them be required from aggregators to ensure proper planning and operation of the bulk power system?

8. Do the RTOs/ISOs need any directly metered data about the operations of DER aggregations to ensure proper planning and operation of the bulk power system?

Based on the discussion at the April 10–11 Technical Conference, comments are also requested on the following additional questions:

9. What can DERs offer to support or enhance bulk power system reliability? How can these benefits be quantified? Are these opportunities unique to DERs?

10. With the recently approved IEEE 1547–2018 Standard, what coordination or collaboration is needed to leverage the Standard's technical requirements (*e.g.,* ride-through settings, communication capabilities) in a manner that supports bulk power system reliability?

11. Is a formal development of a grid architecture that includes distribution and transmission systems necessary to facilitate planning efforts to incorporate DERs?

12. What specific real-time DER data is needed to manage bulk power system reliability? Why is that data needed? Is there a specific penetration-level of DERs above which real-time data is needed? Without real-time DER data to ensure visibility of DER installations, what, if any, potential challenges and mitigating actions exist for RTOs/ISOs and transmission operators (*e.g.,* the potential need to procure additional contingency reserves)? Please give examples.

13. What challenges exist for DER developers and owners to provide DER real-time data? Please give examples.

*Incorporating DERs in Modeling, Planning, and Operations Studies (Panel 5)*

Bulk power system planners and operators must select methods to feasibly model DERs at the bulk power system level with sufficient granularity to ensure accurate results. The chosen methodology for grouping DERs at the bulk power system level could affect planners' ability to predict system behavior following events, or to identify a need for different operating procedures under changing system conditions. Further, the operation of DERs can affect both bulk power systems and distribution facilities in unintended ways, suggesting that new tools to model the transmission and distribution interface may be needed. Staff is also aware of ongoing work in this area, for example efforts at NERC, national labs, and other groups, to evaluate options for studies in these areas, which could also inform future work. The following questions focus on the incorporation of DERs into different types of planning and operational studies, including options for modeling DERs and the methodology for the inclusion of DERs in larger regional models. The Commission Staff DER Technical Report, issued on February 15, 2018, provides a common foundation for the topics raised in this panel.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. What are current and best practices for modeling DERs in different types of planning, operations, and production cost studies? Are options available for modeling the interactions between the transmission and distribution systems?

2. To what extent are capabilities and performance of DERs currently modeled? Do current modeling tools provide features needed to model these capabilities?

3. What methods, such as net load, composite load models, detailed models or others, are currently used in power flow and dynamic models to represent groups of DERs at the bulk power system level? Would more detailed models of DERs at the bulk power system level provide better visibility and enable more accurate assessment of their impacts on system conditions? Does the appropriate method for grouping DERs vary by penetration level?

4. Do current contingency studies include the outage of DER facilities, and if they are considered, how is the contingency size chosen? At what penetration levels or under what system conditions could including DER outages be beneficial? Are DERs accounted for in calculations for Under Frequency Load Shedding and related studies?

5. What methods are used to calculate capacity needed for balancing supply and demand with large amount of solar DER (ramping and frequency control) and determining which resources can provide an appropriate response?

Based on the discussion at the April 10–11 Technical Conference, comments are also requested on the following additional questions:

6. For planning efforts, how are model parameters determined and incorporated into existing models using currently available data on DER capabilities? What types of validation techniques are used for the data in these models and how often are they applied?

7. Given the discussion on interactions between distribution and transmission operators, are further requirements for distributed controls, interoperability and/or cybersecurity protections being evaluated? Would advanced techniques and methods to simulate real-time systems, distributed controls and demand response or additional risk-based planning methods, forecasting techniques and data analytics provide a benefit in this area? Which of these methods would provide the most value to operators and why?

[FR Doc. 2018–09450 Filed 5–3–18; 8:45 am]

**BILLING CODE 6717–01–P**

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## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

**[Docket No. RM18–9–000]**

### Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators; Notice Inviting Post-Technical Conference Comments

On April 10 and April 11, 2018, Federal Energy Regulatory Commission (Commission) staff convened a technical conference to discuss the participation of distributed energy resource (DER) aggregations in Regional Transmission Organization (RTO) and Independent System Operator (ISO) markets and to more broadly discuss the potential effects of DERs on the bulk power system.

All interested persons are invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including the questions listed in the Supplemental Notices issued in this proceeding on March 29, 2018 and April 9, 2018. In addition, Commission staff is interested in comments on several follow-up topics and questions. Commenters need not respond to all topics or questions asked. Attached to this notice are the *DER aggregation topics and questions related to Panels 1, 2, 3, 6, and 7* from the two previous notices, as well as Commission staff's follow-up questions related to those panels. *Please file comments relating to these issues in Docket No. RM18–9–000.*

A notice inviting post-technical conference comments on *the topics and questions relating to the potential effects of DERs on the bulk power system related to Panels 4 and 5* is being concurrently issued in Docket No. AD18–10–000. *Please separately file* *comments relating to Panels 4 and 5 in Docket No. AD18–10–000.*

Commenters may reference material previously filed in this docket but are encouraged to avoid repetition or replication of previous material. In addition, commenters are encouraged, when possible, to provide examples in support of their answers. Comments must be submitted on or before 60 days from the date of this notice and should not exceed 30 pages.

For further information about this Notice, please contact:

*Technical Information*

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*Legal Information*

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Dated: April 27, 2018.

**Kimberly D. Bose,**

*Secretary.*

**Post-Technical Conference Questions for Comment**

**RM18-9-00**

**Economic Dispatch, Pricing, and Settlement of DER Aggregations (Panel 1)**

In the Commission's Notice of Proposed Rulemaking on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (NOPR), the Commission proposed to require each RTO/ISO to revise its tariff to remove barriers to the participation of DER aggregations in its markets by, among other measures, establishing locational requirements for DER aggregations that are as geographically broad as technically feasible.[1] The NOPR also addressed the use of distribution factors[2] and bidding parameters[3] for DER aggregations. In consideration of comments received in response to the NOPR, the Commission seeks additional information about how DER aggregations could locate across more than one pricing node. The Commission would also like additional information about bidding parameters or other potential mechanisms needed to represent the physical and operational characteristics of DER aggregations in RTO/ISO markets.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. Acknowledging that some RTOs/ISOs already allow aggregations across multiple pricing nodes, what approaches are available to ensure that the dispatch of a multi-node DER aggregation does not exacerbate a transmission constraint?

2. Because transmission constraints change over time, would the ability of a multi-node DER aggregation to participate in an RTO/ISO market need to be revisited as system topology changes?

3. Do multi-node DER aggregations present any special considerations for the reliability of the transmission system that do not arise from other market participants? How could these concerns be resolved?

4. What types of modifications would need to be made to the modeling and dispatch software, communications platforms, and automation tools necessary to enable reliable and efficient system dispatch for multi-node DER aggregations? How long would it take for these changes to be implemented?

5. If the Commission requires the RTOs/ISOs to allow multi-node DER aggregations to participate in their markets, how should a DER aggregation located across multiple pricing nodes be settled for the services that it provides? One approach to settling a multi-node DER aggregation could be to pay it the weighted average locational marginal price (LMP) across the nodes at which it is located. What are the advantages and disadvantages of this approach? Are there other approaches that should be considered?

6. The NOPR considered the use of ''distribution factors'' to account for the expected response of DER aggregations from multiple nodes. Are there other characteristics of DER aggregations that may not be accommodated by existing bidding parameters in the RTOs/ISOs? If so, what are they? Would new bidding parameters be necessary? If so, what are they?

Based on the discussion at the April 10–11 Technical Conference, comments are also requested on the following additional questions:

7. During the technical conference, several panelists indicated that there has been limited interest in using CAISO's DER provider model (DERP). Please explain why DER aggregators have not used that model to date, what other approaches, if any, that DERs are using to access the CAISO and other RTO/ISO markets, and whether those alternative approaches provide adequate RTO/ISO market access for both behind-the-meter and front-of-meter DERs.

8. During the technical conference, some panelists noted that for multi-node aggregations (a) there is a need to accurately represent the capabilities of DER aggregations at each node that they are located, and (b) more accurate representation at each node of a multi-node aggregation begins to make the aggregation look like a single-node resource. Some of the benefits discussed of multi-node aggregation included allowing an aggregation of DERs to provide more reliable services to the market and reducing transaction costs as a market participant, among others. Conversely, there was a discussion of the market operator's need to accurately represent the capabilities of the aggregation at individual nodes. Please comment on the benefits of being able to aggregate across multiple nodes versus the market operator's need to accurately represent the capabilities of the aggregation at individual nodes. If multi-node resources present risks or challenges to the system, what are they? Can they be overcome? How?

9. During the panel discussion, CAISO mentioned that it allows multi-node aggregations within a defined set of nodes that have been deemed to have sufficiently little congestion across the nodes. Other panelists expressed a preference for single node aggregations. Are there methods to identify sets of nodes within which aggregation could be allowed that would balance concerns with multi-node aggregations against the benefits of multi-node aggregations. For instance, are there ways to group nodes associated with load centers that would facilitate aggregation while not threatening reliability and undermining the benefits of nodal pricing?

10. Would reducing the minimum size requirement for DER aggregations to participate in the RTO/ISO markets (for example, to 100 kW as proposed in the NYISO DER Roadmap) help alleviate some of the concerns about requiring DER aggregations to be located only at a single pricing node? Or, would locating at a single node inhibit the development of DER aggregations

[1] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 139.

[2] The Commission proposed to require each RTO/ISO to revise its tariff to include the requirement that DER aggregators (1) provide default distribution factors when they register their DER aggregation and (2) update those distribution factors if necessary when they submit offers to sell or bids to buy into the organized wholesale electric markets. *Id.* P 143.

[3] The Commission sought comment on whether bidding parameters in addition to those already incorporated into existing participation models may be necessary to adequately characterize the physical or operational characteristics of DER aggregations. *Id.* P 144.

regardless of the minimum size requirement?

11. How are the concerns about constraints on the transmission system different for multi-node demand response aggregations versus multi-node DER aggregations?

12. During the technical conference, some panelists raised questions regarding potential tradeoffs between establishing rules for DER aggregations now in anticipation of a high DER future, and the potential technology and market efficiency costs of requiring nodal aggregation or other measures to manage the potential effects of DER aggregations before it is necessary. What are these tradeoffs? Do they change over time? Does the penetration of DERs affect how to assess the tradeoffs? Does the penetration of DERs affect the appropriate locational requirements for DER aggregations?

**Discussion of Operational Implications of DER Aggregation With State and Local Regulators (Panel 2)**

Comments are requested on state and local regulator concerns about the operational effects that DER participation in the wholesale market could have on facilities they regulate. Please respond to the following topics and questions that were included in previous supplemental notices:

1. What are the potential positive or negative operational impacts (e.g., safety, reliability, and dispatch) that DER participation in the wholesale market could have on facilities regulated by state and local authorities? How should the costs associated with monitoring and addressing such potential impacts on the distribution grid caused by the NOPR proposal be addressed, and fairly allocated? Are existing retail rate structures able to allocate costs to DER aggregations that utilize the distribution systems, and if not, what modifications or coordination are feasible?

2. Do state and local authorities have operational concerns with a DER aggregation participating in both wholesale and retail markets? If so, what, if any, coordination protocols between states or local regulators and regional markets would be required to facilitate DER aggregations' participation in both retail and wholesale markets? Could the use of appropriate metering and telemetry address the ability to distinguish between markets and services, and prevent double compensation for the same services? What is the role of state and local regulators in monitoring and regulating the potential for such double compensation? How should regional flexibility be accommodated?

3. What entities should be included in the coordination processes used to facilitate the participation of DER aggregations in RTO/ISO markets? Should state and local regulatory authorities play an active role in these coordination processes? Is there a need to modify existing RTO/ISO protocols or develop new protocols to accommodate state participation in this coordination? What should be the role of state and local regulators in the NOPR's proposed distribution utility review of DER aggregation registrations?

4. Does the proposed use of market participation agreements address state and local regulator concerns about the role of distribution utilities in the coordination and registration of DERs in aggregations? Are the proposed provisions in the market participation agreements that require that DER aggregators attest that they are compliant with the tariffs and operation procedures of distribution utilities and state and local regulators sufficient to address such concerns?

5. What are the proper protections and policies to ensure that DER aggregations participating in wholesale markets will not negatively affect efficient outcomes in the distribution system?

Based on the discussion at the April 10–11 Technical Conference, comments are also requested on the following additional question:

6. During the technical conference, some panelists noted interest in a limited opt-out provision which would allow states to require DERs to choose participation in either the RTO/ISO market or retail compensation programs, but not both. How would such a limited opt-out be implemented? What are the benefits and drawbacks of such an approach?

**Participation of DERs in RTO/ISO Markets (Panel 3)**

DERs can both sell services into the RTO/ISO markets and participate in retail compensation programs. To ensure that that there is no duplication of compensation for the same service, in the NOPR the Commission proposed that individual DERs participating in one or more retail compensation programs, such as net metering or another RTO/ISO market participation program, will not be eligible to participate in the RTO/ISO markets as part of a DER aggregation.[4] In consideration of comments received in response to the NOPR, the Commission seeks additional information about potential solutions to challenges associated with DER aggregations that provide multiple services, including ways to avoid duplication of compensation for their services in the RTO/ISO markets, potential ways for the RTOs/ISOs to place appropriate restrictions on the services they can provide, and procedures to ensure that DERs are not accounted for in ways that affect efficient outcomes in the RTO/ISO markets.

[4] *Id.* P 134.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. Given the variety of wholesale and retail services, is it possible to universally characterize a set of wholesale and retail services as the ''same service''? If so, how could the Commission prohibit a DER from providing the same service to the wholesale market as it provides in a retail compensation program?

2. In Order No. 719, the Commission stated that ''[a]n RTO or ISO may place appropriate restrictions on any customer's participation in an [aggregation of retail customers]-aggregated demand response bid to avoid counting the same demand response resource more than once.''[5] How have the RTOs/ISOs effectuated this requirement or otherwise ensured that demand response participating in their markets is not being double counted? What would be the advantages and disadvantages of taking this approach for DER aggregations instead of the approach proposed in the NOPR for preventing double compensation for the same service?

3. What other options besides the NOPR's proposed limits on dual participation exist to address issues associated with the participation of DERs or DER aggregations in one or more retail compensation programs or another wholesale market participation program at the same time as it participates in a wholesale DER aggregation? Is there a way to coordinate DER participation in multiple markets or compensation programs? Is a possible solution having a targeted prohibition, such as the limitation placed on net-metered resources in CAISO?[6] Are there other means?

[5] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, FERC Stats. & Regs. ¶ 31,281, at P 158 (2008), *order on reh'g,* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g,* Order No. 719–B, 129 FERC ¶ 61,252 (2009).

[6] *See* CAISO Tariff, § 4.17.3(d).

**Coordination of DER Aggregations Participating in RTO/ISO Markets (Panel 6)**

In the NOPR, the Commission proposed to require each RTO/ISO to revise its tariff to provide for coordination among itself, a DER aggregator, and the relevant distribution utility or utilities when a DER aggregator registers a new DER aggregation or modifies an existing DER aggregation.[7] The Commission proposed that this coordination would provide the relevant distribution utility or utilities with the opportunity to review the list of individual resources that are located on their distribution system that enroll in a DER aggregation before those resources may participate in RTO/ISO electric markets. In consideration of comments received in response to the NOPR, the Commission seeks additional information on the potential ways for RTOs/ISOs, distribution utilities, retail regulatory authorities, and DER aggregators to coordinate the integration of a DER aggregation into the RTO/ISO markets. In addition, because the use of grid architecture[8] can help identify the relationships among the entities involved in coordinating the integration of DER aggregations, the Commission is also interested in comments about potential architectural designs for the initial coordination processes from the point of view of the RTO/ISO markets.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. If the Commission adopts its proposal to require the RTO/ISO to allow a distribution utility to review the list of individual resources that are located on their distribution system that enroll in a DER aggregation before those resources may participate in RTO/ISO electric markets, is it appropriate for distribution utilities to have a role in determining when the individual DERs may begin participation? Should the RTO/ISO tariff provide the distribution utility with the ability to provide either binding or non-binding input to the RTO/ISO? Should the RTO/ISO provide the distribution utility with a specific period of time in which to consult before DERs may begin participation? Should the Commission require the RTO/ISO to receive explicit consent from the distribution utility before a DER is included in a DER aggregation? Are there other approaches to coordinate with the distribution utility? What are the advantages and disadvantages of these approaches?

2. Are new processes and protocols needed to ensure coordination among DER aggregators, distribution utilities, and RTOs/ISOs during registration of a new DER aggregations? How can the Commission ensure that any new processes and protocols occur in a way that provides adequate transparency to the interested parties and also occurs on a timely basis?

3. Should there be a coordination agreement in place prior to the participation of DER aggregation in RTO/ISO markets? Who should be parties to this coordination agreement? How would the coordination agreement be enforced?

4. What is the best approach for involving retail regulatory authorities in the registration of DER aggregations in the RTO/ISO markets?

5. What types of grid architecture could support the integration of DER aggregations into the RTO/ISO markets? Knowing that a variety of grid architectures are being explored in various regions, does it make sense for the Commission to consider specific architectural requirements for RTOs/ISOs for the effective integration and coordination of DER aggregations?

Based on the discussion at the April 10–11 Technical Conference, comments are also requested on the following additional questions:

6. During the technical conference, several panelists expressed the need for criteria to evaluate the ability of an individual DER to participate in a DER aggregation. What specific criteria should distribution utilities use to evaluate the ability of a DER to participate in an aggregation, and who should set these criteria?

7. During the technical conference, several panelists expressed the need for criteria to evaluate the ability of a DER aggregation to participate in the RTO/ISO markets. What specific criteria should distribution utilities use to evaluate the ability of a DER aggregation to participate in the RTO/ISO markets, and who should set these criteria?

8. Some panelists suggested that the state and RTO/ISO interconnection processes could provide the means to evaluate the ability of a DER to participate in an RTO/ISO market. To the extent that RTOs/ISOs currently have a process that applies to the interconnection of DERs to Commission-jurisdictional transmission and distribution facilities, please explain the process and criteria evaluated, including referencing any relevant tariff or business practice manual provisions.

9. During the technical conference, panelists highlighted the importance of coordination procedures and frameworks. Should coordination frameworks for DER aggregation, particularly between RTOs/ISOs and distribution utilities, be required or encouraged to be developed between the appropriate entities?

10. During the technical conference, some panelists commented on the importance of specifying roles with regard to DER aggregation. What should be the specific roles and responsibilities for distribution utilities, DER aggregators, retail regulators, and RTOs/ISOs associated with the participation of DER aggregators in RTO/ISO markets? Should the Commission specify these roles?

11. During the technical conference, several panelists discussed the need to know the attributes of DERs on their distribution system. Please describe, where applicable, what types of static and dynamic information is currently being provided about aggregated or individual DERs to distribution utilities and to RTOs/ISOs. Is there additional static information about aggregated DERs or the individual DERs in those aggregations that distribution utilities need that would not be made available during the interconnection process? What, if any, dynamic information would the distribution utility need from the RTO/ISO in real time regarding DER aggregations that are participating in the RTO/ISO markets, or the individual DERs in those aggregations? How would the distribution utility use this static or dynamic information?

12. As more DERs are added to the distribution system, the system may become more variable due to the output of certain variable resources such as wind and solar PV, and the operation of self-scheduled resources such as batteries and electric vehicles. Given this anticipated volatility at the distribution level, would the participation of aggregations of these DERs in the RTO/ISO markets further increase or decrease system variability?

13. Do the safety and reliability concerns discussed at the technical conference exist on distribution systems with high DER penetration regardless of whether those resources are participating in the RTO/ISO markets? What current standards, procedures, or other measures are used to manage the safety and reliability of a distribution

[7] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 154.

[8] As an aid to thinking about the electric power grid, Pacific Northwest National Laboratory and others have coined the term ''grid architecture,'' which they define as the application of network theory and control theory to a conceptual model of the electric power grid that defines its structure, behavior, and essential limits. *See, e.g., https://gridarchitecture.pnnl.gov/.* Expanding upon this concept, some researchers have begun discussing different types of ''grid architecture,'' which presumably differ in structure, behavior or essential limits from current norms.

system with high DER penetration where those resources do not participate in the RTO/ISO markets? Would these measures also help manage the safety and reliability of a distribution system where these resources do participate in the RTO/ISO markets? Would additional safety and reliability measures be necessary if DERs participate in the RTO/ISO markets, or would the current safeguards against backflows, islanding, or other concerns adequately ensure safety and reliability? If additional measures are necessary, what are they?

**Ongoing Operational Coordination (Panel 7)**

In the NOPR, the Commission acknowledged that ongoing coordination between the RTO/ISO, a DER aggregator, and the relevant distribution utility or utilities may be necessary to ensure that the DER aggregator is dispatching individual resources in a DER aggregation consistent with the limitations of the distribution system.[9] The Commission proposed that each RTO/ISO revise its tariff to establish a process for ongoing coordination, including operational coordination, among itself, the DER aggregator, and the distribution utility to maximize the availability of the DER aggregation consistent with the safe and reliable operation of the distribution system. To help effectuate this proposal, the Commission also proposed to require each RTO/ISO to revise its tariff to require the DER aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages. The Commission also sought comment on the level of detail necessary in the RTO/ISO tariffs to establish a framework for ongoing coordination between the RTO/ISO, a DER aggregator, and the relevant distribution utility or utilities.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. What real-time data acquisition and communication technologies are currently in use to provide bulk power system operators with visibility into the distribution system? Are they adequate to convey the information necessary for transmission and distribution operators to assess distribution system conditions in real time? Are new systems or approaches needed? Does DER aggregation require separate or additional capabilities and infrastructure for communication and control?

2. What processes/protocols do distribution utilities, transmission operators, and DERs or DER aggregators use to coordinate with each other? Are these processes/protocols capable of providing needed real-time communications and coordination? What new processes, resources, and efforts will be required to achieve effective real-time coordination?

3. What are the minimum set of specific RTO/ISO operational protocols, performance standards, and market rules that should be adopted now to ensure operational coordination for DER aggregation participating in the RTO/ISO markets? What additional protocols may be important for the future? Should the Commission adopt more prescriptive requirements with respect to coordination than those proposed in the NOPR? If so, what should the Commission require?

4. Should distribution utilities be able to override RTO/ISO decisions regarding day-ahead and real-time dispatch of DER aggregations to resolve local distribution reliability issues? If so, should DER aggregations nonetheless be subject to non-deliverability penalties under such circumstances?

5. Is it possible for DERs or DER aggregations participating in the RTO/ISO markets to also be used to improve distribution system operations and reliability? If so, please provide examples of how this could be accomplished.

6. Can real-time dispatch of aggregated DERs address distribution constraints? If not, can tools be developed to accomplish this?

7. Should individual DERs be required to have communications capabilities to comply with control center obligations? What level of communications security should be employed for these communications?

8. How might recent and expected technical advancements be used to enhance the coordination of DER aggregations, for example, integrating Energy Management Systems (EMS) and Distribution Management Systems (DMS) for efficient operational coordination?

[9] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 155.

[FR Doc. 2018–09455 Filed 5–3–18; 8:45 am]

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## DEPARTMENT OF ENERGY

## Federal Energy Regulatory Commission

**[Docket No. EL18–138–000]**

## Midcontinent Independent System Operator, Inc., ALLETE, Inc., Montana-Dakota Utilities Co., Northern Indiana Public Service Company, Otter Tail Power Company, Southern Indiana Gas & Electric Company; Notice of Institution of Section 206 Proceeding and Refund Effective Date

On April 27, 2018, the Commission issued an order in Docket No. EL18–138–000 pursuant to section 206 of the Federal Power Act (FPA), 16 U.S.C. 824e (2012), instituting an investigation into whether the transmission formula rate templates of ALLETE, Inc., Montana-Dakota Utilities Co., Northern Indiana Public Service Company, Otter Tail Power Company, and Southern Indiana Gas & Electric Company under Attachment O of the Midcontinent Independent System Operator, Inc. Open Access Transmission, Energy and Operating Reserve Markets Tariff may be unjust, unreasonable, or unduly discriminatory or preferential. *Midcontinent Independent System Operator, Inc., et al.,* 163 FERC 61, 061 (2018).

The refund effective date in Docket Nos. EL18–138–000, established pursuant to section 206(b) of the FPA, will be the date of publication of this notice in the **Federal Register**.

Any interested person desiring to be heard in Docket Nos. EL18–138–000 must file a notice of intervention or motion to intervene, as appropriate, with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, in accordance with Rule 214 of the Commission's Rules of Practice and Procedure, 18 CFR 385.214 (2017), within 21 days of the date of issuance of the order.

Dated: April 27, 2018.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2018–09452 Filed 5–3–18; 8:45 am]

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