UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators	Docket No. RM16-23-000

COMMENTS OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP

On November 17, 2016, FERC issued its Storage and DER Aggregation NOPR[1] proposing to remove barriers to the participation of electric storage resources and distributed energy resource ("DER") aggregations in the capacity, energy, and ancillary service markets operated by regional transmission organizations and independent system operators ("RTO"). The Transmission Access Policy Study Group ("TAPS") welcomes the opportunity to comment on this important NOPR. TAPS sees the potential value to consumers of participation in RTO markets by emerging storage and DER technologies, and it supports the Commission's goal of eliminating unnecessary barriers to such participation. TAPS generally supports the NOPR's proposals to better incorporate transmission-level storage resources in RTO markets, and recognizes that RTO market participation by distribution-level storage resources, as well as other DERs, could provide consumer benefits. Implementation of the NOPR's proposals for DERs (including distribution-connected storage), however, could be complex and have significant impacts on distribution utilities. TAPS, whose members (or in the case of TAPS members that

[1] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86,522 (proposed Nov. 17, 2016), FERC Stats. & Regs. ¶ 32,718 (2016) ("NOPR").

are municipal joint action agencies, their distribution utility members) operate distribution systems, offer these comments—from a real-world perspective—on how a Final Rule could be crafted to achieve the Commission's objectives while respecting jurisdictional boundaries and reducing adverse impacts to distribution utilities.

In Part I of our comments, we discuss three overarching principles that should be reflected in any Final Rule on DERs:

- The Commission should confirm the limited scope of this rulemaking and resist calls to expand that scope.
- The Commission should ensure that any Final Rule does not impose on distribution utilities undue burdens related to metering, settlements, and rate unbundling.
- At minimum, to protect retail jurisdiction and to limit the ability of RTOs to impose excessive new burdens on small utilities, the Final Rule should include provisions patterned on Order No. 719-A's[2] treatment of aggregators of retail customers ("ARCs") for purposes of demand response resources—i.e., requiring express consent by the relevant electric retail regulatory authorities ("RERRA") before the RTO may accept bids from DERs located on a small utility system.

In Part II, we apply these principles to DERs and address the NOPR's questions as to operational considerations. In Part III, we discuss challenges specific to storage DERS—i.e., storage resources connected to distribution systems; and in Part IV, we discuss the Regulatory Flexibility Act issues associated with the NOPR.

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[2] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), *corrected*, 126 FERC ¶ 61,261 (2010), *on reh'g*, Order No. 719-A, 74 Fed. Reg. 37,776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009) ("Order No. 719-A"), *on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

INTEREST OF TAPS

TAPS is an association of transmission-dependent utilities ("TDUs") in more than 35 states, promoting open and non-discriminatory transmission access.[3] Representing load-serving entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has supported the Commission's initiative to form truly independent regional transmission organizations to provide non-discriminatory transmission access and foster robust competition, to enable them to meet their load reliably and affordably. Thus, TAPS supports the development and implementation of new and advanced technologies that will increase reliability and access to more economic power supplies, provided that those technologies reduce cost to the ultimate ratepayer. Because TAPS members (or the distribution utilities that are members of TAPS members) operate distribution systems, they are directly affected by the development of DERs and the Commission's proposal to facilitate participation of DERs in RTO wholesale organized markets.

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COMMENTS

I. OVERARCHING CONSIDERATIONS

TAPS recognizes that DERs, a term that includes storage resources located on the distribution system, are starting to transform the electric grid; and TAPS agrees that developing new storage will help integrate growing amounts of intermittent renewable resources into the nations' power supply. TAPS members and the distribution utilities they serve have had a front-row seat for these changes. They are actively developing storage[4] and distribution-connected generation;[5] attempting to accommodate distribution-

[4] For example, in early December 2016, Missouri Basin Municipal Power Agency d/b/a as Missouri River Energy Services filed an application for preliminary permit for the Gregory County Pump Storage Project, a proposed 1.2 GW open loop pumped storage project that would use the existing Lake Francis Case reservoir in South Dakota. *Mo. Basin Mun. Power Agency*, Project No. 14806 Application for Preliminary Permit (Nov. 30, 2016), eLibrary No. 20161201-5132.

[5] For example, TAPS member Missouri River Energy Services ("MRES") has installed a 1 MW solar project in its member Pierre, South Dakota; and TAPS member WPPI Energy buys the output of a distribution-connected biogas generation facility located in its member community Richland Center. In addition, several distribution utility members of MRES and WPPI Energy have either already developed or are considering community solar projects connected at the distribution level.

connected generators and storage owned by retail customers;[6] and working with their distribution utility systems to help them prepare for expanded use of behind-the-meter distributed resources.[7]

TAPS supports the Commission's effort to address DERs proactively and to eliminate unnecessary barriers to their participation in organized wholesale markets. Any Final Rule, however, must respect state and local jurisdiction over DERs, recognize the Commission's limited jurisdiction over facilities used in local distribution, and avoid imposing undue burdens on distribution utilities.

The Commission should confirm the limited scope of this rulemaking and resist calls to expand that scope. The NOPR appropriately focuses on the RTOs' treatment of energy and ancillary services from storage and DERs when those resources have been successfully delivered to Commission-jurisdictional RTO markets. It does not attempt to establish new rules or requirements governing the details of distribution interconnections, or whether and how deliveries from DERs to the RTO (and, for DERs that include storage, from the RTO to the DER) might occur.

A broader scope would be premature. DERs and the metering and control systems needed to integrate those resources are still developing. There are significant regional differences in market penetration and resource mix.

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[6] For example, a large retail customer of the City of Naperville, a distribution utility member of TAPS member Illinois Municipal Electric Agency, is installing a 250 kW battery/600 kW solar facility. Naperville has worked with the customer to authorize load reductions from use of the device to be bid as demand response into PJM's frequency response market.

[7] Wholesale supplier AMP prepares utilities for possible boom in distributed resources, Jeannine Anderson, *Wholesale Supplier AMP Prepares Utilities for Possible Boom in Distributed Resources*, Public Power Daily (Jan. 27, 2017), http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=47440.

There is also a wide variety of approaches being taken by distribution utilities and their RERRAs to address DERs. In some areas, DERs are being handled on an ad hoc basis by individual distribution utilities and/or their RERRAs. In contrast, the California Public Utilities Commission ("CPUC") has promulgated a rule creating a state-jurisdictional DER interconnection process.[8] And New York has developed a completely new state regulatory paradigm, Utility 2.0, that treats the retail electric utility as a platform for coordinating the flow of electricity from DERs, instead of functioning as a monopoly distributor of retail power coming from a few large plants.[9] DER policies are changing rapidly at the state and local level and have not converged on a single model.[10] Now is not the time for the Commission to attempt to impose an all-encompassing, one-size-fits-all approach to DERs.

A broader scope would also be inconsistent with the Commission's limited jurisdiction "over facilities used in local distribution." Federal Power Act ("FPA") section 201(b)(1), 16 U.S.C. § 824(b)(1). While some public utilities have filed wholesale distribution tariffs patterned on the Commission's *pro forma* Open Access

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[8] The CPUC's Electric Rule 21 is a tariff that describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction. Cal. Pub. Utils. Comm'n, *Rule 21* (last visited Feb. 6, 2017), http://www.cpuc.ca.gov/General.aspx?id=3962.

[9] *Re Reforming the Energy Vision*, 319 P.U.R.4th 1 (N.Y. Pub. Serv. Comm'n 2015).

[10] Even in California, which has progressed further than most regions with respect to DER penetration and aggregation, the CAISO has noted that existing state-jurisdictional tariffs and interconnection requirements may well continue to evolve in response to the development of DERs. In the CAISO's DER aggregation proposal accepted by the Commission last year, in Docket No. ER16-1085, the CAISO emphasized that "[its] proposal will not interfere with or dictate the outcome of such efforts. Rather, the CAISO's proposal only serves to facilitate the participation of aggregations of distributed energy resources in the CAISO's markets that are compatible with the safe and reliable operation of distribution system." *Cal. Indep. Sys. Operator Corp.*, Distributed Energy Resource Provider Initiative 3 (Mar. 4, 2016), eLibrary No. 20160304-5258.

Transmission Tariff ("OATT"), establishing Commission-jurisdictional rates, terms, and conditions for generators connected to distribution facilities that wish to reach the RTO-controlled grid,[11] elsewhere the Commission's jurisdiction over distribution facilities is much more limited. As the Commission has previously recognized:

> FPA Section 201(b)(1) gives the Commission the authority to regulate "all facilities" used for transmission and for the wholesale sale of electric energy in interstate commerce. The same FPA Section denies the Commission jurisdiction "over facilities used in local distribution" except as specifically provided in Parts II and III of the FPA.

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[11] The California public utilities that turned their high-voltage transmission facilities over to the CAISO, for example, have filed separate wholesale distribution tariffs; and distribution-connected resources currently take distribution and interconnection service under those tariffs. *See*, *e.g.*, *Pac. Gas & Elec. Co.*, 100 FERC ¶ 61,156 (2002) (ruling on the terms and conditions of the wholesale distribution tariffs of PG&E and Southern California Edison Company) (subsequent history on other issues omitted); *San Diego Gas & Elec. Co.*, 86 FERC ¶ 61,265 (1999) (approving settlement regarding San Diego Gas & Electric Company's Wholesale Distribution Open Access Tariff, including Service Agreements for individual plants not directly connected to the CAISO-controlled grid); *S. Cal. Edison Co.*, Docket No. ER16-1688-000, Letter Order (June 28, 2016), eLibrary No. 20160628-3007 (accepting generator interconnection agreements and Service Agreements for Wholesale Distribution Service); *S. Cal. Edison Co.*, Docket No. ER17-592-000, Letter Order (Feb. 2, 2017), eLibrary No. 20170202-3015 (accepting generator interconnection agreement and Service Agreement for Wholesale Distribution Service between SoCal Edison and PPA Grand Johanna, LLC, for a 2.0 MW battery storage project in Irvine, California).

Many public utilities, however, have not established a separately stated Commission-jurisdictional rate for deliveries over distribution facilities for wholesale transactions. *Cf.* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,539, 21,577-78, 21,625-27 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,699-700, 31,780-85 (1996) (recognizing that unbundling of retail rates is a state prerogative) ("Order No. 888"), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). And the Commission has rejected efforts to interpret RTO tariffs to broadly encompass open access service over distribution facilities. In *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,191, P 17 (2006), *reh'g denied*, 116 FERC ¶ 61,102 (2006), the Commission rejected arguments that PJM's OATT, which stated that "Interconnection Service under this Tariff shall include the construction and/or use of [] distribution facilities," gave the Commission jurisdiction over proposed interconnections by wind plants to Commonwealth Edison's distribution system. Instead, the Commission ruled that, because the PJM OATT cannot confer jurisdiction over local distribution facilities where the Commission otherwise lacks jurisdiction, the PJM tariff language must be interpreted to apply only to local distribution facilities where there is a preexisting generator interconnection and a preexisting wholesale transaction over the local distribution facilities, prior to the new interconnection request being made. *Id.*

Order No. 2003-C, P 52 (footnote omitted).[12] Applying these FPA boundaries, the Commission has held that it has jurisdiction over interconnection to, and deliveries over, the distribution facilities of public utilities only when: (a) the generator is connecting to the distribution facility for the purpose of wholesale sales; and (b) the distribution facility is already subject to a Commission-filed OATT at the time the interconnection request is made.[13]

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[12] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49,846 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003) ("Order No. 2003"), *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003), *clarified*, 69 Fed. Reg. 2135 (Jan. 14, 2004), 106 FERC ¶ 61,009 (2004), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005) ("Order No. 2003-C"), *aff'd sub nom. NARUC v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

FPA section 201(f), 16 U.S.C. § 824(f), further limits the Commission's jurisdiction over distribution-connected resources by generally exempting states and their political subdivisions, certain electric cooperatives, and related entities from the Commission's FPA Part II jurisdiction.

[13] Order No. 2003-C, P 53; Order No. 2003, P 804; *NARUC v. FERC*, 475 F.3d at 1282. *See* 114 FERC ¶ 61,191, PP 14-17, (applying Order No. 2003-C criteria to disclaim jurisdiction over unexecuted interconnection service agreements for wind plants seeking to interconnect with Commonwealth Edison's distribution system in order to make wholesale sales). *See also* Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 Fed. Reg. 34,100, 34,191 (June 13, 2005), FERC Stats. & Regs. ¶ 31,180, P8 (2005) ("[b]ecause of the limited applicability of this Final Rule, and because the majority of small generators interconnect with facilities that are not subject to an OATT, this Final Rule will not apply to most small generator interconnections"), *order on reh'g*, Order No. 2006-A, 70 Fed. Reg. 71,760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005), *clarified*, Order No. 2006-B, 71 Fed. Reg. 42,587 (July 27, 2006), FERC Stats. & Regs. ¶ 31,221 (2006), *corrected*, 71 Fed. Reg. 53,965 (Sept. 13, 2006).

The Commission has also clarified that when a "dual use" facility is involved—i.e., a facility used both for the transmission of both retail sales and wholesale sales—the Commission "do[es] not claim jurisdiction over the facility itself, just the wholesale sale transaction occurring over that facility." Order No. 2003-C, P 53 n.42. *See also* Order No. 2003, P 804 n.129; *Detroit Edison Co. v. FERC*, 334 F.3d 48, 51 (D.C. Cir. 2003); *DTE Energy Co. v. FERC*, 394 F.3d 954, 962 (D.C. Cir. 2005). And it has held that there is no Commission-jurisdictional delivery service associated with purchases by a distribution utility from a distribution-interconnected generator, where: (1) that generator sells its total electric output to the host utility, and (2) the host utility takes title to the electricity at the point of interconnection to its local distribution system. 114 FERC ¶ 61,191, P 15. *Cf. W. Mass. Elec. Co.*, 61 FERC ¶ 61,182 (1992), *aff'd*, *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999) (holding that Commission-jurisdictional transmission service takes place when a host utility does *not* purchase the output of a distribution-connected generator and instead transmits that output over its distribution facilities for delivery to a third party). These cases establish that RERRA and distribution utility decisions about how DERs will be integrated into the distribution utility's power supply will drive the extent to which the

Footnote continued on next page.

Given the limited circumstances in which the Commission has the authority to require interconnection to, or deliveries over, distribution facilities, the NOPR properly does not attempt to address those issues. Any Final Rule should likewise be limited to: (1) the treatment by RTOs of energy and ancillary services from DERs, after those resources have already been delivered to the RTO's organized wholesale markets; and (2) assuring that any such participation of aggregations of DERs in RTO markets is compatible with the safe and reliable operation of the distribution system, and with RERRA and distribution utility tariffs, rules, and requirements.

The Commission should ensure that any Final Rule does not impose on distribution utilities undue burdens related to metering, settlements, and rate unbundling. As discussed in Part II below, distribution utilities will need complicated and expensive administrative and technical systems to enable DERs within their footprints to participate in organized RTO wholesale markets. Particularly for small utilities, the costs of implementing those systems will likely far outweigh any potential efficiency benefits that might be achieved by allowing DERs to participate directly in RTO markets. Any Final Rule should assure that the costs to distribution utilities of

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Commission has jurisdiction over those resources and their delivery. They are also consistent with the deference to RERRA jurisdiction reflected in the FPA, the Commission's regulations, precedent, and long-standing Commission policy. *See, e.g.*, FPA section 201(b)(1), 16 U.S.C. § 824(b)(1) (the Commission "shall not have jurisdiction . . . over facilities used . . . only for the transmission of electric energy in intrastate commerce"); *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016) (FPA section 201(b) reserves regulatory authority over retail sales and intrastate wholesale sales to the States); Order No. 888, 61 Fed. Reg. at 21,625-27, FERC Stats. & Regs. at 31,780-85 (the Commission's jurisdiction over unbundled transmission service is contingent on a public utility decision to unbundle its retail sales, either "voluntarily or as a result of a state retail wheeling program," and states would still have authority over the service of delivering electric energy to end users and that any Commission jurisdiction would not change historical state franchise areas or interfere with state laws governing retail marketing areas of electric utilities); 18 C.F.R. § 35.27 ("Nothing in this part . . . [s]hall be construed as preempting or affecting any jurisdiction a State commission or other State authority may have under applicable State and Federal law").

accommodating DERs that wish to participate in an RTO's organized wholesale markets are not shifted to others taking service from the distribution system (i.e., retail customers).

At minimum, to protect retail jurisdiction and to limit the ability of RTOs to impose excessive new burdens on small utilities, the Final Rule should include provisions patterned on Order No. 719-A's treatment of ARCs for purposes of demand response resources—i.e., requiring express consent by the RERRA before the RTO may accept bids from DERs located on a small utility system. In Order No. 719-A, the Commission recognized that to avoid imposing undue burdens on small utilities, RTOs should not be allowed to accept demand response bids that include the demand response of a small utility's retail customers, unless that utility's RERRA has expressly permitted such customers' demand response to be bid into organized markets by an ARC. Order No. 719-A, P 51; 18 C.F.R. § 35.28(g)(1)(iii). A similar requirement limiting the ability of RTOs to accept bids from DERs located on the distribution systems of small utilities absent express RERRA permission is also necessary. Indeed, such a restriction is even more important for DERs because their operation can have significant impacts on distribution facilities that were not originally designed to handle bidirectional flows, and because the distribution utility's costs of the metering, settlements, and rate-unbundling required to accommodate DER sales to RTOs are higher than the administrative costs associated with accommodating aggregators of demand response.

An approach patterned on Order No. 719-A—*i.e.*, requiring RTOs to accept bids from DERs located in large utilities unless the RERRA expressly opts out, and to reject bids from DERs located in small utilities unless the RERRA expressly opts in—would better respect retail jurisdiction and simplify implementation. It would make clear where DERs will be permitted to participate in organized wholesale markets, thus providing the certainty needed to support investment decisions; and it would enable distribution utilities and their RERRAs to coordinate decisions on DER participation with related decisions on unbundled rates for delivery service over distribution systems, the terms and conditions of distribution-level interconnections, and retail rate design.

II. TAPS COMMENTS ON DER AGGREGATION

TAPS strongly supports the Commission's goal of assuring robustly competitive wholesale electric markets, and it agrees that RTO market rules should not create unnecessary barriers to entry for emerging technologies that are technically capable of participating in its organized wholesale markets (NOPR, P 9).

The NOPR correctly recognizes, however, that allowing DERs to participate in wholesale markets poses special challenges, because of their potential to straddle wholesale and retail service and the resulting need to assure that there is no duplication of compensation. TAPS supports the NOPR's proposal (P 134) that DERs that are participating in one or more retail compensation programs such as net metering, or in another wholesale market participation program, will not be eligible to participate in the organized wholesale electric markets as part of a DER aggregation. We urge the Commission to clarify the scope of that prohibition, particularly with respect to distribution-connected storage (as discussed in Part III below), and to confirm that its proposed reforms of RTO market rules do not exempt or preempt existing tariffs, rules, and requirements regarding deliveries over distribution facilities and distribution-level interconnection.

A. The Commission Should Clarify that this Rulemaking Does Not Exempt DERs from Applicable Tariffs or Rates for Delivery Over Distribution Facilities.

The Commission should clarify that: (1) the NOPR's requirements apply only to energy and ancillary services from DERs that have been delivered to the RTO's organized wholesale markets; and (2) this rulemaking does not exempt DERs from, or preempt, any FERC- or state/local-jurisdictional tariff or rate that may be applicable to the delivery of energy over distribution facilities to the RTO grid, including related rules for eligibility and terms and conditions (including losses).

In contrast to sales of demand response resources under Order No. 719—which the Commission has held are *not* sales of electricity[14]—the storage and generation DERs addressed by this NOPR seek to sell electricity to organized wholesale markets (and, in the case of distribution-connected storage, also to purchase electricity from those markets). To effect these sales for resale, DERs must have adequate arrangements in place to move electricity between the DER's point of interconnection with the distribution utility's system and the RTO.

The NOPR is silent on the issue of whether and how generation and storage DERs can obtain such distribution-level service, which may be a usage different from those for which the distribution system was designed. However, there is substantial existing law on the extent and limits of the Commission's jurisdiction over distribution facilities.[15] Some public utilities have already filed Commission-jurisdictional wholesale distribution tariffs that establish terms and conditions for delivery service over distribution facilities

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[14] *EnergyConnect, Inc.*, 130 FERC ¶ 61,031, PP 30–31 (2010).

[15] *See supra* Part I, especially notes 11-13.

for certain wholesale transactions (in some cases, including *pro forma* generator interconnection agreements) and rates to recover the costs of the distribution utility's system.[16] In other cases, the Commission has held that it has no jurisdiction to require transmission arrangements over distribution facilities.[17] In *California Independent System Operator Corp.*, 155 FERC ¶ 61,229, P 60 (2016), the Commission ruled that DERs seeking to participate in the CAISO's organized markets through a DER aggregator could interconnect pursuant to the CPUC's state-jurisdictional interconnection process, and do not need to satisfy the interconnection requirements of the otherwise applicable Commission-jurisdictional wholesale distribution tariff. The Final Rule should confirm that this rulemaking does not alter existing precedent on these issues, or exempt DERs from the obligation to adhere to applicable distribution utility tariffs and requirements of RERRAs with respect to delivery service over the distribution utility's system.[18]

B. Any Final Rule Should Require that DER Aggregators Demonstrate Compliance with the Interconnection Requirements of the Distribution Utility and RERRA.

The NOPR correctly acknowledges that DER aggregations "will likely fall under the purview of multiple organizations" (NOPR, P 157); and TAPS supports the NOPR's proposal that RTOs must require each DER aggregator to attest "that its distributed

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[16] *See supra* note 11.

[17] *See supra* Part I, notes 11 and 13.

[18] Such a ruling would also be consistent with the CAISO DER aggregation system accepted by the Commission in 155 FERC ¶ 61,229, P 15, which provides:

> DER Providers must comply with applicable utility distribution company tariffs and operating procedures incorporated into those tariffs and applicable requirements of the local regulatory authority (such as the Public Utilities Commission of the State of California (CPUC) or relevant municipal entity).

energy resource aggregation is compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any other relevant regulatory authority" (*id.*). Today, a customer must comply with the interconnection rules of its distribution utility and RERRA, unless the DER is interconnecting pursuant to a Commission-jurisdictional Small Generator Interconnection Agreement ("SGIA") or Large Generator Interconnection Agreement ("LGIA"). These local and state interconnection rules provide for the distribution utility to conduct appropriate studies and place appropriate limits on the interconnection of DERs to ensure the reliability and safety of the distribution grid.

The rules protect line workers by ensuring the distribution utility is aware of energized resources at a site, and in some cases by requiring DERs to install, test, and maintain automatic equipment to cut-off the DER in the event of a distribution line outage. Local and state rules are used to ensure that DERs have technical capabilities to operate reliably (e.g., fault protection). They are also crucial to assuring that the distribution system has the capability to manage any bidirectional flows that may result from the operation of DERs. It is common to have distribution circuits with less than 1 MW of total load; a DER located on that circuit and participating in the RTO's organized markets could potentially reverse flows on the distribution line, wreaking havoc on protection equipment.

Local interconnection procedures are an important means to identify serious problems that must be addressed before the DER is connected. For example, the municipal distribution utility in St. Charles, Illinois, which is a member of TAPS member Illinois Municipal Electric Association ("IMEA"), considered a retail customer's plan to construct a 500 kW solar facility and 1 MW battery at the end of a relatively lightly loaded distribution feeder. The battery was intended to participate in the PJM frequency response market. Engineering review of the plan identified operational risks for the distribution system. Specifically, the review concluded that the 1 MW battery responding to PJM's control signals could undermine the ability of the municipal utility to maintain voltage control for its other retail customers.

Any Final Rule should make clear that, absent proper application of a Commission-jurisdictional SGIA or LGIA, the Commission does not seek to alter or preempt local and state rules governing interconnection to the distribution system.[19]

C. The Commission Should at Minimum Adopt a System Patterned on Order No. 719-A to Govern RTO Acceptance of Bids from DER Aggregators.

The NOPR recognizes that accommodating wholesale sales by DERs to RTOs will require "ongoing coordination, including operational coordination, between the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utility or utilities." NOPR, P 153. According to the NOPR, ongoing coordination with distribution utilities may be necessary to "ensure that the distributed energy resource

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[19] Based on the experience of TAPS member AMP, such a requirement is workable and consistent with the manner in which PJM has implemented its existing system for enabling DERs to participate in PJM's organized wholesale markets. For example, in evaluating a DER interconnected to one of AMP's municipal utility members, PJM left the local system evaluation to the municipal utility, while PJM focused on the transmission system flows in the area.

PJM's process also called for a Wholesale Market Participation Agreement ("WMPA") between the DER and PJM, which required the DER to execute an interconnection agreement with the municipal utility prior to being able to sell into the PJM market. The WMPA also required the DER to obtain the municipal utility's agreement allowing the DER's Wholesale Market Participation to utilize the municipal's facilities to transport energy produced by the DER to the PJM grid. In addition, upgrades to the interconnection between PJM and the municipal utility were needed to accommodate the DER, and the costs of those upgrades were allocated to the DER developer.

aggregator is disaggregating dispatch signals from the RTO/ISO and dispatching individual resources in a distributed energy resource aggregation consistent with the limitations of the distribution system." *Id.* P 155. The administrative costs of these functions will likely be substantial, as will the added costs of the metering, settlements, and rate-unbundling needed to support DER sales to RTO markets. Particularly for a small utility—where any increased costs not directly assigned to the DER would be borne by a small customer base, and only a few DERs would be likely to participate in RTO markets—those costs may far exceed the potential efficiency benefits from DER participation in organized wholesale markets.

To avoid imposing undue burdens on small utilities, the Commission should at minimum adopt a system for DER aggregation patterned on Order No. 719-A's treatment of ARCs for the purpose of demand response resources. Specifically, the Commission should require express permission from the RERRA before the RTO may accept bids from DERs located on a small utility system. In Order No. 719-A, the Commission recognized that this approach was appropriate to reduce the burden of that rule on small systems. Order No. 719-A, P 51; 18 C.F.R. § 35.28(g)(1)(iii). It is even more important here, since the administrative and technical costs of accommodating DER aggregators are so much higher.

The NOPR correctly recognized that the relevant tariffs, rules, and regulations applicable to DERs may already include laws or regulations that do not permit demand response DERs. NOPR, P 157 n.238. However, to respect state and local jurisdiction over distribution facilities, and to be effective and applicable to storage and generation DERs in addition to demand response resources, the Final Rule should establish the following general limits on the ability of RTOs to accept bids from DER aggregators (including distribution-connected storage):

- An RTO must not accept offers or bids from a DER aggregator that aggregates the DERs located on utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the RERRA expressly permits such DERs to be offered and bid into organized markets by a DER aggregator.
- An RTO must not accept offers or bids from a DER aggregator that aggregates the DERs located on utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the RERRA expressly prohibits such DERs to be offered and bid into organized markets by a DER aggregator.

This approach would also simplify implementation. It would make clear where DERs will be permitted to participate in organized wholesale markets, thus providing the certainty needed to support investment decisions. In addition, it would enable distribution utilities and their RERRAs to coordinate decisions on DER participation with related decisions on unbundled rates for delivery over distribution systems, the terms and conditions of distribution-level interconnections, and retail rate design. Finally, because the approach tracks the framework used in Order No. 719-A, RTOs should be able to implement it by making only relatively minor changes to the systems and standards that they already use to implement the RERRA provisions related to aggregation of demand response resources.

D. The Commission Should be Mindful of the Operational, Reliability, and Economic Impacts its Proposal Could Have on Distribution Utilities.

Many distribution utilities will have to implement new operational and reliability practices in order to allow DERs on their distribution systems to participate in an RTO market. In some cases, system upgrades will be required to facilitate sales to the RTO market. And in many cases, distribution utilities will also have to develop new tariffs to appropriately charge those resources for use of the distribution system. State regulations and upstream contracts could also complicate or limit a distribution utility's ability to allow DER participation in an RTO market. Thus, participation of DERs in RTO markets could potentially impose significant expense on distribution utilities, disproportionately burdening the smallest utilities.

The first major challenge some distribution utilities will face is that system upgrades may be needed to facilitate the delivery of energy from a DER to the RTO. The studies and distribution system requirements needed to simply interconnect a DER for local use are different from those needed to ensure safe and reliable delivery over the distribution system to the RTO. Even where an existing DER had complied with local interconnection procedures when it was originally developed,[20] the DER's decision to participate in an RTO market, thereby changing the use of the interconnection and the distribution facilities, may impose additional operational challenges on the distribution utility. For example, an IMEA member had an existing, distribution-connected generator that was not participating in PJM's markets; when the distribution utility attempted to configure the generator to sell energy to PJM markets, the utility discovered that significant distribution system upgrades would be needed to provide the required firm delivery path from the generator to the RTO.

The second major challenge for some distribution utilities will be developing tariffs to appropriately charge DERs for their use of the distribution system. Many utilities have not established separate rates for that service. Moreover, to the extent that

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[20] *See* discussion *supra* Section II.B.

DERs are located behind the retail customer meter, it may be necessary for the utility to unbundle its retail rate to allow for DERs to participate in the RTO market. Rate unbundling is a politically sensitive process, and RERRAs—not the Commission—have the authority to decide whether to unbundle retail rates.[21]

A third major challenge is that distribution utilities must confirm that allowing DERs to participate in RTO-organized markets will not conflict with or trigger burdensome obligations under state regulation or contractual agreements. For example, TAPS member Northern California Power Agency ("NCPA") and many of its member distribution utilities have an interconnection agreement with Pacific Gas and Electric Company ("PG&E").[22] Pursuant to that agreement, the installation or operation by a third party of generation connected to any distribution utility's system is a "Significant Operational Change" if power from that generator "is intended to or may possibly flow" onto PG&E's system and if that may create an adverse impact.[23] Thus, a DER aggregator that intends to sell the output of several DERs from a distribution utility to the CAISO could cause that distribution utility to trigger all of the potentially costly notice, study, and upgrade provisions of the PG&E interconnection agreement.[24]

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[21] *See* Order No. 888, 61 Fed. Reg. at 21,577-78, 21,625-27, FERC Stats. & Regs. at 31,699-700, 31, 780-85 (recognizing that unbundling of retail rates is a state prerogative).

[22] Pac. Gas & Elec. Co., PG&E, Service Agreement No. 292 (Sept. 21, 2015), eLibrary No. 20150922-5006.

[23] *Id.* § 10.2.

[24] This provision was triggered when NCPA-member Gridley planned to connect two 3.5 MW solar resources to its distribution system. Because Gridley is quite small, PG&E claimed that the output of the solar resources could exceed load in the spring, and that the resulting energy export could have an adverse impact on PG&E's system. To prevent the need for costly upgrades, Gridley was required to install equipment that would, if the net exchange at the city gate meter reached a defined point near zero, automatically reduce the output of the solar units to prevent the export.

A fourth major challenge for distribution utilities allowing DERs to participate in RTO markets will be the acquisition and deployment of new modelling and forecasting tools. Tools to accurately model DERs on a distribution system are novel, complex, and costly; that modeling will be made even more complex by the ability of DER aggregators to coordinate the operation of multiple DERs, including storage facilities, independently from the distribution utility. Even basic functions like load forecasting will be more complex, as retail load projections and retail power supply planning must be based on meter data different from the data used to plan the adequacy of the distribution utility's distribution facilities. In states with retail competition, the problem is even more acute because some utilities are required to perform daily load profiles to allocate obligations between marketers and the utility. The significant complexity—and associated cost—of acquiring and deploying modelling and forecasting tools that address these issues will be a burden on many utilities, particularly smaller distribution utilities.

Metering requirements pose a fifth major challenge for distribution utilities. As discussed in more detail below,[25] a distribution utility may not have meters at each individual interconnection to its distribution system that are appropriate to support the sale of energy from DERs to the RTO. Without appropriate metering, energy generated by a behind-the-retail-customer-meter DER cannot be distinguished from either demand response or, in the case of a DER that includes storage, a prohibited resale of energy purchased by the retail customer at the retail rate. Even where appropriate metering is installed, distribution utilities may not have the systems to communicate that meter data

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[25] *See infra* Section II.E.

to DER aggregators or the RTO. Developing systems to share meter data with multiple entities has significant cost, as well as privacy, implications.

These five challenges—system upgrades, tariff development, compliance with regulations and upstream agreements, acquisition of modelling tools, and metering—are just a subset of the significant operational, safety, and reliability issues that the NOPR could create for distribution utilities. And these challenges disproportionately affect small utilities, because the large costs associated with addressing these challenges will be paid by a relatively small amount of retail load, if not borne directly by the DER. Imposing expensive new requirements on small systems is particularly unwarranted since they would benefit only a comparatively small number of DERs.

Moreover, the NOPR presents challenges to small distribution utilities that other distribution utilities will not face. Many small utilities—particularly small municipal utilities that belong to a joint action agency—are not RTO market participants and currently have no interaction with their RTO. Participation in RTO markets of DER located on such a small municipal utility would require the utilities to develop significant new capabilities (e.g. communication, settlements, etc.) to interject itself into RTO operations. For small utilities, the associated costs will likely far outweigh any potential efficiency benefits that might be achieved by allowing DERs located in those utilities to participate in RTO markets.

Ultimately, many small utilities may choose, with approval from their RERRAs, to do what is necessary to facilitate DER aggregation and the participation of distribution-connected electric storage in RTO markets. But that decision should and must remain with the distribution utility and its RERRA. The Commission should not force distribution utilities and their retail customers to bear the significant costs of addressing the operational, reliability, and economic challenges created by the NOPR's proposal.

E. The Commission Should Require that DER Aggregations Consisting of Generation or Storage Resources Use Revenue-Quality Metering and Appropriate Telemetry, and Confirm that the Costs of Any Metering and Telemetry Above What is Required by Distribution Utilities and their RERRAs Must be Borne by the DER or the DER Aggregator.

The NOPR recognizes that RTOs need metering data for settlement purposes, and it recognizes that DER aggregations may contain different types of resources in different configurations (e.g., in front of or behind the meter, with or without the ability to inject energy onto the grid, etc.).[26] The NOPR asks whether it would be appropriate to establish specific telemetry and metering requirements, and whether different requirements should be established for each of the different types of DERs that could be aggregated.[27] TAPS urges the Commission to require revenue-quality metering for DER aggregations that include generation or storage resources, as well as appropriate telemetry.

Revenue-quality metering is necessary for generation and storage connected to a distribution system to properly settle wholesale transactions. Without that metering, an RTO cannot properly allocate deviations between load and various generators on the distribution system. Requiring revenue-quality metering for generation and storage would be consistent with the Commission's previous determinations for DERs.[28]

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[26] NOPR, PP 150-151.

[27] *Id.* P 151.

[28] *See* 155 FERC ¶ 61,229, P 41 ("CAISO's proposal includes sufficient measurement and verification protocols because each distributed energy resource will be directly metered pursuant to the applicable

Footnote continued on next page.

Additionally, we agree with the NOPR (P 152) that DERs should be required to provide appropriate telemetry. An RTO, for example, must have situational awareness of the status of storage devices—it is not enough to know after-the-fact that energy flowed into or out of the storage facility. To effectively manage the system, RTOs must know the charge state, any impact on performance that is dependent on the charge state, as well as the present capability of the storage facility. (Technology advances have yet to overcome the battery degradation that accompanies repeated charge/discharge cycles.)

Moreover, the problems caused by inadequate metering and telemetry are compounded when multiple generation and storage DERs are aggregated. The measurement errors from each DER in an aggregation are additive, so the combined measurement error of the aggregation as a whole may quickly become unmanageable if accurate information is not available for each individual resource.[29] TAPS recognizes the Commission's goal of avoiding unduly burdensome information and data requirements (*see, e.g.,* NOPR, PP 145, 151), but we are not aware of any mechanism other than revenue-quality metering and telemetry that could provide the necessary information. Accordingly, to maintain control over the system, accurately charge and credit market participants for the electricity they consume and provide, and assure that facilities are not inadvertently directed to operate beyond their physical capabilities, it is important to have revenue-quality metering and appropriate telemetry on all generation and storage DERs.

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utility distribution company tariff [and] scheduling coordinators will submit settlement-quality meter data for the aggregation for each operating interval.").

[29] As a matter of error propagation analysis, the theoretical limit of the accuracy of a string of measured values is the sum of the errors of each measuring devices. Because the error of each measuring device must be summed, the statistical uncertainty associated with an aggregation of meters may become unmanageable.

Some distribution utilities or their RERRAs may require DERs to install the types of metering and telemetry equipment needed to support sales to RTO markets.[30] In those cases, the NOPR appropriately proposes that RTOs rely on those meter data whenever possible.[31] RTOs should not re-invent the wheel if sufficient metering data are already available from existing metering systems.

But where local metering requirements are insufficient for RTO participation purposes, the NOPR expects RTOs to "apply[] additional metering system requirements" for DER aggregations.[32] The Final Rule should clarify that, if an RTO does apply additional metering requirements as a condition of RTO market participation, the cost of any such additional metering must be borne by the DER aggregator or DER, not the distribution utility or its other customers. The Final Rule should also clarify that DERs must still satisfy all local metering requirements.

F. The Commission Should Require RTOs to Obtain Distribution Utility Consent for Any New or Modified DER Aggregation

Even when a distribution utility "opts-in" to allowing DER aggregation on its system (or, for larger utilities, does not opt-out), that distribution utility should still have the right to disapprove any particular DER aggregation that would pose a reliability, operational, or safety problem. The NOPR's proposal with regard to this issue is inadequate.

The NOPR would require RTOs to "coordinat[e]" with the distribution utility when a DER aggregator registers a new DER aggregation or modifies an existing DER

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[30] NOPR, P 152.

[31] *Id.*

[32] *Id.*

aggregation to include new resources.[33] It further proposes to give distribution utilities the "opportunity to report" problems with a new or modified DER aggregation for "consideration" by the RTO.[34]

Despite recognizing that a distribution utility might conclude that some DERs "would [not] be able to respond to RTO[] dispatch instructions without posing [a] significant risk to the distribution system,"[35] the NOPR would give RTOs the ability to override those concerns and nevertheless approve a new DER aggregation. In other words, the NOPR's proposal would allow an RTO to take actions that would pose a reliability and safety threat to the distribution system. That is not reasonable.

Thus, in addition to providing for a general opt-in/opt-out requirement modeled on Order No. 719-A (as requested above), the Commission also should modify its proposal to require RTOs to coordinate with *and obtain consent from* the relevant distribution utility, subject to RERRA oversight, prior to a new or existing DER aggregation participating in the wholesale markets.

G. The Commission Should Adopt the Proposal to Require DER Aggregators to Report Distribution Outages to the RTO, and Should Confirm that Distribution Utility Maintenance Practices Will Not be Disrupted.

The NOPR proposes to require a DER aggregator to report to the RTO "any changes to its offered quantity and related distribution factors that result from distribution line faults or outages."[36] This proposal properly accounts for the fact that distribution

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[33] *Id.* P 154.

[34] *Id.*

[35] *Id.*

[36] *Id.* P 155.

facility outages may temporarily restrict the ability of individual DER resources from participating in a DER aggregation. The DER aggregator—not the distribution utility—knows what bids have been made to the RTO, and the need for any particular resource in the aggregation to fulfill those bids. Since distribution utilities will not have information about the DER aggregators' bids or how the aggregator intends to dispatch to satisfy those bids, a distribution utility does not have the ability to inform the RTO of how distribution line faults or outages will change an aggregator's offered quantity and distribution factors.

Moreover, as noted above, many small distribution utilities—particularly those that are members of a joint action agency—have no interaction with their RTO. Requiring the distribution utility to establish formal communications with outside parties (*e.g.*, DER aggregators and RTOs) will be burdensome for small municipal systems; they do not have the systems or staffing to do this.

The Commission should also state explicitly that RTOs and DER aggregators will not be allowed to impede the routing and emergency maintenance practices of a distribution utility. Today, distribution utilities can take circuits out of service as needed to address reliability, safety, or outage issues. Coordination with RTOs and DER aggregators could unnecessarily impede those critical reliability tasks. And RTOs cannot be allowed to override distribution utility decisions that are taken during distribution line faults or outages to prioritize work and restore service to retail customers as soon as possible.

H. The Commission Should Allow RTOs to Craft Appropriate Rules to Address the Complexity Arising from DER Aggregations Containing a Mix of Generation, Storage, and Demand Response Resources.

The NOPR defines a DER as any "source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter."[37] That definition includes a wide variety of resource types, including storage, distributed generation, and electric vehicles, as well as virtually any retail load. The NOPR proposes to remove limitations on the types of technologies that are allowed to participate in RTO markets through DER aggregators, and it explicitly contemplates "[c]ombining electric storage resources with distributed generation."[38]

Combining multiple types of DER within a single aggregation may be beneficial, but it can also pose complex operational issues. For example, locational requirements, as addressed in the NOPR,[39] could be different for mixed aggregations than for simple distributed generation aggregations. And determining minimum size requirements—including minimum capacity requirements, minimum offer requirements, and minimum bid requirements[40]—becomes more complicated when dealing with mixed aggregations. Given these complexities, the Commission should give RTOs discretion to propose appropriate rules based on what types of mixed aggregations are feasible and the specific limitations that would apply to them.

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[37] *Id.* P 1 n.2.

[38] *Id.* P 133 & n.231.

[39] *Id.* P 139.

[40] *See id.* P 86, n.148 (describing the different types of minimum size requirements).

III. TAPS COMMENTS ON STORAGE RESOURCES

The NOPR recognizes that we are on the cusp of a quantum leap forward in storage technology. Advancements in storage technology are already being implemented in utility-scale applications and are increasingly available in mass-marketed consumer devices. Inexpensive, widespread storage has the potential to transform the grid, and TAPS supports the Commission's goal of better integrating storage into RTO markets.

As the NOPR recognizes, however, storage devices connected to the distribution system present special regulatory challenges because the new wholesale activities envisioned by the NOPR must be delineated from any retail activities of the storage device. NOPR, P 102. As discussed below, reasonable metering and accounting practices cannot assure that separation is maintained. Accordingly, TAPS urges the Commission to clarify the application of paragraph 134 of the NOPR in the storage DER context, so that any retail usage of a storage DER disqualifies the resource from participating in wholesale electric markets as part of a DER aggregation.

A. Storage Interconnected to RTO-Operated Transmission Facilities

TAPS strongly supports the NOPR's goal of facilitating the participation of transmission-connected storage in RTO markets. There is a long history of connecting utility-scale storage to the transmission system, and the participation of such storage will benefit wholesale markets. TAPS generally supports the NOPR's proposals with regard to transmission-connected storage, including its proposal that "the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale [locational marginal price]." NOPR, P 100.

B. Storage Interconnected to Distribution Systems

While participation in RTO markets by distribution-connected storage could also yield benefits, the NOPR's proposal regarding such resources raises concerns that should be addressed in any Final Rule.

Storage DERs seeking to participate in RTO wholesale markets face all of the challenges discussed above with respect to DERs generally. Accordingly, distribution-connected storage resources seeking to transact in RTO wholesale markets should be subject to all of the conditions and clarifications discussed in Part II above. Such storage DERs, for example, should be required to comply with distribution utility tariffs and rates for delivery of energy between the RTO grid and the DER's point of interconnection to the distribution system (including losses provisions and other terms and conditions of service), both for the DER's sales to RTO markets *and* the DER's purchases of energy from RTO markets. While (as noted above) TAPS agrees that storage DERs making wholesale energy purchases from RTO markets should be charged the locational marginal price ("LMP") for that energy, the LMP is the not the only cost for which the DER should be responsible.[41] Any Final Rule should make clear that it does not exempt DERs from, or preempt, any FERC- or state/local-jurisdictional tariff or rate for interconnection to, or delivery over, the distribution system.

Further, the fact that storage DERs both purchase and sell energy adds another layer of complexity. Since purchased energy is converted for storage rather than

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[41] *Cf. Electric Storage Participation in Regions With Organized Wholesale Electric Markets*, Response of Tesla Motors, Inc. 1 (June 6, 2016), eLibrary No. 20160606-5247 ("[The Commission should] clarify that electricity stored for resale is not an end-use load and thus should be only subject to pay the wholesale locational marginal price").

instantaneously transferred or consumed, its ultimate use cannot be verified at the time of the original wholesale energy purchase. As a result, storage interconnected to a distribution system poses additional challenges that generator DERs do not, and additional conditions must be placed on the operation of such storage to respect jurisdictional limitations.

First, as the NOPR recognizes (P 100), all energy purchased from RTO markets at the LMP by distribution-connected storage must be resold, rather than consumed by the purchaser. This point is fundamental because FPA section 201(b)(1), 16 U.S.C. § 824(b)(1), limits the Commission's jurisdiction to sales of electricity at wholesale in interstate commerce; the Commission cannot authorize—let alone require—RTOs to allow sales of energy from organized wholesale markets to end-use customers. Thus, to assure that the wholesale market access contemplated by the NOPR for distribution-connected storage does not become a vehicle to improperly evade the distribution utility's retail service, the Commission must assure that any energy purchased by distribution-connected storage from RTO markets is subsequently resold.

Second, the Commission must also assure that electricity is not purchased at retail by distribution-connected storage and then resold in the RTO's organized wholesale markets. Very few retail jurisdictions have implemented time-of-use rates for retail customers. Instead, retail rates generally are an average of lower off-peak rates and higher on-peak rates. Thus, when wholesale market prices are high, there is an obvious financial incentive to buy from a retail provider at the average price while selling into the wholesale market at the peak price. Indeed, if the owner of a storage resource could simultaneously purchase energy from the retail market and sell energy to the wholesale market in such conditions, it could reap enormous financial returns and shift costs to other retail customers—all without ever changing the physical energy level balance of its storage resource.

To address these concerns, the NOPR seeks comment on metering and accounting practices that can delineate between wholesale and retail activities and determine the end use for energy used to charge an electric storage resource. NOPR, P 102. As discussed above,[42] revenue-quality metering will be needed to separately measure the activities of all distribution-connected storage and generation units that seek to participate in RTO markets. For distribution-connected storage, however, such metering may be inadequate to delineate between wholesale and retail activities. Consider a homeowner with a battery wall, rooftop solar panels, and a collection of electric-powered consumer goods. Even if the battery wall and solar panels are metered separately from the homeowner's consumption of energy, it is virtually impossible to assure that all energy purchased by the battery wall at wholesale is subsequently resold as required to support Commission jurisdiction over the original wholesale market purchase, and that all retail electricity used to charge the battery is subsequently consumed on-site.

From an accounting perspective, two separate energy level balances—one for wholesale and one for retail—would have to be maintained for each distribution-connected storage facility. In each interval, discharge from the retail balance must be limited to the homeowner's consumption in that interval (or perhaps sales to the distribution utility); and discharge from the wholesale balance must be reconciled with

[42] *See supra* Section II.E.

sales to the RTO. Charging from retail or wholesale purchases must be attributed only to the corresponding energy balance, and charging from the rooftop solar panels must be allocated between wholesale and retail use. Situational awareness would require that the DER aggregator and RTO know the wholesale share of the energy level balance for each storage DER, not just its total energy balance. Maintaining and auditing such a system would be enormously complicated and expensive.

Therefore, rather than requiring RTOs and distribution utilities to attempt to design metering and accounting systems to accommodate simultaneous wholesale and retail activities by storage DERs, owners of such storage should be required to make a binding choice between transacting in the wholesale market or using its storage capability at retail. In paragraph 134 of the NOPR, the Commission proposed that a DER should not be permitted to participate in RTO-organized markets if it is "participating in one or more retail compensation programs such as net metering or another wholesale market participation program." The Commission should clarify that in the case of storage DER, any retail usage of storage capability disqualifies the use of that capacity in the wholesale markets. Thus, to the extent a consumer seeks to use storage capacity to manage its own retail load or to sell to its distribution utility, or uses energy purchases from its distribution utility to charge its storage capability, the Commission's rules should prohibit participation by that facility in RTO-organized wholesale markets. Similarly, to the extent the storage participates in the wholesale market, the Commission's rules should prohibit simultaneous use of the same capacity for any retail purpose. Storage resources participating in wholesale markets would have the opportunity to provide and seek compensation for multiple services at wholesale, consistent with the Commission's just-issued Policy Statement.[43]

IV. REGULATORY FLEXIBILITY ACT

As noted above, TAPS understands, and has asked the Commission to confirm, that the NOPR does not attempt to establish new rules or requirements governing the details of distribution interconnections, or whether and how deliveries from DERs to the RTO (and, for DERs that include storage, from the RTO to the DER) might occur; and that the NOPR does not seek to interfere with, nor require change to, any RERRA or distribution utility tariff, rule, or regulation. TAPS has also requested that the Commission require, consistent with Order No. 719-A, express permission from the RERRA before the RTO may accept bids from DERs located on a small utility system. As long as the Commission confirms the limited scope of the NOPR and adopts opt-in/opt-out provisions patterned on those promulgated by Order No. 719-A, TAPS does not dispute the Commission's certification (NOPR, PP 164-166) that the reforms required by this NOPR will not have a significant economic impact on a substantial number of small entities.[44]

However, if the Commission expands the scope of this proceeding—for example by attempting to require distribution utilities to allow DERs to use their distribution facilities to participate in RTO markets, or by requiring that distribution utilities take certain actions to facilitate energy storage resource participation in RTO markets—it

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[43] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017) ("Policy Statement").

[44] NOPR, P 166.

would trigger the obligation to perform a regulatory flexibility analysis. The Commission is required to perform a regulatory flexibility analysis when its "regulations expressly require[] certain actions by small entities."[45] And many small entities would be affected. As discussed in these comments, the proposed regulations could impose significant operational, reliability, safety, and economic impacts on distribution utilities, and those impacts would disproportionately affect small entities.[46] Thus, if the Commission expands the scope of this proceeding, it must consider alternatives to minimize impact on small entities, including the recommendations proposed in these comments.

CONCLUSION

The Commission should clarify and modify the proposed rule as set forth above.

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[45] Credit Reforms in Organized Wholesale Electric Markets, Order No. 741, 75 Fed. Reg. 65,942 (Oct. 27, 2010), FERC Stats. & Regs. ¶ 31,317 (2010), *on reh'g*, Order No. 741-A, 76 Fed. Red. 10,492, 10,497 (Feb. 25, 2011), FERC Stats. & Regs. ¶ 31,320, P 42 (2011) (citing *Aeronautical Repair Station Ass'n, Inc. v. FAA*, 494 F.3d 161 (D.C. Cir. 2007)), *reh'g denied*, Order No. 741-B, 135 FERC ¶ 61,242 (2011).

[46] *See supra* Section II.D.

Respectfully submitted,

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February 13, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 13th day of February, 2017.

/s/ Latif M. Nurani
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