach its full potential. Incumbent market actors—including system operators tasked with balancing supply and demand—are strongly biased in favor of supply-side investments (principally fossil-fueled generation but also the seductive new option of grid-connected batteries) even when empowering demand-side discretion would be less expensive. Progress has also been stymied by some of the very stakeholder groups that could benefit most, including some consumer advocates understandably spooked by a long history of seeing the most vulnerable consumers end up on the short end of utility "innovations."

Two inexorable trends are converging: A growing share of supply resources that are "variable" and a growing share of demand that is discretionary, having some degree of latitude to choose when and how much grid electricity to consume depending on what it costs or how it is produced.

Barriers to Effectively Mobilizing Flexible Consumption

As a result, realizing this opportunity to mobilize flexible consumption effectively faces two broad and interdependent challenges. The more direct, visible challenge is in the design and implementation of rules, pricing, and programs, which has both practical dimensions (how to inform and effect flexible consumer choices that can benefit all) and social dimensions (how to address concerns like equity and public safety). The less obvious challenge is contextual—deeply ingrained supply-side bias privileging principally investment in generation, that limits the scope of ambition on demand-side options.

These barriers lead to discrimination (suppressing market price signals to flexible consumers by shifting compensation to out-of-market capacity procurement) and market pre-emption (centralizing commitments to pay for uneconomic capacity years in advance). In short, embedding outdated assumptions about the inelasticity of demand overstimulates supply-side investment, which in turn undermines the value of empowering demand flexibility. Missing money from energy prices is institutionalized by and off-boarded to out-of-market mechanisms like forward capacity and ancillary services markets that are demonstrably difficult for most demand-side flexibility to access. Consumers lose because the transition to a decarbonized power grid becomes far more expensive than it needs to be.

Summary of Recommendations for Overcoming the Barriers

This paper locates the principal sources and drivers of value from flexible consumption. It makes the case that the lion's share of potential benefit from flexible loads is in avoiding uneconomic capital investment and examines what it will take to realize those benefits. The analysis reveals the need to move beyond the narrow focus on demand response as a proxy for supply, to a focus on decentralized coordination of flexible demand as shifts in load forecasts in response to the ebb and flow of supply. It then zeroes in on contextual barriers to doing so.

This paper locates the principal sources and drivers of value from flexible consumption. It makes the case that the lion's share of potential benefit from flexible loads is in avoiding uneconomic capital investment and examines what it will take to realize those benefits.

As discussed more fully in the recommendations section at the end of the paper, achieving this decentralized coordination of the bulk of the potential for flexible loads will require that we:

- **Adopt** retail-level innovations to widen access to the untapped potential for flexible loads to reduce cost and defer/avoid infrastructure investment, including:
  - Creating "safe" options for diffusion of real-time pricing
  - Introducing intra-day price outlooks several hours in advance of real time to enable informed consumption decisions
  - Phasing in dynamic, volumetric congestion ("capacity shortage") distribution network tariffs to coordinate grid-edge responses to bulk system price signals
  - Phasing in dynamic transmission tariffs for flexible consumers that enable them to lower their bills by avoiding periods of peak system demand
  - Providing open access to distribution-level load management by third-party service providers with direct exposure to full real-time marginal-cost pricing in order to maximize price-driven service innovation
- **Attack** the contextual barriers that have led to persistent underestimation and suppression of the value of decentralized demand flexibility, including:
  - Raising reserve shortage pricing in energy market prices to a level that values real-time demand for reserves as nearly as practical to the value attributed to reserves in capacity mechanisms
  - Limiting capacity mechanism support for supply-side solutions (i.e., generation) to no more than one-year rolling commitments
  - Eliminating wholesale market design features that discriminate against demand-side options
  - Introducing intra-day markets and pricing to enable more intra-day transparency between supply-side and demand-side options for supplying balancing flexibility
- **Assess** in a deliberate, progressive program the expected impact of increased participation of flexible demand and internalize it into infrastructure planning and procurement.

Sources and Drivers of Value

There has been no shortage in recent years of ink spilled and conferences organized on the topic of demand-side flexibility. While welcome, most of that attention has been devoted to traditional roles for demand response, principally on payment to consumers to curtail a small fraction of demand during those few hours when gross demand for energy and reserves approaches the limits of supply. Where new roles for flexible demand have been explored, they have principally focused on very short-term flexibility that can lower the cost of "ancillary" or "balancing" services system operators have historically obtained from generators to address a range of last-minute system balancing contingencies. And in most cases, the focus (in organized market regions) has principally been on affording demand access to wholesale energy, ancillary services, and capacity markets in competition with generation (see, for example, the Federal Energy Regulatory Commission's Order 2222) (FERC, 2020).

There is nothing wrong per se with any of these efforts. Each has value. The problem is, they mostly bypass the largest pool of value available from flexible demand—avoided capital investment—and they mostly ignore the business models needed to drive the largest share of flexible demand potential.

Sources of Value

Flexible demand offers multiple sources of potential value across both the bulk and the distribution systems. Several recent analyses demonstrate that the largest share of that potential value lies in displacing the need for costly infrastructure investment. This is due in part to better utilization of the massive capital investment that will be required in any case.

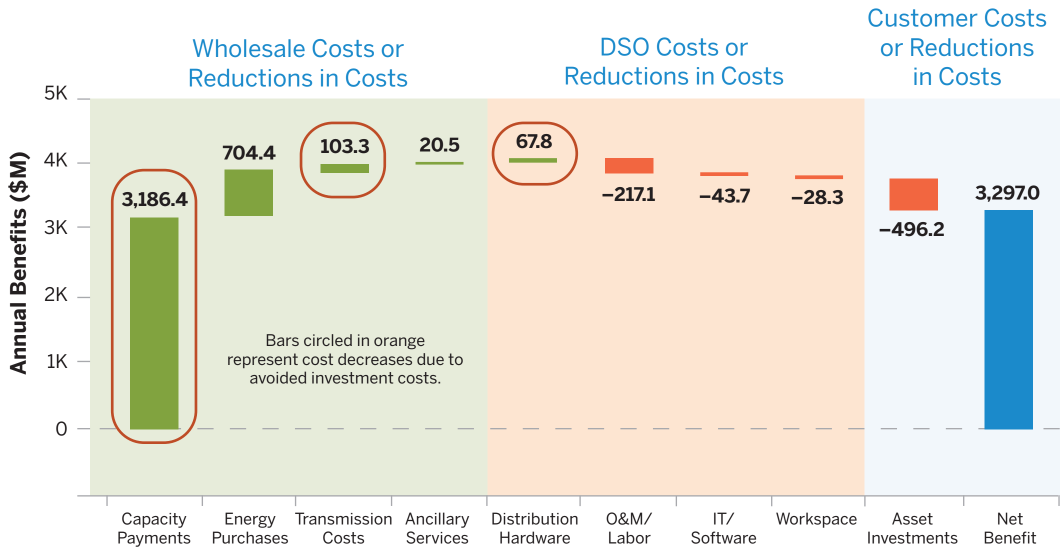
Current efforts mostly bypass the largest pool of value available from flexible demand—avoided capital investment—and they mostly ignore the business models needed to drive the largest share of flexible demand potential.

For example, a recent study published by Pacific Northwest National Laboratory examined the potential for flexible demand to reduce the overall cost of a bulk power system with a growing share of variable resources (Reeve et al., 2022). Their findings demonstrate significant potential for savings owing to a reduction of up to 15 percent in peak system load and a reduction of up to 44 percent in daily load variation. Figure 1 (p. 4) shows the breakdown of the $3.3 billion in annual net savings by cost category for a system modeled on the Electric Reliability Council of Texas (ERCOT) but with a moderate penetration of renewables (approximately 15 percent of annual energy, compared to ERCOT's 2021 level of 28.4 percent of annual energy).[1] The study also modeled a "high variable renewables" scenario with penetration of over 40 percent of annual energy, showing a total of up to $6 billion in net savings.

1 See https://www.ercot.com/gridinfo/generation.

FIGURE 1

Potential Cost Savings from Demand Responding to Wholesale Market Price Signals



Analysis of the amount and sources of economic benefit to consumers on a hypothetical ERCOT-sized grid from deploying flexible loads in response to system needs.

Source: Reeve et al. (2022) / Pacific Northwest National Laboratory.

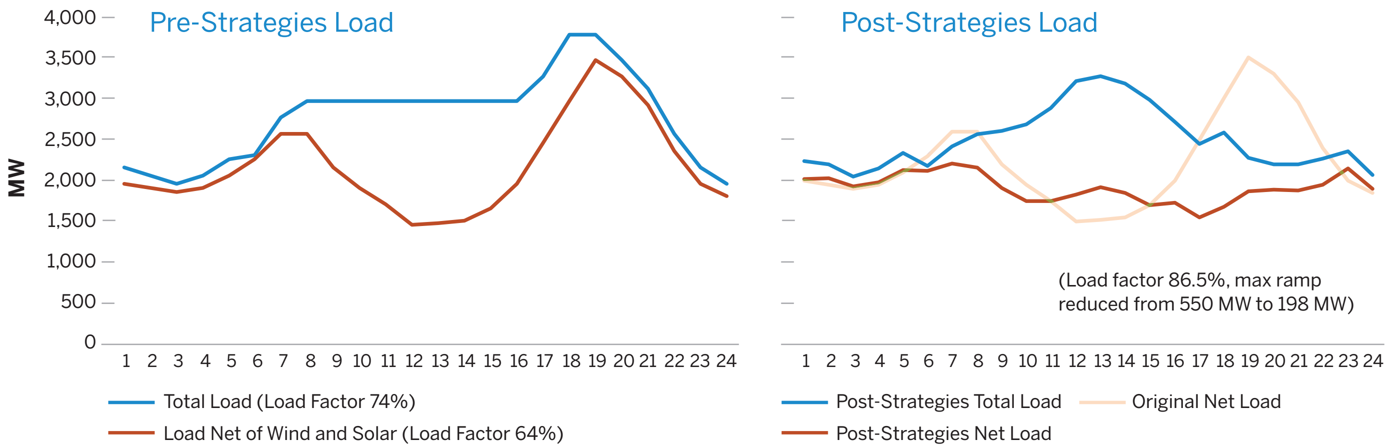
As indicated by the columns framed in red, the sources of value are located overwhelmingly in avoiding the cost of investment in infrastructure (capacity, transmission and distribution hardware). Savings in the cost of ancillary services—the focus of a great deal of current activity—are relatively tiny. Savings in reduced energy market-clearing prices (the price of purchasing wholesale energy)—another major focus of both wholesale market initiatives as well as many time-of-use tariffs—are more significant but still a small share of the overall savings. Avoided capital costs represent over 82 percent of total gross savings, while the gross savings just from avoided generation capacity investment equates to nearly 97 percent of overall net savings.[2] A separate, soon-to-be-published study by Pacific Northwest National Laboratory looked at potential distribution-level savings just from smart electric vehicle charging in response to prices reflecting real-time conditions on the distribution system and found significant additional opportunity for cost reductions, again predominantly from avoiding the need for costly distribution system capacity upgrades and expansion.

These findings are not outliers. Other studies of flexible demand potential have also pointed explicitly or implicitly to similar conclusions. Using a different approach, Jim Lazar in his *Teaching the "Duck" to Fly* series of desktop analyses found that by adopting 10 specified strategies—principally reliant on demand-side measures—one could not only reverse the deterioration in system load factor (the share of the potential capacity of investments in assets that is utilized in practice) seen in the now-familiar "duck curve," but could increase system load factor above the pre-renewables level (Lazar, 2016). In other words, by employing strategies, including mobilizing load flexibility, that enable investments in infrastructure to be more fully utilized, unneeded investment in infrastructure can be avoided. Demand-side strategies examined included amending retail pricing to incentivize shifting of electricity consumption for water pumping and water heating in response to changing supply and demand conditions on the grid, and more aggressively implementing flexible demand programs that better align consumption decisions with

2 While the study modeled a system resembling ERCOT, it incorporated a typical forward capacity market (which ERCOT does not have) as a way of capturing the impact of flexible demand in lowering the need for generation investment, and therefore lowering the capacity market costs to be recovered through capacity payments.

FIGURE 2

Role of Demand Flexibility in Improved Asset Utilization, Before and After Implementation of 10 Specified Strategies



The 10 strategies studied the following, with strategies involving load flexibility indicated in orange.

- One was energy efficiency
- One was transmission
- One was batteries
- Two were supply-side strategies, including dsitributed generation
- Five were demand-side flexibility

Desktop analysis of the impacts on asset utilization on a hypothetical high-renewables grid before and after the application of 10 system adaptation strategies.

Source: Lazar (2016).

system needs. Only one strategy involved the role of conventional supply resources. The before-and-after figures from the analysis are shown in Figure 2.

In regulated cost-of-service regions and market regions with centralized capacity procurement mechanisms of various kinds, centralized decisions to invest in infrastructure can lock flexible consumers into non-bypassable financial obligations many years into the future. In these regions the only way to realize the benefit of avoiding the need for infrastructure is not to invest in the unneeded system infrastructure in the first place. Flexible demand participating in forward capacity markets—for instance, a large industrial customer offering to be paid to reduce consumption at the direction of the grid operator—can displace unneeded supply-side infrastructure to some extent, but, as discussed in the following section, this business model can be expected to tap only a very small proportion of the potential benefit available from low-cost demand flexibility.

Furthermore, flexible demand can provide benefits that forward capacity markets are not designed or suited to capture. As noted in many recent analyses (CAISO, CPUC, and CEC, 2021; ESIG, 2021; NERC, 2020), the principal concern for resource adequacy is shifting focus from gross peak load—which is the target of forward capacity markets—to the dynamics of net load, involving not just net peak but also the predictable ramps that typically precede and follow net peak. This shift implicates capital investment in resource capabilities at least as much as in resource capacity.[3] Studies consistently demonstrate that flexible demand can reduce both net peak and associated ramps, avoiding the need for redundant resource investments, which current forward capacity markets cannot capture. The key question is what compensation and risk/reward models are available to consumers (directly or via their service providers) to drive them to offer their flexibility.

3 Another emerging focus is on the need to deal with energy-limited resources, addressing gas storage limits or extended periods of low variable resource availability. Demand flexibility can address this only to some extent.

Most of the focus up to now has been on force-fitting flexible demand to mimic supply offered into wholesale supply markets—considering only reduced consumption bundled together and constrained to operate like an equivalent amount of power generation, in return for a pre-agreed price and deployed at the grid operator's discretion.

Drivers of Value

The lion's share of the potential for flexible demand to contribute to lowering the costs of the energy transition lies in mobilizing and internalizing flexibility as demand elasticity—consumers as a matter of course foregoing or deferring consumption in response to high prices and increasing consumption in response to low prices, either directly or via their electricity service providers. However, most of the focus up to now has been on force-fitting flexible demand to mimic supply offered into wholesale supply markets—considering only reduced consumption bundled together and constrained to operate like an equivalent amount of power generation, in return for a pre-agreed price and deployed at the grid operator's discretion.

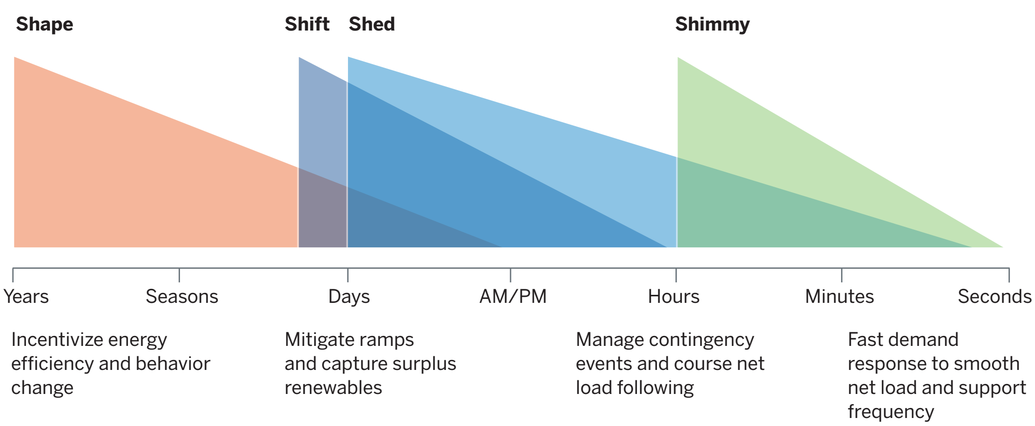
Benefits That Flexible Demand Could Deliver

A recent study by Lawrence Berkley National Laboratory examined the full range of services that flexible demand could deliver as power grids integrate increasing shares of variable supply resources (Alstone et al., 2017). Figure 3 combines a figure and table from that study that illustrate their helpful categorization of flexible demand services into "shape/shift/shed/shimmy."

The highlighting (added) in yellow on the table below points to beneficial impacts of flexible demand that either cannot be or mostly will not be delivered as direct substitutes for supply resources through participation in wholesale energy, ancillary services, or capacity markets. These benefits are largely accessible only through the price-responsive behavior of consumers (directly or through service providers) with flexible loads.

FIGURE 3

Range of Benefits Available from Flexible Demand, 2017–2019



DR Service Product

Shape	Load Modifying DR—Event-based
	Load Modifying DR—Load-shaping
Shift	Economic DR
	Flexible Ramping Capacity
Shed	Peak Capacity
	Economic DR
	Contingency Reserve Capacity (Spinning)
	Contingency Reserve Capacity (Non-spinning)
	Emergency DR
	DR for Distribution System
Shimmy	Load Following
	Regulating Reserve Capacity

Demand-Curve Demand-side Flexibility

A description, based on a study of the mobilization of flexible loads in response to the needs of the California bulk power system, of the different categories of benefits available from flexible demand, together with the associated grid services.

Note: DR = Demand response.

Source: Alstone et al. (2017) / Lawrence Berkeley National Laboratory.

In the case of "shaping," for instance, the effect is inherently indirect in the form of evolving load curves—changes in the shape of projected demand against which grid operators plan to deploy supply resources. In other cases, such as "shifting" services, the requirements that system operators impose on offering such services into the energy and ancillary services markets, such as measurement and verification, effectively exclude most of the day-to-day potential. Again, most of this potential can only be accessed in the form of distributed, short-term consumer responses to prices.

A Case in Point: California Load-Shed Event of August 2020

A recent illustration of the challenges faced by flexible demand as a proxy for supply-side resources in traditional wholesale market mechanisms can be found in the assessments of flexible demand's contribution to mitigating the August 14-15, 2020, load shed event in California. Only a tiny share of reliability resources was procured from demand-side flexibility, despite broad agreement that the potential contribution was much greater. As to what limited share of the potential that was included in the grid operator's plan, there is still considerable disagreement over how demand-side resource providers performed, tied to intrinsic challenges in measurement and verification, and whether they were fairly compensated for their actual contribution to mitigating the severity of the event. That experience (well covered elsewhere; see, for example, St. John (2021)) illustrates (a) the barriers that flexible demand providers confront in participating, (b) the risks they face once they have qualified relative to the potential rewards available for participation, and (c) the inadequacy of mechanisms available to measure and compensate for actual performance.

The results from the Lawrence Berkeley National Lab study suggests that the greatest potential from flexible demand can only realistically come from distributed responses by flexible loads using close-to-real-time information about system conditions and costs. In the California load shed example, these decentralized responses can address more than just the *contingencies* targeted by the various reliability services. They can also mitigate forecast, scheduled resource needs by reducing expected ramps and lowering net peak, reducing the demand for whatever resources (including centrally dispatchable demand-side resources) can measurably and reliably respond.

Wholesale Capacity Markets—More Curse Than Blessing for Flexible Demand

Similarly, the participation of flexible demand in wholesale capacity markets relies on qualification processes that constrain individual flexible demand offers by requiring them to look, smell, and feel like the generation with which they are competing. For instance, flexible demand—valued in only one direction (reduced consumption)—must be bundled as a discrete quantity of capacity that must guarantee a specified level of performance around the clock, at the direction of the grid operator, years in advance of delivery. While this may be appropriate for generation, it drastically constrains the share of flexible loads that can participate. As a result, the track record of participation is unpromising. Where there have been mildly encouraging early results, they have often been reversed by developments such as pay-for-performance reforms that require an individual provider to guarantee delivery year-round (see, for example, PJM (2021)). As California Public Utility Commission staff documented in a recent report, "supply-side demand response" participation models (such as bidding into capacity markets) impose significant constraints on the amount of flexible demand that realistically can ever participate (CPUC, 2022, Section 3.3.1).

These wholesale capacity markets also focus on centrally dispatched reductions in demand that are contractually limited in duration and frequency. A capacity market award is, in essence, prior compensation for the right to inconvenience a customer (mostly industrial and commercial customers) at a time of the system operator's choosing. While this has much the same value it has always had, it barely scratches the surface of the value flexible demand can provide. As the supply adequacy challenge shifts from gross peak capacity to net energy supply, however, the resource adequacy benefits that flexible demand can provide shift from reducing gross demand a few times a year to decreasing and increasing demand as frequently as daily—or even multiple times within a day—across potentially millions of devices. The business case for that kind of flexibility will be grounded principally in the energy market, yet revenues that should be available in the all-inclusive energy market are diverted to exclusive capacity markets. As a result, current practice in most markets does not offer a viable business model for flexible demand to offer its full potential to the system.

Social Welfare Impacts

There is significant potential value in flexible demand. We will leave most of that potential value on the table if we fail to capture it in our plans and price its value fairly. It is helpful to envision these opportunities to increase the net benefit of the electricity system to all stakeholders by examining what economists refer to as "social welfare," in essence, the net cost or benefit to consumers of obtaining the energy services they want or need. The following analyses consider, in a hypothetical case, what the social welfare implications might be for both the demand curves and supply curves that determine how the market clears in any given pricing interval.

Comparing Inelastic and Elastic Demand Curves

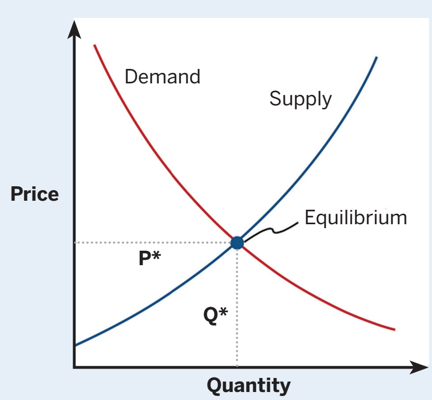
Figure 5 (p. 9) offers a typical conceptual representation of electricity supply and demand curves (including the conventional fiction of a largely inelastic demand curve), in this case in a pricing interval when demand approaches the level at which load would be shed to preserve a

Supply and Demand Curves

These analyses utilize supply and demand curves to demonstrate how the market price of the product—in this case electric energy—is set (Figure 4). The supply curve depicts the quantity of energy that can profitably be delivered at each point across a range of prices. Put differently, it represents the marginal cost to consume each incremental unit of energy.

The demand curve depicts the amount of energy consumers would be willing to consume at each point across the same range of prices (put differently, it represents the marginal price consumers would be willing to pay to consume each incremental unit of energy). Where the two curves intersect is the equilibrium point often referred to as the market-clearing price per unit (P*) and market-clearing quantity of units (Q*). In the case of the electric energy market, each set of curves is specific to a time and place, reflecting the need for the various energy services in those locales, and the cost of providing the services can vary with time of day, day of the week, and season of the year. As a result, the market clears at different prices at different times in different places. The extent to which the quantity of supply or demand changes—or does not change—as the market-clearing price rises or falls reflects the elasticity or inelasticity of supply or demand.

FIGURE 4
Supply and Demand Curve

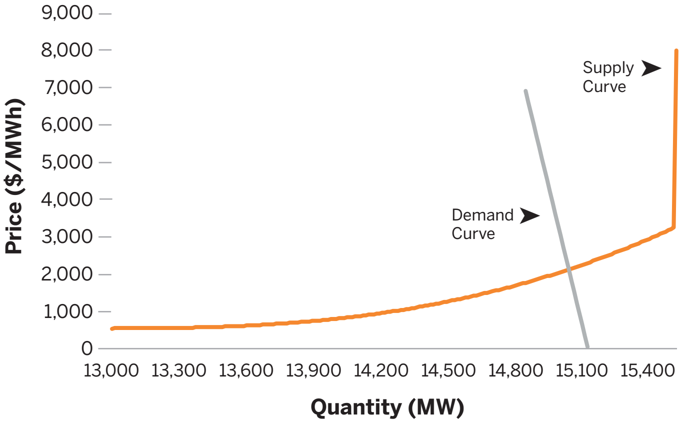


Note: P* = market-clearing price per unit
Q* = market-clearing quantity of units

Source: Hogan (2016).

FIGURE 5

Conventional Depiction of Electricity Supply/Demand Curves

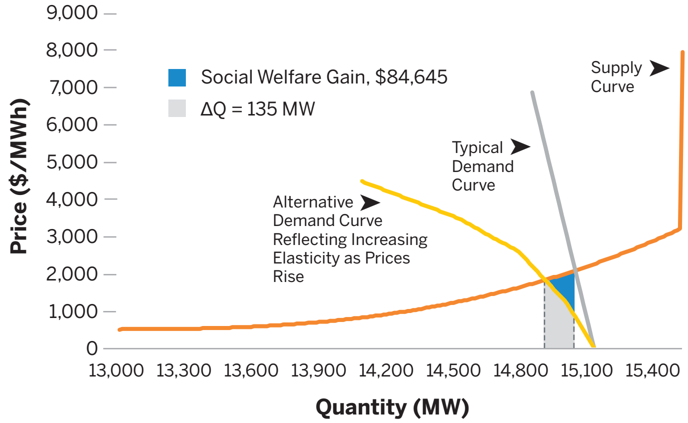


Typical representation of the supply and demand curves for a hypothetical organized electric energy market, depicting a "pure" energy-only supply curve and a largely inelastic demand curve.

Source: Regulatory Assistance Project.

FIGURE 6

Addition of a More Price-Elastic Demand Curve, with Welfare Gain



Incorporating a corrected demand curve into the previous figure that captures the inherently variable price elasticity of electric loads, with a graphical depiction of the associated gain in social welfare.

Source: Regulatory Assistance Project.

minimum safe level of contingency reserves. (A pricing interval could be 5 minutes, 15 minutes, or an hour, depending on what market is being considered.) The demand curve implies fixed demand elasticity of -0.1 (calculated as the ratio of the rate of change in demand associated to the rate of change in price), consistent with various backward-looking studies of demand elasticity among residential electricity consumers.[4] (Studies of industrial and commercial demand elasticity offer conclusions ranging from -0.1 to -1.0 or even higher.) Put simply, it depicts an assumption that demand remains nearly constant no matter what the price is.

This depiction is more than just a typical academic representation. It reflects a historical—and increasingly anachronistic—assumption about demand that is baked into nearly every resource planning and procurement mechanism employed in wholesale and retail markets, both in organized markets and in regions outside of organized markets. To pick just one noteworthy example, the 2019-2020 California Public Utility Commission's Integrated Resource Plan examines a range of alternatives for ensuring reliability as the system transitions to a high-renewables future, including overbuilding and curtailing renewable generation, a major build-out of new transmission, and rapid expansion of grid-connected energy storage (CPUC, 2019). What the plan excludes is any potential for price-driven shifting of flexible load—in a state that has devoted considerable attention to deploying dynamic retail pricing and promoting responsive demand.

Figure 6 considers an alternative demand curve during the same interval, one that is relatively inelastic at lower price levels but becomes more elastic as prices rise. The curve reflects an assumption that the more flexible residential loads—particularly new transportation and heating loads—would have elasticity across a range comparable to the elasticity of flexible industrial and commercial loads. (In the case of electric vehicle charging, this is most likely a very conservative assumption.) In this case, as demand rises and prices rise, the market clears at lower levels of demand than if demand were as inelastic as historically assumed. In the depicted interval, the market clears 135 MW lower, and at a somewhat lower price, with a social welfare gain for this one interval of $84,645. The corrected curve reflects the fact that meeting that extra 135 MW of demand would cost

4 A typical example is Burke and Abayasekara (2017).

Forward capacity markets incorporate an assumption for the finite value consumers place on reliability. To avoid discriminating against flexible market actors that are excluded from participating in forward capacity markets, a similar value should be attributed to the demand for reserves in constructing the supply and demand curves in the energy market.

consumers $84,645 more than it is worth to them to consume it. Everyone benefits from the lower market-clearing price.

Compensating Flexible Demand to Reflect Its True Value

Beyond the question of how elastic various loads might be, is the question of whether the compensation available to diverse, distributed, decentralized flexible actors is adequately reflective of the value of their flexibility to the system (and therefore to the larger community of the system's users). There are several dimensions to this question, some of which are discussed below. Figure 7 (p. 11) addresses one aspect in particular: whether energy prices incorporate a fair value for the demand for reserves compared with the value attributed to reserves procured outside of the energy market, for example, in the forward capacity market.

Reserves are maintained by grid operators to reduce the risk of having to curtail load in order to maintain the stability of the grid in the event of a problem. Some level of resource reserve is included in long-term planning, with the expectation that at any given moment sufficient reserves will be available to allow the grid operator to comply with the value consumers place on not having various energy services interrupted. In maintaining the desired level of reserves, grid operators act as a proxy for the finite value consumers place on reliability. Forward capacity markets incorporate an assumption for what that finite value is—typically valuing the demand for reserves in the range of $15,000 to $20,000 per MWh.[5] To avoid discriminating against flexible market actors that are excluded from participating in forward capacity markets, a similar value should be attributed to the demand for reserves in constructing the supply and demand curves in the energy market. That is, the cost of taking a resource out of reserve to meet an increase in the demand for energy should be based on a comparable value for reserves.

In Figure 7 it is assumed that the default supply curve depicted in the previous graphs reflects only the demand for energy, without sufficient recognition of the impact the demand for reserves should have on where the energy market clears. To correct this error, Figure 7 introduces a revised supply curve that incorporates reserve shortage pricing (augmented as needed administratively to account for the fact that many consumers do not yet have the information or capability to set the true price of resource scarcity on their own).[6] In effect, the supply curve shifts to the left. The difference between the two supply curves reflects the so-called "missing money" problem that administrative capacity markets are intended to address —an administrative reserve shortage pricing adder increases the revenues available from the energy market to support resource investments, in so doing reducing the need to make up missing money in out-of-market forward capacity mechanisms.

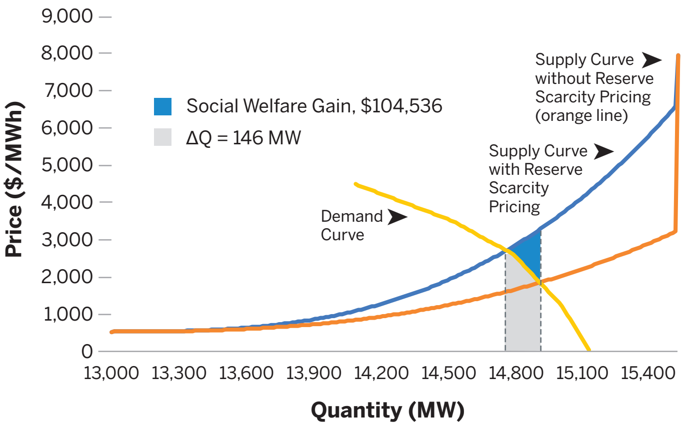
Because of the added demand for reserves, the true cost of consumption at the previous market-clearing quantity was considerably higher than the previous market-

5 See, for example, London Economics International (2013).

6 The curves reflect a hypothetical market, where the orange curve assumes some amount of scarcity pricing based on a reserve value of $7,000/MWh (about half of what is typically assumed for investment in reserves in forward capacity markets) and the blue curve assumes scarcity pricing based on an assumed value of about $16,000/MWh (in the range of value typically imputed in forward capacity markets). In most markets with centralized forward capacity procurement the difference between the two curves would actually be much greater, with the orange curve often flat-lining at $1,000-$2,000/MWh. No assumption is made about the maximum allowed price in either case.

FIGURE 7

Correcting the Supply Curve for the Value of Reserves

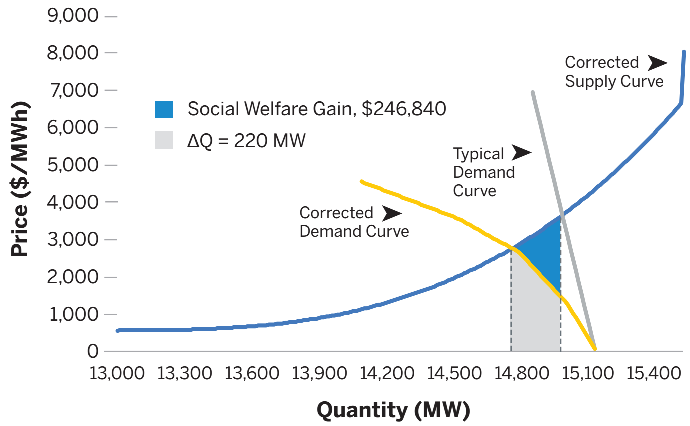


Incorporating corrected supply curve reflecting administrative adder to energy prices to reflect energy cost impact of coincident demand for reserves, with graphical depiction of associated welfare gain (blue triangle).

Source: Regulatory Assistance Project.

FIGURE 8

From Standard Operating Practice to Best Practice



Composite of changes introduced to original supply/demand curves, including the corrected demand curve (yellow) and corrected supply curve (blue), with the area inside the blue triangle depicting the associated social welfare gain.

Source: Regulatory Assistance Project.

clearing price, higher than the price consumers would be willing to pay for that level of consumption. Under the corrected supply curve, the market clears at a lower level of demand and at a lower cost to consumers. Consumers avoid buying energy at an artificially low price, energy that in reality costs more than it is worth to them. In this case, the market clears with a gain in social welfare in this one interval of $104,536; while the market-clearing price is higher, consumers should realize a net reduction in their bills by avoiding the cost of paying for additional supply-side investment. This is not just a technical issue—in markets with forward capacity procurement, it is a matter of redressing the discriminatory practice of paying resources able to participate in forward capacity mechanisms (i.e., generation) at a level that often far exceeds the value of reserves reflected in the energy market prices on which most flexible demand must rely.

Figure 8 combines the two steps (internalizing price elasticity and more fully pricing the value of reserves) to depict the social welfare opportunity in going from standard operating practice (in most markets, at least) to best practice. The market clears 220 MW lower with a gain in social welfare in this interval of $246,840. The cumulative effect of correcting these deficiencies in supply and demand curves is to empower flexible consumers to make their own decisions about how much on-demand service they want at what cost, and to compensate them fairly for doing so. Uneconomic infrastructure investment can be avoided, to the benefit of all consumers.

The cumulative effect of correcting these deficiencies in supply and demand curves is to empower flexible consumers to make their own decisions about how much on-demand service they want at what cost, and to compensate them fairly for doing so.

Looking Beyond the Retail Energy Charge

In assessing possible social welfare gains, a final consideration is whether the price signals available to flexible loads capture all or only a small part of the impact flexible consumption can have in reducing the need for infrastructure investment. In the great majority of examples of dynamic retail pricing, the focus is restricted to the energy component of the retail bill—the contribution flexible demand can make to balancing the bulk-system-level supply of and demand for energy and reserves at a lower market-clearing energy price. In a system with high levels of variable resources, this will be a significant opportunity. However, in most systems today, reducing the infrastructure investment needed to balance energy supply and demand constitutes only a small share of the infrastructure costs that must be recovered from consumers, and that is likely to remain the case for some time to come.

By affording flexible loads (or their service providers) the information and opportunity to lower their bills by responding to these local conditions, some amount of otherwise necessary upgrades of distribution infrastructure can be deferred or avoided.

Typically, as much as two-thirds of the retail bill reflects non-energy infrastructure costs, principally recovery of transmission and distribution network costs. In the case of residential customers, these costs are typically recovered through flat volumetric charges, even under dynamic retail tariff offerings. This flat charge significantly mutes the information available to flexible loads. In so doing, it precludes the potential for flexible demand to displace unnecessary investments in upgrading and expanding network infrastructure.

Encompassing Transmission Charges to Amplify the Signal

In some markets, consumers are offered a version of a two-sided market opportunity to use their flexibility to avoid at least a portion of these costs. Two familiar examples are (1) the 4CP mechanism in ERCOT, under which bulk transmission costs are recovered during the four highest-load hours in the year; and (2) a similar mechanism in the UK market called Triad, that was initially based on the three highest-load half-hours in the year. As they stand, these mechanisms are flawed in that they focus only on a very few hours of system gross peak load. They also tend to shift cost recovery from large consumers to small consumers. Yet, in principle, such mechanisms afford buyers (those with the ability to do so) a chance to anticipate and shift load away from high-demand hours to reduce their payments for transmission. The concept can be made fit for purpose by significantly expanding the number of hours involved (perhaps all hours) and introducing a dynamic dimension, recovering more transmission costs during high-demand hours and less during low-demand hours.[7] As more and more consumer loads acquire the ability to respond to system conditions, consumers should be afforded the opportunity to lower their bills by shifting consumption in a more dynamic fashion than the anachronistic three to four times a year model.

Doing the Same for Distribution Charges

A similar opportunity exists at the distribution level, where the rational responses of distributed flexible loads to bulk power system prices may exacerbate congestion in one part of the distribution system while leaving another part underutilized. For instance, at a given point in time the bulk system may be offering surplus supply at very low prices at a given node, incentivizing flexible loads behind that node to shift consumption from more expensive hours. At the same time, on the distribution system some transformers may be at or near their thermal limits whereas others are lightly loaded. By affording flexible loads (or their service providers) the information and opportunity to lower their bills by responding to these local conditions, some amount of otherwise necessary upgrades of distribution infrastructure can be deferred or avoided. In the past, distribution utilities have deployed overly static demand charges on industrial and large commercial customers as a way of managing this issue, but as the system transitions to become more bi-directional, such legacy mechanisms fail to align consumption choices with grid needs. They must be replaced with more dynamic tariff options.

As the share of variable resources grows and the opportunity for flexible demand to reduce costs grows with it, we must identify pathways to deploy dynamic network recovery mechanisms to a wider and wider set of flexible end users. These mechanisms will need to be designed to address legitimate concerns about equity, implementation costs, and efficient cost recovery. A detailed examination of this issue is beyond the scope of this paper; however, some suggestions are offered below in the recommendations as promising options.

7 The UK's Triad mechanism was reformed in 2022 to be based on daily load-shifting rather than three intervals a year.

The Problem of Energy Price Suppression and Discrimination

Current energy pricing methodology in many markets discriminates against the dominant share of the potential for low-cost demand flexibility, the commercial viability of which will rely on the information and remuneration available in energy and ancillary services markets as previously discussed.

The welfare analysis illustrates the extent to which the potential benefits of flexible demand rely on (a) making transparent through day-ahead, intra-day, and real-time energy prices the full system cost implications for flexible consumers—or more likely their service providers—of consuming electricity at one time rather than at another time, and (b) internalizing the expected behavior into resource planning and procurement to avoid lock-in of uneconomic infrastructure investment. In other words, the first step is to ensure that prices do reflect the opportunity to avoid lock-in of uneconomic capital investment. The next step will be to act on that opportunity.

Capturing the Demand for Reserves in Demand Curves

As already alluded to, investments in reserves to meet societal standards for supply reliability are often valued differently in centralized, forward capacity procurement processes than they are in energy markets. To begin to address this, energy market prices should reflect the real-time demand on system resources for both energy and reserves. As discussed in the section on social welfare benefits, the energy price impact of the demand for reserves should, in turn, reflect the same security of supply value imputed to investment in planning reserves in whatever parallel capacity mechanism may be in place. Yet in most markets that have adopted centralized forward capacity procurement, if the demand for reserves is internalized in energy prices at all, it is internalized at a small fraction of the value imputed to reserves in the forward capacity mechanism.

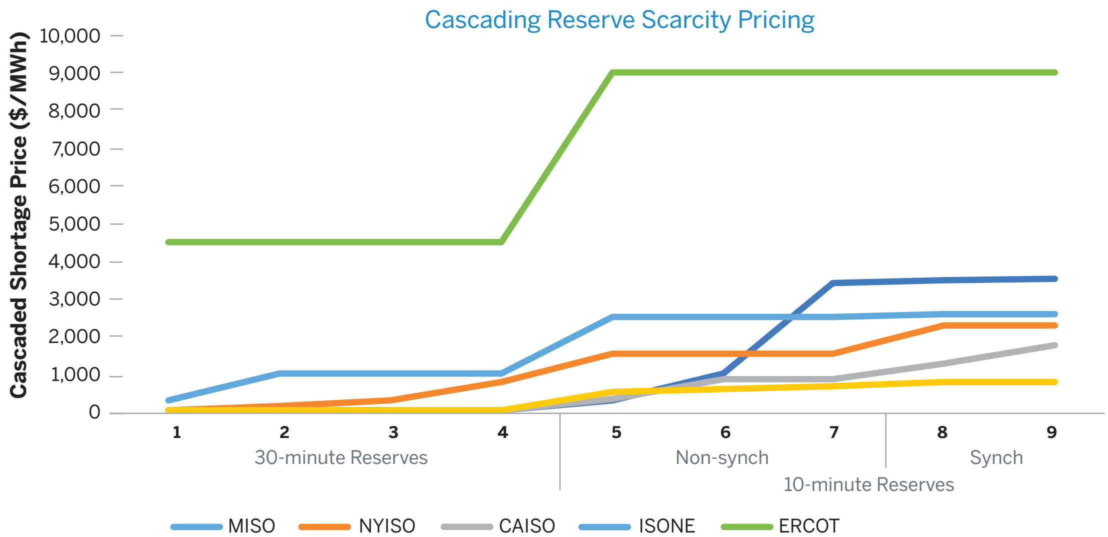
In most markets that have adopted centralized forward capacity procurement, if the demand for reserves is internalized in energy prices at all, it is internalized at a small fraction of the value imputed to reserves in the forward capacity mechanism.

Conceptually, the idea of administratively adjusting wholesale market prices to reflect the value of different categories of reserves, particularly when reserves fall below target levels, is a well-established practice in many markets. Figure 9 (p. 14) illustrates one of the ways this materializes in practice. The figure compares reserve shortage pricing mechanisms employed in various U.S. independent system operator and regional transmission organization's (ISO/RTO) markets, which are administrative measures designed to ensure that energy prices reflect the value of reserves under tight scarcity conditions. These mechanisms go by different names but are often referred to as operating reserve demand curves.

All of the markets shown incorporate a mechanism to internalize in energy prices an imputed cost when the demand-and-supply balance reaches the point where the system operator's demand for reserves can no longer be met by re-dispatching generation, leaving the system operator increasingly short of the desired level of reserves as demand for energy continues to rise. The practical

FIGURE 9

Reserve Shortage Pricing in ISO/RTO Markets as of 2018



Graphical depiction of the administrative reserve shortage pricing functions applied in various ancillary service categories for six U.S. ISO/RTO regions in 2018.

Note: Since 2018 several changes have occurred, including reduction of the ERCOT curve to a maximum price of $5,000 following Winter Storm Uri event, an increase in the maximum price for the NYISO curve to approximately $3,200, and a slight increase in the PJM curve for 30-minute and 10-minute non-synch reserves; nonetheless, there remains significant variation in reserve scarcity pricing among the ISO/RTO markets.

Source: Adapted from data presented by PJM in staff/stakeholder training materials (Rocha Garrido, Morelli, and Walter, 2018), slide 67. (PJM does not guarantee the accuracy of the data for the other ISO/RTOs. ERCOT data were added by the author.)

consequence of reserve shortages is a gradual rise in the chances of the system operator being forced to impose involuntary load-shedding to preserve a minimum safe cushion of contingency reserves. The security of supply standards imposed on system operators are typically based on an assumed value (or opportunity cost) associated with shedding (or "losing") firm load. As noted earlier, when applied to demand for reserves in centralized forward capacity procurement, this value is typically set between $15,000 and $20,000 per MWh.

Bringing Consistency to Valuing the Demand for Reserves

However, as shown in Figure 9, in those markets that have adopted various forms of centralized forward capacity procurement (that is, in all but the ERCOT market) the valuation of reserves in energy market pricing is typically capped at much lower levels.[8] The effect is to ensure that there is money "missing" from energy markets to reflect demand for security of supply. That is, the impact the demand for reserves can have on the cost of energy via these administrative energy market mechanisms is arbitrarily limited to a level that is not only far below the actual cost, but also far below the cost reflected in the compensation available in most capacity-based

Prevailing forward capacity mechanisms strongly favor conventional generation investment. Where these mechanisms are open to demand-side options, participation is necessarily limited to the small fraction of flexible demand potential that can profitably mimic dispatchable generation capacity.

8 As noted above, the ERCOT cap was reduced from $9,000/MWh to $5,000/MWh effective January 1, 2022, though at the same time the curve was extended, leading to the expectation of more hours of scarcity pricing compared to the pre-2022 parameters.

mechanisms. As a result, that value is then available only to those resources participating in forward capacity procurement mechanisms. PJM recently proposed a modest correction to its reserve shortage pricing in order to partially redress this situation (approved and then denied by the Federal Energy Regulatory Commission on narrow legal grounds), though the proposal still fell well short of putting energy market reserves valuation on an equal footing with reserves valuation in PJM's forward capacity market.

As discussed above, prevailing forward capacity mechanisms strongly favor conventional generation investment. Where these mechanisms are open to demand-side options, participation is necessarily limited to the small fraction of flexible demand potential that can profitably mimic dispatchable generation capacity. In regulated cost-of-service regions, centralized forward procurement of resources is a core feature of the utility business model, which (coupled with the capital bias dominant in utility cost-of-service ratemaking models) has similar implications for the business case for flexible demand.

As demonstrated by recent increases in reserve scarcity pricing in the New York Independent System Operator as well as the recent PJM proposal, many grid operators recognize that this discrepancy between real-time market signals and long-term investment incentives can and should be addressed. In other words, adopting a forward capacity mechanism is not an excuse for limiting the ability of energy prices to value investment in reserves. In fact, the original intent of forward capacity mechanisms was simply to top up energy market compensation for investment in reserves as needed, not substitute for it. By instead treating forward capacity markets as an excuse to ignore good energy market price formation, current energy pricing methodology in many of these markets undermines the business case for a range of cost-effective flexible loads. In so doing, it discriminates against the dominant share of the potential for low-cost demand flexibility.

By instead treating forward capacity markets as an excuse to ignore good energy market price formation, current energy pricing methodology in many of these markets undermines the business case for a range of cost-effective flexible loads. In so doing, it discriminates against the dominant share of the potential for low-cost demand flexibility.

The Problem of Pre-emption and Capacity Over-Procurement

The greatest share of the value of flexible demand, especially in power grids with growing shares of variable renewables, lies in the opportunity to reduce the need to invest in infrastructure. There is little point in pursuing this opportunity if consumers, flexible and otherwise, are pre-emptively locked into paying for uneconomic infrastructure investments. Yet in many regions this is exactly what is happening.

Figure 10 (p. 17) illustrates in dramatic fashion how pre-emptive over-procurement of supply-side infrastructure can crowd out more cost-effective demand flexibility. Put simply, the low value in recent years available to flexible consumers in many regions can be attributed in large part to the pre-emptive commitment to a significant over-supply of production capacity contracted outside of the energy market, which in turn artificially suppresses the energy price volatility that would support a business model for more cost-effective demand flexibility. The figure shows the trend since the 2008-2009 delivery year in expected planning reserve margins following each annual auction relative to the reference margin in the PJM market. (Margins in real time have generally been higher because peak demand has consistently been over-forecast.) Reference margins represent an approximation of the level of investment in planning reserves that ensures compliance with resource adequacy standards while also providing net value to consumers, based on assumptions about the cost of added margin vs. the opportunity cost to consumers of having service involuntarily curtailed. In other words, more is not always better—at higher levels of reserve margin, the cost of added increments of generation reserves increasingly exceeds their value to consumers.

More is not always better—at higher levels of reserve margin, the cost of added increments of generation reserves increasingly exceeds their value to consumers.

While PJM's results are on the high side, over-procurement of generation capacity relative to reference levels is common across most of the reliability regions designated by the North American Electric Reliability Corporation, in both organized market regions and regulated cost-of-service regions (NERC, 2022). In the cost-of-service regulated SERC Reliability Corporation region in the U.S. Southeast, for instance, in 2021 the planning reserve margin was well over 30 percent against a reference margin of 15 percent. Forecasts underlying these analyses incorporate only a very limited accounting for supply-equivalent demand flexibility, if any at all.

ROOT CAUSE #1

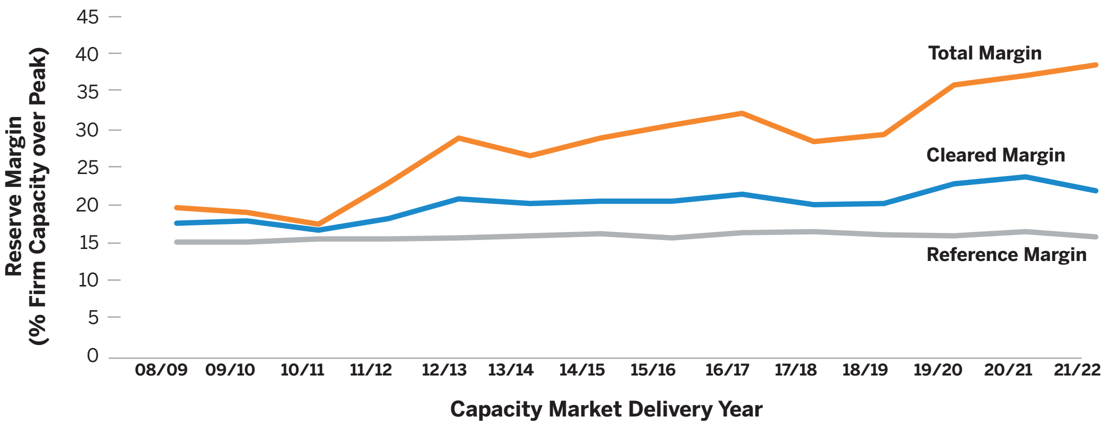
Price Discrimination

There are numerous reasons for persistent supply-side over-procurement, but three primary drivers are relevant here. The first is bound up in the price discrimination already discussed above. Where out-of-market forward capacity mechanisms have been used to substitute for, rather than top up, energy market remuneration of the value of reserves, outcomes are skewed toward more costly supply-side alternatives (predominantly generation) that can participate in the out-of-market mechanisms, rather than toward less costly flexible demand options that must rely on the information and remuneration available in the energy market.

Even in markets without such mechanisms, a similar dynamic can be set up by forward procurement of ancillary

FIGURE 10

Planning Reserve Margins in PJM Based on Reliability Pricing Model (RPM) Auction Results



Graph of PJM capacity reserve margins as calculated at conclusion of annual capacity market auctions.

Notes: Gray = reference planning reserve margin; blue = margin reflecting only cleared capacity resources; orange = margin including capacity not cleared or not participating in auction but remaining online.

Source: PJM data from post-auction published reports (e.g., https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx).

services in excess quantities in what are effectively alternative forward capacity mechanisms, again based on a valuation of reserves that far exceeds their valuation in energy market prices. This is emerging as an issue in the ERCOT market, with significant cost implications for consumers, in response to the 2021 Winter Storm Uri crisis (even though the inadequate freeze protection standards and fuel supply chain disruptions that precipitated the crisis would have rendered any additional capacity largely as useless as the existing capacity).

ROOT CAUSE #2

A Lack of Transparency in Forward Capacity Mechanisms

The second driver is associated with the complex and opaque nature of forward capacity mechanisms. In most cases they offer myriad opportunities for supply-side (and specifically generation) bias to skew outcomes. For instance, forecasts of load growth are consistently overstated, reflecting a combination of the innate difficulty of predicting the future, system operators' deeply ingrained risk aversion, and the fact that someone else—the consumer—bears the risk of committing far into the future to pay for uneconomic infrastructure. It is thus hardly surprising that system operators often implicitly (even explicitly) err generously on the side of avoiding incidents of scarce reserves under all foreseeable scenarios, despite the fact that a certain frequency of periods of reserve scarcity is inherent in complying with widely

Forecasts of load growth are consistently overstated, reflecting a combination of the innate difficulty of predicting the future, system operators' deeply ingrained risk aversion, and the fact that someone else—the consumer—bears the risk of committing far into the future to pay for uneconomic infrastructure.

Taken together, these in-built biases and standard practices can effectively preclude flexible demand from ever having the opportunity to displace less cost-effective supply-side investment. It is possible to counteract this dynamic, but it requires aggressive intervention by regulators to ensure that efforts to mobilize price-elastic demand are matched by progressive incorporation of the expected results into planning and procurement.

recognized standards for cost-effective resource adequacy (e.g., "one day of lost load in 10 years").[9] In addition, the determination of the amount of generation to be procured through the auctions typically assigns no capacity value to resources that choose not to participate or that remain online despite not clearing capacity auctions (the orange line in Figure 10). The rationale—that such resources have no contractual obligation to perform when needed—can justify some discounting, but this standard practice clearly goes too far given that these resources have every financial incentive to perform when prices are high.

ROOT CAUSE #3

Outdated Planning Assumptions About Demand

The third driver, which is particularly relevant for this paper (and as noted above, for instance, in the example of California's 2019/2020 Integrated Resource Plan), is that resource planners and system operators typically assume near-perfect inelasticity of demand. While this may have been a valid assumption 20 years ago, the trends noted here in cost and performance of distributed technology and growth of intrinsically flexible loads, are rendering it increasingly anachronistic. Persisting in this outdated assumption becomes a self-fulfilling prophecy—no elasticity drives commitments outside of the energy market to costly infrastructure investments, which in turn pre-empts the opportunity for lower cost demand flexibility.[10]

Taken together, these in-built biases and standard practices can effectively preclude flexible demand from ever having the opportunity to displace less cost-effective supply-side investment. It is possible to counteract this dynamic, but it requires aggressive intervention by regulators to ensure that efforts to mobilize price-elastic demand are matched by progressive incorporation of the expected results into planning and procurement.

9 For example, note this excerpt from the Independent System Operator of New England's 2020 Energy Security Improvements proposal (White, 2020): "[The problem of inadequate fuel-firm reserves] is self-correcting because [Pay for Performance] would tend to induce resources to arrange fuel to ensure they can perform if the frequency of reserve shortages becomes high enough. That, however, should be viewed as a Pyrrhic victory from a reliability standpoint." That is, an inducement that kicks in only when the value to consumers of acting is greater than the cost of doing so, is not good enough.

10 A similar tendency informs many mandates for battery storage, crowding out less costly flexible demand.

Conclusion

This paper has explored how the greatest potential value from flexible demand lies beyond traditional approaches to demand response, in diverse, distributed, decentralized responses of flexible loads to opportunities to reduce consumers' energy bills. The paper describes how the inherent elasticity of many loads can and should be progressively enabled and embedded in long-term investment instruments and planning. The principal sources and drivers of value from flexible consumption require that we re-focus our attention to decentralized demand response as a re-shaping of demand curves rather than as a jury-rigged stand-in for generation in supply curves. The following recommendations are offered as important steps in achieving this.

The principal sources and drivers of value from flexible consumption require that we re-focus our attention to decentralized demand response as a re-shaping of demand curves rather than as a jury-rigged stand-in for generation in supply curves.

Retail-Level Measures That Reduce Cost and Defer Network Investments

The Creation of "Safe" Options for Diffusion of Real-Time Pricing

Direct exposure to real-time pricing is unlikely to gain traction with most small consumers, and a more feasible pathway is to create risk-managed alternatives. One promising option is to offer consumers a flat-priced pre-purchase of energy shaped to their historical load profile, with the option (likely exercised by their service provider) of trading around it against real-time prices (buying more when energy is cheap and selling off pre-bought energy when it is expensive) (CPUC, 2022, Section 4.6).

The Introduction of Intra-day Price Outlooks Several Hours in Advance of Real Time to Enable Informed Consumption Decisions

There is growing interest in the adoption of intra-day energy market mechanisms, as reflected in Europe's continuous intra-day trading model, that can improve the efficiency of responses to grid conditions as they deviate from day-ahead expectations through the course of the day.[11] In addition to improving bulk system performance, these should provide the basis for periodic intra-day price updates to flexible load service providers to inform consumption decisions.

Phasing in of Dynamic, Volumetric Congestion ("Capacity Shortage") Tariffs for Distribution Network Charges to Coordinate Grid-Edge Responses to Bulk System Price Signals

Bulk system pricing should be augmented at the distribution node with network tariffs that shape pricing incentives based on real-time congestion conditions on the local distribution system. Where fixed demand-based charges have traditionally been used for some customer classes to manage use of the system, this more dynamic mechanism should replace them.

Phasing in of Dynamic Transmission Tariffs for Flexible Consumers That Enable Them to Lower Their Bills by Avoiding Periods of Peak System Demand

The extant dynamic transmission charging model, such as ERCOT's 4CP mechanism, should be expanded into

11 See, for example, Herrero, Rodilla, and Batlle (2016).

a more dynamic mechanism that recovers network costs over most or all hours, recovering more when supply is tight and less when supply is plentiful. It should be extended to all flexible load customers.

Providing Open Access to Distribution-Level Load Management by Third-Party Service Providers with Direct Exposure to Full Real-Time Marginal-Cost Pricing in Order to Maximize Price-Driven Service Innovation

The possibilities for mobilizing price-responsive loads are too broad and too difficult to predict to confine load management to a monopoly service provider. Competition in providing load management services will be essential to the innovation necessary to realize the potential, and open access for third-party load management services at the distribution level is required.

Wholesale-Level Measures That Reduce Costs and Defer Bulk System Investments

Raising Reserve Shortage Pricing in Energy Markets to a Level That Values Real-Time Demand for Reserves as Nearly as Practicable to the Value Attributed to Reserves in Capacity Mechanisms

Where infrastructure investment is centralized in forward procurement mechanisms, resource adequacy is often valued differently in such mechanisms than it is in the way demand for reserves is priced in energy markets. This discriminates against the great majority of flexible load potential that must rely on the energy market to realize its value to the system.

Limiting Capacity Mechanism Support for Supply-Side Resource Adequacy Solutions (i.e., Generation) to No More Than One-Year Rolling Commitments

Committing consumers to pay far into the future for investments in "capacity" can pre-empt more cost-effective demand-side solutions for maintaining a reliable system when based (as they often are) on outdated assumptions about demand inelasticity, excessive risk aversion, and/or a strong supply-side bias. Rolling commitments of no more than one year at a time have proven to be effective and strike a good balance between insurance and flexibility.

Eliminating Wholesale Market Design Features That Discriminate Against Demand-Side Options

While this paper is focused principally on retail market issues, the many ways that wholesale markets are designed, intentionally or not, to favor central generating plants over more cost-effective distributed consumer action should never be overlooked.

Introducing Intra-day Markets and Pricing to Enable More Intra-day Transparency Between Supply-Side and Demand-Side Options for Supplying Balancing Flexibility

Related to the retail measure noted above regarding intra-day price outlooks, mechanisms should be developed and introduced to accommodate intra-day trading in the wholesale markets in order to provide the market signals needed to inform better choices by flexible consumers.

All-System Measures—From the Meter to the Busbar

Progressively Assessing and Incorporating Expected Demand Elasticity into Long-Term Capacity Planning and Procurement at Both the Bulk System and Distribution System Levels

The bulk of the value in mobilizing flexible loads lies in avoiding uneconomic infrastructure investment. To realize that value, it will be necessary to actively assess the expected impact of measures introduced to promote decentralized load flexibility and internalize those expectations in planning and procurement processes at all levels of the system.

References

Alstone, P., J. Potter, M. A. Piette, P. Schwartz, M. A. Berger, L. N. Dunn, S. J. Smith, M. D. Sohn, A. Aghajanzadeh, S. Stensson, J. Szinai, and T. Walter. 2017. *2025 California Demand Response Potential Study—Charting California's Demand Response Future: Final Report on Phase 2 Results*. Section 3.4. Berkeley, CA: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf.

Burke, P., and A. Abayasekara. 2017. *The Price Elasticity of Electricity Demand in the United States: A Three-Dimensional Analysis.* Acton, Australia: Centre for Applied Macroeconomic Analysis, Australian National University. https://cama.crawford.anu.edu.au/sites/default/files/publication/cama_crawford_anu_edu_au/2017-08/50_2017_burke_abayasekara_0.pdf.

CAISO, CPUC, and CEC (California Independent System Operator, California Public Utilities Commission, and California Energy Commission). 2021. *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave.* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

CPUC (California Public Utilities Commission). 2019. *Inputs and Assumptions: 2019-2020 Integrated Resource Planning*. San Francisco, CA. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf.

CPUC (California Public Utilities Commission). 2022. *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation: Energy Division White Paper and Staff Proposal.* San Franciso, CA. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

ESIG (Energy Systems Integration Group). 2021. *Redefining Resource Adequacy for Modern Power Systems.* Report of the Redefining Resource Adequacy Task Force. Reston, VA. https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf.

FERC (Federal Energy Regulatory Commission). 2020. *Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators.* Washington, D.C. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.

Herrero, I., P. Rodilla, and C. Batlle. 2016. *Enhancing Intraday Price Signals in U.S. ISO Markets for a Better Integration of Variable Energy Resources.* Cambridge, MA: MIT Energy Initiative. https://energy.mit.edu/wp-content/uploads/2016/06/MITEI-WP-2016-05.pdf.

Hogan, M. 2016. *Hitting the Mark on Missing Money: How to Ensure Reliability at Least Cost to Consumers.* Montpelier, VT: Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/09/rap-hogan-hitting-mark-missing-money-2016-september.pdf.

Lazar, J. 2016. *Teaching the "Duck" to Fly.* 2nd edition. Montpelier, VT: Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingtheduck2-2016-feb-2.pdf.

LEI (London Economics International). 2013. *Estimating the Value of Lost Load.* Boston, MA. https://www.ercot.com/files/docs/2013/06/19/ercot_valueoflostload_literaturereviewandmacroeconomic.pdf.

NERC (North American Electric Reliability Corporation). 2020. *Ensuring Energy Adequacywith Energy-Constrained Resources.* Atlanta, GA. https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf.

NERC (North American Electric Reliability Corporation). 2022. *2022 Summer Reliability Assessment.* Atlanta, GA. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

PJM. 2021. *Load Management and Price Responsive Demand Performance Report 2020/2021.* Norristown, PA. https://www.pjm.com/-/media/committees-groups/subcommittees/drs/2021/20211004/20211004-item-05-lm-perf-report.ashx.

Reeve, H. M., S. Widergren, R. Pratt, B. Bhattarai, S. Hanif, S. Bender, T. Hardy, and M. Pelton. 2022. *Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report.* Richland, WA: Pacific Northwest National Laboratory. https://doi.org/10.2172/1842485.

Rocha Garrido, P., L. Morelli, and L. Walter. 2018. "Price Formation Education 4: Shortage Pricing and Operating Reserve Demand Curve." PowerPoint presentation. Norristown, PA: PJM. https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/price-formation/20180117-pm/20180117-price-formation-education-4.ashx.

St. John, J. 2021. "Seeking a Better Way to Pinpoint the Value of Demand Response in California." Greentech Media, January 25. Boston: MA. https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/seeking-a-better-way-to-pinpoint-the-value-of-demand-response-in-california.

White, M. 2020. *Energy Security Improvements: Creating Energy Options for New England.* Holyoke, MA: Independent System Operator of New England. https://www.iso-ne.com/static-assets/documents/2020/04/esi-white-paper-final-with-cover-page-04152020.pdf.

Tapping the Mother Lode

Employing Price-Responsive Demand to Reduce the Investment Challenge

By Michael Hogan

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.

ESIG
ENERGY SYSTEMS INTEGRATION GROUP