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TransActions

2022 Q1

MANAGING TRANSMISSION LINE RATINGS

FERC's ORDER NO. 881

On December 16, 2021, ***the Federal Energy Regulatory Commission ("FERC") issued Order No. 881 which finalized its proposed rulemaking from docket RM20-16-000.*** GDS Associates provided a summary of the proposed rulemaking in an earlier TransActions article and is providing this update with a summary of the final rule, including responsibilities for transmission providers and transmission owners. The final rule was published in the Federal Register on January 13, 2022, with an effective date of March 14, 2022. Transmission providers are required to submit their compliance filings by July 12, 2022, with an implementation deadline no later than July 12, 2025.

DEFINITIONS

FERC established the following final definitions for ambient-adjusted and dynamic line ratings:

Ambient-Adjusted Rating (AAR): ***"a transmission line rating that: (1) applies to a time period of not greater than one hour;*** (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (3) reflects the absence of solar heating during nighttime periods where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently; and (4) is calculated at least each hour, if not more frequently."

Dynamic Line Rating (DLR): ***"a transmission line rating that: (1) applies to a time period of not greater than one hour;*** and (2) reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating intensity, transmission line tension, or transmission line sag."

REQUIREMENTS FOR AARs

FERC ruled that transmission providers must use AARs for evaluating transmission service requests for transmission service that will end within the next 10 days. Also, transmission providers must use AARs as the basis for their determination of the necessity of certain curtailment, interruption, or redispatch of transmission service anticipated to occur within those 10 days. Transmission providers must keep seasonal ratings available as the default if

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Upcoming Conferences

MAY 10, 2022
EBA Annual Meeting & Conference
Washington, DC

MAY 22-25, 2022
NWPPA Annual Conference
Couer d'Alene, ID

MAY 25-27, 2022
MEPAV Annual Conference
Virginia Beach, VA

JUNE 12-15, 2022
APPA National Conference
Nashville, TN

UPCOMING WEBINARS

MAY 10
Electric Services for the EV Fleet

JUNE 14
Interconnection of Battery & Solar Systems

JULY 19
2023 NESC Sneak Peak

***Note** All webinars are recorded & available for viewing post-presentation* the forecast data is not available or there is a communications failure. These short-term ratings will therefore likely deviate from ratings utilized in the system planning process. Transmission Owners are ultimately responsible for developing the AARs.

If the equipment is affected by ambient air temperature, it requires an AAR. If it is not affected by ambient air temperature, an exception can be utilized consistent with good utility practice. AARs must incorporate a set of electrical equipment ratings that collectively operate as a single bulk electric system element (e.g., transformers, relay protective devices, terminal equipment, and series and shunt compensation devices) and that the most limiting component from that set determines the transmission line rating.

Ratings must be provided in a table or database format and cover the range of local historical temperatures +/- 10° Fahrenheit for the area where the equipment is located. Ratings must be provided in increments for every 5 degrees or less, but forecasting margin is allowed consistent with good utility practice.

FERC ruled that transmission providers must use seasonal line ratings for evaluating transmission service requests that will end beyond 10 days from the date of the request.

REQUIREMENTS FOR SLRs

FERC ruled that transmission providers must use seasonal line ratings for evaluating transmission service requests that will end beyond 10 days from the date of the request. Similar to AARs, transmission providers must also use ***seasonal line ratings (SLRs)*** when determining to curtail, interrupt, or redispatch transmission service beyond the next 10 days. SLRs must utilize at least 4 seasons that "reasonably reflect portions of the year where expected high temperatures are relatively consistent." Seasonal ratings must be recalculated at least annually using historical temperatures.

USE OF EMERGENCY RATINGS

Transmission providers must use uniquely determined emergency ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. These must incorporate adjustments for ambient air temperature and solar heating impacts and include the amount of time the equipment can operate at the higher current.

Transmission owners are allowed to develop the methodology for emergency ratings, but they must be calculated separately from normal ratings. However, emergency ratings must still consider ambient air temperatures and impacts (or the lack thereof) from solar radiation.

DECLINING REQUIREMENTS FOR DLRs & STUDIES

FERC declined to mandate DLR implementation like AARs and SLRs but did open a new docket to "further explore" in AD22-5-000.

EXCEPTIONS & ALTERNATE RATINGS

FERC will allow exceptions to the required AARs and SLRs if the transmission line rating is not affected by ambient air temperature or where a transmission provider an alternate rating is needed to ensure the safety and reliability of the transmission system. Exceptions must be reviewed every 5 years or less to determine whether it should endure.

REQUIREMENTS FOR RTOs & ISOs

FERC required ***RTOs/ISOs*** to establish and maintain the systems and procedures necessary to allow transmission owners in their regions to electronically update transmission line ratings on at least an hourly basis. TPs must also verify but not audit these ratings. Consistent with the NOPR, RTOs/ISOs must revise their dispatch and unit commitment models to implement AARs for both day ahead and real time markets and any intra-day reliability unit commitment or reliability assessment commitments.

TRANSPARENCY ENHANCEMENTS

Public utility transmission owners must share transmission line ratings and methodologies with their transmission provider(s) and with market monitors in RTOs/ISOs. Transmission providers must share their transmission owners' transmission line ratings and methodologies with any transmission provider(s) upon request. Transmission providers must maintain a database of their transmission owners' transmission line ratings and methodologies on the transmission provider's Open Access Same-Time Information System (OASIS) site or another password-protected website. Transmission providers must post on OASIS or another password-protected website any uses of exceptions or temporary alternate ratings.

WHAT ORDER NO. 881 MEANS FOR TRANSMISSION OWNERS

1 ***More data, equipment, and training.*** In order to comply with requirements for AAR calculations, additional data on ambient temperature, humidity, wind speed, wind direction and other factors will need to be captured in real-time. This will include field equipment, more granular weather/wind

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forecasting and modifications to SCADA to provide real time ratings for state estimation and ATC (Available Transfer Capability) calculations. Additional training will also be needed for system operators and operations support staff to ensure AARs are properly monitored in real-time and accounted for in short-term planning studies and curtailment protocols.

2. ***Revised methodologies, processes, and documentation for NERC (North American Electric Reliability Corporation) compliance.*** Updated rating methodologies need to be documented and should be ready for the July 12, 2022, Compliance Filing to ensure compliance with regional and NERC facility rating standards and FERC guidance from the NOPR. New facility ratings processes will need to be developed for AAR calculations. Other affected documents will include the Capacity Benefit Margin Implementation Document (CBMID) and Transmission Reliability Margin Implementation Document (TRMID). On the operations front, calculation of IROLs/SOLs will need to be reviewed and adjusted, as necessary.

3. ***Open Access Transmission Tariff revisions.*** Changes to line ratings inevitably impact the calculation of Available Transmission Capacity/Available Flowgate Capacity (ATC/AFC). The methodology for ATC/CBM/TRM calculation needs to be revised to reflect changes made to the ATCID (Available Transfer Capability Implementation Document), CBMID and TRMID. These changes may also lead to changes to short-term and secondary non-firm transmission service.

4. ***OASIS Changes.*** Depending on the method of automation you choose for calculation and posting of ATC, software enhancements for real-time calculation tools, algebraic decrementing of ATC based on confirmed service, incorporating real-time transmission modeling for ATC values all need to be implemented.

5. ***WEIM, WEIS and SEEM Impacts.*** These intra-hour energy imbalance markets in the West and Southeast will be impacted by AARs to the extent they either free up or reduce short-term transmission capacity. If DLR changes are implemented at some point, the imbalance markets will certainly feel the pinch.

WHAT NOW?

GDS recommends the following steps to be ready for the line rating NOPR and its eventual implementation:

GET IN FRONT OF THE ISSUE: The Compliance Filings are due on July 12, 2022. Participate in various associations such as APPA (American Public Power Association) and NRECA (National Rural Electric Cooperative Association) to learn best practices from others. Read up on Order 881 so you are familiar with what you need to do.

START EVALUATING YOUR CONTRACTS: Begin reviewing your power supply and transmission contracts to understand how any changes to facility ratings impacts short-term deliverability, interconnection rights, transmission service reservations and tagging procedures, and curtailment/force majeure provisions.

START EVALUATING PROCESS CHANGES: Start doing your research now to look at tools and equipment you will need to implement Order 881. Begin assessing your NERC Standards documentation and OATT (Open Access Transmission Tariffs) processes such as your Facility Rating Methodology, ATCID, CBMID, TRMID, TPL (Transmission Planning) practices and IROL/SOL methodology. Leverage the expertise of your consultants to assist in the transition.

START EVALUATING HARDWARE AND SOFTWARE CHANGES: Talk to your SCADA and OASIS vendors by communicating what you need. Make sure they see Order 881 the way you see it and ask questions when you do not agree.

COMMUNICATE WITH NEIGHBORS AND WITH THE RTO/ISO: *Initiate the conversation with your utility neighbors to discuss how to best coordinate ratings on shared facilities.* Be engaged with the RTO/ISO stakeholder processes where the rules will be made and the OATT changes will be discussed.

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KEEP AN EYE OUT FOR DISCUSSIONS REGARDING IMPLEMENTATION OF ANYTHING RELATED TO DYNAMIC LINE RATINGS: FERC is certainly not done with this issue. GDS will also be tracking this and will be ready to assist with any regulatory filings or technical assessments when the time comes. ■

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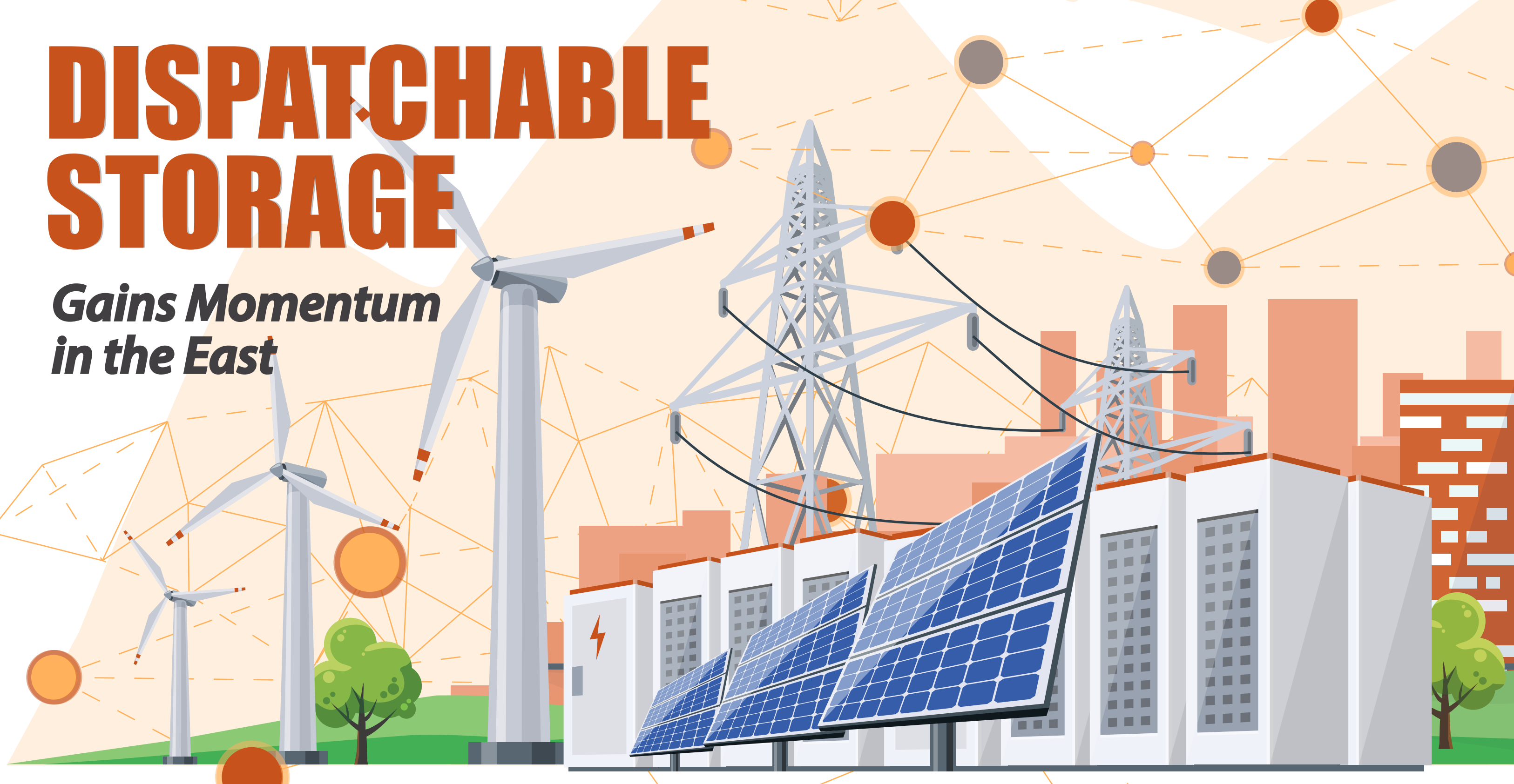
DISPATCHABLE STORAGE

Gains Momentum in the East



Distributed energy resources ("DERs") are generally defined as small-scale generation and battery storage systems that are installed at utility retail customers' homes and businesses. There is a growing trend to aggregate DERs to provide significant benefits to the utility grid in times of constrained capacity or outages. DERs often consist of a renewable generation source in tandem with battery energy storage and electric utilities across the world are increasingly interested in the economic and resiliency benefits of aggregating these customer sited systems into dispatchable resources. While the concept of moving these DER assets into a single dispatchable resource is not new, the complex coordination of the various components has become an easier reality for many utilities in recent years due to technology and communication advancements. Many utilities have turned to deployment of ***Distributed Energy Resource Management Systems*** or **"DERMS"**, as a solution to handle the multitude of variables that must be accounted for in utilization of the DER assets.

DERMS has a number of industry leaders in the electric utility and manufacturing / software vendor space, resulting in a number of encouraging but exploratory implementations that is paving the way for the future of utility grid operation. In Connecticut, the Public Utilities Regulatory Authority ("PURA") took an aggressive approach to promoting DERMS throughout the state by putting forth an order for the electric utilities (aka, Eversource and United Illuminating ("UI")), to develop and implement a program for battery energy storage systems. These battery energy storage systems will be connected to the electric distribution system and would provide multiple types of benefits to the grid, including ancillary services, peak shaving, support for the deployment of other distributed energy resources, and additional grid resiliency. The Eversource and UI program consists of two key incentive offerings:

01 **Passive Dispatch:** ***a declining-block upfront incentive which requires eligible systems to automatically store and dispatch during passive event periods.***

02 **Active Dispatch:** ***a performance-based incentive structure managed by the EDCs which compensates participants for the average kW dispatched during events over the summer and winter seasons.***

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The PURA order further defines specific customer categories that will be allowed to compete in the New England Independent System Operator ("ISO") market in addition to qualifying for dispatch incentives based on their status as a: 1) Grid-edge customer, 2) Critical facility, 3) Owners of fossil-fueled generators, or 4) Small Business customers. ***In this program, the electric utility has responsibility over the DERMS product and serves a critical role in the relationship with the retail customer's assets and relationship with the ISO.*** The customers receive installation and performance incentives for both active and passive dispatch, all aggregated through the DERMS platform. The program was developed over the past two years as part of PURA's broader effort to modernize the electric grid, and is the final product of the coordinated efforts between utilities, vendors, stakeholders, and consultants. It also follows the Connecticut legislature's passage of a law last year establishing a statewide goal of deploying 1,000 megawatts of energy storage by 2030.

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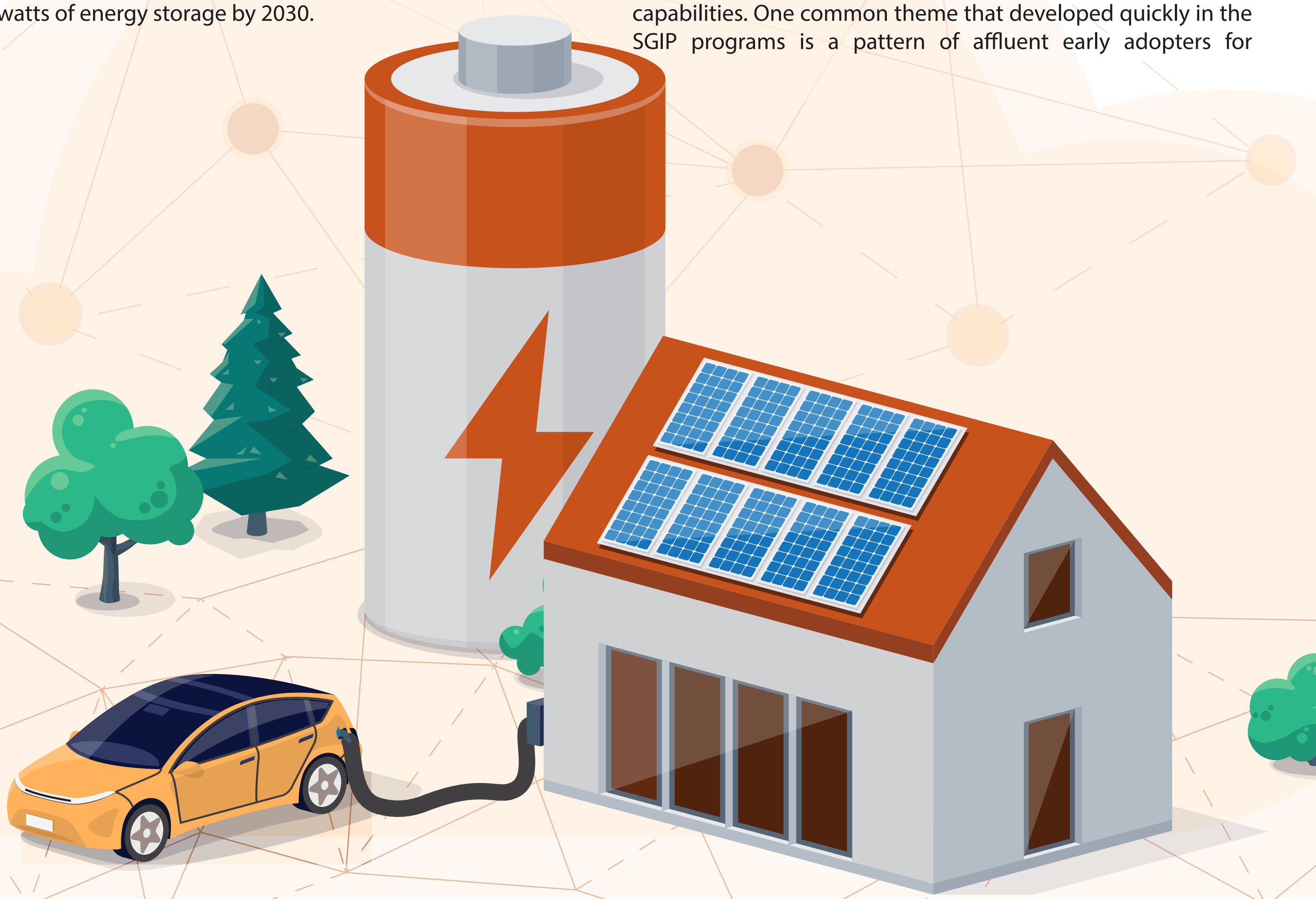
In DER deployment heavy states like California where there is combination of higher electric rates, demand charges, and the Self-Generation Incentive Program (SGIP), the economics can be more attractive for homeowners and businesses to engage in generation to serve peak load reduction and resiliency. The SGIP program, known as one of the more advanced self-generation incentive programs in the country, provides a range of long-term performance incentives for both renewable and renewable with storage projects. Incentive rates for reimbursement of renewable generation are $2.00/watt as of 2021, as one example, but when designed as a resiliency focused renewable project, that incentive can move to $4.50/watt. With recent actions by utilities, such as Southern California Edison and Pacific Gas & Electric, to implement Public Safety Power Shutdowns (PSPS's), the purposes and economics for storage systems were quickly expanded in the SGIP program to improve resiliency capabilities. One common theme that developed quickly in the SGIP programs is a pattern of affluent early adopters for



residential storage, including medical facilities and assisted living / long-term care residences. In these cases, the value proposition is not about the cost of the energy being displaced, but about the value that the energy has for the lives of the end-users. This dual benefit also exists in the aforementioned Connecticut program, allowing for financial and resiliency benefits to the retail customers.

Building a network of battery storage systems that need to respond relatively quickly to signals from the DERMS provider requires a reliable and swift communication pathway. Currently, Tesla is the only battery manufacturer that consistently provides real-time, 15-minute interval data. All other battery partners provide interval data via periodic uploads to hosted SFTP sites or other data sharing platforms. In most cases, battery partners provide these data files in one bulk upload at the conclusion of the battery demand response season to enable Measurement and Verification ("M&V") calculations. This lag can be problematic in terms of the feedback loop between the customer site and the program operators, but the dispatch signals sent to the systems are uninhibited by this delay. Still, discussions are underway with manufacturers to better understand the limitations to system modification and improve the data communication timeline (e.g, bi-weekly or weekly) for sending back interval data.

As the adoption of individual DER systems grows, the coordination can become cumbersome without unified direction. Furthermore, electric utilities in the United States have become the focus of discussion around centralization and FERC's Order 2222 allows DER systems to be accepted as capacity resources in wholesale markets. In this specific order, the aggregation of DERs is the goal and regional electric operators (i.e. regional transmission operators) must coordinate to accommodate the industry's move to utilize DER assets as generation resources. Along with this increased coordination comes the complexity of utility incentives that can be upstream for installation cost reduction or dispatchable performance incentives paid at the kW level, or both.

It is expected that the electric utility is going to be a central player in DERs and customer sited dispatchable storage processes, which requires the electric utility to invest in planning efforts and dedicated personnel to manage the DER systems on their grid. ***Lessons learned from implementation and program evaluation are going to be critical as the deployment of these systems spreads across the country – this will be accelerated with falling equipment prices and State regulators' motivation to electrify and incentivize electric utilities to be more nimble and increase grid resiliency.***

As the sharing of DER ideas and success stories continues in industry conferences, white papers, and formal reports, the barriers to entry will be reduced for smaller utilities or utilities with very dynamic peaks that have been eager to participate in this style of DER implementation. What lies beneath the complex nature of a dispatchable DER grid is a reliable and resourceful American energy grid. ■

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