Sandia National Laboratories

ISSUE BRIEF
Energy Storage & Resource Adequacy

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ABSTRACT:
The concept of resource adequacy (RA) is not new. Within the energy and utilities (E&U) sector, it has been a topic within regulatory and legislative discussions, and a basis for grid planning, for decades. In fact, RA has been a primary topic in regulatory proceedings since the early 2000s when blackouts in California prompted new considerations of how to ensure that markets have electricity-generating resources in the right places at the right times to balance supply and demand and, in real-world terms, "keep the lights on." That is no easy task, and RA assessments can in turn shape resource investment decisions for decades to come.

While RA is a well-established concept, what is comparatively new is the extent to which "clean power"—whether it originates from renewable energy or distributed energy resources (DERs), including energy storage systems (ESSs)—are playing more prominent roles in contributing to RA needs. The impact that these alternative resources are having is profound. No longer is RA a straightforward process of determining a specific amount of generation that is needed to meet a static load. The proliferation of renewables and DERs create new opportunities but also new complexities, both operationally and from a policy perspective, which in turn require new approaches, new methods of analysis, and considerations of how legacy policies are no longer appropriate. Indeed, existing policies at both the federal and individual state level require reconsideration to enable such alternative energy sources to contribute to RA needs to the extent they are presently able.

The topic of policy and operational reforms specific to RA has a direct impact on the energy storage sector and the opportunities it will have to contribute to RA solutions going forward. Energy storage can play a significant role in meeting demand at both the wholesale and retail levels but will only achieve its full potential if legacy practices in the E&U sector that have existed for decades are reconsidered. The purpose of this **ISSUE BRIEF** is to summarize the policy and operational considerations when considering the relationship between RA and energy storage.

WHAT IS RESOURCE ADEQUACY?
RA is a primarily a regulatory concept. In practical application, RA policies shape the creation of rules that govern grid planning at both the federal and individual state levels and are germane to wholesale and retail markets, respectively. RA—sometimes referred to "capacity accreditation"—has been emphasized in various regulatory jurisdictions to ensure that sufficient resources will be available when and where they are needed to match supply with demand. "RA assessments" or "RA planning" both refer to the processes that are used to ensure that electricity resources will be available to meet demand *after* taking into consideration an array of factors (e.g., demand forecasts, transmission constraints, the known availability or unavailability of generators, predictable and unpredictable weather patterns, etc.). Put into the simplest terms, it may be helpful to see the analogies between RA and putting cash into a bank for potential future needs or taking out an insurance policy to prepare for events that may not ever occur.

Until recently, the ways in which RA has been managed have followed some fairly consistent patterns, despite geography or which entity is managing the process, First, load requirements for a specific region are determined based on a number of factors, including population growth profiles, historic data on prior outages, weather patterns, etc., along with factoring in occurrences such as unexpected generator outages and fluctuating load. Establishing load requirements is a necessary first step toward guaranteeing that grid operators have adequate resources at their disposal to meet demand at any given time, particularly when demand peaks occur due to critical factors such as extreme weather conditions, a data point that has grown increasingly important in direct correlation to the amount of renewable resources that are to be relied upon. Determining load requirements is used both wholesale and retail environments.

The process of determining load requirements provides a foundation for identifying what is referred to as the necessary planning reserve margin (PRM) that a region will need to have in place to ensure reliability. A PRM is usually defined as the difference between available capacity and peak demand, with peak demand used as the high-end estimate of load forecasts. A PRM is used to determine the amount of generation supplies that will be needed (and be available) to meet expected demand in specific time periods. When paired with various forms of modeling and probabilistic analysis, calculating a PRM has been an industry standard used by grid planners for decades. It is typical to see regions establish a PRM in the range of 15 to 18 percent, which acts as a safety net over forecasted demand.

Determining load requirements and reserve margins is a complex process, and usually relies upon a suite of modeling tools that can run thousands of hourly scenarios with differing impact considerations. Despite varying levels of complexity, the most significant variables that are used to simulate real-world conditions and determine RA needs are weather patterns, load forecasts, and generation outages. These variable inputs are modeled under numerous hypothetical scenarios to ultimately determine the necessary reserve margins that form the foundation for subsequent RA policies. Grid planners have often forecasted reserve margins based on peak load scenarios, operating on the assumption that procuring supplies needed to meet the highest levels of anticipated load is the simplest way to ensure RA requirements.

Regardless of the calculation methodology that is used, once the load requirements and PRM are established, grid operators enter into binding contracts with electricity suppliers, often with terms that can run years into the future. These contracts obligate suppliers to provide needed resources that can be called upon on a moment-by-moment basis. In vertically integrated, non-restructured markets, a regulated investor-owned utility (IOU) typically has the responsibility of securing the required supplies to meet the load requirements for the regions in which they are the designated load serving entity (LSE). In restructured, competitive markets it is typically a regional transmission operator (RTO) or independent system operator (ISO) that engages in contracts with suppliers, or otherwise secures necessary resource through a centralized auction platform. In either scenario, the process of securing required supply is referred to as RA planning.

Traditionally, RA planning has been driven by economic considerations. In other words, when determining the resources that will be needed to provide the required reserve margins, such planning decisions have usually been based on the lowest-cost bid submitted by energy suppliers. Using cost as the primary metric has also enabled comparisons between supply solutions and other reliability initiatives such as upgrades to distribution and transmission (D&T) infrastructures.

HOW ARE RA MARKETS REGULATED?

Both federal and state regulators have a role in the regulation of RA and RA-related issues. The line between jurisdictional oversight can often seem unclear because multiple entities facing regulatory oversight from distinct agencies are potentially involved. In a vertically integrated scenario, which was the norm prior to the emergence of restructuring that took place in the late 1990s / early 2000s and is still in place in some regions of the U.S., as noted above typically IOUs have responsibility to either self-supply or procure sufficient resources from other suppliers, and those decisions are regulated by a state public utility commission (PUC).

Within state regulatory environments, procurement of resources typically occurs through bi-lateral contracts established between the IOU/LSE and the supplier, if the IOU/LSE is unable to fully self-supply. Again, these contracts require approval from the state PUC. RA can also be addressed in other regulatory proceedings, including the review of integrated resource plans in which IOUs articulate detailed plans to secure adequate resources, often a decade in advance. The important point here is that, in those environments in which IOUs are vertically integrated and maintain responsibility for procuring adequate supplies to meet demand, state-level regulatory oversight remains primary.

At the federal level, as a central part of the restructuring process that has occurred in many areas of the U.S., wholesale markets were formed on a regional basis.[1] These regional wholesale markets, regulated by FERC and managed by RTOs/ISOs, were created to enable markets for wholesale transactions whose initial purpose was to maximize revenue opportunities for energy suppliers and in that sense originated as “energy markets.” In other words, economics were the original catalyst for the RTO markets and managing reliability or RA planning was not the original focus. Considerations of reliability and the creation of capacity markets (discussed below) came after the initial formation of the ISOs/RTOs.

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[1] FERC Order 2000, issued in December 1999, laid out the general principles around which RTOs should be developed. The Order also outlined four minimum characteristics for RTOs: 1) Independence from market participants; 2) Appropriate scope and regional configuration; 3) possession of operational authority for all transmission facilities under RTO control; and 4) exclusive authority to maintain short-term reliability of the grid. Functions of RTOs were also established in FERC Order 2000 as follows: tariff administration and design; congestion management at the wholesale level; market monitoring; and responsibility for planning and expanding facilities under its control.

There are nine ISOs/RTOs operating in North America, and seven in the U.S.[2] RTOs and ISOs are similar but also have important differences; typically an RTO coordinates, controls, and monitors a multi-state electric grid, whereas an ISO typically coordinates, controls, and monitors the operation of the electrical power system within one state (there are exceptions, namely the New England ISO). Although these differences are important, but for simplicity sake, references to RTOs only should suffice in this **ISSUE BRIEF.** RTOs and ISOs both fall under the regulatory jurisdiction of FERC, although an exception is ERCOT, which does not extend beyond the state of Texas and therefore is not subject to FERC jurisdiction.

In its oversight role, FERC does not set RA requirements and is in fact prohibited from doing so under the Federal Power Act Section 215. Nevertheless, FERC is directly involved in RA due to its regulation of the nation's RTOs. RTOs have been established to make determinations of resource needs based on transmission system reliability, wholesale market efficiency, and opportunities for suppliers to be compensated fairly. It is the often the RTO that has the authority to set the minimum quantities of capacity that will be needed to be procured, but the RTO needs to have these minimum capacity quantities approved by FERC. Through this review and approval process, market signals are established that influence the balance of resources within an RTO and whether contracted resources for RA are comprised of coal and nuclear plants, new gas plants, or carbon-free technologies.

There is not a uniform approach toward RA that is commonplace among the RTOs, and therefore it is difficult to make broad generalizations. Nevertheless, restructured electricity markets run by RTOs feature payments for capacity in addition to day-ahead/real-time energy and ancillary services. The use of capacity markets (discussed in greater detail below) and use of an auction process has become well established since the RTOs were first established. An auction process is the platform through which multiple suppliers submit bids to provide resources within specified time frames and are approved or rejected by the RTO. There are important exceptions to this approach (e.g., the California ISO, which is discussed in greater detail below).

Regulation of the RTOs by FERC has huge implications. Most pertinent at this time is the continuing efforts by the RTOs to comply with FERC's Order 841, which was issued in 2018. Order 841's scope extends well beyond the RA topic, but is directly relevant to the extent that it requires the RTOs to "level the playing field" for the participation of energy storage in wholesale market transactions. Compliance with the order is resulting in the revision of existing tariffs for wholesale transactions in RTO markets.

RA policies at the federal level often bump up against state policies, and vice versa. For example, the minimum capacity requirements set by RTOs and approved by FERC can have ripple effects into states as regulatory commissioners impose reliability requirements at the distribution system level that are considered against regional requirements. For regulated utilities operating in states that are part of an RTO, uncertainty about what is the authoritative source of regulatory requirements (state PUC versus an RTO) may increase to frustrating levels. The degree to which a state can influence RA policies made at the RTO varies greatly. However, in extreme cases states that have minimal influence on RTO policies may consider leaving an RTO altogether.

RA & CAPACITY MARKETS

RA as a regulatory concept and the associated RA planning processes are intrinsically tied to the capacity markets that operate within RTOs, although these markets can be run quite differently. Whereas RA criteria are used to determine the resources that will be needed to meet varying levels of demand, capacity relates to anticipated resource deficiencies and supply contracts established to address those deficiencies. Capacity markets are related to but distinct from both energy and ancillary-services

[2] The nine ISOs/RTOs are:

- Alberta Electric System Operator (AESO) - ISO
- California independent system operator (CAISO) - ISO
- Electric Reliability Council of Texas (ERCOT) - ISO
- Midcontinent Independent System Operator, Inc. (MISO) - RTO
- ISO New England (ISO-NE) - RTO
- New York Independent System Operator (NYISO) - ISO
- Ontario Independent Electricity System Operator (IESO) - ISO
- PJM Interconnection (PJM) - RTO
- Southwest Power Pool (SPP) – RTO

markets. Energy markets involve the electricity (measured in *megawatt-hours*) that is sold and consumed in real-time by end-use customers, whereas capacity markets include purchases of power (measured in *megawatts*) far in advance of when it needs to be delivered. Ancillary-services markets involve an array of services related to grid stability and security and can include frequency regulation and control, spinning reserves, black starts, etc. Ancillary services generally account for a very small portion of market revenue.

Capacity can be purchased from days to years in advance, depending upon the nature of the RTO market. As with energy, capacity can be secured through ownership of a generating unit or through a bilateral contract or some other form of self-supply. Capacity can also be purchased through wholesale capacity markets operated by some RTOs. In either scenario, utilities that operate inside an RTO generally must meet the capacity requirements calculated for the utility by the RTO. At their most basic level, capacity markets in RTOs can be thought of as the mechanisms through which RA requirements are fulfilled.

Capacity can be offered from a variety of resource options, including renewables and DERs, but also new and existing generators; energy efficiency and demand response; T&D upgrades, etc. In most capacity markets, distinctions are not made regarding the resources included in the capacity offer (i.e., no distinctions made between fossil fuels and renewables), and no distinction is made between supply-side and demand-side resources either (i.e., power from a power plant is not distinguished from demand response resources that can also contribute to capacity offers). Instead, suppliers who own resources bid into a capacity market based on their total cost of operation. A clearing price is established based on this bidding process and is determined by the most expensive unit that is deemed necessary to meet demand. All power is then sold at this highest market clearing price to generators that bid to provide power at or below this market clearing price. This process can result in many distinct contracts between the RTO and suppliers until the RTO determines that enough capacity has been acquired to meet demand.

The seven ISOs/RTOs operating in the U.S. approach capacity needs and deficits in different ways. The following chart summarizes the ways in which RA is addressed within the seven U.S. RTOs. four of the nation's seven RTOs operate capacity markets. As discussed above, capacity represents a utility's obligation to have enough generation to meet customer demand at all times.

ISO/RTO	UNDER FERC JURISDICTION?	RA APPROACH	TRANSACTION FORMAT
California ISO	Yes, because the state's transmission lines connect to infrastructure in other Western U.S. states.	RA requirements, but no capacity market.	LSE's engage in bi-lateral contracts with energy suppliers to ensure that the capacity required by the CA-ISO is available. California also employs an Energy Imbalance Market (EIM), which operates in similar ways to a central clearinghouse for matching supply bids with demand.
ERCOT	No, because the transmission lines in the ERCOT region do not extend beyond the borders of Texas.	Energy-only / No capacity market. ERCOT does not fall under FERC jurisdiction.	Reserve margins are still used.
MISO	Yes, as the transmission networks of multiple member states transcend state borders.	Voluntary capacity market (referred to the "Planning Resource Auction"), which applies to the	MISO's capacity market operates several months in advance of any given planning year. This market is considered voluntary in that utilities are generally free to self-supply capacity and only use the market to purchase capacity needed for residual needs. MISO acknowledges that its member states have RA responsibility, but maintains that is shared

		northern region of MISO. MISO does not operate a capacity market in its southern region.	with the LSEs, FERC and MISO itself. In practice, MISO establishes RA requirements based on initial input from the states, and each LSE can meet the requirement through owned resources, contracted resources, or participation in MISO's voluntary capacity Planning Resource Auction.
New England ISO	Yes, as the transmission networks of multiple member states transcend state borders.	Mandatory capacity market	ISO-NE operates a mandatory capacity market, called the "forward capacity market," which procures capacity three years in advance. It is a mandatory market in the sense that all capacity used to meet required reserve margins must be purchased through a capacity market auction. Year-long commitments to provide capacity are procured through auctions held three years in advance.
New York ISO (NYISO)	Yes, because the state's transmission lines connect to infrastructure in neighboring states.	Mandatory capacity market	Mandatory in the sense that all capacity used to meet required reserve margins must be purchased through a capacity market auction. The ISO operates a shorter-term capacity market than in PJM and ISO-NE, but it is only mandatory within the New York City and Lower Hudson Valley zones.
PJM Interconnection	Yes, as the transmission networks of multiple member states transcend state borders.	Mandatory capacity market	PJM's capacity market is referred to as (known as the "Reliability Pricing Model") as an example, but most capacity markets work in a similar way. Mandatory in the sense that all capacity used to meet required reserve margins must be purchased through a capacity market auction. • Annual auction (referred to as a "Base Residual Auction") for deliveries three years in advance. • Smaller, balancing auctions (referred to as Incremental Auctions") that are held in advance of delivery dates so that adjustment to capacity needs can be made. PJM operates a three-year forward mandatory capacity market, called the reliability pricing model. In December 2019, FERC decided to dramatically expand PJM's capacity market's MOPR, greatly restricting public power's self-supply ability and state efforts to procure renewable resources or prevent nuclear plants from retiring.

Southwest Power Pool (SPP)	Yes, as the transmission networks of multiple member states transcend state borders.	RA requirements, no capacity market	SPP transitioned to a full RTO with both a day-ahead and real-time market in March 2014, but has not implemented a capacity market.

Unlike pure energy markets, several RTO capacity markets (ISO-NE, PJM, and NYISO) also include mechanisms that influence how capacity is priced, such as minimum offer price rules (MOPR) in PJM and buyer-side mitigation (BSM) rules in the NY-ISO (both discussed in greater detail below). Some of these mechanisms have created conflicts between pure-play economic transactions that are customary in RTO markets and subsidies provided at the state level for renewables, DERs and other demand-side solutions that impact the market clearing price.

Nevertheless, data from the North American Electric Reliability Corporation (NERC) show that the three U.S. regions with capacity markets have some of the largest surpluses of generating capacity. For instance, the ISO-NE has a reserve target of 17.9 percent, but forecasts estimate the region's PRM to be between 27 percent and 40 percent. Similarly, PJM has a target reserve of 15.7 percent but is projected to have a 34 percent reserve margin at minimum, and it could be as high as 70 percent.

RA & ENERGY STORAGE

Given that RA is a well-established concept, it might be assumed that RA practices are also well defined, but that would be the wrong assumption to make. Despite the fact that RA has been a prominent regulatory concept since the early 2000s, and that some capacity markets were formed soon thereafter, what is changing, and changing at a rapid pace, are the variations among the resources that comprise the required supply.

Historically, RA planning relied on traditional resources such as coal and natural gas. These resources have been viewed as being particularly reliable during peak periods when compared to renewable resources that are inherently intermittent due to weather factors that can be frustratingly unreliable. However, as a result of multiple market factors previously mentioned (e.g., falling prices, improved technologies, enabling policies at the state level) in the last five years nearly half of new capacity added to RTO markets has been from renewable resources with intermittent production (i.e., solar and wind). Demand response resources have also earned a substantial market share in capacity markets in the last five years.

Despite this increasingly prominent role that renewables are playing in RA policy discussions, from a practical standpoint the extent to which renewables can be relied upon to meet supply requirements is a separate consideration. This is the market entry point at which ES technologies become particularly relevant and a necessary component. Adding an unprecedented (and large) amount of renewables onto the grid to meet RA requirements, while simultaneously removing traditional resources off the grid, requires major changes in power system planning fundamentals. Grid operators who are witnessing in real time how market forces are driving more fossil-based plants offline are justifiably concerned about how power supply that is increasingly comprised of intermittent resources may not have the capability of being dispatched at will. Periods of risk are no longer isolated to peak loads but instead may be shifting to extreme weather events that exacerbate the intermittency of renewables.

ES, or at least some ES technologies, have assumed a place among a suite of options now available to address system-wide RA, evaluated against existing peaker generators, demand response strategies, and T&D upgrades. In addition, the relationship between ES and renewable forms of energy such as solar and wind is becoming increasingly better understood, and this means ES is increasingly being positioned to participate in most of the existing energy, capacity and ancillary services markets within the ISO/RTOs, along with being included in state-level initiatives that address reliability at the distribution level. The result is that ES technologies are expected to play an ever-greater role in RA contracts, correlated with the ever-greater role that renewables will play. Failing to address outdated RA models and policies may perpetuate existing barriers that preclude ES technologies from contributing to RA needs to the extent they are presently able and will be able in the future.

Another factor that is proving to foster the role of ES in RA solutions is that capacity needs are also evolving. Some capacity shortfalls may be made up of frequent but short-duration events, which batteries can ideally support. Other capacity needs that result from unpredictable but long-duration events can also be served by battery technology as duration levels increase. The quick ramp-up ability of battery storage technologies is also appealing when compared to baseload resources that may not be as flexible or able to respond as quickly. Of course, ES is still not economically justified in all cases, but pairing energy storage with solar offers a more economic approach and solar + storage applications are increasingly used to match supply with demand during periods of extreme RA needs.

CASE STUDY: RA IN CALIFORNIA

As is frequently the case, California was one of the first states to create an RA program. The need stemmed from what has been generally referred to as the "California energy crisis" of the early 2000s, in which widespread outages drove policy changes that required the state to ensure that necessary power resources would be identified and guaranteed to be available on a year-ahead basis. Now nearly 20 years in existence, the maturity of California's program provides the opportunity to evaluate key policy and operational issues from which other states can learn and, through proactive measures, develop sound policies in their own regions. For instance, California's RA market was established long before cost reductions in renewable resources established them as feasible alternatives to more traditional resources.

RA in California involves both the CPUC and the CA-ISO, which is regulated by FERC. The CPUC adopted a RA policy framework back in 2004, which placed RA obligations applicable to all LSEs within the CPUC's jurisdiction: IOUs, energy service providers (ESPs), and community choice aggregators (CCAs). The RA framework requires that LSEs procure capacity so that sufficient capacity is available to the CAISO when and where it is needed. California does not have formal capacity market, but instead addresses RA needs through the CPUC program. The CPUC's RA program contains three distinct requirements: system RA requirements, local RA requirements, and flexible RA requirements.[3] As previously stated, California's RA market is based on bi-lateral contracts established directly between LSE's and power suppliers.

Just recently in June 2020, the CPUC adopted a "central buyer" framework that puts two of the state's IOUs (PG&E and SCE) in charge of managing local RA, which in this case relates to the resources needed for grid reliability in the Los Angeles and San Francisco Bay Area regions. At this time, the CPUC has not yet approved an RA framework for the San Diego area, for which SDG&E would serve as the central buyer.

The CA-ISO also recently amended its tariffs to allow aggregations of DERs to participate in its markets. Currently, DERs like local renewables + storage — generally referred to as hybrid resources — are barred from participating in California's RA market. The CPUC has declined to count such "behind-the-meter" systems for RA for now, despite ongoing calls from distributed generation supporters asking it to do so. The barrier to their participation is entirely regulatory, not one of technical capability or cost. Meanwhile, more than 30,000 MW of DERs and renewables are in CAISO's interconnection queue with no path to market. In June 2020, the CPUC decided that in the future, suppliers must identify generation resources included in their RA bids, but the barrier aggregated DERs remains.

CASE STUDY: RA IN NEW YORK

New York is an example of where conflicts between federal and state regulatory policies are become increasingly apparent. For context, RA was historically under the sole domain of the New York Public Service Commission (PSC) through its regulation of the state's vertically integrated utilities, but that paradigm changed when the state's electricity market was restructured and the New York ISO was created, which now oversees RA.

As noted above, NYISO's capacity market employs "buyer-side mitigation" (BSM) rules that requires renewables and DERs to comply with administratively determined minimum bids that are likely to be too high to allow them to clear the market. The conflict arises due to inconsistencies between NYISO market rules and clean-energy policies adopted by the PSC and New York Legislature, namely the state's Climate Leadership and Community Protection Act (CLCPA), which requires that New York get 70 percent of its electricity from renewables by 2030 and reach 100 percent zero-carbon emissions by 2040, which in turn has led to PSC requirements that regulated utilities in the state procure 6 GW of distributed solar by 2025, 9 GW of offshore wind by 2035, and 3 GW of energy storage by 2030. Due to the BSM rules in place at the NY-ISO, however, in practice renewables and DERs are essentially restricted from participating in the state's capacity market.

The NY-ISO has applied to revise the existing BSM rules to allow wind, solar, batteries and other carbon-free resources to compete against fossil-fueled power plants in its capacity market. Further, the New York PSC has sought to secure an exemption

[3] These are defined as follows:

- System Capacity: These requirements address peak load when California uses the most electricity. The exact requirements are determined by forecasting the next year's peak load and adding 15% just to be safe.
- Local Capacity: These requirements address local areas during grid emergencies.
- Flexible Capacity: These requirements fluctuations in load patters associated the increase of renewables (e.g., the "duck curve" phenomenon in California). These requirements vary greatly across different time periods.

for energy storage resources from NYISO's BSM rules, arguing that the rules are in direct conflict with the CLCPA and requirements for energy storage included therein. However, FERC has denied those propose revisions, ruling that the NY-ISO has not provided sufficient justification for "prioritizing the evaluation of public policy resources [i.e., clean energy resources] before non-public policy Resources [i.e., fossil fuels] independent of cost."

In response, the New York PSC has also started a process to examine the pros and cons of remaining under a FERC-regulated capacity market (the NY-ISO) versus a state-operated market for bilateral contracts between load servers and capacity sellers. If the PSC were to continue down this path toward exiting the NY-ISO, it could lead to developing a system similar to California's RA framework in which utilities engage in bi-lateral contracts with energy suppliers.

CASE STUDY: RA IN PJM

Issues that have surfaced in the PJM capacity market are similar to issues being addressed in the New York ISO. Just as the NY-ISO has its BSM rules, PJM rules include what is referred to the minimum-offer price rule (MOPR) that is applied to capacity auction participants, including new energy storage participants (but exempting existing storage resources). The MOPR, which was confirmed in FERC's December 2019 response to PJM's Order 841 compliance filing, requires that nuclear and renewable resources that receive subsidies from state programs still must bid into the capacity markets at the established minimum price, which may not economically "pencil out" against the minimum price floor that would likely be set by more traditional resources that don't receive state subsidies. In other words, the impact that the MOPR has on state-sponsored resources such as renewables and storage is that raises the prices for these resources, essentially eradicating any benefits achieved from the state programs.

PJM has attempted with subsequent filings to revise the MOPR based on the argument that its mandatory inclusion in PJM transactions is not a long-term durable solution for the market. However to date FERC has maintained the position, which was clearly articulated in its December 2019 response to PJM's Order 841 filing that the MOPR is needed in response to state policies that encourage renewables and DERs to ensure that state actions do not shape entry and exit through the capacity market. Maryland and New Jersey have been some of the most vocal critics of the MOPR and have looked into potential alternatives to the grid operator's capacity market, including a fixed resource requirement alternative. As of this writing the issue remains pending in PJM as multiple parties have filed official challenges to FERC's ruling.

ISSUE BRIEF ADDENDUM—
FERC ISSUES ORDER 2222

On September 17, 2020, FERC adopted final rules aimed at the further removal of barriers to the participation of DERs in RTO/ISO markets for electric energy, capacity, and ancillary services. Previous FERC rulings (namely Order 841) have opened wholesale markets to DERs in general. Order 2222 is intended to enable these resources to be bundled together into a single bidding entity, opening new possibilities and competitive opportunities. In this respect, Order 2222 can be seen as an extension of Order 841, which FERC issued in 2018. Compliance with FERC's Order 841 is an ongoing effort as RTOs/ISO continue to submit plans for FERC approval that include modifications to existing tariff structures.

Order 2222 carves out new policy specific to the "aggregations of DERs," a term that is defined as combined groups of small independent DERs participating in the RTO/ISO markets as a single resource represented by their aggregators. FERC has intentionally kept definitions of which DERs can participate as aggregated resources, referring to DERs broadly as "any resource located on the distribution system, any subsystem thereof or behind a customer meter." The open-ended definition is intentional as FERC seeks to foster a "technology-neutral" approach by prohibiting RTOs/ISOs from limiting the kinds of technologies that can join DERs aggregations.

Under Order 2222, regional grid operators must revise their tariffs to establish DERs aggregators as a type of market participant, which would allow them to register their resources under one or more participation models that accommodate the physical and operational characteristics of those resources. According to FERC, these aggregations will permit DERs to provide a variety of products and services that will compete with more conventional resources in RTO/ISO markets.

DERs can be located on the distribution system, a distribution subsystem or behind a customer meter. They range from ES systems and intermittent generation to distributed generation, demand response, energy efficiency, thermal storage and electric vehicles and their charging equipment. While the requirements of Order 2222 are listed at the end of this **ISSUE BRIEF**, it is also important to be clear on what Order 2222 does not do: the Order does not impose any limitation on the number of DERs that can be networked together. In other words, multiple DERs can be aggregated to satisfy minimum size and performance requirements that they might not meet individually.

Further, Order 2222 does not establish any minimum size requirements on individuals DERs. Rather, Order 2222 requires that DERs aggregations meet a minimum size specified by RTO rules, not to exceed 100 kW. FERC did require each RTO to propose the maximum size for any DERs participating in its markets through a DERs aggregation, above which a DER would be required to participate on an individual basis. In addition, Order 2222 provides flexibility in terms of the system location of DERs and DER aggregations, requiring RTO/ISOs to specify in their filings locational requirements that are "as geographically broad as technically feasible."

While Order 2222 attempts to remove regulatory barriers for the participation of aggregated DERs to participate in wholesale markets, at the same time the line between federal and state oversight may become unclear. On the one hand, Order 2222 prohibits retail regulatory authorities from broadly excluding DERs from participating in regional markets. Further, Order 2222 does not assert jurisdiction over the interconnection of DERs to distribution systems for the purposes of joining DERs aggregations and participating in RTO markets, which remains under state jurisdiction.

On the other hand, Order 2222 prohibits regional grid operators from accepting bids from aggregated DERs unless the relevant state regulatory authority allows such participation, and also acknowledges that state regulatory policy may prohibit some resources (for example, demand response) from being able to bid into regional markets by aggregators. What this means is that DERs aggregators will still need to navigate multiple regulatory frameworks and comply with both federal and state regulations before getting a green light to bid aggregated DERs into wholesale markets.

FERC acknowledges the potential for "double counting" DERs when they provide both retail/distribution services and wholesale/transmission services and within Order 2222 establishes that RTOs/ISOs are permitted to craft market rules limiting the participation of DERs where those resources receive compensation through other programs (such as those offered by distribution utilities) for providing the same services as they would to the wholesale markets.

Order 2222 will officially take effect 90 days after its publishing date (Sept. 17, 2020) and the RTOs/ISOs will need to submit within 270 days. The Order 2222 compliance filings required by the RTOs/ISOs must address the following:

1. Allow DERs aggregations to participate directly in RTO/ISO markets and establish DERs aggregators as a type of market participant;
2. Allow DERs aggregators to register DERs aggregations under one or more participation models that accommodate the physical and operational characteristics of DERs aggregations;
3. Establish a minimum size requirement for DERs aggregations that does not exceed 100 kW;
4. Address locational requirements for DERs aggregations;
5. Address distribution factors and bidding parameters for DERs aggregations;
6. Address information and data requirements for DERs aggregations;
7. Address metering and telemetry requirements for DERs aggregations;
8. Address coordination between the RTO/ISO, the DERs aggregator, the distribution utility, and the relevant electric retail regulatory authorities;
9. Address modifications to the list of resources in a DERs aggregation;
10. Address market participation agreements for DERs; and
11. Accept bids from a DERs aggregator if its aggregation includes distributed energy resources that are customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year.

Order 2222 has direct relevance to resource adequacy considerations as it opens the door for aggregated DERs to provide a full suite of services to RTOs/ISOs, including energy, capacity and ancillary services.

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