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# Less carbon means more flexibility: Recognizing the rise of new resources in the electricity mix

Thousands of megawatts of renewable resources—chiefly wind and solar—are in the works. What types of grid services can these provide as electricity markets and policies evolve?

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Renewables such as wind and solar now account for the majority share of new electricity generation capacity being built globally. Though still dwarfed in the generating fleet by more traditional generation options such as coal, gas, and nuclear power, intermittent resources have risen dramatically, first aided by supportive policies, technology advances, and consumer preferences but now driven more by economics.[1] This has resulted in a growth of the contribution of renewable generation in the United States. As year-end 2017, approximately 17 percent of electricity in the United States was generated by renewables (including hydropower). Through March 2018, renewables accounted for about 21 percent of all electric generating capacity.[2] The European Union is even farther ahead of the United States: in 2017, approximately 30 percent of the EU's electricity was generated by renewable energy sources.[3]

The rise of renewables is expected to continue, at least for the next few years. Policy makers in the European Union have set high and aspirational decarbonization goals: by 2030, cut greenhouse-gas emissions by 40 percent compared to a 1990 baseline.[4] Germany's coalition government agreement[5] set a new 65 percent target for renewable penetration by 2030. France is aiming for a 40 percent share of renewables in electricity production.[6]

In the United States, despite the announced withdrawal from the Paris accord, some states are implementing their own renewable-energy policies: California,[7] New Jersey, and New York have required utilities under their jurisdiction to have 50 percent of their electricity come from renewable resources by 2030, while Massachusetts recently enacted a 35 percent renewable portfolio standard. Many utilities in the United States are replacing coal capacity with a mix of renewables plus, in many occasions, energy storage.

Other drivers abound. On both sides of the Atlantic, some customers—ranging from Fortune 500 companies to individual homeowners—are scrutinizing their electricity options with an eye to lowering their carbon footprints and greening their supply chains. A growing pool of investment capital is backing "clean" or "green" electricity options. This is partly a play toward diversification, but renewable generation also represents many of the characteristics of the stable returns pension funds and other institutional capital seek. Their long horizon and low cost of capital is part of the overall reduction in the final cost to consumers seen in recent responses to requests for proposals for electric generation.

## Renewable electric prices fall while challenges rise

Beyond policy goals, the growth of renewables is supported by their improving cost outlook. According to Lazard's year-end 2017 estimate, levelized cost of energy (LCOE) for utility-scale renewable electricity continue to fall, averaging $45 per megawatt-hour (MWh) for unsubsidized wind power and $45 to $50 per MWh for utility-scale solar, compared to approximately $60 per MWh for combined-cycle natural gas.[8]

In several geographies, solar and wind are already competitive with other sources of generation based on LCOE, even without tax or production subsidies. In LCOE terms, these resources are expected to be the cheapest source of electricity within the next decade.

However, LCOE metrics ignore one important consideration. Renewable generation is intermittent and frequently unpredictable. Furthermore, the uneven geographic distribution of wind and solar potential is likely to stress the grid in some locations, leading to transmission and distribution constraints.

These low-cost, renewable kilowatt-hours come with intermittency, volatility, and grid-integration costs, creating new grid-planning requirements for backup capacity and ramping. New types of electricity services, beyond the traditional energy and four-to-six-hour capacity requirements, can be fostered to manage these intrinsic characteristics of clean-generation technologies. Those services are flexibility and resiliency.

Some electricity markets, such as the California Independent System Operator (CAISO), Germany, and the United Kingdom, have started to recognize, to varying degrees, flexible, and resilient electric resources. And policy makers at the Federal Energy Regulatory Commission (FERC) and the PJM Interconnection are shifting focus, in the United States at least, to the role that battery energy storage and flexible resources like distributed resource aggregators (DRA) could play as electricity markets evolve.

We believe significant steps can be taken toward decarbonizing the electricity supply through thoughtful, concerted action, as we discuss below.

High renewable penetration can cause several issues in the operation of the grid that can vary by geography, depending on, among other things, the mix of renewable-energy sources (solar versus wind), the availability of transmission and distribution (T&D) capacity, the fleet of nonrenewable generating stations, and the shape of electricity demand. There is no universal, one-size-fits-all solution to integrating ever-greater amounts of renewable generation into the grid. What works in Philadelphia may not work in Portland or Phoenix.

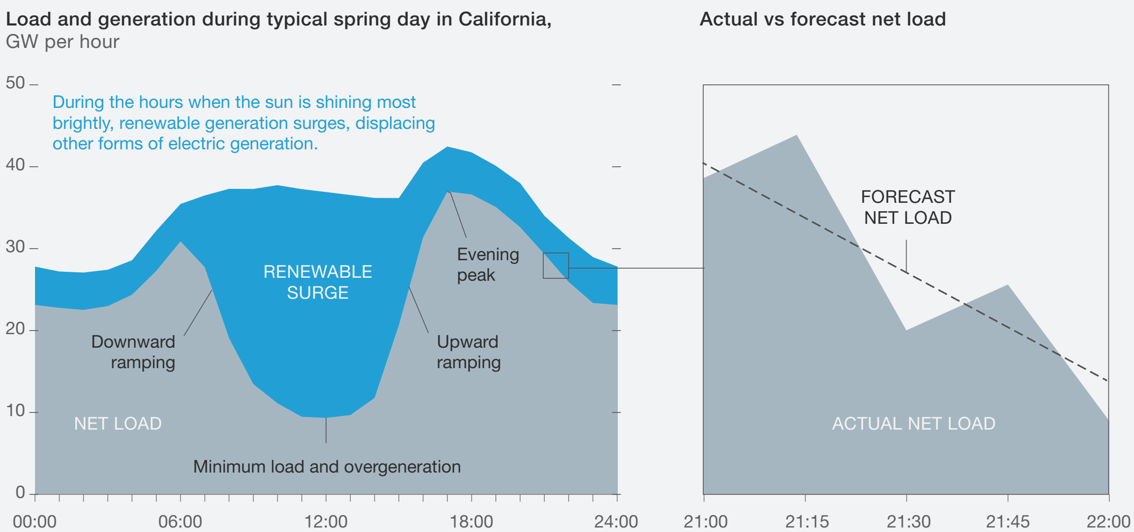
Heading off current and future challenges is not simply a matter of tinkering at the margins with market rules or mandating a set level of electricity-storage projects. Holistic solutions that encompass supply, demand, regulation, and market structure are needed. Storage could be part of the solution, as could supply-side resources, customer programs, and regulatory leadership. The solutions could also recognize that different resources provide different services and thus a differentiated set of market products and customer programs will likely deliver a lower cost solution.

Operating electric grids with high penetration of intermittent resources poses unique challenges for utilities and grid operators. While not limited to California, that state's much discussed "duck curve" (Exhibit 1) illustrates one of the difficulties managing a grid with a high percentage of renewable generation, which sometimes is dispatched at zero or even negative variable cost, resulting in displacement of other resources which may be needed to manage flexibility.

Though this particular iteration of the "duck curve" is a projection, it differs little from recent years' operational facts. During the hours of a spring day when the sun is shining most brightly, that is, from 9:00 a.m. to 3:00 p.m., renewable generation surges, displacing other forms of electric generation. The problem is most acute in the first and second quarters of a year. During the first quarter of 2017, the price of generation on the CAISO fell to zero or less than zero for as much as 15 percent of the time between the hours of 11:00 a.m. and 4:00 p.m.[9]

As solar generation peaks mid-day, non-solar generation is ramped down. More importantly, later in the day those ramped-down plants will need to ramp up as solar output declines. The significant amount of renewable output during the mid-day solar peak means that nonrenewable-generation plants will have to operate close or at their minimum generation levels and possibly shut down for several hours each day, stressing equipment as well as operating economics. For wind-based systems, the need for flexibility might manifest in different ways. For example, significant investments might be needed to alleviate power-export constraints from zones with significant wind potential to major load centers, an effect that has already been observed in Texas's Panhandle Renewable Energy Zone. Additionally,

**Exhibit 1** Demand response is expected to address several issues associated with high renewable penetration.




McKinsey&Company | **Source:** California Independent System Operator (CAISO); Lawrence Berkeley National Laboratory; McKinsey analysis

night-time wind-overgeneration issues might arise, an effect already apparent in the Electric Reliability Council of Texas and Southwest Power Pool. Furthermore, short-term wind-forecasting errors might hamper the grid operator's ability to match supply and demand, degrading the system's primary and secondary frequency response, as has already been observed in several European markets.

This creates a series of far-ranging consequences. The operational and planning challenges caused by the intermittency, volatility, and uneven placement of these intermittent resources are becoming more significant and, likely, costlier.

The United States is neither alone nor the first country to be forced to tackle the challenge of integrating ever-greater amount of renewable generation into the grid. European markets have implemented some measures that bear consideration by US regulators, which we discuss below. In the United States, some regulatory bodies are taking important preliminary steps, which we also discuss below, to more effectively and economically add more intermittent resources to the electricity mix.

First, we will examine some of the new resources that are creating value in this variable operating environment. Then, we will identify barriers prohibiting the full realization of their potential. Finally, we will conclude with solutions that electric-power stakeholders could consider.

## Enter the age of new resources

New challenges require new thinking. The market has a set of traditional options for responding to the ramp-down of intermittent resources, but in a decarbonized future, those traditional options are increasingly misaligned with overarching policy goals.

For example, one traditional response to falling output from intermittent generation is to ramp up gas-fired generators. But that practice comes with a cost—to customers and to the policy goal of decarbonizing.

Enter battery-energy storage and DRAs. As Exhibit 2 shows, there are two categories of options for the intraday shifting type of flexibility service that could be competitive against the traditional options: battery energy storage and distributed resource aggregation.

Exhibit 2 shows storage options in the not-too-distant future could compare favorably with traditional supply-side options like constructing a combined-cycle gas turbine generator as well as some traditional demand-side options.

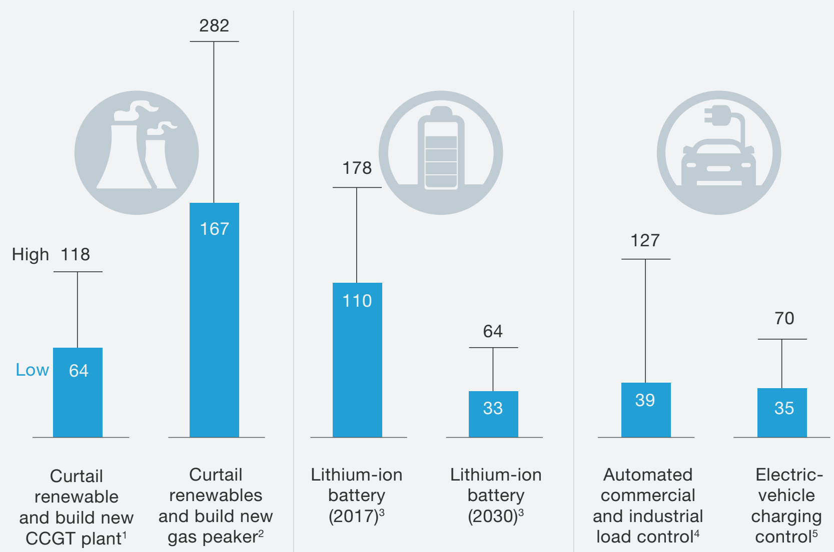
Today, at prices of $320 to $410 per installed kilowatt-hour for a five-hour lithium-ion battery, energy storage is currently significantly more expensive than curtailing renewables. However, with projected cost declines in the approximately 70 percent range by 2030, lithium-ion battery storage has the potential to be a competitive option for avoiding curtailments through time shifting.

The role of storage already is being recognized by policy makers in jurisdictions with high

**Exhibit 2**

Cost varies depending on the technology for shifting renewable energy.

**Cost of shifting renewable energy,** $ per MWh shifted




[1]Represents the cost of curtailing renewable generation during overgeneration periods and procuring additional MWh at the levelized cost of electricity (LCOE) of a new combined cycle gas turbine (CCGT) plant during peak period. CCGT utilization assumed at 30–50%. Includes a carbon price of $50/metric ton to penalize renewable curtailment.
[2]Represents the cost of curtailing renewable generation during overgeneration periods and procuring additional MWh at the LCOE of a new peaker plant during peak period. Peaker utilization assumed at 8–10%. Includes a carbon price of $50/metric ton to penalize renewable curtailment.
[3]Assuming a 5-hr duration battery with ~85% roundtrip efficiency and 5,000–10,000 cycles of useful life.
[4]Cost of load shifting includes cost of automated demand-response equipment as well as customer-acquisition costs and customer incentives.
[5]Includes additional cost of smart electric-vehicle charger and associated customer incentives.

**Source:** McKinsey analysis

penetration of renewable generation. Following the California Public Utility Commission's 1.3 gigawatt (GW) storage target in 2013 (supplemented with an additional 0.5 GW target in 2017[10]), several states set aggressive storage goals: Massachusetts has a 200 MW target by 2020, New Jersey recently announced a 600 MW goal by 2021 (and 2,000 MW by 2030), and New York has defined a road map to 1,500 MW by 2025. Responses to recent requests for proposal for renewable projects often come bundled with storage. Even conventional generation is looking at co-located storage to optimize dispatch to improve economics and performance of traditional natural gas, coal, and nuclear units.

Battery storage is new and interesting for the same reason other advanced technologies driving change in the electricity business—cloud computing, big data analytics, and two-way digital meters—are exciting: they uncover new value-creation opportunities. Value stacking, the ability to combine multiple use cases for storage, is beginning to pencil out. Storage is being used to defer investments in the T&D systems of some utilities. Storage also can be used to get around system constraints: battery-storage projects kept the lights on in Southern California when the Aliso Canyon gas-storage facility was closed.

Distributed energy resources (DERs) have made their mark on utility integrated resource plans (IRPs). Coming right behind DERs are DRAs, an emerging resource category too-often overlooked in the United States. Aggregation pilots are taking place across the country, with companies like Stem and Advanced Microgrid Solutions working on DER aggregation projects. Distributed-energy-resource management systems (DERMS) are being adopted from leading utilities across the world, as tools to monitor, oversee, and even help control DERs offering services to the grid. As the landscape of DERMS providers matures, the capabilities of these systems will extend to active, real-time dispatch and measurement of DER assets, further facilitating the role of DRAs.

Though DRAs are still early in the adoption cycle, regulators are starting to realize the value this category of resources could bring as the electricity business evolves into a decentralized basis from a centralized, generation-centric basis.

We see a future where DRAs operate in energy and capacity markets in regional transmission organizations (RTOs) and independent system operators (ISOs). As customer charges evolve to include the cost of flexibility, a new class of services emerges for energy assets that can respond at the right time and the right location in the grid.

The role of the customer also is evolving as large commercial and industrial enterprises explore ways to use their energy assets beyond offsetting volumetric charges and toward providing grid-flexibility services. As shown in Exhibit 2 automated control of customer load, inclusive of customer incentives and customer acquisition, can be a cost-competitive source of load-shifting flexibility even today, frequently cheaper than the generation alternative.

The evolution of technology and provider business models is finally facilitating this new role for distributed resources. The proliferation of smart meters is providing utilities and providers with access to customer data and enabling seamless measurement and verification of the customer demand-side response to grid-operator needs. Providers such as Ecofactor, OhmConnect, and Stem can now more easily acquire and onboard customers to demand-side aggregation programs, addressing one of the industry's perennial hurdles: high customer-acquisition costs. Advances in digital tools for customer engagement and targeting will only further facilitate this trend.

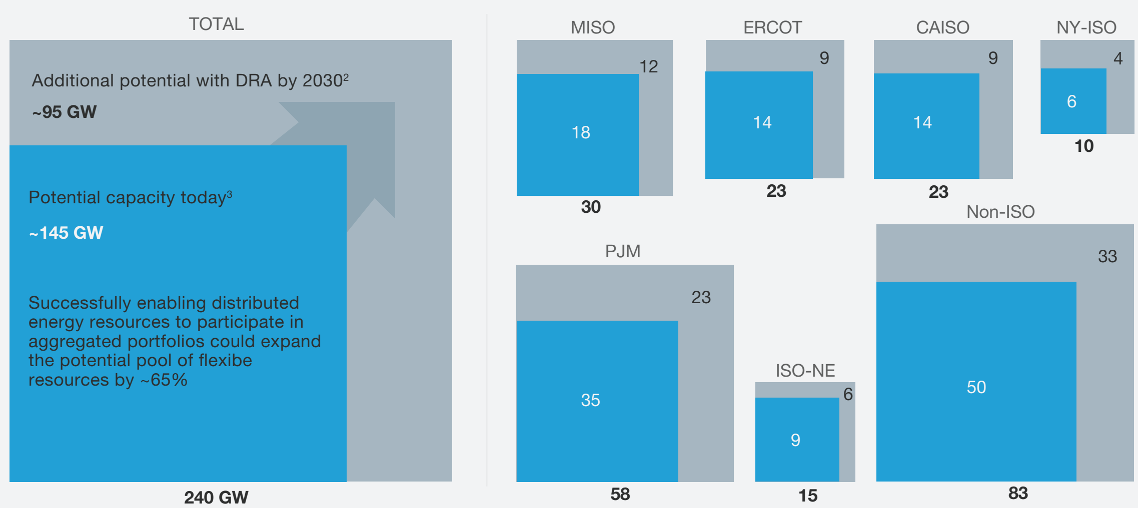
Regulators are also adjusting to enable DRAs more meaningfully. Reforming the Energy Vision in New York has explicitly stated a goal of increased customer and third-party participation in energy markets and has created the foundation of a distributed system platform to support this goal. In the United Kingdom, the National Grid's Power Responsive Initiative has set an objective of increased participation of new flexible resources, such as DERs and storage.

We expect the potential of distributed resources to support the grid will be significant. Exhibit 3 shows the cumulative potential to provide short-term flexibility services by type of resource. A total of 145 GW of technical potential are available today, and an additional 95 GW can become available by 2030 as DER-adoption scales and market rules for DRAs improve, for a total of 240 GW.

Of course, not all of this technical potential will be realized, limited by customers' willingness to participate in aggregation programs. According to a survey of 400 customers familiar with demand response and aggregation concepts, 30 to 50 percent of commercial and industrial customers exhibit interest in participating as part of a broader aggregated portfolio of resources in energy markets, while 35 to 60 percent of owners of DER assets have expressed interest in participating in a capacity-aggregation program. If we adjust the 240 GW of technical potential for approximately 30 percent participation, a total of nearly 70 GW of flexible capacity, equivalent to approximately 7 percent of US electricity demand, could be available to address the grid's flexibility needs.

**Exhibit 3** Enabling distributed resource aggregation (DRA) to fully participate in markets could unlock about 95 gigawatts of new potential flexible capacity in the United States by 2030.

**Flexible capacity for distributed resources across independent system operators (ISO),**[1] GW




[1]Potential not actual capacity numbers. Actual adoption of distributed flexible resources is lower than the potential. 2017 numbers are: ~9.2 GW of distributed resources (DR) in PJM (2017 delivery year), 0.85 GW in ERCOT (2017 essential-reliability-services demand response), 1.5 GW in CAISO (2017 estimate of dispatchable DR resources, including the demand-response-auction-mechanism program), 0.6 GW in MISO (2017 estimate of demand-response-resource (DRR) type I and DRR type II), 0.35 GW in ISO New England (includes only actively dispatched resources and not passive energy efficiency in the OnPeak program) and an estimated 8.0–12.0 GW in non-ISO regions.
[2]Assumes that rules favorable to distributed resource aggregation are instituted: no minimum size requirements, no minimum dispatch duration, no limits to the type of resource.
[3]Potential today is limited by the types of resources that can participate (eg, minimum size, duration for which each resource needs to dispatch, telemetry and measurement requirements).

McKinsey&Company | **Source:** McKinsey analysis

## Action to consider in four critical areas

As technological improvements and the new operational realities of a renewables-based electricity mix create opportunities for new types of resources, it is important that market designers, market participants, and policy makers take part fully in the market's evolution. Here are four clusters of issues we believe could be addressed so that storage and DRAs can play their appropriate roles in a low-cost, lower-carbon electricity business.

### Create new services to meet new realities

As energy-imbalance issues manifested in European markets with high renewables penetration (for example, Germany and the United Kingdom), these providers have grown beyond the traditional demand-response-provider model to offer new flexibility services. For example, in Europe, electricity markets in Germany and Belgium recognize the ability of independent market actors known as balancing responsible parties (BRPs) and balancing service providers (BSPs) to submit aggregated energy schedules and balancing services from a set of aggregated resources under their control. This has given rise to what is referred to as "virtual power plants," which are in the forefront of the flexibility landscape.

Through this construct, providers such as NextKraftwerke (over four GW in managed load) have been able to balance the intermittency of large-scale renewables that they manage with the flexibility of distributed energy assets (such as onsite generation) and load resources (such as large commercial and industrial facilities). However, this requires sophisticated software, bidding, and verification programs. In the United States, it would also require a significant amount of regulatory and market transformation to enable full participation.

### Improve integration at the T&D interface

There is insufficient regulatory clarity regarding the oversight of resources connected to the distribution grid but participating in wholesale-level markets overseen by regional transmission organizations (RTOs) and independent system operators (ISOs). The policy framework is often disjointed, particularly when distribution assets provide wholesale-market services. The ability of these resources to create value is dampened by legacy rules, including the divergence and lack of integration between distribution and transmission markets. Furthermore, the metering, telemetry, and control standards for distributed resources participating in wholesale markets have not been seamlessly defined.

The paradigm of the distribution-system operator, frequently ascribed to electric utilities in the United States, has not yet evolved to seamlessly price, measure, verify, and manage electricity services from distributed assets. These operational "seams" issues require changes not only at the market and transmission-operator level but also often within distribution utilities themselves. With the wide range of capabilities and software, it may take a while for demand-side resources to be full participants in electric markets.

### Update legacy market-participation models and dispatch rules

Rules for participation in wholesale markets have not matured to allow a more expansive set of market participants beyond traditional generating plants. For example, market models and participating rules are not currently accounting for the physical characteristics of energy storage, such as its need to maintain adequate charge and discharge and its ability to potentially "stack" multiple types of products (for example, capacity and frequency regulation).

Furthermore, by guaranteeing "out of market" payments, such as in the case of "make-whole" payments for curtailments of renewable generation, market rules are in many occasions not exposing inflexible resources to their true market risk. On top of that, market operators have been reluctant to explore innovative market designs, such as load-shifting and ramping services.

However, there are early indications that markets are responding. FERC has already approved Order 841, mandating that market rules evolve to accommodate the characteristics of energy storage assets and that market mechanisms evolve to allow storage to more fully participate. In an effort to prepare for California's high renewable future, CAISO is already experimenting with a load-shifting product and has already instituted payments for a flexible ramping product. The regulatory framework is starting to be created, though different organizations are proceeding at different speeds.

### Recognize separate roles for flexibility services and resiliency

"Resiliency" has been a topic of much discussion in the electricity business over the past year. As yet, there is no accepted definition of resiliency, though steps are being taken to define this elusive term.

It is worth noting that while storage and demand-side resources are working to change the rules and allow for their fuller participation in energy and intraday capacity markets, they also should recognize importance of security and backup. Distributed resources potentially contribute to grid resiliency by providing localized backup during grid outages and emergencies. Nevertheless, there could still be a unique role for conventional resources in providing grid resiliency and backup that these new resources might be unable to offer.

Aggregated distributed resources and storage are resources that ultimately shift energy and can help a grid operator better manage daily capacity needs and peaks. However, those resources cannot deliver multiday or seasonal capacity. Resources that back up the renewables on the system will need to also develop unique market services that identify and monetize their contribution to grid reliability.

Storage and demand-side resources could potentially strike a compromise in obtaining access to energy and flexibility services by supporting, rather than fighting, some of the conventional players.

### Steps market participants could consider

Here are potential solutions that market stakeholders can explore to speed the transition to a lower-carbon electricity industry.

### For utility decision makers

- Expand the scope of the grid-planning process to consider nonwire alternatives to grid-capacity expansion. T&D planning in the future should consider both utility-owned plants, including utility-owned storage, as well as competitive solicitations of third-party aggregated distributed resources.

- Evolve the utility model into a platform for grid products and services. The value of the distribution grid will be enhanced when it acts as the access point for a landscape of distributed resource aggregators providing services to the transmission grid. Regulated distribution utilities could offer a layer of measurement and verification, customer acquisition, and DER management services to third-party providers—leveraging their extensive smart meter, communications, IT infrastructure, and operational-technology infrastructure.

- Redesign utility information and operations technology with an eye toward integrating millions of distributed resources through distributed-energy-resource management systems (DERMS). These systems should be able to track, monitor, and facilitate the control and management of DERs, providing essential grid-balancing services. DERMS should also be integrated with critical utility processes, such as distribution management systems and grid planning.

- Innovate in rate design. Utilities and their regulators should explore more flexible and cost-reflective rate-design options, encouraging customers to shift consumption toward times of the day when renewable energy is abundant and enabling owners of distributed energy resources to enhance the value of their assets by responding to grid needs. Time-varying rates (such as the California solar time-of-use policy,[11] enacted in 2017) and locational DER rates (such as the Value of DER rule in New York, announced in 2017) are steps in that direction.

## For market participants

- Rethink power purchase agreements (PPAs) and risk allocation. Renewable-energy providers need to face increasing market risk, such as more mandated curtailments or negative prices. As long-term PPA contracts become less common, the management of long-term risk allocation between the developer and the power purchaser increases in importance.

- Create hybrids. Providers might increasingly see value in balancing their renewable-energy projects with flexible assets such as energy storage or demand-side aggregations. Synergies in equipment siting and permitting as well as engineering and procurement costs could drive significant value in renewables and storage projects.

- Prepare for increased volatility. The value associated with sophisticated trading operations has seen a decline as price volatility flattened. In high-renewable environments, a period of high volatility is upcoming. As market participants face new types of risks, understanding electricity markets and managing price risk are likely to represent new opportunities.

- Invest in automation. Automatic monitoring, market participation, and dispatch of diverse asset types, ranging from front of the meter to behind the meter, are necessary elements for a winning strategy as this new landscape emerges.

- Recognize the value of diverse resources. Renewable developers should advocate for large interconnected markets and should support resiliency and reliability payments to the backup generation necessary to maintain the performance expectations of customers.

## For policy makers

Policy makers are pushing the boundaries of existing policy and frameworks to deal with these challenges. In a number of geographies, there are new ideas being developed, including the enactment of rules favoring aggregated resource participation in market constructs consisting of combined transmission-level and distribution-level assets. For example, recent PJM rules favoring participation of intermittent and seasonal resources as aggregate capacity resources in the PJM's 2020 to 2021 capacity auction are opening up that market to a wider set of resources. European markets are a step ahead of this, with their emphasis on BRPs and BSPs.

FERC has signaled its intent to move in a similar direction, with its notice of proposed rule-making on DER aggregation. This development is slated to allow DER aggregation to participate in ISO and RTO markets and to remove barriers for distributed resource aggregation.

Regulators are also creating new markets for flexibility services. As the cost component associated with flexibility increases, regulators could increasingly consider instituting market mechanisms that will minimize out-of-market payments and will increasingly enable third-party-provider access. There are several types of new flexibility services that are being introduced:

- Load-shifting services that give incentives for moving demand to periods when renewable-energy sources are abundant. The load-shifting service under development by CAISO is an example. This concept already has been investigated in Europe (for instance, through the Demand Turn Up market in the United Kingdom).

- Primary-frequency-control products that offer incentives for the participation of fast-response assets that can balance the grid with response times lower than five seconds. These include the Fast Frequency Response and the Enhanced Frequency Response markets in the United Kingdom and the primary-frequency-control reserve markets in Belgium and Germany, all of which allow demand-side participation.

- Secondary and tertiary control products that balance longer-term fluctuations relating to forecast errors in wind and solar resources, such as the ones frequently exhibited in high-wind environments.

- Separate markets for resiliency and reliability services that cover system-backup and resiliency needs.

- Evolution of rigid renewable-portfolio standards to integrated-resource-planning (IRP) approaches that account for the total cost of a resource portfolio and assign procurement targets for renewable assets as well as associated investments that will enable them. Frequently, a balanced mix of resources (for example, wind and solar) lead to reduced flexibility needs. As renewable targets increase, the reliability and resiliency impacts should also be co-optimized in an IRP process.

- Rules that accommodate assets that cut cross the electric-power value chain: as storage and DER aggregations can offer distribution and generation-related services, existing regulatory frameworks are likely to face new challenges. State regulators and federal authorities are likely to find themselves jointly regulating assets that can “stack” multiple sources of value across the value chain. Policy makers are pressed to consider rules that govern the interface between transmission-system and distribution-system markets.

## Laying the foundations for a lower-carbon future

In ten years, we expect that market participants—and customers—will look back and see the current turbulent but exciting time of industry transformation as forming the critical foundations for a dramatically different, lower-carbon, more efficient, and highly decentralized electricity business. The framework that will emerge from today’s discussions could shape the industry’s future as dramatically as the Federal Power Act, the Public Utility Regulatory Policies Act, or the Energy Policy Act of 2005. ■

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[1] “Nearly half of utility-scale capacity installed in 2017 came from renewables,” U.S. Energy Information Administration, January 10, 2018, eia.gov. These sums do not include smaller-scale renewables (for example, rooftop solar) that came online in a given year.

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