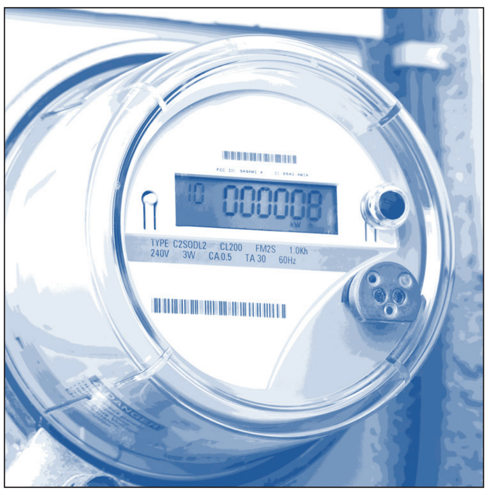
WHITE PAPER

Treating Demand Equivalent to Supply in Wholesale Markets

AN OPPORTUNITY FOR CUSTOMER, MARKET, AND SOCIAL BENEFITS

By Richard O'Neill, Debra Lew, and Erik Ela



An elegant approach to aligning demand with grid needs is demand participation in wholesale markets equivalent to supply participation today. This will become more important with the increase in variable renewables, electrification, and new large loads. The transformation of today's one-sided markets into two-sided markets presents an opportunity to benefit customers, electricity markets, and the overall grid.

In full, active demand participation (bid-in demand), customers have the same rights, requirements, penalties, and privileges as generators. For example, large industrial customers or load-serving entities bid in prices they are willing to pay for quantities of electricity along with their load resources' operating constraints, participate in the day-ahead and real-time electricity markets, are able to set the price, and are exposed to and hedged by wholesale market prices. These customers can operate according to their day-ahead schedule or can participate in the real-time market and be dispatched based on real-time prices. Not only are these customers incentivized to reduce demand when prices are high and increase demand when prices are low—naturally supporting the grid—but they are precisely dispatched, giving the grid operator more control to balance the system. Large customers already seeking to align demand with certain grid conditions may be the best place to start.

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

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ESIG

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About ESIG

The Energy Systems Integration Group is a non-profit 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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Aligning Demand with Grid Needs Through Wholesale Market Participation

System operators must balance supply against demand at every moment to maintain reliability. In the last three decades, much of the U.S. power system has transformed to competitive, wholesale electricity markets. These markets function relatively well for efficiently managing supply but have done a poor job of inducing efficiently managed demand. For the most part, the role of demand has not changed and continues to be relatively passive; demand is typically self-scheduled based on demand forecasts. The small portion of demand that does actively support the grid does so largely through demand response products that are offered as "supply-side" resources.

In this paper we argue that a robust two-sided electricity market with an active demand side solves many problems faced today in extracting flexibility from demand. In a two-sided market, wholesale customers on the demand side (e.g., large customers or load-serving entities) submit price-sensitive bid curves, which can vary with quantity and over time, are scheduled in the day-ahead market, and can respond to opportunities in the real-time market.

A two-sided market allows for more efficient market operation, maximizing benefits to market participants who participate and reduce overall system costs, which can reduce costs to all ratepayers. The participation of demand in wholesale markets will help manage a future with high levels of wind, solar, and limited-duration storage resources, because the market naturally shifts demand from high- to low-priced periods, reducing demand when prices are high and increasing demand when prices are low or negative. Full, active participation from demand (called "bid-in demand" in this paper) also improves price formation by enabling demand to set the price, which can improve incentives, reduce market power, and minimize other challenges related to price formation.

A two-sided market allows for more efficient market operation, maximizing benefits to market participants who do participate and reducing overall system costs, which can reduce costs to all ratepayers.

Giving Demand the Same Opportunities as Supply

Markets are two-sided, having a supply curve and a demand curve, with economically efficient production occurring at the intersection of the two. Electricity markets are unusual in that the demand "curve" is often considered to be a vertical line: demand is assumed to be price-inelastic. This assumption is based on the fact that demand self-schedules in the market by providing expected consumption quantities to the market auction that it plans to consume without regard to price. Most small retail customers see fixed prices or relatively modest variations in prices that are set months or years in advance by the regulator, whereas wholesale market prices vary widely across time and space. Electricity markets were designed to be, and are most efficient as, two-sided markets, but that requires the demand curve to be a function of price. This requires the recognition and engagement of the price elasticity of demand.

Consider how supply-side resources participate in electricity markets. Generators submit offer curves to sell

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electricity to wholesale electricity markets at particular prices, which can vary with quantity and with each market interval. The prices are generally determined to match the incremental cost of supplying energy at different forecasted output levels. Within the constraints of the individual units, generators are scheduled in the day-ahead market such that demand is reliably met. In addition to offering energy, generators may offer operating reserves or other ancillary services. The independent system operator's (ISO's) market software determines an optimal solution in which energy needs and ancillary services are met each interval at least total system cost, and each generator is scheduled within individual resource constraints. The generator may operate from this schedule or participate in the real-time market. If the latter, the generator will submit an offer curve to sell quantities of electricity at particular prices in the real-time market and receive a dispatch set point from the ISO for each interval.

There is an opportunity for demand to participate in an analogous way and be on an equivalent footing to supply-side resources. This opportunity exists today in that most wholesale markets have options for wholesale demand to bid into the day-ahead market (this may be used more in some ISOs than others), although it is not clear to what extent demand bids into the real-time market. There is a need to assess how this works across different ISOs, to what extent this capability is used, and whether the participation leads to a physical response. Because this concept addresses wholesale market participation by sophisticated customers that understand how energy markets work and likely have automation, "customers" in this paper refers to large customers, e.g., load-serving entities or large industrial customers. We will specify "retail" customers when we discuss customers like residential customers or commercial customers whose link to wholesale markets is through a load-serving entity or other provider.

For example, a chemical refinery customer may need 20 MW of electricity and 200 MW of thermal energy for every hour of the day. It is willing to pay a very high price for the 20 MW of electricity that is needed hourly because electricity reliability is essential to its chemical processes. However, this customer also has 500 MW of thermal storage that is recharged with electric heaters. The customer is sited in a region with high levels of solar, and prices are typically low or negative midday, especially in the shoulder months. This customer might bid into the day-ahead market for each hour of the day: the market cap price for 20 MW for its electricity needs, \$30/MWh for 200 MW to ensure that its storage is recharged, and \$0/MWh for the remaining 500 MW to take advantage of zero or negative prices. The market clears and the customer receives a schedule for the next day. It can dispatch its electric heating load to charge the thermal storage according to this schedule, or it can choose to participate in the real-time market, just as generators can. If it is scheduled to use 220 MW at 2 pm and its thermal storage is relatively full, it might bid into the real-time market a willingness to back down by 200 MW if real-time prices hit \$100/MWh. It would realize financial savings from the 200 MW reduction that is settled at the higher real-time price. Similarly, it might bid into the real-time market a willingness to increase consumption by 500 MW if real-time prices went negative. If that bid cleared the real-time market, the customer would make money by charging its storage during that interval.

When a generator self-schedules, or bids only a quantity without an associated price into the market, it becomes a price-taker—it will take whatever price the market clears

By bidding a quantity and price, customers are now able to set the price and become a price-maker. When demand sets the price, the market clears at a lower price than when demand is a price-taker, and overall system costs are lower.

Currently, most retail customers see wholesale prices only after consumption and in their bills, diluted by retail rate-making policies. With wholesale market participation, the customer is exposed to day-ahead and real-time prices, and the auction market optimizes the value of consumption based on the customer's expressed value and flexibility.

at. Similarly, a customer that self-schedules or bids only a quantity without an associated price is a price-taker, paying whatever price the market clears at. By bidding a quantity and price, customers are now able to set the price—become a price-maker. When demand sets the price, the market clears at a lower price than when demand is a price-taker, and overall system costs are lower.

Paying for What You Use

Currently, most retail (smaller) customers see wholesale prices only after consumption and in their bills, diluted by retail ratemaking policies. With wholesale market participation, the customer is exposed to day-ahead and real-time prices, and the auction market optimizes the value of consumption based on the customer's expressed value and flexibility. The market clearing algorithm shifts consumption into low price periods, reducing system costs by consuming low- or zero-marginal-cost power that may otherwise be curtailed. It also reduces consumption during high-price periods, reducing the need for high-cost generation with very low utilization, such as an old combustion turbine. Finally, it reduces market power of generators.

With wholesale market participation, customers simply pay for what they use. There is no baselining or monitoring and verification, only metering. These customers are exposed to wholesale market prices and given a schedule that reflects their willingness to pay and their price sensitivity. It is rational to expect that if they participate in this way, they will flex their demand according to market prices, because deviations from their schedules are subject to real-time prices. By bidding in price curves for their demand, they help make the market more efficient and reduce overall system costs, which in turn yields lower costs for all customers.

In his white paper in this series, Travis Kavulla argues that default time-varying rates are superior to opt-in rates because participation is higher. Higher MW shifts of demand can be possible with opt-out rates.[1] Direct exposure to wholesale prices, as outlined here, is also likely to yield participation from customers. First, the process of determining price sensitivity allows customers to engage in decisions about what loads they are willing and able to shift and at what price points. Second, wholesale prices have a much wider range than typical time-varying rates, providing a higher incentive to flex demand.

With wholesale market participation, customers simply pay for what they use. There is no baselining or monitoring and verification, only metering. These customers are exposed to wholesale market prices and given a schedule that reflects their willingness to pay and their price sensitivity.

1 T. Kavulla, "Why Is the Smart Grid So Dumb?: Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector," A White Paper from the Retail Pricing Task Force (Reston, VA: Energy Systems Integration Group, 2023, https://www.esig.energy/aligning-retail-pricing-with-grid-needs).

The Benefits of Bid-in Demand

More Control for Customers over Consumption and Bills

In the wake of the Griddy experience during the 2021 Texas winter storm, there has been widespread concern about small retail customers' exposure to wholesale prices because of the customers who were exposed to days of $9,000/MWh prices.[2] **It is important to note that by bidding in demand at the price the customer is willing to pay, the customer does not pay more than they are willing to pay (unless they decide to deviate from their dispatch point).** It can be beneficial to have direct communication from the ISO or scheduling entities so that the customers know their scheduled consumption. Even better is to have automation so that consumption is controlled via the consumption dispatch signal, without the need for a human in the loop.

By bidding in a quantity and a price, customers have more control over their consumption and their bills. For example, in a time of grid emergency, one could imagine bidding a very high price for a small amount of electricity for absolutely essential needs, a lower price for a moderate amount of electricity for most needs, and a very low price for optional needs or charging of any storage.

Bid-in demand also provides better risk management than conventional demand response. By allowing the ISO market software to schedule demand, bid-in demand eliminates the risk associated with large customers self-scheduling based on forecast prices. The same way that day-ahead markets provide a financial hedge against real-time prices for generators, bid-in demand can provide a financial hedge against real-time prices for customers.

Bid-in demand provides better risk management than conventional demand response. By allowing the ISO market software to schedule demand, bid-in demand eliminates the risk associated with large customers self-scheduling based on forecast prices.

A participating customer can take advantage of real-time price volatility by deviating from its day-ahead market dispatch schedule in response to real-time prices that are higher or lower than day-ahead prices. Table 1 (p. 5) gives a risk comparison with and without bid-in demand.

Benefits for Grid Reliability

Full, active participation from demand also allows the ISO to accurately determine the *amount* of demand flexibility to balance the system, as opposed to an open-ended call which may yield less or more flexibility than what is actually needed and potentially lead to instability on the system. In this approach, *quantities of load are dispatched*; this is distinct from "prices-to-devices" or load chasing prices. For example, if a large load were to passively respond to prices during an open-ended call for load reductions, without being dispatched by the system operator, this could potentially create a large deviation in generation and load balance and lead to a frequency

2 See, for example, https://www.npr.org/sections/live-updates-winter-storms-2021/2021/02/21/969912613/after-days-of-mass-outages-some-texas-residents-now-face-huge-electric-bills%20.

TABLE 1

Risk Comparison With and Without Bid-In Demand

Issue or Need	Non-bidding, Conventional Demand Response	Bid-in Demand
Financial risk management prior to day-ahead market	Customers contract before the day-ahead market in response to forecast prices for financial risk management.	Same as for non-bidding demand response.
Day-ahead market	Customers scheduling into the market based on a price forecast risk overpaying.	Schedules from day-ahead market are profitable. Prices are fully hedged in the real-time market.
Day-ahead market profits	Non-bidding demand response is less profitable due to forecast errors and lower market surplus.	Bid-in demand has greater profits and market surplus.
Low prices	Non-bidding demand response is less profitable because the customer has no ability to adjust low prices; for example, it pays average prices.	Bid-in demand is more profitable for the customer and leads to greater market efficiency.
Capacity obligation	Customer must purchase its capacity obligation for generation, transmission, and distribution (often called the peak or demand charge).	Customer can be its own generation capacity obligation and does not need to purchase capacity. The market algorithm will shift consumption from the high-value peak to the low-value off-peak.
Value	ISO market software assumes the value placed on consuming is exceedingly high or infinite.	The customer provides its value of electricity.

Source: Energy Systems Integration Group.

deviation that can cause involuntary load shedding or worse. Later, when prices go down, the demand increases and can cause under-generation and under-frequency. Had the large load bid in the market, the ISO would have scheduled it optimally with its willingness to consume, creating a balance in generation and load and helping to ensure the reliability of the grid.

Advantages Relative to Demand Response

The demand side of the balancing equation has traditionally been treated as price-inelastic. To recognize the ability of demand to provide flexibility, demand response programs were introduced, and these were treated as supply-side options by system operators. That is to say, the reduction of demand from average consumption is used as a supply resource in the supply curve that system operators economically dispatch to meet the remaining fixed demand. This paper does not seek to disparage traditional demand response programs, but rather aims to show how active wholesale market participation of demand can be a more efficient and powerful tool for providing significant flexibility to the system.

Active wholesale market participation of demand can be a more efficient and powerful tool for providing significant flexibility to the system.

The current construct of price-inelastic demand combined with demand response programs suffers from several issues:

- Demand response programs require monitoring and verification to determine deviations from a baseline of usage. This will become more difficult in the future as the grid becomes more dynamic, for example, if baselines are based on the previous day's demand and demand response is called for two days in a row.
- Demand response can suffer from gaming of baselines by customers.
- It can be difficult to quantify demand response programs' value, responsiveness, and effectiveness.
- There is a potential issue of double payments with existing demand response resources being paid as suppliers while also paying less as consumers, when they pass the Federal Energy Regulatory Commission's required net benefits test.

- It can be difficult to know the potential quantity of demand response available to a system operator at any given time.
- Costs of demand response programs are typically paid by all ratepayers, not just those who participate in and are compensated by them.

During the periods of resource shortage or near-shortage in the California Independent System Operator territory during 2020 and 2022, voluntary flex alerts, including use of cell phone amber alerts, helped reduce demand enough to either reduce the shortfall or help prevent a shortfall. Small retail customers were asked to reduce consumption as a public service, without compensation beyond paying for fewer kWh at their retail price, which does not reflect stress conditions. Meanwhile, generators that responded to this event were compensated at wholesale market prices that do reflect stress conditions. Bid-in demand can provide much better price signals to customers to (1) discourage consumption during stress periods, and (2) provide compensation at wholesale market prices when they respond. This significant financial incentive to reduce demand is likely more compelling than only a moral or environmental incentive.

Advantages Relative to Time-Varying Pricing

By exposing customers to wholesale day-ahead and real-time electricity prices, bid-in demand can potentially meet grid needs more effectively than current time-varying pricing.

- Time-of-use and many other time-varying rates are set months before, or at least a day before, the wholesale market clears. But many factors can conspire to make those prices inaccurate in the day-ahead and real-time time frames, including wind/solar/load forecast errors, generator outages, transmission outages, or unpredictable or fluctuating fuel prices. In addition, increasing wind/solar and increasing electrification will make high and low prices harder to predict in the future. Bid-in demand is based on day-ahead and real-time electricity prices, and therefore serves specific grid needs as they emerge in the day-ahead and real-time time frames.
- Typical real-time pricing programs use day-ahead prices or, in the case of the Texas retail provider Griddy, the previous period price, rather than actual real-time prices for the period in question. In the Electric Reliability Council of Texas (ERCOT), the market price was set by the operating reserves demand curve. Bid-in demand helps avoid this price.
- All versions of retail time-varying rates include passive participation, where the response of the demand to the prices does not form the wholesale price. This leads to inefficient price-setting and prices that do not align with conditions.

Benefits to Resource Adequacy and Reducing the Risk of Overbuilding the System

As Table 1 (p. 5) points out, if a customer were to bid a price and quantity for all of its demand into the wholesale market, it could potentially be its own generation capacity obligation and obviate the need to purchase capacity.

There is a risk of overbuilding—and building an unnecessarily expensive system—by ignoring the price-sensitivity of demand.

We have resource adequacy requirements, capacity markets, planning reserve margins, and other constructs because (1) we treat demand as price-inelastic, and (2) system operators have an obligation to serve. In many jurisdictions, resources are built to ensure that assumed-inelastic load is served; however, there is a risk of overbuilding—and building an unnecessarily expensive system—by ignoring the price-sensitivity of demand. If *all* demand were price-sensitive, there would be no need for resource adequacy constructs because only the amount of demand that could be met by supply at the strike price would be served. However, some amount of demand is price-inelastic, and if the elasticity of price-elastic demand could be captured, the remaining—reduced—amount of price-inelastic demand would set the requirements for resource adequacy.

Potential Applicability to the Distribution System in the Future

Because we do not yet have distribution system pricing that varies across time or location, this paper only addresses wholesale market prices, which do. This means that it may be difficult for customers to support distribution system needs through wholesale market participation in its current form. However, it is possible that if distribution-level locational marginal prices were available, then distribution system operators could use bid-in demand price curves to clear the market just as the wholesale system operator can do today. This would allow demand to support the needs on the distribution system—for example, voltage support and congestion—in a similar manner.

Tractable for ISOs

With large quantities of demand actively participating in wholesale markets, it may take more time to solve the market clearing software. However, as computing power continues to advance, market participation by demand can be handled without major impacts to market clearing timelines. Customers can utilize existing communication and telemetry or custom solutions to participate.

ISOs vary in their treatment of bid-in demand. A simplified example of a price-sensitive demand bid in the day-ahead market of the Independent System Operator of New England (ISO-NE) is shown in the following tables. For hour 16, the Rhode Island Load Company bids that it is willing to pay $59/MWh for the first 100 MW, $54/MWh for the next 150 MW, and $51/MWh for the next 150 MW (left side). The day-ahead market clears at $52.96/MWh, with the customer scheduled for 250 MWh at that price. The real-time price for that hour was $61.21/MWh (middle). Let's say that in real-time, the customer consumes more than its schedule, say, 400 MWh. The customer pays the day-ahead price for the 250 MWh, and the remaining 150 MWh are settled at the real-time price. If, instead, the customer consumed less than its schedule (say, 150 MWh), it would still pay for its day-ahead position of 250 MWh, but it would receive a credit for the 100 MWh that it did not use, at the $61.21/MWh real-time price (right side).

This opportunity exists today for wholesale customers, and the authors of this paper believe it should be used more, because it helps the grid, helps the customer, and aligns grid needs with prices. Customers can set the day-ahead price. However, we note that this does not provide the precision of real-time dispatch that helps the ISO balance the system and respond to unexpected events and forecast errors. We also note that demand can respond in an open-ended way to real-time prices, and that chasing prices could destabilize the grid as described earlier. If an option were added so that demand can bid in a price curve and get dispatched in the real-time market, this would further help the ISO balance the system in real time. This would allow demand to set the price in the real-time market. In this case, penalties may be warranted for demand that deviates from a dispatch base point.

TABLE 2

Simplified Example of a Price-Sensitive Demand Bid in the ISO-NE Day-Ahead Market

Rhode Island Load Company Demand Bids — Load Zone, Rhode Island – Hour: 16

Segment	Quantity (MW)	Price ($/MWh)
A	100	$59
B	150	$54
C	150	$51

Market settlement if Rhode Island load customers consume *more* in real time than bought day ahead — Load Zone, Rhode Island – Hour: 16

Segment	Quantity (MWh)	Price ($/MWh)	Payment
Day ahead	(250)	$52.96	($13,240)
Real time	(150)	$61.21	($9,182)
Total	(400)		($22,422)

Market settlement if Rhode Island load customers consume *less* in real time than bought day ahead — Load Zone, Rhode Island – Hour: 16

Segment	Quantity (MWh)	Price ($/MWh)	Payment
Day ahead	(250)	$52.96	($13,240)
Real time	100	$61.21	$6,121
Total	(150)		($7,119)

An example of market settlement when bid-in demand consumes more vs. less in real time than the customer bought in the day-ahead market.

Source: Independent System Operator of New England.

ERCOT's framework for controllable load resources (CLR) allows for this. CLRs are capable of reducing or increasing consumption under 5-minute dispatch control by ERCOT and can follow base points. They submit a price-quantity bid into the day-ahead market for the CLR, the market clears, and the CLR receives a day-ahead schedule. The CLR has telemetry so that ERCOT can monitor its net power consumption, resource status, ancillary service schedule, and maximum and minimum power consumption. In the real-time market, it submits a "Bid to Buy" price curve that represents the price sensitivity of the CLR, including the threshold above which the CLR is willing to drop load. ERCOT economically dispatches the CLR to any level between its maximum and minimum power consumption. The performance of the CLR in following the ERCOT base point signals is measured, and deviation charges can be incurred for over- or under-consumption.

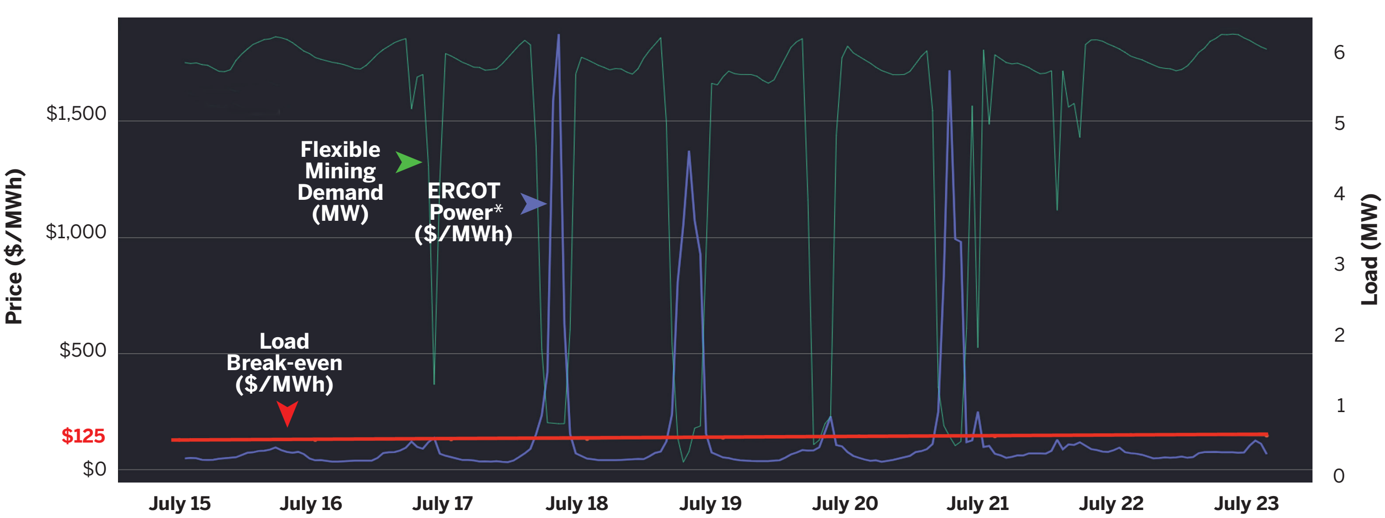
Similar to generators in ERCOT, CLRs must provide primary frequency response according to a droop curve (this proportional response differs from the binary response provided by ERCOT's non-controllable load resources on under-frequency relays). CLRs can participate in regulation reserves, responsive reserve service, and non-spin reserve service if qualified.

The company Lancium recently developed the first load-only CLR in ERCOT. It has partnered with bitcoin mining datacenters to use software controls to provide primary frequency response and follow dispatch base points in the real-time market. Figure 1 shows the response of one of Lancium's bitcoin mining datacenters reducing its demand when real-time prices are high. This facility has a breakeven threshold of $125/MWh and submits a Bid to Buy price curve that reflects its willingness to drop load when prices exceed this threshold. Lancium anticipates that other energy-intensive loads, such as hydrogen or high-throughput computing, would be ideal future partners.

ERCOT is working on improvements to its CLR program. This may include the settlement of CLRs at nodal prices instead of zonal prices (which are currently used to settle loads). Currently, there is the possibility that CLRs which are dispatched based on nodal prices but settled based on zonal prices could be dispatched in a way that is not aligned with the incentives provided.

FIGURE 1

Real-Time Economic Dispatch



* ERCOT Load Zone West Real Time Settlement Point Price

A bitcoin mining datacenter in the ERCOT territory follows the ERCOT base points and reduces its demand when real-time prices are high, providing additional flexibility to the grid.

Source: Lancium.

Considerations for Pilot Programs for Large Customers

While small retail electricity customers generally do not have the experience of participating in day-ahead or real-time markets that generators have, some large customers already interact with wholesale markets. Large customers that are concerned about their consumption (e.g., for pricing or carbon content) typically forecast prices, run an internal optimization model, and self-schedule in the market. They may also purchase a price hedge from the off-ISO financial markets that is more expensive and riskier than direct participation in the markets by bidding in a price curve. Because wind/solar tend to bid in negative prices and other zero-carbon resources tend to have low marginal costs, customers that are concerned about decarbonization may be able to use price as a proxy for carbon content. Examples of customers that may be first movers in bid-in demand could be companies with large data center loads and other customers that have carbon targets for all hours of all days.

The nature of the load is also critical, with some loads having more flexibility than others. Many large industrial processes have similarities to thermal generators in that they have start-up costs, fixed and variable operating costs, maximum and minimum operating levels, minimum run times and down times, and multiple modes of operation. The customer's production scheduling problem is a dynamic optimization problem that explicitly accounts for the constraints of the plant, including safety and product quality. Production scheduling considers a time horizon that spans multiple hours and usually uses forecasted electricity prices.

Loads that have temporal flexibility in advance of a deadline, such as overnight electric vehicle fleet charging, may be optimized similarly to how storage is optimized today, based on either customer or ISO forecasted prices. Data centers' loads, including customers that have multiple locations and the ability to shift load between them (creating spatial flexibility), could be potential loads to bid in.

Lastly, although small retail customers generally neither have the ability to participate directly in the market nor tend to have the sophistication to determine their price sensitivity, load-serving entities that are already engaging their customers through demand response programs, distributed energy resource (DER) programs, and advanced pricing may want to become a more active participant in the wholesale markets. By activating their programs and pricing to respond to wholesale market signals, load-serving entities can reduce their overall costs, better understand which of their pricing/programs are most effective and reliable, and inform future pricing/program activities.

Challenges to Overcome

There are some practical challenges to consider and explore to maximize the benefits of bid-in demand. First, there is the challenge of volume and responsibility. As discussed, trials and pilots should focus on large loads that can determine bid values directly through business profits, fixed costs, and other means. This may include large industrial loads, data centers, and cryptocurrency mining applications that have high ramp-rate or interruptible processes. However, wider adoption among residential and commercial customers may be necessary to truly maximize the benefits of bid-in demand. More thought is needed around the way these entities may consider bids and how that gets aggregated through a third-party aggregator or the load-serving entity.

Wider adoption among residential and commercial customers may be necessary to truly maximize the benefits of bid-in demand. More thought is needed around the way these entities may consider bids and how that gets aggregated through a third-party aggregator or the load-serving entity.

We have discussed some of the benefits of equal treatment between generation and demand when it comes to participation in energy markets. One standard procedure in energy markets is around what occurs when market participants do not follow the schedules that were cleared in the auctions. In most regions, if a generator was cleared at a specific quantity and it deviates from that quantity by a meaningful amount, it incurs financial penalties. This is because if market participants do not act according to their schedules, there can be large inefficiencies, misaligned price formation, and even threats to system reliability. Generator participants may also be deviating from market clearing schedules to game in a way that they would earn greater profits than if they followed the schedule provided from the market operator. A similar feature may need to be in place for demand in order to provide equal treatment and to avoid these issues. If financial penalties were instituted for demand in a similar way, it adds financial risk to the participating customers, especially those that may have less control over consumption patterns. This can limit the voluntary participation of demand in these programs, and market designs may need to take this into account.

Example of the Benefits of Bid-In Demand for Market Efficiency, Value to Customers, and Emissions

Bid-in demand provides an elegant solution to aligning demand with grid needs by exposing customers to electricity market prices and allowing the full functionality of electricity markets to be used. As we increase variable renewables and electrify, bid-in demand will become an increasingly important tool to manage the reliability and affordability of the electric power system. It is in our best interest to gain experience using this tool today to prepare for that future, and large customers seeking to manage costs or emissions will be a good place to start.

As we increase variable renewables and electrify, bid-in demand will become an increasingly important tool to manage the reliability and affordability of the electric power system. It is in our best interest to gain experience using this tool today to prepare for that future,

Table 3 shows a simple one-period example of replacing fixed, price-insensitive demand with bid-in demand. The bid-in demand case increases market surplus, increases customer value/profit, increases generator profit, and decreases generator emissions.

The table compares a fixed, price-insensitive demand of 150 MW with a price-sensitive demand curve. The value of this load is $327/MWh; the load does not bid in a price but self-schedules. The price-sensitive demand curve includes five blocks of load up to 150 MW: the

TABLE 3

Example of Replacing Fixed, Price-Insensitive Demand with Bid-in Demand

Fixed Price-Insensitive Demand			
Step	**% of Fixed Load**	**Value**	**Comment**
1	100%	$327/MWh	Fixed load
Bid-in Price-Sensitive Demand			
Step	**% of Fixed Load**	**Value**	**Comment**
1	20%	$1,000/MWh	Load that is reduced in an emergency, i.e., when the price is above $1000/MWh
2	20%	$500/MWh	Load that is reduced in system stress, i.e., when the price is above $500/MWh
3	20%	$100/MWh	High value load served most of the time
4	20%	$25/MWh	Flexible consumption
5	20%	$10/MWh	Low-value load

Source: Energy Systems Integration Group.

TABLE 4

Operational Constraints of the Resources and Loads

Device	$/MWh	Minimum Operation	Maximum Operation	Startup Cost	Emissions
Fossil generator	$20/MWh	100 MW	140 MW	$1,000	Positive
Wind generator	$0/MWh	0 MW	145 MW		0
Fixed demand		150 MW	150 MW		Positive
Price-sensitive demand		0 MW	150 MW		Less than or equal to fixed demand

Listing of operational constraints of the resources and loads that cause the bid-in demand to show benefits. The fossil fuel generator has a minimum generator level of 100 MW and a maximum output of 140 MW and a start-up cost.

Source: Energy Systems Integration Group.

first is extremely high priority and is only reduced during emergencies; the second is high priority and is only reduced when the grid is stressed; the third is a high-value load that needs to be served most of the time; the fourth can be flexed when needed; and the fifth is a low-value load that can be turned on when prices are very low. This load bids in the price curve according to the values shown in Table 3 (p. 11).

Table 4 shows the operational constraints of the resources and loads that cause the bid-in demand to show benefits. The fossil fuel generator has a minimum generator level of 100 MW and a maximum output of 140 MW and a start-up cost.

Table 5 shows the optimal dispatch of this system for this interval for make-whole payment (MWP) pricing. (The make-whole payment is a side payment to cover start-up costs for the fossil generator.) In the fixed demand case, the wind generator is insufficient to serve the total load, so the fossil generator needs to be committed, which has a minimum generation level of 100 MW and a start-up cost of $1,000. Meeting load results in the fossil generator dispatched at 100 MW for a total cost of $3,000 (including the start-up cost) and the wind generator dispatched at 50 MW for a cost of $0. Generator profits are $0, and the net value to customers is the value of the load served minus the generator payments, or $46,050.

TABLE 5

Optimal Dispatch with Prices Plus Make-Whole Payment Pricing

			Demand			Fossil Generator			Wind Generator	
	LMP	Market Surplus	Dispatch	Gross Value	Net Value	Dispatch	Profits	MWP	Dispatch	Profits
Fixed demand	$0	$46,050	150 MW	$49,050	$46,050	100 MW	$0	$3,000	50 MW	$0
Price-sensitive demand	$10	$49,000	145 MW	$49,000	$47,550	0 MW	$0	$0	145 MW	$1,450

Notes: MWP = make-whole payment; LMP = locational marginal price.

Source: Energy Systems Integration Group.

In the price-sensitive demand case, the first 145 MW of demand is dispatched because the price for that generation is $0 due to the wind generator. If the next MW of demand were price-insensitive (firm), it would result in the fossil generator being dispatched at a cost of $3,000; instead, the price of this fifth block of load of $10/MWh determines the locational marginal price, and the fossil generator is not dispatched at all. This results in lower emissions. Generator profits are $1,450 (145 MW x $10/MWh). The gross value to customers is the value of 145 MW applied to the value curve in Table 5 (p. 12), or $49,000. The net value to customers is the gross value minus the generator payments or $47,550, which is higher than the fixed demand case ($46,050). The market surplus is $49,000, which is also higher than the fixed demand case ($46,050).

The Time for Bid-in Demand Is Now

With higher levels of variable generation resources, the power system needs flexibility in order to balance supply against demand. Exploiting the price sensitivity that exists in demand today—plus that which may come from electrification of transportation, buildings, and industry—is likely to be one of the cheapest sources of flexibility. Looking forward, new loads such as hydrogen production may be a future driver for load growth; by bidding in that demand, hydrogen producers may be able to produce green hydrogen at least cost while also supporting grid reliability.

For those customers that care about real-time system conditions (such as periods of low carbon emissions), this will become harder to forecast with increased wind and solar, and bid-in demand provides a simpler, more efficient option than attempting to forecast those conditions.

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Treating Demand Equivalent to Supply in Wholesale Markets

An Opportunity for Customer, Market, and Social Benefits

By Richard O’Neill, Debra Lew, and Erik Ela

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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