Exhibit No.:	
Issue:	Demand Response Resource Participation in Wholesale Markets
Witness:	Burton L. Crawford
Type of Exhibit:	Supplemental Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2018-0145
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2018-0145

SUPPLEMENTAL DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
June 2018

Q: Please state your name and business address.

A: My name is Burton L. Crawford. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: Are you the same Burton L. Crawford who pre-filed Direct Testimony in this matter on behalf of Kansas City Power & Light Company ("KCP&L" or "Company")?

A: Yes.

Q: What is the purpose of your testimony?

A: The purpose of my Supplemental Direct Testimony is to respond, in part, to the Commission's Order Granting Motion for Supplemental Direct Testimony in Furtherance of Staff's Report on Distributed Energy Resources.

SECTION 1: <u>Retail Demand Response Participation in PJM, MISO, and SPP Wholesale Markets</u>

Q: What is the purpose of this portion of your testimony?

A: The purpose of this section of the testimony is to provide background information on retail demand response ("DR") participation in wholesale markets and describe some of the similarities and difference in how retail DR resources may participate in the PJM, MISO, and SPP wholesale markets.

Q. Please provide some background on the issue of retail customers or aggregators of retail customers offering demand response directly into wholesale markets.

A: In 2008, the Federal Energy Regulatory Commission ("FERC") issued Order 719 requiring Regional Transmission Organizations ("RTO"s) and Independent System Operators ("ISO"s) to amend their market rules to allow Aggregators of Retail Customers ("ARC"s) to bid demand response resources from retail customers directly into the RTO and ISO wholesale energy and ancillary services markets like any other market participant, unless the laws or regulations of the relevant retail electric regulatory authority do not permit retail customer participation.[1] FERC found that allowing ARCs to act as intermediaries in the organized markets would reduce barriers to DR participation.

In FERC's final Order 719A, ISOs and RTOs may not accept bids from ARCs that aggregate the demand response of customers of utilities that distributed more than four million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority ("RERRA") prohibits ARCs from doing so. The ISO and RTO may not accept bids from ARCs that aggregate the demand response of customers of utilities that distributed four million MWh or less in the previous year unless the RERRA specifically permits it.[2]

The term "relevant electric retail regulatory authority" means the entity that establishes retail electric prices and any retail competition policies for customers, such as the state public utility commission.[3] All four of the Missouri electric investor-owned public utilities ("IOUs") distribute more than four million MWh each year. As such, unless the Missouri Commission affirmatively prohibits ARCs from aggregating customers' DR, the ARC is allowed to aggregate retail customer DR and bid it into the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") wholesale markets.

[1] Order No. 719, Final Rule, Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. RM07-19-000 and AD07-7-000, 125 FERC 61,071 para 128 (October 17, 2008).

[2] Order No. 719-A, Order On Rehearing, *Wholesale Competition in Regions with Organized Electric Markets*, Docket Nos. RM07-19-001, 128 FERC 61,059 para. 60 (July 16, 2009)

[3] Order 719, para. 158 c.

Q. What action has the Commission taken regarding this matter?

A. In case EW-2010-0187, the Commission issued an 'Order Temporarily Prohibiting the Operation of Aggregators of Retail Customers'. In that order, the Commission determined that "Demand response load reductions of customers of the four Missouri electric utilities regulated by the Commission are prohibited from being transferred to ISO or RTO markets directly by retail customers or third-party ARCs."[4] Subsequent to that order, the Commission conduced several topical workshops but closed the docket without taking any further action.

Q: Do MISO and SPP tariffs allow retail customers or ARCs to offer demand response in their energy and ancillary service markets?

A: Yes. Per the FERC Orders, MISO and SPP implemented tariff changes to allow qualified retail customers and ARCs to offer DR resources into their wholesale and ancillary service markets. Specific to the SPP Open Access Transmission Tariff ("OATT"), the definition of market participants expressly includes "(g) any retail customer or eligible person that is not precluded under the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s) from participating directly in wholesale demand response programs in the Energy and Operating Reserve Markets and that is technically qualified to offer Demand Response Load (as defined in Attachment AE of this Tariff) into the Energy and Operating Reserve Markets or an aggregator of such retail customers that offers qualified Demand Response Load into the Energy and Operating Reserve Markets under Section 2.8 of Attachment AE".[5] However per the

[4] EW-2010-0187, Order Temporarily Prohibiting the Operations of Aggregators of Retail Customers, Effective March 31, 2010.

[5] Open Access Transmission Tariff, Sixth Revised Volume No. 1, Southwest Power Pool, Inc., March 23, 2018, Section I.1.M., Available at: https://www.spp.org/spp-documents-filings/?id=18162

2010 Commission Order, Missouri retail customers and third party ARCs are precluded from offering DR resources directly into wholesale markets.

Q: When were changes made to the SPP OATT to integrate DR resources and what is the current level of DR resource participation in the SPP Integrated Marketplace?

A: Changes to the SPP OATT to integrate DR resources with the current methodology were implemented with the start of the SPP Integrated Marketplace ("SPPIM") in March 2014. There are no DR resources currently registered to participate in the SPPIM. Current SPP energy market conditions (i.e.: low and stable energy market prices) may continue to deter market participants from developing DR resources that can participate in the market.

Q: Please describe how the 'Indiana Model' works and allows Indiana retail customers and ARCs to participate in the MISO and PJM Interconnection ("PJM") wholesale markets.

A: The Indiana Model is an example of a mechanism utilized to enable DR resource participation in the MISO and PJM RTO markets. Similar to the Missouri prohibition, the Indiana Utility Regulatory Commission ("IURC") precludes retail customers or third-party ARCs from entering retail DR resources directly into the wholesale markets. Under the 'Indiana Model' the retail customer or ARC enrolls the customer DR resources in a regulated retail utility's wholesale market demand response tariff. The retail utility, as the load serving entity ("LSE") and market participant, offers the DR resources into the ISO/RTO market on behalf of the retail customer/ARC and communicates market bid acceptance and dispatch instructions to the customer/ARC. The customer/ARC receives compensation from the retail utility based on actual DR resource performance and market settlement rules.

Q: Would changes to the 2010 Commission DR aggregation order be required for DR resources to participate in the SPP wholesale market?

A: No. There are a couple of options that may enable DR resources to participate in SPP and align with the vertically integrated nature of SPP states without the need for changes to the existing order. The order states in part "Demand response load reductions of customers… are prohibited from being transferred to ISO or RTO markets **directly** (emphasis added) by retail customers or third-party ARCs."[6] Under both the 'Indiana Model' and where the utility aggregates DR, either through itself or through a third party, the DR resources are registered with the ISO/RTO market through the regulated utility, not directly by the retail customer or third-party ARC.

Q: Do SPP, MISO, and PJM provide the same opportunities for DR resources to participate in their respective energy and ancillary service markets?

A: No. There are many similarities, but some of the differences are subtle and others are significant. Of the three markets, PJM offers the most opportunities and the most flexibility for DR resource market participation, while SPP has the fewest and most restrictive criteria for market participation by DR resources. For example, PJM aggregated residential DR resources are only required to have interval metering installed on a statistical sample of accounts.[7] In contrast, SPP treats DR resources similar to all

[6] EW-2010-0187, Order Temporarily Prohibiting the Operations of Aggregators of Retail Customers, Effective March 31, 2010.

[7] PJM Manual 11: Energy & Ancillary Services Market Operations, Revision: 94, April 12, 2018, pg. 135.

other market resources, requiring all participating customer meters to have telemetry and interval metering installed.[8]

Q: Can you provide some additional differences between the markets?

A: Since all Missouri electric IOUs participate in either the SPP or MISO market, I will highlight some of the more significant differences in market participation opportunities available to DR resources.

First, MISO offers opportunities for DR resources in the following market products: Energy (day-ahead & real-time); Operating Reserves (spinning, supplemental, regulating, and ramping); Planning Resources (generation capacity); Emergency Demand Response ("EDR") (load curtailment during ISO declared emergencies). By contrast, SPP only provides opportunities to DR resources to participate in the Energy and Operating Reserves markets and does not have a capacity market or payments for emergency load curtailment. Later in my testimony, I will discuss how SPP member utilities can use DR to impact capacity costs.

Secondly, both MISO and SPP permit DR resources to be registered as a Demand Response Resource ("DRR") and participate in energy and operating reserve markets, but they have slightly different classifications and requirements for participation. MISO defines two classes of DRR: DRR-Type I, fixed load reduction amount and DRR-Type II, variable load reduction amount. SPP provides for a similar registration of two types of DRR, but refers to them as Block Demand Response ("BDR") which can only be committed in hourly blocks and Dispatchable Demand Response ("DDR") resources which can be dispatched by SPP.[9] While the MISO DRR-Type I and DRR-Type II

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[8] Market Protocols SPP Integrated Marketplace, R58, Southwest Power Pool, May 1, 2018, pgs. 148-150.
[9] Market Protocols SPP Integrated Marketplace, R58, Southwest Power Pool, May 1, 2018, pg. 135-139.

resources are similar in operation to the SPP BDR and DDR resources, there are differences in the technical requirements for each resource type to participate in a specific market product. For example, SPP treats DR resources similar to all other market resources and generally has more stringent telemeter, metering and verification requirements for BDR resources than MISO has for DDR-Type 1 resources.

Additionally, within the MISO capacity planning market, planning resources are defined as either Capacity or Load Modification Resources ("LMR"). DRR-Type 1 and II resources may be registered as either Capacity or LMR resources. Other DR resources may register a LMR. Planning resources have monetary value because they can be substituted for generation resources by an LSE in meeting its assigned Planning Reserve Margin Requirement (PRMR) or 'sell' them in the Planning Reserve Auction. SPP does not have a similar capacity market or LMR registration. Furthermore, if a non-utility participant (whether an individual customer or an ARC) bids its DR resource into the SPP market, the capacity value of the DR resource is lost. Current SPP market protocols do not have a mechanism that would enable the utility to reduce its capacity reserve obligation for a non-utility controlled DR resource.

Finally, DRRs and LMRs can be registered as MISO EDR resources[10] and receive EDR payments when they curtail load during MISO declared emergencies. LMRs that clear the MISO Resource Planning Auction must still respond during MISO declared emergency events. SPP does not have a similar EDR tariff.

[10] Demand Response Business Practice Manual, BPM-026-r2, MISO, July 01, 2017, pg. 10-13.

Q: Earlier you stated that SPP provides for the registration of Dispatchible Demand Response (DDR) and Block Demand Response (BDR) resources. Can you explain the differences?

A: A Dispatchable DR Resource is a special type of resource created to model demand reduction associated with controllable load and/or a behind the meter generator that is dispatchable on a 5-minute basis. The DDR load must be telemetered and provided to SPP on a 10-second basis. Most DDR resources will require submission of an hourly baseline load profile for use in calculating the actual load reduction for settlements. Interval meter data (5- or 60- minute depending on the resource and market product) must be submitted within five days.[11]

A Block DR Resource is a special type of resource created to model demand reduction that is not dispatchable on a 5-minute basis but can be committed and dispatched in hourly blocks. SPP requires that BDR loads also be telemetered and provided to SPP on a 10-second basis. All BDR resources will require submission of a baseline hourly load profile to calculate the load reduction for settlements. Interval meter data (5- or 60-minute depending on the resource and market product) must be submitted within five days.[12]

"Typically, demand reduction would be registered as a Block Demand Response Resource but an industrial site that has a generator or can control its load consumption on a real-time basis could register as a Dispatchable Demand Response Resource."[13]

[11] Market Protocols SPP Integrated Marketplace, R58, Southwest Power Pool, May 1, 2018, pg. 135-136.
[12] Market Protocols SPP Integrated Marketplace, R58, Southwest Power Pool, May 1, 2018, pgs. 137-139
[13] Market Protocols SPP Integrated Marketplace, R58, Southwest Power Pool, May 1, 2018, pg. 894.

Q: Are there differences in the SPP market products in which the DDR and BDR resources may participate?

A: Yes. If the DR resource meets the requirements just outlined, the SPP Market Protocol provides for DDR and BDR resource participation in both the SPP Day-Ahead and Real-Time Energy Markets. Although the SPP Market Protocols do not preclude DR resources from participating in the Operating Reserve Markets, there are more stringent requirements that can only generally be met by certain types of DDR resources.

Q: If SPP does not have a capacity market, how does the SPP address capacity?

A: As a vertically integrated utility participating in the SPPIM, the Company must own or otherwise provide sufficient generation capacity to meet its forecasted annual peak load plus required reserve capacity. The Company must also have load curtailment procedures to curtail load in response to SPP defined emergency conditions.

Q: If SPP does not provide for the market participation of LMRs, how does the Company utilize its existing retail DR programs and tariffs in conjunction with the SPPIM?

A: The existing Company retail DR programs do not incorporate the required telemetry, metering, and verification necessary for participation in the SPPIM as BDR or DDR resources. While these DR programs cannot be used within the SPPIM, they are reported to SPP and can be used by the Company as LMR to modify the Company's retail system load that would otherwise be supplied from the market. The Company uses the existing DR programs to lower system load; 1) as part of its emergency load curtailment plan, 2) to modify forecasted system peak load levels to avoid additional capacity requirements, and 3) during periods of significantly increased market energy prices.

SECTION 2: <u>Description of SPP OATT Language Regarding Distributed Energy Resources ("DER") and Practical Implementation of Aggregated DERs</u>

Q: What is the purpose of this portion of your testimony?

A: The purpose of this section of the testimony is to describe how the SPP OATT currently addresses DER and how the OATT would need to be modified to fully implement a program to allow DER resources to participate in the SPP wholesale market.

Q: How is DER currently accounted for in the SPP OATT?

A: There is no specific language in the SPP OATT that directly addresses the inclusion of DERs either individually or as an aggregation. The SPPIM would currently treat any DER the same as any other generating resource or as a DR resource. The SPP OATT provides for some types of DER (behind the meter generation and demand response) participation in the SPPIM as DR resources. The SPP OATT does not address electric storage DER, but behind-the-meter electric storage resources could potentially participate today as a DR resources in a similar manner to behind-the-meter generation.

Q: Has FERC addressed participation of other forms of DER in wholesale markets?

A: Yes. In Order 841 (issued February 15, 2018), FERC requires "each RTO and ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."

Q Has SPP progressed in addressing tariff changes related to electric storage resource participation in the SPPIM?

A: SPP is currently developing tariff and protocol revisions in response to Order 841 related to Electric Storage Resources Participation in Markets. A compliance filing is due to FERC in December 2018 with implementation in December 2019.

Q: Has FERC addressed the potential for aggregated DER participation in wholesale markets?

A: Yes. In Order 841, FERC determined that more information was needed with respect to proposed distributed energy resource aggregation and that the Commission would continue to explore the proposed distributed energy resource aggregation reforms under Docket No. RM18-9-000.[14] FERC recently conducted at Technical Conference to gather additional information on this issue.

Q: Has SPP provided comments to FERC regarding any issues that need to be addressed relative to DER aggregation participation in the SPPIM?

A: Yes. In response to the FERC's initial Notice of Proposed Rulemaking ("NOPR"), issued November 17, 2016, SPP submitted comments on establishing a model for DER aggregators to participate in the SPPIM. Those comments are included in **Schedule BLC-8**. In SPP's response to the FERC NOPR, it addresses concerns related to DER aggregation. Specifically, SPP says that the aggregated DERs should meet the minimum and maximum capacity requirements that are determined by each RTO and that the resources making up an aggregate should be connected to a transmission system pricing node. The connection to the transmission system is vital for SPP to control the system and appropriately value the impact on the market. SPP goes on to say that aggregated DERs should not be geographically dispersed (not electrically equivalent) unless they provide capacity of less than 10 MW.

[14] Order No. 841, Final Rule-Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket Nos. RM16-23-000; AD16-20-000, February 15, 2018, pg. ii.

Q: Does SPP have documented procedures on how to evaluate aggregated DR or DER to determine their impact on system reliability?

A: SPP has no formally documented procedures or guidelines for evaluating the system impact of aggregated DR or other DERs. SPP will likely need to evaluate each aggregation on a case-by-case basis and set specific thresholds on system impacts for approval or denial of market entry. Such changes would require revisions to the SPP Market Protocols and/or Business Practices which would require approval through the SPP stakeholder process. If changes in the SPP OATT are also required, then FERC approval would be needed.

Q: Has SPP progressed in addressing any tariff changes related to DER aggregation?

A: At this time, SPP is waiting on a definitive ruling by FERC to proceed with the development of OATT and Market Protocol language changes to include DER aggregation in the SPPIM.

Q: Does the Company have any concerns related to FERC's order regarding DER aggregation by independent third-party aggregators for wholesale market participation?

A: Yes. The distribution utility is responsible for maintaining and reliably operating the distribution system for all customers. This obligation to serve and maintain distribution system reliability separates the utility from other independent third-party energy providers or aggregators. The utility is the only entity that has the ability and responsibility to maintain distribution system reliability and must have visibility and control over the resources connected to the distribution system, as these resources will often be critical in maintaining system reliability.

The distribution utility is also the only entity with real-time operational information of the entire distribution system and DER integration, not just interconnection. This is key to realizing the full potential of DERs for the electric system. The ability of DER to improve system operations, grid reliability, and to alleviate grid constraints will depend critically on operator visibility into the grid, controllability of the DERs, and location of the resources. As such, the utility is in the best position to serve as the coordinator of all DER integrations and as the Market Participant, facilitate DER access to the wholesale markets.

Q: Does this conclude your testimony?

A: Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2018-0145

AFFIDAVIT OF BURTON L. CRAWFORD

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Burton L. Crawford, being first duly sworn on his oath, states:

1. My name is Burton L. Crawford. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Energy Resource Management.

2. Attached hereto and made a part hereof for all purposes is my Supplemental Direct Testimony on behalf of Kansas City Power & Light Company consisting of thirteen (13) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Burton L. Crawford

Subscribed and sworn before me this 19th day of June 2018.

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

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 Nos.**	**RM16-23-000** **AD16-20-000**

COMMENTS OF SOUTHWEST POWER POOL, INC.

In response to the Federal Energy Regulatory Commission's ("Commission") Notice of Proposed Rulemaking, issued on November 17, 2016 ("NOPR"),[1] and in addition to the comments submitted by the ISO/RTO Council in response to this same NOPR, Southwest Power Pool, Inc. ("SPP") respectfully submits these comments[2] specific to the SPP Integrated Marketplace.

I. INTRODUCTION AND BACKGROUND

At the highest level, the NOPR sets forth a balanced and consistent approach designed to remove barriers and establish a model for stored energy resources ("SER") and distributed energy resource ("DER") aggregators to participate in the wholesale electricity markets and define DER aggregators as a type of market participant that can participate in the organized wholesale electricity markets. SPP believes the goal of this rule is just and

[1] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016).

[2] SPP's silence in these comments on any proposed rule or request for comment should not be construed as SPP's agreement with any such proposed rule or issue.

valuable to the energy industry. Allowing Resources of different types, sizes, and capabilities to participate in wholesale electricity markets, either directly or by aggregation, creates a more diverse and resilient electric market.

SPP's current Open Access Transmission Tariff ("Tariff") and the SPP Integrated Marketplace Market Protocols ("Market Protocols") provide that any Resource type can provide Operating Reserves or Energy so long as the Resource can sustain energy level output for one hour or longer. However, SPP has been working through the stakeholder process to develop rules that will allow Resources, such as SER, to be able to participate in the Regulation market[3] if the Resource can sustain an output for at least 15-minutes at the registered capacity limits of the Resource. For other products, such as Energy and Contingency Reserves, SPP maintains the position that in order to provide such a product, the Resource must be able to sustain the registered capacity limits for at least one hour.

SPP performs the majority of the Market and Reliability Unit Commitment process for balancing the SPP area hourly; as such, when a Resource is committed, SPP expects that Resource to be available for at least one full hour and that full hour may be in a single direction (charging or discharging). In addition, SPP's Contingency Reserve events may last up to one hour, which means deployed Resources may have to sustain the output of requested megawatts ("MW") for up to one hour. Accordingly, SERs that can sustain the registered capacity limits of the Resource for one hour or longer may participate in all products including Contingency Reserves and Energy.

[3] At SPP, the regulation market is comprised of two distinct products, RegulationUp and Regulation-Down.

SPP is in support of leveraging the capabilities of SERs and their ability to regulate supply and demand in the market. The overwhelming majority of SPP's market structure and commitment design is set such that Resources are committed to meet load and net scheduled interchange on an hourly basis. Resources are committed and dispatched for a full hour in the Day-Ahead Reliability Unit Commitment studies and the Day-Ahead Market. This situation is one of the drivers behind the rules envisioned by SPP that would allow for Energy participation from any Resource type as long as they can sustain the energy level output that is offered for a minimum of one hour in order to meet the commitment obligation.

SPP's Contingency Reserve events may last up to one hour. As such, Resources participating in Contingency Reserve products must be able to sustain the offered quantities for at least the requisite one hour. Both Balancing Authority ("BA") needs and the reliability of the Resource providing the product offered for a requisite duration (in case it is needed for commitment duration or Contingency Reserve duration) are also drivers underlying SPP's language in the developmental stages.

II. COMMENTS

A. Elimination of Barriers to Electric Storage Resource Participation in Organized Wholesale Electric Markets

1. Creation of a Participation Model for SER

SPP is generally supportive of the five rules proposed to accommodate the physical and operational characteristics of SERs as outlined in paragraph 28 of the NOPR. However, SPP requests clarification of the term "technically capable of providing" a product. SPP's position is that a Resource should be able to participate in *any Market or Tariff based product* as long as meeting the requisite sustainability for the product is an element of being "technically capable of providing" that product, *e.g.*, the requisite sustainability for an Energy product is one hour or longer. Regulation may be dynamic and diverse in deployment directions. As such, a SER participating in Regulation may charge and discharge intra-hour, thereby allowing such a Resource to participate in the Regulation market.

In response to the Commission's invitation to comment as to whether qualification criteria should be established, and, if so, what specific qualification criteria should be required, SPP notes that we are in the midst of developing and incorporating language, rules, and design intended to integrate and best manage SER participation in the market and SPP BA.

SPP is in support of leveraging the capabilities of such Resources and their ability to regulate supply and demand in the market. The overwhelming majority of SPP's Integrated Marketplace structure and commitment design is set such that Resources are committed to meet load and net scheduled interchange on an hourly basis. Resources are committed and dispatched for a full hour in the Day-Ahead Reliability Unit Commitment studies and the Day-Ahead Market. As mentioned above, this situation is the driver underlying future rules envision by SPP to allow for Energy participation from any Resource type as long as they can sustain the energy level output that is offered for a minimum of one hour in order to meet the commitment obligation.

SPP's Contingency Reserve events may last up to one hour. As such, Resources participating in Contingency Reserve products must be able to sustain the offered quantities for at least the requisite one hour. BA needs and the reliability of the Resources providing the product offered for a requisite duration (in case it is needed for commitment duration or Contingency Reserve duration) drive SPP's proposed language.

The Commission proposes that, in addition to including a participation model for SERs in its Tariff, each regional transmission organization ("RTO") and independent system operator ("ISO") propose any necessary additions or modifications to its existing Tariff provisions to specify: (1) whether Resources that qualify to use the participation model for SERs will participate in the organized wholesale electric markets through existing or new market participation agreements; and (2) whether particular existing market rules apply to Resources participating under the SER participation model.

SPP plans to modify the Tariff and Market Protocols in order to integrate SERs into the market design. Any new rules will be structured in a manner that is consistent with SPP BA needs and requirements while providing as much flexibility and opportunity for participation as possible to the SER.

The Commission seeks comment on the changes that would be required to implement the proposed participation model for SERs as well as the associated costs and how those costs could be minimized.

SPP notes that implementing the proposed participation model will require extensive changes to software, the Tariff, and the Market Protocols. SPP is in the early stages of a process intended to develop the rules and the design for incorporating SERs into the Integrated Marketplace. The design envisioned by SPP would allow SERs to participate in the Regulation market provided they can sustain the registered capacity limits of the Resource for at least 15-minutes. These Resources can currently participate in all other products provided the Resource can sustain the registered capacity limits of the Resource for at least 1-hour. This anticipated design affects many of SPP's current software systems/designs; however, it does not impact the structure and core of SPP's market rules and criteria. Any changes further affecting how a Resource may clear for Energy and Operating Reserves or affecting the duration for which it may clear those products will make this a more complex and impactful change for SPP and its Market Participants. Specifically, the requirement to support SERs State of Charge ("SOC") and restrictions on resource capability to sustain a product would require changes to accept and utilize in the commitment and dispatch logic of both the Day-Ahead and Real-Time Balancing Markets.

2. Requirements for the Participation Model for Electric Storage Resources a. Eligibility to Participate in Organized Wholesale Electric Markets

The Commission proposes requiring RTOs/ISOs to modify their tariffs to establish a participation model consisting of market rules for SERs under which a participating Resource is eligible to provide any capacity, Energy, and ancillary service that it is technically capable of providing in the organized wholesale electric markets. In addition, SERs should be eligible, as part of the participation model, to provide services that the RTOs/ISOs do not procure through a market mechanism, such as blackstart, primary frequency response, and reactive power, if they are technically capable.

Prior to this NOPR, SPP planned to modify the Tariff, Market Protocols, and software systems/designs to incorporate an adequate and proper market design to integrate SERs into the SPP market. The intended design would provide the most flexibility for SERs while maintaining BA and reliability standards through the appropriate market rules and structure (i.e. qualification for products driven by duration of the output sustainability from any Resource).

SER and DER may, as any other Resource may, participate in non-market based products, e.g., blackstart and volt-ampere reactive ("VAR"), to the extent that they meet the qualifications.

The Commission also proposes requiring each RTO/ISO to revise its tariff to clarify that a SER may de-rate its capacity to meet minimum run-time requirements to provide capacity or other services. In RTOs/ISOs with capacity markets, it is also proposed that the de-rated capacity value for SER be consistent with the quantity of Energy that must be offered into the Day-Ahead market for Resources with capacity obligations.

SPP supports the ability to de-rate the maximum capacity in a SER in order to qualify for provision of other products, *e.g.* a sub-hourly Resource de-rating the maximum capacity in order to become an hourly Resource capable of providing the Energy product. However, SPP asks that the Commission include in the final rule that such action is not physical withholding. The Commission has previously ordered SPP that a Resource offering to another market at a higher price is not to be considered physical withholding by the SPP Market Monitoring Unit.

The Commission concludes that a market participant's eligibility to provide a particular reserve service should not be conditioned on requirements that were designed for synchronous generators, specifically the requirement to be online and synchronized to the grid to be eligible to provide ancillary services. Further, the Commission preliminarily finds that participation in ancillary service markets should be based on a Resource's ability to provide services when it is called upon rather than on the Real-Time operating status of the Resource.

SPP agrees that rules should not be driven by the conventional Resource capability to provide products. SPP proposes that the BA needs drive the eligibility of any Resource type rather than Resource specificity. However, a Spinning Reserve product, by definition, means the Resource must be synchronized and spinning. If there is a desire to change the rule relevant to Spinning Reserve products, that effort would necessitate involvement by the North American Electric Reliability Corporation. SPP's Integrated Marketplace allows for Supplemental Reserves participation if the Resource is not connected or synchronized. The ability to respond to a call-on from a SER is consistent with treatment of Quick-Start Resources ("QSR") when they clear offline Supplemental Reserves.

The Commission seeks comment on whether the requirement to have an Energy schedule to provide ancillary services could be adjusted so that SERs and other technically-capable Resources could participate in the ancillary service markets independent of offering Energy to the RTO/ISO. Specifically, comment is sought on whether dispatch and pricing of Energy and ancillary services would continue to be internally consistent if a Resource were not required to offer to provide Energy in order to offer to provide ancillary services. Further, comment is sought on whether the capability of Resources to provide an ancillary service absent an energy schedule can be determined in the regular performance tests that the RTO/ISO conducts and whether a Resource's start-up time and ramp capability are generally represented in bidding parameters and would adequately guarantee the Resource's ability to provide other services absent Energy market participation. Finally, comment is sought on the extent of software changes necessary to factor the elimination of such an energy schedule requirement into the RTO/ISO co-optimization models.

A Resource that is not qualified to provide Energy (i.e., a SER with less than one hour ability to sustain offered MW), would not be precluded from participating in the Regulation market. These Resources will not be eligible to set price in for Energy market nor can their MWs be substituted for Contingency Reserves (which has similar requirements to providing Energy). Such a Resource would be eligible to set price in the Regulation market and would also be eligible to be compensated for Regulation at the cost set by the marginal Resource of any type. Resources that qualify for all products (including SER with at least one hour ability to sustain offered MW) are eligible to set price in any product in which they participate (as is the case for all Resource types).

All Resources of any type are subject to performance testing and compliance for any product that they are qualified to provide. Those that only qualify for Regulation, but not Energy, are subject to similar testing.

The extent of software changes required to implement the approach *in development at SPP* is not great. However, the additional data suggested by the NOPR will require changes to the current commitment and dispatch logic which will necessitate more extensive software changes.

b. <u>Bidding Parameters for SER</u>

The Commission proposes to require each RTO/ISO to revise its tariff to include a participation model for SERs that incorporates bidding parameters that reflect and account for the physical and operational characteristics of SERs.

SPP agrees. Clearly, SERs have unique characteristics of operation relative to conventional generation. SPP is aware of these characteristics and the required parameters/data necessary to manage their dispatch/charge/discharge appropriately.

The Commission proposes that the RTOs/ISOs establish SOC, upper charge limit, lower charge limit, maximum energy charge rate, and maximum energy discharge rate as bidding parameters for the participation model for SERs that participating Resources must submit, as applicable. The Commission seeks comment on whether there are conditions under which an RTO/ISO should not allow a SER to manage its SOC and upper and lower charge limits.

SPP agrees that a Real-Time parameter that can be managed and used to determine the dispatchability and expectation in Real-Time as needed. Knowing the initial conditions of a Resource at the time of clearing is integral for all Resources. In order to manage the SOC of the Resource and in order to dispatch and clear the appropriate amount of products, the Real-Time SOC for the Resource is needed. For Resources managing their own SOC, these parameters would become informational from an SPP BA standpoint.

SPP's position is that SERs that are not able to sustain the offered MW for at least one hour shall only be eligible to participate in the Regulation market. SPP also takes the position that these Regulation Resources' SOC shall be managed *by the RTO/ISO*. This is due to the variability in the Regulation signal and the complexity inherent in finding opportunities to charge the Resource or discharge the Resource without harming the BA Area Control Error ("ACE"). SPP expects these Resources to be deployed to meet Regulation needs, however, there may be a need to charge or discharge outside of a Regulation event, thereby presenting an opportunity to manage SOC of the Resource.

SERs that are able to sustain their offered MW for at least one hour are eligible to provide all products. SPP proposes that these Resources' operators and Market Participants are best suited to manage their own SOC in order to offer and bid the Resource beyond the Real-Time horizon and to allow for pre-positioning as the Market Participant sees fit. SPP's software is not equipped to optimize the fuel of any Resource type. This is something that should be handled delicately as SPP would be potentially taking a position or preventing a Market Participant from having a position on a longer than Real-Time horizon. Managing the SOC for these Resources beyond Real-Time would add a high degree of complexity to the design and would require both significant software changes and significant time to accomplish. SPP proposes continuing to allow the SER to manage their own SOC rather than implementing an SPP process beyond that necessitated by the SER Resources that are only eligible to participate in the Regulation market.

The Commission proposes requiring that the participation models for SERs include the following bidding parameters that market participants may submit, at their discretion, for their Resource based on its physical constraints or desired operation: minimum charge time, maximum charge time, minimum run time, and maximum run time.

SPP agrees that the addition of new bidding parameters that are unique to SERs is necessary, and SPP will respect these parameters.

Where the RTO/ISO has reserved for itself the right to manage the SOC of a SER, the Commission proposes requiring that the RTOs/ISOs allow SERs to self-manage their SOC and upper and lower charge limits.

SPP recommends that the SOC management requirement be determined by each RTO individually. SPP would manage the SOC of those SERs that qualify for *Regulation only* (Resources that can sustain the offered MW (Capacity limits) for less than one hour). However, those SERs that qualify for other products including Regulation (Resources that can sustain the offered MW (Capacity limits for at least than one hour)) shall manage their own SOC.

The Commission seeks comment on the time and Resources that would be necessary for the RTOs/ISOs to incorporate these bidding parameters, including the optional bidding parameters, into their modeling and dispatch software.

Adding parameters to the system will most likely have adverse effects on performance of the market clearing engine as well as add complexity when including the conditions and logic required to respect such parameters. With this said, SPP is in favor of receiving more information about the Resources from the Market Participants. SPP strongly supports receiving Real-Time SOC of a SER in order to evaluate system conditions and manage SOC for the appropriate Resources.

c. <u>Eligibility to Participate as a Wholesale Seller and Wholesale Buyer</u>

The Commission previously recognized that a market functions effectively only when both supply and demand can meaningfully participate. Improving SERs' opportunity to participate as both wholesale sellers of services and wholesale buyers of Energy could improve market efficiency by allowing the RTO/ISO to dispatch these Resources in accordance with their most economically efficient use (i.e., as supply when the market clearing price for Energy is higher than their offer and as demand when the market clearing price is lower than their bid). Allowing SERs to participate in the organized wholesale electric markets as dispatchable load would allow these Resources, under certain circumstances, to set the price in these markets, better reflecting the value of the marginal Resource and ensuring that SERs are dispatched in accordance with the highest value service that they are capable of providing during a set market interval.

SPP agrees that any Resource types may set price for any product that Resource is qualified to provide to the market.

The Commission proposes requiring each RTO/ISO to revise its tariff to ensure that SERs can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing rules that govern when a Resource can set the wholesale price

SPP supports the proposal that a SER may run as either an injecting or Energy withdrawing Resource. For either state, an offer and a bid shall be submitted to the RTO/ISO to clear based on economics relative to the offer and bid of the Resource and appropriately set Locational Marginal Price ("LMP").

The Commission states that in order to optimize the capabilities of SERs and for the RTOs/ISOs to use them efficiently, it is important for the RTOs/ISOs to be able to symmetrically utilize the capabilities of these Resources to both receive Energy from the grid and inject it back to the grid. The bi-directional capabilities of SERs are what make them unique, and allowing SERs to participate in the organized wholesale electric markets as both wholesale sellers and wholesale buyers will help optimize the value that they provide and enhance price formation, as they will be dispatched in accordance with their most economic use.

SPP supports the idea that SERs should be dispatchable in order to realize their full potential as assets to the grid. SPP asks that the Commission clarify the impact on scarcity pricing of a SER that is in the charging state being able to "instantly" become a Resource and eliminate the scarcity. Is it the Commission's position that scarcity pricing not be effective to the extent that the sum of the SER capacity in a charging state could become a Resource?

The Commission seeks comment on whether there should be a mechanism that identifies bids and offers coming from the same Resource that ensures the price for the offer to sell is not lower than the price for the bid to buy during the same market interval so that an RTO/ISO does not accept both the offer and bid of a Resource using the SER participation model for that interval.

SPP agrees that the coordination of a single asset as both load and Resource is important. Both the mechanism utilized and the rules should ensure that the offers for use as load and Resources would be monotonically increasing. Additionally, non-LMP components, e.g., start-up costs, may need specific consideration to avoid a situation wherein such costs are not considered in dispatch.

The Commission seeks comment on whether any existing RTO/ISO rules may unnecessarily limit the ability of Resources using the participation model for SERs to set prices in the organized wholesale electric markets.

SPP's position is that any Resource type may set price for any product that the Resource is qualified to provide and offers to provide in the market. The Resource must be dispatchable and must have available range to provide the system's marginal MW. Otherwise, SPP does not have restrictions that would unnecessarily limit the ability of any Resource type, including SER, to set price.

B. Participation of DER Aggregators in the Organized Wholesale Electric Markets

1. Proposed Reforms a. Eligibility to Participate in the Organized Wholesale Electric Markets through a DER Aggregator

The Commission seeks comment on whether a minimum or maximum capacity limit for individual Resources seeking to participate in the organized wholesale electric markets through a DER aggregator should be established, or whether to allow each RTO/ISO to propose such a minimum or maximum capacity requirement on compliance with any Final Rule issued in this rulemaking proceeding.

SPP proposes that the RTO/ISO set the maximum based on their individual system needs. It is not necessary that each individual DER in a DER aggregation meet the requirement. However, the *aggregate* Resource must meet this requirement as a whole. SPP proposes that Resources making up an aggregate be connected to an electrically equivalent transmission system pricing node for injection and withdrawal. This is important for visibility and calculation of impacts on the system, which is critical to reliability and achieving proper control on the system. This aggregation will also be key in the appropriate pricing of the Resource's node under various system conditions.

With respect to the size of the DER aggregations, the Commission proposes that these aggregations meet any minimum size requirements of the participation model under which they elect to participate in the organized wholesale electric markets. The Commission seeks comment on this proposal to require DER aggregations to meet the minimum size requirements of the participation model that they use to participate in the organized wholesale electric markets.

SPP agrees with the minimum size requirement for the aggregate Resource. This is consistent with current SPP registration requirements for any Resource type. SPP would also ask the Commission to consider a proposal for a maximum capability registration requirement for those aggregates that would not be connected to an electrically equivalent pricing node on the transmission system. For those aggregates that are comprised of Resources connected to an electrically equivalent pricing node on the transmission system, no such restriction on the maximum capability is needed.

The proposed threshold is a quantity that would materialize as inaccuracy in the models but should be of minimal impact on the system for either reliability or economics.

It is critical for an RTO/ISO to account for MW impacts on the transmission system in order to reliably manage constraints and reflect system conditions in pricing to incentivize a market behavior consistent with system needs.

b. Locational Requirements for DER Aggregations

To the extent that commenters would prefer that the Commission require the RTOs/ISOs to adopt consistent locational requirements, further comment is sought on what locational requirements the Commission could require each RTO/ISO to adopt that would allow DERs to be aggregated as widely as possible without threatening the reliability of the transmission grid or the efficiency of the organized wholesale electric markets

SPP proposes a restriction such that Resources in an aggregate shall be connected to an electrically equivalent transmission pricing node if the aggregate Resource's registered maximum capability is greater than the RTO/ISO max capability to be defined individually by each RTO/ISO. SPP identifies zones for the purpose of deploying reserves; however, for Energy, it is imperative that SPP be able to control congestion and optimize around the congestion as granularly as feasible. A single registered aggregate that is made up of Resources located on different sides of the constraint will both challenge reliability on the system and may disturb pricing and economics (manual action may be taken by the Reliability Coordinator ("RC") to resolve the issue if the SPP Integrated Marketplace is incapable of resolving due to lack of granularity).

Identifying geographical zones months in advance may not reflect Real-Time or even near Real-Time conditions. Thus, congested "zones" are best identified dynamically and as needed by the RTOs/ISOs and RCs at any time. SPP identifies congestion by creating flowgates and constraints that are activated. Each constraint is deemed to have Resources that may help or hurt when re-dispatching. An aggregate Resource spanning both sides, thru the "child" Resources of the constraint, may present a challenge or uncertain response to congestion when dispatching in either direction. This presents a reliability and operational challenge through lack of visibility and granularity. Moreover, this directly impacts the pricing at the node as it is directly correlated with the Resource impact on congestion and losses. This may cause inconsistent pricing in attempting to reflect the impact of the aggregate Resource on the system.

SPP, therefore, proposes that the Commission consider allowing aggregate Resources to be geographically disperse (not electrically equivalent from transmission perspective) only if the product is non-locational, e.g., VAR, or the aggregate registered maximum capability is at or less than 10 MW. This quantity would materialize as inaccuracy in the models but should be of minimal impact on the system for either reliability or economics.

The Commission seeks comment on potential concerns about dispatch, pricing, or settlement that the RTOs/ISOs must address if the DERs in a particular DER aggregation are not limited to the same pricing node or behind the same point of interconnection.

SPP proposes a restriction such that Resources in an aggregate shall be connected to an electrically equivalent transmission pricing node if the aggregate Resource registered maximum capability is above the RTO/ISO maximum capability to be defined individually by each RTO/ISO. SPP identifies zones for the purpose of deploying reserves, however, for Energy, it is imperative that SPP be able to control congestion and optimize around the constraint as granularly as feasible. A single registered aggregate that is made up of Resources located on different sides of the constraint will both challenge reliability on the system and may disturb pricing and economics (manual action may be taken by the RC to resolve the issue if the market is incapable of resolving due to lack of granularity).

c. Distribution Factors and Bidding Parameters for DER Aggregations

The Commission proposes that the market rules governing DER aggregations allow the RTOs/ISOs to require sufficient information from the Resources in a DER aggregation to reliably operate their systems. Specifically, the proposal requires 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. The Commission further proposes to require each RTO/ISO to revise the bidding parameters for each participation model in its tariff to allow DER aggregators to update their distribution factors when participating in the organized wholesale electric markets. The Commission seeks comments on this proposal and also on alternative approaches that may provide the RTOs/ISOs with the information from geographically or electrically disperse Resources in a DER aggregation necessary to reliably operate their systems.

In addition to the concern expressed relative to the aggregate spanning congested locations, while the distribution factors information attempt to help the RC with more information on the distribution of the Resource, implementing these factors in the software is not trivial. In addition, distribution factors merely provide the RC with the distribution of the Resource but that does not prove that the Resources in the aggregate will move pro-rata across. The uncertainty in the aggregate response may cause a reliability issue by introducing uncertainty of effective dispatch to resolve constraints. Added to this and directly related are economics and pricing of the aggregate, which are done 10 minutes ahead in Real-Time and longer in Day-Ahead, may not reflect the actual response on the sub-aggregate level.

SPP proposes that distribution factors be sent to the host RTO/ISO as they could be useful in estimating the impact of the sub-aggregate injection and withdrawals. This is in addition to the maximum registration capability defined individually by each RTO/ISO for those aggregates that are comprised of Resources which don't have an electrical equivalent connection into the transmission system.

The Commission seeks comment on whether bidding parameters in addition to those already incorporated into existing participation models may be necessary to characterize adequately the physical or operational characteristics of DER aggregations.

SPP encourages the Commission to leave the bidding parameters requirement at the discretion of each RTO/ISO as they see fit given their unique needs relative to their individual software and applications.

The Commission proposes requiring each RTO/ISO to revise its tariff to identify any necessary metering and telemetry hardware and software requirements for DER aggregators and the individual Resources in a DER aggregation. The Commission seeks comment on whether the RTOs/ISOs need to establish metering and telemetry hardware and software requirements for each of the different types of DERs that participate in the organized wholesale electric markets through DER aggregations, as well as whether specific metering and telemetry system requirements should be established, and, if so, what requirements would be appropriate.

SPP notes that there is a reference to "each of the different types" of DER. This implies that a DER aggregate may have a subcategory in the market systems. The complexity inherent in managing a Resource as a discrete set of different assets may be infeasible in commitment and dispatch. As far as requirements for metering and telemetered parameters, SPP proposes that there would be no global rule or set requirements on what is needed. This should be left to each RTO/ISO to determine the needed parameters for each of their software and applications in order to meet the intent of the integration these Resource types and in consultation with the distribution utility.

If the Resource desires to be registered as more than one type, SPP's rules on minimum registration requirements and connectivity into the transmission system remain consistent with what has been outlined above. However, the concept of adding distribution factors to those DERs with geographical dispersion would not apply to any other Resource types. This would add a large degree of complexity as it currently is not only part of the design but it would require significant changes to the market registration process and other processes.

The Commission proposes that each RTO/ISO should rely on meter data obtained through compliance with these distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes, only applying additional metering system requirements for DER aggregations when this data is insufficient.

SPP contemplates a DER being implemented as a unique Resource type and would not be able to operate as two different Resource types. SPP encourages the Commission to leave the metering and parameter requirements to the discretion of each RTO/ISO as they see fit given their unique need relative to their individual software and applications in order to meet the intent of the integration of these Resource types. SPP also requests clarity as to whether the Commission intended additional special treatment for a storage device being provided as a DER above and beyond that afforded other DERs. Sub-categorizing DERs would be extremely complex.

d. <u>Coordination between the RTO/ISO, the DER Aggregator, and the Distribution Utility</u>

The Commission proposes to require each RTO/ISO to revise its tariff to provide for coordination among the RTO/ISO, a DER aggregator, and the relevant distribution utilities with respect to (1) the registration of new DER aggregations and (2) ongoing coordination, including operational coordination, between the RTO/ISO, a DER aggregator, and the relevant distribution utility or utilities.

SPP is, of course, in favor of coordination with distribution utilities and local regulatory bodies.

The Commission proposes that each RTO/ISO 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 to include new Resources. In addition, the Commission proposes that this coordination 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 the organized wholesale electric markets through the aggregation. The Commission further proposes that this coordination provide the relevant distribution utility or utilities the opportunity to report such information to the RTO/ISO for its consideration prior to the RTO/ISO allowing the new or modified DER aggregation to participate in the organized wholesale electric market. Comment is sought on whether the RTO/ISO tariffs should provide for any additional review by or coordination with other parties prior to a new or existing DER aggregation participating in the organized wholesale electric markets.

Next, the Commission proposes 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 account for the possibility that distribution facilities may be out of service and impair the operation of certain individual Resources in a DER aggregation, the Commission also proposes requiring 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. Comment is sought 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. Comment is also sought on any related reliability, safety, and operational concerns and how they may be effectively addressed. Finally, the Commission seeks comment on the appropriate lines of communication to require.

SPP is in agreement with the proposals above and fully intends to cooperate and comply. The process and agreements to accomplish this will require a significant effort to coordinate with entities with which the RTO/ISO has not previously had two-way communications.

III. CONCLUSION

SPP respectfully requests that the Commission accept and consider the comments and information provided herein.

Respectfully submitted,

/s/ Christopher M. Nolen
Christopher M. Nolen
Attorney
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
501.482.2394
cnolen@spp.org